Second Edition

Smart Grids

Advanced Technologies and Solutions

Edited by **Stuart Borlase**

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Smart Grids

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CRC Press
Taylor & Francis Group
Boca Raton London New York

CRC Press is an imprint of the
Taylor & Francis Group, an **informa** business

CRC Press
Taylor & Francis Group
6000 Broken Sound Parkway NW, Suite 300
Boca Raton, FL 33487-2742

Printed on acid-free paper

International Standard Book Number-13: 978-1-4987-9955-3 (Hardback)

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Foreword

When I co-founded the GridWise Alliance in 2003, the intent was to empower a diverse, industry-oriented, member-driven, non-governmental organization (NGO) to play the role of educator and convener in transitioning the power industry toward our shared vision of a smarter grid. Now that I've recently taken the helm again more than a decade later, I find the mission very much intact, the goals clearer, and the urgency greater than ever.

Today, a general consensus holds: A modern (and smarter) grid offers a path to a healthy economy and a sustainable energy future that involves utilities, regulators, vendors, and consumers, and is founded on a positive business case and a logical implementation framework. How this path takes shape for any individual utility will, of course, depend on myriad factors, though the traditional mandates for reliable, affordable, and safe power remain intact.

This second edition of *Smart Grids: Advanced Technologies and Solutions* that you hold in your hands is a milestone and supports the notion that the question today is not whether a modern grid is beneficial and much-needed but how to best accomplish it. Since the turn of the century, the power industry has gained considerable insight into a variety of new technologies and best practices, creating a body of knowledge and experience that provides an excellent basis to move forward. The challenge now is to engage stakeholders in a way that can bring together the diversity of interests toward a common outcome.

Achieving consensus among stakeholders with diverse interests, motivations, and means is akin to the old saying about democracy: It's a messy business. The history of grid modernization in general and the GridWise Alliance in particular reflects that we've traveled a sometimes arduous road to our current, forward-looking position.

In the summer of 2001, as director of energy programs at the Pacific Northwest National Laboratories, I was asked by the Senate Energy and Natural Resources Committee to testify on the potential impact that new information and communication technologies (ICT) could have on the energy sector. In that testimony I described conceptually how ICT could be deployed to optimize electricity delivery and consumption. Soon after, the lab and a few partner companies began working with the U.S. Department of Energy to create a new federal research and development (R&D) program focusing on ICT and the grid. We chose the name "GridWise."

From the beginning, we understood that changes in the electric power sector would need to be undertaken and accomplished as a public and private partnership that included federal and state lawmakers and regulators, as well as traditional power industry stakeholders. In 2003, as political winds blew cold and the Senate's interest waned, we launched the GridWise Alliance with six founding member companies. Our mission was to advocate for prudent changes to policies that would encourage innovation and new technologies to be deployed across the electricity sector. While we were still finalizing the incorporation papers for the Alliance, a major blackout spread across the Northeastern U.S. and parts of Canada, leaving 55 million people without power, some for days and weeks. At the time, it was the world's second most widespread blackout in history. The cause was traced to a software glitch in an alarm system in a control room in Ohio. Suffice to say it was preventable, and yet it served to draw federal attention back to the issue of grid modernization and helped to solidify the importance and relevance of the Alliance's mission.

In early 2007, the Alliance was asked to provide input to a new energy bill, and by the end of that year, President Bush signed into law the Energy Independence and Security Act of 2007 (EISA 2007). Title XIII of the legislation contained a number of key provisions that would fundamentally support the Alliance's mission and, indeed, support the broader power industry need to modernize. Title XIII's opening paragraph stated: "It is the policy of the United States to support the modernization of the Nation's electricity transmission and distribution system to maintain a reliable and secure electricity infrastructure that can meet future demand growth…." Henceforth, grid modernization would be a U.S. national policy and the Secretary of Energy was tasked with coordinating federal agencies and power industry stakeholders to perform related research and development, create standards that supported interoperability, and encourage state regulators to demand proof that utility investments would be cost effective and secure, secure, improve reliability, and benefit society. We were on our way.

The severe recession of 2008 proved to be another setback that, nonetheless, led to forward momentum. The federal American Recovery and Reinvestment Act of 2009 (ARRA 2009) authorized $4.5 billion in federal monies for cost-sharing grid modernization work to be spent on demonstration and pilot projects. Data collection and reporting were, of course, mandatory for participants so that these investments would yield lessons learned and report on best practices.

These projects were just getting underway when the first edition of this book was written in 2010–2011, and most results were not reported when the first edition was published in 2012. Yet the thinking around grid modernization had matured considerably. In my case, by then a vice president for grid integration at the National Renewable Energy Laboratory (NREL) in Golden, Colorado, I wrote an article, "Grid 3.0, a Full-featured Smart Grid, Will Keep Us Competitive in the 21st Century," for *Electricity Policy* (December 2010). I defined what I referred to as "Grid 3.0" because I thought that would lend specificity where "grid modernization" and the sometimes baffling term "smart grid" fell short. It's a definition, I think, that remains relevant:

> Grid 3.0 represents a future architecture of the electricity infrastructure that includes everything from the point of generation to the point of consumption. It will include a complex network of technologies and systems, hardware and software, communication and controls that will provide both producers and consumers a high level of visibility and control…. Its timeline will be driven by a variety of factors, including federal, state and local policies, economics and technology innovation.

As you can see, my "definition" is really a general set of market activities and technology attributes and innovations, rather than a prescription. The depth of the book in your hands is proof positive that the toolkit has expanded and that the mantra "one size doesn't fit all" remains true. We now see that the fundamentals of a smarter, more functional grid rests on a foundation of utility-wide ICT networks that can support diverse functionalities and applications, which will continue to contribute to the traditional needs for reliability and resiliency, while also supporting distributed energy resources and interactions with, and participation by, utility customers.

At the time of this writing in 2017, technology has raced ahead of developments in policies and evolving utility business models that will enable these new technologies to play an important and cost-effective role. The challenge is often about getting the rules, regulations, and procedures in place to optimize the benefits both to consumers and their utility. Only with that clarity can needed investments take place at scale. The GridWise Alliance's five "pillars for action" remain a useful guide for orchestrating stakeholders to shape the future:

- Establish clear and comprehensive guiding principles to shape grid modernization.
- Facilitate industry input into unifying architectures to ensure interoperability across the entire grid and its markets.
- Create frameworks to guide local, state, and regional policymakers and utilities in their transition to the future grid.
- Craft solutions through stakeholder engagement and education.
- Identify technology challenges and limitations through robust research and analysis.

Readers of this book are, no doubt, already involved in such actions and are probably intimately involved in helping their own utilities or communities they serve in one capacity or another to make forward progress. Tangible achievements light the path for the industry, and the Alliance's "Grid

Modernization Index" is an annual measure of successes in each state in the USA across a broad spectrum of utilities and stakeholders.

As you read, however, keep in mind the market context: The arc and speed of technology development and the power of market forces mean that, as policy and standards play catch-up, disruptive forces are rampant. Utilities, in particular, must seize the challenges and opportunities that will help define our energy future.

In my view—and that of many others—utilities must transition from a commodity-based business to a service-based business. That implies differentiated service offerings, an advanced understanding of consumers and savvy in many areas in which utilities traditionally have not needed expertise.

Today's fabric of central generation-driven grids will survive in some form: It serves the public well, and we will rely on it for the foreseeable future as end-users at the grid's edge become both producers and consumers of electric energy.

As we move forward, the power industry's diverse stakeholders, and even its disruptive forces, must work together to meet our mutual needs for a sustainable energy future that is beneficial for utilities, consumers, the economy, and the environment. I'd humbly suggest that readers keep these values in mind as they make their way through this book.

Steve Hauser
CEO, GridWise Alliance
Washington, DC

Preface

SMART MINDS, SMART GRIDS—DISRUPTION AND TRANSFORMATION THROUGH INNOVATION

The utility industry has made great progress in grid transformation and modernization since the first edition of this book was published in 2012. In my view, one of the most significant changes has been at the "grid-edge"—the area of the distribution network close to the customer and at the customer interface. Distributed energy resources (DERs) and the IoT (Internet of Things) will be key technology deployments at the grid-edge. While the deployment of smart meters and advanced metering infrastructures in the USA seemed to reach a plateau when the first edition of this book was published, the meter communication networks are now proving to be valuable foundations and operating experiences for real-time communications to the grid-edge. Pervasive and cost-effective sensors and controllers will also be essential for the smart grid IoT, and to enable transactive energy exchange between customers in an open retail market. The emphasis will be on device interoperability and data connectivity.

We have seen recent changes in the USA net-metering programs for retail customers signaling the need for an increased focus on DER energy exchange on the grid. Both wholesale and retail markets will need to support DERs and the dynamic balancing of supply and demand resources across the grid by moving toward real-time, market-based locational pricing of transactive energy exchanges, and while maintaining equitable cost allocation among all customers. An increase in customer- and third-party-owned DERs will preclude utilities from earning rates of return on infrastructure investment in the current policy and regulation environment. In addition, the demand and supply paradigm may shift to include the need for a more distributed architecture requiring a different grid configuration and energy exchange management solution. Therefore, there will need to be a fundamental change in the way electricity is economically and safely generated, transported, and distributed. Microgrids and DERs may be this solution, but while the current focus is on developing cost-effective technologies and adjusting policy and regulation to facilitate integration of DERs in the grid, there are far more challenges to consider; not only the real-time and secure management and operation of the DERs, but also how to ensure the DER supplies are reliable and available for delivering power to the grid when required. Distribution system operators (DSOs) will play a key role in bridging this open energy market framework, and performance-based and decoupled rate structures will continue to be a priority. Policies and regulation will need to be more forward-looking, and will likely shift to the responsibility at the state level. Regulators in the USA are already making moves in this area, as seen by competitive DER market options and a rate of return allowed on Software-as-a-Service (SaaS) in New York's Reforming the Energy Vision (REV) initiative; and the proposal to encourage utilities to invest in DERs and open DERs to the wholesale market in California. With the focus on the grid-edge, DERs, and microgrids, the smart grid now provides a fundamental technology framework for smart cities, smart towns, smart communities, and integrated approaches to energy systems and public infrastructure.

Significant advances in the convergence of enterprise and operational technologies are proving to be very beneficial. The utility industry will continue along the path of digital transformation while looking to other industries for proven successes in the areas of cloud computing, data analytics, visualization, and social and mobility applications. Digitization efforts and, in particular, the emphasis on the grid-edge, will result in a tremendous amount of data exchanged in real-time that will need to be managed and transformed into meaningful information in order to improve utility operations and better serve customers. There will be some point in the grid modernization process where the application of advanced technologies, energy efficiency, demand response, and distributed energy resources reaches the point of diminishing returns. While higher efficiencies and lower costs of advanced technologies will keep moving that point forward, some level of significant capital investment will also be required to upgrade the aging grid infrastructure (wires, transformers, substations, etc.). Utilities are realizing the need for both technology and infrastructure upgrades, but while technologies continue to advance, and policies, regulations, and standards evolve to guide the path to grid modernization, the journey will have challenges, not the least being costly and decidedly slow. Grid security and resilience, shrinking demand growth, and the aging grid infrastructure and workforce will still be a priority in the USA. However, I think we will continue to see waves of smart grid advances, and, as the industry continues to move past initial pilots and proof of concept projects, the learning experience will hasten the progress, and the time scale of change will accelerate. The number of stakeholders in this grid transformation journey will continue to increase. Digitization, IoT, DERs, and open markets add a new layer to the technology and vendor ecosystem. This will help to speed up the smart grid adoption process.

Essential with the shift in focus on the grid-edge is the need to view the customer not as a ratepayer, but as one of the key stakeholders in the smart grid, as both producers and consumers of energy—prosumers. Utilities need to move away from being the commodity, cost-based supplier, and generate greater customer value through more energy choices and services, while allowing customers to participate in the open market in real time. Disruption will not only be in terms of technology advances, but also about transforming the way utilities do business with new processes and revenue models. Innovation will ultimately be the driver of the disruption and transformation. Will utilities expand their dominance in the energy supply and delivery market, or will they focus on customer choice while facilitating energy exchanges? Or will utilities resign themselves to merely owning and maintaining the physical grid infrastructure?

Above all the smart grid successes, let us not forget the millions of people worldwide who do not have access to electricity, or have unreliable electricity supplies, and determine how the technology advances and innovative way of thinking with smart grid can help to overcome such obstacles. More importantly, we should not lose sight of the future of the energy industry, and what it will take to continue the transformation and modernization journey. I think, first and foremost, we need to instill the desire and passion in our younger generation to pursue fulfilling careers in engineering, technology, and science, and ensure they have the knowledge and skills to build a smarter, sustainable energy future.

Acknowledgments

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Editor

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Borlase has published and presented numerous papers on smart grids and grid modernization. He is a coauthor of the "Role of Substations in Smart Grids" chapter for the book *Electric Power Substations Engineering*, third edition, published by Taylor & Francis Group/CRC Press in 2012. He is the editor in chief and coauthor of the first edition of this book, which was published by Taylor & Francis Group/CRC Press in 2012.

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1 Overview of the Electric Utility Industry

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When electricity was first made available in the late nineteenth century, it was through central stations serving a group of nearby customers. Generation and distribution were localized, and long-distance transmission was not yet necessary. As demand for electricity service increased, distribution networks expanded in capacity and geography. Systems once isolated from one another were becoming interconnected. Out of this emerged the basic operating structure of the grid still in place today:

1. Large geographically dispersed power plants generate electricity[1] at low voltage levels.
2. The voltage is then stepped up via transformers in transmission substations.

[1] Most large power plants function in a similar fashion: using an energy source to drive a rotating turbine attached to a generator. These turbines can be driven by water, wind steam, or hot gases. Steam requires nuclear fission or the burning of a fossil fuel like coal, whereas hot gases require the burning of natural gas or oil. A combined cycle plant uses both hot gases and steam—they typically burn natural gas in a gas turbine and use the excess heat to create steam to power a steam turbine.

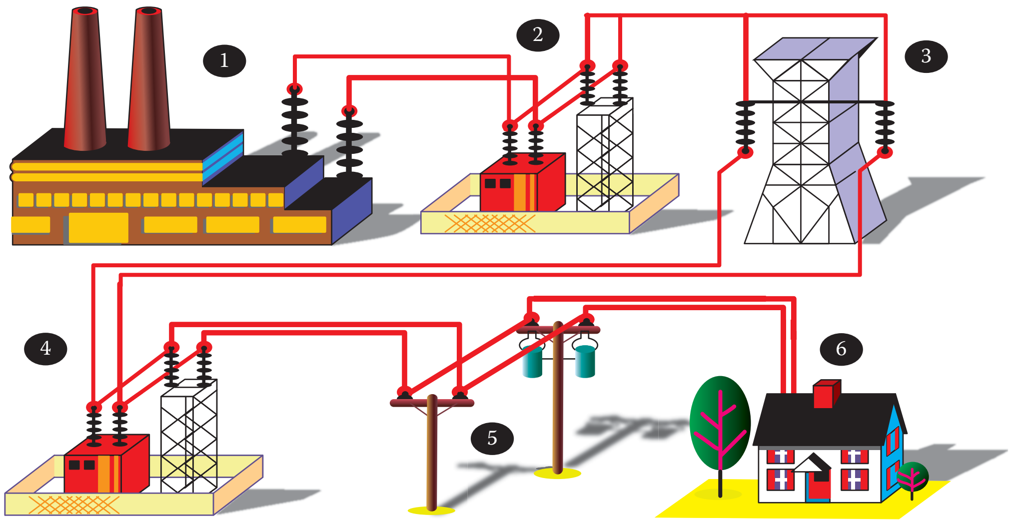

FIGURE 1.1 Electric utility interconnection overview. (Courtesy of the Advisory Board of the Utility Executive Course, University of Idaho, Moscow, ID.)

3. The electricity at high voltage levels is transmitted over long distances on interconnected transmission lines to distribution substations, where transformers step down the voltage[2] to low levels.
4. The electricity at low voltage levels is then distributed over relatively short distances via a network of lines using smaller transformers, which step the voltage down further to levels safe and appropriate for customers—homes and businesses.

These elements are illustrated in Figure 1.1, including (1) a power plant, (2) a transmission substation, (3) a transmission line, (4) a distribution substation, (5) a distribution line/transformer, and (6) an end user.

While the basic operating structure of the grid has largely remained the same over the decades, the practices used to plan and operate the grid and the regulatory structures that govern the industry have evolved substantially since that time. The history of the industry, in particular, the United States, is essentially a timeline of regulatory responses to a relatively small number of key events.

While electric power is now available to approximately 4.8 billion people around the world, more than 1.8 billion people are left "in the dark" with no, or very limited, access to electricity. Developing nations continue to lag in the provision of electricity to their citizenry. Globally, more than 1.6 billion electricity meters are installed at end-use locations (houses, apartments, commercial establishments, and industrial sites and factories), measuring energy usage information that provides the global electric utility industry with revenues of more than one trillion dollars annually.

This chapter aims to provide context for the more focused, technical chapters that follow. A full understanding of the new challenges and opportunities the industry will face over the coming decades requires an understanding of the factors that have shaped the utility industry's history. The regulatory structures that exist today will also fundamentally shape the development of the smart grid. The complexity of the energy infrastructure, coupled with its social, economic, regulatory, and political operating environments, directly impacts the understanding, acceptance, and ultimate promotion of innovative technologies, solutions, and new service models described through smart grid and many other definitions.

[2] Transmission lines carry *alternating current* (AC) electricity at voltages ranging from 110,000 V (110 kV) to 1,200,000 V (1.2 MV), which are eventually stepped down to 110/220 V for residential use. When electricity is transmitted at higher voltage levels, less of it is lost along the way; *line loss* is currently about 7% in the United States. *Direct current* (DC) power may be more suitable for transmitting power over long distances if the reduced energy loss offsets the required investment in stations at each end of the line to convert it back to AC.

1.1 THE UNITED STATES: A HISTORICAL PERSPECTIVE

The electric utility industry in the United States today is highly fragmented, operating under a variety of different industry and regulatory structures. Much of the heterogeneity is a result of the history of the industry and the strong influence of ever-evolving regulatory structures. There are more than 3100 investor-owned utilities, municipals, cooperatives, and federal and state agencies that deliver electric power in the United States today. These entities collectively deliver electric power across 50 states, 3 interconnections, and 8 distinct "reliability regions," and own more than 160,000 miles of high-voltage transmission lines, 60,000 transmission and distribution substations, and millions of miles of distribution networks. This vast and intricate network keeps the lights on and systems running for more than 142 million residential, commercial, industrial, and governmental customers [1].

1.1.1 Electrification and Regulation

When electricity was first made available in the late nineteenth century, it was provided by relatively small central stations serving a group of nearby customers. Generation and distribution were initially highly localized. However, demand for electric service grew quickly leading to the development of larger and larger distribution networks. Rapid technology improvements also enabled improvements in both electric power generation and transport. Systems once isolated from one another eventually became *interconnected*. Eventually, the interconnection of localized systems led to substantial industry consolidation by the end of the 1920s.

The interconnection of once isolated systems brought both benefits and risks. The biggest benefit was that generation could be shared among distribution networks. Since power plants have significant economies of scale, this allowed electricity to become cheaper to produce. Reliability was also improved as the failure of a local generator could be offset by another generator farther away—without customers even knowing that there had been a problem. Such was, and is the case, the vast majority of the time. However, the fact that localized distribution networks were now interdependent exposed utilities to the risk of disruptive events miles away.

This consolidation resulted in a handful of public holding companies controlling more than 80% of the U.S. electric power market. While utilities had been state regulated since as early as 1907, the state public utility commissions (PUCs)[3] had limited or no control over the actions of interstate holding companies. These holding companies were often highly leveraged[4] and financial failures were not uncommon. In addition, some holding companies were being operated essentially as "pyramid schemes," in which resources were transferred from utilities at the bottom to the parent company at the top—to the benefit of a small number of large investors at the expense of ratepayers and smaller investors. For a service as vital as electricity to the economy, this was an unsustainable situation. It was eventually addressed in the 1930s during a wave of legislative reform that followed the stock market crash of 1929.

The *Public Utility Holding Company Act of 1935* (PUHCA), in particular, had an enormous impact on the structure of the industry. In sum, this legislation

1. Broke up the large holding companies that dominated the industry.
2. Gave the Federal Power Commission [predecessor of today's Federal Energy Regulatory Commission (FERC)[5]] power over activities that crossed state jurisdictional boundaries, such as electric transmission and wholesale power pricing.

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[3] PUC is a general term for a state regulatory agency. State regulatory agencies can go by a variety of names.

[4] Excessively reliant on debt to fund their activities.

[5] The FERC is an independent regulatory agency within the Department of Energy. According to its most recent strategic plan, its top priorities remain interstate/national matters: (1) promote the development of a strong energy infrastructure, (2) support competitive markets, and (3) prevent market manipulation. At present, FERC is composed of up to five commissioners appointed by the President for 5-year terms, with one appointed by the President to be the Chair. No more than three commissioners can belong to the same political party, and there is no Presidential or Congressional review of the FERC's decisions.

3. Gave the Securities and Exchange Commission the power to regulate holding companies in a way that state PUCs never could.

In direct response to the *cross-subsidization*[6] that took place in the pyramid schemes of the 1920s, PUHCA required new cost accounting complexities that remain today in nearly all utility holding companies. PUHCA regulation is also the reason why the parent companies of most investor-owned utilities[7] are typically based in the United States with holdings concentrated within the industry (i.e., not industrial conglomerates), and why most mergers and acquisitions take place between geographically contiguous entities. Simply put, policymakers preferred the electric industry to be run by local electric companies, not by outside speculators, and this legislation helped accomplish that goal.

It was a noble plan, though not without its flaws. For one, as the world around it changed, the ability of utilities to adapt was greatly limited by the PUHCA. For example, utilities were constrained in their ability to reduce operating risk by diversifying their activities. PUHCA was also a "deal-breaker" for many acquisition opportunities; non-energy businesses would essentially have to overhaul their business model (i.e., divest non-energy businesses) and subject themselves to higher levels of regulatory scrutiny in order to "buy in" to the industry.

1.1.2 Northeast Blackout of 1965

From 1935 to 1965, the utility industry was stable and relatively uneventful. Transmission interconnection had become so pervasive that isolated power systems in the continental United States were essentially nonexistent. Oversight of these interdependencies was in place via the North American Power Systems Interconnection Committee (NAPSIC)—which had been formed by the industry in the early 1960s to help ensure effective governance of the nation's transmission system—and by *regional reliability councils*.[8]

However, on November 9, 1965, a confluence of events—a minor power surge, an improperly configured system protection component, and extremely cold weather pushing the electric system near peak capacity—triggered a cascading blackout that affected 25 million people in parts of New York, New Jersey, New England, and Ontario. A review of what happened and why it happened revealed that effective governance of the nation's transmission system had not been ensured—specifically, that interconnection pervasiveness was not accompanied by the appropriate level of interconnection planning and operations. In other words, though a utility's service reliability was heavily dependent on the reliability of its neighbor utilities, this did not prevent independent operating standards and procedures, system protection schemes, and restoration practices from evolving. In response to constituent outcry about the blackout, more formalized oversight was legislated through the *Electric Reliability Act of 1967*.

As part of this act, external scrutiny of the industry increased. The North American Electric Reliability Council (NERC) was formed on June 1, 1968, as a successor to the NAPSIC. Its charter was to promote electric reliability, adequacy, and security by driving utilities to common policies and procedures. Also, out of the *Electric Reliability Act of 1967* came the impetus for large-scale energy management systems (EMSs) and Supervisory, Control and Data Acquisition (SCADA) systems that utilities use to efficiently and reliably remotely monitor and control their transmission networks.

[6] Funding one entity with the assets and resources of another.

[7] Investor-owned utilities serve the largest number of customers in the United States. In addition to investor-owned utilities, there is another classification of utilities called publicly owned utilities. Publicly owned utilities are often referred to as "municipals" (municipality-owned) or "cooperatives" (customer-owned), the latter typically serving rural areas.

[8] Regional reliability councils remain in place today, covering the continental United States and much of Canada. Examples of reliability councils include the Northeast Power Coordinating Council, the Electric Reliability Council of Texas, and the Western Electricity Coordinating Council.

1.1.3 Energy Crisis of 1973–1974

The Arab oil embargo of 1973 and 1974 drove the U.S. economy into recession and prompted unprecedented interest in conservation and renewable energy. For the first time since average retail price data have been tracked, the *real*[9] cost to the consumer for electricity increased. In *nominal*[10] terms, electric bills essentially doubled from 1973 to the end of the decade. In response, many electric utilities shifted their marketing focus from consumption to conservation—promoting investment in home insulation, higher efficiency heating and air conditioning equipment, and other energy efficiency measures through financial assistance programs to residential and business customers. The federal government also attempted to promote more efficient generation technologies and encourage new players to enter the generation market through the Public Utility Regulatory Policies Act (PURPA).

Put forth as part of the National Energy Act of 1978, PURPA created incentives for nonutilities (e.g., chemical refineries, paper mills) to produce power and required utilities to buy that power. In order to create enough of an incentive for these nonutilities to make the necessary upfront investment, certain risks were transferred from the nonutility to the utility (and, therefore, ultimately to its customers). This was done through purchased power contracts, which were often long term in nature. When oil prices fell during the 1980s, these *cogeneration* contracts proved to be a significant drag on utility earnings—and on the energy efficiency PURPA sought to promote. Ultimately, PURPA was used by many utilities in their arguments that less regulation, not more, was needed to drive efficiencies in the electric industry.

1.1.4 Deregulation

The first major attempt at deregulation of the electric power industry was the *Energy Policy Act of 1992*, which sought to drive efficiency in the industry through wholesale[11] competition. As airline deregulation had driven down prices in the 1980s, it was believed that the price of electricity to the end user would go down if the price of generation to the electric delivery company was determined by a free market. Many economists argued that electricity was not a natural monopoly, but rather the *delivery* of electricity was; *generation* of electricity was not. If power plants could be exposed to competition, it was believed, then the most efficient generation operations would prevail and prices would drop below those set by state regulators.

Policymakers and regulators recognized there was the potential for new electricity markets to be *gamed*—rules manipulated and loopholes exploited, to the benefit of a few at the expense of the many. It was understood that control over transmission assets—the high-voltage lines that link power plants (generation) and customers (distribution)—could be used to stifle competition. In anticipation of this, FERC was given the ability to mandate utilities to provide access to the transmission grid, preventing them from keeping competition out of their market by denying the entry of outside power to the transmission "highway." Policymakers also understood the value of information related to transmission and created *standards of conduct* designed to ensure that all players in the marketplace had access to the same information at the same time[12] and keep information from finding its way from the regulated side of utilities to the deregulated side—an information flow that could create a significant competitive advantage for a utility's generation business.

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[9] Net of inflation.

[10] Inclusive of inflation.

[11] The wholesale market is where bulk power is bought and sold by grid operators based on immediate or long-term system load levels, whereas the retail market—which was deregulated in certain states later in the 1990s—is where electric supply choices can be made by the end user.

[12] This is done through OASIS—an open access same-time information system.

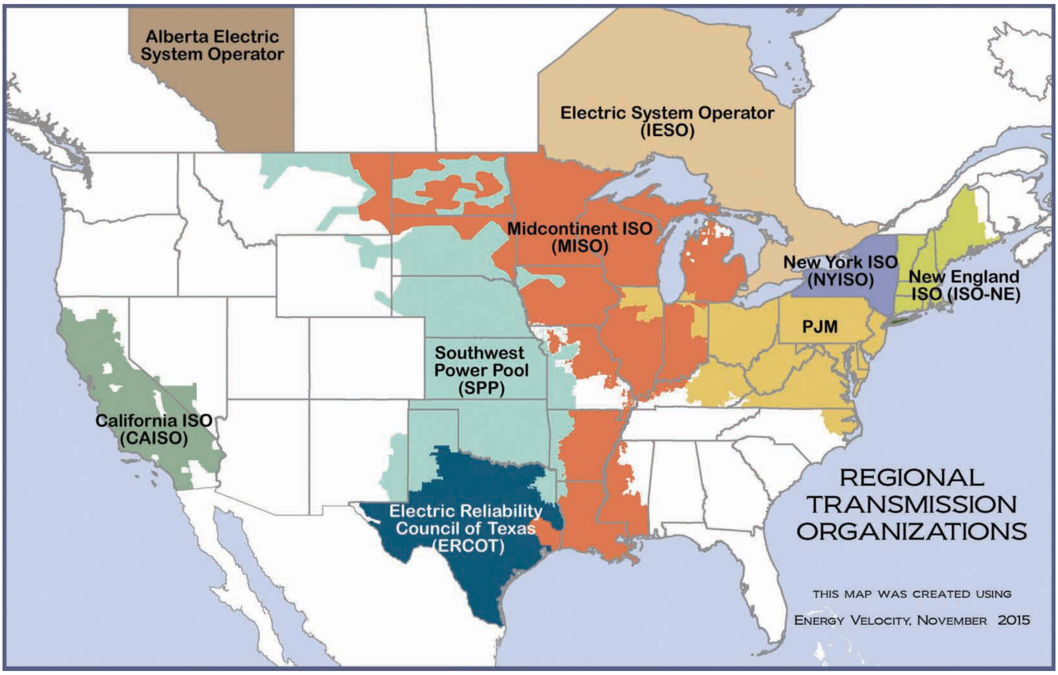

FIGURE 1.2 Regional Transmission Organizations. (From FERC, Washington, DC. https://www.ferc.gov/industries/electric/indus-act/rto/elec-ovr-rto-map.pdf.)

FERC relied heavily on *independent system operators* (ISOs) and *regional transmission operators* (RTOs)[13] to help ensure a functioning marketplace for wholesale electricity. ISOs and RTOs were given responsibility for managing transmission assets that, in most cases, are owned by one utility but essential to multiple utilities. ISOs and RTOs were established across a wide number of states and regions in the late 1990s in the United States, including California, Texas, New York, New England, the Mid-Atlantic, and the Midwest, as depicted in Figure 1.2. If it had been in FERC's power to do so, it would have mandated—in the interest of marketplace efficiencies—that all transmission assets be governed and operated by an independent agency, such as an ISO or an RTO. However, FERC did not—and still does not—have this authority. Not all state PUCs or utilities believed that their interests would be best served by abdicating transmission asset responsibility to an independent agency. As a result, RTOs and ISOs help oversee only about two-thirds of the nation's electricity consumption (Figure 1.2).

The results of restructuring have been mixed. In the PJM market and in Texas, for example, deregulation has been considered a very real success. In California, as described in the following section, it was, at least at first, a very vivid disaster. The difference between success and failure in these situations has often attributed to specific details of market design.

1.1.5 Western Energy Crisis of 2000–2001

> In the final analysis, it doesn't matter what you crazy people in California do, because I've got smart guys who can always figure out how to make money.
>
> *Enron CEO Ken Lay to the Chairman of the California Power Authority (2000)*

[13] U.S. ISOs and RTOs include California ISO, Electric Reliability Council of Texas, Midwest ISO, New York ISO, New England RTO, PJM Interconnection, and Southwest Power Pool. Some of these overlap with regional reliability councils.

> I inherited the energy deregulation scheme which put us all at the mercy of the big energy producers. We got no help from the Federal government. In fact, when I was fighting Enron and the other energy companies, these same companies were sitting down with Vice President Cheney to draft a national energy strategy.
>
> *California Governor Gray Davis (2003)*

On September 23, 1996, deregulation of the electric market was passed into law in California by a unanimous vote of the state legislature. This legislation required that investor-owned utilities (i.e., Pacific Gas and Electric in the north, and Southern California Edison and San Diego Gas and Electric in the south) divest their generation business. Power plants were sold off to independent power producers (e.g., Enron, Mirant, Reliant, Williams, Dynegy, AES), who would then sell this energy to the regulated utilities responsible for power delivery to residential and business customers.

Of great concern to the utilities were *stranded assets*—capital that they had previously invested and which, under the new rules, they would be unable to recover. In return for asset recovery, the utilities agreed to retail price caps. Though the price the utilities would be paying to purchase energy would change with the market, the amount the utilities could pass on to the customer was fixed. It can take several decades for bad legislation to become apparent. In California, it took <5 years.

The spot market for electricity began operating in April of 1998. Caps were removed from wholesale prices in May of 2000, while caps remained on retail prices. Energy prices began to rise in May of 2000. Rolling blackouts first started in June 2000 and lasted through May 2001, including two days in mid-March when 1.5 million customers were affected. A state of emergency was declared in January 2001, with the state of California having to step in for the utilities (which were essentially insolvent due to rising wholesale prices and retail price caps) to buy power at market rates, which were financed through significant levels of long-term debt. Pacific Gas & Electric filed for bankruptcy in April 2001. Southern California Edison nearly did the same. In aggregate, the two utilities took on an additional $20B in debt and saw their credit ratings[14] downgraded to the level of junk bonds. The State of Emergency was not lifted until November 13, 2003.

As it was happening, there was no consensus on the key factor driving the Western Energy Crisis. In retrospect, it was a combination of the following:

- *Weather:* It was hot and dry. The worst Pacific Northwest hydroelectric year in history drove down supply, and unusually hot weather over much of the West drove up demand—with drought-fueled fires knocking out key transmission lines along the way.
- *Capacity:* From 1993 to 1999, California's peak load demand had grown by over 15% while growth in capacity was virtually nonexistent. In addition, the ability to easily exchange power back and forth throughout the region was constrained by transmission line capacity.
- *Flawed market design:* Utilities reduce their exposure to energy supply fluctuations through a number of strategies, most notably long-term, fixed-cost (aka *hedged*) power contracts. During the summer of 2000, only 50% of the energy purchased by California utilities was hedged compared to 85%–90% by utilities in the PJM market. Market rules forced California utilities to be excessively reliant on the inherently riskier *spot market* (i.e., "that day's price") to meet demand.
- *Corporate malfeasance:* The flaws in the deregulated marketplace were being manipulated, most notably by Enron. One of the most common techniques involved the exploitation of supply constraints to drive up prices. Wholesale energy companies' business models often focus on peak demand days—and the ability to meet that demand using *peaking units*[15]—as a key driver of profitability. Enron's business model involved *creat-*

[14] Third-party assessments of a company's ability to repay its debts.
[15] Peaking power plants that can be brought on-line and off-line quickly, as opposed to base load power plants that require much more time to "turn on and off."

ing peak demand days by shutting off power plants for unplanned maintenance and then selling their remaining capacity into the market at exorbitant rates to meet the needs of a captive market. This is just one example of the many schemes that Enron employed to game the market.

- *Failed oversight:* It is evident now that California and FERC were operating under an inconsistent set of assumptions. An implicit assumption was made by the California legislature that FERC would play a role in keeping out-of-state interests from manipulating the market. An implicit assumption was made by FERC that the wholesale markets they were advocating could and would be designed in a manner that did not require extensive oversight to prevent manipulation.

Though labeled a state or regional crisis, the impact of this series of events was felt well beyond California and the West, extending throughout the industry as the market responded to the dramatic levels of uncertainty in what had historically been a relatively stable industry. Any number of statistics could underscore this point, but here is one particularly striking one that captures the state of the industry in the first years of the new century: Over the three-year period from 2000 to 2002, there were 65 upgrades compared to 342 downgrades of electric utility credit ratings.

The California crisis also substantially slowed the momentum that had emerged for markets in the late 1990s. In the years that followed, some regions publicly considered reverting to the traditional model of industry regulation (though no regions switched) and no new ISOs/RTOs were formed. FERC has repeatedly reaffirmed its support for wholesale market competition over the past decade and those regions with organized markets continue to evolve their market designs. However, today only about two-thirds of the nation's electricity consumption occurs in regions with organized wholesale markets.

It is unclear if or when further deregulation will occur in the U.S. electric power industry. Today, the electric power industry in the United States remains in a state of partial deregulation. While many utilities continue to operate in open wholesale and retail markets, the Enron debacle is still fresh in enough people's minds to dampen any enthusiasm for expanding deregulation further. Though the Western Energy Crisis in the United States had everything to do with wholesale markets and little to do with retail markets, the distinction is not clear in the public's mind—and the impact on existing or proposed regulatory reform efforts has been significant. The industry remains in a state of partial consolidation, with merger and acquisition activity well below the pace projected by many in recent years.

1.1.6 Northeast Blackout of 2003

Only a couple of years after the California crisis, August 14, 2003 saw a massive power outage that affected around 50 million people in Michigan, Indiana, Ohio, Pennsylvania, Maryland, New York, Vermont, Connecticut, and Ontario. As with the Northeast Blackout of 1965, the initial cause was a fairly innocuous one that eventually triggered a system imbalance that cascaded across neighboring utilities. The investigation eventually identified the root cause to be a handful of high-voltage transmission lines—which, by the laws of physics, sag (literally) as load increases—encountering overgrown trees in Ohio and going off-line. As with the Northeast Blackout of 1965, failures in other parts of the system protection process allowed this outage to spread wider—specifically, a problem that caused alarms on First Energy's EMS to go unnoticed.

In addition, as with the Northeast Blackout of 1965, the governmental response to this issue has been to legislate greater oversight of the industry. As part of the *Energy Policy Act of 2005*, FERC was authorized to designate a national Electric Reliability Organization (ERO). On July 20, 2006, FERC certified NERC (the North American Electric Reliability Corporation) as the ERO for the United States. With this designation, NERC's *guidelines* for system operation and reliability became *standards*. This Act gave NERC the power to exact financial penalties for entities operating out of compliance with the standards.

As should be clear, the history of the electric power industry is one in which a relatively small number of disruptive events (major blackouts, market manipulation) resulted in significant governmental responses to those events. Because legislation is rarely written in a manner that allows it to adapt to changes in the marketplace, the impact of governmental intervention on the structure of the industry is felt for years to come and is not always in the way it was intended.

1.2 OTHER WORLD REGIONS

Globally, electric power is now available to approximately 6.3 billion people of a world population approaching 7.4 billion [2]. However, more than 25% of the population continues to be left "in the dark" with no or very limited access to electricity. Developing nations continue to lag in the provision of electricity to their citizenry. Furthermore, the World Bank estimates that in fragile and conflict regions, only about 41% of the population has regular access to electricity. According to UN definitions, only about one-third of residents of the least developed countries in the world have access to electricity (Table 1.1) [3].

There are now more than 1.8 billion electricity meters serving residential, commercial, industrial, and state organizations. These metering devices measure usage information that provides the global electric power industry with revenues of more than one trillion dollars annually.

While there are now some 45,000 fossil fuel power plants operating outside of North America, the growth of utility scale renewable energy installations has been impressive over the past several years.

According to the Global Wind Energy Council (GWEC) [5], 2015 was the most impressive year to date for growth of wind power as an additional 64 GW of wind-generated capacity was added to electric power networks around the world. Going into 2016, electricity derived from wind power installations had the capacity to generate 433 GW of electricity. China was the global leader in the past year in wind project completions. All told, the GWEC reported recently that cumulative wind power market growth exceeded 22% year-over-year for 2015 (Figure 1.3).

According to Enerdata, the use of wind and solar power has increased dramatically over the past several years in many parts of the world. The share of renewable energy sources in global electricity production has doubled in the last 4 years, according to that company's latest statistical report [6]. The Enerdata report indicates that the growth rate of 18.5% for combined wind and solar renewable power sources from 2014 to 2015 outpaced the already strong long-term global growth rate of 15.6% for the period 2000–2015. According to this report, the BRIC[16] nations' installation of renewable resources for power production led among all world regions/groupings in terms of increases in production capacity (a 27.3% increase from 2014 to 2015).

TABLE 1.1
Global Population Access to Electricity

	1990	2012	2016
World population estimates (in billions) [2]	5.300	7.100	7.400
% of world population with access to electricity [3]	75.600	84.600	86.000
Population with access to electricity (in billions) [4]	4.007	6.007	6.364
Population without access to electricity [4]	1.293	1.093	1.036

Source: From the World Bank: Access to Electricity (% of Population): Sustainable Energy for All (SE4ALL) database from World Bank, Global Electrification database. With permission.

[16] BRIC = Brazil, Russia, India, and China.

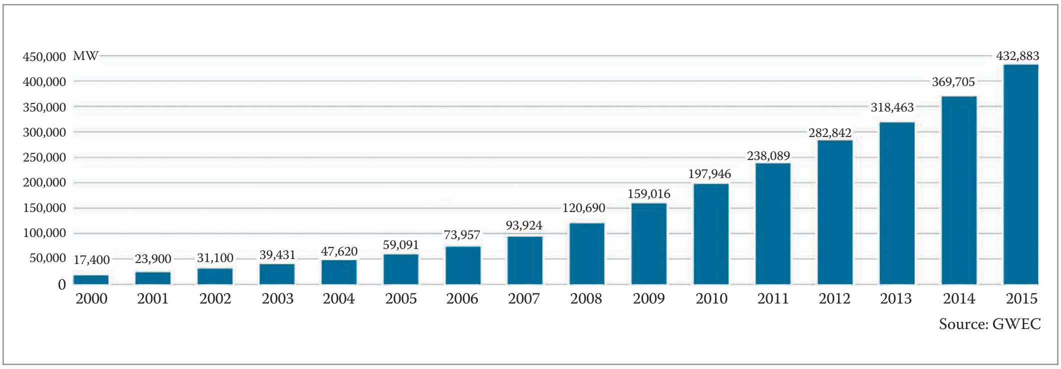

FIGURE 1.3 Global Cumulative Installed Wind Capacity 2000–2015. (From Global Wind Energy Council, GWEC.)

In total, the 45,000 international power plants together with 8,000 U.S. power plants (20,000 generating units) plus the hundreds of large-scale renewable power production sites now available to generate electric power are operational. These generators then transmit electricity through a global grouping of regional, national, and local electric power networks via nearly 60,000 high-voltage (transmission level) substations, with more than 125,000 large power transformers installed at these substations. The electric power is further distributed via a combined 255,000 medium-voltage (distribution) substations and additional hundreds of thousands of medium power transformers. Further down the power delivery network, there are another several million secondary substations used to lower voltages suitable for domestic consumption of electricity. In North America, more than 45 million pole and pad-mounted transformers lower and regulate the voltages further for residential/domestic consumption.

1.2.1 Western and Eastern Europe

Western European nations have a total of about 20,000 generating facilities providing electricity to over 400 million residents via a strongly interconnected (mainland international) transmission network. The HV/EHV network includes more than 14,300 transmission substations, some 44,000 primary distribution substations, and hundreds of thousands more of secondary distribution substations. Nearly 60% of the Western European power generation capacity can be found in just three countries (Germany, France, and the United Kingdom).

Central and Eastern European nations have an installed power generation base of more than 2700 large and medium plants, with a capacity of more than 425 GW. Most residents of Central and Eastern Europe have access to electricity. There are more than 12,000 transmission substations and 32,000 distribution substations in the combined Central-Eastern European region.

Some of the world's largest electric power utilities are found in Western Europe, where state-run or quasi-state-owned utilities dominate in some countries (EDF in France, EDP in Portugal, ENEL in Italy), while some nations have 5–20 major electric utilities (United Kingdom, Denmark, the Netherlands, Spain, and others). A few countries (e.g., Germany and Switzerland) have scores or hundreds of small municipal or rural area utilities with a few large to very large urban utilities.

In Eastern Europe and the Baltic nations, several countries continue to operate state-controlled electric power companies. In the forefront of these is Russia's UES, generating and transmitting electricity to about sixty mid-size to quite large distribution utilities in the country's larger cities. Russia accounts for just over one-half of the total generating capacity for the entire Central and Eastern European region; Ukraine is second and Poland is third in generating capacity and in populations served with electricity. According to the IEA (International Energy Agency), all residents of Eastern and Central Europe now have access to electricity.

1.2.2 Latin America

Two countries (Brazil and Mexico) dominate the Central and South American regions in terms of population (300 million out of a region-wide 565 million inhabitants), electricity production (about 55% of the total); and in the investment in existing T&D infrastructure. Argentina and Venezuela are next in terms of the status of electricity infrastructure development.

The entire region provides about 280 GW of electric production capacity, has nearly 5000 transmission substations and 18,000 distribution substations already in operation. There are still perhaps 20 million residents in the region without access to electricity, but each year brings some progress with new areas being served by power utilities and by micro-grid developments based on renewable energy sources.

Latin American countries are home to about 3650 large and medium power generation facilities, most of which are hydropower facilities (other than Mexico). Some of the world's largest hydropower facilities are found in South America, including the world-class Itaipu Binacional hydropower facility, just behind China's Three Gorges in terms of its production capacity (12,600 MW). According to the IEA, about 96% of residents of Latin America and the Caribbean now have access to electricity.

1.2.3 The Middle East and Africa

The Middle Eastern countries of the Mashreq and Maghreb regions provide more than 200 GW of mostly gas (and oil)-fired electric power capacity to more than 350 million users out of a total of about 400 million residents. More than one-half of the region's inhabitants reside in three countries (Egypt, Turkey, and Iran). There are more than 4200 transmission substations delivering power to about 100 million end use electric power sites. The IEA indicates that about 86% of the entire Arab world now has access to electricity.

The African nations currently rely on coal-fired plants for most electricity generation, but coal is expected to be overtaken by gas-fired plants by 2020. Nonetheless, coal consumption continues to increase, with new plants being largely combined cycle gas-fueled facilities.

Sub-Saharan African nations have about 750 million inhabitants, but only 90 GW of electricity production capacity. More than one-half of the existing generating capacity is in South Africa. There are an estimated 450 million or more people in sub-Saharan Africa without direct access to a reliable electric power supply. IEA data indicate that only about 35% of sub-Saharan Africa's citizens have access to electricity. As renewable energy production methods develop and their costs decrease, African countries will be able to adopt them more rapidly than at present.

1.2.4 Asia-Pacific Region

This vast region includes the two most populous, rapidly developing nations in the world, India, and China. Across the expanse of the Asia-Pacific region, there are more than 14,000 large power generation facilities in operation. China and India both have more than 2150 of the large (mostly coal-fired) power plants in the region.

South Asia as a subregion includes 1.6 billion people, with less than 250 GW of electricity production capacity, of which India holds the major share of people (1.1 billion) and electricity production capacity (160 GW). The country also has most of the substations in the region (about 17,500 out of about 22,000 in total). Pakistan and Bangladesh are other large countries in South Asia neighboring India, together having 315 million residents, but only about 32 GW of capacity.

Other Asian and Pacific countries have more than 2.1 billion inhabitants, of which 1.3 billion live in China. China accounts for about one-half of this region's electricity production capacity and one-half of the power delivery infrastructure. Japan is second in terms of electricity production and delivery infrastructure, though Indonesia is a more populous country (235 million Indonesians and 127 million Japanese). South Korea is third in electricity production and delivery, with 49 million energy consumers.

The entire Asia-Pacific and South Asian regions represent more than one-half of the world's population and have invested greatly in accounting for about 30% of the world's electricity production capacity. The IEA states that about 78% of the South Asian population has access to electricity, while nearly 96% of other Asian-area populations have access to electricity. Non-OECD (Organization for Economic Co-operation and Development) countries in Asia will be making impressive gains in the use of renewable energy production, but the reliance on coal-fired plants, primarily in China, is still expected to double by 2020.

1.2.5 Australia

Being a country with a vast territory, Australia's electrical delivery systems are divided into essentially three parts: (1) The NEM (New Electricity Market) covering the states of Victoria, South Australia, New South Wales, Queensland, Tasmania, and the Australian Capital Territory; (2) The SWIS (South West Interconnected System) covering part of Western Australia; and (3) Isolated systems in the remaining regions of Australia, which can range from large isolated mining operations and towns to small to medium townships. Although the NEM is essentially a deregulated market, with generators, retailers, and network companies as the main actors, the network is split into several regulated monopolies. Electricity pricing in the NEM is unregulated, except in the state of Queensland, where it is regulated by the local state government.

The NEM maximum demand during the summer of 2016/2017 was 38.3 GW. This demand has been flat to decreasing in the last five years, with contributing factors including closure of manufacturing, increased efficiency, and increased solar PV adoption by customers (historically focused on residential, but now extended to the C&I market, which exhibits a steady growth currently). The current generation mix is: 25 GW of coal-fired plants, 10.7 GW of gas, 8 GW of hydro, 4.6 GW of solar (of which 4.3 GW is rooftop solar), 3.7 GW of wind, 577 MW of biomass, and 181 MW of other fuels. Currently, it is estimated that the market has an overcapacity of approximately 30%, unevenly distributed though among states. This overcapacity has led to early retirements and mothballing of some of the older coal plants, which cannot compete in the markets where wholesale prices have been consistently low and price spikes occurring in very short periods of time. The current RET (Renewable Energy Target) scheme will require an additional six GW of large-scale utility renewables to be built by 2020, which will likely lead to further generation retirements. This target is driving a surge of new solar and wind projects in Australia, with retailer-signed PPAs (Power Purchase Agreement) as preferred offtake, but with other solutions becoming more attractive, such as pure merchant (independent power) suppliers, added with the ability to sell REC (Renewable Energy Certificates) to any retailer that hasn't met their RET allocation). There is currently a total of 3.5 GW of new renewable energy projects under construction or in the planning phase, some of them including large battery installations. The largest battery installation worldwide to date (as of July 2017) has been announced for South Australia – 100 MW/129 MWh, scheduled for completion before the beginning of the southern hemisphere summer of 2017/8.

Although Australia has a stable and robust NEM electricity system, there are regional disparities and vulnerabilities that not only have driven recent outages but have contributed to regional wholesale price disparities, namely, in the state of South Australia. This is due to a conjunction and interplay of many factors, such as gas price volatility, wind generation yield variation (current wind penetration sits around 35% and residential solar at 5%), early coal plant retirements, weather variability, and problems with the state transmission interconnectors, which are key for maintaining stability. There is currently a strong Australian Federal Government push into market reform that can reduce these disparities and increase grid stability in this state, as well as in Tasmania, where low rain coupled with long outages of interconnectors have led to severe power constraints. Some of the propositions under analysis currently range from building additional transmission interconnectors, to changing the energy only market into a capacity market and aligning settlement and bidding periods to 5 min, which are able to incentivize the deployment of fast reacting energy resources, such as batteries.

Electricity Distributors are a mix of privately owned and state government owned (Queensland, Tasmania and Western Australia). Stability and good SAIDI/SAIFI (System Average Interruption Duration Index/System Average Interruption Frequency Index) performance have been the norm in recent years, although the occasional disruptive natural events (storms, floods, and bushfires) have had significant impacts on the electricity network and consumers. The recently increased adoption of residential solar PV has brought concerns over carrying capacity and local stability (e.g., high voltage with low load and during times of high solar PV production). Feeders with high solar PV penetration have been subject to additional spending (e.g., forced upgrades to reduce voltage rise effects), but also R&D has been increasingly considering effects and solutions to reduce impacts of solar. Almost all networks have undertaken (or are planning to undertake) projects with energy storage, recognizing the potential that batteries and inverters can bring to distribution network operation. However, the deployment of solar and batteries behind the meter is currently under regulatory review (the "ring-fencing" guidelines) of which the outcome will determine how networks, retailers, and other service providers interact between themselves and with the customer commercially in what concerns services delivered to the customer and by the customer. Two other significant regulatory reviews under way are (1) the five-year price determinations, when networks present their spending plans to the regulator, which then determines what spending is acceptable; and (2) the DMIS-Demand Management Incentive Scheme, where it is currently debated whether networks should be incentivized to implement non-network solutions if they provide the most efficient and cost-effective outcome.

Despite these current reviews, regulators and market participants are eyeing the long-term picture, recognizing a future empowered customer with customer generation and storage as a norm,[17] which will require a very different set of products and services from the market.

1.3 UTILITY REGULATORY SYSTEMS

The nature of the electric industry cannot be fully appreciated without understanding the nature of how the industry is regulated. The electric industry is, arguably, the most externally controlled industry in the United States and most nations around the world. The impact of this regulation on how and why utilities do what they do cannot be overstated.

Regulatory oversight of electric utilities is necessary because they are natural monopolies. The term *natural monopoly* applies to industries where the best outcome, in terms of the societal interest, will be one and only one provider of that product or service in a given market. Society does not benefit, the reasoning goes, when overlapping subway systems, water mains, or electric delivery networks are attempted.

The most common natural monopoly occurs in a market where the cost of entry is exceedingly high—such as a "poles and wires" company or any other entity for which significant capital resources are required to "open up shop." Investors will not fund any venture without some reasonable assurance that they will be able to earn a return on their investment. If multiple entities are allowed to build competing distribution networks, then no such assurance exists that any of these entities will be able to earn a return on the capital they have invested. Rational investors anticipate this and, therefore, they will not put capital toward stringing wires on poles unless they are guaranteed to be the sole provider of electricity to that market.

With a monopoly, however, comes market power—specifically, the power to set profit-maximizing prices with no concern for competitive pricing. No rational public policymaker will agree to such a sole-provider arrangement without being able to control prices.

So, a deal is struck: For a society to benefit from the provision of a vital service, (1) public policymakers grant an exclusive franchise to an entity to provide electricity to homes and businesses, and (2) the entity must agree to a customer service obligation and consent to pricing controls and third-party oversight.

[17] See CSIRO, "Future Grid Forum."

Electric power utilities are always subject to some form of regulation or oversight. This can be at the national, regional, or local level. For example, in the United States, investor-owned utilities are regulated by FERC and state PUCs, while municipal and cooperative utilities are regulated by local communities and/or boards of directors made up of their members. Many countries throughout the world have national regulatory bodies including OFGEM in the United Kingdom, Commission de Regulation de l'Energie in France, CRE in Mexico, and so on. In many Middle Eastern and African countries, the regulatory function is provided by the ministry of energy.

The design of regulatory systems has a strong impact on incentives for shareholder-owned utilities. The nature of these incentives will also have important impacts on the pace of smart grid development throughout the world. For example, because a regulated utility serves 100% of their designated market, customer growth is driven not by product-based or price-based competition but by the underlying growth in the market. Furthermore, because prices are fixed by regulatory tariffs, utilities are severely limited in their ability to drive revenue increases through pricing strategies. In addition, because prices are set by regulatory tariffs, utilities often give regulatory relationship management the same or greater emphasis than customer relationship management. In fact, some will argue that the regulator is the customer.

Profitability is determined largely by an administratively determined regulated rate of return on a utility's asset base, so great emphasis is placed by the utilities on investing capital in a prudent manner and on the preparation and defense of rate cases. To grossly oversimplify the rate-making process, utilities, and regulators reach agreement on

1. What assets are essential to service delivery (i.e., the *rate base*)
2. What an appropriate rate of return on those assets should be

With these two variables in place, an allowable annual return (i.e., net income as a percentage of assets) can be calculated. Rates for different classes of customers are then set, which are projected to result in that level of return. This does not eliminate all variability in a utility's earnings, but it does create a far more predictable environment than that in which a typical nonregulated entity operates.

Profitability is determined in the following way:

- Utilities can make very large capital investments and take on relatively high levels of debt with a much lower degree of uncertainty than an unregulated company. The business case for such an investment is driven primarily by the regulatory recoverability of the investment rather than—in unregulated companies—by the anticipated impact of the investment on revenue or expense.
- The distinction between capital costs (spending that ends up on the company's books as an asset, such as the labor and equipment required to put a new transformer in service) and operating costs (spending that does not end up on the company's books as an asset, such as an administrator's salary) is nontrivial. Expense that can be charged to an asset should eventually earn the utility a regulated rate of return.

With profitability capped by a regulated rate of return on the asset base, utilities have at times had a disincentive to drive down spending. For example, a utility with a regulated rate of return of 10% generates significant operational efficiencies that allow it to earn a rate of return of 12%, only to have to "return" those excess earnings to the ratepayers during the next rate case. This phenomenon has contributed to a few recent trends, including utilities going many years between rate cases, utilities proposing rate caps to regulators in return for other concessions, and utilities and regulators establishing *performance-based rates* in which rate of return is driven by factors other than cost of service (e.g., service reliability levels).

ACKNOWLEDGMENTS

The editor would like to thank the University of Idaho's Utility Executive Course and the UEC Advisory Board for the material used in this chapter to describe the history of the U.S. electric utility industry.

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2 Smart Grid Challenges and Transformations

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Smart grid has numerous definitions and interpretations, which depend on the specific drivers and benefits to each utility, country, and federal goals, and the various industry stakeholders. A preferred view of smart grid is not what it is, but what it does, and how it benefits utilities, consumers, the environment, and the economy.

- The European Technology Platform (comprising European stakeholders and the surrounding research community) defines smart grid as "An electricity network that can intelligently integrate the actions of all users connected to it—generators, consumers and those that do both, in order to efficiently deliver sustainable, economic and secure electricity supply" [1].
- According to the U.S. Department of Energy (DOE), "Grid 2030 envisions a fully automated power delivery network that monitors and controls every customer and node, ensuring two-way flow of information and electricity between the power plant and the appliance, and all points in between" [2].
- The US Electric Power Research Institute (EPRI) defines smart grid as "The modernization of the electricity delivery system so it monitors, protects, and automatically optimizes the operation of its interconnected elements—from the central and distributed generator through the high-voltage network and distribution system, to industrial users and building automation systems, to energy storage installations and to end-use consumers and their thermostats, electric vehicles, appliances, and other household devices" [3].

The U.S. DOE's National Energy Technology Laboratory (NETL) established seven principal characteristics that define the functions of smart grid [4]. Table 2.1 summarizes these seven characteristics and contrasts today's grid with the vision for the smart grid.

These seven points have come to define the smart grid for many, although there are variants to the list that emphasize additional points, such as encouraging the deployment of renewable resources in the transmission, subtransmission, and distribution system; the use of sensors and sensory signals for direct automatic control; accelerating automation, particularly in the distribution system; and

TABLE 2.1
DOE Seven Characteristics of a Smart Grid

Today's Grid	Principal Characteristic	Smart Grid
Consumers do not interact with the grid and are not widely informed and educated on their role in reducing energy demand and costs	Enables consumer participation	Full-price information available, choose from many plans, prices, and options to buy and sell
Dominated by central generation, very limited distributed generation and storage	Accommodates all generation and storage options	Many "plug-and-play" DERs complement central generation
Limited wholesale markets, not well integrated	Enables new markets	Mature, well-integrated wholesale markets, growth of new electricity markets
Focus on outages rather than PQ (power quality)	Meets PQ needs	PQ a priority with a variety of quality and price options according to needs
Limited grid intelligence is integrated with asset management processes	Optimizes assets and operates efficiently	Deep integration of grid intelligence with asset management applications
Focus on protection of assets following fault	Self-heals	Prevents grid disruptions, minimizes impact, and restores rapidly
Vulnerable to terrorists and natural disasters	Resists attack	Deters, detects, mitigates, and restores rapidly and efficiently

intelligently (optimally) managing multiobjective issues in power system operation and design. The seven cited DOE elements may be viewed more generically as making the grid as follows:

- *Intelligent:* Capable of sensing system overloads and rerouting power to prevent or minimize a potential outage; of working autonomously when conditions require resolution faster than humans can respond and cooperatively in aligning the goals of utilities, consumers, and regulators
- *Efficient:* Capable of meeting increased consumer demand without adding infrastructure
- *Quality focused:* Capable of delivering the power quality necessary (free of sags, spikes, disturbances, and interruptions) to power our increasingly digital economy and the data centers, computers, and electronics necessary to make it run
- *Accommodating:* Accepting energy from virtually all fuel source including solar and wind as easily and transparently as coal and natural gas; capable of integrating any and all better ideas and technologies (e.g., energy storage technologies) as they are market-proven and ready to come online
- *Resilient:* Increasingly resistant to attacks and natural disasters as it becomes more decentralized and reinforced with smart grid security protocols
- *Motivating:* Enabling real-time communication between the consumer and utility so consumers can tailor their energy consumption based on individual preferences, like price and/or environmental concerns
- *Green:* Slowing the advance of global climate change and offering a genuine path toward significant environmental improvement
- *Opportunistic:* Creating new opportunities and markets by means of its ability to capitalize on plug-and-play innovation wherever and whenever appropriate; moving away from hidden subsidization to support fair and open markets.

Utilities have long been hampered by heavy regulation, modest technology change, and predictable consumer behavior, but utilities are now starting to face the same kind of competitive pressures that have changed other industries. There are significant factors that are currently impacting the traditional business and operating model of utilities, which are helping to realize the smart grid vision, and challenge and transform the electric utility industry. These changes arise due to a convergence of factors, including: more demanding consumers; increased focus on digital technologies; rising cybersecurity threats; and, with the shift toward distributed generation, an increase in regulatory pressure and the number of competitors with the growing popularity of “behind the meter” distributed energy resources (generation and storage), which could impact grid stability. Whether the impacts are potential game-changers and are considered “disruptive” or not, it may get to the point where utilities will need to think about how to disrupt their own business before they are disrupted themselves. This will require not just new technologies and solutions but also innovative thinking around a different grid operating model and changes in the utility business processes.

2.1 FOCUS ON THE GRID-EDGE

Current transmission and distribution grids were designed for the cost-effective, rapid electrification of developing economies. Since the invention of electric power technology and the establishment of centralized generation facilities, the greatest changes in the utility industry have been driven not by innovation but by system failures and regulatory or government reactions to those failures. Smart grid technologies have the potential to be the first true “game-changing” technology since alternating current supplanted direct current in the late 1800s. As an example, the design of today’s power system took advantage of the economies of scale through the establishment of large centralized generation stations. Supply and demand are continuously balanced by dispatching the appropriate level of generation to satisfy load. This operating model schedules the dispatch of generation to meet the day ahead forecast load. This supply dispatch model is the predominant method of balancing supply and demand today. One vision to optimize the end-to-end system would entail not just the dispatch of supply but also a complementary dispatch of customer and demand resources, as well as persistent load shaping, such as load-modifying demand response, with pricing programs, such as time-of-use (TOU) rates and critical peak pricing.[1] Currently, generation is matched to supply consumer load plus a reserve margin, and often expensive generating plants are used to satisfy peak demand or supply reserve energy in the case of contingencies.

The utility portfolio of generation and energy resources is undergoing significant change as the impact of various market and legislative forces is felt. Coal provides nearly 50% of the United States' electricity generation at a relatively low average cost. However, its share of electricity generation has been in decline for most of the past decade, while international demand has helped drive its cost steadily upward. While the Energy Information Administration forecasts coal to still produce 45% of the nation's electricity output in 2025, "cap and trade" legislation that constrains carbon emissions will effectively serve as a tax on coal that will necessarily drive producers to revisit and reallocate their fuel portfolio. A reduction in natural gas prices in the US has made it the second largest generation source. Natural gas plants are far cleaner to operate than coal plants and far easier to build than either coal or nuclear plants. Even though no new nuclear plants have been built in the United States in decades, nuclear plants still provide 20% of the nation's electricity at a price point below coal and natural gas. More than 70% of the cost of nuclear energy goes to non fuel operating and maintenance (O&M) expenses, which help to illustrate the plant operation challenges inherent with this power source. Even though nuclear power costs are relatively stable and there is an increasing recognition by environmentalists [5] that its minimal carbon footprint offsets the low probability risk of catastrophic failure, plant construction is exceedingly slow due to regulatory, licensing, and siting issues, as well as increasing competitive pressure from alternative generation options.

Ever-heightening concern about the impact of power plant emissions on the environment and the climate, combined with very favorable government subsidies and mandates in which non-emissive distributed and utility-scale renewables can compete with traditional resources, has led to increased interest in renewable generation sources. Renewable energy accounted for 10% of the nation's electricity generation mix in 2010, with hydro making up the vast majority of this generation followed by wind, biomass, geothermal, and solar. However, every state in the United States has a statewide renewable electricity goal, and twenty-nine states and the District of Columbia have renewable electricity standard mandates, known as RPS (Renewable Portfolio Standards). RPS-type mechanisms have also been adopted in several other countries, including Australia, Western Europe (Britain, Italy, Poland, Sweden, and Belgium) [6], and in Latin America (Chile and Brazil). These mandates vary, but most are stated as a percentage of renewable energy in the generation portfolio by a specified date. These regulations and policies, combined with the potential for federal carbon-constraining legislation and rising fuel commodity prices, and public sentiment that have led companies like Google and Walmart to commit to limiting their greenhouse gas (GHG) footprints, have spurred significant investments in renewable generation. Energy storage technology can have a significant impact on the proportion of wind and solar energy in a generation portfolio. As energy storage becomes increasingly cost effective and scalable, wind and solar energy will be to some extent "dispatchable," and load management will be greatly facilitated. Environmental advocates have long maintained that comparing the relative merits of coal, nuclear, and natural gas (90% of the nation's generation portfolio) alone is fundamentally flawed because it does not include the demand reduction option. Conservation, if viewed as an energy source, can be a suitable and equivalent alternative to a new power plant. The ability to fully leverage this option, however, depends in large part on the following factors: (1) technology that better enables customers to manage and control their usage; (2) rates that send price signals to customers while removing the financial disincentives for utilities to drive demand reduction; and (3) the business model allowing opportunities for utilities to profit from hosting and facilitating the optimization of distributed energy resources.

[1] Researchers at Lawrence Berkeley Labs estimate that shaping DR resources can be a significant, low-cost resource in California. http://www.cpuc.ca.gov/General.aspx?id=10622.

Large central power plants including environmentally friendly sources, such as wind and solar farms and advanced nuclear plants, will continue to play a major role even as large numbers of smaller distributed energy resources (DERs) are deployed. Various capacities from small to large will be interconnected at all voltage levels and will include DERs, such as photovoltaic, wind, advanced batteries, plug-in hybrid vehicles, and fuel cells. It will be easier and more profitable for commercial users to install their own generation sources, such as highly efficient combined heat and power installations and electric storage facilities. We are proceeding to a world of a decentralized grid, where distributed energy resources can be optimized, and sited at specific customer locations to maximize customer and grid value.

Although distributed generation is on a path to becoming competitive in some markets without subsidies and mandates (e.g., Australia), it still depends heavily on incentives and favorable market rules. Those rules—which are steadily changing in favor of a distributed grid—still create boundaries around what's possible. Even though technology prices are falling, renewable energy (worldwide) is still very heavily subsidized [7]. Subsidies are passed on to consumers in a surcharge, so those consumers who cannot afford to, or are not able or willing to install solar panels, do not receive any credit and are essentially paying more for their electricity. While economies of scale apply to the supply of distributed generation and energy storage technologies (DERs), it does not apply to the collective DER generation of electricity—what will it cost to maintain and operate all the DER units on the grid, and who is going to ensure that the DER units (continually) comply with interconnection requirements or safety standards while economically generating electricity back onto the grid. Even if the DER units are owned, operated, and maintained by a third-party company, the same principles apply. "Behind-the-meter" DER may seem to be an obligatory regulatory requirement and R&D project for now. Until the day-to-day operation of the DER can be orchestrated within the larger grid, the path forward may be more along the lines of larger, community-scale DER units involving the need for third-party and industry partners.

Even with government subsidies, renewable generation and storage are being scaled rapidly by companies such as Tesla Motors and Panasonic. "Energy storage, when combined with solar power, could disrupt utilities in the U.S. and Europe to the extent that customers move to an off-grid approach. We believe Tesla's energy storage product will be economically viable in parts of the U.S. and Europe and at a fraction of the cost of current storage alternatives."—Greentech Media [7]. GE estimates that annual distributed power capacity additions will grow from 142 GW in 2012 to 200 GW in 2020, representing an average annual growth rate of 4.4%. When compared to an average annual growth rate of global electricity consumption of 3.3%, decentralized energy will grow at a rate that is almost 40% faster than demand [8]. Solar PV, distributed storage, electric vehicles, and home energy management platforms are giving many consumers direct technology choice for the first time—enabling third-party companies to erode the market share of incumbent utilities that have mostly operated in a limited competitive environment. In addition, community choice aggregation is exacerbating load defection. For example, Marin Clean Energy now provides service to 250,000 customers within the service territory of PG&E.

As supply constraints continue, there will be more focus on the distribution network and the grid-edge for cost reduction and capacity relief. The smart grid will see an increase in utility and consumer-owned resources on the distribution system. Utility customers will be able to generate electricity to the grid or consume electricity from the grid based on determined rules and schedules. This means that consumers will no longer be pure consumers but both producers (sellers) and buyers of energy ("prosumers"), switching back and forth from time to time. This will require that the grid operates with two-way power flows and create an open market for real time, transactive energy exchange while monitoring and controlling the generation and consumption points on the distribution network in real-time. The distributed generation will be from disparate and mostly variable sources and subject to great uncertainty (at least in the near term until there is greater understanding of, and comfort with, their capabilities that, when aggregated, have the potential to be far more resilient and stable than centralized plants).

From the transmission perspective, increased amounts of power exchanges and trading will add more stress to the grid. The smart grid challenge will be to reduce grid congestion, ensure grid stability and security, and optimize the use of transmission assets and low-cost generation sources.

To keep generation, transmission, and consumption in balance, the grids must become more flexible and more effectively controlled. The transmission system will require more advanced technologies, such as FACTS and HVDC, to help with power flow control and ensure stability. The changes in the generation mix will likely require substantial new transmission growth over the coming decades. Transmission network expansion, especially projects that connect renewable generation to densely populated regions of the country, will help the nation utilize its existing generation fleet more fully while providing stimulus for further investment in additional renewable capacity. However, the transmission network will have additional challenges to cope with, such as the forecasted minimum demand levels for South Australia that show there will be a zero net demand at times on the transmission network by 2023–2024 (in the middle of sunny, minimum demand days) [9].

Monitoring and control requirements for the distribution system will increase, and the integrated smart grid architecture will benefit from data exchange between smarter distribution field devices and enterprise applications. With the focus on the grid-edge, substations in a smart grid will move beyond basic protection and traditional automation schemes to bring complexity around distributed functional and communications architectures, more advanced local analytics, and the management of vast amounts of data. There will be a migration of intelligence from the traditional centralized functions and decisions at the energy management system (EMS) and distribution management system (DMS) level down to the substations and feeders in order to enhance responsiveness of the T&D system. System operation applications will become more advanced in being able to coordinate the distributed intelligence in the substations and feeders in the field to ensure system-wide reliability, efficiency, and security. Smart grid technologies will generate a tremendous amount of real-time and operational data with the increase in sensors and the need for more information on the operation of the system. Real-time pricing and consumer demand management will require advanced analytics and forecasting of the electricity consumption of individual consumers.

While the “cloud” has shown to be a flexible, scalable, agile, and cost-effective alternative to host IT and business applications and platforms, the focus on the “edge” and IoT (Internet of Things) will challenge this centralized, consolidated, and remote computing and data management model. Real-time monitoring, control, data acquisition, and analytics at the grid-edge and in IoT applications will necessitate a different or more advanced approach to today’s centralized cloud architecture. This is mostly due to the real-time component requiring computations and communications latency in the order of a few seconds, or in the sub-second range. Add to this the large amounts of data generated and exchanged by edge applications and the IoT, more computing power distributed at the edge of the smart grid will be required and accompanied by an equally effective communications solution. The emphasis will be on locational and real-time processing, interactions, and data exchange. However, smart grid and the IoT will not be the only driver as real-time edge computing is adopted in other industries—consider, as examples, the onerous real-time computing and data exchange in self-driving vehicles and virtual reality. Can edge computing simply be part of the cloud, extended and distributed? Perhaps, but there will be numerous users, interfaces, and systems, possibly with overlapping and interconnected clouds. The solution will need to be more autonomous, and dynamically flexible and agile.

The concepts of “fog computing” and “machine learning,” therefore, lend themselves well to the grid-edge and the IoT in order to reduce the amount of data exchanged between devices and communicated to centralized, enterprise-level applications and systems, especially if low data latency is critical. Fog computing, also known as fog networking or fogging, is a decentralized computing infrastructure in which computing resources and applications are distributed in the most logical, efficient place at any point along the data source continuum [10]. The goal of fog computing is to improve computational and communications efficiency by reducing the amount of data that needs to be transported to a central location (or to the cloud) for storage and analysis. The choice of the word “fog” is meant to convey the idea that the advantages of cloud computing should be brought closer to the data source—in meteorology, fog is simply a cloud that is close to the ground. Machine learning is the ability of computing devices to learn and adapt their operation through experience in their specific application, without being specifically programmed [11]. Therefore, machine learning allows computing devices to find hidden insights without being explicitly programmed where to look. Fog computing and machine learning at the edge may also need to take on dynamic characteristics—locational and collective computing and communications resources that could be dispatched, shared (communal), or leased from nearby third-party devices and IoT participants in order to help in times of increased computing and communications demand—much like "crowdsourcing" or a "flash mob," borrowing from social media terms.

2.2 NEW MARKET DYNAMICS

The increase in renewable penetration will soon have significant impact on the operation and stability of the grid. This will require grid operators to look for new alternatives to mobilize large amounts of "flexible controllable reserves." These reserves have historically been conventional generation assets operating in idle as "spinning reserve"; however, these are no longer sufficient, which is encouraging grid operators to look for new alternative resources, composed of flexible demand as well as new portfolios of storage technologies directly connected to the grid or at a consumer premise behind a grid meter. In California, however, regulators are not leaving it up to utilities to decide whether this approach is suitable for them. Instead, to support the growth of energy storage developers, the state's Public Utilities Commission (PUC) has mandated that utilities purchase a predetermined amount of energy storage capacity and that a company other than the utility must own more than half of this capacity, and has approved vehicle-to-grid integration pilots specifically designed to enable day-time EV charging at workplaces to store solar-sourced generation. Concurrently, residential ratepayers are already being given the option of TOU rates that offer low prices at midday to align demand when solar and wind generation curtailment has already become routine [12].

The smart grid will link buyers and sellers together—from the consumer to the regional transmission organization (RTO)—and all those in between. With a dynamic distribution grid and new markets for transactive energy, utilities will become empowered to serve as energy clearing houses and address consumer demand with optimal sources of supply. It will facilitate the creation of new electricity markets ranging from the home EMS at the consumers' premises to the technologies that allow consumers and third parties to bid their energy resources into the electricity market. Consumer response to price increases felt through real-time pricing will mitigate demand and energy usage, driving lower-cost solutions and spurring new technology development. New, clean, energy-related products will also be offered as market options. The smart grid will support consistent market operation across regions. It will enable more market participation through increased transmission paths, aggregated demand side management (DSM) initiatives, and the placement of energy resources including storage within a more reliable distribution system located closer to the consumer. As a consequence, the management of the end-to-end energy value chain is currently evolving from the optimization of limited numbers of generation units whose marginal costs were historically largely dependent on their fuel long-term sourcing strategy toward the provision of coordination services for millions of distributed subsystems capable to produce at zero marginal cost when renewables are available and flexibly consume and store energy when economics justify it. Grid operators will seek new contractual arrangements to define their role and responsibility into the overall system balancing and stability management. This is fundamentally changing the energy market structure enabling such transactions, requiring, on the one hand, to open toward prosumers transacting energy peer to peer with each other, as well as to reconsider the way real-time prices are formed to reflect renewable intermittency, demand elasticity as well as storage cycling capability.

At the prosumer aggregation level, virtual power plants (VPPs) will be introduced to aggregate flexible resources from the lowest levels of the grid into the energy market mechanisms operated by the transmission and distribution grid operators. This design has indirectly redefined the roles of both grid operators in this process considering distributed energy resources have both impact on distribution network congestions and constraints (primarily voltage related) and transmission network balancing (primarily frequency related). Considering the regulatory model already in place for wholesale transactions (positioning the grid operator as a regulated monopoly), new market-based interactions have been considered to source flexibility from deregulated market participants. The underlying optimization is performed through the design of an auction mechanism allowing grid operators to source their flexibility at minimal costs while managing controls to prosumers through transactive price signals [13].

There are many questions around distribution grid access for DERs and transactive energy. If a consumer generates electricity to cover most of their needs, but requires power from the grid for only a few times a month, how should the consumer be charged to ensure that the utility is compensated for providing the grid connection service—should it be a fixed connection charge, or a different (higher) kWh rate for the small amount of energy that the consumer received from the utility grid? This is without considering net metering. If the utility does not need the additional power, why should they buy it back from the consumer? What about a charge for the consumer using the utility grid as a backup supply when the consumer does not require additional energy from the utility grid (stranded assets)? What happens if the distribution grid is congested, who has priority to generate or supply energy back onto the grid (or transact energy with another consumer) versus another DER owner, and how will the DER owner be held to any type of energy supply or demand agreement (for availability of the resource), especially when operation and maintenance is the responsibility of the consumer? Also, what happens if a consumer has a transactive agreement to supply or consume energy from another "prosumer," and either party does not hold up to their supply or consumer agreement, and then the distribution grid must supply or consume the additional power, how is everyone compensated? Are these transactive agreements on an energy or demand basis, and how are the transactive agreements or contracts administered and upheld?

With the change in grid-edge dynamics and open market energy exchanges, utilities will need to create an optimized grid with interoperable standards, but this will only be possible through a long-term commitment to partner with both peers and competitors. Engaging with regulators will be essential to redesign the market, using performance-based models that work for all its participants. Early successes are likely to play a role in establishing industry-leading standards; in the long run, they will separate winners from losers. To make this concept a reality, data must be integrated seamlessly into operations, with a customized customer platform at the front end. Electricity companies will need to accept that payback for investments in optimizing the grid may only materialize in the long term [14].

2.3 THE DIGITAL TRANSFORMATION

"The promise of digital transformation is huge. From grid management to customer relations, an effective digital strategy can revolutionize all areas of the power utility business. It's at the heart of the energy transformation challenge."—Norbert Schwieters, PwC's Global Power & Utilities Leader [15].

The smart grid would not be complete without an equal focus on the digital transformation of utilities—data, processes, and business models. Digital technologies can provide unparalleled opportunities for value creation and sweeping transformations across multiple aspects of an industry. While, clearly, digital technology will transform most industries, there are several challenges specific to the utility industry, such as the pace of changing customer expectations, cultural transformation, outdated regulation, and identifying and accessing the right skills—to name just a few [14]. There are several key areas where advanced and digital technologies can significantly transform the utility.

2.3.1 Operations

For decades, utilities have used remote sensing and communications technologies, such as supervisory control and data acquisition, to optimize their generation, transmission, and distribution systems. While the concept of operational efficiencies is relatively obvious, the notion of informational efficiencies is not as apparent. Smart grid devices, from AMI technology to distribution automation components, are essentially various forms of grid sensors that will generate an enormous amount of data. Furthermore, customer-owned devices behind the meter will also be capable of producing data that can facilitate both the integration in a smart grid as well as the conception of new products and services that will build the foundation for the working smart grid and commercial models that serve as base to its operation. Digital technologies will increase the number of sensors and amount of data that utilities must manage by one or two orders of magnitude. The opportunity to understand how energy is consumed closer to the consumer grows bigger—but so does the challenge of extracting meaningful information from volumes of data—turning big data into smart data [16].

The utilities that can develop the analytical infrastructure necessary to transform these data into actionable information, and eventually into decision-making knowledge, will be able to better plan and manage their assets—which will translate into meaningful process improvements, such as better repair/replace decisions or highly targeted preventive maintenance programs. As utilities further mine these data, optimization of distribution network performance based on near real-time (as opposed to historical) information becomes possible.

Grid optimization is possible through real-time load balancing, network controls, and end-to-end connected markets, enabled by connected assets, machines, devices, and advanced monitoring capability. Evolving to the digital grid requires reconsidering the way control principles have been architected to enable bi directional communication and power flow across generation sources (conventional and renewable), managing energy storage on the utility side and consumer side of the meter, as well as dynamic control of flexible loads. This requires reinventing how transactions are managed along the energy value chain—expanding current wholesale energy markets developed at the transmission level into new distribution level markets, and down to the prosumer. Digital grids will ultimately allow new regulatory options by bringing new choices and incentives to electricity consumers and prosumers, exposing them to real-time electricity prices. New digital grid technologies enable the real-time assessment of grid congestion, security, and asset conditions, through the deployment of sensors, controllers, and computers distributed throughout the grid infrastructure, from centralized control rooms to the grid-edge and the consumer. These new architectures will combine centralized IT processing on premise (at the utility) or in the cloud depending on data and process criticality with distributed intelligence deployed throughout the architecture [13].

Digital and mobile tools can also help to improve efficiency and effectiveness of field operations. For example, utilities can improve outage management by pinpointing which customers are experiencing them (integrating advanced metering infrastructure, social media, text messages, and other data), directing resources toward restoration (through traditional distributed and outage management systems, mapping, and GPS), and communicating with customers. Technology solutions can also enable real-time, remote-control, or predictive maintenance to extend the life cycle or operating efficiency of the generation, transmission, or distribution assets and infrastructure.

2.3.2 Convergence of Operational and Information Technologies (OT/IT)

OT/IT integration is not just happening within technology hardware and software but also within the company's functional organizations. These two groups and sets of activities have been converging for some time, but smart grid greatly accelerates that convergence and forces some organizational decisions. For a utility to be successful, it would not be sufficient for IT to simply manage the back-office integration of business systems (the typical purview of most such groups). The technology being deployed in the field via smart grid in many ways bears a greater resemblance to the technology that IT groups have been supporting than it does to what operations technology groups have been supporting. The most successful utilities, if they have not done so already, will find a way to integrate the best of both by:

- Adopting a smart grid patch management process that leverages a tried and true IT process for devices and systems specifically out "in the field."
- Leveraging the capabilities of those responsible for the corporation's data network and bringing that skill base to bear on smart grid communications infrastructure challenges.

- Building a network monitoring process that establishes common visibility to all mission critical systems and networks, whether the systems and networks are in the data center, system operations, a substation, a remote facility, or any other grid-attached location.
- Interconnect with customer devices or with aggregators that manage them in order to bring the visibility of those resources that support the grid to the centers of decision so they are able to operate with the grid and derive value.

2.3.3 Customer Engagement

Industry leaders agree on the need to make deeper customer engagement a priority and the pivotal role of digital technologies in making this a reality. Personalized connected services beyond the electricity value chain ("beyond the electron") are required that adapt to the consumer so that electricity can move from being a commodity to becoming an experience [14]. Mobile, social, and web interfaces give customers a better view of their energy use and enable richer two-way communication between the utility and customers. They also improve the ability of utilities to test and deliver new capabilities, such as customized rate plans based on individual customer usage and needs. Digital technology opens the way for new energy products and services, but utilities will also need to change in order to make the most of these new opportunities. For example, inexpensive sensing and communications technologies will support a range of energy management services from residential smart homes to large commercial and industrial energy efficiency programs. But utilities will need to develop new capabilities to research, develop, market, and support these new services. Utilities will also need to improve their ability to innovate and experiment to help determine which offers make the most sense given their regulatory landscape, competitive markets, and customer base. Mobile is also enabling new business scenarios, while social channels are transforming the ability to connect with customers quickly, directly, and cheaply.

Digital technology also offers utilities both cost-to-serve efficiencies and improved customer intimacy; crowdsourcing, online forums, and wikis all offer ways for companies to learn about customers' views and buying behaviors, at the same time improving brand engagement and loyalty. In addition, instant messaging and mobile applications extend the concept of self-service by allowing people to book appointments or analyze energy consumption patterns in new, easily accessible ways.

The smart home, which integrates features such as security, entertainment, and energy management, is a prime example of the sort of new service enabled by new technologies in sensing and communications. Utilities operating in competitive retail environments can view the smart home as a premium service offering, and a way to improve customer loyalty. UK utilities have bundled premium residential services for years to improve customer loyalty and reduce churn. While it's still early for smart home services, they are likely to bring some of the same benefits to utilities across North America and Europe [16]. To succeed in the smart home space, utilities will need to navigate a complicated ecosystem of platform providers, subscription service providers, and hundreds of device manufacturers. The same applies to the commercial and industrial sectors with original equipment manufacturers offering energy efficiency solutions. Here, too, utilities will need to partner with the right subset of players to tailor offerings to their business and regulatory environments, and test and scale across their customer bases.

Cloud computing is improving business agility, with a time-to-market advantage. Big data is helping companies innovate, with the capability to analyze large quantities of both structured and unstructured data, generating insights in real time. With the emergence of the IoT, the volume of data that electricity companies can access—through the car, connected home, wearables, and smart cities—will increase exponentially [17]. As machine-to-machine or peer-to-peer communications become more prevalent, the interaction and integration of data, applications, people, and organizations will have a far-reaching impact on the utility.

By leveraging the building blocks of digitization, such as service platforms, smart devices, the cloud, social and mobile technologies, and big data and advanced analytics, utilities could increase the asset life cycle of infrastructure, optimize electricity network flows, and innovate with customer-centric products. Yet, the maturity of digital initiatives in the industry varies: from projects using advanced analytics to optimize assets and the widespread implementation of smart meters, to early moves by some utilities to manage and integrate distributed generation resources. Over the coming years, these technologies will combine to deliver a new layer of connected intelligence. It will revolutionize the ability of electricity companies to improve the efficiency of the electricity system and better meet their customers' diverse needs [16]. To realize these digital opportunities, utilities need to transform operations. To begin, they must develop a digital transformation strategy that can be successfully embedded and scaled in the organization. It should be designed around the company's existing value drivers and strengths, including the product portfolio, technical competence, and customer proximity.

The next digital grid business era is not only a matter of technology and change management but also a matter of establishing the right business framework across the energy value chain to enable the necessary transformation. This future framework should consider modernized market design, revisiting market mechanisms across the energy value chain, while leveraging latest market clearing approaches to properly price scarce grid flexibility in real time. The framework should favor the deployment of innovation on both regulated and unregulated domains of the energy value chain taking advantage of the latest digital technologies to lower the cost and barrier to real-time data access. Regulation should favor the development of the new digital grid.

By their very nature, digital transformations also bring about a cultural shift. The business horizons for utilities have traditionally been of long- or medium-duration and for good reason. The industry is based on the use of expensive assets requiring serious investment and taking account of regulatory factors [18]. With the rise of distributed generation, alternative energy sources, and the data-driven customer interface, utilities are intersecting an information-based digital economy. Here success depends on new capabilities, especially the rapid scaling of innovations. As they plan to meet the digital challenge, utilities can, fortunately, draw on a wealth of experience from recent change programs in diverse industries.

The maturity of digital initiatives in the electricity industry is varied—from projects using advanced analytics to optimize assets and the widespread implementation of smart meters, to early moves by some utilities to manage and integrate distributed generation resources. To illustrate, 43% of utilities are currently investing in digital technologies as part of their overall business strategy, indicating a mixed approach [19]. The investment required for the adoption of smart and digital technologies presents utilities with difficult choices [20]. For those who do not plan to utilize digital technologies, there will be doubt regarding their ability to succeed with the smart grid transformation and market changes. For some, there is the option of using digital to make tactical improvements to their existing businesses, by streamlining operations and reducing the cost to serve and cost to acquire, and to get closer to customers. Finally, there are those utilities who will embrace digital technology as the way to transform their business. They will create competitive advantage through digitally enabled cost-effective operations, expand their scope of services to new markets, and use the smart meter as a platform to gain further traction in the smart home of the future. For today's consumers, digital technology is mainstream, as their accelerating adoption of online connectivity and social media demonstrates. With new entrants keen to enter the market, and smart metering offering them a way to do so, utilities are facing the last chance to innovate and stay ahead. To be successful, energy companies must show they can change how they operate, switching from being an "energy supplier" to an "energy services provider."

2.4 CONSUMER PERCEPTIONS AND EXPECTATIONS

Although consumers are becoming more aware of climate change and energy efficiency, the majority are not aware of the necessity to evolve electricity networks as a means of reducing emissions.

The integration of demand side resources in the form of renewable energy and consumer demand management will, in many cases, require making the existing network stronger and smarter, and require the building of new infrastructures. The public may negatively perceive changes in their electricity experience, particularly if it is accompanied by rising bills or tariffs they do not wish or feel incentivized to uptake.

Stakeholders do not see a "burning platform" or a case for change. The societal consequences of inaction (i.e., not modernizing the grid) have not been clearly articulated to our diverse group of stakeholders. A lack of understanding of the fundamental value of a smart grid and of the societal and economic costs associated with an antiquated one has created the misperception that today's grid is good enough or at least not worth the sacrifices involved in improving it. Even the inconvenience and cost of infrequently occurring large-scale blackouts are quickly forgotten. To secure customer and regulatory support for increased investments in a smart grid, the benefits must be apparent and the risk of doing nothing clear. More work is needed to communicate the concepts and benefits of the smart grid to a wide variety of stakeholders, especially consumers, and to encourage them to embrace the changes that will be needed to achieve the smart grid vision. Smart grid should also be seen in the eyes of the customer, not just the utility industry, and in terms of moving from customer to consumerism. But the utility industry also should understand customer trends and let those guide their roadmaps in what concerns the planning for the smarter grid. Effective consumer education is still lacking. The benefits of a smart grid have not been made clear to consumers. Some potential components of the consumers' value proposition include

- More effective monitoring and control of energy consumption to reduce overall electricity costs
- Participation in future electricity markets for distributed generation and demand response
- Enjoyment of future value-added services that may be enabled by a smart grid
- Customer situational awareness to enable, e.g., price-to-devices strategies and associated prosumer opportunities

Public perception can create a key barrier to implementing policy and accelerating smart grid deployment. This is especially the case in open- and competitive-leaning markets that consult widely on policy implementation. Public pressure against a perceived societal disadvantage can force policy abandonment. For example, in the Netherlands, the rollout of smart meters was quashed by a small but vocal group concerned about the increased level of personal information that the meters would provide. Conversely, public sentiment, such as a desire to green the electricity and transport sectors, can be directed to support smart grid. Utilities should educate customers before any technology deployment, and budget for costs in significant customer outreach and education. They should be ready to pass through AMI data, along with tools and incentives for customers to manage their onsite energy production, storage, and use—including the ability to safely share their data with third-party entrepreneurs. Customers should understand the real-time price of energy and services they consume, and deliver, to the grid. Ultimately, customers should pay—and be paid—that price (locational marginal pricing [LMP] or another agreed upon market signal). Pilots such as PowerCentsDC [21] have shown consumer enthusiasm for TOU rates when they are carefully designed to provide choice and to help customers understand pricing options.

Consumer protections on disconnection and low-income assistance should be provided at the same or improved level, and investment and technology risk should be shared by utilities and their customers. Where customers do pay upfront for these investments, with surcharges or other riders, utilities should be held accountable for delivering the promised benefits. For instance, the California PUC included in its approval of a surcharge the requirement that utilities share projected operational savings—whether realized or not. That is, eight months after the cost of the meter is included in the customer's bill, the Investor-Owned Utilities (IOUs) must credit customers \$1.42/month in operational savings, even if the utility has not realized those savings. Cost recovery mechanisms that reward over-performance will incentivize utilities to seek out the most effective solutions.

Consumer involvement is a required ingredient for grid modernization, and consumer education is the first step in gaining their involvement. Much remains to be done in the area of consumer education. The not in my backyard (NIMBY) philosophy must be resolved to reduce the excessive delays experienced today in deploying needed upgrades to the grid. Solutions are needed to reduce the concerns of citizens who object to the placement of new facilities near their homes and cities. New ideas are needed to make these new investments desirable rather than objectionable to nearby citizens. Communication of the smart grid vision with its goals of improving efficiency and environmental friendliness may help address this issue.

The active participation of consumers in electricity markets will bring tangible benefits to both the grid and the environment. The smart grid will give consumers information, control, and options that allow them to engage in new "electricity markets." Grid operators will treat willing consumers as resources in the day-to-day operation of the grid. Well-informed consumers will have the ability to modify consumption based on balancing their demands and resources with the electric system's capability to meet those demands.

Digital transformation is helping create a more engaged and efficient electricity consumer, while also ensuring they spend less time thinking about the power bill. Utilities will see engagement increase as customers have more options and take more control of their energy sources, whether it's from their own solar panels or whether they participate in a demand response program. Customers will be more engaged and have more control, but they do not need to be as hands-on as they have been in the past. The question of just how much interaction consumers want with the power company is a difficult one. For many consumers, the utility is something best forgotten until rates rise or the lights go out. But utility offerings, when targeted and delivered efficiently, also make for happier customers [22]. Most utility companies are trying to put themselves in front of their consumer base with the options of contacting the utility whenever or wherever the consumers feel are in their best interest [23]. Besides customer service offerings, there are other impactful offerings like demand-side management, load control, and efficiency. J.D. Power reported that more than three-quarters of utilities are increasing investment in customer engagement [24].

Now, with IoT and the increase in data and analytics capabilities, utilities have the advantage of customer insight that can be used to sell in adjacent categories, starting with energy saving and energy production. According to Utility Dive [22], over 70% of utilities consider that billing and customer support are the top ways their utility engages with consumers, followed by outreach, conservation tips, energy usage data and service offerings. Whether it's through the smart meter or other mechanisms, utilities can proactively inform customers and households how they're using energy today, suggesting how to save more and programs they may find valuable. J.D. Power reported [23] that overall utility customer satisfaction is higher primarily due to improvements in corporate citizenship and outage communications. But the results also showed the rate of improvement lagged as similarly demonstrated in utility business models, such as communications and television services.

2.5 OUTDATED POLICIES AND REGULATIONS

To meet operational challenges, the industry is looking toward new technology while still relying on much that is a century old. However, the expectations of the end user have changed dramatically. Increasingly, utilities are attempting to build regulatory support—with mixed results—for smart grid investments. Utilities may find that these operational challenges cannot be met through new technology unless accompanied by increased investment in core technology. Investment, particularly in transmission infrastructure, has been far outpaced by load growth—significantly so in certain parts of the country—due, in large part, to difficulties in getting projects of this magnitude planned, approved, permitted, and funded.

The industry is returning to its reliance on rate cases to secure the level of revenue necessary to maintain a vital component of the national infrastructure but is doing so without the same level of regulatory support it enjoyed prior to deregulation. While rate case frequency has increased, the average awarded return on equity for shareholder-owned electric utilities in the United States has declined steadily. This reflects, in part, the industry's mixed success in rebuilding the regulatory relationships damaged by deregulation initiatives that either failed to generate the expected results or were outright disasters. Rebuilding trust will be essential, whether seeking approval for new technology or simply reaching reasonable outcomes on rate cases. Going forward, the trend is for utilities to submit rate cases far more frequently to regulators than in the recent past. These regulatory discussions are also increasingly turning to matters of technology that could provide enhanced service to customers, including the ability to manage their usage more proactively.

"The thing that keeps me awake at night is the regulatory model is outdated. We're going to get burned by that at some point if we don't start thinking about how we change that regulatory model sooner rather than before it's too late," said Sunil Garg, SVP & Chief Information & Innovation Officer, Exelon Corporation [15].

Some consider the biggest impediment to the smart electric grid transition is neither technical nor economic. Instead, the transition is limited today by obsolete regulatory barriers and disincentives that echo from an earlier era [24]. Public policy is commonly defined as a plan of action designed to guide decisions for achieving a targeted outcome. In the case of grid modernization, new policies are needed if truly integrated smart grids are to become a reality. This statement may sound dire, but, in fact, work is under way in several countries to encourage smart grids and smart grid components. However, the risk still exists that unless policies are modernized to reflect changing grid participant roles and responsibilities, smart grid investments may fall short. This would be an unfortunate outcome when one considers the many benefits of a true smart grid: cost savings for the utility, more choices and better value for customers, improved reliability, and increased environmental stewardship.

The rapid expansion in the penetration of various forms of distributed energy resources and interest in improved local resiliency, through approaches like microgrids, illustrates the fascination many consumers and policymakers have with the interplay between the electric grid and the climate. That said, consumers largely lack a robust understanding of the integral role the smart grid plays in managing the new complexity inherent in a more distributed energy model.

Meanwhile, policymakers face a difficult trade-off between (1) being sufficiently directive to provide clarity to companies on the future shape and rules for the market and (2) providing sufficient incentive for companies to invest in innovative technologies and services. Utilities must establish a positive dialog with regulators to ensure that the industry and market are redesigned so that they work for all participants, and achieve the essential objectives of decarbonization, decentralization, and digitization. The regulation pertaining to the grid-edge is rapidly evolving; the implications of distributed energy resources and their integration into the market are likely to shape and affect the digital regulation outcomes. Equally, the evolution of discussions relating to grid defection has a big role to play in how "connected" and "effective" the future system can be, with a more disconnected system potentially less optimal than a fully connected and optimized system.

While regulation can help in implementing smart grid technologies, regulatory structure and other factors can create revenue uncertainties. If a company is required to invest in smart grid technologies, the revenue model must align with the associated costs and benefits. Yet, many policymakers are resistant to the new mechanisms needed to properly align rate designs with the evolving costs associated with building and maintaining an integrated smart grid. Perhaps, the most glaring, and often quoted, disparity between current revenue drivers and smart grid drivers in many markets is the link between revenue and throughput. If smart grid technologies are successful, energy efficiency measures will be supported that will reduce throughput. In this common scenario, without appropriate regulatory adjustments, the company would be investing to reduce its own revenue. To restructure the regulatory model to address issues such as revenue assurance, both utilities and policymakers need a broad understanding of the primary role that smart grid technologies can play in meeting energy and environmental policy. This understanding will help them define a suitable regulatory regime that can align utilities' rewards with the benefits that their investments bring.

Incentives to stimulate smart grid investments that provide societal benefits are lacking. Regulatory policies often do not give credit to utilities for investments that provide substantial societal benefits (e.g., improvements in reliability and national security, reduction in our dependency on foreign oil, reductions in environmental impacts). Regulators play a vital role in ensuring that customers' interests are reflected in the decision-making of the service provider. As such, regulators are a critically important gatekeeper in a smart grid project life cycle. This is particularly important for AMI, which (1) is a technology that fundamentally transforms the utility-customer relationship, and (2) offers potential benefits that cannot be realized without changes in customer behavior. To the latter point, the most obvious examples are the innovative rate structures, such as critical peak pricing, which can leverage AMI technology to drive beneficial changes in customer usage patterns. To maximize their value, smart meters require smart rates, and smart rate design requires detailed dynamic pricing discussions among utilities, regulators, and customer advocates. Effective collaboration among these groups will result in programs and pricing tailored appropriately to the customer segments being served. Progress is being made to bring clarity to roles and align costs and incentives as evidenced by recent actions taken in a few leading states in the US, such as New York, California, Minnesota, and Massachusetts. While these states show that progress is under way, most energy companies and the communities they serve are still operating under policy structures that have not kept pace with advances in technology. These lagging policies result in market uncertainty regarding how the overall market structure and rules will develop, which technologies merit investment, and the levels of grid capability required.

2.6 SECURING THE VULNERABLE GRID

The smart grid will need to incorporate a system-wide solution that reduces both physical and cyber vulnerabilities and enables a rapid recovery from disruptions. Its resilience will need to deter would-be attackers, even those who are determined and well equipped. Its decentralized operating model and self-healing features will also make it less vulnerable to natural disasters than today's grid. Security protocols will contain elements of deterrence, detection, response, and mitigation to minimize impact on the grid and the economy. A less susceptible and more resilient grid will make it a more difficult target for malicious acts.

Utility investments in security upgrades have been historically difficult to justify. A standard approach is beginning to develop for conducting security assessments, understanding consequences, and valuing security upgrades. NIST (National Institute of Standards and Technology) has developed security assessment models, for example, that are being adopted in many utilities [25]. While there have been recent legislative changes, there is still very limited access to government-held threat information, which makes the case for security investments even more difficult to justify. When examined independently, the costs and benefits of security investments can seem unjustifiable. It is difficult to place a value on preventing a cyber or physical attack through implementation of security measures. However, the consequences of cyber attacks on critical infrastructure have been more widely discussed in the public, and with the growing awareness of the risks, utilities are increasingly being asked to demonstrate their cybersecurity programs' effectiveness.

Various cybersecurity intrusion studies have demonstrated the vulnerability of communication, automation, and control systems to unauthorized access. Many real-world cases of intrusion into critical infrastructures have occurred, including illegal access into electric power systems for transmission, distribution, and generation, as well as systems for water, oil and gas, chemicals, paper, and agricultural businesses. Confirmed damage from cyber intrusions include intentionally opened breaker switches and the shutdown of industrial facilities. Very few of the incidents have been publicly reported, and initiatives aimed at creating an open repository of industrial security incidents encounter resistance. Threats come from hackers, employees, insiders, contractors, competitors, traders, foreign governments, organized crime, and extremist groups. These potential attackers have a wide range of capabilities, resources, organizational support, and motives.

The possible vulnerability of the utility's system, business and customer operations, and consumer premises represent serious security risks; therefore, security must be approached and managed with an extreme level of care. Apart from active, malicious threats, accidental cyber threats are increasing as the complexities of modern data and control systems increase. Security risks are growing in diverse areas, including the following:

- Risk of accidental, unauthorized logical access to system components and devices and the associated risk of accidental operation
- Risk of individual component failure (including software and networks)
- Number of failure modes, both directly due to the increased number of components and indirectly due to increased (and often unknown) interdependencies among components, devices, and equipment
- Risk of accidentally misconfiguring components
- Failure to implement appropriate maintenance activities (e.g., patch management, system housekeeping)

Worldwide, initial security gaps have been highlighted by security companies and were discovered within pilot projects, which are not designed to resist sustained cyber attack. While such systems are now broadly secure against elementary hacking techniques, situations where an insider, who knows the system, can exploit the vulnerabilities are of concern to smart grid technology stakeholders. All parties involved in managing network operations centers or the relevant IT systems should be trained and alert to tamper from the inside. Specially trained security officers need to be working in all potentially vulnerable areas.

Open communication and operating systems may be vulnerable to security issues. Although open systems are more flexible and improve system performance, they may not be as secure as proprietary systems. The increasing use of open systems must be met with industry approved and adopted standards and protocols that ensure system security.

A utility needs to define its own selection of security controls for system automation, control systems, and smart devices, based on normative sources and as appropriate for the utility's regulatory regime and assessment of business risks. The security controls need to be defined within each security domain, and the information flows between the domains need to be based on agreed risk assessments, established corporate security policies, and possible legal requirements imposed by the government. In addition, limitations related to the existing legacy systems must be accommodated in a manner that does not hamper organizational security. Emerging smart grid systems and solutions should be thoroughly tested by qualified laboratories to ensure that new digital communications and controls necessary for the smart power grid do not open new opportunities for malicious attack. The responsibility for this security rests with all market participants—both industry and governments.

The idea of extending an Internet protocol (IP)-based network to the meter level does open the potential for both internal and external hacking. To protect against those threats, the structure of the system architecture should be considered carefully. By having a distributed intelligence in the grid, we mitigate a single point of failure, but also increase the complexity of management. Every utility thinking about providing equipment and services for smart grid technology enterprises should be cognizant of security and standards, with thought given to security certification for hardware and software providers.

The massive amount of potentially sensitive data collected in a smart grid, particularly with the implementation of consumer technologies, offerings, and services (e.g., advanced metering infrastructure [AMI] and DSM), inherently creates data privacy and security risks. Consumer involvement applications and solutions put privacy interests at risk because information is collected on energy usage by a household or business. With granularity, down to fifteen minutes and less, meters already collect a unique meter identifier, timestamp, usage data, and time synchronization every fifteen–sixty minutes. Soon, they will also collect outage, voltage, phase, and frequency data, and detailed status and diagnostic information from networked sensors and smart appliances. Interpreted correctly, such data can convey precisely whether people were present in the home, when they were present, and what they were doing. Utilities implementing consumer technologies, offerings, and services within a smart grid environment that fails to address these issues will encounter consumer and political opposition, restricting their ability to realize the economic promise of smart grid technologies. They may face angry regulators and customers as well as liability issues.

In the consumer context, the right to privacy means the consumer's ability to set a boundary between permissible and impermissible uses of information about themselves. What is impermissible is a matter of culture, as expressed in law, markets, and what individuals freely accept without objection (i.e., consensus values). If customers believe a utility is misusing personally identifiable data or is generally enabling the use of personal information beyond what they deem acceptable (whether legal or not), then they are likely to resist the implementation of vital smart grid functionality related to consumer offerings and services. Consumers may refuse to consent (where required), hide their data, or awaken political opposition. Utilities may face customer liability claims or regulatory fines if inadequate privacy or security practices enable eavesdroppers, adversaries, or bad actors to acquire and use collected data to a customer's detriment. Utilities must take into account privacy and security concerns when designing consumer technologies, offerings, and services, and must persuade consumers, regulators, and politicians that privacy interests are adequately protected.

What constitutes permissible uses of personally identifiable information varies from culture to culture and over time; yet, what goes on inside a residence is generally an area of special privacy concern. The collected data reveal more about what goes on inside a residence than would otherwise be known to outsiders, and the collection and use of such data would reduce the scope of private information. Although privacy is generally considered a personal right, businesses typically have analogous rights.

Once a utility establishes the permissible uses of consumer data, it is in its best interest to assure that unauthorized uses do not occur. For example, if an electricity service provider can sell appliance-related data to a manufacturer or retailer, the utility will want to protect its economic interest by preventing access or use by others who might become competitive data brokers. Every utility will want to avoid regulatory sanctions for violating express or implied privacy policies, as well as damage claims based on compromised customer data or facilities.

Concerns about data privacy in smart grid environments and AMI are now being widely discussed. In the Netherlands, for example, the formerly compulsory AMI rollout was subsequently made voluntary. The US Department of Energy (DOE), responding to this concern, has created DataGuard, which provides a set of principles that, if agreed upon, would enable the utility to use the DataGuard logo as an indicator of their participation in the program [26]. What is ultimately needed is a secure system for utilities to provide key information to the marketplace at very low transactional costs, but with proper protections, in order to unlock the potential for innovative smart grid-enabled services to be realized.

2.7 CONFLUENCE AND ACCELERATION OF STANDARDS

Global standardization is essential for the deployment and successful operation of smart grids. While progress is being made, challenges remain due to fragmentation among stakeholders in the process of standards development, the lack of well-defined standards for smart grid interoperability, and intellectual property issues. At the same time, standards defined too early risk stifling innovative technological advances.

While smart grid technologies continue to progress, without well-defined and technology-neutral interoperability standards, further innovations and opportunities for deployment at scale are limited. Global cooperation for defining standards has not kept pace with technology innovation and development, which could impede large-scale development and rollout. Therefore, interoperability and scalability should be priorities, while taking care to avoid stifling innovation.

Since smart grid technologies encompass a diverse scope of technology sectors, including electricity infrastructure, telecommunication, and IT, misinterpretation and error may arise where there is a lack of interface standardization and related communication protocols. Therefore, even after standardization of the respective technologies, conformity testing and certification of interoperability may prove problematic for providers, since each technology must go through a conformity assessment specifically designed for the particular technology.

Existing international standards development organizations (SDOs) include the following:

- IEC—International Electrotechnical Commission (www.iec.ch)
- IEEE—Institute of Electrical and Electronics Engineers (www.ieee.org)
- ISO—International Organization for Standardization (www.iso.org)
- ITU—International Telecommunication Union (www.itu.int)

In addition to the SDOs, many country or region-based standard associations influence the smart grid standards community. A key barrier is the lengthy process to develop and reach international consensus on a standard. For example, the average development time for IEC publications in 2008 was thirty months. Even after one of the SDOs has defined a standard, it still must go through the harmonization process.

The smart grid is a large and complex marriage of the traditional electrical infrastructure and modern IT systems. This is truly a global effort involving thousands of utilities and vendors to implement and deploy the smart grid. To complete, a successful and cost-effective deployment of the smart grid "international standards" will have to be followed by all who participate in its deployment. Why do we say this and why are standards so important to success? The following points characterize the importance of standards:

- Shareability—economies of scale, minimize duplication
- Ubiquity—readily utilize infrastructure, anywhere
- Integrity—high level of manageability and reliability
- Ease of use—logical and consistent rules to use infrastructure
- Cost-effectiveness—value consistent with cost
- Interoperability—define how basic elements interrelate
- Openness—supports multiple uses and vendors, not proprietary
- Secure—systems must be protected
- Scalable—low- or high-density areas, phased implementation
- Quality—many entities testing and verifying

The smart grid is broad in its scope, so the potential standards landscape is also very large and complex. Therefore, "standards" adoption has become a challenge. However, the opportunity today is that utilities, vendors, and policymakers are actively engaged and there are mature standards that are applicable and much work on emerging standards and cybersecurity can be leveraged. Technology is not the primary barrier to adoption. The fundamental issue is organization and prioritization to focus on those first aspects that provide the greatest customer benefit toward the goal of achieving an interoperable and secure smart grid. It is critical that we find a process that will accelerate the adoption of new smart grid standards. First, consider the challenges the industry must overcome to accelerate the smart grid standards adoptions:

1. There are many standards bodies and industry committees working in parallel with many duplicate and conflicting efforts. The industry must come together in a concerted effort to accelerate the adoption of the stands on which they are focused.

2. The number of stakeholders, range of considerations, and applicable standards are very large and complex, which require a formal governance structure at a national level involving both government and industry, with associated formal processes to prioritize and oversee the highest value tasks.
3. The smart grid implementation has already started and will be implemented as an "evolution" of successive projects over a decade or more. Standards adoption must consider the current state of deployment, development in progress, and vendor product development life cycles.
4. Interoperability is generally being discussed too broadly and should be considered in two basic ways, with a focus placed on prioritization and acceleration of the adoption of "inter-system" standards.

How can these challenges be quickly overcome?

1. NIST (National Institute of Standards and Technology) should continue its work in developing and coordinating smart grid interoperability standards (https://www.nist.gov/engineering-laboratory/smart-grid/about-smart-grid).
2. Develop a smart grid "road map" that outlines a path and direction of deploying existing and future standards giving the industry clear direction forward.
3. Identify focus areas are as follows:
   a. Common information model
   b. Cybersecurity
   c. Interoperability base on open protocol
   d. Application interface standards
   e. Messaging
4. Governance principal definitions include the following:
   a. Openness
   b. Integrity
   c. Separation of duties and responsibility
   d. Compliance
5. Establish clearly defined test and verification methodologies and certification bodies shall be established to certify compliance with standards.
6. Encourage rapid vendor adoption of established standards.

The grid will become "smarter" and more capable over time and the supporting standards must also evolve to support higher degrees of interoperability enabling more advanced capabilities over time. The implication of the smart grid evolution for standards adoption is that at any point in time the industry will be characterized by a mix of no/old technology, last generation smart technology, current generation smart technology, and "greenfield" technology opportunities. Smart grid implementation is an evolutionary process involving long project development life cycles from regulatory approvals through engineering and deployment. Given that technology life cycles are much shorter than the regulatory-to-deployment cycle, it is very likely that the grid will continuously evolve in the degree to which intelligence is both incorporated and leveraged.

The issue of evolution is particularly important because investments are a continuum based on policy imperatives, system reliability, and creating customer value. Policymakers and utilities must balance these considerations regarding certain smart grid investments before a complete set of standards has been adopted and customer benefit dictates moving forward. In many instances across the nation, utilities and regulators have given much thought to balancing accelerating customer benefits, project cost-effectiveness, and managing emerging technology risks. While there is no single "silver standards bullet" for legacy and projects currently in development, projects that are in the customers' and public policy interest should proceed. However, not having clear standards going forward compounds the technology obsolescence risk.

There is no technical reason to attempt to standardize all aspects of the smart grid today if engineered and designed correctly. Nor is it likely possible, considering the lack of clear definition of all the elements and uses of the smart grid and complexity and given the number of systems involved. Smart grid systems architected appropriately should be able to accept updated and new standards as they progress, assuming the following standards evolution principles are recognized:

- Interoperability must be adopted as a design goal, regardless of the current state of standards.
- Interoperability through standards must be viewed as a continuum.
- Successive product generations must incorporate standards to realize interoperability value.
- Smart grid technology roadmaps must consider each product's role in the overall system and select standards compliant commercial products accordingly.
- Standards compliance testing to ensure common interpretation of standards is required.

These principles are being followed by many utilities implementing smart grid systems today by requiring capabilities such as remote device upgradability and support for robust system-wide security, and identifying key boundaries of interoperability to preserve the ability of smart grid investments to evolve to satisfy increasingly advanced capabilities.

Accelerating smart grid standards adoption can be achieved by focusing industry efforts on the right tasks in the right order. A system's engineering approach provides a formal, requirements-based method to decompose a complex "System of Systems," such as the smart grid, from a high intersystems view through a very structured process to a lower intrasystems view. Applying systems engineering to smart grid capabilities and supporting standards reveals that it is more important to create a unifying design for the entire system operationally than to focus on implementing individual elements at the risk of future systems operations. This means that it is not necessary to first resolve interoperability of "intrasystem" interfaces within the utility's smart grid implementations before projects can proceed. This is true, if the important "inter-system" boundaries are well understood and the following interoperability design concepts are preserved.

2.8 BUILDING THE BUSINESS CASE, MOVING PAST THE PILOTS

All stakeholders must be aligned around a common vision to fully modernize today's grid. Throughout the twentieth century, the electric power delivery infrastructure has served many countries well to provide adequate, affordable energy to homes, businesses, and factories. Once a state-of-the-art system, the electricity grid brought a level of prosperity unmatched by any other technology in the world. But a twenty-first-century economy cannot be built on a twentieth-century electric grid. There is an urgent need for major improvements in the world's power delivery system and in the technology areas. Several converging factors is driving the energy industry to modernize the electric grid. These factors can be combined into the following five major groups.

Policy and Legislative Drivers

- Electric market rules that create comparability and monetize benefits
- Electricity pricing and access to enable smart grid options
- State regulations to allow smart grid deferral of capital and operating costs
- Compatible Federal and state policies to enable full integration of smart grid benefits

Economic Competitiveness

- Creation of new businesses and new business models and adding of "green" jobs
- Technology regionalization
- Alleviation of the challenge of a drain of technical resources in an aging workforce

Energy Reliability and Security

- Improve reliability through decreased outage duration and frequency
- Reduce labor costs, such as manual meter reading and field maintenance, etc.
- Reduce non labor costs, such as the use of field service vehicles, insurance, damage, etc.
- Reduce T&D system delivery losses through improved system planning and asset management
- Protect revenues with improved billing accuracy, prevention, and detection of theft and fraud
- Provide new sources of revenue with consumer programs, such as energy management
- Defer capital expenditures because of increased grid efficiencies and reduced generation requirements
- Fulfill national security objectives
- Improve wholesale market efficiency

Customer Empowerment

- Respond to consumer demand for sustainable energy resources
- Respond to customers increasing demand for uninterruptible power
- Empower customers so that they have more control over their own energy usage with minimal compromise in their lifestyle
- Facilitate performance-based rate behavior
- Accommodate customers that bring their own generating and storing devices, and be able to create value for them beyond self-generation and consumption

Environmental Sustainability

- Respond to governmental mandates
- Support the addition of renewable and distributed generation (DG) to the grid
- Deliver increases in energy efficiencies and decreases in carbon emissions

Many of these drivers are country- and region- specific and differ according to unique governmental, economic, societal, and technical characteristics. For developed countries, issues such as grid loss reduction, system performance and asset utilization improvement, integration of renewable energy sources, active demand response, and energy efficiency are the main reasons for adopting the smart grid. Many developed countries experience system reliability degradation resulting from aging grid infrastructure. Inadequate access to "strong" T&D grid infrastructure limits the potential benefits of the integration of renewable energy generation.

The smart grid provides enterprise-wide solutions that deliver far-reaching benefits for both utilities and their end customers. Utilities that adopt smart grid technologies can reap significant benefits in reduced capital and operating costs, improved power quality, increased customer satisfaction, and a positive environmental impact. With these capabilities come questions: What is the potential of the smart grid? Is there one set of technologies that can enable both strategic and operational processes? How do the technologies fit together? How do you leverage benefits across applications? Smart grids should be based on integrated solutions that address business and operating concerns and deliver meaningful, measurable, and sustainable benefits to the utility, the consumer, the economy, and the environment (Figure 2.1).

Various components come into play when considering the impact of smart grid technologies. Utilities and customers can benefit in several ways. Rate increases are inevitable, but smart grids can offer the prospect of increased utility earnings, together with reduced rate increases (plus improved quality of service). Viewing smart grid programs in the context of, for example, a "green" program for customer choice or a cost reduction program to moderate customer rate increases can help define

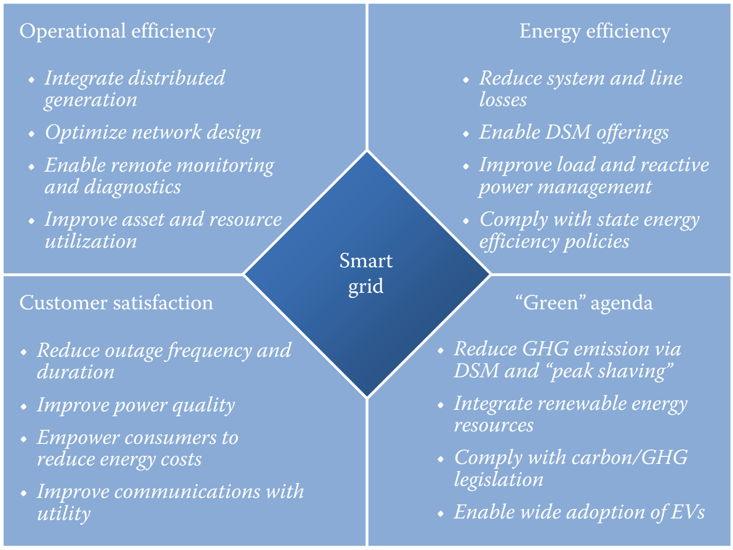

FIGURE 2.1 Smart grid benefits.

utility drivers and shape the smart grid roadmap. A smart grid program should have a robust business case where numerous groups in the utility have discussed and agreed upon the expected benefits and costs of smart grid candidate technologies and a realistic implementation plan. In some cases, the benefits are modestly incremental, but a smart grid plan should minimize the lag in realized benefits that typically occur after a step change in technology. A smart grid deployment is also intended to allow smoother and lower cost migrations to new technologies and avoid the need to incur "forklift" costs. A good smart grid plan should move away from the "pilot" mentality and depend on wisely implemented field trials or "phased deployments" that provide the much-needed feedback of cost, benefit, and customer acceptance that can be used to update and verify the business case.

2.8.1 Utility Benefits

Improving grid reliability and operational efficiency is possible using more intelligence in the delivery network to monitor power flow in real time and improve voltage control to optimize delivery efficiency and eliminate waste and oversupply. This will reduce overall energy consumption and related emissions while conserving finite resources and lowering the overall cost of electricity. Software applications—including smart appliances, home automation systems, etc.—that manage load and demand distribution help to empower consumers to manage their energy usage and save money without compromising their lifestyle—encouraging consumers to become smart consumers in smart homes, by giving them access to TOU rates and real-time pricing signals that will help them to save on electricity bills and cut their power usage during peak hours. This also helps to improve overall system delivery efficiency and reduce the number of power plants and transmission lines that will need to be built.

In 2008, the United States had electricity distribution losses adding up to 271 billion kilowatt-hours [27], more than 6% of total net generation. Xcel Energy estimates that the smart grid can reduce those losses by 30%, utilizing optimal power factor performance and system balancing [28]. The U.S. DOE estimates that conservation voltage reduction and advanced voltage control can reduce GHG emissions from electricity by 2% nationally in 2030 [29].

The rapid deployment of smart grid technologies across the country reflects the multiple operational and reliability benefits utilities expect to realize, including savings on operation and maintenance costs and the avoidance of costly outages. Operational and energy efficiency benefits are highly valuable, but will not always—by themselves—justify the ratepayer expense. Boston

Consulting Group (BCG) estimates that just 60% of the cost of smart grid deployment can be justified through the utility business case alone. Making smart meters, for example, a "winning proposition," per BCG, will require that 20%–30% of a utility's customers use the new technology to reduce their overall consumption or peak demand by 15%–20%. "Falling short of that threshold," says Pattabi Seshadri, a consultant at BCG's Energy Practice, "will likely prevent the utility from delivering the necessary return on investment" [30].

Increasing reliance on distributed and demand-side resources, reducing line losses, and increasing capacity of existing transmission lines using dynamic thermal rating and wide area control technology—all could reduce the need for new transmission and generation units, saving money and avoiding impacts on land and wildlife [31]. The California Public Utility Commission recognized that value in its June 2010 decision on smart grid deployment plans: "The Smart Grid can decrease the need for other infrastructure investments and these benefits should be considered when planning infrastructure" [32].

Such analyses elsewhere in the country have resulted in the deferral of several transmission lines. Synapse, for instance, has provided expert testimony on electric power transmission issues on behalf of consumer advocates and environmental groups in Pennsylvania, Virginia, and Maine. The key issue in all three cases was "how recent increases in demand response and energy efficiency affect utility and RTO forecasts of the need for new transmission over the next decade." In Virginia, they demonstrated that—factoring in efficiency and demand response resources under development in PJM's easternmost states—an AEP/APS (American Electric Power/Arizona Public Service) proposed 765 kV line would not be needed within the ten-year planning period. PJM sensitivity studies confirmed Synapse's estimates, and the transmission line application was withdrawn [33].

2.8.2 Consumer Benefits

Under the current regulatory structure, investor-owned utilities propose investments, regulators approve those investments—the rate of return the utility will earn on them—and consumers (ratepayers) foot the bill. As witnessed in the United States in Indiana, Maryland, and elsewhere, regulators around the country are requiring utilities to demonstrate that they will deliver long-term benefits to consumers commensurate with the public's investments. Designing to maximize those benefits will, in turn, benefit utilities. As J.D. Power and Associates found in a consumer survey: "Utility providers that develop smart systems with customer satisfaction in mind may be able to get things right the first time, ultimately saving in long-term development and implementation costs" [34].

Fortunately, a well-designed smart grid can deliver significant additional benefits, which can repay that investment many times over. Consumers will benefit from reduced bills and much greater control: the ability to use electricity when it is cheapest and to produce and sell power and other services into the grid when demand and prices are high. Entrepreneurs and their employees will benefit from new opportunities to provide energy services—from storage at substations to behind-the-meter "energy apps." Communities will enjoy greater energy security, as they rely increasingly on distributed energy resources in their own backyards. The most valuable benefit could be the opportunity to radically reduce the hidden costs of electricity to the environment and public health.

The smart grid will enable significant reductions in both overall energy consumption [35] and peak use of electricity by giving customers real-time information and pricing, facilitating much broader use of demand response, providing the necessary information to support "continuous commissioning" in the built environment, increasing the capacity of existing transmission lines, and reducing T&D line losses.

Numerous studies have found that giving customers real-time energy usage information cuts consumption by 5%–15%. Adding pricing incentives and automated home energy management tools, such as programmable thermostats and smart appliances linked to home area networks, can double those savings [36,37].

A June 2010 report from the American Council for an Energy-Efficient Economy (ACEEE) found that U.S. consumers could cut their household electricity use as much as 12% and save $35 billion or more over the next twenty years if U.S. utilities go beyond AMI deployment to include a wide range of energy-use feedback tools that engage consumers in using less energy. ACEEE based its findings on a review of fifty-seven different residential sector feedback programs between 1974 and 2010, concluding that "to realize potential feedback-induced savings, advanced meters must be used in conjunction with in-home (or on-line) displays and well-designed programs that successfully inform, engage, empower, and motivate people" [38].

The Pacific Northwest National Laboratory (PNNL) and the Brattle Group have found that conservation tends to be strongest when feedback is based on actual usage data, provided on a frequent basis over a year or more, involves goal setting and choice with specific behavioral recommendations, and involves normative or historical comparisons [39].

Existing demand response programs, focused on large industrial users, can currently deliver 37 GW nationwide. Without new programs, that capacity will grow little over the coming decade, to just 38 GW by 2019, saving just 4% compared to a scenario with no demand response programs at all. A smart grid will almost quadruple those savings, according to modeling done for Federal Energy Regulatory Commission (FERC): large-scale deployment of AMI, enabling technologies, and dynamic pricing will enable peak reductions of 138 GW by 2020 [40].

A smart grid greatly expands the potential participants in demand response programs by making it possible to send the necessary signals, including dynamic prices, to residences and small- and medium-sized businesses. A Battelle-PNNL pilot, for instance, using predefined customer preferences and fast, autonomous controls on clothes dryers and water heaters to respond to ancillary service signals on very short timescales, achieved peak residential demand reductions of 16%, and average demand reductions of 9%–10% for extended periods of time [41]. In Oklahoma Gas and Electric's pilot, customers with smart thermostats achieved peak demand reductions of 57% [42].

Dynamic pricing is particularly valuable for cutting peak power demand. Analyzing a range of experiments, Brattle's Ahmad Faruqui found that TOU rates cut peak demand by 3%–6% and critical peak pricing (CPP) cut peak demand by 13%–20%. When accompanied with enabling technologies, CPP cut peak demand by 27%–44% [36].

Several studies have shown that customers respond to, and appreciate, TOU rates. PowerCentsDC [21]—an American Recovery and Reinvestment Act of 2009 (ARRA)-funded pilot in the nation's capital—ran from July 2008 through October 2009. This voluntary program chose 900 customers at random, providing each with a smart meter and smart thermostat and assigning them to one of the three pricing plans. One of those plans, a Critical Peak Rebate, rewarded customers for reducing their use below baseline during critical peaks. It cut peak use by 13%, with low-income customers achieving savings in line with others' results. Nearly three-quarters of the customers who participated were satisfied with the program and 93% preferred the dynamic rates over the utility's standard rates [21]. A September 2010 meta-study for the Edison Foundation Institute for Electric Efficiency found similar results in its assessment of recent dynamic pricing programs at Connecticut Light and Power, Baltimore Gas and Electric, and Pacific Gas and Electric. They not only found that low-income customers did shift load in response to dynamic pricing but also found that because they began with a flatter load, they saved money even when they did not shift load [43].

The economic benefits of these peak reductions are broadly shared, even by consumers who do not shift their consumption. Shifting just 5% of peak demand reduces prices substantially for everyone, both because the most expensive peak power plants do not get turned on and because new peakers need not be built [44].

2.8.3 Environmental and Economic Benefits

Environmental, health, and other social benefits of the smart grid can contribute real value to these calculations if the grid is designed to capture them. Capturing those social benefits is especially important because it is customers, ultimately, who are financing this new grid. Smart grids will enable broader deployment and optimal inclusion of cleaner, greener energy technologies into the grid from localized and distributed resources, including rooftop solar, combined heat and power plants and DG, thereby reducing dependence on coal and foreign oil and promoting a sustainable energy future. Electric and plug-in hybrid electric vehicle (EV) integration will bring another distributed resource to market, but one at scale—with supporting rates and billing mechanisms that can help flatten the load profile and reduce the need for additional peaking power plants and transmission lines potentially reducing the carbon footprint and fostering energy security and independence.

Electricity generation and use in the United States is one of the biggest sources of pollution on the planet, accounting for more than one-fifth of the world's CO_2 emissions [45]. The U.S. power plants also draw a huge fraction of the nation's freshwater supply. Nearly 40% of all domestic water withdrawals in the United States are used for cooling thermoelectric power plants. Depending on the cooling system, that water may be returned to the source at a higher temperature and with diminished quality, or evaporate and be lost for good [46]. In the Interior West, for example, where power plants rely primarily on recirculating cooling systems, approximately 56% of the water is lost to evaporation [47]. Conventional power plants in Arizona, Colorado, New Mexico, Nevada, and Utah consumed an estimated 292 million gallons of water per day (MGD) in 2005—approximately equal to the water consumed by Denver, Phoenix, and Albuquerque combined. By 2030, water use for power production in the Rocky Mountain/Desert Southwest region is projected to grow by 200 MGD—that water would otherwise be available to meet the needs of almost 2.5 million people [47]. In Texas, power plants consume as much water as three million people, each using 140 gals per person, per day [48]. With climate change already impacting water resources—reducing, for instance, snowpack in the West, a major source of freshwater—and with U.S. energy demand projected to grow 1.7% per year through 2030, these stresses will only grow [47].

Peak shaving delivers huge environmental and health benefits that 138 GW of peak reductions forecast by FERC is equivalent to the output of 1300 peaking power plants [40]. Many of these plants—often inefficient natural gas turbines—are in or near major population centers, where their smog-forming emissions harm public health. As with the coal fleet, the National Academy of Sciences (NAS) study found that just 10% of natural gas-fired power plants contribute a majority (65%) of the air pollution damages from all the 498 plants they studied. Replacing those plants with smart-grid enabled efficiency and demand response would significantly reduce public health impacts as well as GHG emissions, cutting 100–200 million tons of CO_2 per year—5%–10% of total GHG pollution from the U.S. power sector in 2007.

A concerted effort to make full use of demand response opportunities in regions now served by the dirtiest coal-fired power plants could also multiply benefits for human health by altering the economic calculus for those plants [49]. The entry of low-cost demand-side resources into the PJM market, for example, has put downward pressure on the capacity revenues earned by marginal power plants for being on standby to meet demand spikes. This downward price pressure contributed to the decision to retire two old, marginal coal plants in Philadelphia, and is putting financial pressure on other high-polluting, marginal coal, oil, and natural gas-fired units in the region; it may well cut more pollution than the direct effects of avoided demand [50].

The biggest environmental gains of demand response will come from the combined effects of these shifts on the overall generation portfolio: providing demand-side balancing for renewables in place of fossil-fueled backup generation, avoiding the need for new peaker plants, and hastening retirement of old dirty coal. Whether load shifting will also directly reduce emissions will depend on the current resource mix: Since the emissions from one source of electricity are effectively traded for those of another, the environmental result will depend on the emissions profile of that second source. For example, carbon emissions will go down when the use shifts from inefficient, simple cycle natural gas-fired plants that serve peak loads to efficient, combined cycle plants that serve intermediate loads. One analysis of twelve NERC subregions showed that most regions would shift to natural gas and reduce carbon emissions, but a few would shift to coal and increase carbon emissions [29]. As clean energy makes up a larger portion of base load generation, shifting away from peak power will have an increasingly positive impact. Applying an algorithm with CO_2 reductions as its primary objective and adding energy storage will make possible still greater reductions in CO_2 [29].

A 2003 Synapse model of demand response in New England indicates that a system-wide analysis will also be necessary to capture critical health benefits. It found that if demand response was used for more efficient unit commitment, reduced operation of oil- and gas-fired steam units, and increased operation of combined-cycle units in New England, it would significantly reduce NO_x, SO_2, and CO_2 in summer months. Those benefits would not be realized, however, if it simply shifted load to on-site diesel- or natural gas-fueled internal combustion (IC) engines [51].

As the smart grid improves the ability to measure real-time environmental impacts of dispatch decisions, it will facilitate prioritization of cleaner alternatives. Because power plant dispatch presents thousands of options for rearranging the generation mix, Charles River Associates (CRA) and others have been developing sophisticated modeling tools to precisely measure the actual carbon impact of electricity use in real-time, or "marginal carbon intensity" (MCI). CRA's analyses indicate that the real-time and locational variability of carbon emissions is as great as the variability of electricity prices: both depend on which marginal generators are brought online or displaced as the system is redispatched to accommodate changes in load and transmission congestion [52]. PJM Interconnection—which administers the competitive wholesale market serving 51 million people in Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia—has begun applying a similar analysis to estimate CO_2 reductions from demand response, energy efficiency measures, and increases in carbon-free generation [53].

PJM is among the leaders in incorporating demand response into wholesale markets: more than 9000 MW of demand-side capacity resources participated in its 2010 capacity market, equivalent to 120 grid-scale, gas-fired combustion turbines or eighteen medium-sized coal-fired power plants. Roughly a quarter of this, 2444 MW, participated as an economic resource, responding solely to market price signals to provide service to the grid. The remainder was emergency capacity, which jumps into service at the direction of the grid operator. In terms of actual energy delivered, PJM received 94,000 MWh from all demand-side resources in 2010, 60% on price signal alone. Though some of this DR may have come from on-site generators, most came from avoided energy consumption, translating to about 77,000 tons of avoided carbon. In short, PJM's demand response market rules enabled about 6% of the region's total peak load to be served by demand-side resources, up from less than 2% four years ago but still, less than half the 15% potential DR Brattle found in this region.

Smart grid-enabled monitoring of chillers, control systems, and other equipment in large (>100,000 ft^2) commercial buildings can detect suboptimal performance and prescribe operational improvements or maintenance, thus achieving overall electricity savings of 9% [54]. Applied in 20% of such buildings nationwide, the annual energy savings would be 8.8 billion kWh, avoiding 5 million metric tons of CO_2 emissions [55]. A smart grid will also provide detailed consumption data: Utilizing that data for improved diagnostics in residential and commercial buildings will allow for accurate targeting of efficiency investments in HVAC, lighting, and other systems, translating to a 3% reduction in U.S. CO_2 emissions from the electricity sector in 2030 [29].

Monetizing these environmental impacts gives a clearer sense of the real price we currently pay for conventional electricity generation and use. A report from the NAS (National Academy of Sciences) on "Unpriced Consequences of Energy Use and Production" estimates that in 2005 alone, environmental externalities from U.S. electricity production cost $120 billion. That figure underestimates the true costs, the report notes, because it does not include the costs of climate change or damage to ecosystems. Half of that $120 billion comes from aggregate damages from sulfur dioxide (SO_2), nitrogen oxides (NO_x), and particulate matter (PM) from production of coal-fired electricity at 406 plants, for an average of $1.56 million per plant. Natural gas plants tend to be less polluting due to their cleaner fuel and smaller size, but are not without cost—averaging $1.49 million in annual damages per plant [49].

These are not theoretical costs but real costs—for water, health care, and premature deaths—borne directly by citizens. In Utah, for instance, burning coal to provide electricity for its residents and for neighboring states produces health and water impacts of up to $2.1 billion dollars per year [56]. These costs include hospital visits from respiratory injuries and asthma and the use of twenty-four billion gallons of water annually, adding as much as $45 per MWh to the cost of fossil fuel generation. Those harmful externalities, in other words, effectively double the true cost of that electricity.

Like the NAS numbers, the Utah figure does not include costs from GHG emissions. Nationally, the costs of climate change impacts related to real estate loss due to sea level rise, damages from more extreme hurricanes, increased energy costs to keep comfortable in a warmer world, and water supply impacts are forecasted to exceed $270 billion by 2025 [57]. U.C. Berkeley researchers David Roland-Holst and Fredrich Kahrl found that if no action is taken to avert the worst effects of global warming, California alone will face damages of "tens of billions per year in direct costs, even higher indirect costs, and expose trillions of dollars of assets to collateral risk." Costs in the water, energy, tourism and recreation, agriculture, forestry, and fisheries sectors will be as high as $23 billion annually, with another $24-billion annually in public health costs [58].

Air pollution impacts are not evenly distributed: The NAS study notes that just 10% of coal-fired power plants account for 43% of all damages. For those dirtiest plants, the damages cost a stunning 12 c/kWh [49], five times greater than the price the plants pay for coal today [59]. The distribution is even more extreme for natural gas—the top 10% of the most polluting facilities produce 65% of air pollution-related damages [49]. Developing smart grid-enabled alternatives to those plants will be particularly valuable.

The smart grid has the potential to radically reduce costly damage to the environment and public health—while increasing energy independence and security and creating new industries and jobs by:

1. Increased reliance on clean, renewable energy—integrating plug-in hybrid electric vehicles (PHEVs), plug-in electric vehicles (PEVs), distributed wind and photovoltaic solar energy resources, storage and other forms of distributed generation
2. Facilitating mitigation of renewable generation variability of output—mitigation of this variability is one of the chief obstacles to integration of large percent of renewable energy capacity into the bulk power system
3. Vastly improved efficiency of electricity production, transportation, and use, including the ability to shift demand to lower impact times and supply resources
4. Leveraging DR/load management to minimize the use of costly peaking generation, which typically uses energy resources that are comparatively fuel inefficient
5. Avoiding the curtailment of renewable generation capacity with technology and policy innovations needed to signal energy users, their buildings, appliances, and cars to use electricity when it is abundant, cheap, and clean
6. Facilitating increased energy efficiency through consumer education, programs leveraging usage information, and time-variable pricing
7. Decarbonization of the transport sector
8. Reduced water impacts—wind, solar photovoltaics (PVs), and demand-side resources use very little or no water to generate electricity [47]

A well-designed smart grid will help electricity customers meet their need for affordable, adaptable, and efficient power. It will equip communities to protect public health, conserve water, and promote energy self-sufficiency and local economic development. And it will maximize the diversity of clean, low-carbon energy production, reducing the overall environmental footprint of the largest and most polluting industry in the world.

2.8.4 Benefits Realization

Business cases for investing in smart grid processes and technologies are often incomplete and therefore not compelling. It is often easier to demonstrate the value of the end point than it is to make a sound business case for the intermediate steps to get there. Societal benefits, often necessary to make investments in smart grid principles compelling, are normally not included in utility business cases. Additionally, lack of protection from inherent investment risks, such as stranded investments, further impacts the ability of these investments to pass financial hurdles. An example of that is the lack of visibility on what consumers will do (e.g., purchase solar PV and batteries) that will impact the asset that is being considered for upgrade. Meanwhile, the increased number of players and the extent of new regulation has complicated decision-making. Credit for societal benefits in terms of incentives and methods for reducing investment risks might stimulate the deployment of smart grid processes and technologies.

Smart grid cost-benefit analyses should take into consideration the full range of benefits of deployment, including the reduced use of high-polluting peak power plants; reduced land and wildlife impacts (through avoided construction of power plants and transmission lines); and the lowest cost achievement of state and federal energy and environmental policies through efficiency and generation options made possible by smart grid investments [60,61]. Some smart grid benefits are under the control of the utility while others are dependent on changes in customer behavior.

While the typical non-price regulated entity seeks to earn a return on its investment through profit-maximizing pricing, product and marketing strategies, a price-regulated entity such as a power delivery utility does not have that level of autonomy. Benefits maximization rather than profit maximization is the key goal. A portion of these benefits is in the control of the utility—such as the reliability improvements gained through effective distribution automation implementation or the operational benefits gained through automated meter reading. The bulk of the potential benefits, however, are driven by changes in customer behavior, specifically their consumption levels and patterns. To help drive that behavior, customer education is critical—as is the transition of a utility's customer care function from a transactional "call taker" to a trusted energy advisor. But we also expect that utilities will still be wires and poles companies, receiving fees for hosting distributed energy resources, and motivated to help customers find third-party solutions providers. In this respect, the utility advises their customers and facilitates vendors. More importantly, education goes both ways since the customer must be heard and the utility will have to understand how best to deliver the lifestyle the customer expects. The nimbler aggregators and providers of energy services behind the meter, much more used to understanding the consumer, may move quicker and make available products the customer engages in, which then will need to be integrated into the overall considerations and plans for the smart grid.

An example of an approach to benefits realization that recognizes the need for collaboration and education would be as follows:

1. Prioritize customer-facing smart grid benefits and work toward "early delivery"—while effectively managing stakeholder expectations.
2. Establish stakeholder-working groups that provide opportunity for detailed discussions about dynamic pricing programs and their benefits.
3. Conduct public regulatory hearings that assess and verify the cost and benefits of programs.
4. Provide greater availability of information to customers through improved website capabilities (and ensure customer care access to the same information to facilitate "energy advisor" conversations).
5. Launch proactive customer programs that provide a clear, simple message about the utility's offerings and programs to manage customer expectations. Ideally, these programs would be informed by market research that focuses on (1) increasing enrollment and retention in dynamic pricing programs, (2) improving behavioral responses to pricing options and usage information, and (3) ensuring that benefits flow to all customers.

One of the greatest obstacles in smart grid initiatives is approval from public utility commissions when a rate case is required by utilities to fund smart grid programs. The rates that regulated utilities are allowed to charge are based on the cost of service and an allowed return on equity (ROE). Once base rates are established, the rates remain fixed until the utility files for a rate change. Throw in an environment where power generation has been deregulated and the business case for a wires company still under regulation is more challenging. An additional challenge is presenting a rate case where the total system load decreases with DR and energy efficiency programs.

Utilities are looking for that magic "easy" button for smart grid deployments, but smart grid plans may be "subject to regulatory approval." Therefore, it is important to not only have a solid business case internally but also a business proposition around the view of regulatory approval. The focus on the business case should also show regulators

1. How smart grid technology maintains low customer bills. Benefits may include
   a. Reduced O&M through lower meter-related and outage costs
   b. Reduced cost of energy through DSM and Integrated Volt/VAr Control (IVVC)
   c. Reduced capital expenditures through M&D (Monitoring and Diagnostics), DSM, and IVVC
   d. Ability to provide customer network support programs that give a return for the participating customer in exchange for the delivered service, instead of only pursuing an assets augmentation policy
2. What smart grid does to secure the "green image" of the state or service territory. Benefits may include
   a. Lower carbon emissions through reduced energy consumption and field force drive time via DSM, IVVC, AMI, and FDIR (fault detection, isolation, and restoration)
   b. Renewable energy source integration, facilitated by DSM and DER (distributed energy resources) to help with renewable energy intermittency
   c. Distributed generation and plug-in hybrids facilitated by AMI and DA (distribution automation)
3. How the smart grid improves poor reliability. Benefits may include
   a. Significant SAIFI (system average interruption frequency index) and SAIDI (system average interruption duration index) improvement through AMI, FDIR, integrated OMS (outage management system), and FFA (field force automation)
   b. Improved power quality for an increasingly digital economy
   c. Ongoing M&D will further improve reliability
   d. Improved customer service through billing accuracy and reduced outages
4. How proper management of the grid during emergencies can reduce large-scale outages and blackouts by
   a. Making outage management more cost effective through predictive analytics
   b. Reducing system blackouts using system-wide monitoring, control, and protection
   c. Increasing system resilience through topology switching and preventive control
   d. Improving dependability and security of relaying schemes using adaptive, corrective, and predictive protective relaying approaches

Customer choice, energy efficiency, and customer value are key to a successful smart grid implementation platform and the likely acceptance by regulators. The opportunities lie in leveraging the foundation of AMI to support a more comprehensive smart grid program, but also going beyond AMI and working with behind the meter resources. In response, utilities will be looking to regulators to provide incentives for smart grid programs, such as accelerated depreciation and higher returns for rate cases. The bottom line for regulators and consumers: "Look for Smart Grid initiatives that are likely to reduce long-term bills as well as emissions and outages."

The importance of the business case will vary from country to country. In some centralized markets, the development of a smart grid may be a matter of policy, driven primarily by security of supply, environmental, or research and development (R&D) aspirations. In competitive markets, an economic business case may be more important, with clearly defined internal rate-of-return hurdles to jump.

Creating a complex business case for smart grid technologies is difficult: All networks within a market, and circuits within networks, will have different levels of capability required, all driven by interdependent supply and demand characteristics, making cost estimation difficult. Benefit estimation is similarly complex as benefits will depend on the levels of capability in different network areas and will comprise direct and indirect benefits that are difficult to quantify (e.g., carbon and pollution reduction, improvement in security of supply).

A key smart grid market barrier is business case fragmentation, particularly in more competitive fragmented markets. A utility with different companies operating individually in each part of the value chain will have a fragmented business plan that may not realize the synergies of benefits. In a fragmented market, creating a commercial model means allocating investment, reward, and risk among the stakeholders. This allocation will be driven by the extent to which each party captures benefits and best manages different risks. However, the number of different entities involved makes the business case and commercial model particularly difficult. For example, a smart grid project benefits power generation companies through avoided capital expenditure required for generation, or support for the introduction of intermittent energy supplies (e.g., from wind). For networks, benefits include improved operational efficiency and reduced losses, and for retail, it can support the introduction of innovative offerings and help trim load curves. A networks-only investment into smart grid technologies will, therefore, support huge opportunities for other parties. However, given recent quick adoption of customer technologies, such as solar PV and soon batteries, smart grid projects may become part of a strategy to reduce the risk of load defection, therefore maximizing the utilization of the grid by customers who make such investments. There is also controversy about the long-term benefits of smart grid-enabled policies; e.g., long-term generation, transmission and distribution system savings associated with the broad adoption of TOU rates are hard to defend in the near term, even if the benefits can be real and significant in the future. In addition, a regulatory cost-benefit analysis that considers long-term, total societal benefits will need to use total resource cost (TRC) comparisons. Some would argue that the true societal cost of carbon is considered much higher than the abatement cost.

It is also possible that a less savory outcome will involve utility smart grid investments without delivering the full suite of potential benefits, thereby leaving customers with the costs of a gold-plated grid that exceed benefits. In this less pleasant future, load defection will be exacerbated by an expensive grid that underperforms. The EPRI (Electric Power Research Institute) report, *Electricity Sector Framework for the Future, Vol. 1*, estimates $1.8 trillion in annual additive revenue by 2020 with a substantially more efficient and reliable grid [62]. To elaborate, according to the Galvin Electricity Initiative, “Smart Grid technologies would reduce power disturbance costs to the U.S. economy by $49-billion/year. Smart grids would also reduce the need for massive infrastructure investments by between $46-billion and $117-billion over the next 20-years. Widespread deployment of technology that allows consumers to easily control their power consumption could add $5-billion to $7-billion per year back into the U.S. economy by 2015, and $15-billion to $20-billion per year by 2020. Assuming a 10% penetration, distributed generation technologies and smart, interactive storage capacity for residential and small commercial applications could add another $10-billion/year by 2020” [63].

Around the globe, countries are pursuing or considering pursuit of GHG legislation suggesting that public awareness of issues stemming from GHGs has never been at such a high level. According to the National Renewable Energy Laboratory (NREL), “utilities are pressured on many fronts to adopt business practices that respond to global environmental concerns. According to the FY 2008 Budget Request, NREL stipulates that, if we do nothing, U.S. carbon emissions are expected to rise from 1700-million tons of carbon per year today to 2300-million tons of carbon by the year 2030. In that same study, it was demonstrated that utilities, through implementation of energy efficiency programs and use of renewable energy sources, could not only displace that growth, but actually have the opportunity to reduce the carbon output to below 1000-million tons of carbon by 2030” [64].

2.9 TECHNOLOGY INVESTMENT

Smart grid represents a complete change in the way utilities, regulators, customers, and other industry participants think about electricity generation, delivery, and its related services. This new thought process will likely lead to constantly evolving technologies and solutions, and will benefit from greater integration of utility engineering, IT, operations, and new business models. The set of solutions that will provide these benefits is vast. Perhaps more importantly, it is also about the new information made available by these technologies and the new customer-utility relationships that will emerge. Enabling technologies, such as smart devices, communications and information infrastructures, and software, are instrumental in the development and delivery of smart grid solutions (Figure 2.2). Global, regional, and national economics and growth will serve as the cornerstones for investments in smart grid infrastructure and in greater use of integrated communications and information technologies. Drivers will include national and state government policy directives and incentives to enable energy futures and development of smart infrastructure.

A high-level review of the smart grid technology functionalities and capabilities landscape suggests representative maturity levels and development trends as shown in Table 2.2. This assessment is based on the scale and level of deployed technologies in existing smart grid projects across the globe.

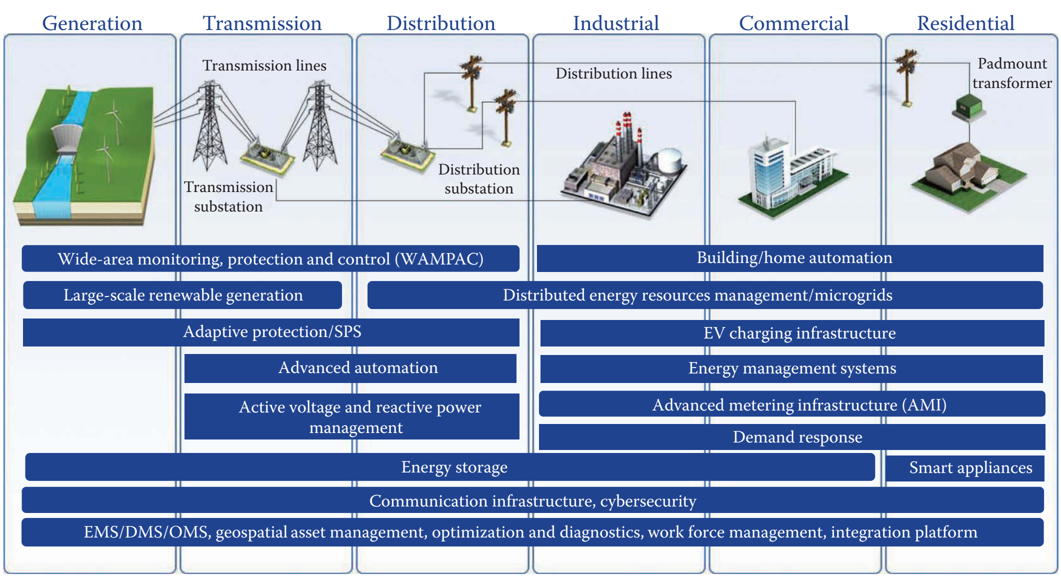

FIGURE 2.2 Smart grid technologies span the entire electric grid. (Copyright 2016 General Electric. All rights reserved. With permission.)

TABLE 2.2
Smart Grid Technology Landscape

	Functionalities and Capabilities	Maturity Level	Development Trend
1	Communication and security	Developing	Fast
2	EVs, large-scale renewable generation, DERs	Developing	Fast
3	Metering	Mature	Fast
4	Embedded sensing automation protection and control	Developing	Fast
5	Advanced system operation	Developing	Moderate
6	Advanced system management	Mature	Fast
7	Advanced system planning	Developing	Moderate
8	Intentional islanding (microgrids) and aggregated load	Developing	Moderate
9	Home/building	Developing	Fast

Technical challenges the smart utility will face include the following:

- Managing an increasing number of operating contingencies that differ from "system as design" expectations (e.g., in response to wind and solar variability, possible occurrence of zero demand in transmission in the middle of the day, etc.)
- Facilitating the introduction of intermittent renewable and distributed energy resources with limited controllability and dispatchability
- Mitigating power quality issues (voltage and frequency variations) that cannot be readily addressed by conventional solutions
- Integrating highly distributed, advanced control, and operations logic into system operations
- Developing sufficiently fast response capabilities for quickly developing disturbances
- Operating systems reliably despite increasing volatility of generation and demand patterns, given increasing wholesale market demand elasticity
- Increasing the adaptability of advanced protection schemes to rapidly changing operational behavior (due to the intermittent nature of renewable and DG resources)
- Accommodate customer diversity of preferences in their generation, storage and loads options, and respect and be guided by customer choice

Many of the technologies necessary for smarter grids are available today as discrete capability building blocks. However, the levels of maturity and commercial viability differ. R&D efforts continue to advance the development of these technologies, particularly those essential to the advanced capabilities of smart grid solutions: communications, embedded sensing, automation, big data, and remote control. The speed of technology research, development, and deployment in the power industry has been slower than in other industries. Technology development and deployment need to be accelerated. Utility regulators do not want to allow recovery for failed R&D efforts, so most R&D efforts are through the industry vendors.

Each of these technologies has differing requirements for R&D to reduce technology and deployment risk, lower costs, and secure confidence that they can be implemented at scale. The challenge is to develop all component technologies necessary for an integrated smart grid solution to a level of maturity sufficient to deploy them all at scale at the same time. For this to occur, R&D for some components may need to be accelerated. An emerging area for R&D is the integration of component technologies to ensure interoperable, coordinated, secure, and reliable electric system operations. This focus area includes the integration of high-penetration renewable energy (e.g., wind, solar), distributed generation, and electric vehicles into the electric grid.

The level of R&D spending in the utility sector is amazingly low. Utilities are among the lowest of all industries in R&D as a percent of revenue (<1%) [65]. Competitive high-tech industries are five to ten times higher. Yet, the move to make electricity competitive has not spurred more industry

R&D. R&D costs are typically not explicitly stated as a line item in rate cases. As a result, these costs are often the first to be cut when less than favorable rate case decisions are made.

Technology development efforts lack coordinated R&D for both individual technology components and integrated smart grid projects. Smart grids are potentially a global solution, albeit, in different forms for different markets. However, R&D is not entirely coordinated, and there is a natural tendency for institutes and companies to choose to develop those technologies most closely aligned with their own capabilities and interests. This may leave some technologies with less focus than others. Given the high cost of R&D, technologies with less potential economic payback may well be left behind, leaving a maturity gap in the smart grid technology chain.

The integration of multiple key technologies needs greater focus. The benefit realized from the integration of suites of technologies normally exceeds the sum of the benefits of the individual ones. For example, the deployment of integrated communication systems, including supercomputers, is needed to support the processing and analysis of the large data volumes that will be supplied by advanced technologies of the smart grid. Deployments of individual technologies often fail because they have not been adequately integrated with other needed technologies. Economies of scale and design innovation are needed to drive costs down. For example, our ability to store electrical energy remains limited. One of the most fundamental and unique limitations of electricity is that it cannot easily be stored for use at a later time. Although incremental progress is being made in energy storage research, the discovery of a transformative storage technology would greatly accelerate grid modernization. But also, mass adoption of storage by customers may bring storage capability to the grid sooner, as long as a smarter grid allows the usage of such resources and provides the foundation for a business model that incentivizes customers to do so. At the prosumer level, new-generation smart inverters have been deployed to enable full controllability of photovoltaics resources to be able to curtail outputs in case of grid congestions. Simultaneously, smart inverters allow customers to focus on self-consumption, reducing their energy export by using loads when solar is maximized, or using batteries to absorb the excess power and increasing self-consumption at night. Battery storage and demand response have also been integrated into the grid to provide grid support services, such as voltage support on the distribution system, as well as frequency reserve on the transmission system.

2.10 BUILDING KNOWLEDGE, SKILLS, AND A READY WORKFORCE

2.10.1 Industry Expertise and Skills

A declining infusion of new thought is occurring. The technical experience base of utilities is graying. The talent pool is shrinking due to retirements and a shortage of new university graduates in the power engineering field. Additionally, fundamental knowledge and understanding of power system engineering principles are being lost as more and more of the technical analysis is done by computers rather than by human resources. This, in turn, has led to a reduction in the number of power systems programs being offered by engineering schools across the US [66].

It is common knowledge that baby boomers in the United States are beginning to retire and leave the workforce. The electric power and energy industry is already beginning to experience shortages caused by these retirements. Over the next five years, roughly one-half of the utility industry engineers may retire or leave for other reasons. These experienced engineers provided the expertise needed to design, build, and maintain a safe and reliable electric power system. Over the years, they have planned for and expanded the system to serve a growing population, developed needed operating and maintenance practices, and brought about innovations to make improvements.

The departure of this engineering expertise is being met by hiring new engineers and by using supplementary methods, such as knowledge retention systems. The future engineering workforce will supplement traditional power system knowledge with new skills, such as in communication, cybersecurity, data analytics, and IT. Traditional and new skills will still be necessary to successfully deploy advanced technologies while maintaining the aging infrastructure.

Meeting the functional needs of a smart grid will require consideration not only of the end state when a smart grid vision is realized but also the evolutionary period to that state during which the legacy infrastructure will be used side-by-side with new technologies. To integrate engineering elements in design and operation, the engineer must have a sufficient depth of understanding to put aside preconceived legacy notions. These legacy notions admittedly comprise most power system engineering, but to realize new paradigms, a more holistic approach is required. For example, the use of time-varying wind power, or solar power available in an uncertain schedule, the engineer needs to consider: (1) at the design stage, control error tolerances, timing of controls, electronic designs of inverters needed to incorporate the alternative energy sources, and other basic system configurations; and (2) in power system operation, the operating strategies of generation control, system control, and managing multiple objectives.

The integrative requirements of smart grid philosophies require that the depth of comprehension of engineers extend to the several areas illustrated in Figure 2.3. It appears that the legacy power engineering educational programs, while valuable for the installation of legacy systems, and maintenance of those systems, are not sufficient to accommodate the main elements of the smart grid. To ensure that our society has the well-qualified power and energy engineers it needs, the following objectives must be sought [66]:

1. Develop and communicate an image of a power engineer based on a realistic vision of how engineers will be solving challenges facing companies, regions, the nation, and the world, thereby improving the quality of life. Youth want to choose jobs that make a difference in the world and make their life more meaningful.
2. Motivate interest in power and energy engineering careers and prepare students for a post-high-school education in power and energy engineering. Students should be exposed to

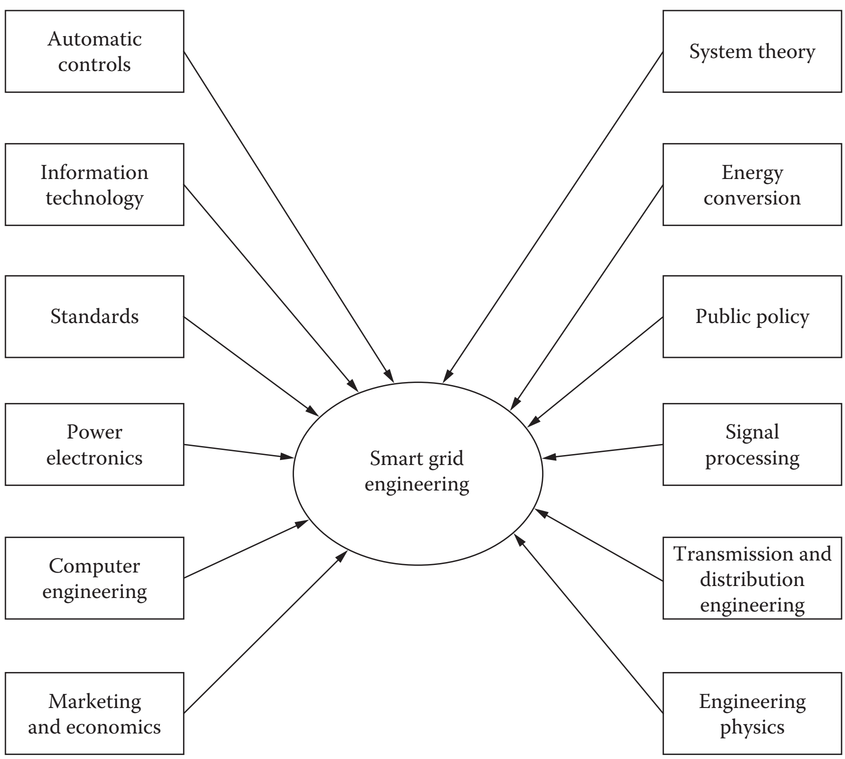

FIGURE 2.3 Integrative approach to smart grid design and operations. (Copyright 2012 Kezunovic, M. All rights reserved. With permission.)

engineering even before high school. Teachers, counselors, and parents must be the target of information as well as the students.
3. Make the higher education experience relevant, stimulating, and effective in training high-quality and professional power and energy engineers. Establish and maintain a direct link between power engineering and the solution of major challenges facing the United States and the world.
4. Increase university research funding to find innovative solutions for pressing challenges and enhance student education.

Expertise and skill development are facilitated by government policies, such as the U.S. Green Jobs Act and Workforce Investment Act, which formalize investment in next-generation skills development. There are also international efforts like CCiNet (Climate Change Information Network) of the UNFCCC (United Nations Framework Convention on Climate Change), which include education, training, and public participation programs. Currently, major initiatives specifically dedicated to developing smart grid skills are few in existence, with a noted exception being the workforce development in the United States for the electric power sector to implement a national clean-energy smart grid. This U.S. $100 million initiative—as part of the ARRA U.S. $4.5 billion investment to grid modernization—targets new curricula and training activities for the current and next-generation workforce, including cross-disciplinary training programs spanning the breadth of science, engineering, social science, and economics.

The facts indicate there are workforce and education system problems summarized as follows [66]:

- Over the next 5 years, approximately 45% of engineers in electric utilities will be eligible for retirement or could leave the engineering field for other reasons. If they are replaced, then there would be a need for over 7000 power engineers by electric utilities alone: Two or three times more power engineers may be needed to satisfy the needs of the entire economy.
- About 40% of the key power engineering faculty at U.S. universities will be eligible for retirement in 5 years with about 27% anticipated to retire. In other words, of the 170 engineering faculty working full time in power engineering education and research, some fifty senior faculty members will be retiring. This does not account for senior faculty who are already working less than full time in the area. Finally, even more faculty will be needed to increase the number of power engineering students to meet the demand for new engineers in the workplace.
- The pipeline of students entering engineering is not strong enough to support the coming need, with surveys showing (1) that most high school students do not know much about engineering and do not feel confident enough in their math and science skills; and (2) that few parents encourage their children, particularly girls, to consider an engineering career. Furthermore, often career counselors and teachers know little about engineering as a career. Workforce diversity is also a concern. Women constitute only 18% of the engineering enrollments and 12% of the electrical engineering students. Enrollment of under-represented student populations should be higher.
- Enrollment by university students in power and energy engineering courses is increasing (perhaps fueled by interest in renewable energy systems and green technologies); however, the overall number of students interested in electrical engineering is declining. A shrinking pool of electrical engineering students limits the future supply of new power engineers.
- The hiring rate of new power engineering faculty is beginning to grow after years of insufficient hiring to replace retiring faculty; however, as time has passed, many historically strong university power engineering programs have ended or significantly declined;
- There are less than five very strong university power engineering programs in the United States. A very strong program has (1) four or more full-time power engineering faculty; (2) research funding per faculty member that supports a large but workable number of graduate students;

(3) a broad set of undergraduate and graduate course offerings in electric power systems, power electronics, and electric machines; and (4) sizable class enrollments of undergraduate and graduate students in those courses. The general lack of research funding opportunities has made it difficult for faculty in existing programs and new emerging programs to meet university research expectations and for engineering deans to justify adding new faculty.

For electric and gas utility employees, the results of a survey by the Center for Energy Workforce Development (CEWD) in 2008 showed that approximately 50% of all employees would be eligible for retirement within ten years [67]. The survey was comprised of fifty-five electric and gas utilities nationwide, as well as all electric cooperative organizations. As of 2010, indications were that nearly 45% of the eligible retirement age employees would have to be replaced by as early as 2013 [68]. An updated survey by the CEWD in 2016 [69] (Figure 2.4) shows that overall, the electric and natural gas utility workforce is now getting younger, with lineworkers, engineers, and nuclear operations being the youngest of the surveyed jobs. Hiring has increased, particularly in the 23- to 38-year age group, and a little over half of the hires reported were in key jobs, with almost 20% of all hires in the lineworker category. At the same time, the number of older workers has declined as workers in key jobs are retiring, with retirement forecasts in future years trending downward for the first time since CEWD began surveying.

Current estimates of global job losses due to digitization range as high as two billion by 2030, but there is considerable variation in these projections. The World Economic Forum (WEF) predicts significant opportunity in the electricity sector for digitization to create jobs. They expect digital initiatives will create up to 3.45 million new jobs between 2016 and 2025—translating to 10.7% job growth in the electricity industry. Job creation potential is highest in the consumer renewables sector, with energy storage integration creating up to 1.07 million new jobs. New jobs in smart asset planning (925,000) and asset performance management (596,000) will more than address job loss from automation or more efficient technologies. The WEF notes that a significant problem that utilities are facing is an aging workforce, with a weak pipeline of new talent and a potential productivity gap as new employees are recruited and trained. Digital initiatives go some way in ensuring that experience is captured as the workforce retires, with significant productivity gains expected [70].

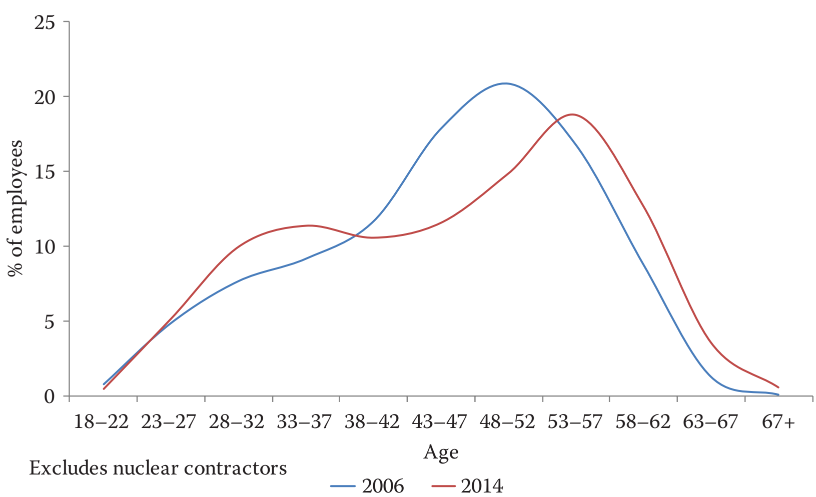

FIGURE 2.4 US Electric and Natural Gas Utilities Age Distribution Total Company 2006 vs. 2014. (From Center for Energy Workforce Development, Gaps in the Energy Workforce Pipeline 2015 CEWD Survey results, 2015. With permission.)

2.10.2 Knowledge and Future Education

Since implementing the smart grid initiative will take engineering professional resources of broad expertise and different profile than previously available, one may naturally ask the question as to where the new generation of electrical and electronic engineers shall come from with the specialized integrated skills needed by smart grid engineers.

Traditional power engineering skills include

- Power system dynamics and stability
- Electric power quality and concomitant signal analysis
- Transmission and distribution system operations
- Economic analysis, energy market, and planning
- Reliability and risk assessment

The traditional power engineering educational programs, while valuable for the installation of legacy systems, and maintenance of those systems, are not sufficient to accommodate the main elements of the smart grid. This is the case since simple replicative engineering is not sufficient to formulate new designs and new paradigms. The innovation extends to power system operation as well. The solution to this quandary appears to be in the integration of new technologies into the power engineering curriculum programs, and extending the depth of those programs through a master's level experience. It is desirable that the master's level experience is industry oriented in the sense that the challenges of the smart grid be presented to the student at the master's level.

Traditional power engineering education, the source of engineers for the future grid, needs to include several topics that are not traditionally included in a power engineering program. Among these are

- The design of wind energy systems
- The design of photovoltaic solar energy systems
- The design of solar thermal (concentrated solar energy) systems
- The calculation of reserve margin requirements for power systems with high penetration of renewable resources
- The modeling of uncertainty/variability in renewable energy systems
- Inclusion of cost-to-benefit calculations in generation expansion studies
- Conceptualization, design, and operation of energy storage systems, including bulk energy storage systems
- Discussion of the socio-political issues of renewable energy development
- Data System Architecture and Big Data Analytics
- Cybersecurity

The desired elements of the cross-cutting energy engineering skills for the next generation of "smart grid" power engineers appear to include all or most of the following elements. The exposure to these subjects is not recommended to be a casual, low-level exposure; rather, the exposure is recommended to be at a depth that analysis is possible in a classroom environment. Moreover, it is recommended that research is performed by the student so that synthesis can be accomplished. Some of the elements identified are discussed in the following.

Direct digital control: The importance of direct digital control is important in realizing most of the smart grid objectives. Direct digital control needs to be examined not only in terms of classical automatic control principles (including, if not emphasizing discrete control) but also how digital control relies on communication channels, how these controls need to be coordinated in terms of safety and operator permissive strategies, the impact of latency [71] new instrumentation, and how that instrumentation will impact the power system design and operation.

Identification of new roles of system operators: Components of the system that need to be fully automated versus components that are "operator permissive" controlled need to be identified. This must be presented to the students in a way that integrates computer engineering and power engineering. As an example, visualization of power systems is an especially important subject area [72].

Power system dynamics and stability: Power system stability is a classical subject. However, the new issues of this field relate to how maximal power marketing can occur and yet still ensure operationally acceptable system operation and stability. The subject appears best taught as an in-depth semester course that includes modeling and practical examples. The examples should be examined by the students in a project format.

Electric power quality and concomitant signal analysis: With the advent of electronic switching as a means of energy control, electric power quality has taken on a new importance in power engineering education. Again, we find that simply a casual discussion of this topic is insufficient to achieve the analytical stage: Rather, it is recommended that a semester's course, complete with project work and mathematical rigor, is needed as instruction. Power quality is discussed as an educational opportunity in Ref. [73].

Transmission and distribution hardware and the migration to middleware: New materials are revolutionizing transmission designs. Transmission expansion needs to be discussed in an in-depth fashion that includes elements of high-voltage engineering and engineering physics, new solid-state transformer designs, and solid-state circuit breakers [74]. Classical power engineering seems to leave a gap between software and hardware, and it is recommended that hardware-oriented courses at the master's level include issues of middleware applications. The use of intelligent electronic devices (IEDs) is deemed important. This development is especially important in the area of substation automation and synchronized phasor measurement systems [75].

New concepts in power system protection: With increased loading of power systems and dynamic behavior due to accommodating deregulated electricity markets and interfacing renewable resources, designing protective relaying solutions that are both dependable and secure has become a challenge. Introduction of microprocessor-based relays, high-speed communications, and synchronized phasor measurement systems made opportunities for adaptive and system-wide relaying. Learning how the relaying field evolves from traditional approaches designed for handling $N - 1$ contingencies to new schemes for handling $N - m$ contingencies becomes an integral part of a modern power systems curriculum. The use of modern modeling and simulation tools is required [76].

Environmental and policy issues: Exposure to environmental and policy issues need to be included in the master's level in power engineering education. This exposure needs to go beyond "soft science" and it needs to appeal to the students' capability in mathematics and problem-solving [77].

Reliability and risk assessment: There is little doubt that the importance of reliability of the power grid is widely recognized. However, when transformative changes are planned and implemented, the traditional tried and tested rules to ensure reliability cannot be relied on. Such changes need to be modeled and analyzed for reliability assessment based on sound mathematical foundations. Fortunately, now a large body of knowledge exists for modeling and analysis of power system reliability and risk assessment. The students at the master's and doctoral level should be provided this knowledge so that they can effectively use it in the integration and transformative process.

Economic analysis, energy markets, and planning: Planning can no longer be done incrementally, motivated largely to satisfy the next violation of planning reliability criteria. Investment strategies must be identified beyond the standard 5- to 20-year period at an interregional if not national level, to identify cost-effective ways to reach environmental goals, increase operational resilience to large-scale disturbances, and facilitate energy market efficiency. Engineers capable of organizing and directing such planning processes require skills in electric grid operation and design, mathematics, optimization, economics, statistics, and computing, typically inherent only in programs for PhD graduates [78]. Engineers from the BS and MS levels will be needed to participate in these processes, and these engineers will require similar skills at the analysis level or above.

The smart grid approach combines advances in IT and data analytics with the innovations in power system management to create a significantly more efficient power system for electrical energy. Modern society is migrating to an Internet-based business and societal model. As an example, it is common to pay bills, order equipment, make reservations, and perform many of the day-to-day tasks of living via the Internet. In power engineering, one needs only to examine such tools as the Open Access Same-Time Information System (OASIS) to realize that the same Internet model applies to power transmission scheduling [79]. The identical model appears in many power engineering venues including setting protective relays, transcommuting of engineering personnel, managing assets and inventory, scheduling maintenance, and enforcing certain security procedures. Cloud data storage and virtual networks may be a key to solving operational issues associated with concerns on the distribution grids, such as localized peak loads caused by concentrated areas of charging electric vehicles. While the open Internet has security issues, similar models in an intranet or virtual private network may be used to enhance security. As this general model progresses, in many cases, one may wonder why certain procedures, whether in power engineering or elsewhere, have not been automated.

Automation is at the heart of the smart grid. That is, various decisions in operation may no longer be relegated to operators' action. Instead, operating decisions considering a wide range of multiobjectives might be "calculated" digitally and implemented automatically and directly. While safety, redundancy, and reliability considerations are clearly issues as this high level of direct digital control is implemented, it is believed to be possible to realize the objectives of the smart grid. To this end, the analogy between the needs of Internet opportunities and the needs of smart grid translates into a new philosophy in power engineering education: Develop the cognitive and cyber skills while focusing on domains of specific expertise. This often translates to instruction tools that are highly interactive and have strong modeling and simulation background. Interestingly, the very same Internet philosophy may be applicable to the identification of where engineering expertise will be obtained—and how the complex issues of power engineering, public policy, and IT can be presented to students in undergraduate and graduate programs.

To tackle the smart grid research issues, a variety of engineering and non-engineering disciplines need to be brought together. Almost every engineering discipline has its role in this development: electrical and computer engineering (grid generation, transmission, and distribution enhancements), petroleum engineering (alternative fuels for electricity generation), nuclear engineering (sustainable electricity production), chemical engineering (alternative and renewable electricity production), aerospace engineering (wind energy infrastructure), mechanical engineering (design of generators and energy-efficient buildings), civil engineering (environmental impacts), etc. In addition, some non-engineering disciplines are needed to resolve associated economic, societal, and environmental and policy issues: economics, sociology, architecture, chemistry, agriculture, economics, public policy, etc. The fact that some of the disciplines are allocated to different colleges should not be underestimated since bringing those resources together will require a concerted university-wide effort.

2.10.3 Forms and Goals of Future Learning

University education: The overall education model will include a combination of in-residence and distance education programs offered by universities, community colleges, and government and industry providers. In addition, the model will include certificate programs and professional development programs. Universities can hire nontenured staff, such as adjunct professors, relatively quickly to supplement the available instruction time of university faculty. This will allow universities to expand educational opportunities to address the rising shortage of well-trained power engineers. However, actions must also be quickly taken by industry and government to build and sustain university power engineering programs through increased research support for faculty. Strong university power programs are needed to meet the needs for innovation, for future engineers, and for future educators. The following are recommendations for the university education:

- Work toward doubling the supply of power and energy engineering students.
- Continue enhancing education curricula and teaching techniques to ensure an adequate supply of well-qualified job candidates who can be successful in the energy jobs of the future.

- Increase research in areas that can contribute to meeting national objectives.
- Get involved in state and regional consortia to address workforce issues.
- Conduct seminars and encourage industry to provide information sessions to develop university student interest in power and energy engineering careers.
- Build communications and collaborations with industry, particularly between industry executives, department chairs, and college deans.
- Communicate with industry about education needs that may require innovative approaches to education.
- Ensure that adequate educational opportunities exist for retraining engineers with education and experience in fields other than power engineering.
- Use college or university student recruiting programs to also spread the word about opportunities in power and energy engineering.

Career and technical education

- Identify and communicate needs and ideas on education materials, lesson plans, and computer-based learning related to energy and engineering.
- Encourage students to consider engineering as a career.
- Increase the number of specialized teachers in math, physics, and chemistry to improve scientific education and increase professional awareness.
- Work with industry to provide projects, case studies, field trips, and learning-by-doing experiences into lesson plans to increase student interest in engineering.

Continuing education

- Inform students about engineering career opportunities.
- Provide course opportunities that prepare students for an engineering education at a university.
- Work with universities to establish credit transfer programs so that students can continue education at a university after graduating from a community college.

Certification and professional licensing

- Provide education opportunities for trainees to obtain the certification or license for engineering career.
- Build tools and relationships to recruit and train people leaving the military and from underrepresented populations.

Training of non-engineering workforce segment

- Partner with professional societies in areas of career awareness, workforce development and education, and workforce planning.
- Provide support in education planning and a career awareness video for engineers in cooperation with professional societies.
- Publish promotional materials and presentations that target potential power and energy engineers and transitioning military personnel; adjust messaging to appeal to underrepresented groups.
- Develop industry-wide and regional solutions that maximize the efficiency of electric utility workforce development activities.
- Perform annual electric utility surveys to identify high-priority energy industry engineering workforce needs.

Role of professional societies

- Take advantage of delays in retirements due to the economic downturn to more fully develop collaborations to implement wide-scale training and marketing programs.
- Keep the organization and its members knowledgeable of engineering workforce issues, and mobilize the membership, so individuals, chapters, or regions as a whole get involved in responding.
- Develop training plans targeted toward lifelong learning. The development needs to consider the adjustment of skills arising out of technological change and new fields.
- Explore ways to support retraining of engineers whose education and experience are in fields other than power and energy engineering.
- Provide opportunities to bridge promising student talent and industry.

2.11 NEW BUSINESS MODELS FOR GROWTH

Adherence to a set of core principles will maximize the return on the enormous investments countries around the world will make over the next two decades in electric infrastructure. The fundamental question that each market will face is how to provide incentives for electricity companies, consumers, and service providers to invest in, and implement the right level of smart technology. This question is immediately followed by another important set of questions: What is the commercial business model that makes sense to accommodate the new services and new prosumers, which still allow investments to be recovered by utilities? What are the regulatory models that will support those commercial ventures, while still focusing on grid efficiency and resilience? Electricity companies, in this case, should be viewed in the broadest sense. They include both traditional utility network companies that will be responsible for the provision of the underlying electricity network infrastructure, generators, retailers, and a wide range of nonutility companies providing diverse technologies, solutions, applications, and services to deliver the full value from smart grid deployment, such as communications companies behind home-area networks, companies providing microgeneration and devices to support advanced end-user services, electric vehicle and battery manufacturers, and companies that will provide the associated electric vehicle charging and billing infrastructure. In market terms, a smart grid supports a whole new range of product offerings, services, and opportunities that create value for users, electricity companies, third-party vendors, and host governments.

Electricity consumption in the United States and Europe represents approximately 40% of global demand, but demand has been declining in both regions in recent years. In contrast, energy consumption in the rest of the world grew by 5.1% from 2007 to 2012, driven by a higher rate of economic growth in emerging economies [14]. With cleaner energy available from renewable energy and the increased interest in shale gas in North America, utilities are now forced to evaluate and evolve their generation supply mix and innovate and change their business outlook and processes in order to protect their customer base. Customers are also changing their perspective on energy supplies and are looking to reduce consumption and produce energy themselves. Utilities are also driven by mandates and regulations to reduce CO_2 emissions in their generation mix, and are faced with excess generation capacity, certainly in northwest Europe. While the nature of this trend is uncertain in the longer term, in part, due to the growth of renewables and distributed generation, clearly, utilities must act now to decouple their revenue growth from future electricity demand in developed markets.

"The writing is on the wall and we have to change. The whole economics of the sector is changing—from old-style cost-plus economics to a world of high renewables feed-in and where customers want to have a say in decision-making and the economics of energy."—Praveer Sinha, CEO, Tata Power Delhi Distribution [15].

For American utilities, the current economy has led to leveling or even a decline in retail demand and corresponding revenues. In Europe, where the high penetrations of distributed generation have been a major effect on wholesale markets, this has led to enormous losses in utility revenues. While these changes threaten the financial stability of power companies, they do not yet indicate the end of traditional utilities. For some, the coming of the “utility death spiral” is inevitable. In such a scenario, utilities that don’t actively invest in distributed generation and find new ways to engage their customers, will wither away and die, and large-scale power stations—the backbone of traditional utilities—could be “on a path to extinction” [7]. Disruption is inevitable, more notably driven by the customer, but it is important that utilities recognize that there are many other stakeholders and companies vying for the customer and grid-edge business. Utilities will need to be proactive and address the economic challenges early in the process, and look to new business models going forward. Ultimately, all stakeholders must embrace change in technology and new business models in order to maintain a viable utility industry. Distributed energy resources are the most imminent threat and could become the biggest driver of industry growth. While we frequently hear about the threat of the “utility death spiral,” distributed energy resources could be seen by utilities as a growth opportunity [22].

The traditional utility business model is being challenged, placing utilities under pressure to innovate. Many integrated utilities have struggled to deliver shareholder returns amid regulatory changes, price volatility, and demand fluctuations. According to the World Economic Forum (WEF) [14], the return on invested capital (ROIC) for the 25 largest integrated utilities worldwide declined from an average of 6.6% in 2009 to 4.1% in 2014. Most of the decline for these companies was due to a decrease in operating profits, where twelve of the utilities had profits that fell by an annual rate of 5.2% over a 5-year period. Despite this decline in profits for integrated utilities, profits for the utility industry increased at an annual rate of 2.7% from 2009 to 2014, mostly from independent power producers in Asia, particularly China, whose profits grew at an annual rate of 25%. The shift to renewable generation, coupled with slowing demand growth in developed markets, has meant that a larger share of industry profits is now captured by nonintegrated energy companies—particularly those engaged in renewable equipment manufacturing, generation, and distribution. The WEF notes that analyst forecasts indicate that nonintegrated energy companies have captured a larger share of the industry profit pool over the past five years, and this trend is expected to continue. A vast number of nontraditional entrants in renewables are challenging incumbents, and investment in advanced renewable technologies is a significant source of innovation within the electricity industry. The WEF also notes that solar received the largest amount of startup investment in renewables from 2012 to 2015, totaling $5.4 billion, with Sunrun and SolarCity among the major recipients. In addition, investment in wind power totaled $2.2 billion over the same period, with Pattern Energy, a major startup in wind power generation and transmission, accounting for most of the investment. Investment by both disrupters and incumbents into emerging technologies and the unbundling of services across the value chain will result in a major shift of value over the coming decade. Utilities will need to react to changes in their business models and growth expectations.

Utility Dive notes [22] that as utilities shift away from traditional profit centers, regulators must enable them to adopt new business models. More than half of the utilities see distributed generation as an opportunity, and are now building new business models around it, the report found, and 55% say partnering with a third-party provider is the strongest investment in the new space, followed by potential regulated investment in distributed energy resources.

A study by the World Economic Forum (WEF) [14] shows that digital initiatives have tremendous potential to deliver exceptional value in the electricity market as a function of financial performance and shareholder value; customer value in terms of affordability, reliability, and satisfaction; and environmental and social value in terms of economic growth, sustainability, and job creation. In this study, the WEF estimates that from 2016 to 2025, a potential total of U.S. $1.3 trillion of industry and societal value will be generated globally from the following eleven initiatives identified in terms of value and opportunity time line:

1. Asset performance management—high value, short-term
2. Real-time supply and demand platforms—high value, medium-term
3. Energy solution integration—medium value, medium-term
4. Real-time network controls—medium value, long-term
5. Digital customer models—medium value, short-term
6. Energy storage integration—medium value, medium-term
7. Energy management—low value, short-term
8. Energy aggregation platforms—low-value, medium-term
9. Connected and interoperable devices—low value, short-term
10. Digital field workers—low value, short-term
11. Smart asset planning—low value, short-term

Of the eleven initiatives included in their analysis, the first five are worth at least U.S. $100 billion over the next ten years and should be prioritized for investment. WEF's estimates of the societal benefits are based on three factors: (1) value creation for customers (worth $986 billion); (2) reduction in carbon emissions ($754 billion); and (3) net job creation ($271 billion).

The WEF study concluded that asset performance management can provide the highest additional value to the utility industry at $387 billion, of which $276 billion is expected from the sale of smart sensors and software services. Energy technology companies have already identified asset management as a key growth potential, such as GE (General Electric) with their Industrial Internet and Predix platform initiatives. Real-time supply and demand platforms provide the largest societal benefits in addition to significant industry benefits, where customers can expect to gain up to $559 billion of value from postponing consumption during peak demand periods. Connected and interoperable devices are expected to generate more than 5% of the cumulative industry profits over the next 10 years. The WEF also notes that customers can expect to realize up to $290 billion of savings from lower peak demand consumption between 2016 and 2025, and the impact could be significantly higher if adoption rates increase further. In addition, initiatives that increase the penetration of renewable energy sources, such as the integration of energy storage, also have the potential to add significant value; however the current higher costs of renewable and energy storage supply compared to traditional fuel-based resources are likely to keep adoption rates suppressed over the next four to five years, after which grid parity is expected.

As part of the focus on the consumer, most utilities are digitizing the customer experience by investing in online (and especially mobile) customer services, such as on-line bill payment, outage notification and status, and energy usage reporting. In some cases, this presents an additional revenue opportunity for utilities while improving customer satisfaction and lowering costs. While many of the efforts to date have yielded optimal results, some lag with respect to usability and the interface between the online and traditional sales channels—a multichannel platform that seamlessly connects customer interactions across all channels—online, mobile, call center, and local sales [18]. For utilities, their digitization efforts also result in improved and more cost-effective customer processes, and a seamless multichannel platform allows them to increase customer interaction touch-points and obtain more data about customer usage and behaviors. Utilities are using advanced analytics to enhance service quality, lower costs, and preserve and deepen customer relationships. Utilities can also use customer data analytics to make process improvements and increase up-selling and cross-selling opportunities. While previous attempts by utilities to move into adjacent markets have generally been unsuccessful, with digital and smart technology, utilities will have much more meaningful customer level data on which to build new propositions, which could include bundling a range of home services [20].

"Our strategic imperative must be to invent and invest in our own disruptive business model before somebody else does that against us."—Erwin van Laethem, Chief Innovation Officer at RWE (Rheinisch-Westfälisches Elektrizitätswerk AG) [15].

Business as usual in the smart grid will look very different: partnering with peers and competitors to offer valuable customer services, improving and optimizing the grid, adopting digital technologies, and thinking beyond the traditional business model and processes will become core business activities for utility and technology companies. Services in this new business model will include markets where utilities have not traditionally ventured, such as big data and analytics. Utilities will need to move beyond traditional industry boundaries and position themselves as consumer brands by providing innovative cross-industry services. However, in doing so, utilities will need to work cooperatively with vendor partners, both inside and outside the utility industry.

2.12 EMBRACING CHANGE

Many electric utility executives do not see a burning platform that would motivate them to change. Most say that their customers are happy, their reliability is good, and their customers want lower rates not higher ones. They are hesitant to make major investments in their systems. In fact, the financial markets are driving them to minimize investments and there is no force on the horizon to make them do otherwise, apart from customer trends (e.g., solar PV adoption) that have yet to reach the scale to impact those utilities in the short term. Regulators are equally hesitant to allow rates to increase and are pushing for decreases in some areas of the world (e.g., Australia). However, the consequences of "doing nothing" should be considered:

- Disruptive change that could achieve a tipping point
- Increasing number of major blackouts
- More local interruptions and power quality events
- Continued vulnerability to attack
- Less efficient wholesale markets
- Higher electricity prices
- Limited customer choice
- Increased load defection whereby customers provide some of their needs with self-generation, load shifting, and storage strategies, thereby reducing the ability of utilities to recover their investments through volumetric energy tariffs. In some instances, this can be a self-fulfilling prophesy. If utilities continue to see rate basing as the primary means of cost recovery for all grid modernization, then they can enable the same future "grid parity" that they are trying to prevent.
- Rising product prices
- Greater environmental impact

More cooperation and the free exchange of information are needed among the approximately 3000 diverse utilities, to successfully achieve the smart grid vision. Some industry observers believe that because of deregulation, the industry's corporate culture has moved from cooperation and coordination to competition and confrontation. These relationships must span beyond the utility industry and encompass the new players who are coming to behind meter space.

Industry executives are reluctant to change processes and technologies. Some utility cultures are resistant to change and operate in "silos" organizationally. As a result, processes and technologies that are based on long-standing practices and policies are difficult to change. Additionally, senior managers today may be more focused on marketing and legal issues, rather than the technical aspects of power systems. The result may be an overreliance on regulation and/or markets to address grid modernization issues rather than proactive investment in new processes and technologies. Integration of change management techniques into utility organizations might stimulate change in their culture. Utilities are unlikely to heavily invest in areas with uncertain regulatory treatment; regulators are unwilling to permit rates to rise without good cause in the face of customer/advocate pushback. Alignment of utility shareholders and customer needs seem paramount.

"The biggest threat to innovation is internal politics and an organizational culture, which doesn't accept failure and/or doesn't accept ideas from outside, and/or cannot change."—Gartner, July 2016 Financial Services Innovation Survey.

Industry technical staffs are reluctant to change planning and design traditions and standards. Utility planning and design traditions and standards generally focus on the traditional model of the electric grid—centralized generation, legacy technologies, and little reliance on the consumer's decisions on energy (e.g., consumers buying Solar PV and Batteries) as well as looking at them as an active resource that can provide grid support services. Smart grid principles have generally not yet been incorporated into technical policies and standards, which can limit the deployment of new processes and technologies that exist today. A significant change management effort is needed to encourage technical staffs to modify their current approach. Resources at many utilities (both human and financial) are limited and stressed. The amount of resources available to look beyond day-to-day operations is limited. While it may seem that slow progress is being made in grid modernization from the project deployment perspective, there has been significant progress in aligning utilities around the core smart grid concepts that will ultimately build strategic plans, as evidenced by the development of standards for the new technologies. Early adopters are forging the way for followers who will benefit from an easier logical transition to modernize their grids.

None of the previously mentioned can be done without multiple perspectives at the table, working with a common definition of success and common guiding principles, and commitment to collaborate to achieve the best outcome for the organization. Since smart grid, from a utility perspective, is a company-wide challenge, not a technology deployment, there will necessarily be some new organizational components to consider. These could include, if they are not in place already, some notions that are relatively new to the utility industry, such as a senior business transformation executive, an enterprise architecture function, a design authority to which technology issues and opportunities are directed, a company-wide smart grid steering committee to ensure alignment across all the activities described earlier, and a commitment to a change management discipline and process. Among other things, this change management process should include a standard approach for measuring performance and providing feedback across the stakeholder community. Openly sharing successes and unsuccessful efforts is at odds with the current utility culture. However, doing so would ultimately break down many of the barriers that would cause untimely starts and stops and potentially reduce the overall investment by eliminating rework (Figure 2.5).

Take a moment to reflect on the tasks and challenges noted at the outset:

- Business requirements that are both flexible and specific
- Vendor selection under uncertainty
- System interoperability, both new and legacy
- Innovative rates that are effective and acceptable
- High-profile technology deployment that needs to be as transparent as possible
- Behavioral-driven benefits

These are not tasks and challenges that are purely technical in nature and these are not tasks and challenges that can be wrestled to the ground by any one group, or by a series of groups working independently. This effort requires subject matter expertise, certainly, but more importantly, it requires a cohesive application of that expertise across organizational boundaries to achieve the full range of operational, informational, and behavioral benefits made possible by the smart grid.

Matching internal culture to a new and changing digital customer environment is a challenge. It is a drastic change for utilities in terms of customer orientation. PwC's research [15] concluded that customers see a role for the utility in advising them how to make an energy transition, that they

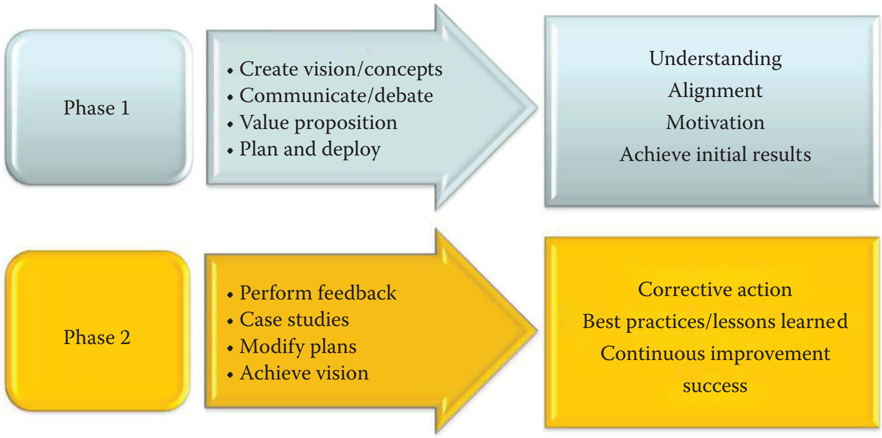

FIGURE 2.5 Components of managing change. (From Sharing smart grid experiences through performance feedback, National Energy Technology Laboratory, Morgantown, WV.)

trusted utilities to help them, or at least be a backstop to help them make that transition. Utilities need to be more customer-centric with a sales and outward-focused mindset, with skills and capabilities around business intelligence and business analytics.

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3 Smart Energy Resources: Supply and Demand

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CONTENTS

Planning and operating the grid is a complex process to ensure the dynamic balance of the supply and demand of the electrical grid. Utilities must ensure there is sufficient margin of supply for any contingencies in the generation supply as well as the changes in the transmission and distribution grid configuration. Utilities must schedule and dispatch generation sources to minimize costs and maximize efficiency and security of supply.

In the past, the load on the grid depended on individual consumer energy usage patterns. Utilities had very little visibility of loading patterns at the distribution feeder or individual consumer level. As utilities deploy more smart meters and additional monitoring devices further down into the distribution network, they will have a greater understanding of the system load dynamics and can better plan and manage generation and grid assets. Utilities can now also implement more advanced technologies to help balance the supply-demand equation, such as adding distributed generation to the grid, and changing consumer load behaviors through energy pricing options or real-time pricing signals.

Smart Energy Resources is the term used in this book to define the new set of resources available to utilities to balance the supply-demand equation—renewable generation, energy storage, and consumer demand management. The challenge is not only the long-term planning and implementation of the resources, but also the real-time operation and management of the supply-demand equation, while operating in an open access market, and with generation resources that are more distributed further down on the distribution grid.

3.1 THE ENERGY SUPPLY SIDE OF THE EQUATION

In the early beginnings of the electric industry, power generation was comprised of a series of small generators installed at large customer facilities, towns, and cities. As the demand for reliable electricity supply increased and the industry developed, the need for larger generators and interconnected power systems grew as well. Three basic types of power generation are used meet the varying characteristics of electric loads: baseload units, intermediate units, and peak load units. These three categories of power generation largely reflect trade-offs between capital cost and operating cost, where each type of generator serves a different role, and in combination, they lower total costs and meet reliability needs.

Baseload units: Baseload generation capacity represents generation that essentially operates continuously at the same level. Baseload generation typically includes nuclear, coal, or very efficient gas-fired plants. The generation from these plants is used during all hours of the year. Note that in some regions, hydro may also be used to supply base load when it is in ample supply.

Intermediate or responsive and load following units: These generation plants are generally more responsive to load changes than baseload units and are intended to ramp (up and down) to supply varying load. Many units in this group may be considered load following units. Moving up the load duration curve from baseload, these units help the grid supply electricity load demanded by consumers on the timescale of minutes or hours, and some of these plants can respond to load changes in seconds. Responsive and load-following generation capacity is often provided by combined-cycle natural gas power plants and hydro generation. Intermediate generation units are not always needed on the grid, such as at night, and when they are, it is not always at full capacity.

Utilities or system operators pay a premium for intermediate and responsive load following power over baseload units because such plants can be quickly dispatched as needed at a relatively low variable cost. As they must be flexible enough to be ramped up and down as a regular part of operations, the operating efficiency of these plants is usually less than baseload generation, which translates to somewhat higher variable costs.[1] These price premiums help compensate plant owners for the reduced production that occurs, to make up for the fact that they do not generate power for as many hours as baseload plants. In exchange for this higher cost, intermediate plant owners make assurances that they will be available to provide power when needed.

Peaking units: Peaking units help utilities serve loads during the hours of highest demand. For most utilities, peak load only occurs for a few hours in the year, and is typically much greater than the total average base load. For example, it may be the case that ~20% of the total system generation capacity must be available to serve <10% of the hours in the year. As with responsive and load following units, peaking units operate even fewer hours per year, and the owners of these plants must receive premium payments to stay profitable.

The pattern of generation usage and the types of generation available determines the economic and environmental cost of generation systems. Less efficient fossil fuel units tend to emit greater pollution and are more expensive to operate, but they are responsive when needed. Responsive, load following, and peaking units many times sit idle until the few hours per day or per year they are needed. While utilities and grid operators would undoubtedly prefer not to have to pay for these expensive units, they represent the only supply-side tool to meet large spikes in demand to respond to contingencies that occur with other plants and the T&D (transmission and distribution) system.

Because utilities and system operators have minimal influence and control on the load or demand side of the grid, they are required to build out redundant supply-side capacity to ensure a high level of reliability. With significant peak demand by consumers, utilities must procure generation portfolios that are largely overbuilt. As a result, most power systems have low-capacity factors. To illustrate, in 2006 in the ISO-NE region (Independent Systems Operator-New England) of the United States, 25% of the entire generation fleet ran 2.92% of the time or less, and 15% of the entire generation fleet ran 0.90% of the time or less. These calculations exclude the idle generation that was kept available to meet the required 10% planning reserve margin [1]. Put another way, 20% of ISO-NE's total generation capacity was used to deliver only 0.34% of the annual energy use, and 30% of its total generation capacity was used to deliver only 1.63% of annual energy use [2]. In most other parts of the United States, generation asset utilization is similarly low, and, on average, the entire U.S. generation fleet operates at a 50% capacity factor.

These illustrations show that building generation to meet the highest peak loads is quite cost-inefficient, and much of the generation fleet is unused over many hours of the year. In other words, the system is significantly overbuilt to compensate for varying loads, and these generation units must still be paid for by the utility or power market, and ultimately by consumers. The electric

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[1] This also reflects the distinction between energy payments and capacity payments. Energy payments are for electricity produced ($/MWh) in an hour. Capacity payments are for the availability to respond as needed to major changes in load or generation on the grid and provide a specific level of output ($/MW). Baseload units are considered to provide energy supply. Responsive and load-following units provide energy and capacity and, thus, in some markets get paid for both.

power industry has followed this paradigm for many years. However, smart grid technology is now able to provide efficient alternatives to supply-side only solutions.

Large-scale centralized generation dominated the power industry for decades until growing environmental and socioeconomic concerns and rising interest in power system efficiency improvement favored the construction of smaller-scale generation facilities (particularly those of renewable nature) closer to customer loads over the construction of large power plants and long transmission lines. This trend, prompted, for instance, by the Public Utilities Regulatory Policy Act (PURPA) of 1978 or the Energy Policy Act of 1992, has led to the emergence of the distributed energy resource (DER). DER technologies are smaller capacity power generation and storage resources typically located close to the load they serve, either owned by the utility, a third party, or by the consumer. DERs may be located "behind-the-meter" on a customer's premises where they may supply all or a portion of the customer's load, or DERs may be located on the main primary distribution circuit as a "community-level" energy supply. DERs may also be capable of injecting power into the grid, or into a nonutility local network in parallel with the utility grid. DERs typically use renewable energy sources, combined heat and power (CHP) or cogeneration systems, wind turbines, micro gas turbines, backup diesel generators, batteries, fuel cells, or a combination of technologies, e.g., PV and battery storage. DG (distributed generation) is a term that is commonly used to refer to generation only (not storage). There are many potential configurations for DERs, from basic backup generation all the way up to a full microgrid.

Providing backup has been the most basic and prevalent application of DERs in the past. Backup generators are usually small diesel generators designated as support for specific loads. Under this configuration, the grid has primary responsibility for providing power; the backup generator only operates when the grid has been compromised or demand exceeds the ratings of the grid equipment that serves the load. Backup generation can be owned by the utility or by the consumer (private). The problem with backup generations is that they lead to what is called *low asset utilization*, since the backup generators do not run unless the grid is unavailable. Because they have relatively low asset utilization rates, the cost of delivered energy over the lifetime of backup generators tends to be very high. Those high costs drive private backup generator customers to opt for smaller backup generators that are generally not large enough to pick up the entire load. When an outage occurs, most of the load must be dropped with only critical loads, such as emergency lighting, remaining active. Furthermore, these critical loads are often on a separate circuit, meaning that even if the backup generators were large enough, they would not be able to power regular loads. Utilities follow similar logic, putting backup generators only on circuits where critical operations, such as hospitals or high-tech businesses, are located. In many situations, it would be helpful to the system to have the DER operating much of the time. But without embedded intelligence in these resources, they cannot be effectively integrated into the rest of the system. In some cases, private backup generators can support the grid when there is a requirement to do so or there are opportunities in the wholesale market.

The last two decades have seen the resurgence of grid-connected DER, either independent power producers (IPPs), privately owned DER, or utility-owned DER. This DER application has the objective of supplying service to the grid or directly to customers in a continuous fashion, that is, in the same way as conventional centralized generators. The main difference with this approach is the location (close to the loads), installed capacity (smaller size), and type or lack of ancillary services (e.g., voltage regulation and frequency regulation) that the DER provides. Furthermore, it requires interconnection with the distribution system using synchronous, induction, and electronically coupled generators. This can represent a significant challenge since distribution systems have historically designed to be operated in a radial fashion, without any special considerations for DG, and it may lead to impacts that could affect the operation of both distribution systems and DG, particularly for intermittent DG, such as solar PV and wind. Smart grid technologies can play a significant role in facilitating the integration of DG and mitigating impacts on the distribution grid.

More recently, the increasing deployment of large scale wind and solar plants is also changing the equation on the supply side. Indeed, in places like Australia, the progressive deployment of wind and solar utility plants has resulted in a number of older coal and gas plants being retired or mothballed since they are no longer profitable. This change in the supply mix is changing the characteristics of the supply side of the equation since solar and wind, although variable in nature, assume the role of variable non-dispatchable baseload. This changes the requirements for the balance of the generation fleet, increasing the value of generation that is flexible and can respond to load changes quickly, e.g., batteries, or fast acting open cycle gas plants that can ramp up within 15 min. This opens an additional opportunity for demand side flexibility, but also paves the way for a faster evolution towards the smarter grid so that DER and flexible loads can become more prominent actors in the grid space.

3.2 THE CONSUMER DEMAND SIDE OF THE EQUATION

Utilities and power providers have, for the most part, found that management of consumer loads results in lower financial returns. To utilities and other grid operators, consumer loads must be met regardless of how much power is demanded. Utilities and grid operators have assumed complete responsibility for meeting consumer demand, regardless of the pattern of the demand or how much it costs to provide the electricity.

However, the deployment of variable renewables, both at utility-scale as well as at DER customer-scale, is a challenge to meet this consumer demand, due in part by utilities having no control of what happens behind the meter, and extreme grid conditions, such as zero net load in the middle of the day, as the case forecasted for South Australia in 2026/7 [3].

There are significant pilots and research examples that indicate that consumers may be willing to change their demands in response to incentives, information, and prices. Recent studies have shown that something as simple as an in-home display that shows peak hours or peak prices can help shift consumer demand. Recent advanced technology allows appliances to automatically change power use based on the grid needs or in response to different electricity prices in ways that minimize the impact to consumers. These advances suggest that the consumer mass market can change their demand, which opens a whole new industry for Demand Side Management (DSM) technologies and services. This has resulted in the development of a cohesive set of product technologies, programs, standards, and consumer devices for consumer demand management. Measurement and validation of demand management participation by the consumer are required in addition to a means of financial settlement, both of which can be enabled by *smart meters*. Communication is also a key component over both the utility service area as well as within a customer premise. AMI infrastructures can provide communications to the consumer for demand management, although other communications technology options are also being explored and piloted.

Assume that consumer loads can be divided into two categories, so-called critical or nondiscretionary loads that cannot be disconnected from the grid at any time and noncritical or discretionary loads that are not significantly impacted if disconnected from the grid. Critical loads might include hospitals, critical telecommunication infrastructure, security systems, and emergency response sites. Noncritical loads might include residential customer washers and dryers, hot water heaters, decorative lights, and some part of air conditioning load. Management of discretionary loads could include dimming certain lights, reduced heating/cooling needs, and altering less critical certain business processes.

Beyond the distinction between critical and noncritical loads, it is useful to think of loads across a spectrum of values based on the customer's willingness to alter usage patterns. Consider a potential scenario where each load is prioritized compared to other loads, and the importance of each load is reflected in the price the consumer will pay to retain the service provided by that end-use device. The load (importance) ranking for every load in every house, neighborhood, or city could be put in line to receive power based on how much value it provides, rather than treating all loads as having equal importance. If each load can be controlled on or off based on the current price of electricity and the value placed on the service by the consumer, one could envision a prioritization of each load in terms of a specific electricity price level. A similar approach is to couple specific consumer electricity uses with specific incentive levels that the customer will accept. Both market pricing and customer incentives aim to provide a value proposition for consumer responses to specific loads, which reflect the customer's value to sustain or curtail each load.

Figuring prominently in any discussion of the smart grid is the role of the consumer. Smart grid enables informed participation by customers, making it an integral part of the electric power system. With bidirectional flows of energy and coordination through communication mechanisms, a smart grid should help balance supply and demand and enhance reliability by changing how customers use and purchase electricity. These changes are expected to be the result of smarter consumer choices and shifting patterns of behavior and consumption. Enabling such choices requires new technologies, new information regarding electricity use, and new pricing and incentive programs.

Having smarter consumers allows a smart grid to add consumer demand as another manageable resource, together with power generation, grid capacity, and energy storage. From the standpoint of the consumer, system management in a smart grid environment involves making economic choices based on the variable cost of electricity, the ability to shift load, the level of economic incentives and how they affect the customer's financials, the impacts of curtailing load (e.g., loss of comfort or impact in the business), and the ability to store or sell energy. From the standpoint of a smart grid operator, system management in a smart grid environment involves sending the price signals necessary to stimulate the right load shift or utilization of energy storage at the right time.

Consumers who are presented with a variety of options for purchasing power, consuming and producing energy are given the ability to do at least two things. First they could respond to price signals and other economic incentives to make better-informed decisions regarding when to purchase electricity, when to generate energy using DG, and whether to store and reuse it later with distributed storage. Second, consumers need to make informed investment decisions regarding more efficient and smarter appliances, equipment, and control systems.

System engineers must be able to understand and incorporate models of the devices consumers use and the patterns of their use. This knowledge doesn't necessarily need to reside with an electric utility because other providers in the market (e.g., load aggregators, smart thermostat providers) are expected to become more pervasive in the market. However, utility system engineers will have to change their processes and models to incorporate this knowledge. The models must include all the salient features of the devices and their aggregation that support the smart grid, so planners and engineers can quantify the financial benefits and the operational impact of the smart grid on the overall electric system.

3.3 RENEWABLE GENERATION

3.3.1 Regulatory and Market Forces

Many countries across the world, including the United States, have developed regulations to enable integration of more renewable energy into the overall generation portfolio. These include renewable energy portfolio standards (RPS), renewable tax credits, and feed-in tariffs. In some countries, various jurisdictions have also created Renewable Energy Targets to further accelerate the move toward renewable energy. Some of these requirements for renewable energy are so aggressive that utilities are concerned about the grid performance and system operational impacts of the intermittent nature of renewable energy generation (e.g., wind and solar).

For example, in 2002, California established its RPS program, with the goal of increasing the percentage of renewable energy in the state's electricity mix to 20% by 2017. On November 17, 2008, Governor Arnold Schwarzenegger signed Executive Order S-14-08 requiring that California utilities reach the 33% renewable goal by 2020. Achievement of a 33% by 2020 RPS would reduce generation from nonrenewable resources by 11% in 2020. This is currently the most aggressive RPS proposed by any of the U.S. states. Other state governments have similar, although at lower penetration levels, but also aggressive RPS allocations [4]. We can also find a good example in Australia, where, for example, the state of South Australia has a target of 50% by 2025 and the state of Queensland a target of 50% by 2030.

As electric utilities prepare to meet their respective renewable regulatory requirements, it becomes evident that utilities must adapt their planning and operations practices in order to maintain high levels of service reliability and security. These initiatives require integration of significantly higher levels of renewable energy, such as wind and solar, which exhibit intermittent generation patterns. Due to the geographic location of renewable resources, much of the expected new renewable generation additions will be connected via one or two utility's transmission systems. This presents unique challenges to these utilities as the level of intermittent renewable generation in relation to their installed system capacity reaches unprecedented and disproportionate levels.

Entities in the United States, such as CEC (Consumer Electronics Control), NERC (North American Electric Reliability Council), CAISO (California Independent Systems Operator), NYSERDA (New York State Energy Research & Development Authority), SPP (Southwest Power Pool), and CPUC (California Public Utilities Commission), have initiated and funded several studies on the integration of large levels of renewable energy, and most of these studies concluded that with 10%–15% intermittent renewable energy penetration levels, traditional planning, and operational practices will be sufficient. However, once a utility exceeds 20% penetration levels of renewable resources, it may require a change in engineering, planning, and operational practices, including the development of a smarter grid. These studies support continuing transmission and renewable integration planning studies and recommend that smart grid demonstration project installations should be conducted by the different power utilities.

The United States, and especially California, has a different set of electric system characteristics than in Europe, but there is no experience or research in Europe that would lead us to think that it is technically impossible to achieve 20%–30% intermittent penetration levels at most U.S. utilities. Long transmission distances between generation resources and load centers characterize the network in the United States and especially in the WECC region. There are now areas in Europe and Australia that are highly penetrated with intermittent renewable, especially wind generation, at higher levels of around 30%–40%.

Large-scale wind and solar generation will affect the physical operation of the grid. The areas of focus include frequency regulation, inertia, load profile following, and broader power balancing. The variability of wind and solar regimes across resource areas, the lack of correlation between wind and solar generation volatility and load volatility, and the size and location of the wind plants relative to the system in most U.S. states suggest that impacts on regulation and load profile requirement resource smoothing will be large at above 20% penetration levels [4].

The European experience taught us that there are consequences of integrating these levels of wind resources on network stability that should be addressed as wind resources reach substantial levels of penetration. A list of the major issue categories follows:

- New and in-depth focus on system planning. Steady-state and dynamic considerations are crucial.
- Accurate resource and load forecasting become highly valuable and important.
- Voltage support to manage reactive power compensation is critical to grid stability. This also includes dynamic reactive power requirements of intermittent resources.
- Evolving operating and power balancing requirements. Existing generator ramp rates must be considered in order to balance power from large-scale wind and solar generation. Grid operations must also ensure grid stability and minimize start-stop operations for load-following generators.
- Increased requirements for ancillary services. Faster ramp rates and a larger percentage of regulation services will be required, which can be supplied by responsive storage facilities. These requirements may require specific market incentives that can drive deployment

and operation of such resources; otherwise, these services may continue to be delivered by existing plants.
- Equipment selection. Variable-speed generation (VSG) turbines and advanced solar inverters have the added advantage of independent regulation of active and reactive power. This technology is essential for large-scale renewable generation.
- Strong interconnections. Renewable generation and energy storage are, by their nature, only available in certain geographic locations. Therefore, strong interconnections make geographic integration of energy resources possible.

Technical renewable integration issues should not delay efforts to reach the renewable integration goals. However, focus has increased on planning and research to understand the needs of the system, for example, research on energy storage options.

Studies and actual operating experience indicate that it is easier to integrate wind and solar energy into a power system where other generators are available to provide balancing power and precise load-following capabilities. The greater the number of wind turbines and solar farms operating in a given area, the lower the variability in their aggregated generation. However, this variability will be strongly correlated with weather and how it impacts the various specific geographical areas where the renewable portfolio sits. High penetration of intermittent resources (>20% of generation meeting load) affects the network in the following ways [4]:

- Thermal and contingency analysis
- Short circuit
- Transient and voltage stability
- Electromagnetic transients
- Protection coordination
- Power leveling and energy balancing
- Power quality

The largest barrier to renewable integration in the United States is sufficient transmission facilities and associated cost-allocation in the region to access the renewable resources and to connect these resources to load centers. Other key barriers include environmental pressure and technical interconnection issues, such as forecasting, dispatchability, low-capacity factors, and intermittency impacts on the regulation services of renewable resources.

In the United States, the sources of the major renewable resources are remote from the load centers in California and the Midwest states. This results in the need for addition of new major transmission facilities across the country. Wind and solar renewable energy resources normally have capacity factors between 20% and 35%, compared to higher than 90% of traditional nuclear and coal generation. These low-capacity factors place an even higher burden on an already scarce transmission capacity. Identification, permitting, cost-allocation, approval, coordination with other stakeholders, engineering, and construction of these new transmission facilities are costly and time-consuming barriers.

Although energy production using renewable resources is pollution free, wind and solar plants need to be balanced with fast ramping regulation services like peak generation, hydro generation plants, or energy storage batteries. Existing regulation generation is too slow and more pollutive during ramping regulation service. The increased requirements in regulation services counteract the emission savings from these renewable resources, depending on what fuel is used to deliver the additional regulation services. Currently, the frequency regulation requirement at the CAISO is around 1% of peak load dispatch, or about 350 MW. This is currently mainly supplied by peaker (gas) generating plants and results in higher emission levels. It has been calculated that around 2% regulation would be required for integrating 20% wind and solar resources by 2010 and 4% to integrate 33% renewables by 2020 [4].

With the integration of wind and solar generation, the output of the fossil fuel plants needs to be adjusted frequently in order to cope with the fluctuations in wind and solar generation. Some power stations will be operated below their maximum output to facilitate this, and extra system balancing reserves will be needed. At high penetrations (above 20%), wind and solar energy may need to be "spilled" or curtailed because the grid cannot always utilize the excess energy.

In grids with a very high penetration of renewables, occasional season variations in renewable resources (e.g., the wind "drought" in South Australia during July 2017) may have wider generation fleet implications that require utilities to switch baseload generation fuels (from wind to gas, for example). Therefore, generation fleets have to include not only fast reacting resources, as described above, but also slow reacting resources that are able to provide inertia to minimize the effect of these types of events. This can be a technical challenge as well as a market challenge, since the generation fleet and grid will have to balance fast and slow acting generation resources, whilst being profitable, yet not dramatically increasing consumer prices.

3.3.2 Technologies

There are several renewable sources of electric energy (generically called renewables). The main difference between renewables and other conventional energy sources is that renewables provide energy that is cleaner with respect to pollution. Another distinguishing difference is that renewable energy sources do not deplete natural resources in the process of creating power. The third difference is that renewables are scalable to the appropriate size anywhere from single-house applications all the way up to large-scale renewables, which can supply power to thousands of homes. Some of the most common renewable energy resources are introduced in the next sections.

3.3.2.1 Solar PV

Solar PV generation has experienced a tremendous growth in recent years due to growing demand for renewable energy sources. PV represents a method of generating electric power in solar panels that are exposed to light. Power generated is based on the conversion of the energy of the sun's radiation. A solar cell that is exposed to light transfers electrons between different bands inside the material. This, in turn, results in a potential difference between two electrodes, which caused direct current (DC) to flow. There are several main PV applications, such as solar farms, building, auxiliary power supply in transportation devices, stand-alone devices, and satellites. Utilities around the world started incorporating solar farms into their generation portfolios mostly during the last decade. To incorporate solar farms into utility grids, alternating-current/direct-current (AC/DC) converters are required, as well as the associated control and protection systems. The main issue with PVs is intermittency. Since PV is a variable power source that cannot be accurately predicted, several efforts have been undertaken to increase the dispatchability of PV power. Successful approaches have included adding battery storage to store the PV energy during off-peak hours or low demand, and then discharging the batteries during peak usage periods. However, when PV is combined with other generating technologies and/or load management, the issues of intermittency may be strongly reduced. Today, solar PV represents <0.5% of total global power generation capacity. However, in some areas of the world, the penetration of PV has been increasing to much higher levels (e.g., states in Australia such as South Australia and Queensland). PV growth is currently seen in both the deployment of centralized power plants, as well as small customer-owned DG, bringing electrical challenges not only to the large transmission power systems but also at the distribution level, an area that traditionally has been "a set it and forget it" deployment of assets.

3.3.2.2 Solar Thermal

Solar thermal energy (STE) is a technology that converts solar energy into thermal energy (heat). There are three types of collector levels that are based on the temperature levels: low, medium, and high. In practice, low-temperature collectors are placed flat to heat swimming pools or space heating, medium-temperature collectors are flat plates used for heating water or air, and high-temperature collectors are used for electric power production. Heat represents the measure of the thermal energy that an object contains, and three main factors, specific heat, mass, and temperature, define this value. Essentially, heat gain is accumulated from the sun rays hitting the surface of the object. Then, heat is transferred by either conduction or convection. Insulated thermal storage enables STE to produce electricity during the days that have no sunlight. The main downside to STE plants is the efficiency, which is a little over 30% at best for solar dish/stirling engine technology, while other technologies are far behind.

3.3.2.3 Wind

Wind power is obtained by using wind turbines to convert the energy of the wind into electricity. Wind energy is a highly desirable renewable energy source because it is clean technology that produces no greenhouse gas emissions. The main downside of wind power is its intermittency and the impact on the environment (visual, noise, and wildlife). During normal operation, all the power of the wind turbine must be utilized when it is available. If the power from the wind turbine is not used, the wind turbine output must be curtailed, or the excess power generated can be used to charge an energy storage system. Due to the intermittency or variability of the wind speed, power output from wind turbines is inconsistent. Inconsistency in power output is the main reason why wind farms cannot be used in a utility's base-load generation portfolio without the addition of energy storage. The capacity factor of a wind power turbine ranges from 20% to 40%.

3.3.2.4 Biomass and Biogas

Dead trees, wood chips, plant or animal matter used for production of fibers, chemical, or heat all refer to biomass. Technologies associated with biomass conversion to electrical energy include releasing energy in the form of heat, or the conversion to a different form, such as combustible biogas or liquid biofuel. The downside of biomass as a fuel is its potential for increased air pollution. The biomass industry has recently experienced an upswing, and the level of electricity in the United States produced by biomass plants is around 1.4% of the total U.S. electricity supply.

3.3.2.5 Geothermal Power

Geothermal power is extracted from the earth through natural processes. There are several technologies in use today, such as binary cycle power plants, flash steam power plants, and dry steam power plants. The main issue with geothermal power is low thermal efficiency of geothermal plants, even though the capacity factor can be quite high (up to 96%). Geothermal plants can be different in size. Geothermal power is reliable and cost effective due to no fueling costs, but initial capital costs associated with deep drilling as well as earth exploration are the main deterring factors from higher penetration of geothermal resources.

3.3.2.6 Wave Power

There are two types of ocean power that can be harnessed: wave power and tidal power. Wave power is associated with the energy produced by ocean waves that are on the surface and converting that energy for the generation of electricity. Today, wave farms have been installed in Europe. Currently, this type of renewable does not have significant penetration, because it is highly unreliable, and it requires large wave energy converter to be deployed. The first such farms are expected to be a wave park in Reedsport, Oregon, and the Perth wave energy project in Western Australia. The PowerBuoy technology that will be used for this project will have modular, ocean-going buoys, and the rising and falling of the waves will cause the buoys to move, creating mechanical energy that will be later converted to electric energy and transmitted offshore through the underwater transmission line.

3.3.2.7 Hydro

Hydropower plants use the energy of the moving water as the main source for producing electricity. The water fall and gravitational force of this falling water hit the blades on the rotor, which cause the rotor to turn, thus producing electricity. Most of the time, hydropower plants are built in places where there is not an abundance of water, but the water is very fast moving (like in mountainous areas), and in the valleys where there is an abundance of water, but the water is moving slowly.

3.3.2.8 Fuel Cells

A fuel cell uses the chemical energy of hydrogen or another fuel to cleanly and efficiently produce electricity. If hydrogen is the fuel, electricity, water, and heat are the only products. Fuel cells work like batteries, but they do not run down or need recharging. They produce electricity and heat as long as fuel is supplied. A fuel cell consists of two electrodes—a negative electrode (or anode) and a positive electrode (or cathode)—sandwiched around an electrolyte. Fuel cells can convert the chemical energy in the fuel to electrical energy with efficiencies of up to 60%.

3.3.2.9 Tidal Power

Tidal power converts the energy of tides into electricity. The most common tidal power technologies are tidal stream generators and tidal barrages. Tidal stream generators rotate underwater and produce electricity using the kinetic energy of tidal streams. Tidal barrage uses a dam located across a tidal estuary to produce electricity using the potential energy of water. Water flows into the barrage during high tide and then it is released during low tide while moving a set of turbines. New technologies, such as dynamic tidal power, are being discussed and evaluated; this technology is intended to take advantage of a combination of the kinetic and potential energy of tides.

3.3.3 Renewable Energy in the Smart Grid

To integrate renewable energy generation at high penetration levels, several planning and operational guidelines should be followed. A smart grid strategy to achieve high renewable penetration should include [4].

- Generation mix to utilize different complementary resources
- Advanced smart grid transmission facilities, including fast responsive energy storage, Flexible AC Transmission Systems (FACTS), HVDC (high-voltage direct current), Wide Area Monitoring, Protection and Control (WAMPAC), etc.
- Smart grid applications on distribution networks including distribution automation, fast demand response, including distributed resources (DRs) on the distribution feeders, distributed energy storage, controlled charging of plug-in electric vehicles (PEVs), demand-side management (DSM), etc.

Additional transmission planning is required to identify facilities and storage options to integrate these high levels of renewables.

Most of the models for these advanced wind and solar facilities have not been fully developed yet and need to be validated. The generator models for wind and solar generation technologies need to be upgraded and validated to include short-circuit models and dynamic variance models like clouding and short-term wind fluctuations.

The European experience with high levels of intermittent resources up to 80% penetration levels does not transfer fully due to the difference in U.S. grid design and load density. The integration of renewable energy at this scale will have significant impact, especially if the addition of energy storage devices (central and distributed) and FACTS devices utilized to counterbalance the influence of the intermittent generation sources. Utilities and ISOs in the United States should conduct Research, Development, and Demonstration (RD&D) projects and commence studies to fulfill its obligation to accurately and reliably forecast the impacts on future system integrated resource planning. Due to the long lead time for some of the proposed technology solutions, it is recommended that utilities engage these challenges sooner versus later. If technical challenges manifest, a timely solution cannot be implemented if studies, demonstration installations, and field tests still must be conducted. Additionally, utilities should study all conceivable options that may severely affect transmission system integrity and stability. Otherwise, utilities may experience unintended consequences due to unforeseen technical issues resulting from high penetrations of new renewable energy sources.

3.4 ENERGY STORAGE

Energy storage, in general, is a very old concept, even though it was not recognized as such. For instance, solar energy has been transformed and stored in the form of fossil fuels that are used today in many applications. Energy storage concepts have not been widely applied to power systems until recently, due mainly to technological and economic limitations given the large volumes of energy that typically are of interest in the power industry. Some exceptions are pumped hydro and uninterruptible power supply (UPS) systems. However, energy storage concepts have been commonly applied to other areas of electrical engineering, such as electronics and communications, where the amounts of energy to be stored are easier to manage.

3.4.1 Regulatory and Market Forces

Grid energy storage or the ability to store energy within the power delivery grid can arguably be regarded as the "holy grail" of the power industry, and it is expected to play a key role in facilitating the integration of renewables, DRs and plug-in electric vehicles (PEVs)[2] and fully enabling the capabilities, higher efficiency, and operational flexibilities of the smart grid. The main challenge with electric energy is that it must be used as soon as it is generated, or if not, it must be converted into other forms of energy. During the times when their assistance is not required, storage systems accumulate energy. Later, stored energy is dispatched into the power system for certain periods of time, thus decreasing the demand for generation and assisting the system when needed.

The ability to store energy in an economic, reliable, and safe way would greatly facilitate more efficient operation of the power systems. Unfortunately, high costs and technology limitations have constrained the large-scale application of storage systems. Historically, pumped hydro has been the most common application of energy storage technologies on power system level applications. Nevertheless, the last two decades have seen the emergence and practical applications of new technologies, such as battery systems and flywheels, prompted by the increasing interest and need to integrate intermittent renewable resources and PEVs, growing demand for high reliability, for instance, via implementation of microgrids, and the need for finding alternative technologies to provide ancillary services and system capacity deferral among others. There is growing interest worldwide in this area, and regulatory mechanisms and incentives are being proposed and debated.

[2] PEV—Plug-in electric vehicle, typically meant to include the entire family of grid-rechargeable vehicles, including plug-in hybrids (PHEVs), battery electric vehicles (BEVs or EVs), and extended range electric vehicles (EREVs).

One of the most successful regulations is currently in California where the California State Law (AB 2514) [5] sets energy storage procurement targets in the State of California (Enacted 2010). The IOU utilities must procure and deploy 1.325 GW of energy storage by the year 2020. This legislation is designed for the following reasons:

- Reduce emissions of greenhouse gases
- Reduce demand for peak electrical generation
- Defer or substitute an investment in generation, transmission, or distribution assets
- Improve the reliable operation of the electrical transmission or distribution grid

A failed legislation, which provides a tax incentive, may be redrafted and implemented in the future. In this code, the U.S. Congress Storage Act of 2009 (S. 1091) called for an amendment to the Internal Revenue Code to:

- Allow a 20% energy tax credit for investment in energy storage property directly connected to the electrical grid (i.e., state systems of generators, transmission lines, and distribution facilities) and designed to receive, store, and convert energy to electricity and deliver such electricity for sale
- Make such property eligible for new, clean, renewable energy bond financing
- Allow a 30% energy tax credit for investment in energy storage property used at the site of energy storage
- Allow a 30% nonbusiness energy property tax credit for the installation of energy storage equipment in a principal residence

Other market examples include Australian State Governments directly funding deployment of storage, such as in South Australia (100 MW/129 MWh battery), Victoria (100 MW, undetermined energy capability); and the UK Government, which is funding £246 million of research, innovation and the scale-up of battery technology.

There are several main applications where energy storage systems can be used. Some of those include frequency regulation, spinning reserve, peak shaving/load shifting, and renewable integration [6].

3.4.1.1 Frequency Regulation

In practice, there always exists a mismatch between generation and load in a power system. This mismatch results in frequency variations. System operators are always trying to match the generation to the load so that the frequency can be as close as possible to 60 Hz (or 50 Hz in Europe and Australia and other International Electrotechnical Commission (IEC) standards-based countries). Variability of the frequency is further increased by the addition of intermittent renewables, such as solar and wind. Any power system is required to maintain the frequency within the desired limits. Any large variations from 60 Hz will cause unwanted system instability and can bring the whole system down. As noted earlier, system operators are trying to balance the generation and load by varying the output of certain generating units based on the system frequency. This type of regulation is called frequency regulation. In addition to having the whole system being able to supply power for the desired load, utility operators always have an extra amount of generation that is known as spinning reserve. This spinning reserve must be enough to provide power for frequency regulation purposes as well as support the tripping of the largest generating unit in the system to prevent the power interruptions. The amount of regulation capacity is most based on historical records and might vary on several factors, such as time of the day and time of the year.

One basic difference between the regulated and deregulated markets is that deregulated markets may have a market for ancillary services, such as frequency regulation. In this market, reserve capacities of every generating unit can be bid and market price is paid for capacity reserved for the regulation as well as actual provided energy. The system works by using a control system for each balancing authority that sets the outputs of each generation asset. The system computes the difference between the power output and load demand (adjusted with frequency error bias) called area control error or ACE. From this signal, another signal called automatic generation control or AGC is computed and sent to regulation service providers. These providers, in turn, adjust their power output based on the AGC signal that was received. A frequency increase requires providers to supply additional power to the grid, which is equivalent to an energy storage system discharging energy to the system. On the opposite side, a frequency decrease requires providers to reduce power to the grid, which is equivalent to charging an energy storage system.

In the past, thermal generators or hydro facilities have been used to provide frequency regulation due to their fast response, which is needed for effective regulation. However, this was not the most optimal way for economic dispatch because of the emissions, fuel costs, losses, and increased wear and tear on the generating sources. In addition, these are sometimes base-load generating plants, so output had to be reduced to provide frequency regulation capacity, which, in turn, caused higher-cost generating units to be online to support the load. Energy storage that provides frequency regulation allows for better optimization of generation assets. In addition, every MW of renewable resources added to the system will require between 3% and 10% increase in regulation service.

3.4.1.2 Spinning Reserve

As mentioned earlier, the total generation in a region that belongs to one utility system is equal to the load demand plus some spinning reserve. The amount of spinning reserve is equal or larger to the highest power-producing unit connected to the system plus some margin. The reason for this is the need for immediate additional power if the largest unit goes off-line suddenly. Knowing that it takes a certain amount of time to start any generating unit, having energy storage systems provides additional benefit because those systems can be immediately deployed. During the high-load periods, majority of thermal and hydro units are dispatched and run at their maximum efficiency and cannot be utilized as spinning reserve. So, to have spinning reserve, additional units are needed. Note that during light- or medium-load conditions, these generating units have output less than maximum, with the difference being designated as spinning reserve. Committing generating resources for spinning reserves is mandatory, but it results in increased operating costs and decreased efficiency. Energy storage systems help in reduction of spinning reserves provided by thermal and hydro generating units and allow dispatchers to set operating points at maximum levels during the economic dispatch. Like frequency regulation market, in deregulated markets, there exists a spinning reserve service market, where generation owners bid to provide this service. The only downside to energy storage systems is that they provide output only for a limited amount of time. After the energy storage system has started providing energy to the utility system, additional generating units must be deployed before the output of energy storage systems runs out to avoid service interruptions. At a time where energy storage systems come at a premium cost, a possible strategy is to size the energy storage system to be able to support the service while a peaking generator is started and ramps up to the desired output. As energy storage systems decrease their costs, they may be able to serve more of the requirements in a cost-effective way.

3.4.1.3 Peak Shaving and Load Shifting

Load demand is always changing, and utilities employ different techniques to predict daily load curves. Major inputs into load estimation are temperature, load demand during the last seven to ten days, and historical data. Based on the estimated load curves, economic dispatch is created to identify generating units that will be supplying the needed power along with spinning reserves and uncertainty in load estimation. Every generating unit has operating costs, and economic dispatch is based on these costs. Units with lowest operating costs are used for base loading, and run most of the time. For example, nuclear, hydro, and modern coal plants are almost exclusively used for base load generation. Note here these units also have the highest capital cost of construction. To cover the peak load demand, utility must bring on-line its higher operating cost generating units. For example, plants that have combustion turbines (CTs) might only be utilized a few hours during the whole year to cover the peak load. To level demand and move energy usage toward the off-peak hours, energy must be stored first. This can be done during the time with low demand because the cost of generation is low. This energy can be supplied from energy storage systems to the grid during the peak times.

3.4.1.4 Renewable Integration

Energy storage, power electronics, and communications have a key role to play to mitigate the intermittency and ramping requirements of large-scale renewable energy penetration of wind and solar energy. Since their inception, wind and solar technologies have made major breakthroughs and become more reliable and cost effective. Many utilities are constantly incorporating additional renewable resources into their generation portfolios. However, the biggest issue associated with wind and solar power is their unpredictability and variability of the output, although developments in wind forecasting techniques have come a long way to give a much higher predictability to the use of wind in the system. Solar forecasting techniques are also being developed to bring increased forward-looking visibility. These developments will reduce the need for regulation and support a higher-carrying capacity at a lower cost. In addition, these technologies also require regulation. Solar and wind energy productions are not dispatchable and result typically in high levels of power and associated voltage fluctuations. However, coupled with sophisticated forecasting techniques, they can be used for bidding in wholesale markets. Common problems in remote wind production areas include low capacity factors for all the wind farms, impacts of line contingencies on wind farm operations, curtailment of wind farm outputs during high production times, and high ramp rate requirements [4]. In most urban regions, PV flat-plate collectors are predominately used for solar generation and can produce power production fluctuations with a sudden (seconds time scale) loss of complete power output. With partial PV array clouding, large power fluctuations can also result at the output of the PV solar farm with large power quality impacts on distribution networks. These power variations on large-scale penetration levels can produce several power quality and power balancing problems. Cloud cover and morning fog require fast ramping and fast power balancing on the interconnected feeder. Furthermore, several other solar production facilities are normally planned in close proximity on the same electrical distribution feeder that can result in high levels of voltage fluctuations and even flicker. Reactive power and voltage profile management on these feeders are common problems in areas where high penetration levels are experienced. In the case of low voltage (LV) feeders that support a large number (50–150) of customers (e.g., Australia), situations of low-load high solar production can contribute to voltage rise in distribution networks to levels that can either cause potential problems to PV owners (their inverters trip under high-voltage conditions) or to appliances of all users in the feeder, driving the need for anticipated network upgrades and the associated expense.

3.4.2 Technologies

Energy storage methods can be divided into several groups: chemical, electrical, electrochemical, mechanical, thermal, and biological. Table 3.1 summarizes some of the most common types of energy storage systems connected to the utility power grid.

TABLE 3.1
Energy Storage Technology Comparisons

Storage Technologies	Main Advantages (Relative)	Disadvantages (Relative)	Power Application	Energy Application
Pumped hydro storage	High energy, low operating cost, very high ramp rate, mature technology	Special site requirements, high project cost	Not feasible or economical	●
Compressed air energy storage (CAES)	High energy, low cost, better ramp rate than gas turbines, mature technology	Special site requirements, need gas fuel, lower efficiency, slower response than flywheels or batteries	Not feasible or economical	●
Flow batteries: PSB VRB ZnBr	High capacity, independent power and energy ratings, can perform high number of discharge cycles, lower efficiency, very long life	Medium-energy density, complicated design, slow dynamic response, developing technology	◑	●
NaS	High power and energy densities, long discharge cycles, fast response, long life, mature technology	High production cost, safety concerns since required to run at high temperatures, limited applications	●	●
Li-ion	High power and energy densities, high efficiency, good cycle life, mature technology	High production cost, special balancing circuits, safety concerns	●	◑
Ni-Cd	High power and energy densities, mature technology	Higher losses, lower lifetime	●	◑
Advanced lead-acid	High power and energy densities, high efficiency, low capital cost, mature battery technology	High production cost, low-energy density, large footprint, limited useful life	●	●
Traditional lead-acid	Low capital cost, mature technology	Limited cycle life when deeply discharged	●	Feasible, but not practical or economical
Flywheels	High power, rapid response, high efficiency, mature technology	Low-energy density, limited energy storage time due to frictional losses	●	Not feasible or economical
Superconducting magnetic energy storage (SMES)	High power, high efficiency	Low-energy density, high production cost, developing technology	●	Not feasible or economical
Electrochemical capacitors (EC)	Long cycle life, high efficiency, fast discharge	Very-low-energy density, high production cost, developing technology	●	Not feasible or economical

Source: Based on data from the DOE report on Grid Energy Storage, December 2013; and Energy Storage Association (ESA), http://www.energystorage.org.

3.4.2.1 Batteries

Battery energy storage is mostly used for load leveling (Figure 3.1), peak shaving, PV smoothing, and frequency regulation. Today, there are two main types of batteries based on their chemistry and structure. One type is called a power battery, and these batteries can deliver fast charge/discharge. These types of batteries are mainly used for frequency regulation and PV smoothing. Another type

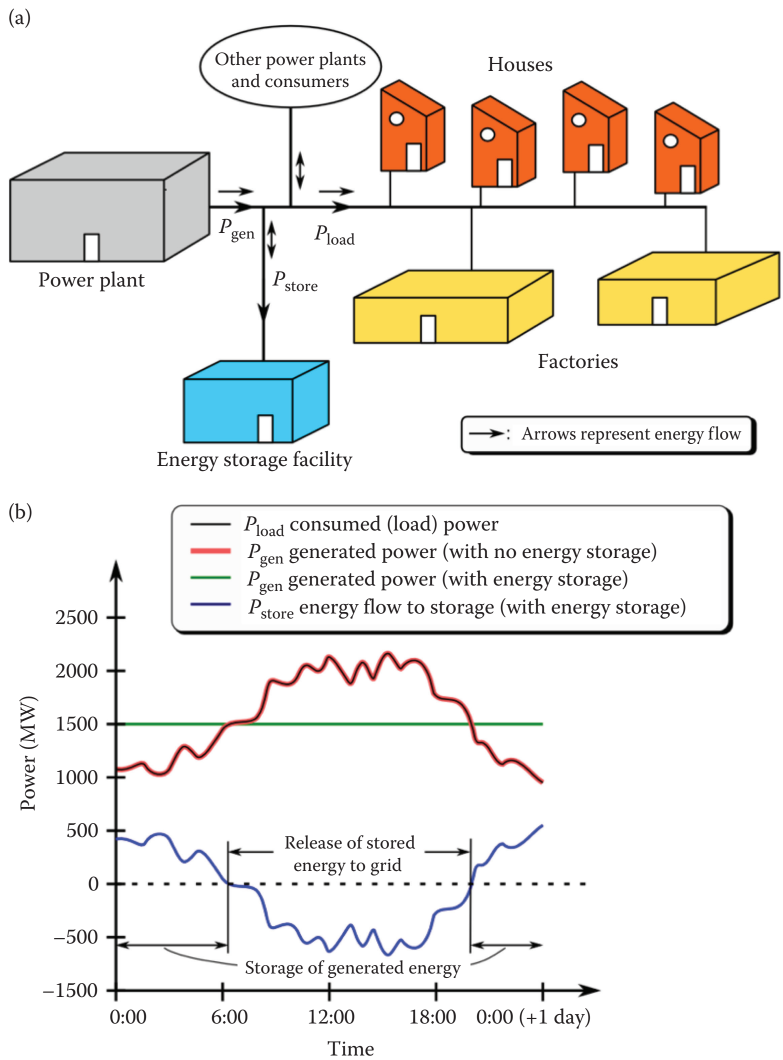

FIGURE 3.1 Conceptual description of grid energy storage. (a) Network power flows and (b) energy storage and release cycles. (From Wikipedia, Grid Energy Storage, http://en.wikipedia.org/wiki/Grid_energy_storage.)

of battery has slow charge/discharge times, and those types of batteries are mostly used for load leveling and peak shaving.

Energy storage systems can be used for smoothing the power out of renewable sources. This can be accomplished by limiting the rate of change of the output of a renewable resource. Energy storage systems can either add or remove power from the system as needed to smooth the power output of a renewable resource. One of the most promising solutions to mitigate these integration issues is by implementing a hybrid fast-acting energy storage and STATCOM (static synchronous compensator) in a smart grid solution. Several fast-reacting energy storage solutions are currently available on the market. For mitigating the mentioned wind and solar integration problems, the energy storage device needs to be fast acting and a storage capability of typically 15 min to 4 h and a STATCOM that is larger than the battery power requirements to have adequate dynamic reactive power capabilities. Figure 3.2 shows an example of a STATCOM

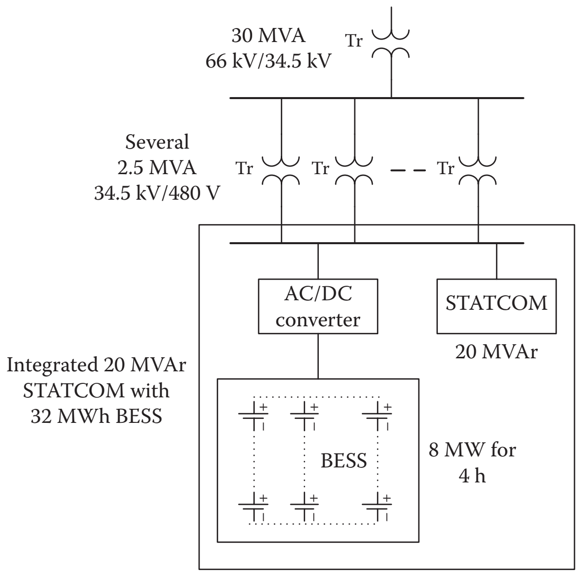

FIGURE 3.2 Basic schematic of STATCOM-BESS application. (From Enslin, J., Dynamic reactive power and energy storage for integrating intermittent renewable energy, Invited Panel Session, Paper PESGM2010000912, *IEEE PES General Meeting*, Minneapolis, MN, July 25–29, 2010. With permission.)

and battery energy storage application for mitigating a wind farm-related integration issue [9]. The main components and technical characteristics of this smart energy storage solution are as follows:

- 8 MW/4 h battery
- 20 MVAr inverters for the battery energy storage and STATCOM
- Integrated control and HMI (human-machine interface) of STATCOM and battery energy storage system
- Substation communications interface for integrating the battery energy storage solution into a distribution automation and ISO market participation environment

High-power batteries, efficient inverters, and sophisticated switching make energy storage a practical new technology application for distribution systems. There are a small but growing number of installations of 0.25–4 MW energy storage systems on utility systems using a wide variety of battery technologies. Figure 3.3 is an example of bulk energy storage ("utility-scale") installed in a utility substation that can be used for a variety of applications. In a peak shaving application, the intelligence in the control system charges the batteries during off-peak times and then supplies energy during peak times. This creates several opportunities for economic justification, such as the ability to make full use of intermittent renewable sources regardless of the time of day or present loading, the ability to shave peak load, and the deferral of substation and feeder capacity upgrades. This utility-scale energy storage can also be used for microgrid applications.

Energy storage that is connected to the electric distribution system outside the substation is likely to be of smaller MW sizes but can still have a great impact on reliability and automatic restoration systems. Figure 3.4 shows an example of a smaller footprint 250 kW energy storage inverter and controller that would be installed out of the substation closer to the customer ("community-scale" storage), perhaps also installed on a large commercial or industrial customer site. The batteries would typically be separate to the inverter in an adjacent cabinet.

FIGURE 3.3 A 2-MW energy storage installed in a utility substation. (© 2016 S&C Electric Company. All rights reserved. With permission.)

FIGURE 3.4 A 250-kW energy storage inverter and controller for distributed applications. (© 2016 S&C Electric Company. All rights reserved. With permission.)

3.4.2.2 Superconducting Magnetic Energy Storage (SMES)

SMES stores energy in the magnetic field that is created due to the flow of DC in a superconducting coil. The coil has been cooled cryogenically to below its superconducting critical temperature. SMES consists of three parts: bidirectional AC/DC inverter system, superconducting coil, and cryogenically cooled refrigerator. DC charges the superconducting coil, and when the coil is charged, it stores magnetic energy until it is released. This energy is released by discharging the coil. Bidirectional inverter is used to convert AC to DC power and vice versa during the coil charging/discharging cycles. The cost of SMES is high today because of its superconducting wires and refrigeration energy use, and its main use is for reducing the loading during the peak times.

The main technical challenges associated with SMES are large size, mechanical support due to high forces, superconducting cable manufacturing, infrastructure required for installation, low levels of critical current when superconducting properties of materials break down, levels of critical magnetic field, and health effects due to exposure to large magnetic fields.

3.4.2.3 Flywheels

Flywheel Energy Storage (FES) operates on the principle of conservation of rotational momentum—a flywheel is accelerated to a very high speed to store kinetic energy. When energy is demanded from the system, the flywheel rotational speed is reduced. To reduce friction during the rotation, a vacuum chamber is used to contain the rotor. The rotor is connected to an electric motor or generator. FES is not affected by the change of temperature, and stored energy is easily calculated, but the main danger is the fatigue failure of the flywheel and the containment of damage from any failure.

3.4.2.4 Compressed Air

Energy generated at one point in time (off-peak) can be stored and later used during different periods of time (peak). Compressed Air Energy Storage (CAES) represents one viable option. There are three types of air storage: adiabatic, diabatic, and isothermic. Adiabatic storage retains the heat that is produced by compression and later returns the heat to the air when the air is expanded to generate power. Diabatic storage dissipates some portion of heat as waste. For air to be used after it is removed from storage, it must be heated again prior to expansion in the turbine to power the generating unit. Isothermal storage operates under the same temperature conditions by utilizing the heat exchanger. These exchangers account for some losses.

Most CAES systems currently in operation do not utilize the compressed air to directly generate electricity [10]. Rather, the compressed air is fed into simple-cycle CTs, reducing the compression work in the standard recuperated Brayton cycle. In this mode, the CAES system serves to pre-compress combustion air during off-peak periods, improving the output of the CT during on-peak periods.

3.4.2.5 Ultracapacitors

Ultracapacitors or supercapacitors are storage devices for DC energy. To be able to be connected to the power grid, a bidirectional AC/DC inverter is needed. Because of their fast charge/discharge rates, ultracapacitors are used only during short power interruptions and voltage sags.

Unlike batteries where energy is stored chemically, ultracapacitors store this energy electrostatically. Ultracapacitors consist of two electrodes called collector plates, which are suspended in an electrolyte. The dielectric separator is placed between the collector plates to prevent the charges from moving from one electrode to another. Applied potential difference between the two collector plates causes negative ions in the electrolyte to be attracted to the positive collector plate and positive ions in the electrolyte to be collected on the negative collector plate.

Ultracapacitors have several advantages and disadvantages compared to batteries. Some of the disadvantages include lower amount of energy stored per unit of weight, more complex control and switching equipment, high self-discharge, additional voltage balancing, safety issues, while some of the advantages include long life, low cost per cycle, good reversibility, high rate of charge/discharge, high efficiency, and high output power.

3.4.2.6 Pumped Hydro

Pumped hydro storage method stores energy in the form of water, which is pumped from a reservoir on a lower elevation to a reservoir on a higher elevation. This is done during the off-peak hours when the cost of production of electricity necessary to run the pumps is lower. During the high-demand period, this water is released through the turbines. Pumped hydro is the highest-capacity storage system currently available. It is used for load flattening, frequency control, and reserve generation. However, the cost of building pumped hydro storage is very high.

3.4.2.7 Thermal

Thermal energy storage consists of a series of technologies that store thermal energy in reservoirs (e.g., using molten salt or ice) when electricity production is cheap (e.g., during off-peak, when most of the electricity is produced by using efficient and relatively inexpensive "base" units) and releases it for heating or cooling purposes when electricity production is expensive (e.g., during peak, when electricity is produced by using costly "peaking" units), which equates to electricity production savings and/or T&D capacity deferral due to load shaving.

Recent developments in thermal storage have investigated conversion of stored heat directly into electricity, using Brayton or Rankine cycles [11]. Work on these systems has been catalyzed by thermal storage systems utilized for concentrating solar power, where excess heat captured during the day is stored for power generation in the evening. Round-trip efficiency of electrical-thermal storage remains problematic, with typical verified efficiencies below 30%. As a result, much attention is currently focused on increasing the temperature of thermal storage to greater than 500°C, utilizing phase-change materials to reduce system size and augmenting thermal storage material to improve thermal conductivity within the storage tanks.

3.4.3 Energy Storage in the Smart Grid

Energy storage applications can be centralized or distributed. The selection of the type of solution and technology to be used in an application is a function of the type of problem to be addressed and a series of technical and economic considerations such as ratings, size and weight, capital costs, life efficiency, and per-cycle cost. Figure 3.5 shows a summary of the installed

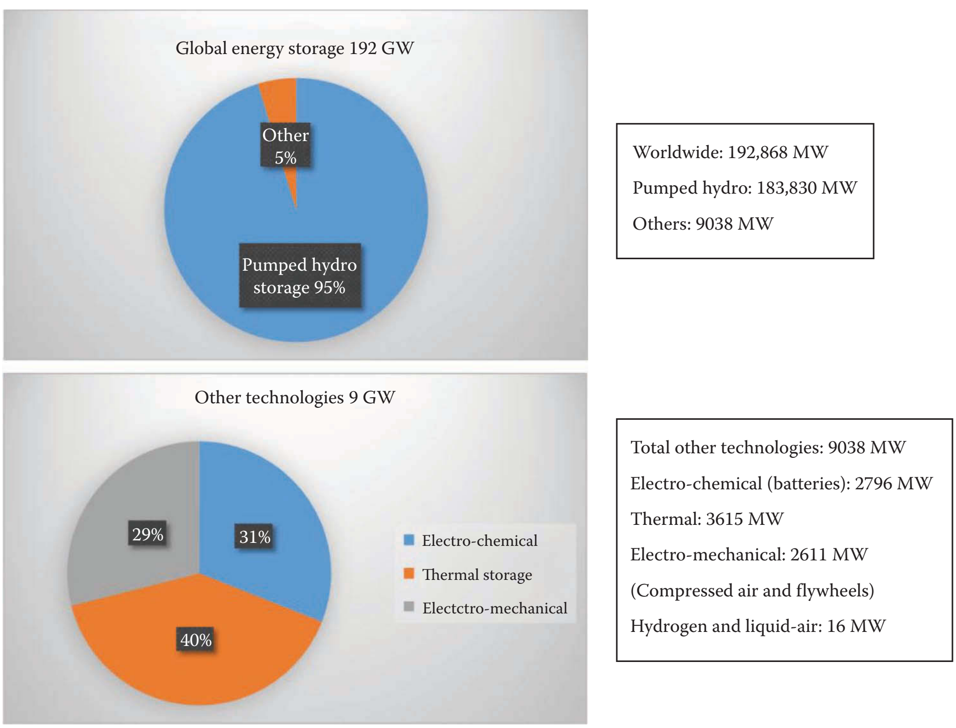

FIGURE 3.5 More than 1500 installed grid-connected energy storage projects worldwide as July of 2016. (From DOE Global Energy Storage Database, http://www.energystorageexchange.org/projects/data_visualization.)

grid-connected energy storage technologies worldwide. Table 3.2 summarizes the key grid applications of energy storage.

Centralized energy storage applications consist of large MW-size facilities usually connected to transmission system level voltages; these applications are typically used for providing ancillary services during short periods of time (e.g., seconds or minutes) and for mitigating the impacts of intermittent renewable generation. Distributed storage consists of smaller MW-size facilities connected to distribution system level voltages, either at distribution substations, feeders, or customer facilities;

TABLE 3.2
Energy Storage Applications

Electric (grid-supplied) energy time shift	Charges the storage plant with inexpensive electric energy purchased during low price periods and discharges the electricity back to the grid during periods of high price
Electric supply capacity	Reduces or diminishes the need to install new generation capacity
Load following	Alters power output in response to variations between electricity supply and demand in a given area
Area regulation	Reconciles momentary differences between supply and demand within a given control area
Electric supply reserve capacity	Maintains operation when a portion of normal supply becomes unavailable
Voltage support	Counteracts reactive effects to grid voltage so that it can be upheld or reinstated
Transmission support	Enhances transmission and distribution system performance by offsetting electrical irregularities and interruptions
Transmission congestion relief	Avoids congestion-related costs by discharging during peak demand to reduce transmission capacity requirements
Transmission and distribution upgrade deferral and substitution	Postpones or avoids the need to upgrade transmission and/or distribution infrastructure
Substation on-site power	Provides power to switching components and communication and control equipment
Time-of-use energy cost management	Reduces overall electricity costs for end users by allowing customers to charge storage devices during low price periods
Demand charge management	Reduces charges for energy drawn during specific peak demand times by discharging stored energy at these times
Reliability	Provides energy during extended complete power outages
Power quality	Protects on-site loads against poor quality events by using energy storage to protect against frequency variations, lower power factors, harmonics, and other interruptions
Renewables energy time-shift	Stores renewable energy (which is frequently produced during periods of low demand) to be released during periods of peak demand
Renewables capacity firming	Addresses issues with ramping from renewable sources by using stored energy in conjunction with renewable sources to provide a constant energy supply
Wind/solar generation grid integration	Assists in wind- and solar-generation integration by reducing output volatility and variability, improving power quality, reducing congestion problems, providing backup for unexpected generation shortfalls, and reducing minimum load violations

Source: US DOE report Electric Power Industry Needs for Grid-Scale Storage Applications, December 2010, https://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/Utility_12-30-10_FINAL_lowres.pdf.

this includes applications such as community energy storage (CES) and vehicle-to-grid (V2G). CES is a concept that is increasingly being implemented with applications ranging from 25 kWh to 75 kWh and devices similar to pad-mounted distribution transformers. Distributed energy storage, in general, is typically used for intermittent renewable generation integration, distribution reliability improvement, capacity and T&D deferral; therefore, they are required to have longer storage times (e.g., minutes or hours), as shown in Figure 3.6. This application is also increasingly being considered for integration of PEVs. The US DOE and Energy Storage Association (ESA) provide very comprehensive descriptions of the recommended applications, as well as advantages and disadvantages of each technology, which are summarized in Table 3.1 and Figure 3.6, and discussed in the next sections.

The coordinated implementation of smart grid technologies, such as distributed energy storage, communications, control, power electronics, and power system technologies, allows the seamless integration of intermittent DG and adds further capabilities to it including controllability (i.e., dispatchability) and predictability. These capabilities can be used for capacity planning applications (e.g., capacity deferral), increased operational flexibility during outages (intentional islanding), and reliability improvement. Furthermore, distributed storage in the smart grid context may be used to mitigate impacts caused by both, DG (especially PV) and PEVs. Table 3.3 summarizes the suitability of energy storage technologies for grid applications.

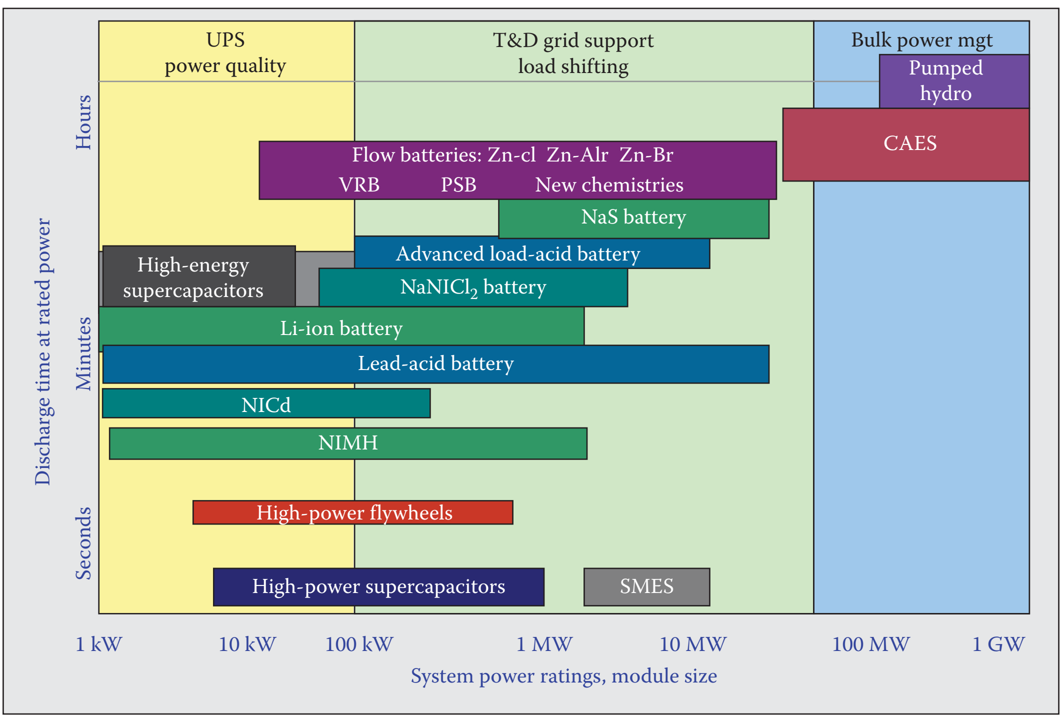

FIGURE 3.6 Energy storage technology ratings and discharge times for electric utility applications. (From Sandia Report Electricity Storage Handbook, SAND2015-1002, February 2015.)

TABLE 3.3
Suitability of Energy Storage Technologies for Grid Applications

Application	Description	CAES	Pumped Hydro	Flywheels	Lead-Acid	NaS	Li-ion	Flow Batteries
Off-to-on peak intermittent shifting and firmin	Charge at the site of off peak renewable and/or intermittent energy sources; discharge energy into the grid during on peak periods	◑	◑	○	●	●	●	●
On-peak intermittent energy smoothing and shaping	Charge/discharge seconds to minutes to smooth intermittent generation and/or charge/discharge minutes to hours to shape energy profile	○	◑	◑	●	●	●	●
Ancillary service provision	Provide ancillary service capacity in day ahead markets and respond to ISO signaling in real time	◑	◑	◑	◑	◑	◑	◑
Black start provision	Unit sits fully charged, discharging when black start capability is required	◑	◑	○	●	●	●	●
Transmission infrastructure	Use an energy storage device to defer upgrades in transmission	○	○	○	●	●	●	●
Distribution infrastructure	Use an energy storage device to defer upgrades in distribution	○	○	○	●	●	●	●
Transportable distribution-level outage mitigation	Use a transportable storage unit to provide supplemental power to end users during outages due to short term distribution overload situations	○	○	○	◑	●	●	●
Peak load shifting downstream of distribution system	Charge device during off peak downstream of the distribution system (below secondary transformer); discharge during 2–4 hour daily peek	○	○	○	●	●	●	●
Intermittent distributed generation integration	Charge/Discharge device to balance local energy use with generation. Sited between the distributed and generation and distribution grid to defer otherwise necessary distribution infrastructure upgrades	○	○	○	●	◑	◑	◑
End-user time-of-use rate optimization	Charge device when retail TOU prices are low and discharge when prices are high	◑	◑	○	◑	◑	◑	◑
Uninterruptible power supply	End user deploys energy storage to improve power quality and /or provide back up power during outage	○	○	◑	●	●	●	●
Micro grid formation	Energy storage is deployed in conjunction with local generation to separate from the grid, creating an islanded micro-grid	○	○	○	●	●	●	●

Definite suitability for application ●; Possible use for application ◑; Unsuitable for application ○

Source: US DOE report Grid Energy Storage, December 2013, https://energy.gov/sitesw/prod/files/2014/09/f18/Grid%20Energy%20Storage%20December%202013.pdf.

3.5 ELECTRIC VEHICLES

3.5.1 Regulatory and Market Forces

With the implementation of smart grid technologies and the associated improvements in the reliability, sustainability, security, and economics of the electric grid comes the opportunity to include vehicles as an active participant in the smart grid. Although electrification of segments of the transportation energy sector does not require any technological or systemic advancements of the electric grid over what is presently available, the large scale of the transportation energy sector will provide long-term challenges to the legacy systems of the electric grid along with considerable opportunities for improved power, energy, and economic management in a smart grid system.

Electric transit (including electric trains and catenary trolleybuses) has a long history of integration with the electric grid. Electric transit has traditionally always operated at large, centralized scales, “tethered” to the grid. These technologies require a more-or-less continuous provision of electricity during operation of the vehicle. The introduction of high-density energy storage has introduced a watershed change in electric transportation in the form of distributed, small vehicles operating in an untethered mode. The ongoing and large-scale introduction of PEVs to the world automotive fleet is one of the most important changes to the transportation energy sector in history, and the capabilities of the smart grid will play a large role in determining whether the electricity sector can realize benefits from this integration.

Relative to a conventional internal combustion vehicle or conventional HEV baseline, there are numerous potential benefits that come with the electrification of transportation energy through PEVs [15]:

- Reduced petroleum (fossil fuel) consumption
- Lower life-cycle greenhouse gas and pollutant emissions (depending on the mix of electricity generation type)
- Typically lower fueling costs
- Lower life-cycle cost of ownership (depending on vehicle comparison)

Because of these potential benefits, there is a steady and growing interest in the development of PEVs. Numerous traditional and entrepreneurial automakers have research, development, and limited production plug-in vehicle programs. Nearly every OEM and several entrepreneurial vehicle manufacturers have launched large-scale production PEV programs. The rate of introduction of PEVs into the world vehicle fleet will continue to accelerate under pressures from regulators, such as Environmental Protection Agency (USA), California Air Resources Board, and others. The increasing commercial and private investment in PEVs will drive a corresponding investment in electrical infrastructure servicing PEVs. This investment in infrastructure will include public and in-home electric charger installations, which will incorporate passive or active forms of communication to facilitate the integration of large fleets of PEVs onto the electric grid.

The following sections will examine the potential impact of PEVs on the existing grid, describe methods of using smart grid technologies to alleviate foreseen problems, and investigate potential opportunities to enhance the performance of the electric grid using PEVs.

3.5.2 Technologies

3.5.2.1 Hybrid (HEV)

An HEV is a type of EV that uses a combination of a conventional Internal Combustion Engine (ICE) and an electric motor for propulsion. HEVs use different technologies to improve efficiency and reduce emissions; such technologies include using regenerative breaking, using the ICE to generate electricity to recharge batteries or power the electric motor, and using the electric motor during most of the time and reserving the ICE for propulsion only when needed. Commercial examples of this type of vehicle include the Toyota Prius and the Honda Insight. HEVs are not PEVs since they can operate autonomously without the need of recharging batteries using the power grid. Therefore, no impact on the power grid is expected from proliferation of this type of EV.

3.5.2.2 Plug-in Hybrid (PHEV)

A PHEV is a type of EV that has an ICE and an electric motor (like an HEV) and a high-capacity battery pack that can be recharged by plugging-in the car to the electric power grid (like a BEV). There are two basic PHEV configurations [16]:

- Series PHEVs or Extended Range Electric Vehicles (EREVs) are PEVs where only the electric motor and drivetrain provide tractive power to the wheels and the ICE is only used to generate electricity. Series PHEVs can run solely on electricity until the battery is discharged. The ICE will then generate the electricity needed to power the electric drivetrain. For shorter trips, these vehicles might use no gasoline at all.
- Parallel or blended PHEVs are PEVs where both the engine and electric motor are mechanically connected to the wheels, and both propel the vehicle under most driving conditions. Electric-only operation usually occurs only at low speeds.

The main advantage of PHEVs with respect to BEV is that PHEVs have longer driving range and shorter recharge time. Relative to conventional internal combustion engine vehicles, PHEVs are characterized by lower operation cost and lower environmental impact.

3.5.2.3 Battery (BEV)

A battery electric vehicle (BEV) is a type of EV that uses rechargeable battery packs to store electrical energy and an electric motor (DC or AC depending on the technology) for propulsion. Intrinsically it is a PEV since the battery packs are charged via the electric vehicle supply equipment (EVSE), that is, by "plugging-in" the BEV. The North American standard for electrical connectors for EVs is the SAE J1772, which is being maintained by the Society of Automotive Engineers (SAE) [17]. The standard defines two charging levels AC Level 1 (120 V, 16 A, single-phase) and AC Level 2 (208–240 V, up to 80 A, single-phase). Furthermore, additional work is being conducted on standardizing Level 3 (300–600 V, up to 400 A, DC). The technical requirements of BEV batteries are different from those of other energy storage applications include demanding requirements on power/weight ratio, energy/weight ratio, cost, and energy density. At present, a variety of lithium-ion chemistries has demonstrated the ability to meet these requirements in the automotive application. No single lithium-ion chemistry has yet emerged as dominant in the BEV application. Since BEVs do not have combustion engines, their operation fully depends on charging from the electric grid. Therefore, uncontrolled charging cycles of BEVs under scenarios of high market penetration may cause increased loads on power distribution systems. For example, if BEVs are charged upon their return to "home," their loads may be coincident with the afternoon/evening residential demand peak, leading to higher costs to generate, transmit, and distribute electricity to vehicles [18].

In the US, BEVs are, as of 2016, the highest selling EVs in the market. US PHEV and BEV sales for the 2010–2016 period exceeded 550,000 units, as shown in Figure 3.7.

3.5.3 Electric Vehicles in the Smart Grid

The adoption of electric vehicles reduces gasoline consumption and tailpipe emissions and improves the urban area air quality. However, electric vehicles can have disruptive impacts on the power grid if they are not integrated carefully. Most vehicles return home in late afternoon and

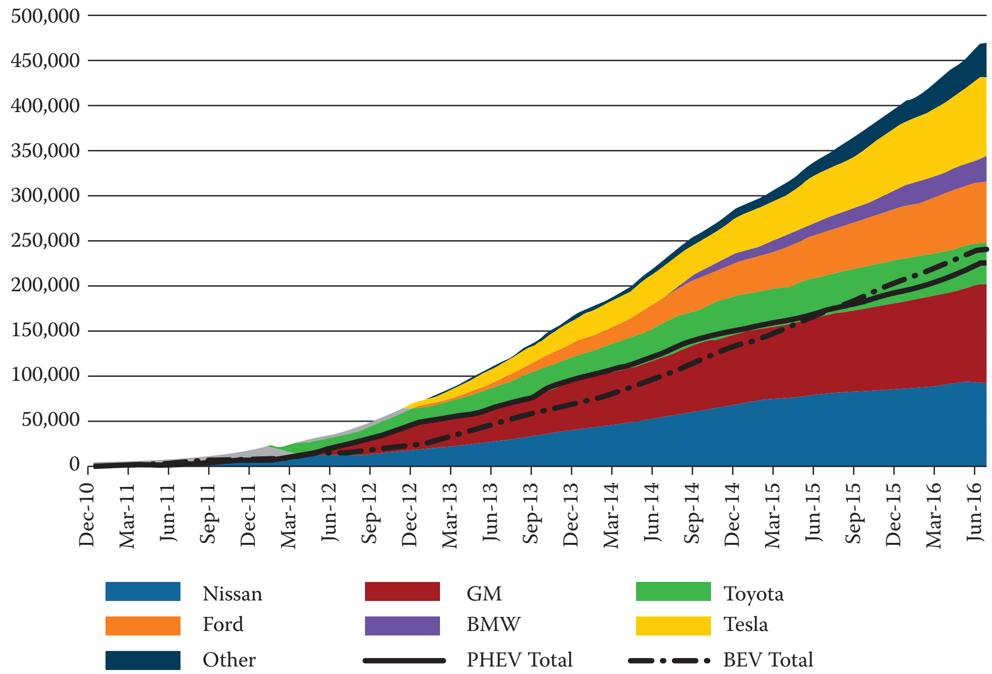

FIGURE 3.7 U.S. PHEV and BEV sales from 2010 to 2016. (Willard, S., *Energy Storage Trends and Challenges*. Electric Power Research Institute, Palo Alto, CA, 2016. Copyright Electric Power Research Institute. With permission.)

early evening. If they all begin charging the moment they arrive home, the power grid, which may already be at peak load, can have difficulties providing for the additional demand. Distribution system problems, such as transformer overloading and feeder congestion, may become more prevalent. At a larger scale, the bulk system may lack the necessary supply capacity to meet the added demand. Therefore, generation, transmission, and distribution systems are expected to require costly upgrades to support the demand of many more electric vehicles. However, the difference between the total time required to fully charge an electric vehicle and the total time that the vehicle is plugged in allows for charging flexibility that can potentially be used to charge vehicles in a more grid-friendly way.

The environmental benefits of fuel switching from gasoline to electricity is not going to be fully achieved if primarily fossil resources are used to supply the energy requirement of electric vehicles. The main obstacle to non-fossil resources (excluding nuclear that has its own challenges) is the intermittency of renewable generation, which limits the amount that can be integrated and compels system operators to schedule/dispatch expensive reserve units. Implementation of charge controlling strategies eases the operation of bulk power systems with a high penetration level of intermittent renewables, which is beneficial from both economic and environmental perspectives.

The role of electric vehicle demand response is to facilitate a cost-effective and emission-minimizing alignment between charging demand and available energy supply resources. Our interest in demand response for electric vehicles is motivated by the fact that the EV load is inherently different from other deferrable loads, and including this load in the demand response will increase the diversity of the flexible load fleet, and as a result potentially its performance capabilities: (1) EV loads can be delayed for relatively more time than thermostatically controlled loads; (2) EVs can potentially feed electricity into the grid; (3) EV chargers are physically located where other flexible loads may not exist; (4) charging stations are equipped with controls that can provide system operators with voltage response resources even when no EV is plugged to it; and (5) the power factor of the EV charger load differs from other flexible electric loads, which is valuable from the operation point of view.

3.5.3.1 Grid Support

Due to the higher cost of PEVs compared to conventional vehicles, research has been conducted to determine if PEVs can provide additional services to help offset the added expense of a PEV. Studies have shown that vehicles sit unused, on average, for >90% of the day [20]. Using this fact, researchers have conducted studies on the ability of PEVs to provide grid support services to provide a source of revenue for the vehicle owner. If this revenue helped offset the initial cost of the plug-in vehicle, it could increase the incentive for consumers to purchase PEVs. The primary means for monetizing the capabilities of PEVs is proposed participation in a deregulated ancillary services market. Studies to date have determined that frequency regulation is the component of the ancillary services market most compatible with plug-in vehicle capabilities and will provide the largest financial incentive to vehicle owners [21–23].

There are two primary types of power interactions possible between the vehicle and the electric grid. Grid-to-vehicle charging (G2V) consists of the electric grid providing energy to the plug-in vehicle through its charging connector. G2V is the traditional method for charging the batteries of BEVs and PHEVs. A vehicle-to-grid (V2G) capable vehicle has the additional ability to provide energy back to the electric grid. V2G provides the potential for the grid system operator to call on the vehicle as a distributed energy and power resource.

For PEVs to achieve widespread near-term penetration in the ancillary service market, the two primary stakeholders in the plug-in vehicle ancillary service transaction must be satisfied: grid system operators and vehicle owners. The grid system operators demand industry standard availability and reliability for regulation services. The vehicle owners demand a robust return on their investment in the additional hardware required to perform the service and minimal impact on the performance and lifetime of the vehicle's battery.

Since PEVs are not stationary but instead have stochastic driving patterns, these resources possess unique availability and reliability profiles in comparison to conventional ancillary services generation system. In addition to this, the power rating of an individual plug-in vehicle is significantly less than the power capacity of conventional generation systems that utilities normally contract for ancillary services. These key aspects of PEVs create unique challenges for their integration and acceptance into conventional power regulation markets to provide ancillary services.

The connection between the grid system operators and the PEVs to provide grid support services can be classified as one of two types that have been proposed to date: a direct, deterministic architecture and an aggregative architecture. The direct, deterministic architecture, shown conceptually in Figure 3.8, assumes that there exists a direct line of communication between the grid system operator and the plug-in vehicle so that each vehicle can be treated as a deterministic resource to be commanded by the grid system operator. Under the direct, deterministic architecture, the vehicle can bid and perform services while it is at the charging station. When the vehicle leaves the charging station, the contracted payment for the previous full hours is made, and the contract is ended. The direct, deterministic architecture is conceptually simple, but it has recognized problems in terms of near-term feasibility and long-term scalability.

First, there exists no near-term information infrastructure to enable the required line of communication. The direct, deterministic architecture cannot use the conventional control signals that are currently used for ancillary service contracting and control because the small, geographically distributed nature of PEVs is incompatible with the existing contracting frameworks. For example, the peak power capabilities of individual vehicles (1.8 kW [25], 17 kW [26]) are well below the 500 kW–1 MW threshold that is required for many ancillary service hourly contracts [27].

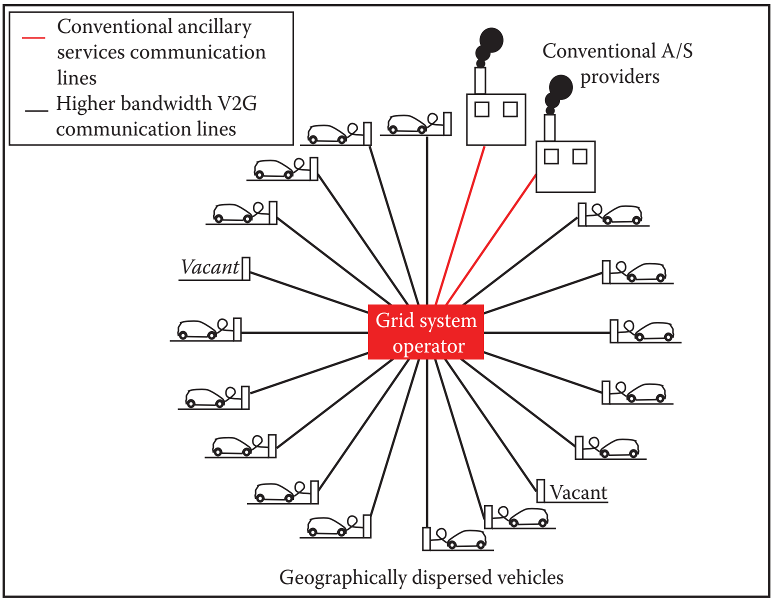

FIGURE 3.8 Example V2G network showing geographically dispersed communications connections under the direct, deterministic architecture. (From Quinn, C. et al., *Journal of Power Sources*, 195(5), 1500, 2010. With permission.)

In the longer-term, the grid system operator might be required to centrally monitor and control all the PEVs subscribed in the power control region—a potentially overwhelming communications and control task [28]. As these millions of vehicles engage and disengage from the grid, the grid system operator would need to constantly update the contract status, connection status, available power, vehicle state of charge, and driver requirements to quantify the power that the system operator can deterministically command. This information would need to be fed into the operator's market system to determine contract sizes and clearing prices.

The aggregative architecture is shown conceptually in Figure 3.9. In the aggregative architecture, an intermediary is inserted between the vehicles performing ancillary services and the grid system operator. This aggregator receives ancillary service requests from the grid system operator and issues power commands to contracted vehicles that are both available and willing to perform the required services. Under the aggregative architecture, the aggregator can bid to perform ancillary services at any time, while the individual vehicles can engage and disengage from the aggregator as they arrive at and leave from charging stations. This allows the aggregator to bid into the ancillary service market using existing contract mechanisms and compensate the vehicles under its control for the time that they are available to perform ancillary services. As such, this aggregative architecture attempts to address the two primary problems with the direct, deterministic architecture.

First, the larger scale of the aggregated power resources commanded by the aggregator and the improved reliability of aggregated resources connected in parallel allow the grid system operator to treat the aggregator like a conventional ancillary service provider. This allows the aggregator to utilize the same communications infrastructure for contracting and command signals that conventional ancillary service providers use, thus eliminating the concern of additional communications workload placed on the grid system operator.

In the longer term, the aggregation of PEVs will allow them to be integrated more readily into the existing ancillary service command and contracting framework, since the grid system operator needs only directly communicate with the aggregators. The communications network between

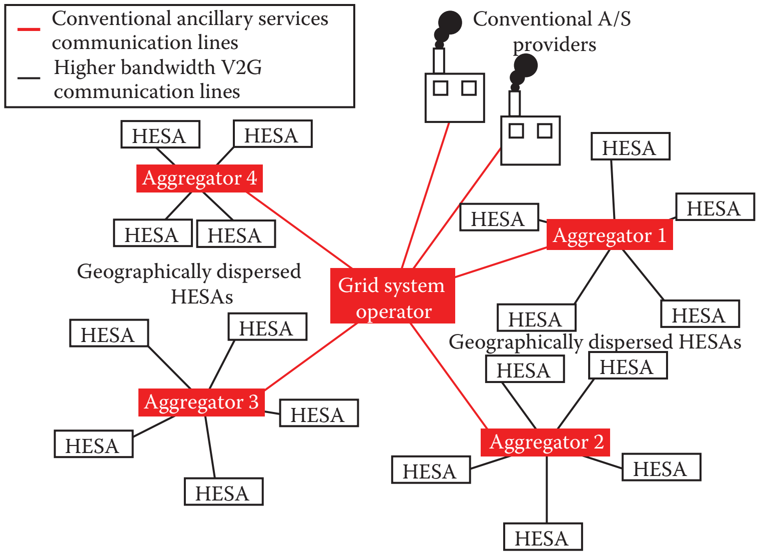

FIGURE 3.9 Example V2G network showing geographically dispersed communications connections under the aggregative architecture. (From Quinn, C. et al., *Journal of Power Sources*, 195(5), 1500, 2010. With permission.)

the aggregator and the vehicles is of a more manageable scale than communications network required under the direct, deterministic architecture. The aggregative architecture is, therefore, more extensible than the direct, deterministic architecture as it allows for the number of vehicles under contracts to expand by increasing the number of aggregators, increasing the size of aggregators, or both. Since many distribution utilities are installing "advanced metering" systems, allowing two-way communication with individual consumers, these utilities could potentially enter the ancillary service market by providing such aggregation services using their metering communications networks. From the perspective of the grid system operator, the aggregative architecture represents a more feasible and extensible architecture for implementing PEVs as ancillary service providers. For the system operator, the aggregative architecture is an improvement relative to the direct, deterministic architecture because it allows PEVs to make use of the current market-based, command and control architectures for ancillary services. Aggregators can control their reliability and contractible power to meet industry standards by controlling the size of their aggregated plug-in vehicle fleet, thereby providing the grid system operator with a buffer against the stochastic availability of individual vehicles. This allows the aggregator to maintain reliability equivalent to conventional ancillary service providers including conventional power plants. Because the payments from the grid system operator for ancillary services are equal for both architectures, the direct, deterministic architecture offers no apparent advantages from the perspective of the grid system operator.

From the perspective of the vehicle owner, the direct, deterministic architecture is preferred relative to the aggregative architecture. The initial allowable investment for the aggregative architecture is ~40% of the initial allowable investment for the direct, deterministic architecture [24]. The substantially higher initial investments allowed by the direct, deterministic architecture suggest that the average vehicle owner will prefer the direct, deterministic architecture.

These divergent preferences of the vehicle owners and the system operator highlight a fundamental problem that must be overcome before PEVs can be successfully implemented into the ancillary service market. The differing requirements of the stakeholders make only the aggregative architecture acceptable to both parties. The direct, deterministic architecture is unacceptably complex, unreliable, and unscalable to utilities and grid system operators. The aggregative architecture more than halves the revenue that can be accrued by the vehicle owners but still allows for a positive revenue stream. Only the aggregative architecture is mutually acceptable to all stakeholders and can provide a more feasible pathway for the realization of a near-term utilization of PEVs for ancillary service provision.

3.5.3.2 Energy Buffering

There exists a daily load cycle for the U.S. electric grid. In general, the grid is relatively unloaded during the night and reaches peak loading during the afternoon hours in most U.S. climates. Balancing authorities dispatch power plants to match the power generation to the time-varying load. Types of generation resource are dispatched differently to meet different portions of the load. Nuclear and large thermal plants are typically dedicated to relatively invariant “base-load” power. Thermal generation with fast response rates (e.g., combustion turbines), hydropower, and energy storage can be dispatched to meet predicted and actual load fluctuations. By combining generation types, the control authority meets the time-varying load with a time-varying power generation, while meeting constraints imposed by environmental requirements, emission caps, transmission limitations, power markets, generator maintenance, unplanned outages, and more.

Even at relatively low market penetrations, plug-in vehicles will represent a large new load for the electric grid, requiring the generation of more electrical energy. In one set of scenarios analyzed by NREL researchers, a 50% plug-in market penetration corresponded to a 4.6% increase in grid load during peak hours of the day [29]. When vehicle charging and discharging can be controlled, other studies have found that as many as 84% of all U.S. cars, trucks, and SUVs (198 million vehicles) could be serviced using the present generation and transmission capacity of the U.S. electrical grid [30]. Controlling the electrical demand of PEVs will determine the infrastructure, environmental and economic impacts of these vehicles. Smart grid technologies can provide the control, incentives, and information to enable the successful transition to PEVs, but these technologies must reconcile the requirements of the electricity infrastructure with the expectations and economic requirements of the vehicle owner.

The simplest and most effective means for controlling the energy consumption of PEVs is direct utility control of charging times. Under this scenario, the utility would only allow consumers to charge during off-peak hours. By filling the nightly valley in electrical load, PEVs would reduce the hourly variability of the load profile. This has the effect of improving the capacity factor of base-load power plants, reducing total emissions and costs, and eliminating the load growth due to plug-in vehicle market penetration. From a utility perspective, having direct control of the vehicle charging is ideal. From a consumer perspective, the willingness of vehicle owners to tolerate utility control of charging times depends on the type of plug-in vehicle that is being considered. For BEVs, the charger is the only source of energy for the vehicle, and being limited to charging during off-peak periods would significantly limit the usability of the vehicle and perhaps reduce its consumer acceptability. For PHEVs, the vehicle can operate with normal performance and reduced fuel economy when charging is not available. The degree to which consumers would tolerate increased fueling costs due to utility control of charging is under debate.

A more acceptable means for using smart grid technologies to control the energy consumption of plug-in vehicles is by providing incentives for off-peak charging through a time-of-use (TOU) rate. A TOU rate is an electricity rate structure where the cost of electricity varies with time. Smart grid technologies, such as advanced metering and consumer information feedback, are necessary conditions for implementation of TOU tariffs. TOU rates are generally designed to represent the fact that electricity is more expensive during the day (when the grid is highly loaded) and less expensive during the night (when the grid is lightly loaded) to incentivize the conservation of electricity during the day. Special TOU rate structures have been designed for EV use to encourage EV owners to charge their vehicles at night, thereby conserving electricity during hours of peak demand. These legacy EV TOU rate structures have also been made available to PHEV owners. In theory, TOU rates should be able to be designed to provide an economic incentive for plug-in vehicle owners to charge their vehicles at night. In practice, the TOU rate can provide robust economic incentives for EV owners to charge their vehicle during off-peak periods because electricity is the only fuel cost for EVs. When TOU rates are applied to low all-electric range PHEVs, they can only provide partial compensation for the increase in vehicle fuel consumption that is caused by delaying charging until off-peak periods. For high all-electric range PHEVs, TOU rates are very effective at incentivizing off-peak charging of PHEVs. In summary, achieving the goals of controlling the energy consumption of many PEVs cannot be achieved solely by incentivizing off-peak charging through TOU rates [31].

These results do not necessarily suggest that an increase in peak load is inevitable with the introduction of PEVs. Instead of the smart grid being used to enable consumer controls, punitive pricing structures, and price volatility, smart grid must be used to engage the consumers in understanding how they can improve the sustainability and economy of the vehicle/grid systems. Consumer education and real-time information exchange between the utility and consumers will be a critical component of controlling the energy consumption rate and timing of plug-in vehicles.

3.5.3.3 Transactive Energy Support

Implementation of time-of-use rates changes the consumption habits by shifting the demand from expensive peak hours to less coincident hours, but the dynamic pricing provides a better alignment of consumption with real-time conditions. Under real-time pricing, EV chargers wait for lower electricity prices, particularly if the difference between the time needed for the EV to reach full charge and the time available before the next departure is large. The role of electric vehicle demand response is to facilitate a cost-effective and emission-minimizing alignment between charging demand and available energy supply resources. Our interest in demand response for electric vehicles is motivated by the fact that the EV load is inherently different from other deferrable loads. The EV load management will potentially improve the capability of the demand response program because: (1) the EV charging load can be delayed for relatively longer time than thermostatically controlled loads, (2) EVs can potentially feed electricity into the grid, (3) EV chargers are physically located where other flexible electric loads may not exist, (4) charging stations are equipped with controls that can provide frequency/voltage regulation service, and (5) the power factor of the EV load differs from other flexible loads, which is valuable from the operation point of view.

In order to make use of the charge flexibility, a charge control strategy using the transactive control paradigm was examined in [32]. Transactive control is related to the concept of agent-based control, which refers to methods that control agents' collective behavior via a limited number of inputs. Transactive control can be considered as a special type of agent-based control for agent-based systems where the agents are able to perform economic transactions [33]. This strategy evaluates the willingness of an EV to buy energy (and potentially to sell energy under the vehicle to grid technology scenario) in real time. Every EV submits its willingness-to-pay price to the local utility, which aggregates these prices and clears the market given the available supply resource. If an EV's offer price was above the cleared price, it charges at full capacity; otherwise, it forgoes charging until the next market cycle (e.g., every 5 min). The willingness-to-pay price is computed based on (1) the expected mean and uncertainty of electricity price in the time window that the EV expects to be plugged-in, which is periodically provided by the utility to every individual vehicle, (2) the remaining time to departure, (3) the battery state-of-charge, (4) the charging station's characteristics, and (5) the EV owner's comfort control setting, which helps the charger satisfy the consumer's anxiety about having a full charge at the time of departure.

3.5.4 Case Study: EV and PV Participation in the Retail Real-Time Market

Analysis of electric vehicle charge control strategies requires detailed simulation of charging times and locations. To simulate EV load on the power grid, a mobility model is required to represent driving/parking habits, which differ from one region to another and from one season to another. A mobility model is usually based on driving diary of conventional vehicles, including daily trip departure times, arrival times, and traveled distances. It is reasonable to expect that as electric vehicles become more common, data from these vehicles will be more widely used in place of today's survey. Often, the sample size of the surveyed vehicles is too small or the length of driving diary is too short, and it cannot accurately or generally represent needed driving patterns. One solution is a statistical method that employs copula multivariate probability distributions [34] to produce a larger sample population spanning multiple days, with the same statistical properties, including correlations between driving parameters found in the original under-sampled population.

A case study of 50 homes with both PVs and EVs on a capacity-constrained feeder was considered to demonstrate the performance of the transactive charger control strategy. Three charging scenarios were considered (Figure 3.10): the V0G scenario assumes chargers begin charging as soon as vehicles are plugged in, unless the real-time price (RTP) exceeds the customer's maximum price to prevent feeder overloading. The V1G scenario assumes chargers only charge when the RTP is below the customer's willingness-to-pay price. V2G scenario assumes that charging is like V1G but a vehicle also discharges when the RTP is above the opportunity cost of recharging later, given the expected average price for the remaining time to departure, with comfort setting considered. Notice that the battery degradation costs are neutral with V1G, but is impacted by V2G.

We assume the residential rooftop PV panels have power capacity normally distributed about a mean of 2 kW with 0.1 kW standard deviation truncated at ±3 SD. The PV generation profile used is for a July day in Victoria, BC (~48° N latitude) with intermittent cloudiness, using data available at www.victoriaweather.ca. The general assumptions for this case study are shown in Table 3.4 (more

(a)

(b)

(c)

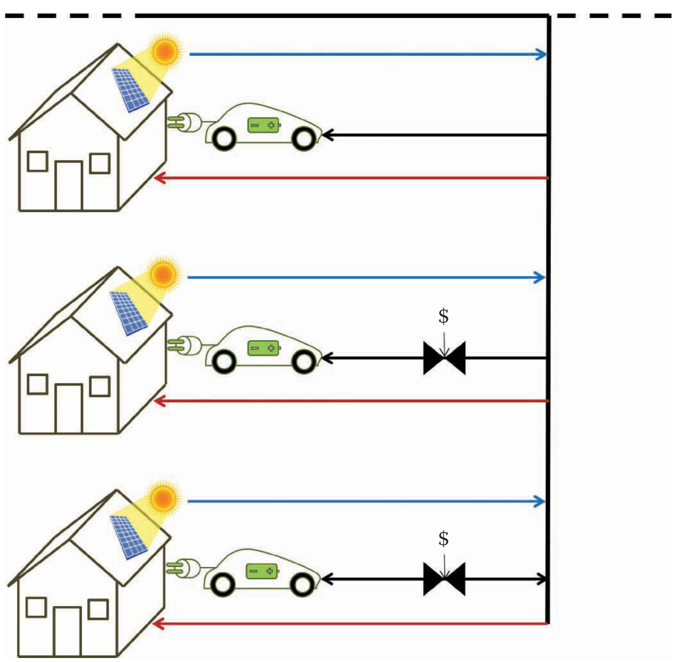

FIGURE 3.10 Household load and rooftop solar PV with vehicle-grid integration scenarios: uncontrolled charger (V0G—a), unidirectional price-responsive charger (V1G—b), and bidirectional price-responsive charger/discharger (V2G—c). (Courtesy of the University of Victoria, BC, Canada.)

TABLE 3.4
Modeling Assumptions and Inputs

Parameter	Unit	Mean	Stdev
Arrival SOC level	%	60	10
Battery capacity	kWh	50	10
Charging rate	kW	6.6	1
Customer comfort	%	100	10
Round trip efficiency	%	90	5
LMP	$/MWh	80	24
LMP peak time	HH:MM	16:00	
Feeder capacity	kW	150	
Total PV capacity	kW	100	
Non-EV peak load	kW	100	

information available in [32]). The locational marginal price (LMP) is the electricity price on the feeder, which reflects the underlying wholesale market's clearing price. It should be noted that the bid price for PV is zero.

The driving diary of the EV fleet is generated using the copula multivariate probability distributions with the same characteristics as the survey data in [35]. Figure 3.11 shows how the correlation between driving parameters is similar for the original population and the new population, which is ~10 times larger.

The RTP resulting from the charging strategies, as well as the total and feeder load profiles, and the corresponding state-of-charge profiles are illustrated in Figures 3.12 through 3.14, respectively, for V0G, V1G, and V2G scenarios.

The results are summarized in Table 3.5 and suggest that the price is generally reduced when control strategies are applied. The peak price time is shifted to later in the evening under V0G scenario but not under V1G or V2G scenarios. Total EV energy consumption is reduced only about 2% using V1G and about 3% using V2G, whereas the net payments are significantly reduced in comparison to V0G. More sophisticated bidding strategies can provide more improvements. It should be noted that non-EV flexible loads, such as HVAC can also actively participate in the real-time pricing in parallel with the EV load, but because the purpose of this simulation was to highlight the impact of the EV load, the flexibility of other loads was precluded.

3.6 CONSUMER DEMAND MANAGEMENT

The management of energy demand at the consumer has been the focus of research and debate for several decades. Consumer demand management takes many forms driven by utility incentives for consumers to reduce overall energy usage or to change energy usage patterns. Widely used terms for consumer demand management include energy efficiency, energy conservation, demand response (DR) management, and demand-side management (DSM).

A major challenge for a utility regarding supply and demand of electricity is that the load on the system is not constant and the utility must try to efficiently dispatch generation to meet the load on the system at various times during the day. Utilities typically have various generation sources, such as coal-fired plants, gas turbines, hydroelectric power, or power purchased on the open market, that cause the utility to incur different costs. The cost to deliver electricity to customers on the grid is related to the change in load and supply over time, and any changes in the operation of the grid and available generation sources. Changes in supply include outages of generation and transmission and changes in supply from energy sources, such as wind and solar

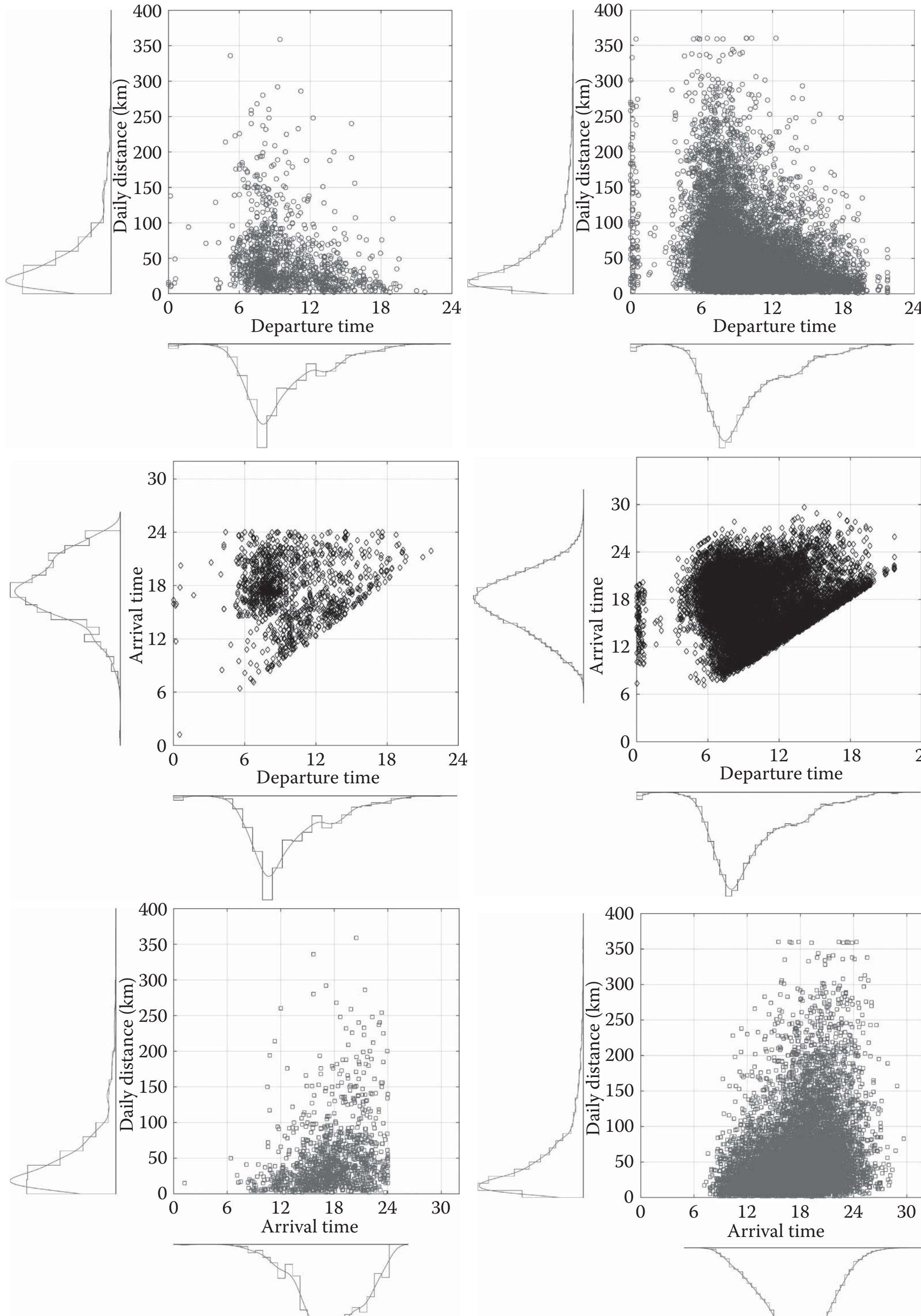

FIGURE 3.11 Case study driving patterns: original population (left) versus new population (right): departure time and daily commuted distance (top), departure time and arrival time (middle), and arrival time and daily commuted distance (bottom). (Courtesy of the University of Victoria, BC, Canada.)

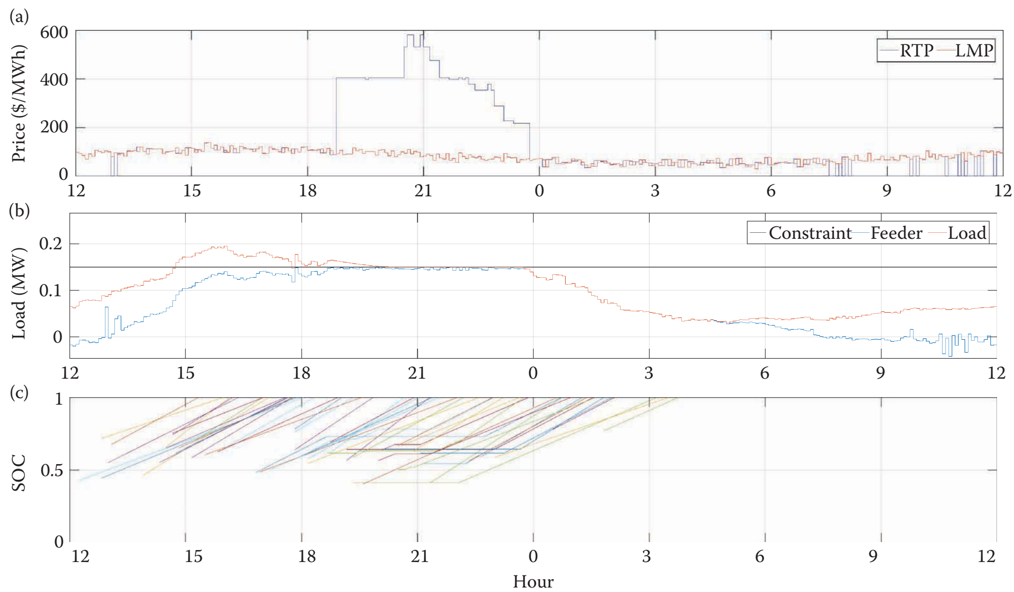

FIGURE 3.12 Case study in V0G scenario: price (a), load (b), and state-of-charge (c). (Courtesy of the University of Victoria, BC, Canada.)

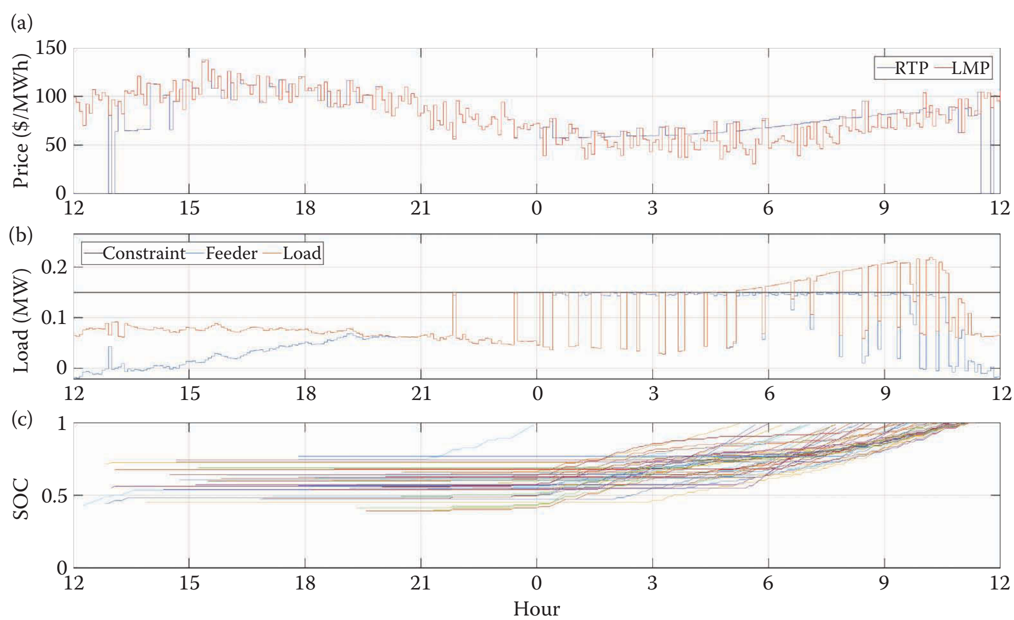

FIGURE 3.13 Case study in V1G scenario: price (a), load (b), and state-of-charge (c). (Courtesy of the University of Victoria, BC, Canada.)

photovoltaic (PV). During peak energy demand or major changes in supply, higher cost generation sources are used, such as gas turbines, which result in a higher cost to supply required energy grid needs. During the lowest demand periods, lower cost generation, such as nuclear, hydro, and coal-fired power plants, are the primary sources of electricity. A traditional way to bill customers for electricity is to charge the average price to supply electricity throughout the year and to

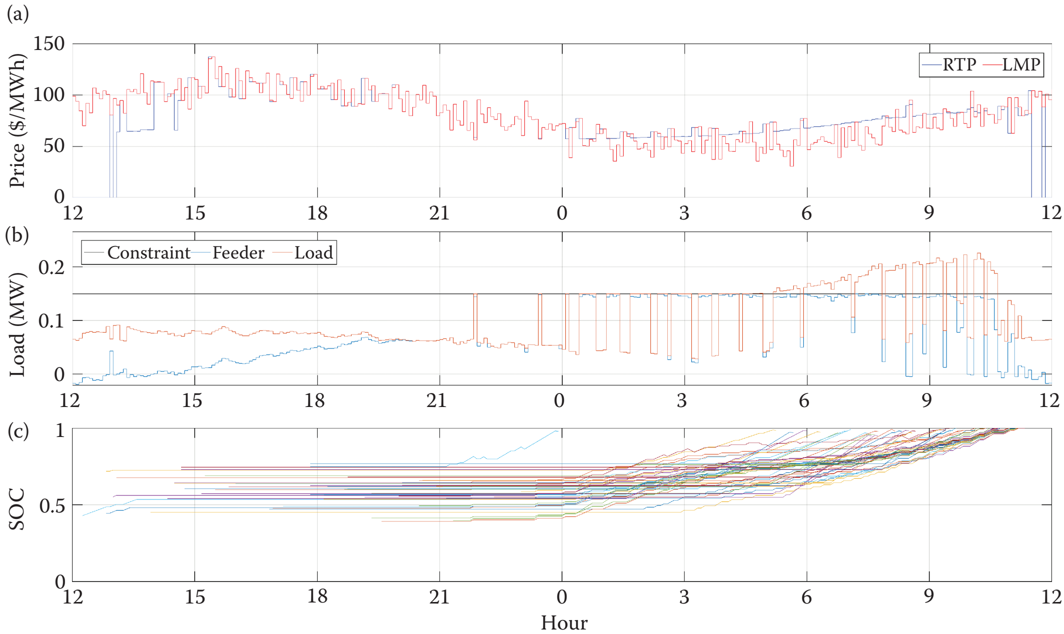

FIGURE 3.14 Case study in V2G scenario: price (a), load (b), and state-of-charge (c). (Courtesy of the University of Victoria, BC, Canada.)

TABLE 3.5
Charging Price, Energy, and Cost

Output	Unit	V0G	V1G	V2G
RTP mean	$/MWh	128.14	76.86	76.83
RTP stdev	$/MWh	146.30	26.94	26.92
RTP peak time	HH:MM	20:40	15:25	15:25
Energy	kWh/EV.day	22.27	21.82	21.59
Charge cost	$/EV.day	4.70	1.51	1.49

measure energy consumption in terms of non-time-differentiated energy (kWh) use over a period or weeks of months.

It may seem counterintuitive for a utility to implement measures that reduce consumer consumption since it reduces the utility revenue. However, in some cases, the reduction in energy consumption during peak, load periods can provide significant operating and financial benefits to a utility. This may translate to avoiding grid congestion, or the ability to supply electricity to customers during contingencies, such as when generation is unreliable. In the long term, it may also help defer grid upgrades when this reduction of energy consumption comes to the grid as a cost less than the annualized cost of the grid investment. But also, importantly, a grid with a growing portion of local customer generation changes the network planning activity and associated spending. For example, in some areas the network operator may prefer not to upgrade the grid when forecasts identify that the constraint will be short-lived (e.g., 3 to 5 years) and will disappear with increased customer local generation adoption trends. This shift of peak electricity may result in significant reductions in capital investment and operating costs, while maintaining grid reliability. Many retail electricity suppliers currently implement specific usage rates or charges for industrial and commercial customers that include some type of maximum demand component and corresponding fee or penalty for consumption beyond agreed-upon levels.

3.6.1 Demand Management Mechanisms

Demand management is generally based upon actions on the consumer side of the meter that reduce consumer load, invoke energy efficiency, DR, distributed generation (DG), or energy storage. Use of the full set of demand management options is also called integrated DSM (IDSM) [36]. Energy efficiency measures alone generally focus on reducing total energy consumption of consumer loads, such as lighting, space conditioning, appliances (e.g., refrigerators, air conditioners, hot water heaters, washing machines, dishwashers), and variable speed motors. Instead, IDSM is an approach to offer customers a full suite of demand-side opportunities.

One part of this, DR, typically refers to reducing consumer electricity usage at specific times during the day, week, or season. Historically, DR has been used to reduce electric usage during peak load times. Reduction in the peak load typically results in deferral of the energy used to an off-peak period. Alternatively, peak load reductions can effectively reduce the load on the system altogether. In recent times, DR has taken several forms, such as voluntary curtailable load, behavioral-based response, price (or incentive)-based response, or event-based response.[3] An early form of DR is direct load control where utilities could remotely control consumer loads, such as water heaters and air conditioners to turn them off during peak load.

The idea that the demand side of the grid can be managed and demand can respond to information and to signals from the utility is not new. Still, in most markets, demand remains unresponsive to price signals from suppliers or the suppliers may not yet provide demand signals. Both direct load control and price response are increasingly being considered or piloted in various locations. To illustrate, consider the impact of higher gas prices on the amount of air travel or the type of car you consider purchasing. If prices go up a few cents per gallon, you might not care, but when gas prices double, or triple, or even go up by an order of magnitude, your behavior is more likely to change. Presumably, most consumers will shift their behavior or respond in some way as prices change. As an alternative approach, customers may be offered incentive payments in lieu of high prices as a method to encourage demand reductions. In markets where end customers are not exposed directly to high wholesale prices (e.g., Australia, where wholesale prices can go up to AUD$14,000 per MWh), retailers, if exposed to these prices, may choose to engage customers and pay them to reduce load.

If load reduction measures can be encouraged through customer incentives, information, pricing, and technology, the costs to provide the capacity needed for reliable electric service can be significantly reduced. In these ways, a portion of the burden of reliability and the risks with power outages can be shifted to the consumer who will either directly or indirectly realize the benefits. As consumers more cost-effectively manage their consumption through load response, overall system costs can be reduced. For example, with customers enrolled in peak load response in ISO-NE, the system reserve margin may be lowered 10% or more [37]. Correspondingly, this is expected to reduce the probability that peak load would exceed power availability by between 10% and 50%. This reduction in peak capacity may reduce ISO-NE supply side costs by as much as 8.5%. Thus, with an incremental amount of demand management, significant electricity cost reductions are possible. DG installed at the consumer site is another effective means to reduce load demand on the grid seen by the utility. DG generally includes any generation at the customer premises, such as solar PV, wind turbines, fuel cells, combined heat-and-power, and diesel generation or microturbines.

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[3] On the one hand, voluntary customer curtailment can reduce loads but is usually paid only an energy price ($/kWh) for such reductions. This behavior is neither certain nor predictable. On the other hand, sophisticated electronic controls enable rapid dispatchable load reduction at a specific location. These certain, predictable actions to lower loads may be in response to network operating events or changes in generation pricing.

Some of the DG is considered *must-take* as it is simply put on the grid whenever electricity from these sources is produced. In other cases, it has become dispatchable[4] by either the utility or the ISO who can determine when consumer sources are connected to the grid. When DG provides power to the grid, it may be *net-back-metered* (credited at retail rates), paid or credited at wholesale prices, or valued at some other contractual or tariff regulated rate. If the DG is dispatchable by the utility or the ISO, consumers may be paid for both availability of the distributed energy resources (DERs) as well as additional incentives when the resources are called upon. Larger-scale nondispatchable DG, such as wind power or PV electricity, are generally paid an energy value but are not considered to provide capacity benefits or avoided transmission and distribution (T&D) benefits as they are variable in nature and, thus, are uncertain resources. This is changing, however, as some renewable resource deployments (e.g., wind and PV) are integrated with battery storage to create a reliable source of energy. Importantly, the combination of non-dispatchable renewable resources with dispatchable loads and DERs in a portfolio approach can greatly enhance the capability of the former resources to contribute to the overall load curtailment goal. Reliability of delivery, in this case, will be strongly correlated with weather and how it affects the availability of these resources and increase in load.

Energy storage devices at a consumer site can take power from the grid (to be charged) and provide power back to the grid (discharge) at critical times, or at least offset the amount that is being drawn from the grid. Accordingly, storage can be dispatched to gain market benefits and take advantage of low-cost power (for charging) at times when grid reliability and costs are less consequential, or when a renewable resource is generating in excess and exporting to the grid at low cost. The ability of storage to perform market arbitrage, as with DR, depends on the speed of the response and the availability of the storage when grid needs and market prices are greatest. Storage may be controlled through voluntary (manual) behavioral response or automatically with use of event- or price-based triggers. This suggests that for storage to be of greater value, advances in control algorithms and grid/market interface technology are a high priority. Energy storage can serve many purposes to meet peak loads, variability of renewable generations, or another grid dispatchability needs. Increased use of storage is expected to provide capacity availability, energy, voltage support, and frequency regulation. It is considered a flexible resource with significant market opportunities. Batteries can be utilized in various formats. Larger batteries are being piloted in substations and to support large PV or wind installations. Smaller batteries are being installed as community energy storage (CES) and technology is being developed that can utilize energy backfeed from vehicle batteries. Virtual power plants, aggregating a thousand or more small residential batteries, are also being piloted to mimic the outcomes and benefits that a larger battery can deliver.

3.6.2 Consumer Load Patterns and Behavior

At the same time, every day as people get up and go to work and as industry and commerce begin, electric power systems ramp up to meet demand. The electric grid sees predictable changes in load over the course of each day depending on the type of load and various other factors, such as the day of the week, temperature, etc. This results in a series of daily, weekly, seasonal, and annual cyclical changes in load and load peaks. In each case, the utility must provide sufficient generation and transmission/distribution capacity to ensure that demand is fully met in all circumstances.

During the hottest hour of the hottest day in the summer, some utilities experience an enormous demand for electricity, caused by air conditioning units, that the utility must meet to avoid a local brownout (low-voltage condition) or a system blackout (complete loss of voltage). These situations can be even more extreme when some of the generating assets are undergoing maintenance or are

[4] Dispatchable resources are those available to be turned on and synchronized to grid frequency or can be turned up or down to vary generation capacity, in response to grid operator instructions. Non-dispatchable resources cannot respond to grid operator instructions, so are considered *must-take* or may be *baseload* resources.

out of service. To meet these few hours of "peak demand," the utility must build or have access to enough generation and transmission/distribution capacity to meet the system peak. However, much of that capacity remains unused during the remainder of the year. In fact, for much of the year, electricity demand does not approach the level of the annual peak. In countries with extensive (one distribution transformer serving 50 to 150 customers) low-voltage networks, a quick and large uptake of solar PV (e.g., Australia, with state level penetration of almost 30% in the states of Queensland and South Australia) by customers may cause the reverse problem, or local voltage rise. In this case, the distribution network will also need to have enough capacity to absorb this energy and deliver it upstream.

Load shapes describe the changes in load on a daily or seasonal timescale. Most load shapes are typically represented as an average hourly energy use, for example, kWh/h (Figure 3.15). However, seasonal load shapes are sometimes represented as peak values, for example, MW, even though sometimes that peak value is obtained from the maximum of an average diurnal load shape, i.e., MWh/h. In either case, the load is effectively a power value and not an energy value.

There are some important characteristics of load shapes that must always be considered when they are used. First, the difference between summer and winter lighting load shapes is greater the further the load is from the tropics. This means that any load control system that is affected by diurnal phenomena, such as temperature or insolation, is going to vary more seasonally the further the location is from the equator. Second, for the same outdoor temperature, air-conditioning loads are typically higher in humid climates than dry climates. This means that air-conditioning control strategies may tend to yield greater benefits in humid climates than they do in drier climates. Third, higher-income regions typically have higher loads per capita than less affluent areas. Fourth, commercial loads may be less dependent on climate and weather than are residential loads. Commercial buildings' cooling systems are more dominated by internal heat gains from lights, computers, and people, and they have less exterior surface area per square foot of floor than do residential buildings. Fifth, industrial loads are also sensitive to economic conditions. When the economy slows, the first things to slow are typically the factories. Sixth, agricultural loads are highly seasonal and sensitive to weather. Water pumping and refrigeration are driven by the growing season in any given region. Seventh, load shape data can change significantly over time because of evolving energy efficiency standards and consumer purchasing habits. Much of the load shape data from the 1980s are still being used because of a lack of newer better data. But the penetration of consumer electronics into the residential market has changed substantially since then, even though the efficiency of appliances

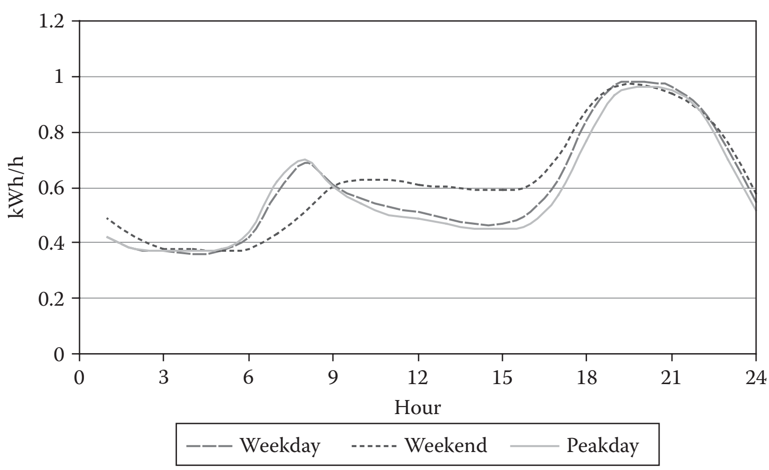

FIGURE 3.15 Example diurnal load shape. (© 2012 Pacific Northwest National Laboratory. All rights reserved. With permission.)

has improved significantly at the same time. Eighth, the composition of the load has changed over the years, particularly due to an increase in consumer electronics and motor loads. Ninth, because lighting efficiency programs have been successful in recent three or four decades and new loads have emerged, lighting load has become a smaller fraction of the total load. In contrast, refrigeration, washing and drying loads may experience a "rebound" when high-efficiency appliances come equipped with new features that can consume more electricity. And finally, the quick uptake of customer-owned generation (e.g., rooftop solar PV), such as in Australia and California, and the associated variations induced through seasons and weather are creating a "negative" element to change the overall load profile.

One way to visualize utility peak loads is to take all the hours in a year and the corresponding maximum load in each hour and then rank them by the load demanded. Graphing this from the hour of the highest load to the hour of lowest load produces a "load duration curve," which is shown in Figure 3.16.

The figure immediately makes evident that the slope of the line does not remain constant. Rather, the slope is steeper at the left end and at the right end of the graph and less steep in the middle. This signifies rapid change in power demand as you consider the top 1000 load hours and lowest 1000 load hours of the year. Figure 3.16 labels a few notable features of the load duration curve. In addition to the peak shown in this curve, the response of consumer loads can also add value when utilized to compensate for variations in output from renewable energy sources. The most common use of a load duration curve is for planning studies, when planners estimate the number of hours per year for which a system resource must be allocated. The load duration curve can also be used to estimate the maximum amount of load that should be curtailed during a certain period. Although from a generation mix perspective, this planning activity will essentially look at aggregated demand throughout the network from a network assets perspective. Planning focuses on the smallest transformers and other distribution assets since their suitability to deliver electricity reliably will depend on the localized load curves.

While the load shape describes the amount of load that is present at any given time of day and day of year, that description is *not*, by itself, sufficient for the study of loads in the context of the smart grid. The load ramp time, duty cycles, and periods of those cycles are also very significant when load control strategies seek to modify them. It is possible to measure directly both the duty cycle and the period of loads using end-use metering technology. However, end-use metering is quite expensive, and the data collected about any given device are often the superposition of the device's natural behavior and other driving functions, such as consumer behavior. So, it is often very difficult to clearly identify the fundamental properties of each load. Furthermore, for any time-domain

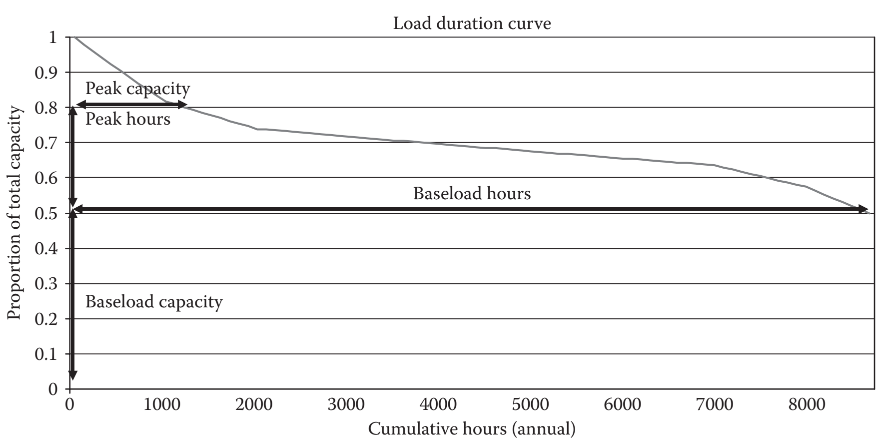

FIGURE 3.16 Typical load duration curve. (© 2012 Alex Zheng. All rights reserved. With permission.)

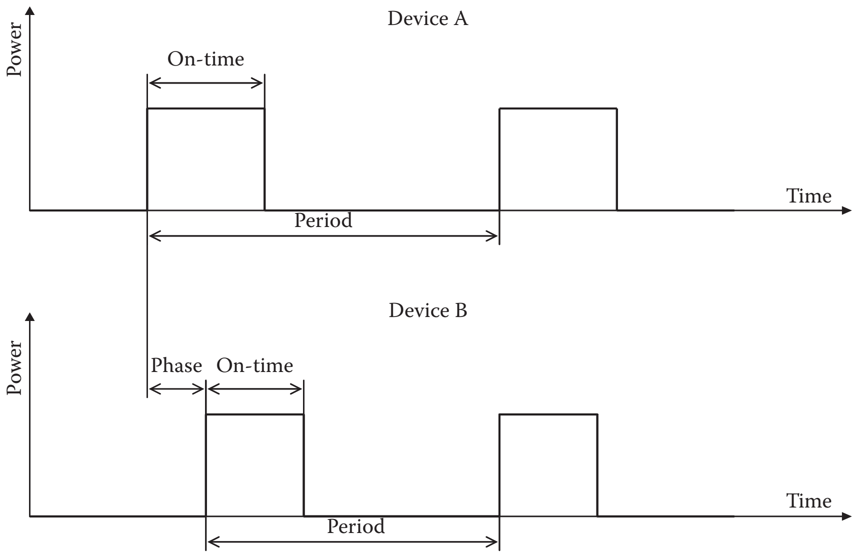

FIGURE 3.17 Load aggregation. (© 2012 Pacific Northwest National Laboratory. All rights reserved. With permission.)

models where the load aggregate is a consideration, not only the duty cycles or probabilities of devices must be considered, but also their periods and state phases, as shown in Figure 3.17.

In such cases, the state of a single device is the timing of the device's on event in relation to one complete cycle. Hence, it may be more complicated to aggregate devices with differing usage patterns and functional power cycles. This is important in demand management where utilities need to consider the diversity of consumer load patterns when modeling loads.

3.6.3 Conserved Versus Deferred Energy

Load managed by DR can be separated into two parts—conserved energy and delayed energy. In some instances, the load that DR turns off at a designated time is not "recovered" or deferred entirely for use later. This permanent reduction in energy use due to short-term reduction in demand is referred to as conserved energy, because the net impact is equivalent to having never used that energy in the first place. However, not all the consumer load reduction is completely conserved. For example, although loads from lighting may not need to be made up for later, shutting off a hot water heater or air conditioner for a short amount of time may result in additional loading later. This "bounce-back" effect can sometimes result in secondary peaks later in the day when the entire curtailed load comes back online. This energy consumption is known as deferred energy, or the "snap-back" effect, because it still occurs but later. Consumer load reduction needs to be managed carefully to ensure that it does not create artificial peaks that are costly to manage because of deferred demand for energy returning later in the day. Utilities have a variety of methods for managing deferred energy, but most methods are essentially different ways of staggering the return of consumer consumption to full load.

From the perspective of load behavior, demand management has two mechanisms to offer utilities and customers (Figure 3.18). The first is energy efficiency or energy conservation. These strategies reduce the total electric energy consumed by a customer. Typically, these include (1) reducing total runtime, for example, by lowering a thermostat; (2) reducing load during operation, for example, by retrofitting higher efficiency equipment; and (3) substituting fuel sources, for example, replacing central fossil-fueled electricity with distributed renewable sources. The primary benefit of energy

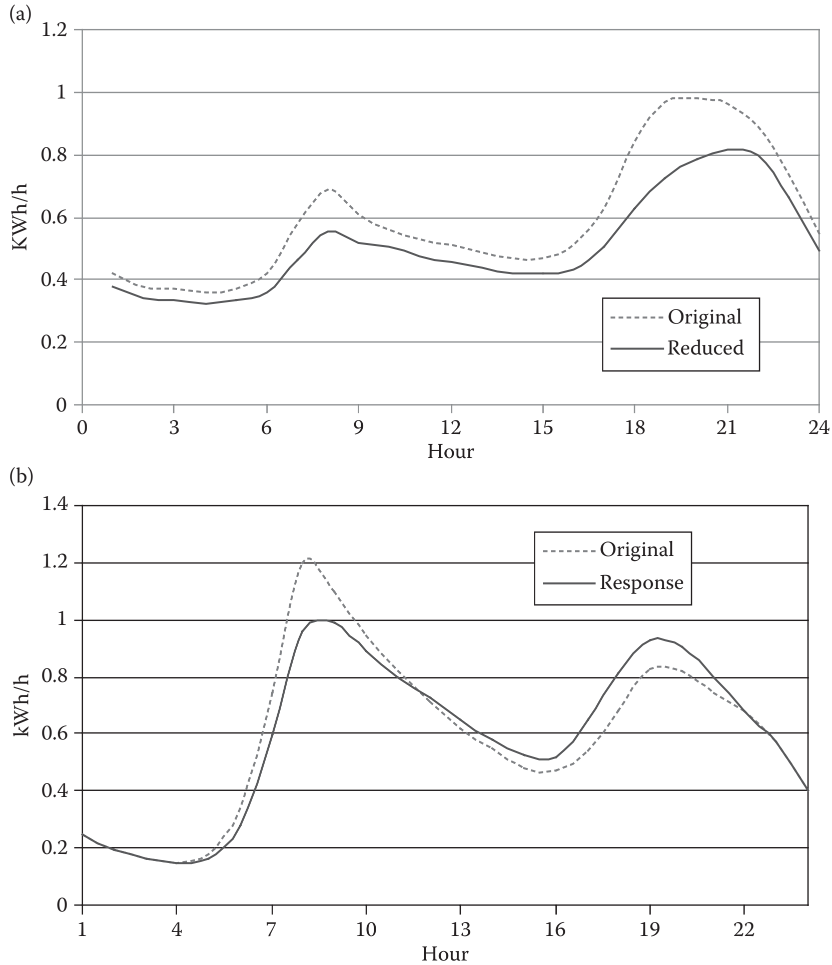

FIGURE 3.18 DSM mechanisms: (a) energy conservation, and (b) peak load shifting. (© 2012 Pacific Northwest National Laboratory. All rights reserved. With permission.)

conservation is to allow the utility to avoid the cost of acquiring new sources of energy or deploying new network assets to meet growing demand. Although a utility's primary incentive is to increase revenue from energy transport and sales, a significant fraction of a utility's costs includes the acquisition and financing of new energy sources and network assets. New energy resources or network assets can often be so expensive that the effect on rates is too great for consumers to bear. For example, if a utility forecasts a 50% growth in demand over the next 10 years, that would result in a 25% rate increase, but it can implement an energy conservation program that reduces that growth to <10% over the same period without a rate increase; the obvious choice is the conservation program.

The second is peak load shifting. This strategy reduces the peak load on the system by shifting coincident demand to non-coincident times, for example, by using energy storage. The primary benefit of peak load shifting programs is that they allow the utility to avoid the need to build new system capacity that does not come with a corresponding increase in energy sales revenue. Adding capacity is typically a very capital-intensive proposition for a utility, so any program that can move load off peak without reducing revenues from energy sales is attractive.

As a rule, strategies that reduce energy consumption are supported by existing utility DSM programs. These programs are not generally considered smart grid programs in today's sense of the word because (1) they are already widespread, and (2) they do not require information technology (IT) to realize most their benefits. In contrast, peak load shifting programs require accurate and timely information to operate effectively, particularly if incentive signals, such as prices, are to capture all possible opportunities and reconcile any contradictory signals that may persist. One exception is conservation voltage reduction (CVR). Given the right mix of load characteristics, CVR can be used to maintain voltage levels between allowed maximum and minimum ranges, by using smart grid technology to monitor, manage, and reduce voltage, producing an overall conservation effect.

The focus of most advanced load modeling research is on those load behaviors that are affected by or can directly participate in smart grid technologies. Hence, most recent load modeling research primarily addresses load shifting behavior and other behaviors that respond to relevant signals from utilities or from the bulk system.

3.6.4 Anticipated Energy

Load managed by DR can also seek to deliver the opposite outcome—to anticipate consumption that would occur later in the day. For example, in a network with residential areas with high penetration of rooftop solar PV, in low load/high generation situations, the export of distributed generation may be too large for the local network assets to handle, leading to the need for early asset upgrades to maintain network and asset reliability. In these conditions, it will be beneficial to the network operator to have DR bringing flexible loads, such as hot water heaters, ice precooling, and pool pumps, to consume part of that excess reverse electricity flow. This consumption would occur at another time but what effectively is attempted is to bring some of the consumption forward with no disruption to the customer. This nontraditional form of DR has been explored in high solar PV penetration grids, such as the case of some states in Australia and in California.

3.6.5 Utility-Customer Interaction

There are several ways that customers can use demand management. Generally, consumers need to know what loads they want to reduce, and utilities need to provide customer participation options that may include advanced metering and market pricing data. With a smart meter or any other connected load interface device in place and either advanced electricity pricing or incentive schemes (e.g., payment for the ability to reduce customer load) that are communicated to consumers, automated DR can be employed to directly trigger load reductions, also called *auto*-DR, when specific price levels are exceeded. A major aim of auto-DR is to enable DR through a preprogrammed response, for example, to reduce appliance loads at specific price levels, so that consumers can directly participate with minimal effort and gain the benefits of DR. It is expected that as IoT connects more and more loads, consumers will be able to choose from a multitude of strategies for their DR participation, which can involve choosing between more "comfort" settings or more "economic" settings, according to consumer priorities for the day and time of the event. Alternatively, customer demand management may be employed manually using "behavioural DR," where the customer receives notice of an upcoming load-reduction request, and through an appropriate incentive structure, makes decisions on their load usage during the event, or even in some cases for residential customers, choosing to leave the house temporarily to reduce consumption to a minimum. This back and forth between market prices, customer preferences, customer incentive, the meter, and consumer loads will enable a more complete electricity market, particularly as loads can increasingly respond to prices as much as the supply-side responds to price. This fully participatory DR market will provide the needed complement to the supply-side of the electricity market, resulting in greater market efficiency.[5] In contrast, today's largely supply-only market leaves electricity prices

[5] This is known as a dual, supply-demand market equilibrium, as compared to the predominantly supply-side only electricity market equilibrium. See Ref. [38].

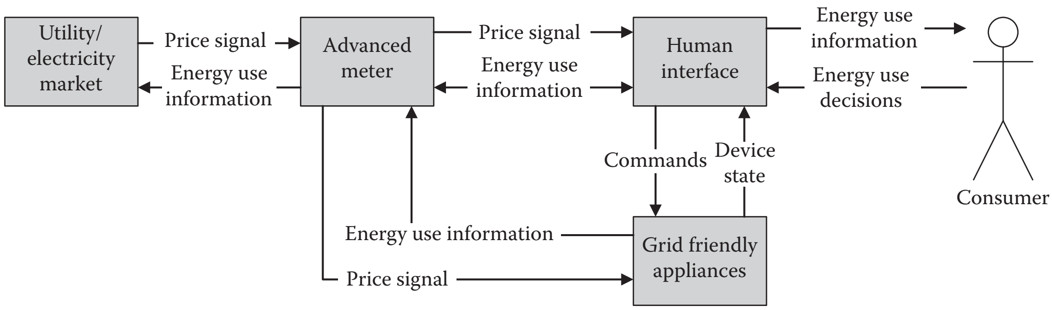

FIGURE 3.19 Example of information flow between utilities and consumers in DR. (© 2012 Alex Zheng. All rights reserved. With permission.)

unresponsive to loads, and consumer response is not a factor. Not only will a more dynamic consumer load and supply-side market be more efficient and increase reliability (reduce blackouts and brownouts), it will reduce market price volatility and the potential for market power manipulation.

Figure 3.19 illustrates a set of steps and information flows between the utility or market and the consumer, focusing on the use of price signals. The electricity market takes energy information and provides price signals, which are sent to consumers by advanced smart meters or other communications mechanisms, such as cable TV, phone line, wireless networks. Consumers can respond extemporaneously or through automated technology to direct incentives and market prices. Smart consumer devices, such as lighting and appliances that can respond to price signals to turn off, reduce, or defer or anticipate load, will provide the basis for consumer DR enablement and help respond to market prices and customer information. One example could utilize home area network (HAN) technology and open standards. The smart meter, in addition to its digital time-based metrology, can provide advanced information flow to the utility, the market, and to customers. This can be especially useful for the electricity market and the grid operator to verify the availability of DR as it prepares to respond to system contingencies and reduce loads in response to prices. However, the smart meter will likely not be the only central point for this information flow since other providers that don't own metrology or have more cost-efficient communications solutions (e.g., existing wireless or cable providers) may utilize other strategies to deliver a DR outcome. In fact, customers might adopt smart thermostats to optimize their own consumption, without having DR as an intended goal, and these thermostats might access the Internet and be optimized via cloud applications. The installed base of these thermostats could then provide a platform to implement DR without using the meter as a gateway into the customer's premise.

3.6.6 Value of Demand Management

Utilities benefit in many ways from demand management programs: (1) avoiding dispatch of expensive peak generation units, (2) deferring long-term capital investments in excess generation and T&D capacity, (3) reducing carbon footprint by using more efficient units, (4) increasing system reliability, and (5) savings from lower energy use during high-cost times, (6) additional tools to support the growth of renewable energy (e.g., wind and solar) for which the power output varies.

The value of demand management is usually compared to opportunities to defer or fully avoid supply-side and grid alternatives that are constructed. The resources and related costs deferred or avoided include electricity generation (power plants), transmission lines, distribution, customer costs, and environmental pollutants, including SO_x, NO_x, and CO_2. Where competitive markets exist for deferred or avoided resources, market prices can be used to value demand management.

Demand management provides grid support functions, such as contingency response, reserves, and frequency control. Demand resources can be called upon to respond to disturbances on the system to prevent and mitigate outages. In addition, by providing reserves and frequency regulation, demand resources can enhance the stability of system operations without the need for additional generation capacity. In California, for example, if only 20% of the state's retail demand in 1999 was subject to time-based pricing, and with only a moderate amount of price responsiveness, the state's electricity costs would have been reduced by 4% or $220 million. The following year, in 2000, electricity prices were more than four times as high, and the same amount of DR would have saved California electricity consumers about $2.5 billion—or 12% of the statewide power bill. These, and other estimates of benefit potential, were presented to the U.S. Congress in a senate-requested report by the General Accounting Office in 2004. The PJM Interconnection estimated that during the heat wave of August 2006, DR reduced real-time prices by >$300 per megawatt-hour during the highest usage hours, estimated to be equivalent to >$650 million in payments for energy. Many utilities, such as PG&E and Southern California Edison, have been able to use demand management programs to help justify recovery on extensive AMI rollouts.

Demand management can also make important contributions to addressing climate change and other environmental issues. One way that it does this is by enhancing and reinforcing customer energy efficiency, the accepted cornerstone of emission reduction policies. With DR technologies, customers will receive information on their electricity usage that they have never had before and receive it in a timely manner such that it acts as feedback to reinforce their energy management efforts. Furthermore, they will have price and rate options or incentives that will stimulate them to be more efficient and target energy consumers. DR technologies will be the answer to the question: "How can you manage what you cannot measure?" A report in 2007 from the Brattle Group [39] has shown that even where customers are not on time-differentiated rates, they may reduce their electricity usage by 11% just by being more informed and understanding better how and when they are using electricity. The report suggested that if DR were implemented nationwide in the United States using only existing, cost-effective technologies, peak load could be reduced by 11.5% (assuming nationwide consumer acceptance of such a program). The study concludes that a more conservative nationwide DR program would result in a peak load reduction of 5%, which would correspond to nationwide savings of $3 billion each year, or $35 billion over the next two decades. This figure does not include other benefits, such as lower wholesale electricity prices, improved reliability, or enhanced customer service.

SIDE BAR: BENEFITS REALIZED: DEMAND RESPONSE SAVES THE TEXAS GRID FROM BLACKOUT

On February 26, 2008, the Texas grid suffered a significant increase in demand (4.4 GW) due to colder than expected weather coupled with a decline in wind power (1.4 GW) and an underdelivery of power from other power sources. This sudden strain caused a drop in system frequency, which triggered emergency grid procedures into action. Because of the system-wide lack of generation capacity, the Electric Reliability Council of Texas (ERCOT) turned to their demand response (DR) program, also known as Load acting as a Resource (LaaRs), to help bring demand back in line with supply. These loads consisted of large industrial and commercial users who signed up in advance to curtail their electricity use for payment during grid emergencies. The cost of dispatching these resources is significantly lower than dispatching peaking gas turbines, whose costs can be as much as an order of magnitude higher. This program enabled an estimated 1.1 GW of DR resources within a 10-min period, helping to stave off a blackout. Most of these loads were restored after an hour and a half [40,41].

The economic benefits of demand management have historically been based on grid capacity needs and demand management operational capabilities. In many places, demand management has been used only during system emergencies when generation capacity was scarce. It is increasingly accepted that demand management can reduce the need to purchase high-cost, capital-intensive infrastructure (e.g., generation and transmission capacity) that is used to preserve reliability, and reduce uncertainties in loads and system conditions. This contrasts with earlier versions of demand management programs that had limited availability and uncertain response times when called. Still, these earlier demand management programs did offer significant operational certainty to ensure that specified load reductions occur.

In the last three decades, demand management has been primarily viewed as a means to bolster grid reliability during emergencies. More recently, demand management is viewed as a flexible resource to respond to a full set of market needs, mitigate price and congestion needs, and respond to a series of needs for specific reliability and energy-based services. The Federal Energy Regulatory Commission (FERC) in the United States has provided rules to enable demand management to be treated comparably with supply-side resources, which means that demand management can be used, and compensated, in the same specific ways as supply-side resources. Demand management, in response to price or reliability needs, is no longer just for emergency peak load management. Demand management can now be used for the full set of market opportunities, on the one hand, to respond to variations in renewable energy supplies and, on the other, to reduce fuel costs in power plants.

The long-standing goal of many in the demand management industry has been to reduce the peak loads and increase loads during minimum load times, and increase power plant fleet utilization, that is, increase the fleet *capacity factor*. With greater use of demand management, daily load curves would have lower peaks resulting in lower average electricity costs. With a flatter load profile, grid operators and utilities can use the more efficient plants more hours per year.

Demand management can provide major wholesale benefits and is increasingly used to derive benefits that are monetized in organized electricity markets. When electricity market generation is scarce or prices are high, load reduction from demand management is valuable. Many demand management resources can participate directly in organized markets, though energy efficiency is largely the exception.

The basic competitive wholesale market services that demand management, DR, and energy storage may participate in are as follows:

1. Resource adequacy (planning reserve), which can be defined on a locational (subregional) basis (e.g., 15% of total planned load)
2. Operating reserves, including spinning and non-spinning generation reserves that must be available online within 10 min (e.g., 7.25% of current hourly load)
3. Frequency control or automatic generation control to ensure that regional frequency (on a subsecond basis) is maintained
4. Emergency capacity, which may include capacity market requirements (e.g., in PJM and ISONE)
5. Energy, on a zonal, nodal, *instructed*, or distribution circuit basis, including providing supplemental energy needed to "back-fill" operating reserve requirements
6. Congestion management for locational "out-of-merit" or "out-of-sequence" conditions
7. Energy price mitigation, particularly on a locational basis, to reduce energy prices, such as when scarcity conditions exist

Organized competitive markets provide most of these services in separate markets for day-ahead, hour-ahead, and "real-time" trading and scheduling. Power generation plants and demand management services that comparably satisfy necessary conditions can operate in many different markets on a given day. A major increase in the need for ramping capacity for grid balancing is in response to the large amount of variable renewable resources on the grid, particularly wind generation and PV generation.

Demand management can also be used for load management at specific locations on the distribution system. At a time when energy demand is flattening but demand peaks still exist, building network assets may not be the most economical and efficient option. In areas where the network component of consumer retail bills is high, grid operators will face government pressure to manage growth. Regulators may seek non-network options that have better financial returns. The rapid deployment of customer self-generation, such as rooftop solar PV and very soon batteries are also further complicating the work of planners and utilities in general. Consumer choices in response to higher rates may render network upgrades stranded when these choices contribute to reducing the peak demand that motivated the upgrade in the first place. This is a new element or rather its effect has become more pronounced with the advent of more efficient appliances, solar PV, and energy storage.

Case Study: United Energy Partners with Demand Response Provider to Use DR for Network Support

The Australian network services provider United Energy has entered a partnership with a Demand Response Service provider Greensync to deliver a demand response and energy storage project that will allow the deferral of a network upgrade in the Mornington, Peninsula. The evaluation of the options to serve the constraint was done under a regulatory process designated a Regulatory Investment Test—Distribution (RIT-D), which is managed for compliance by the Australian Energy Regulator (AER). This process undertakes a cost-benefit analysis to ascertain the net-present-value (NPV) of all proposed solutions whether they involve the building of network assets or a non-network option, such as Demand Response. The network upgrade is estimated at AUD$29.5 million for a need to deploy in 2022. Three alternatives were compared: A pure network augmentation, a hybrid DR and network augmentation, and a generation (diesel genset) network support. The winning hybrid DR comprises a DR service running for 4 years starting in 2019 with load curtailment of 11.5 MW, growing up to 13.1 MW in 2022, followed by network augmentation in 2022. Although not eliminating the need for the network augmentation, this non-network demand response initiative will allow UE to delay having to build new infrastructure to meet infrequent high demand in the area.

Although there are several cases of long-standing network support agreements with generators or large loads for network support purposes, this landmark project in Australia is the first public regulatory project that has won by NPV value to deliver DR encompassing households, small businesses, and community organizations, as well as large, medium and small loads for network support [42,43].

The greatest value from demand management is realized when it can serve multiple purposes—such as for the high-voltage grid, customer needs, and the distribution grid. The flexibility of demand management to serve these purposes depends on the hours of availability and the trigger(s) used to activate and, thus, harness the demand management. There is a likelihood that the accrual of these benefits may occur at different times of the days, making the ability to meet multiple objectives difficult to achieve.

The potential contribution that demand management can make to renewable energy development should be noted. In the case of wind energy, a geographic wind resource may not be available during peak demand periods. By matching that wind resource with DR during the period that wind is unavailable, the wind resource may become more viable. Conversely, in periods of excess solar PV generation in the distribution grid, bringing flexible loads (e.g., hot water heaters, pool pumps) to consume that excess generation may allow for more solar PV to be deployed without resulting in the need for network augmentation or the creation of a barrier for customers that wish to adopt the technology. To support high levels of intermittent renewables on the grid, demand management enables load to follow generation, instead of the traditional model of generation following load. The result is a greater opportunity to replace higher marginal cost and less environmentally friendly resources with a combination of wind (or solar) and DR.

The calculation of benefits for demand management usually depends on (1) whether it can be dispatched (in contrast to voluntary response), (2) the certainty (predictability) of availability, (3) the response times when it is called, and (4) the ability to verify its availability and its dispatchability when called upon.[6]

The installation of interval metering has been one of the main enablers of demand management and has brought about a greater certainty of demand management availability and performance. Many states in the United States have begun to address demand management cost-effectiveness.[7] California has decided that dispatchable demand management qualifies as resource adequacy, which allows it to be more valuable.[8] This also means that dispatchable demand management can qualify to provide grid ancillary services called operating (spinning and non-spinning) reserves and emergency capacity.[9] Fast responding demand management may also qualify to provide *instructed energy*,[10] which is usually paid for at the highest energy market prices.

Case Study: PNNL Olympic Peninsula Project Saves Utility and Consumers Money

In 2004, Pacific Northwest National Laboratory (PNNL), in partnership with the Bonneville Power Administration, started the Olympic Peninsula GridWise Demonstration Project, which equipped over 100 households with advanced meters, as well as thermostats, water heaters, and dryers that could respond to communications signals from the meter. The software used in the pilot program enabled homeowners to customize devices in terms of choice of the desired level of comfort or economy, to automatically optimize the level of power use based on dynamic electricity prices that changed every 5 min. This DR demonstration project yielded average electricity bill savings of 10% for participants [44].

The project also provided benefits to the utility by reducing transmission congestion during peak hours and the need to build additional transmission. This pilot project showed that the Bonneville Power Administration could successfully defer additional transmission investment for at least 3 years. Called "GridWise," this demonstrated that intelligence-enabled appliances can reliably and economically be used to alter load profiles in response to real-time price signal, and reduce the need for peaking plants and additional capacity expansion.

3.6.7 Beyond Peak Shifting

The benefits of demand management go beyond mere peak shifting and many times include lower overall levels of consumption—a conservation effect—as well as very large price reduction effects.

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6 The recent DR cost-effectiveness protocol highlights the following operational factors for DR: availability, notification time, trigger, distribution, and energy price. These factors do not directly reflect the requirements to qualify for specific CAISO markets or provide distribution load management, which seem essential for cost-effectiveness.

7 For example, see CPUC ALJ Hecht's August 27, 2010, ruling in Rulemaking 07-01-041 (DR OIR) to provide guidance on the scope and contents of the utilities' DR applications. This ruling emphasizes a set of related topics: use of price responsive DR, resource adequacy (planning reserve margin) requirements, integration with the wholesale market, integrated demand-side management, load impact estimates, and cost-effectiveness metrics.

8 Resource adequacy has also been defined as long-term planning reserves, which are needed when other plants and transmission lines do not operate, most typically because of "forced outage."

9 Operating reserves are short-term reserves to be used within 10 min, typically when generation or transmission outages occur. Operating reserves come in two forms, spinning or "hot" reserves and non-spinning or "cold" reserves.

10 Instructed energy is provided by the CAISO's electronic dispatch, which requires the generator to be available and respond, and either rapidly increase or decrease generation output as needed.

It is difficult to convey the economic impact of these benefits as they are complex to estimate and are specific to each electricity control area. The Federal Energy Regulatory Commission (FERC) in the United States reports over 50,000 MW in peak load reduction potential from its 2010 survey [45], which is broken down as follows:

- Wholesale commercial/industrial DR potential increased from 12,656 MW in 2008 to 22,884 MW in 2010.
- Utility commercial/industrial DR potential increased by 23% from 2008 to 2010.
- Wholesale and commercial/industrial segments are over 80% of the DR potential.
- Residential DR potential is estimated to be over 7000 MW.
- Four DR programs (emergency response, interruptible load, direct load control, and load as capacity resource) account for 79% of total U.S. peak load reduction potential.

This FERC report also summarizes the market barriers to greater use of DR that regulatory reform may remove or significantly mitigate [45]:

- Disconnect between wholesale and retail markets—pricing is not consistent.
- Measurement and verification challenges with establishment and use of base-line levels of DR.
- Lack of real-time information sharing—retail entities do not share wholesale or distribution system-level information with customers.
- Ineffective DR program design—retail DR programs do not reflect wholesale market realities and benefits.
- Disagreements on cost-effectiveness analysis—the benefits attributable to DR.

The FERC's estimate of national DR potential broken out by region is shown in Figure 3.20. The gap between business as usual (BAU), achievable participation in DR, and full participation in DR is estimated. These differences reflect varying degrees to which barriers to DR adoption are present.

While demand management at the industrial level has been in place in different forms for decades, at the commercial and residential levels, it is relatively new. This is because industrial loads tend to be larger and more concentrated, making them ideal candidates for curtailment during peak hours. Utilities can easily cut large loads by making only a few calls. But curtailing such high-value loads also risks greater economic harm. Demand management would allow low value, noncritical commercial and residential loads to be turned off with less economic impact.

There are several evolving trends in the industry that hold promise for wider and more active participation from commercial and residential consumers:

- *Improved human interfaces:* Among the many in-home displays recently released or in development, an example is Intel's Intelligent Home Energy Management Proof of Concept. This features a vibrant OLED screen and integrates traditional thermostat features with energy cost management (through connection with ZigBee compatible advanced meters), home security system monitoring, tasks reminders, and media functions such as video memos [46].
- *Portability of human interfaces:* Smart thermostats now can be controlled by an app on the consumer's smartphone and are available at all times to accept settings changes, giving its users a variety of control options where the trade-off between cost and comfort can be decided in advance.
- *Lower-cost sensors and communications devices:* Lower-cost sensors and communications devices will make it cost effective and faster to communicate between the utility and the consumer through a variety of channels.

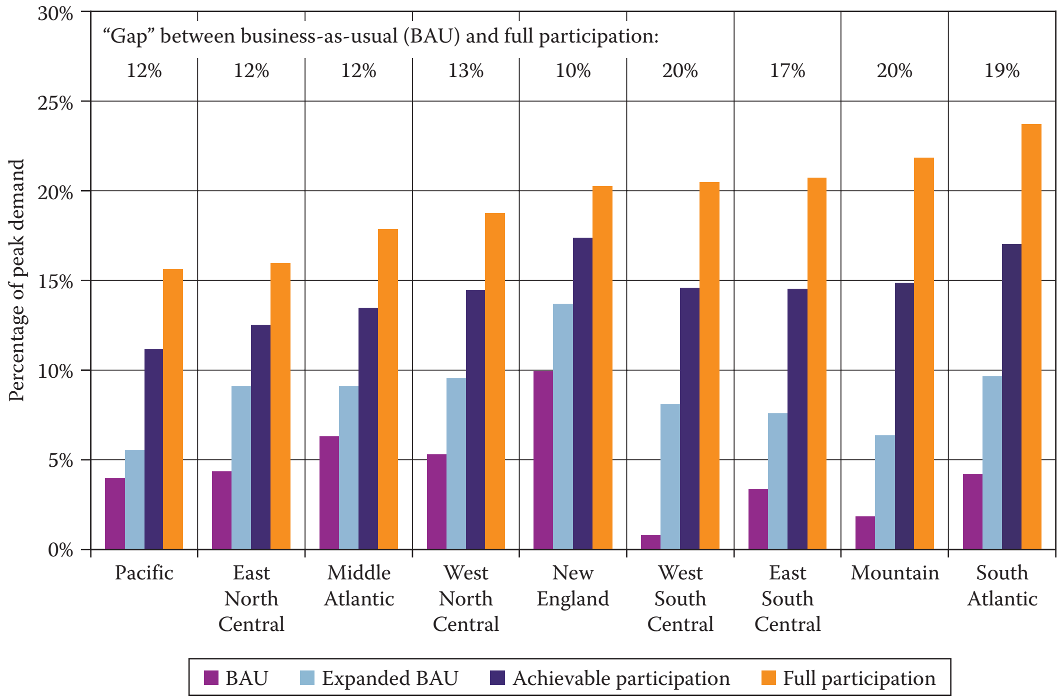

FIGURE 3.20 Gap in demand management participation in the United States. (From National action plan on demand response, Federal Energy Regulatory Commission, June 17, 2010, p. B-1, http://www.ferc.gov/legal/staff-reports/06–17–10-demand-response.pdf.)

- *Better energy management software:* Google's PowerMeter and Microsoft's Hohm energy management software may serve as predecessors leading to new tools for customers to manage their energy use in an online, highly visual environment.
- *Greater public awareness:* Increased public education and concern about environmental and energy issues, especially in the past decade, have driven greater involvement in personal energy use management and demand for information and control over emission sources for both commercial and residential applications.

3.6.8 Demand Response Implementation

Key to the implementation of demand response management programs is an integrated set of applications that enable both the utility and consumers to understand and have control over energy consumption. At the utility level, economic DR programs are implemented that offer economic incentives to customers to contain and/or shift their energy demands to better match system-level demand with system supply resources. At the consumer level, home energy managers (HEM) or smartphone apps provide real-time energy consumption information and optimize the operation of connected appliances and energy management devices in the household. The primary objective is not only to provide consumer applications and HEM devices that empower and allow better management of energy consumption without adversely compromising lifestyle but to also allow utilities to optimize rate structures, reduce reserves, and allow greater economic flexibility in the near and long term. Demand management may also be used to mitigate unexpected supply disruptions or overload conditions. During such conditions, customers may be asked to curtail consumption on short notice or utilities may use direct load control to shed consumer loads.

Demand management should not be limited to solutions that are able to suppress or shift demand and alleviate peak load. The vision should be to provide a solution that goes beyond peak shifting and provides flexibility and increased efficiency in managing overall demand. The solution should match generation resources with demand from electricity consumers in an efficient, predictable manner and incorporate the control, integration, and optimization of renewable and other DERs as the adoption of these technologies increases.

The demand response management system (DRMS) is the utility application that manages DR capabilities from the utility down to the consumer. The DRMS also interfaces and operates with other utility operational and information systems, such as EMS, DMS, OMS, customer information systems (CISs), and billing. To be an end-to-end solution, a DRMS needs to have this level of functionality at a minimum to provide real value to a utility.

First-generation DRMSs typically focus on functionalities needed to support peak shifting by obtaining load information from the meter and statistically estimating load availability based on customer enrollment and consumer historical data compared to the load forecast from EMS. Once a DR event is selected, the DRMS sends a basic signal to preestablished groups of customers based on the estimated amount of MWs required. In-home enabling technologies, such as smart thermostats, in-home displays (IHDs), HEMs, and smart appliances, receive the signals and perform the load management activities based on the consumer's preferences. Two-way communications allow the utility to measure the effect and verify consumer participation in demand management.

As load management technologies advance and the DRMS is integrated with more utility enterprise applications, the DRMS enables the use of DR to support emergency response and virtual generation capability in the EMS. Through aggregation, it estimates demand in near real time and can dynamically select customer groups based on electrical nodes and resource availability. The DRMS also incorporates and accounts for distributed resources such as energy storage, wind, solar, and PHEVs.

The operations component of the DRMS contains all the critical applications for a utility to manage and maximize resources for DR events. These applications include response estimation, dispatch, aggregation/disaggregation, measurement and verification, and reports and analysis.

More recently, the concept of a Virtual Power Plant (VPP) has been used interchangeably with DRMS, where the intended outcomes are the same.

3.6.8.1 Load Modeling and Forecasting

For most of the twentieth century, loads were quite simple to understand and represent, even as they grew increasingly unpredictable over the years. The philosophy of power systems engineering is that the purpose of the bulk power system is only to satisfy the load and not to question why it is present or attempt to manage it directly. Consequently, load was treated largely as a boundary condition. In fact, very early electric system planners generally anticipated only three types of loads: constant impedance loads from devices such as incandescent light bulbs, inductive loads from motors, and system losses from cables and transformers. The times and quantities that were present were quite easy to anticipate, and the system could easily meet the need to balance supply and demand by having generators follow the load using voltage and frequency feedback signals.

As a result, with few exceptions, power engineers tended to downplay the significance of load behavior. Load was treated largely as a static boundary condition, even when numerical simulations made it practical to do otherwise. It made perfect sense to keep load a constant parameter in the context of steady-state flow solutions or sub-minute dynamic simulations because (1) that is how the system was operated, and (2) whatever uncertainty was present was both small enough and random enough to be readily addressed by good dispatch practices and the existing feedback controls. At every time scale in between, load behavior simply was not complex enough to warrant much consideration beyond basic forecasting needs.

The first hint of the potential significance and complexity of load behavior came with the cold load pickup problem. This problem arises after prolonged power outages where all thermostatic loads have settled well outside their normal control hysteresis bands and load patterns have lost diversity. When the power is turned back on, all these devices turn on simultaneously, causing a surge in demand that can far exceed the demand prior to the power outage and even exceed the maximum capacity of the system (which is why it can take several days to restore full service to all customers after a major system outage). This phenomenon is also observed in load curtailment rebounds, which are similar in nature although not generally as severe.

But, it was not until the advent of smart grid technology that power engineers came to seriously consider the potential role that loads could play in meeting system needs. It was realized rather quickly that loads exhibit behaviors that are not simply detrimental to the system, such as cold-load pickup or load curtailment rebound. The same phenomena that give rise to adverse behaviors might also be used productively to support strategies such as bulk system underfrequency load shedding at the end-use level (instead of at the neighborhood level), distribution system undervoltage support, or support of intermittent renewable generation, such as wind and solar.

Economies of scale, regulatory barriers, customer expectations, and a strong preference for centralized command and control in vertically integrated utilities have made it far easier to govern a few large generators than many small loads. So for more than one hundred years, the system was controlled exclusively from the supply side. Understanding load behavior was unnecessary, and with remarkably few exceptions,[11] it remained largely an academic question.

The introduction of smart grid technology, the growth of intermittent renewable generation resources, the surge of local DG such as rooftop solar PV and the advent of intelligent load controls have converged to make loads potentially an equal partner in the electric system's physical and economic operation. As a result, load modeling has become an increasingly important consideration in the design and operation of smart grid technologies and in the debate about how to host and enable the implementation of renewable resources.

To understand how loads respond to changes in circumstances, utilities must begin by understanding how loads behave in general. Load behavior analysis and modeling require subdividing loads into the main classes that influence the kinds of behavior observed. Primary among these taxonomies is the economic nature of the load, namely, residential, commercial, industrial, and agricultural. For smart grid purposes, residential and commercial loads are the most challenging and interesting. In contrast, industrial loads are not the focus because they have individual characteristics that can be difficult to model, and agricultural loads because they tend to be simple in comparison.

In addition, at least from the perspective of electric system modeling, it is vital to identify the degree of electrification of the load itself. Electrification is typically characterized by end use, that is, the type of device that meets an electric customer's needs. Not all devices use electricity to satisfy the demand for goods and services, and the fraction of those that do varies according to factors such as geography, demographics, regulatory policy, and long-term expectations for energy prices for the fuels, if any, needed by the various prime movers, for example, steam, water, wind, sun.

Finally, intermittent availability of lower-cost fuels, particularly those that are relatively uncorrelated with electricity prices, can make multifuel systems economically advantageous. From the standpoint of load behavior, these can either be implemented as direct-delivery systems, such as solar water heaters, or be mediated by electricity delivery systems, such as rooftop PVs. The availability and behavior of these systems can influence load behavior as well.

Smart and efficient execution of demand management commands relies strongly on smart measurement and analysis of consumer and market data. Different portions of end-user consumption level are qualified for various demand management programs, such as interruptible load, direct load control, or demand dispatch. Metering of individual consumer load consumption versus an aggregate measurement of the consumer total load provides detailed knowledge on the consumer habits and consumption patterns and enables a more appliance-oriented DR approach with a higher chance

[11] One notable exception was the advent of DSM programs focused on energy conservation. These programs address the problem of load growth through conservation measures, such as efficient appliance retrofits and consumer education. To this day, DSM programs remain effective at controlling the net rate of load growth.

of success. This would require smart and efficient analysis of the raw data to extract meaningful information from it for DR purposes. Various estimating and forecasting techniques can be used to develop a reasonably accurate model for consumer demand and provide a forecast for its demand during the future time intervals. The sensitivity of the consumer to the electricity prices can be incorporated into the model to reflect the response of the consumer to demand management events. More complicated econometric models can be developed to account for the qualitative data, such as the personal habits of the individual consumer toward DR events. These models can determine a probability value by which an individual consumer may comply with a demand management event issued by the utility, and if proved reliable, they become part of statistical reliability. This information proves to be very useful in validating the demand management event and determining whether extra measures are necessary. Matching this information with electricity market prices, from the full set of separate market elements, is an additional challenge.

Traditionally, DR programs have been offered to the customers as a set of fixed options with preset terms and conditions. The customer would then pick the program that fits his/her needs the best. There are several attributes that are directly associated with each program, such as the maximum duration of the demand management event, the maximum number of times a demand management event may be issued in a year/month, and the maximum number of consecutive days a demand management event may be issued. Other attributes are more related to the consumer, for instance, the minimum notice for the event. All these attributes could make a difference in the comfort level of the customer participating in the corresponding programs and, therefore, impact the acceptance and success of the program.

With proper modeling of the customer load patterns and habits, it is possible to customize the programs to tailor these attributes to fit customer needs and habits. This will create a wider and more flexible set of program terms and incentives for selection by the customer. More choices can lead to higher customer program participation. With additional choices, a consumer may view the process of selecting the suitable programs confusing, making the selection difficult or even risky. This issue could be buffered via a mechanism that utilizes consumption patterns and habits of individual consumers to propose an optimal program selection to the consumers to create mutual benefits for both parties.

3.6.8.2 Price Signals

Consumer DR can be controlled using price signals. Different rates at different times, implemented effectively, can drive desired end-user consumption behavior. However, unlike the availability cost of other services, such as airfare or hotel rooms, currently the typical electric price to the residential customer is "one size fits all." Such a price offers no reduction for conservation and no premium for consumption during peak periods. While utilities across the country have used these types of pricing mechanisms to differing extents for some time now, AMI technology paves the way for much greater adoption of dynamic rates and pricing signals for all customer classes—"smart meters" enable "smart rates." As with any control system, utilities can employ either an open-loop strategy or a closed-loop strategy. An open-loop price-based control strategy generally relies on time-varying prices with the expectation that higher prices lead to lower loads. Several types of open-loop pricing strategies are commonly found and are distinguished by the rates or tariffs they use. Each rate is designed to elicit a different response from customers.

Time of use (TOU): TOU rates have existed in some countries for many decades because they are simple to implement and meter. The peak-time schedule is typically determined seasonally, and it sometimes has a "shoulder" rate that is an intermediate rate between the off-peak and on-peak rates.

Critical-peak pricing (CPP): CPP is like TOU pricing, but instead of having a daily schedule, the CPP is declared only on the few days the utility expects peak conditions to prevail. For this reason, the price on critical peak is usually very much higher than the standard rate. It is not unusual to find the CPP rate is >10 times the standard rate.

Peak-time rebate (PTR): PTRs are like CPP rates, but instead of charging customers more, the rebate works by refunding customers who reduce load on peak. Unfortunately, it is often difficult to determine the savings precisely for any given customer, and solving this problem can lead to complexity in the program implementation.

Dynamic pricing (DP) or real-time pricing (RTP): DP or RTP works by sending customer prices that reflect, to some extent, the variations in prices seen at the wholesale level. Unfortunately, because the fluctuations in wholesale prices can be unpredictable and vary as frequently as every 5 min, RTP can be difficult for customers to respond to without special hardware. RTP is a closed-loop price-based DR control strategy. The implementation of RTP can be difficult to understand, but its flexibility and scalability are very important attributes that have led to growing interest in its use. RTP systems may require DR equipment to be installed in the customers' homes. The fact that prices change in periods as short as 5 min means that customers cannot be expected to respond all the time. Some may contend that customers will not accept price change more frequently than hourly. For this reason, RTP systems include devices that can respond to prices and interact automatically on behalf of the customer. One very important caveat for RTP is that a customer's subscription must be voluntary. Some customers may have load shapes that are particularly ill suited to RTP because the unresponsive part of their peak load is highly coincident with peak price. In contrast, other customers may have highly responsive loads on peak and may be able to provide a load of flexible DR to the utility. At the other end of the scale, some customers may not have enough demand on peak for the cost of the RTP system to be justified, and utilities must retain the ability to exclude certain customers from using RTP when they would essentially be free riders or not viable as a DR resource.

From a utility planning and operation perspective, predicting the demand curve for RTP presents an additional challenge, particularly in response to a price disturbance after which the demand response resource may be depleted. From a first-principles approach, there is evidence supported by field demonstrations using transactive control systems [47,48] that the random utility model [49] best describes the demand curves of thermostatically controlled loads that respond primarily to short-term real-time price fluctuations [50].

This demand curve is illustrated in Figure 3.21. In addition, the elasticity of demand is shown, and it is apparent that the maximum elasticity of demand in the short term is not necessarily found in the equilibrium price and quantity. Deviations from the equilibrium point give rise to significantly reduced short-term demand elasticity and can be expected to result in reduced responsiveness in subsequent dispatch intervals.

Regardless of the specific pricing mechanism proposed by a utility, there are two fundamental implications of these changes:

- More active involvement on the utility's part in helping customers understand what they can do to reduce their usage
- More active involvement on the customers' part in what they use and when they use it

Smart grid is more than simply new technology. It will have a significant impact on a utility's processes. Perhaps more importantly, it is also about the new information produced and made available by these technologies and the new customer-utility relationship that necessarily emerges because of these technologies. A critical element of this new relationship is "decoupled rates." Decoupled rates break the linkage between what a utility charges for power delivery and how much energy the end user consumes. While the costs of generating power are clearly a function of usage, the cost a utility incurs to provide a power delivery system has little to do with how much energy an individual customer typically uses. Public, regulatory, and local government interest in renewable energy sources and DSM programs has never been higher. However, until new pricing mechanisms such as "decoupling" become more common, utilities will continue to have a financial disincentive to encourage their customers to use less of their product. Greater alignment between the end user and the utility interests will result in greater reductions in energy consumption (and emissions).

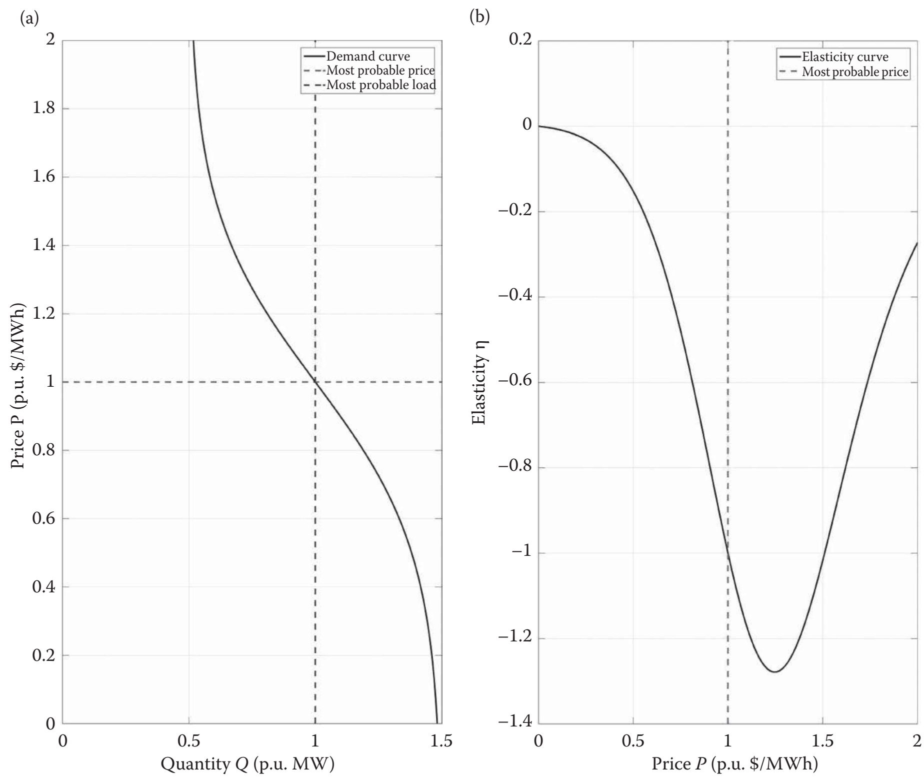

FIGURE 3.21 (a) Demand curve and (b) short-term elasticity of thermostatic loads responding to real-time prices for a nominal case with $\eta = -0.037$.

3.6.8.3 Demand Dispatch

With few exceptions, utilities today rely on manual processes, spreadsheets, and independent software applications to decide if, when, and how much demand resource is needed to support forecasted demand requirements. The demand dispatch application in the DRMS is a decision support tool that provides utilities with recommendations as to when to initiate a DR event and how many customers to include in the event. The demand dispatch tool determines the optimal schedule and resource mix, considering generation costs and the impacts of the rebound effect when providing recommendations for how much DR to request for each given period. The demand dispatch tool should consider optimal dispatch of demand across multiple customer types and pricing programs.

3.6.8.4 Consumer Response Estimation

Load response can be separated into two distinct behaviors: one behavior is a one-time irreversible behavior, for example, a person turns off the lights when leaving home; the other behavior is reversed later, for example, a person defers doing a load of laundry until the next day. Some load responses have both. For example, lowering a thermostat by 2°F for 8 h every day will reduce the heating energy consumption in the short term. But the load will experience a recovery period during which some of the energy savings are lost when the thermostat setting is raised back up again. A comparison of the reversibility of different residential load responses is shown in Table 3.6.

Irreversible load responses reduce overall energy consumption by the amount of load that responds. Irreversible load response is simply a change in the load shape, which results in a net

TABLE 3.6
Residential Load Response Reversibility

Irreversible Responses	Reversible Responses
Lighting controls	Heating and cooling thermostat schedules
Cooking/heating fuel switch	Washer and dryer deferral
Heating and cooling thermostat setback	Refrigeration and freezer defrost deferral
Energy efficiency retrofits	

reduction of both energy and maximum power, as illustrated in Figure 3.18a. Most irreversible load responses require a one-time investment, and the benefit is typically enduring. However, some load responses, such as consumer awareness programs, may appear to be irreversible over the short term, but in fact decay in the long term.

Reversible load response is a change in the load shape that results in a change in maximum power but no net change in energy consumption, as shown in Figure 3.18b. This behavior is typical for thermostatic loads, such as heating and cooling systems. These responses are often called load shifting or deferral. Preheating and precooling are also reversible load responses, but with the opposite sign (i.e., load increase precedes load decrease).

Reductions in consumer real power consumption are typically associated with energy efficiency programs; that is, reducing real power consumption reduces energy consumption for non-thermostatic loads such as motors and lights. In some cases, though, reduction of real power can also reduce peak load, which, from a smart grid perspective, may result in deferred capacity expansion. One caveat is important for thermostatic loads: reduction in real power typically results in increased duty cycle or run time and does not result in reduced energy consumption. This can affect the saturation load (the load at which diversity disappears) and contribute to increased adverse load behavior associated with loss of load diversity, such as the onset of load rebound and real-time price instability.

Many existing direct load control programs do not enable utilities to accurately estimate how much load reduction they will obtain when an event is initiated. As a result, a common strategy is to send a signal to a larger subset of the population to ensure the necessary reduction is met. The impact of the event is evident at the system level; however, there is no direct feedback from premises and very little learning on the impact from one event to the other, making the planning and execution of demand management very inefficient. The lack of feedback also makes estimation of the potential rebound effect after the demand management event more difficult, making the grid vulnerable to a subsequent rebound peak or operational instability. The response estimator function in the DRMS determines the amount of MW and MWh available for DR over a time frame of interest, including the estimated rebound effect. In addition, this estimation can be tied to existing load forecasting tools since there is direct correlation between the two. The response estimator evaluates the likely response from participating homes, as well as their associated probabilities of participation.

3.6.8.5 Aggregation/Disaggregation

Aggregation is a necessary component of the response estimator application. The aggregation function determines the total DR available based on customer participation and availability. The aggregation function collects up-to-date metering data from each of the applicable premises to enable as accurate an assessment as possible of the current load state and potential for DR. The disaggregation function identifies the participating customers for each pricing event.

3.6.8.6 Measurement and Verification

As utilities initiate demand management events, there is little feedback to measure the extent to which an event is successful. Customers may have participated in their demand management program, or they may not have participated due to an endless range of possibilities. This function in the DRMS calculates baseline customer load profiles according to contractual terms and verifies reductions/changes in load from their profile for billing purposes. This information can be tied into a utility's CIS to facilitate accurate billing and rewarding for participation in demand programs. The application also validates the probabilities of participation, expected load change, and anticipated rebound effect as estimated by the response estimator application.

3.7 ENERGY RESOURCE CHALLENGES

3.7.1 DERs

Distribution systems were not designed to accommodate active generation and storage at the distribution level. Even though DERs can be connected anywhere on the distribution system (substation, primary feeder, low-voltage or secondary feeder, customer premises), their size and location have the most impact on the distribution system. Some factors to consider include bidirectional power flow, short-circuit current levels, system losses, reactive power flow, impact on lateral fusing, reverse power flow, islanding, and voltage and frequency control. The technologies and operational concepts to properly integrate DERs into the existing distribution feeders need to be addressed with smart grid solutions to avoid negative impacts on system reliability and safety.

There are several types of DER interconnection systems. They can be divided into two main groups:

- *Inverter-based systems*—These systems are used in batteries, fuel cells, PV, microturbine, and wind turbine applications. Some systems, such as batteries, fuel cells, and PV, generate DC power, and an inverter is required, which is a bidirectional DC/AC converter. Microturbines generate AC power with a high frequency that is typically converted to DC and then back to AC 50/60 Hz.
- Systems that run parallel to the distribution system and interconnection system that require synchronization with the common bus—These systems are typically used for load peak shaving, emergency power supply, and cogeneration.

Every DER system consists of the following major parts:

- *Prime mover*—This represents the primary source of power. There are several prime movers available today, such as reciprocating engines, microturbines, wind turbines, PV systems, fuel cells, and storage technologies.
- *Power converter*—This represents the way that power is converted from the prime mover to the electrical output of the DER. Synchronous generators, induction generators, double-fed asynchronous generators, inverters, and static power converters are examples of power converters.
- *Transformer, switches, relays, and communications devices*—These devices enable the connection and protection of the DER on the distribution system and vice versa.

Studies and operating experience indicate that it is easier to integrate PV solar and wind energy into a power system where other generators are available to provide balancing power, regulation, and precise load-following capabilities. The greater the number of intermittent renewable generation is operating in each area, the less their aggregate production is variable. Typical T&D system-related problems with high penetrations of DER [51] (greater than 20% of load) include the following.

3.7.1.1 Standards

Most small- and large-scale distributed renewable generation resources are currently governed by the IEEE (Institute of Electrical and Electronics Engineers) 1547 [52] set of standards that include references to UL1741 for interconnecting to low voltage networks. Some countries, like Australia and New Zealand, have their own set of standards, such as AS 4777. IEEE 1547 standards were developed toward the end of the 1990s when DG, especially distributed PV and wind generation, was at very low penetration levels. IEEE 1547 describes the interconnection issues of DG resources in terms of voltage limits, anti-islanding, power factor, and reactive power production mainly from a safety and utility operation point of view.

There are, however, concerns on some of the practical impacts of the IEEE 1547 standard on distribution feeder design, operation, and safety. These include reactive power injection, voltage regulation, low-voltage ride-through (LVRT), and power quality of high levels of inverters penetrating the distribution network without any coordinated control. Currently, there are several IEEE standard groups working on different application notes and setting the requirements for a future update on IEEE 1547. Larger wind generation facilities above 10 MW are now required to have LVRT capability to increase system reliability. New-generation interconnection requirements have been adopted by FERC as part of the FERC Order 661, docket RM05-4-0000 Notice Of Proposed Rulemaking (NOPR), mainly for large wind and solar power facilities, larger than 20 MW. These provisions are updated and adopted as Appendix G to the Large Generator Interconnection Agreement (LGIA) [53]. FERC also now requires renewable energy plants to be able to provide sufficient dynamic voltage support and reactive power if the utility's system impact study shows that it is needed to maintain system reliability. This implies that wind generators should have dynamic reactive power capability for the entire power factor range.

Currently, there is also an industry-wide initiative on the Smart Grid Interoperability Panel [54]. This initiative is coordinated by NIST and EPRI. The main purpose of this panel is to develop interconnection and communications requirements for DERs, including PV, energy storage, and demand response. Some of the communication and protocol profiles for PV generation and storage systems include DNP3 (Distributed Network Protocol) and IEC 61850, but other standards are emerging, such as the Sunspec Alliance and Manufacturing Enterprises Solutions Association (MESA), for energy storage. The purpose of defining a standard communication profile is to make it easier to interconnect and operate DERs with increased security levels.

3.7.1.2 Intermittency and Dispatchability

PV and wind capacity factors (average output power as a ratio of maximum output power) typically range from 15% to 30%. Due to the fluctuating and uncontrollable nature of wind and PV power, their power generation must be balanced with other very fast controllable energy sources. These include gas, hydro, or renewable power-generating sources, as well as fast-acting energy storage, to smooth out fluctuating power from wind generators and increase the overall reliability and efficiency of the system. The costs associated with capital, operations, maintenance, and generator stop-start cycles must be considered.

In most urban regions, PV flat-plate collectors are predominately used for solar generation and can produce power production fluctuations with a sudden (seconds time scale) loss of complete power output. PV generation penetration within residential and commercial feeders is approaching 4–8 MW per feeder. During cloudy and foggy days, large power fluctuations are measured on the feeders with high penetration levels and can produce several problems—voltage quality, protection, uncoordinated reactive power demand, and power balancing [51]. Cloud cover and morning fog require fast ramping and fast power balancing. Furthermore, several other solar production facilities in close proximity on the same electrical distribution feeder can result in high levels of voltage fluctuations and even flicker on the feeder. Reactive power and voltage profile management on these feeders are common problems in areas where high penetration levels are experienced. Feeder automation and smart grid communications are, therefore, crucial to solve these intermittency problems.

IEEE Std. 1547 states that each DER unit or DER aggregate of 250 kVA or more shall have provisions for monitoring its connection status, real and reactive power output, and voltage at the point of DER connection. Monitoring the exchange of information and control for DER systems should support interoperability between DER devices and the distribution system. Use of standard commands and protocols and data definitions enables this interoperability. In addition, this reduces costs for data translators, manual configuration, and special devices. DER can be dispatched as a unit for energy export as needed, according to a certain schedule, during peak periods, shut down for maintenance, used for ancillary services, such as load regulation, energy losses, spinning reserve, voltage regulation, and reactive power supply.

3.7.1.3 Voltage and Reactive Power

Electric distribution systems were designed for one-way power flow—from the substation downstream to the customers. In such systems, voltages are highest at the substation, and they are the lowest at the end of the line. However, this assumes that there are no distributed energy sources on the distribution system. Depending on the size of DERs and their placement on the feeder, it is possible to have the voltage at the end of the line to be higher than the voltage at the substation.

Reactive power management and coordination on feeders were not designed for high DER penetration levels. Due to PV and wind power variations and required ramp rates larger than 1 MW/s, fast-acting reactive power sources should be employed throughout the feeders and network. Reducing system losses represents one of the main challenges of a power utility today. Utilizing DERs reduces system losses if DERs are properly sized and placed. To obtain the maximum loss reduction in a radial distribution circuit with DERs, the DER must be placed at a position where the output current of DER is equal to half of the load demand. The reason for this is that the distance that power must travel from sources to loads is minimum, which, in turn, minimizes losses. However, if the DER is too large, then it will cause feeder losses to increase.

Voltage regulation in distribution power networks is specified in the ANSI C84.1 standard, where a nominal voltage of 120 V is the standard for a residential consumer supply, with allowable deviations of ±5%. The standard describes the process and equipment that is needed to keep the voltage within the limits. According to IEEE Std. 1547, "The DER shall not actively regulate voltage at the PCC (point of common coupling). The DER shall not cause the Area EPS (distribution system) service voltage at other local EPSs to go outside the requirements of ANSI C84.1 standards."

DER significantly impacts voltage regulation and relay protection schemes. Voltage on MV (medium voltage) distribution networks is controlled by voltage regulators and capacitor banks, but LV (low voltage) feeders typically have no voltage control. The voltage drop depends on the wire size, type of conductor, length of the feeder, loads on the feeder, and power factor. DER can affect the voltage on distribution feeder in several ways. If DER power is injected into the distribution system, then it will reduce the amount of current needed from the substation for the load, thus automatically reducing the voltage drop. If DER supplies reactive power, the voltage drop will also be reduced. If DER absorbs reactive power, the voltage drop will increase. Most existing PV inverters do not provide reactive power and voltage support capability and do not have LVRT (low voltage ride-through) capability.

If there is a feeder with a voltage regulator that uses line drop compensation, and there is a large DER located downstream of the voltage regulator, it is possible that that the DER can supply most or all power to the load on the feeder, and it might also be capable of supplying the load upstream from it. If the voltage regulator cannot detect reverse power flow, then the voltage regulator assumes that the feeder is lightly loaded and will produce a voltage change that is opposite from what control algorithm expects. Voltage regulators should include a reactive bidirectional mode to operate correctly with DERs in reverse power flow scenarios.

Small-scale DER devices are mostly single phase. Injecting power will have an effect only on one phase, and the voltage difference can change between the phases, thus creating highly unbalanced phase voltages. This unbalance can exist even if the voltages are within ANSI C84.1 range. To alleviate this problem, the DER can be connected to the phase with the most load, and transferring single-phase load from the highest loaded phase to the other two phases. However, this brings additional cost to the utility to rebalance the load along the phases every time one or more consumers connect a DER (e.g., install solar PV on the rooftop). In areas of the world where the LV distribution system serves 50–150 customers, voltage unbalance is becoming a significant problem.

DER devices (e.g., wind or solar) can be very unpredictable, and their output can be intermittent. The output of DERs can change rapidly, and this can cause voltage regulating devices to operate excessively. Most of these devices have a daily maximum limit in the number of operations. One solution is to change the time delay settings on voltage-regulating devices to provide better coordination with DER.

3.7.1.4 Protective Relaying

Short-circuit current levels on the distribution system vary greatly with respect to impedance of the feeder and length of the conductor. The addition of DER affects the levels of short-circuit currents, thus inadvertently affecting relay settings. One measure that is of interest is the ratio of the rated output current of DER with respect to the available short-circuit current at the POI (point of interconnection). For DERs on feeder primary voltage levels, if this ratio is ≥1%, then DER will have noticeable impact on voltage regulation, power quality, and voltage flicker. If the DER is on the secondary or low-voltage level of the feeder, a ratio of <1% can have major impact on secondary voltage.

The integration of DER may lead to reverse power flows through feeder sections and substations. The distribution grid, in general, has not been designed, built, and is not prepared for bidirectional power flows. It has been a long-standing practice of utilities to protect feeder lateral circuits with fuses. Utilities generally use two philosophies for protection coordination, fuse clearing and fuse saving, and in some case, a combination of both—fuse clearing where fault currents are high and fuse saving where fault currents are moderate to low. For the case of fuse saving, relays on substation breakers and upstream feeder reclosers trip before the fuse blows. The breaker must trip before the fuse starts to melt. Depending on the severity of the fault, these schemes sometimes cannot operate correctly. DER causes fuse saving schemes to be even more complex because of the increased fault currents. In addition, DER increases the fault current level through the fuse, but not necessarily through the substation breaker or feeder recloser. Furthermore, the addition of DER causes issues with fuse-to-fuse coordination. Choosing correct fuse sizes, relay settings, and DER tripping settings can alleviate this problem, but may not be optimal.

A critical component of protective devices on distribution networks is overcurrent relays. These relays have instantaneous and time-delayed settings, which cause the distribution breakers to trip if fault current levels have been exceeded. In addition, on 34.5-kV long distribution lines, sometimes distance relays that are overcurrent relay supervised are used because it might be hard to distinguish between the high-load currents and low-fault currents. The commonality between all these relays is that they are designed and built for one-way flow. However, reverse power flow can cause protection devices to misoperate. Additional impacts on protection systems are modification of the sensitivity of protective devices, such as circuit reclosers and relays due to the feeder load offset effect of DER, particularly for the case of large DER, and potential overvoltage issues during unintentional islanding conditions.

Smart grid technologies can play an important role in mitigating these impacts, for instance, by using adaptive protection systems, which allow the settings of protective devices to adapt to the varying system conditions, either feeder loading and configuration, or DER output. Most important is to recognize the need for distribution protection systems to evolve; this is expected to become more important as the penetration level of DERs and other smart grid technologies increases. As the complexity of operating the smart distribution system increases, the need for replacing conventional protective devices, specifically fuses, will also increase. It is likely that the distribution grid of the future will be similar to modern transmission systems, from a protection system standpoint.

3.7.1.5 DER Placement

Substations represent the strongest point of the distribution system. Placing DER in the substation represents less of a challenge for the distribution system since DER acts as another power source.

The only additional requirement is the modification of protection and control schemes that will account for the addition of DER. However, if capacity of the DER is greater than 15%–20% of the substation load, then additional issues arise, such as voltage regulation, equipment ratings, fault levels, and protective relaying. If capacity of the DER is close to the substation load, then issues will arise with voltage regulation on the transformer tapchanger since the transformer tap changer will see a light loading and will not boost the voltage appropriately, thus causing the low voltage at the end of the line. If the capacity of DER is larger than substation load, then it will export power into the transmission system, thus creating additional protection and control issues.

The distribution system has a higher impedance on primary feeder lines, so DER placed anywhere on distribution lines will have more influence on the system than comparable DER placed in the substation. DER placed on the feeder can cause reverse power flows, and it requires additional protection and/or control equipment. Generally, security and safety of all protective devices may be compromised if DER causes fault levels to change by >5%.

3.7.1.6 Intentional and Unintentional Islanding

Islanding happens when part of the utility system has been isolated by operation of one or more protective devices, and DER that is installed in that isolated part of the system continues to supply power to the customers in that area. This is a very dangerous operating condition for several reasons:

- DER might not be able to maintain proper system parameters, such as voltage and frequency, and can damage customer equipment.
- The islanded area might be out of phase, so the utility system might not be able to reconnect the islanded area.
- There are safety issues with utility personnel working on downed lines that can be back-fed from DERs.
- Improper grounding can lead to high voltages during the islanding.

DERs that can self-excite are capable of islanding, while non-self-exciting DERs can island only if certain conditions have been met. There are two main techniques that are used to prevent islanding: frequency regulation and voltage regulation. During normal operation, frequency and voltage are fluctuating within certain ranges. For frequency, the settings are set to anywhere from 0.5 to 1.0 Hz from nominal frequency of 60 Hz. Allowed voltage variations are 120 ± 6 V at the customer meter. Thus, having frequency, undervoltage and overvoltage protection can prevent islanding.

An additional issue is reconnection of lines when attempting to clear faults. When a fault occurs on a feeder with DER, breakers trip, and depending on the reclosing sequence, they can reclose up to three times to attempt to clear the fault. IEEE Std. 1547 recommends DER to trip before any breaker reclosing occurs. After the DER trips off-line, for safety reasons, it is not advisable to have control logic programmed such that DER reconnects to the system immediately after the normal power supply has been established. DER should only be allowed to be reconnected after the voltage and frequency have returned to their normal limits. There are, however, some situations when the load on the island is balanced with the DER output. In that case, several techniques, such as voltage shift and frequency shift, are used to detect islanding. This protection should operate within a few seconds after islanding has occurred.

3.7.1.7 Frequency Control

Small-scale DER itself cannot control or change the system frequency. Large-scale (MW-size) DER, depending on the size and regulatory framework, may be allowed to provide ancillary services. Potentially, the wide-area controllability that can be achieved via smart grid technologies can allow the implementation of the "virtual power plant" concept, which consists of the aggregated and coordinated dispatch, and operation, of many DERs (either small-scale, medium-scale, or utility-scale), may allow this type of ancillary service. Similarly, the implementation of the microgrid concept requires the availability of DER with frequency control capability; This can be accomplished by means of distributed generation, the combination of intermittent distributed generation and storage, or using only distributed storage.

3.7.1.8 Power Quality

Fluctuations in PV and wind power production result in large-voltage fluctuations, as well as voltage flicker and other power quality issues. Potential impacts of DER integration are voltage rise, voltage fluctuation, flicker, voltage unbalance, voltage sags and swells, and increased total harmonic distortion (THD). In addition, when large numbers of small-scale DERs (e.g., rooftop solar PV) are connected to low-voltage feeders, they will change the voltage dynamics by increasing the voltage during low-load (e.g., in residential systems when occupants are away during the day) and high-generation conditions, since when a DER is supplying power to the grid, its inverter raises the voltage at the point of connection. This high voltage can lead to inverter (and DER) disconnect, as well as potential customer load damage. Furthermore, extreme PV intermittency due to cloud cover may lead to rapid voltage fluctuations; this has motivated some utilities to require the evaluation of potential flicker impacts as a requisite for authorizing DER connections. Voltage unbalance can be accentuated by large penetration levels of single-phase DER, particularly if different technologies and capacities are used, and if they are connected to different phases of the power distribution grid. Voltage sags and swells can be the consequence of fault current contributions and sudden connection and disconnection of utility-scale DG. Increased harmonic distortion may be caused by electronically coupled DERs; noting that even though individual inverters may comply with standard requirements pertaining to harmonic injection, it is the interaction and cumulative effect of harmonics produced by many inverters that could have a negative effect on feeder total harmonic levels. As previously indicated, smart grid technologies and intelligent control of DER inverters can help alleviate issues related to voltage rise, voltage fluctuation, and intermittency. Other issues, such as voltage sags and swells due to larger fault currents, may be mitigated using, for example, fast reacting fault current limiters. Issues related to increased voltage unbalance and harmonic distortion should be addressed in the planning stage of the smart grid, where maximum penetration levels and location of DER must be carefully evaluated. Another potential and more complex solution is the coordinated dispatch of these technologies via the virtual power plant concept.

3.7.1.9 Equipment Loading, Maintenance, and Life Cycle

In the same way that low-to-moderate penetration levels of DER (either conventional or intermittent) reduce equipment loading, moderate-to-high penetration levels or a condition that leads to reverse power flow may increase equipment loading up to a point where this can become a concern from an equipment rating perspective and lead to equipment overload. Similarly, the interaction among intermittent DER (PV and wind) and voltage control and regulation equipment, such as load tap changers (LTC), line voltage regulators, and voltage-controlled capacitor banks, may lead to frequent operation of this equipment (frequent tap changes and status changes). This, in turn, increases maintenance requirements, and, ultimately, if it is not properly addressed, it may impact equipment life cycles. The smart grid plays a key role in this regard with advanced monitoring, control and diagnostic capabilities. Energy storage and dynamic Volt/VAr control and compensation using smart technologies, such as inverters and flexible AC distribution systems (FACDS), allow for the mitigation of potential voltage and power flow impacts due to intermittent DG.

3.7.2 Electric Vehicles

3.7.2.1 Charging

PEVs (plug-in EVs—PHEV and BEV) have the potential to improve multiple facets of the transportation sector. However, for PEVs to have a significant positive impact on the transportation sector, a substantial fraction of the vehicle fleet must be converted to PEVs. Any significant conversion of this type will impose a large demand on the electric sector if not properly administered. Therefore, to realize transportation improvements on a grand scale without creating concurrent electrical problems, changes in the electric and transportation sectors must be collaborative and occur concurrently.

The charging of PEVs is the most important interaction between electrified transportation and the electric grid, and is the area in which smart grid technologies can provide tools to integrate the two sectors. Plug-in vehicle charging is divided into two main categories: “smart” charging, and unconstrained charging. Unconstrained charging is the simplest form of plug-in vehicle charging and allows the vehicle owner to plug in at any time of the day without any limitations [55]. Constrained charging is defined as any charging strategy in which the electricity provider and vehicle can coordinate charging strategies to maximize the economic efficiency of vehicle charging. PEVs currently charge without control or restriction from the utility. Due to the current low volume of vehicles, this has a low impact on the electric grid [30,56]. However, most research to date has shown that as PEVs penetrate the market, unconstrained charging will need to be replaced with some level of constrained or “smart” charging to reduce the possibility of exacerbating peak electric demands [55,57]. Studies have shown that “smart” charging can potentially permit replacement of at least 50% of the traditional vehicle fleet with PEVs without the need to increase generation or grid capacity. Larger penetrations also present opportunities for the electric sector to regulate the system more effectively, resulting in more uniform daily load profiles, better capital utilization, and reduced operational costs [55,57].

The most prevalent strategies currently being pursued to implement smart charging are as follows:

- *Financial (TOU pricing, critical peak pricing, real-time pricing)*—Charging different rates at different times of the day to incentivize users to change their behavior
- *Direct (delayed charging, demand response)*—Curtailment of charging activities, enabled by smart charging chips or charger-side intelligence in a demand-response type program
- *Information based (home area network, smart meters, and displays)*—Giving users information and signals to help them make informed decisions about the cost and impact of charging on the grid [55,56,58,59]

Due to the variation in the energy sources used throughout the electric sector, some charging strategies may prove more advantageous and effective than others. All the “smart” charging strategies require some level of communication between the PEV, vehicle owner, and the electricity provider or grid system operator. For direct and financial smart-charging strategies, the plug-in vehicle or owner must be able to receive and process pricing and/or power control signals sent by the electricity provider [57]. More advanced charging strategies, especially market-oriented or two-way power flow strategies, require reliable, two-way communication between the plug-in vehicle and the electricity provider or the grid system operator [23,57]. Two-way communication is required because the electricity provider or grid system operator needs to know the state of charge (SOC) of all the PEVs connected to forecast the charging load for the valley-filling algorithm and the availability of PEVs to provide V2G (vehicle-to-grid) frequency control. Research has shown that the communication task can be achieved by integrating broadband over PowerLine and HomePlug, Zigbee, or cellular communications technologies into a stationary charger or into the PEV’s power electronics [59].

Regardless of the type of smart-charging strategy utilized, the required charging infrastructure and strategies will impose constraints on the electric grid. The largest impact smart charging will have on the electric grid is associated with the communications requirements needed between PEVs and owners, and the electricity provider or grid system operator. The simplest method (in terms of communication) for the electric sector to control charging behavior is to implement TOU rates. TOU rates can be relayed to PEV owners through rate plans that only change based on time of day and year and require the installation of an electric meter capable of metering energy transfer in real time for billing purposes. However, it is yet to be determined if TOU rates are strong enough motivators to affect the charging habits of most plug-in vehicle owners. The next level of complexity available for the electric sector is the use of real-time data communication. Control could be based upon one-way communication: For example, vehicles could charge only when real-time rates drop below a set threshold. Several proposed control strategies (e.g., V2G) would also require two-way communication. However, for many PEVs, real-time data transfer is an overwhelming task [22].

The two most common automotive industry charging standards are the Society of Automotive Engineers (SAE) standard J1772 in the USA, and IEC 61851 in Europe and China. SAE J1772 defines three AC and DC charging levels (Table 3.7). Utility power is delivered as AC to the premise where the EVSE (Electric Vehicle Supply Equipment) is installed. The vehicle battery stores DC power, so the conversion from AC to DC is required to charge the battery. In AC charging, the AC to

TABLE 3.7
SAE PHEV and BEV AC and DC Charging Ratings

	Supply Voltage (V)	Maximum Charge Current (A)	Maximum Charge Power (kW)	Estimated Charge Time
AC Level 1	120, single-phase	12	1.4 (on-board charger)	• PHEV: 7 h (SOC[a]—0% to full) • BEV: 17 h (SOC—20% to full)
		16	1.9 (on-board charger)	
AC Level 2	240, single-phase	80	Up to 19.2 (on-board charger)	3.3 kW charger: • PHEV: 3 h (SOC[a]—0% to full) • BEV: 7 h (SOC—20% to full) 7 kW: • PHEV: 1.5 h (SOC[a]—0% to full) • BEV: 3.5 h (SOC—20% to full) 20 kW: • PHEV: 22 min (SOC[a]—0% to full) • BEV: 1.2 h (SOC—20% to full)
AC Level 3 (to be determined)	Single-phase or three-phase		>20	
DC Level 1	200–500	80 A	Up to 40 (off-board charger)	20 kW charger: • PHEV: 22 min (SOC[a]—0% to 80%) • BEV: 1.2 h (SOC—20% to 100%)
DC Level 2	200–500	200 A	Up to 100 (off-board charger)	45 kW charger: • PHEV: 10 min (SOC[a]—0% to 80%) • BEV: 20 min (SOC—20% to 80%)
DC Level 3 (to be determined)	May cover 200–600	Up to 400	Up to 240 (off-board charger)	45 kW charger: • BEV: <10 min (SOC—20% to 80%)

Notes: SAE International, "SAE Charging Configurations and Ratings Terminology," ver. 100312, 2012, http://www.sae.org/smartgrid/chargingspeeds.pdf; BEV (25 kWh usable pack size) charging always starts at 20% SOC, and stops at 80% SOC instead of 100%; ideal charge times assume 90% efficient chargers, 150 W to 12 V loads, and no balancing of traction battery pack.

[a] PHEV can start from 0% SOC since hybrid mode is available.

SOC, state of charge = % of charge in the battery (0%–100%); EVSE, electric vehicle supply equipment.

DC conversion for the DC battery occurs in the vehicles onboard charger. In DC charging, the AC to DC conversion occurs in the EVSE off-board the vehicle. Currently, the most common is AC charging. Level 1 AC is when the charger is simply plugged into a 120-V wall socket, and it requires that the charger electronics be built into the car. Level 2 AC charging also assumes the electronics are in the car, but the charging source is single-phase AC at a nominal 240 V, with a maximum current capability of 32 A. Level 3 AC charging is still to be determined, but assumes that the vehicle charging electronics can handle either single-phase or three-phase AC via the charging port. Although various power levels of charging have been proposed, Level 1 charging (110 V, 15 A) is currently the most common. Level 2 and Level 3 rapid chargers have increased power ratings, but the installation of Level 2 and Level 3 chargers can be a slow and costly process, especially for residential installations [60,61]. The IEC 61851 used in Europe and China was derived from J1772 and has similar requirements, adapted for the European and Asian AC line voltages. Most terminology differences are superficial. Where the SAE standard describes "methods" and "levels," the IEC standard talks about "modes," which are virtually the same. For example, IEC 61851 Mode 1 relates to household charging from single-phase 250 V (maximum) or three-phase 480-V power connections, with a maximum current of 16 A. There are further unique requirements for grounding. IEC 61851 Mode 2 uses the same voltages as Mode 1, but doubles the maximum allowable current to 32. Mode 2 also adds a requirement for a "control pilot function," and an integral ground-fault interrupter. IEC 61851 Mode 3 supports fast charging with currents up to 250A. Above that, as with J1772, it allows an external DC supply that may supply up to 400A.

Limitations on the size of household electrical services will impact the introduction of EVs—particularly, the selection of charging solutions. Many newer houses in the United States are equipped with 100A electrical services, while older homes may have smaller services, and larger homes may have 200A services or larger. Regardless of the absolute service size, in most cases, the installed service was properly sized for the anticipated loads in the household. Similarly, multiunit developments also size electrical services to meet electrical codes with limited spare capacity.

Although electrical codes remain relatively conservative, allowing for increased demand, introduction of a new, large electricity demand will likely violate those codes and possibly overload the electrical service. Furthermore, electrical codes do not generally allow the introduction of additional circuits based on the understanding that those circuits will not be utilized simultaneously with existing household loads. That is, although vehicle connections could be electronically limited to nighttime charging, when other household loads are low, there are currently few mechanisms in electrical codes to allow for such expansion.

The layout of household electrical services also presents issues. While newer homes frequently have the incoming electrical service in the garage area, in many older homes, the electrical service entrance is located far from the garage—a location that has traditionally experienced far lower loads than other parts of the house. The expense of modifying the incoming electrical panel and adding new circuits to the garage areas will likely slow the adoption of Level 2 and Level 3 charging. Vehicles charged at Level 1 will typically require continuous electrical connections all night to reach a full state-of-charge. Therefore, if only Level 1 charging is widely implemented, many of the most promising control mechanisms (controlled charging, V2G, etc.) offered by integrating EVs into the electrical grid will be inaccessible.

Clearly, some level of smart-charging infrastructure will be needed as PEVs begin to penetrate the transportation market. Smart grid technologies provide a variety of charging methods that can help ensure PEV customer satisfaction while maintaining a balance between plug-in vehicle charging demand and the electric grid's resources. However, "smart" charging of PEVs will require a large investment in electric grid and communications infrastructure and will significantly increase the workload of the electric sector. For PEVs to be capable of V2G energy exchange, either an inverter must be added to the vehicle's power electronics or equipment capable of utilizing the onboard charger as both an inverter and a rectifier would need to be used [58].

3.7.2.2 Voltage Regulation and Feeder Losses

The additional currents flowing through distribution transformers and lines due to moderate-to-high penetration scenarios of PEV may lead to an increase in voltage drop along distribution feeders that can cause low-voltage violations, particularly on areas located far from distribution substations. This issue can be addressed by installing additional line voltage regulators and switched capacitor banks, as well as by the coordinated dispatch and control of local DER, and the implementation of demand response and load control/management. PEV charging loads are expected to have a power factor close to unity; however, as the penetration level increases, higher charging loads imply higher currents and, therefore, increased distribution line and transformer losses. Therefore, PEV proliferation is expected to increase distribution system losses. Again, the combined implementation of conventional and smart grid solutions via the additional communications and control capabilities enabled by the smart grid is expected to be the more successful approach for ensuring adequate voltage regulation and minimizing the impact of PEVs on distribution losses. This also highlights the need for multiobjective optimization approaches for a coordinated utilization of all available resources.

3.7.2.3 Power Quality

As indicated in previous sections, increased harmonic distortion may be caused by large proliferation of inverter-based equipment, including PEV charging facilities; it is worth noting that despite the fact that individual inverters may comply with standard requirements pertaining to harmonic injection, it is the interaction and cumulative effect of harmonics produced by a large number of inverters (including PEV and electronically coupled DER inverters) that could have a negative effect on feeder harmonic levels. This is an area that requires attention and further research, since it is expected to become more important as the deployment of these technologies grows. As previously indicated, issues related to the increase of harmonics should be addressed in the planning stage of the smart grid, where maximum penetration levels and location of DERs and PEVs must be carefully evaluated.

3.7.2.4 Vehicle-to-Grid Energy Exchange

Almost since the first sales of hybrid vehicles, there has been considerable interest in using the vehicles as auxiliary power supplies—backup generators or supplemental power systems. In some geographical areas, there remains a substantial risk of power failure due to natural disasters, such as storms or floods. Owners of PEVs in these areas could tap into their vehicles' electrical systems for backup power in the event of power failure. Several informal projects have utilized electric vehicles for this purpose, connecting directly to the traction battery [62] or operating solely off the vehicle's 12-V convenience power [63].

These efforts have been hampered by the lack of support from vehicle manufacturers and the lack of suitable inverters capable of both connecting to the grid and supporting EV battery voltages. This application could rapidly become a de facto standard if many vehicles are equipped with inverters to support V2G operations, and if vehicle manufacturers see the backup power market as a potential added feature in their product offering. Serious safety issues must also be addressed, including electrical safety with both DC and AC circuits and the buildup of emissions if the vehicle is unintentionally operated in enclosed spaces.

It should be noted that vehicle manufacturers currently have little incentive to modify vehicles to support grid functions. Many proposed solutions, including V2G, controlled charging, and backup power applications, are likely to negatively impact battery life and/or decrease customer satisfaction—primary goals of the vehicle manufacturers. Ultimately, integration of PEVs into both the transportation and electricity sectors is a system problem, requiring system solutions. Viable solutions will need to balance competing goals of vehicle owners, grid operators, and vehicle manufacturers, as well as address issues as diverse as electrical code compliance and dispersed communication.

3.7.2.5 Equipment Loading, Maintenance, and Life Cycle

Arguably, the most significant impact of PEVs charging on the power grid is the increase in equipment loading, specifically on distribution transformers and lines. Here, it is worth noting that the severity of this impact is a function of the charging scenarios, charging strategy (uncontrolled or controlled charging), market penetration level, and distribution feeder characteristics (existing loading, voltage level, load profile, etc.). In order to determine the impact of PEV charging on the grid, it is necessary to conduct preliminary studies to determine (1) charging scenarios, like the one shown in Figure 3.22, which indicates the expected Level 1 and Level 2 charging profiles of PEVs (PHEVs and BEVs), that is, the time of day when charging is expected to occur and the likely charging demands in percentage of PEVs; and (2) market penetration levels, which indicate the amount of PEVs that are expected to be charged in a geographic area as a function of time. Studies and common sense indicate that residential PEV charging is expected to occur during the late afternoons and early evenings when commuters return home. Unfortunately, in many cases, this coincides with peak feeder loading conditions, which has a direct impact on increasing distribution transformer and line loadings.

The electric utility sector has expressed concern regarding expected increased loads on residential transformers and other electric grid components. Studies have shown that the growth of HEVs (such as the Toyota Prius) has typically occurred nonuniformly throughout geographic areas, with high concentrations in certain areas and little-to-no adoption in others. The adoption of PEVs is expected to follow a similar pattern [64].

Increased loading on residential transformers poses a problem for the electricity provider as most residential transformers are already approaching their load capacities. In addition, although "smart" charging of PEVs will help the electric sector reduce peak demands, "smart" charging may force transformers—especially residential transformers—to be fully utilized for the majority of the day. Increased use will reduce the amount of equipment rest and cooling time, which could shorten the operational life of the transformers and other electric grid equipment [65]. These studies agree, however, that these pressures will not result in significant decreases in reliability or functionality of distribution systems. They will merely require changes in distribution system maintenance schedules.

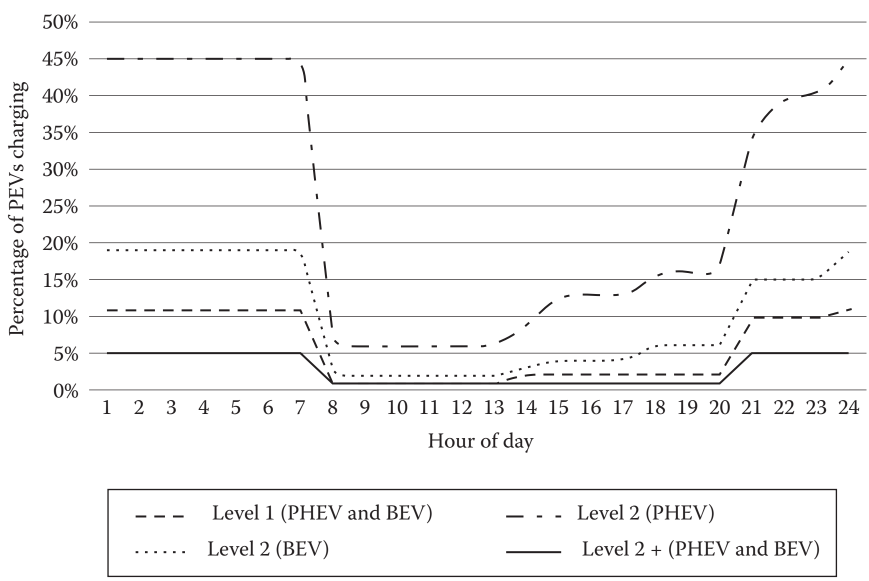

FIGURE 3.22 Example of an expected PEV charging scenario (projected 2020). (From Xu, L. et al., A framework for assessing the impact of plug-in electric vehicle to distribution systems, *2011 IEEE PSCE*, Phoenix, AZ, March 2011. With permission.)

Once charging and market penetration scenarios are determined, it is necessary to conduct power flow analyses under a series of varying loading conditions to determine equipment loading. These simulations consist of superimposing PEV loads on expected customer or distribution transformer loads and running power flow analyses to determine feeder electrical variables (voltages, currents, etc.). The complexity of these analyses will vary depending on the accuracy sought, and they may include conducting statistical analyses to model the uncertainty about charging and market penetration scenarios. These analyses must be conducted for uncontrolled charging scenarios to determine "worst case" impacts, and under controlled charging scenarios that are designed to mitigate expected impacts. Controlled scenarios aim at modifying PEV charging profiles by providing incentives or penalties via TOU rates or exerting charging load control or management to displace charging to off-peak hours.

The literature indicates that under uncontrolled charging scenarios, transformer overloads are expected to occur even at low penetration levels (Figure 3.23). Even though, at first sight, smart grid technologies, such as controlled charging, appear to be a mitigation measure for equipment loading impacts, it has the disadvantage of shifting charging to off-peak hours, for example, during early morning. This ultimately leads to (1) increasing load coincidence and creating new peaks that may also overload distribution transformers and lines, especially for large market penetration levels (Figure 3.24) and (2) "flattening" distribution transformer load profiles, that is, increasing their load factors. Obviously, the former is undesired, and even though the latter seems attractive, it may have a negative impact on equipment maintenance and life cycle, since off-peak loading conditions allow distribution transformers to cool down. Therefore, incentives and load control or management strategies must be carefully designed and applied to avoid creating further impacts. Other solutions to equipment overload are conventional approaches, such as capacity increase (transformer upgrade, line reconductoring, etc.). Furthermore, the coordinated control and dispatch of local DER and the implementation of demand response are promising alternatives for solving these issues (Figure 3.25). Finally, a combination of all the approaches (conventional and smart grid technologies) is recommended. As indicated previously, the smart grid will play a critical role in enabling these solutions.

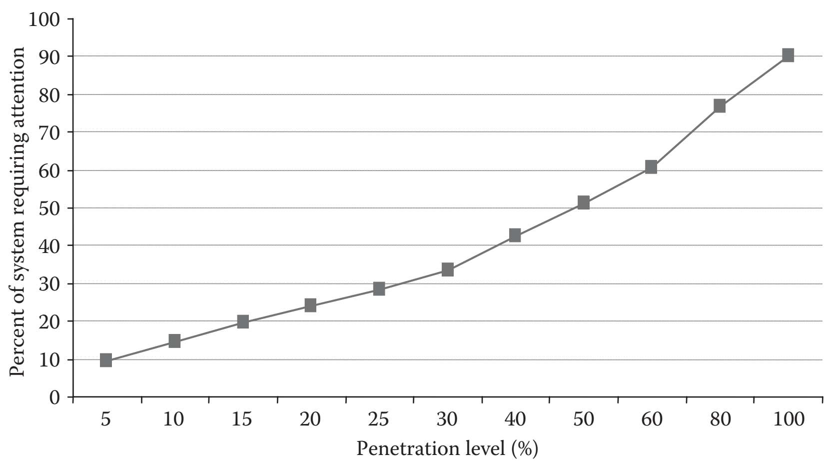

FIGURE 3.23 Example of percent of distribution system impacted versus PEV market penetration (uncontrolled charging). (From Dow, L. et al., A novel approach for evaluating the impact of electric vehicles on the power distribution system, *2010 IEEE PES General Meeting*, Minneapolis, MN, July 2010. With permission.)

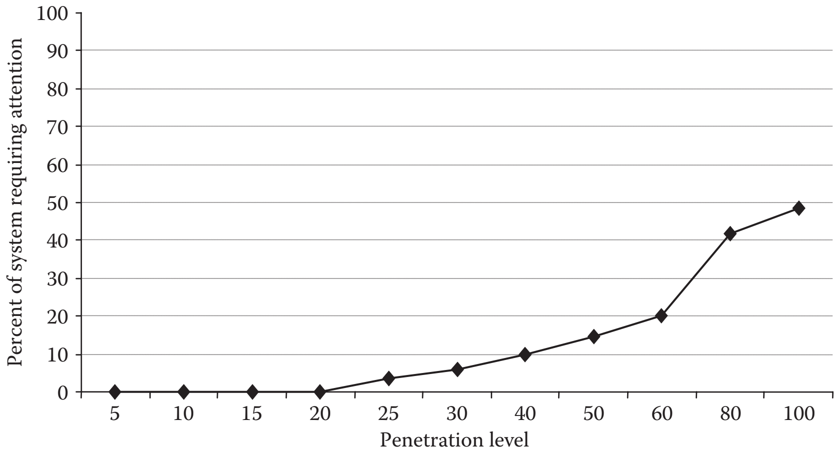

FIGURE 3.24 Example of percent of distribution system impacted versus PEV market penetration (controlled charging). (From Dow, L. et al., A novel approach for evaluating the impact of electric vehicles on the power distribution system, *2010 IEEE PES General Meeting*, Minneapolis, MN, July 2010. With permission.)

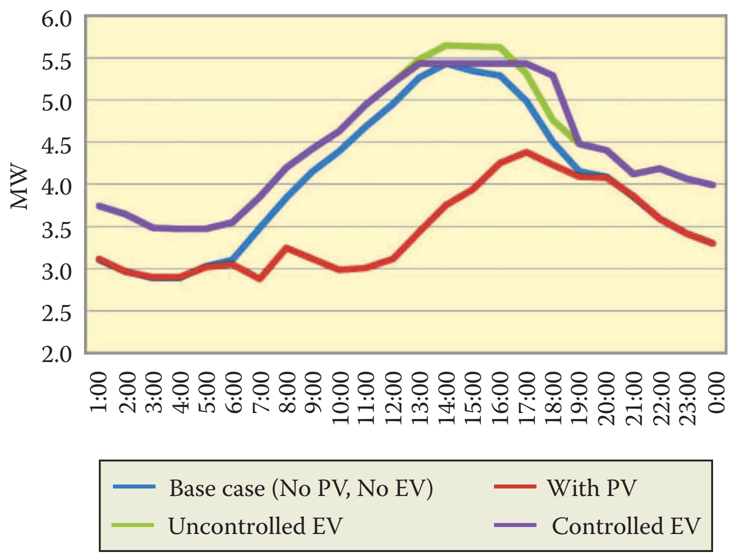

FIGURE 3.25 Example of feeder load under PV and EV penetration scenarios. (From Agüero, J.R., *IEEE Power and Energy Magazines*, 82–93, 2011. With permission.)

3.7.3 Consumer Demand

3.7.3.1 Changing Consumer Behavior

Different rates elicit different behaviors from consumers. Consumer behavior affects many aspects of utility's operations, sometimes in very complex ways. Specifically, utilities are often concerned with one or more business performance metrics, such as the rate of return on capital investments, exposure to short-term wholesale price fluctuations, minimizing operating costs, controlling net revenue, or maximizing earnings. Consequently, utilities are challenged to not only design the different rates that elicit needed behaviors from customers, but they must also determine what fraction

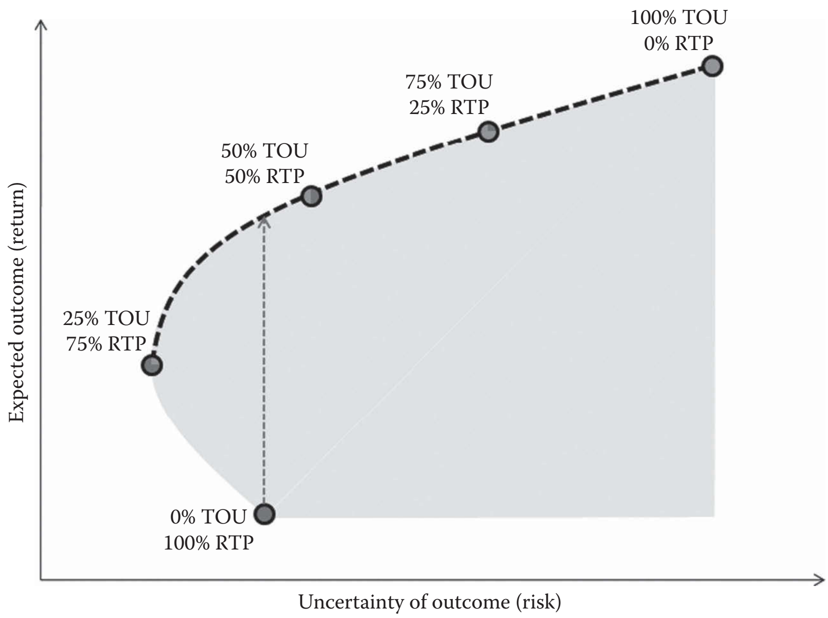

FIGURE 3.26 Portfolio theory applied to utility rate design. (© 2012 Pacific Northwest National Laboratory. All rights reserved. With permission.)

of their customers would ideally have to be on each rate to meet any of these business performance metrics.

One approach to this challenge lies with a method developed as part of the capital asset pricing model used in modern portfolio theory. The concept of an efficient frontier (dotted line) is illustrated in Figure 3.26, where the expectation of an outcome for a mixture of two rates is plotted against the uncertainty of that outcome [69].

The concept of the efficient frontier applies in this situation because a utility would try not to choose a mixture of rates that does not lie on the dotted line shown in Figure 3.26. Suppose a utility proposed to place all its customers on the RTP rate and none on the TOU rate. The expected earnings would be low, but the uncertainty would also be quite low. However, for the same uncertainty, the utility could realize significantly higher expected earnings by choosing a more balanced mixture of customers on each rate. Thus, for any outcome the utility wishes to maximize, only the mixtures of rates that lie on the top of the curve would be efficient, and all other mixtures would be suboptimal. Similarly, for any outcome the utility wishes to minimize, only mixtures that lie on the bottom of the curve would be efficient, and all other mixtures would be suboptimal. Typically, utilities have more than two rates that are being mixed, so the mixing regions between each of the rates may overlap as all combinations of mixtures are examined. However, the frontiers remain either the upper or lower boundaries of these regions.

In practice, utilities must collect data on consumer behavior in response to the rates. These data can be used to establish both outcomes for each business performance metric under each rate as well as the uncertainty of those outcomes in the face of uncertainty about costs and operating conditions. Therefore, utilities may wish to continuously update the analysis at least annually, perhaps more frequently, to determine the objective rate mixtures that the utility's DR programs seek to achieve. The rate mixture objectives evolve over time in response to changing demographic conditions, the seasons, and perhaps even wholesale market conditions. The portfolio analysis method can be thought of as a long-term closed-loop control process that the utility uses to continuously optimize the performance of its DR systems.

A demand management event issued by the utility is successful if it can attract sufficient participation by end-use consumers resulting in the amount of demand reduction desired by the utility. Clearly, this creates a dynamic environment where the consumers and the utility interact through a system of incentives and agreements to achieve the target demand reduction. Large numbers of consumers, with their stochastic nature of energy consumption patterns, make it difficult to model the problem in a deterministic way. The behavior of consumers is affected by various market-driven factors, such as energy prices as well as personal habits and consumption patterns that vary from one individual to another.

When a store runs a sale advertisement, they learn over time their expected response rate from direct mail or other media. Customers do not tell them, "If you put this item on sale, I will come into your store and make a purchase." However, the response rate from the sale ad is learned over time and can become very predictable. This ability to learn the response reliability over time based on data management experience is referred to as statistical reliability. Certain customer responses to smart grid stimuli will fall under this category of statistical reliability. Over time, the grid and utility operations will learn that when a specific signal is sent out, the response will be a predictable amount based on their historical learning. Statistical reliability is already applied in grid operations, utilizing inputs such as experience with the load curves, weather predictions, and utility experience to predict peak days and peak energy consumption. Learning to apply this concept to predict the response to demand management will save a considerable amount of cost and will enable inclusion of additional consumers and devices. This way, responses that cannot be measured via electronic means, or where the customer or device manufacturer does not support communications to the devices, can be included under this category of DR.

Throughout the years, most demand management applications have adopted solutions based on control and response models of aggregating individual consumers into groups of end users connected to a specific substation, feeder, or service transformer. This way, the volatility of the individual consumer behavior is reduced, and the problem can move further toward a probabilistic problem where the uncertainties can be treated as random variables. However, DR necessitates the introduction of a higher level of granularity where the stochastic models of individual customers are accounted for. On the one hand, these models should consider the behavioral and financial aspects of individual customers; on the other hand, they must incorporate the impact of the terms and conditions of the demand management programs into the decision-making by the consumers. Therefore, grid entities prefer an accurate indication of the current availability of the dynamically changing components of the demand management environment.

Identifying the behavioral patterns of consumers when it comes to electricity consumption is essential for ensuring sufficient participation following issuance of a demand management event. On the one hand, the event must be issued at times and locations when there is enough electricity consumption available; on the other hand, it must not contradict with individual consumer lifestyles, or at least need to be considered as acceptable (by consumers). In other words, there is a clear trade-off between achieving demand reduction and consumer inconvenience. From the utility perspective, an accurate model/prediction of consumer behavior and consumption patterns is critical to a successful demand management program. From the consumer perspective, there must be the ability to opt out of any program or specific instance that conflicts with a consumer lifestyle or specific schedule. Consumer device manufacturers, concerned about the satisfaction of their customers, require the opt-out feature before allowing their products to participate in demand management automation. This will tend to induce an element of variability into consumer demand management programs. In a general sense, the demand pattern of consumers can be analyzed and estimated from two aspects.

Consumption habits: This is related, in part, to the individual habits of using various household electric appliances, for instance, washer/dryer, dishwasher, etc. The number of times a week/day that each appliance is used and the duration of each usage are likely to reflect a specific pattern for each consumer. This portion of demand reduction is what qualifies for demand dispatch, where the utility tries to shift the consumption from peak-load to off-peak hours. This can be done either manually by proposing time frames for usage of the various appliances or automatically by remote activation/deactivation of appliances according to utility needs and customer acceptance parameters. A currently less common source of demand reduction, which is likely to grow, is associated with charging electric vehicles. This is perhaps one example where most consumers are very flexible as to what time of the day the charging phase should take place (as long as it is done automatically). Another major portion of demand reduction is related to the temperature settings of heating and air conditioner units in winter and summer seasons, where consumers show different levels of sensitivity to heat/cold and show various degrees of flexibility to deviations from their habitual comfort zone because of demand management. This flexibility is complex since the settings may lead to different comfort perceptions according to the specific environment on each day, such as the difference between the outside and inside temperatures, as well as cumulative effects (e.g., how many consecutive days of hot weather).

Elasticity to electricity prices: A rather crucial assumption behind DR assumes that consumers are willing to temporarily forgo their convenience to avoid higher electricity prices or to capture incentives. While this is perhaps true for a sizeable portion of the consumers, the degree to which they are willing to give up their comfort level (and what the perception of comfort really entails) varies from one individual to another and may be impacted by the financial incentives offered. The consumer sensitivity to the electricity prices is utilized by the utility by introducing real-time pricing tailored toward peak-hour needs.

Incentives offered to consumers to encourage them to participate in a demand management event play an important role in its success. For demand dispatch applications at the residential level, to shift certain loads from peak to off-peak hours, the value of the incentives is not extremely critical, especially if the shifting is done automatically and may not even be detected by the consumer. Examples of this are electric vehicle charging and water heating. However, for other residential applications, for instance, air conditioning usage, where the comfort level of the consumers is affected most immediately, the role of the incentive payments is higher. For commercial buildings, air conditioning usage can be shifted—rather than curtailed—by preheating/ precooling the building during off-peak hours, for example, early in the morning before arrival of the occupants, and turning off the air conditioning unit during peak-load hours. Such practice becomes more difficult in the residential market where consumer lifestyles and schedules are more dynamic in nature. The financial incentives a utility can offer have limitations dictated by the financial calculations by the utility relative to their cost structure and level of vertical integration.

3.7.3.2 Delivery of Real-Time Information

To look at an electric load as a resource, there must be an architecture-enabling management of the load. As the wholesale price of electricity fluctuates, there is a desire to be able to reflect this fluctuation in the retail electric rates. Most people have become accustomed to watching the cost of fuel for their car. Their buying decision may be accelerated or delayed in accordance with the price. In a similar way, the price of electricity can impact consumer purchases of the electricity product. In the past, there was no mechanism to inform the consumer of the current price of the electricity product. But when the price of these products starts to change rapidly, the price became a key piece of information the consumer needs to know prior to the purchase, or in the case of electricity, consumption of the product.

With the trend toward a variety of time-based pricing rates, electric customers need access to the price information they have not had to deal with before. Compared with auto fuel, the consumption of electric power has additional layers of complexity. One could easily determine the miles-per-gallon (MPG) in a vehicle. But in my home, it is like having multiple vehicles with a very wide range of MPG ratings. Furthermore, these “vehicles” may operate concurrently or in any combination. Some of them operate without our knowledge and without a reasonable method to control their utilization. For example, consumers do not know exactly when their refrigerator will operate. Other than unplugging it completely, there is little control over its operation. To motivate a change in electricity use, customers will need more information prior to purchase.

Unlike other commodities purchased as consumers, the electric information has several caveats to address. Getting the information to the customer via an adequate mechanism may also have a dependency on how often they need to have the information updated. Can the price change every month, week, day, and hour or even in a shorter block of time? How much notice of the price is needed? As noted in the MPG discussion, price is not enough information for a consumer to manage consumption in an environment where usage is not known. The customer needs to know the quantity they expect to consume.

This leads to the two core requirements for smart display of information: price and consumption. Consumers can also benefit from additional information, such as when the price will change again and whether it will be expensive in the future. Knowing how much electricity will need to be purchased must also be known to make good financial decisions.

It is also necessary to communicate information customers have not previously had to understand. A kilowatt-hour is not a term in the average daily vocabulary nor is its meaning. Some manipulation of the data is required before it is presented to the customer. Several types of display devices have been designed to do this. The first devices for demand management applications were mostly independent In-Home Displays (IHDs) that, using their own sensors or meter access methods, could be located or mounted according to consumer preferences. The IHDs generally displayed the key pieces of information to answer the questions: How much has my electricity cost me this month (or during some selectable period)? At what rate am I purchasing electricity now? An IHD may indicate the current electricity price, the rate at which it is being used, and the cost per hour. For example, the display may indicate that at the current rate of energy consumption, the cost is $0.37 per hour. The display could show additional computations for the consumer. These could include the projected cost of the current month at the current rate of energy consumption, a comparison with last month, a graph of usage by day or month, or any of several other potential calculations depending on the amount of energy usage history the device is able to store.

In the 2009–2010 time frame, NIST (National Institute of Standards and Technology) in the United States was approaching a task handed to them via legislation. Recognizing the need to make this type of information available, a priority action plan was initiated to help create a standard method to communicate electric consumption and usage information in a standard format. With the introduction of these standards, a variety of methods of reporting this information to the consumer was enabled, and the open market could look at the best way to relay the information to the consumer. The standards also led to the introduction of the "Green Button," which utilizes this usage[12] information to display energy consumption to consumers in new creative ways via a variety of personal devices that include dedicated devices in the home, the Internet, and personal smartphones.

The smart meter is one device that can be enabled with communications technology to provide consumption information to the consumer. The newer communicating electric meters, often referred to as the "smart meter," are designed to calculate consumption at programmed intervals. To provide this information to the customer, several methods are available. One is to design communication electronics in the meter that will transmit this information into the home/premise. Another method is where the utility uses the Internet to forward real-time data back to the home/premise.

An advantage of routing the real-time consumption through the Internet is that it would enable a third-party firm to contractually agree with the utility and consumer to have access to the data. This third party could provide the service of displaying the data in a very advanced graphical format that is accessible via a number of devices including the computer, Internet, PDA, phone, TV, text message, and any other available means. These third-party service providers could also provide

[12] Based on UCAIug OpenADE and NAESB PAP10 standards ratified in October 2011.

technology to assist the consumer in managing the energy inside the premise. A disadvantage is the dependency on other nonutility and nonconsumer-owned systems and devices that may exist in the communication and control path. There may also be more concerns with data security and privacy when the data pass through more systems.

One advantage of having a smart meter capable of transmitting the data directly to devices inside a premise is that the route is more direct. The information may be available sooner and more reliably due to fewer points in the pathway. Privacy concerns are easier to manage since the data do not pass through third-party systems.

3.7.3.3 Delivery of Advanced Information

In cases like the use of behavioral demand response in incentive programs, where the customer is compensated for the curtailment they can achieve, results can be achieved by informing customers before the upcoming event, giving them advice on how they can maximize their energy reductions, perhaps also include information on incentives, and performance from previous events. Customers will then act without the need for any real-time information or technology interfacing to their loads or any other energy device in the home.

3.7.3.4 Smart Loads and Appliances

Past approaches to controlling large residential loads have included ways to limit electric use in water heating, pool pumps, and air conditioners. The basic approach is to control a switch to turn on or off the load remotely. For certain loads, such as the water heater or pool pump, this can be done typically without consumer objection or knowledge of when activation has occurred. The cost of adding this type of switch required on-site installation at a total cost nearing the cost of the device being controlled. Manufacturers are starting to include this switching ability in core product lines that makes the addition of this type of control possible at a small fraction of the cost of after-market methods. These advances will likely pave the way to a simple consumer installable add-on that is also utility trackable and verifiable. For control of air conditioning, several approaches have been tested. These have included control of the compressor itself in some pilots. Another approach is to wire the control between the thermostat and the AC unit to effectively mimic the thermostat control without having to enter the premise for installation. Other more sophisticated approaches involve smart thermostats able to receive demand management messages that provide both control and the interface to the consumer. The thermostat messages from the smart grid could include messages used for other methods of impacting consumption.

In addition to the energy display mechanisms, the same data can be utilized anywhere the capability exists to receive the information and relay it to a customer. As other in-premise devices advance, they continue to have better hardware to communicate with the consumer, and additional places become available for the display of energy information. One distinct advantage of this display advancement is that the consumer could use the display to decide when to operate an appliance, such as an oven, dishwasher, or washing machine. This provides an opportunity to impact the use at the decision-making time for these process-oriented devices (e.g., cooking and cleaning) that interact directly with the consumer. In addition to optionally displaying energy information, a device can respond by changing or limiting energy consumption in an automated manner with full knowledge of the best way to limit, delay, or optimize performance over a specified period. In considering this capability, information can be transmitted into a home or premise for impacting energy consumption in parallel with an informational display and ability to manage consumer preferences.

Devices that can receive communicated energy information and respond by altering energy consumption are often referred to as "smart devices" or "smart appliances." For example, a drying appliance could reduce the amount of heat applied and lengthen the drying cycle. A product utilizing refrigeration may have a variable-speed component able to scale back the use of electricity in an acceptable way over a temporary period without turning off the device. The microprocessor controlling the device, based on detailed internal knowledge, can determine what it can do and for how long while maintaining safety and success of the process being controlled.

By automating the process of demand reduction/curtailment, smart appliances can help smooth the execution of DR events with minimum effort from the consumer. The key to designing smart appliances is to reduce the amount of consumer interaction needed in decision-making by putting energy management and interface logic into the device controls. The appliance can perform necessary actions to both meet the utility needs as well as accommodate the customer's preferences. These preset rules and conditions, updated by the consumer according to individual needs and preferences, remove the burden of decision-making from consumers. A demand management event issued by the utility is followed to the variable extent that matches requirements and options set forth by the consumer. The actions taken afterward, turning off a device, reducing the load, shifting the load to a different time, or ignoring the request, can then be implemented automatically. The smart appliances already have an interface with the consumer and are well qualified to present the energy configuration options to the consumer for their selection. For simple devices, such as water heaters, thermostats, or even remote switches, the device may be turned on/off entirely. In more complicated designs or appliances that have specific modes of operation, there can be intelligent controls or responses to intelligent controllers that react in accordance with the price of energy or demand management events issued, and considering the preferences of the local consumer, while complying with optimal operation as defined by the manufacturer.

3.7.3.5 Consumer Energy Management

As smarter load controls evolve with communications technology, it is possible to integrate and manage the control of loads to more effectively respond to DR signals. The smart loads exchange data over a local communications network (wired or wireless) in the home or consumer premise, commonly known as a HAN.

Such devices that integrate and manage the control of consumer loads are commonly referred to as HEMs. A HEM can determine the operating status of all loads and optimize the control and scheduling of loads based on consumer preferences along with demand and price signals from the utility or grid. More advanced HEMs will include the capability to manage consumer renewable generation and even electric vehicles to provide estimation and historical data to help consumers make more informed decisions about managing their energy usage. These HEM functionalities are also provided by apps that are usable on smartphones, making consumer accessibility to these permanent and providing remote control of the connected appliances.

3.7.3.6 Consumer Education and Participation

Successful smart grid implementation requires educating consumers on the benefits of the technologies and enlightening them on the easiest ways to enjoy the benefits without having to change their lifestyle, thereby ensuring consumers are voluntarily engaging in the programs offered by their respective utility. For a demand management program to be effective, the consumer benefits must be clearly understood and sought by the consumer. The value of the smart grid investment increases significantly as consumer participation increases, and in the long run, increased participation could drive down the cost of electricity for everybody.

It will be important for customers to understand how the cost of the DRM program will be recovered, especially if it is tied to a smart meter deployment, and ensure that customers do not associate implementation of smart meters and smart grid with increased personal energy costs. Additionally, through effective education, consumers will "opt-in" to utility programs and continue to be engaged about how much they are saving—both themselves and the environment.

Customer education is key to the success of DR. Without proper information, consumers might consider DR as an action that leads to inconvenience and a disruption of their lifestyle. This means the utility will have to be close to the customer and adapt to customer-changing preferences and provide innovative products that keep the customer positively engaged. Customers also need help to determine their most effective course of action in impacting their energy consumption and cost [70]. The incentive payments for subscribing to DR—specifically for the residential customers—might not be high enough to provide financial justification by itself. Clearly, DR can lead to beneficial short-term impacts on the electricity market that increase as the number of customers participating in the demand management program increases. However, more efficient results could be achieved by focusing on the benefits to individual customers. These include

- Individual financial savings: In addition to receiving incentive payments and discounted rates, a customer participating in a demand management event, for example, by shifting the noncritical portion of demand from peak-load hours to off-peak hours, could also benefit from savings in monthly electricity bills.
- Besides personal costs savings, consumers have a growing concern about the environment [70]. Consumer engagement may be increased by making sure they understand the environmental benefits of their proposed response to grid conditions.
- Avoiding uncontrolled loss of service: By participating in a demand management event, for instance, through direct load control program for air conditioning units, a customer can help the utility achieve a controlled load reduction where power will be restored after the preset duration of the event is passed. Lack of sufficient participation, in the long run, could lead to weakening of the distribution network during peak-load hours, which, in turn, could lead to an uncontrolled loss of supply.

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4 Communications Systems

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CONTENTS

The great majority of the applications and concepts described in this book rely upon the capability to exchange information, within the utility for operations and business processes, and to external interfaces and users. Communications and information connectivity is the underlying foundation of the smart grid. Extensive volumes of information must be transported to 'the right user, at the right time, in the right format', with a time latency appropriate for envisaged use, and with an adequate level of reliability and security to ensure data integrity and confidentiality—electronic monitoring and control devices, energy management platforms, customer metering, and consumption control devices, as well as field worker mobile data systems, must continuously be capable of interacting across the system.

Bulk generators, high-voltage grid substations, and system operation control centers have been the focus of communications systems in the past, but the communications systems were not designed for the capacity to accommodate emerging applications. At present, the need to communicate with more devices further out on the grid, such as distribution substations, dispersed renewable energy generation and storage plants, and consumer sites, represents far larger numbers and additional communication challenges. Moreover, if in the high-voltage portion of the grid, the communication vector remains the power transmission line and its corridors allowing optical fiber cable and microwave radio deployment, the distribution system and its constituents present a high diversity of situations and requirements: Sites may be in a dense residential or commercial urban area, a suburban or industrial area, in a sparse rural area, in underground locations, or integrated into customer premises. Moreover, new mobile connectivity requirements are arising from customer and field worker data access expectations.

Assuring economically viable communications across the power system with an appropriate level of coverage, capacity and performance are therefore prerequisites for grid modernization and smart grid applications. This network connectivity often necessitates the deployment of a mix of different communication technologies and architectures to fulfill a range of requirements and ensure communication coverage in different environments.

Communications may be assured through procurement of services from a telecom or other third-party service provider, through the usage of "mobile internet," or through the deployment of dedicated infrastructures owned by the utilities. Capital expenditure can be reduced to a minimum in the former cases at the expense of yearly operation costs, uncontrolled availability, security risks, quality issues, and uncontrolled changes of service. The severe constraints and imperatives of availability and service continuity for grid automation applications may not be met by a service provider's contractual engagement reflected in a Service Level Agreement (SLA). Deploying dedicated communication infrastructures to reach hundreds of thousands of end points in the distribution and consumer segment may represent substantial investments, and an implementation time incompatible with the planned deployment of smart grid applications.

As more devices, systems, and applications are connecting in a smart grid, the concerns on information security are escalating and regulatory authorities in many countries across the world show great concern on the security of the bulk electric power system as a national critical infrastructure. The North American Reliability Corporation (NERC) Critical Infrastructure Protection (CIP) standards for critical assets on the Bulk Power System, further described in another section of this book, requires comprehensive cybersecurity solutions, including the segmentation of the communication network, authentication and authorization, monitoring and logging, as well as physical security with access control and video surveillance. These security requirements not only impact the communication architecture but also generate further secure communication requirements across the system to assure required interactions between the concerned security devices and platform.

To conclude, communications is an essential component for the proper operation of the power system and its related information infrastructure. The consequences of its nonoperation render its reliability and security a highly critical component of the rules and regulations in the modern power utility.

This chapter aims to provide an overview of communication requirements, architectures, technologies, and solutions covering the different segments of the smart grid from power generation to power delivery at the consumption point.

4.1 BUILDING A COMMUNICATION MODEL

The most basic information exchange model for the Smart Grid was given by the US National Institute of Standards and Technology (NIST) in its Smart Grid Framework [1] presented in Figure 4.1. Here, the electric power is shown as flowing from bulk generation (power plants and energy farms), across the transmission and distribution grids to end up at the customer. Information exchange associated with this power flow is shown to be, not only inside and between the grid nodes constituting this power flow, but also between each of the grid nodes and the Power System Operations (Control Centers) and Market (or Power Exchange) actors. A further actor, the retail power Service Provider, interacting with the final customer, completes this basic model and allows to reflect the technical and commercial information exchange across the power system.

The European Committee for Electrotechnical Standards (CENELEC) and the European Telecom Standards Institute (ETSI) brought some complementary precisions to the NIST model by the addition of the Smart Grid Architecture Model (SGAM) framework [2] with Distributed Energy Resources (DER) as a new grid node. The European Smart Grid Architecture Model (SGAM) framework (Figure 4.2) also introduced a more structured concept based on five different interoperability layers: component, communication, information, function, and business, reflecting different physical and logical interconnection views across the power system.

Associated with each interoperability layer, the SGAM model presents an interconnection view across five domains (Generation, Transmission, Distribution, DER, and Customer Premises) and over six zones (Process, Field, Station, Operation, Enterprise, and Market). Figure 4.3 presents one such interoperability view showing power system equipment and energy conversion system (all in the power process zone).

An immediate benefit of these modeling initiatives, which go far into the actual definition of interconnections and interactions, resides in the distinction between information exchange, logical communication, and physical interconnection. In other words, interacting entities need not be on the same communication network to exchange information. In practice, most power systems collect raw the data across a network, transform it into meaningful information at some nodes, and then communicate the information across several distinct communication networks, each of them often composed of multiple physical communication technologies according to site coverage and cost imperatives.

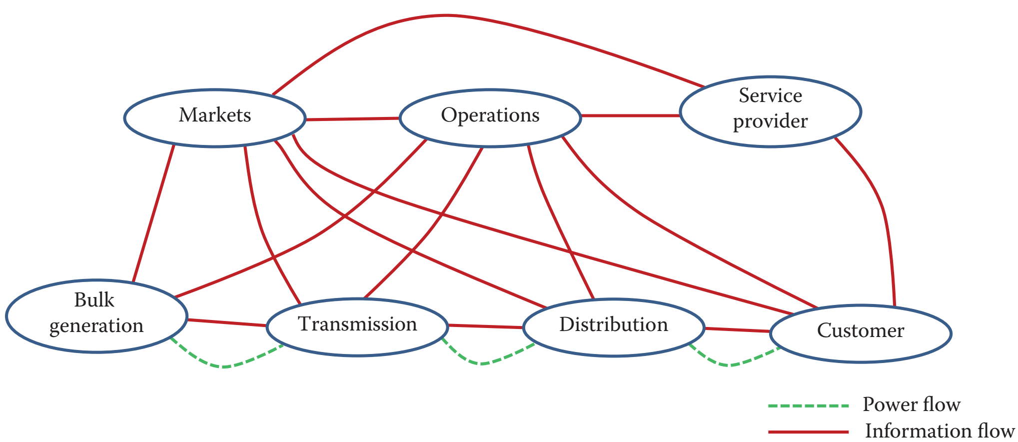

FIGURE 4.1 NIST smart grid interconnection model. (© NIST.)

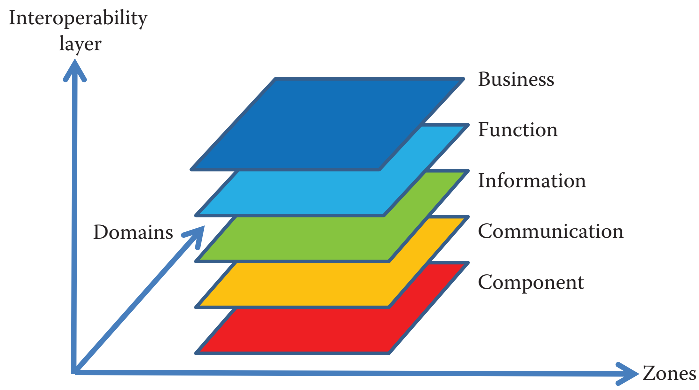

FIGURE 4.2 CEN-CENELEC-ETSI 3-dimensional smart grid architecture model (SGAM). (© CEN-CENELEC-ETSI.)

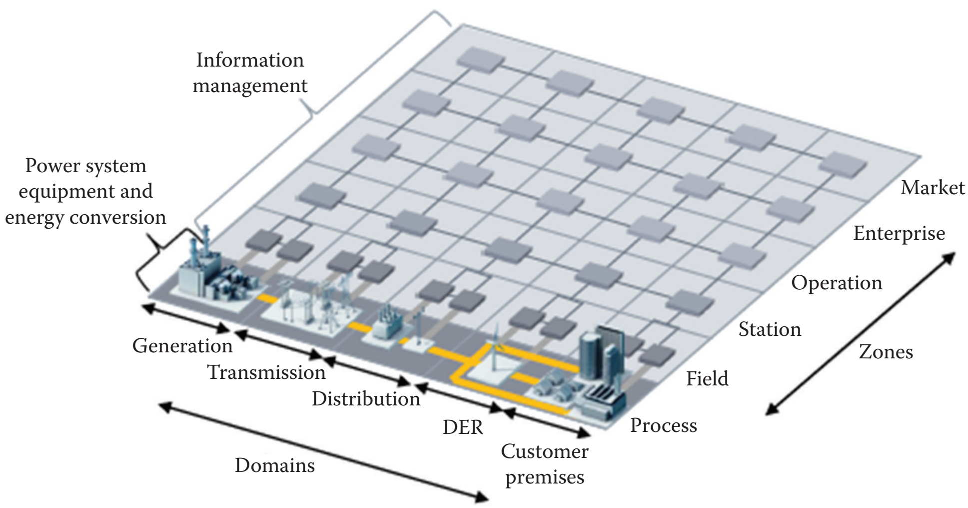

FIGURE 4.3 CEN-CENELEC- ETSI SGAM model across one interoperability layer. (© CEN-CENELEC-ETSI.)

A simplified model for smart grid information exchange used in this section is provided in Figure 4.4. The model uses similar building blocks to the SGAM, each of which is composed of multiple nodes dispersed across an extended area.

Transmission and distribution substations exchange protection and control information. Bulk generation plants and large renewable energy farms are represented together, exchanging generation metering and scheduling information with the power exchange, and control information with the power operations. Power exchange and markets, composed of all actors involved in energy transaction balancing and settlement activities, are connected to all retail energy service providers, energy producers, and operational control centers. The operation centers exchange status, measurement, and control information with transmission and distribution substations and dispersed renewable energy sources. The operations centers also exchange higher level load/resource information with power exchange, and exchange demand-side management and outage information with energy consumers. Finally, the retail energy service provider exchanges information with the energy consumer for smart metering and for customer relationship management.

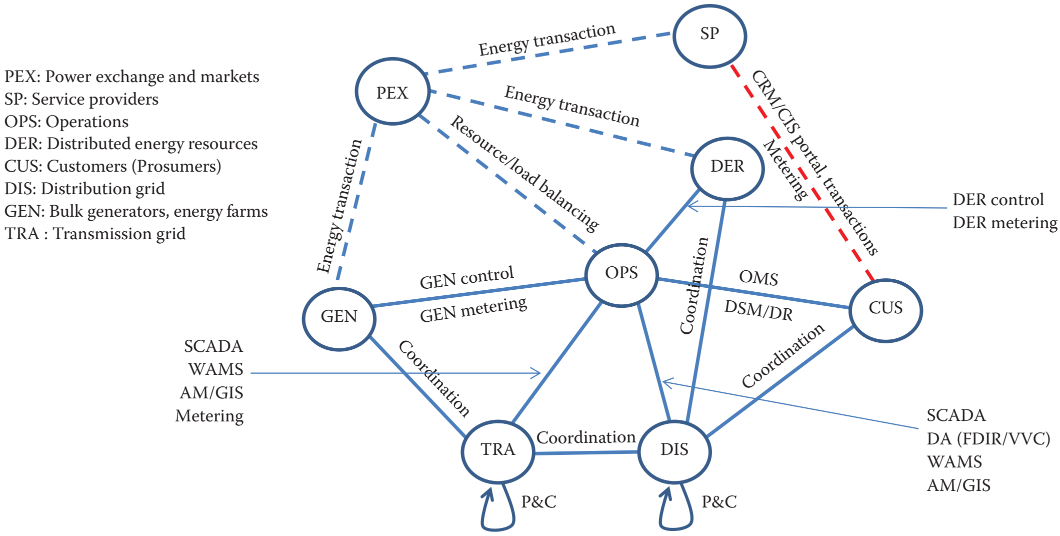

FIGURE 4.4 Simplified information flow in the power system. (© 2016 GE grid solutions. All rights reserved. With permission.)

As previously presented in the SGAM model, information exchange does not necessarily signify direct communications. Information may be relayed directly, transferred from one network to another through a gateway, or synthesized in an intermediate function before being networked to its destination. Moreover, each node in the model may represent multiple sites dispersed across the footprint of the power system, with multiple communicating devices at each site.

From a communication point of view, we can distinguish many different communications segments, each representing a local or a wide area network, as shown in Figure 4.5:

- *Home Area Network*—This network covers the different intelligent devices inside a customer's premises, such as a metering device, Home Energy Management System (HEMS), heating, ventilation and air conditioning (HVAC) controller, and intelligent appliances.
- *AMI and Customer Premise Access Network*—This network allows the utility or another service provider to exchange information with the customer premise gateway device. This network corresponds to the Advanced Metering Infrastructure (AMI), exchange of consumer demand management data (such as demand response, etc.), and access to the customer HAN. The term Neighborhood Area Network (NAN) is sometimes employed, although this terminology is somehow less precise in its functional and geographical significance. In practice, the same network may be used to transport customer metering and some grid device control communications, although many AMI networks today lack sufficient bandwidth and quality (and sometimes common ownership!) to also handle field control information flows. We have, therefore, opted to describe separate functional segments, which may in certain cases be aggregated together (as with many other segments in our terminology).
- *Customer Portal Access Network*—This network allows customer relationship management (e.g., smartphone or other Internet access). This network may, or may not be, aggregated with the customer premises access network.
- *Grid Operations Communications Networks*—These networks interconnect electrical grid substations and field devices with control platforms to assure grid-level protection and control, as well as centralized monitoring and control of the power system, grid assets, and site surveillance. The term FAN (Field Area Network) is sometimes used to designate electrical grid field device connectivity. This level of communications is commonly referred

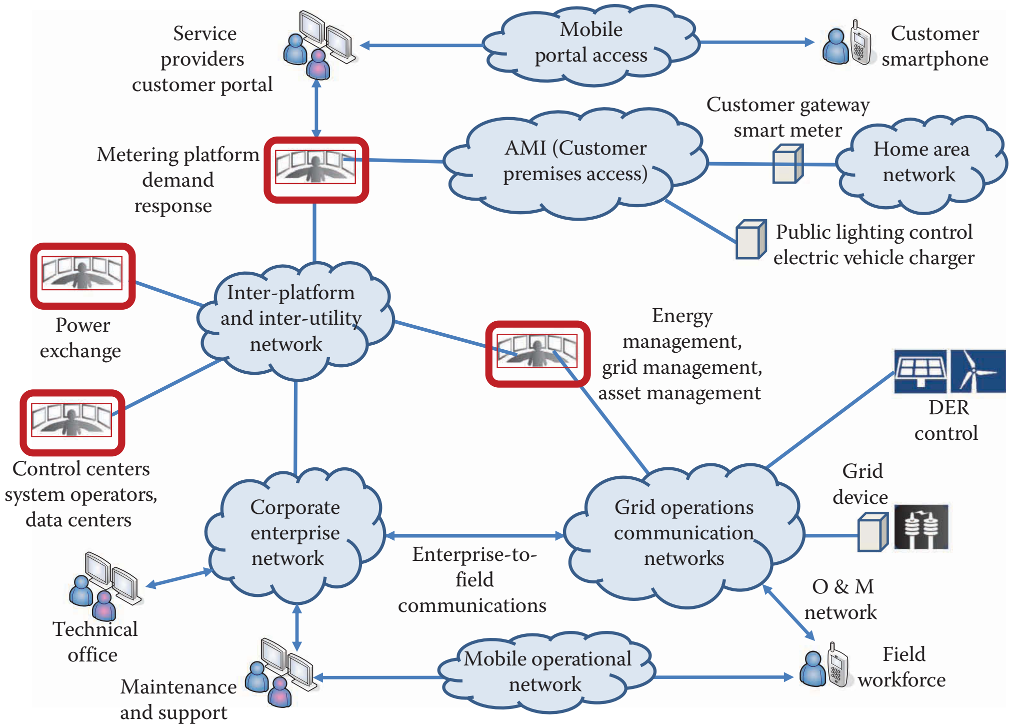

FIGURE 4.5 Example of communication segments for utility information flows. (© 2016 GE grid solutions. All rights reserved. With permission.)

to as "real-time" for the exchange of "operational data." The communication networks are often based on a dedicated infrastructure, or less frequently use procured communication services. A new standard has emerged, as described in the Smart Grid Standardization Work chapter of this book called OpenFMB. This standard aims to drive communication between end devices (such as smart meters) and grid operation devices without having to backhaul data through the communication cloud and up to the enterprise.

- *Inter-platform and Inter-utility Communications Network*—Interconnection of energy dispatch and control centers, system operation platforms, power exchanges, and energy metering/billing centers constitute a specific communication segment in which the data exchange peers are often beyond the perimeter of a single company, and where the information flow is more sporadic and less time sensitive.
- *Enterprise-to-Field Communications Network*—Many new applications in the smart power system require the access of utility office-based staff and platforms to field-collected data. Substation asset monitoring and remote engineering and maintenance are such applications. This level of communications is commonly referred to as "non-real-time or near-real-time" for the exchange of "nonoperational data." These cross-domain IT/OT office-to-field applications constitute a specific communication segment.
- *Mobile Workforce Communications Network*—Field workers increasingly need expert support, connection to asset management centers, and access to central information platforms located at remote utility offices.
- *Utility Corporate Enterprise Network*—This is the administrative communication network covering the office environment of the utility and its IT enterprise applications.
- *Backhaul and Core Communications Network*—A common network can be used to forward information collected at an access point or to aggregate multiple networks.

4.2 COMMUNICATION REQUIREMENTS AND NETWORKING SOLUTIONS

4.2.1 Home Area Network

Applications—Home area networks (HANs) are local networks in residential consumers' house environments allowing remote connection to smart appliances, Heating, Ventilation and Air Conditioning (HVAC) controllers and programmable communicating thermostats, in-home displays, and residential electric vehicle chargers. Energy efficiency opportunities are, indeed, not limited to the systems owned and controlled by the electric utility. Home Energy Management Systems (HEMS) can monitor and control a broad variety of "intelligent" energy consuming devices, and locally optimize power consumption through consumer preferences and the knowledge of the consumed energy marginal costs. HANs' applications also include local or remote control of smart appliances for potential time of use setting, variable rate billing, demand response, consumer efficiency, and use reports. Future applications will require access to new data from the electric supplier (marginal price, current consumption, load curtailment signals) as well interactive capabilities, and action notices to the homeowner (e.g., to permit override of planned/automated actions). More informed and efficient consumption decisions on the part of the consumer will require gathering and storing of information that has the potential for misuse. Privacy and security of data, therefore, become a major issue for all participants of the sector, energy supplier, communication service provider, and the residential consumer.

Performance requirements—Local home energy automation requires minimal data exchange volume and throughput. Local monitoring (e.g., in-home displays and alarms) have low time constraints and can, therefore, be implemented without a large communication throughput. Remote controlled applications are more likely to be limited by the customer's access network beyond the HAN perimeter. However, at the local level, many "beyond smart grid" home applications associating different appliances and home computing facilities (PCs, tablets, smartphones) may require broadband communications.

Architecture—Many HAN applications relate to the access of the electric utility to different devices in the home's physical area. In this case, a gateway device assures the connection from the utility's customer access network to the home area network. The electric meter or a separate home access device can provide the residential consumer's communications interface to an Advanced Metering Infrastructure (AMI), through various means of communications to the customer premise, such as powerline carrier, cable TV, phone lines, and commercial wireless networks. Commercial wireless solutions typically provide application connectivity to a household high bandwidth gateway, or through the meter up through the AMI network. The home area network coverage area is typically around 2000 ft^2 or 200 m^2.

Communication solutions and protocols—Within the customer premises, common communications options include Broadband Power Line (BPL) and wireless LAN technologies such as ZigBee, WiFi, and Z-Wave. Broadband Power Line technologies typically transport several 100 kbps to 10 s of Mbps data over the home electrical wiring, although more recent technologies allow substantially higher bit rates. ITU-T standard G.9960 or Ghn (home network) specifies operation at 1 Gbps even if the envisaged domain of applications is well beyond the current requirements of energy management in the home environment. Different technologies and standards relating to BPL are described later in this chapter. The wireless LAN solutions provide similar bandwidth range. Low-power consumption is a major feature for wireless devices in this context to permit operation using long-life batteries. The IETF standard 6LoWPAN (RFC 6282) defines low-power consumption, the IEEE 802.15.4 standard defines the technology (ZigBee), and the IPv6 standard provides for in-home networking. Other technologies on the consumer side for HAN-based energy management include low-power Wi-Fi and Bluetooth low energy, each of which can coexist at the link layer with the corresponding full-power implementations.

4.2.2 Customer Communications (AMI, Premise and Portal Access)

Applications—Applications in this segment include the collection of metering data, status, and measurements from customer premises, remote control of facilities and exchange of information with the consumer (portal access), and data exchange for demand response and energy efficiency programs and customer relation management, etc. Collection of AMI interval metering data determines when customer consumption occurs in time, what customers do in response to grid management needs, and the value of customer response. Smart meters that are the end points in the AMI architecture provide two critical roles:

- Access to more granular interval usage data (e.g., last 15 min rather than last 30 days).
- Bidirectional (two-way) communications delivering messages/instructions to the meter.

The advanced metering infrastructure communication system can also integrate the transport of communications for urban street-side public electric vehicle chargers and public lighting control, as well as the communications with micro-grid controllers and distributed energy generation and storage controllers. Detailed descriptions of Smart Metering and AMI applications, Distributed Generation and Microgrids, and customer demand management and demand response are provided in other chapters of this book. In addition to bidirectional connection with customer premise devices, it is increasingly necessary to provide consumer access to (PC or mobile) web-based utility applications (i.e., customer portal access, or customer self-service), or send consumer notifications via personal mobile devices. Typical applications are the monitoring of electric consumption, monitoring of appliance usage, viewing and paying bills, reporting/confirming outages, etc. Other interactions between customers and utilities may take place via social media, such as Twitter or Facebook.

Performance requirements—The scope of communications beyond the present grid interface will continue to expand dramatically, requiring capabilities to reliably exchange large amounts of information in short periods of time. The volume of information and, hence, the network throughput in this segment is highly variable ranging from a few kbps to a few 100 kbps to be shared in a cluster of end devices. Some other major requirements are:

- High coverage and flexible network capability to enable access to all customer meters
- Adaptable enough to change as customer and business needs change
- Scalable to very large networks, for required service capacity and manageable in the large-scale network
- Sufficiently low cost to justify investment recovery in reasonable time (for the regulator and for the utility)
- Fully address cybersecurity imperatives, especially unauthorized access, data privacy, and integrity imperatives of metering data
- Open-standard protocol support to enable interoperability among systems, flexibility in communications choices, and future innovations from third-party technology providers

Architecture—The AMI communication network must provide connectivity between grid devices, such as electric meters, and a head-end system connecting to the utility's metering, demand management, and control platforms. A two-level architecture composed of an access layer assuring the coverage of end devices and a backhaul layer providing aggregated transport to decision and control platforms is commonly employed. This allows the diversity of technologies in the access layer according to site characteristics in association with a public or private transport core connecting to the platforms. Alternatively, when public wireless services are employed at the customer side, then the platforms can be attained without any backhaul network. Customer portal access over mobile personal devices is typically through public cellular 3G/4G services. This can be integrated with or fully separate from the customer metering and home automation access network.

Communication solutions—Communications solutions for access to customer premises, street-side public facilities (public lighting, electric vehicle charger) and dispersed energy resources are numerous, and the choice is made according to end device density, required network performance, and application throughput requirements. Several "access coverage" and transport technologies may be associated together for cost-effective delivery of reliable, secure and functionally adequate services. Different technologies may be employed for covering different grid environments (e.g., urban, suburban, and rural), or for access and backhaul levels. Some potential dedicated connectivity solutions are narrowband power line carriers, such as IEEE 1902 (PRIME and PLC-G3), Broadband Power Line (IEEE 1901, OPERA), RF (radio frequency) mesh, and various generations (2G, 3G, 4G) of public cellular wireless service. PLC and cellular technologies (general packet radio service (GPRS)) have been more commonly used in Europe, whereas the United States has generally favored wireless technologies (cellular, RF mesh). These technologies are described later in this chapter.

Communication protocols—High-level communication protocols for reading, monitoring, and control of customer metering devices are described in more detail in the Smart Meter and AMI section of this book. These are often XML (eXtensible Markup Language)-based and generally require the communication network to provide a TCP (Transmission Control Protocol) or UDP (User Datagram Protocol) over IP protocol stack. Some commonly encountered low voltage metering protocols are IEC 61968-9 and IEC 62056 DLMS-COSEM as well as ANSI (American National Standards Institute) C12.18 to 22 in North American utilities[1].

4.2.3 Grid Operations Communications

The operational communication network in T&D (transmission and distribution) grid segments carry measurements, status, and command information from/to grid devices across the power system. The exchanged information is related to the operation of protection, control and monitoring applications, which may be implemented locally (within the substation, or between multiple substations) or centrally (from a central operations location). This communication segment covers the grid from the transmission substations down to the distribution substations and down the distribution feeder to what is known as the "grid-edge." Grid-edge devices are monitoring and control devices on the grid that are close to, but not including, the customer interface. These devices may include street lighting controls, public EV charging interfaces, distribution transformer monitors, feeder fault locators, microgrids, DER managed by the utility (community-scale), etc. There may be some overlap between these grid-edge communication networks, which are mostly for operational purposes, and the customer premise and AMI communications network. Grid-edge devices are still in their infancy but are becoming more predominant as small-scale monitoring and control device technologies advance and the grid becomes smarter. More work is required on identifying the needs and suitable technologies for communicating with these devices since they are expected to be much higher in number than the current T&D devices. The grid-edge devices are potential candidates for the growing IoT (Internet of Things) technology in the smart grid.

Transmission grid applications impose specific constraints on the communication service. Dedicated telecom infrastructures have been deployed using mainly optical fibers over power transmission lines and RF microwave links. These transmission grid substation applications comprise conventional protection schemes, such as blocking, transfer trip relaying, and current differential protection. Modern packet-based protection and control including System Integrity Protection Schemes (SIPS) are at present appearing in the power system landscape requiring a fair level of performance control, although not as stringent as the conventional protection. The IEC 61850 standard defining common packet communication protocols for this new generation of power network automation still requires predictable and dependable underlying Ethernet connectivity to transport Sampled Values (SV) and Command information (Goose messages).

[1] DLMS : Device Language Message Specification; COSEM : Companion Specification for Energy Metering.

Distribution grid applications have historically relied on very little communication, which was typically provided over industrial point-to-multipoint UHF multiple access radio systems. This mainly comprised polling systems for SCADA RTU communications in the substations, as well as remote command (and status collection) of fault isolation switches on the feeders. The ongoing grid modernization is, however, extending some of the mentioned transmission and sub-transmission applications and techniques to the primary distribution feeders leading to communication requirements like those of the transmission grid with slightly reduced performance severity.

Some common requirements for transmission and the primary distribution grid communications are as follows:

- High dependability and service continuity
- Latency control for time-sensitive applications
- Predictable behavior, robust hardware, harsh electrical environment
- Long-term sustainability of services and network infrastructure

However, the transmission and distribution grid operations communication segments differ in a number of their characteristics:

- Number of sites to cover in the distribution grid is much greater,
- Distances to cover between sites are generally much shorter in the distribution grid.
- There are legacy applications and telecom infrastructure in the transmission grid
- Time constraints are less stringent in the distribution grid.
- In most cases on the distribution grid, there is no installation of overhead optical fibers, and underground installation of fibers is often not cost effective.

The following major communicating applications in this segment are described in detail in other chapters of this book:

- Grid Monitoring, Protection & Control (P&C)
- Energy Management Systems, Distribution Management Systems and SCADA (Supervisory Control and Data Acquisition)
- WAMPAC (synchrophasor-based Wide Area Monitoring, Protection and Control)
- Flexible AC Transmission Systems (FACTS) and High Voltage DC (HVDC)
- Distribution Feeder Automation

4.2.3.1 Performance Requirements

As stipulated earlier, different communication performance objectives are required for transmission and distribution grid communications networks, which again can vary significantly according to the envisaged applications in each case.

4.2.3.1.1 Transmission Grid Requirements

Transmission grid communicating applications can be classified into 4 main categories:

- *Protection and Control* time-sensitive applications in the power transmission system require a communication service with a latency ranging from a fraction of a power cycle (around 5 ms) for a legacy current differential protection relay with no GPS synchronization (still widely in use), up to 1–2 power cycles (20–40 ms) for a permissive transfer tripping protection scheme, and around five power cycles (100–120 ms) for a synchrophasor-based System Protection Scheme (SPS) or Wide Area Protection and Control Systems

(WAMPAC). FACTS and HVDC inverter controls are also some specific cases of remote control applications requiring a latency in the range of 10–100 ms. Moreover, due to delay compensation and consequent phase adjustments in legacy differential protection relays being performed through an echo mechanism, the communication channel must have equal delays in Go and Return directions, with a delay asymmetry less than around 200–400 ms. This signifies that the same path must be used for the two directions of communication. Modern protection systems with GPS synchronization or network-wide IEEE 1588 time distribution may have less stringent requirements, although time sensitivity remains an implicit character of any closed loop substation-to-substation protection and control application. In addition to the described time constraints, protection and control applications require communications systems with high availability, high dependability (no failure to operate), and operational security (no spurious operation).

- *SCADA and WAMS* applications in the utility operations control center require cyclic collection of status and measurements from substations across the grid with data refreshed every few seconds. The cyclic data collection can be interrupted for transmitting higher priority remote commands, such as to operate substation circuit breakers. Wide Area Monitoring Systems (WAMS) are the measurement and monitoring components of the WAMPAC systems described in this book. A bandwidth allocation of around 10 kbps per SCADA RTU, and 10–100 kbps per WAMS Phasor Measurement Unit (PMU) device, is generally sufficient for covering these applications. Time constraints on SCADA and WAMS are less critical and depend upon the employed communication protocol. A centralized polling type protocol requires shorter time latency across the system. Regarding WAMS applications, it should be noted that these may also be employed for post-incident analysis, static modeling, and monitoring of slow variations of grid monitored parameters (line loading, power swing, etc.), in which case the application can tolerate a relatively large time latency in the order of tens of seconds.

4.2.3.1.2 Distribution Grid Requirements

Primary distribution grid applications can be divided into three main categories, distinguished by their respective communication performance demands:

- Grid optimization
- Rapid self-healing distribution automation
- Protection applications

Grid Optimization applications are those that measure and operate on long-term averages to offer grid efficiency improvements using slow, open or closed loop data control via data analytic engines (e.g., Volt-VAr Optimization). The non-real-time nature of the applications results in one-way message delivery latency tolerance of several seconds. These applications present data to various data analytic engines to enhance and optimize the modernized grid operational efficiency aspects.

Rapid Self-Healing Distribution Automation applications comprise fault location, isolation, and service restoration. To quickly isolate faulted line segments and restore power, these applications typically operate in a non-centralized or distributed architecture, and require one-way message delivery in 10 s of milliseconds.

Protection Applications that make use of messaging are typically found within the substation fence and can operate in fractions of power cycles. However, on the distribution network, advanced protection applications offer dynamic time-current curve coordination shifts via messaging and, therefore, require a message latency that can follow the time-current curve differentials, which could be as low as 80 to 100 ms.

A fourth category, *Microgrid Applications and Distributed Generation*, is a specific grouping of the above-mentioned categories and is already mentioned under Customer Communications and AMI earlier in this chapter. Communications systems for microgrid applications have performance requirements that range from those required for Grid Optimization applications to provide slow historical control and parameter awareness (such as controlling power quality), to delivering control signals in six cycles or less to disconnect distributed generation from the grid per IEEE 1547. Many dedicated and high speed, low-latency communication networks can support such applications. The modernized grid requires communication system support for transfer trip functionality and islanding/resynchronization to a micro-grid breaker in a few cycles.

Each primary grid application category imposes a different set of performance and architectural demands on the communication system's latency, message rate, system uptime (availability), and overall data volume exchanged (which translates to operational expenditure cost when using public or consumer-owned communications systems). Figure 4.6 illustrates the three main application categories, and the high-level communication system performance attributes required to properly support them.

Moving from Grid Optimization to Protection applications, the most notable item is that latency imperatives reduce in orders of magnitude from being noncritical minutes, to milliseconds, to a quarter of a cycle (3 or 4 milliseconds depending on the network frequency), such as the case with transfer trip relay applications. Therefore, for smart grid applications, one of the most critical performance parameters is one-way latency, which is defined as the time it takes for a given device to send a message to another given device.

A view of the three primary distribution application categories and their associated one-way message latency categories is provided in Figure 4.7, with one-way latency represented in a log scale.

System message rates for Rapid Self-Healing distribution automation applications can grow as a function of the system size, the fault area impact, and number of fault contingencies. In practice, a message latency in the range of 100 s of milliseconds can result in a corresponding grid restoration time of seconds, while one-way message latency of seconds can extend restoration times to minutes.

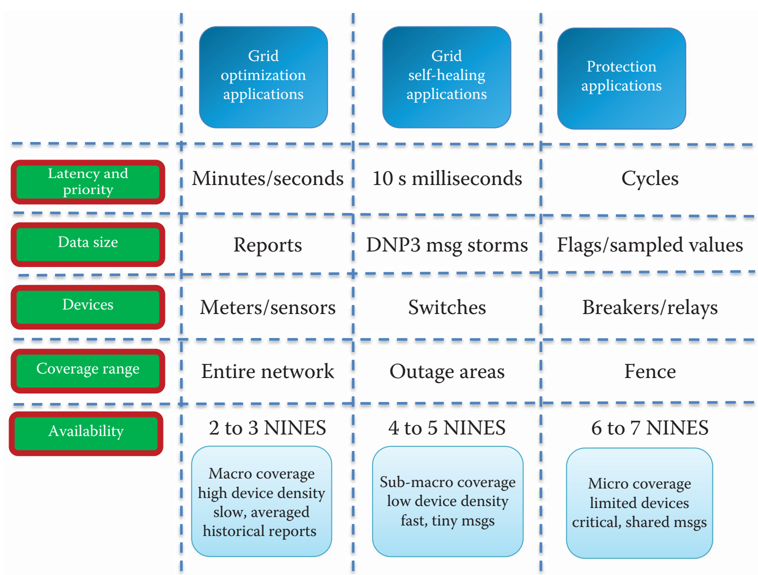

FIGURE 4.6 Primary smart grid applications and key performance demands. (© 2016 S&C Electric. All rights reserved. With permission.)

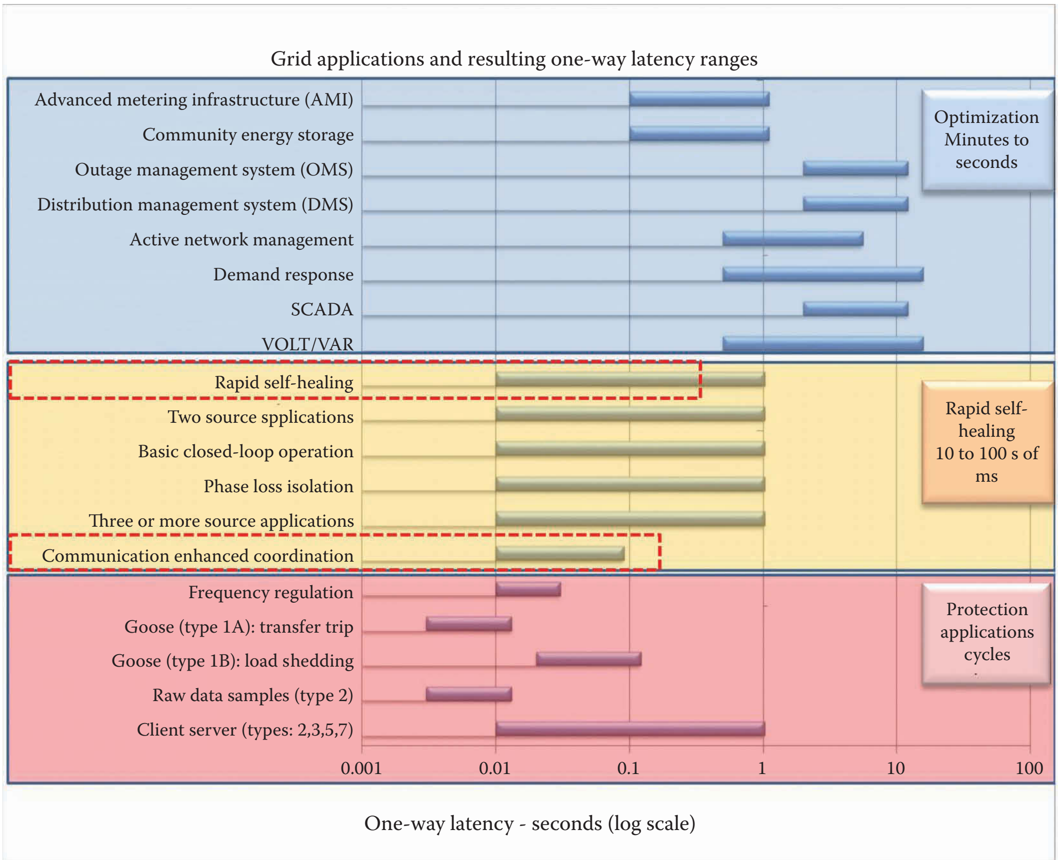

FIGURE 4.7 Primary distribution grid applications and one-way message latency. (© 2016 S&C Electric. All rights reserved. With permission.)

4.2.3.1.3 Performance Considerations

4.2.3.1.3.1 Quality of Service An important performance attribute to consider when evaluating communication network technologies is the capability to prioritize communications according to the grid applications and specific types of messages.

Multiple grid applications may simultaneously share the same communication system. Consider a communication system that is shared for both AMI and Rapid Self-Healing. Upon an event and sustained loss due to a switch opening or a segment being sectionalized, several meters may simultaneously report loss of voltage, while at the same time the Self-healing application may need to operate.

To provide message priority across a given communication system, Quality of Service (QoS) capabilities may be offered enabling messages to be treated differently, depending on their classification, thereby guaranteeing average data throughput for a given time duration, guaranteeing a specific message latency, or in some cases, a given message loss rate.

4.2.3.1.3.2 Message Volume and Throughput Metrics Each grid application has a given message size and rate referred to as a traffic signature. Based on the traffic signature, an application may impose differing performance demands on the supporting communication system to ensure proper data transmission.

The traffic signatures of many Grid Optimization functions can easily be 100s of MB per day operating over communication systems capable of transporting 100 s of Kbps to transmit historical reports, sensor data, and metering/usage data. In this case, the best data throughput metric is "bits per second", as for Internet communications. The data traffic is typically Internet Protocol (IP)-based, with message transfer units (MTUs) on the order of 1500 bytes.

Grid applications, such as Rapid Self-Healing, share voltage, current, and loading data during steady-state conditions. Upon an event, the grid devices must interrupt, isolate, and switch to restore service. This results in the need for the devices impacted by a fault to rapidly exchange messages between each other until the fault is isolated, and service is restored where it can be. Such a traffic pattern is known as a "message storm." In such applications, the messages that are shared are small, and can be based on protocols such as Distributed Network Protocol (DNP3), which has smaller 256-byte frame MTUs. Therefore, a better metric for communication system throughput for these applications is the number of messages per second that can be transmitted between devices.

Some communication systems are optimized for bits per second for specific applications, such as Internet browsing, while other communication systems are optimized for smaller messages exchange in higher message rates, measured in messages per second. The difference is in their underlying physical and data link layer channel access and transmission algorithm designs. A slower message per second rate on a given channel will result in slower message exchanges and slower service restoration capabilities. These differences in communication throughput metrics do not favor a single network handling all necessary primary smart grid communication applications.

4.2.3.1.3.3 Scalability An important distinction may also be that the device population support by a given application will vary. For example, millions of meters could be deployed in each utility network, with thousands of IED (Intelligent Electronic Devices) controls and switches across the network, and hundreds of substations as aggregation points for communication networks. Not all communication networks scale to support such device populations, and scalability is of crucial importance to meet existing and future applications.

4.2.3.1.3.4 Communications System Availability Communications system availability is another consideration. System availability is defined as the amount of uptime, measured in a percentage, that a network can communicate to a given device population. A system that is up 99.9% of the time is stated to have 3 NINEs of availability, which amounts to over 500 min of system downtime per year. A system with 5 NINEs of availability has just over 5 min of downtime per year. Communication system downtime occurs for both unscheduled (system impairments), and scheduled (upgrade and configuration changes) outages. Self-healing and protection communication systems require less downtime due to the critical functionality they provide. It is noted that in most scenarios, grid optimization applications require only 2 to 3 NINEs of availability per year.

Various system architectures provide different availability schemes. For example, a point to point architecture, in general, has the lowest availability, because if one of the end points is lost, the communication path is lost.

A point to multipoint system requires a base station to coordinate communication between devices. Communication between devices may be lost if a base station suffers an outage. An availability improvement may be made if base stations are deployed with overlapping coverage.

A mesh communication network can offer the highest level of availability because if a single device is lost, a mesh network can route messages over other paths to reach the destination device. Another benefit of a mesh system is that it can provide connectivity to any device within the mesh coverage area by connecting to a given device anywhere in the mesh. That is, another costly tower or base station need not be deployed to extend coverage in a mesh network (Figure 4.8).

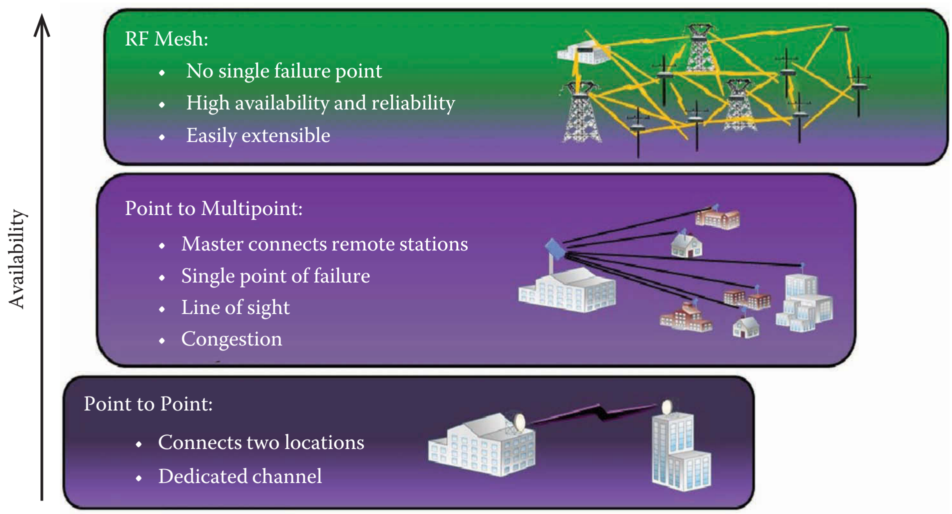

FIGURE 4.8 Communication architectures and communication system availability. (© 2016 S&C Electric. All rights reserved. With permission.)

4.2.3.2 Grid Operations Communication Protocols

Communication protocols in use for exchanging information across smart transmission and distribution grids have an enormous impact on the required throughput and, hence, the dimensioning of the communication links, on the selection of communication architectures, and on the possible migration strategies. In the past, distribution grid sites and assets were not extensively covered by communication systems, except for low-speed SCADA through industrial UHF radio with some type of polling protocol. Transmission grid communications, however, is heavily loaded with the burden of legacy systems whose total replacement across the grid will probably take decades to complete in most utilities.

4.2.3.2.1 Legacy Protocols

SCADA communications protocols allow the connection of substation-based Remote Terminal Units (RTUs) to central control platforms, and to connect control platforms to each other. DNP3 and IEC 60870-5-101/-104 are common for RTU communications and are evolving from link-by-link serial (RS-232/RS-485) into networked IP communications. Many other legacy serial communication protocols are still in use across the world. Migrating to a TCP/IP protocol requires the upgrade or replacement of old RTUs or their communication interface or the deployment of intermediate communication gateways or terminal servers for simplified connection at the control platform end. Both DNP3 and IEC60870-5 were developed in the 1990s and are widely deployed.

IEEE C37.118 PMU communication standard defines the exchange of synchronized phasor measurements used in power system applications. It was first published in 1995 (revised in 2006). A synchronized phasor measurement, or synchrophasor, is produced by a PMU (Phasor Measurement Unit), and represents the magnitude and phase angle of a measured voltage or current waveform. PMUs distributed across the electric grid produce synchronized measurements that are time stamped. As of today, IEEE C37.118 is primarily used for WAMPAC applications. The IEEE C37.118 standard defines the communication rules for a single PMU, or a PMU data aggregator, called PDC (Phasor Data Concentrator). Synchronization of measurement time stamps of PMUs and transmission delays are two important challenges in the protocol. The synchronization aspect is currently handled through the integration of a GPS receiver directly into the PMU at each measurement site. In the future, IEEE 1588 should be able to provide the required synchronization needs through the communications network and, therefore, remove the need for a GPS receiver in PMU devices. The transmission delay challenge depends highly on the network communication topology, number of communications switches in cascade, length, and type of communication links, etc.

Legacy Protection systems, in particular, current differential protection relays, require the exchange of measurement samples across the protected line in order to compare with locally measured sample values and, hence, to determine whether a fault is present in the protected line. Legacy devices are not equipped with GPS time synchronization and, therefore, estimate the received communication delay through an echo measurement. If these legacy protection devices are present on the network (in many cases, still expected ahead for many years), it is necessary to have minimal delay variation on the communication link and equal delays on the two directions of communication. Many existing SDH/SONET (Synchronous Digital Hierarchy / Synchronous Optical Network) systems fulfill this requirement and the migration to packet communications must assure that the same behavior is preserved. In particular, any switchover to an alternate path must be performed simultaneously in both directions of communication. The full deployment of implicitly packet-based protection relay protocols (e.g., IEC 61850) and the implementation of modern time synchronization protocols shall ease this constraint to some extent.

4.2.3.2.2 IEC 61850 Protocol

A major element in the transmission and distribution communications architecture of the future is the IEC61850 standard "Communication networks and systems for power utility automation" providing all the necessary specifications to achieve interoperability between the equipment of an integrated system.

Some particularly relevant components of this standard are listed below:

- IEC 61850-90-1 Communication between substations
- IEC 61850-90-2 Communication between control centers and substations
- IEC 61850-90-3 Communication for Condition Monitoring
- IEC 61850-90-4 Network Engineering Guidelines
- IEC 61850-90-5 Synchrophasor communication according to IEEE C37–118
- IEC 61850-90-6 Communications for Distribution Feeder Automation System
- IEC 61850-7-410 Communication for monitoring and control of Hydro Power Plants
- IEC 61850-7-420 Communication for Distributed Energy Resources (DER)

The standard introduces several features that impact the design of systems, such as the use of communications services for the exchange of time-critical information between IEDs, e.g., protection relays. The standard defines communications services based on TCP/IP and Ethernet and standardized data object models to ensure interoperability between communicating devices. It further defines a language to exchange engineering information. More information on IEC 61850 can be found in the dedicated section of this book.

4.2.3.2.3 Time Synchronization Protocols

Time synchronization over communications networks is mainly achieved through NTP/SNTP (Network Time Protocol, Simple Network Time Protocol), or the IEEE 1588 standard, also called PTP (Precision Time Protocol). While NTP was defined back in 1985, IEEE 1588 is more recent and was first published in 2002 and revised in 2008. Besides the technical differences of the two protocols, their main differentiator is the accuracy they can provide: SNTP can provide an accuracy of tens of milliseconds across a WAN down to a couple of hundreds of microseconds in a LAN, while PTP can provide sub-microsecond accuracy. From a smart grid point of view, SNTP is mainly used for control and monitoring applications, while PTP is mostly used for protection applications.

SNTP and PTP are based on a similar mechanism involving the exchange of messages between a reference time source and a device. The purpose of the message exchange is to transmit the value of the reference clock and then to evaluate the transmission delay. While SNTP assumes a symmetric delay between the reference time source and the device, which is never valid in a WAN because of the switched nature of the network and the unpredictable delays introduced by switches and routers, PTP precisely evaluates the transmission delay by requesting the switches to report the residence time, that is, the delay due to a message being held at the switch. Therefore, for high accuracy, PTP requires some specific features implemented in the switches to support the residence time calculation.

4.2.3.2.4 High-Reliability (Redundancy) Protocols

IEC 62439-3, published in 2003, standardizes several protocols for industrial communication with a strong focus on reliability aspects. From a smart grid point of view, two protocols are particularly of interest: PRP (parallel redundant protocol) and HSR (high-availability seamless ring), both intended for substation automation LAN applications. Compared to other protocols, PRP and HSR provide an instantaneous recovery time in case of a link failure, which is a crucial feature for real-time applications, for example, a differential protection application based on IEC 61850-9-2.

The principles of PRP and HSR are simple and can be summarized in three points: (a) each device is redundantly connected to the network through two independent network interface controllers (NIC) and two independent links; (b) the messages issued by the sender are duplicated over the two connections and sent simultaneously; and (c) the receiver transmits the first received message to the application (e.g., a protection function or a TCP/IP stack) and discards the duplicated message. From an application point of view, PRP and HSR are transparent and, therefore, do not require any modification. Moreover, failure of a link between the sender and the receiver does not introduce any delay since the messages are duplicated and transmitted simultaneously. Selection between PRP and HSR depends on the network topology: PRP is applicable for a point-to-point topology, while HSR is only applicable for a ring topology. PRP can be implemented entirely in software (at the driver level) and only requires an additional NIC on the device, while HSR requires the HSR switch functionality implemented by each device participating in the ring.

4.2.3.3 Grid Operations Communication Media

The great diversity of requirements and situations here lead to a great number of communication solutions used or envisaged in the different segments of grid communications. In all cases, however, grid operations communication needs to be highly reliable, secure, predictable, robust, error-free and sustainable over a very long number of years. Procuring communication services from a public network cannot fulfill these requirements, and except for rare cases, is generally prohibited for this type of utility communication, although public networks are widely used for customer access, in the enterprise network, for inter-utility communications, and for mobile services.

Optical fiber communications, typically installed in the overhead ground wire on power transmission lines, are widely used in the transmission grid segment in conjunction with SDH/SONET, and more recently are associated with different packet communication technologies, such as Ethernet and MPLS. SDH/SONET over fiber remains the dominant technology in use for transmission grid networks across the world. The distribution grid segment is also using optical fiber, but to a much lesser extent due to cost and the limited means to install the fiber on distribution lines. Usage of fiber in the distribution segment is often associated with the interconnection of large substations, or underground in urban areas. In this latter case, the fiber infrastructure also provides communications for nonutility "Smart City" type applications.

Broadband (and Narrowband) Wireless is used in point-to-point configurations instead of, or for completing a fiber network in both transmission and distribution grid communications. Conventional microwave links with SDH/SONET or implicitly packet-based (e.g., IEEE 802.16 or wireless Ethernet) allow the coverage of relatively long distances in the transmission grid, particularly in

North America. In the distribution grid segment, the shorter distances favor the use of Broadband Wireless Mesh networks using IEEE 802.11 as well as the industrial UHF radio systems that have evolved into packet-based communications providing much higher bit rates and extensive communication capabilities.

Power Line Carrier, although no longer the almost unique technology for substation (mostly transmission grid) communications that it had been in the past, it remains a valid cost-effective solution for providing low bandwidth services, such as SCADA and protection signaling for very remote substations, an alternate medium for critical services such as teleprotection, and a way to serve smaller substations with little infrastructure investment. Both analog and digital modulation (Quadrature Amplitude Modulation QAM) and Orthogonal Frequency Division Modulation (OFDM) are employed to provide a bit rate ranging from 10 kbps to around 300 kbps using the overhead transmission line as the communication medium.

4.2.4 Communicating Beyond the Grid Boundaries

In a number of segments identified and described in the previous sections, the power utility must communicate beyond the boundaries of the grid infrastructure, the most important being as follows:

- Access to customer premises (smart metering)
- Access to street-side public facilities (electric vehicle chargers and public lighting)
- Access to independent distributed power generation and storage
- Access to other utilities and external platforms
- Mobile field workers communications
- Office workers, access to field site information

In some of the listed cases, the only way to establish communications is procuring services from a public telecom operator (e.g., other utilities, independent system operator). In most others, both service procurement and building infrastructure can be envisaged with different advantages and shortcomings. We discuss those of the above-mentioned segments which were not analyzed previously, before presenting some issues relating to procured communication services.

4.2.4.1 Inter-platform and Inter-utility Communications

Different information processing and storage platforms of the utility are connected across the grid area for information synchronization, operations coordination, or status reporting. Inter-control center communications to provide data exchange over WANs between utility control centers, power pools, regional control centers, and independent generators are supported through owned, shared, or "procured service" IP networks. Inter-Control Center Protocol IEC 60870-6-5/TASE-2 provides communication protocols for these exchanges. The required bandwidth ranges from 2 to 10 of Mbps.

4.2.4.2 Enterprise-to-Field Communications

Asset condition monitoring, video surveillance, and physical access control applications constitute a growing traffic of non-time-critical data between field sites and monitoring platforms. Here the absolute time latency is not an issue and the system can easily tolerate several seconds of delay. Most often it constitutes an IP traffic stream with the periodic transfer of information. Condition monitoring and management of primary power equipment in the substation (circuit breaker, power transformer, etc.) generate data collected for maintenance, loading and stress analysis, and for asset life-cycle management. An asset monitoring network can be implemented across the communications infrastructure using web services with data servers residing in the substation or at some other location (e.g. in a cloud). Monitoring in the substation should also include environment monitoring to protect substation assets and premises (e.g., temperature monitoring, fire detection). While this type of data is not as time critical as, for example, SCADA data, it potentially includes a large amount of data from equipment all over the grid.

Remote access to substation assets is a group of relatively new applications allowing the access from a technical office, engineering workstation, or asset management site over the enterprise IT network to connect in a secure manner to field devices for diagnostics, change of parameter settings and configuration. The focus is on the security of communication access from the enterprise IT network to the operational technologies (OT) network.

A convergence solution comprising the integration of the enterprise IT communications network with the grid OT communications network is, in most cases, not desirable, as explained below:

- The enterprise IT communications network is by nature open to the outside world, while an OT communications network should be "as closed as possible" to ensure security.
- Existence of legacy applications and integration of legacy applications with advanced applications and systems are a determining parameter in OT communications network design, while enterprise communications networks are largely well-established IP networks requiring mainstream techniques and technologies.
- Enterprise network communications requires rapid evolution in line with office IT tools and applications, while an OT communications network needs to be very stable in time, but evolving at the pace of advances in substation devices and applications
- Service continuity is the focus of an OT communications network, while bandwidth efficiency, flexibility, and cost are the dominant considerations in the enterprise communications network.
- Service management process of an enterprise IT communications network is fundamentally different from that of an OT communications network. Outsourcing can be envisaged more easily and at much lower cost in the enterprise communications network than if it must fulfill operational imperatives.

A more appropriate solution is to allow the connection of the enterprise IT communications network with the OT communications network through adequate firewalls to allow technical office access to restricted substation-based servers and applications. The creation of enterprise tunnels across the grid communication network and dedicated sockets at each substation allows field staff at substation locations to access the enterprise network for asset management and field support, and for enterprise applications.

4.2.4.3 Mobile Workforce Communications

Application—Mobile workforce applications enable utility employees, such as line crews and grid asset maintenance teams to communicate with each other. Traditional communication applications include dispatch and peer-to-peer voice communications, short messaging, and transmission of documents (work orders, schematics, procedures, and product manuals). In-house and contractor maintenance staff require remote access to online maintenance manuals, maintenance applications, substation drawings and plans, accurate maps, pictures, and timely communication of work orders to carry out their tasks.

Performance Requirements—The required bandwidth in this domain is growing from older generation private land-mobile radio systems providing simple trunked voice capability and bandwidth (e.g., MPT-1327, TETRA), to 10 s or 100 s of Mbps across new cellular wireless systems to allow large waveform file transfers, database access, image and video transfers, and streaming, etc.

Communication Solutions—Mobile workforce communication is an area where the utility is most strongly facing the dilemma of deploying its own network or procuring public operator services.

Public cellular networks provide an ever-increasing number of modern communication applications and bandwidth to the utility's mobile terminals. The operator assures a very high coverage over the utility's geographical footprint thanks to its great number of base stations (well beyond the economical capabilities of the utility-owned wireless infrastructure). There is no deployment time delay, no initial capital investment, and no need to maintain a large fixed infrastructure. In addition, the public network is regularly updated in terms of technology, bandwidth, and functionality. However, the survival of the service in times of disaster is not assured. High traffic at disaster time and very low power autonomy (due to base station battery dimensioning) can cause the rapid loss of the service in the case of any power outage. The utility often relies upon its mobile workforce communication to re-establish the power, while the wireless operator relies upon the utility for powering its base stations!

A self-owned mobile service can be very costly to implement with a large coverage (and a very small number of mobiles) and implicitly obsolete terminals, bandwidth, and applications due to far less regular updates. The staff will certainly be tempted to use their own personal mobile service.

A broadband wireless IEEE 802.11 WiFi service through utility-owned telecom infrastructure can be used in conjunction with a public cellular operator procured service with a common mobile terminal for a more appropriate hybrid solution.

4.2.4.4 Utility Corporate Enterprise Communications

Enterprise IT networks providing office communications and staff access to utility enterprise applications is beyond the scope of this book. However, some cases still need to be considered for:

- Permanent or temporary field staff located at sites on transmission or distribution grid communication networks needing access to enterprise applications, utility office support, or external support platforms
- Office-based staff and data platforms requiring access to field collected data (e.g., Asset Management)

4.2.4.5 Public Communication Services

Utilities have been procuring "leased" wired permanent communication lines, switched dialed lines and wireless services from public operators for a long time. Depending on the scope of the utility, this has been used to establish links where deploying the utility's own infrastructure was uneconomical or technically unfeasible. The evolution of public telecom provider communication services over the last two decades has changed the landscape considerably as expressed below:

- Network transparency resulting from simple physical line transmission (and multiplexing) has been replaced by a time-variable packet-switched provider infrastructure delivering a virtual connection with contractual commitments on an "averaged basis." In other words, the time delay or the availability of the service is variable, while respecting contractual limits across a month. Proper operation of a time-sensitive, critical application, therefore, can no longer be guaranteed.
- With the gigantic growth of public communication traffic, a utility, whatever its size, has become a marginal customer of the public telecom provider with negligible data flow. Providing a specific quality of service for any critical application, even if technically feasible, is not likely to happen because it will require a specific process, specific design, specific monitoring, etc., which the operator is not likely to provide.
- Maintaining the continuity of communication services is permanently traded off against the cost penalty of not providing them. The criticality of utility services will probably not weigh heavy compared to the maintenance of a public network highway.
- Management and maintenance of the communication network are often performed by a cascade of external contractors. The telecom operator rarely has very clear control of his network.

- At times of disaster, the rise in traffic can make the network inaccessible for critical users in the utility, and in any case, a power outage will disable the telecom operator's network very rapidly due to restricted battery backup and the cost of backup power facilities. The power utility cannot rely upon this communication network to re-establish power.
- Unscheduled maintenance, repair, and service restoration are prioritized in dense user areas and cell sites where the lost revenue due to downtime is substantial. The utility may have to wait a long time before its procured services are reestablished.
- Connection to alternative base stations (cell sites) may be possible but will likely result in network congestions increasing latency and message loss.
- Scheduled outages for system optimization or upgrades are frequent and can come at a surprise. In any case, the utility may not have the business strength to postpone the outage.

Procuring public communication services may still be an attractive solution in many cases, including customer metering applications, electric vehicle chargers, and small independent producers.

4.3 COMMUNICATION NETWORK TECHNOLOGIES

As stipulated earlier, many communication solutions and technologies are employed in the different segments of the smart grid information networks. Figure 4.9 provides an example of the combined use of some of the potential technologies in the utility network.

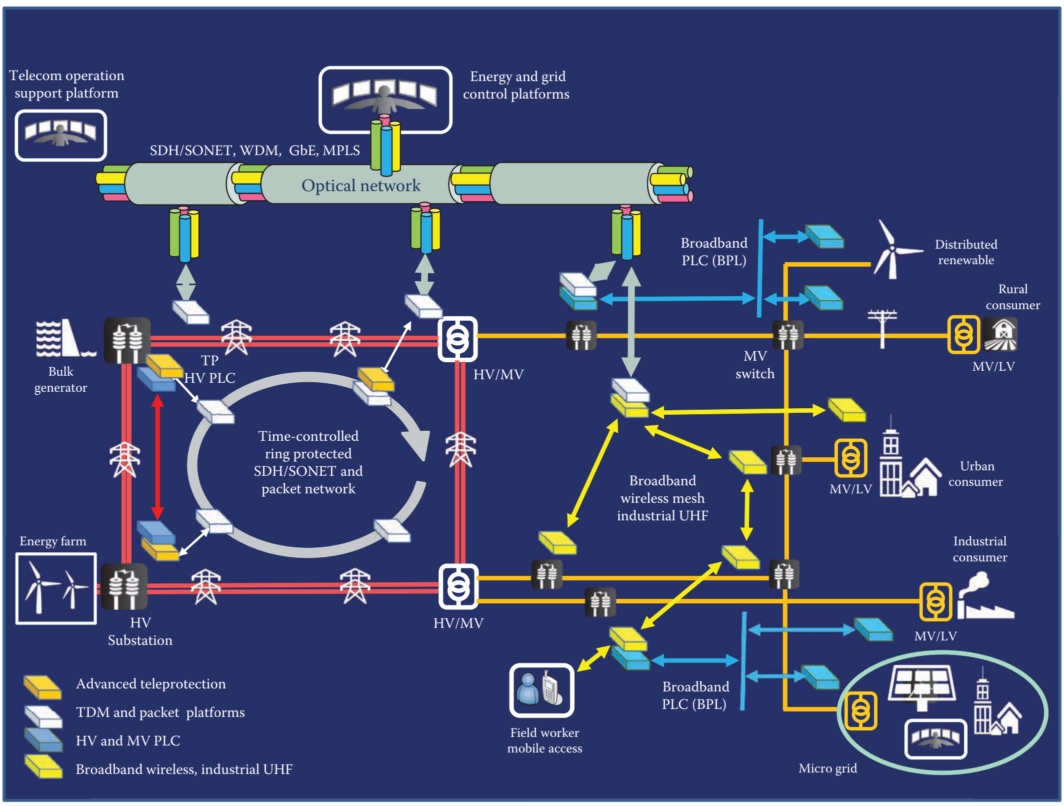

FIGURE 4.9 Combining technologies to deliver smart grid communications. (© 2016 GE Grid Solutions. All rights reserved. With permission.)

4.3.1 Transition to Packet-Switched Networking

Transmission grid utility communication networks have for many years been based on SDH/SONET echnologies providing communication links with almost invariant performance, full utility control on the signal path across the network, and conceptually simple principles. Dedicated bandwidth is allocated in SDH/SONET to each application providing fully isolated communication paths with no major cybersecurity issues and no quality of service or variable latency due to intermediate queuing.

The evolution of communication requirements is changing this situation. Today, Ethernet is the dominant access interface for almost all modern operational applications, the standard local network technology, and the optimal transport technology in the operational environment of the utility providing low connection cost, bandwidth flexibility, and a wide variety of topologies and transmission media (copper pair, fiber, wireless, etc.). Interface converters and coordination between many types of communications interfaces are gradually disappearing. However, legacy interfacing will remain a major issue for a long time. Terminal servers and interface conversion remain the solution to many legacy issues and allow the encapsulation of many non-Ethernet services to benefit from Ethernet flexibility and wire-saving capability. Ethernet over SDH/SONET provides an efficient manner of implementing time-controlled connections for multiple independent data streams with individually allocated bandwidths, and some capacity dedicated to protection relay communications. A large increase in the number of services, however, results in laborious configuration and little flexibility. More scalable technologies, such as MultiProtocol Label Switching (MPLS), are being deployed at the expense of greater complexity and costly interfacing of legacy interfaces. Different hybrid solutions allowing SDH/SONET for the legacy services and native packet switching for new services are presently available. An interesting solution in this context combining SDH/SONET-type quality of service and MPLS scalability is MPLS-Transport Profile (TP). This technology allows the forwarding of packets across the network using Forwarding Class labels (as in IP-MPLS) under the control of a central management system (as in SDH/SONET and unlike IP-MPLS). Peak (maximum) and Committed (minimum) Information Rates (PIR and CIR) are allocated to each information flow, and end-to-end routing (including alternate) is determined by the central control platform.

Another technology, which is increasingly used in utilities communication for separating multiple networks, is wavelength-division multiplexing (WDM). WDM is becoming a secure and affordable way for traffic separation between:

- Operational and corporate networks
- SONET/SDH multiplexed network and MPLS/gigabit Ethernet networks
- Protection relay communications and other communications

4.3.2 Broadband Power Line (BPL)

Broadband power line technology is used in HANs for customer premise access and AMI, and in grid operations communications. BPL transports information over the electrical power conductors through appropriate signal modulation (generally below 30–100 MHz), forward error correction coding (FEC), and a medium access protocol. The signal injection and extraction over the power conductor depend on the nature of the power line. On the low-voltage side, whether in the customer access or in the home network, capacitive coupling is employed, while in the medium voltage segment, metering backhaul or grid communication, both capacitive couplers (for non-isolated overhead line coupling) and inductive couplers (for isolated cable coupling) are in use. A data throughput of 10–20 Mbps can be expected in the distribution line case with a span of around 3–4 km. In the lower-voltage case, the covered distance is significantly lower due to line attenuation and noise characteristics. Finally, in the home environment, a physical bit rate of 1 Gbps is attained with the ITU-T G.9960 HomeGrid specifications, while currently used systems are more in the range of 10–50 Mbps. Several BPL technologies have been developed over the years. The vast majority employ Orthogonal Frequency Division Multiplexing (OFDM) as their modulation scheme. The HomePlug standard now integrated into the IEEE 1901-1 standard, the HD-PLC Alliance system employing wavelet OFDM modulation now standardized as 1901-2, and the OPERA alliance (IEEE1902) are examples of main BPL technologies.

4.3.3 Broadband Wireless LAN

Broadband wireless LANs employed in the HAN or other short range communications in the power system are often based on IEEE 802.11 (a wireless local network, commercially called Wi-Fi or "wireless fidelity") or IEEE 802.15.4 (ZigBee). The IETF standard 6LoWPAN (RFC 6282) combines low-power consumption, IEEE 802.15.4 technology (ZigBee) and IPv6. This latter technology provides a constrained mesh network covering network, transport, and application layers as well as a security layer currently tied to ZigBee called SEP 1.x (Smart Energy Profile 1.x.). The ZigBee Alliance has worked with the HomePlug BPL consortium to create a "link layer-agnostic" version of SEP (version 2.0) leveraging IPv6 and TCP/UDP for the networking and transport layers, off-the-shelf certificate technologies for security, and HTTP for services. In the case of ZigBee and applicable constrained networks, there is also a requirement for 6LoWPAN (IETF RFC 6282), which performs header compression of the IPv6 network layer and the UDP/TCP transport layer, as well as compression of HTTP server and client headers. In addition to being link-layer agnostic, going to an Internet-based network layer and off-the-shelf certificate management allows for SEP 2.0 devices and the next specification for the home automation profile to coexist at the link and network layers.

4.3.4 Wide Area Narrowband and Broadband Wireless

Radio frequency (RF) mesh technologies comprise the communications backbone of numerous existing AMI deployments today. A key feature of RF mesh technologies is the ability to form a "peering" network. In this configuration, each device can communicate with nearby peers and then send information via those peers to an access point that has a direct communications path to the utility. A simple way to think of this is that every mesh node acts as a router—the advantage of this method is that not every device has to have a direct communications path all the way back to the utility; they should only have a communications path to a peer.

Narrowband RF systems are simple, cheap, and widespread and allow for the communication between devices and back to an access point, which is then connected to the utility via a backhaul network. Narrowband RF technologies can generally provide a bandwidth of approximately 100–200 kbps, which is usually deemed sufficient for typical smart grid field applications, but not for backhaul networks that are expected to aggregate data.

Broadband IEEE 802.11 based wireless mesh networks are capable of transporting 10 s or 100 s of Mbps across a wide area. Standard ad hoc network building protocols in IEEE 802.11 (called OLSR) allow each node to establish links with all visible nodes and hence to construct a mesh network with link priorities based on the quality of the received signal. Line of sight links can cover distances up to 10 km, depending on the antenna gains.

4.3.5 IPv4 and IPv6

IPv4 born out of DARPA (Defense Advanced Research Projects Agency) in the 1970s, which is used to this day as the backbone of the modern Internet, has been so successful that it has started to outgrow itself—the network address blocks have been completely depleted to the point that IANA

(Internet Assigned Number Authority) and RIRs (Regional Internet Registries) since April 2011 have been in a constant churn of reclaiming, redistributing, and reallocating network space. This is not so much an issue for the utility sector, but it is for the Internet, and was a problem on the horizon as early as the 1990s. A great amount of research leads to a solution that not only expanded the address space but also solved fundamental problems associated with IPv4. Born out of that research was RFC 2460 (IPv6)—a network protocol that would solve issues of address space, network configuration, network discovery, neighbor discovery, routing redundancy, mobile routing, and network security.

There has been debate in the power industry as to the necessity of migrating utility communications to IPv6. The use of address-translation mechanisms in the relatively closed network environment of the power utility will help to overcome the saturation issues of the public internet. If, and when, IPv4 is abandoned globally, a forced migration may become necessary. In the meantime, network components, such as IP routers, can accept both IPv4 and IPv6, and except for the customer-based segment (metering, mome automation, etc.), the issue remains noncritical.

4.3.6 Mobile Cellular Services

Public mobile cellular technology has been in use in the electric utility industry since the late 1980s for automated meter reading applications, particularly for commercial meters or for very hard-to-read residential meters. The first-generation or “1G” cellular technology employed for these applications (e.g., Advanced Mobile Phone System or AMPS in North America) had the great advantage of not requiring a telephone line to be run to the meter and to be maintained by the customer. In the late 1990s, more competitive pricing and improved electronics led to further adoption of wireless technologies across the utility industry with a bandwidth around 9–24 kbps. However, a challenge to broader commercial wireless adoption led to the decommissioning of the AMPS networks by their owners starting in 2002. These actions, which were due to a combination of federal pressure, wireless carrier economics, and the inefficient use of valuable spectrum by the AMPS technology, led many utilities to question the wisdom of relying on systems and networks not only beyond their control but under the control of a commercial entity with a much broader set of business objectives than just keeping utility communications networks intact. This concern, set off by the experience of “losing” AMPS, would linger for years.

Different generations of cellular technology have followed with an ever-faster evolution. The second generation (2G), which began deployment in the 1990s, introduced two families of cellular technologies: GSM (Global System for Mobile communication) together with its data transmission protocol GPRS (General Packet Radio Service) as well as Enhanced Data rate for GSM Evolution (EDGE), on one side, and CDMA (Code Division Multiple Access) 2000 on the other side. 2G technology (particularly the GPRS) was also extensively used for metering applications with a speed of 28 kbps that later increased to about 150 kbps (EDGE) allowing file transfers and more advanced metering applications. Hundreds of thousands of meters with GPRS radios were installed in Europe by 2009. The attractive economics and profitable spectrum use looked to make an “AMPS-like” decommissioning of the 2G systems unlikely without significant economic fallout for the carriers.

3G networks were deployed in the mid-2000s again as a GSM variant (known as high-speed packet access or HSPA), and a CDMA variant (known as Evolution-Data Optimized or EV-DO). These networks provided approximately 10 Mbps (peak speed) to the mobile device. The uptake of 3G technology by consumers was greater than anticipated mainly due to breakthrough “smartphone devices” and, as a result, the commercial carriers are investing billions of dollars in the infrastructure necessary to support the greater bandwidth requirements. Smart metering applications, such as AMI, however, placed a premium on low cost and ubiquitous coverage rather than greater bandwidth, which has led to further adoption of the 2G technologies that had been deployed. Nevertheless, the introduction of 3G allowed AMI solutions to transmit large volumes of data using data collector units connected to the utility meter data management systems and back-office servers. The customer's personal communication device is ever since part of the smart grid landscape for customer relation management and utility portal communications.

4G networks based on Long-Term Evolution (or LTE) technology and LTE-Advanced were gradually deployed in 2010–2012 with speeds of 100 Mbps up to 1 Gbps, and the bandwidth race is continuing to allow smartphone applications with increasing bandwidth consumption.

With colossal infrastructure investments and millions of customers, mobile operators certainly are in a better position to provide extensive coverage required for customer premises access than any utility-deployed telecom technology. The utility customer can now become part of the energy landscape through a personal mobile terminal, and in many utilities, mobile data capability, together with GPS-based navigation systems linked to Geospatial Information Systems, constitute a major component of field intervention tools.

However, the extremely marginal (for not saying negligible) share of the business represented by utilities means that they will have no significant influence as to the placement of base stations and coverage, dimensioning of backup power autonomy, frequency spectrum provisioning, antenna heights, cell design, or maintenance process. Moreover, communication outages and dropped connections are familiar experiences for most cellular phone users, and similar issues may be expected to occur for cellular-based smart grid communications as well.

For critical operational communications, power utilities need control to minimize operational risk (i.e., the risk that a wireless carrier would default on its responsibility to provide a reliable service to the utility). New-generation industrial radio systems allow implementing dedicated networks while using public wireless services as a backup facility. For very large deployments (e.g., modem integrated into the metering device), utilities need assurance on sustainability of the service (i.e., the risk that technology evolution would drive wireless carriers to make the utility communications equipment obsolete). The great benefits and potentials of modern mobile data systems can, however, be profitably employed for customer communications (utility customer changes smartphones as frequently as the operator changes systems), and for field intervention crew day-to-day operations, as long as some acceptable solution is available for disaster or emergency situations (e.g., a hybrid public/private industrial terminal).

Finally, the regulatory position on cost recovery to which the utility is submitted can have an important impact. Power utilities are generally allowed to reflect the capital cost (CapEx) of dedicated network deployments into their rate base and pass the cost on to consumers, whereas operational expenses (OpEx) relating to procurement of communication services cannot be recovered.

4.4 COMMUNICATIONS CHALLENGES IN THE SMART GRID

Extensive deployment of a new communication infrastructure or major transformation of the existing network for transporting new smart grid applications requires architectural and technological decisions with important consequences as to the cost of implementation, disturbance of existing services during the migration, and the operation and maintenance of the resulting communication network. According to Navigant Research [3], more than \$29B will be spent on smart grid networking and communications equipment over the next decade. It, therefore, is prudent and important that the industry is attentive to some of the challenges in network implementations for the smart grid.

4.4.1 Legacy Integration, Migration, and Technology Life Cycle

Telecommunications is a fast-moving technology driven by an enormous mainstream market and competition. Power system technology, on the other hand, evolves orders of magnitude slower despite smart grid acceleration: older technologies are fully replaced over decades. As an example, public telecom providers in many countries have abandoned delivering basic time-division multiplexing (TDM) leased circuits with E1/T1 or sub-E1/T1 capacity (corresponding to 2 Mbps or less transparent bit rate) used for EMS, SCADA, and protection signaling. This change is sending many utilities into the quest for alternative solutions with equivalent capability at lower cost. Implementing modern communications in the power system must be planned, designed, and deployed, keeping in mind the time dimension.

- Renewing communication technologies in the power system, in particular, the transmission grid, must allow for the provision of legacy interfaces in a cost-effective and technically acceptable manner. Legacy interfaces can, indeed be emulated over any packet technology as a marginal case of use. However, if these are to be provided in an extensive manner, then perhaps a conventional TDM multiplexer remains more costeffective until the legacy devices are replaced.
- Changes in power system automation devices should be coordinated with the transformation of the communication network. As an example, moving to the IEC61850 protocol for protection and control with Ethernet-based communications simplifies the transition from TDM to packet-switched networking. The same is true for moving from "serial RS232 interfaced" SCADA to TCP/IP, and from master-slave polling-based SCADA protocols to peer-to-peer communications.
- The great difference between "substation time" and "communication technology time" means that the power grid and even a single substation may comprise different generations of information and communications technology installed at different times. The same can be assumed for AMI and any other smart grid constituent. This results in a multi-vendor and multi-release environment inside the same functional layer of the network. The power system communications network is implicitly multi-vendor, multi-release, and multi-technology, but should still operates as a single network.
- Operating with older-generation components in the system is not a temporary transitional state but the permanent mode of operation for the power system communications network: By the time that the older-generation equipment is dismantled, the "once new-generation" equipment itself has become obsolete and "legacy." Planning of the operational communications network must include a preestablished migration strategy that stipulates not only how a new technology can be introduced into the network but ideally also how it can be removed from the network in a seamless manner with minimal system outage. Excessive functional integration may present an attractive cost advantage at the time of deployment, but may also be a major concern when one part of the integrated system needs to be replaced. Smart grid communications systems should be built on an integrated framework approach, where one layer can be upgraded or changed without disturbing other layers of the model. For example, specific wireless modems supporting smart meters should be able to be upgraded to LTE without affecting the AMI head-end system or the meter data management system application layer.
- A closely related consideration for designing future-proof communication architectures is "layered design,": the ability to overlay multiple platforms and technologies as new technologies appear in time. For example, a utility may have several coverage technologies for sending data to an integrated meter data management system and still constitute a single network over these different technologies, as presented in Figure 4.10. Network transformation is performed by layer or service according to application requirements (e.g., upgrading or replacing the transport core but not the substation access). A layered network design allows partial transformation replacing one technology without causing major network disturbances and service disruption.

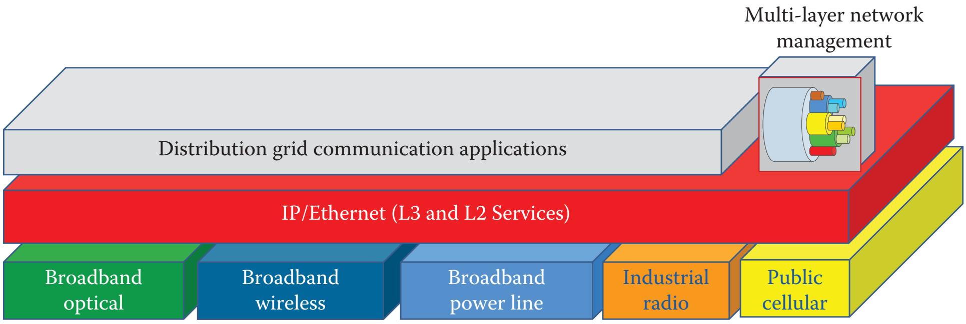

FIGURE 4.10 Typical layered architecture for implementing distribution grid communications. (© 2016 GE Grid Solutions. All rights reserved. With permission.)

4.4.2 Managing Technical Complexity

Modern operational applications in the smart grid environment and the corresponding communication access systems are propagating network intelligence to hundreds of substations spread across the grid. IP routers and Ethernet switches, VPN coding and firewalls, web servers, service multiplexers, and communication gateways require a great amount of expert parameter settings. Any latent errors in these settings and incorrect parameters can considerably change the network behavior without necessarily interrupting system operation as with previous communication systems. Latent "setting errors" in the substation communications can impact the network's performance, availability, throughput, and security. Network devices installed in the substation environment should have dedicated "substation-oriented" HMIs converting substation communication requirements into device settings for error-free configuration and operation by staff with limited communications network expertise.

4.4.3 Predictable Behavior

Many critical power process-related applications require predictable behavior in the related communications service. Predictability in this sense can be defined as follows:

- *Deterministic information routing*—means that both in normal time and in presence of anomalies and failures, one can precisely determine the path taken by the communication message. Fixed or constrained routing limits the operation of network resilience mechanisms into a predefined scheme in which every state taken by the network is previously analyzed. Deterministic routing is not a natural instinct of the network designer who is tempted to employ every resilience capability of the employed technology. However, it constitutes one of the bases for fault tolerant design and for a predictable time behavior.
- *Predictable time behavior*—is the capability to determine the time latency of the communications link for an application. This attribute is essential for applications such as protection relaying, and requires, as a prerequisite, deterministic information routing. A store-and-forward system with packet queuing generates variable delays and, hence, unpredictable time behavior. Delay variation can be absorbed by an elastic buffer but translated into higher absolute delay (time latency). Predictable time behavior must also take into account the time required to restore service in the event of a network anomaly. Predictable time behavior assumes monitoring the "time latency" for critical services through appropriate measuring tools.
- *Predictable fault behavior*—is the system's capability to have predetermined states and defined mechanisms for overcoming a great number of anomalies that may arise during its operation:

- Predictable fault behavior requires predictable routing and time behavior.
- Fault tolerance is the capability of continued service in the event of a communications network fault, achieved through the predictable behavior of the system, for example, normal and backup services without use of common resources, equipment, link, power supply, fiber cable, etc.
- Robustness is a system's capability to resist the severe environment in which it must operate.
- Reliable and stable hardware and software—duplication of critical modules and subsystems and, in certain cases, of the entire equipment or platform, increases the availability of the system. Availability complements but cannot replace fault tolerance, which is a deterministic concept.
- Power autonomy—is the continuity of operational communications in the event of AC power supply interruption for a specified duration ranging from a few hours to a few days. Adequately dimensioned DC batteries and backup generators allow the communications infrastructure to remain operational for restoring the power system.

4.4.4 Maintaining System Operation

Providing communications services to the whole spectrum of new smart grid operational applications in the power utility represents a change of scale in terms of management and organization. The requirements are, indeed, very different for maintaining the operational communications in the transmission or distribution grids over several hundred sites, and for assuring customer metering communications for millions of consumers.

In a procured service scenario, the infrastructure is operated and maintained by a public service provider through its large-scale operations support system facilities, processes, and organization. The task of the power utility is, therefore, to negotiate the contract for the provision of cost-effective services with an adequate level of quality of service, and then to assure that the provider meets its obligations. Defining specific Service Level Agreements (SLAs) regarding the availability, promptness, and continuity of communications services, specifying the process and methods to measure the quality of the delivered service and the potential sanction for not meeting the contracted SLAs can be extremely difficult tasks.

In a utility-operated dedicated telecommunications network environment, a significant increase in the number of communications services may require the reorganization of the telecommunications delivery structures and the deployment of new monitoring tools and new processes. If previously service management was nothing more than a few informal phone calls between the telecoms Operation & Maintenance, the SCADA supervisor, and the substation staff, a sharp increase in the number of concerned parties may imply a fundamentally different "service user/service provider" management model in which the tasks of service management need to be explicit and formal. A first step toward this change of scale is the formal definition of a two-level architecture separating core communications services from different application networks using core communications resources. The management of the core network infrastructure then becomes the responsibility of the "core service provider" with SLA obligations toward each power system application network. The core service provider notifies service users of the availability and performance of the communications services through "service dashboards" constituting the basis for communication service "situational awareness."

4.4.5 Cybersecurity Challenges

Moving from isolated silos to a networked environment and using mainstream communication standards, operating systems, terminals and, in particular, public communication support, greatly increase cybersecurity vulnerability of utilities' communication infrastructures. Cybersecurity in the smart grid is the subject of a separate chapter in this book. Here is a brief description of the challenge regarding communication system design.

Many of the existing communication protocols lack inherent security, which is added later, on the top of the existing communication stack (e.g., DNP3), or introduced in later firmware revisions, resulting in a mix of devices and protocol versions deployed in the field (e.g., AMI protocols). Only in more recent times, accounting for security from the beginning of the design phase has become the standard practice.

Considerable effort has been given in recent years for reinforcing the security of modern information infrastructure and communications. In particular, the NERC-CIP (Critical Infrastructure Protection) cyber-security framework in North America is a landmark framework for the identification and protection of critical cyber assets.

As far as communications are concerned, the following cases are particularly important and merit great care in their design:

- Transport of information over public procured services or the Internet
- Transport of information over wireless networks
- Office access to file-located assets (IT/OT connections)
- Local or remote access to communications management facilities and routing modifications

Assuring cybersecurity in the smart grid also requires security event collection and detection devices deployed across the system (e.g., substation firewalls), secure connections to Authentication Servers (e.g., RADIUS servers), and continuous monitoring of network behavior to detect any changes that could result from an unwanted intrusion (e.g., network performance monitoring). A specific security management network can be implemented over the telecommunication system with specifically allocated bandwidth and quality objectives.

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5 Real-Time Grid Management

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Real-time grid management is critical in ensuring safe, reliable, and optimized operation of the utility grid. The availability of electric power is a prerequisite for the survivability of modern society, and power grids are virtually its lifelines. The aspect of sustainability is gradually gaining in importance, given such challenges as the global climate protection and economical use of power resources are running short.

Large synchronous power grids, for example, in the Americas and Europe, continue to develop in complexity, and were not originally designed to serve the purpose they are expected to serve nowadays, and this progression will continue. Originally, conventional power plants, which were easy to control, were mostly built in the vicinity of cities and load centers, and the grid around them was designed to provide the required capacity. The power demand was growing over the past few years, and the ever-increasing amount of power capacity had to be transferred from the adjacent grids over long distances. In addition to this, during deregulation and privatization, a great number of power plants had to change their location. In the meantime, wind and solar power, with its inherent variability, has been installed in many countries, causing parts of the grid, which may already be overloaded, to become even more overloaded. These fluctuations create great difficulties for the grids, for, in this case, not only the power flow but also the voltage of the grids are affected. The future will likely see more renewable generation on both the transmission and distribution grids, distributed generation sources usually (but not always) closer to the load centers, and increased customer control, which will require new types of measurement and control capabilities to be deployed across the grid. Increased data from the grid will greatly benefit not only utility operations but also planning, design, and management of the grid. Real-time grid management in the vision of smart grid will take many forms of predictive and corrective actions: from avoiding system congestion while maximizing efficiency and minimizing supply costs, to reacting quickly to system faults while maintaining power to as many customers as possible. These are goals not only at the transmission level but also at the distribution level of the grid.

Continual development of control center applications and tools will play a critical role in driving smart grid advances in the transmission arena: wide area measurements and control, congestion alleviation, increased power delivery efficiency and reliability, and system-wide stability and security. Already, globally synchronized measurements of grid operating parameters in the subsecond range are being used in control centers to facilitate earlier and faster detection of system problems and make it easier to assess the conditions across the grid. Novel control center applications will be developed to use this new type of synchronized measurement technology to further improve the ability to maintain the integrity of the power system. These applications will also be able to identify disturbances, unplanned events, and stability problems at a much faster rate.

Distribution control systems already contain smarter applications, and this trend will continue. Grid operators are accustomed to managing the grid on an exception basis, for example, responding to a feeder lockout alarm only after local auto-reclose schemes have completed. In the future, there will be a lot of information available to the system, which, in turn, means that additional intelligence must be applied to that information in order to present the operator with the relevant information to make a decision, rather than simply passing on more data. Taking the example of a fault on a distribution feeder further, an example would be that, instead of presenting the user with a lockout alarm, accompanied by data on associated low voltage, fault passage indications, battery alarms, etc., leaving it up to the operator to drill down, diagnose, and work out a restoration strategy, the distribution control system will notify the operator that a fault has occurred and that analysis and restoration are in progress in that area. The system will then determine the extent of the fault using the current network model; identify current relevant safety documents, operational restrictions, and sensitive customers; and locate the fault using data from the field. The system will automatically run load flow studies identifying loading scenarios, available capacities, and possible weaknesses, using this information to develop a restoration strategy. The system will then attempt an isolation of the fault with the maximum restoration of customers with safe load transfers, potentially involving multilevel feeder reconfiguration to prevent cascading overloads to adjacent circuits. Once the reconfiguration is complete, the system can alert the operator to the outcome and even automatically dispatch the appropriate crew to the identified faulted section.

For real-time grid management systems, one of the key trends in the industry is the increase of bandwidth from the substation to the control center and from the monitoring and control points on the distribution network to the control center. This increase in bandwidth enables the proliferation of thousands of low-cost sensors to be deployed on the network to increase the monitoring and measuring capability of real-time management systems, which will enable the applications at the control center to have a complete view of the network and increase the accuracy of calculations and optimizations.

Real-time grid management systems are a vital part of modern power networks and are enabling the development of smart grids, the highly automated energy systems of the future. Smart grids will need to handle large quantities of renewable power from both large- and small-scale generators. To maintain grid stability despite these potentially disruptive sources of power and the two-way flow of power in what is currently a one-way system will require advanced real-time monitoring and control systems.

5.1 SCADA SYSTEMS

The primary purpose of an electric utility supervisory control and data acquisition (SCADA) system is to acquire and monitor real-time data from the grid (via sensors and intelligent electronic devices [IEDs]), and then send the data to a central computer system in a control center, which uses the data to manage and control the grid remotely, and present the information to the operating personnel. In the past, real-time monitoring and control focused on generation and transmission systems, but more recently, smart grid has been driving the need for SCADA capabilities further down the distribution system closer to the customer. SCADA systems were installed as early as the 1920s, mostly in generation plants with monitoring and control of the nearby substations. This eliminated the need to have the personnel on-site to monitor and control power plants and critical substations 24 h a day.

Figure 5.1 conceptually illustrates the major components of a SCADA system. Typically, SCADA systems include at least one data acquisition processor, one or more remote terminal units (RTUs), and a communications system. RTUs are installed at the power plants, transmission and distribution substations, distribution feeder equipment, etc. The SCADA master hardware and software are typically located centrally at the control center. The control center consists of SCADA application servers, communications front-end processors, a data historian, interfaces to other control systems, operator workstations and user interfaces, and other supporting components. In smaller SCADA systems, it may be composed of a single PC. In larger SCADA systems, it may include multiple redundant servers, distributed software applications, and disaster recovery sites. The primary SCADA system is often redundant, with a local backup system and/or a remote backup system at another site. Other system environments are often installed by the utility for testing and quality assurance, development, and training. Various types of communications links to the RTUs are used. These communications links are now becoming more IP-based using open protocols. Recently, phasor (or synchrophasor) measurement units (PMUs) have been used to supplement the measurement information from conventional RTUs for more precise observation of the system state.

The electric power industry has a specific set of requirements for SCADA systems. Real-time requirements for the monitoring and control of the transmission system, and for main distribution substations and feeders are typically in the range of 1–5 s. The RTU is a microprocessor-based device that provides real-time data to the SCADA system and enables the SCADA system to issue controls to the field equipment. Typical RTUs have physical hardware inputs to interface with field equipment and one or more communications ports (Figure 5.2). In some modern systems, the RTU can generate commands for local control actions at the site of the RTU without the need to

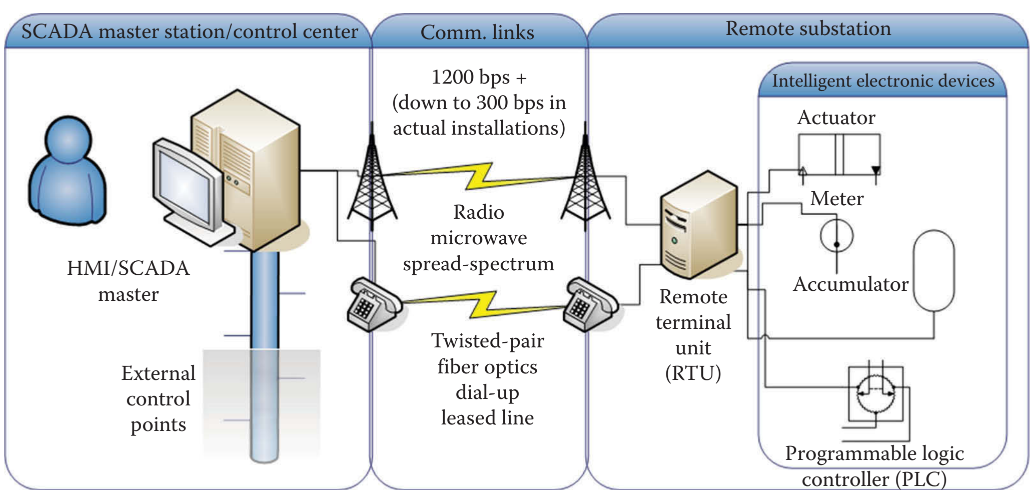

FIGURE 5.1 Major components of a traditional SCADA system.

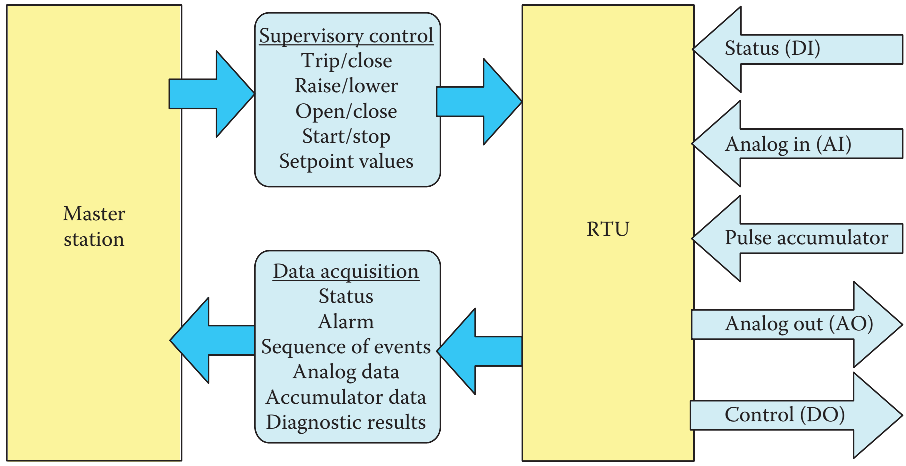

FIGURE 5.2 SCADA system data flow architecture.

communicate to the SCADA system. In recent years, with the proliferation of IEDs, many of these devices are taking over the RTU functionality.

Different RTUs process data in different ways, but in general several internal software modules are common among most RTUs (Figure 5.3):

- Central real-time database (RTDB), which interfaces with all other software modules
- Physical input/output (I/O) application, which acquires data from the RTU hardware components that interface with physical I/O
- Data collection application, which acquires data from the devices with data communications capabilities via communication port(s), for example, IEDs
- Data processing application, which presents data to the master station or human–machine interface (HMI)

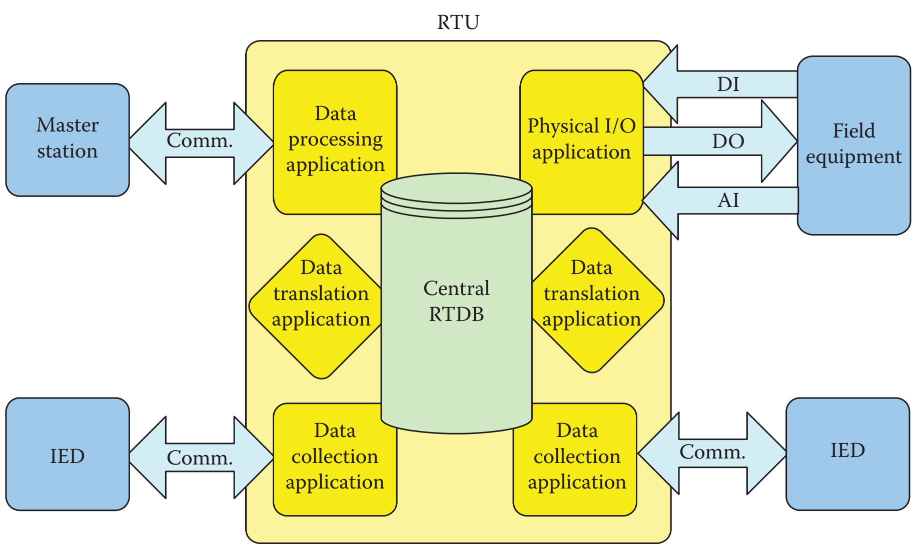

FIGURE 5.3 RTU software architecture.

Some RTUs also have data translation applications that manipulate data before they are presented to the master station or support stand-alone functionality at the RTU level.

There are more than 3000 electric service territories in the United States responsible for managing their portion of the electric grid. Most of the very high-voltage transmission substations in the United States have sensors and meters that monitor real-time operating conditions and have the means to remotely operate transmission equipment, such as circuit breakers and transformer tap changers. Although SCADA has been more predominantly used in monitoring and controlling power generation plants and transmission systems, there is an increasing need to extend SCADA capabilities further down the distribution network to take advantage of advances in technologies, such as distributed energy resource (DER) and integrated Volt/VAr control (IVVC). Less than 25% of the distribution substations have any remote monitoring and control capability, and the final supply to the end user typically has no technology at all. However, this is changing with technology evolution and the reduction in monitoring and control device costs. Smart grid has been driving increased implementations of intelligent residential meters and other technologies and applications that will help drive more visibility of the distribution network through SCADA. Recent trends in SCADA systems include providing increased situational awareness through improved *graphical user interface*s and presentation of data and information, intelligent alarm processing, the utilization of thin clients and web-based clients, improved integration with other engineering and business systems, and enhanced security features.

In the application of SCADA for distribution systems, the costs of the additional sensors, IEDs, RTUs, communications, and SCADA master station must be considered relative to the benefits that are realized. It is rarely economical to monitor and control an entire distribution system with SCADA points. Distribution organizations typically choose to apply SCADA only to equipment that provides them with an adequate return on investment in terms of improving reliability, Volt/VAr control (VVC), situational awareness, remote control, or other business benefits. Monitoring and control of large distribution substations is usually always beneficial, but monitoring and controlling equipment further down the network on distribution feeders is not widespread, at least in the United States and other utilities with geographically large distribution systems. Figure 5.4 shows typical equipment types that can be part of a SCADA system applied on overhead distribution systems.

The most common equipment monitored and controlled in distribution SCADA include recloser controllers, switch controllers, voltage regulator controllers, and switched capacitor bank controllers. In many cases, IEDs and associated CTs and PTs are installed in these devices on the feeder, and adding the communications capability is only an incremental cost. The status and analog values monitored at these points provide operators with valuable visibility of the network operations further down the distribution system. In addition, if a remote control is enabled for these devices, then reliability can be improved from the control center (through the recloser controllers and the switch controllers), and VVC can be improved (through the voltage regulator controllers and the switched capacitor bank controllers).

In underground distribution systems, SCADA can be applied to equipment such as the network protectors in network transformer vaults, automatic throw-over equipment, and ring main units that are used in many parts of the world for protection and switching. In these cases, the status, analog, and control points are similar to those for the overhead distribution system.

With the extension of SCADA to the distribution system, an important consideration is the best way to manage SCADA within the distribution substation, both from a technology viewpoint and from a business process perspective. If the transmission and distribution SCADA systems are handled by the same utility operators, then management of the grid is greatly simplified. However, in many organizations, distribution operations and transmission operations are separate. In such cases, coordination between the two organizations for workflows, such as switching, tagging, and control, must be established. Development, maintenance, and coordination of the two network models must also be addressed.

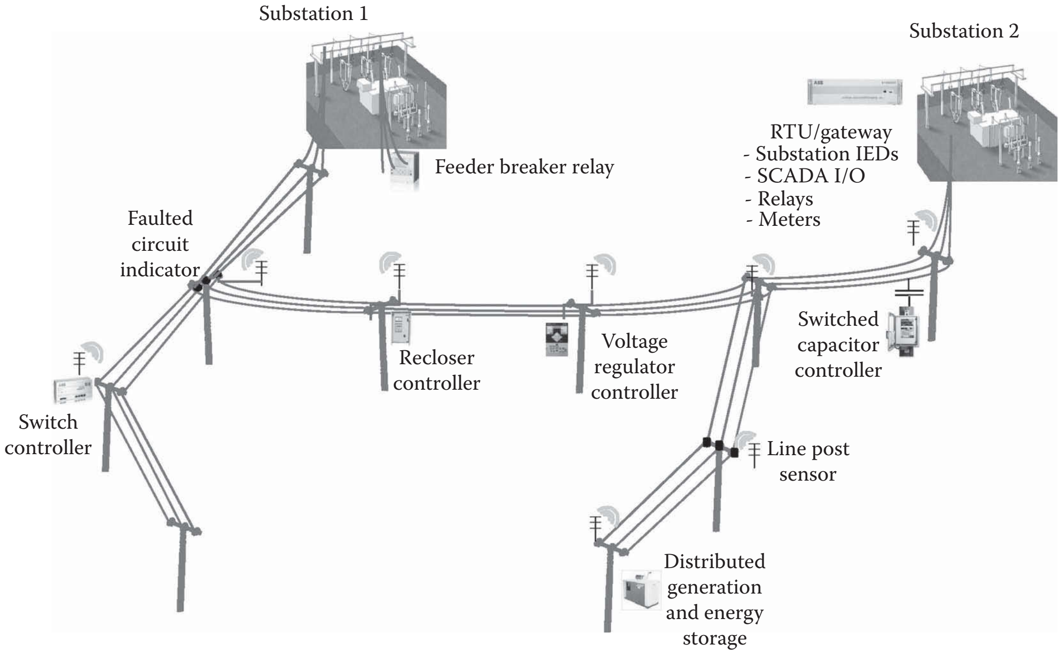

FIGURE 5.4 Typical overhead distribution equipment included in a distribution SCADA system.

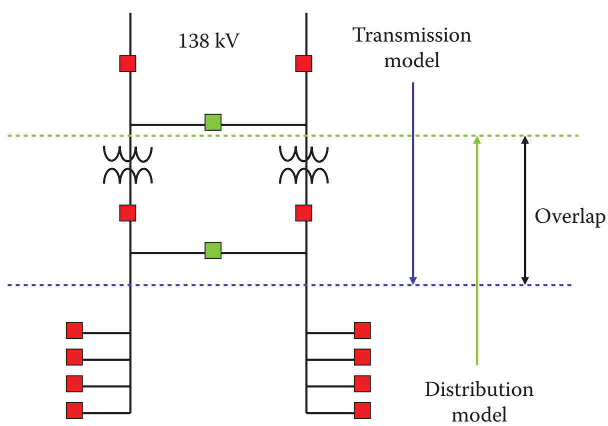

FIGURE 5.5 Possible overlap in separate transmission and distribution SCADA systems.

Figure 5.5 shows a typical distribution substation. An area of overlap exists between a newly defined distribution SCADA and an existing transmission SCADA/energy management system (EMS). It shows the area of overlap between transmission and distribution, as well as the extent of their respective network models.

5.2 CONTROL CENTERS

Operating the electric grid at close to a normal frequency, without causing any unexpected disconnections of load or generation, is known as maintaining electrical integrity or "normal synchronous operation." The first centralized control centers designed to maintain the integrity of the electric grid were implemented in the 1950s. Control center is a general term for a centralized location where the utility grid is monitored and controlled remotely. Depending on whether the utility owns generation, transmission, or distribution systems, control centers can monitor and control a combination of the three systems. In large utilities, or in utilities where the service area covers a large geographical area, there may be multiple regional control centers, and their transmission and distribution systems may be monitored and controlled in separate control centers. Some smaller utilities may only have one control center for both transmission and distribution. The SCADA system is sometimes implemented as only a monitoring and a control system, but is integrated typically as part of an EMS (for generation and transmission systems), or a Distribution Management System (DMS—for distribution systems). The EMS and DMS use the SCADA system to collect, store, and analyze data from hundreds of thousands of data points in national or regional networks, and perform advanced monitoring, control, and optimization, such as AGC (automatic generation control) and generation dispatch, network modeling, load flow calculations, fault analysis, substation and distribution automation, and participate in energy trading markets. It is also becoming common to incorporate wide area measurement system (WAMS) information within EMS functionality to extend the observability to include the dynamic state of the network as well as the steady-state perspective.

With the move to open market operations, there have been shifts in the locations where various operation and monitoring functions are performed. The generation control functions, in many cases, have been moved to independent system operators (ISOs). Also, the transmission analysis operation functions have been transferred to ISOs or RTOs (regional transmission system operators). However, some utilities still operate traditionally with integrated generation, transmission, and distribution control systems.

A large electric utility control center typically has the following (Figure 5.6):

- One or more data acquisition servers or front-end processors (FEP) that interface with the field devices via the communications system
- Real-time data server(s) that contain RTDB(s)

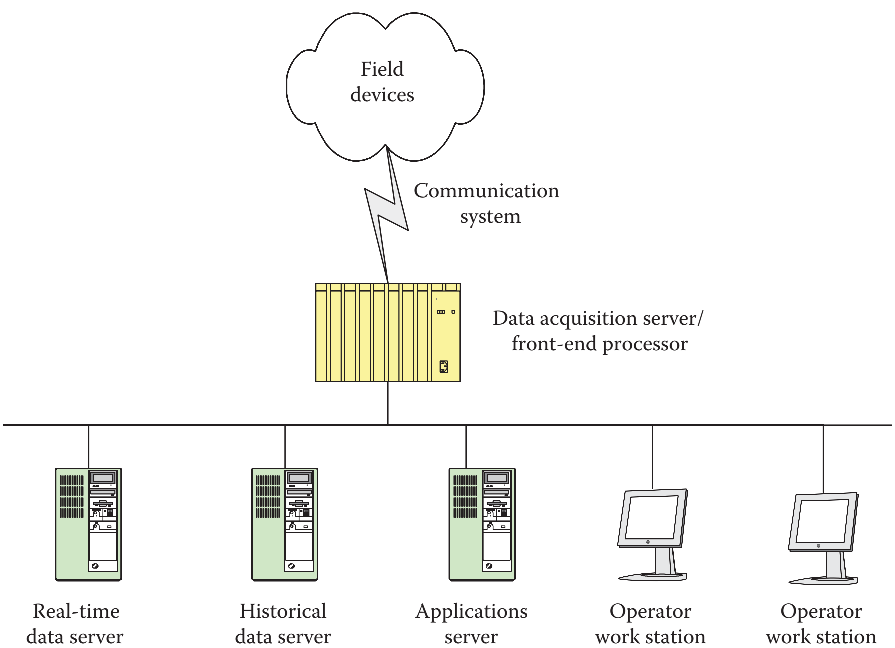

FIGURE 5.6 Typical modern control center architecture (simplified).

- Historical server(s) that store the historical data
- Application server(s) that runs various EMS and DMS applications
- Operator workstations with an HMI

In most modern control centers, hardware components are connected via one or more local area networks (LANs). Many systems have a secure interface to the corporate networks to make the data available to the corporate users.

The control center can include the following responsibilities:

SCADA primary functions:

- Data acquisition
- Remote control
- User interface
- Areas of responsibility
- Historical data analysis
- Report writer

Generation control primary functions (in addition to SCADA):

- AGC
- Economic dispatch (ED) and hydro scheduling
- Interchange transaction scheduling

EMS primary functions (in addition to SCADA/AGC):

- Network configuration/topology processor
- State estimation
- Contingency analysis
- Three-phase balanced operator power flow
- Optimal power flow
- Disturbance and oscillation analysis (in combination with WAMS)
- Dispatcher training simulator

DMS primary functions:

- Interface to automated mapping/facilities management (AM/FM) or geographic information system (GIS)
- Interface to customer information system (CIS)
- Interface to outage management
- Three-phase unbalanced operator power flow
- Map series graphics

Substation and distribution automation system primary functions:

- Two-way distribution communications
- Fault identification/fault isolation/service restoration
- Voltage reduction
- Load management
- Power factor control
- Short-term load forecasting

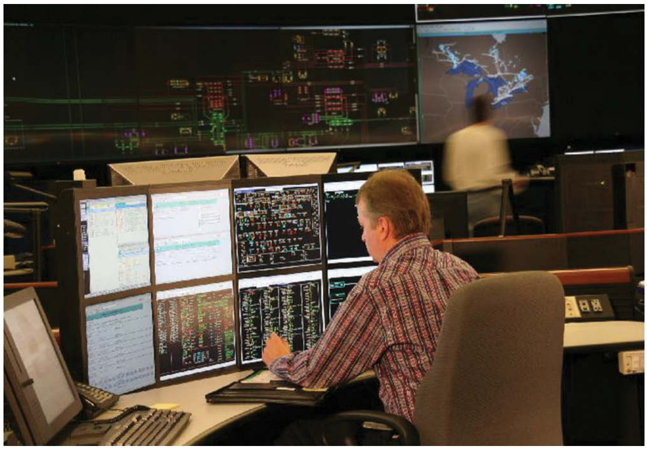

FIGURE 5.7 Control center operator console. (© 2016 General Electric. All rights reserved. With permission.)

Figure 5.7 shows a typical modern-day control center environment with the different display screens the operator uses at the console to monitor and control grid conditions. The control center consists of many such operator consoles, as well as large wallboards or digital displays that provide a bird's eye view of the entire system. The operators' responsibilities are to monitor data on their consoles, coordinate with other operators within their control center, coordinate with plant operators, and periodically exchange information with neighboring system operators. Most of the time, the grid is relatively quiescent with no adverse conditions. But when a disturbance suddenly occurs, the operators each need to perform their specific individual tasks and coordinate with other operators in the control center in order to use their collective expertise to identify specific actions that may need to be taken to mitigate the impact of the disturbance.

5.3 ENERGY MANAGEMENT SYSTEMS

The first EMS application placed in control centers across the country was basic SCADA functionality. The first SCADA systems were hardwired analog systems, and visualization of the system was implemented via "static" displays on the control center walls, with basic status changes, such as breaker operation, implemented by small motorized indicators ("tiles"). There was also basic control capability via switches on the "static" display. The next main function implemented at control centers was load frequency control (LFC). The objective of LFC is to automatically maintain system frequency to address load changes by changing generation output accordingly. In the early implementations of LFC, the control center operator visually monitored the system frequency measurement and periodically sent incremental change signals to generators via analog-wired connections or by placing phone calls to generating plant operators to keep generation output close to system load demand. Later, as analog systems transitioned to digital, LFC became the first automated application to help the control center operator keep power available at all times. In the 1930s, the next progression in system monitoring and control was interconnecting one power utility with neighboring utilities to increase overall grid reliability and reduce operating costs by allowing power sharing during emergencies and exchange cheaper power during normal operations. With this came the need to control generation much more closely, so analog computers were developed to monitor and control generator output, tie-line power flows, and frequency.

By the 1950s, the analog computers were enhanced to allow the scheduling of each generator to provide the lowest cost of generation. These functions were called economic dispatch (ED) and automatic generation control (AGC). In the late 1960s, digital computers and software were developed to replace the analog EMS systems. Software applications were developed to include off-line analysis functions, along with transmission system analysis models. Vendors typically modified the computer supplier's operating system to meet their design and each set of application software was usually unique for each customer. Thus, when the computers needed to be upgraded, or more functions were required, the entire EMS typically had to be replaced. This trend continued into the 1980s and 1990s until open standard operating systems were developed that supported real-time applications [1]. Some recent advances in EMS functionality are discussed in the following sections.

5.3.1 Situational Awareness and Grid Operator Visualization

Timely visualization of real-time grid conditions is essential for successful grid operations. In the aftermath of the 1965 blackout of the northeast United States and Canada, the findings from the blackout report included the following: "control centers should be equipped with display and recording equipment which provide operators with as clear a picture of system conditions as possible." Since then, many more blackouts have occurred, small and large, around the world, and in almost all cases, improvements in the visibility of grid conditions were identified as one of the primary recommendations.

On August 14, 2003, the largest blackout in the history of the North American power grid occurred. Subsequently, numerous experts from across the industry were brought together to create a blackout investigation team. A primary objective of this team was to perform in-depth post-event analyses to identify the root causes and, more importantly, to make recommendations on what could be done to prevent future occurrences of such events. The report (the United States–Canada, 2004) identified four root causes: inadequate system understanding, inadequate situational awareness (SA), inadequate tree trimming, and inadequate reliability coordinator diagnostic support. This report gave a sudden new prominence to the term "situational awareness."

There are several definitions of SA. Very simply, SA means to constantly be aware of the health of changing power system grid conditions. Other definitions include "Being cognizant of the current power system state and the potential imminent impact on grid operations" and "The perception of the elements in the environment within a volume of time and space, the comprehension of their meaning, and projection of their status in the near future" [2].

An essential aspect of SA for grid operations is being able to extract and concisely present the information contained in the vast amount of ever-changing grid conditions. An advanced visualization framework (AVF) is necessary to be able to present real-time conditions in a timely, prompt manner. AVF needs to provide the ability to efficiently navigate and drill down, to discover additional information, such as the specific location of the problem. More importantly, AVF needs to provide the ability to identify and implement corrective actions to mitigate any risks to successful grid operations. Operators do not just want to only know that there is a problem now or that a problem is looming on the immediate horizon. They also want to know how to fix the problem.

A number of visualization products have been developed over the past decade. These include PowerWorld [3], Real Time Dynamics Monitoring System (RTDMS) [4], Space-Time Insight, and so on.

A frequently cited human limitation has been described as Miller's magical number seven, plus or minus two [5]. Miller's observation was that humans have a limited capacity for the number of items or “chunks” of information that they can maintain in their working memory. Therefore, as increasing volumes of data are streamed into the control center, one must keep in mind that there is a limit on how much of these data are useful to the operator. As per Miller, the operator can typically handle only five to nine such “chunks” of information. The limitation with the traditional display technologies has been that they approach the problem by “rolling up” (aggregating) the data and then allowing the operator to “drill down” for details. The result is a time-consuming and cognitively expensive process [6].

The challenge is to translate the ever-increasing deluge of measurement data being brought into the control center into useful, bite-size, digestible “chunks” of information, which has been the primary objective of all the recent SA developments for grid operations: “converting vast volumes of grid data into useful information and showing it on a display screen.”

As the saying goes, “a picture is worth a thousand words.” More importantly, the correct picture is worth a million words! What this means is that providing the grid operator with a concise depiction of voluminous data is meaningful; providing a depiction of voluminous data that needs immediate operator attention is immensely more meaningful; this is the objective of an advanced, intelligent SA, to provide timely information that may need prompt action, for current system conditions.

The way to develop the “correct” picture is to organize the visualization presentation around operator goals; that is, what is the result the operator is seeking? Use-cases need to be developed to document the specific actions an operator takes to reach a specific goal. These use-cases can then be used to develop efficient navigation capabilities to quickly go from receipt of an alert to analyzing the “correct picture” and determining the appropriate course of action.

These are the requirements upon which today’s advanced visualization and SA capabilities have been developed. SA capabilities continue to be developed and enhanced to help improve grid operations. Figure 5.8 shows how SA has evolved with analytical tools over the past few decades and what is foreseen for the immediate future.

Generation 1 visualization and applications were focused on monitoring and control; these capabilities were developed in the 1980s and 1990s. Generation 2 focused on creating information from data to facilitate decision-making to take corrective action; these capabilities were developed in the last two decades and are operational in many control centers around the world. Generation 3 is foreseen to focus on developing real-time measures to determine exposure and associated risk related to ensuring the integrity of the grid. This generation will likely be focused on stochastic analytics,

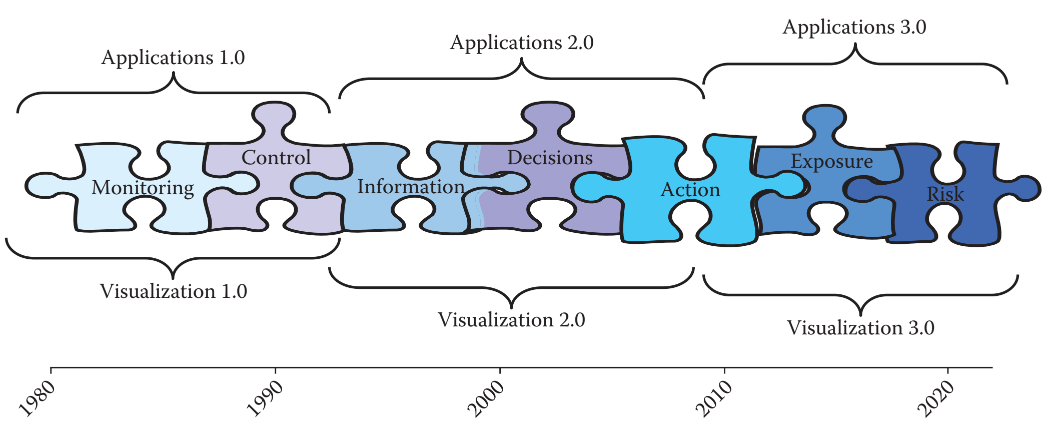

FIGURE 5.8 Evolution of EMS situational awareness (SA) capabilities. (© 2016 General Electric. All rights reserved. With permission.)

as well as heuristic and intelligent systems, for the development of advanced risk management and mitigation applications and visualization capabilities. These developments will be aided by ongoing technology advances, such as subsecond, synchronous measurements, coupled with fast-acting, subsecond controllers.

5.3.2 Decision Support Systems

Most control center operator decisions today are essentially reactive. Current information, as well as some recent history, is used to reactively assess the current state and its vulnerability. Operators then extrapolate from current conditions and postulate future conditions based on personal experience and planned forecast schedules.

The next step is to help operators make decisions that are preventive. Once there is confidence in the ability to make reactive decisions, operators will need to rely on "what-if" analytical tools to be able to make decisions that will prevent adverse conditions if a specific contingency or disturbance were to occur. The focus, therefore, shifts from "problem analysis" (reactive) to "decision-making" (preventive).

The industry trend next foresees predictive decision-making, and in the future, decisions will be proactive. These types of the decision-making process are the foundation of a decision support system (DSS) that will be essential to handle the operation of smarter grids with increasing complexity and more diverse generation and load types. The DSS will use more accurate forecast information and more advanced analytical tools to be able to confidently predict system conditions and use what-if scenarios to be able to act now to preclude possible problematic scenarios in the future. The components of DSS include the following:

- AVF
- Geospatial views of the grid
- Dynamic dashboards generated on demand
- Holistic views combining data from multiple diverse sources
- Use-case analysis to enhance ergonomics
- Advanced, fast, alert systems
- Root-cause analysis to quickly identify sources of problems
- Diagnostic tools that recommend corrective actions
- Look-ahead analysis to predict imminent system conditions

Figure 5.9 is an overview of a look-ahead analytical tool to help the operator make preventive decisions to obviate potential problems. The current system state is used to calculate projected future system states based on load forecasts, generation schedules, etc., to determine whether conditions in the future are safe. As the figure depicts, if the projections indicate a problem is imminent, the operator could then determine and implement an action, in advance, to avoid the problem.

Figure 5.10 is one example of a DSS implemented by Alstom Grid. It consists of a central DSS server and database. The DSS server provides information to a map board (for wide-area visualization) and operator workstations. A power system simulator is used as a look-ahead engine to forecast immediate future conditions. This look-ahead data, together with traditional EMS SCADA and state estimator data, are shown at the operator workstations to facilitate and improve timely, preventive decision-making.

5.3.3 Uncertainty Modeling

On November 4, 2013, Denmark's wind turbines supplied 122% of the country's demand for electric power. On October 3, 2013, Germany's solar and wind power peaked at 59.1%, with

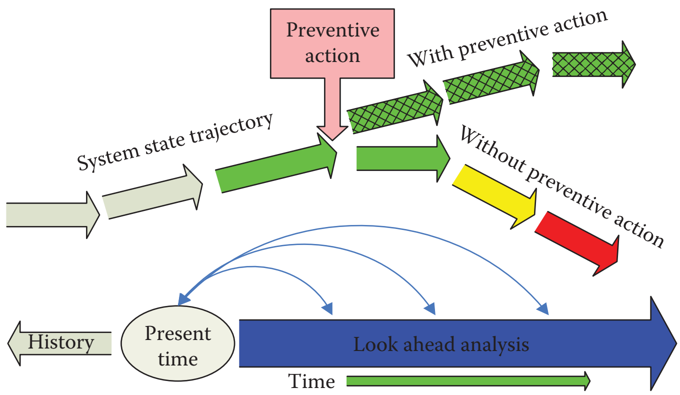

FIGURE 5.9 Look-ahead analysis for preventive control. (© 2016 General Electric. All rights reserved. With permission.)

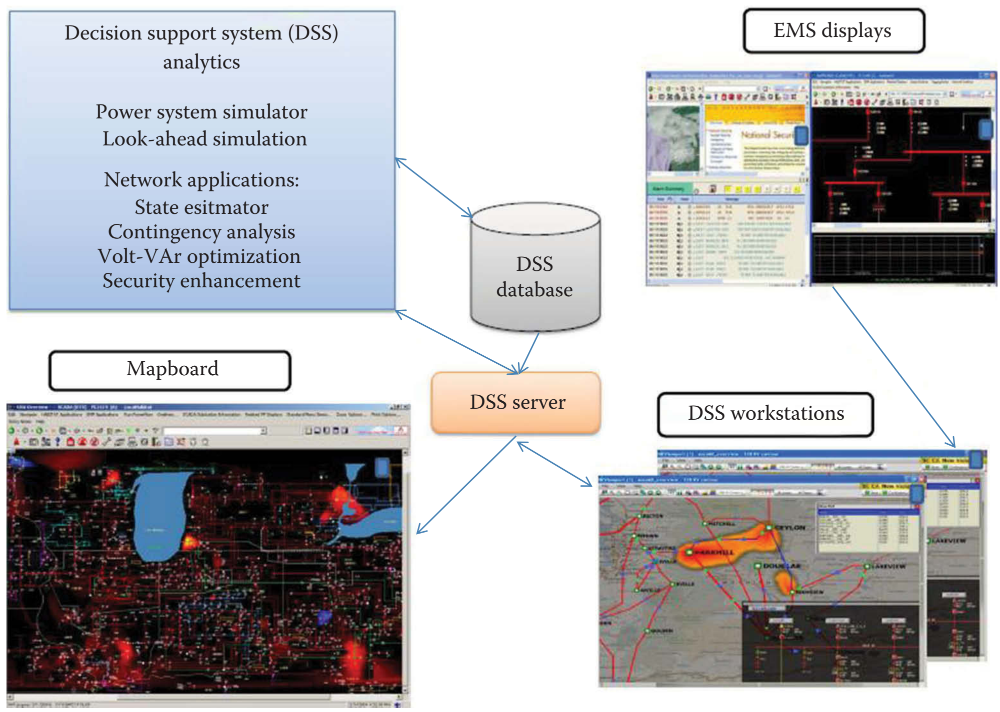

FIGURE 5.10 Decision support system (DSS) implementation. (© 2016 General Electric. All rights reserved. With permission.)

solar contributing 11% at 20.5 GW at its peak. In 2015, Germany's annual renewable power energy production surpassed 180 TWh, by more than 30% of the annual gross power consumption of 597 TWh. In one year, the UK connected 7.7 GW of solar energy at distribution voltages, in a system with demand between 30 GW and 60 GW and variable renewable capacity now exceeding the minimum demand. The trend is global. According to the Global Wind Energy Council [7] (Figure 5.11), at the end of 2015, total global wind power capacity reached 432,883 MW, representing cumulative growth of 17%. Similarly, solar power is growing at a remarkable

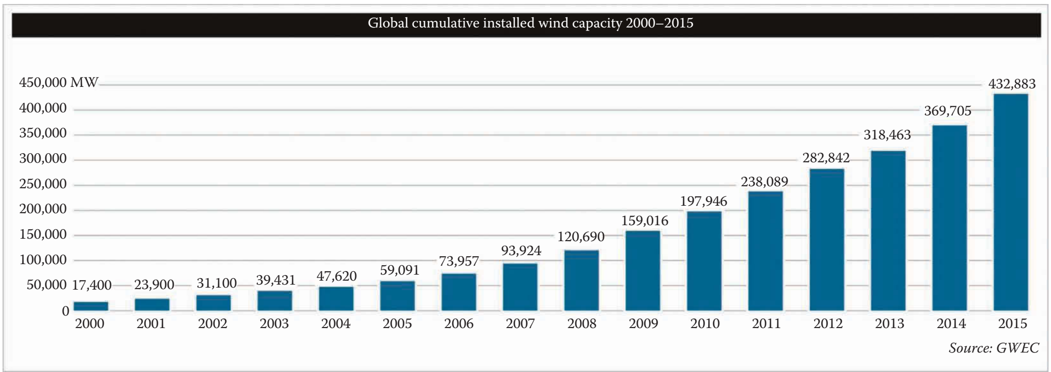

FIGURE 5.11 Global cumulative installed wind capacity 2000–2015. (From Global Wind Energy Council (GWEC).)

speed. According to PV Magazine [8], a record 40 GW Solar Capacity was installed in 2014, and 55 GW was predicted in 2015 globally. By 2020, the cumulative installation will reach 540 GW.

Unlike fossil fuel-based power or hydropower, renewable powers from wind and photovoltaic sources are non-dispatchable. There is little control over how much power is produced and when it is produced. Renewable power productions can also be very volatile (uncertainty) and sporadic (intermittence). At high levels of renewable power penetration, these properties of renewable power can no longer be ignored and must be considered explicitly in power system planning and operation. Traditional deterministic scheduling will not do well with a high level of uncertainty, which will become the new norm ushered in by renewable power. To ensure operation feasibility and security, deterministic resource scheduling will likely result in excessive reserve cost, load shedding, and curtailment of renewable power. While DERs and demand response can help to mitigate some of the renewable uncertainty, energy storage is still very costly and its deployment very limited. An important challenge to power system planners, operators, and researchers is how we can make better planning and operation decisions under such high level of uncertainty.

Uncertainty or randomness ubiquitously exists in the whole power industry and fundamentally affects almost all facets of this industry. Because of the critical role of EMS and transmission systems, many advanced stochastic optimization methods to handle various uncertainties have been introduced to this field and implemented in practical packages. Next, the most popular modeling schemes and their corresponding computational methods will be reviewed, as well as their typical applications in EMS functional components.

Uncertainty modeling schemes can be classified into two groups, which naturally leads to two types of optimization formulations. The first group is the (approximate) distribution-based one, where an analytical distributional function or a finite set of representative scenarios (to approximate a distribution) will be used to capture the underlying random factors or processes. Obviously, if sufficient data are available and reliable, such uncertainty description guarantees a high fidelity to the randomness and provides a solid basis for model verification and validation. With a random distribution function or a set of scenarios, we can extend a deterministic formulation, in terms of size and complexity, into a so-called stochastic programming model or its variant (e.g., a chance-constrained model).

On the contrary, the second group does not assume any probabilistic information. It just considers an uncertainty set, which can be flexibly defined based on existing data or practitioners' understanding toward randomness. For example, when the data set of random factors is rather small and less accurate, an uncertainty set that includes existing data as a proper subset can be employed to minimize the risks of data insufficiency or inaccuracy. As another example, the most popular N-k contingency concept can be conveniently described as an uncertainty set, given that the system reliability is imposed regardless of the realization probability of any N-k scenario. Compared to the distribution-based uncertainty scheme, the uncertainty set-based one is more robust to data availability and quality, and it emphasizes the reliability and feasibility. With the uncertainty set, a deterministic formulation can be extended, through a multilevel structure, into a so-called robust optimization model or its variant (e.g., risk constrained robust optimization).

In deterministic optimization, all the parameters in the problem definition are assumed to be deterministic and known at the time the problem is solved. In the stochastic approach to optimization under uncertainty, we summarize the approach as:

- Characterize the underlying stochastic process of the uncertainty parameters
- Account for the impact of uncertainty on feasibility of the solution
- Define objective function that evaluates the merits of the solution under uncertainty

The uncertainty of a parameter can be modeled by interval values or by discrete probability distributions. It's also important to consider any cross correlations between the stochastic parameters across space and time. Feasibility constraints are handled on a deterministic (satisfied under all scenarios) or probabilistic basis (satisfied for most but not all scenarios).

There are two types of decisions to make in optimization under uncertainty: the decisions that are made before uncertainty is resolved (outcome is known) and the decisions that are made after the uncertainty is resolved. If the uncertainty is resolved all at once, it is a two-stage stochastic optimization problem. If the uncertainty is resolved in multiple stages, it requires a multi-stage stochastic optimization.

Security Constrained Unit Commitment is key in both the day-ahead market and the real-time market in operating the power system securely and economically. Figure 5.12 illustrates the error of forecast for Hour 24 made at Hour 18 is no greater than the error of forecast for Hour 24 at Hour 6 or 12. The transmission constraints are affected by not only the amounts but also the locations of renewable powers. This feature limits the use of aggregations of renewable power to reduce the number of uncertainties. The number of uncertainty scenarios can grow to astronomical numbers even for problems with modest sizes. Assuming ten wind farms with only two possible output states in a 24-interval optimization, the number of scenarios is in the order of 10 raised to the 72nd power.

The growth of renewable power in electric power systems increases uncertainty and presents new challenges to resource scheduling. Stochastic optimization is a non-hardware solution in a

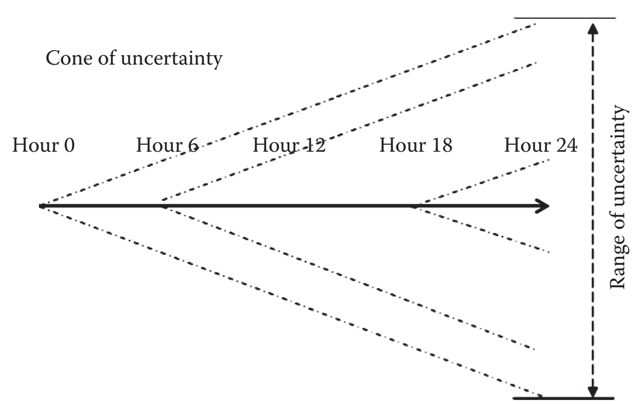

FIGURE 5.12 Uncertainty of forecast as a function of lead time.

multi-pronged strategy (including energy storage, demand response) toward cost-effective integration of renewable powers. Stochastic optimization has its unique challenges, from uncertainty characterization, selection of uncertainty stages, choices of objective functions, choice of constraint enforcement, to the development of computationally tractable solutions. Credible and realistic uncertainty modeling and effective solution techniques will remain an area of active research as the levels of renewable power in power systems reach new heights.

5.4 DISTRIBUTION MANAGEMENT SYSTEMS

5.4.1 Current Distribution Management Systems

Distribution management systems (DMSs) started with simple extensions of SCADA from the transmission system down to the distribution network. A large proportion of dispatch and system operations systems in service today rely on manual and paper-based systems with only a little real-time circuit and customer data. Operators must contend with several systems and interfaces on the control desk ("chair rolls") based on multiple network model representations. The experience of operators is the key to safe system operation. With an increase in regulatory influence and smart grid focus on advanced technologies, there is a renewed interest in increasing investment in distribution networks to defer infrastructure build-out and reduce operating and maintenance costs through improving grid efficiency, network reliability, and asset management programs.

As distribution organizations have become more interested in increasing asset utilization and reducing operational costs, advanced DMS applications have been developed. These include load allocation and unbalanced load flow analysis; switch order creation, simulation, approval, and execution; overload reduction switching, and capacitor and voltage regulator control. Two specific examples of advanced applications that reduce customer outage durations are the fault location application and the restoration switching analysis (RSA) application. DMS applications commonly used today include:

Fault detection, isolation, and service restoration (FDIR) are designed to improve the system reliability. FDIR detects a fault on a feeder section based on the remote measurements from the feeder terminal units (FTUs), quickly isolates the faulted feeder section, and then restores the service to the unfaulty feeder sections. It can reduce the service restoration time from several hours to a few minutes, considerably improving the distribution system reliability and service quality. The fault location application estimates the location of an electrical fault on the system which is different than identifying the protective device that operated, which typically is done based on the pattern of customer outage calls or through a change in a SCADA status point. The location of the electrical fault is where the short-circuit fault occurred, whether it was a result of vegetation, wildlife, lightning, or something else. Finding the location of an electrical fault can be difficult for crews, particularly where there are no protective or measuring devices on long runs of the distribution feeder. Fault location tends to be more difficult when troubleshooters or crews are hindered by rough terrain, heavy rain, snow, and darkness. The more time required to locate the fault, the more time customers are without power. DMS-based fault location algorithms use the as-operated electric network model, including the circuit connectivity, the location of open switches, and lengths and impedances of conductor segments, to estimate fault location. Fault current information, such as magnitude, predicted type of fault, and faulted phases is obtained by the DMS from IEDs, such as relays, reclosing controls, or RTUs. After possible fault locations are calculated within the DMS application, they are geographically presented to the operator on the console's map display and in tabular displays. If a geographic information system (GIS) land base has been included, such as a street overlay, an operator can communicate to the troubleshooter the possible location, including nearby streets or intersections. This information helps crews find faults more quickly. As business rules permit, upstream isolation switches can be operated and upstream customers can be reenergized more quickly, resulting in much lower interruption durations. The DMS fault location application uses the electrical DMS model and fault current information from IEDs to improve outage management.

Restoration switching analysis (RSA) is an advanced application that improves reliability performance indices. This application can improve the evaluation of all possible switching actions to isolate a permanent fault and restore customers as quickly as possible. The application recommends the suggested switching actions to the operator, who can select the best alternative based on criteria such as the number of customers restored, the number of critical customers restored, and the required number of switching operations. Upon the occurrence of a permanent fault, the application evaluates all possible switching actions and executes an unbalanced load flow to determine overloaded lines and low-voltage violations if the switching actions were performed. The operator receives a summary of the analysis, including a list of recommended switching actions. Like the fault location application, the functionality uses the DMS model of the system but improves outage management and reduces the customer average interruption duration index (CAIDI) and system average interruption duration index (SAIDI). The RSA application is particularly valuable during heavy loading and when the number of potential switching actions is high. Depending on the option selected, the application can execute with the operator in the loop or a closed-loop manner without operator intervention. In closed-loop operation, the RSA application transmits control messages to distribution devices using communications networks, such as SCADA radio, paging, or potentially advanced metering infrastructure (AMI) infrastructure. Such an automated isolation and restoration process approaches what many call the "self-healing" characteristic of a smart grid.

IVVC has three basic objectives: reducing feeder network losses and providing reactive power support to sub-transmission systems by energizing or de-energizing the feeder capacitor banks, ensuring that an optimum voltage profile is maintained along the feeder during normal operating conditions, and reducing peak load through feeder voltage reduction by controlling the transformer tap positions in substations and voltage regulators on feeder sections. Advanced algorithms are employed to optimally coordinate the control of capacitor banks, voltage regulators, and transformer tap positions.

Topology processor (TP) is a background, off-line processor that accurately determines the distribution network topology and connectivity to display colorization and provide accurate network data for other DMS applications. The TP may also provide intelligent alarm processing to suppress unnecessary alarms due to topology changes.

Distribution power flow (DPF) solves the three-phase unbalanced load flow for both meshed and radial operation scenarios of the distribution network. DPF is one of the core modules in a DMS, and the results are used by many DMS applications for analyses, such as FDIR and IVVC.

Load modeling/load estimation (LM/LE) is a very important base module in DMS. Dynamic LM/LE uses all the available information from the distribution network—including the user transformer capacities and customer monthly billings, if available, combined with the real-time measurements along the feeders to accurately estimate the distribution network loading for both individual loads and aggregated bulk loads. The effectiveness of the entire DMS relies on the data accuracy provided by LM/LE. If the load models and the load values are not accurate enough, all the solution results from the DMS applications will be useless.

Optimal network reconfiguration (ONR) is a module that recommends switching operations to reconfigure the distribution network to minimize network energy losses, maintain optimum voltage profiles, and balance the loading conditions among the substation transformers, the distribution feeders, and the network phases. ONR can also be utilized to develop outage plans for maintenance or service expansion fieldwork.

Contingency analysis (CA) in the DMS is designed to analyze potential switching and fault scenarios that would adversely affect supply to customers or impact operational safety. With the CA results, proactive or remedial actions can be taken by changing the operating conditions or network configuration to guarantee a minimal number of customer outages and maximum network reliability. *Switch order management (SOM)* is a very important tool for system operators in real-time operation. Several of the DMS applications and the system operators will generate numerous switch plans that must be well managed, verified, executed, or rejected. SOM provides advanced analysis and execution features to manage all switch operations in the system better.

Short-circuit analysis (SCA) is an off-line function to calculate the short-circuit current for hypothetical fault conditions to evaluate the possible impacts of a fault on the network. SCA then verifies the relay protection settings and operation and recommends more accurate relay settings or network configuration.

Relay protection coordination (RPC) manages and verifies the relay settings of the distribution feeders under different operating conditions and network reconfigurations.

Optimal capacitor placement/optimal voltage regulator placement (OCP/OVP) is an off-line function used to determine optimal locations for capacitor banks and voltage regulators in the distribution network for the most effective control of the feeder VARs and voltage profile.

Dispatcher training simulator (DTS) is employed to simulate the effects of normal and abnormal operating conditions and switching scenarios before they are applied to the real system. In distribution grid operation, DTS is a very important tool that can help the operators to evaluate the impacts of an operation plan or simulate historical operation scenarios to obtain valuable training on the use of the DMS. DTS is also used to simulate conditions of system expansions.

5.4.2 Advanced Distribution Management Systems

The concurrent DMS systems are predominately based on the features of the conventional distribution systems with passive networks where the power flow is one-way, i.e., from distribution substations to the individual loads. There exist no other power sources in the networks. With more and more penetration of DERs, self-sustainable homes and connections of microgrids to the distribution networks, the distribution systems are no longer passive but highly active networks, which introduces dramatic changes to the fundamental characteristics of the distribution system operation and considerable challenges to the distribution system control and management. The DERs are more dispersed renewables and various scales of energy storages, where some of them are at the consumer sites along the distribution network. Such types of energy resources are usually subject to considerable uncertainty in both normal operation and emergency conditions.

The electricity consumption of individual consumers is also with great uncertainty when they respond to the demand response management (DRM) and real-time pricing and rewarding policies of power utilities for economic benefits. The conventional solution methods or approaches utilized in the traditional DMS applications are no longer effective or even useless in some cases.

In the active distribution networks, the power flow becomes bidirectional, flowing in two ways, depending on the operation conditions of the loads and the DERs in addition to the power supply buses of the distribution substations. The transition from one-way power flow to two-way power flow creates huge impacts on all the distribution network analysis-related applications. The high penetration of DERs requires the distribution network analysis algorithms to deal with multiple, incremental, and isolated supply sources with limited capacities, as well as a network topology that is no longer radial or is weakly meshed. In a faulted condition, some of the distributed generation resources may also contribute to the short-circuit currents, adding to the complexity of the SCA, RPC, and FDIR logic. With the increasing installation of inverter-controlled DER resources, the balance of frequency, voltage, and power quality will all be inevitably affected and pose challenges for conventional DMS applications.

The impact of DRM and consumer behaviors due to dynamic pricing may be modeled or predicted from the utility pricing rules and rewarding policies for specified time periods, which can be properly incorporated into the LM and LE algorithms but it will require a direct linkage between the DMS and the DRM applications, as well as the predicted price impacts. When the DRM application attempts to accomplish load relief in response to a request from the independent system operator (ISO), it will need to verify from the DMS that the DRM load relief will not cause any distribution network connectivity, operation, or protection violations.

All the challenges and impacts introduced by the above-mentioned new developments require advanced DMS system to integrate the adjacent systems and enhanced advanced applications. A number of smart grid advances in distribution management are expected, as shown in the Figure 5.13.

Monitoring, control, and data acquisition will extend further down the network to the distribution pole-top transformer and perhaps even to individual customers using an AMI and demand response and home EMSs on the home area network (HAN). More granular field data will help increase operational efficiency and provide more data for other smart grid applications, such as outage management. Higher speed and increased bandwidth communications for data acquisition and control will be needed. Sharing communication networks with an AMI will help achieve system-wide coverage of remote monitoring and control devices located on the distribution network and at individual consumer sites. Integration, interfaces, standards, open systems, and centralized data management will become a necessity. Ideally, the advanced DMS will support an architecture that allows advanced applications to be easily added and integrated with the system. Open standards databases and data exchange interfaces—such as Common Information Model (CIM), Simple Object Access Protocol (SOAP), eXtensible Markup Language (XML), service-oriented architecture (SOA), and enterprise service buses (ESB)—will allow flexibility in the implementation of the applications required by the utility, without forcing a monolithic distribution management solution. For example, the open architecture in the databases and the applications could allow incremental distribution management upgrades, starting with a database and monitoring and control application (SCADA), then later adding an IVVC application with minimal integration effort. As part of the overall smart grid technology solution or roadmap, the architecture could also allow interfacing

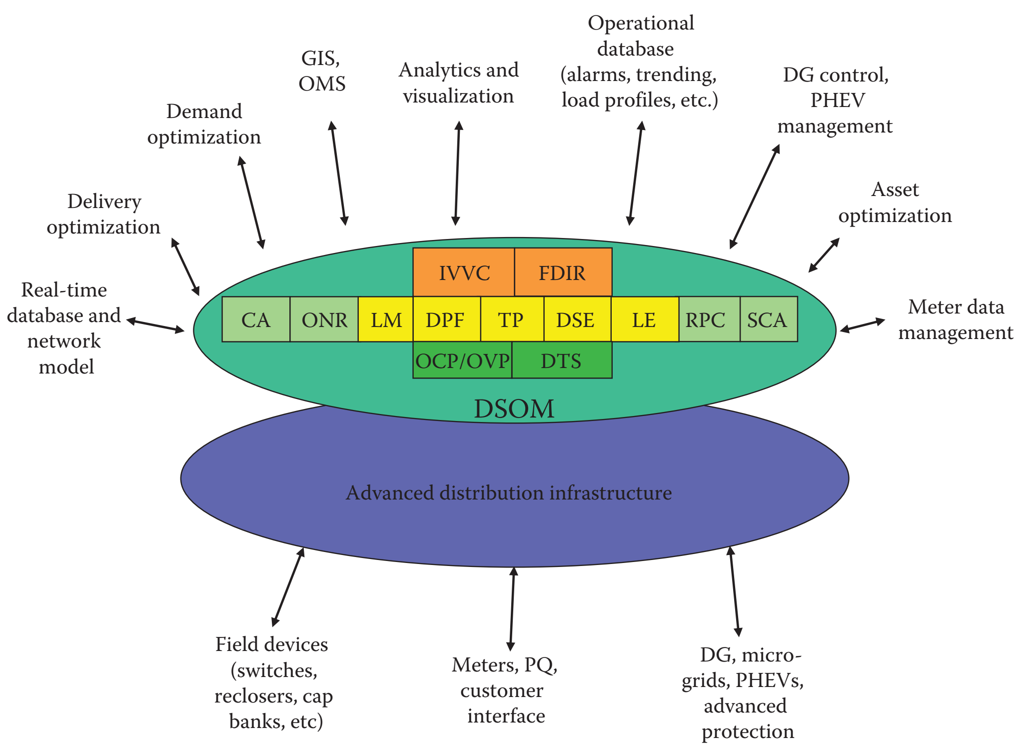

FIGURE 5.13 Advanced distribution management for the smart grid. (From Fan, J. and Borlase, S., The evolution of distribution, *IEEE Power and Energy Magazine*. © March/April 2009 IEEE. With permission.)

with other enterprise applications, such as a GIS, an outage management system (OMS), or a meter data management system (MDMS) via a standard interface. Standardized web-based user interfaces will support multi-platform architectures and ease of reporting. Data exchange between the advanced DMS and other enterprise applications will increase operational benefits, such as MDM and outage management. It is, therefore, beneficial to have a centralized data repository where heterogeneous power system data are ingested, aligned, and analyzed. Such data center may contain network topology, equipment data, and consumption information, and so on for both off-grid applications and streaming data analysis. A high-speed database is then desired to handle the massive volume and heterogeneous nature of data.

As described previously, the distribution grid is becoming highly active with the penetration of DERs and micro-grid connections. The advanced applications in the DMS are facing completely new environments that are not like the traditional passive networks as the basis of the conventional applications and will result in considerable challenges. The most important challenge comes from the bidirectional power flow in the grid, which may change from time to time depending on the real-time dynamics of the load, the DER generation distributions. The second challenge comes from the additional uncertainties associated with DER generation, in which most of the generation may come from intermittent renewable resources. The advanced DMS applications may, thus, need to be sufficiently robust and able to respond quickly to cope with dramatic changes in certain conditions. Some of the key applications may need to be able to look ahead when providing predicted operational schedules and strategies, including IVVC, FDIR, and ONR. The following paragraphs discuss the key features of the typical advanced DMS applications. In the case that a microgrid is involved, advanced distribution management system (ADMS) may also be required to maintain system power quality through balanced frequency and voltages.

TP will no longer be able to determine flow directions solely based on the network connectivity. The flow directions of the individual feeder sections may have to be determined from power flow results of the DPF based on the actual network topology, load, and DER generation distributions, which inevitably create new data inputs from each party. The directions of real and reactive power flow at each phase may not be the same.

DPF solution algorithms and methods may not be required for fundamental changes just because of the DER and micro-grid connections. Although distribution grids may become highly active with bidirectional power flows, they may remain in a radial configuration, sometimes with a few loops, which is similar to what is found in conventional passive networks. The DERs connected to the distribution network may be classified into two classes, of which some may be rotational machine-based and others may be inverter-based. Regarding rotational machine-based DERs, their internal source voltages would be well balanced among the three phases, while their power outputs among the three phases may vary significantly, largely depending on the grid operational conditions, even though the total output from the three phases may be a given and fixed quantity. It is not possible to specify the power outputs for the individual phases for a rotational machine-based generator in DPF, so it would thus naturally share the unbalanced loads proportionally. Regarding an inverter-based DERs, however, its power output can be specified both for the total output and for the individual phases. If it is specified for the total power injection to the grid, one may assume that its internal three-phase voltages would be balanced and that the output power at each phase would be determined by the grid operational condition also, a situation that is like that associated with the rotational machine-based generators. If the power output is specified for the individual three phases, it means that the DER is chosen to provide constant power for each phase that may intend to balance the unbalanced local loads.

FDIR will require a higher level of optimization and will need to include optimization for closed-loop, parallel circuit, and radial configurations. Multi-level feeder reconfiguration, multi-objective restoration strategies, and forward-looking network loading validation will be additional features with FDIR. The penetration of DERs and microgrids will introduce significant challenge regarding FDIR. This challenge is the result because conventionally the FDIR was designed to only deal with the restoration of load service and no DER generation was in the scope of consideration. In the active distribution network with DERs and microgrid connections, the objectives, algorithms, and approaches of FDIR will need to consider the impacts of DERs and microgrids in the restoration plans, including the restoration of both load and DER generation. The transition in which load is restored first and then generation is restored later may occur because the DERs may have been disconnected during de-energization and will not reconnect right away when the feeder is re-energized.

IVVC is designed to control capacitor banks and substation transformer taps and feeder voltage regulators. These are all binary control variables. The connections of DER and microgrids may provide additional VAr resources for voltage and VAr control and optimization in IVVC. These resources will be continuous control variables, resulting in more complicated mixed-integer programming problems in voltage and VAr optimization. Moreover, fluctuations in the DER outputs may have additional impacts on IVVC operation that must be considered in the new solution approaches. Moreover, IVVC will include operational and asset improvements—such as identifying failed capacitor banks and tracking capacitor bank, tap changer, and regulator operation to provide sufficient statistics for opportunities to optimize capacitor bank and voltage regulator placement in the network. Regional IVVC objectives may include operational or cost-based optimization.

ONR is designed to minimize network energy losses and increase power delivery reliability while maintaining good voltage profiles in the grid within a given period. Like other advanced DMS applications, it has traditionally built based on passive distribution networks. The connections of DER and microgrids will also introduce considerable challenges for the ONR. It needs to include the DERs and microgrid operational schedules in its optimization process and apply a look-ahead logic. It may also need to include some of the DERs and microgrids as dispatchable resources in its optimization. Such a design will allow ONR to generate the overall optimal configuration, leading to better use of DERs.

SCA may also require some fundamental changes to the solution algorithms because some of the DERs may be strong contributors to the fault currents, leading to multiple fault current contribution sources, a situation that is quite different from that of conventional passive networks. The inverter-based DERs are not strong contributors to the fault current, even though they may still play important roles during the first couple of cycles. Special attention to inverter-based DERs may be needed on a case-by-case basis.

LM/LE will significantly change where customer consumption behaviors will no longer be predictable but more smartly managed individually and affected by distribution response management, the available utility, and government incentives as well as individual load management systems.

With a significant increase in real-time measurements available from more widespread installations of field IEDs on feeders and meter data from end users and AMI systems, distribution state estimation (DSE) will play an important role in monitoring the overall grid operation condition and situation awareness, as well as in supporting IVVC and other distribution optimization functions. More accurate estimation of distribution system voltages extending from the substation down the feeders to end-user locations will allow IVVC to precisely control the voltage profiles along the feeder and at the end user to realize more economic benefits.

CA and RPC will be used on a more frequent basis. They will need to include single-phase and three-phase models and analysis. Moreover, the distribution optimization functions, such as FDIR, IVVC, and ONR, will be more effectively integrated for real time and look-ahead operational support. Distribution optimization functions will also be coordinated with consumer demand management and DER optimization.

Distributed generation, microgrids, and customer generation (such as plug-in hybrid vehicles (PHEVs) and rooftop solar panels) will also add many challenges to the protection, operation, and maintenance of the distribution network. The bidirectional power flow will complicate network analysis, including Contingency Analysis (CA) and emergency control of the network. Protection and control schemes will need to account for bidirectional power flow and multiple fault sources. Protection settings and fault restoration algorithms may need to be dynamically changed to accommodate changes in the network configuration and supply sources.

In addition to addressing conventional monitoring and control functions, integrating DMS with microgrids and DERs will extend the functionalities in its monitoring, control, and management of the distribution system. There will be more "knowing" and less "guessing" based on the understanding of the current operational condition that is gained and based on the look-ahead knowledge of conditions provided via the availability of the operational schedules of the DERs and microgrids provided by DER management systems and the micro-grid control systems, respectively.

Considering the intermittent nature of the renewable DERs in the distribution grid and microgrids, it is also necessary to reinforce the generation forecast for the advanced DMS applications. For instance, short- to very short-term solar forecast for each feeder will be critical for distribution operators to be aware of the upcoming generation boost or drop from the end of the line and properly dispatch adjustable load to accommodate the changes. Accordingly, the advanced DMS applications, e.g., the DPF, can predict the near-term load flow condition along the feeders. For many solar-rich areas, the challenges are to absorb excessive generation at light feeder load, which can induce temporary overvoltage (TOV) at feeder end and may cause damage to residential loads.

The development of new technologies and applications in distribution management can help drive optimization of the distribution grid and assets. The seamless integration of smart grid technologies is not the only challenge. Also challenging are the development and implementation of the features and applications required to support the operation of the grid under the new environment introduced using clean energy and distributed generation as well as the smart consumption of electricity by end users. DMS and distribution automation applications must meet the new challenges, requiring advances in the architecture and functionality of distribution management, that is, an advanced DMS for the smart grid. Expect to see an evolution of traditional distribution management to include advanced applications to monitor, control, and optimize the active distribution network with DER and microgrid connections in the smart grid, that is, an advanced DMS (aDMS) for the smart grid.

Databases and data exchange will need to facilitate the integration of both geographical and network databases in an advanced DMS. The geographical and network models will need to provide single-phase and three-phase representations to support the advanced applications. Ideally, any changes to the geographical data (from network changes in the field) will automatically update the network models in the database and user interface diagrams. More work is required in the areas of distributed RTDBs, high-speed data exchange, and data security.

Dashboard metrics, reporting, and historical data will be essential tools for tracking the performance of the distribution network and related smart grid initiatives. For example, advanced distribution management will need to measure and report the effectiveness of grid efficiency programs, such as VAr optimization, or the system average interruption duration index (SAIDI), the system average interruption frequency index (SAIFI), and other reliability indices related to delivery optimization smart grid technologies. Historical databases will also allow verification of the capability of the smart grid optimization and efficiency applications over time, and these databases will allow a more accurate estimation of the change in system conditions expected when the applications are called upon to operate. Alarm analysis, disturbance, event replay, and other power quality metrics will add tremendous value to the utility and improve relationships with customers. Load forecasting and load management data will also help with network planning and optimization of network operations.

Analytics and visualization will assimilate the tremendous increase in data from the field devices and integration with other applications, and they will necessitate advanced filtering and analysis tools. Clearly, that machine intelligent-based methods will greatly advance the efficiency for data screening, cleansing, and processing, either in stream or database. Artificial intelligence can also contribute to applications that otherwise require intensive labor to sort, evaluate, and analyze, such as transformer overloading analysis, energy theft, and equipment health monitoring. With increasing availability of distribution data, machine learning society also gains greater confidence in the development and verification of novel algorithms.

Visualization of the data provides a detailed but clear overview of the large amounts of data. Data filtering and visualization will help quickly analyze network conditions and improve the decision-making process. Visualization in an advanced DMS would help display accurate, near-real time information on network performance at each geospatially referenced point on a regional or system-wide basis. For example, analytics and visualization could show voltage magnitudes by color contours on the grid, monitor, and alarm deviations from nominal voltage levels, or show line loading through a contour display with colors corresponding to line loading relative to capacity. System operators and enterprise users will greatly benefit from analytic and visualization tools in day-to-day operations and planning.

Enterprise integration is an essential component of the smart grid architecture. To increase the value of an integrated smart grid solution, the advanced DMS will need to interface and share data with numerous other applications. For example, building on the benefits of an AMI with extensive communication coverage across the distribution system and obtaining operational data from the customer point of delivery (such as voltage, power factor, loss of supply) help to improve outage management and IVVC implementation.

Enhanced security will be required for field communications, application interfaces, and user access. The advanced DMS will need to include data security servers to ensure secure communications with field devices and secure data exchange with other applications. The use of IP-based communication protocols will allow utilities to take advantage of commercially available and open-standard solutions for securing the network and the interface communications.

5.5 WIDE-AREA MONITORING, PROTECTION, AND CONTROL SYSTEMS

Wide Area Measurement Systems (WAMS) provide a way of observing the dynamics of a power system, while SCADA/EMS systems conventionally observe only the steady-state condition of the grid. The observability of the power system using WAMS, together with real-time analytics and geographic visualization, reveals information on the stability of the power system, in particular, its oscillations and dynamic response to disturbances. This information can be of value in real-time operations and in post-event analysis and longer-term performance metrics.

5.5.1 Overview

Time-synchronized measurements across widely dispersed locations in an electric power grid are a key and differentiating feature of a wide-area monitoring, protection, and control (WAMPAC) system. WAMPAC systems are based on the synchronized sampling of power system currents and voltage signals across the power grid using a common timing signal derived from GPS[1] (Figure 5.14). The sampled signals are converted into phasors—vector representations of the grid's voltage and current measurements at fundamental frequency—that are synchronized and compared across the electrically connected power system using an accurate GPS time reference. Bus voltage and current phasors define the state of an electric power grid in real time.

5.5.1.1 Phasor Measurement Unit

The PMU is the basic building block of a WAMPAC system. The PMU samples the power system signals from voltage and current sensors and converts them into phasors. Phasors are complex number representations of the sampled signals commonly used in the design of, and inputs to, control

[1] The Global Positioning System (GPS) is a satellite-based navigation and time signal system made up of a network of satellites placed into orbit by the U.S. Department of Defense. GPS was originally intended for military applications, but in the 1980s, the government made the system available for civilian use.

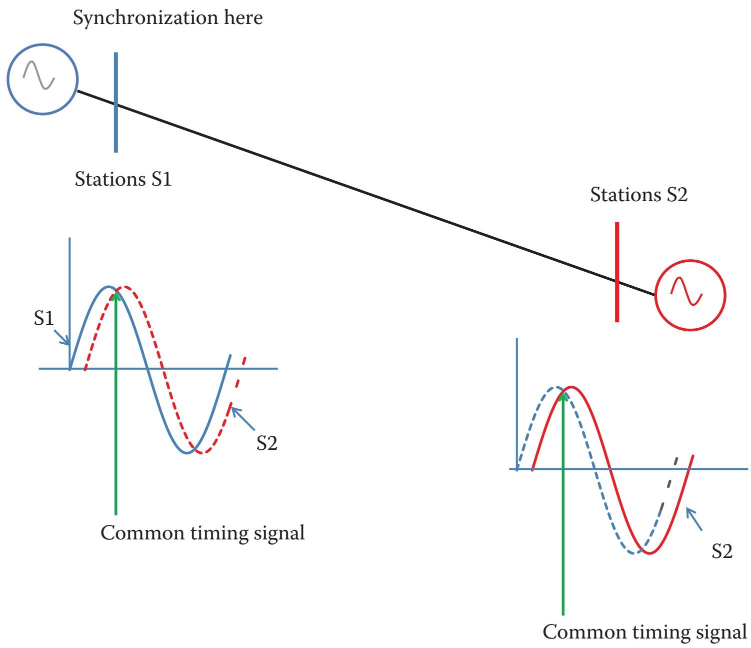

FIGURE 5.14 Synchronized sampling of power system signals.

and protection systems for bulk power transmission grids. The phasors are time tagged from a timing pulse derived from the GPS and then streamed into the wide-area communications network as fast as one phasor per cycle of the power system frequency (Figure 5.15). Currently, the IEEE synchrophasor standard C37.118 (2005, revised 2011, 2014) defines the format by which the phasor data are transmitted from the PMU. The phasor angle information is referenced with the GPS timing pulse; for it to have physical significance, it must be compared to (subtracted) other phasor angle measurements from the same system. Phasor angle differences provide useful information concerning system stress or modes of oscillatory disturbances in the power system. The PMU provided the critical synchronized time-lapsed information that enabled a clear understanding of the events leading to the Northeast blackout of 2003 in the United States.

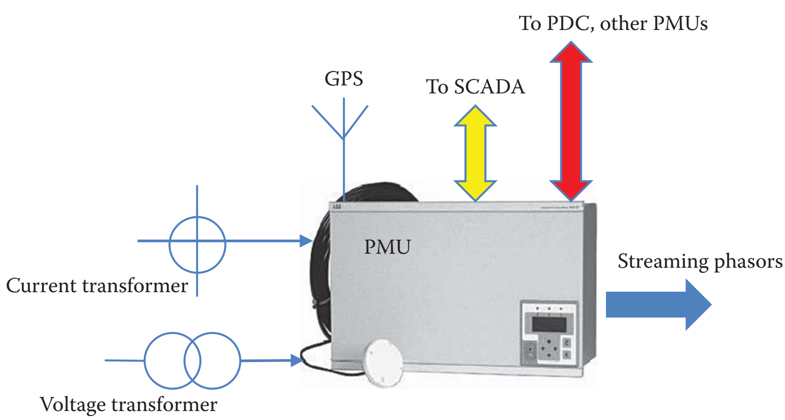

FIGURE 5.15 Phasor measurement unit (PMU).

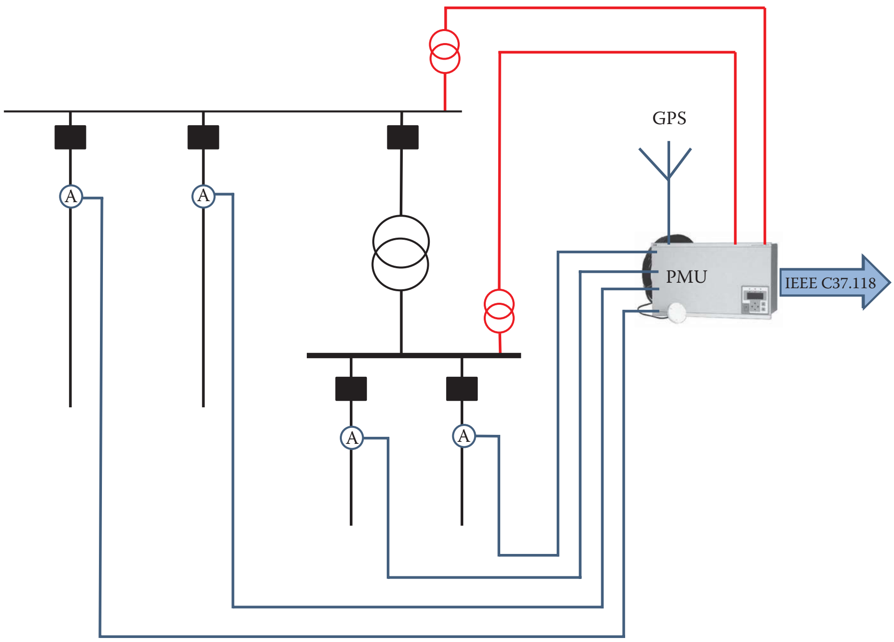

FIGURE 5.16 Typical PMU connection in a transmission substation.

PMU technology has advanced significantly since Dr. Arun Phadke and his team developed the first PMU at Virginia Tech in 1988. Modern-day PMUs have become more accurate and capable of measuring a larger set of phasors in a substation. Most PMUs have binary output modules for transmitting binary signals, such as trip signals to open a circuit breaker. Some vendors have PMUs integrated within protection relays or digital fault recorders, with timing signals taken from IRIG-B[2] time sources instead of GPS antennae. A typical PMU connection in a transmission substation is shown in Figure 5.16. The PMU is considered one of the most promising, if not the most important, measurement device in modern transmission systems.

5.5.1.2 Time Synchronization

Time synchronization is the core of WAMPAC-based applications. WAMPAC applications rely on a precise time stamp transmitted with each PMU measurement to monitor, control, and protect the electrical network. In general, time synchronization requirements range from nanoseconds to microseconds. Time synchronization can be achieved by multiple means. All methods are based on the distribution of a common source clock signal across the network either by satellite, via the communications network (e.g., using the IEEE 1588[3] protocol) or using dedicated synchronization networks (e.g., IRIG-B). The crucial need for a highly reliable and available time synchronization system implies the systemic use of a high-quality clock with accuracies expressed in PPM (parts per million) to maintain high accuracy, even in the case of a temporary loss of the synchronization signal.

5.5.1.3 Phasor Data Concentrator

A phasor data concentrator (PDC) collects phasor data from multiple PMUs or other PDCs, aligns the data by time tag to create a synchronized data set, and then passes the data on to applications

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2 The Inter-Range Instrumentation Group (IRIG) time protocol is widely used by electric utilities to precisely communicate time to power system devices, such as breakers, relays, and meters from a clock source. IRIG-B is one of the IRIG standards in a serial communication format.

3 1588 is an IEEE protocol standard for precision clock synchronization for networked measurement and control systems.

processors. For applications that process PMU data from across the grid, it is vital that the measurements are time aligned based on their original time tag to create a system-wide, synchronized snapshot of grid conditions. To accommodate the varying latencies in data delivery from individual PMUs and to consider delayed data packets over the communications system, PDCs typically buffer the input data streams and include a certain "wait time" before outputting the aggregated data stream. A PDC also performs data quality checks, validates the integrity or completeness of the data, and flags all missing or problematic data.

PMUs utilize the data format IEEE C37.118 data rates, and communications protocols—e.g., Transmission Control Protocol (TCP), User Datagram Protocol (UDP)—for streaming data to the PDC. On the input side, the PDC must support these different formats; additionally, it must be able to downsample (or up-sample) the input streams to a standard reporting rate and process the various data sets into a common format output stream. There may also be multiple users of the data. Hence, the PDC should be able to distribute received data to multiple users simultaneously, each of which may have different data requirements that are application specific.

The functions of a PDC can vary depending on its role or its location between the source PMUs and the higher-level applications. Broadly speaking, there are three levels of PDCs (Figure 5.17):

1. *Local or substation PDC*. A local PDC is located at the substation for managing the collection and communication from multiple PMUs within the substation or neighboring substations and sending this time-synchronized aggregated data set to higher-level concentrators at the control center. Since the local PDC is close to the PMU source, it is typically configured for minimal latency. It is also commonly utilized for local substation control operations. Local PDCs may include a short-term data storage system to protect against communications network failures. A local PDC is a hardware device that requires limited maintenance, and that can independently operate if it loses communications with the rest of the communications network.
2. *Control center PDC*. This PDC operates within a control center environment and aggregates data from one utility's PMUs and substation PDCs, as well as neighboring utility PDCs. They are capable of simultaneously sending multiple output streams to different applications, such as visualization, alarms, storage, and EMS applications, each of which has its specific data rate requirements. Control center PDC architectures are typically redundant to handle expected future loads and to satisfy high-availability needs of a production system regardless of PMU vendor and device type. PDCs need to be adaptable to accommodate new protocols and output formats, as well as interfaces with new applications.

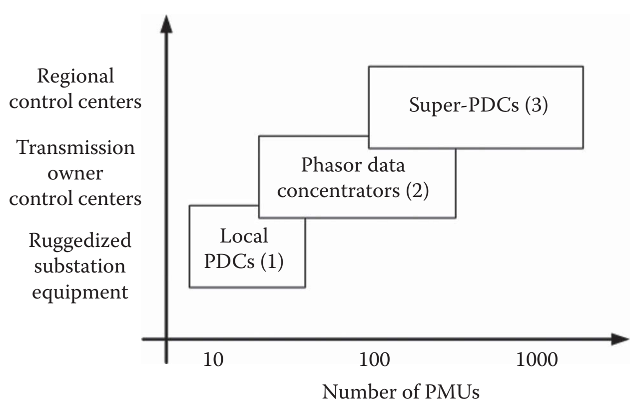


FIGURE 5.17 Levels of PDCs: (1) local or substation level, (2) transmission owner control centers, and (3) regional control center level (ISOs, RTOs).

3. *Super-PDC*. A Super-PDC operates on a larger, regional scale and is responsible for collecting and correlating phasor measurements from hundreds of PMUs and multiple substations and control center PDCs; it may also be responsible for facilitating PMU data exchange between utilities. In addition to supporting applications such as wide-area monitoring system (WAMS) and visualization, and EMS and SCADA applications, it can archive a vast amount of data (typically, several terabytes per day). Super-PDCs are, therefore, typically enterprise-level software systems running on clustered server hardware to accommodate scalability to meet the growing PMU deployment and utility needs.

5.5.1.4 Phasor Data Communication Systems

The wide-area nature of phasor measurements requires the significant support of a data communication system so phasor data can be transferred from PMUs to PDCs, among PDCs, and eventually to phasor applications (see Figure 5.18). Phasor communications networks can be configured in several ways, depending on the applications used. Most, if not all, PMU-PDC networks can be described as one of three types of data and device networks: *hierarchical, peer-to-peer*, and *multicast peer-to-peer*. It is possible for any device to be a participant in more than one such network.

Communication issues, such as reliability, bandwidth, latency, and security are essential to phasor applications. All applications, including monitoring, visualization, oscillation detection, and control, require access to the right data at the right time. Reliability is always desirable and can be the highest consideration in some cases where critical controls depend on the measurement. In other cases, such as an optional measurement, reliability may be less important. Bandwidth describes the amount of data that needs to be sent over a given link in each period. Once the user determines the data reporting rate and quantity of data to be reported, the required bandwidth can be calculated based on the communication protocol. The communication system needs to have the bandwidth to support the requirement under both ideal and stressed conditions. Latency refers to the length of time it takes to transfer a data item from the source to the destination. Delay due to distance and low serializing clock rates is typically in the low milliseconds. Data buffering for coding, error recovery, or congestion are usually the largest causes of delays. The delays can vary from milliseconds to several seconds. Security here refers to the cybersecurity of a phasor measurement system. Security is to avoid intrusion. The North American Electric Reliability Corporation (NERC) has classified phasor measurement systems as critical assets and requires them to meet NERC cybersecurity standards. In deployment, one would need

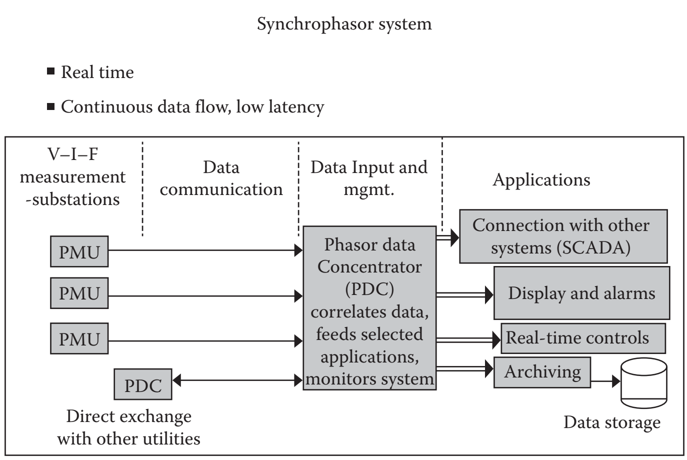


FIGURE 5.18 Typical real-time phasor measurement systems.

TABLE 5.1
Normalized Values of Expected Quality Parameters

Difficulty (5:hardest)	Latency (ms)	Bandwidth, Rate (Hz)	Criticality	Data Quantity	Geographical Distance	Deadline (Bulk tran)
5	5–20	240–720+	Ultra	Very high	Access a grid or multiple ISOs	<5 s
4	20–50	120–240	Highly	High	Within an ISO or RTO	1 min
3	50–100	30–120	Medium	Medium	Between a few utilities	1 h
2	100–1000	1–30	Low	Low	Within a single utility	1 day
1	>1000	<1	Very low	Very low	Within a substation	>1 day

Source: Bakken, D., Bose, A., Hauser, C., Whitehead, D., and Zweigle, G. Smart generation and transmission with coherent, real time data. *Proceedings of the IEEE* (Special Issue on the Smart Grid), 2011.

to consider authentication, encryption or other methods to ensure the data are from the right device and may not be compromised in any manner.

Other phasor communication systems metrics include: availability, criticality, provisioning, data quantity, geographical distance, deadline, anomaly management, augmentability, reconfigurability, compatibility, and traceability [11].

While these metrics define the quality of communication system in a qualitative manner, it is difficult to measure these metrics quantitatively. Quantitative metrics will keep on changing based on advancements in technologies and progress made in the development of applications. Table 5.1 shows some of the metrics in qualitative and quantitative manners as required by different applications. When ranking the level of difficulty, five means most difficult and one means least challenging quality metrics to provide. To get a sense of the wide ranges of difficulties involved in different phasor applications, this ranking enables intuitive comparison of different properties that have very different ranges. It is important to note that a given application will not have all its values in the same row: some requirements for a given application may be quite stringent (e.g., ultra-low latency) while others may be more forgiving (e.g., low volume of traffic). For example, state estimation application can be classified by the difficulty level of one in latency, two in rate, four in criticality, three in data quantity, four in geographical distance, and four in deadline. Similarly, short-term transient stability control application may be classified as five in latency, four in rate, three in criticality, four in data quantity, two in geographical distance, and five in deadline.

Among these communication metrics, cybersecurity is worth elaborating. NERC CIP standards identify the requirements to ensure cybersecurity for the Bulk Electric System (BES) [12]. Most initial uses for PMUs and PDCs are expected to be in the BES and, thus, cybersecurity requirements apply. Because phasor communication systems involve routable protocols, it is recommended that cybersecurity be applied to all installations, even those situations where communications are within the substation or plant (within the electronic security perimeter), especially where any external communication is through a boundary layer security interface (e.g., firewall and VPN). Routable protocols can provide an attack surface that malware can utilize to compromise connected devices and gain access to the internal network. The requirements for cybersecurity are evolving in the smart grid. The consideration of PMU, PMU-PDC, and PDC-PDC communications overlaps the areas of internal (within an electronic and physical perimeter) and external paths. While it was originally thought that internal substation PMU data could be un-encoded and external data encoded by an interface device at the electronic perimeter, current understanding indicates that all data will have to be secured at the source.

SCADA communication is particularly important more so by the incorporation of network interconnections. Smart meters are not a direct comparison to the PMU-PDC use-cases due to the voltage levels and systems they interact with, but they have attracted wide attention. It appears that the methods adopted (or in the process) for SCADA communications might be most readily adapted for protection of PMU data. Ongoing work in IEC TC57 on IEC 62351 and how it relates to PMUs as defined in IEC 61850-90-5, as well as the work from IEEE P1711, should be used as much as possible to increase the use of best practices and reduce the chances of having incompatible solutions.

Cybersecurity usually requires taking measures for authentication, integrity, and confidentiality, which can have an impact on phasor applications against other metrics, such as increased latency, consumed bandwidth, and increased requirements for processor computing power. Such impact should be carefully considered when developing phasor applications while still satisfying cybersecurity requirements.

5.5.2 Drivers and Benefits

Microprocessor-based computer relaying, information technology, and advances in communications are changing the landscape of transmission systems monitoring. WAMPAC systems are driven by the need for alternative solutions for managing transmission reliability and security via improved SA. Electric transmission grids interconnect bulk power systems that are spread across geographical regions. As such, electric transmission grids have evolved to be very reliable and secure systems—the cost of failure is great. Now, smart grid initiatives will impose new reliability and economic requirements that will further impact how transmission systems will be monitored, protected, and controlled in the future.

Smart transmission grids are expected to be self healing; that is, when experiencing disturbances, component failures, or cyberattacks, the grid is expected to recover. New and unconventional generating sources from renewable energy introduce operational challenges. With the increase in renewable energy sources, smart grids need to provide the most efficient transmission corridors for delivering energy to major load centers. Power systems are being operated closer to their thermal and stability limits. As a result, transmission operators need to increase their SA of the grid. The onset and early indications of disturbances and contingencies need to be visible to the operator in a timely fashion. SCADA and EMS systems need more advanced WAMPAC applications for the transmission grid to meet these challenges.

5.5.3 Major Activities

5.5.3.1 United States

Most of the groundbreaking research and initial WAMPAC applications worldwide first started in the United States. The work and research plans the North American Synchrophasor Initiative (NASPI) developed in 2009 convinced the U.S. Department of Energy (DOE) to provide significant federal R&D funding for synchrophasor technology and PMU deployment between 2010 and 2015 with the award of approximately $350 million in federal funds to thirteen Smart Grid Investment Grant (SGIG) and Smart Grid Demonstration (SGD) projects implementing synchrophasor technology. NASPI is a collaborative effort between the U.S. DOE and North American electric utilities, vendors, consultants, federal and private researchers, and academics, as well as NERC and The Electric Power Research Institute (EPRI). NASPI's mission was to improve power system reliability and visibility by creating a robust, widely available, and secure synchronized data measurement infrastructure for the interconnected North American electric power system with associated analysis and monitoring tools for better planning and operation and improved reliability.

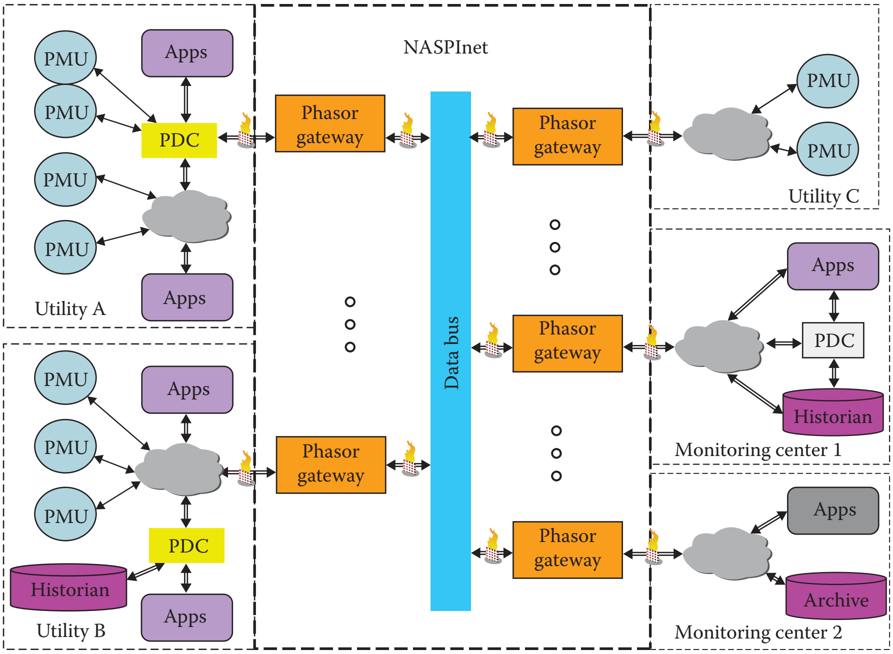


FIGURE 5.19 NASPInet conceptual architecture (phasor gateways and data bus). (Courtesy of the North American SynchroPhasor Initiative (www.naspi.org) and the U.S. Department of Energy.)

The DOE funded a NASPI-advised technical effort in 2008–2009 that produced the NASPInet conceptual design for a databus, and phasor gateways (Figure 5.19). These designs were not as detailed as technical specifications but did motivate broad agreement that the ideas of a central databus, phasor gateway, and publish-subscribe architecture were the appropriate way to collect data from distributed PMUs and deliver the data to diverse data concentrators and users with high reliability, high accuracy, and low latency. Several of the SGIG projects implemented and tested versions of the NASPInet design; however, there has never been a formal NASPInet design, nor has a single, continent-wide NASPInet PMU data communications network been implemented.

As the SGIG and Smart Grid Demonstration Program (SGDP) projects proceeded, NASPI and its industry members and partners addressed a variety of challenges and obstacles with over $150 million of additional RD&D investment by the U.S. DOE for a total of $330 million of federal and industry investment. These efforts produced many accomplishments to achieve technology maturity, including:

- Deployment of over 1800 production-grade PMUs across North America, with associated phasor data concentrators, data storage, communications networks, and a variety of applications using the PMU data
- A suite of technical interoperability standards (including harmonization between IEEE and IEC standards), which facilitated the rapid commercialization of PMUs from research-grade to production-grade, high-volume devices
- Technical guidance on various topics, such as cybersecurity for synchrophasor systems, PMU placement, how to define and monitor PMU data quality, and the problems caused by imprecise leap second implementation and other timing issues
- A standards conformance testing and certification process
- Rapid development of a number of valuable grid planning and management applications, including generator model validation, oscillation detection, voltage stability, phase angle

monitoring, wide-area visualization, identifying equipment misoperations, setting alarms and alerts using PMU data, linear state estimation, and much more
- Continuing evolution in the design and deployment of synchrophasor data networks in response to changes in ITC technology and costs, and feedback from users regarding using synchrophasor data in new ways
- Business guidance on the synchrophasor technology value proposition and a draft maturity model.

5.5.3.1.1 Phasor Gateway

The phasor gateway is the primary interface between the utility, or another authorized party, and the data bus for synchrophasor data exchanges via NASPInet. The phasor gateway manages the connected devices on the entity's side, manages the quality of service, administers cybersecurity and access rights, performs necessary data conversions, and interfaces the utility's PMU network with the data bus. The main functions of the phasor gateway include the following:

- Serve as the sole access point to the data bus for interorganizational synchrophasor traffic via a publisher-subscriber-based data exchange mechanism.
- Facilitate and administer the registration of user PMUs, PDCs, and phasor signals, which is done through a name and directory service (NDS) system-wide registry. All real-time data streaming sources need to be registered through the owner's phasor gateway before their data can be published to NASPInet, which includes information such as physical location of the device, device type, device identifier, signal description, signal quality, and ownership according to the phasor gateway owner and NASPInet naming conventions. Only upon successful registration of the data source with the NDS can the phasor gateway publish data.
- Facilitate and administer the subscription and publishing of phasor data. The publish/subscribe mechanism consists of three parts: device/signal registration by publishers, subscription setup between publisher and subscriber that is initiated by subscribers, and quality of service and data security of the subscribed data. The owner of the phasor gateway that publishes the data to NASPInet maintains full control of data distribution regarding who could subscribe to the data and which data could be subscribed to on a per-subscriber and per-signal basis. Nonsubscribers are, therefore, prevented from receiving the published data without a valid subscription. Subscribers are ensured that the data will only come from publishers to which they subscribe.
- Administer and disseminate cybersecurity and access rights. The phasor gateway should provide system administrator functions to configure, operate, diagnose, and control the phasor gateway access rights to ensure appropriate access to, and usage of, the data on a per-user and per-signal basis, including who can add, edit, and remove users, and control each user's access rights. The security must meet corresponding NERC (North American Reliability Corporation), CIP (U.S. CIP program), FIPS (U.S. Federal Information Processing Standard), and other relevant cybersecurity standards and guidelines to safeguard reliable operation and data exchange.
- Manage traffic priority through the phasor gateway according to data service classes. It is well understood that different applications have different data requirements regarding latency, data rates, availability, etc. Five different classifications of applications are identified based on these requirements: Class A, feedback, and control; Class B, open loop control (e.g., state estimation); Class C, visualization; Class D, postevent analysis; and Class F, R&D. The phasor gateway must support data delivery based on the priority traffic levels, that is, higher priority data are always processed and delivered before lower priority data.
- Monitor data integrity, which includes the ability to monitor both data that are forwarded to and received from the data bus for error and conformance with the data service class

specifications to ensure that all transported data meet quality-of-service requirements. The types of statistics provided by the phasor gateway are the number of missing packets and missing packet rate, a number of packets with data integrity checks, data stream interruptions, data stream delays, and changes in input data configuration. The phasor gateway should also be able to notify the administrator when there are excessive data errors, or the data do not conform to the data service class specification.

- Provide logging of data transmission, access controls, and cybersecurity for analysis of all anomalies. The phasor gateway should log all user activities (e.g., access requests), system administration activities (e.g., data source registration), data subscription-related activities, quality-of-service alerts, cybersecurity alerts, application errors, etc. Therefore, any anomaly can be traced and analyzed to determine whether it is the result of NASPInet's degradation or failures, or intentional/unintentional intrusion by unauthorized entities (hackers, intruders, unauthorized equipment connection, unauthorized user logins, etc.).
- Provide APIs for interfacing with a user's systems and applications to access data bus data and services.

5.5.3.1.2 Super-PDC

The term "super-phasor data concentrator" or "Super-PDC" was first coined within the context of the Eastern Interconnection Phasor Project (EIPP), which was a U.S. DOE-led initiative started in 2002 to deliver the immediate value of synchrophasor information within the U.S. Eastern Interconnection. The initial focus of the project involved networking existing PMU installations across the entire eastern interconnection and streaming these data to a centralized site for data concentration and archival. To support this EIPP endeavor, Tennessee Valley Authority (TVA) made a substantial investment in developing this "centralized" PDC (termed as the "Super-PDC") for the entire Eastern Interconnection that (1) was capable of gathering data from multiple PDCs and PMUs deployed across several utilities and ISOs, (2) supported a variety of phasor data transmission protocols—e.g., Bonneville Power Administration (BPA) PDCStream, IEEE C37.118, IEEE 1344, OLE for Process Control (OPC), VirginaTech Frequency Monitoring Network (FNET)—to ensure that all PMU capable devices within the interconnection could be integrated, (3) included a comprehensive database mechanism to manage the metadata associated with the phasor measurements, and (4) was capable of archiving huge amounts of this measurement data with fast historical data retrieval mechanisms.

The Super-PDC architecture that was developed by TVA is shown in Figure 5.20. It includes the real-time data acquisition module for parsing the data packets from various devices and protocols, the interface to TVA's proprietary DatAWare database, which maintains a 30-day rolling archive, data preprocessing module responsible for synchronization and encapsulation of these time-aligned data into a single stream, and finally the real-time broadcast module for streaming these data in real time to applications. The Super-PDC at TVA is currently receiving data from approximately 120 PMUs across the Eastern Interconnection (the largest collection of PMU data within North America). It archives the data in a historian with no data compression, collecting approximately 36 GB per day (1 TB per month).

In 2008, the NERC contracted TVA to architect the second generation to TVA's "centralized" Super-PDC architecture, where multiple regional Super-PDCs could work collaboratively to create a "distributed" system of data collection and concentration nodes that are centrally managed and configured, with minimal amount of information, exchanged between nodes to ensure high availability. In this way, computationally intensive tasks, such as data archival with I/O speed limitations, could be dispersed across distributed resources. Additionally, such a distributed approach also eliminates the concern for a single point of failure associated with the earlier centralized approach (Figure 5.21).

In late 2009, TVA released the Super-PDC source code to open source development as the openPDC and formally posted the openPDC Version 1.0 source code in January 2010. The openPDC is

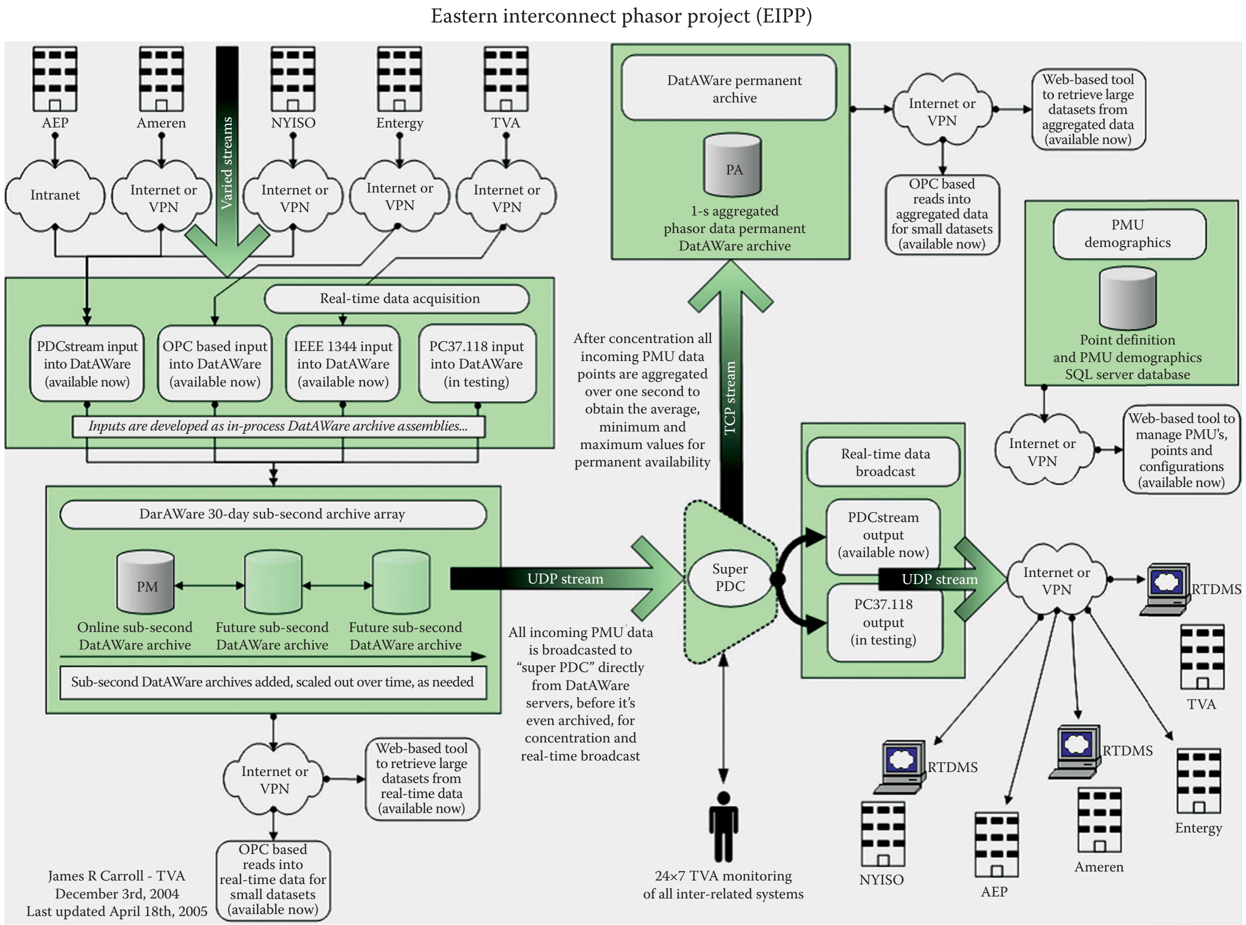


FIGURE 5.20 NASPI Super-PDC architecture. (From Myrda, P.T. and Koellner, K., NASPInet—The internet for synchrophasors, *43rd Hawaii International Conference on System Sciences (HICSS)*, Kauai, HI, January 5–8, 2010. With permission.)

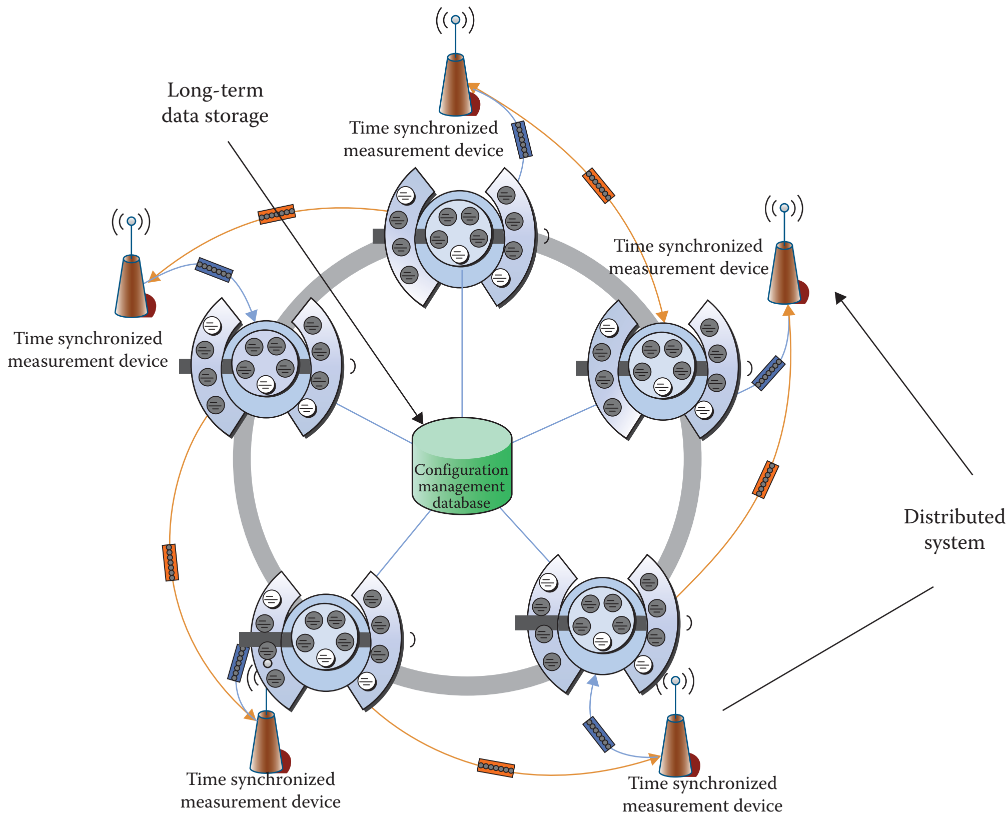


FIGURE 5.21 Generation II Super-PDC system (also known as the NERC phasor concentration system). (From Myrda, P.T. and Koellner, K., NASPInet—The internet for synchrophasors, *43rd Hawaii International Conference on System Sciences (HICSS)*, Kauai, HI, January 5–8, 2010. With permission.)

an enhancement of the original TVA Super-PDC that has been modified for greater performance and scalability. In April 2010, TVA and NERC positioned the Grid Protection Alliance (GPA) to provide ongoing administration of the openPDC code base. GPA is a not-for-profit corporation that has been formed to support the electric utility industry.

Several U.S. utilities, under their 2010 SGIG, have already undertaken pilot projects to implement and demonstrate various aspects of NASPInet. It is envisioned that NASPInet, once fully deployed, would support hundreds of phasor gateways and thousands of PMUs, each typically sampling data at 30 times per second.

5.5.3.2 Europe

Concepts of and experience with wide-area monitoring systems (WAMS) in Europe date back to the years 1980–1990, when EdF, the French transmission system operator (TSO) of that time, developed a comprehensive plan based on phasor measurements. However, since all the required telecommunication from the substation to the central control system and back was based on very expensive satellite channels, the system has never been put into operation. The further development of PMU technology based on accurate GPS time synchronization as well as the development of low-cost and reliable terrestrial communications channels has facilitated a restart of the phasor technology only some ten years later. In the meantime, accurate synchronized off-line transient recorders have been developed and used for dynamic model calibration as well as for complex events analysis within the highly meshed CE system. One of the main driving factors for using more accurate measurement equipment was the increase of system dynamic challenges due to the increase of system size caused by the connection of power systems from the eastern European system to the western European system in the early 1990s. This need is intensified today by the more and more extensive use of the transmission system infrastructure due to increased market activities as well as increased power flow distances caused by renewable (wind) infeed far from the main energy consumers.

In the British power system, the concept of oscillatory stability monitoring was developed and deployed as a control room monitoring tool in 1996 in Scottish Power and National Grid, and extended to continuous on-line monitoring in 1998. This monitoring enabled the transmission companies to raise the transfer limit of the important transmission corridor between Scotland and England. The stability monitoring extracted frequency, damping, and amplitude of oscillations, used with synchronized power monitors and presented with alarms in the control room. The first use of oscillatory stability set a precedent, and has been used from 1998 up to the present day, and the application transitioned from using proprietary acquisition hardware to PMUs once the C37.118 (2005) standard was released, and PMUs became sufficiently reliable for the application. This application set a precedent for oscillatory stability monitoring as one of the most widely adopted uses of WAMS worldwide.

Power system equipment manufacturers have recognized the needs of system operators and have developed devices able to measure voltage and current phasors that are subsequently computed online in central PDCs. On the level of this centralized communication and data computation, together with a corresponding visualization platform, a large number of corresponding applications have been developed. Due to the nature of a relatively new technology, the ongoing WAMS activities can be divided into two categories.

5.5.3.2.1 Universities/Research & Development and Demonstration Projects

For this kind of application, the data acquisition is performed using the public internet connection, and the data servers are located inside universities or manufacturer labs. The PMUs used are mainly installed on the low voltage outlets in the buildings. Due to this fact, the related analyses are restricted to frequency and voltage phase angle as system input measurements. A few projects financed by the European Commission, such as ICOEUR, have already delivered valuable results.

Recently, there have been several national and European research programs that have a focus on applying WAMS information to the challenges facing the grid with the transition to low carbon energy. These projects typically include both industrial and research organization collaborations. An example is the Massive InteGRATion of power Electronic Devices (MIGRATE) project under the European Union (EU) Horizon 2020 research program, involving 11 transmission utilities, as well as research institutes and manufacturers. The MIGRATE project considers the questions of reducing inertia, short circuit capacity, and dynamic interactions with the rapid rise of power electronic connected sources of energy.

Another demonstration project of note is the Visualisation of Real Time System Dynamics (VISOR) project in the Great Britain (GB) grid, supported by the regulator Office of Gas and Electricity Markets (Ofgem) through its Network Innovation Competition (NIC) program. This project was motivated by the changing dynamics due to renewables and the introduction of transmission technologies previously not used in the GB grid—series compensation and high-voltage, direct current (HVDC) links embedded in the AC network. It was recognized that an improved observability of the power system was necessary to ensure continued stable operation of the power system in transition. A number of notable innovations have arisen from this project, which is expected to be integrated into the business as usual practices of the transmission utilities in the near future:

1. Extension of the established oscillation monitoring concepts to cover a wider range of frequencies
   a. Governor-frequency control at 0.002 to 0.16 Hz
   b. Electromechanical and voltage control at 0.1 to 4 Hz
   c. Subsynchronous oscillation monitoring at 4 Hz to near-nominal frequency
2. New oscillation source location methods to identify the nearest monitoring location to key contributors to poor damping of oscillations, providing operator guidance on how to respond to alarms
3. System disturbance identification and impact measures

It may be noted that the subsynchronous oscillation monitoring required a new synchronized measurement approach to capture subsynchronous resonance. The same hardware, infrastructure, and communication protocol were used as for synchrophasor measurement, but waveform data were downsampled and streamed without a conversion to phasors. Generator shaft speed measurements were also incorporated. The approach of using downsampled analog values was chosen above using accelerated phasor conversion because a phasor conversion requires a window of at least one cycle for reasonable accuracy and stability, which acts as a filter and limits the bandwidth of issues that can be reproduced.

The monitoring project also provided input to a wide-area control project described later in this section.

5.5.3.2.2 Industrial Applications

In the industrial applications, data acquisition is performed with the help of private TSO communications channels, where the PDC is embedded in the TSO IT environment, and the output of the WAMS is already used within the operation or planning departments of the TSOs. In contrast to university-driven R&D projects, the TSO measurements are performed on the high-voltage level using dedicated CT and VT measurements. Consequently, exact and high-resolution active power and reactive power measurements are also available.

Based on different technologies and corresponding software and hardware suppliers, the Continental Europe (CE) power system is monitored by receiving WAMS measurements from various transmission substations in each country. For the analysis of all major and minor events with a system-wide impact within the last years, those devices have delivered an important contribution to the related postmortem dynamic system analysis. The same measurements are continuously used for monitoring of the dynamic system performance as well as for the calibration of system dynamic models.

Some European TSOs have already integrated the PMU and corresponding PDC information within their SCADA systems. The corresponding main applications are the following:

- Voltage phase angle difference monitoring
- Line thermal monitoring
- Voltage stability monitoring (online P-V curves)
- Online monitoring of system damping (online modal analysis with online parameter estimation)
- Intelligent alarming if predefined critical levels are exceeded
- Online monitoring of system loading

The GB system now has over 100 PMUs integrated across the three onshore transmission systems. The key uses are currently in oscillatory stability and disturbance analysis. There are several prospective applications under investigation, for example, in defining constraints using regional angle differences to enable transfer levels across stability constrained boundaries that would not be known to be safe using a power-only constraint definition.

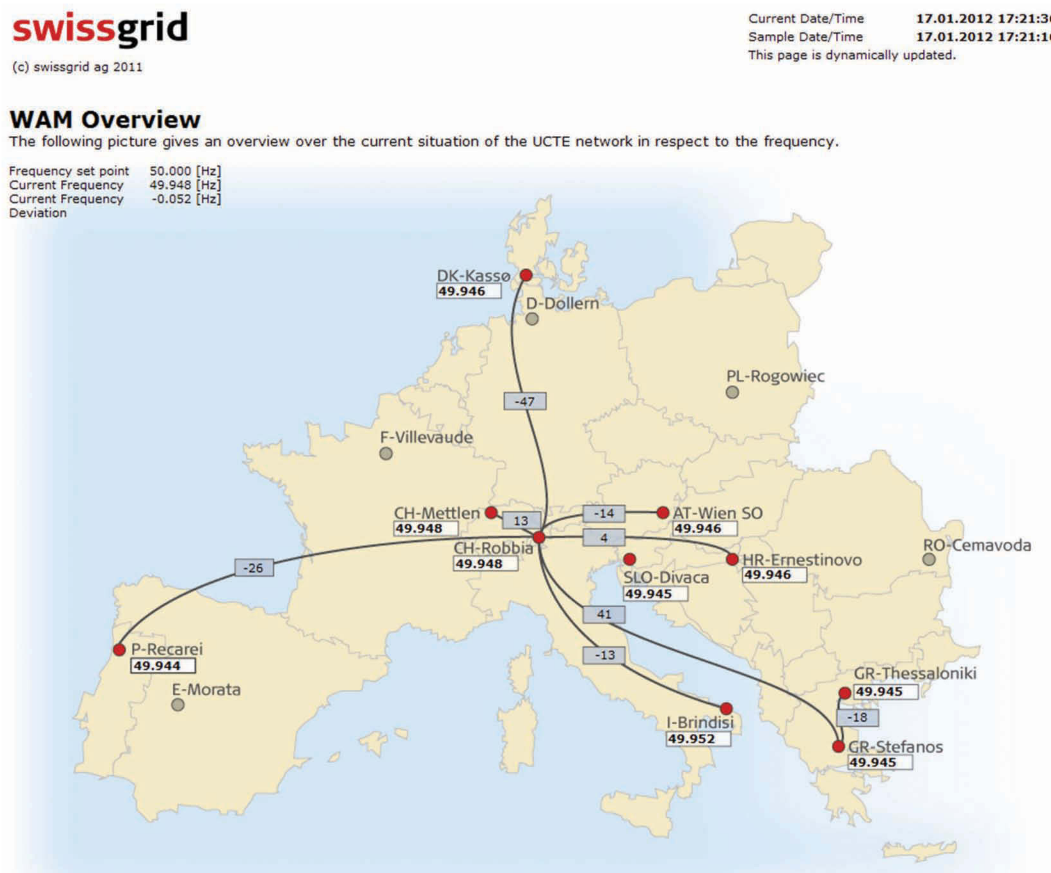


FIGURE 5.22 Swissgrid web page showing current European PDCs links (January 2012). (© 2012 Swissgrid AG. All rights reserved. With permission.)

To increase system observability[4] beyond their system observation area, a few European TSOs have already meshed their PDCs by exchanging PMU data online. One of these applications is a web page application setup by Swissgrid (Figure 5.22).

Within the CE power system, more than 100 WAMS devices are currently in operation, continuously delivering high-quality measurements for system operation and system planning. Accurate time-stamped measurements have shown that they are a valuable component to ensure secure system operation. The related tools for data post-processing have also demonstrated their maturity. However, WAMS integration with traditional SCADA systems has only reached the initial stages. Also, the effort for enhancement of these links, in combination with future implementation of dynamic security assessment (DSA), voltage security assessment (VSA), and wide-area protection (WAP) systems, must be increased with the active participation of all partners (universities, manufacturers, TSOs, consultants).

5.5.3.3 Brazil

Brazil spans a large part of the South American continent. The distance of the far ends of the Brazilian territory (from north to south, and from east to west) is about 3900 km. Today, the

[4] Observability related to electric power systems is a necessary condition for state estimation. State estimation provides estimation of all measured and non-measured electrical quantities of the power system. Its output is used for online operation and management of the power system, such as load flow analysis.

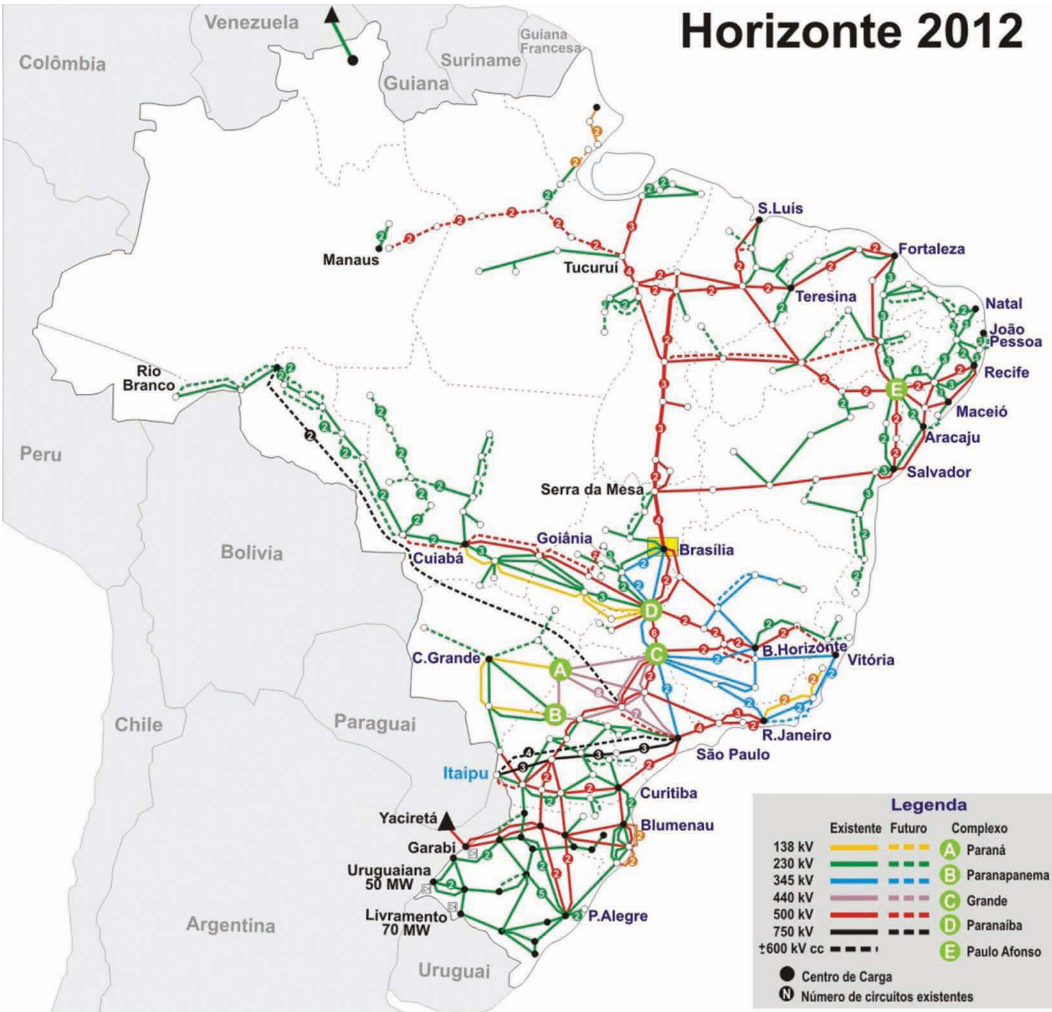


FIGURE 5.23 The BIPS. (Courtesy of ONS, Brazil, 2010.)

Brazilian Interconnected Power System (BIPS) covers almost 70% of the Brazilian territory with a large transmission network that includes over 90,000 km of 230, 345, 440, 500, and 765 kV transmission lines, one 600 kV HVDC transmission line, ~400 substations, and more than 170 power plants. Figure 5.23 shows the Brazilian main transmission grid.

The country's main generation source is hydroelectric. In the past, more than 80% of the total installed capacity and nearly 90% of the total energy production came from hydroelectric generation plants. The plants are located along 12 major hydrographic basins all over the Brazilian territory and many of them are not close to the major load centers in the southeast and south region. Some of the largest hydroelectric plants are the furthest from the load centers, resulting in bulk power transfers over long distances. Rainfall and the resulting inflow patterns are distinct in different regions and may vary significantly over the year for each, as well as between dry and wet years. In this scenario, one of the main operational tasks in the Brazilian power system is to allow the economic gains through interregional power transfers, taking advantage of the seasonal rainfall and water flow differences in each of its geoelectric regions. This is realized through optimization of the available hydro resources, mixed with complementary thermal energy. The result of this process has a direct impact on the overall operating cost of the system. As in all systems of this proportion, disturbances due to significant generation and load unbalances may cause excessive frequency variations, voltage collapse situations, and even the islanding of certain parts of the network, with the loss of important load centers. Studies of the system dynamic behavior have shown inter-area low-frequency electromechanical oscillations in the range of 0.3–0.8 Hz. These oscillations are usually well damped but could, in some disturbances, spread with severe consequences. To avoid such situations, conventional (not synchronized measurement) system integrity protection schemes (SIPS) were deployed to perform predefined actions. Load shedding or generator tripping are some planned actions for expected system contingencies, such as losing one or more circuits of a major transmission path. The economic and reliable operation of the Brazilian power system must also accommodate the needs of a deregulated electricity market established since 1998, which increased the number of players in the electricity market. The main operational challenge of the Brazilian power system, thus, is how to achieve optimal hydro resource utilization while ensuring reliable system operation within the constraints of a long transmission system and market operation regulations.

The interest in transmission grid synchronized measurements in Brazil emerged in the 1990s due to the difficulty to assess the system dynamic performance during wide-area disturbances. The PMU received the attention of the Brazilian Electric Studies Committee, a member of the Group to Coordinate the Interconnected Operation (GCOI) of the Brazilian power system. The feasibility of PMU application in the Brazilian power system was subject of preliminary studies performed by this committee, with utilities' and manufacturers' participation.

With the electricity sector restructuring that happened in Brazil by the end of the 1990s, BIPS operation was transferred to a recently instituted Independent System Operator, called the Office for National Statistics (ONS). On March 11, 1999, only two months after the ONS started operating the BIPS, Brazil faced a huge blackout. This blackout affected mainly the southeastern region, which accounts for the largest load in Brazil. The March 11 event highlighted the need for better tools aiming at long-lasting dynamic behavior recording. Following the blackout recommendations, ONS started a project in 2000 to deploy a WAMS on the BIPS to record its dynamic performance, and in 2003, the first commercial PMU product was available in Brazil. In 2004, the regulatory environment in Brazil changed, and ANEEL (the Brazilian regulatory office) decided not to allow ONS to own transmission assets. After working with ANEEL to reformulate the project strategy from the early centralized approach to a decentralized one, a resolution was passed in 2005 establishing the framework, under which the responsibilities and tasks for ONS and utilities in implementing the WAMS project were defined. For ONS, its main responsibilities and tasks are as follows: (1) define and specify the WAMS architecture and equipment; (2) specify, acquire, and install the ONS PDCs; (3) define PMU placement on BIPS; (4) coordinate certification tests on PMU models to guarantee the system's integration and WAMS global performance; and (5) define the WAMS deployment schedule and coordinate the PMU installation by utilities. For utilities, their responsibilities and tasks are as follows: (1) purchase, install, operate, and maintain the PMU placed in their substations and (2) supply the communications links, complying with technical requirements, specifications, and schedules coordinated by ONS.

The deployment plan for Brazilian WAMS consists of three main components:

- *A phased deployment plan:* ONS has adopted a phased deployment plan to address most of the challenges of this project. On the application side, ONS will focus on first deploying enough PMUs at selected locations to facilitate the system dynamics recording for envisioned off-line applications, such as postmortem analysis, system model validation, and performance assessment. The number of PMUs will be gradually increased for real-time system operation support, such as state estimator improvement until a full observability of BIPS's higher voltage level (345 kV and above) by phasor measurement is reached. Additional PMU installations for WAC and protection applications will be considered only at a later stage of the system deployment, as practical experience is gained with this technology. This phased deployment plan allows utilities and ONS to limit the initial capital investment, minimize the risks associated with many uncertainties of the project, and gradually gain experience on the system before making a full-scale deployment.

- *Top-down system design approach:* ONS has adopted a top-down system design approach aimed to avoid potential future problems in its phased deployment plan. This top-down approach allows ONS to take into account not only the requirement of the current applications but also the need of future applications in the WAMS design. The system architecture is designed to be highly flexible and scalable to allow for easy system expansion later. It also allows the system design to consider the availability of current, off-the-shelf products, the maturity of technologies, as well as current communication support from the BIPS. In addition to system design, this approach enables ONS to provide unified design specifications for PMUs and any other system component that will be installed and operated at a utility's substation, such as substation phasor data concentrators (SPDC). These specifications will be used by all utilities involved in this project in their procurement process.
- *PMU/PDC certification test process:* To ensure the global performance of the Brazilian WAMS, ONS has included a PMU and PDC certification test process as an integral part of its deployment plan. The PMU certification test process included first developing a PMU test methodology and the test guidelines and then conducting the PMU certification test to ensure that all PMUs to be acquired by utilities will meet the same standards and system requirements. ONS is also envisioning the need for PDCs testing and certification. The WAMS architecture design includes the use of substation PDCs to aggregate and process the data from PMUs at the substation and then forward the data to PDCs installed at ONS control centers. Substation PDCs must, therefore, be verified to be interoperable with all PMU models and with the PDCs installed at ONS control centers. With a phased deployment plan, one of the main system design objectives of the Brazilian WAMS was the system flexibility and scalability for easy system expansion. For PDCs at ONS control centers, they will only support a small number of phasor measurements initially, but they will be easily expanded to support hundreds of PMUs at the project's final stage. ONS is investigating testing tools/methods that will allow it to verify whether main PDCs can meet the earlier requirements.

Another important WAMS initiative in Brazil came from the Santa Catarina Federal University (UFSC). The initiative started in 2001 as a research project carried out jointly by UFSC and a Brazilian industry partner. In 2003, the project received financial support from the Brazilian Government, which allowed the deployment of a prototype phasor measurement system. This first Brazilian system measures the distribution system low voltage in nine university laboratories communicating with a PDC at UFSC over the Internet. This system recorded the BIPS dynamic performance during the latest major power system disturbances. Currently, another project from UFSC installed PMUs on three 500-kV substations in the South of Brazil.

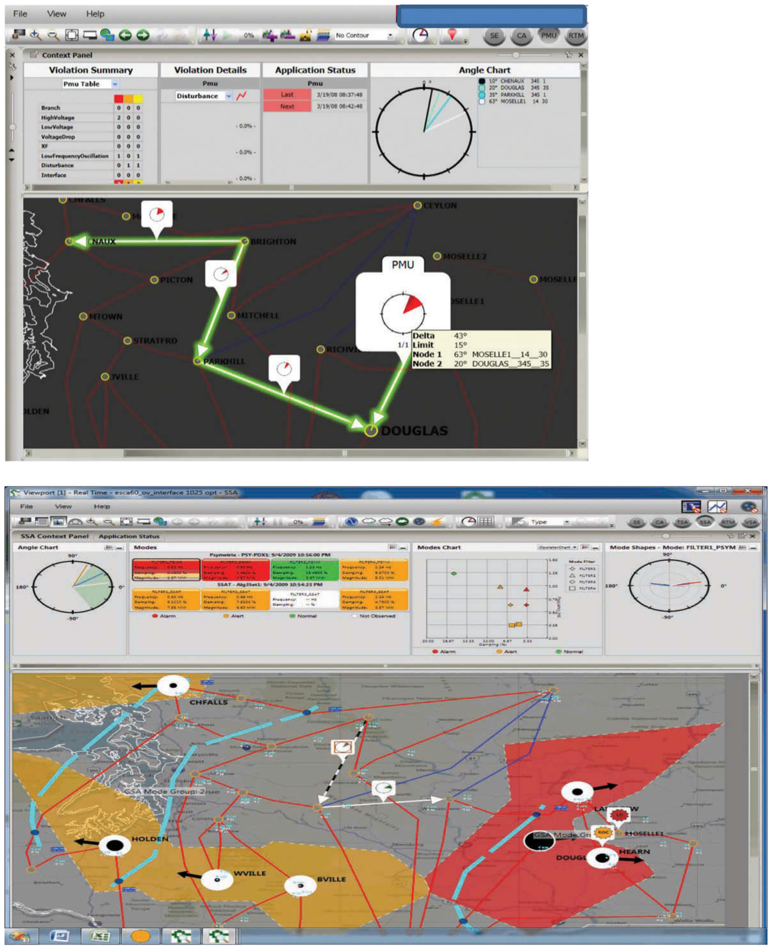
WAMS deployment is understood as an important step to allow the Brazilian transmission system to evolve to a true smart grid. There is a common agreement that synchronized measurements will be part of the next generation of SCADA and EMSs. Without a better measurement system, it will be very difficult to develop more advanced EMS applications.

5.5.4 Role of WAMPAC in the Smart Grid

5.5.4.1 Monitoring

5.5.4.1.1 Grid Stability and Security

Existing transmission grids are being pushed to their limits with the tremendous growth of energy demand worldwide. The energy infrastructure must also consider environmental constraints and



(a)

(b)

FIGURE 5.24 (a) Phase angle difference monitoring and (b) local and inter-area oscillations monitoring.

energy-efficiency requirements while maintaining the grid stability. Since power grid conditions are constantly changing, the overall health status of the grid is also constantly changing. It is the responsibility of grid operations to continually monitor real-time conditions to assess the current state of the system, to determine if corrective actions are required, and to identify and implement corrective actions if warranted.

The phase angle separation information that is provided by WAMS is a good measure of grid instability and may signify potential voltage or oscillatory stability problems in the system. Similarly, rapid changes in phase angles that can be quickly detected by the high-resolution measurements can indicate a sudden weakening of transmission capacity due to line outages. Additionally, it is possible to assess the current damping levels of both local and inter-area oscillations directly from the measurements, provide locational information on where the oscillations are most prominent, and alarm the operator should poor damping conditions occur (Figure 5.24). Other measurement-based wide-area security assessments include the use of localized frequency measurements from synchrophasors and observable time delays within this subsecond PMU data, along with any additional real-time EMS SCADA and transmission network topology information, to quickly identify the specific location of the origin of the disturbance, detect and manage electrical islanding conditions, and then monitor system restoration following grid separation.

Synchrophasors and WAMPAC technology are smart-grid enabling technologies that offer great promise in terms of providing the industry with new situational awareness tools to quickly assess the current grid conditions. Specifically, PMUs are capable of directly measuring the system state (i.e., voltage and current phasors) very accurately and at the high subsecond resolution, which is well suited for observing the dynamic behavior of the power grid and characterizing its stability. Of equal importance is the time-alignment property of these measurements that allows for comparison of phase angles from widely disparate locations to assess grid stress over a wide area. Measurement-based techniques that leverage these characteristics of WAMS technologies will complement existing EMS capabilities. Figure 5.25 illustrates how a PMU-based WAMS and network model-based EMS hybrid solution can provide a more comprehensive grid security assessment. While measurement-based techniques may be applied quickly and accurately to assess grid conditions over a wide-area basis, the model-based EMS applications offer the required context in terms of establishing dynamic security limits and suggesting corrective actions to mitigate potentially harmful conditions.

Substantial amounts of renewable energy and the use of HVDC and Flexible AC Transmission Systems (FACTS) devices in transmission systems result in more complexity in grid controllability. A system-wide approach is essential to utilize these assets and improve the overall grid stability. One of the major precursors of having system-wide control utilizing signals from remote locations is a very reliable communication infrastructure with a high bandwidth. PMUs are the building blocks of a wide-area control system. Employing PMUs in a wide-area control system that includes monitoring and control of FACTS or power systems stabilizers can help to improve transfer capability and counter disturbances, such as power oscillations, as shown in Figure 5.25. Such remote

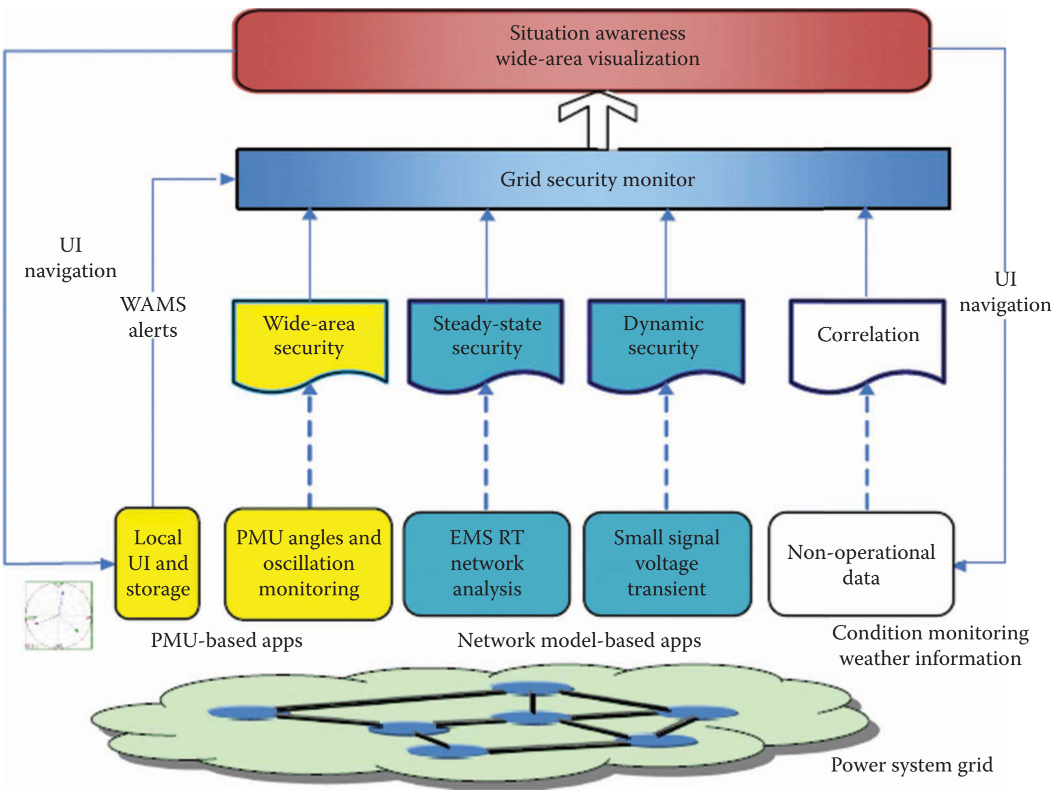


FIGURE 5.25 Integration of WAMS and EMS for enhanced grid security assessment. (© 2016 General Electric. All rights reserved. With permission.)

power grid information could come from a wide-area monitoring system (WAMS). WAMS/WACS applications range from monitoring (such as state estimation and voltage security monitoring) to wide-area control, such as the damping of power oscillations. It is envisioned that future smart transmission grid operation could be highly improved by WAMS/WACS. For example, events often cause failure or isolation of transmission lines and generators that could potentially lead to grid collapse. WAC can be used for transferring blocking or overriding signals to protection and control systems to allow grids to ride through disturbances. For example, it is well known that during voltage collapse events, transformer tap changer operation to restore voltages to normal levels aggravates the voltage collapse. WAC can send blocking signals to these transformers to inhibit their tap changer operations during voltage collapse.

WAMS technologies also benefit steady-state network analysis applications. PMUs directly measure the system state. Using additional real-time measurements in the grid improves the EMS state estimator application, which helps in increasing the grid reliability and performance. A *predictive* element of system operations is needed in smart grid to help the decision-making process of the control center operator. Once the operators have assessed the current state and its vulnerability, operators will need to rely on "what-if" analytical tools to be able to make decisions that will prevent adverse conditions if a specific contingency or disturbance were to occur and make recommendations on corrective actions. Thus, the focus shifts from "problem analysis" (reactive) to "decision-making" (proactive/preventive). WAMPAC will play a significant role in future decision support systems that will use more accurate forecast information and more advanced analytical tools to be able to confidently predict system conditions and analyze "what-if" scenarios in the transmission grid.

Synchrophasor measurements are an enabler for system response driven control for defense against stability issues. The view of relative angle movements reflects the stress and dynamic state of the system in real time, without requiring full observability. Novel wide-area control approaches make use of the movements of the system reflected in phasor measurement to drive countermeasures to restore a stable state. By adopting a system response driven approach, the countermeasures can be inherently proportionate to the triggering events and self limiting. They can also make use of widely distributed response capability, which is particularly useful where renewable penetration is high and large conventional centralized generation are not available for SIPS.

The growing stress and complexity of power systems and their modes of failure lead to a growing need for wide-area control that is not designed only for specific known N-1 or N-2 scenarios. Rather, defense mechanisms need to mitigate the consequences of multiple failures and interactions through distribution and transmission voltages and across multiple control areas. It can no longer be assumed that all critical contingencies can be predicted with certainty. Fast-acting wide-area control can be applied to mitigate the more serious effects of large-scale events and help to avoid or ride through islanding. The two practical examples of wide-area control serve to illustrate how this can be achieved in a general way.

There are challenges to wide-area control, mainly around the design and implementation of robust infrastructure, control algorithms, error handling, and testing for complex event scenarios. In contrast to other forms of control where parallel redundant systems deliver robustness, a synchrophasor-based wide-area control system must accommodate loss or degradation of a number of its data sources without loss of functionality. Similarly, in the actuation of control, phasor-based systems can be used to apply a distributed control where loss of some of the controllable resources can be accommodated. A phasor-based wide-area control scheme can, therefore, be designed such that a catastrophic failure is extremely unlikely, even if there are elements of the system unavailable. Wide-area control is becoming a viable and accepted option for system defense, and its adoption is currently low but growing. More practical trials, demonstration, and live pilots would be of value in the industry to pave the way for a widespread adoption of the technology.

5.5.4.1.1.1 Low-Frequency Oscillations in the U.S. Grid Smart grid deployment results in both generation and loads being more dynamic and stochastic, which would make the grid more vulnerable to adverse oscillations. Electromechanical oscillations, also known as small signal stability[5] problems, are one major threat to the stability and reliability of transmission grids. A poorly damped oscillation mode can become unstable, producing large-amplitude oscillations, leading to system breakup and large-scale blackout. Existing transmission capacity in most countries is derated to provide a margin of safety for reliable operations. There have been several incidents of system-wide low-frequency oscillations. Of them, the most notable is the August 10, 1996 U.S. western system breakup involving undamped system-wide oscillations. Figure 5.26 shows the measurement of power transfer from the Pacific Northwest to California for the August 10, 1996 event in the United States. The system deteriorated over time since the first line was tripped at 15:42:03. About 6 min later, undamped oscillations occurred and the system broke up into several islands.

The first step to address this concern is to develop real-time monitoring of low-frequency oscillations. Significant efforts have been devoted to monitoring system oscillatory behaviors from measurements in the past 20 years. The deployment of advanced sensors, such as PMUs, provides high-precision time-synchronized data needed for detecting oscillation modes. A category of measurement-based modal analysis techniques, also known as ModeMeter, uses real-time phasor measurements to estimate system oscillation modes and their damping. There is yet a need for new methods to bring modal information from a monitoring tool to actionable steps. The methods should be able to correlate low damping with grid operating conditions in a real-time manner so that operators can respond by adjusting operating conditions when low damping is observed.

Modal Analysis for Grid Operations (MANGO) is a U.S. effort funded by the U.S. DOE to address the problem of adequately detecting transmission grid power oscillations and establish a procedure to aid grid operation decision-making for mitigating inter-area oscillations [14]. Compared to alternative modulation-based methods, MANGO aims to improve damping through adjustment of operating points, whereas the modulation-based methods do not change the grid operating points. Figure 5.27 illustrates the difference btween these two types of damping improvement methods. Modulation control retains the operating point but improves damping through automatic feedback control. Figure 5.28 illustrates the overall proposed MANGO framework.

Based on the effect of operating points on modal damping, MANGO can improve small signal stability through operating point adjustment. Simulation studies show that damping ratios can

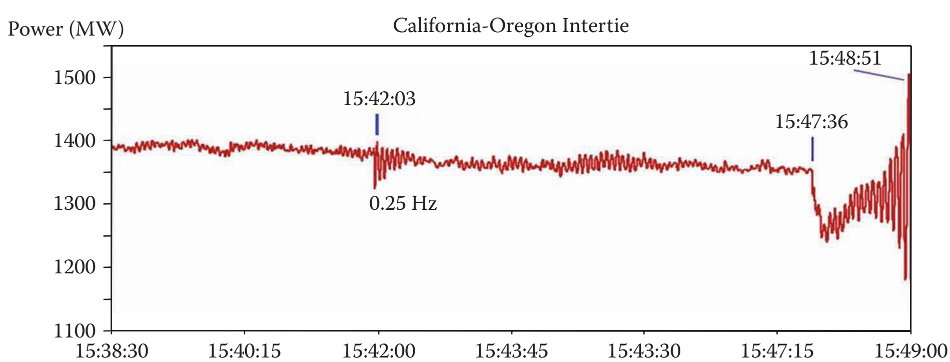


FIGURE 5.26 Undamped oscillations leading to the August 10, 1996 U.S. western system islanding event.

5 Small signal stability is the ability of the power system to maintain synchronism when subjected to small disturbances.

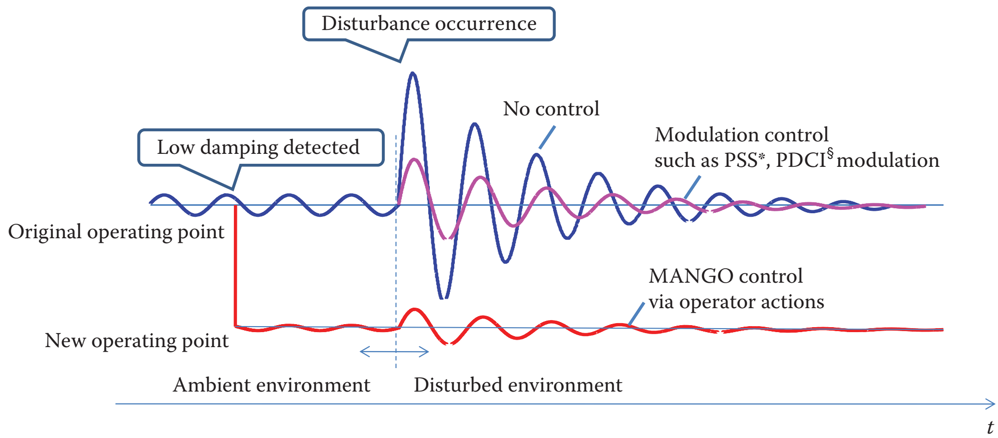


FIGURE 5.27 MANGO versus modulation stability control. (*Power system stabilization; §Pacific DC Intertie damping).

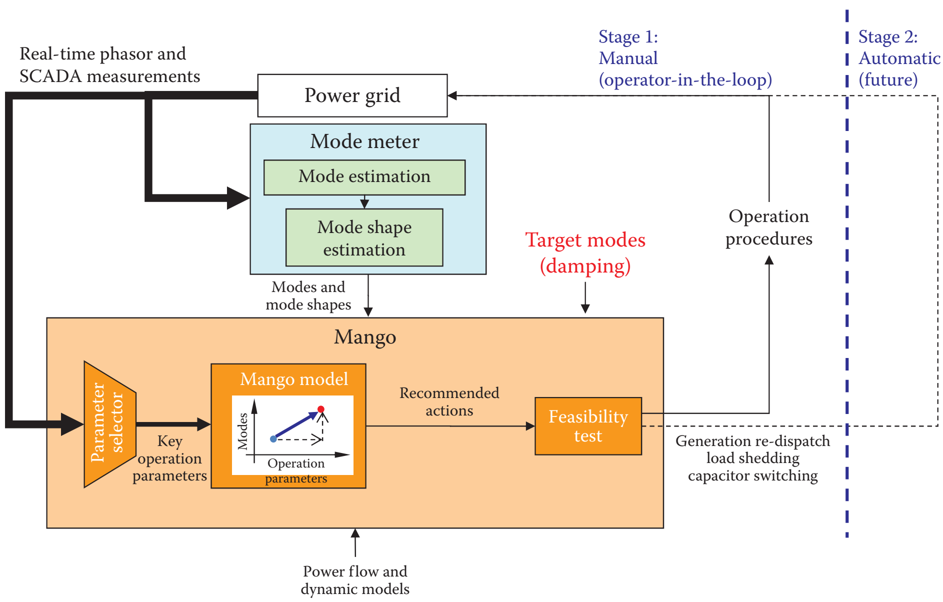


FIGURE 5.28 Proposed MANGO framework.

be controlled by operators through adjustment of grid operating parameters, such as generation redispatch, or load reduction as a last resort. At the same stress level (total system load), inter-area oscillation modes can be controlled by adjusting generation patterns to reduce flow on the interconnecting tie-line(s).

5.5.4.2 Control

5.5.4.2.1 Infrastructure Requirements

The infrastructure to deliver wide-area control must be designed with consideration for latency and resilience, with the following requirements:

- Several individual PMU signals can be lost, degraded or delayed, and the Regional Aggregators will continue to provide useful signals
- The Regional Aggregators should be connected to a robust and fast communications network with redundancy and, therefore, be very reliable signals. However, loss of any one Regional Aggregator signal does not result in failure of the whole system.
- The Regional Aggregator signals should be broadcast and made available to all of the Control Units. The Control Units connect to an access point and receive all the Regional Aggregator signals and take the fast response decisions based only on the incoming phasor data.
- The Central Supervisor is a slower non-real-time process that coordinates the arming and thresholding of the control units to ensure a predictable response from diverse resources.

The latency requirements should be appropriate for the issues to be addressed, but in many systems, a response deployed within 0.5 s is sufficient to address most angle stability related issues. A time budget is required to ensure that a fast response is achieved, including:

- PMU internal latency for the data window and processing delay
- Communication latency
- Power system's response to event, e.g., time for frequency and angle to change following a disturbance
- Controller unit cycle times
- Time from trigger the resources to power response being delivered

As noted previously, it is possible to implement a wide-area control scheme as a "hybrid" scheme with an initial fast event-driven outcome triggered directly from known critical contingencies, followed by a response-driven control to mitigate a much broader range of events including high impact/low probability disturbances. A hybrid scheme would typically use line end opening or specific plant tripping detection with very low latency to carry out an initial stage of action within about 70–200 ms depending on the scheme, followed up with a response-driven process using phasors. The hardware to implement such schemes should, therefore, have facilities for fast control protocols, such as IEC 61850 GOOSE, as well as synchrophasor protocols, such as IEEE C37.118.

5.5.4.2.2 Event-Driven versus Response-Driven Control

WAMPAC offers an alternative to conventional SIPS. SIPS are widely used around the world for defending against instability and extending the transfer capability of the network capability beyond N-1 security limits that can be achieved with local protection and control. SIPS applied to stability problems is event-driven, responding to a logical combination of discrete events such as line-end-opening signals, with pre-defined actions, such as generator tripping. These protection schemes are typically applied to large generators or loads, in response to specific corridor line faults.

By contrast, synchrophasor-based WAMPAC defense schemes can be designed to be driven by the system's response to a disturbance. A response-driven scheme acts when the power system responds to a disturbance in such a way that the angular stress is increased, and if not halted, would proceed to a load loss or system split condition. Synchrophasors are a very useful input to a grid defense mechanism, measuring the stress in the system and enabling a proportionate response that can restore the grid to a new stable state.

A response-based system using synchrophasors has several advantages over an event-based approach, in particular

- The location and volume of response are sensitive to the needs of the transmission system
- The system will respond appropriately even if the specific disturbance scenario has not been planned, for example for a complex sequence of disturbances

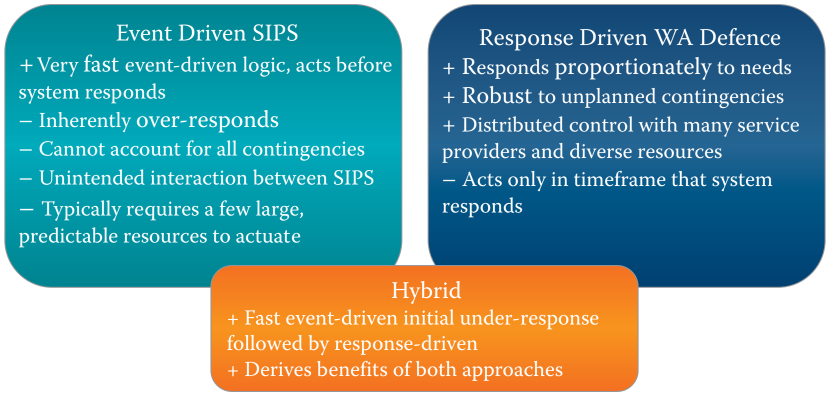


FIGURE 5.29 Relative advantages of event-driven and response-driven control approaches. (© 2016 GE Grid Solutions, UK. All rights reserved. With permission.)

- A distributed response can be achieved using many smaller devices rather than relying on a few large units.
- The control system may adapt its behavior if islanding occurs in the progression of the event sequence

Figure 5.29 summarizes the relative advantages and disadvantages of event-driven and response-driven control. It may be noted an event-driven response can be designed to be very fast, and in some situations, it can be appropriate to use a first-stage event-driven action for specific events, followed up by a more general stability response service, described as "Hybrid" in the figure.

5.5.4.2.2.1 Fast Frequency Response in the Great Britain Grid The GB system inertia is reducing due to the rapid increase in renewable generation, HVDC, and other power electronic infeeds. This means not only a more rapid change in frequency following a loss of generation or load but also a greater divergence in frequency that could lead to out-of-step between areas. The differences in frequency observed across the GB grid are shown in Figure 5.30 from PMU records of a real grid disturbance. An innovative approach to coordinating and controlling fast-acting resource services from a diverse range of technologies, which improves both frequency and angle stability, is currently being developed and tested to meet the emerging need for fast-frequency response.

In the event shown in Figure 5.30, the apparent rate of change of frequency (ROCOF) at the start of the event, near the source of the disturbance is −1.65 Hz, while the largest ROCOF of the GB system is currently expected to be around 0.125 Hz. The records taken further from the event source also show a larger ROCOF than the system average, but later in the event progression. The event record illustrates some of the challenges with using only local signals to drive a fast-acting response. It is predicted that the GB system inertia changes will soon require a fast-frequency response to be fully deployed in 2–3 s to avoid load shedding. However, responding in this time frame coincides with the electromechanical transient stability time frame, and a fast-frequency response may degrade the angular stability of the grid, if not applied to account for the disturbance location.

To maintain stable frequency without load shedding requires accelerating frequency response to start acting within about 1 s of the disturbance. Frequency response can no longer be delivered by conventional large generation alone, as it is becoming too slow to prevent load shedding. However, fast response is required with a second, during the period of the disturbance when the frequency and angles are diverging. If the response is delivered rapidly, but predominantly in the wrong location of the grid, the risk of islanding is increased, or the stability transfer limits is eroded. However, if the response is applied close to the disturbance, the impact of the disturbance is reduced.

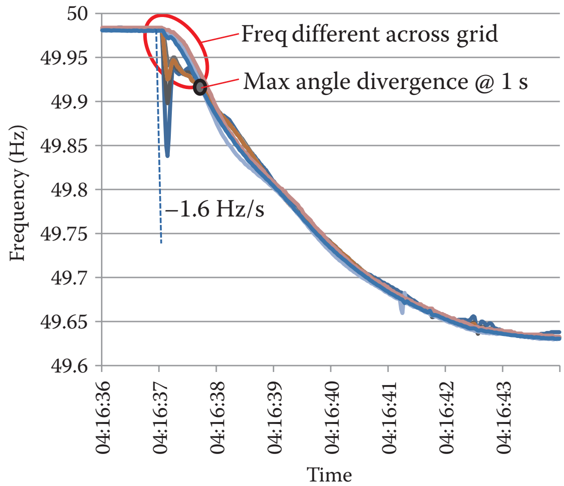


FIGURE 5.30 Deviations in frequency across the Great Britain grid following a loss of infeed from an interconnector. (Based on data from National Grid. © 2016 GE Grid Solutions, UK. All rights reserved. With permission.)

There are many devices that can provide a useful response, including:

- Battery storage
- Interconnector dynamic control
- Conventional generation with an accelerated control capability
- Wind generation with temporary power increase capability ("buying time" until slower resources can be deployed)
- Renewable generation with downward ramp capability
- Demand control and tripping
- Deploying motor or generator resources with real inertia

Much of this non-conventional response is comprised of relatively small units, which serve other purposes, yet have the capability to provide a useful service to the grid, if incentivized and suitably coordinated.

A wide-area coordinated distributed control mechanism is designed for demonstration of a fast-frequency control approach, illustrated in Figure 5.31. Control units receive real-time data from PMUs via aggregation points. Using this wide-area view, each Control Unit can identify the occurrence, location, and severity of an event, and trigger a response. The purpose of the Central Supervisor is to track the available resources and coordinate the arming and thresholds applied in the Control Units. The system can, therefore, deliver a predictable response to the grid, comprising the individual responses from widely distributed resources.

The structure of the wide-area control system minimizes the communications latencies for the fast-real time response to disturbances. The Zone Aggregators each receive measurements from several PMUs and produce an aggregate frequency and angle representing the zone. These aggregated signals are robust against loss or degradation of PMU signals. The Zone Aggregator signals are broadcast to all control units. Each participant in the control scheme receives a fast data stream comprised of all the Zone Aggregator signals from around the country.

An example of a controlled resource is shown in Figure 5.32, where a solar farm and battery storage are coordinated to provide fast-acting upward and downward response. The controller shown will observe and track the available response capability of the plant, and will also command the

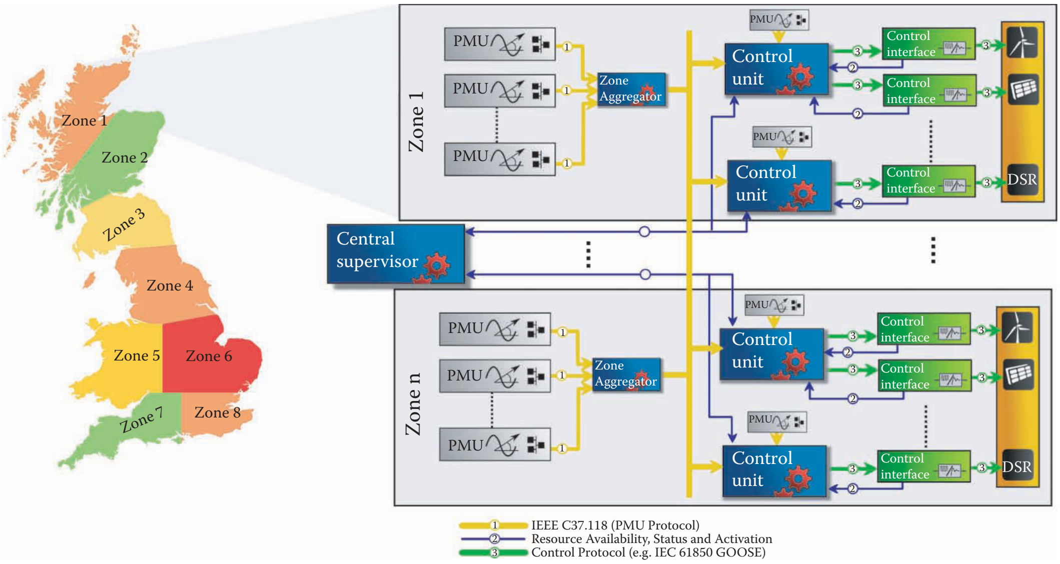


FIGURE 5.31 Wide-area distributed control structure of the Great Britain fast-frequency stability control scheme. (© 2016 GE Grid Solutions, UK. All rights reserved. With permission.)

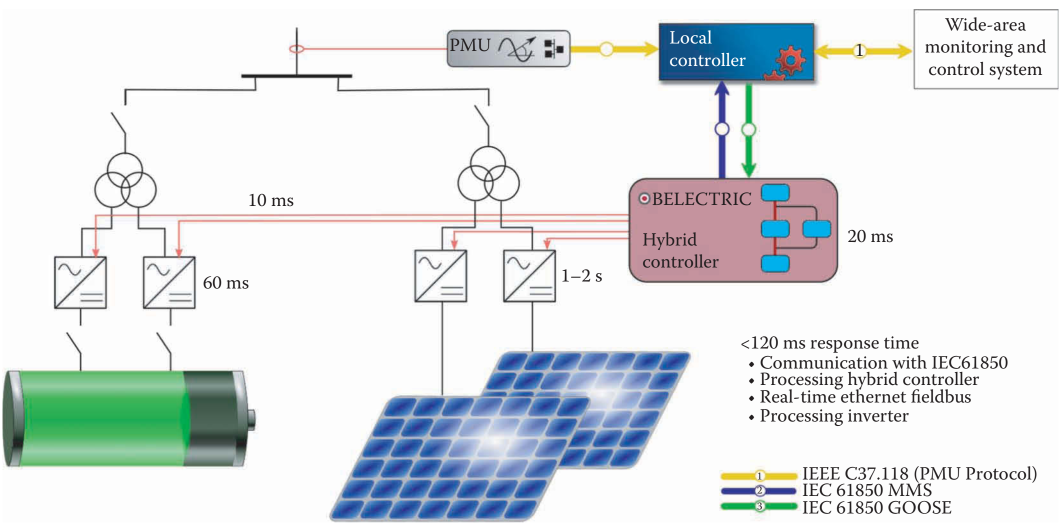


FIGURE 5.32 Solar PV and battery storage operator with wide-area control.[6] (© 2016 GE Grid Solutions, UK and Belectric. All rights reserved. With permission.)

required power response to an event. The plant operator would also be able to declare the resource to be available or unavailable for the fast-frequency response service.

By contrast with conventional SIPS, where typically a small number of large units of generation or load are intertripped, in this case, there are many relatively small resources utilized. When a new resource is made available, it simply receives the broadcast "system view" of the aggregated zone measurements, and the provider declares basic information, such as response time and volume of response. The resource can then be linked to the scheme and share the response duty.

[6] From GE and Belectric presentation at National Grid EFCC Project Knowledge Dissemination Event, Birmingham, February, 2016.

5.5.4.2.2.2 Wide-Area Stability Control in the Icelandic Grid A wide-area scheme designed for improving the security of the Icelandic power system uses many of the same principles and is another example of a system responsive scheme. The power system has a relatively weak transmission grid connecting large generation and load centers. A feature of the Icelandic grid is that the load is comprised mainly of large industrial units, and a large load loss can lead to frequency and angle differences and system splitting.

The Icelandic system is shown in Figure 5.33. The main centers of inertia are in the southwest and the east of the country, connected by a 920 km 132 kV ring. The ring forms a relatively weak connection between the areas, which is prone to splitting.

The generation is entirely from renewable resources, using hydro and geothermal energy. The load is mainly industrial, with large units such as smelters, silicon wafer manufacturing, and other energy-intensive processes. The loss of a large load results in an acceleration in the area of the load loss, and a frequency and angle difference created in the system, as shown in Figure 5.34.

The purpose of the wide-area control system is to counteract the loss of load or generation within the area of the loss, so that islanding is avoided. However, they may not always be sufficient resource to avoid islanding, in which case a response close to the source of the disturbance also serves to improve the power balance in the resulting islands, and islanding occurs with relatively low subsequent impact.

Like the GB control system, the response is distributed across a variety of resources, including:

1. Thyristor-controlled loads (smelters)
2. Accelerated generation control
3. Controlled fast load shedding

The scheme is also like the GB case in terms of the need for a response in the area near where the disturbance occurs, hence, the need for a wide area control approach.

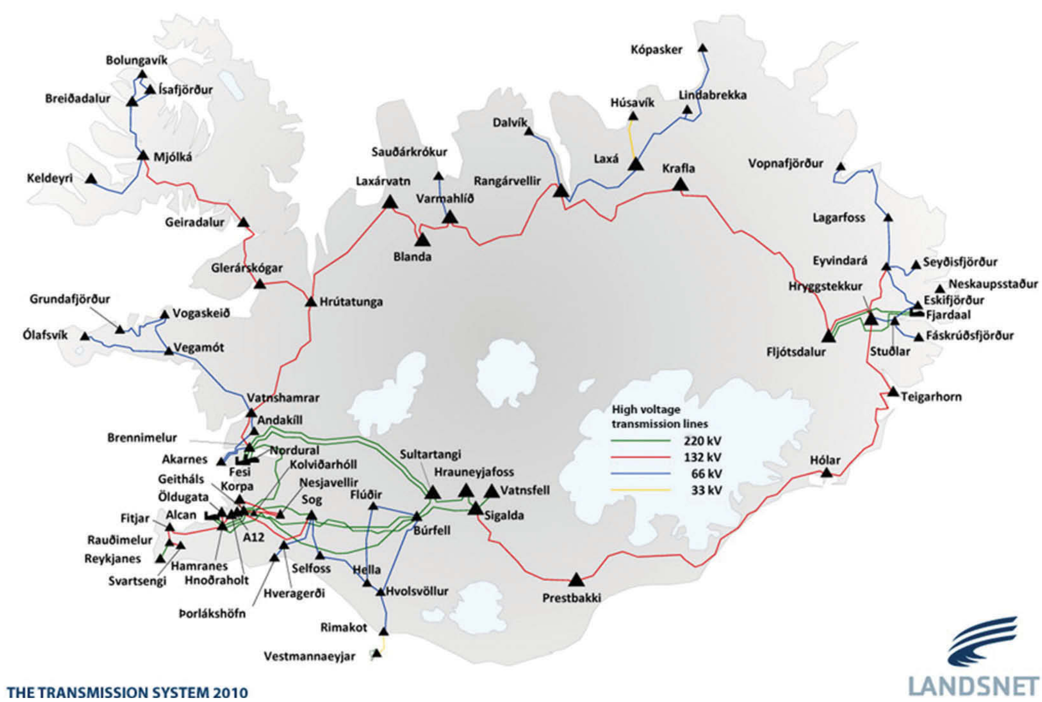


FIGURE 5.33 Icelandic power system. (© 2016 Landsnet. All rights reserved. With permission.)

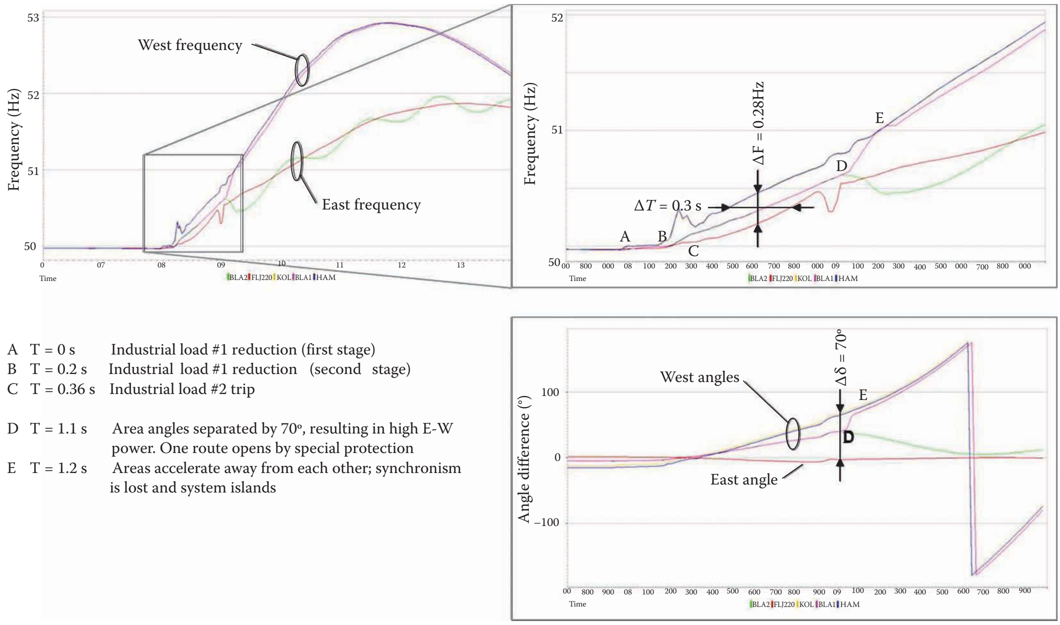


FIGURE 5.34 Angle and frequency deviations as system separates following a large load loss. (Based on data from Landsnet. © 2016 GE Grid Solutions, UK. All rights reserved. With permission.)

The emphasis of the Icelandic scheme is on maintaining angular stability where possible, but where islanding does result, it acts to improve the chance of survival of the islands by improving the area balances. In addition to the control of the resources, it is possible to control the split line created where islanding is inevitable so that certain generation units can be connected to the appropriate area of the grid for better island power balance. The resulting islands have a better power balance and, therefore, a greater likelihood of continued operation.

5.5.4.2.3 Enhanced Protection Schemes

Protection in smart transmission grids will become more challenging due to the entry of renewable generation and distributed energy resources. The underlying protection systems in traditional grids are largely designed based on conventional generator responses to short circuits. The pattern of fault currents flow from generators to the short circuit points is estimated with a high degree of certainty. Renewable and distributed energy resources will distort these responses, resulting in increased risk of failure to detect short circuits or increased risk of false operation of protection systems in the absence of a fault. A large number of distributed generation on the grid can also make the system behave dynamically different after fault clearing, thus posing a greater risk of system disturbances. These system disturbances include power swings and oscillations that could propagate throughout the system. Fault detection and isolation schemes in a smarter grid will need to be revised to consider the impact of distributed generators responding to short circuits. WAP will be able to process multiple local and remote measurements and implement wider-area protection schemes to contain or prevent the spread of disturbances in an interconnected power system. WAP could be used to isolate unstable areas of smart grids to prevent the disturbance from cascading into the other regions and identify the separation boundaries in the grid to create islands that survive major disturbances. WAP systems are designed to protect the system when control actions fail to address the disturbance. Protection actions include system separation, controlled islanding, generator tripping, and any other actions designed to contain a large-scale disturbance from precipitating into a system collapse.

5.5.4.2.4 Support High Penetration of Variable Renewable Generation

There is now a lot of controllable resources within the distribution network, including renewable generation, storage, and demand response. With a significant proportion of energy supplied at distribution level (now almost 50% at times in the GB network), it is critical that the valuable services that these resources can provide to the grid are used to good effect. The potential for active services include both grid-level services, such as the fast frequency response described above, and services within the distribution system itself, which requires a significant change from a traditionally passive view of the distribution grid to an actively managed approach.

More detailed monitoring of distribution systems are advisable to understand and design control-room and automated control systems. Synchrophasor measurements offer a fast-dynamic measurement approach that can be used both for monitoring and control, and can be used to address the historical problem of distribution systems being poorly observed.

Wide-area control can be applied in a number of areas, for example:

- Supporting DMS-based adaptive network management systems, providing fast-acting security actions while the DMS provides the optimization of the steady-state capability
- Managing a distributed microgrid, riding through separation, island operation, and resynchronization
- Angle-based control of generation resources to simplify and accelerate control actions
- Adapting to short circuit capacity levels

Furthermore, an adaptive control mechanism to release services for grid duty can be useful to coordinate transmission and distribution services. For example, a battery operator may provide at various times and to a varying extent:

- Service to distribution grid to manage the power loading of the distribution grid
- Voltage control for the distribution system
- Fast-frequency control ancillary service to the transmission grid—upward and downward service
- Fast reactive power support for the transmission grid

Detecting and adapting the control to the prevailing conditions is a potential application of WAMPAC with high penetration renewables. The use of cloud technology for acquiring and sharing synchrophasor measurements across transmission and distribution boundaries is being investigated for coordination purposes.

5.5.4.2.5 Increase Transmission Efficiency

Smart grids are expected to increase utilization of existing grid assets, such as lines and transformers. In this way, the grid can be more efficient in delivering power from the source to the loads. One approach to increasing transmission utilization is to dispatch generators to maximize power flow through the grid without exceeding system thermal and stability limits. Maximizing efficiency across the grid requires sufficient system-wide measurements to support system optimization applications. The efficient utilization of grid assets is also limited by the requirement for operating margins to account for potential grid instabilities or generation outages. It is anticipated that renewable generation and plug-in electrical vehicles will further complicate the estimation of these limits and that operators will probably establish higher margins for operational security. Countermeasures against instabilities can be instituted to provide security against these instabilities. More advanced decision support tools are needed to ensure increased efficiency in a smart grid.

WAMPAC systems can contribute to improving smart grid transmission efficiency in the following ways: (1) improved smart grid network management, (2) congestion management via stabilizing control, and (3) real-time optimization of grid operating parameters. Unlike traditional EMS/SCADA systems, WAMPAC systems can capture the accurate real-time state of the system. For example, up-to-date conductor temperatures calculated from phasor measurements can help determine additional power transfer capability of the transmission grid. Thermal margins in smart grid operations can be used by economic dispatch to ensure that most economical units are allocated, thereby minimizing total cost of power delivery. PMUs can also be used to enable stabilizing controls to mitigate potential destabilizing phenomena, such as voltage collapse and angle instability. Traditionally, operators place flow limits on transmission lines to ensure that no destabilization takes place following a disturbance. It results in inefficient utilization of transmission assets. In most cases, stabilizing control will contribute to transmission efficiency by releasing extra transmission margins and allowing more economical generator dispatch. As discussed previously, deployment of PMUs enables an accurate estimation of the smart grid system model. This model can be used to calculate the most optimal set points for HVDC and FACTS devices. HVDC and FACTS devices can contribute to transmission efficiency if WAMPAC can modulate their operating set points according to the current smart grid conditions. For example, the objective can be expressed defined as optimal power flow with minimum transmission losses.

5.6 DISTRIBUTED ENERGY RESOURCE MANAGEMENT SYSTEMS

5.6.1 The Need for Grid-Edge Resource Management

Spurred by diminishing deployment costs, transforming regulatory environments, and changing consumer behavior, the past decade has seen the beginning of a fundamental shift toward the decentralization of generation and the increased focus on the distribution system for power delivery efficiency and grid resilience. The distribution system is being exercised in ways that challenge traditional design and operation practices. Two-way power flows and an increase in power quality issues will create a design and operational challenges that will require more visibility of the distribution system down to the customer interface. DERs will provide opportunities to increase grid efficiency and resilience, but if not adequately monitored and controlled, DERs may be the detriment to the same cause they are trying to resolve.

As the use of DER increases in the electrical grid, there comes the point where these devices need to be actively managed, usually for any given distribution circuit with ~20%–30% of DER penetration. At this level of penetration, DER can be disruptive. This is due, in part, to the need to actively match the generation with the load in real time. With some types of DER, such as wind turbines and solar panels, their generation output can rise and fall very rapidly as the wind or cloud cover. For distribution-level interconnections, DERs typically use an inverter to manage the energy output of the DER or to isolate the DER from the grid in the event of a power outage.[7] However, there is a limit to which the distribution grid can absorb generation sources, and the DERs need to be actively managed to minimize adverse effects.

To have more insight into the power generation characteristics of inverters, there is a need to communicate with them. With this communication, there is a desire to have better control of the DERs, enabling grid operators to better match local load and generations conditions and provide ancillary market services. In 2009, this need led to an EPR effort to define so-called "smart inverter" functions [15]. This work was eventually codified in IEC 61850-90-7 [16] and IEC 61850-7-420 [17] technical reports published by the IEC.

However, with smarter inverters and the continued increase in penetration of DERs, there came a desire to manage DERs in aggregate, that is, to manage a group of DERs, but treat it as a single

[7] This for non-microgrid uses, where, for safety purposes, the DERs cannot be allowed to energize the power line when utility crews might be working on them.

resource so that grid operators were not required to individually control hundreds or even thousands of devices with numerous different capabilities and performance. This led to the notion of a Distributed Energy Resource Management System (DERMS). This DERMS would report on DER status and respond to any control or forecast requests from other enterprise applications while managing communication to individual DERs. In this way, the DERMS behaves much like other real-time grid management systems, such as a DMS or SCADA system. The DERMS may respond to data and messages exchanged with other enterprise applications, such as a DMS or GIS, and presents a group of DERs to the applications or system user as a single resource that can be called upon.

5.6.2 Functional Architecture

Figure 5.35 is an ArchiMate[8] diagram showing a generic infrastructure architecture for a DERMS. Business-to-business messages are exchanged on the left, utilizing the various services that the DERMS supports. On the right, the local field communications network is used to control the individual DER that make up a group. In this way, the function of the DERMS can be very much defined by the interfaces that it supports, and how these functions are supported by the various vendors is specific to the "black box" of the DERMS. Different vendors may seek to differentiate themselves based on their ability to optimize the support for the various DERMS control and reporting functions. Some of these DERMS functions are listed below:

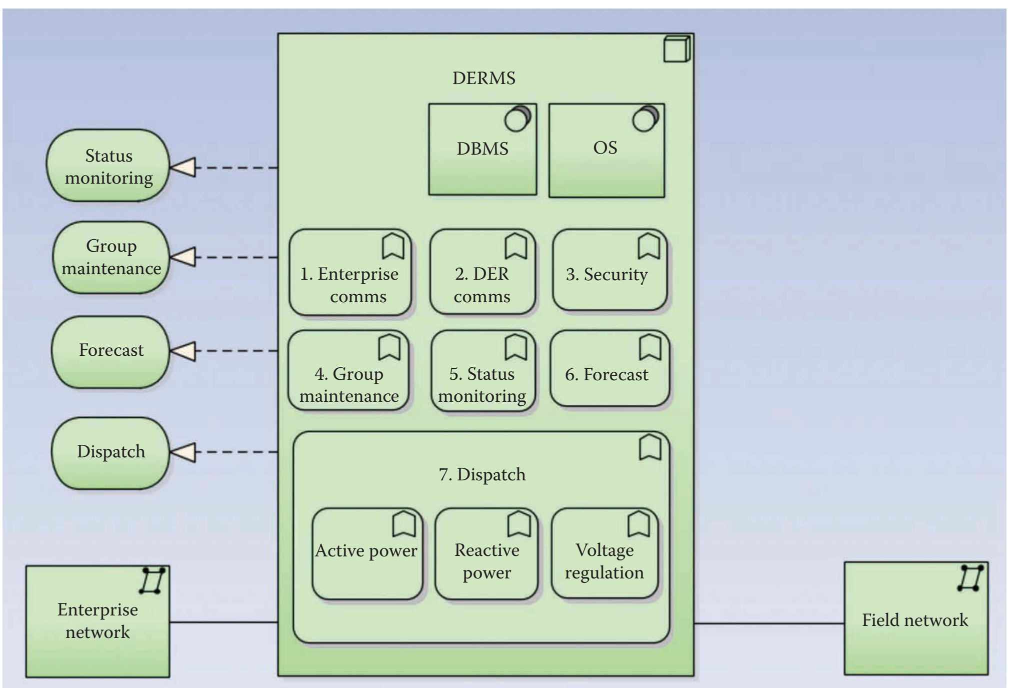


FIGURE 5.35 DERMS infrastructure showing some of the functions and services that a DERMS may perform. (© 2016 Electric Power Research Institute. All rights reserved. With permission.)

[8] ArchiMate is the enterprise architecture diagramming standard supported by The Open Group, www.theopengroup.org.

1. Enterprise communications—manages the business-to-business communications. This interface will typically be based on IEC CIM messages using IEC 61968-100 or the forthcoming IEC 61968-5[9] standard, or perhaps using MultiSpeak.
2. Field Communications—manages the field communications to the individual DERs. This may employ a variety of standards or protocols, such as Open Field Message Bus (OpenFMB), IEC 61850, or Distributed Network Protocol (DNP3).
3. Security—manages the communication and local security requirements.
4. Group management—this function responds to requests for, or manages locally, the creation of DER groups, the addition, deletion, or updating of DER members of the group, or the deletion of the groups.
5. Status monitoring—this function monitors the power output of the various DER members and alerts the enterprise of any events coming from individual DER.
6. This function handles the forecast function that will likely use both status monitoring and event data, historical performance, and related weather data.
7. Dispatch—this function supports the various dispatch modes of the DERMS. For this illustration, only active power, reactive power, and voltage regulation are shown, but the DERMS could show numerous types of dispatch and control.

As Figure 5.36 illustrates, because the interfaces for a DERMS utilize web services[10] for the interfaces, an implementation of a DERMS is agnostic to architecture. The DERMS functionality might be subsumed into a DMS; it might be a stand-alone edge system, much like how an AMI head-end system operates; it could be a "black box" located in a substation, managing any DER in the local area; or it could be a third-party aggregator, operating the DERMS as a service in the cloud.

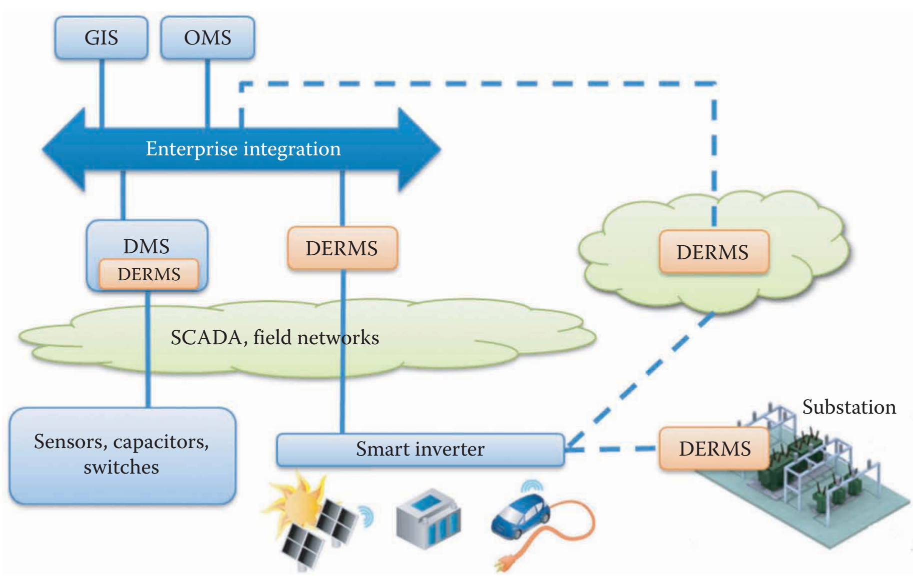


FIGURE 5.36 DERMS architecture options: part of a DMS, stand-alone, in a substation, or in the cloud. (From Distributed Energy Resource Management Systems (DERMS): Designing for Architectural Flexibility, Distributech, 2016, Electric Power Research Institute. With permission.)

[9] As of this writing IEC 61968-5 Distributed Energy Optimization is going through the IEC standardization process.
[10] Technologies such as SOAP or Representational State Transfer (REST) allow for loosely coupled web services.

5.6.2.1 Grouping

The DERMS manages the DER capabilities in aggregate, as a group of DERs that are presented as a single resource. However, the membership and organization of the groups are left to the operator. The operator may choose to group the DERs by type, for example, all photovoltaic, or perhaps by all battery storage. The operator may decide to group the DER by location, or by all the DERs on a feeder. Or the operator may choose to use a grouping scheme that includes both DER type and location, for example, all PV on a given feeder. This allows for the maximum flexibility when managing these grouped assets. However, it is incumbent upon the operator to create groups that make sense. When a DER group capability needs to be called upon in relation to grid activity, for example, congestion at a location in the grid, if the dispatched capability is in a different region of the grid, the outcome may not be desirable. Therefore, the knowledge of grid location and DER type is important for grid operation. However, in an enterprise system, location data would not necessarily be replicated in a DERMS, but rather in systems of record, such as a GIS or other asset management system (an important reason why DERMS should support standardized messaging to other enterprise systems). A distributed DERMS may contain knowledge of a localized set of assets if it is being used to manage a smaller area, for example, a microgrid.

Once a DER group is created, like any information object that is used by software, there needs to be a mechanism for maintenance of the group. Consider a group that was created to contain all the PV on a specific feeder. Over time additional PV may be installed in the feeder circuit. Rather than creating a new group, the operator would more likely desire to add the new PV to an existing group. Additionally, as a DER ages, its performance characteristics may change, necessitating the ability to update the characteristics stored in the DERMS, or if the DER is taken out of service, then the operator would want the ability to remove that DER from the DER group. These changes also suggest the need for the versioning of groups so that operators can have an insight as why the performance of a group may have changed over time.

The IEC Common Information Model (CIM) can be used as the basis for standardized information objects for managing DER groups, and for communication between utility enterprise systems, such as a DMS or DERMS. This data model is shared among three IEC standards to support distribution (IEC 61968), transmission (IEC 61970), and energy market (IEC 62325) applications, hence the "common" designation. A DER group needs to have an identifier, a name, and a description that can be helpful in identifying a group.

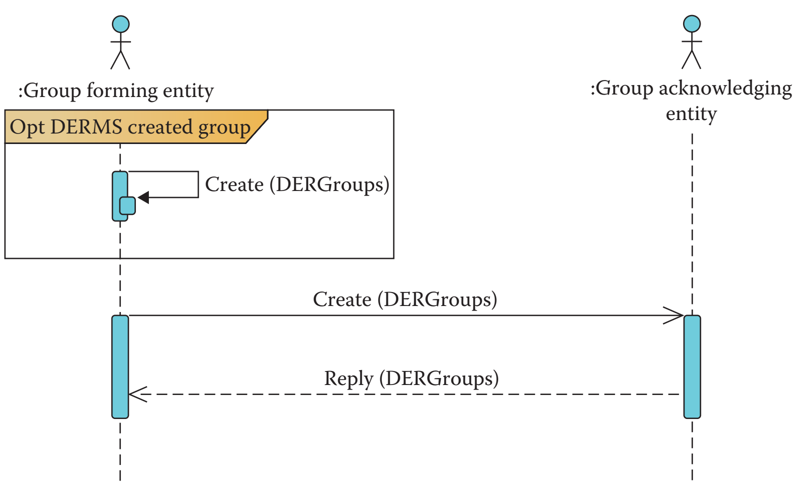


FIGURE 5.37 Sequence diagram showing the message interaction to support the creation of DER groups. (© 2016 Electric Power Research Institute. All rights reserved. With permission.)

Exploring the service-oriented architecture paradigm further, consider the messaging sequence diagram in Figure 5.37. A sequence diagram is a standard unified modeling language diagram that is read from left-to-right, and top-to-bottom. This diagram illustrates how the messages to support the creation of DER groups could be initiated by any other system, in this case, referred to generically as the "group forming entity." The "group acknowledging entity" is most likely the DERMS. Optionally, at the top right of the diagram, this notation reflects that DER groups could be created locally. It is the loosely coupled nature of web services that supports the architectural paradigm that the DERMS could physically be deployed over a variety of locations and architectures.

5.6.2.2 Status and Event Monitoring

To have the insight into the status of the DERs on the grid and, hence, the capabilities of the DER group, a mechanism needs to be provided to exchange status and event information. The IEC CIM allows for generic status information to be exchanged in the status class. Additionally, other information could be passed to reflect specific events. IEC 61968-9 Meter Reading and Control provides such a mechanism. While nominally 61968-9 addresses metering this standard also includes the support for many other types of end devices, which in the standard, is the generic term for devices that are deployed in the field. The list of end device events is in Annex E of the IEC 61968-9 standard. This list is in the process of being extended to support specifically a broader array of assets. The domain part of the event supports enumerations, such as DER switch, firmware, power factor, and power quality. The type includes enumerations such as alarm, configuration, and test mode, while the index lists hundreds of individual errors that might be communicated from the device. For example, if the smart inverter broadcast a 2.9.1.47 event, this is decoded as Device Asset, DER Switch, Alarm, Current Loss, which allows for very verbose information to be sent but utilizing a very small message space.

Keep in mind that events are not broadcast by a DER group, but rather by an individual DER. It would be up to the programmed logic in the DERMS to determine how any specific events should be treated, whether that event would need to be passed to other systems, such as a DMS, whether the operator should be notified (some events may be informational, Some events may be more serious like alarms), or whether the event might impact the overall capability of a DER group.

In addition to event and generic status information, the status monitoring message also provides for the monitoring of the real-time power capabilities of the DER. The CIM has been extended to support tracking of the current, minimum, and maximum values of real, reactive, and apparent

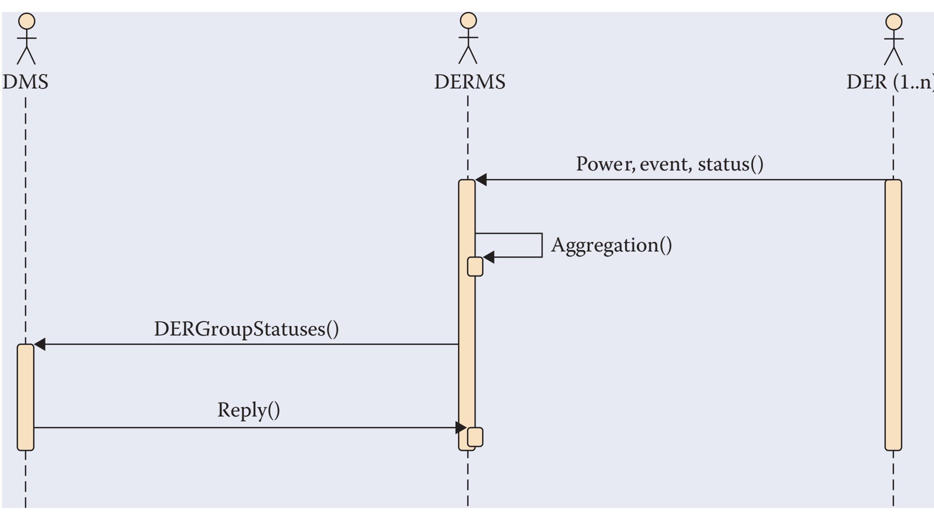


FIGURE 5.38 DERMS in context showing the aggregation of various status, event, and power information from individual DERs. (© 2016 Electric Power Research Institute. All rights reserved. With permission.)

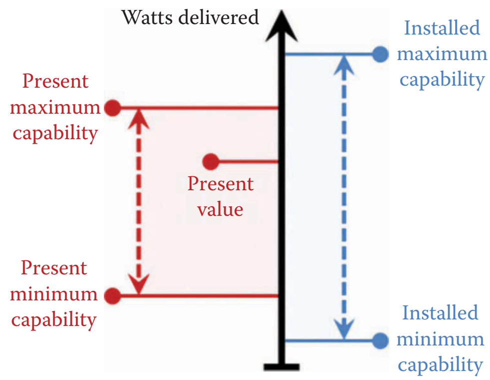


FIGURE 5.39 DER installed versus actual power output capability. (From Common Functions for DER Group Management, Third Edition, Electric Power Research Institute. With permission.)

power, which can also be included in the status message either to the console operator or to other systems that need this information, such as a DMS. The sequence diagram in Figure 5.38 puts this message exchange in context. The various individual DERs send status, event, and power information to the DERMS. The DERMS aggregates this information and provides it to other interested systems, such as the DMS (shown on the left). On the right-hand side the label "DER (1..n)" reflects the notion that the DER group could consist of a single DER, or multiple DERs. Keep in mind that the power availability at any given moment may not be the installed capacity, but some intermediate availability based on current conditions, as shown in Figure 5.39.

5.6.2.3 Forecasting

A prelude to control of the smart inverters associated with the DER is both understanding their status as was discussed in the prior section and the ability to understand the capabilities that can be called upon in the future, which necessitates the requirement to ask a DERMS for a forecast of the capability of any given group, and the duration and confidence of that forecast. For example, Figure 5.40 shows an example of the forecasted capability for a storage unit. With battery storage, the capability can be known with some certainty. Given a state of charge, the battery has a corresponding remaining capacity and, depending on the duration of the request, can provide that capacity for some known period.

Other types of DER, such as solar panels and wind turbines, are more complicated as they may have some maximum rated capacity, but their output is dependent on the availability of wind and

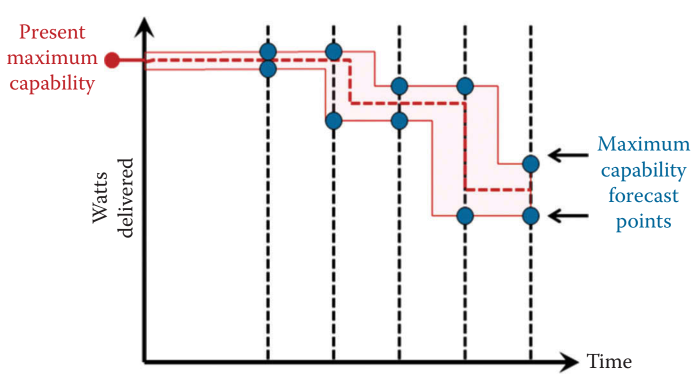
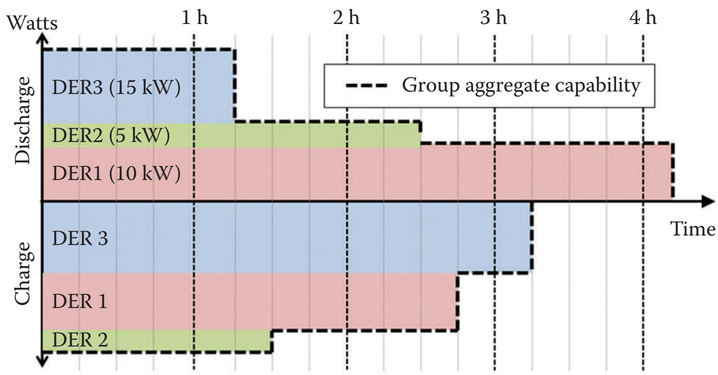


FIGURE 5.40 Example storage forecast curve. (From Common Functions for DER Group Management, Third Edition, Electric Power Research Institute. With permission.)



Power available		
Duration (h)	Discharge (kW)	Charge (kW)
1	30	30
2	15	25
3	10	15
4	10	0

FIGURE 5.41 Example of DER capacity as an aggregate capability of three battery storage DERs. (From Common Functions for DER Group Management, Third Edition, Electric Power Research Institute. With permission.)

sun. Thus, a forecast for these types of resources requires additional data sources, such as forecasted wind/cloud cover, and the historical performance data for these resources on like days. Also, consider that the forecast would most likely be made for a group of devices. Since the DER group is managed in aggregate, the operator likely does not know or care about how this forecast is derived, only that it is accurate when the need arises for this resource to be called upon. This notion of group aggregated capability is illustrated in Figure 5.41. This DER group example is made up of three battery storage DERs, each with different capacities and output availability.

If the DER group is made up of multiple types of DER, then the forecasting would be more complex and would need to use a combination of the data inputs to create a reliable prediction of capabilities.

When the operator or system requests a forecast, the request needs to include the start date and time of the forecast, the type of interval (for example, 5 min, 15 min, hourly), and the number of intervals. For example, a forecast request might take the form of "How many watts are available beginning

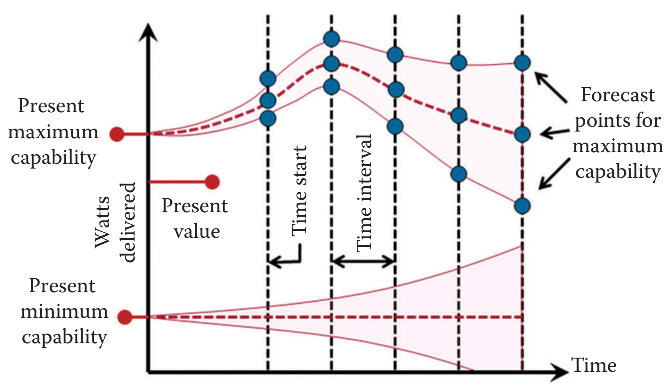


FIGURE 5.42 Example of a DER group forecast showing the intervals. (From Common Functions for DER Group Management, Third Edition, Electric Power Research Institute. With permission.)

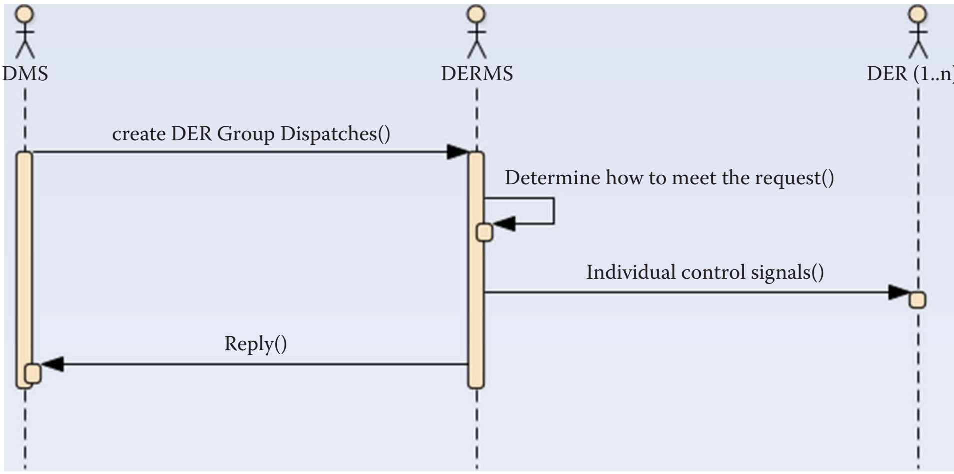


FIGURE 5.43 Sequence diagram showing the integration of DERMS dispatch requests. (© 2016 Electric Power Research Institute. All rights reserved. With permission.)

TABLE 5.2
Proposed DERMS Functions

DER Group Function	Description
DER group creation	Adding individual DERs (with known capability); naming and identifying the group
DER group version and member query	Query a DER group for its members based on a given version of the group. This allows the operator to track the changes to a group over time
DER group deletion	Deleting a group
DER group maintenance (adding, updating, deleting members)	In addition to adding or removing members from the group, this may involve updating the capabilities of one or more DERs within the group
DER group capability discovery	Querying the group for the types of capabilities and control functions for which the DERMS supports
DER group status monitoring	Broadcast or query of a DER group for status, power, or event related information
DER group forecasting	Based on a set of query parameters indicating start time, time interval, and duration; respond with a forecast that includes the confidence expressed as a percentage of the accuracy of the forecast
DER group historical aggregate meter data	This allows the DERMS to query other systems, such as an AMI or a meter data management system (MDMS) for historical metering data that might include power quality, status, or event data, that the DERMS may then use in the internal algorithms to optimize group performance
DER group maximum real power limiting	Set the power limit factor for a DER group
DER group ramp rate limit control	Set the ramp rate curve for a DER group
DER group phase balance limiting	This sets the phase balance limits within which the DER group is required to operate
DER group real power dispatch	Request that the DERMS dispatch energy in terms of real power
DER group reactive power dispatch	Request that the DERMS dispatch energy in terms of reactive power
DER group voltage regulation	Set the voltage level for a DER group
Regulation function	This refers to services that regulate an area control error (ACE) signal. ACE has three components: • Frequency—frequency error (delta-frequency) • Power net interchange—reflects the present power import/export for a balancing authority • Time error—cumulative phase error

(*Continued*)

TABLE 5.2 (*Continued*)
Proposed DERMS Functions

DER Group Function	Description
DER group primary frequency response	This differs from the regulation function above. It does not use an ACE signal and is concerned with frequency "droop" and synthetic inertia
Set DER group curve functions	Curve refers to the smart inverter of a specific DER ability to have both a controlled and controlling variable. For example, the controlling variable might be local voltage or frequency, and the controlled variable might be real or reactive power produced. There might be multiple such curve functions to make up the aggregate response for a DER group
Provide price to DER group	If a tariff predetermines a given cost of service, provide this information to a DER group
Request cost of service from DER group	Query for cost related to a specific control action from a DER group
Manage power at a point of reference	This informs the DERMS the point at which it is to manage power; for example, this might be the point of common coupling where a microgrid is interconnected to the grid
Connect/disconnect DER group	This function allows a DERMS to disconnect or reconnect a DER group from the grid. This might be used for various activities, such as maintenance in a local area where the grid needs to be de-energized
Specify bellwether meters	This function allows a DERMS to make a request of perhaps an AMI system, to obtain data from select bellwether meters. The purpose would be to be able to read data from the metering system to give the DERMS greater insight into the status of the area it controls, for example, selecting meters that measure the highest or lowest voltage points on a feeder

tomorrow at noon, for the next six hours." The response to this request is a set of intervals and forecasted capability, along with a level of confidence (expressed as a percent) that lets the requestor have a sense of the accuracy of the forecast. An example of this forecast is shown in Figure 5.42. As expected, the further out a forecast, the lower the confidence in the ability of a DER group to meet the request.

5.6.2.4 Dispatch

Once the operator has visibility into the status of the DER groups and has made forecast requests to understand the capability of a DER group over time, the operator is able to make a dispatch request. The interaction is shown in the sequence diagram in Figure 5.43. In this example, a DMS makes the request to the DERMS, the DERMS in turn needs to determine how to meet the parameters of the request. Once the determination is made, the DERMS sends the individual control signals to the DER, and then sends a response to the DMS to let it know that the dispatch request has been initiated.

Use of the IEC CIM currently allows for dispatch requests to be made using active, reactive, and apparent power. The IEC CIM also allows for the flexibility of dispatch requests to be made to support unforeseen capabilities in addition to the various DERMs functions shown in Table 5.2.

5.6.2.5 Hierarchical Control

Earlier, it was noted that one of the architectural options for a DERMS is a substation controlling device local to that substation or feeder. In the future, DERMS functions could be implemented at multiple layers within the grid as shown in Figure 5.44. At the highest-level system operators might call upon a DERMS managed by distributors or aggregators. These, in turn, might call upon a

DERMS at a more granular level in the grid, for example, substations, microgrids, or facilities. The feature that supports this layered architecture is the ability of the DERMS to group resources. This uses the same paradigm as the Open Automated Demand Response (OpenADR) standard summarized in Figure 5.45 that was first described in an EPRI report on DER in 2010 [18].

OpenADR uses the notion of a virtual top node (VTN) and a virtual end node (VEN). However, a given VTN does not know or care whether a given VEN is itself, a VTN that is also aggregating resources. In Figure 5.45, node A represents a VTN, which, in turn, calls VENs B and E. However, node A does not know (or care, even if it is a human operator) that VENs B and E are themselves

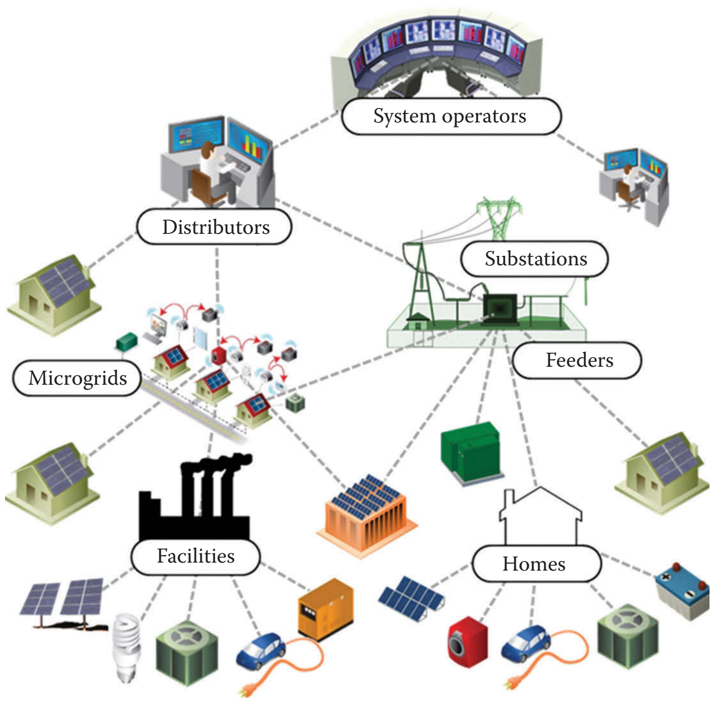


FIGURE 5.44 DERMS hierarchical architecture. (From Common Functions for DER Group Management, Third Edition, Electric Power Research Institute. With permission.)

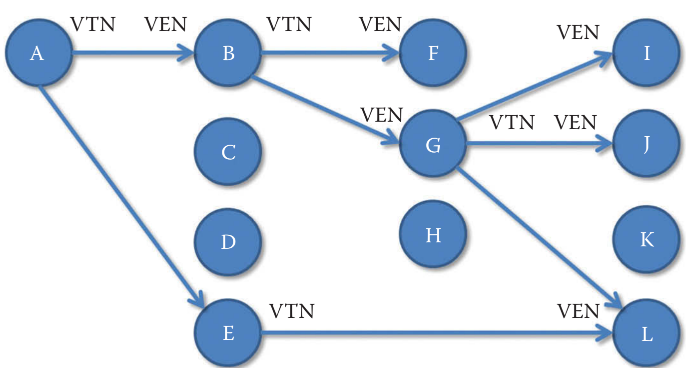


FIGURE 5.45 Relationship between OpenADR virtual top nodes and virtual end nodes. (Adapted from Oasis Energy-Interoperation based on the earlier Concepts to Enable Advancement of Distributed Energy Resources, Electric Power Research Institute white paper, https://www.oasis-open.org/committees/tc_home.php?wg_abbrev=energyinterop. With permission.)

also VTNs calling VENs F and G, and L, respectively. This OpenADR concept can be applied to a hierarchical DERMS architecture of the future. A system operator will not know or care that the DERMS capability that is being called upon in DER group A may be calling, in turn, a DER group B that has members F and G, with member G also being a group with members I, J, and L. What the system operator will care about is: when a DER or group of DERS is dispatched, it will operate at or near the capability indicated by the status monitoring function or within the confidence level of the forecast.

5.6.2.6 Autonomous Control

In addition to hierarchical control, the future DERMS will have greater ability to operate autonomously. Consider the case of a microgrid. A DERMS could be used to control a microgrid, but to enable this functionality, the DERMS will need a model of the local power system. The IEC CIM provides a mechanism for the exchange of power system models using Resource Description Framework Schema (RDFS). RDFS files are often used to exchange power system models at the ISO level. However, the same mechanism could be used to provide a DERMS with a model of the local grid. Then, in the case of the microgrid, the DERMS could manage the microgrid at the point of common coupling (where the microgrid is interconnected with the main distribution grid) in one of three contexts:

- Nominal operation—the energy within the microgrid is balanced with the energy exchanged at the point of common coupling
- Islanded operation—the DERMS controls the devices within the microgrid when it is islanded
- Discharge operation—the DERMS manages energy flow from the microgrid into the distribution network at the point of common coupling

In addition to managing individual DERs within the microgrid, the DERMS might also communicate with other grid devices, such as capacitor bank controllers, transformers, or switches, to control their settings to optimize energy within the local grid. The DERMS can communicate with the devices using various communication standards, such as IEC 61850, DNP, Open Field Message Bus (OpenFMB). As the DERMS evolves into this type of capability, a DERMS could be considered a distributed DMS (or DDMS).

5.6.2.7 Additional DERMS Functions

Table 5.2 lists the proposed DERMS functions from the EPRI report, Common Functions for DER Group Management, Third Edition [20].

5.6.3 DERMS and Transactive Energy [21]

Conventional DMSs have visibility and control of most of the primary distribution substations and feeders, and they rely on mathematical models to analyze the distribution system. Further down the distribution network, accurate data on line impedances, line loading, and real-time measurements are not readily available. There is, therefore, the need for a DERMS to augment the capabilities of the traditional DMS to extend the reach of real-time remote monitoring and control down to the customer side of the meter. Key to facilitating DERs on the distribution system is a more extensive SCADA network with additional sensors, metering, and controls on the feeder and a more widespread communications network. Since DERs can be owned by the customer, the utility, or a third-party, there is the challenge of DER owners allowing utilities, or the managing retail company, the capability to monitor and control DERs not owned by the utility.

The current focus of DERMS is on managing DERs to optimize grid performance and alleviate disruptions within the distribution grid. While the global DERMS market is nascent, regions with higher distributed and renewable generation penetration tend to have a higher degree of adoption. DERMS could be considered one of the tools in real-time grid management that the system operator might use; other systems, such as a demand response application server (DRAS) based on OpenADR might be another option. A DERMS or a DRAS might be used separately or together, but in the future, the use of these options will include a cost of service. For example, if both systems can give the operator a certain level of VAr support at a given time, for a given duration, at the required location on the grid, the system operator will be inclined to use the option that can provide that service at a lower cost.

As the grid evolves to be more market oriented—early regulatory efforts include New York Reforming the Energy Vision (REV) [22] and California's Rule 21 [23]—consider an environment where the transactions are not solely between the distribution grid operator and its customers, but where any two parties can transact an energy exchange—known as transactive energy. For example, a "prosumer" (the transactive energy term for a party that both buys and sells energy) may have a battery storage DER that can bid into the market controlled by the local DERMS, and the prosumer may also have a water heater that can bid its services into the market controlled by a DRAS.

In the same construct as the ISOs and RTOs, there will be a need for Distribution System Operators (DSOs) to manage and coordinate DERs and provide an open market for customers to generate and consume power on the distribution grid. DERs and transactive energy will also affect transmission wholesale open markets, with the capability to provide operating reserve and grid ancillary services in support of the bulk power system operation (discussed further in other chapters of this book). Therefore, there will be a need for the DSO to interact with the ISOs and RTOs. Microgrids and other supply and demand resources (such as Building EMSs) could also be part of the DERMS and DSO responsibilities.

As the penetration of DERs continues to increase, there will be a corresponding need to actively manage DERs. However, the sheer numbers of DERs will overwhelm the ability of human operators to effectively manage these resources. The DERMS provides human operators with the ability to manage DER in aggregate, facilitating the management of DER within defined parameters that will promote the efficient and resilient operation of the grid. However, DERMS development is still in its infancy. The list of proposed functions a DERMS could support is extensive, but in practice, only a subset of these functions have been demonstrated to date (DER group creation, management, status monitoring, forecast, and dispatch). As the requisite standards (IEC, IEEE, etc.) continue to be developed, these will continue to promote an environment of innovation in this space. The market will determine which functions are most valuable, and policy changes suggest that the future of DER within these markets will be more distributed and transactive. Because a DERMS uses web services, it is both agnostic to how groups are managed and agnostic to solution architecture, supporting a wide variety of scalable and flexible implementations that will meet the future requirements of distributed, market-oriented operation.

5.7 GRID MANAGEMENT CYBERSECURITY CONSIDERATIONS

NERC CIP Standards 002–009 [24] require utilities and other responsible entities to create an electronic security perimeter around critical cyber assets. Figure 5.46 is a diagram representing the primary assets found in a typical electric system, with the addition of PMUs and PDCs. The assets are grouped into four major blocks: a control center, a PDC, and two transmission substations. Each block is electronically isolated by an electronic security perimeter. The electronic security perimeters are denoted as dashed lines around each isolated block. NERC CIP does not specify the

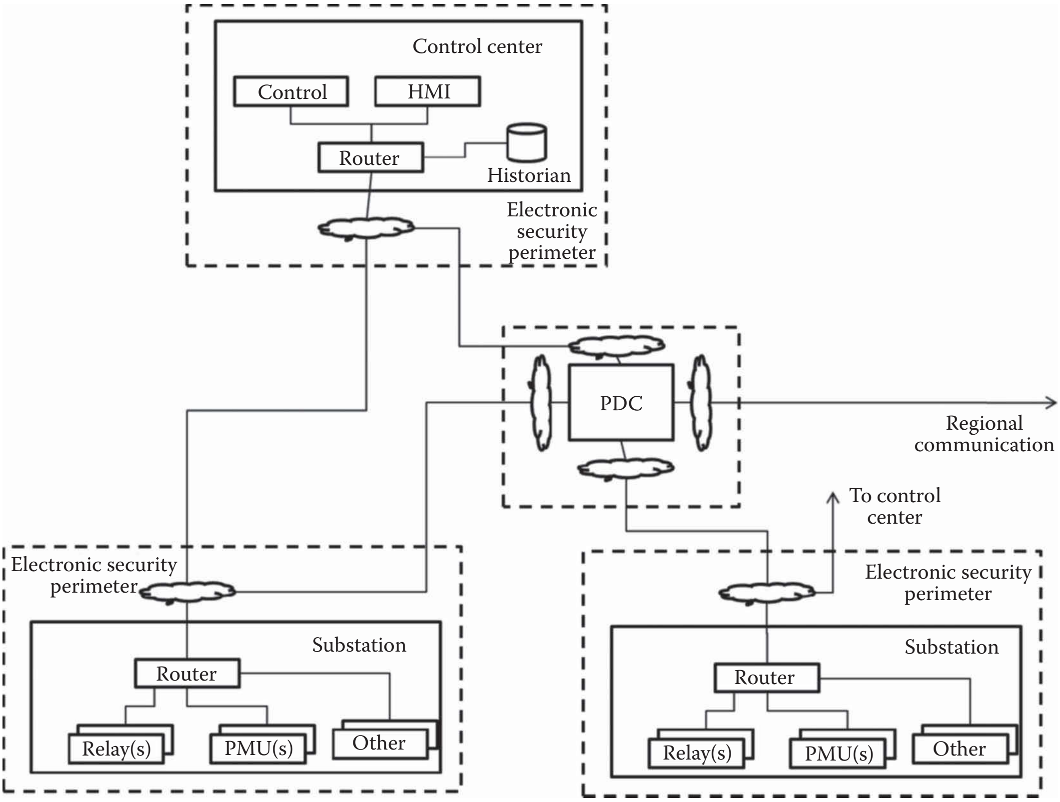


FIGURE 5.46 Typical electric system electronic security perimeters.

methods for creating the electronic security perimeter. As such, the methods vary widely and are, therefore, drawn as security clouds in Figure 5.46.

The electronic security perimeters must be subjected to vulnerability analyses, use access control technologies, and include systems to monitor and log the electronic security perimeter access. The Federal Energy Regulatory Commission (FERC) requires responsible entities involved in bulk electricity transmission to adhere to the NERC CIP standards. No such regulation exists for the electric distribution systems in the United States. Electronic perimeter security minimizes the threat of illicit network penetrations; however, persons with electronic access to grid management systems within the electronic security perimeter remain a threat. Such persons include hackers who have penetrated the electronic security perimeter via external network connections, disgruntled insiders, and hackers who may penetrate wireless interconnection points within the electronic security perimeter.

Cybersecurity should address three core principles: confidentiality, integrity, and availability. It is agreed that they should be ranked by importance for the smart grid and grid management systems as availability, integrity, and then confidentiality.

5.7.1 Network Penetration Threats

There are three primary threats to process grid management systems: sensor measurement injection, command injection, and denial of service (DOS).

Sensor measurement injection attacks inject false sensor measurement data into a system. Since grid management systems rely on feedback control loops before making control decisions, protecting the integrity of the sensor measurements is critical. Sensor measurement injection can be used by attackers to cause control algorithms to make misinformed decisions.

Command injection attacks inject false control commands into a grid management system. Control injection can be classified into two categories. First, human operators oversee grid management systems and occasionally intervene with supervisory control actions, such as opening a breaker. Hackers may attempt to inject false supervisory control actions into a system network. Second, RTUs and IEDs protect, monitor, and control grid assets. The protection and control algorithms take the form of ladder logic, C code, and registers that perform calculations and hold key control parameters, such as high and low limits, comparison, and gating control actions. Hackers can use command injection attacks to overwrite ladder logic, C code, and remote terminal register settings.

DOS (denial of service) attacks attempt to disrupt the communication link between the remote terminal and master terminal or human machine interface. Disrupting the communication link between master terminal or human machine interface and the remote terminal affects the feedback control loop and makes process control impossible. DOS attacks take many forms. A common DOS attack attempts to overwhelm hardware or software so that it is no longer responsive.

5.7.2 Protocols

SCADA systems remotely monitor and control transmission and distribution grid physical assets. Present-day SCADA systems are commonly connected to corporate intranets, which may have connections to the Internet. SCADA communication protocols, such as MODBUS, DNP3, and Allen Bradley's Ethernet Industrial Protocol, lack authentication features to prove the origin or age of network traffic. This lack of authentication capability leads to the potential for network penetrators and disgruntled insiders to inject false data and false command packets into a SCADA system either through direct creation of such packets or replay attacks.

Modern power systems are being upgraded with the addition of PMUs and phasor data concentrators (PDCs) that facilitate wide-area monitoring and control. The IEEE C37.118 protocol carries phasor measurements between PMUs and PDCs to historians and EMSs. As with MODBUS and DNP3, the IEEE C37.118 protocol does not include a cryptographic digital signature. As such, a hacker or disgruntled insider may potentially inject false synchrophasor data into a transmission control system network without detection. Furthermore, the IEEE C37.118 protocol includes command frames used to configure PMUs and PDCs. False command frames may also be injected in a manner like that used to inject false data frames.

IEC 61850 is one of the new protocol stacks developed to increase interoperability among protection and control devices—IEDs. However, the IEC 61850 protocol does not directly include cybersecurity features, though a separate IEC recommendation, [25] IEC 62351, guides users on how to secure an IEC 61850 network installation. IEC 61850 offers features, such as a standardized XML-based substation configuration language (SCL), for describing and configuring substation protection and control devices. IEC 61850 also offers standardized data-naming conventions for power system components. Such standardization greatly simplifies power system management and configuration, though it is also an enabler for hackers since it can minimize a hacker's learning curve. It is imperative that IEC 61850 installations adhere to the IEC 62351 recommendations.

5.7.3 Availability

The smart grid is considered critical infrastructure. Loss of grid management system availability may lead to incorrect control actions. Furthermore, loss of the ability to make control actions may lead to system damage or failure, and ultimately blackouts and economic harm to the local or regional economy. There are two primary components to ensuring grid management system availability: intrusion detection systems (IDSs) and system design.

Loss of availability can come from DOS attacks and command injection attacks that attempt to directly take control of the grid management system. Control injection attacks can be detected with intrusion detection systems (IDSs) and prevented with authentication techniques that are covered under the integrity discussion. DOS attacks attempt to deny network service by flooding a network with information at a rate faster than it can be processed. IDSs can detect and mitigate many DOS attacks.

Grid management systems should include IDS sensors to monitor network transactions at all entry points to the system network or at points guaranteed to capture traffic from all entry points to the system network. Entry points include local area network (LAN) drops, dial-up modems, wireless terminals, and connections to trusted neighbors, such as regional operators and independent system operators, as well as connections to the corporate LAN.

System design also affects grid management system availability. First, many attack vectors can be stopped by eliminating unneeded network services. NERC CIP 007 requires electric responsible entities to disable all network ports and services not used for a normal or an emergency operation. For instance, TCP and UDP each use port multiplexing to support many transport layer services. In total, TCP and UDP can support 64-K ports. The Internet Assigned Numbers Authority (IANA) assigns port numbers to frequently used services, such as Telnet, SSH, and SMTP. Many grid management system protocols have IANA-reserved port numbers; for example, MODBUS TCP servers listen on port 502, Allen Bradley EtherIP uses TCP port 44818, and UDP port 2222. DNP3 over TCP uses port 20000. Any unused port should not have a listening server running on any cyber system connected to the grid management system network. IDSs should monitor for activity on all TCP and UDP ports. Grid management systems should be designed to allow each user to have a unique account ID and password. This requirement supports traceability and role-based access control. Traceability means that actions taken on the system can be traced to an individual user. Role-based access control means that each user can be assigned roles and associated privileges (levels of authority). For example, a dispatcher may be allowed to open a breaker, while a less privileged user may only be able to view the status of the same breaker. Legacy grid management system equipment may not be able to support separate usernames. In this case, NERC CIP 007 requires entities to limit password knowledge to those individuals with a need to know. The security clouds shown in Figure 5.46 include access control features that limit access to an entire electronic security perimeter. These access control features can be certificate based, can support separate user ID and passwords for all users, and can support role-based access control.

The final design-related element to the availability principle may be obvious but is worth mentioning. All cybersecurity solutions should, of course, do no harm to the grid management system. The algorithms used for grid management systems and control decisions often have data age requirements. For instance, some EMS algorithms require data to be less than 2–4 ms old to support control decisions. "Bump-in-the-wire" (additional hardware and software in the communications link) for cybersecurity solutions, such as those shown in Figure 5.46, add latency to traffic delivery. The additional latency must never cause the system to become nonfunctional or uncontrollable. Furthermore, many proposed IDS systems include automated mitigation actions. These actions should only be taken when the IDS system is deterministic. Statistical IDS systems are probabilistic and, therefore, always have a probability of misclassifying network traffic. In such cases, the IDS may recommend mitigation actions, but a human should be kept in the control loop to validate mitigation recommendations.

5.7.4 Integrity

The integrity cybersecurity principle is intended to protect network traffic from unauthorized modification. The most common method for ensuring network traffic integrity is authenticating network traffic using digital signature algorithms (DSAs). The MODBUS, DNP3, Allen Bradley EtherIP, IEEE C37.118, and IEC 61850 standards do not include features to authenticate network traffic. Authentication is left to the responsibility of a high layer protocol.

The security clouds in the network architecture shown in Figure 5.46 can digitally sign network traffic. Bump-in-the-wire solutions exist that can capture network traffic as it leaves an electronic security perimeter and appends it with a digital signature. The security cloud in a receiving electronic security perimeter can validate the digital signature before forwarding the traffic to cyber systems inside the electronic security perimeter. The digital signatures can be based on multiple algorithms. FIPS 186 (the NIST Federal Information Processing Standards publications for the Digital Signature Standard) specifies the NIST-recommended DSA. DSA uses public key cryptography techniques to sign network traffic. This method is often considered too slow and resource intensive for grid management systems; however, if cryptographic processors are used in place of the security clouds in Figure 5.46, it is likely that DSA signing and validation can meet required latency targets for grid management applications. The elliptic curve digital signature algorithm (ECDSA) is an alternative approach for network traffic authentication. The ECDSA is considered faster, uses smaller keys, and therefore has fewer storage requirements than DSA. ECDSA is patented by CERTICOM, RSA, the U.S. National Security Agency, and Hewlett-Packard. This may slow the adoption of ECDSA. A third alternative for authentication is the keyed-Hash Message Authentication (HMAC). HMAC is the least resource-intensive DSA of the three discussed here.

A key consideration when using digital signatures in grid management systems is the length of the signature and the latency added to the network traffic result by adding and validating the signature. This is especially pertinent for low data rate systems, such as SCADA systems, that often have data rates of 1200–19,200 baud. The Pacific Northwest National Laboratory [26] released a study that measures round-trip response times for DNP3 frames signed with various length HMAC authenticators. The response times varied according to the length of the authenticator, according to the data rate of the communication link and according to the type of bump-in-the-wire cyber system used to authenticate the DNP3 frames. The worst case was 1996-ms latency for 1200 baud using industrial PCs to create and validate the 12-B HMAC signatures. The best case was 210-ms latency for 19,200 baud using industrial PCs to create and validate the 12-B HMAC signatures. Systems, such as YASIR, [27] have been developed to minimize latency involved in adding digital signatures to MODBUS and DNP3 network frames.

Another important consideration when planning to use digital signatures is the availability of hardware resources. Many RTUs are equipped with cryptographic resources and storage capabilities that may conflict with the needs of an adequate DSA, which presents three possibilities for grid management systems that support digital signatures for authentication. First, system designers may choose to use existing hardware and add a bump-in-the-wire cybersecurity solution (to sign and validate network traffic). Second, system designers may choose to upgrade existing remote or master terminal hardware to integrate the required cryptographic and storage resources. Third, system designers may choose to use a lightweight DSA that can execute on existing master terminal and remote terminal platforms.

5.7.5 Confidentiality

The confidentiality cybersecurity principle intends to protect network traffic from unauthorized eavesdropping. The most common method for ensuring network traffic confidentiality is encryption. The need for confidentiality of grid management system network traffic can be a controversial topic, with many system engineers arguing against the need for grid management system network traffic confidentiality. The need for confidentiality will vary for each installation. However, it must be stressed that hackers use eavesdropping to collect information about systems before executing attacks. Confidentiality minimizes the potential attacker's capabilities in this intelligence gathering stage.

The security clouds in the network architecture shown in Figure 5.46 can encrypt and decrypt network traffic. Bump-in-the-wire solutions exist that can capture network traffic as it leaves an electronic security perimeter and encrypts the network traffic. The security cloud in a receiving electronic security perimeter can decrypt network traffic before forwarding the traffic to cyber systems inside the electronic security perimeter. Encryption algorithm choice can be based on multiple algorithms.

A key consideration when using encryption in grid management systems is the latency added to the network traffic because of encryption and decryption of the traffic. This is especially pertinent for low data rate systems, such as SCADA systems, which often have data rates of 1200–19,200 baud. Symmetric block ciphers, such as Advanced Encryption Standard (AES), Data Encryption Standard (DES), or 3 DES, seem best suited for use in grid management systems. These ciphers are quite fast, and all three have many open source implementations in software and hardware. All three of these ciphers can be used as a stream cipher (output feedback, cipher feedback, or counter mode) to speed up the encryption/decryption process and, thereby, reduce latency.

Another important consideration when planning to use encryption is the availability of hardware resources. Many RTUs are equipped with cryptographic resources and storage capabilities that may conflict with the needs of an adequate encryption algorithm, which presents three possibilities for grid management systems that support encryption for confidentiality. First, system designers may choose to use existing hardware and add a bump-in-the-wire cybersecurity solution (to sign and validate network traffic). Second, system designers may choose to upgrade existing remote or master terminal hardware to integrate the required cryptographic and storage resources. Third, system designers may choose to use a lightweight encryption algorithm that can execute on existing master terminal and remote terminal platforms.

5.7.6 Isolating the Grid Management Network

Grid management systems should be isolated from corporate networks or LANs to minimize the potential of illicit penetration. Corporate networks are used by most employees of a company. Corporate networks often include connections to the Internet, some via wireless LAN connections using IEEE 802.11 protocols. These portable nodes, such as laptop computers, which come and go from the corporate network, generally allow the use of e-mail and typically see frequent use of USB disk drives. These characteristics lead to cybersecurity vulnerabilities and the need to isolate the grid management system network from the corporate network.

Connections to the Internet are a common point for external network penetration. Hackers commonly use port scanning tools to scan for TCP and UDP services. Contemporary port scanning equipment software, such as NMAP, [28] can target specific IP address ranges, find TCP and UDP services, identify service demon version numbers, and identify operating system name and version numbers. Armed with such information, hackers can use look-up tables available on the Internet to find exploits targeted at specific versions of specific network services running on specific operating system platforms. These exploits often allow hackers to bypass network defenses and penetrate the corporate network.

Wireless LANs on corporate networks are also a significant weak link. The IEEE 802.11 standards include multiple security sub-standards of which a predominant group has been cracked and is subject to penetration attacks. [29] The Wireless Equivalent Privacy (WEP) standard is vulnerable to exploit in less than 60 s. The Temporal Key Integrity Protocol (TKIP) portion of the Wireless Protected Access standard has also been cracked. These vulnerabilities allow an attacker in close wireless proximity to a corporate network to penetrate the corporate network for further port scanning, eavesdropping, and network traffic injection.

Portable nodes, such as laptop computers, commonly travel between many networks. For instance, a corporate user may use his or her laptop at home, at the local coffee shop, or in the airport and then later connect the laptop to the corporate Internet. External networks, such as the home, coffee shop, and airport networks, often have less robust cybersecurity profiles and provide a convenient platform for injecting malware, such as key loggers and root kits, onto corporate laptops via viruses and worms. When the laptop returns to the corporate network infected with a root kit or key logger, it may offer a backdoor for hackers to then penetrate the corporate network for further port scanning, eavesdropping, and network traffic injection.

Corporate employees almost always have e-mail access. E-mail is a very common platform for infecting computers in a corporate network. Hackers use spam e-mail to spread viruses that contain root kits and key loggers, which may then be used to offer a backdoor to penetrate the corporate network for further port scanning, eavesdropping, and network traffic injection.

Another malware injection vector is through thumb drives. In April 2010, the Industrial Control Systems Cyber Emergency Response Team (ICS-CERT) released an alert warning to grid management system operators of the threat of USB drives with autorun features that can be used to inject malware. The advisory recommends grid management system operators disable CD-ROM autorun capability, establish strict policies for the use of USB drives on system networks, and train users on the treatment of these drives.

The previously mentioned penetration threats, connections to the Internet, usage of wireless LANs, and the use of laptop computers, e-mails, and USB drives lead to the need for isolation of the grid management system network from the corporate network. Figure 5.46 shows two grid management system network architectures: an insecure architecture and an architecture secured via isolation.

Figure 5.47a shows seemingly separate corporate and grid management system networks. Often in such network arrangements, the corporate network and grid management system network will be separated via routers and the two networks will be on separate virtual networks. However, if there is no mechanism in place to stop unauthorized network traffic from entering the grid management system network from the corporate network, penetrators can harm the grid management system via data or control injection attacks or DOS attacks.

Figure 5.47b shows a grid management system network isolated from a corporate network. The diagram labels the box between the networks as a firewall, intrusion detection system (IDS), and access control system. The firewall can be used to limit access between the two networks. Network address translation (NAT) firewalls hide the internal IP address of nodes on the grid management system network from nodes on the corporate network. This protects the grid management system nodes from port scanning attacks. Furthermore, the firewalls can be used to scan the contents of network packets for signatures of known attacks. Firewalls can also be used as gateway devices to limit traffic to only certain applications on specific TCP and UDP ports.

Access control may reside in the firewall or may reside on a separate server within the grid management system network. Access control schemes limit network access to authorized individuals and systems. Access control schemes vary in strength. A simple access control scheme is the use of user ID and passwords. NERC CIP 007-3, Cybersecurity—Systems Security Management, requires that when passwords are used, passwords must be at least six characters long and include a mixture of letters, numbers, and special characters. The use of passwords for access control should be avoided wherever possible. Passwords systems are subject to dictionary attacks and other brute force attacks. Also, password files are vulnerable to exploits, including password files in grid management systems [30].

A more robust access control system may use a public key infrastructure (PKI) to provide all grid management system users and systems with a certificate. PKI systems assign individual public/private key pairs to each user or system in a network. Certificates signed by a certification authority are used to communicate a user's or system's public key to other users or systems. When a user or system accesses a network device, a challenge response protocol can be used to allow the connecting

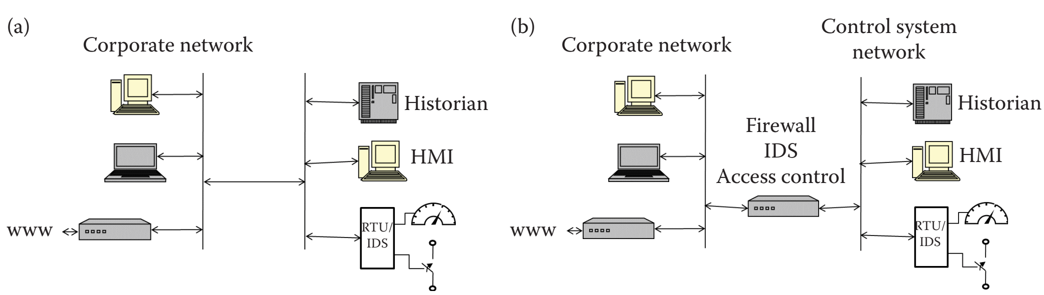


FIGURE 5.47 Grid management systems (a) insecure versus (b) isolated.

user or system to authenticate identification by proving the user or system possesses the private key associated with the public key in their certificate. Systems within a PKI-protected network may also confirm certificate validity via an inquiry to the network certificate authority. Certificates may be revoked by a certificate authority, and PKI certificates also have expiration dates. PKI provides a good means for adhering to NERC CIP requirements that require access control and encourage the use of individual user accounts with individual roles. Role-based access control allows each user to be assigned privileges, which match his or her work needs, without providing excess privileges that may allow a user to inadvertently or intentionally harm a system.

IDSs are used to monitor network activity for patterns related to cybersecurity threats. IDS systems may reside within a firewall or external to the firewall. Often, multiple types of IDSs are used on a single network. There are two basic types of IDS: signature-based IDS and statistical IDS.

A signature-based IDS scans network packets for signatures of known attacks. If a packet matches a known signature, the packet is flagged, and an alert is generated. The alert may be audible, e-mail, or just written to a file for later review. Signature-based IDSs are deterministic, meaning that they will always detect an attack that matches a known signature. Because signature-based IDS monitors for exact pattern matches, they can be bypassed by small changes to previously known attacks. Also, signature-based IDSs cannot detect completely new attacks since no signature will exist to match. Signature-based IDS systems are also relatively fast, which can be important in real-time system applications. Some work has been done to develop signature-based IDS patterns for grid management systems using SNORT® (an open source network intrusion prevention and detection system (IDS/IPS)) for the MODBUS and DNP3 protocols [31]. Additionally, Oman and Phillips have used signature-based methods to detect SCADA cyber intrusions [32].

A statistical IDS estimates the probability that a network transaction or a group of network transactions are part of a cyberattack. The general idea of statistical IDSs is to attempt to detect intrusions that do not match a previously known intrusion signature, yet are still different enough from normal traffic to warrant review. Most statistical IDSs are anomaly detectors that use data mining classifiers, such as neural networks or Bayesian networks, to classify network transactions as anomalous or normal. Many statistical IDS methodologies exist in both the research and practical domains. No statistical IDS are deterministic, all are probabilistic, meaning that all have less than 100% accuracy and all sometimes classify normal traffic as abnormal (a false-positive) and sometimes classify abnormal traffic as normal (a false negative). Grid management systems monitor and control critical physical processes and, therefore, one of the most important cybersecurity criteria is availability. The system must remain available for monitoring and control at all times, but the corollary is that the cybersecurity solutions must do no harm to the grid management system. As such, IDS inaccuracies are problematic and lead to the need for statistical IDS alerts to always be sent to a human for validation before intrusion mitigation actions are taken. Statistical IDS are being developed specifically for use with grid management systems and the smart grid. These involve development of IDS inputs (or features) specific to grid management system applications and network protocols. The introduction of grid management system and smart-grid-specific IDS features will lead to more accurate IDSs.

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6 Advanced Protection and Control for the Smart Grid

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CONTENTS

6.1 INTRODUCTION

While the physical transmission and distribution infrastructure ("poles and wires") of the utility grid has largely remained the same over the past few decades, advances in generation, transformation, and power switching devices is changing the way the grid is operated and maintained and, therefore the need to change the way of thinking of traditional protection, monitoring, and control schemes. The focus over the next few years will be on ensuring grid stability, reliability, and safety with the increase in renewable generation at the transmission level, and the increasing trend of more distributed energy resources (DER—both generation and energy storage) closer to the consumer. There will be a need for a broader perspective on how the integration of substation and feeder data and Transmission & Distribution (T&D) automation can benefit the smart grid. In the new environment, more granular field data will help increase operational efficiency and provide more data for other smart grid applications, such as outage management. The realization of potential benefits in the new environment necessitates additional protection, monitoring, and control requirements, such as the following:

1. With the addition of renewable generation in large numbers to distribution systems, plus the creation of microgrids, grid modernization efforts will add advanced technologies and an advanced communication infrastructure to the grid to extend monitoring, control, and data acquisition capabilities further down the distribution system closer to individual customers (the "grid-edge"). These extended monitoring and control capabilities are achieved either through the substation communications network, using a separate communications network, or by utilizing the advanced metering infrastructure (AMI). This will require

higher speed and increased bandwidth communications for the increase in data acquisition and control further down the distribution system.
2. Fault detection, isolation, and service restoration (FDIR) on the distribution system will require a higher level of optimization for closed-loop, parallel circuit, and radial configurations. FDIR will offer additional features such as multi-level feeder reconfiguration, multiobjective restoration strategies, and forward-looking network loading validation.
3. Integrated Volt/VAr Control (IVVC) will include operational and asset improvements, such as identifying failed capacitor banks and tracking capacitor bank, tap changer, and regulator operation to provide sufficient statistics for opportunities to optimize capacitor bank and regulator placement in the network. Regional IVVC objectives may include operational or cost-based optimization.
4. DER integration will cause some protection challenges for utilities—especially when installing in large numbers. Potential protection issues on distribution systems may arise with the deployment of DER at the customer site, thereby changing the paradigm that load and fault currents always flow downstream from the substation to the customer. Traditional utility practices for designing protection schemes that do not account for the changes in fault current flow due to the presence of DER may result in schemes that are uncoordinated and possibly nonfunctional.
5. A special case for which traditional protection system design practices for distribution systems almost certainly fail are microgrids (aka intentional islanding) since the protection needs to be able to interrupt faults during both grid-connected modes (fault current from the utility grid and DERs) and stand-alone mode (fault current from DERs only). A challenge that is very different from the creation of intentional islands is the prevention of unintentional islands, which is yet another example of DER creating a concern, but, at the same time, presenting a solution by leveraging the advanced monitoring and control capabilities of smart inverters.

This chapter discusses (1) improved protection, monitoring, and control technologies; (2) the development of smart substations; (3) opportunities for improved control of the grid that DER-rich distribution feeders offer; and (3) new protection challenges caused by a high penetration of DERs.

6.2 SENSORS AND INTELLIGENT ELECTRONIC DEVICES (IEDS)

Generators, substations, and feeders are the sources of critical real-time data for efficient and safe operation of the utility grid. Real-time data, also called operational data, are instantaneous values of power system analog and status points, such as volts, amps, MW, MVAr, circuit breaker status, and switch position. These data, collected by sensors and utilized by Intelligent Electronic Devices (IEDs), are time critical and are used to protect, monitor, and control the power system equipment. There is also a wealth of operational (non-real-time) data available from the grid. Non-operational data consist of additional data measurements and files (such as event summaries, oscillographic waveforms, event reports, and sequential event records) that are not needed in realtime to monitor and control the power system but are analyzed and used by other applications to help operate and manage the grid more efficiently and reliably.

IEDs are microprocessor-based devices with the capability to exchange data and control signals with another device—another IED, an electronic meter, a controller, Supervisory Control and Data Acquisition (SCADA), etc.—over a communications link. IEDs perform protection, monitoring, control, and data acquisition functions in generating stations, substations, and along feeders, and are critical to the operations of the electric network.

IEDs are a key component of substation and feeder integration and automation. Integration involves integrating protection, control, and data acquisition functions into a minimal number of platforms to reduce capital and operating costs, decrease panel and control room space, and eliminate redundant equipment and databases. Automation involves the deployment of substation and feeder operating functions and applications ranging from SCADA and alarm processing to IVVC to optimize the management of capital assets and enhance operation and maintenance

(O&M) efficiencies with minimal human intervention. Multifunctional IEDs can perform several protection, monitoring, control, and user interfacing functions on one hardware platform. The main advantages of multifunctional IEDs are they are compact in size, and they combine various functions in one design, allowing for a reduction in the size of the overall systems and an increase in efficiency and improvement in robustness and providing extensible solutions based on mainstream communications technology. Advanced IED functionalities, such as an increase in data measurements, can help utilities improve reliability, gain operational efficiencies, and enable asset management programs including predictive maintenance, life extensions, and improved planning.

With the introduction of digital and optical technologies in combination with communication capabilities, new sensors are becoming available to acquire different types of asset-related information. Optical apparatus, with fiber-based sensors, can now replace the original copper-wired analog apparatus, for monitoring and metering. The most prominent advantages of such sensors are higher accuracy, no saturation, reduced size and weight, safe and environment friendly—avoid oil or sulfur hexafluoride (SF6)—higher performance, wide dynamic range, high bandwidth, and low maintenance. The main advantages of optical sensors are the wide-frequency bandwidth, wide dynamic range, and high accuracy. Furthermore, these new sensors allow implementation of monitoring and control with important application features:

1. A single sensor may serve different types of IEDs.
2. A single sensor may serve many IEDs via a communications bus.
3. The sensors include accurate time synchronization of the measurements.

A recent survey [1] conducted for North American utilities indicates that installations of microprocessor relays have grown over time and at present ~70% of the installed relays are microprocessor based. These installations have been made in all the segments of the power system, i.e., generation, transmission, distribution, and motors. Moreover, the survey also shows that around 61% of relays in the power system have been in service for more than 15 years and most of the aged electromechanical relays will be replaced in the next three years. In future purchases of the replacement, interoperability of relays shall be a critical factor. Therefore, penetration of IEDs shall increase even further.

6.3 SMART SUBSTATIONS

An electrical substation is a focal point of an electricity generation, transmission, and distribution system where the voltage is transformed from high to low or reverse using transformers. Electric power flows through several substations between generating plants and consumer and usually is changed in voltage in several steps. There are different kinds of substations, such as transmission substations, distribution substations, collector substations, and switching substation. The general functions of a substation include the following:

- Voltage transformation
- Connection point for transmission and distribution power lines
- Switchyard for electrical transmission and distribution system configuration
- Monitoring point for control center
- Protection of power lines and apparatus
- Communication with other substations and regional control center

6.3.1 Substation Technology Advances

Early generations of SCADA systems typically employed one Remote Terminal Unit (RTU) at every substation. With this architecture, it was necessary to terminate all cables from the field equipment at the RTU. RTUs have typically offered limited expansion capacities. For analog inputs, the RTU required the use of transducers to convert higher level voltages and currents from Current Transformers (CTs) and Potential Transformers (PTs) outputs into the milliamp and volt levels. Most RTUs had a single communication port and were only capable of communicating with one master station. The communication between an RTU and its master station was typically achieved via proprietary bit-oriented communication protocols. As technology advanced, RTUs became smaller and more flexible, which allowed for a distributed architecture approach, with one smaller RTU for one or several pieces of substation equipment, resulting in lower installation costs with reduced cabling requirements. This architecture also offered better expansion capabilities (just add additional small RTUs). Also, the new generation of RTUs could accept higher-level alternating current AC analog inputs, which eliminated the need for intermediate transducers and allowed direct wiring of CTs and PTs into the RTU, enabling RTUs to have additional functionality, such as digital fault recording (DFR) and power quality (PQ) monitoring.

There were also advances in communications capabilities, with additional ports available to communicate with IEDs. However, the most significant improvement was the introduction of an open communications protocol. The older SCADA systems used proprietary protocols to communicate between the master station and the RTUs. Availability of an open and standard (for the most part) utility communications protocol allowed utilities to choose vendor-independent equipment for the SCADA systems. The de facto standard protocol for electric utilities SCADA systems in North America became DNP3.0. Another open communications protocol used by utilities is MODBUS. The MODBUS protocol came from the industrial manufacturing environment. The latest communication standard adopted by utilities is International Electrotechnical Commission (IEC) 61850. IEC 61850 is a very powerful and flexible network-based, object-oriented communication standard that allows for utilities to move their next-generation substations that are flexible and expandable; allows for the implementation of multivendor solutions; and in addition to the communication, facilitates a standardized engineering approach allowing for optimization of utility engineering and maintenance processes.

The latest survey [1] of North American Utilities shows that DNP3 remains as the most prevalent protocol for SCADA applications (88%) followed by SEL (Schweitzer Engineering Laboratories) Fast Messaging interleave and MODBUS. At present, IEC 61850 penetration is around 4%. However, its deployments will gradually increase.

Another technology that aided SCADA systems was network data communications. The SCADA architecture based on serial communications protocols put certain limitations on system capabilities. With a serial SCADA protocol architecture, there is a static master/slave data path that limits the device connectivity. Serial SCADA protocols do not allow multiple protocols on a single channel. Furthermore, there are issues with exchanging new sources of data, such as oscillography files and PQ data. Configuration management must be done via a dedicated "maintenance port." The network-based architecture offers some advantages:

- *There is a significant improvement in speed and connectivity:* An Ethernet-based local area network (LAN) greatly increases the available communications bandwidth. The network layer protocol provides a direct link to devices from anywhere in the network.
- *Availability of logical channels:* Network protocols support multiple logical channels across multiple devices.
- *Ability to use new sources of data:* Each IED can provide another protocol port number for file or auxiliary data transfer without disturbing other processes (e.g., SCADA) and without additional hardware.
- *Improved configuration management:* Configuration and maintenance can be done over the network from a central location.

The network-based architecture in many cases also offers a better response time, ability to access important data, and reduced configuration and system management time. These benefits are in line with the utility's interest in higher bandwidth connections to the relays [1]. Take, for example, SCADA systems that have been around for many years. These were simple remote monitoring and control systems exchanging data over low speed communications links, mostly hardwired. In recent years, with the proliferation of microprocessor-based IEDs, it became possible to have information extracted directly from these IEDs either by an RTU or by other substation control system components, which is achieved by using the IED communications capabilities, allowing it to communicate with the RTU, data concentrator, or directly with the master station. As more IEDs were installed at the substations, it became possible to integrate some of the protection, control, and data acquisition functionality. A lot of the information previously extracted by the RTUs now became available from the IEDs. However, it may not be practical to have the master station communicate directly with the numerous IEDs in all the substations. To enable this data flow, a new breed of devices called substation servers is utilized. A substation server communicates with all the IEDs at the substation, collects all information from the IEDs, and then communicates back to the central master station. Because the IEDs at the substation use many different communications protocols, the substation server must be able to communicate via these protocols, as well as the master station's communications protocol. A substation server allows the SCADA system to access data from most substation IEDs, which were only accessible locally before.

With the substation server-based SCADA architecture (Figure 6.1), all IEDs (including RTUs) are polled by the substation server. The IEDs and RTUs with network connections are polled over the substation LAN. The IEDs with only serial connection capabilities are polled serially via the substation server's serial RS232 or RS485 ports (integrated or distributed). In addition to making more IED data available, the substation server significantly improves overall SCADA system communication performance. With the substation server-based architecture, the master station must communicate directly with only the substation server instead of multiple RTUs and IEDs at the substation. Also, a substation server's communications capability is typically superior to that of an IED and so this, and the reduced number of devices directly connected to the master station, contributes to a significantly improved communications performance in a polled environment.

Data available in the substation can be divided into two types: operational or real-time data and non-operational data. Operational data are real-time data required for operating utility systems and performing energy management system (EMS) software applications, such as Automatic Generation Control. These data are stored by EMS applications and are available as historical data. Non-operational data are historical, real-time, and file type data used for analysis, maintenance, planning, and other utility applications.

Modern IEDs, such as protection relays and meters, have a tremendous amount of information. Some of these devices have thousands of data points available. Also, many IEDs generate file type data, such as DFR or PQ files. A typical master station is not designed to process this amount of data and this type of data. However, a lot of this information can be extremely valuable to the different

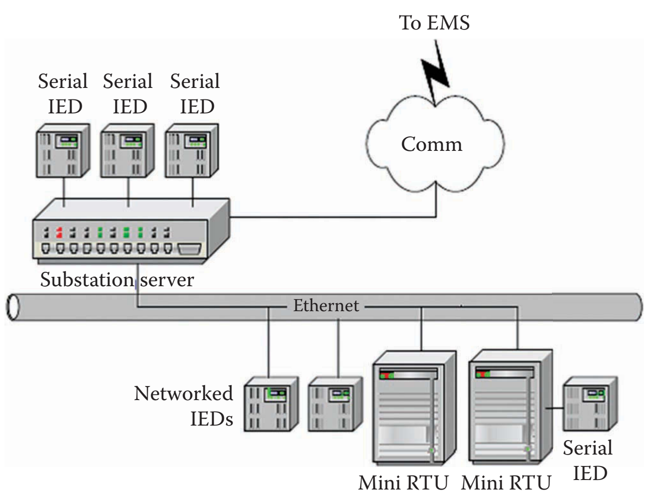

FIGURE 6.1 Server-based substation control system architecture.

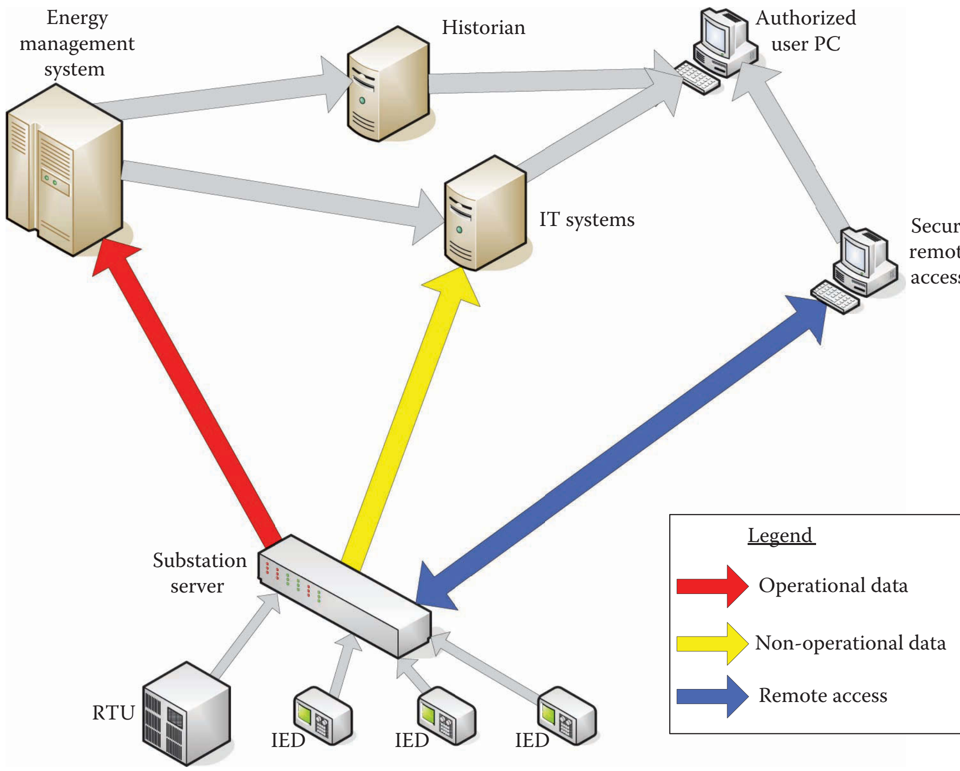

FIGURE 6.2 Substation data flow.

users within the utility, as well as, in some cases, the utility's customers. To take advantage of these data, an extraction mechanism independent from the master station needs to be implemented.

Operational data and non-operational data have independent data collection mechanisms. Therefore, two separate logical data paths should also exist to transfer these data (Figure 6.2). One logical data path connects the substation with the EMS (operational data). A second data path transfers non-operational data from the substation to various utility information technology (IT) systems. According to a recent survey [1], more than half of the North American utilities have a separate operational data network from their IT network. Also, these networks are managed by separate departments in many utilities, and in general, physical demarcations exist between the networks at control centers and substation. Furthermore, various methods are also employed to increase the reliability and availability of operational data networks.

With all IEDs connected to the substation data concentrator and sufficient communications infrastructure in place, it also becomes possible to have a remote maintenance connection to most of the IEDs. This functionality is referred to as either "remote access" or "pass-through." Remote access or pass-through is the ability to have a virtual connection to remote devices via a secure network.

This functionality significantly helps with troubleshooting and maintenance of remote equipment. In many cases, it can eliminate the need for technical personnel to drive to a remote location. It also makes real-time information from individual devices at different locations available at the same computer screen that makes the troubleshooting process more efficient. An advanced substation integration architecture offers increased functionality by taking full advantage of the network-based system architecture, thus allowing more users to access important information from all components connected to the network. However, it also introduces additional security risks into the control system. Special care must be taken to mitigate these risks, when designing the network, with special emphasis on the network security and the implementation of user authentication, authorization, and accounting. It is very important to develop and enforce a substation communication, and physical access security policy.

6.3.2 Interoperability and IEC 61850

IEC 61850 is a vendor-neutral, open systems standard for utility communications, significantly improving functionality while yielding substantial customer savings. The standard specifies protocol-independent and standardized information models for various application domains in combination with abstract communications services, a standardized mapping to communications protocols, a supporting engineering process, and testing definitions. This standard allows standardized communication between IEDs located within electric utility facilities, such as power plants, substations, and feeders but also outside of these facilities, such as wind farms, electric vehicles, storage systems, and meters. The standard also includes requirements for database configuration, object definition, file processing, and IED self-description methods. These requirements will make adding devices to a utility automation system as simple as adding new devices to a computer using "plug and play" capabilities. With IEC 61850, utilities will benefit from cost reductions in system design, substation wiring, redundant equipment, IED integration, configuration, testing, and commissioning. Additional cost savings will also be gained in training, IT operations, and system maintenance.

IEC 61850 has been identified by the National Institute of Standards and Technology (NIST) as a cornerstone technology for field device communications and general device object data modeling. IEC 61850 Part 6 defines the configuration language for systems based on the standard. Peer-to-peer communication mechanisms such as the Generic Object Oriented System Event (GOOSE) will minimize wiring between IEDs. The use of peer-to-peer communication in combination with the use of sampled values (SVs) from sensors will minimize the use of copper wiring throughout the substation, leading to significant benefits in cost savings, more compact substation designs, and advanced and more flexible automation systems, to name a few. With high-speed Ethernet, the IEC 61850-based communications system will be able to manage all the data available at the process level as well as at the station level.

The IEC 61850 standard was originally designed to be a substation communications solution and was not designed to be used over the slower communications links typically used in Distribution Automation. However, as wide area and wireless technologies (such as WiMAX) advance, IEC 61850 communications to devices in the distribution grid will become possible. It is, therefore, possible that IEC 61850 will eventually be used in all aspects of the utility enterprise. Currently, an IEC Working Group (WG) is in the process of defining new logical nodes (LNs) for distributed resources—including photovoltaic (PV), fuel cells, reciprocating engines, and combined heat and power.

With the introduction of serial communication and digital systems, the way we look at secondary systems is fundamentally changing. Not only are these systems still meant to control, protect, and monitor the primary system but we expect these systems to provide more information related to a realm of new functions. Examples of new functions include the monitoring of the behavior, the aging, and the dynamic capacity of the system. Many of the new functions introduced in substations are related to changing operating philosophies, the rise of distributed generation, and the introduction of renewable energy. For protection, new protection philosophies are being introduced focused more on the dynamic adaption of protection functions to the actual network topology, wide-area protection and monitoring, the introduction of synchrophasors, and much more.

This tendency is not new. Ever since the introduction of the first substation automation systems and digital protection, we have been searching for ways to make better use of the technologies at hand. After many experiments and discussions, this has led to the development of IEC 61850, originally called "Communication networks and systems in substations." It has now evolved into a worldwide standard called "Communication networks and systems for power utility automation," providing solutions for many different domains within the power industry.

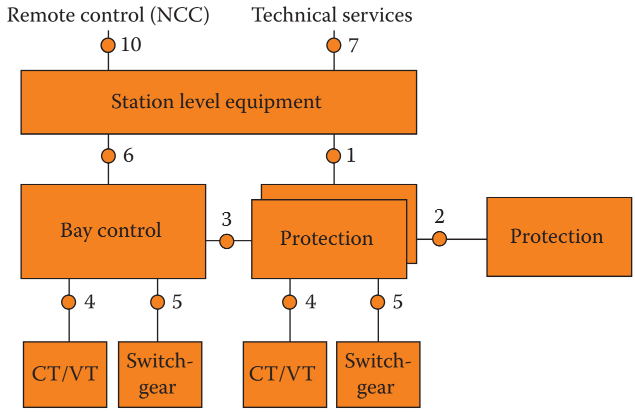

FIGURE 6.3 Interfaces within a substation automation system. (© 2012 Marco Janssen. All rights reserved. With permission.)

The concepts and solutions provided by IEC 61850 are based on three cornerstones:

- *Interoperability:* The ability of IEDs from one or several manufacturers to exchange information and use that information for their functions.
- *Free configuration:* The standard shall support different philosophies and allow a free allocation of functions; for example, it will work equally well for centralized (RTU based) or decentralized (substation control system based) configurations.
- *Long-term stability:* The standard shall be future proof; that is, it must be able to follow the progress in communications technology as well as evolving system requirements.

The above cornerstones are achieved by defining a level of abstraction that allows for the development of basically any solution using any configuration that is interoperable and stable in the long run. The standard defines different logical interfaces within a substation that can be used by functions in that substation to exchange information between them.

IEC 61850 does not predefine or prescribe communications architectures. The interfaces shown in Figure 6.3 are logical interfaces. IEC 61850 allows in principle any mapping of these interfaces on communications networks. A typical example could be to map interfaces one, three, and six on what we call a station bus. This bus is a communications network focused on the functions at bay and station level. We also could map interfaces four and five on a process bus, a communications network focused on the process and bay level of a substation. The process bus may in such a case be restricted to one bay, while the station bus might connect functions located throughout the substation. However, it may be possible as well to map interface four on a point-to-point link connecting a process-related sensor to the bay protection.

IEC 61850 is, in principle, restricted to digital communications interfaces. However, IEC 61850 specifies more than the communications interfaces. It includes domain-specific information models. In the case of the substation, a suite of substation functions has been modeled, providing a virtual representation of the substation equipment. The standard, however, also includes the specification of a configuration language. This language defines a suite of standardized, XML-based files that can be used to define in a standardized way the specification of the system, the configuration of the system, and the configuration of the individual IEDs within a system. The files are defined such that they can be used to exchange configuration information between tools from different manufacturers of substation automation equipment (Figure 6.4).

The definitions in IEC 61850 are based on a layered approach. In this approach, the domain-specific information models, abstract communications services, and the actual communications protocol are defined independently; this basic concept is shown in Figure 6.5.

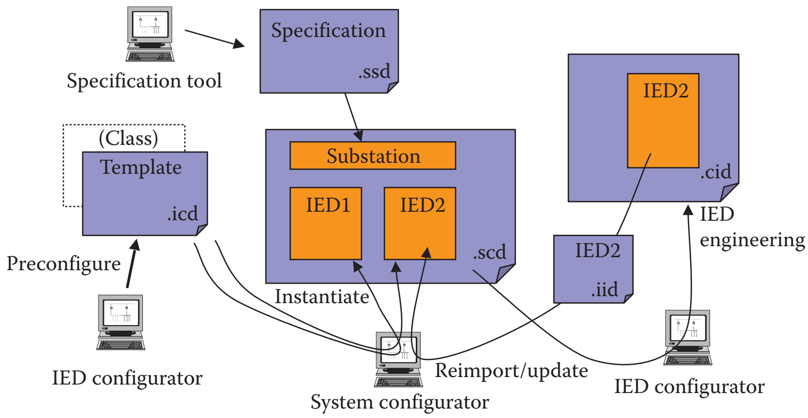

FIGURE 6.4 Engineering approach in IEC 61850. (© 2012 Marco Janssen. All rights reserved. With permission.)

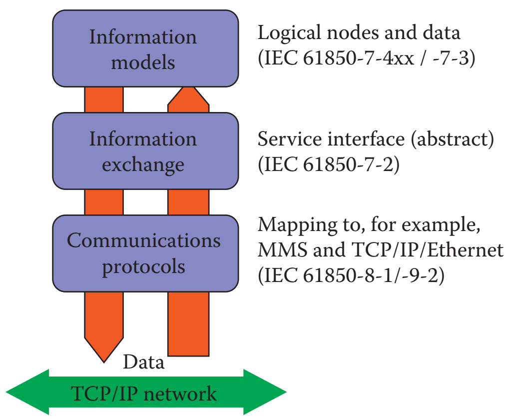

FIGURE 6.5 Concept of the separation of application and communications in IEC 61850. (© 2012 Marco Janssen. All rights reserved. With permission.)

EC 61850 specifies the information model of the substation equipment. These information models include models for primary devices, such as circuit breakers and instrument transformers, such as CTs and voltage transformers (VTs). They also include the models for secondary functions, such as protection, control, measurement, metering, monitoring, and synchrophasors.

To have access to the information contained in the information models, the standard defines protocol-independent, abstract communications services. These are described in part 7-2, such that the information models are coupled with communications services suited to the functionality making use of the models. This definition is independent of any communications protocol and is called the abstract communications service interface (ACSI). The major information exchange models defined in IEC 61850-7-2 are the following:

- Read and write data
- Control
- Reporting
- GOOSE
- SV transmission

The first three models are based on a client/server relation. The server is the device that contains the information while the client is accessing the information. Read and write services are used to access data or data attributes. These services are typically used to read and change configuration attributes. Control model and services are somehow a specialization of a writing service. The typical use is to operate disconnector, earthing switches, and circuit breakers. The reporting model is used for event-driven information exchange. The information is spontaneously transmitted when the value of the data is changed.

The last two models are based on a publisher/subscriber concept. In the IEC 61850 standard, the term peer-to-peer communication is introduced to stress that publisher/subscriber communication involves mainly horizontal communication among peers. These communications models are used for the exchange of time-critical information. The device, being the source of the information, is publishing the information. Any other device that needs the information can receive it. These models are using multicast communication (the information is not directed to one single receiver).

The GOOSE concept is a model to transmit event information in a fast way to multiple devices. Instead of using a confirmed communications service, the information exchange is repeated regularly. Application of GOOSE services are the exchange of position information from switches for interlocking or the transmission of a digital trip signal for protection-related functions.

The model for the transmission of SVs is used when a waveform needs to be transmitted using digital communication. In the source device, the waveform is sampled at a fixed sampling frequency. Each sample is tagged with a counter representing the sampling time and transmitted over the communications network. The model assumes synchronized sampling; that is, different devices are sampling the waveform at the same time. The counter is used to correlate samples from different sources. That approach creates no requirements regarding variations of the transmission time. While IEC 61850-8-x specifies the mapping of all models from 7-2 except the transmission of SVs, IEC 61850-9-x is restricted to the mapping of the transmission of SV model. While IEC 61850-9-2 is mapping the complete model, IEC 61850-9-1 is restricted to a small subset using a point-to-point link providing little flexibility. Both mappings are using Ethernet as the communications protocol.

Of course, to create real implementations, we need communications protocols. These protocols are defined in parts 8-x and 9-x. In these parts is explained how real communications protocols are used to transmit the information in the models specified in IEC 61850- 7-4xx/-7-3 using the abstract communications services of IEC 61850-7-2. In the terminology of IEC 61850, this is called "specific communication service mapping" (SCSM).

Through this approach, an evolution in communications technologies is supported, since the application and its information models and the information exchange models are decoupled from the protocol used, allowing for upgrading the communications technology without affecting the applications.

The core element of the information model is the LN. An LN is defined as the smallest reusable piece of a function. It, as such, can be considered as a container for function-related data. LNs contain data, and these data and the associated data attributes represent the information contained in the function. The name of an LN class is standardized and always comprises four characters. We can differentiate between two kinds of LNs:

- LNs representing information of the primary equipment (e.g., circuit breaker—XCBR or current transformer—TCTR). These LNs implement the interface between the switchgear and the substation automation system.
- LNs representing the secondary equipment including all substation automation functions. Examples are protection functions, such as distance protection—PDIS or the measurement unit—MMXU.

The standard contains a comprehensive set of LNs allowing to model many, if not all, substation functions. In case a function does not exist in the standard extension rules for LNs, data and the data attributes have been defined allowing for structured and standardized extensions of the standard information models.

The mappings currently defined in IEC 61850 (parts 8-x and 9-x) are using the same communications protocols. They differentiate between the client/server services and the publisher/subscriber services. While the client/server services are using the full seven-layer communication stack using Multimedia Messaging System (MMS) and Transmission Control Protocol/Internet Protocol (TCP/IP), the publisher/subscriber services are mapped on a reduced stack, basically directly accessing the Ethernet link layer.

For the transmission of the SVs, IEC 61850-9-2 is uses the following communications protocols:

- *Presentation layer:* ASN.1 using basic encoding rules (BER) [ISO/IEC 8824-1 and ISO/IEC 8825]
- *Data link layer:* Priority tagging/VLAN and CSMA/CD [IEEE 802.1Q and ISO/IEC 8802-3]
- *Physical layer:* Fiber optic transmission system 100-FX recommended [ISO/IEC 8802-3]

Ethernet is a nondeterministic communications solution. However, with the use of switched Ethernet and priority tagging, a deterministic behavior can be achieved. To avoid collisions, using full duplex switches is essential. Tagging the transmission of SVs requires a constant bandwidth due to the cyclic behavior, and ensures that the SVs always get through with a higher priority than nondeterministic traffic, such as event reports.

The model for the transmission of SVs, as specified in IEC 61850-7-2, is rather flexible. The configuration of the message being transmitted is performed by an SV control block. Configuration options include the reference to the dataset that defines the information contained in one message, the number of individual samples that are packed within one message, and the sampling rate.

While the flexibility makes the concept future proof, it adds configuration complexity. That is why the UCA (Utility Communications Architecture) Users Group has prepared the "Implementation guideline for digital interface to instrument transformers using IEC 61850-9-2." This implementation guideline is an agreement of the vendors participating in the UCA users group that describes the basis for the first implementations of digital interfaces to instrument transformers. The implementation guideline defines the following items:

- A dataset comprising the voltage and current information for the three phases and for neutral. That dataset corresponds to the concept of a merging unit (MU), as defined in IEC 60044-8.
- Two SV control blocks: the first one for a sample rate of 80 samples per period, where for each set of samples an individual message is sent, and the second one for 256 samples per period, where eight consecutive sets of samples are transmitted in one message.
- The use of scaled integer values to represent the information including the specification of the scale factors for the current and voltage.

The use of IEC 61850 for the utility applications is growing gradually, and a survey of North American utilities revealed that GOOSE is the most popular feature at present and is planned in future employments. Other features, such as data modeling, setting groups, command issuance, and reporting schemes, are also planned in future projects [1].

6.3.2.1 Process Level

Process level technology is a maturing technology. Designed primarily to interface with nonconventional CTs and VTs, a process level communication will also include "transitional" hardware that will interface with existing copper CTs and VTs. The benefits of the process near implementation of the IEC 61850-based technology include the elimination of copper, the elimination of CT saturation, and avoidance of CT open circuits, which are a serious safety hazard.

With this solution, new designs become possible, where electronic transformers are used instead of conventional transformers in the switchyard. The voltage and current signals are captured at the primary side, converted to the optic signals by an MU, and transferred to the protection and control devices via optical fibers. This can lower the requirement of transformer insulation and reduce the conducted and radiated interference suffered in the analog signal transmitted through legacy wiring. Intelligent control units are used as an intermediate link to circuit breaker controls. The intelligent control unit also converts analog signals from primary devices (such as circuit breaker and switches) into digital signals and sends it to the protection and control devices via process bus. At the same time, the tripping and reclosing commands issued by protection and control devices will be converted into analog signals to control the primary equipment. A large amount of copper wiring between IEDs and primary devices in conventional substations are replaced by optical fibers.

6.3.2.2 Bay Level

All the IEDs in the control house fully support IEC 61850. Synchronous phasor measurements are realized by phasor measurement units (PMUs) or in protection IEDs. PMUs are used for wide-area power system monitoring and control, improving state estimation and archiving more reliable system performance; GOOSE messaging and SV network over the process bus are used. The interoperation between IEDs is realized by GOOSE messages sent over the network. The Ethernet switch is used to process the message priority to realize the GOOSE exchange scheme between relays.

About one third of the North American utilities are already using PMUs, and major applications of these devices include observation, control center, and protection and control. The most commonly employed method of time synchronization for these PMU installations in utilities is IRIG-B [1] way of implementing full digital.

6.3.2.3 Station Level

At the station level, an MMS-based communications network is used, also providing the communications link between SCADA, Control Centers, and IEDs located at the bay level.

6.3.2.4 IEC 61850 Benefits

High-speed peer-to-peer communications between IEDs connected to the substation LAN based on the exchange of GOOSE messages can successfully be used to replace hardwiring for different protection and control applications. Sampled analog values communicated from MUs to different protection devices connected to the communications network replace the copper wiring between the instrument transformers in the substation yard and the IEDs. IEC 61850 is a communications standard that allows the development of new approaches for the design and refurbishment of substations. A new range of protection and control applications results in significant benefits compared to conventional hardwired solutions. It supports interoperability between devices from different manufacturers in the substation, which is required to improve the efficiency of microprocessor-based relays applications and implement new distributed functions.

Process-bus-based applications offer some important advantages over conventional hardwired analog circuits. The first very important one is the significant reduction in the cost of the system because multiple copper cables are replaced with a small number of fiber optic cables. Using a process bus also results in the practical elimination of CT saturation because of the elimination of the current leads resistance. Process-bus-based solutions also improve the safety of the substation by eliminating one of the main safety-related problems—an open current circuit condition. Since the only current circuit is between the secondary of a current transformer and the input of the MU located right next to it, the probability for an open current circuit condition is very small. It becomes nonexistent if optical current sensors are used. The process bus improves the flexibility of the protection, monitoring, and control systems. Since current circuits cannot be easily switched due to open circuit concerns, the application of bus differential protection, as well as some backup protection schemes, becomes more complicated, but this is not an issue with process bus because

TABLE 6.1
Anticipated IEC 61850 Benefits

Description	Network	Legacy	Impact
Equipment purchase	$	$	–
Installation	$	$	0
Configuration	$$$	$	+
Equipment migration	$$$	$	+
Application additions	$$$	$	+

any changes will only require modifications in the subscription of the protection IEDs receiving the sampled analog values over IEC 61850 9-2.

IEC 61850-based substation systems provide some significant advantages over conventional protection and control systems used to perform the same functions in the substations:

- Reduced wiring, installation, maintenance, and commissioning costs
- Optimization possibilities in the design of the high-voltage system in a substation
- Improved interoperability due to the use of standard high-speed communications between devices of different manufacturers over a standard communications interface
- Easy adaptation to changing configurations in the substation
- Practical elimination of CT saturation and open circuits
- Easier implementation of complex schemes and solutions as well as the easier integration of new applications and IEDs by using GOOSE messages and SVs that are multicasted on the communications network and to which applications and IEDs can simply subscribe.

The greatest benefits of using IEC 61850 may not reveal themselves in initial deployment, but it will be IEC 61850's additional flexibility later in the substation life cycle that shows the greatest benefits. Table 6.1 shows the factors. Of the three factors for which IEC 61850 is believed to show a clear benefit, only the configuration benefits could be realized on the first installation by a utility.

The result is a significant improvement in configuration time as well as a reduction in the errors introduced by having to configure both the IED and server, as in a traditional approach. An expected 75% reduction in labor costs when configuring a substation represents significant savings. For a more complex device that would normally take a day to configure, the savings could be even higher, perhaps approaching 90% (Figure 6.6).

6.3.3 IEC 61850-Based Substation Design

In a smart grid environment, availability of and access to information is key. Standards like IEC 61850 allow the definition of the available information and access to that information in a standardized way. IEC 61850 Communication Networks and Systems for Utility Automation is a standard for communications that creates an environment that will allow significant changes in the way the power system is protected and operated. Also, these concepts can also be used outside of the substation, allowing the implementation of wide-area protection using standardized communications.

The IEC 61850 standard Communication Networks and Systems for Utility Automation allows the introduction of new designs for various functions, including protection inside and outside substations. The levels of functional integration and flexibility of communications-based solutions bring significant advantages in costs at various levels of the power system. This integration affects not only the design of the substation but almost every component and system in it, such as protection, monitoring, and control by replacing the hardwired interfaces with communication links. Furthermore, the design of the high-voltage installations and networks can be reconsidered regarding the number

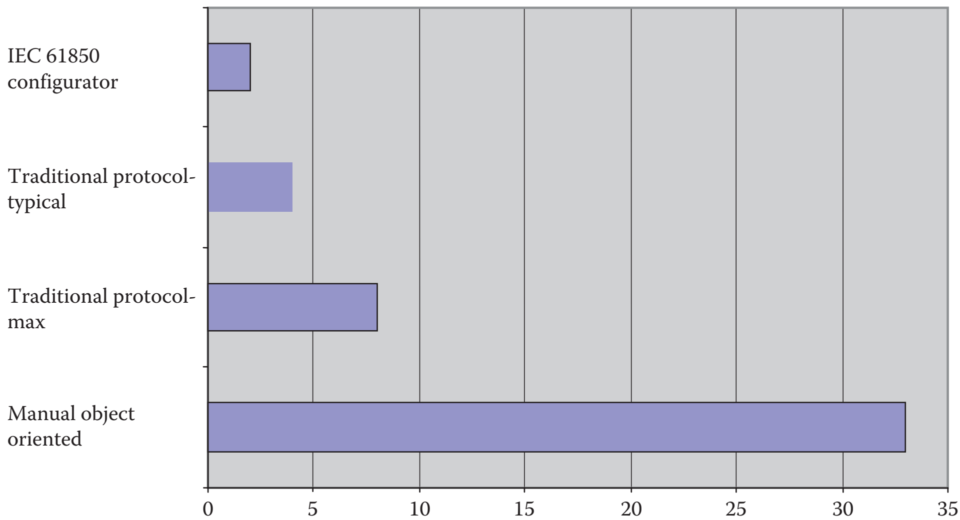

FIGURE 6.6 Approximate time (min) to configure an IEC 61850 client to communicate with a 200-point IED.

and the location of switchgear components necessary to perform the primary function of a substation in a high-voltage network. The use of high-speed peer-to-peer communications using GOOSE messages and SVs from MUs allows for the introduction of distributed and wide-area applications. Also, the use of optical LANs leads in the direction of copperless substations.

6.3.3.1 Paradigm Shift in Substation Design

For many years, the current generation substation designs have been based on that functionality, and over time, we have developed several typical designs for the primary and secondary systems used in these substations. Examples of such typical schemes for the primary equipment are shown in Figure 6.7 and include the breaker and a half scheme, the double bus bar scheme, the single bus bar scheme, and the ring bus scheme. These schemes have been described and defined in many documents including Cigré Technical Brochure 069 General guidelines for the design of outdoor AC substations using fact controllers.

For the secondary equipment (protection, control, measurement, and monitoring), typical schemes have also been in use, but here we have seen more development in new concepts and philosophies. Typical concepts for secondary equipment include redundant protection for transmission system using different operating principles and manufacturers and separate systems for control, measurements, monitoring, data acquisition, operation, etc. At distribution, integrated protection and control at feeder level are common solution. In general, it can be said that the concepts used for the secondary systems have been based on the primary designs and the way the utility wants to control, protect, and monitor these systems.

The existing or conventional substations are designed using standard design procedures for high-voltage switchgear in combination with copper cables for all interfaces between primary and secondary equipment.

Several different types of circuits are used in the substation:

- Analog (current and voltage)
- Binary—protection and control signals
- Power supply—DC or AC

Figure 6.8 shows a typical conventional substation design.

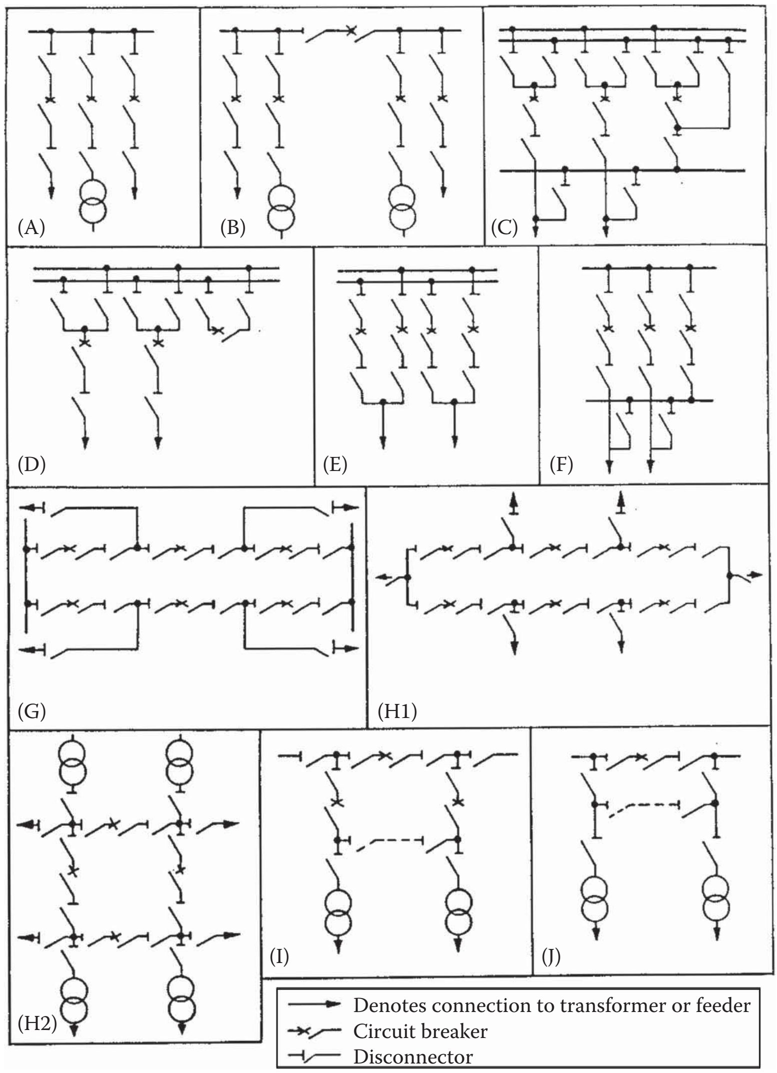

FIGURE 6.7 Typical traditional primary substation schemes. (Labels A–J refer to different substation primary plant topologies as they are used in the Cigré report that this comes from.) (Reprinted with permission from CIGRE, Technical Brochure 069, General guidelines for the design of outdoor AC substations using FACTS controllers. © 2000. With permission.)

Depending on the size of the substation, the location of the switchgear components, and the complexity of the protection and control system, there vare very often a huge number of cables with different lengths and sizes that need to be designed, installed, commissioned, tested, and maintained. A typical conventional substation has multiple instrument transformers and circuit breakers associated with the protection, control, and monitoring, and other devices being connected from the switchyard to a control house or building with the individual equipment panels.

These cables are cut to a specific length and bundled, which makes any required future modification very labor intensive. This is especially true in the process of refurbishing old substations where the cable insulation is starting to fail.

The large amount of copper cables and the distances that they need to cover to provide the interface between the different devices expose them to the impact of electromagnetic transients and the possibility of damages because of equipment failure or other events.

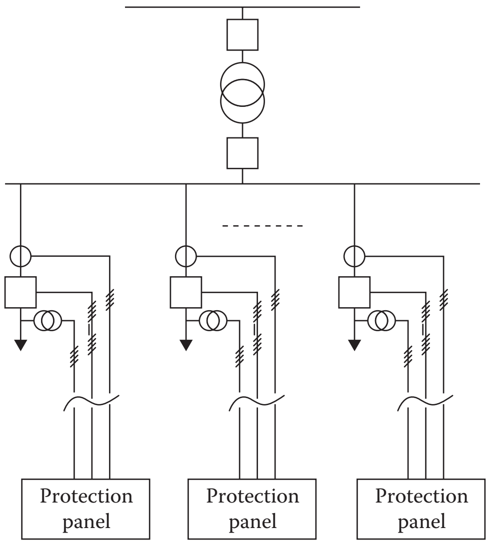

FIGURE 6.8 Typical conventional substation design. (From Apostolov, A. and Janssen, M., IEC 61850 Impact on Substation Design, paper number 0633, Transmission & Distribution Conference & Exposition, 2008 IEEE/PES. © 2008 IEEE. With permission.)

The design of a conventional substation needs to take into consideration the resistance of the cables in the process of selecting instrument transformers and protection equipment, as well as their connection to the instrument transformers and between themselves. The issues of CT saturation are of special importance to the operation of protection relays under maximum fault conditions. Also, ferroresonance in voltage transformers must be considered in relation to the correct operation of the protection and control systems.

Failures in the cables in the substation may lead to misoperation of protection or other devices and can represent a safety issue. Also, open CT circuits, especially when it occurs while the primary winding is energized, can cause severe safety issues as the induced secondary Electromagnetic Force (EMF) can be high enough to present a danger to people's life and equipment insulation.

The earlier discussion is not a complete list of all the issues that need to be taken into consideration in the design of a conventional substation. It provides some examples that will help better understand the impact of IEC 61850 in the substation.

To take full advantage of any new technology, it is necessary to understand what it provides. The next part of this chapter gives a summary of some of the key concepts of the standard that have the most significant impact on the substation design.

6.3.3.2 IEC 61850 Substation Hierarchy

In a smart grid environment, availability of and access to information is key. Standards like IEC 61850 allow the definition of the available information and access to that information in a standardized way.

The IEC 61850 standard Communication Networks and Systems for Utility Automation allows the introduction of new designs for various functions, including protection inside and outside substations. The levels of functional integration and flexibility of communications-based solutions bring significant advantages in costs at various levels of the power system. This integration affects not only the design of the substation but almost every component and system in it, such as protection, monitoring, and control by replacing the hardwired interfaces with communications links. Furthermore, the design of the high-voltage installations and networks can be reconsidered regarding the number and the location of switchgear components necessary to perform the primary function of a substation in a high-voltage network. The use of high-speed peer-to-peer communications using GOOSE messages and SVs from MUs allows for the introduction of distributed and wide-area applications. In addition, the use of optical LANs leads in the direction of copperless substations.

The development of different solutions in the substation protection and control system is possible only when there is a good understanding of both the problem domain and the IEC 61850 standard. The modeling approach of IEC 61850 supports different solutions from centralized to distributed functions. The latter is one of the key elements of the standard that allows for utilities to rethink and optimize their substation designs.

A function in an IEC 61850-based integrated protection and control system can be local to a specific primary device (distribution feeder, transformer, etc.) or distributed and based on communications between two or more IEDs over the substation LAN.

Considering the requirements for the reliability, availability, and maintainability of functions in conventional systems, many primary and backup devices need to be installed and wired to the substation. The equipment, as well as the equipment that they interface with, must then be tested and maintained.

The interface requirements of many of these devices differ. As a result, specific multi-core instrument transformers were developed that allow for accurate metering of the energy or other system parameters and provide a high dynamic range used by, for example, protection devices.

With the introduction of IEC 61850, different interfaces have been defined that can be used by substation applications using dedicated or shared physical connections—the communications links between the physical devices. The allocation of functions between different physical devices defines the requirements for the physical interfaces and, in some cases, may be implemented in more than one physical LAN or by applying multiple virtual networks on a physical infrastructure.

The functions in the substation can be distributed between IEDs on the same or different levels of the substation functional hierarchy—station, bay, or process, as shown in Figure 6.9.

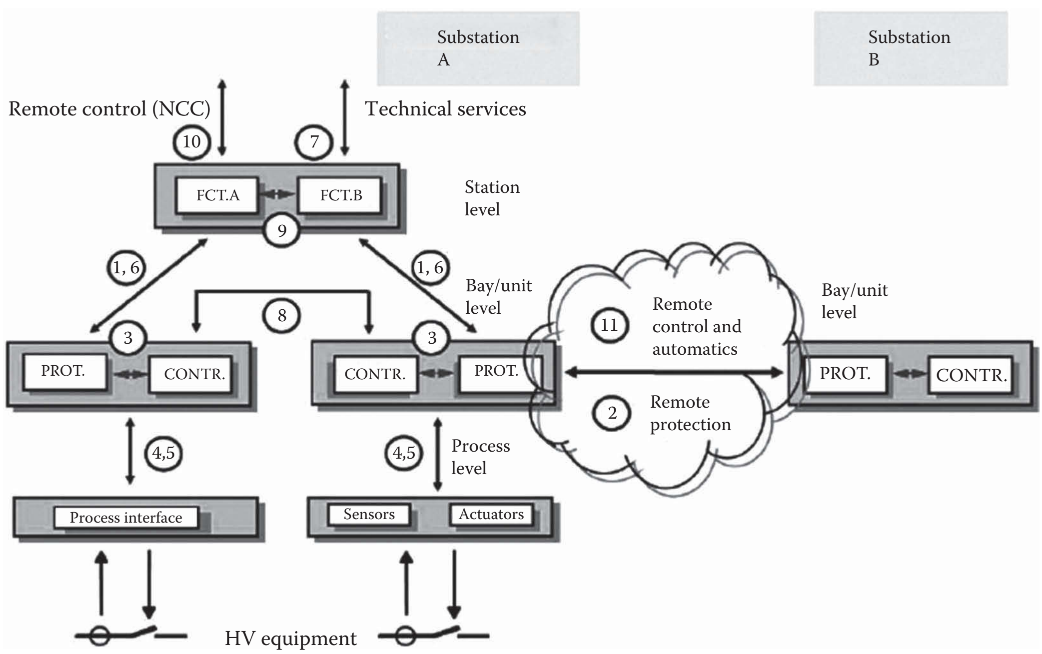

FIGURE 6.9 Logical interfaces in IEC 61850. (From IEC/TR 61850-1 ed.2.0. © 2013 IEC Geneva, Switzerland. www.iec.ch. With permission.)

A significant improvement in functionality and reduction of the cost of integrated substation protection and control systems can be achieved based on the IEC 61850-based communications as described in the following.

One example where a major change in the substation is expected is at the process level of the substation. The use of nonconventional and conventional instrument transformers with a digital interface based on IEC 61850-9-2 or the implementation guideline IEC 61850-9-2 LE results in improvements and can help eliminate issues related to the conflicting requirements of protection and metering IEDs as well as alleviate some of the safety risks associated with current and voltage transformers. The interface between the instrument transformers (both conventional and nonconventional) and the different types of substation protection, control, monitoring, and recording equipment is defined in IEC 61850 as an MU. The definition of an MU in IEC 61850 is as follows:

Merging Unit (MU): An interface unit that accepts multiple analog CT/VT and binary inputs and produces multiple time-synchronized serial unidirectional multi-drop digital point-to-point outputs to provide data communication via the logical interfaces four and five.

MUs can have the following functionality:

- Signal processing of all sensors—conventional or nonconventional
- Synchronization of all measurements—three currents and three voltages
- Analog interface—high- and low-level signals
- Digital interface—IEC 60044-8 or IEC 61850-9-2

It is important to be able to interface with both conventional and nonconventional sensors to allow for, the implementation of the system in existing or new substations.

The MU has similar elements (Figure 6.10) as a typical analog input module of a conventional protection or multifunctional IED. The difference is that in this case, the substation LAN performs as the digital data bus between the input module and the protection or functions in the device. They are in different devices, just representing the typical IEC 61850 distributed functionality.

Depending on the specific requirements of the substation, different communications architectures can be chosen as described hereafter.

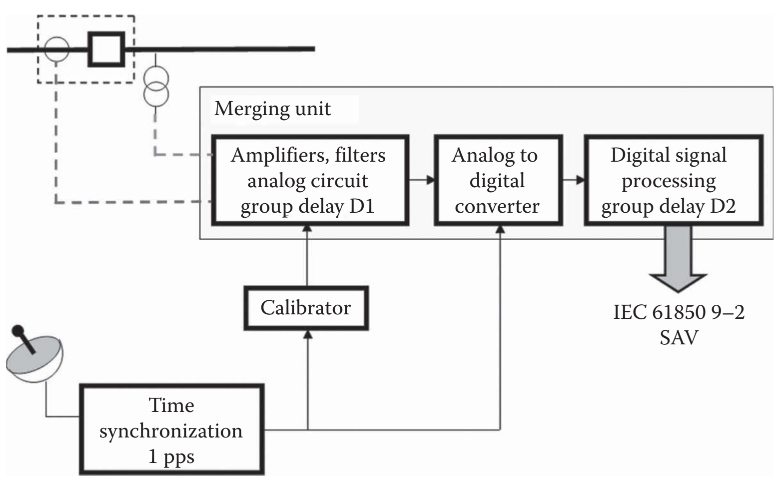

FIGURE 6.10 Concept of the MU. (From Apostolov, A. and Janssen, M., IEC 61850 Impact on Substation Design, paper number 0633, Transmission & Distribution Conference & Exposition, 2008 IEEE/PES. © 2008 IEEE. With permission.)

IEC 61850 is being implemented gradually by starting with an adaptation of existing IEDs to support the new communications standard over the station bus and at the same time introducing some first process-bus-based solutions.

6.3.3.3 IEC 61850 Substation Architectures

IEC 61850 is being implemented gradually by starting with an adaptation of existing IEDs to support the new communications standard over the station bus and at the same time introducing some first process-bus-based solutions.

6.3.3.4 Station-Bus-Based Architecture

The functional hierarchy of station-bus-based architectures is shown in Figure 6.11. It represents a partial implementation of IEC 61850 in combination with conventional techniques and designs and brings some of the benefits that the IEC 61850 standard offers.

The current and voltage inputs of the IEDs (protection, control, monitoring, or recording) at the bottom of the functional hierarchy are conventional and wired to the secondary side of the substation instrument transformers using copper cables.

The architecture, however, does offer significant advantages compared to conventional hardwired systems. It allows for the design and implementation of different protection schemes that in a conventional system require a significant number of cross-wired binary inputs and outputs, which is especially important in large substations with multiple distribution feeders connected to the same medium voltage bus where the number of available relay inputs and outputs in the protection IEDs might be the limiting factor in a protection scheme application. Some examples of such schemes are a distribution bus protection based on the overcurrent blocking principle, breaker failure protection, trip acceleration schemes, or a sympathetic trip protection.

The relay that detects the feeder fault sends a GOOSE message over the station bus to all other relays connected to the distribution bus, indicating that it has issued a trip signal to clear the fault; this can be considered a blocking signal for all other relays on the bus. The only requirement for the scheme implementation is that the relays connected to feeders on the same distribution bus must subscribe to receive the GOOSE messages from all other IEDs connected to the same distribution bus.

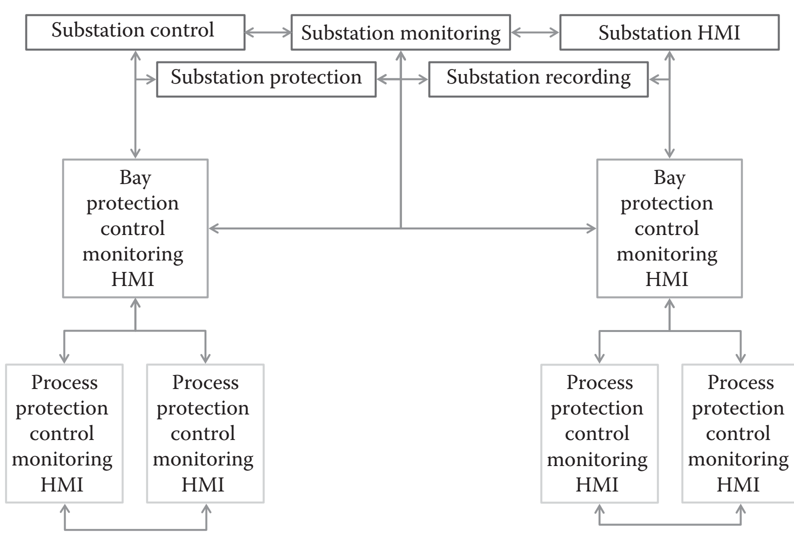

FIGURE 6.11 Station bus functional architecture. (© 2012 Marco Janssen. All rights reserved. With permission.)

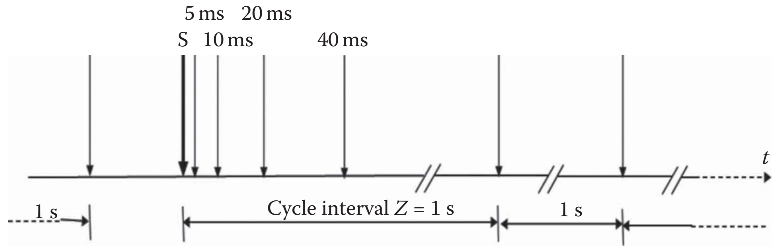

FIGURE 6.12 GOOSE message repetition mechanism. (From IEC/TR 61850-1 ed.2.0. © 2013 IEC Geneva, Switzerland. www.iec.ch. With permission.)

The reliability of GOOSE-based schemes is achieved through the repetition of the messages with increased time intervals until a user-defined time is reached. The latest state is then repeated until a new change of state results in sending of a new GOOSE message, which is shown in Figure 6.12.

The repetition mechanism does not only limit the risk that the signal is going to be missed by a subscribing relay but it also provides the means for the continuous monitoring of the virtual wiring between the different relays participating in a distributed protection application. Any problem in a device or the communications will immediately, within the limits of the maximum repetition time interval, be detected and an alarm will be generated, or an action will be initiated to resolve the problem, but this is not possible in conventional hardwired schemes where problems in the wiring or in relay inputs and outputs can only be detected through scheduled maintenance.

One of the key requirements for the application of distributed functions using GOOSE messages is that the total scheme operating time is similar to, or better than, the time of a hardwired conventional scheme. If the different factors that determine the operating time of a critical protection scheme, such as breaker failure protection, are analyzed, it requires a relay to initiate the breaker failure protection through a relay output wired into an input. The relay output typically has an operating time of 3 to 4 ms and it is not unusual that the input may include some filtering to prevent an undesired initiation of this critical function.

As a result, in a conventional scheme, the time over the simple hardwired interface, being the transmission time between the two functions, will be between 0.5 and 0.75 cycles—longer than the required 0.25 cycles defined for critical protection applications in IEC 61850-based systems.

Another significant advantage of the GOOSE-based solutions is the improved flexibility of the protection and control schemes. Making changes to conventional wiring is very labor intensive and time consuming, while changes in the “virtual wiring” provided by IEC 61850 peer-to-peer communications require only changes in the system configuration using the substation configuration language (SCL)-based engineering tools.

6.3.3.5 Station and Process Bus Architecture

Full advantage of all the features available in the new communications standard can be taken if both the station and process bus are used. Figure 6.13 shows the functional hierarchy of such a system.

IEC 61850 communications-based distributed applications involve several different devices connected to a substation LAN. MUs will process the sensor inputs, generate the SVs for the three phase and neutral currents and voltages, format a communications message, and multicast it on the substation LAN so that it can be received and used by all the IEDs that need it to perform their functions. This “one to many” principle like that used to distribute the GOOSE messages provides significant advantages as it not only eliminates current and voltage transformer wiring but it also supports the addition of new ideas and applications using the SVs at a later stage as these can simply subscribe to receive the same sample stream.

Another device, the input/output unit (IOU), will process the status inputs, generate status data, format a communications message, and multicast it on the substation LAN using GOOSE messages.

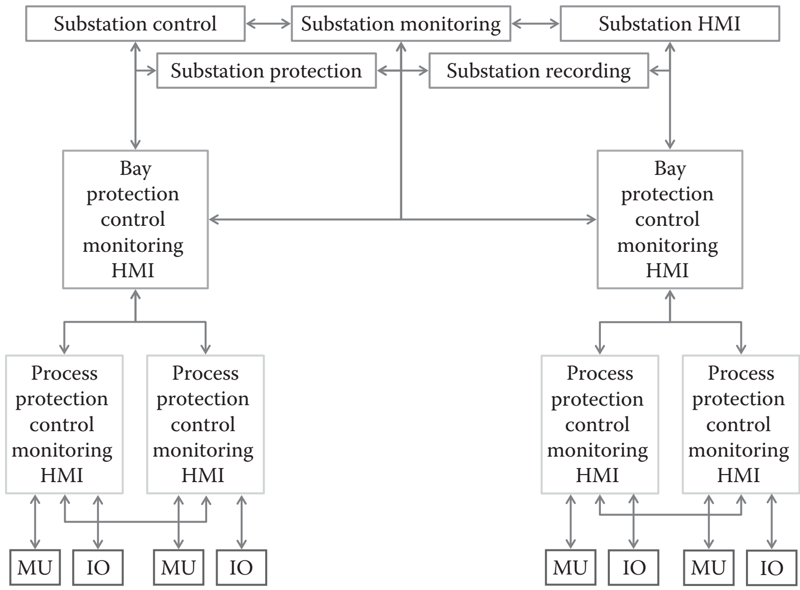

FIGURE 6.13 Station and process bus functional architecture. (© 2012 Marco Janssen. All rights reserved. With permission.)

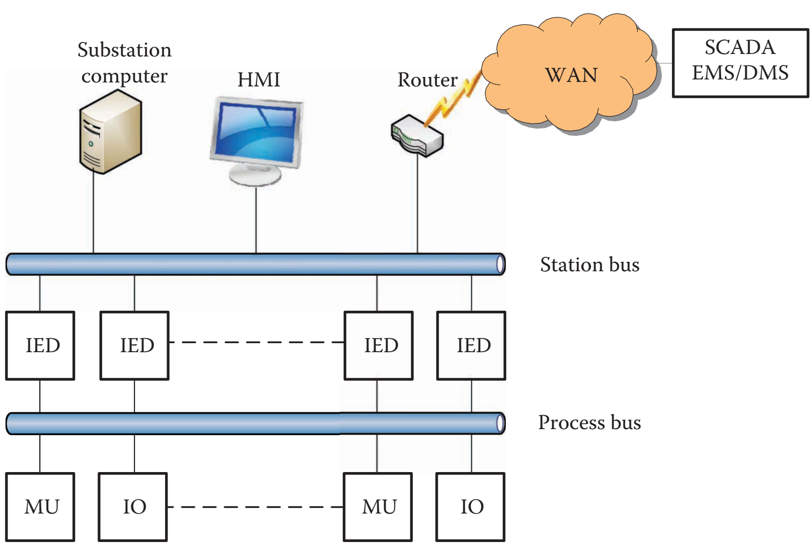

FIGURE 6.14 Communications architecture for process and station bus. (© 2012 Marco Janssen. All rights reserved. With permission.)

All multifunctional IEDs will receive the SVs messages as well as the binary status messages. The ones that have subscribed to these data then process the data, decide, and operate by sending another GOOSE message to trip the breaker or perform any other required action.

Figure 6.14 shows the simplified communications architecture of the complete implementation of IEC 61850. The number of switches for both the process and substation buses can be more than one depending on the size of the substation and the requirements for reliability, availability, and maintainability.

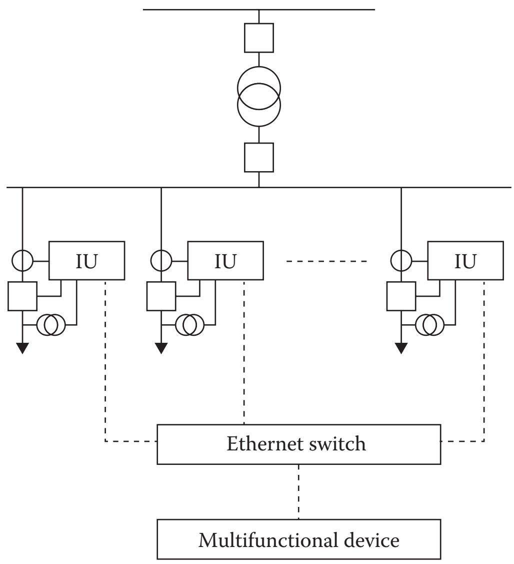

FIGURE 6.15 Alternative substation design. (From Apostolov, A. and Janssen, M., IEC 61850 Impact on Substation Design, paper number 0633, Transmission & Distribution Conference & Exposition, 2008 IEEE/PES. © 2008 IEEE. With permission.)

Figure 6.15 is an illustration of how the substation design changes when the full implementation of IEC 61850 takes place. All copper cables used for analog and binary signals exchange between devices are replaced by fiber optic links. If the DC circuits between the substation battery and the IEDs or breakers are put aside, the "copperless" substation is a fact. We then can even go a step further and combine all the functions necessary for multiple feeders into one multifunctional device, thus eliminating a significant amount of individual IEDs. Of course, the opposite is also possible. Since all the information is available on a communication bus, we can choose to implement relatively simple or even single function devices that share their information on the network, thus creating a distributed function.

The next possible step when using station and process bus is the optimization of the switchgear. For the protection, control, and monitoring functions in a substation to operate correctly, several instrument transformers are placed throughout the high-voltage installation. However, with the capability to send voltage and current measurements as SVs over a LAN, it is possible to eliminate some of these instrument transformers. One example is the voltage measurements needed by distance protections. Traditionally, voltage transformers are installed in each outgoing feeder. However, if voltage transformers are installed on the bus bar, the voltage measurements can be transmitted over the LAN to each function requiring these measurements. These concepts are not new and have already been applied in conventional substations. In conventional substations, however, it requires large amounts of (long) cables and several auxiliary relays limiting or even eliminating the benefit of having fewer voltage transformers.

Process-bus-based applications offer important advantages over conventional hardwired analog circuits. The first very important one is the significant reduction in the cost of the system because multiple copper cables are replaced with a small number of fiber optic cables.

Using a process bus also results in the practical elimination of CT saturation of conventional CTs because of the elimination of the current leads resistance. As the impedance of the MU current inputs is very small, this results in the significant reduction in the possibility for CT saturation and all associated with its protection issues. If nonconventional instrument transformers can be used in combination with the MUs and process bus, the issue of CT saturation will be completely eliminated since these nonconventional CTs do not use inductive circuits to transduce the current.

Process-bus-based solutions also improve the safety of the substation by eliminating one of the main safety-related problems—an open current circuit condition. Since the only current circuit is between the secondary of a current transformer and the input of the MU located right next to it, the probability for an open current circuit condition is very small. It becomes nonexistent if optical current sensors are used.

Last, but not least, the process bus improves the flexibility of the protection, monitoring, and control systems. Since current circuits cannot be easily switched due to open circuit concerns, the application of bus differential protection, as well as some backup protection schemes, becomes more complicated, which is not an issue with process bus because any changes will only require modifications in the subscription of the protection IEDs receiving the sampled analog values over IEC 61850 9-2.

6.3.4 The Role of Substations in Smart Grid

Substations in a smart grid will move beyond basic protection and traditional automation schemes to bring complexity around distributed functional and communications architectures, more advanced local analytics, and data management. There will be a migration of intelligence from the traditional centralized functions and decisions at the energy management and DMS level to the substations to enhance reliability, security, and responsiveness of the T&D system. The enterprise system applications will become more advanced in being able to coordinate the distributed intelligence in the substation and feeders in the field to ensure control area and system-wide coordination and efficiency.

The integration of a relatively large scale of new generation and active load technologies into the electric grid introduces real-time system control and operational challenges around reliability and security of the power supply. These challenges, if not addressed properly, will result in degradation of service, diminished asset service life, and unexpected grid failures, which will impact the financial performance of the utility's business operations and public relationship image. If these challenges are met effectively, optimal solutions can be realized by the utility to maximize return on investments in advanced technologies. Some challenges must be addressed to achieve these needs:

- Very high numbers of operating contingencies different from "system as design" expectations
- High penetration of intermittent renewable and distributed energy resources, with their (current) characteristic of limited controllability and dispatchability
- PQ issues (voltage and frequency variation) that cannot be readily addressed by conventional solutions
- Highly distributed, advanced control and operations logic
- Slow response during quickly developing disturbances
- Volatility of generation and demand patterns and wholesale market demand elasticity
- Adaptability of advanced protection schemes to rapidly changing operational behavior due to the intermittent nature of renewable and DER resources

With wide deployment of the smart grid, there will be an abundance of new operational and non-operational devices and technologies connected to the wide-area grid. The wide range of devices will include smart meters; advanced monitoring, protection, control, and automation; EV chargers; dispatchable and non-dispatchable DER resources; energy storage; etc. Effective and real-time management and support of these devices will introduce enormous challenges for grid operations and maintenance. To adequately address all these challenges, it is necessary to engineer, design, and operate the electric grid with an overarching solution in mind, enabling overall system stability and integrity. A smart grid solution, from field devices to the utility's control room, utilizing intelligent sensors and monitoring, advanced grid analytical and operational and non-operational applications, comparative analysis, and visualization will enable wide area and real-time operational anomaly detection and system "health" predictability. These will allow for improved decision-making capabilities, PQ, and reliability. An integrated approach will also help to improve situational awareness, marginal stress evaluation, and congestion management and recommend corrective action to effectively manage high penetration of new alternative generation resources and maximize overall grid stability.

6.3.4.1 Engineering and Design

Future substation designs will be driven by current and new well-developed technologies and standards, as well as some new methodologies, which are different from the existing philosophy. The design requirements for the next-generation substations will be based on the total cost of ownership and shall be aimed at either cost reduction while maintaining the same technical performance or performance improvement while assuring a positive cost-benefit ratio. Based on these considerations, smart substation design may take the form of (1) retrofitting existing substations with a major replacement of the legacy equipment with minimal disruption to the continuity of the services, (2) deploying brand-new substation designs using the latest off-the-shelf technologies, or (3) greenfield substation design that takes energy market participation, profit optimization, and system operation risk reduction into combined consideration.

Designing the next-generation substations will require an excellent understanding of primary and secondary equipment in the substation, but also the role of the substation in the grid, the region, and the customers connected to it. Signals for monitoring and control will migrate from analog to digital, and the availability of new types of sensors, such as nonconventional current and voltage instrument transformers, will require shifting the engineering and design process from a T&D network focus also to include the substation information and communications architecture. This will require a better understanding of communications networks, data storage, and data exchange needs in the substation. As with other communications networks used in other processes or time-critical industries, redundancy, security, and bandwidth are an essential part of the design process. Smart substations will require protocols specific to the needs of electric utilities while ensuring interconnectivity and interoperability of the protection, monitoring, control, and data acquisition devices. One approach to overcoming these challenges is to modify the engineering and design documentation process so that it includes detailed communication schematics and logic charts depicting this virtualized circuitry and data communications pathways.

6.3.4.2 Information Infrastructure

Advances in processing technology have been a major enabler of smarter substations with the cost-effective digitization of protection, monitoring, and control devices in the substation. Digitization of substation devices has also enabled the increase in control and automation functionality and, with it, the proliferation of real-time operational and non-operational data available in the substation. The availability of the large amounts of data has driven the need for higher-speed communications within the substation as well as between the substation and feeder devices and upstream from the substation to SCADA systems and other enterprise applications, such as outage management and asset management. The key is to filter and process these data so that meaningful information from the T&D system can be made available on a timely basis to appropriate users of the data, such as operations, planning, asset maintenance, and other utility enterprise applications. Soon, about one third of North American utilities will be well on their way of implementing full digital substations [1].

Central to the smart grid concept is design and deployment of a two-way communications system linking the central office to the substations, intelligent network devices, and ultimately to the customer meter. This communications system is of paramount importance and serves as the nervous system of the smart grid. This communications system will use a variety of technologies ranging from wireless, RF, to broadband over power line (BPL) most likely all within the same utility. The management of this communications network will be new and challenging to many utilities and will require new engineering and asset management applications. Enhanced security will be required for field communications, application interfaces, and user access. An advanced EMS and DMS will need to include data security servers to ensure secure communications with field devices and secure data exchange with other applications. The use of IP-based communications protocols will allow utilities to take advantage of commercially available and open-standard solutions for securing network and interface communications.

IEC 61850 will significantly improve the way we communicate between devices. For the first time, vendors and utilities have agreed upon an international communications standard, which will allow an unprecedented level of interoperability between devices of multiple vendors in a seamless fashion. IEC 61850 supports both client/server communications as well as peer-to-peer communications. The IEC process bus will allow for communication to the next generation of smart sensors. The self-description feature of IEC 61850 will greatly reduce configurations costs, and the interoperable engineering process will allow for the reuse of solutions across multiple platforms. Also, because of a single standard for all devices, training, engineering, and commissioning costs can be significantly reduced.

6.3.4.3 Operation and Maintenance

The challenge of operations and maintenance in advance substations with smart devices is usually one of acceptance by personnel. This is a critical part of the change management process. Increased amounts of data from smart substations will increase the amount of information available to system operators to improve control of the T&D network and respond to system events. Advanced data integration and automation applications in the substation will be able to provide a faster response to changing network conditions and events and, therefore, reduce the burden on system operators, especially during multiple or major system events. For example, after a fault on a distribution feeder, instead of presenting the system operator with a lockout alarm, accompanied by associated low volts, fault passage indications, battery alarms, and so on, leaving it up to the operator to drill down, diagnose, and work out a restoration strategy, the applications will instead notify the operator that a fault has occurred and analysis and restoration are in progress in that area. The system will then analyze the scope of the fault using the information available; tracing the current network model; identifying current relevant safety documents, operational restrictions, and sensitive customers; and locating the fault using data from the field. The master system automatically runs load flow studies identifying current loading, available capacities, and possible weaknesses, using this information to develop a restoration strategy. The system then attempts an isolation of the fault and maximum restoration of customers with safe load transfers, potentially involving multi-level feeder reconfiguration to prevent cascading overloads to adjacent circuits. Once the reconfiguration is complete, the system can alert the operator to the outcome and even automatically dispatch the most appropriate crew to the identified faulted section.

6.3.4.4 Enterprise Integration

Enterprise integration is an essential component of the smart grid architecture. The smart substation will need to interface and share data with numerous other applications to increase the value of an integrated smart grid solution. For example, building on the benefits of an AMI with extensive communication coverage across the distribution system and obtaining operational data from the customer point of delivery (such as voltage, power factor, loss of supply) help to improve outage management and IVVC implementation locally at the substation level. More data available from substations will also allow more accurate modeling and real-time analysis of the distribution system and will enable optimization algorithms to run, reducing peak load and deferring investment in transmission and distribution assets. By collecting and analyzing non-operational data, such as key asset performance information, sophisticated computer-based models can be used to assess current performance and predict possible failures of substation equipment. This process combined with other operational systems, such as mobile workforce management, will significantly change the maintenance regime for the T&D system.

6.3.4.5 Testing and Commissioning

The challenge of commissioning a next-generation substation is that traditional test procedures cannot adequately test the virtual circuitry. The best way to overcome this challenge is to use a system test methodology, where functions are tested end to end as part of the virtual system, which allows performance and behavior of the control system to be objectively measured and validated. Significant changes will also be seen in substation interaction and automation database management and the reduction of configuration costs. There is currently work under way to harmonize the Electric Power Research Institute (EPRI) Common Information Model (CIM) model and enterprise service bus IEC 61968 standards with the substation IEC 61850 protocol standards. Bringing these standards together will greatly reduce the costs of configuring and maintaining a master station through the plug and play compatibility and database self-description.

6.4 DISTRIBUTION GRID CONTROL IN THE NEW SMART GRID ENVIRONMENT

The high penetration of DER and the deployment of other smart devices in the distribution system that are linked together by an advanced communication infrastructure will allow utilities to improve control of the grid. DER technologies that both enable this controllable environment, as well as necessitate it (due to potential DER-caused problems), include PV generators, distributed wind turbine generators (WTG), and energy storage devices. Much of the discussion in the industry has been about the so-called "smart inverters" of the DERs (mostly PVs to date), which have advanced capabilities that can be used to optimize grid performance.[1] These capabilities can be either activated through (1) autonomous control, such as Volt/VAr algorithms that determine active and reactive power injection/absorption based on the condition at the PV terminal or, even better, (2) distributed control in which some PV systems are controlled in a concerted fashion to achieve a pre-determined optimization goal (e.g., flat voltage profile, overload prevention, shaping of the load curve). Until the relatively recent amendment to IEEE Standard 1547 in 2014, such voltage control capability could not be implemented to support distribution systems and mitigate DER impacts in the United States since the original standard did not permit active voltage regulation by the DER. Furthermore, other voltage regulation equipment did not have the capability to coordinate with smart inverters and, in most cases, except for implementation of AMI, Volt/VAr and other distribution feeder applications, the voltage along the feeder and at consumer interfaces was not measured, so there was no basis for determining the reactive power output of the DER for voltage control. Fortunately, fast, low-cost monitoring and communications systems are becoming available, which can form the basis for control systems to utilize both traditional distribution equipment and solar inverters.

The following sections describe recent industry efforts and developments that are aimed toward leveraging the monitoring and control potential of inverter-based DER, including the challenges that utilities must face when integrating large numbers of DERs into their system. There is also discussion on opportunities to leverage DERs for advanced grid control.

6.4.1 Smart Inverter Technologies—Recent Developments

In this section, we review recent developments on the regulatory front and in the Research and Development (R&D) communities that pave the road for smart inverter technologies.

[1] Note that most of the capabilities of smart inverters have long existed, or could readily be implemented, in synchronous generators, although the expected large numbers in which these smart devices will be deployed in the near future is certainly an unprecedented scenario that warrants research.

6.4.1.1 The IEEE 1547 Standard

More advanced DER inverters have reactive power and voltage control capabilities like most modern wind turbines. However, the original IEEE 1547-2003, which was reaffirmed without changes in 2008, did not permit the DER to actively regulate voltage, which has been a somewhat controversial requirement. Opponents of this requirement argued that this restriction is counter-innovative in the sense that it curbs the full potential of DER technology. A consequence of the IEEE 1547 restriction is that on systems that require active regulation to meet the area service voltage requirements and to minimize voltage variations caused by DER power output variations, equipment other than the DER must be employed to provide the reactive power in direct response to measured voltage conditions. Active regulation can come from, for instance, D-STACOMs (switched shunt capacitance), which typically use inverter technology that is like the inverter technology employed in modern DERs. The opponents of the original IEEE 1547 restriction pointed out that it is inefficient to use DER inverters to force operation at constant power factor (in response to varying environmental conditions) and then employ D-STATCOMs to provide dynamic power factor control (in response to the measured voltage fluctuations), instead of using the DER alone to control the power factor in response to varying environmental conditions and system voltage fluctuations. There is consensus in the standard-developing community that employing DER for active regulation of the voltage at the DER connection is (1) technically feasible, (2) requires coordination between the DER operator and the distribution grid operator to ensure proper operation of grid regulation equipment, and (3) violated the original IEEE 1547 standard and was, therefore, not an option on systems that follow IEEE 1547. This restriction was put in place because the working group that developed the IEEE 1547 standard decided that at the time the standard was written, the problems associated with active regulation from the DER outweighed the obvious benefits of DER providing active regulation of the voltage. Some of the arguments that led to the acceptance of this IEEE 1547 requirement are listed below:

- Certain entities involved in the original IEEE 1547 development believed that DER should be "plug and play" and that utilities should not be allowed to have any type of discretion regarding DER interconnection requirements. Because proper coordination of voltage regulation necessitates the utility-specifying characteristics, such as set points and regulation droops to coordinate with existing utility-owned voltage regulation equipment, it was determined that it would not be feasible to allow voltage regulation by DERs if the utility were not allowed to be involved. Therefore, the consensus was to not allow voltage regulation if it could not be properly implemented in a coordinated fashion.
- The current market structure makes it difficult to provide ancillary services to the distribution grid operators due to the need for uniform rules for the public utilities.
- Since IEEE 1547 was published, many manufacturers designed their products to meet IEEE 1547 requirements. Consequently, many current installations that employ these products do not have the capability to actively regulate voltage and will not benefit from lifting the IEEE 1547 requirement.

The revised proposed standard, IEEE 1547a, has been pursued under the new Fast Track Amendment Process. A Project Authorization Request (PAR) has been established to amend IEEE 1547-2008, which was approved by the IEEE Standards Association in August 2012 [3]. IEEE 1547a was balloted in 2013 and adopted in 2014. IEEE 1547a removes the prohibition of active voltage regulation but requires coordination with and approval of the distribution grid operators. Since the original IEEE 1547-2003 standard development, the understanding of DER integration has matured, and it is realized by almost all parties that such integration requires interaction with the utility and "plug and play," particularly in high-penetration scenarios, is not realistic. At the time of this writing, there has been an establishment of a working group with several participants cognizant of bulk grid issues to perform a complete rewrite of IEEE 1547-2008. Under the recently changed IEEE renewal cycle for standards, IEEE 1547 must be revised or withdrawn by 2018. Also, the large working group has been divided into some sub groups having frequent (typically weekly) telephone conferences to work on the various sections of the standard. The scope and purpose of the rewritten standard are as follows:

Scope: This standard establishes criteria and requirements for interconnection of DER with electric power systems (EPS) and associated interfaces.

Purpose: This document provides a uniform standard for the interconnection and interoperability of DER with EPS. It provides requirements relevant to the interconnection and interoperability performance, operation and testing, and safety, maintenance, and security considerations.

Apparent thrusts in the P1547 development include [4,5]:

- Mandatory voltage (i.e., during fault) and frequency disturbance ride through capabilities.
- Enhanced voltage regulation and frequency regulation (governor) characteristics, including mandatory DER reactive power capability and control functions (e.g., voltage regulation) to utilize this capability.
- Models and model verification testing.
- Increased communication and interoperability requirements.
- Expanded testing of short-circuit and overvoltage behavior.

Other thrusts, yet to arise, are likely given the early stage of standard development.

6.4.1.2 Harmonizing Distribution and Transmission Standards

The working group that developed the original IEEE 1547 had a strong participation of utility distribution/distribution protection engineers and DER manufacturers/advocates, and very little participation of individuals with a bulk transmission system perspective. The degree of DER penetration increase that has been experienced in the past 12 years was also not foreseen. Consequently, IEEE 1547-2003 was conceived without consideration of transmission grid impacts, which is an increasing concern as DER has grown to be a sizeable portion of generation assets. Specifically, FERC Order 661A, which applies to wind generation interconnected to transmission systems, has a 'not trip' Low Voltage Ride through (LVRT) requirement,[2] which mandates that the wind generators must remain connected in service to the grid during normally cleared three-phase faults to a maximum of nine cycles, while IEEE 1547, which applies to distribution systems, has a 'trip' requirement that requires any distributed generation to disconnect during a fault after a certain period that depends on the voltage at the terminal. Similarly, NERC PRC-024 requires that transmission system power plant relays cannot trip generators for low- or high-voltage and frequency variation events of prescribed severity and duration.

LVRT requirements are currently a "hot topic" that is relevant for both transmission and distribution because widespread tripping of distributed resources can impact bulk system reliability when there is significant DER penetration on a regional or interconnection-wide basis. The IEEE 1547-2003 trip requirements are beneficial for the prevention of unintentional islanding and protection miscoordination at the distribution level; however, there is now increasing concern that simultaneous tripping of high-penetration DER on a feeder when not necessary, such as due to a fault on an adjacent feeder, may also create loading and power quality issues at the distribution level. Feeder voltage regulators, switched capacitor banks, and substation transformer Load Tap-Changers (LTCs) are configured to accommodate the DER power output, but with an abrupt loss of the DER output, the settings and configurations may not be correct for the post-disturbance net power flow, with consequential voltage violations. Harmonization of these conflicting requirements is needed, and the harmonization effort requires studies that look at the impact of distributed

[2] Ride through requirements are basic disturbance tolerance attributes that prevent generators from tripping during temporary voltage/frequency excursions, thereby contributing to system stability.

generation on transmission systems. The P1547a working group debated ride through requirements versus just relaxing the mandatory trip requirement. The outcome of this debate is that IEEE1547a, which was adopted in 2014, settled on the latter by changing the must-trip thresholds slightly and allowing (but not mandating) ride through.

This decision is at odds with the California Rule 21 on Smart Inverter requirements, and the shift in sentiment toward a consensus that voltage and frequency ride through requirements are needed. In fact, California's Smart Inverter Working Group has driven by distribution-level high-penetration concerns, developed a set of extreme ride through requirements that appear to be far more stringent than needed for ensuring transmission grid security. These extreme requirements are physically impossible for synchronous generators to comply, thereby inhibiting "technology neutrality" and, perhaps, endangering the adoption of any ride through requirements in IEEE 1547 [5].

On December 22, 2014, California's Public Utilities Commission (PUC) issued Decision 14-12-035, which adopts modifications to California's Electric Tariff Rule 21. These modifications are intended to leverage the capabilities offered by smart inverter technology, such as (1) delivery of power in four quadrants (leading and lagging power factor in both forward and reverse power flow directions), (2) voltage/frequency sensing, (3) autonomous mitigation of abnormal system conditions, and (4) utility-controlled charging/discharging of storage facilities. The modified rule requires all new distributed generation interconnecting via PUC's Rule 21 process to have a smart inverter by either (1) December 31, 2015, or (2) 12 months after the date Supplement SA of UL-1741 (with California requirements) is approved (whichever is the later date).

Modifications were made based on recommendations issued by the Smart Inverter Working on February 7, 2014. These recommendations, which were categorized by the Working Group as "Phase 1" capabilities, include the following features:

1. Revise the anti-islanding protection to include voltage ride through settings.
2. Default settings for under-/overvoltage ride through.
3. Settings for under-/overfrequency ride through.
4. Dynamic Volt/VAr operations requirements.
5. Ramp rate requirements.
6. Fixed power factor requirements.
7. Reconnection by soft-start method.

On July 18, 2014, California's Investor-Owned Utilities—i.e., San Diego Gas & Electric (SDG&E), Pacific Gas & Electric (PG&E), and Southern California Edison (SCE)—set forth revisions to Rule 21 to conform to the seven recommendations made by the Working Group. PUC Decision 14-12-035 granted this motion. All new inverters in California are required to have the Phase 1 capabilities but are not required to have them activated. The future Phase 2 and Phase 3 focus on "Communication" and "Advanced Smart Inverter" capabilities, respectively.

6.4.1.3 Smart Inverter Research and Development Activities

In 2009, EPRI launched a cooperative initiative with storage equipment providers, utilities, and the National Laboratories to define common functions and communication protocols for "smart inverters" to facilitate the grid integration of inverter-based DERs of varying sizes and from different manufacturers. Selected functionalities for which the initiatives develop requirements/use cases are listed below [6]:

- Connect/disconnect function
- Battery storage management function
- Volt/VAr control function
- Frequency control function
- Low/high voltage and frequency ride through functions

- Dynamic reactive current support function
- Real power smoothing function
- Peak load limiting function

EPRI is currently conducting a three-phase project aimed at paving the road for the so-called "Integrated Grid," which is the electricity grid that fully realizes the value of DERs by integrating these resources in the planning and operation of the grid. The project focuses on the following four key areas [7]:

1. *Interconnection Rules and Communications Technologies and Standards* including (1) rules that preserve voltage support and grid management, (2) rules for operating DER and storage devices, (3) communication technologies that allow robust, secure, and seamless interconnection and (4) standard language to enable interoperability among DERs for different types, and from different manufacturers.
2. *Assessment and Deployment of Advanced Distribution and Reliability Technologies* including (1) smart inverters that provide voltage/frequency support and that communicate with energy management systems, (2) distribution management systems and sensors that can be utilized for DER integration, and (3) distributed energy storage and demand response.
3. *Strategies for Integrating Distributed Energy Resources with Grid Planning and Operation* including frameworks for data exchange and coordination among DER owners.
4. *Enabling Policy and Regulation* including (1) capacity-related costs, (2) power market rules, and (3) policy and regulatory frameworks for allocating and recovering costs incurred in the transformation to an integrated grid.

The Integrated Grid project comprises the following three phases:

Phase I includes the development of a concept paper, supporting documents, and knowledge transfer. The concept paper, "The Integrated Grid: Realizing the Full Value of Central and Distributed Energy Resources," resulting from Phase I has been completed and was published in February 2014.

Phase II is a six-month effort to develop the methodology and framework that lead to the Integrated Grid, and *Phase III* is a two-year effort to conduct global demonstration and modeling, utilizing the methodologies/frameworks developed in Phase II.

Based on the plethora of research initiatives that are aimed to pave the road for smart grid technologies, it seems clear that a wide-scale adoption of these technologies is inevitable. Consequently, utilities are faced with the challenge to identify grid support functions that offer sufficient advantages to warrant investment in these technologies and dismiss the ones that do not prove effective (or more effective/cheaper devices exist), are too expensive, or cause problems such as integration issues with existing operating procedures and controllable devices. Part of the investigation challenge is to appropriately account for the interplay between (1) DER stressing the system by, for instance, causing localized over-/undervoltage and being detrimental to the power quality, (2) the potential for "smart" DERs to mitigate the same issues it causes, and (3) the potential for smart DERs to mitigate non-DER caused issues and provide general grid enhancement functionality.

6.4.2 Integration Challenges of DER

Various factors including tax credits, net electrical metering rules, feed-in tariffs, and a growing desire by the public to make a "green" statement have led to a rapidly accelerating increase in small residential DER installations, most prominently in an increase of PV generators to the extent that, in some distribution systems, the total capacity of small residential PV has reached values exceeding the level of the load demand. DERs at high levels of penetration have the potential to impact distribution systems adversely. Regulatory bodies must ensure that utilities can accommodate small-scale DER interconnections with a minimum of delay and expense to the applicants, while at the same time the utilities are obligated to provide acceptable power quality to all customers and limit system operating and maintenance costs. In this section, we discuss concerns and potential issues associated with a high penetration of DERs. Whether any of the potential issues discussed here becomes actual issues is highly dependent on the type of feeder (urban, rural, etc.), the level of DER deployed on the feeder, and other factors, which are illustrated conceptually in Figure 6.16. For instance, a rural feeder (Feeder Category C in the figure) may experience minor issues at relatively low PV penetration levels of 20% while, at the same penetration levels, an urban feeder (Feeder Category A) would not experience any issues.

6.4.2.1 Unforeseen Detrimental Behavior of Smart Inverters

DERs equipped with smart inverters are key components in grid modernization efforts in that they can be utilized on distribution systems to control voltage, power flow, and frequency. However, many utilities are concerned with the operation of smart inverters when deployed in large numbers in distribution systems under conditions. Specific concerns include but are not limited to the following:

1. Inverters operating during poor power quality (e.g., excessive harmonics).
2. Incompatibility issues due to deploying smart inverters from different manufacturers.
3. Unwanted control interaction (e.g., hunting) between
   a. Autonomously acting smart inverters.
   b. Smart inverters used to control voltage and traditional voltage control equipment, such as capacitor banks, substation transformer tap changers, voltage regulators.

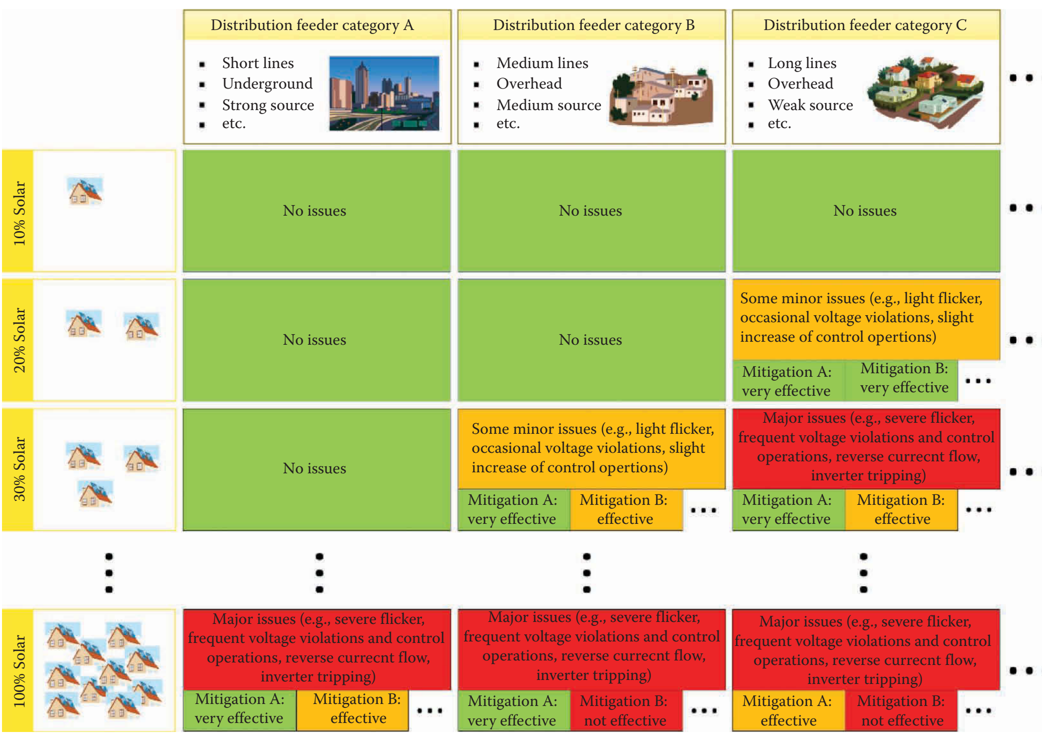

FIGURE 6.16 Solar penetration levels and effectiveness of mitigation options according to distribution feeder categories (conceptual).

4. Closed loop current regulators, which can potentially cause interactions between inverters, or between inverters and the grid's resonances (this concern applies to all inverters, whether or not they possess "smart" capabilities).

6.4.2.2 Changes in Power Flow

Utility engineers measure the power flow at the substation and, based on the measurements, can determine the feeder load profile. DER deployed on distribution feeders supplies local loads and, consequently, the power flow into the feeder observed at the substation is not necessarily the total feeder load, but rather the net power flow (the red line in Figure 6.17) between the power consumed by the aggregate feeder load (the green line in the figure) and the power generated by the aggregate DER supply (the blue line in the figure). This can cause the following effects:

1. *Load Masking and Changing Load Shape:* PV deployed in large numbers can mask load, which is illustrated in Figure 6.17 where PV generation reduces the power consumption on the feeder observed at midday. The resulting shape is often referred to as a "duck curve". Conventional power plants on the transmission system need to ramp up generation quickly to supply the sharply changing load demand (between 3 pm and 6 pm in the example illustrated in the figure); this is one of the DER integration challenges that migrate from the distribution system to the transmission system.
2. *Peak Load Reduction and Uncertainty:* PV can reduce the peak load on feeders during times of PV production. This is the case for the feeder load profile shown in Figure 6.18 (but not the case for the feeder load profile shown in Figure 6.20, where the peak occurs in the evening hours). Although peak load reduction is viewed as beneficial to utilities, the uncertainty introduced by the PV-induced peak load reduction also presents a challenge to utility engineers who must make planning and operation decisions based on peak load conditions. The uncertainty stems from the fact that PV only reduces the peak load during favorable condition (i.e., PV production coinciding with load peak, no overcast sky), so utility engineers should be cautious when relying on the peak load reducing the capability of PV.
3. *Peak Load Shifting:* PV can shift the peak load toward later hours, as shown in Figure 6.18. This trend may be enhanced with the increasing popularity of electric vehicles (EV) if the EV charging is uncontrolled and consumers charge their EV after typical work hours in the

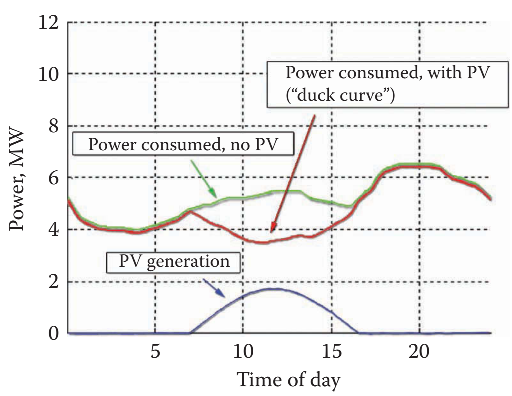

FIGURE 6.17 Illustration of load masking and changing load pattern due to PV generation during a clear-sky day.

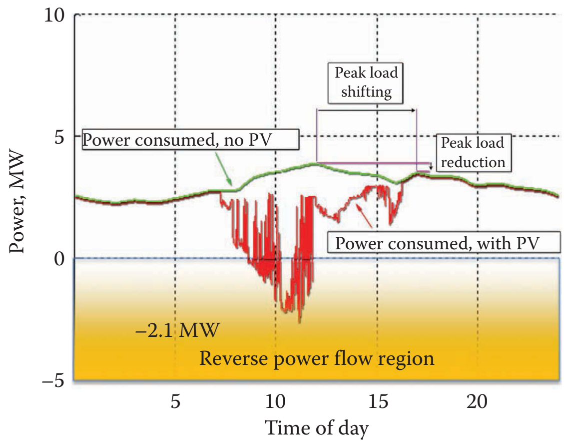

FIGURE 6.18 Illustration of peak load shifting and reduction, and reverse power flow during a day with scattered clouds.

evening. Consequently, the peak on a feeder that has high penetration of PV and EV may be shifted to a later time and have a larger magnitude compared to a traditional feeder that does not have these new technologies, and utilities need to account for this in their operating practices.

4. *Reverse Power Flow*: For very high levels of PV, the power flow observed at the substation can be reversed at times of high PV generation, as illustrated in Figure 6.18. Reverse power flow through voltage regulation equipment may interfere with proper operation of the voltage regulators installed in the utility system, and the utility would need to adjust for that.

6.4.2.3 Voltage Regulation and Imbalance

The voltage provided to utility customers must be kept within certain limits with regards to magnitude and balance to (1) ensure correct operation of the customers' equipment that is supplied by the voltage and (2) prevent safety hazards due to overvoltages. Detrimental effects of sustained over- and undervoltage include:

- Inhibiting the correct operation of the customers' equipment (e.g., machines running too fast or too slow),
- Tripping of sensitive load,
- Overheating of induction motors (induction motors operated below rated voltage draw more current, which increases heating losses),
- Premature failure (e.g., the life of incandescent lights decreases when operated at higher-than-rated voltage),
- Increased losses during overvoltage conditions.

Most utilities control the voltage on the secondary distribution circuit (the low-voltage circuit the customer is directly connected to) within ±5% of rated voltage. Figure 6.19 shows the phase-B secondary voltage profile of a distribution feeder over a 24-hour period for two scenarios: (1) no PV in the system, and (2) a net-zero PV scenario. The results in the figure illustrate that the traditional utility concern of undervoltage at remote locations on the feeder ("no PV" scenario) changes with the inclusion of PV in that overvoltage now becomes a concern, especially during times of PV peak production where overvoltages well above ±10% were simulated.

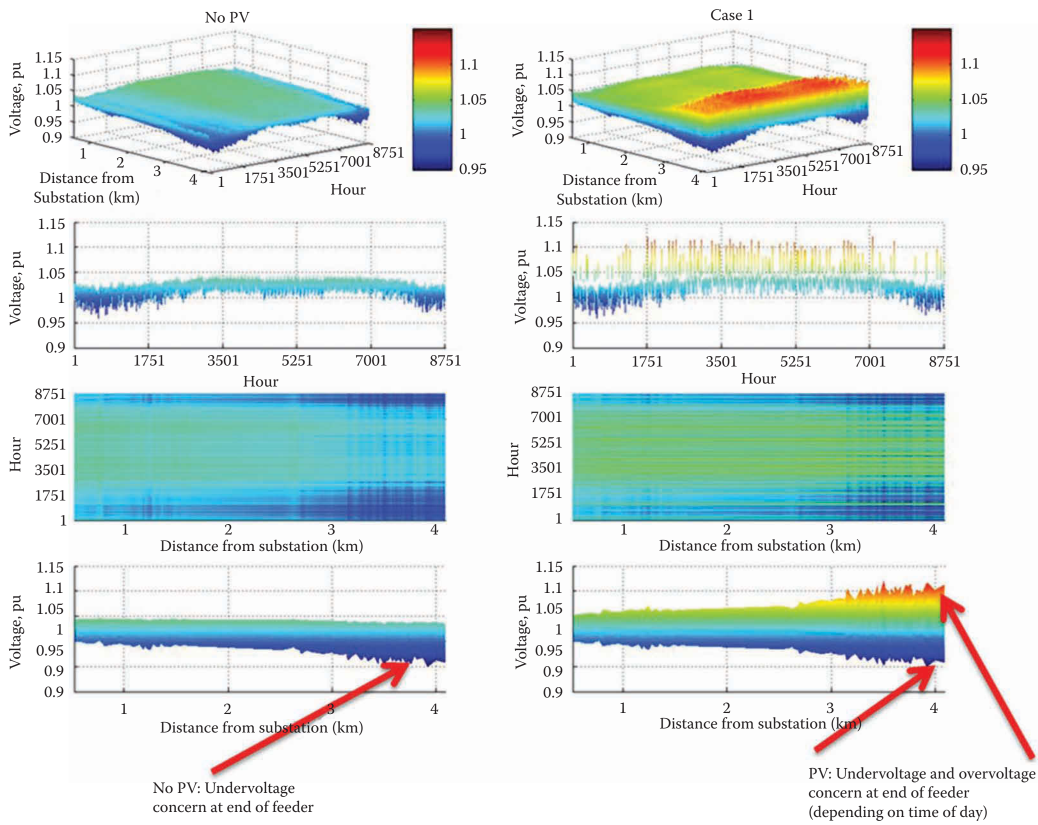

FIGURE 6.19 Feeder voltage profiles without PV (left side) and with PV (right side).

6.4.2.4 Operation of Voltage Control Equipment

The voltage on the secondary distribution circuit (the low-voltage circuit the customer is directly connected to) is typically controlled by regulating the voltage on the primary circuit (the distribution feeder circuit with typical voltage levels between 4 kV and 35 kV). The service voltage is the stepped-down feeder voltage minus the losses (i.e., service transformer losses and wiring losses). Based on the expected load, utilities can design service transformer sizes and the size and length of a service connection so that the service voltage stays within acceptable limits. Equipment that is at the utilities' disposal for regulating the primary circuit voltage includes (1) transformers and voltage regulators with LTCs in the substation and on the distribution line; and (2) shunt capacitor banks. In general, any excessive operation of the voltage regulation equipment (changing of the taps or switching of capacitor steps) can dramatically reduce the equipment life.

Power generated by PVs is subject to high variability and uncertainty (intermittency) due to noncontrollable environmental factors, such as cloud movement. Opaque clouds cause reductions in output by 50% to 80% within the time it takes a large cloud to cover an array, which typically ranges from a few seconds for small-scale (kW) PV facilities to a few minutes for utility-scale (MW) PV plants. Short-term irradiance fluctuations can cause voltage fluctuations that can trigger automated operations of line equipment (e.g., voltage regulators) on distribution feeders leading to higher maintenance costs for utilities due to equipment wear. Counteracting such fluctuations would require dynamic inverter VAr control (e.g., provided by PV inverters) or a secondary power source (e.g., energy storage, which is costly) that could ramp up or down at high frequencies to provide load following services.

Traditionally, forecasting is used for economic dispatch to optimize planning decisions for meeting the load demand at all times in the presence of variable generation. There are currently efforts underway that attempt to extend the usefulness of forecasting from the transmission realm to distribution system applications. The idea is to employ short-time-scale (seconds) forecasting data to mitigate voltage fluctuation issues—the forecasting data would yield information of an oncoming cloud and ramp down the PV output just before the cloud shades the PV, thereby avoiding a large step change of PV generation and excessive voltage fluctuation during the transition period from "clear-sky condition" to "cloud shading." After the cloud has passed, the PV output can be ramped up again slowly and in a controlled manner to minimize voltage fluctuation.

6.4.2.5 Impact on Losses

The presence of solar PV generators on distribution feeders will influence the transmission and distribution losses. PV will reduce transmission losses if the power from the DER is solely used to supply the loads on the distribution feeder (i.e., the PV does not inject power into the transmission system). Figure 6.20 illustrates loss reduction due to the presence of PV. The figure shows that during the daytime, the losses on the distribution system are significantly less for the PV scenario than for the non-PV scenario. If PV generation exceeds the feeder load and excess power from the PV are injected into the transmission system and is consumed outside the feeder, then distribution losses may increase. In other words, PV reduces distribution feeder losses if it is placed close to the loads it supplies, thereby providing support to the distribution system, and this is because the PV decreases the distance between the generation and the load, which relieves transfer capacity and reduces line losses. Additionally, losses may increase during DER-induced overvoltage conditions when a unity power factor cannot be maintained.

6.4.2.6 Widespread Tripping of DER during Faults

Integration of large, renewable generation plants into transmission power systems raises concerns about system stability, especially during system disturbances. Historically, the concerns were mostly related to the integration of wind plants because they are larger in numbers and, typically, larger in size compared to PV plants, but utility-scale PV plants are on the rise and the same concerns apply. A widespread tripping of renewable generators following disturbances may lead to the propagation of transient instabilities and can potentially cause local or system-wide blackouts. To avoid this scenario, FERC Order 661A requires that the Renewable Generators have fault ride through capabilities, such as Low-Voltage Ride through (LVRT) or Zero Voltage Ride through (ZVRT).

FIGURE 6.20 Losses on a distribution feeder with PV and without PV.

Generators with LVRT/ZVRT capabilities will not disconnect immediately during low or zero voltage conditions and instead will remain connected for a set time (typically a few cycles), giving the generator the chance to ride through the fault. The generator will continue normal operation if the fault is cleared before the generator disconnects.

6.4.2.7 Reduced System Inertia

Frequency control is a critical element of power system stability. For large and sudden changes to the generation/demand balance, as would be the case if a large generator trips, system frequency will begin to deviate from the target almost instantaneously, and well before any adjustments can be made by the EMS; this is the realm of primary frequency control, with immediate and autonomous responses of individual generators. There are two components of primary frequency control. The first involves the physical characteristics of the conventional generator and turbine mechanical system. Many conventional turbine generators have an inertia constant of 4 to 5 seconds, meaning that the kinetic energy stored in the rotating components of generator and turbine is equivalent to the rated output of the machine for that length of time. As system frequency and therefore generator speed begins to change, mechanical energy in the rotating components is either extracted (for declining frequency) or augmented (if system frequency is increasing) via the synchronous generator and the grid. The second element of primary frequency control is for large and sudden changes to system balance, where the frequency deviation and speed error will invoke responses from individual generators through governor speed control. PV generators do not have any moving parts and, consequently, the PV generators do not have inertia and are not capable of primary frequency control provided by conventional synchronous regulation, and this can have a negative impact on reliability and grid stability.

6.4.2.8 Unintentional Islanding

Islanding refers to the condition where DERs are isolated on a portion of the power system and operate as an "island" separate from the main power system. Islanding is often referred to as "loss-of-mains." Islanding can be either unintentional or intentional. Unintentional islanding has the following implications on electric power system operation:

1. Typically, the utility cannot control voltage and frequency at the customer in an islanded system (unless the system was specifically designed to operate in islanded mode, such as microgrids).
2. Islanding may create a safety hazard to utility workers and customers as the lines in the islanded system are still energized, whereas it is assumed otherwise.
3. Typically, the utility cannot control the DER and cannot always de-energize downed lines, which can compromise public safety.
4. Rotating machines in the islanded part of the system could be damaged when the island is reclosed out-of-phase to the main power system; out-of-phase reclosure can cause heating and mechanical stresses on generator shafts, enough to cause damage.
5. Islanding may interfere with manual or automatic restoration of normal service for the neighboring customers; if the island's frequency drifts away from that of the rest of the system, it must be brought back into synchronism before all connections can be restored.
6. The islanded system may not be adequately grounded. Unintentional islanding changes the topology of the system, which means the islanded portion may no longer have a correctly engineered ground return.
7. Protection systems on the islands are likely to be uncoordinated since the short circuit current availability and direction of flow change when the system is islanded.

The increasing penetration of DERs results in increasing difficulties in meeting utility anti-islanding requirements. The time interval in which islands must be detected and the DERs disconnected are often mandated by standards, such as the IEEE Standard 1547 for interconnecting distributed resources with electric power systems. The standards dictate maximum time frames in which the DERs (1) must detect an island and trip, and (2) describe test procedures that are designed to ensure that the DERs meet these requirements, but these test procedures often do not account for high-penetration scenarios in which the combined power generated by all DERs in the system is sufficient to support the load in an islanded system. In this scenario, many islanding detection methods fail in detecting the islanded state because the voltage and frequency at any given DERs in the islanded system are identical to the voltage and frequency before islanding occurs.

6.4.2.9 Power Quality

High-penetration levels of solar PV generation may result in excessive harmonics. Harmonic distortion in distribution systems predominately originates from loads in which the current is not linearly related to the voltage. However, harmonics can also be generated on the generation side. All distributed generation technologies that generate either dc or non-power frequency ac power must use an electronic power inverter to interface with the electric power system. The early thyristor-based, line-commutated inverters quickly developed a reputation for being undesirable on the power system. These inverters produced harmonic currents in similar proportion to loads. To achieve better control and avoid harmonic problems, the inverter technology has changed to switched, pulse-width modulated (PWM) technologies with high-switching frequencies, which do not produce low-order harmonics, which are of most concern on the power system. However, unexpectedly high harmonic levels have been observed in systems with a high penetration of inverter-based PVs. The reason for these high-harmonic distortion levels is unclear, but a possible explanation is that unstable or poorly designed inverter controls inject harmonics that are amplified by system resonances.

6.4.3 DER Opportunities for Distribution System Control

There are some potential benefits that DERs bring to distribution systems; many of them are facilitated by the introduction of advanced DER control and communication technology. Much of the discussion in the industry concerns “smart inverters” with advanced capabilities that can be used to optimize grid performance. However, most of these features can also be implemented, or have historically been available with non-inverter DER, such as rotating generators. Examples of how DER technology can be utilized to optimize the grid are discussed.

6.4.3.1 Volt/VAr Control

Smart inverters offer communication capability combined with reactive control capability that can be utilized for active voltage control on the system, thereby keeping voltage within permissible limits and reducing line losses. However, leveraging this technology has been, until recently, hampered by standards that do not permit DER to actively control voltage (see the previous section on standards). Also, the inability of the legacy infrastructure to accommodate PV inverters is in the way of taking full advantage of the new technology. Four-quadrant inverters are a classic example: though the device capability exists (and, indeed, is being used in Europe and China) for solar inverters to provide adjustable Volt/VAr services to the utility. Synchronous generators have always had controllable reactive power control capability and are frequently equipped with automatic voltage regulators.

Different smart inverter control strategies are currently contemplated, such as Volt/VAr and Volt/Watt control curves, or regulating the reactive power flow by setting the power factor to a certain value. For instance, smart inverters that use a Volt/VAr curve provide reactive power injection/absorption through autonomous responses to local voltage measurements. The Smart Inverter Working Group (SIWG) proposed a default Volt/VAr curve that is shown in Figure 6.21 where the percentage of voltage (with respect to a reference voltage V_{ref}) determines the percentage of reactive power (with respect to the available reactive power VAr_{avail}). Furthermore, the SIWG proposes

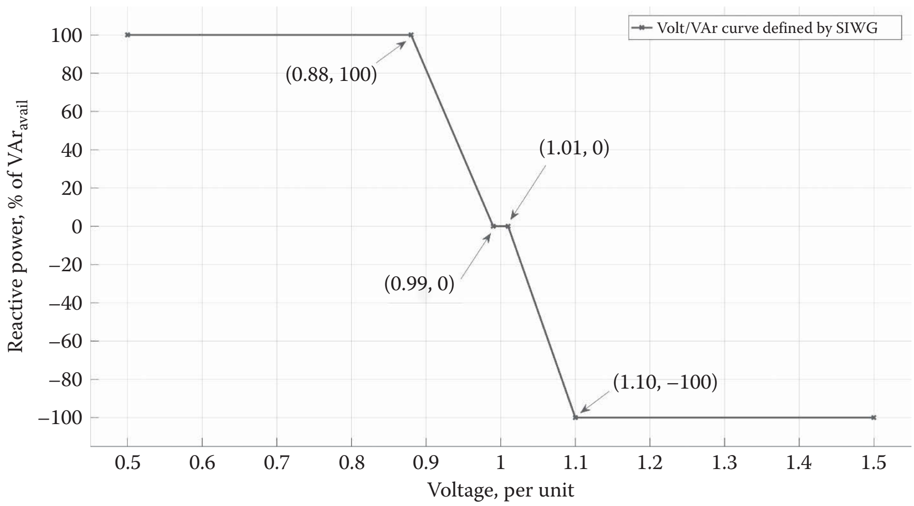

FIGURE 6.21 Volt/VAr curve defined by SIWG.

default settings for the decrease VAr Ramp Rate Limit ($VRRL_{decrease}$) (fastest allowed decrease in VAr output in response to either power or voltage changes), the increase VAr Ramp Rate Limit $VRRL_{increase}$ (fastest allowed increase in VAr output in response to either power or voltage changes), and the Randomization Interval (mode or setting changes of each inverter is to be made effective at a random time during the randomization interval) as follows:

- $VRRL_{decrease}$: 50% of VAr_{avail}/second
- $VRRL_{increase}$: 50% of VAr_{avail}/second
- Randomization Interval: 60 seconds

The effect of the ramp rate limits and the randomization interval is that sudden large changes due to inverter control actions are avoided by curbing the VAr injection/absorption over time and randomizing when control actions from individual inverters are issued.

Smart DERs can also enable Conservation Voltage Reduction (CVR), thus reducing system losses and managing system peak demand. With present systems, CVR and load management are difficult because of the variations in system impedance and loads and because each phase can have different levels of load and installed DER.

6.4.3.2 Detection of Unintentional Islanding

As increasing numbers and types of distributed generation are connected to utility systems, distribution engineers face rising concerns on the formation of unintentional islands. Low-cost islanding detection techniques, such as passive detection, can be employed, but their reliability is in question—for typical scenarios in which multiple DERs are in the system. The most reliable forms of islanding detection are remote methods that monitor the system breakers, and when any of them open, signal the appropriate DER to disconnect from the power system. Many new multifunction DER products feature two-way communications that can be used for anti-islanding purposes, and any sensing equipment and control options the utility selects to be included in the devices can be used to sense possible islanding conditions and shut down the DER. The availability of a communications infrastructure may be the greatest impact that smart grid deployments have on anti-islanding; if the cost of communications infrastructure is incurred for a smart grid deployment, the communications infrastructure can be used for islanding detection as well. Methods in which the DER monitors the breaker status and trips offline if necessary are the most direct way of using a communications infrastructure for remote islanding detection. Methods in which the control center monitors the breaker status via SCADA and the control center sends out the order for the DER to trip offline are another approach to remote islanding detection, but it should be noted that the standard SCADA sampling rate is often too slow to meet the two-second window mandated by IEEE 1547-2003 for anti-islanding during which the DER is required to disconnect.

6.4.3.3 Microgrids

Microgrids are intentional islands that are created by purposefully sectionalizing a utility system. A microgrid is designed to autonomously operate when required with DER continuously supplying sufficient power to the loads, keeping voltage and frequency within required limits. Ideally, microgrids have the capability to disconnect seamlessly from the local utility and operate in islanded mode. However, a momentary interruption of the generation supply during the transition to islanded mode may be acceptable (and often unavoidable for practical reasons). Microgrids provide increased reliability during disasters among other benefits.

6.4.3.4 Controlling Ramp Rate

DER hosting capability on distribution feeders can be improved by implementing controls that limit the rate of change of variable DER (i.e., solar and wind) production (ramp rate limiting); this is easy to achieve as irradiance or wind levels increase, but harder to achieve during a cloud transient or a sudden wind decrease, when levels can drop sharply. Sky image forecasting could be used with PV as a method to curtail output when cloudy conditions are pending. The energy production loss, however, can be significant, and this approach may be less favorable than others to address the consequences of power variations. Some distribution-connected renewable generation plants (solar and wind) are composed of multiple generation units within the facility, connected to the utility via a collection system. The power plant may control the ramp rate of production so that if the sky forecasting shows an oncoming cloud, the system will automatically curtail production in anticipation of a cloud transient.

6.5 DISTRIBUTION GRID PROTECTION IN THE NEW SMART GRID ENVIRONMENT

It is critical to understand the effects of renewable generators on the grid to maintain reliable system operations and power quality when the penetration of these sources increases to a considerable scale. The fault contribution from renewable generators is an important piece of information for selecting equipment ratings and ensuring that protection schemes are coordinated properly. The fault contribution from renewable generators, particularly inverter-based renewable generators, is fundamentally different from the fault contribution from conventional generators, and much uncertainty exists regarding how to account for renewables when sizing equipment and setting protection relays. In the following subsections, we describe (1) an overview of protection systems, (2) the differences of fault contribution between inverter-based DER and conventional generation technologies, (3) their implications for utility operation, and (4) merits and demerits of conventional and advanced protection systems for modern distribution systems.

6.5.1 Overview of Protection

To provide proper protection coordination, a power system may be divided into several zones of protection. Each zone of protection has two types of protection provided—primary and backup protection. These zones are defined for generators, transformers, buses, lines, and loads. If a fault occurs anywhere within a zone, a remedial action is taken by the primary protection to isolate that zone from the rest of the system. Moreover, adjacent zones overlap each other to avoid any unprotected area and account for any circuit breaker failures. The backup protection may exist locally, or it may be provided by the primary protection of overlapping zones. The backup protection is always slower than the primary protection dedicated to a zone, and it only comes into action if the dedicated primary protection does not respond to faults in its region.

The following list provides main attributes of a protection system:

- Sensitivity: The ability of a protection system to detect and identify all fault events that it is supposed to detect.
- Selectivity: The ability to isolate a specific portion of the system that contains the fault (instead of the entire system).
- Speed: The ability to clear the fault from the system fast enough to avoid damages and to maintain stability.
- Accuracy: The ability to measure and calculate parameters that are a true representation of the real-time system operating conditions.
- Reliability and dependability: The ability of the protection system (1) to operate when it is expected to do so, and (2) to not cause false trips.
- Economy: Preferably, a protection system should be the least cost for the desired level of protection.
- Simplicity: Preferably, the design of a protection system should be "tried and true" rather than being unnecessarily complex.

A protection system consists of the following components [8]:

- Current transformers (CT): An instrument to measure current and reduce the current to a lower level suitable for input to a protection relay.
- Voltage transformers (VT): An instrument to measure voltage and reduce the voltage to a lower level suitable for input to a protection relay.
- Protection relays: A device that detects a system fault by measuring and monitoring input data from CTs and VTs, and sending trip signals to interrupting devices.
- Interrupting devices: These devices operate to isolate faulted sections of the grid from the unfaulted sections. These include circuit breakers (CB), reclosers, etc.

6.5.2 Fault Contribution from Inverter-Based DER and Other DER

The fault response of an inverter-based DER can be different for the time before fault detection and the time after fault detection as described below:

1. Immediately after a fault, the output current of the DER will increase for the first one or two cycles since the voltage on the distribution feeder will be reduced due to the fault and the inverter will try to maintain constant active and reactive power output. The initial fault response depends on (1) the residual voltage at the terminals, and (2) the pre-fault operating condition (active/reactive power output, wind speed), although, in principle, the fault current output during this time is between zero and the maximum current the converter can produce.
2. Upon fault detection, which usually occurs after one or two cycles, the fault current is determined by either (1) the pre-set fault ride through mode (if present), (2) a closed-loop terminal voltage regulation function, or (3) continuance of the pre-fault real power output to the extent possible in observance of inverter current limits. Either way, the new current set point is typically increased in response to the detected fault. For this time frame, the inverter behaves as a current-limited source during the fault. However, unlike a conventional synchronous or induction generator, the power factor angle of the injected current is controlled by the inverter and may be the same angle as in the pre-fault operation, or the reactive power may be increased by modes (1) and (2), as described above.

The behavior of three-phase inverters during unbalanced faults is complex and varies widely between different designs. Some designs inject only positive sequence current; other designs allow varying degrees of negative sequence current to flow. Almost all three-phase inverters do not allow zero-sequence current flow in or out of the inverter itself, but the interconnection transformer may contribute zero sequence current depending on its winding connection. PV generators, unlike other types of DER, have a Maximum Power Point of Tracking (MPPT) algorithm, which adjusts the operating point of the solar cells to deliver maximum power based on the irradiance, albeit this control feature does not have an impact on the short-circuit characteristics of PV generators once the fault is detected and the fault current is controlled by the inverter.

6.5.3 Protection Challenges in DER-Rich Distribution Systems and Microgrids

Traditional distribution systems in the USA are radial, that is, power is generated at large power plants located on the transmission system and is supplied to feeders via a substation; this allows for relatively simple protection schemes because of the unidirectional flow of power (i.e., from the substation downstream to the fault location). Consequently, it is a common practice in the USA to install inverse overcurrent protection relays at distribution substations, reclosers at main distribution feeders, and mechanical fuses on feeder laterals. The same simple strategy cannot be applied to modern distribution systems with significant amounts of DER and for microgrids since the direction of power flow and fault current can be in either direction. Furthermore, in such systems, the directions and the levels of short-circuit current depend on the configuration and operation mode (grid-connected or stand-alone/island). In the case of the stand-alone mode operation of microgrids, the total short-circuit current is relatively small due to limited source capacity (fault current is only provided by the DER, and inverter-based DERs, such as PV, typically have low short-circuit currents compared to rotating machines). Therefore, conventional schemes are likely to fail in detecting and isolating faults when there is unintentional islanding, or a microgrid operates in stand-alone mode. Specific protection challenges associated with increased DER penetration are reviewed in the following sections.

6.5.3.1 Increase in Fault Current

If a fuse is located on a distribution feeder lateral and a fault occurs downstream from the DER/DG and the fuse, then fault current from both the grid and from the DER will feed into the fault, which can interfere with fuse-saving protection schemes because, in this scenario, the fuse may operate before the recloser can protect it. Figure 6.22 illustrates such a scenario.

6.5.3.2 Reduction of Fault Current

If the DER is located downstream from the overcurrent protection device and the fault occurs downstream, then fault current detected by protection relay may be reduced resulting in a reduced zone of protection and desensitizing of relays, and the relay may not trip for these lower detected fault currents, depending on the relay current setting. In some cases, depending on the type of fault, there

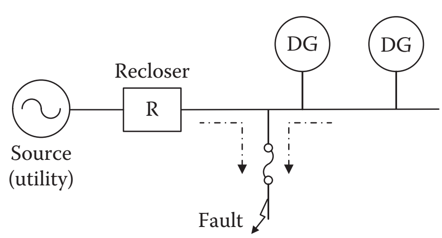

FIGURE 6.22 DER infeed to a fault can operate the fuse before the recloser can protect it.

may not be any change in the current level at the protection relay during a fault if most of the fault current is supplied by the DER. Figure 6.23 depicts such a scenario.

6.5.3.3 Sympathetic Tripping

Sympathetic tripping is when overcurrent protection devices on unfaulted feeders operate due to faults on adjacent feeders fed from a common source (Figure 6.24). If one of the unfaulted feeders has a significant penetration of DER with a relatively high short-circuit contribution, then the overcurrent relay on the unfaulted feeder would see the fault current from the DER and may trip. However, this can only occur if all of the following conditions are met: (1) the fault current contribution from the DER is sufficiently high so that it can cause the overcurrent relay to trip, (2) the overcurrent relay on the healthy feeder with DER is not able to distinguish the direction of the fault current, and (3) the overcurrent relay on the healthy feeder is set to trip faster than the overcurrent relay on the feeder with the fault. The overcurrent protection coordination on the faulted feeder must account for the increase in fault current.

6.5.3.4 Anti-islanding

The increasing penetration of DER results in increasing difficulties in meeting anti-islanding requirements, which the DER has to meet before connecting to the utility. The time interval in which islands must be detected and the DER disconnected are often mandated by standards, such as the IEEE Standard 1547 for interconnecting distributed resources with electric power systems. The standards dictate maximum time frames in which the DER (1) must detect an island and trip, and (2) describe test procedures that are designed to ensure that the DER meets these requirements, but these test procedures often do not account for high penetration scenarios in which the combined power generated by all DERs in the system is sufficient to support the load in an islanded system. In this scenario, many islanding detection methods fail in detecting the islanded state because the voltage and frequency at any given DER in the islanded system are identical to the voltage and frequency at the DER before islanding occurs.

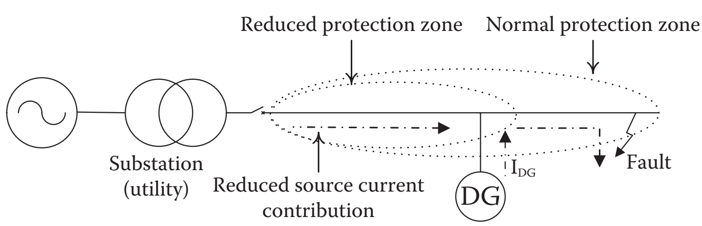

FIGURE 6.23 DER infeed to a fault can limit the fault current detected by an overcurrent relay.

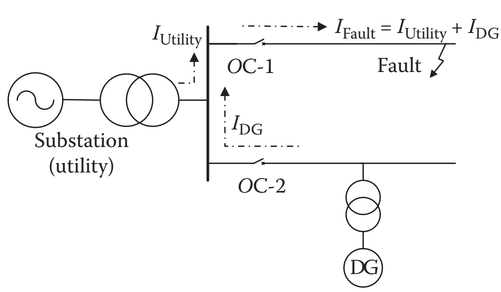

FIGURE 6.24 Fault on an adjacent feeder can cause sympathetic tripping of protection on a PV feeder.

Sandia National Laboratory (SNL) in its 2012 report "Suggested Guidelines for Assessment of DER Unintentional Islanding Risk" suggests a methodology for determining if islanding is a concern for a specific system. This methodology is based on (1) comparing the aggregate ac rating of all DER and the minimum feeder loading, (2) comparing the total reactive power of the PV and load with the total aggregate capacitive rating within the island, and (3) comparing the sum of all rotating machine a.c. ratings of the DER with the sum of all inverter-based DER.

6.5.4 Protection Needs for Modern Distribution Systems

This section describes available and proposed protection schemes for modern distribution systems with DER-rich feeders and microgrids.

6.5.4.1 Overcurrent Protection

A conventional generator produces current during low-impedance short circuits and ground faults that are several times the normal load current. The magnitude of this excess or overcurrent is used for identification of faults in overcurrent protection schemes [9]. Overcurrent protection is used to protect almost all types of power equipment, such as transmission lines, distribution feeders, transformers, generators, reactors, capacitor banks, motors. As discussed earlier, inverter-based DER may not produce fault currents that are sufficiently high for overcurrent protection schemes to work properly.

Figure 6.25 shows protection of a feeder using measuring devices (CTs and VTs), protection relays, and interrupting devices. The most common type of protection function on a distribution system is the detection and isolation of high currents (overcurrents). A fault on the feeder will cause a proportional increase in current, which the CTs measure and the CT measurement is monitored by the protection relay. The relay logic evaluates this information and decides whether or not a fault exists. Upon fault detection, the relay sends a command to a CB (circuit breaker) to open its contacts to de-energize the faulty portion of the feeder from the distribution system.

Overcurrent relays are classified into the following three groups, and their characteristics are depicted in Figure 6.26.

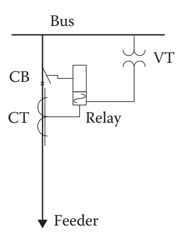

FIGURE 6.25 Basic overcurrent protection scheme for a feeder.

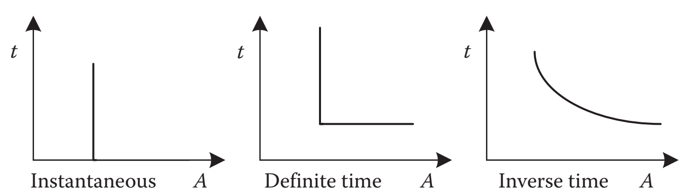

FIGURE 6.26 Characteristics of overcurrent relays.

- Instantaneous: The relay operates as soon as it detects a fault current that exceeds preset threshold (i.e., no intentional delay).
- Definite time: The relay operates after detecting fault current for the prespecified duration of time.
- Inverse time: The relay operates based on a time-current curve. Faults with large currents are isolated quicker than less severe faults.

Based on the ability to detect the direction of the fault, overcurrent protection can be divided into two types of detection—non-directional overcurrent and directional overcurrent.

6.5.4.2 Non-Directional Overcurrent Protection

Non-directional overcurrent relays are widely used in traditional distribution systems due to their simple schemes, lower cost, and easy coordination with other protection devices. However, their employment in the modern distribution system environment comes with some advantages and challenges.

Advantages

- Application of non-directional overcurrent relay schemes is simple for traditional distribution systems.
- Schemes require a small number of instrument transformers as each overcurrent relay needs measurement input from only one current transformer.

Disadvantages

- Non-directional overcurrent relays may result in unwanted tripping in microgrids, parallel lines, and circuit loops since the direction of fault currents depends on the fault location in these configurations.
- Fault currents may be too low for overcurrent relays to detect if generation comes primarily from inverter-based DERs because converter based sources have limited capacity to produce fault currents.
- A significant amount of DER on the feeder may render overcurrent protection schemes ineffective due to a reduction of sensitivity as the sensitivity of an overcurrent relay depends on the fault current measured by the relay. The measured fault current may be lower than the expected fault current when a fault occurs downstream of a point where a DER is connected, and the relay is installed near to the source substation. In such a situation, sources of the fault current are both DER and substation whereas current through the relay is only of the substation.
- The coordination of overcurrent relays will be difficult in DER-rich distribution systems and microgrids because the direction and level of the fault current will keep on changing based on the type, number, and configuration of active DERs. The coordination of overcurrent relays in traditional distribution systems is much simpler because the fault current is unidirectional and the fault current reduces predictably the farther the fault location is from the substation [10].

6.5.4.3 Directional Overcurrent

The need for directional overcurrent relays arises in the non-radial system (parallel lines, loops, and doubly fed circuits). In this protection scheme, overcurrent relays respond to fault current only when it flows in a particular direction. The directional feature in overcurrent protection is provided by adding a voltage phasor measurement (directional element) in the protection scheme [11]. Thus, both CT and VT measurements are needed to implement a directional overcurrent scheme [12].

Assume a load at B is fed from two sources (feeders or substations) A and C (Figure 6.27). Fault current will flow through circuit breaker CB3 for faults in section AB or BC. However, for proper protection, CB3 should only operate for faults in section BC; this is ensured by adding a directional feature to the relay associated with CB3 (and CB2 in the similar case for a fault in section AB).

Directional overcurrent relays are usually installed in transmission systems. In DER-rich and microgrid environments, they have the advantage of identifying fault direction. This information may be employed to prevent unwanted tripping, which is a challenge with using non-directional overcurrent relays (as discussed in the previous section). However, directional overcurrent relays still have limitations:

Advantages

- Can distinguish the direction of flow of current. This information may be added to the protection logic to prevent unwanted tripping in parallel lines, loops, and microgrids.

Disadvantages

- Like non-directional overcurrent relays, fault currents may be too low for directional overcurrent relays to detect if generation comes primarily from inverter-based generators.
- A substantial amount of DER on the feeder may render overcurrent protection schemes ineffective due to a reduction of sensitivity when a fault occurs downstream of a point where a DER is connected.
- The coordination of overcurrent relays will be difficult in DER-rich environments because the level of the fault current will keep on changing based on the type, number, and configuration of active DERs in the system.
- The protection scheme requires an additional VT measurement, which makes it a relatively expensive scheme for distribution systems due to a large number of protection relays on the distribution system.
- Using a voltage measurement (voltage polarization) for directional measurement becomes unreliable when faults are close to the relay since the fault reduces the voltage on the feeder, which can be the case for small microgrids [13].

Researchers [14–18] have proposed DER-rich distribution system and microgrid protection schemes based on overcurrent protection. However, additional resources, such as flywheels, batteries, and communication links, were needed in the proposed schemes. These other resources increase the fault current during stand-alone mode and frequently update relays settings according to the active DER connections and the configuration of the microgrid.

6.5.4.4 Distance Protection

A distance protection scheme is based on the calculated impedance value between the point of fault and location of the relay. It is also referred to as impedance protection and is traditionally used for protection of transmission lines.

In this scheme, current (I) and voltage (V) are measured at the relay location using a CT and a VT. The ratio of voltage to current ($Z = V/I$) is compared with a predefined value of impedance.

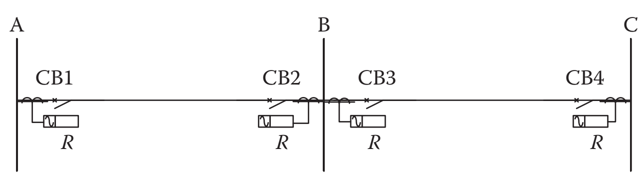

FIGURE 6.27 Principle of directional overcurrent protection.

During a fault on a line, current in the line increases resulting in a lower voltage-to-current ratio. When the measured voltage-to-current ratio decreases to below the preset impedance threshold, the relay issues a trip command to the circuit breaker. The predefined value of impedance is calculated based on known line parameters. Figure 6.28 shows the characteristics of a distance relay on the *R*–*X* plane. A measured impedance value within the circle represents the operating region for the relay.

Two other types of distance relays are also used in power system protection, namely, reactance relays and mho relays. The reactance relay operates based on the measured reactance and its preset value. Similarly, mho relays are based on the measurement of admittance. Typical characteristics of reactance and mho relays are depicted in Figure 6.29.

Impedance relays do not possess directional property because their operating characteristics are based on a circle with the center at the origin that represents both positive and negative values of *R* and *X*. These values are independent of direction and, consequently, impedance relays are inherently non-directional. Similarly, reactance relays are inherently non-directional because their operating characteristics lie on a horizontal line parallel to the *R*-axis, and the relay operates for *X* lower than a preset value, even when it is a high value in the reverse direction. In contrast, mho relays are inherently directional because they have characteristics only on the first quadrant on the *R*–*X* plane. Impedance and reactance relays can also be constructed as directional by adding a directional element to them.

Distance relays are widely used in transmission networks with three to four zones of protection. They offer advantages of better selectivity, sensitivity, speed, accuracy, and directionality for traditional systems. These features can also be advantageous for distribution system protection with high DER penetration and microgrid protection and, indeed, researchers [19–22] have suggested methods to recognize faults of microgrids in its operation by using distance relays. However, it is our opinion that there are certain advantages and limitations when using distance protection in a distribution system/microgrid environment, as described below.

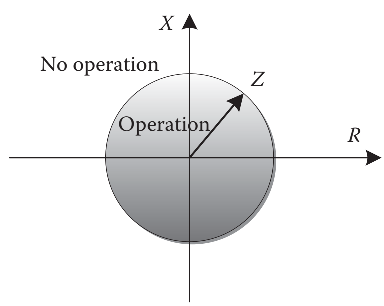

FIGURE 6.28 Typical characteristic of the distance (impedance) relay.

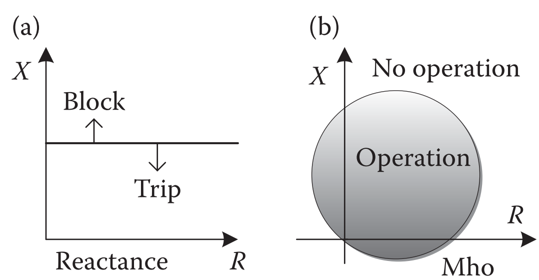

FIGURE 6.29 Typical characteristic of reactance (a) and mho (b) relays.

Advantages

- Higher sensitivity, selectivity, and accuracy compared to overcurrent relays.
- Directionality.
- Faster operation compared to overcurrent relays in its zone of protection.

Disadvantages

- Accurate measurement of impedance by distance relays is challenging in small microgrids that operate at the distribution-level voltage and that have a high penetration of inverter-based DER. The measured impedance of a distance relay depends on the voltage and current from instrument transformers (CTs and VTs). As the line length decreases, the voltage at the relay is very low during a fault, and inverter-based sources in the microgrid have limited capacity to produce fault currents. Consequently, the accurate operation of distance relays is inhibited when the microgrid operates in stand-alone mode. This problem is exacerbated further if a DER is present between the relay and fault point. In such a scenario, the expected fault current is not the same as current measured at the relay and, consequently, the accuracy of the relay is compromised [19].
- Higher total harmonics distortions are expected in microgrids operating in stand-alone mode due to (1) the higher source impedance (i.e., the "stiff" utility grid that provides a low-impedance source is disconnected), and (2) inverter-based DERs potentially injecting high-order harmonics. The accuracy of distance relays can be compromised in an environment with high harmonic distortion levels [19].
- The mostly inductive line impedance (for overhead lines), which is a crucial parameter in distance protection schemes, is a relatively small portion of the total impedance measured by the distance relay as the measured impedance also includes the (mostly resistive) fault impedance [11].

6.5.4.5 Differential Protection

Differential protection schemes utilize the fact that a fault changes the balance between current entering the faulted system and current leaving the system ("protection zone"). This protection scheme requires the application of CTs at each end of the protection zone.

Figure 6.30 illustrates the basic function of differential protection. During normal operation of the protected zone, with a fault external to the system, there is no difference in currents measured at each end of the zone. However, an internal fault in the protected zone results in a difference of currents. An overcurrent relay can measure this difference of currents. Similarly, other differential protection schemes also exist in which voltage is compared between the two ends of the zone.

The following provide the merits and drawbacks of differential protection for DER-rich distribution systems and microgrids.

Advantages

- Simple
- Fast operation

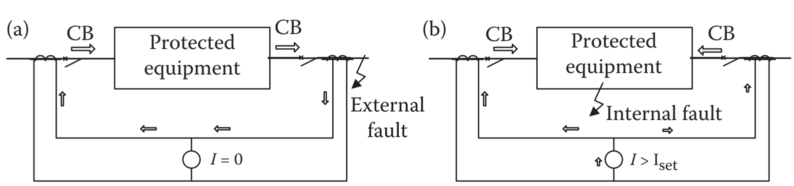

FIGURE 6.30 Differential protection scheme: external fault (a) and internal fault (b).

- Defined zone of protection.
- Operation independent of the direction of flow of power.
- Independent of fault current capacity of DERs.

Disadvantages

- Communication infrastructure required for feeder protection.
- Backup protection necessary to avoid problems when communication system is not available.
- Relatively expensive due to the need of communication infrastructure and sensing instruments at each end of the feeder.

Due to the advantages, this scheme is commonly applied to the protection of transformers, generators, motors, busbars, and sometimes feeders. On the same grounds, the literature [23–28] has proposed various protection designs for microgrids based on differential schemes. Since these schemes are independent of power flow direction and absolute values of current, they resolve modern distribution system protection challenges associated with bidirectional power flow, meshed configuration, varying fault current level due to the intermittent nature of DERs, and reduced fault current levels in an islanded mode of microgrids. However, a reliable and fast communication link is essential for the application of these schemes on feeders as the measurements from each end of the protection zone must be brought together to calculate the difference. Additionally, an appropriate time synchronization of current phasors is also needed to avoid the false differential currents due to communication delays. Furthermore, a backup protection scheme is also required to ensure the reliable operation of the system when the communication link is not available. Moreover, some differential relays shall be needed to cover the whole area of microgrids in a system consisting of several DER connections. This requirement is based on the condition that no load or source should be present between two ends of a line protected by the differential scheme. Albeit differential protection can deal with most, if not all, technical challenges of microgrid protection, the requirements make differential schemes relatively expensive.

6.5.4.6 Adaptive Protection

Some adaptive protection schemes for DERs and microgrids have been proposed in the literature [16,29–31]. In these schemes, the settings of the relays are adjusted in real time by external signals according to the distribution system configuration, the number of active DERs, and operation mode of the microgrid.

Adaptive protection schemes fulfill the needs of modern distribution system protection as they provide the flexibility of adjusting protection settings based on system changes (stand-alone mode vs. grid-connected mode) and generation changes (changing generation levels of variable DER). However, there are some merits and demerits of adaptive protection schemes summarized as shown below.

Advantages

- Adjustable protection settings can deal with changing DER-rich and microgrid environments.

Disadvantages

- Adaptive protection may require the upgrade and update of already installed protection devices and software since all relays must be microprocessor-based and software must be available for modeling and coordination of the relays.
- All configurations, operation modes, and their corresponding fault levels must be known to select a setting that meets the protection needs for all possible system/generation conditions. This requirement involves extensive and complex calculations due to (1) many possible operating conditions and configurations of microgrids, and (2) uncertainties regarding the fault contribution of inverter-based DER [19].

- A communication infrastructure is required to dynamically update relay settings based on the actual (or forecasted) system/generation condition [32]. This requirement makes this solution relatively expensive.
- Some of the proposed adaptive schemes require a central protection or control device to communicates with all relays and distributed generations to record their data (e.g., status, rated current, fault current contribution), update relay settings, and detect the direction of fault current. Such frequent monitoring and control of all the assets might lead to exchanges of large amounts of data and, consequentially, a high burden on the communication system.

6.5.4.7 Voltage-based Protection

Voltage measurements and analysis may be employed to detect various modern distribution system faults. In voltage-based protection schemes, the measured voltage is analyzed by its sequence components, peak component, or by d-q (direct-quadrature) reference frame transformation [33–36]. The advantages and disadvantages of voltage-based protection schemes in are summarized as shown below.

Advantages

- Ability to differentiate between (1) in-zone and out-of-zone faults and (2) grid-connected and island mode faults.

Disadvantages [19]

- Voltage-based protection schemes are highly dependent on the individual distribution system/microgrid configuration since the analyzed voltage is highly dependent on system characteristics, such as line lengths, conductor types, and connections. Consequently, each distribution system requires a highly customized protection scheme (more so than overcurrent protection schemes).
- The possibility of false trips due to voltage drops during normal operating conditions.
- Difficult to detect high impedance faults inside the system as they only result in a small voltage change.
- Less sensitivity in the grid-connected operation mode of microgrids because the "stiffer" system results in a smaller voltage variability during a fault.

6.5.4.8 Time-Domain Protection

The sinusoidal shape of voltage and current is distorted for a few cycles following the inception of a fault. The detection of these transients and their observed relative timing is the basis of time-domain protection schemes [37]. Time-domain-based relays use traveling-wave and incremental quantity principles to identify faults [38]. Figure 6.31 shows the two-step process involved in these schemes. The first step is the signal acquisition in which analog signals of line voltage and current are converted into suitable digital signals at a high sampling frequency (MHz). The second step is related to signal processing (e.g., wavelet transform) and analysis in which traveling waves are identified from normal signals.

Time-domain protection is proposed in the literature as a future protection scheme with advantages and disadvantages.

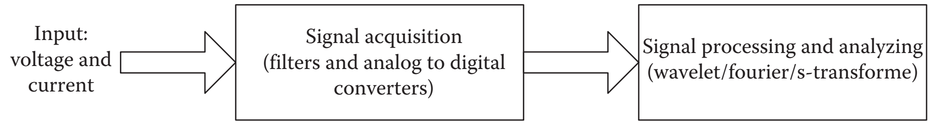

FIGURE 6.31 Time-domain relay function.

Advantages [39–42]

- Ultra-high-speed.
- The direction of fault can be distinguished.
- May help in identification of the fault location.
- Differentiate internal and external faults by using devices at the both terminals of a line.
- Not affected by unbalanced load.
- Not affected by microgrid operation mode.

Disadvantages

- Not fully developed/unproven technology.
- Require high-fidelity instrument transformers to measure traveling waves [38].
- Require high-sampling rates, data storage, and signal computational processing power [38].
- Fast communications capabilities needed to distinguish between internal and external faults.
- Might not be practical for small systems.

Considering all the benefits listed above, time-domain protection is an enticing but expensive, solution—particularly for DER-rich distribution system and microgrid protection. However, this technology is not fully developed yet, and to our knowledge, no information on the real-world application and performance of time-based relays is currently available. We think that the applicability of time-based protection in small systems is in question as it might not be practical to resolve traveling wave reflections for comparatively small distances on a distribution system.

6.5.4.9 Grid Devices to Enhance Protection Functionality

The use of additional grid devices can help to enhance the functionality (or mitigate shortcomings) of protection schemes for DER-rich distribution systems and microgrids [43–45]. The idea is to increase the short-circuit current in the stand-alone mode of inverter-based microgrid by using additional grid energy resource devices, such as batteries and flywheels, thereby mitigating the need for entirely different protection schemes for each microgrid operation mode.

In the case where a high penetration of DERs in the distribution system increases the fault current close to the ratings of protection devices, current limiting devices can be employed to help reduce the fault current, thereby avoiding the need to upgrade protection schemes.

The following summarizes the advantages and disadvantages of protection schemes with the use of external devices.

Advantages

- Same protection scheme may work for both island and grid-connected operation of microgrids.

Disadvantages

- Investments are needed for external devices.
- Additional technology is required to detect the change in the modes of a microgrid. Hence, protection solutions using additional grid devices can become costly [19].
- Fault current limiters generate extra power losses in normal conditions.

6.5.4.10 Conclusion

A DER-rich and microgrid environment poses some challenges to protection system design due to the varying nature of fault levels and the direction of power flows. We reviewed and discussed the suitability of available and noteworthy proposed protection schemes to tackle these challenges. All schemes have limitations with regards to selectivity, sensitivity, reliability, and economy.

Overcurrent protection by itself may not be a feasible solution for providing reliable protection in a modern distribution system. Differential and adaptive protective schemes have the potential to meet the needs of future system protections, but call for substantial investments in additional sensors, more advanced protection relays, and reliable communications infrastructures. Advanced, and mostly experimental, protection schemes, such as time-domain-based protection, have the potential to be a viable option for future distribution grid protection, but their real-world applicability is yet to be determined. As the smart grid evolves, modern distribution grid protection schemes will move away from basic, single-function schemes to more complex combinations of traditional and new protection schemes.

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7 Automatic Restoration Systems and Outage Management

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CONTENTS

Transmission grids are typically well monitored in real time by Supervisory Control and Data Acquisition (SCADA) systems due to their high levels of power transfer critical to the operation of the grid. An outage of a transmission line or transformer would affect many customers and may lead to other operating issues on the grid, such as voltage instability and cascading outages. The business case to include remote monitoring and control capabilities further down the distribution system closer to the customer depends on various factors, such as the criticality of the loads and the time required to restore power in remote locations. With a large number of distribution feeders and substations than transmission lines and substations, the number of sensors and monitoring and control devices required for distribution systems is far greater than that for the transmission system. For this reason, most utilities have limited monitoring and control capabilities across their distribution systems, using SCADA for monitoring and control of their main, large distribution substations. With limited visibility of the operation of the distribution feeders all the way down to the customer interface, utilities typically only become aware of distribution system power outages when they receive trouble calls from their customers. With the more widespread use of smart meters and advanced metering infrastructures (AMIs), utilities now have the capability to receive outage notifications automatically from the smart meters without the customer having to report the outage.

When a fault occurs in the system, it is detected, interrupted, and isolated by a protective device such as a fuse, a recloser, a pulsecloser, or a circuit breaker with protective relaying. In addition to faults, other reliability-related issues arise in the normal day-to-day operations of a distribution utility, such as the failure of key distribution system assets, power quality issues caused by utility and customer equipment, and protection device miscoordination. Automatic restoration systems today usually begin when a protective device has locked out due to a persistent fault, regardless if it was caused by equipment failure, external hazards, such as vehicle-hit-poles, or weather. Some protective devices can automatically reclose a few seconds after interrupting the fault in order to attempt to automatically restore power in the case of transient faults that clear by themselves (such as a tree branch on a line that falls or burns away), resulting in only a momentary outage lasting less than 1 min. In the case of a persistent fault, the protective device will not successfully restore power and "lock out," resulting in a sustained outage. The utility system control center then dispatches a trouble crew to the field. The crew first needs to find the precise fault location, usually by driving down the affected feeder, and then investigate the fault and ensure that it is safe to perform any restoration work in the field, sometimes during extreme weather conditions, or at night. In cases of more severe faults, the crew performs manual switching in the field to isolate the faulted section and restore power to customers who are not directly supplied to the faulted section. Restoring power to customers after an outage may take several hours to complete, depending on how quickly customers report the power outage and how easy it is for the crew to locate the fault and conduct the power restoration [1]. Thus, one of the main drivers for smart distribution systems is the possibility to minimize the outage time and enhance and optimize the reliability of the distribution system, which is being pushed strongly by utility regulatory bodies, such as the U.S. public utility commissions (PUCs).

With the recent push in smart grid, utilities have deployed more feeder switching devices with intelligent electronic controls for automation, protection, and control applications. Together, the electronic control and its software algorithms are often referred to as an intelligent electronic device (IED). The IED measurement, monitoring, control, and communication capabilities make it practical to implement automated circuit restoration applications. IED data can be transmitted via communications between the IEDs themselves or back to a substation computer or a control center. However, the common objective is to reduce power outage frequency and duration, which results in the system reliability being improved significantly. For this chapter, all systems will be referred to categorically as automatic restoration systems. Although the objective is common, that being to restore electric service to as many unfaulted sections of the power system as quickly as possible, the restoration applications that provide this benefit are known by different names: self-healing systems; fault detection, isolation, and restoration; and fault location, isolation, and service restoration (FLISR). These reliability improvement applications can be implemented in several ways. Automatic restoration systems can be implemented autonomously in the field by devices on the distribution system or can be part of centralized outage management system (OMS) that utilities use to monitor and manage outages on the distribution system.

Automatic restoration systems have been proven effective in improving reliability as it is typically measured, which is average sustained outage frequency and duration per customer. As smart grid technologies evolve and more distributed energy resources (DERs) are connected to the distribution system, the challenges of bidirectional overcurrent, momentary outages, voltage sags, and other power quality issues become more apparent. Equipment monitoring and diagnostics are key technologies that will be significant in the smart grid due to their capability to prevent, and potentially to predict, the failure of assets vital to the operation of the distribution system. Power electronic devices for distribution system control and DER interfaces are gaining more attention due to their capability to reduce power quality issues. Adaptive protection schemes will also play a key role in modifying the substation and feeder IED protection and control settings in real time for the optimal device and system performance during faults, especially if advanced restoration functions include islands or microgrid configurations.

7.1 FAULTS ON DISTRIBUTION SYSTEMS

Faults that occur on distribution systems can be linked to a partial or complete failure of electrical insulation of power system equipment or external causes, such as trees, animals, storms, and human interference. The electric fault results in an increase in current, causing much stress on the overhead conductors, underground cables, transformers, and connectors along the feeder. Of the faults that occur on medium-voltage overhead networks of utilities across the world, approximately 80% of the faults are transient (temporary), of which 80% of those transient faults involve only one phase to ground [2].

Most distribution feeders today are radial in nature, meaning that power flows in one direction, from the distribution substations out to the loads. Most feeders have a three-phase main line, which forms the backbone of the power delivery system, and are protected in the substation by a circuit breaker. It is typically an overhead line, which allows for easier fault location and repair, but is more susceptible to temporary faults. Single-phase and three-phase laterals, both overhead and underground, are fed from the main distribution line and are typically protected by fuses or reclosers for fault isolation. Single-phase and three-phase sectionalizers and reclosers for overhead circuits, as well as underground fault interrupters, could also be used on the laterals where heavy loads are connected. A fault on the main line causes the substation circuit breaker to operate to isolate the fault. If automatic reclosers or sectionalizers are also used on the main line and a fault occurs downstream from one of those devices, then the fault can be isolated to the downstream portion of the feeder only.

Due to the radial nature of most distribution systems today, no backup source is available, so customers are susceptible to a power outage even when the fault occurs several miles away. A basic grid is formed when the capability to transfer loads to adjacent circuits is added. A smart distribution grid emerges when the switching points between circuits, as well as several points along each circuit, have the intelligence to reconfigure the circuits automatically after an outage occurs, either autonomously themselves or when receiving control commands from a substation computer or a control center. More intelligent switching points yield more options to reroute power to serve the load, and communication between or to those points makes fully automated restoration systems a practical reality.

Thus, in the future, it is envisioned that the distribution system will be more meshed than radial, especially when considering the connection of distributed generation and energy storage systems, which means that multiple sources will be connected to the same load centers. Changes in the operation of the distribution grid with smart technologies will be a significant technical challenge in maintaining reliability and managing outages. Automation and protection functions become more intertwined instead of being separate silos of control. Advanced protection schemes, along with advanced sensing and high-speed communications, will be required to quickly isolate a distribution fault and restore unaffected customers.

7.2 DRIVERS, OBJECTIVES, AND BENEFITS OF AUTOMATIC RESTORATION

The major drivers for automatic restoration systems and other similar initiatives are improved reliability, enhanced system operation, and improved system efficiency. These factors all contribute to restoring unaffected customers faster after a disturbance, reducing the number of affected customers significantly, thus increasing customer satisfaction. The improved reliability is tied directly to utility operating metrics. In most cases, utilities are under pressure from regulatory bodies and their customers to improve reliability, and reliability metrics are used to measure distribution circuit performance. The main reliability indices that are predominantly used throughout the world are variations of the following Institute of Electrical and Electronics Engineers (IEEE) Standard 1366 metrics [4]:

- System Average Interruption Duration Index (SAIDI) = Sum of all customer interruption durations/Total number of customers served
- System Average Interruption Frequency Index (SAIFI) = Total number of customer interruptions/Total number of customers served
- Momentary Average Interruption Frequency Index = Total number of customer momentary (typically less than 5 min or less than 1 min in duration, depending on the utility) interruptions/Total number of customers served

The majority of the world uses the IEEE reliability indices per the standard, or indices calculated in a similar way, but with a different name. Some other metrics used by utilities worldwide include the average cost per outage, the total energy not supplied, the number of customer interruptions, the total customer minutes of interruption, and the average interruption time. It should be noted that each utility may define its metrics to assess reliability; that is, the IEEE indices are the closest thing to a standard on reliability but by no means the only metrics used.

The major benefit related to smart grid applications is the improvement in the reliability metrics, which ultimately results in an improvement in customer service. The need to meet goals related to the reliability metrics has motivated many utilities to install more automated switching devices out in the distribution system, which has reduced the duration of the outages due to the faster response time for the isolation of the fault and the restoration of the unaffected customers. With the installation of these devices as part of automated restoration systems, most utilities or regulatory bodies have established a target restoration time for fault disturbances, such as 1 or 5 min. In the future, the proliferation of more automated switching devices with communications and control capabilities will lead to even faster restoration times, leading to an even higher level of reliability. The automation of feeder switching devices also benefits other distribution automation applications. For example, the deployment of multi-feeder reconfiguration or load balancing schemes enables a utility to transfer load from one feeder or substation transformer to another feeder or substation transformer, in the cases of transformer failure or peak loading conditions.

Other methods that can be used to improve reliability include more frequent tree trimming programs, the deployment of faulted circuit indicators, and the deployment of reclosers and sectionalizers instead of fuses, as well as fuse-saving schemes to only interrupt customers for sustained faults [3]. Also, circuit topology and load density of distribution feeders have a large effect on the frequency of faults and, thus, the duration of outages. Longer circuits typically lead to more interruptions. Shorter circuits, especially urban networks that form a meshed network, have been found to be more reliable. Also, utilities with higher load densities tend to have better SAIFI indices [4]. These factors are a key issue for utilities because as city areas and suburbs expand, the circuits will get longer and, thus, become less reliable.

7.3 FEEDER SWITCHING EQUIPMENT

All automatic restoration systems have an element of physical switching hardware, electronic controls, and software algorithms. It is not possible to interrupt and isolate faults without a robust mechanical switch that is purposely designed for this application. For decades, fault interruption was accomplished by purely mechanical means, meaning no electronics or software was used or needed. Over time, utility operators desired remote visibility and control of the switching equipment, so electronics and communication technologies were added. For automatic restoration systems, electronic controls and software algorithms are a necessity. Not all automation restoration systems rely on communication between devices or back to the control center, but in the absence of such communication, the individual IEDs cannot coordinate their measurements or switching actions with other nearby IEDs. This section covers a variety of hardware devices and IEDs used in automation restoration systems.

7.3.1 Substation Circuit Breaker

A circuit breaker is a device typically located in the substation that can make, carry, and break currents under normal and short-circuit conditions [2] by opening and closing mechanical contacts.

Most distribution feeders have a substation circuit breaker as the most upstream protective device, feeding the medium-voltage conductor wires that leave the substation. For automatic restoration systems, each substation circuit breaker has a protection and control relay (IED) that can communicate with the local substation automation devices, transmitting data and receiving control commands. Many circuit breakers today contain vacuum interrupters with magnetic actuators to operate a drive shaft, with encapsulated contacts for protection from the weather and external elements. Figure 7.1 shows an example of a substation outdoor circuit breaker.

7.3.2 Manual Disconnector Switch

A disconnector switch is a device that can make, carry, and break currents under normal conditions (not short-circuit conditions) by opening and closing contacts. Manual switches are typically located out on the distribution feeders, although some manual disconnect switches are deployed by utilities in distribution substations. Therefore, manual switches cannot be used in automatic restoration systems, only in manual restoration schemes when maintenance crews are dispatched to perform the switching. Most switches today contain air blade-type contacts that open and close in such a way that they give a visual indication to the maintenance crews.

7.3.3 Remotely Operable Load-Break Switch

A remotely operable load-break switch is a device typically located outside the substation that can make, carry, and break currents under normal conditions (not short-circuit conditions) by opening and closing contacts. Remotely operable switches allow for the utility operations department to

FIGURE 7.1 Outdoor substation circuit breaker. (© 2012 ABB. All rights reserved.)

operate the switches via communications from the control room or the substation, typically through a SCADA system or a substation computer interface. For automatic restoration schemes, each remotely operable switch has a control IED that can communicate with neighboring IEDs to perform local self-healing restoration. Most remotely operable load-break switches today contain either air blade-type contacts or vacuum interrupters with magnetic actuators as the operating mechanism. Figure 7.2 shows an example of an overhead load-break switch.

7.3.4 Automatic Sectionalizer

Automatic sectionalizers are essentially remotely operable load-break switches located out on the feeder with added intelligence in their IEDs. The sectionalizer cannot operate when carrying fault current. The added intelligence allows for a local control decision to be made based on local voltage and current measurements. The sectionalizer IED counts the number of overcurrent events and voltage drops when a fault on the connected feeder occurs. When the sectionalizer reaches its preconfigured count number, it opens during the dead time of an upstream circuit breaker in the substation or recloser outside the substation. Sectionalizers can be incorporated as part of automatic restoration systems that would typically allow for local control decisions to be made for the fault isolation, and subsequent restoration decisions made by a master device or peer as part of a multipoint communication scheme. It should be noted that in some cases, single-phase automatic sectionalizers are used on laterals to isolate a single-phase fault that may occur, so that the rest of the distribution feeder can remain energized.

FIGURE 7.2 Overhead load-break switch. (© 2012 S&C Electric Company, Chicago, IL. All rights reserved.)

7.3.5 Three-Phase Recloser

The three-phase recloser is a switch that can make, carry, and break currents under normal and short-circuit conditions. Like sectionalizers, automatic reclosers are also placed outside the substation out on the feeder.

The term "reclosing control" refers to the part of the functionality of a protection and control IED, where it can sense fault current and send multiple open and close control operations to a switch. A "recloser" is typically the term for the switch used on distribution feeders outside the substation, but "reclosing control" can also apply in the case of similar control of a circuit breaker in the substation.

A recloser protection and control IED is typically coordinated with the upstream substation circuit breaker relay and downstream recloser IEDs and fuses, to ensure that faults along each section of the feeder are isolated only by their closest upstream protection device. During the reclosing sequence, one or more fast trips are typically used to clear a temporary fault, followed by slower trips if the fault is permanent. Like sectionalizers, automatic reclosers can be incorporated as part of automatic restoration systems, which would typically allow for local control decisions to be made for the fault isolation, and subsequent restoration decisions made by a master device or peer as part of a multipoint communication scheme.

Many reclosers today contain vacuum interrupters with magnetic actuators to operate a drive shaft, with encapsulated contacts for protection from the weather and external elements. Figure 7.3 shows an example of a pole-top three-phase recloser.

7.3.6 Single-Phase Recloser

This device is a switch with a similar operation capability to three-phase reclosers, but it is a single-phase switch used on feeder laterals to isolate a single-phase fault so that the rest of the distribution feeder can remain energized. Utilities will often implement a "fuse-blowing" scheme that coordinates the operation of the substation breaker with the lateral fuse so that the fuse will isolate any downstream fault within its rating, and not rely on the breaker, which minimizes the number of power interruptions to customers. However, the customers may experience a prolonged outage if the fault is temporary. In a "fuse-saving" scheme, the substation breaker is intentionally set to

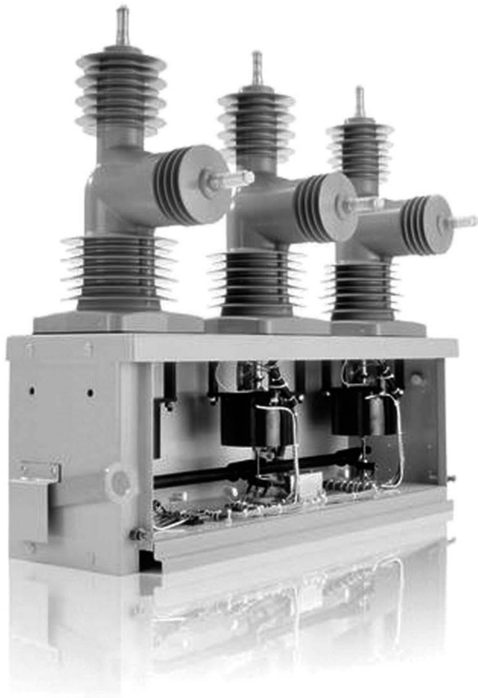

FIGURE 7.3 Pole-top three-phase recloser. (© 2012 ABB. All rights reserved.)

operate faster than the fuse to clear a temporary fault downstream of the fuse. Often, the fault will be cleared during the open time interval, so that when the breaker closes back in, service is automatically restored, and there is no prolonged customer outage. The second breaker trip and reclose cycle are slower so that, if the fault is permanent, the lateral fuse will operate to clear the fault and isolate that section. A downside is that all feeder customers experience a momentary interruption for a lateral fault when the breaker trips before the fuse, regardless if the fault is transient or sustained. Overall, this can have a negative impact on customer satisfaction because most faults occur on taps off the main lines. A single-phase recloser, used instead of a fuse, provides the best of both scenarios. The fast trip prevents a sustained outage for a transient fault, and the substation breaker is spared from any trips even if the fault is persistent.

7.3.7 Pulseclosing

After a conventional recloser or circuit breaker opens to interrupt a fault, it typically recloses into the fault several times to determine if the fault is still present. Pulseclosing is a relatively new technology for overhead distribution system protection that checks for fault persistence during operation without creating high-current surges that cause stress on the feeder. The pulsecloser device (Figure 7.4) very rapidly closes and reopens its contacts at a precise point on the waveform to send a very short low-current pulse down the line, then analyzes the pulse to determine the next course of action. If the pulse indicates a persistent fault, the pulsecloser device will keep the contacts open, wait for a user-configurable interval, and pulse again. This process can repeat several times until it determines that the line is no longer faulted. It then closes to restore service. However, if the fault persists for the duration of the test sequence, the pulsecloser device will lock out to isolate the faulted section.

Figure 7.5 shows a typical current waveform pattern that would result from a conventional recloser or relayed circuit breaker operating in response to a permanent single-phase to ground fault.

FIGURE 7.4 IntelliRupter® PulseCloser® fault interrupter. (© 2012 S&C Electric Company, Chicago, IL. All rights reserved.)

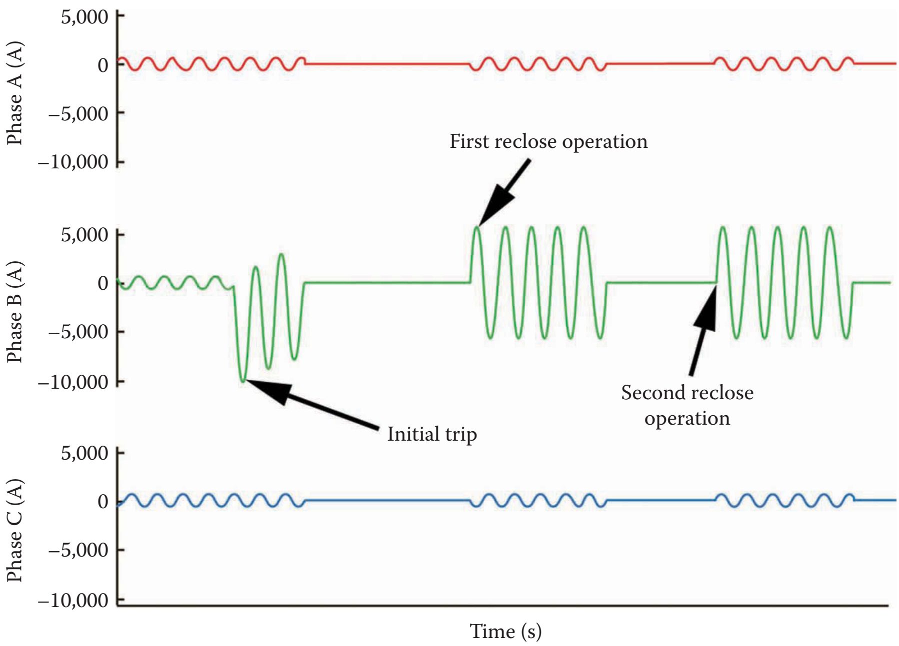

FIGURE 7.5 Conventional reclosing in response to a permanent fault. (© 2012 S&C Electric Company, Chicago, IL. All rights reserved.)

The random point-on-wave closing often results in asymmetric fault current, significantly increasing peak energy into the fault. When the pulsecloser clears a fault, however, it tests for the continued presence of the fault using pulseclosing technology, closing at a precise point on the voltage wave. Figure 7.5 shows how a pulsecloser device would respond to the same permanent fault. Note that both the positive and negative polarities are tested to verify that high currents are due to faults, and not transformer inrush currents (Figure 7.6).

7.3.8 Source Transfer Switch

Source transfer equipment typically consists of a pad mounted switch connected to multiple feeders and the connected loads. Voltage sensors are used on each feeder to determine the presence of voltage on both the primary and secondary sources. If the voltage on the primary source feeder

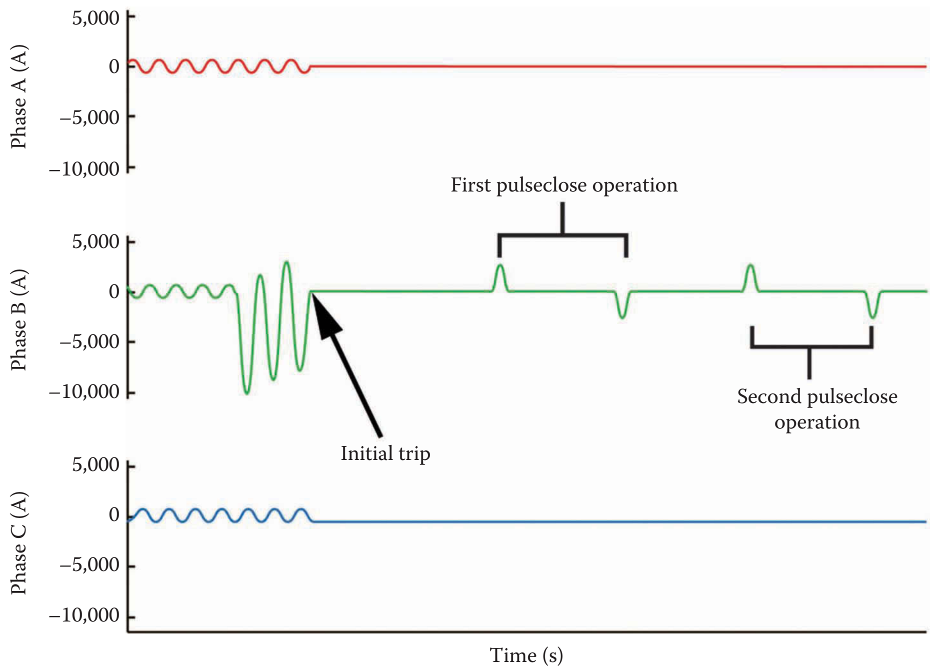

FIGURE 7.6 Pulseclosing technology in response to a sustained fault. (© 2012 S&C Electric Company, Chicago, IL. All rights reserved.)

FIGURE 7.7 Source transfer switch. (© 2012 S&C Electric Company, Chicago, IL. All rights reserved.)

drops below a predetermined threshold and the voltage on the secondary source feeder remains above a predetermined threshold, then the three-phase switch connected to the primary source is first opened, and subsequently, the three-phase switch connected to the secondary source is closed. In an industrial park configuration, the source transfer switch is connected as part of a multi-loop system, where one feeder acts as the primary source for the first set of loads and the secondary source for a second set of loads, and a second feeder is the primary source for the second set of loads and a secondary source for the first set of loads. If one feeder loses voltage upstream, then all the loads are switched to the healthy feeder. Figure 7.7 shows an example of a source transfer switch.

7.3.9 Fault Indicators

Fault indicators come in many forms and perform various functions. Sensors used for the fault location application are typically in the form of clamp on fault current indicators (FCIs); however, the data from other types of sensors on the feeder (e.g., line post sensors, reclosers) could also be applied. All FCIs measure current, and some also measure voltage, which can be useful for other distribution applications. Most FCIs have a visual indication that fault current has passed through the device or they can communicate their status to a local data collector or even directly back to the substation or control center for use in the automatic restorations application and outage management.

7.3.10 Recent Trends

Substation circuit breakers and reclosers are controlled with microprocessor-based control devices commonly referred to as IEDs. Recent trends in automatic restoration take advantage of distributed architectures and multifunctional IEDs with embedded intelligence to enable condition based control of reclosers and reclosing circuit breakers. In this application, the auto-reclosing sequence and logic are governed, in part, by the measured feeder conditions determined at the time of the fault [5].

A typical IED has analog inputs for secondary voltage and current measurements from the instrument transformers (CTs and PTs) and contacts that operate the breaker open and close mechanisms. A standalone IED performs, at the very high level, three basic tasks of data acquisition, data analysis, and control. These functions are traditionally internal to the IED. Most IEDs now include communication interfaces that enable the IEDs to communicate among themselves, which makes it possible to implement a distributed scheme for condition-based feeder restoration. In this scheme (Figure 7.8), data analysis is augmented by another device categorically called Intelligent Control Device (ICD) that communicates locally or remotely with the main IED. The ICD receives waveform data or sampled values from the IED and runs a set of dedicated algorithms to determine the nature of the fault. This process may optionally include other data, such as weather measurements, to enhance the reliability of determination of the fault type. The classification results from the ICD is sent back to the IED and incorporated in the control logic. If the fault is reliably determined to be permanent, the auto-reclosing sequence is advantageously blocked, thus preventing unnecessary reclosings into a permanent fault.

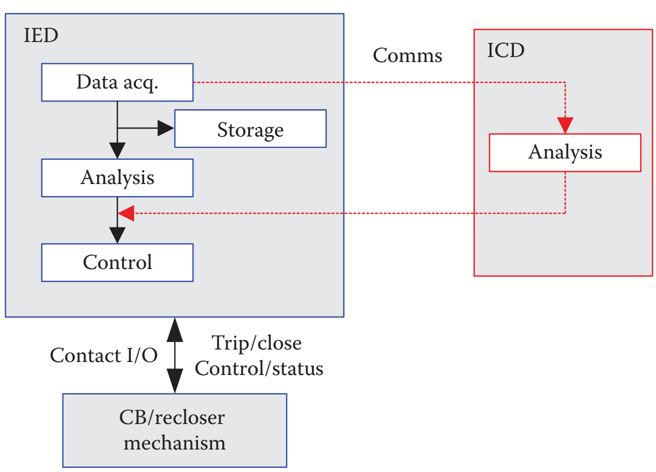

FIGURE 7.8 Auto-reclosing control using a distributed control architecture (© 2012 ABB. All rights reserved.)

The distributed architecture allows for the use of data from multiple IEDs, and the IED capabilities to be expanded with new firmware. Communications interoperability standards, such as IEC 61850, provide a practical framework for implementing this architecture.

7.4 FIELD-BASED AUTOMATIC RESTORATION SYSTEMS

As stated earlier, all automatic restoration systems require a combination of physical switching hardware, electronic controls, and software algorithms. The logic can be implemented in several ways. Each approach has its own strengths and weaknesses. The most beneficial approach will depend on a utility analyzing their existing infrastructure and the intended goals of reliability optimization, as well as the speed of response to the fault conditions required by the utility and expected by their customers. Interoperability and integration of various systems are essential to enable utilities to have complete and effective control over their whole system [6]. A key to success in building a smart distribution system is the concept of integrating multiple layers of intelligence throughout the system that work together and complement each other versus silos of response and control solutions [7].

7.4.1 Substation Breaker with Remotely Operable Switches

Basic feeder protection is implemented with a substation breaker that coordinates with fuses on the feeder. When customers report an outage, or the outage is reported automatically via smart meters, a crew is dispatched and uses the outage information to identify the blown fuses. The fault is isolated when the crew opens a manual switch. Faults can be located more quickly if fault passage detectors with a visible indicator have been installed in each phase at the switches. Response times can be further improved using remotely operable switches that can report fault current to the control center and can be opened remotely by a SCADA command, in which case service can be restored to all customers on the substation side of the switch after isolating the fault. The problem with using this approach is that during breaker operation, the whole feeder is subjected to momentary outages, and if the fault is sustained, the entire feeder will be locked out until the fault is located and manual switching is performed. The restoration time in this case can take hours.

7.4.2 Substation Breaker with Automatic Sectionalizers

Automatic sectionalizers sense the passage of fault current and then open after a predetermined loss of power count (substation breaker operations) when the fault current is interrupted. This coordinates the operation of multiple sectionalizers. Multiple automatic sectionalizers can be installed on the feeder, and more customers will avoid a permanent outage whenever a fault occurs near the end of a radial feeder. The advantage of this approach is that better segmentation can be achieved and the impact of the outage can be reduced within seconds. On the negative side, the entire feeder is subject to momentary outages during faults.

7.4.3 Substation Breaker with Midpoint Recloser

About half the customers on a feeder can be spared during an outage if a recloser is installed at the midpoint of a radial feeder. Like the substation breaker, a recloser can interrupt fault current. The midpoint recloser will sense current for a fault near the end of a feeder. If a fault occurs on the load side of the recloser, it is coordinated to open and isolate the fault before the substation breaker operates. Therefore, customers on the substation side of the recloser will not experience loss of power. The advantage of this scheme is that it can limit the extent of an outage by effectively splitting the feeder into two sections. However, upstream customers are still subjected to voltage dips caused by reclosing. In the case of sustained faults on the main distribution feeders, SAIDI can be improved on average by 50% for the upstream half of the feeder, although no improvement is experienced by those customers downstream of the recloser, so the overall expected SAIDI improvement is approximately 25%.

7.4.4 Loop Schemes with Reclosers (No Communications)

A loop scheme can automatically restore service using a normally open midline tie switch to a nearby feeder. Initial sectionalization occurs after multiple coordinated overcurrent protective devices respond to a feeder fault. Reconfiguration to restore power to the unfaulted feeder sections occurs by using a combination of time delays and voltage measurements, and no communication is required. Loop restoration is automatic, but it does not account for circuit capacity constraints, and it will not automatically return the feeders to their normal configuration. The feeder is returned to normal configuration manually by opening the tie device and closing the midline tie switches. Figures 7.9 and 7.10 show the circuit topology for a loop scheme with three reclosers and one with five reclosers, each with a normally open recloser at the tie point. Simple reliability calculations for loop systems assume a constant fault incidence rate in all feeder segments, equal segment lengths, uniform customer distribution, and a constant restoration time throughout the system. The benefit of a three-recloser loop system compared to two radial feeders is a 50% reduction in SAIFI and SAIDI for feeder faults compared to a feeder with only a breaker. Expanding to a five-device loop improves the reliability indices by 66% compared to a feeder with only a breaker.

Conventional loop schemes use timers based on the detection of loss-of-voltage to determine the order of device operations. Reclosing into a fault is the only way to know if the fault is still present. The first reconfiguration action to occur, after the fault has been interrupted and isolated by the breaker or recloser, is to close the normally open tie recloser based on detecting loss of voltage on either side of the tie point. A three-recloser loop system with equal segment lengths has a one-in-two chance that the tie recloser will sense loss of voltage due to a fault in the adjacent line section. When the tie recloser closes, fault current flows through the entire previously unfaulted feeder until

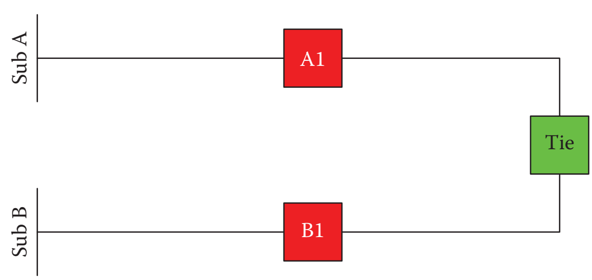

FIGURE 7.9 Loop scheme with three reclosers.

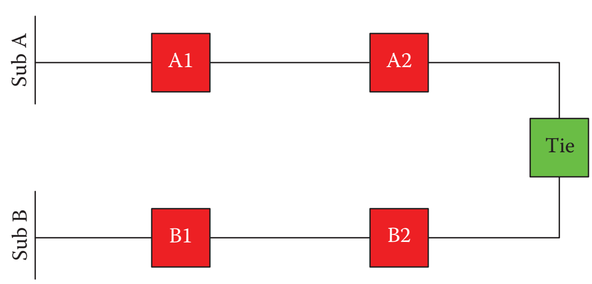

FIGURE 7.10 Loop scheme with five reclosers.

the recloser detects the passage of fault current and locks open. For a five-recloser loop system, the faulted section is found when the tie recloser closes onto the fault or when the next midline recloser subsequently closes onto the fault. A loop scheme application is commonly limited to the use of two feeder sources, and each source must have capacity to supply the combined load of both feeders. A downside of this is that customers on both feeders will either experience a momentary outage, sustained outage, or voltage sag for faults that occur on either feeder.

7.4.5 Loop Schemes with Pulseclosing Technology (No Communications)

A pulseclosing device used at the tie point, in an otherwise conventional recloser loop scheme, will use a pulseclose operation to test for faults before closing. This avoids putting a fault on the otherwise unfaulted feeder. Benefits are compounded when multiple pulseclosing devices are used in series, since pulseclosing devices will properly sectionalize a system without subjecting them to fault current. A loop restoration system with automatic non-communicating restoration can be expanded to include any number of pulseclosing devices to provide desired segmentation and improve reliability. Furthermore, the entire restoration process can be completed without reintroducing the fault to either feeder.

7.4.6 Distributed Logic using Peer-to-Peer Communications

The predominant use of self-healing systems consists of a mix of distributed logic for fast-acting local response and a centralized system for oversight and optimization. Clusters of locally automated feeders can function independent of the centralized system to isolate problem areas and minimize disruptions quickly. Peer-to-peer communications is used as the basis for such distributed restoration systems.

Distributed logic is also capable of handling multiple events, looking for alternate sources to restore unfaulted sections that are without service. This is especially useful during storms that sweep across a service territory and cause multiple outages. Reconfigurations can occur simultaneously at more than one location, and by monitoring real-time loading, it ensures that a feeder will not pick up more adjacent segment load than it can handle. The system can automatically restore power to as many customers as possible, quickly and efficiently, and report the final reconfigured state to the control center.

Figure 7.11 is an example of how a four source, 12-switch deployment divided into teams of switches with distributed logic. All the switching points that bound a given line segment form a team. Switching points can be load-break switches, reclosers, pulsecloser fault interrupters, or breakers. The controls for each switching point communicate directly with all other controls in the team. Each team can share information with adjacent or remote teams. Applications are scalable since additional teams of switching points can be added as necessary.

7.4.7 Substation Computer-Based Schemes

Some utilities prefer to deploy substation computer-based automatic restoration schemes. The substation computer typically has a simple connectivity model of the connected feeders with switching devices and receives data from the feeder and substation IEDs to make intelligent switching actions after a fault has been isolated. After a recloser or the substation circuit breaker has operated to isolate the fault, the substation computer processes the IED data, determines the downstream isolation switching device that must be opened, and then determines the normally open switch that must be closed to restore power to unaffected customers.

The restoration algorithms of substation computers vary, but typically a capacity check is at least performed to ensure that alternate feeders can pick up the excess load. Some substation computers are also capable of supporting restoration schemes with more than two alternate sources, and thus at

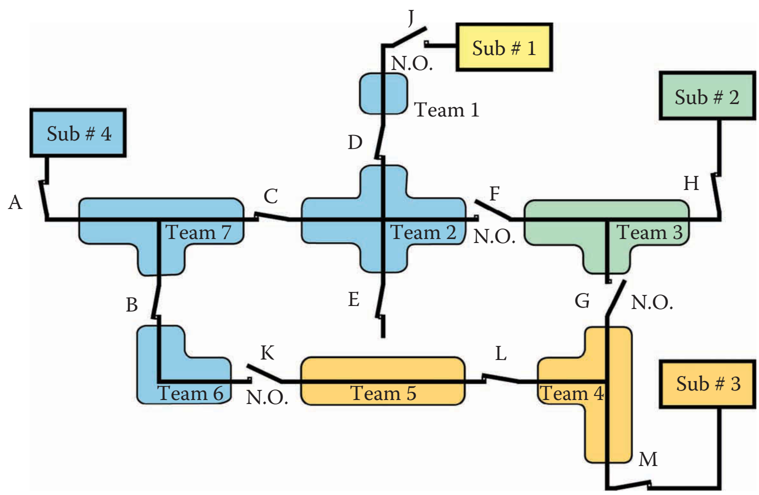

FIGURE 7.11 Example of distributed logic using peer-to-peer communications. (© 2012 S&C Electric Company, Chicago, IL. All rights reserved.)

least two normally open switching devices. These schemes also typically support restoration when multiple faults occur in the system, and include logic to restore feeder configurations to normal after the fault is cleared. The restoration schemes can be activated or deactivated, either remotely from the control center via SCADA, or directly via the graphical user interface in the substation (Figure 7.12).

7.4.8 Deployment Considerations

Field-based automatic restoration systems vary significantly, and there are a wide range of deployment aspects that must be considered, including the use or nonuse of communicating devices and fault-passage indicators, and the deployment of automated reclosers and sectionalizers. These devices help to determine the fault location quicker, thereby enhancing reliability. By automating the field switches with communications and intelligent control devices, the reliability indices will be significantly reduced compared with the noncommunicating, nonautomated schemes. The system topology must also be considered when determining the type of field-based restoration scheme that is deployed. For basic radial systems, simpler schemes can be deployed, such as the midpoint recloser. For the more complex multi-backfeed (meshed) systems, more automated devices are required, driving the deployment cost up, but the level of reliability improvement and cost savings will also increase due to the available alternate backfeed sources. For these systems, the more advanced distributed logic solutions based on peer-to-peer communication or substation computer-based schemes could be deployed. Cost is, therefore, a major factor in considering the deployment of field-based automatic restoration schemes. Utilities perform a cost-benefit analysis to determine the return on investment to deploy and maintain the automation devices and control schemes compared to the reliability improvements and outage management cost savings.

In many states in the United States, the regulatory bodies in each state encourage utilities to report action plans for improving the reliability of their worst performing feeders. In this fashion, reliability is considered in the utility rate case decisions, providing a financial incentive for reliability improvement. In some other countries, particularly in Europe, there are both financial penalties to the utility for poor performance, and incentives in the form of capital reimbursement funds for improved results. The external influence of positive or negative cash flow based on service reliability provides a more quantitative environment for cost/benefit calculations.

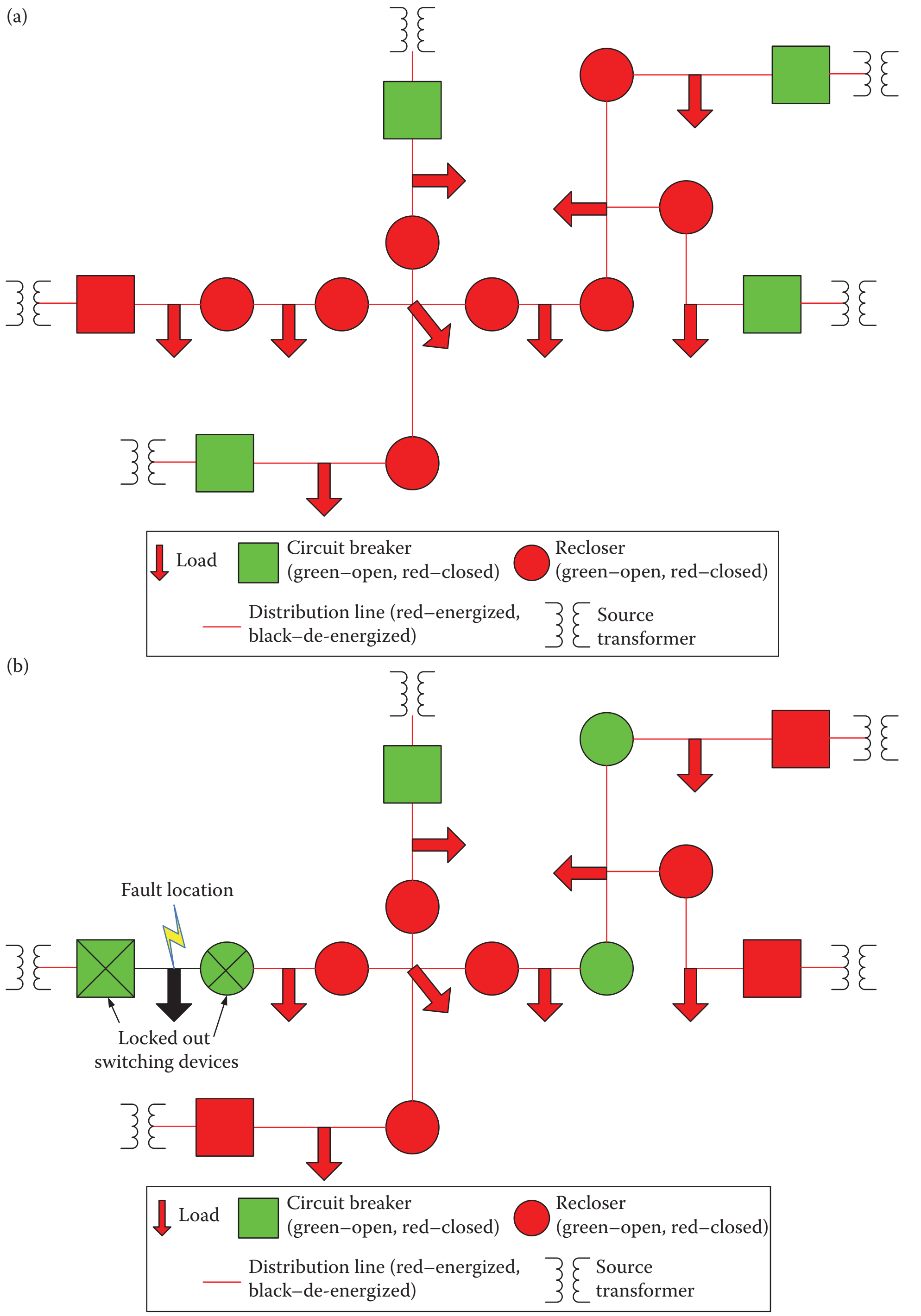

FIGURE 7.12 Example of substation computer-based scheme. (a) Pre-fault configuration; (b) Post-fault configuration. (© 2012 A)

7.5 OUTAGE MANAGEMENT AND CENTRALIZED AUTOMATIC RESTORATION SYSTEMS

Outage management is typically used to describe a centralized process and software application that utilities use to monitor and manage outages on the distribution system. The OMS uses SCADA data or is interfaced with the utility distribution management system (DMS), to obtain real-time system status, while also using connectivity models and graphical user interfaces for outage analysis, service restoration, trouble-call handling, crew management, and reliability reporting. The outage analysis and service restoration functionality of the OMS for reliability improvement is commonly referred to as FLISR. These centralized systems use software applications and models of the distribution system to analyze data from field devices to detect and identify the fault location as accurately as possible, and then to recommend or automatically perform switching operations to isolate the fault while minimizing the number of customers and load impacted. These systems also provide the logic to restore the distribution system to normal operating configurations after the fault has been cleared and any switching operations or repairs have been made out in the field.

Connectivity maps of the distribution system assist operators with outage management, including partial restorations and detection of nested outages. Outage management was originally based on receiving calls from customers and did not include a connectivity model of the system with the connection points of all customers. At that time, manual data recording and the use of paper maps were used to estimate the location of outages.

With the modern OMS, system connectivity information is typically stored in the geospatial information system (GIS)—discussed in a separate chapter in this book—Network data from the GIS (and other data sources) are imported to the OMS database using a data interface. This interface extracts data from GIS and performs a data model conversion based on business rules and data model mapping. The interface initially populates the database with all network data, including connectivity information, system components, including protection and switching device types and locations, and distribution transformers. This is referred to as the "bulk network data load" or bulk load. The data interface can also be periodically run to transfer the subset of data that has changed since the last update. This process is referred to as the "incremental network data update" or simply incremental update. A screen capture of an OMS system model for a large metro area is shown in Figure 7.13.

The data extracted from the GIS captures the necessary network data to support OMS and DMS operation. The required data can also be provided from other sources or entered manually. Another key to successful outage management predictions includes an accurate representation of customer connectivity on the system. When a customer calls in to report an outage or an AMI meter sends an outage notification or restoration notification, the system needs to know where on the server the customer is. Customer connectivity information is typically maintained in either the GIS or customer

FIGURE 7.13 OMS system connectivity model for a large metro area. (© 2012 ABB. All rights reserved.)

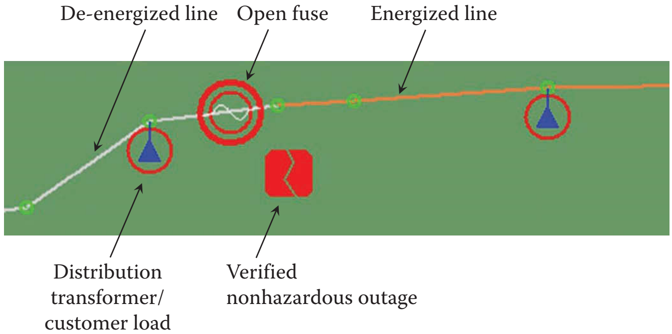

FIGURE 7.14 Example of outage representation using dynamic symbols in an OMS.

information system (CIS). By evaluating reported outage locations and the as-operated topology of the network, an OMS can identify probable outages that may constitute a single customer out, a single transformer out, a protective device operation, or a de-energized source. Outage management algorithms use the connectivity model, location of customer calls, and statistical parameters, such as the ratio of affected customers to total customers, the number of distribution transformers with predicted outages, and the number of downstream protective devices with predicted outages, to determine probable outage location. These parameters can be combined in various ways to achieve optimum prediction accuracy for the network. System operators are then able to track outages using dynamic symbols on the geographic maps, such as the one in Figure 7.14, as well as in tabular displays.

7.5.1 Fault Detection and Location

When outages occur, one of the first things the utility wants to know is where the fault is located. For safety purposes, typically no switching is done until the crew verifies the location of the fault in the field. The process of dispatching a crew to patrol the feeder and find the fault location can take a long time, especially for long feeders. This increases the outage time, which in turn impacts reliability. The fault location capability of FLISR can greatly reduce the fault location time and, thereby, improve SAIDI significantly.

Field devices—such as the substation relay or a midline recloser—that have the capability to capture information regarding the fault (faulted phase identification, fault current magnitudes, captured waveforms, etc.), can provide valuable information to help with the fault analysis and restoration of service. This information is captured by SCADA and provided to the FLISR application to detect the fault event and estimate the location of the fault on a real-time network model. Operators receive an alarm about the fault event and can graphically see the possible location(s) of the fault on the map. They can then instruct the crew to travel directly to the vicinity of the fault, reducing the travel time of the crew for finding the fault.

The fault location calculation uses a short-circuit analysis of the affected feeder to determine the possible locations on the feeder that match the phase and magnitude of the fault recorded. The requirements for this analysis are the short-circuit capacity of the feeder source as well as impedances of the feeder lines and transformers. Fault impedance can be defaulted to a typical value or assumed zero without much impact on the operational benefit of the application. It is important that the short-circuit analysis is able to handle meshed and parallel networks in addition to radial for cases when faults occur in those configurations. Depending on the feeder configuration, the analysis may find multiple candidates for a given fault event. In this case, fault indication information from other devices, if available, can be used to narrow the list of candidates. If there are still multiple possible fault locations, they are all displayed on the network map.

In summary, fault location can be an ideal first step toward a full FLISR rollout. Even without the fault isolation and restoration switching components, fault location can provide significant benefits to a utility with minimal data and infrastructure requirements. Fault location has been implemented at several utilities for years with good operational results. While there is a significant body of work on fault location, practical implementations are often limited by the amount of information that is required in the algorithms [8].

7.5.1.1 Impedance-Based Fault Location

The most common approach for fault location is based on impedance calculations. Often, the apparent fault impedance measured by IEDs in the substation, defined as the ratio of selected voltage to selected current based on the fault type and faulted phase, is utilized. For simplicity, the heterogeneity nature of the lines and the dynamic nature of the loads and laterals are often neglected. A common drawback of most impedance-based methods is that they lead to multiple fault location estimations due to reliance solely on the measured voltage and current signals at the substation [9].

As an improvement, the system can iteratively solve a set of equations that describe the voltage and current quantities during fault to obtain the fault location and fault resistance estimates [10]. The input for this algorithm is the fundamental frequency voltage and current phasors measured in the substation. Alternatively, the faulted section can be decided first by comparing the apparent fault impedance with the modified reactance. Then, the voltage and current phasors are calculated from the substation measurements, and the fault location is obtained using the voltage-current relationships.

Data collected from fault indicators along the network may be utilized to solve the multiple fault location estimation problems. Installation of fault indicators at the beginning of each tap increases the implementation cost and may not be a preferred solution. Recent enhancements consider the impact of distributed generation and utilize synchronized voltage and current measurements at the interconnection point as input for fault location [11].

7.5.1.2 Direct Circuit Analysis-Based Fault Location

These methods propose an iterative approach using direct phase-domain circuit analysis to calculate fault location. Although these methods are suitable for unbalanced distribution systems, they do not yield unique results for fault location.

7.5.1.3 Superimposed Components-Based Fault Location

These techniques use an iterative fault location approach using superimposed voltage and current measurements. The assumed fault location point is varied systematically, and the actual fault point is found when the superimposed current at the unfaulted phase reaches a minimum. This method also suffers from multiple fault location estimations.

7.5.1.4 Bus Impedance Matrix-Based Fault Location

This technique provides a method based on a phase-domain bus impedance matrix. This approach directly utilizes the measured voltage or current phasors at the substation and does not require an iterative procedure to calculate the voltage or current phasors at the terminal of the faulted segment [12]. The sequence-domain bus impedance matrix has also been explored for fault location [13]. The equivalent three-phase line models for the multiphase (single-phase, two-phase, and three-phase) line segments are established where the line segment is represented by its equivalent sequence impedances. The equivalent bus impedance matrix is built for each sequence network. Fault location is calculated using this matrix similar to transmission system applications.

7.5.1.5 Short Circuit Analysis-Based Fault Location

Recent methods identify the faulted segment(s) on multiphase distribution primaries using sequence component modeling and standard three-phase short-circuit analysis [8]. The methodology utilizes fundamental frequency current magnitudes measured in the substation in conjunction with an approximate sequence model of the multi-phase feeder, including single-phase and double-phase line segments augmented with dummy lines. Under certain fault conditions, multiple faulted segments may be identified, which may be reduced using voltage sag data.

7.5.1.6 Intelligent Systems-Based Fault Location

Methods based on intelligent systems, such as neural networks and fuzzy logics, have also been developed, e.g. an adaptive neuro-fuzzy inference system (ANFIS) net, a learning algorithm for multivariable data analysis (LAMDA) classification technique, and fuzzy clustering analysis. The common drawback of these methods is that they require many training data and a retraining process when topology changes occur in the network [9].

7.5.1.7 Traveling Wave-Based Fault Location

Methods based on traveling waves have also been explored for distribution systems. The time difference between successive traveling waves is used for distance estimation [14]. These methods require high-frequency data measurements and suffer from variability in line configuration affecting propagation velocity. This high-frequency sampling requirement also increases implementation cost. The presence of laterals and load taps cause additional reflections and confusions in data interpretation. As such, these methods are more amenable to transmission lines that are long, point-to-point, and equipped with monitoring devices with high sampling rates.

7.5.1.8 Power Quality Monitoring-Based Fault Location

The fact that faults cause voltage sags with different characteristics at different nodes can be exploited for fault location, which often involves pre-fault and during-fault voltage and current phasor measurements at the substation, and voltage sag measurements at nodes along the feeder. The idea is to assume each node as a potential faulted node, vary the fault currents injected into the node, and compute the load flow until the calculated feeder current phasors equal the actual measurements. Meanwhile, voltage sags throughout the network are calculated. The voltage sag mismatches are determined using the calculated voltage sag and the measured voltage sag data. The node with the smallest mismatch is considered the actual faulted node. Recent improvements utilize voltage phasors captured by power quality meters.

7.5.1.9 Faulted Segment Identification

Fault location as an integrated function for service restoration is executed from the control center environment where the operators have access to the as-operated network models and parameters, as well as circuit topology information denoting the real-time status of switches, breakers, and reclosers. Although not explicit, the restoration process does require that the faulted segment be known; this is a relaxed requirement for fault location in which, as opposed to determining the distance to fault, i.e., pinpointing, the faulted segment between two switches is identified for isolation purposes. The repair crew still needs to locate the fault on the faulted segment, but that work takes place later outside the restoration window of seconds or minutes.

Distribution circuits are composed of three-phase main lines as well as many single-phase and double-phase laterals. It has been observed that over 80% of faults occur on single-phase or double-phase laterals, which are mostly isolated by fuses on the laterals. These fuse-cleared faults do not operate circuit breakers and are, thus, not typically reported to the control center via SCADA. Also, the fault location algorithm used by most power providers today is limited to faults on three-phase main lines, and it is an industry-wide challenge to identify the fault location for faults that have occurred on single-phase or double-phase laterals. Another major challenge in fault location for distribution networks is the penetration of distributed generation (DG), such as wind and solar, which modifies the assumed network topology and affects short-circuit currents.

As a cost-effective solution to speed up the service restoration process, faulted segment identification (FSI) addresses some of the practical challenges in the fault location problem. The cost-effectiveness results, in part, from the relaxation of the location accuracy, which in turn reduces the requirement for network data, often provided in sequence domain for multiphase feeders. FSI relies on three-phase sequence domain short-circuit analysis and the measurement of the fundamental frequency current magnitudes in the substation during the fault. By using dummy nodes and dummy lines, the FSI method establishes equivalent three-phase line models for all the multi-phase (single-phase, double-phase, and three-phase) line segments. As a result, the equivalent sequence impedances for all the multi-phase line segments can be calculated, and the bus impedance matrix for each sequence (zero-, positive-, and negative-sequence) network can be constructed.

This method relies on the root mean square (RMS) current magnitudes retrieved from the substation feeder protection IEDs. It also requires the feeder connectivity model and calculates the equivalent sequence line parameters to build the bus impedance matrix for each sequence network. The fault type is also required, which may be obtained from the IED or determined on-the-fly from the fault data. Like the other impedance-based fault location methods, this approach yields a superset containing potential faulted segments each associated with a fault resistance range. Other information from faulted circuit indicators, customer outage calls, AMI outage notifications, and social media trends may be leveraged to identify the faulted segment uniquely.

The FSI approach discussed applies to typical radial circuits. For a meshed network with at least two generation resources, the current measurements from the two generation resources are required. For each segment, a fault at two terminal nodes is applied in sequence, and the short-circuit currents are calculated. When the measured currents are between the calculated values, the corresponding segment is considered a potential faulted segment. Given that there are additional measurements, there will be fewer candidate faulted segments compared with the radial circuit scenario with a single source and measurement point [8].

7.5.2 Fault Isolation and Service Restoration

Once the fault location (or faulted section) has been determined, the next step is to perform switching to isolate the faulted section and, if possible, restore customers who are not connected to the faulted section. After possible fault locations are calculated within the FLISR application, they are geographically presented to the operator on the console's map display and in tabular displays. If a GIS land base has been included, such as a street overlay, an operator can communicate to the field crew the possible location, including nearby streets or intersections. This information helps crews find faults more quickly. As operating rules permit, upstream isolation switches can be operated, and upstream customers can be reenergized more quickly, resulting in much lower interruption durations.

Upon the occurrence of a permanent fault, the FLISR application evaluates all possible switching actions and executes an unbalanced load flow to determine overloaded lines and low-voltage violations if the switching actions were performed. Like the fault location application, the fault isolation and restoration application uses the DMS model of the system but tries also to reduce the customer average interruption duration index (CAIDI) and SAIDI indices. This capability is particularly valuable during heavy loading and when the number of potential switching actions is high. The operator receives a summary of the analysis, including a list of recommended switching actions. Fault isolation and service restoration can be done on two levels, one with remotely controlled devices first (if available) to quickly restore the customers that can be restored, and second, with a combination of manual and remotely controlled devices to restore additional customers. FLISR provides two modes of execution of the initial remotely controlled switching scheme; one is the advisory mode where the operator reviews and executes the recommended switching, and the second is the automated mode where the application automatically executes the recommended switching scheme. Such an automated isolation and restoration process approaches what many call

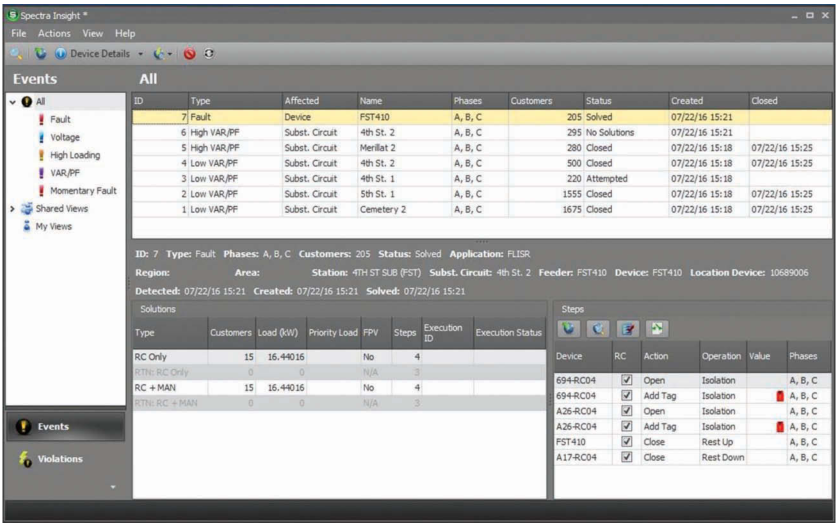

FIGURE 7.15 Centralized FLISR (© 2016 OSI Inc. All rights reserved.)

the "self-healing" characteristic of a smart grid. Figure 7.15 shows an example of a control center FLISR operator interface with proposed switching actions.

FLISR must consider several factors in deriving a recommended switching sequence:

1. The availability of switches for remote control: this includes consideration of control inhibit tags, alarms, and quality flags on the switch, as well as other operational restrictions.
2. The capacity of adjacent feeders: so that load transfers do not cause overload or voltage issues for those adjacent feeders. If sufficient capacity is not available on adjacent feeders, other schemes, such as splitting the transfer area or unloading adjacent feeders (cascading), may have to be considered.
3. The look-ahead analysis: to check the feasibility of the load transfer for the period it takes for permanent repairs to be performed, which could take hours or even days.

The FLISR analysis is based on the detailed network model and power flow analysis of the network model to check for current and voltage violations. In North America and other parts of the world, it is a requirement to support unbalanced grounded systems, which are typical since the loads are split between the phases due to the way in which the loads are dispersed. In Europe and other parts of the world, a balanced power flow analysis is sufficient to support the three-phase ungrounded distribution systems in place. FLISR performs a network topology analysis that typically supports both lightly loaded and heavily loaded network conditions. If the loading of the distribution network is light, most likely a single-path restoration is sufficient. If the loading on the network is heavy, either a multipath restoration or multi-layered feeder segment restoration has to be used.

7.5.3 Deployment Considerations

When deploying outage management and centralized service restoration systems, the main deployment factors to consider are the communications system, supervisory modes, and the integration of the OMS with other utility applications.

For the communications part, some utilities prefer to communicate to the feeder devices directly via the SCADA system. However, there is an advantage to communicating to the feeder devices using the substation as a gateway due to the proximity of the substations to the feeder devices.

Another factor is the setting of the operation mode of the control center, centralized scheme. Most utilities prefer to employ an advisory mode for automatic switching schemes, allowing the operator to have some level of control of the field switching. However, some utilities prefer the automatic mode to expedite the management of the fault, allowing restoration to occur much more quickly.

In recent years, the OMS have become more automated. Outage prediction—the process of analyzing outage events, such as trouble calls, AMI outage notifications, and SCADA-reported status changes— has improved. Interfaces to interactive voice response systems (IVR) permit trouble call entry into an OMS without call-taker interaction and permits the OMS to provide outage status information to customers and provide restoration verification callbacks to customers who request them. Advances in smart grid have made it possible to easily and more effectively integrate IT and OT systems in the utility enterprise, such that the OMS can now share data in real time with GIS, CIS, mobile work force management (MWFM)/field force automation (FFA), SCADA, and AMI. Integration of OMS with these systems results in improved workflow efficiency and enhanced customer service. Today's OMS is a mission-critical system. It integrates information about customers, system status, and resources, such as crews, providing a platform for operational decision support.

AMI and additional sensor technologies are a significant benefit for centralized automatic restoration schemes. These technologies are being used to help enhance both the outage analysis and the restoration verification processes. AMI data are typically retrieved by the DMS via an interface to the AMI Meter Data Management System (MDMS), and help to more accurately pinpoint the fault location. The AMI real-time data also allow the utility to dispatch field crews for repairs before customers even call the utility trouble call system to report an outage. Once the work is completed and power is restored to the affected customers, the meter data can then be used to verify that the power has been restored to all customers. Obtaining AMI and additional sensor data could be a costly undertaking, and it may be wise to first incrementally integrate the data for areas of the distribution system where reliability issues are the most critical. In the future, it is envisioned that utilities may call affected customers immediately after a fault has occurred, and provide estimated times for restoration. The availability of metering accuracy power quality data can also help to determine the effect of disturbances on the distribution system and the customer. The more data the utility can obtain regarding the fault, the more effectively it can run its operations, becoming more proactive rather than reactive.

7.6 IMPACT OF DERS

The introduction of DERs, such as solar generation and energy storage, especially in high penetration cases, present several operational challenges to distribution system operators. These challenges include reverse power flow, intermittency of renewable generation, voltage fluctuations, and the fault contribution of DERs.

In high penetration DER feeders, the power can sometimes flow in the opposite direction in some sections of the feeder, or even back to the substation. This creates problems for protective and voltage regulating devices, which traditionally operate with the assumption that power flows in one direction from the substation down to the consumer on distribution systems. Utilities are beginning to deploy bidirectional protective and voltage regulating devices in these cases. These devices can sense the reverse flow of current and automatically switch to an alternative setting appropriate for that configuration. Note that reverse orientation and thus reverse power flow can also occur when feeders are reconfigured and parts of one feeder are switched to another feeder.

Another challenge is the intermittency of renewable generation, such as residential solar generation. The power generated by solar rooftop installations can change drastically in a short period of time when clouds pass overhead. This intermittency can create voltage swings on the distribution feeders. In addition, some DERs, such as rotating equipment (e.g., gas microturbines), can contribute to fault currents, and this contribution must be considered when performing fault location analysis. The impact of DERs must also be considered when designing and implementing service restoration systems. The service restoration system must be able to consider the fault contribution of DERs, operation of bidirectional devices, and the impact of DERs on restoration switching. In addition, when known, DER forecasts may be used to evaluate and enhance switching options in look-ahead, study, and training simulation modes.

7.7 RELIABILITY NEEDS IN A SMARTER GRID

With the future smart grid, there are many challenges that must be addressed to reap the operational benefits. Deploying automatic restoration schemes alone does not ensure that reliability will be optimized. Coordinating reliability improvements with other control functions, such as Volt/VAr Control (VVC) and optimization schemes, demand response programs, DER dispatch, and load balancing, will result in more effective distribution grid management. Coordination with Volt/VAr schemes alone will help to increase efficiency and minimize losses after a fault has occurred on the distribution system. Load balancing is another future function that will allow for dynamic reallocation of load to adjacent feeders to ensure reliability during overload conditions.

DER and demand response programs will have a significant impact on utility operations and grid management, as well as the way in which consumers receive and use power. DER can improve distribution reliability by supplying power to loads that have either lost a connection to a traditional utility source, or it can offset a shortage of supply in situations where there is a connection to a utility source, but there are capacity constraints either in the substation or on the distribution feeder. Next-generation automatic restoration systems will need to account for energy storage and larger distributed generation resources in reliability algorithms, and likely this will include the ability to create temporary islanded systems that are supported by the energy storage and distributed generation in the island. Demand response is another resource for grid management, where loads can be shaved during peak periods of operation to reduce overall system demand. By coordinating demand response with automatic restoration systems, restoration can be achieved over larger areas of the grid due to the lower demand, again enhancing reliability. These DER and demand response capabilities can extend reliability improvements into distribution areas requiring extra resiliency. This application of energy storage to create a more robust power system has gained a lot of attention since Superstorm Sandy hit the Eastern Coast of the US in 2012.

Reliability is becoming much more of an issue in the smart grid due to technologies becoming available that can make the deployment of reliability functions such as automatic restoration and load balancing more realistic. Many regulatory bodies are also pushing for higher reliability from the utilities over which they monitor. As the level of reliability increases in other industries, especially consumer industries (e.g., smart phones and laptops with "on demand" features), the expectations on reliability of the electricity supply from consumers will only increase as a result. These realities will make reliability optimization of the utility distribution grid a mandatory requirement in the future.

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8 Volt/VAr Optimization

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CONTENTS

Volt/VAr Optimization (VVO) relates to the control of distribution substation and feeder voltage regulation equipment and capacitor banks with two main objectives: reducing VAr flow on the distribution system and adjusting voltage at the customer revenue meter delivery point within required limits. An effective VVO approach combines, coordinates, and optimizes the control of both VAr flow and customer voltage. Components of VVO are as follows:

VAr Control, VAr Compensation, Power Factor Correction

Substation and distribution feeder capacitor banks are used to minimize VAr flow (improve power factor) on the distribution system during all load levels (peak and base). Reduction of VAr flow reduces distribution system losses, which reduce load on the substation and distribution feeders. Reduction of VAr flow also reduces the voltage drop along the distribution feeder.

Voltage Reduction

Voltage reduction is the concept that lowering the operating voltage will reduce demand. This concept is true when the majority of the load is resistive load.

Peak Voltage Reduction

Peak voltage reduction is when voltage reduction is used to attempt to reduce system peak load. Some utilities attempt to reduce the peak on a daily basis, while others only attempt to reduce seasonal peaks. While operating in this mode, the utility is still required to keep all secondary voltages within American National Standards Institute (ANSI) Range A (Table 8.1). A typical reduction in voltages of 1%–3% is attempted.

Emergency Voltage Reduction

Emergency voltage reduction is when a utility reduces voltage in an attempt to reduce load because the demand is larger than the supply. This is typically the last step used before system brownouts or blackouts. While operating in this mode, the utility is still required to keep all secondary voltages within ANSI Range B (Table 8.1), which allows them to reduce the voltage an additional four volts (from 114 to 110) on a 120 base for short durations under emergency conditions. Typically, a 5%–7% reduction in voltage is attempted when in the emergency mode.

Conservation Voltage Reduction

CVR (conservation voltage reduction) is operating the distribution system in a voltage reduction mode 24 h per day in an attempt to reduce generation requirements, and hence greenhouse gases. When operating in this mode, the utility should still leave room for further reduction of the voltage in case of emergency. One utility in the southeastern USA lowered the control bandcenters on the substation transformer LTCs (load tap changers) and distribution feeder voltage regulators from 123 to 121 so that they are in constant CVR mode with a 2-V reduction. If needed, the utility can further

TABLE 8.1
Acceptable Delivery Voltages for US Customers (ANSI Standard)

Nominal Service Voltage	Range B Minimum	Range A Minimum	Range A Maximum	Range B Maximum
Percentage of nominal	91.7%	95%	105%	105.8%
Single phase				
120/240, three wire	110/220	114/228	126/252	127/254
Three phase				
240/120, four wires	220/110	228/114	252/126	254/127
208Y/120, four wires	191/110	197/114	218/126	220/127
480Y/277, four wires	440/254	456/263	504/291	508/293
2.4–34.5 kV% of nominal	95%	97.5%	105%	105.8%

Source: Voltage ratings for electrical power systems and equipment, American National Standard ANSI C84.1–1989.

reduce the voltage to 118 and remove over 400-MW demand from the system should a power plant go down or major transmission lines trip off-line.

Integrated Volt/VAr Control or VVO

Integrated Volt/VAr control or VVO is the coordination of VAr flow and CVR to reduce distribution feeder losses and control the voltage profile on the feeder, which may reduce system losses and improve service voltage to the customer. Other possible benefits may include reduction in capacitor bank inspections and capacitor bank troubleshooting, as well as a reduction of operations on transformer LTCs and voltage regulators by allowing the capacitor banks to provide the primary voltage support.

The following discussions reference the voltage levels and operation of the U.S. electrical system as an example.

8.1 INEFFICIENCY OF THE POWER DELIVERY SYSTEM

Electric utilities have two concerns when it comes to transmitting electricity from the generator to the customer. First, it must get there safely and reliably. Second, the majority of what is generated must make it to the customer in order for the utility to be profitable—efficiency of power delivery to the customer. For a utility to maximize profits, it must minimize the amount of electric losses on the system during the transfer of electricity from the generation site to the customer. Electric losses are mostly a result of the heating effect (I^2R losses) of current passing through power delivery equipment. These are known as resistive losses. Other electric losses, known as reactive losses, are a result of losses in magnetic flux coupling in transformers and other inductive equipment, including transmission and distribution lines themselves. Power is transmitted over long distances at high voltages in order to reduce losses. The losses are caused by current flow. The higher the current flow, the greater the losses. Power is the product of current and voltage. With this in mind, if one doubles the magnitude of the voltage and halves the magnitude of the current, the power being transported remains the same. Therefore, to reduce losses, transmitting power at higher voltages is more efficient. Utilities have increased both transmission voltages and distribution voltages in order to reduce losses. Traditionally, 115 and 230 kV were considered the primary transmission voltages, but lately 500 and 745 kV have become more dominant. The same is true at the distribution level, where 4 kV distribution lines are replaced with 12, 25, or even 34.5 kV lines.

The purpose of the distribution system is to deliver power at the required voltage level to the customer. In the United States, residential customers interface to the system at 120 or 240 V, not the 115–500 kV found on the transmission lines. It is cost prohibitive to have 115 kV–240 V transformers at the many customer service points. So, from the generator to the customer, the voltage is transformed multiple times and carried over hundreds of miles. Each transformation causes losses. Likewise, each mile the power flows causes additional losses in lines and cables. Since the distribution system operates at a lower voltage and a higher current than the transmission system, the distribution system will produce more losses per mile of equivalent impedance compared to the transmission system.

Another factor that can reduce electrical losses is a reduction in the distance from generation to end use. In the early days of electricity, power plants were built close to the customers in large cities. Since then, several trends have occurred, resulting in placing the power plants further away from the customers. First, more customers are moving away from the city centers and living greater distances apart. Power plants are also moving further away from the customer load. This is due to several factors. First, customers do not want power plants close to their homes. Next, with the advent of gas peaking generation plants, power plant sites were selected based on the availability of gas pipelines, water, and transmission line capacity as the major factors, and not where the main load centers were located. This has resulted in an increase in the distance electricity is transmitted and distributed, which increases electrical losses on the system. In the future, with the advent of distributed generation, smaller plants that are closer to the end customer will help to reduce electrical losses.

Electrical losses occur at every level of the transmission and distribution system due to the electrical impedance (resistive and reactive) of the equipment: from the step-up transformers at the power plants and the transmission and distribution grid (lines and transformers) down to the customer end delivery points. VArs in the system are caused by current flowing through inductive equipment on the system, such as transformers and lines, and also by the type of load. VArs in the system increase the current flowing in the system, which results in an increase in energy delivery losses.

8.2 VOLTAGE FLUCTUATIONS ON THE DISTRIBUTION SYSTEM

Electric utilities are required to deliver voltage to the customer at a nominal voltage (to be measured at the revenue meter) within a specified operating range. In the United States, for single-phase, three-wire service, the nominal service voltage is specified under ANSI standard C84.1* as 120 Vac with an acceptable range (Range A) of ±5% of the nominal voltage (see Table 8.1). Range A is considered the favorable zone where the occurrence of delivery voltages outside these limits should be infrequent. Therefore, in the United States, any voltage between 114 and 126 Vac is deemed to be an acceptable voltage or, as the standard states, a "favorable voltage." Range B is considered the tolerable range and includes voltages above and below Range A limits, where the voltage is allowed to enter an acceptable zone of 110–127 Vac for short durations. Corrective actions must be undertaken for sustained voltages in Range B to meet Range A requirements.

If the distribution system voltage is too high, it can damage power delivery equipment, such as transformers, as well as consumer equipment, such as appliances and electronic equipment. High voltages can also reduce the life of lighting products. If the incoming voltage is too low, lighting will dim, motors will have less starting torque and can overheat, and some equipment, such as computers and TVs, will power down. As a general rule, lower voltages result in more damage to the load on a distribution system and higher voltages cause more permanent damage.

Power flows from generators through transmission and distribution lines and several transformers before it reaches the end customer. Transmission and distribution lines and transformers all have electrical impedance (resistive and reactive), and the current flowing through the impedance results in a voltage drop. Therefore, the main factors affecting the amount of voltage drop are the load (the amount of current), the types of load, and the distribution system impedance.

If the voltage at the customer revenue meter closest to the distribution substation is below 126 and the voltage at the customer revenue meter furthest from the substation is above 114, then there may be no need for any voltage corrective action. This is typically not the case. Without any means to compensate for the reduction and the continual change in distribution voltages, customers closest to the substation will experience highest voltage levels and customers furthest from the substation will experience lowest voltage levels. To regulate the voltage levels at the substation and along the distribution feeder and ensure the voltage levels are within limits at the customer revenue meter, substation power transformers and distribution feeder voltage transformers (voltage regulators) are equipped with means to actively change the turns ratio (taps) of the transformer while energized. The tap changing equipment on power transformers are referred to as LTCs.

8.3 EFFECT OF VOLTAGE ON CUSTOMER LOAD

Studies have shown that a reduction in voltage typically results in a maximum reduction in load when the voltage is first reduced. The level of load reduction achieved with voltage reduction is highly dependent on the type of load on the distribution feeder [1]. The behavior of loads to changes in voltage varies. There are three generally accepted load types (Figure 8.1):

1. Constant impedance load, where the ratio of voltage to current remains constant. With constant impedance loads, when the voltage is decreased, the current also decreases. Resistive load, mostly lighting and heating, as well as appliances powered via no-switching power supplies, has been the predominant type of load on electric systems in the past.

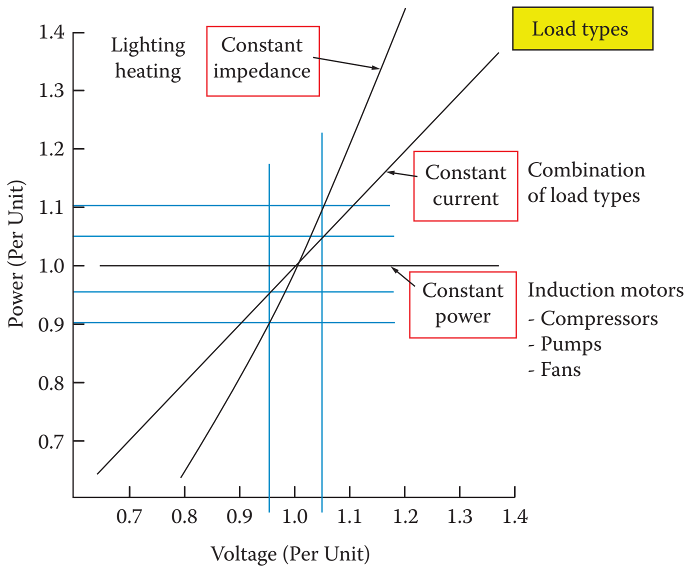


FIGURE 8.1 Load types from ANSI/IEEE Standard 399–1980. (From ANSI/IEEE Std 399–1980. IEEE Recommended Practice for Industrial and Commercial Power Systems Analysis (Brown Book). American National Standards Institute, June 28, 1979. IEEE Standards Board, December 20, 1979. p. 74.)

Consolidated load profiles usually appear somewhere between constant power and constant impedance characteristics.

2. Constant power load where the power consumed is constant as voltage varies. With constant power load, when voltage is decreased, current increases. Constant power loads, such as fluorescent lighting, appliances with switching power supplies, and motors, are becoming more dominant. Motors are the worst type of load for voltage fluctuations because as the voltage decreases excessively, the current increases in a linear manner. If the voltage at the motor load is too low, the motor stalls and this causes an exponential increase in load current.
3. Constant current, where the current is constant as voltage varies. There are few real-world examples of constant current loads, and are usually represented by a combination of loads.

The magnitude of potential CVR benefits on a given feeder is partially a function of the types of loads being served. As shown in Figure 8.1, feeders with high concentrations of constant impedance loads, such incandescent lighting or resistance-based appliances, will see greater benefits from CVR than feeders with higher concentrations of constant power loads. In general, feeders serving residential and small commercial loads are the best candidates for CVR based on their load compositions. Motors provide a more complex case. Many induction motor applications, such as compressors and fans, are actually excellent candidates for CVR. The reasons for this are twofold:

- CVR load reductions from motors are, in part, a function of loading on the motor itself. Since motors tend to be oversized, motors running at partial loadings create energy savings when voltages are reduced within allowable tolerances.
- Lower voltage levels can also increase useful life. Since motors are typically designed to run at voltages on the lower end of the ANSI ranges, reducing voltage can lengthen equipment life. However, it should be noted that motor performance degrades precipitously when voltages fall below 10% of nominal voltage levels.

Technology changes, over time, will have an impact on CVR potential. For example, the move away from incandescent lighting to fluorescent and LED alternatives, and an increase in solid state technologies will impact the implementation of CVR schemes over time.

The effects of the voltage reduction diminish over time as certain loads require additional current at the lower voltage to complete the task. For example, with hot-water heaters, once the water temperature falls below the desired setting, the water heater turns on. At lower voltages, the water heater does not produce as much heat and, therefore, has to run longer to heat the water to the appropriate temperature. This load reduction will typically take 15–30 min to occur, and may not be suitable for peak load shaving applications. If the time required to reduce peak load is less than the time it takes for appliances, such as dyers, water heaters, and heaters, take to cycle on again, then the full benefit of the VR will be realized. For full-time CVR, the maximum load reduction (by percentage) will be seen within the first 30 min, and then it will be reduced by 10%–15%, but should be fairly consistent over the remaining time in CVR.

To decrease the load, either during emergencies or when generation is not available or too expensive, utilities can only reduce the voltage to the point where customers at the end of the feeder are still served above 114 V. This means that customers closest to the substation are served power at a higher voltage. If this is the case, the full benefit of voltage reduction cannot be achieved. A constant level (or "flat") voltage profile from the substation down the distribution feeder to each customer would allow for maximum voltage reduction benefits. Large reactive loads and impedance in the distribution system result in an uneven voltage profile that sometimes cannot be entirely compensated by adjusting the substation transformer and distribution feeder voltage regulator taps. The LTC and regulators can account for voltage drop due to real power but cannot eliminate the voltage drop caused by reactive current flowing to support motor loads. In this case, reducing the VArs flowing in the distribution system will help maintain a flatter voltage profile along the distribution feeder.

8.4 DRIVERS, OBJECTIVES, AND BENEFITS OF VOLTAGE AND VAr CONTROL

Not all utilities have generation, transmission, and distribution systems as part of their operations, so the drivers, objectives, and benefits of VVO differ for utilities. Whether utilities have generation plants or purchase energy from other utilities or power pools, by reducing the losses in the system through VAr control, the utility can obtain more revenue for the same amount of electricity generated or purchased. However, the grid has a limited capacity. As load continues to increase, the capacity of the grid has to increase with it, meaning more power plants, more transmission lines, and more transmission and distribution substations. This is a high cost to the utility, both financially and politically. Customers consider electricity a commodity and are not always willing to pay for the costs that it takes to deliver it. Customers want to keep the cost down but are not always willing to allow the construction of the plants, lines, and substations in their neighborhoods. By reducing losses through VAr control and customer demand through voltage control, utilities can increase the capacity of the grid and avoid or defer system expansion projects. Time is also a factor that has to be taken into consideration. It typically takes upward of a year to build a substation, several years to build transmission lines, and in the case of nuclear power plants, up to 10 years to bring a new power plant online. With the current increase in demand, it may not be possible to keep up with the customer demand, even if customers are willing to help with the costs. If the amount of power generated can be reduced by eliminating losses, less CO_2 will be generated from the power plants. Reducing the emissions from the plants can be a tremendous benefit for both the utilities and the public in general.

Utilities generate electricity in multiple ways: hydropower plants (power plants that use water to generate the electricity), fossil power plants (plants that use coal, natural gas, or oil to generate electricity), nuclear power plants, and the green power from the sun or wind. Each of these plants has different costs associated with producing the electricity, with hydro and nuclear the cheapest to produce, followed by the fossil fuel plants, and finally the green plants. Utilities maximize their profits by generating electricity from the most cost-effective plants, using the remaining plants for peak or emergency power only. Sometimes it is actually cheaper for the utility to reduce load rather than run an additional power plant for a few hours to support the temporary increase in load. Weekday load typically starts to increase in the morning when customers are getting ready for work and commercial and industrial businesses start for the day. Load then typically peaks during the day before reducing to the lowest level overnight, as shown in Figure 8.2. The distribution feeder and substation load profile depends on the type of customer and load. Other factors can change the load pattern, such as weather. Residential loads typically peak between 2 and 6 pm in the summer in areas with high temperatures due to air-conditioning load. Irrespective of the load pattern, there will always be times when the load on the system is higher or lower than average. Ideally, a constant load on the system would help utilities operate the most cost-effective base generation, such as fossil or nuclear power plants. However, peak loading requires utilities to operate more expensive, fast-responding generation, such as gas turbines. Utilities are also required to have reserve generation capacity on immediate standby as contingency for any loss of generation on the system or any possible system reconfiguration due to equipment failures. As discussed earlier, lower voltages will, for at least short periods, reduce the power consumed by customer loads. The opposite is true for higher customer delivery voltages, causing a general increase in load. Customers on the same distribution feeder with exactly the same loads will have slight differences in their electricity bill, with the customers closer to the substation having a slightly higher bill due to the fact that their incoming service is at a higher voltage than those of customers located at the end of the line. Therefore, changing the voltage can change the loading and, therefore, the revenue. One would think that a utility would always want to run the voltage on the high side to increase revenue, but this is not always the case. There are several operating conditions that benefit the utility to run the system at lower voltages.

While VVO has been implemented for many years to varying degrees, smart grid initiatives now bring renewed focus on the implementation considerations and measured benefits of voltage and VAr control to utilities. Current utility installations have shown that VVO can reduce distribution feeder losses up to 25% and the peak load by up to 3% (Table 8.2), depending on the load characteristics.

Another key benefit of VVO is that of security and reliability. As the growth of customer load outpaces the supply, the utility power delivery reserves are dwindling, making the system more

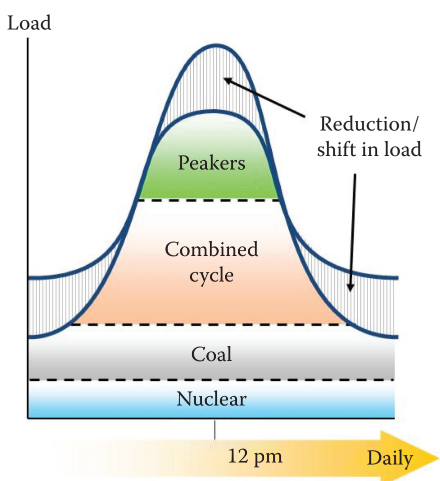


FIGURE 8.2 Typical system load curve and corresponding generation dispatched.

TABLE 8.2
Typical Load Reduction Due to CVR

Percentage Voltage Regulation	Percentage Load Reduction at Unity Power Factor	Percent Load Reduction at 0.9 Power Factor
2	1.5	0.5
4	3.0	2.0

Source: M. S. Chen, R. R. Shoults and J. Fitzer, Effects of Reduced Voltage on the Operation and Efficiency of Electric Loads, EPRI, Arlington: University of Texas, EL-2036 Volumes 1 & 2, Research Project 1419-1, 1981.

Note: Empirically, load reduction can be in the range of 0.6%–0.9% for each percentage of voltage reduction on a distribution feeder. The trend with recent smart grid initiatives has included some form of field pilot or verification phase in order to verify the implementation requirements and costs of distribution automation applications before deciding on any system-wide deployment strategies. More importantly, the focus has been on measuring and verifying the expected benefits of the applications, such as from Volt/VAr control.

susceptible to brownouts (suppressed voltage conditions) and blackouts (loss of power). VVO helps increase the available capacity of the power delivery system.

An emerging trend in generation is that of CO_2 emission restrictions with carbon taxes and credits. If a utility can reduce the amount of generation required, especially with the coal and fossil plants, the utility can reduce the CO_2 levels, thus reducing the taxes and possibly actually building up credits.

While VVO brings significant benefits to the utility, the downside is that more equipment is required on the distribution system, such as voltage regulators and capacitor banks, as well as the means to monitor and control the devices. However, smarter monitoring and control can minimize the number of total operations of the equipment and, therefore, reduce maintenance costs. Smarter monitoring can also identify failed equipment, such as fuses and pole-top transformers or capacitor banks, to allow for quicker service restoration. Besides detecting outages faster, the smart grid will enable utilities to restore faster by remotely changing the configuration of the grid. This change in configuration can add complexity to the role of VVO implementation, which will be discussed in upcoming sections.

Utilities have several options when deciding how to mitigate VAr and voltage problems on the distribution system. Utilities will typically identify the top "worst performing" feeders in terms of VAr and customer voltages. For CVR applications, some feeder circuits may be bypassed due to critical loads or a circuit just not having enough load to produce a positive ROI when reducing the voltage. Utilities may have sufficient remote monitoring of VArs and voltages through supervisory control and data acquisition (SCADA) or a distribution management system (DMS) to identify worst performing feeders, or they add temporary sensors at locations along the feeder to record VAr and voltage levels for analysis. The addition of capacitor banks is typically the most effective approach to reducing VArs on the distribution feeders; the equipment and control will be discussed in the following sections. However, utilities have several options for controlling voltages levels at the customer. Utilities will identify and evaluate the most cost-effective options, depending on the amount of voltage reduction required. These options range from upgrading (with an increased rating) transformers, reconductoring feeders and customer secondary connections to using substation transformers with LTCs and voltage regulators on the distribution feeders. The following sections describe the equipment and approaches to voltage control.

8.5 VOLT/VAr CONTROL AT THE SUBSTATION

The majority of electricity delivery losses occur at distribution voltages. Distribution substations are typically fed from two or more transmission lines (e.g., 115 or 230 kV). There are typically one or more power transformers in the distribution substation that step the voltage down to between 4 and 34.5 kV. The low side of each transformer will connect to a bus that feeds multiple distribution feeders to distribute the power to the end customers. Some substation configurations allow the interconnection of the low-side busbars so that one transformer can feed multiple buses if another transformer fails or is removed from service for maintenance. The distribution power transformers and low-side buses in the substation are the primary point in the distribution system for voltage regulation.

8.5.1 Power Transformers

A power transformer has fixed winding ratio connections (taps) and, as discussed earlier, may also have variable taps to actively change the turns ratio of the transformer while energized (LTCs). The fixed taps allow for an adjustment of the voltage on the low side and there are typically settings for 0%, ±2.5%, and ±5%. This means when the rated incoming voltage is present, the secondary voltage can be at rated voltage (0% fixed tap) or 2.5% or 5% higher or lower than rated voltage. The fixed tap setting can only be changed when the transformer is out of service. If the transformer is equipped with an LTC, the low-side voltage can be varied with the transformer in service. The LTC typically allows for a 10% variation in voltage in either the raise or lower direction by having 32 taps—16 taps that lower the low-side voltage and 16 taps that raise the low-side voltage. The LTC has very little effect on the high-side voltage. When in the neutral position, the LTC has no effect on the low-side voltage.

The LTC is a single-phase sense, three-phase operating device. It monitors one phase of voltage and current to make decisions, but then acts on all three phases. For the LTC to operate correctly, all three phases of load need to be fairly well balanced. If one phase has significantly more load than another, the voltage drop will be greater. If it is not sensing that phase, the customers on that phase may have low voltage near the end of the line. If the phase with the highest current is the phase monitored, the customers on the other two phases may have high voltage near the source. Therefore, in order to have correct three-phase operation while only monitoring one phase, an assumption is made that all three phases have close to the same load. A photograph of a typical distribution substation power transformer with an LTC is shown in Figure 8.3, and a single-line representation of a distribution substation power transformer with an LTC controlling voltage on four distribution feeders is shown in Figure 8.4.

The first advantage of an LTC is that of cost. If the transformer is feeding more than two or three distribution feeders, it will be less expensive to use the LTC than to use single-phase regulators on each distribution feeder. Second is the cost of property. The LTC takes up the smallest amount of real estate. There are several disadvantages of LTCs. First, because it is a single-phase sense, all three phases have to be fairly well balanced. This is easy to do in urban areas where customers are

FIGURE 8.3 Photograph of a distribution substation power transformer with an LTC.

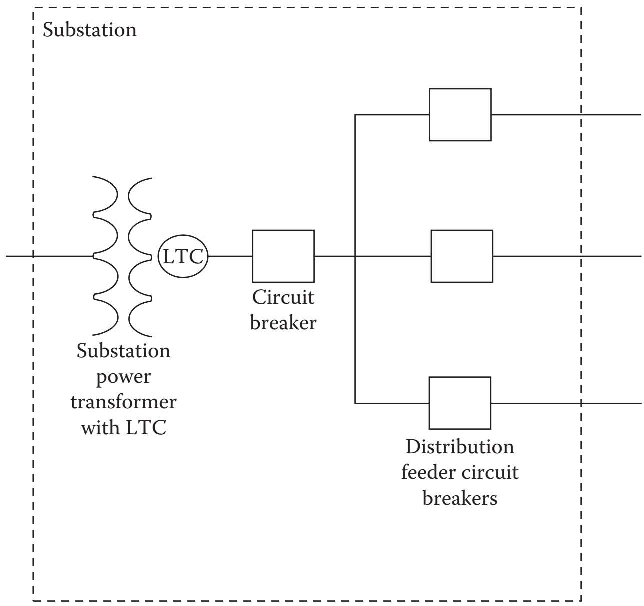


FIGURE 8.4 Single-line representation of a distribution substation power transformer with an LTC controlling voltage on three distribution feeders.

condensed in small areas and distribution feeders are short, typically less than 4 miles. It is not so easy to do in rural areas with distribution feeders that are over 15 miles, most of which are single-phase runs. Another disadvantage is that a failure by either the LTC or the LTC controller can cause over- or undervoltages. Because the LTC is regulating the voltage to all the customers on all three phases of all feeders attached to the transformer, a failure affects many more customers. Another disadvantage is one of maintenance. To maintain the LTC mechanism, the entire transformer has to be taken out of service. This typically requires many hours for switching and limits the maintenance to off-peak load times, such as evenings and weekends.

For smart grid applications, LTCs make life much more difficult. Because one device is affecting the voltage on many feeders, it is difficult to achieve a flat voltage profile. Each distribution feeder attached to the LTC will have a different length and, therefore, different impedance and also different loading conditions. Therefore, the voltage drops (and profile) along each feeder will be different, making it difficult for the LTC alone to attempt to correctly regulate all the feeders.

8.5.2 Substation Bus Regulation

Substation bus regulation attempts to regulate the voltage on the low-side bus of the distribution substation power transformer before the individual distribution feeders. There are two approaches to bus regulation: single-phase regulation and three-phase regulation. With three-phase regulation, the approach is similar to that of the LTC with one exception: The LTC is separate from the power transformer. The advantage of doing this is that maintenance of the three-phase regulator can be performed without taking the transformer out of service. The disadvantage of a separate bus regulation LTC over the transformer LTC is that the bus regulation LTC is more expensive and the installation footprint is much larger. This approach was popular many years ago, but few implement and manufacture three-phase regulators today.

The second approach to bus regulation is the use of three single-phase voltage regulators. One advantage of using three single-phase regulators is that with each phase being individually sensed and controlled, the loads do not have to be balanced for effective phase regulation. Another

FIGURE 8.5 Photograph of three single-phase bus voltage regulators.

advantage is that a failure of the regulator or regulator controller now only affects the customers on that phase. This can also be a disadvantage for customers with three-phase loads. A failure of one phase can cause a large voltage difference between the failed phase and the remaining two phases. If the voltage difference is too large, the imbalance can cause heating and failures of three-phase motors. The primary disadvantage to single-phase bus regulation is that of equipment size. The single-phase regulators cannot handle as much current as the three-phase bus regulators and, therefore, the substation transformer size and loading must be limited when using single-phase voltage regulators. From a cost standpoint, if the transformer is 20 MVA or smaller, single-phase bus regulation can be very economical. For this reason, single-phase bus regulation is very popular in rural substations, which tend to have fewer distribution feeders and less load as customers are more dispersed. Figure 8.5 shows a set of three single-phase bus regulators, and Figure 8.6 shows a single-line representation of a distribution substation with bus voltage regulation.

Bus regulation, whether single phase or three phase, still poses many of the same limitations of the LTC, mainly one device, or set of devices, regulating the voltage of multiple distribution feeders.

8.5.3 Single-Phase Voltage Regulators

With single-phase regulation, each distribution feeder is regulated separately prior to leaving the substation. In this approach, the transformer and low-side bus are left unregulated. This approach requires the most space in the substation for installation and is typically the most expensive, but offers the most flexibility and reliability. For example, if the substation transformer is attached to a bus feeding four distribution feeders, then 12 single-phase regulators and controls would be required.

The reliability of this voltage regulation approach is higher than the approaches discussed earlier, since a failure of a single control or regulator only impacts the customers on that phase of that distribution feeder. The flexibility comes from the fact that each feeder is independently regulated. This allows for different distribution feeder lengths and loads to be accommodated independently. For this reason, many utilities are now designing new substations with single-phase voltage regulation

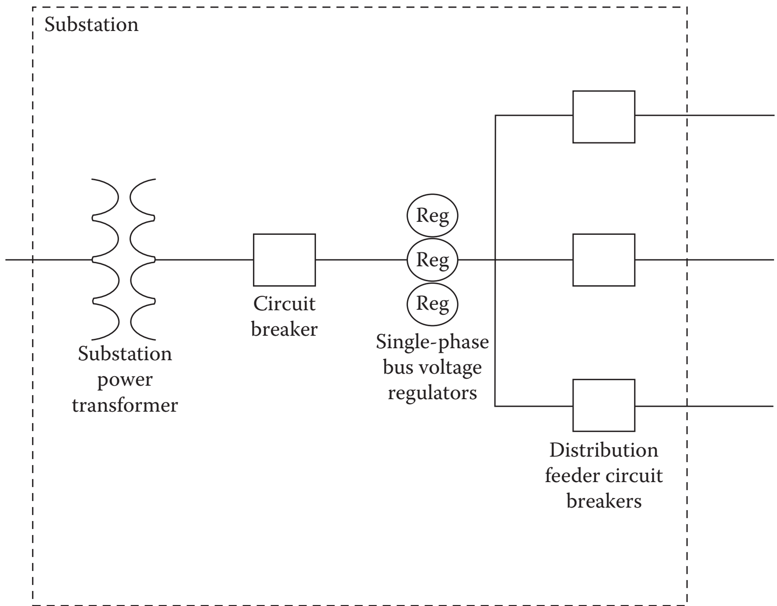


FIGURE 8.6 Single-line representation of a substation with bus voltage regulation using single-phase voltage regulators.

FIGURE 8.7 Photograph of single-phase voltage regulators on distribution feeders in the substation.

even though it has the highest installed cost. Figure 8.7 shows single-phase voltage regulators on distribution feeders in the substation, and Figure 8.8 shows a single-line representation of a distribution substation with single-phase voltage regulators on each of four distribution feeders.

8.5.4 Substation Capacitor Banks

Placing capacitor banks at the substation bus level is sometimes done in order to both regulate the bus voltage and supply VArs to the distribution system and load (VAr compensation). Use of

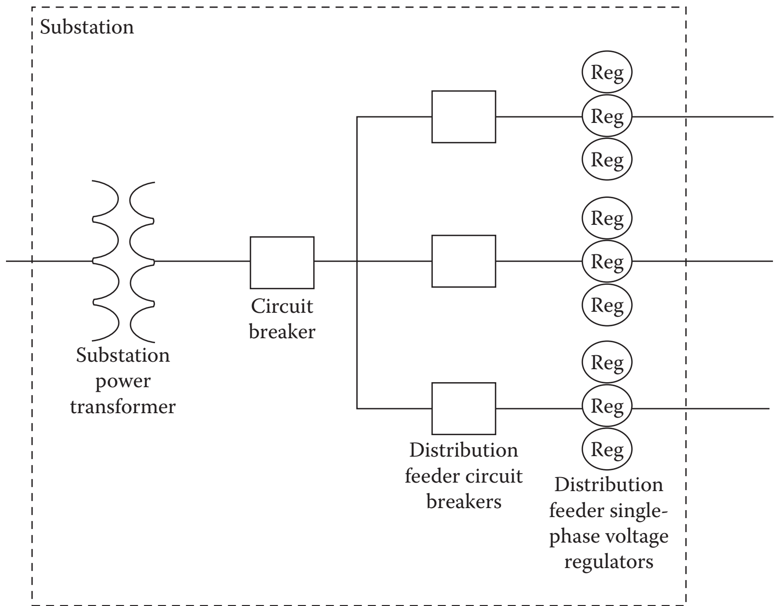


FIGURE 8.8 Single-line representation of a substation with single-phase voltage regulators on each of three distribution feeders in the substation.

capacitor banks at the substation level has disadvantages. First, the size is typically fairly large, so when the capacitor banks operate, they have a larger effect on the bus voltage. This can cause LTCs and regulators to operate in response. It is not recommended to use substation capacitor banks with LTCs, as it is typical to see the LTC having to operate 5–8 times per operation of the capacitor bank. As discussed earlier, it is difficult to perform maintenance on LTCs, so it is not a good idea to increase the number of operations. The other negative effect to the use of substation capacitor banks is that the use of the bank provides VArs at the substation and does not compensate the VArs flowing down throughout the distribution system. Therefore, station capacitor banks do not reduce losses in the distribution system. Capacitor banks for VAr compensation to reduce losses are more effective if distributed throughout the distribution system and applied close to the inductive load. A good use for substation capacitor banks is to provide the capacitive VArs to cancel out the inductive VArs of the substation transformers. When applying capacitor banks in this method, the banks should be sized appropriately and remain closed when the transformer is in service and open when the transformer is taken out of service.

While voltage regulators, whether LTCs, three phase or single phase, can adjust the secondary or load voltage dynamically, capacitor banks can also perform a similar function. When capacitor banks are added to a point in the power system, there is a resulting increase in system voltage at the capacitor bank. Therefore, capacitor banks provide both VAr and voltage support in the system. There are two primary differences between capacitor banks and regulators regarding voltage control. First, regulators are unidirectional in that they only affect the voltage on the load side of the regulator. Capacitors are bidirectional in that when they operate, the voltage on both sides of the capacitor is affected. Next, regulators can control the voltage in smaller increments, whereas capacitor banks do not have multiple steps of voltage control as a bank is either on, which will cause the voltage to increase, or off causing the voltage to decrease. The effect that the capacitor has on the secondary voltage is a combination of the rating of the bank (kVAr or MVAr) and the location of the bank in the distribution system. Figure 8.9 shows a typical distribution substation capacitor bank.

FIGURE 8.9 Photograph of a substation capacitor bank. (Courtesy of Siemens.)

8.6 VOLT/VAr CONTROL ON DISTRIBUTION FEEDERS

As can be seen, some form of voltage regulation is typically required inside the substation. Transformers with LTCs or bus regulators can be used in service areas with short distribution feeders and balanced load, but from a smart grid standpoint, ultimate flexibility is achieved with individual distribution feeder voltage regulation. Even with this equipment in place, it is typically not possible to adequately regulate the voltage along the length of an entire distribution feeder from within the substation. For this reason, devices on the distribution feeder can be added to provide additional voltage support as well as VAr compensation. Control of these down-line devices has to be coordinated with the substation devices in order to achieve the overall VVO goals.

There are two main components used to aid in the voltage regulation and VAr compensation outside the substation down the distribution feeder: the single-phase line regulator and the pole-top capacitor bank. Most utilities use pole-top capacitors to flatten the voltage profile along the distribution feeder and then regulators to adjust the voltage levels.

8.6.1 Single-Phase Line Regulators

On feeders of considerable length or load, the regulating device at the substation may not be adequate due to the excessive amount of voltage drop along the entire feeder. If the voltage difference between the customer closest to the substation and the customer furthest away is more than 6–8 V (on a 120 base), additional voltage correction will be required by placing single-phase line regulators somewhere between the substation and the end of the feeder ("down-line" of the substation). The single-phase voltage regulators used along the distribution feeder are similar to the single-phase voltage regulators used in the substation, but are typically smaller in size and rating.

Substation regulation will regulate the voltage of the entire feeder, with primary voltage control of the section of the feeder up to the set of line regulators. The line regulators will control the voltage on the section of the feeder below the regulators. Coordination of the operation of multiple sets of regulators is required, usually the substation regulation acting first, then the line regulators. This is needed to reduce operations and avoid hunting. Line regulators can correct voltages on the load side, but not on the source side. Therefore, if the voltage is low on the entire feeder circuit and the line regulator raises the voltage first, the voltage will be within range on the load side of the line regulator but still low on the source side. The substation regulator will have to raise the voltage. Once this is done, the load side of the line regulator may be too high, as the substation regulating device impacts the entire circuit. This may force the line regulator to lower the voltage below it, causing the operations to be placed on the line regulators that were not needed. Coordination is achieved through time delay settings, with each set of the regulators having a longer time delay than the set on the source side of it. Figure 8.10 shows three single-phase voltage regulators down-line on a distribution feeder, and Figure 8.11 shows a single-line representation of a distribution substation with single-phase voltage regulators down-line on three of the four distribution feeders.

From a smart grid standpoint, additional real-time information from customer revenue meters on the feeder can better help in determining the placement of the line regulators and sizing that will be required to handle both normal operations and emergency operations.

8.6.2 Feeder Pole-Top Capacitor Banks

There are two types of pole-top capacitor banks: fixed and switched. Most utilities will use fixed capacitor banks to compensate for the minimum or average amount of VAr support required on the distribution system. VAr flow on the distribution system varies daily and, therefore, fixed capacitor banks cannot effectively compensate VAr loads continuously over the load profile, and in some cases, fixed capacitor banks with the inappropriate rating and location on the distribution feeder can contribute to increased VAr flow on the distribution system. Figure 8.12 shows a pole-top switched capacitor bank.

Switched capacitor banks are similar to fixed banks except that they have additional switches and controls, which allow the capacitor banks to be switched on or off either remotely via SCADA, or a VVO controller, or locally via an automatic sensing control. Capacitor banks are similar to LTCs in that they use a single-phase sense with a three-phase operate device. If multiple capacitor banks are deployed on the same distribution feeder, each bank is typically connected to sense-alternating phases of the feeder. The sense on the given phase can be a voltage, current, or both, depending on the type of control selected. Coordination of capacitor bank control is done exactly the opposite of regulators. Coordinated control is required between the capacitor banks and the regulators in order

FIGURE 8.10 Photograph of three single-phase voltage regulators on a distribution feeder.

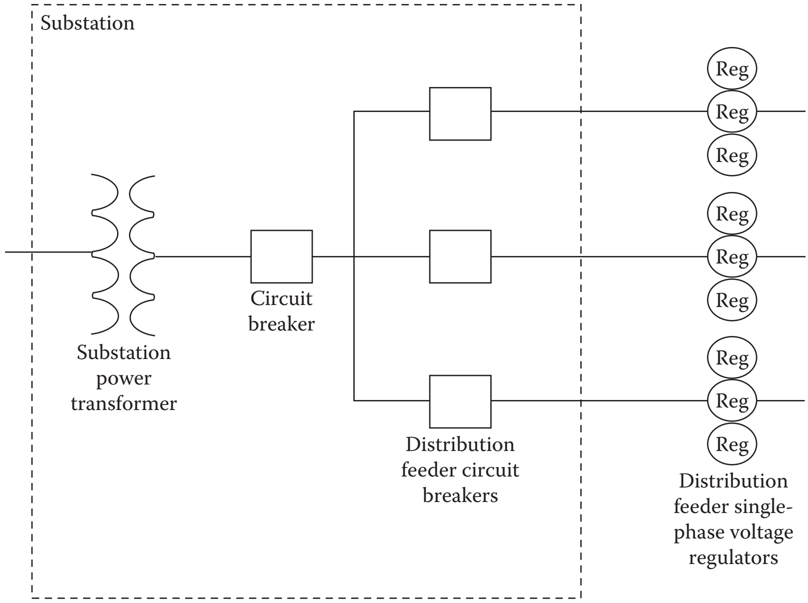


FIGURE 8.11 Single-line representation of a substation with single-phase voltage regulators down-line on three distribution feeders.

FIGURE 8.12 Photograph of a pole-top switched capacitor bank.

to avoid conflict between the control schemes. Coordinated control between voltage regulation and capacitor bank switching is the premise of VVO.

The voltage drop across a distribution circuit is due to the current flowing through the impedance of the circuit. Both the current and impedance are made up of two components: real and reactive. The reactive component of the impedance and the current is typically inductive. To minimize the inductive current, a capacitor bank is used. The main reason to use a voltage regulator in the distribution system is for voltage correction due to the voltage drop caused by the flow of real current. Voltage drop caused by the flow of reactive current is corrected using switched capacitor banks. There are two possible reasons for applying capacitor banks: power factor correction and voltage correction. Some utilities use capacitor banks for voltage correction. Switched capacitor banks are less expensive to purchase and install than single-phase line voltage regulators, and the long-term maintenance costs are also less. The theory is to apply many small capacitor banks along the length of the distribution feeder so that the voltage can be regulated in smaller steps. The capacitor bank controls used for this type of system are typically voltage controls, as it is easier to coordinate substation LTCs or feeder voltage regulators with switched capacitor banks if they are all using the same measured parameter. If capacitor banks are used mainly for VAr compensation, then coordination is not as critical between the capacitor banks and the LTCs and regulators. The capacitor bank controls will typically be based on power factor or VAr measurements and will include voltage overrides in the control, which require coordination with the LTCs and regulators.

8.6.3 Power Electronics-Based Devices

In recent years, distributed generation (DG) has become much more prevalent, with both solar and wind becoming more cost-effective. Placing generation directly on the distribution grid presents several challenges. First, the distribution grid was not originally designed to accommodate two-way power flow, which requires more advanced solutions to regulate the voltage and VAr flow on the distribution grid. Then there are two primary differences in the way DG supplies power to the distribution grid compared to traditional large-scale generation sources.

The first difference is that DG can supply power in the form of single-phase generation. Traditionally, all power has been generated and transmitted at three-phase over the grid, where customers consume power at three-phase and single-phase delivery points. With the advent of residential PV, power can now be generated single-phase at the customer power delivery point. This makes it more difficult to balance the loads on each phase and to regulate the feeder voltage caused by the load imbalances.

The second difference in the way DG generates power over traditional generators is in the area of the fuel source. Traditional generation uses a prime mover to control the output of the generator and keep the power output at desired levels. The prime mover was water for hydro plants and steam for fossil fuel plants. If the prime mover is reduced (less water or steam), the output power from the generator was reduced. It is fairly easy with closed-loop systems to keep the power at the level required to meet the load demands. With solar and wind, the prime mover cannot be controlled, and therefore the output of the generator is variable. The variability in the output will cause variability in the voltage on the feeder. The faster the change in the DG power output, the more difficult it is to regulate the voltage. The cycling of DG power output during changing wind and solar conditions can occur several times per minute, with variations in the feeder voltage exceeding 5% from specified supply levels, which is seen as "flicker" in the power supply to customers. In order to respond to the voltage variations created by DG power output variations, a voltage-regulating device on the feeder needs to be able to operate with high speed and an unlimited number of operations.

As discussed earlier, the current generation of regulators and LTCs used for voltage control on the feeder has time delays in the order of seconds, and also requires between 0.25 and 12 s to mechanically change a transformer or regulator tap to adjust the feeder voltage. These regulators and LTCs will not be able to regulate voltages on the feeder, which are rapidly changing due to the presence of DG. Another concern is the increased cost of maintenance. Both regulators and LTCs have moving mechanical components, and therefore a limited number of operations between maintenance cycles and eventual replacement. The increased number of regulator and LTC operations caused by DG can reduce the life expectancy of the regulators and LTCs by half or more, while still not mitigating the flicker. Switched capacitor banks have similar issues. After de-energizing, the capacitor banks are out-of-service for at least 5 min before they can be closed again, so their operating cycle and responsiveness to variations of feeder voltage are much more limited. Likewise, the switches on the capacitor banks have a limited number of operations over their life.

With this in mind, new power electronics-based devices have been developed for application on the distribution feeder to provide the desired operating speed with the capability for virtually an unlimited number of operations. Using power electronics to perform AC-DC and DC-AC back-to-back conversions, these devices can both boost and buck the feeder voltage. The operating speeds of the devices are typically in the range of 1–2 cycles, so they are capable of removing the flicker caused by DG. They are also designed with no moving parts and no batteries, and therefore require minimal maintenance with an unlimited number of operations. These devices were first deployed on the distribution secondary systems to assist in mitigating voltage fluctuation due to roof top solar, and have now migrated to the primary side of the feeder. The sections that follow will focus on the use of these devices on both the primary and the secondary side of the feeder.

8.6.3.1 Feeder Primary Devices

An example of a feeder primary power electronics device is the MVPER (Medium Voltage Power Electronics Regulator) that connects directly to the distribution feeder and can be deployed anywhere on the circuit in a manner similar to the line regulators and switched capacitor banks mentioned earlier in this chapter. The MVPER has a rating similar to feeder capacitor banks, such as 1 MVAr (333 kVAr per phase), and can either inject or absorb reactive current that is 90° out-of-phase with the voltage. Therefore, the device can be used to regulate the feeder voltage, the power factor, or both. The MVPER controller can regulate the voltage and power factor on all three phases independently. This allows the MVPER to regulate voltage imbalances caused by load imbalances due to single-phase generation of the residential PV. Figure 8.13 shows the functional block diagram of an MVPER.

While the MVPER device performs faster than traditional feeder regulators and capacitors, and also has an unlimited number of operations unlike the regulators and capacitors, it is currently at a higher price point, but has a positive ROI (Return-on-Investment) for applications that require faster response time or unlimited number of operations, such as feeders with DG and large motor loads that are constantly changing (e.g., metal shredders, saw mills, and car crushers). It is expected that

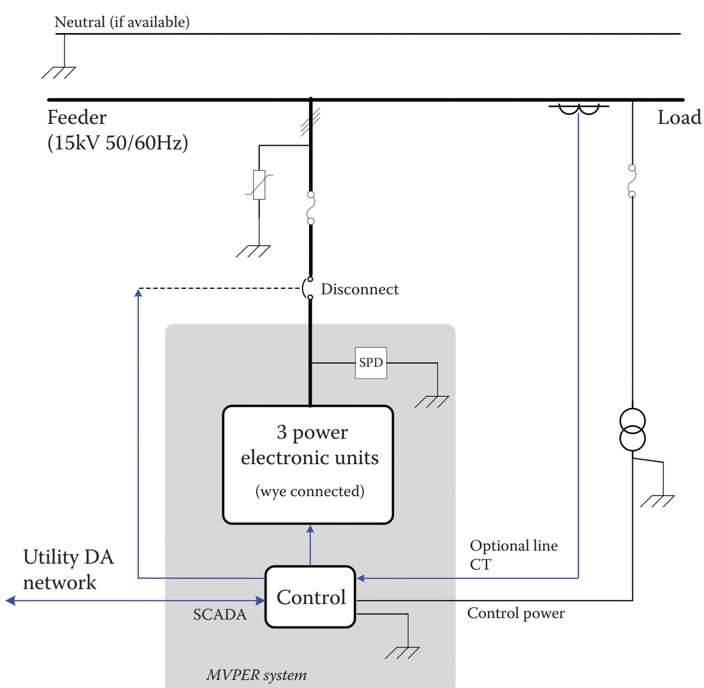


FIGURE 8.13 MVPER functional block diagram. (© 2017 AMSC. All rights reserved.)

these devices will gain additional market penetration as their demand increases and the price comes down to the point of possibly replacing regulators and switched capacitor banks.

When compared to traditional switched capacitors, the MVPER has several technical advantages besides speed and unlimited operations. First, the MVPER regulates each phase independently, while most switched capacitor banks are gang-operated to operate all three phases together. Switched capacitors are either on or off, so a 1200 kVAr switched capacitor is providing 1200 kVAr when closed and 0 kVAr when open. If the feeder circuit is supplying power at 400 kVAr lagging with the capacitor bank open, closing the capacitor bank will cause the circuit to now be 800 kVAr leading. Therefore, it is difficult to obtain the desired power factor on a circuit using switched capacitor banks alone unless many smaller (e.g., 300 kVAr) banks are used. With the MVPER, it can inject reactive current at varying amounts, that is, it can inject 20, 23, or 400 kVAr increments. This allows easier control of the desired power factor on the feeder circuit. In combination with switched capacitor banks, the MVPER can provide the level of fine-tuned control required while allowing the capacitor banks to address larger VAr swings. Coordination is not an issue because the MVPER will always operate faster, thereby reducing the number of operations on the switched banks, which is an added maintenance benefit. Because the MVPER is injecting a variable amount of reactive current on the feeder, it does not cause a negative impact on customer voltage levels as sometimes is the case when closing large capacitor banks. The inrush of large amounts of currents can cause temporary (in cycles) voltage rises that can damage customer loads. The MVPER does not inject large amounts of currents instantaneously. Capacitor banks use capacitors to supply reactive current and can cause resonance of voltage harmonics, magnifying their effect on the system. Because many of the current designs of inverters used with DG create harmonics, this is a factor to consider when using switched capacitor banks with DG. The MVPER does not use capacitors to supply reactive current, but instead uses back-to-back AC-DC-AC converters, which generate minimal harmonics, and do not contribute to the magnification of existing harmonics. Finally, while capacitor banks can only inject reactive current, the MVPER can also absorb reactive current, which allows the MVPER to provide both boost and buck for the voltage on the circuit. It also allows the MVPER to bring the power factor of the circuit closer to the desired power factor compared to switched capacitor banks. By placing one MVPER at the midpoint of the feeder, the utility can maximize the power factor of the feeder and reduce losses, address any imbalances caused by load (or generation), and reduce the number of operations on existing equipment and therefore the operations and maintenance budget requirements. The addition of the MVPER on the feeder also allows for additional DG hosting capacity in the future, as the circuit now has a regulating device with the speed required to address any flicker caused by the variability of the DG.

The MVPER is currently being deployed as a pilot project in a utility in the USA. The application is to correct voltage issues (both high voltages and flicker) caused by two 1.2 MW wind turbines that are generating power at the end of a feeder circuit. Figure 8.14 is a single-line representation of the pilot installation. Power quality meters are used to record voltages at different segments along the feeder, with segment 1 being the substation source and segment 12 being the end of the feeder. The DG is located at segment 11, and there is a set of line regulators between segments 6 and 7. A switched capacitor bank is located on segment 12. The utility attempted to regulate the voltage with the regulators and capacitor bank, but found that the voltage was varying too rapidly, and too often. The regulators were operating over 1000 times per month, and the capacitor bank was operating over 20 times a day. The flicker level (the difference between the lowest and highest voltage over a 1-min interval, in this case) was >5%, which was unacceptable. The utility was also seeing high voltages near the end of the feeder when the wind turbines were producing maximum power.

Figure 8.15 shows the set of three MVPERs installed in the field. They look similar to single-phase regulators, but are electrically connected in a shunt configuration, like switched capacitor banks. While the installation shows three single-phase units installed on a four-wire distribution circuit, single units can also be installed on single-phase feeder laterals.

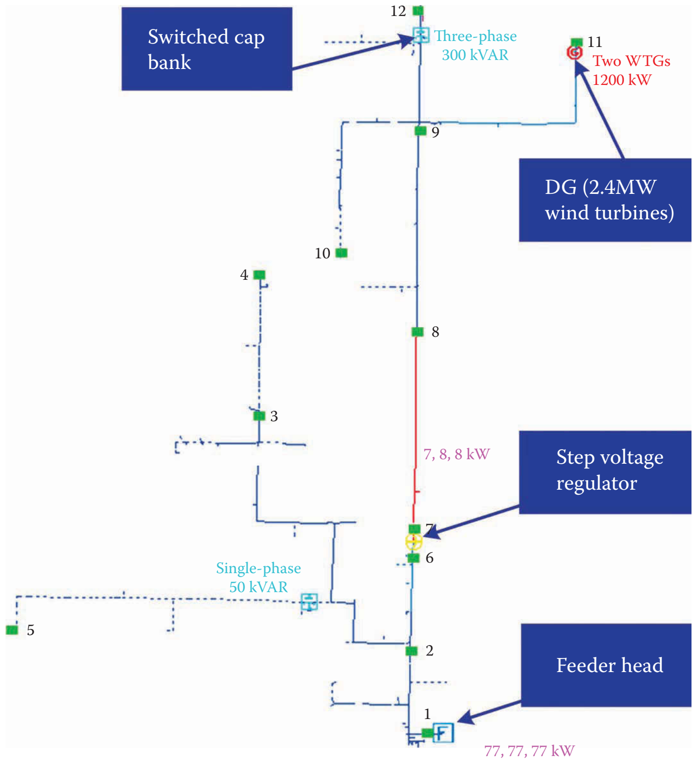


FIGURE 8.14 Single-line diagram of MVPER pilot implementation. (© 2017 AMSC. All rights reserved.)

FIGURE 8.15 Three, single-phase MVPERs installed on a feeder. (© 2017 AMSC. All rights reserved.)

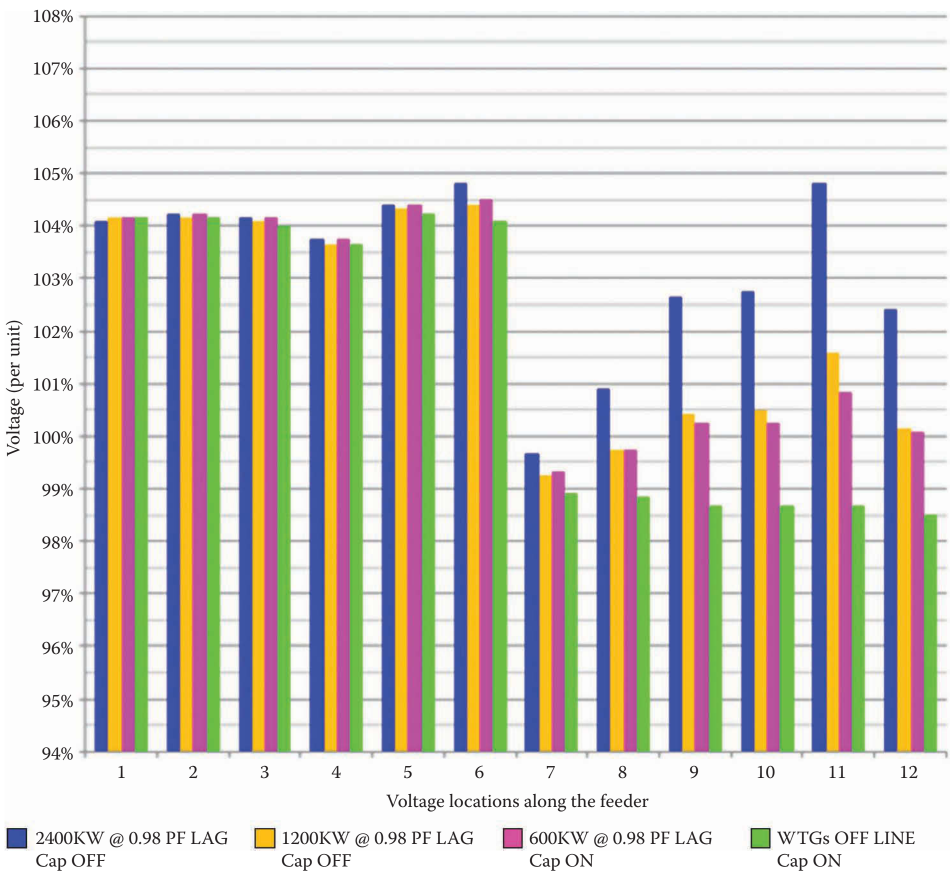


FIGURE 8.16 Measured voltages on the feeder with variable DG and existing feeder regulation equipment (maximum voltage variation is 6.2% at segment 11). (© 2017 AMSC. All rights reserved.)

The feeder circuit was first analyzed by measuring the base case of the voltage controlled with the regulators using a 125 V setpoint. The wind turbines were configured to operate at 0.98 pf, and the switched capacitor banks were voltage-controlled. Voltage measurements were taken at different wind turbine output levels (0%, 25%, 50%and 100%). Figure 8.16 shows the voltages measured along the circuit. The locations are from the substation (leftmost and segment 1) to the end-of-the-line (rightmost and segment 12). The four bars for each section of line are the voltages at the different wind turbine output levels (0%, 25%, 50%, and 100% output). The regulators between segments 6 and 7 were set to buck the voltage (#8 lower tap on the regulators, and placed in manual control) to reduce the voltage near the end of the circuit. One can see that there are possible flicker concerns starting at section 8 through to section 12. The voltage in section 11 was also reaching the high-end of the ANSI-Range A limit of 105% when the wind turbines were at full output, even with the line regulators between segments 6 and 7 lowering the voltage to their maximum possible limit. As a comparison, the circuit and MVPER were modeled and analyzed using Synergy software. The software model results closely matched the measured field results.

Next, an MVPER was added to the circuit at different points, and the output voltages were modeled and analyzed by the software program. The results showed that the optimal placement of the MVPER was at segment 11. The model was then run to compare with the model of the base case system above. The regulators between segments 6 and 7 were left in the voltage buck setting (#8 lower tap on the regulators, and in manual control), and the capacitor bank was left switched on the

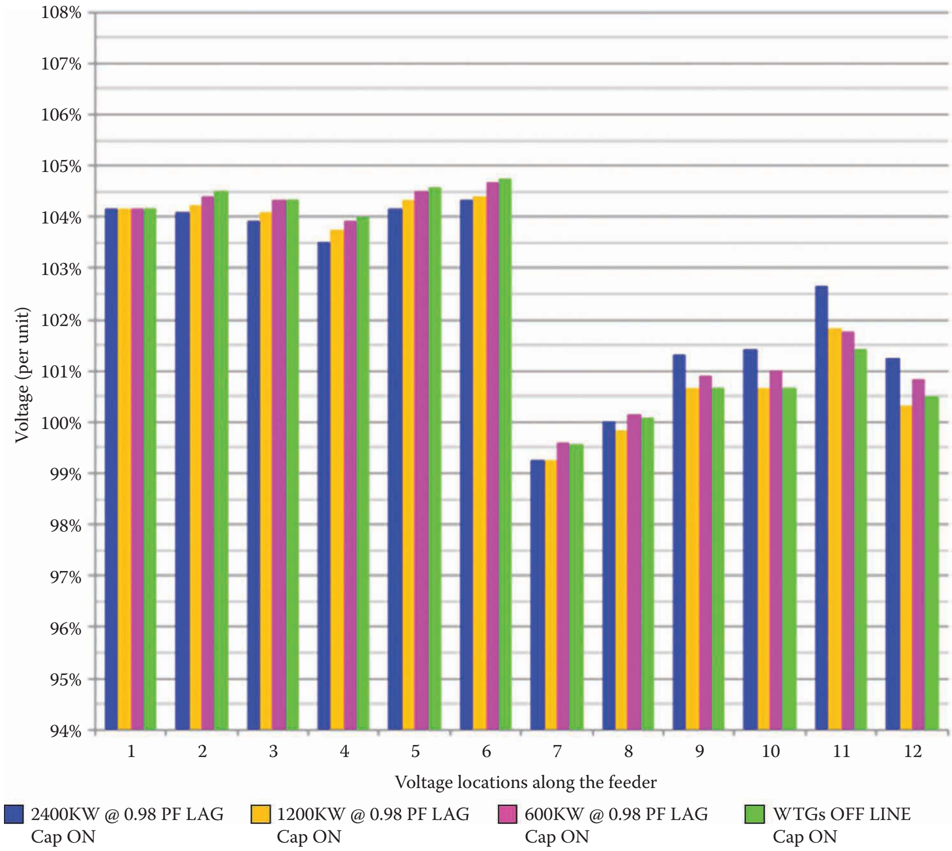


FIGURE 8.17 Modeled voltage differences along feeder with variable DG, MVPER, and existing feeder regulation equipment (maximum voltage variation is 1.3% at segment 11). (© 2017 AMSC. All rights reserved.)

feeder circuit. Figure 8.17 shows the modeled results. As can be seen, the flicker results are now within allowable limits across the entire feeder, and the high voltage at full wind turbine output in segment 11 is no longer present. The MVPER is capable of providing full current injection within 2 cycles.

As a final step, the utility modeled the circuit with the removal of the capacitor bank and the line regulators, leaving the MVPER as the only voltage-regulating device. Figure 8.18 shows the modeled results. As can be seen, the MVPER provides a flatter voltage profile across the entire feeder, to the point where the utility can now implement a 2.4% voltage reduction as part of their overall CVR (Conservation Voltage Reduction) plan. Before the application of the MVPER, the variability caused by the DG would not allow the circuit to be a candidate for CVR. On a typically distribution circuit, the MVPER is able to provide 2%–6% of voltage regulation, and multiple MVPERs can be placed on the same circuit without any concern for voltage resonance.

Series-connected power electronics-based devices are not yet commercially available for feeder primary circuits, but it is predicted that within the next 2–3 years, a combined series and shunt device will be available that will allow for larger voltage boosts/bucks than the current technology.

Power electronics-based devices on feeder primary circuits, such as the MVPER, are best suited for feeders with one or more large utility-scale (1–8 MW) DG sites, or feeders with a high concentration of customer PV installations. For feeder circuits with a low concentration of customer PV installations that are scattered across the circuit, a similar power electronics-based technology

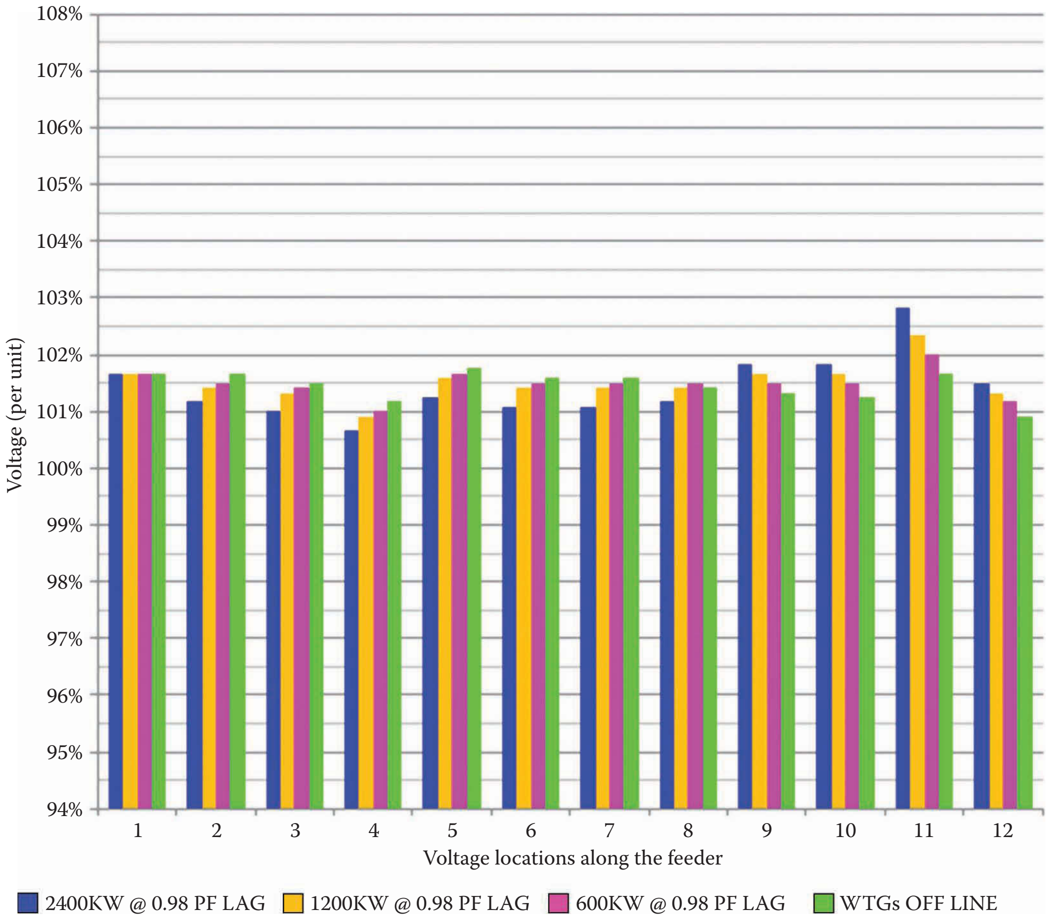


FIGURE 8.18 Modeled voltage differences along feeder with variable DG and MVPER only (maximum voltage variation is 1.2% at segment 11). (© 2017 AMSC. All rights reserved.)

deployed on the feeder secondary may be a more cost-effective approach. This will be discussed in the next section.

8.6.3.2 Feeder Secondary Devices

A recent new technology that benefits both VVO and CVR implementations is the use of power electronics to aid in regulating voltages on the customer secondary networks. The secondary is often referred to as the "last mile," or the "grid-edge." This is somewhat misleading as the average length of the secondary in the USA is not a mile, but is often 100–500 ft in length. The secondary starts with the distribution transformer that reduces the voltage from the primary distribution voltage (4–34.5 kV) to the voltage delivered to consumers, which for residential single-phase loads is 120/240 Vac. The secondary comprises a cable from the distribution transformer to the individual customer access point. The secondary terminates at the customer revenue meter. The secondary supply can be strung overhead, fed from a pole-mounted transformer, with either open insulated wire (individual conductors with spacing between each conductor) or triplex cable (the insulated conductors are wound around each other in a bundle). The secondary supply can also be triplex cable buried underground, fed from a pad-mounted transformer on the ground. A hybrid secondary supply option is using an overhead pole-mounted transformer with the cable to the customer buried in the ground.

The secondary is a critical component of the distribution grid since it is the interface with the customer, and the utility must supply the voltage to the revenue meter within the ANSI standard limits (114–126 V for 120 V service supply, and 228–252 V for 240 V service supply). There is voltage drop across the secondary cable caused by the current flowing through the impedance of the distribution transformer as well as the impedance of the cable. The distribution transformer impedance is mainly inductive but the cable is both resistive and inductive. Open wire cable has a higher reactive (inductive) impedance than triplex cable and, therefore, will create larger voltage drops for inductive type loads. The voltage drop caused by the impedance is what typically limits the length of the secondary as well as the number of customers connected to the same secondary transformer.

Implementations of VVO/CVR have focused on flattening the voltage on the primary sections of the distribution system in order to free up room to lower the primary voltage, but they have not addressed the voltage drops caused on the secondary network. If a utility assumes a 6 V drop for secondary voltages, but the majority of their secondaries only have 2–3 V drops, an additional 2–3 V reduction can be obtained on the primary by addressing the few secondaries with low voltages. Historically, low secondary voltages were corrected by upsizing the transformer (which can reduce the voltage drop by 1%–2%), reconductoring the secondary from open wire to triplex or from a small gauge cable to a larger gauge cable (which can reduce the voltage drop by 1%–1.5%), extending the primary to shorten the secondary, or by splitting the secondary into multiple secondaries. Many of these options are expensive and time consuming. Within the last few years, voltage regulators and switched capacitors using power electronics have been developed to allow the utility to regulate problematic secondaries with dynamic regulating devices. These devices can provide 10% boost/buck in the case of the regulator, or 1%–3% boost in the case of the capacitor banks. They are not limited in the number of operations, as they have no mechanical switches, relays, or other moving parts that are rated on operations or wear. They also operate much faster than primary devices. By applying these devices on secondaries with larger than normal voltage drops, the VVO/CVR system can allow a further reduction in the primary voltage, which justifies the business case for installing the secondary control devices. AMI data can be used to identify locations requiring additional secondary voltage mitigation equipment.

In US urban areas, a 75–100 kVA transformer will typically provide power to 20–40 customers, while in rural areas, a 15–25 kVA transformer may provide power to 1–3 customers as the customers are further away from each other. Most secondaries are radial in nature, with one transformer providing power to all customers on the secondary side. In larger cities, the secondary may be networked, in which case several transformers provide power to one secondary. Networked distribution systems are more reliable, but also more complicated as power can flow in both directions at any point on the secondary. Figure 8.19 shows an example of a secondary with a 50-KVA transformer feeding 5 homes, three of which have PV.

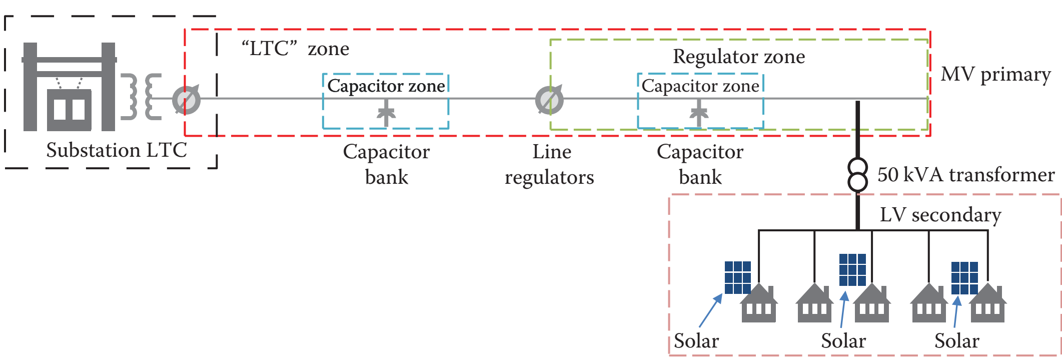


FIGURE 8.19 Typical distribution supply in the USA.

Historically, the secondary side of the distribution system has had little technological advances from the beginnings of the grid until as recently as 10 years ago. Utilities had little information on the performance or behavior of the secondary other than the billing information obtained by the revenue meter (kWh). The technology upgrade for the distribution secondary started with new technologies for the revenue meter and automated meter reading (AMR), followed by advanced metering infrastructures (AMIs). AMR allowed utilities to remotely retrieve billing data, but provided very little in other features or measurement data. With AMI, utilities can now also monitor the voltages and load currents at each meter. This is a critical change for the operation, maintenance, and planning of distribution systems because secondary voltages that were outside ANSI limits were not known unless customers complained. For high voltages, their light bulbs would burn out quicker, and for low voltages, motor starts (air conditioning) would cause the lights to flicker. In the past, most customers did not complain, so many secondary circuits were out of compliance and the utility would not know. Now that secondary voltages at the customer revenue meter can be retrieved from revenue meters, utilities can proactively correct voltage issues without relying on customer complaints.

The distribution secondary has gone through dramatic changes in the last 10 years, and this trend will continue with advances in technology and the need to efficiently and safely operate a smarter distribution system. The first change occurring is that of load. Load in a typical home is increasing due to use of more devices, and higher-powered devices using switching power supplies. An HD TV draws more power than the traditional TV, and some homes can have several HD TVs. An increase in laptops, tablets, smart phones, and so on is also adding load, as are smart appliances. These loads are also changing from mostly constant resistive load to more constant power type loads, and the switching power supplies are increasing the amount of harmonics being generated by the consumer loads. Harmonics cause an increase in the voltage drop. The second trend on the secondary is that of distributed generation installed by customers. The distribution secondary was designed to have power flowing from the utility to the consumer. With the advent of residential photovoltaic (PV), customers are now able to supply power back to the utility. When the customer is supplying power back to the grid, it causes a voltage rise on the secondary circuit close to the PV, and the voltage drop due to the current flow is now from the customer access point to the distribution transformer. The variable output of the PV due to clouds can also introduce flicker on the secondary, as the direction of power flow can quickly change causing the direction of voltage drop to quickly change. Electrical vehicle chargers can also cause dramatic changes in load profiles. Distribution transformers are rated for a maximum kVA value, and the load required to charge a vehicle may force the transformer into overload conditions, especially if multiple homes on the same secondary have car chargers. This may require utilities to replace the transformer with one that has a higher rating. Another cause of changing loads is house upgrades or remodels. Many older neighborhoods are having their homes increased in square footage, either by adding on the home or rebuilding larger homes on the same lot, thus increasing the load on the secondary. With customer loads increasing, an increase in distributed generation on the secondary, and the utility now monitoring voltages on the secondary at revenue meters, an increase in ANSI voltage limit violations is expected in the future that will need to be mitigated.

Historically, utilities would place a temporary power quality meter on a secondary for 30 days once they received a complaint from a customer to determine whether the secondary was experiencing high or low voltages, and how often. If several customers in the same area were impacted, the resolution to the problem would be performed on the primary side of the distribution circuit, either by changing settings of regulator/capacitor controls, or by adding regulators/capacitors close to the problem area. If the secondary was an isolated problem, then the resolution to the problem would be on the secondary.

For secondary high-voltage problems, the utility would typically replace the distribution transformer with one that has more impedance and, therefore, reduce the voltage at the customer revenue meter. The other option is to change the fixed tap on the distribution transformer (an option with added cost that many utilities do not purchase).

For secondary low-voltage issues, the utility could either reduce the secondary transformer and cable impedance to decrease the voltage drop on the secondary, or reduce the load on the secondary, which would also decrease the voltage drop. To reduce the impedance, there were three options. Option one was to replace the distribution transformer with one that had lower impedance. This would reduce the voltage drop typically by 1%, but would also increase the amount of available fault current. This option is typically the least expensive option. The transformer can also be replaced with one with fixed taps and the fixed tap set to provide a voltage boost; however, the fixed tap transformer is more expensive. The second option, referred to as reconductoring, involves replacing the secondary cable with a lower impedance cable. This option is more expensive, as it is more labor intensive. This can reduce the voltage drop by 1%–2% if switching from open wire to triplex, but if the secondary was already triplex, increasing the size of the cable would only reduce the voltage by 1%. The final option, and by far the most expensive, is to reduce the length of the secondary by extending the primary and mounting the distribution transformer closer to the customers. To reduce the load, there was only one option, and that was to split the secondary into multiple secondaries, thus reducing the load and the distance. This was an expensive but effective option, and typically required adding another transformer, as well as reconductoring.

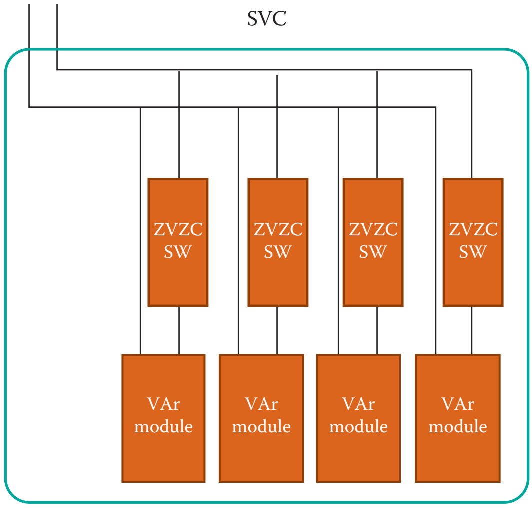
When regulating the voltage on the primary side of the distribution system, the utility will use a combination of regulators/LTCs and switched capacitor banks. Recently, distribution secondary voltage regulators and switched capacitor banks using power electronics-based control have been introduced to the market. While both are used for VVO and CVR, one must look at the differences between the distribution of primary and secondary to determine the benefit of each. One must also have a better understanding of how the regulator differs from the switched capacitor when it is used for voltage regulation.

8.6.3.2.1 Switched Capacitors

The impedance of a circuit can be represented as an *X*/*R* ratio, which is the percentage of the total impedance that is reactive (*X*) versus resistive (*R*). The distribution primary typically has an *X*/*R* ratio of 3: 4, while the distribution secondary typically has an *X*/*R* ratio of 0.8: 1.2. The voltage rise obtained by adding a capacitor to the circuit is a function of the size of the capacitor and the amount of reactive impedance between the capacitor and the source. The more reactive impedance, the more the voltage rise. With this in mind, a larger *X*/*R* ratio will produce a larger voltage rise when adding a capacitor. This means there will be a larger voltage rise per capacitance on the primary versus the secondary, referred to as “delta V” (V/kVAr); therefore, a higher value of capacitance is required when using capacitors on the distribution secondary.

Capacitors can be thought of (or modeled) as current sources for first-order analysis, so closing in a 20-kVAr capacitor on a 240-V secondary will mean that the capacitor is injecting 80 A of reactive current. This can either reduce the loading on the distribution transformer, or increase the loading, depending on the amount of inductive current being drawn by the load. If the load is drawing the same amount or more of inductive current, closing the capacitor will reduce the kVA load on the transformer. If the amount of inductive load is less than half the size of the capacitor rating, the load on the transformer will increase when the capacitor is closed. Any capacitive current not required to reduce the inductive load will flow back through the transformer and onto the primary. This means if several secondary capacitors are used on the distribution secondary, they may impact the current flow on the distribution primary, which would require coordination of the operation of the secondary capacitors with the operation of the primary capacitors.

Figure 8.20 shows the functional block diagram of a type of secondary switched capacitor known as a static var compensator (SVC), and Figure 8.21 shows a secondary switched capacitor installed on a feeder. Secondary switched capacitors are best suited for adding a voltage rise on the secondary when the secondary has smaller (15–25 kVA) distribution transformers, or have large runs of open wire cabling on the secondary. The larger the transformer, the less reactive impedance, and triplex



- Connected in parallel with 240 V secondary
- Zero volt/zero current thyristor-based switching (ZVZC) discrete regulation
- 1–3% boost (dependent on system impedance)

FIGURE 8.20 Secondary switched capacitor functional block diagram (four stages). (© 2016 Gridco Systems. All rights reserved.)

FIGURE 8.21 Secondary switched capacitor installed on a feeder. (© 2016 Gridco Systems. All rights reserved.)

cabling has less reactive impedance than open wire cabling. The capacitor bank should be installed as close to the customer and as far from the distribution transformer as possible to provide the highest level of voltage increase on the secondary cable. Capacitor banks may be suited for secondary voltage mitigation when the issue is low voltage, but they are limited on the amount of voltage support (typically 1%–5%) that they can generate, and they cannot mitigate high-voltage issues. Table 8.3 shows

TABLE 8.3
Examples of Distribution Secondary Voltage Increase with Secondary Switched Capacitors

Transformer Rating (kVA)	Installation Location	Delta V (V/kVAr)	Voltage Increase with 20 kVAr Capacitance Added (V)
25	170 ft from transformer (open wire)	0.49	9.8
50	Same pole as transformer	0.13	2.6
50	70 ft from transformer (open wire)	0.15	3.0
25	Same pole as transformer	0.14	2.8
50	170 ft from transformer (open wire)	0.29	5.8

the voltage rise (V/kVAr) measured at utility field installations with different sizes of transformers and the secondary switched capacitor either mounted on the same pole as the transformer or downstream (with open wire cable). One can see the impact the size of the transformer and the location on the secondary have on the voltage rise created when adding the capacitor.

There are three main advantages of using secondary capacitors. First, they are a shunt device and can be installed (typically in 20–30 min) without the need for a customer outage. Second, they are smaller and lighter than the secondary regulator. Finally, they are approximately half the cost compared to installing a secondary regulator.

8.6.3.2.2 Voltage Regulators

The secondary voltage regulator is a voltage source and, therefore, has no impact on the primary voltage. This means the regulator can be installed on the secondary without the need to coordinate with the primary voltage regulator devices, truly decoupling the secondary circuit from the primary for voltage control. The secondary voltage regulator can provide up to 10% boost (increase) and 10% buck (reduction) of the secondary voltage. As with a primary voltage regulator, the secondary regulator has a source and load side, and the regulator boosts/bucks the source voltage to create the desired voltage change on the load side. This means that only customers connected to the load side of the regulator will receive benefit from the regulator. Also, as with primary regulators, the secondary regulator has a kVA rating. If this rating is exceeded, the regulator will enter a bypass state and stop regulating until the load falls below the maximum rating. It is critical that the maximum load be determined (via AMI data) to verify that the load will remain below the rating of the regulator since voltage violations typically occur at higher loads when the regulator is required to mitigate voltage violations.

Unlike primary regulators, secondary regulators do not have fixed taps, but use power electronics for AC/DC and DC/AC conversion to inject a voltage through a series injection transformer back onto the circuit. Without fixed taps, the secondary regulators do not have moving parts and, therefore, are not limited by the number of operations. They can also regulate with a finer resolution than regulators on the distribution primary. Primary regulators can adjust the voltage by 0.75 V per tap on a 120-V basis, while secondary regulators can regulate the voltage continuously to within 0.1-V on a 120-V basis. While primary regulators typically take 30–120 s to adjust the voltage, the secondary regulator can start changing the voltage within one cycle and can be providing full boost/buck within three cycles.

Figure 8.22 shows the functional block diagram of a secondary voltage regulator, and Figure 8.23 shows a secondary voltage regulator installed on a feeder. By using power electronics, the secondary voltage regulator can also provide features not found in primary regulators. First, secondary regulators can cancel harmonics by injecting similar harmonic waveforms 180° out of phase to provide cancellation. They can also change the phase angle between the voltage and current, and can therefore inject or absorb reactive VArs. The AC/DC converter converts the 240-Vac voltage into a 460 VDC voltage, then the DC/AC inverter converts the 460 VDC back into a 240-VAC

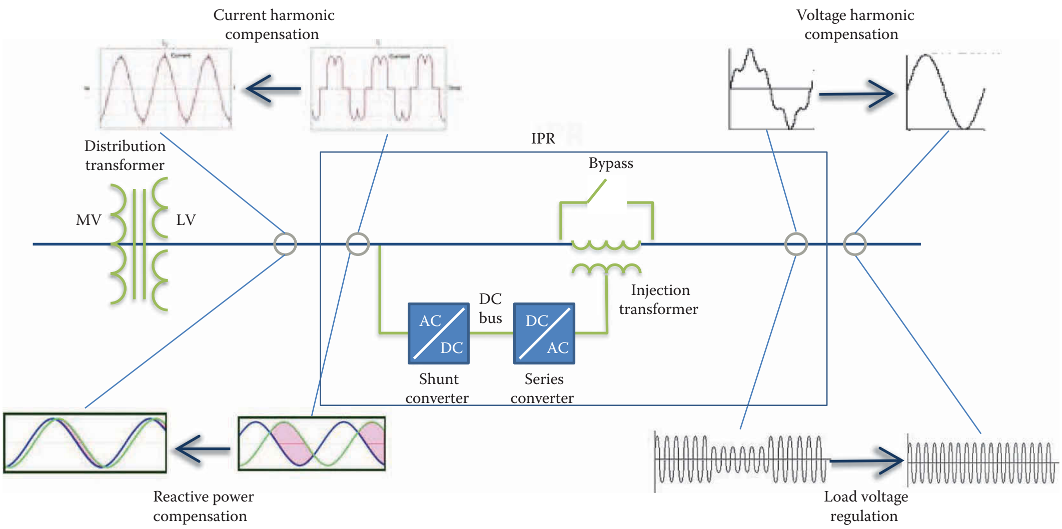


FIGURE 8.22 Secondary voltage regulator functional block diagram. (© 2016 Gridco Systems. All rights reserved.)

FIGURE 8.23 Secondary voltage regulator installed on a feeder (mounted below distribution transformer). (© 2016 Gridco Systems. All rights reserved.)

signal. This allows the regulator to also vary the phase angle so that it can inject or consume VArs on the source side. A series injection transformer then allows the regulator to inject a voltage back onto the load side of the secondary. A voltage that is in phase with the source voltage will boost the load voltage, while a voltage 180° out of phase with the source voltage will buck the load voltage. Voltage harmonics going into the load can also be mitigated. A bypass switch across the injection transformer allows the unit to be taken out of service locally or remotely and also during overload or fault conditions to prevent damage to the voltage regulator.

The advantages of the secondary regulator compared to the switched capacitor for voltage control. First, it can both boost and buck the voltage. Second, it can also provide greater boost and is not dependent on the impedance of the secondary circuit. The regulator is also measuring and monitoring load current, and can provide additional information regarding the secondary circuit, such as loading and waveform capture. Third, the voltage regulator can reduce voltage and current harmonic levels.

8.6.3.2.3 Secondary Voltage Control Applications

There are three primary applications of secondary switched capacitors and voltage regulators:

1. CVR
2. Residential PV operation support
3. Power quality improvements

8.6.3.2.3.1 CVR CVR is an increasingly popular smart grid application that attempts to reduce demand by reducing the voltage at the customer revenue meter. By reducing the voltage, the utility can reduce demand, thus decreasing greenhouse gas from generation supplies, reduce feeder electrical losses, and increase capacity on the distribution system. With this in mind, the primary can only be reduced to the point that allows all secondary to remain above the lower ANSI limit (114 V on a 120 V basis). If a few secondary circuits on a feeder are operating a few volts lower than the other circuits, then these circuits will limit how low the voltage can be reduced on the primary side of the distribution feeder. By adding a capacitor or regulator to those few secondary circuits, the utility can now reduce the voltage on the primary side of the feeder further, and maximize consumer load reduction on the entire distribution feeder. The cost of adding the secondary devices can be justified by the amount of additional load reduction gained. To determine how many secondary circuits will need secondary devices to help with CVR control, AMI data are critical. The AMI data are also essential in determining whether a secondary switched capacitor will be adequate or whether a secondary voltage regulator will be required. Circuit analysis models can be used to identify ideal secondary device applications, but many utilities lack the detailed information required to properly implement the model and analysis (length of the secondary, loading at peak on the secondary, cable material and size, etc.). By having the ability to mitigate individual secondary circuits, the utility can perform a cost/benefit analysis on a per circuit basis to determine the maximum amount of voltage reduction that can be gained.

Figure 8.24 is an example of secondary voltages measured while a utility is operating in and out of CVR mode, and the behavior of the secondary capacitor. The upper measurement is the primary

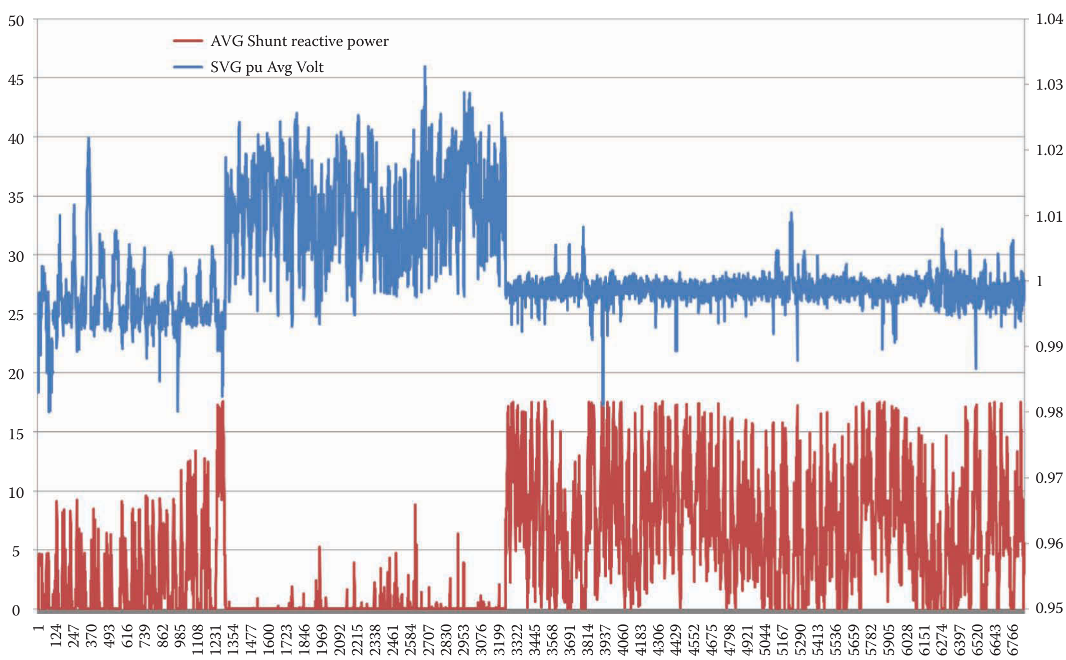


FIGURE 8.24 Secondary switched capacitor boosting voltage in CVR mode. (© 2016 Gridco Systems. All rights reserved.)

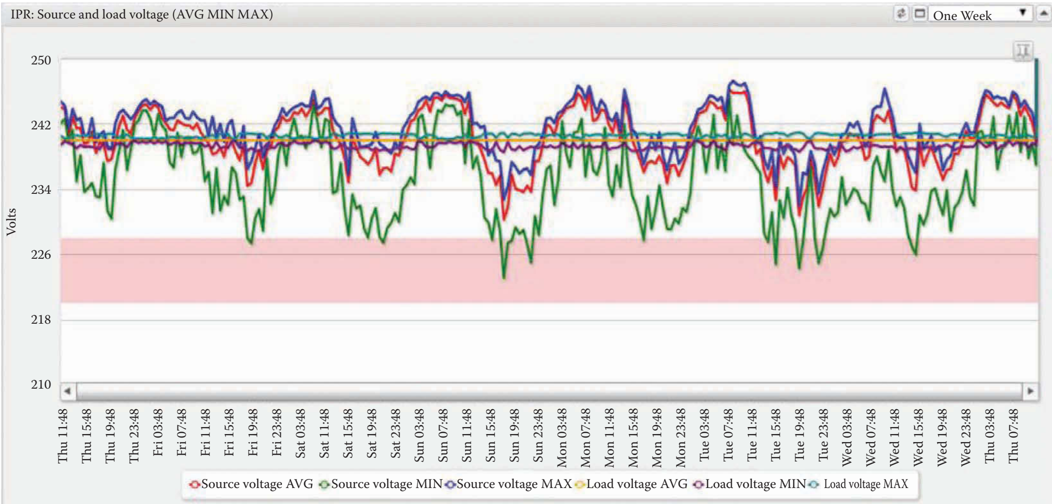


FIGURE 8.25 Secondary regulator boosting load voltage in CVR mode. (© 2016 Gridco Systems. All rights reserved.)

voltage, and the lower measurement is the amount of secondary kVArs being injected. The secondary capacitor bank in this example has four 5 kVAr stages for a maximum output of 20 kVAr. Note that when the primary voltage is operated at higher levels, the secondary capacitor closes less frequently, but when the primary voltage is reduced, the capacitor remains closed for longer durations to keep the secondary voltage above the lower ANSI limit.

Figure 8.25 is an example of a secondary voltage regulator boosting the secondary load voltage when in CVR mode. In this example, the source voltage is the voltage from the distribution transformer into the regulator, and the load voltage is the voltage output from the regulator supplying the customer. The shading on the graph shows the ANSI Range A and Range B lower limits. The graph shows minimum, maximum, and average values for 10-min interals. One can see that when the source voltage is falling below the ANSI limits, the load voltage is being boosted above the lower ANSI limits.

8.6.3.2.3.2 Residential PV Operation Support As mentioned earlier, the distribution secondary was orginially designed for one-way power flow, but with the adoption of residental PV, there is the potential for power to flow in both directions on the feeder. As the PV starts to produce power, it is consumed by the customer, and this reduces the load on the transformer and thus the voltage drop. Residential PV typically reaches maximum output in the middle of the day, but this is also when load is typically very low, so this leads to the possibility of the PV generating more power than is consumed on the secondary. In this case, the excess power will flow through the distribution transformer and back onto the primary side of the distribution feeder. In this scenario, there will now be a voltage drop from the load to the source where the consumer is now at a higher voltage than the transformer supplying the secondary circuit. Figure 8.26 shows an example of the voltage fluctuations caused by residential PV. The measurements are from a utility that has a very weak primary distribution system, and the voltage fluctuations are therefore more extreme in nature.

In Figure 8.26, the area shaded in light green is the acceptable voltage range specified by ANSI, and the areas shaded in yellow above and below are voltages outside the ANSI limits. One can see that during the early mornings and in the evenings when the PV is not generating power, the secondary volatge is approaching or is below the ANSI limit of 228 (240 V base), but when the PV is at maximum output in the early afternoon, the secondary voltage is approaching the upper ANSI limit of 252 V. The voltage swing during the day using the 10-min average voltages ranges from 224 to 245 V.

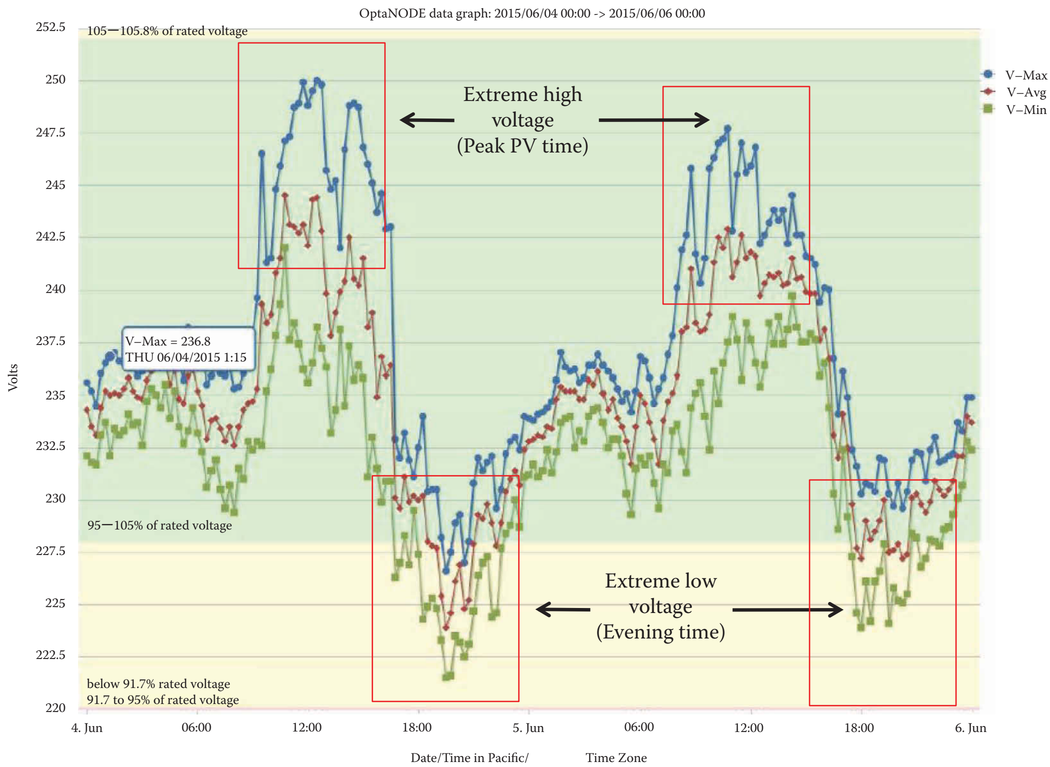


FIGURE 8.26 Impact of residential PV on secondary voltage. (© 2016 Gridco Systems. All rights reserved.)

Figure 8.27 is from the same secondary circuit after a secondary voltage regulator was installed. The blue trace is the voltage on the distribution transformer supply side of the regulator. The orange trace is the voltage on the customer load side of the regulator. The gray trace is the real power flow to the customer through the regulator. The axis on the left side is the voltage and ranges from 200 to 260 V in 10 V increments. The axis on the right side is real power flow and ranges from −6 to 10 kW in 2-kW increments. The dotted red lines are the upper and lower ANSI voltage limits. The regulator was configured to maintain the load voltage at 240 V. One can see that the regulator is maintaining the customer voltage at 240 V even as the power flows in both forward and reverse directions. It can also be seen that the source voltage exceeds the ANSI upper limit when the power is flowing in reverse direction and falls below the lower limit when the power is flowing in the forward direction.

The secondary regulator also has the ability to mitigate harmonics that may be introduced by the PV inverter. In this case, the regulator can mitigate the 3rd, 5th, and 7th harmonics (up to 20 A of harmonic current). The regulator can also mitigate harmonics supplied from the utility that may cause the PV inverter to trip off-line.

The speed of the regulator is also desirable when used with residential PV. On days that are partly cloudy and breezy, the output of the PV will fluctuate rapidly and this can induce voltage flicker on the secondary. The secondary regulator can start adjusting the voltage within the first cycle and can provide full boost/buck within three cycles to mitigate the flicker. The additional advantage is that the secondary regulator has no moving parts, which allows for an unlimited number of operations without the need for maintenance.

It is important to take into account residential PV when implementing CVR and VVO programs for several reasons. First, a well designed and implemented CVR and VVO program can assist with increasing the PV-supply capacity of the feeder if it is being limited by voltage. Residential PV can cause voltage rises on the distribution circuit when the power output of the PV exceeds

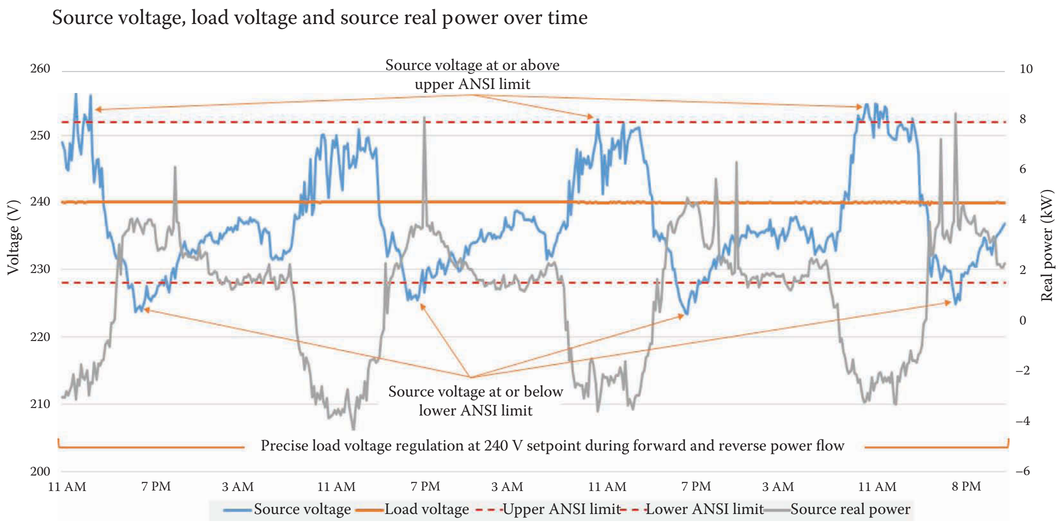


FIGURE 8.27 Secondary regulator operation with residential PV. (© 2016 Gridco Systems. All rights reserved.)

the demand, thus causing reverse power flow. Once the voltage gets too high at the customer revenue meter, the PV inverters will trip off-line as a safety mechanism, thus limiting the amount of residential PV on any feeder. By having the CVR lower the voltage on the primary, the feeder PV capacity is increased. Another possible limiting factor for the feeder PV capacity is current. The cables and equipment on the feeder can only accommodate a maximum amount of current. If the current caused by the reverse power flow of the PV exceeds the limits of the equipment, then outages will occur. Using VVO schemes to reduce the reactive current flow frees up capacity of the feeder for additional real current flow from the residential PVs. While a smart inverter can regulate the secondary voltage to some extent, as the PV generates more real power and generates a voltage rise across wiring resistance, the inverter can act as a motor and absorb inductive VArs. The additional reactive current flow from the transformer to the inverter will then create a voltage drop across the wiring inductive reactance and partially cancel out the voltage rise caused by the the real current flow from the inverter to the transformer. Because of the low *X*/*R* ratios on secondaries, this has limited local impact. In order to do this and not sacrifice a reduction in real output power, the PV inverter must be sized 10%–20% larger (kVA) than the rating of the PV. If PV inverters are configured to regulate the voltage, they may need to be included in VVO and CVR control schemes.

8.6.3.2.3.3 Power Quality Improvements The single-phase secondary regulator can assist with general power quality issues that occur on the secondary circuit, such as rapid voltage change (RVC-quick transition in r.m.s. voltage), harmonics, and flicker (voltage dips, swells, and interruptions). RVC has been addressed by a recent IEC standard (61000-4-30). The secondary voltage regulator can operate fast enough to mitigate most of the RVCs. Figure 8.28 shows measurements on a secondary feeder close to a metal crusher. [The regulating device is referred to as an IPR (In-line Power Regulator).] When the metal crusher operates, it causes RVCs on the secondary. The measurements show the ability of the regulator to mitigate the majority of the voltage changes.

The same site also had a high harmonic content due to the operation of the metal crusher. Figure 8.29 shows the impact the regulator had on the harmonics. While vastly improved, there are still harmonics present. This is due to the fact that the metal crusher is producing high-order harmonics (11th and 13th) that the version of the regulator did not mitigate. Current versions of the regulator can mitigate up to the 15th harmonic.

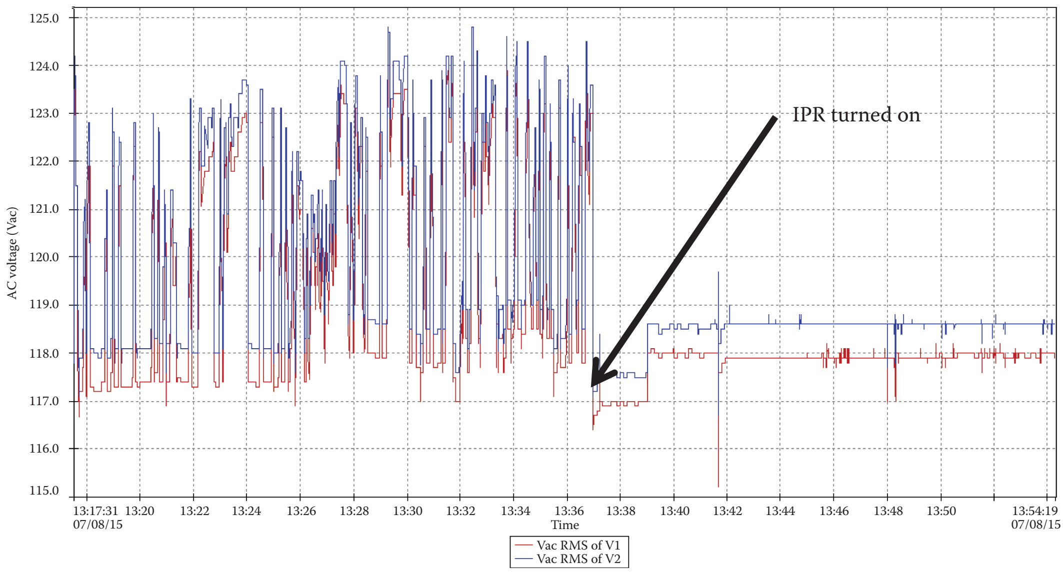


FIGURE 8.28 Secondary voltage regulator mitigating RVC (rapid voltage change). (© 2016 Gridco Systems. All rights reserved.)

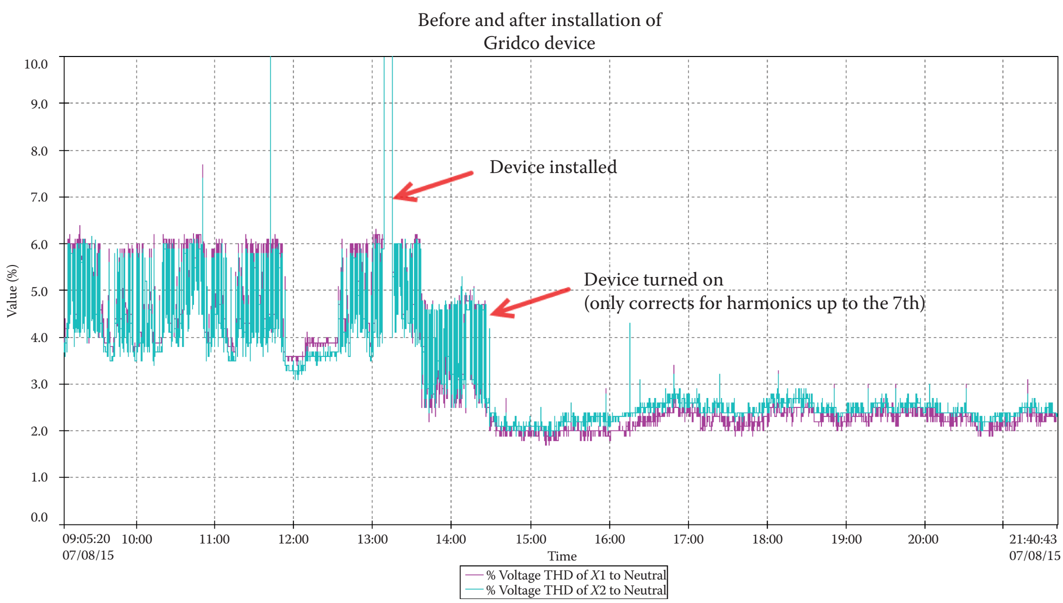


FIGURE 8.29 Secondary voltage regulator mitigating harmonics. (© 2016 Gridco Systems. All rights reserved.)

Flicker can also be partially addressed with the application of the regulator. Again, at the same location, the metal crusher was introducing some flicker. Anything over 1.0 pst is considered to be out of compliance. Before the regulator was installed, the flicker at the location was approaching the limit of 0.8 pst. After the unit was installed and operational, the flicker level was reduced to 0.6 pst. The current design of the regulator allows for 5% boost/buck once per cycle. The next release of the regulator will allow for full boost/buck in under one cycle and will be adjusting the voltage 10 times per cycle. When available, this should reduce the flicker levels to under 0.2 pst.

The secondary regulator is capable of measuring voltage and current on the secondary circuit at an accuracy comparable to a power quality meter. The secondary regulator has a sample rate of 200 samples per cycle and can capture 10 cycles of waveforms. The regulator also measures the odd harmonics up to and including the 15th.

8.7 VVO APPROACHES

VVO can be implemented in several ways. Each approach has its own strengths and weaknesses. Utilities need to analyze their existing infrastructure and the goals of VVO to determine the best approach to deploy VVO. This section will discuss three different approaches: local intelligence, AMI-based centralized, and model-based centralized.

8.7.1 Local Intelligence Approach

The first basic approach relies on the individual transformer LTC, voltage regulator, and capacitor bank controllers to control the voltage and VArs, where the transformer LTC and voltage regulator controllers are set to properly coordinate with the capacitor controllers. With this approach, the transformer LTC, voltage regulator, and capacitor bank controllers are typically not monitored and are controlled remotely, although some utilities will still use communications to monitor overcurrent and obtain metering quantities as a means to verify proper operation by the local controls. The capacitor bank controllers are run in the automatic mode and may use time, temperature, voltage, current, or VArs as the determining factor for operating the capacitor bank, although voltage controlled is the most used method. Figure 8.30 shows the basic architecture of the local intelligence approach to VVO.

The theory of this mode is to allow switched capacitor banks to regulate the voltage drop caused by reactive motor loads and then have the LTCs/regulators regulate any remaining voltage issues caused by resistive loads. By having the capacitor banks minimize the reactive loads on the circuit, distribution losses are reduced and capacity is freed up, meeting two of the major goals of any VVO

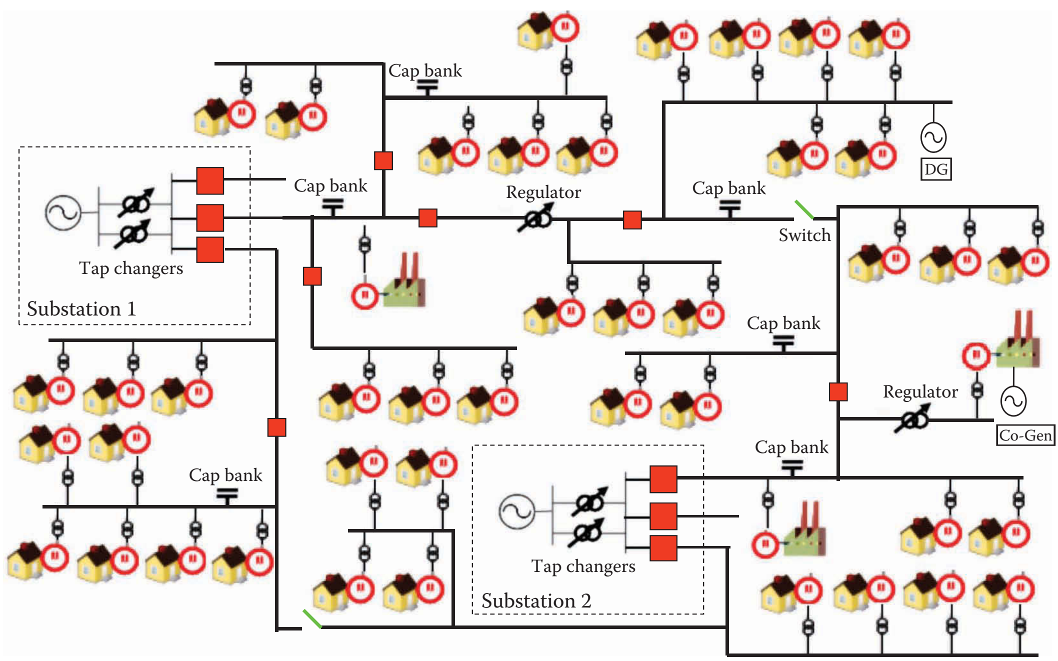


FIGURE 8.30 Local intelligence approach to VVC.

scheme. The third major goal of a VVO scheme is to reduce the voltage drop profile along the distribution feeder ("flatten the voltage") so that the voltage can be uniformly reduced when desired as part of the VR/CVR mode. Having the switched capacitors provide reactive current closer to the motor loads will reduce the voltage drop across the circuit and flatten the circuit voltage profile.

The capacitor banks are usually coordinated so that the one furthest from the substation closes first and opens last. This is implemented by varying the time delays in each control. The capacitor controls are also set to operate before the transformer LTCs and voltage regulators, again by the use of time delay settings. Having the capacitor furthest from the source close first and open last provides two benefits. First, assuming all banks on the circuit are the same size (KVar), then the one furthest from the source will provide the greatest voltage rise when closing (and drop when opening). By closing the furthest first, the voltage at the far end of the circuit (typically where the voltage is lowest) will be raised, thus flattening the voltage profile across the circuit.

There are several types of capacitor controls that are used with this approach. The least expensive approach is to use time, temperature, or voltage control, as these require no additional inputs. The voltage is already required to operate the switch. Typically, a delta voltage, or change in voltage, algorithm provides the best algorithm. The time of day and temperature controls are used with predictable loads, typically residential, and are usually only effective in certain climates and during certain times of the year. The voltage control is easy to use if the capacitor bank is being used more for voltage support than VAr support, as it is easier to coordinate the control of transformer LTCs and single-phase voltage regulators with down-line capacitor banks if both are using voltage measurements to make decisions.

While this approach to VVO is typically not supervised directly with communications, it can be supervised at the distribution feeder level with metering from the substation. Metering data from protection relays, substation panel meters, or single-phase voltage regulators can allow the VVO scheme to monitor the voltage, power factor, and VAr levels at the distribution feeder level to verify the proper operation of the downstream devices.

Newer features in regulator/LTC controls as well as capacitor controls have made this approach easier to implement and have increased the overall effectiveness. The first feature is found in regulator/LTC controls. The overall philosophy of this approach is to have capacitor banks regulate the voltage if the power factor of the circuit is not within the optimal (typically between 0.98 lead and 0.98 lag) power factor range. As an example, if the voltage on the feeder is low and the power factor is below 0.98 lag, it would be better to have a downstream capacitor close to raise the voltage as this will also get the power factor closer to unity, freeing up capacity on the circuit and reducing losses. This will also reduce the number of operations of the regulators/LTCs. Likewise, if the voltage is too high on the feeder circuit and the power is leading by more than 0.98, it would be better to open a downstream capacitor than have the regulator/LTC lower the voltage. With this in mind, the LTC/regulator control that typically looks at only voltage to decide whether to operate or not must now also look at the VAr flow on the load side of the device. If the voltage is out of band and the VAr flow is within band, the regulator/LTC control should take action, but if the VAr flow is out of band, the regulator/LTC control should allow a downstream capacitor bank to correct the voltage first and delay its operation. If the downstream capacitor bank does not correct the voltage within a preset amount of time, the LTC/regulator controller should then take action. This is likely to happen if capacitor banks are out of service or if a feeder circuit does not have enough capacitor banks installed. By having this feature, local coordination between regulators/LTCs downstream switched capacitors can be performed correctly to allow for optimal VAr flow at all times along the distribution feeder, reducing losses and increasing capacity, while maintaining voltages within specified limits and reducing operations of LTCs and regulators.

The final feature that has been introduced to make local VVO smarter is that of the dynamic time delay found in capacitor controllers. As mentioned earlier, the capacitor furthest from the source should be the first to be closed and the last to be open. By doing this, the circuit achieves a flatter voltage profile to allow for a reduced voltage across the entire circuit. Traditionally, this has been done with coordinating the time delays in the capacitor controllers on the feeder, and this is still possible if there are no Fault Location, Isolation, Sectionalizing and Restoration (FLISR) schemes on the circuit. One of the main goals of smart grid is to make the grid more secure and respond quicker to system emergencies, such as storms. The concept is to allow certain parts on one circuit to be temporarily tied to adjacent circuits in order to restore power quicker. In doing so, a capacitor bank that was in the middle of the original circuit may now be at the end of a new circuit. This causes incorrect timing coordination between the regulators/LTCS and capacitor bank controllers. New time delays could be sent remotely to the capacitor controls if communications is present, but this takes time and communications bandwidth. Newer capacitor controls have a feature that allows all capacitor controls to be set to the same base time delay. The actual time delay uses the base time delay biased by the delta voltage. The delta voltage is the impact the capacitor bank has on the voltage when it operates. The controller measures the voltage prior to an operation and again after the operation. The difference is the delta voltage and most controllers use a running average over the most recent 8–10 operations. The impact a capacitor bank has on the voltage is determined by the size of the banks and the amount of reactive impedance between the capacitor bank and the source. The larger the size of the capacitor bank (typically 600, 900, 1200, and 1800 KVAr), the larger is the delta voltage. Since a feeder circuit may have different size banks installed on the feeder, the bank size must be nominalized when calculating the delta voltage. As an example, assume a feeder has a 600-KVAr, 900-KVAr, and 1200-KVar capacitor bank. A nominal size selected is 600 KVAr. Therefore, the delta voltage for the 600-KVAr bank would be the actual measured voltage difference, as it is the same size as the nominal. The delta voltage for the 900-KVar bank would the measured voltage divided by 900/600, and the delta voltage for the 1200-VAr bank would be the measured voltage divided by 1200/600. By doing this, the only variable component of the delta voltage is now the distance to the source (impedance). The bank furthest away will have the largest delta voltage, and the bank closet to the source will have the smallest delta voltage. If the close time delay is calculated by dividing the base time delay by a component of the delta voltage, then the capacitor bank furthest from the source will also have the shortest time delay and will be the first to close. Likewise, if one multiplies the base time delay by the delta voltage to generate the open time delay, then the capacitor furthest from the source will always have the longest open time delay. Using this method, every capacitor control has the same base time delay, and once nominalized for the bank size, it will continuously calculate new delta voltages and, therefore, close and open time delays with each operation. When a capacitor bank is tied to a new source during routine switching or system emergency restoration schemes, it will be miscoordinated for one operation; but once it operates, it will calculate a new delta voltage to the new source and readjust the time delays to be properly coordinated to the new source, and no communications is required.

VVO can now be obtained with no communications required to any devices and voltage reduction or CVR can be implemented with communications only required for the substation regulating devices (regulator/LTC controls). There is one major investor-owned utility in the southeast USA that has implemented this approach and can reduce the load by 300–350 MW by issuing a single voltage reduction command. They have also implemented a full-scale FLISR program that does not impact the operation of their VVO/CVR program.

8.7.2 AMI-based Centralized Approach

This centralized approach uses an application that integrates with an existing SCADA or DMS system. The application also interfaces to an existing AMI software head end system. The theory behind this approach is that with the smart grid capabilities of AMI meters, it is now possible to measure the customer voltage at the very point where ANSI standards are applied. ANSI C84.1 establishes limits for utilization voltage (at the individual customer loads) and the customer service voltage (at the point of delivery). The utility is responsible for maintaining adequate service voltage at the revenue meter for each customer. Historically, voltage reduction and VVO programs have focused on a proxy voltage measurement, such as a measured distribution primary voltage, and assuming a voltage drop across the secondary (through the distribution step-down transformer and cable to the customer meter). Many utilities will assume a 6-V drop (on a 120-V basis) for the allowable secondary voltage drop. This means the primary voltage must be maintained above 120 V in order to ensure that customer meters on the secondary are above 114 V. Sometimes the voltage drop is greater than 6 V and violations occur, but many times the voltage drops will be less than the assumed 6 V, allowing additional voltage reduction with customer-level monitoring. Most systems have focused only on the primary because the devices regulating the voltage are typically only on the primary (regulators/LTCs/capacitors). By measuring the actual voltages at the meter, this type of approach can deliver maximum voltage and load reduction without introducing violations because it is not making assumptions on the voltage drop across the secondary. In cases where the voltage drop is greater than 6 V and violations may have already existed, customer-level monitoring provides visibility and the opportunity to remediate the problem.

When implementing an AMI-based VVO solution, there are several considerations that may be new to the traditional distribution paradigm. Historical voltage analysis changes the distribution engineering approach from modeling to measurement. Controlling circuits with near-real-time voltage feedback from meters requires a design that prevents conflicts with critical metering processes. VVO systems must be configured to achieve voltage control, VAr management, or both. This approach also calls for new cross-functional interaction between departments, such as Energy Efficiency, Metering, IT, Distribution Operations, and Distribution Engineering and Planning.

When starting or updating an AMI-based VVO solution, it is best to start with data. Some AMI solutions can provide daily retrieval of 15-min interval data for each meter, while others offer only 1-h intervals or sometimes 4-h intervals. This voltage profile data, harvested from the meters on a given circuit over a 30-day period, provide valuable insight on how to configure the VVO control software as well as to identify trouble spots on the circuit. Actual meter voltages often reveal that not all secondaries are equal, alerting distribution engineers to previously unknown low voltages on the circuit. Low secondary voltage is most commonly due to shared secondaries, long service drops, or no-standard emergency fixes that are not documented. Fortunately, most circuits have a limited number of these outliers inhibiting the potential voltage reduction. By fixing a small number of secondaries, the utility can greatly enhance energy savings on the whole circuit. In addition to identifying secondary issues, the initial meter voltage analysis can identify overloaded transformers, loose connections, and even failing transformers (which can cause low or high voltage as the turns ratio changes). Because distribution models have historically relied on primary voltage measurements and load flow analysis, the voltage analysis phase is often eye-opening.

Actively managing voltage control devices using customer voltage measurements is a step beyond analyzing historical voltages. Reading near-real-time voltages from all meters every 5–15 min would exceed the communications bandwidth of existing AMI technology. It is necessary to limit the number of meters reporting to just the meters that are of greatest concern. A small bellwether set of the lowest-voltage meters needs to be specified in advance to be read every 5–15 min. Yet, topology changes and new connects and seasonal load variation require that the bellwether set adapt to the dynamic changes in the circuit voltage profile. Advanced AMI-based VVO solutions automatically update the bellwether set daily to ensure that the right meters are being monitored. Another valid concern is trying to manage circuit voltages to react to the highly volatile voltages experienced by individual customers. To ensure stable steady-state voltage control, controls should respond to average voltages, and the response should reflect a slow and steady response. The circuit voltage profile will not change radically over a short period (though this may cease to hold true as distributed resources penetrate distribution systems), so the control response should be incremental. Some systems limit voltage set point changes to 1-V increments with required wait times of 1–2 h between changes. This allows tap changers to respond to local fast-acting disturbances, while the VVO system manages the target voltage in a slow and steady manner.

Voltage control alone does not address the need for VAr control. A VVO solution needs to balance the efficiency needs of the circuit load with the VAr support for the system. Some utilities will not be interested in reducing voltage to customers and, instead, are focused on reducing line losses due to VAr flow. An integrated VVO solution can do either or both. A voltage control system focused on energy savings will flatten the circuit voltage profile to gain maximum voltage reduction along the circuit. An AMI-based system recognizes that the flat voltage profile is determined by flat customer voltages, regardless of the primary voltages along the circuit. A capacitor close to the substation may be closed to address low voltages caused by long secondaries close to the substation. These low voltages may be the limiting factor on how low the LTC setpoint can be set. A VAr optimization approach does not depend as much on local voltages but instead, reacts to the total VAr loading on a substation transformer or distribution circuit. If the circuit needs VAr support, it may be unimportant that the voltage profile is already "flat." The VVO system needs to close a capacitor. Preferably, the system will close the capacitor that does the least harm to the flat voltage profile and preferably, the system will distribute the open/close frequency across similar capacitor banks to avoid excessive wear on any given capacitor bank.

Because utility organizational structures were created to address existing business processes, new solutions often cross traditional disciplines. An AMI-based VVO system is no exception. Although a VVO system may be sought for its operational (line loss) efficiency, often the driver is a larger energy efficiency goal. The energy savings from reducing customer voltage far exceed the energy reduction from simply reducing I^2R line losses. Regardless of which branch of an organization is leading a project, it is important to gather all the vested parties: Metering, IT, Distribution Operations, Distribution Engineering, and so on.

In an AMI solution, the Metering department is a vital stakeholder. Metering has historically been driven by high reliability focused on documenting kWh usage. AMI expands the usage of the meter from the wealth of new data, including interval loads and voltage readings, to the operational uses, including outage notification and remote connect/disconnect functionality. The Metering department now must weigh its traditional responsibilities with the requests of others to utilize the new capabilities. For this reason, the AMI-based VVO vendor must work closely with the Metering department and the AMI provider. Most AMI systems have a feature to prioritize billing reads over other uses, such as on-demand or scheduled bellwether reads for VVO, avoiding conflicts between VVO and mission-critical billing reads. By limiting the number of meters in the bellwether group, placing a lower priority on voltage reads and limiting reads to once every 15 min or so, the VVO solution can stay safely out of the way of the core metering functions.

Communications bandwidth concerns apply to distribution automation systems as well as the AMI-based metering systems. This challenge exists regardless of whether the VVO solution is AMI-based or not. Some VVO solutions solve this concern by leveraging the intelligent local controls already in place on most regulators and LTCs. Instead of taking a command and control approach and issuing raise and lower commands, the centralized system can simply recommend a target voltage to the local controls. This way, the centralized system can interact every 5–15 min, and the local control remains in constant control. If the centralized controller is responsible for raise/lower commands, it must monitor voltage in near real time to react to any system disturbances. Either control requires integration with the DMS system to coordinate communications with field devices, though pilot projects may initially use direct-to-device controls.

IT is a critical stakeholder whenever multiple systems are involved. An AMI-based VVO system reads data from the AMI head-end and issues commands through the DMS system. This raises obvious security concerns across systems. This concern can be effectively managed by carefully deploying the VVO solution in a way that securely crosses the Electronic Security Perimeter (ESP) required by NERC Critical Infrastructure Protection standards. One option is to deploy the AMI components outside the ESP, with the actual control engine sending recommendations to the DMS system from within the ESP. The engine makes calls from inside the secure operational environment out to the business network to retrieve AMI data. The communication with the DMS system is then easily executed completely within the secure area.

On a daily basis, utilities must safely and efficiently operate the electrical system first and foremost. Any VVO solution must operate within this context. The VVO system must sense abnormal conditions within the DMS environment and take appropriate action. This may involve returning to default settings during switching or circuit operations. It may also involve automatically reconfiguring the VVO solution to react to new circuit configurations. All these functions should happen automatically, with little or no direct intervention required. The best VVO solutions are nearly invisible to daily operations, performing energy savings quietly in the background. One exception to this rule is when system loads are near the peak and operations wishes to intervene and reduce the load to address a system need. AMI-based VVO systems bring the capability to rapidly lower the circuit voltage to the minimum level acceptable under the ANSI B voltage range. Because the system is aware of actual voltages, a reduction in excess of 5% is often available.

8.7.3 Model-Based Centralized Approach

The centralized approach to VVO is typically implemented as part of a DMS. Figure 8.31 depicts the basic operation of the DMS model-driven VVO approach. As seen in this figure, the system uses distribution SCADA facilities to acquire real-time field data and execute VVO control actions, an online load flow/power flow program to compute electrical conditions at any point on the feeder, and an advanced "search engine" to identify the optimal switching actions.

8.7.3.1 Data for Load-Flow/Power-Flow Model

Distribution systems have unique characteristics that create complexity beyond the typical transmission system. In general, distribution systems have unbalanced loads due to loads connected as

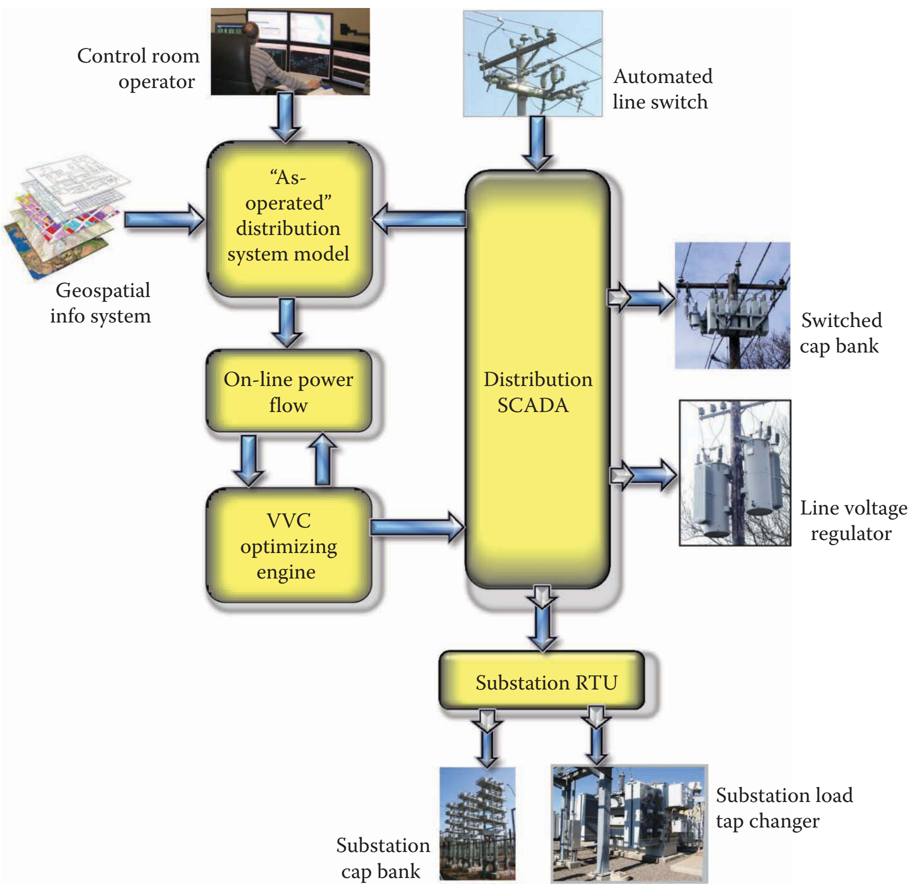


FIGURE 8.31 Basic operation of the DMS model-driven VVO approach. (© 2016 EPRI. All rights reserved.)

either single phase, phase-to-phase, or three phase. Distribution systems also have power lines that are constructed non-symmetrically and nontransposed, with different sizes and types of conductors. Distribution systems typically comprised large loads for industrial and commercial customers served in concentrated areas, while loads for residential and small commercial customers are mostly distributed along miles of distribution lines. Depending on the utility and the service area, the total "distributed" loads usually match or exceed the larger concentrated loads. A few dozen customers may represent the large commercial and industrial load of a utility, while hundreds of thousands of customers represent the distributed load on the system.

The types of data required to develop a load-flow/power-flow model of a distribution system for model-based VVO include topology of the system with connection points (buses), distribution line parameters (such as pi-model parameters), Volt/VAr compensation locations and ratings/limits, transformer turns ratios and transformer primary tap positions and ratings/limits, tie-line locations and ratings/limits, generation locations and ratings/limits, load locations and load compensation, and any real-time data measurements on the system, such as generator outputs, loading, line powers, and bus voltages and phase angles.

8.7.3.2 Data for a Dynamic Model

In order to perform transient analysis and stability studies, additional power system data are required for load-flow/power-flow models. Additional data may include number, size, and types of generators with control parameters; the location, connected size, and mix of residential, commercial, and industrial loads; location and specifications for distributed control devices, such as tap-changing transformers, line voltage regulators, switched shunt capacitors, SAVs; location and specifications for protective devices, such as relays, fuses, and line reclosers; and location and specifications of any other relevant control and protection devices.

The entire sub-transmission network connected to distribution substations must be solved for each power flow solution. The distribution stations that are connected to the sub-transmission network are typically translated into lumped load equivalents. If a distribution station is connected to another station through a closed tie switch, then the full model for both distribution substations must be included.

Model-based VVO as part of a DMS system also allows for other advanced applications to leverage the accurate system model and power flow results generated for VVO control. Some of the additional applications include equipment limit monitoring capability, which can check for branch flows and voltages that are outside the acceptable operating limits; power quality analysis applications, which can determine the extent of feeder voltage violations (including voltage imbalance); loss analysis applications, which can calculate device technical losses and aggregates the losses by feeder; protection analysis applications, which calculate phase-to-ground, double-phase-to-ground, and three-phase fault currents for each feeder circuit breaker and line recloser; and FLISR, which generates a switching sequence to isolate faulted sections and restore service to the nonfaulted sections.

8.7.3.3 Power Flow Analysis

To perform a power flow analysis of the distribution system, it is required to have complete and accurate information for all system components in the network. The power flow application is the foundational component of a DMS. The power flow solution solves the unbalanced power system network model, which includes the individual bus phase voltages, network power flows, and network losses. Power flow solutions are capable of modeling and solving any unbalanced distribution system configuration, including networked (meshed) systems and radial systems. Power flow solutions also account for nonlinear load voltage dependencies, control actions of capacitors and line voltage regulators, distribution secondary voltage allocation, voltage-dependent distribution transformer coil and core losses, line and underground cable charging currents, and support various types of transformers with either fixed tap or with a load tap changer controller. A near-real-time power flow solution utilizes the current power system conditions based on SCADA measurements. These measurements consist of analog and status measurements including switch statuses.

8.7.3.4 Load Estimation and Allocation

In order to implement a power flow solution, load allocation needs to be performed prior to solving for power flow. Power flow load estimation allocates loads (kW and kVAr) at distribution load points and allocates loads to buses without measurements, but accounts for available measurements to ensure consistency between allocated and measured loads.

Load estimation techniques can be divided into two general types: state estimation and allocation procedures. State estimation techniques are commonly used in EMS (Energy Management System) to obtain the best estimate for the bus voltages and angles.

For distribution systems, state estimation procedures have been proposed but several problems arise in their practical application primarily from a lack of measurement. In addition, many distribution measurements are in amperes only, and there are difficulties in parameter tuning.

One load allocation procedure uses real-time measurements from SCADA, along with customer load curve information, to scale the distribution system loads to the real-time measurements. The expected value at a given date/time is obtained by multiplying the nominal load by a scaling factor that reflects the energy usage at a specific time. This allocation procedure minimizes power flow iterations and maximizes the load estimation performance.

The load allocation function allocates loads (kW and kVAr) at distribution nodes to support other analysis functions requiring load flow data. Loads are allocated through the use of the load model data, taking into account actual or predicted feeder loads, and the relevant day and time of day. This type of load allocation function ensures that the load model and current network topology are consistent with metered flows, current breaker statuses, and metered loads along the distribution feeders.

8.7.3.5 Load Flow Accuracy

If the load allocation and power flow models are not accurate, VVO will be attempting to optimize the system based on a model that differs from the existing state. In some cases, power flow will force the calculated voltages on the load side of substation voltage regulators to equal measured values. At other locations on the feeders where real-time voltage is monitored, differences will typically exist between measured voltage values and voltage values calculated in the power flow. Power flow in some instances will attempt to adjust load distribution in the model to force the calculated voltage values to be the same as measured values.

When the power flow calculations do not make load flow adjustments to account for differences between measured and calculated feeder voltage values, VVO may attempt to take the differences into account the differences and create control plans to keep calculated voltages inside the upper and lower voltage limits, but would cause actual voltages to go outside these limits due to differences between measured and calculated voltages. VVO can adjust the voltage limits on a circuit by the amount of the error between the measured and calculated voltage values. The voltage limits apply to all locations on the feeder; however, there are only a few locations where voltages are monitored. Vendors have developed methods that address how to handle limit adjustments at locations that are not monitored; however, there may still be an issue with this preventing VVO from lowering the voltage as much as it could under the "minimum load" optimization mode. Additionally, if power flow is calculating a voltage profile on a circuit that is different than what is measured, VVO will not calculate the correct changes in losses, voltage, voltage effect on customer load, and so on, as it looks at alternative options for capacitor bank status and regulator tap position. Thus, it may produce plans that are not optimized, or even less optimal than the current state.

Model inaccuracies may have a negligible impact on VVO on some circuits, such as those that have large conductor capacity compared to the load and are short in length. At the other extreme, model inaccuracies may have a major impact on VVO on circuits that are heavily loaded compared to conductor capacity and are very long in length.

8.7.3.6 Field Device Accuracy

Data collection can be achieved using multifunction meters, recloser controls, regulator controls, SCADA RTUs, microprocessor relays, or equivalent data collection and storage systems. The accuracy requirements for model-based VVO are not well defined in the industry. Metering accuracy would need to meet or exceed all applicable IEEE and ANSI metering standards. The metering accuracy, including current transformers, potential transformers, and other burdens, should be capable of at least ±0.6% for kW sensing, ±1.2% for kVAr sensing, and ±0.1% for voltage sensing. This level of accuracy may be difficult and costly to achieve on a full distribution automation deployment.

In order to optimize the load allocation power flow and VVO applications, the quantity and accuracy of system data are critical. Typically, substation relays provide the data required at the substation level, but distribution line device data acquisition can be more challenging. Typically, distribution line devices are not configured to collect the amount of accurate data required, and sensing capability is sometimes limited. Newer distribution devices are incorporating enhanced sensing capability, including three-phase voltage, current, and power data. In addition, the ability to sense faults is being incorporated in some devices. The more sensing points on a distribution feeder, the better the load allocation and power flow calculations, which allow VVO to better optimize distribution performance objectives.

8.7.3.7 Model Accuracy

For model-based power flow applications, errors in conductor characteristics and single-phase tap phasing are the most critical. Extensive field checking of geospatial data can resolve some of these errors, but new errors will continue to evolve without rigorous quality control processes.

If communication is lost with a controllable device, VVO loses knowledge of the device status. If VVO has been driving voltage to the lower end of the allowable range, the voltage at most capacitor banks is below the close setting used when VVO is not controlling a capacitor bank. Each capacitor control is configured to revert to automatic "safe" settings when communication to that control is lost. For capacitors that were off when communication was lost, the automatic setting will likely cause it to turn on. Power flow will not know this and may be using a status for the capacitor that is incorrect. An incorrect assumption on capacitor status may cause a significant error in VAr distribution and, thus, a significant error in calculated voltages. Power flow does have the capability in some cases to accurately predict the status of a capacitor bank based on VAr flow. Load allocation associated with power flow must allocate the load based on existing measurements. In some cases, there may only be measurements at limited locations, such as the substation bus or circuit level. Additional monitoring points would provide a better load allocation result and improve power flow, which could improve VVO. These additional monitoring points could come from electronic distribution automation devices, such as reclosers, capacitors, and line sensors. AMI measurements would provide the most effective allocation methods due to the actual load being measured, rather than estimated at the service point.

Distribution planners traditionally have to accurately estimate and allocate load at only the peak hour of the year. For the power flow and VVO application, this must be done at all hours of the year. The challenge is that not all loads follow the same load pattern. For example, when the circuit load changes from 100% to 60%, the residential load on the circuit may have changed from 100% to 50% while the C&I load may have changed from 100% to 80%. Load allocation and power flow utilize load curves for several customer classes to distribute load on the circuit depending on time of day, day of year, and so on. This may work reasonably well if all or most of the loads behave like this, and no individual load is a significant percentage of the total load. However, several things can impact the accuracy of this method. Any load that is a significant percentage of the total circuit load that does not behave every hour of the year in a predictable way will cause errors in the load allocation. For example:

- A manufacturing customer that has several MW of load may run one, two, or three shifts depending on product demand. At 9 PM, the load will be significantly different if this customer is on a one-shift operation compared to a two- or three-shift operation.
- Large wind or solar output can vary from 100% to 20% every few minutes on partly cloudy days.
- Customers with distributed generation, such as healthcare and financial institutions, have several MWs of diesel generators with paralleling capability. They may run these at any time, effectively removing their load from the circuit.
- Small-scale energy storage, such as community energy storage, could become widespread. These may change the load profile of a residential customer in an unpredictable fashion.
- Plug-in electric vehicles could cause a major change in the load profile of a residential customer charging an electric vehicle at home. The load curve will change and be more unpredictable.

Allocation of load on a circuit involves not only real load (kW) but also reactive load (kVAr). While much data exist to determine load curves for real load, little exists for reactive load. Also, larger C&I customers may or may not utilize their own capacitors for power factor correction, and if they do, they may or may not switch the capacitors with load levels. Therefore, significant differences in power factor may exist among C&I customers, making accurate allocation of reactive power on the circuit difficult. Voltage drop on the circuit is typically much more sensitive to reactive power flow than real (kW) power flow.

8.7.3.8 Mitigation of Power Flow Risks for VVO

Owing to the complexity of load flow-based VVO systems, it may be beneficial to have an alternate optimization strategy in place for times when load flow-based VVO is not capable of providing optimization. A VVO system using selected measurements and the system impedance and configuration model can be implemented. The only information this optimization technique needs is the real-time values of voltage at the capacitor banks, the real-time values of kW and kVAr for each feeder at the substation, and predicted voltage changes when capacitor banks operate. In some cases, additional voltage measurements, such as at the end of the feeder, may improve its optimization potential. This issue can be addressed with an optimization tool that is integrated with a DMS and its associated electrical circuit model in order to let the optimization tool calculate the voltage change values from this circuit model. This is still subject to any geospatial data errors, but only for the three-phase feeder portion of the circuit. Other errors, such as incorrect phase designation for single-phase taps, do not impact this approach. If the circuit configuration changes, the model information is available to recalculate the new voltage change values.

For CVR, the basic goal of this optimization technique is to control capacitors to keep the feeder voltage profile as flat as possible, and then adjust the substation and line regulators to lower the voltage profile as close to the lower voltage limit as practical. Additionally, circuit or substation power factor goals can be utilized. For this method, it is not necessary to know what the load distribution is on a circuit. Any changes in load, distributed generation, or load distribution will cause changes in the monitored voltage data and circuit load data monitored at the substation. This optimization tool analyzes only the real-time data and, using a set of rules-based formulas, makes any recommendations for control actions necessary to keep voltages inside the limits and to better optimize the voltage and VAr flow.

This method also performs well with the loss of communication with a capacitor bank. If communication is lost with a capacitor bank and it operates without the optimization tools knowledge, the optimization tool still sees the effect on voltage at other capacitor banks and VAr changes at the substation. It will continue to use the remaining capacitor banks and voltage regulators to optimize toward a flat voltage profile and power factor goal.

8.7.3.9 Circuit Conditioning

In preparation for deployment of VVO systems, it may be desirable for utilities to perform voltage drop studies to determine the circuit voltage range under various loading conditions. These studies will highlight low-voltage areas that may limit the effectiveness of VVO operation. The results of the studies will allow for mitigation of the specific low-voltage areas with additional line capacitors, line regulators, or secondary improvements. In order to achieve VVO benefits from voltage reduction, the targeted reduction must be achievable along the entire feeder.

Case Study: DMS Load Flow-Based VVO Implementation

DESCRIPTION

The primary objectives of this implementation were to validate VVO energy savings for a utility and end user on approximately 70% of distribution circuits, deploy advanced technology along feeders and at substations to optimize VVO performance, and install a DMS to optimize VVO performance. VVO was implemented on 500+ circuits that serve approximately 700,000 electric customers and 5000 MW at peak. The DMS performs the load allocation and load flow calculations and implements the VVO algorithm resulting in commands being sent to voltage regulators, LTCs, and capacitors utilizing a cellular network to devices outside the substation and third-party landline to substation devices with the primary intent of minimizing demand. VVO is utilized in an energy reduction continuous operating mode.

VVO Business Case

VVO is used to better manage the application and operation of voltage regulation and capacitors on the distribution system. Device operation is optimized resulting in a flattened and reduced voltage profile across circuits, thereby reducing energy and system demand and providing better quality of service voltage. The VVO implementation project focused primarily on demonstrating the benefits of a DMS-based VVO algorithm. On the benefits side, the project demonstrated that a 2% system average voltage reduction is achievable, resulting in system energy reduction savings of 1%–1.4%. VVO measurement and verification are performed by using measured voltage and energy along with industry-accepted CVR factor values to measure VVO energy reduction performance.

Key Findings and Lessons Learned

The VVO deployment project provided a number of lessons learned:

1. CVR factor or the ratio of load response to voltage reduction is difficult to measure and quantify. Using an industry-accepted range of CVR factor values has made benefit verification more manageable.
2. The DMS with an integrated CVR system has provided additional benefits and future opportunities in addition to CVR.
3. A DMS-based CVR system relies heavily on model accuracy and requires robust data and support processes to ensure model accuracy.
4. Measurement and verification of benefits are difficult to quantify when operating CVR in a continuous energy reduction mode. CVR performance with a range of savings benefits has proven to be the simplest method of verification.
5. Substation and distribution device communication availability is critical for optimized CVR performance.

6. CVR does not impact reliability. The utility experienced minimal increases in transformer tap changer and capacitor bank operations, and CVR action is not causing increased wear and tear on key components of the distribution system.
7. CVR performance on individual circuits is highly variable, depending on loading and customer load types. System average voltage reduction has proven to be a more effective measurement and verification value.

8.8 VOLT/VAr BENEFIT MEASUREMENT AND VERIFICATION METHODS

Similar to the energy efficiency and demand reduction industries, the use of industry-accepted measurement and verification methods is a critical requirement for determining the actual impacts of deployed Volt/VAr control systems. While some work has been undertaken in this area, the industry has yet to develop a consensus on which measurement and verification methods should be used for measuring Volt/VAr impacts.

Measuring Volt/VAr impacts is complex and data intensive. Since the magnitude of change in the measured variables (i.e., voltages and load) is relatively small, and their natural variation large, Volt/VAr measurement and verification approaches typically require large sample sizes, precise measurement techniques, and sophisticated research designs. Similar to energy-efficient and demand reduction verification, measuring Volt/VAr impacts requires establishing a baseline to which Volt/VAr control impacts are then compared.

Pre/Post Volt/VAr Analysis Method: Pre/post analysis techniques can be used to measure Volt/VAr impacts. Pre/post Volt/VAr measurement and verification methods compare voltage and load correlations pre-implementation and post-implementation on a sample of feeders. The pre-post measurement time frames vary from as little as three months to multi-year studies. Because of the number of factors that can impact Volt/VAr, especially seasonality, large sample sizes and extensive time periods are typically required to generate meaningful results.

Control Group Analysis Method: The use of control groups provides an alternative method for developing a measurement baseline over a consistent time period. Instead of lengthy pre-implementation period measurements, Volt/VAr control group measurement and verification selects two groups of similar feeders and applies Volt/VAr to one, but not the other. Detailed measurements are then taken of voltage and load correlations over a period, typically a year or more. Observed differences between the test and control groups are then attributed to the Volt/VAr impact. To account for the various differences in feeder and customer load, control group measurement and validation typically require large samples of comparable feeders.

ON/OFF Test Method: A hybrid method unique to Volt/VAr is on/off testing. Volt/VAr controls are set to switch on or off at predetermined time periods. Energy use and peak demand are then compared for each period to determine the difference the Volt/VAr control made on performance. This technique is frequently done as a means to compare actual to estimated savings. To be credible, the on/off periods must represent the same time-of-day and weather conditions. Because loads can be highly variable, test periods can last several months to years. Data can be collected at 15-min intervals, hourly intervals, weekly intervals, or more extended periods, depending on data availability and processing tools. Data typically collected during the verification measurement period include hourly temperature, voltage and load measurements at the feeder supply (substation), and corresponding hourly end-of-line voltage (lowest). All measurements are time stamped. A simple day-on/day-off testing is sometimes done. However, this test alone cannot fully capture the savings and should not be the only verification plan. A way to improve the verifiability of on/off cycles is to randomly implement predefined, random schedules. This improves the robustness of the sample data set.

Other Measurement and Verification Methods: A number of additional, newly developed measurement and verification methods are in use by utilities, consultants, universities, and research organizations around the country. Some of these methods include:

- Simplified Voltage Optimization (VO) Protocol[1]
- CVR Standard Protocol #1[2]
- UtiliData's Automated CVR Estimation Method Tools
- Washington State University (WSU) VO Validation Methodology[3]
- EPRI "Green Circuits" Analysis (developed in conjunction with Dr. Bobby Mee of the University of Tennessee)
- Navigant Regression Methodology[4]
- PNNL Protocol
- Survalent's SmartSCADA System
- Dominion Voltage Inc.'s (DVI) EDGE Validator
- S&C Electric's Dynamic Measurement and Verification Module [2] (IntelliTeam Volt-Var Optimization System option)

8.9 VVO IN THE SMARTER GRID

Advances in existing technologies and several new technologies are going to have an immediate and long-term impact on VVO/CVR deployments. But they also come with their challenges.

Regulator controllers are becoming much more advanced. Some controllers include functions, such as voltage sag and swell detection, flicker detection, Computer and Business Equipment Manufacturers' Association power quality violation detection, fault detection, and harmonic measurements. They also have predictive maintenance features, such as motor current monitoring and incorrect tap position alarming. These data can help customer service engineers responding to customer complaints on incoming service. As regulator controllers become more intelligent, changes to the construction of the regulator will follow. Some controllers have the capabilities to detect faults on the feeder. This can be useful in providing exact fault locations to field personnel for quicker restoration of service. Currently, protection relays in the substation can estimate fault distances on distribution feeders, but accuracy of the estimation depends on the distribution feeder design and configuration since the feeder may contain numerous subcircuits (taps or laterals). Therefore, more fault information from equipment down the distribution feeder, such as voltage regulators, can provide more accurate operational data to the utility.

There are many different types of capacitor bank controllers. In the earlier days, most controls operated on either time of day or temperature. Now, more advanced controls are being used that monitor voltage, current, power factor, VAr flow, or a combination of all. Twenty years ago, switched capacitor bank controllers did not include remote control capabilities, but today the majority of controllers are communicating, either via one-way or two-way communications. The amount of intelligence in a capacitor bank controller depends on whether communications to the controller is provided. If communications is not provided, then all the intelligence must be in the controller, but if communications is included, the controller can have varying degrees of intelligence. Time-based

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1 Bonneville Power Administration (BPA). Simplified Voltage Optimization (VO): Measurement and Verification Protocol. Regional Technical Forum (RTF). April 27, 2010.

2 Regional Technical Forum (RTF). CVR Standard M&V Protocol #1—DRAFT. RTF Subcommittee. May 15, 2012.

3 Navigant Consulting. Avista Utilities' Conservation Voltage Reduction Program—Impact Evaluation. Northwest Energy Efficiency Alliance (NEEA). May 1, 2014.

4 Ibid.

controls were popular 20 years ago because of the cost. A time-based control only required voltage to power the capacitor bank switch, so no additional sensing equipment was needed. The theory behind the time control was that for residential feeders, load would peak during certain times of the day, in the morning as people prepared for work and in the early evening as they came home and cooked dinner. The control could be programmed to have the capacitor closed during the peak hours and open during the remaining portion of the day. For commercial and industrial feeders, the load would be greatest when the businesses were open or plants were manufacturing, and then would drop off when the business was closed. The control could even be programmed to take into account the weekends and holidays. Time-of-day controls have lost favor for several reasons. First, load in general is not as predictable as in the past with the advent of 24-h businesses. Second, the time clocks in the capacitor bank controllers could deviate, causing the banks to operate at the incorrect time. The controllers lose power every time there is a feeder outage, and this power loss would cause the control to lose time. Therefore, batteries are used to keep the time when the control was without power. This causes a maintenance nightmare as personnel have to inspect and replace batteries. Other concerns, such as daylight savings time, can also create difficulties. So, while the time-based control is the least expensive to install, it can create large maintenance costs and may not always operate correctly. Some capacitor bank controllers are based on temperature where the controllers monitor the ambient temperature and switch the bank on or off at predefined temperatures. The theory is that, particularly in warm climate on hot days when air conditioners are running, there is a need for the capacitor banks to compensate for the considerable increase in VAr current from the air-conditioning load. The advantage of temperature controls is that they require no additional sensors and are thus very inexpensive, as with time-based controls. The temperature-based controllers, unlike the time controls, do not require a battery backup to keep the time and, therefore, require less maintenance. The problem with temperature-based capacitor bank controllers is that not all load predictably follows the temperature. For this reason, temperature controls are not used very often. Voltage control for capacitor bank switching has gained popularity for several reasons. First, as in the time and temperature controls, voltage control requires no additional sensing equipment and is, therefore, relatively inexpensive. There are two basic types of voltage controls: absolute voltage control and delta voltage control. Both use voltage as the sense to decide operation, but they are done in different manners. Absolute voltage control is based on the actual measured voltage level of the distribution feeder, as in the control of voltage regulators. Delta voltage control is based on the change in voltage level measured on the distribution feeder. The theory of delta voltage control is that the impedance of the system is primarily inductive and, therefore, any voltage change is due to a current change and the majority of the current would be reactive. More advanced capacitor bank controllers using current control, power factor control, and VAr control all require monitoring of the current flowing in the distribution feeder. Since these types of controllers require a current input, the location of the capacitor bank is limited. The capacitor bank must be placed on the main distribution feeder and not off any of the taps or laterals (subcircuits, usually single-phase). This is because, while the voltage on the tapped sections of the line is comparable to the main distribution feeder, the current seen at any tap will only be the amount of current flowing through that tap, not the total current flowing through the main feeder. The VAr control is typically the most popular of the three, the obvious reason being that the capacitor bank should be switched on to provide reactive support when there is a lagging power factor. While time- and temperature-based capacitor bank controls are not extensively used as much as the primary controlling function, many utilities may still employ an override feature using time or temperature. A primary control function, such as voltage or VAr flow, is now more common but may include a temperature or time control override. For example, the capacitor bank may be switched on or off at different voltage levels, but if the temperature exceeded a certain level, the capacitor bank would be closed to provide more VAr compensation.

A utility has an obligation to maintain customer voltages within the limits outlined in Table 8.1. Historically, the challenge has been that the voltage standards apply at the customer meter location where the utility typically has little or no visibility of the actual load voltage data. There is a strong analogy to how distribution operators had to manage distribution systems back in the 1970s and 1980s. For years, substation circuit loads and transformer loads were based on drag hand mechanical meters and monthly downloads of transformer measurements. Until better data became available through SCADA and DMS systems, operators had to estimate loads and voltages at the local substations. Distribution automation and the expansive field communication networks have allowed additional measurements from downstream field devices, such as regulators, reclosers, and some switch locations. This additional monitoring and data collection of operations of the distribution systems can also help determine the optimal location of voltage regulation equipment on any given feeder and the optimal control of voltage to meet the objectives of combined voltage and VAr control.

However, these measurements are still limited to the primary side of the distribution system and there is still no visibility of the voltage and VAr levels on the secondaries at the customer revenue meter. Often this approach is followed by a plan to address low voltages only if there is an increase in customer complaints. For this reason, many VVO solutions seek to estimate customer voltages through modeling. While commonly practiced, this approach has several weaknesses. Individual customer loads are seldom known, with accuracy on an hour-by-hour basis, leading to a generalized load curve feeding the model. A key component of the voltage drop between the substation and the customer is the voltage drop on the secondary or service lateral feeding the home. The combination of unknown loads and unknown secondaries is a key component in low customer voltage, which is often found at locations with secondaries that no longer meet utility guidelines. This information is rarely known by the utility and is critical to understanding true customer voltages. If a utility depends on customer complaints, they may find that consumers will complain more frequently as technology is surging past traditional infrastructure and technically savvy consumers are gaining greater and greater visibility to their home service.

Now, many of the newer AMI implementations provide voltage readings including minimum, maximum, and averages. This allows utilities to proactively seek out secondary violations and perform corrective actions. This new paradigm changes the way customer voltage is known but, as with most new technology, it has its own constraints. Field data from circuits with full AMI deployment are exposing the dominant nature of secondary voltage drop on the overall voltage profile of a distribution circuit. Rarely is the low-voltage point at the traditional "end of line." The low-voltage point is often just a few miles from the substation but is due to long secondaries, shared secondaries, or simply because a failed transformer was replaced by a long run of cable to the next transformer down the street. These "unusual" situations are not at all unusual and reveal that secondary lines are often the cause of voltage delivery outside of the required limits. AMI data can also be used to validate that the VVO/CVR application is not creating any violations when running. Many centralized systems may use AMI data after the fact to determine if there were violations and then they may redo the algorithms to prevent future violations. Others may dynamically change the settings to raise the voltage once violations are detected. Finally, the AMI data can be used to help validate the results of the VVO/CVR systems as many AMI systems provide kWh and kVArH data as well as voltage data. Day on/day off comparisons using data from AMI have been used to validate results.

When implementing a VVO/CVR system, AMI data are critical starting points to help more closely predict results that can be obtained so that a proper business case can be performed. The current state of smart meter deployment does not allow for a similar level of data collection that the mature SCADA and DMS systems allow. The communication pathway is a constraint, and the meter kWh reads for customer billing are the priority data element to be retrieved. It is important to determine a reliable subset of meters, which can be read on a frequent basis to provide voltage feedback on the distribution circuit. Ideally, this subset of meters should be dynamically updated to sense the low voltages as they change along the circuit due to service restoration, load growth, or simply a change in loading patterns as seasons change. Until the technology advances to allow all meters to be read all the time, a sampling approach will be required. Another concern is controlling substation and line devices based on the feedback of individual customer voltages. This can be mitigated by using averages to smooth the voltage reads across the subset as well as making slow gradual moves with the control devices instead of chasing individual customer readings. More work on the use of AMI data is required to ensure that the AMI voltage data correctly represent the accuracy and frequency of the voltage measurements required for VVO implementation. For example, some meters provide average voltage measurements over a limited number of cycles, and only report voltages on an hourly or, at best (currently), 15-min intervals. The AMI data must also be "scrubbed" before using the data to make decisions on possible low-voltage problem areas. If the meters are sending back a 15 min average voltage measurement and there was a power interruption on the meter during the 15 min interval, the 15 min average may appear to be below ANSI limits, when, in actuality, the voltage may have been on the upper area of the ANSI limit when power was present. Any low voltages detected by the meter may also have occurred when the circuit feeding the meter was switched into an abnormal position. For these reasons, the AMI data must be verified and correlated with the outage management system to avoid using readings that were measured during abnormal operating conditions (as utilities are allowed to operate in the ANSI Range B when the conditions are abnormal). Finally, in many utilities that have AMI, the data are collected by the metering department and owned by the billing department. It may be difficult, if not impossible, for the distribution planning or customer reliability groups to access the AMI measurements. It has also been seen that the meter installations are not always documented correctly. Some meters are shown connected to the wrong transformer or phase, and this can cause the VVO/CVR algorithm to perform the wrong control on the wrong phase. Therefore, an interface to the GIS system may also be required to verify proper assignment of the meters to the transformers and phases that are supplying the meter.

Emerging new technologies, such as the use of power electronics for secondary voltage control devices, have shown to be viable solutions to help control voltage and VArs on the customer secondary circuits of distribution grids. Like many emerging technologies, the secondary voltage regulators and capacitors are currently in the evaluation phase, and they will need to be more cost effective and prove to be reliable before they can be considered for full-scale implementations. Additional capabilities, such as mitigating higher harmonics and regulating at subcycle speeds, are currently being added to the devices. As the power electronics components become available at higher voltage and power ratings, this technology will be a viable alternative to replace existing regulators and switched capacitors on the primary side of the distribution feeder.

Another technology that will impact existing and future VVO/CVR schemes is distributed generation, both on the secondary and primary. Residential PV systems are attached to the secondary and can supply power back to the utility. Larger PV farms may attach directly to the primary via a step-up substation. In either case, the PV generates power at DC and an inverter converts the DC power to AC to connect to the distribution system. In order to supply power from the inverter to the grid, the inverter must operate at a higher voltage than the grid. If the PV is on the secondary, the inverter must be at a higher voltage than the secondary, thus causing a voltage rise at the point of connection on the distribution secondary when it is generating power. PV typically reaches maximum output during the low-load periods of the day when the primary voltage can run higher. This may cause a voltage rise on the secondary where consumers are above the upper ANSI Range A limit of 126 V. This may also force the inverter to trip off due to high voltage. By running VVO/CVR, the primary voltages (and thus secondary voltages) will be operated at the lower range of the ANSI limit and, thus, allow the inverters to raise the voltage without crossing over the ANSI limit. This means VVO/CVR can assist in creating additional hosting capacity of feeders if the limiting factor is voltage. Ideally, the centralized VVO/CVR schemes would communicate to PV inverters (and other distributed generation controllers) to coordinate and optimize voltage and VAr control on the feeders, but this may prove to be difficult as most residential PV inverters are purchased and owned by the customer, not the utility. Additionally, there would be additional cost to add communications between the customer and the utility, and the associated security and privacy concerns.

Electric vehicles with charging stations may also impact VVO/CVR systems. As car chargers become more prevalent, they may cause the rating of distribution transformers to be exceeded, forcing utilities to upsize transformers. With VVO, the load may be reduced sufficiently to allow for the addition of car chargers without the need to upsize existing transformers.

As the types of loads on the system change, the VVO/CVR systems will have to evolve. There are circuits with a utility in the eastern USA where dropping the voltage reduces the load during the day but actually increases the load during the evenings. This is due to a shift in the type of residential load. Historically, residential loads have been modeled as mainly resistive, making it the most favorable for CVR reducing load. With the advent of more electronics-based equipment, such as computers, HD TVs, variable speed HVAC units, and other loads using switching power supplies, there are times when residential loads are more constant-power loads than resistive (constant-impedance) loads. With this in mind, the VVO/CVR system may have to adapt and lower the voltage to reduce load when the loads are mainly resistive and then start raising the voltage to reduce the loads as the loads become more constant-power.

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2. S&C Electric Company. High-Voltage Products and Service Solutions. Information Bulletin 102. Chicago IL. sandc.com.

9 Monitoring and Diagnostics

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CONTENTS

Monitoring and diagnostic technologies are used to detect and identify issues on critical grid assets, and are the foundation for predictive operational planning. Monitoring critical assets in near real time helps utilities to improve grid reliability and reduce the frequency and cost of unplanned outages. Monitoring and diagnostics in smart grids rely on the following fundamental components: instruments to continuously measure and collect data from field assets; communications to bring field data into a central location; a database to store the data; and software to analyze the data and create reports for dispatching appropriate actions. Measurements are provided by sensors and intelligent electronic devices (IEDs) attached to field assets. Analysis of the data is either performed locally at the sensors (also known as edge analytics) or in a central location (may also be called cloud analytics). Communications are required to deliver the measurements for analysis and alert the right person(s) as needed, either periodically, on demand, or when a significant event occurs. With the increase in the amount of operational and nonoperational data available from field devices and the IoT (Internet of Things), there is a significant opportunity for advances in grid monitoring and diagnostic applications that can assess/diagnose, predict, and prioritize remedial actions to impending problems, thereby enabling efficient and proactive asset management. The general approach to effective monitoring and diagnostic solutions can be summarized as follows.

Step	Action	Result
1	Collect data	Availability of data in one or more databases for further analysis
2	Analyze data	Assessment of asset condition and associated risk of failure based on known failure modes
3	Diagnosis	Development of remedial actions to rectify identified risks
4	Prognosis	Verification of results and potential impacts of implementing proposed remedial actions
5	Prioritization	Action plan that has a list of prioritized actions to address both short-term and long-term health/performance aspects of assets

Asset action and remedial plans are passed on to a work management system in order to dispatch the appropriate teams to execute the suggested, prioritized action plan. The outcome of implementation of these actions in the field is observed using the same monitoring and diagnostics infrastructure for further remedial actions, as needed or until the desired results are achieved.

9.1 MONITORING

Monitoring is the act of observing or verifying the condition or state of a physical asset using a systematic methodology. In its most basic form, monitoring results in the collection of large amounts of raw data from sensors attached to field assets. Monitored quantities could include electrical measurements, such as voltage and current, and nonelectrical measurements, such as temperature and pressure. They could also include numerical counts, such as the number of times a breaker has operated, and qualitative descriptions, such as those obtained from routine inspections.

The role of monitoring is to warn asset owners and operators of impending problems that could lead to a failure. In its simplest form, this warning is typically inferred by examining deviations of data from accepted or known baseline conditions. In more complex cases, the warning is inferred by expert systems and statistical correlations involving synchronous or asynchronous measurements from multiple sensors.

Monitoring has several attributes. It could be real time, near real time, or historical. In each application, the use case, that is, the specific purpose of monitoring the asset, determines how the data are collected, digitized, stored (local or centralized), and made available for processing. The use case also determines the frequency of data sampling and the availability of the data. Data sampling can range from hundreds of samples per (power frequency) cycle (e.g., for protection and relay applications), to hourly, daily, weekly, or monthly sample rates, depending on the asset and monitoring application. The data may be made available to a central application by polling on a periodic basis, upon event, or on demand, or in an unsolicited approach where it is automatically sent to the central application by the monitoring device. In all cases, the data are subject to inherent errors in the associated sensors, communication, storage, and retrieval systems. While these errors are typically very small and almost always negligible, gross errors may be removed by statistical analysis methods. Bad data detection used in most state estimation algorithms in Energy Management Systems (EMS) and Supervisory Control and Data Acquisition (SCADA) systems is a good example of such data "cleansing" approaches.

Monitoring of assets can provide great value to an organization. Whether for an individual asset, a group of assets, or across the entire grid, monitoring must be able to provide actionable information to enable the organization to achieve its objectives.

9.1.1 Sensors

Asset monitoring and diagnostics applications extensively utilize sensors and sensor systems for various functionalities, ranging from basic alarming to online and nondestructive condition assessment. Transformers, load tap changers, regulators, circuit breakers, reclosers, underground cables,

FIGURE 9.1 Example sensor system with embedded intelligence and communications. (Courtesy of GridSense, Inc.)

overhead lines, switched capacitors, reactors, surge arresters, insulators, batteries, and, more recently, power electronics devices are examples of major grid assets that may be equipped with some kind of sensor or sensor system for continuous monitoring, diagnostics, and real-time asset management. A fault passage indicator on a distribution feeder (Figure 9.1) is an example of a smart sensor that identifies an overcurrent condition on the feeder and communicates information on the passage of the fault current to a central monitoring system, such as a distribution management system or an outage management system, or directly to a work crew.

These sensors, powered by a central processing unit, offer functionalities beyond conventional sensors through embedded intelligence to process raw data into actionable information, which can trigger corrective or predictive actions. It is this combination of sensors, intelligence, and the communication of information, rather than mere data, which earns them the description "smart." The smart sensors may perform a number of functions based on the level of sophistication [1]. These functions, depicted in Figure 9.2, may include:

1. Basic sensing of a physical measurand
2. Digitization and storage
3. Raw data processing and analysis by the central processing unit
4. Local and remote communications
5. Local and remote human-machine interface

Figure 9.3 shows some of the most common grid sensor applications. The sensors and sensor systems supporting monitoring and diagnostics applications range from conventional current transformers and voltage transformers to state-of-the-art optical and acoustic sensors. These sensors are used to measure and sense physical attributes, such as electric current and voltage, temperature, gas-in-oil, moisture-in-oil, acoustic waves, vibration, pressure, weather parameters, Ultra High Frequency (UHF) and Radio Frequency (RF) waveforms, water, thermal profile, motion, proximity, displacement, and wear. Constant improvements in performance and cost are expected to continue and accelerate full-scale and cost-effective deployment of various sensors for the IoT and smart grid.

In addition to monitoring and diagnostics, the data collected from these sensors may be utilized to support other system functions, such as Volt Ampere Reactive (reactive power) (VAr) management, design improvements, real-time control applications, dynamic loading of transformers, triggering advanced diagnostics, and off-line applications. The total cost of the power equipment and

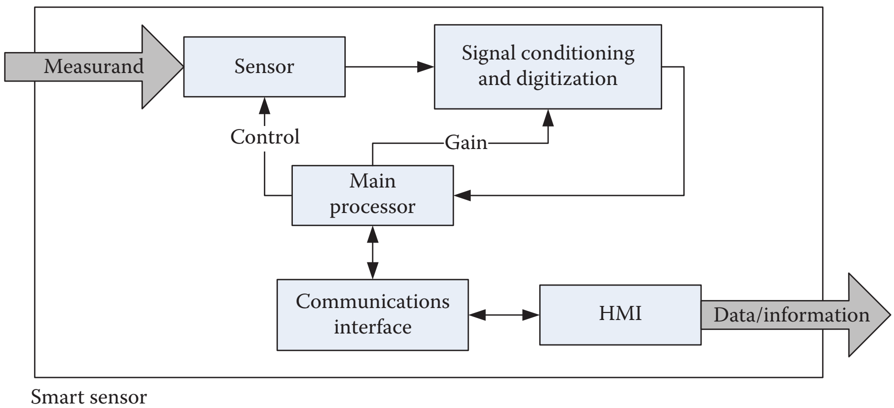

FIGURE 9.2 Functional block diagram of a smart sensor.

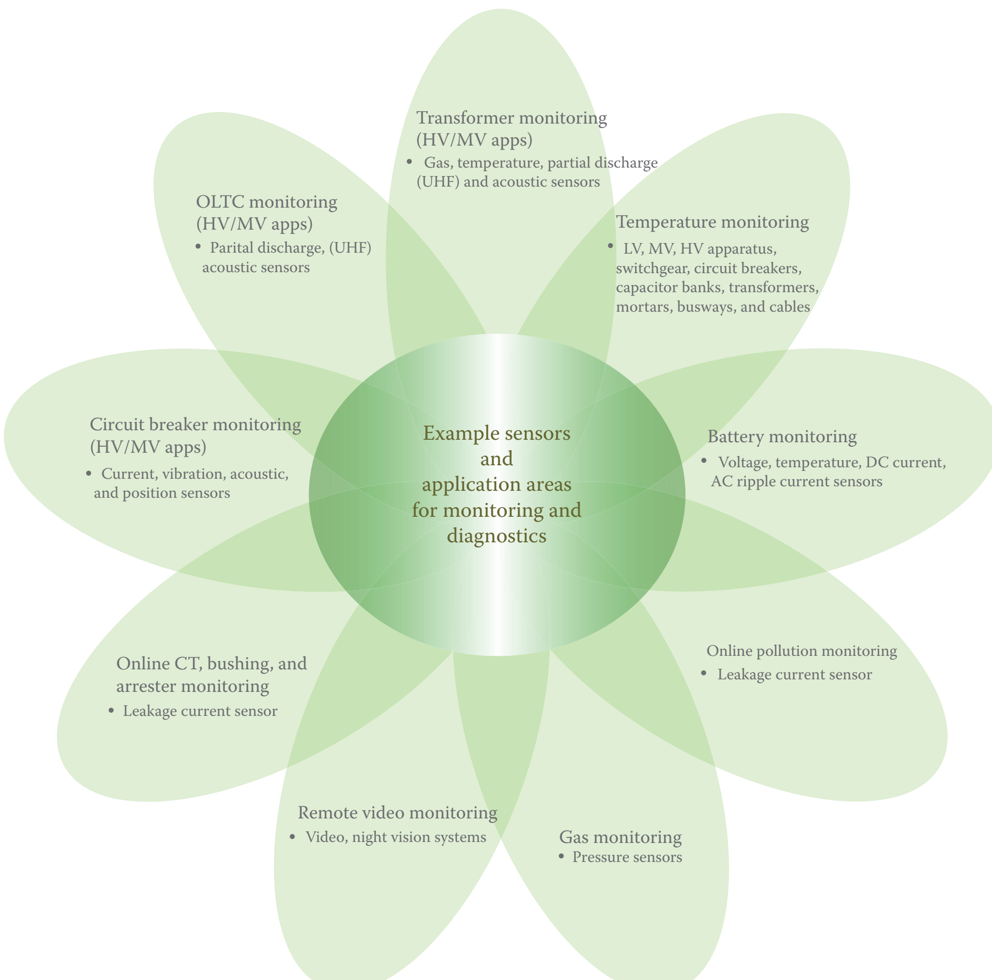

FIGURE 9.3 Examples of grid sensor applications. (© 2012 ABB. All rights reserved.)

its failure probability usually determine the need, complexity, cost, and features of the installed monitoring systems. Some components of the grid may not have a dedicated monitoring system, but a wide range of data is available from the devices as part of grid operations in monitoring and controlling the equipment that can be collected, stored, and analyzed. With most of the monitoring and control devices having communications capability, the data are freely available and should be exploited for monitoring and diagnostics applications.

As noted earlier, the use case—the specific purpose of monitoring the asset—is the key driver for all aspects of the monitoring and diagnostics function.

9.1.2 Monitoring Architectures

Sensors may be stand-alone devices or integrated into multifunctional IEDs and can be deployed in three main tiers of architecture depending on the application and data requirements, and flexibility to future needs.

9.1.2.1 Tier 1: Local

Sensing and analysis can be performed local to the asset being monitored, which has been lately termed "edge analytics." The smart sensor is typically a stand-alone device with embedded intelligence for local data processing and local/remote communications (Figure 9.4). Examples include a transformer oil monitor or a feeder circuit fault current sensor with visual indication. Data and information from the sensors may be integrated into feeder or substation automation systems. These types of sensors typically provide basic alarms to SCADA systems or field crews. By far, this is the most common architecture for smart sensors. Distribution feeder fault sensors are the most common sensors in use today. The future trend is a higher-level integration of these sensors with operations and automation systems. Asset-specific sensors are also emerging that will enable a greater level of observability and controllability of the distribution network where there is a significant penetration of distributed energy resources. Emerging trends also point to a connected future where smart sensors directly and securely connect to the Internet as part of the smart grid IoT.

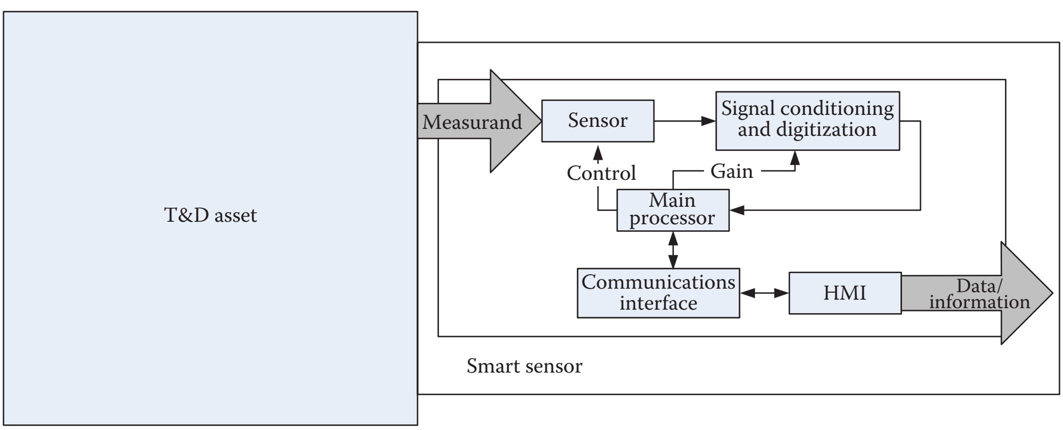

FIGURE 9.4 Tier 1 monitoring and diagnostics architecture—local.

9.1.2.2 Tier 2: Substation Gateway

Monitoring and diagnostics at this level involve smart sensors that are deployed as distributed systems with remote access to sensor measurements outside the substation environment. In these systems, sensor functions are distributed among system components that may be physically separate. A common architecture involves sensing and measurements that are monitored and collected by a central processor in a hierarchical architecture, such as a substation computer/gateway, for analysis and interpretation, as shown in Figure 9.5.

Since smart grids will contain both hierarchical and distributed sensors, the architecture of Figure 9.6 is also likely. In this type of topology, communications occur between peers based on system needs. The substation computer in Figure 9.6 might take on either a supervisory or a gateway role. This architecture might relate to third-party equipment operated by, for example, an energy service provider.

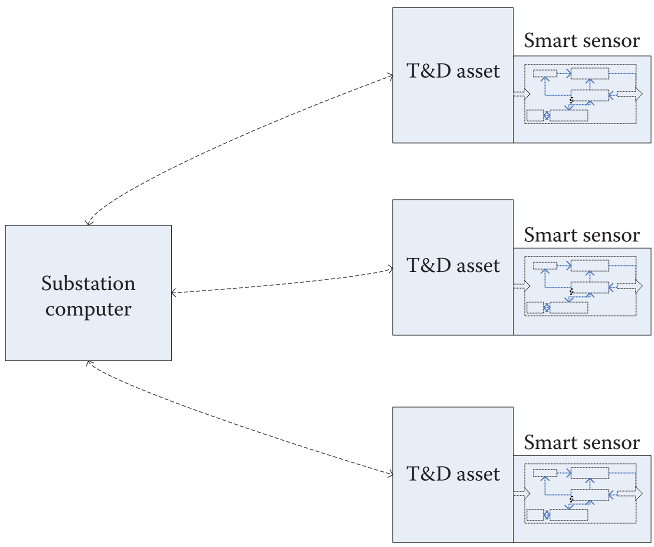

FIGURE 9.5 Tier 2 monitoring and diagnostics architecture—substation gateway.

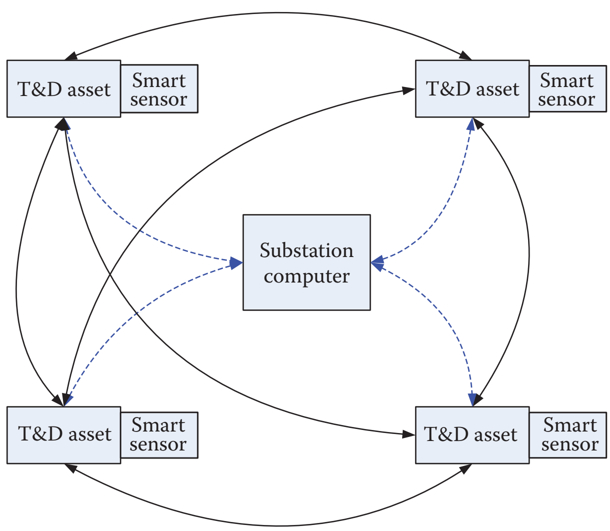

FIGURE 9.6 Tier 2 monitoring and diagnostics architecture—peer-to-peer.

This tier 2 type of substation monitoring architecture may be used to provide basic alarms to SCADA systems and field crews, as well as to send the measurements and analyzed data to central enterprise applications, such as a nonoperational data storage and asset management software. Feeder monitoring through peer-to-peer communications or via a substation computer is an example of this architecture solution. Often these functionalities are integrated into protection and control IEDs.

9.1.2.3 Tier 3: Centralized

System-wide monitoring and diagnostics applications require a centralized architecture where data and information from field sensors are retrieved and stored in a central repository (in the cloud or on premise) to support real-time and back-office applications, as shown in Figure 9.7. The centralized data repository can be part of a stand-alone asset management or diagnostics application, or the data can be shared among other real-time and enterprise applications in the utility, for example, outage management and workforce management.

The centralized architecture allows operations and maintenance departments to access diagnostics based on real-time and historical data, including additional data generated through regular survey and inspection activities. The centralized architecture also allows system-wide analysis and correlation of asset data, for example, to determine if a common problem exists in a "fleet" (e.g., transformers of the same design from the same manufacturer), or a batch date of manufacture of assets. Such decision support systems provide asset condition diagnostics by utilizing pattern recognition and intelligent algorithms, enabling the asset data management system to assist with reliability-based as well as predictive maintenance. Such architectures should be designed for seamless integration into other enterprise applications, such as work management, inventory, financial, and regulatory compliance systems.

9.1.3 Sensor Communications

Monitoring and diagnostics in power grids focus mainly on assets that are within a transmission or distribution substation. This is because sensors deployed outside the substation fence are typically costly and difficult to maintain. However, as these costs become lower, utilities and vendors have been developing improved monitoring capabilities for remote assets. Regardless of the asset's location, the sensor or sensor system installed on these assets must have communications ability to exchange alarms and data with other devices or systems, depending on the monitoring architecture.

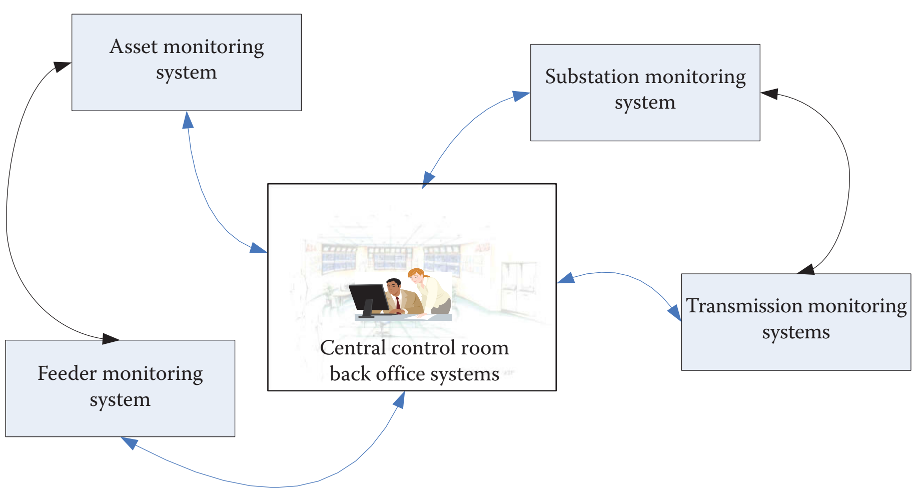

FIGURE 9.7 Tier 3 monitoring and diagnostics architecture—centralized. (© 2012 ABB. All rights reserved.)

The communications and interfacing technology deployed depends on the application and requirements of the specific sensor or sensor system. Most systems are equipped with LCD screens for the local user interface, and RS232, RS485, and Ethernet communication interfaces [1]. Wireless communications are also utilized in some applications with continued research and development to improve performance. The trend in sensor development is toward wireless and battery-less designs, accelerated in part by IoT macro trends. Significant installation cost, long-term maintenance cost, and the limited number of deployed sensors are impediments to the widespread use of wired sensors, but wireless sensor networks are now eliminating these constraints and offering attractive sensor solutions.

A wireless sensor network is typically composed of a number of sensors that are linked to each other through a base station or gateway, or through peer-to-peer connections forming a star or mesh communications network. The data are collected at each sensor node, possibly preprocessed, and forwarded to the base station directly or through other nodes in the network. The collected data are then communicated to the central system via the gateway connection. Recent advances in IoT sensors and wireless sensor networks allow the sensor, radio communications, and digital electronics to be integrated into a single device. This compact design results in substantial cost reduction and enables low-cost sensors to communicate with each other using low-power wireless data routing protocols [2].

The radio link in a wireless network can be characterized in terms of the operating frequency, modulation scheme, and hardware interface to the system. There are many low-power proprietary radio chips available in the market, but the use of a standard-based radio interface enables interoperability among networks from different vendors. Some of the existing radio standards suitable for sensors include IEEE 802.11x (LAN), IEEE 802.15.1 and 2 (Bluetooth), Bluetooth Low Energy (BLE), IEEE 802.15.4, and IEEE 1451. Many other low-power and ultra-low-power standards are in the works and are expected to emerge as a result of the global push toward IoT technologies and the smart grid. Public carrier telecom networks are also now beginning to open up and become viable for backhaul communications.

For short-range wireless sensing applications, IEEE 802.15.4 has a number of features that can be used as a benchmark for other wireless solutions. The IEEE 802.15.4 standard specifies multiple data rates of 20, 40, and 250 kbps for the transmission frequency bands of 868 MHz, 902 MHz, and 2.4 GHz, respectively. The 2.4-GHz band, being essentially license-free worldwide, is the most appealing band. By accommodating higher data rates, it reduces the transmission time and consequently lowers the power consumption level of the radio. This provides for a long-term and potentially maintenance-free network for monitoring applications in many areas of IoT and smart grids.

A number of companies and alliances are working together to develop reliable, cost-effective, low-power, and wirelessly networked products. The ZigBee Alliance, for example, promotes the use of wireless networks for home/building monitoring and control applications using an open global standard (IEEE 802.15.4). As new initiatives are rolled out with respect to grid integration of buildings, wireless sensor networks will be an integral and vital part of many application areas related to monitoring and diagnostics, including the consumer and behind-the-meter space. In this rapidly evolving area, however, new solutions will emerge: EnOcean, LoRa, DASH7 (ISO 18000-7), 6LowPAN, Wibree (Bluetooth low power), and UWB PHY applications of ZigBee are among the many developments that have the potential to open up new niches within low-power and ultra-low-power, short-range wireless transmission.

9.2 DIAGNOSTICS AND PROGNOSTICS

Diagnostics is the analysis and interpretation of asset monitoring data to determine the cause of any changes, variations, or anomalies, and subsequent identification of possible failure modes in progress. In other words, diagnostics is an assessment of the present state or condition of an asset. Diagnostics focuses on answers to the following questions:

1. Are there any anomalies in the operation of the asset?
2. If there are anomalies, what are they, and why are they happening?
3. Can or do these anomalies lead to failures? If so, what particular failure mode?
4. What is the recommended course of action(s) for the identified failure mode(s)?

Prognostics, on the contrary, is the determination or prediction of what the asset will do next, and how it would respond to a given course of action. Prognostics focuses on answers to the following questions:

1. How much time does the asset have before it experiences a certain degraded mode of operation or failure (irrespective of the failure mode—gradual or catastrophic)?
2. What is the impact of implementing a recommended course of action(s) in terms of improvement in expected life, asset health and performance, and risk averted?

The action plan could be based on short-term actions (maintain or repair), or long-term actions (refurbish or replace). In either case, the current health and associated risk of failure play an important role in the prioritization of actions. For example, consider the health of a power transformer, with the long-term goal to replace the transformer before failure (proactive replacement). Certain transformer-operating data must be measured and assessed to determine the transformer condition on a regular basis. If tha data indicate an incipient failure mode, more data may be required for assessment. Intervention must be planned with an appropriate timescale. Besides using the asset's health and risk of failure, the decision to replace the asset is also based on other factors, such as cost, age, technological obsolescence, environmental impacts, safety considerations, and legal/regulatory mandates. Figure 9.8 shows the deterioration of a transformer's condition over time.

Diagnostic intelligence is the result of analytics performed on sensor data using specific algorithms in digital processors. The algorithms and diagnostic logic require a deep understanding of the asset and how it operates (subject-matter expertise); for example, increased load on an electrical asset may increase the asset temperature, which may be acceptable in some asset designs, but

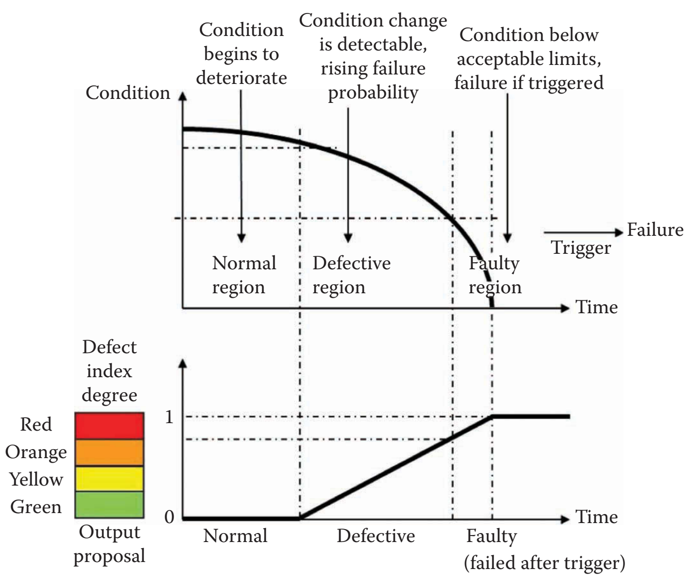

FIGURE 9.8 Schematic representation of transformer condition development over time (top), and an example of condition diagnostics (bottom). (Reprinted from CIGRE, WG A2.44 Tutorial, Technical Brochure 630, Guide on Transformer Intelligent Condition Monitoring (TCIM) Systems, © 2015. With permission.)

not in others. Communications are required to deliver the derived monitoring and diagnostics data and intelligence to the right person or application, in the right format, and at the right time. These three elements are the building blocks of current control and monitoring systems, but in the era of smart grids and the connected world, that is, the IoT, a dramatic boost is needed in sensor and monitoring functionality, performance, and coverage across the power delivery chain down to the last mile, including end customers. More importantly, we should expect to see an infusion of intelligence into every system and device, coupled with integrated communications, connectivity, and interoperability.

The intelligent machine algorithms used for monitoring and diagnostics in smart grids may reside at different levels in the supervision and control hierarchy. Protection and control IEDs can host such algorithms to detect anomalies in the power system behavior and identify an abnormal situation (such as incipient faults). They can take appropriate action (such as tripping appropriate circuit breakers) based on this local analysis, or they can forward the fault and event data to the higher entity in the hierarchy, which can be a substation computer or a centralized asset health management system. The substation computer (or similar intelligent device) may host the intelligent algorithms, or the intelligence can be implemented in a centralized application. Each diagnostic solution has its own benefits and limitations depending on the application, architecture, complexity, scalability, cost, communications options, and user preferences. In other words, the use case determines what type of monitoring and diagnostics architecture is required.

9.3 FUTURE TRENDS

The ability to proactively address grid problems and respond as quickly as possible to outages and asset failures, along with the movement toward predictive maintenance and proactive asset replacement, will be a significant contributor to fulfill the promise of smart grids. Often, maintenance schedules for assets are set on a preprogrammed basis without specific intelligence about the asset condition and health. In a smart grid, with automated analysis of sensor data and predictive maintenance technologies, operations and maintenance departments will have the ability to respond more quickly to outages, send the right restoration/repair crew, assess the risks, and proactively address system problems. Utility crews will have all the required information at their fingertips to help them quickly restore the system to its normal operating state even before they get to the asset to make repairs. The planning department will, in turn, have access to more and improved information to identify and justify system upgrades and long-term reliability enhancement projects.

Although there has been significant progress in recent decades on sensors and sensor systems in general, there is room for continued improvement for smart grid applications, in particular with respect to enabling smart grid and the IoT. These improvement areas include: reduction in the cost per node; minimal power requirements; expanded communications capabilities; reduction in footprint; ease of installation, retrofit, configuration and calibration; improved accuracy, reliability, and interoperability; and a more robust design for cyber and physical security. In recent years, considerable progress has been made in measurement and instrumentation due largely to the progress in integrated circuit technology and the availability of low-cost analog and digital components, sensors, and low-power microprocessors [1]. Consequently, the performance, efficiency, and cost of sensors and sensor systems have seen much improvement. The emergence of local and international standards, coupled with advancements in communications technology, allows for further progress in sensors, such as wireless sensor networks, and sensor applications, such as monitoring and diagnostics in the digital grid. Smart sensors, including acoustic, vibration, partial discharge, and many IoT sensors, are now more widely available with the processing and communications components integrated with the sensor on the same microprocessor chip. These smart sensors also incorporate local intelligence of some form and have the ability to report more meaningful information rather than exchange basic measurement data and alarms, which will also help to reduce communications bottlenecks and improve the functionality and responsiveness of the monitoring and diagnostic scheme. Future efforts will continue to make sensor systems cost-effective, accurate, scalable, fault-tolerant, interoperable, secure, self-powered, and maintenance-free, all as an integral part of the grid monitoring, control, and automation infrastructure.

The focus in the next few years will also be on more real-time analysis and diagnosis of asset condition data in order to support operational decisions and ensure the cost-effective maintenance of assets. Automated, reliable online, and off-line analysis systems are needed in conjunction with sensors and sensor systems supporting smart grid monitoring and diagnostics applications. In the era of connected smart grids, ubiquitous sensors and measurement points will enhance situational awareness and monitoring of the grid and grid assets. This will, in turn, lead to more data and increased processing needs, the identification of anomaly based on predefined rules, and the identification of anomaly based on data mining and machine learning approaches. The utility environment of today can be overwhelmed by the amount of data collected by existing systems. The addition of new data points will exacerbate the situation, unless data-to-information conversion is considered in each step of the process, giving rise to more automation and the emergence of proactive health management and auto-notification systems [3].

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10 Asset Management

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CONTENTS

10.1 INTRODUCTION TO ASSET MANAGEMENT

Asset management is the "*coordinated activity of an organization to realize value from its assets,*" as defined in the international standard ISO 55000, published in 2015 [1]. The standard is based on international consensus and builds on the successful UK-based predecessor, PAS 55 [2]. Derived from a variety of industries, ISO 55000 has been successfully applied in a number of organizations around the world, demonstrating business benefits and value to the organization. Figure 10.1 shows the hierarchy of assets and organizational priorities common to many asset-intensive organizations [3].

Within ISO 55000, an asset is defined as "*an item, thing or entity which has value or potential value to an organization.*" This definition covers a lot of ground and allows the organization to define its area of interest for asset management activities. PAS 55 remains useful guidance for *physical assets*, but is withdrawn as a formal standard.

A good asset management strategy involves the management of costs, risks, and performance to optimize return on investment in assets across the whole asset life cycle. A good asset management strategy should include the following:

- Coordinated planning
- Asset design and selection
- Asset specification, purchase, delivery, installation, and commissioning
- Maintenance and operation
- Monitoring and performance assessment
- Disposal and renewal (sometimes considered as part of an asset "life cycle")

Core asset life cycles will vary between organizations, as shown in Figure 10.2.

An asset management-focused organization looks for efficiencies and consistencies across all the functions and businesses of an organization. Passing information between functions and businesses can result in the loss of information unless there is seamless integration; data silos are often quoted

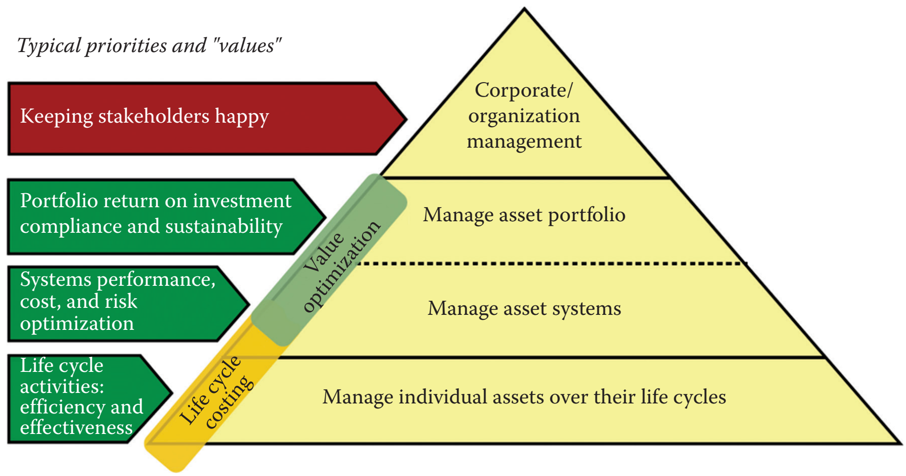

FIGURE 10.1 Hierarchy of assets within an Integrated Management System. (From "Asset Management—an Anatomy, Version 3," The Institute of Asset Management, 2014.)

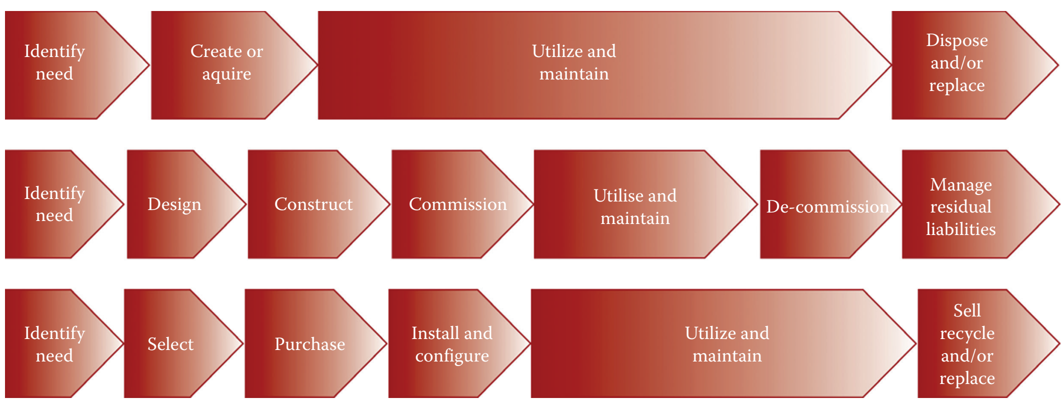

FIGURE 10.2 Examples of variations in core asset life cycles. (From "Asset Management—an Anatomy, Version 3," The Institute of Asset Management, 2014.)

as features of a fragmented organization. The roles of asset management and of accreditation to standards are to remove these integration barriers.

Key stakeholders and organizational elements of asset management within an organization are shown in Figure 10.3. It is crucial that the organization has a strategic plan—something to which every member of the organization can refer, and something that provides alignment for efforts of each element. This strategic plan addresses the needs of stakeholders across the organization.

In a smart grid environment, the life-cycle delivery activity covers a number of actions and may be distributed across several functions and businesses of the organization, ensuring that asset management data are available at the right place at the right time and that they support the strategic plan of the organization. Smart grid activities can provide large amounts of valuable data: This must be managed with appropriate IT and infrastructure activities—all within the appropriate cybersecurity framework—to ensure that the value of the data is realized.

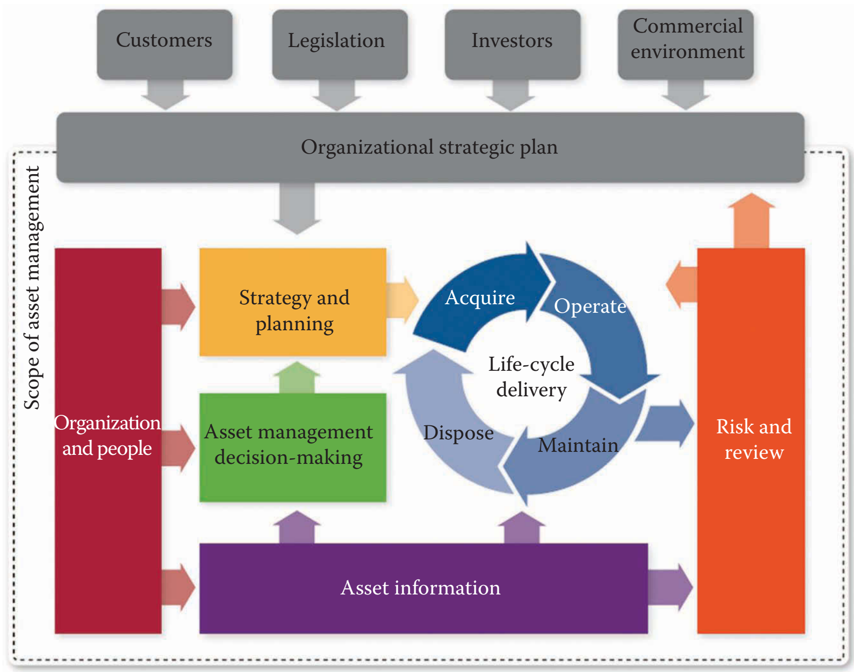

FIGURE 10.3 Elements of asset management in an organization. (From "Asset Management—an Anatomy, Version 3," The Institute of Asset Management. © 2014, www.theIAM.org/copyright.)

The ISO 55000 standard covers all of these organizational elements, which are summarized in Table 10.1.

The ISO 55000 standard has applicability across all activities within an organization, including the management of assets in the context of the business, such as regulatory impact on the business.

The ISO 55000 Standard is divided into three parts:

– ISO 55000: an overview of asset management, and of the concepts, terms, and definitions
– ISO 55001: requirements for an integrated and effective asset management system
– ISO 55002: guidance on the interpretation of the standard and implementation of an asset management system

10.2 DRIVERS

An asset management "program" needs clear identification of the business drivers and benefits that could be accrued—key performance indicators (KPIs) can then be used to track the application of asset management and indicate the level of success in pursuing an asset management approach.

Asset management may be seen as "centralized" in that it must be driven by the strategic goals of the organization—achieving those aims will require coordinated activities across the organization. Some of the drivers for utilities to consider implementing system-wide asset management programs may include:

– Safety
– Reliability
– Regulatory compliance
– Maintenance optimization

TABLE 10.1
Outline of the ISO 55000 Standard

ISO 55000 Sections		
#	**Title**	**Includes**
1	Scope	Application of the standard
2	References	To other standards such as ISO 9000 for Quality
3	Terms	Definitions
4	Context of the Organization	4.1 Understanding the organization and context 4.2 Understanding needs of stakeholders 4.3 Determining scope of AM system 4.4 AM system
5	Leadership	5.1 Leadership and commitment 5.2 Policy 5.3 Organized roles/responsibilities/authorities
6	Planning	6.1 Actions to address risks/opportunities for AMS 6.2 AM objectives and planning to achieve them
7	Support	7.1 Resources 7.2 Competence 7.3 Awareness 7.4 Communication 7.5 Information requirements 7.6 Documented information
8	Operation	8.1 Operational planning and control 8.2 Management of change 8.3 Outsourcing
9	Performance Evaluation	9.1 Monitoring, measurement, analysis, and evaluation 9.2 Internal audit 9.3 Management review
10	Improvement	10.1 Nonconformity and corrective action 10.2 Preventive action 10.3 Continual improvement

– Environmental performance, including reduced carbon footprint
– Strategic asset replacement planning
– Optimized replace/refurbish decisions
– Risk analysis and management
– Increased asset utilization and loading
– Lowering system operation losses
– Reduced outage frequency, duration, impact

Individual asset management programs will reflect the needs and business context of the organization, such as smart meters, Phasor Management Units, Just In Time maintenance practices, which all require risk analysis and cost–benefit justification. Tools applied include smart asset tagging and Radio Frequency Identification Device (RFID) usage, improved field work force tracking, and test/inspection data management.

In the electric utility world, the changing regulatory environment is often seen as a driver for an asset management program. It should be noted that many organizations have been successfully managing assets for many years—it is the change in business context that is the catalyst for an asset management approach. Asset management is neither a quick fix, nor should it be treated as a passing management fad. It can provide value in ensuring that all elements of the organization are working toward the same strategic goals. Having clear goals allows for KPIs to be established in order to track and demonstrate success.

In a >10-year program of asset management activities, China Light and Power (CLP) noted that they had identified key drivers and KPIs for their program [4]. The drivers included regulatory requirements to address reliability issues, maintaining tariffs to customers and addressing load growth requirements in a heavily concentrated commercial/industrial/residential environment. KPIs for the 2000–2010 period showed that as demand rose and the installed base expanded, costs to the consumer fell and reliability improved. CLP attributes its success to a number of well-defined elements of their asset management program:

– Sustained organizational commitment—the initiative was well thought-out, funded, and sustained
– Organizational alignment to improve communications, data flow, and optimization of decisions
– Change management to address cultural issues—including risk analyses
– Increased collaboration between asset managers and service managers
– IT system expansion to support the new approach

The CLP experience has been repeated elsewhere—in Costa Rica, for example, where Instituto Costarricense de Electricidad (ICE) deployed an asset management program for their 26 power plants, which yielded over US $10 M/year in tangible benefits, and over 23 GWh/year of additional generating uptime [5].

10.3 ASSET MANAGEMENT IN THE SMART GRID

Asset management is a growing discipline, with a large body of knowledge and experience available to both newcomers and experienced organizations. For an organization successfully operating for decades, an asset management program offers insights to improve efficiency and reduce risk without jeopardizing performance. For an organization with pressing business drivers, an asset management program offers an auditable justification for expense, action, and performance improvement.

Successful asset management programs are well-defined and bounded—they have a focus and a duration. Successes are well-documented—across many industries. Asset management certification is of value in demonstrating an organization's capability—Pacific Gas & Electric's president stated that accreditation to the ISO standard 55000 has "helped transform the safety and reliability of our gas system and earn back the trust of our customers" [6]. A gap assessment to identify areas for improvement has helped Hydro Tasmania move forward: Tony Ang, manager of Asset Strategy and Risk notes, "As a management system, there are elements that are more important than just fixing the asset" [7].

In a smart grid world, asset management is a means to ensure optimal asset performance within the business context, with line of sight from the asset to the boardroom, and with efficient and optimized data flows for decision support.

10.3.1 Smart Grid Devices

Smart grid development enables the proliferation of "smart devices"—sensors and monitoring devices generating "big data" across a broad spectrum of assets and locations. In an asset management, it is necessary to consider not only the technological possibilities but also the business justification and integration of the data from sensors and monitoring devices to provide value for the organization.

Technology application, from "big data" to the "Internet of Things," needs to be evaluated against the costs, risks, and performance of the organization. For example, there are possible benefits in monitoring real-time temperatures and load on distribution pole-mount transformers in order to better understand the performance and estimated asset likelihood of failure. A successful asset management program includes evaluation of both the investment in such technology and subsequent performance improvement while managing the risks and hazards associated with the program. In this example, information from the real-time monitoring of distribution pole-mount transformers must be weighed against the cost and risk of the additional sensors and data retrieval application. The cost and risk may not be justified for a system-wide deployment, but limiting the program to "worst performing" feeders or critical transformers may prove to be very beneficial. In addition, pole-top transformer monitoring may be justified when combined with other asset management initiatives, such as RFID tagging of the transformers for asset tracking, and voltage phase reconciliation with consumer meters fed by the transformer in order to verify and address any planned versus actual loading on the transformer.

The smart grid helps drive asset management programs in terms of more advanced and lower cost technologies (both hardware and software), and the synergies of integrated applications that can share the data, but there must be "line of sight" [1,2] back to the aims of the organization and the business environment in which it operates. An asset management analysis gives justification for the application of technology for the benefit of the stakeholders in the organization and its activities.

10.3.2 Knowledge Management and Analytics

There are two main drivers for knowledge management within an asset management organization [8–10]:

– The need to identify new knowledge that is of benefit to the organization, and making the data available to various users and systems in the organization
– The need to capture and embed knowledge previously held within an aging workforce using the technology and systems of the organization

A smart grid enables the monitoring and collection of data on the operational performance of utility assets. Analytics convert the data to meaningful information for use by the organization. Analytics can identify anomalies in data or new correlations [11], but to provide meaning, the knowledge generated must be evaluated against standards and guidelines, or against expert opinion. For example, many analyses of power transformer dissolved gas analysis measurements have been performed and confirmed what is already in the standards, such as IEEE C57.104 [12]; new and valuable knowledge related to such data is difficult to generate and must be validated by subject-matter experts.

Analytics used for the identification of asset anomalies is of value to an organization, providing timely information for resources to intervene and remedy or correct a situation. Efficient use of analytics requires "line of sight" across the organization in order to allow appropriate data to be available at key decision points within the organization ("the right information, at the right time, to the right person"). Smart grid applications have the potential for generating vast amounts of data; "good" asset management organizations will make efficient use of that data.

Some organizations have an approach to asset data analytics by generating more and more data, of better and better quality, with a hope that, someday, the perfect data will allow for perfect analyses. This is a flawed approach [13]. The asset analytics path shown in Figure 10.4 is one that has been shown to provide the optimum route for asset data analytics. The important point in this process is to select a starting point, and then implement improvements in the analytical capability before trying to improve data quality.

The ability of an organization to embed knowledge into their systems and processes, and capture the heuristic experiences and personal value of individuals, will enhance their asset management capability. It is part of the risk management process to ensure that the knowledge lost is replaced, or is not a limiting factor in the organization's operation.

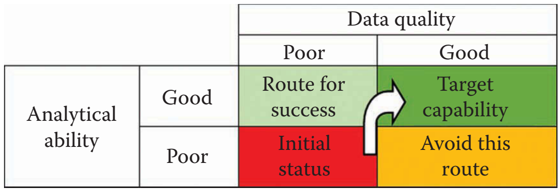

FIGURE 10.4 Asset analytics—route for success.

10.3.3 Asset Condition Assessment and Ranking

By providing more data, a smart grid approach enables more precision in the analysis of individual asset performance and condition. The use of such data in planning both tactical response and long-term strategic asset replacement is well understood [14]—the ability to implement such analyses is less well established. In a regulatory environment, long-term planning, in particular, is a capability that requires analysis of the whole asset base, in order to justify plans, replacement rates, and investment, which impact customer tariffs directly. Asset management merges with the smart grid to provide such capability.

10.4 DISCUSSION

Asset management has developed in response to industry needs for coherent and consistent approaches to strategic business activities. In the electric supply industry, it has shown value across many organizations and across all corners of the globe. In a smart grid context, asset management is a key enabler to ensure that the organization is working toward a common goal; effective and efficient use of technology is promoted; proliferating data are shared appropriately and securely; decisions are justified and auditable.

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11 Geospatial Technologies

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CONTENTS

11.1 TECHNOLOGY ROADMAP

The business of an electric utility is inherently spatial in nature. Managing power flows over a large geographic area requires detailed information about the vast network of wires and equipment that composes the grid—and much of that information is spatial.

Since the genesis of widespread electricity distribution in the 1880s, there has always been a need for geospatial information to help manage the grid. The electrical grid is inherently spatial, rooted in the geography of the service territory served by the utility. It is a complex network of wires, supported by devices that control the flow of electrons through those wires. To build and manage that network, the utility has to know the location of all those components and how they are connected. Managing the locational and topological data and providing users with methods to view and use the data, require technology that is designed to handle large amounts of geographic data.

A great deal of utility work has a high level of "where" content, reflecting the spatial nature of the grid. For any operations function, much of the day-to-day work requires access to location-based facilities data. Where are my facilities? Where are my customers? Where is the device that controls this circuit?

For field crews—the "tech in the truck" that makes up a large part of the utility workforce—there are additional spatial questions at the heart of their daily work. Where am I? Where do I need to be for my next assigned job? Where is the switch that controls this line?

11.1.1 Age of Paper

For almost a century, the mechanism for storing all of these spatial data was the paper map (or, for permanent records, a more durable equivalent such as vellum). The "data" were created and maintained by manual drafting. The data were distributed by making copies of map books for each person (or field crew) needing the data.

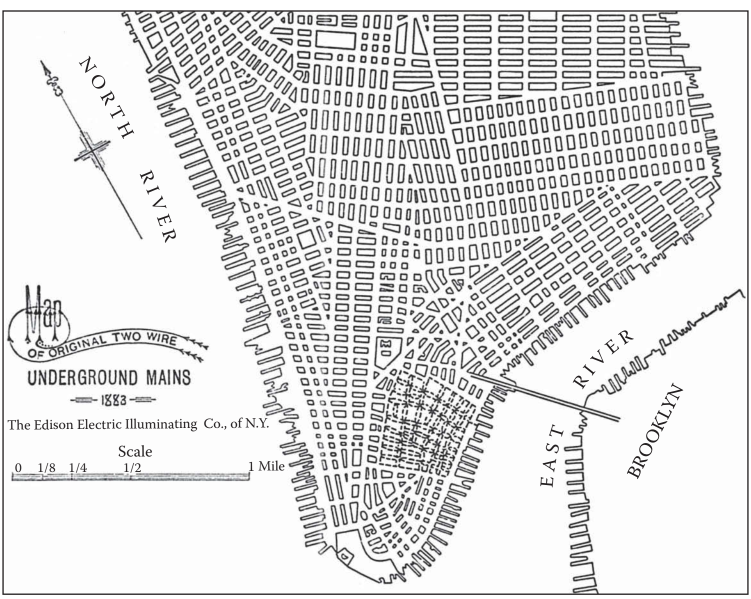

FIGURE 11.1 Pearl Street project in Manhattan. (Courtesy of Consolidated Edison, New York.)

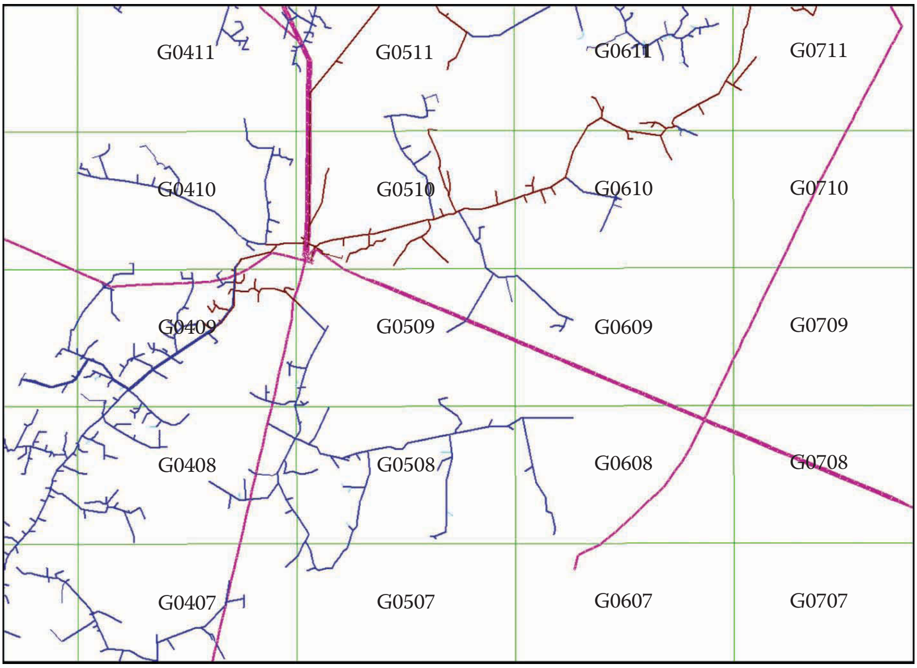

FIGURE 11.2 Typical utility map grid. (© 2016 General Electric. All rights reserved.)

Edison's first distribution network, the Pearl Street project, covered a very small geographic area—several blocks of lower Manhattan. Even with a territory that almost disappears within the territory of a modern utility, however, a map was needed to show the spatial extent of the network (Figure 11.1).

As the size of utilities' service territories grew, the scope of the mapping effort grew as well. Recording changes became more of a problem as data volume rose dramatically. Each utility developed a system for organizing and cataloging maps. The service area was typically divided into a map grid—a series of tiles where each tile corresponded to a defined geographic area and was represented by a map sheet (Figure 11.2). This mapping structure often made its way into the field, as numbers based on the map grid were stamped onto poles and other equipment. As paper maps became more congested, the grids had to be split and redrawn into fourths and sixteenths to provide a workable resolution, adding to the cost and effort of maintaining, publishing, and distributing map books.

11.1.2 Emergence of Digital Maps

Utilities, like most other businesses, first used computers for back-office functions such as payroll, billing, and accounting. Starting in the late 1960s, some utilities (notably Public Service of Colorado) started to experiment with harnessing this computing power for representing maps.

The mainframes were, by today's standards, very limited and primitive tools. Even with the limitations, however, it quickly became apparent that the growth in computing technology offered utilities a new way to handle spatial data. As we moved through the 1970s, there was clearly a new age of geospatial technology in utilities: The sheer volume of map data had overrun the ability of paper-based methods to keep up with changes, and digital tools were increasingly seen as a potential answer.

Over the next two decades, almost every large utility invested heavily in computer infrastructure. Massive data conversion projects were necessary to turn paper maps, often decades old and with questionable cartographic accuracy, into usable data. This required tying points and lines on the old maps to a common coordinate system (latitude/longitude, state plane, or UTM[1]).

[1] UTM coordinate system, based on the Universal Transverse Mercator map projection, is a planar locational reference system that provides positional descriptions accurate to 1 m in 2500 across the entire Earth's surface except the poles.

Although at this stage the storage of spatial data started to move from physical to digital, the communication of spatial knowledge still relied on paper. After all, the mainframe was not readily accessible to the people involved in managing the grid. Interactive, on-screen graphic capability was fairly primitive and very costly. The emphasis, then, was still on producing paper maps. The data used to produce the maps may have been stored digitally, and the maps might have been generated by a digital plotter, but the end result was still a paper map. In most cases, the goal was to reproduce—in a more efficient way—what had been used for decades. The paper map products from a digitally stored map had a more appealing look and feel, with more detail and consistency, but the information that the map contained still had to be communicated through paper to humans, with no interface or tools to make use of all the captured map data. Map content and symbology mirrored the standards in use at each utility but also carried with them the accuracy issues of the original paper maps.

11.1.3 From Maps to Geospatial Information Systems

The next stage in the evolution of geospatial technology shifted the emphasis from maps to applications. The graphic representation of facilities in two- (2-D) or three-dimensional (3-D) space—the map—was still important, but the data behind the map began to be used in different and more powerful ways.

Early systems were used to store geographic data and communicate the data through maps. The next big step was to treat data about the grid as not just a map but as a collection of objects that have location, attributes, and topology. Adding attributes makes it possible to retrieve related information (what are the voltage ratings on that transformer?) and to search (where is pole B45806?). Common database functions allow for complex queries across data sets (where do we have 500-kV oil-filled pad transformers installed within 1000 yards of the Chesapeake Bay management area?). Establishing topology (the relationship of features to each other) enables network connectivity, supporting models of current flow. This added a whole new dimension to the data available from the mapping database, a powerful resource for utility network planning and operations.

This change marked the transition from automated mapping to true geospatial information system (GIS). Together, these characteristics support analysis of asset attributes and much more. Computer-aided design (CAD) systems also played an important role during this period, adding intelligence to the process of designing new facilities on the grid.

Even though these systems enabled profound changes in the way that map data were stored and managed, the direct effect on utility operations back then was minimal. Access to GIS tools and applications was limited to professionals with extensive training in the technology. Frontline users (the crews in their trucks) were, for the most part, still using paper maps. Even though the maps represented digital data and were generated by plotters, the users were still constrained by the limitations of having to use the paper format of the geospatial information.

11.1.4 Across the Enterprise

A fourth stage of the geospatial grid started to emerge in the 1990s. Desktop computers proliferated, network infrastructure grew, and (in the late 1990s) mobile computers rugged enough to survive field conditions were deployed. Paper was replaced by computer applications that could search for objects, display attributes, and even trace through the network to identify trouble spots. A rich set of applications made GIS capabilities accessible to planning and operations managers as well as to field crews.

Geospatial technologies have evolved to become a true enterprise system, extending from meager map digitization to meaningful GIS, to a valuable data resource that crosses many enterprise applications. GIS for utilities has become a business-critical technology, supporting operations as the "system of truth" for the grid. Interoperability has allowed it to become the integration point for other utility enterprise data—asset databases, sensor and monitoring equipment, customer information systems, work management, compliance records, as well as third-party and public map sources. It is now common for a utility to visualize load information, assets, protection schemes, workforce locations, and public/commercial maps and photography all at the same time and through the same interface.

Interoperability has magnified the need for accurate data in all systems. Reliability is tied to properly functioning applications that are dependent on accurate and up-to-date data. Smart devices that report load information can dictate a demand response application, but if there are inaccuracies in the asset management system and geospatial representation, the application will be ineffective.

In many ways, this drive to automation in the utility industry has mirrored technology trends in other sectors, where the platform for computing has moved steadily closer to the user's place of work. It parallels ubiquitous mobile platforms and social networking, which have brought computing power to the hands of almost everyone. (And, in developing countries, it is outstripping conventional desktop computing as the dominant platform.)

Delivering geospatial tools to the field is essential to the operations of a utility company because much of the work has to be done outside the office. The assets and the customers are all outside in the field, spread across the service territory. Consequently, much of the utility workforce is also outside the office. The field personnel jobs are inherently mobile, moving around the grid "in the geography" to job locations that change rapidly (Figure 11.3).

This spread of geospatial technologies to the field is worth emphasizing because of its profound impact on how utilities do their work. While in the early digital age a utility might map the orders and track the location of field workers, the push to provide this capability to the field has been driven by the demand for enterprise information by the field worker. The field technician is usually the front line of work with the grid and is increasingly a frequent point of contact with the customer. There are several forces driving this spread of technology to the field workforce:

- Fewer people, more work
- Growing complexity of work
- Increased safety and security standards
- Increased cost of outages
- Higher expectations for customer service
- Expectation of technology by the younger workers accustomed to social networking

FIGURE 11.3 Extending maps to the field. (© 2016 General Electric. All rights reserved.)

The aging utility workforce has a major impact here. Most utilities are faced with the prospects of replacing a key cadre of workers that represents much of the organizational knowledge. This group, in effect, carries the system maps in their heads. As this segment of the workforce nears retirement age, it will be essential to support less-experienced workers with strong geospatial tools.

Mobile applications often show a short return on investment. By taking technology to the work site, these systems can close the loop and digitize work processes from beginning to end. This eliminates many sources of errors and speeds up processes that were once paperbound. For safety and efficiency, much of the supervisory team is also in the field close to the work being performed. Often the supervisor is the most qualified to make an assessment and network decision, but now the data streaming from the system are required to make those decisions. Extending the data set from GIS and related enterprise applications to the field improves field work efficiency and safety, and provides a synergistic return that is often overlooked and hard to measure by traditional standards.

Over the last decade, we have seen a major transformation in mobile computing technology. The rapid development of consumer technology has helped drive acceptance of smartphones and tablets into commercial markets. Ubiquitous personal and business improvement applications are now used in almost every company. Because of the field-centric nature of much utility work, mobile systems play a large role in operations. Field applications for a utility are job-critical and time-critical. A breaker or regulator that is bypassed for maintenance must be accurately identified and modeled in the GIS for the systems that rely on them to function properly. The most reliable current source for this information is the worker performing the action. Therefore, field applications have to work wherever and whenever they are needed.

11.1.5 Developing World

The technology evolution described earlier has been fairly consistent in North America, Europe, Australia, and many parts of Asia. In the developing world, technology for managing the grid has taken a different shape.

Part of this difference is due to the grids being different. In some emerging economies, large power grids have not been as common as in the developed world. Therefore, with developing countries, there is an opportunity to take advantage of modern tools for the smarter grid in the expansion phase rather than having to deal with issues of retrofitting the older grid. The technology aspect is different, too. By starting later on the GIS curve, some parts of the world are avoiding the sometimes uneven evolution of hardware and software systems over the last four decades.

In much of the developing world where large landline communications infrastructures are lacking, mobile phones are rapidly becoming the tool of choice for both businesses and consumers. A newer technology has replaced the need to build out an older (and more expensive) infrastructure. Similarly, the predominant computing platform is not the desktop, but the mobile devices. Tablet computers and smartphones provide utility employees with enterprise-wide strategies from the onset, rather than having to later add mobile applications to office-bound systems.

A significant benefit of the late implementation of geospatial technologies is skipping much of the data conversion process. Rather than dealing with the painful and expensive projects to convert paper maps of old facilities into digital form and to correct the cartographic error of paper products that were generated over time, a utility, which is now expanding into new areas, can capture designs and as-built drawings electronically as part of the construction process.

Capturing these data electronically not only allows for more accurate asset and grid inventory but also provides a means for spatially accurate records and correct connectivity. These data can be captured at the time of installation to improve accuracy and provide a shorter database posting cycle. This allows the GIS to be as accurate as the actual facilities it represents as quickly as possible.

11.2 THE CHANGING GRID

Throughout the first four stages of geospatial applications, the technology has changed dramatically, but the electrical grid has remained largely the same. (It is often said that Thomas Edison, looking at today's grid a century after his Pearl Street project, would easily recognize what he saw: a one-way, fairly static network where a flow of electrons was created at a small number of power generation plants and distributed to customers.) The electrons, for all practical purposes, flow one way. There is little system-wide information flow. SCADA systems are sometimes used to monitor overall flows through the system backbone, but this capability rarely reaches all the way to the customer. Each customer has a meter—a device that measures the usage at the customer point so that billing can take place. Almost all of these characteristics change with the smart grid. The old grid, with its static, one-way flow, becomes a much more complex and dynamic system.

Much of this added complexity has a geographic dimension. To begin with, take generation: the old paradigm of a few power plants, all controlled by the utility, gives way to a system that may have numerous power sources. Wind farms and solar installations are often privately owned, so the utility has a challenge in adding them to the network data model. And since they are subject to weather factors that neither the owner nor the utility can control, managing system flows becomes far more complex. Information about the "whereness" of weather, which varies over space and time, can help balance the complexity of the generation mix in the utility system.

The emergence of microgrids adds a further degree of complexity to the utility's view of the grid and to the spatial systems that describe it. One growing challenge is keeping this "picture" of the grid up-to-date when sources of power generation are geographically dispersed and, in many cases, not controlled by the utility.

It is a similar story on the customer side. Most utilities have not included details about customer locations in their spatial data. The GIS data model often extended only to a distribution transformer, sometimes with links to data about the customers fed from that transformer. It seems likely that the smarter grid, with smart meters and perhaps smart appliances, will require that the GISs capture location beyond the transformer.

The increased penetration of electric vehicles (EVs) will add yet another dimension. Although charging points are static, the vehicles themselves move around and might connect to the grid at different locations.

There is also an impact of the utility's crews. These frontline employees, who have to build the system and resolve any operational problems, are faced with a more complicated job, needing far more data and new tools to analyze these data.

Clearly, the changing grid will increase the demand for more geospatial data and the need to integrate the geospatial data across numerous business and operational applications in the utility enterprise.

11.3 GEOSPATIAL SMART GRID

Now we are on the edge of a fifth "age" of the geospatial grid. This time, the changes are driven not by gains in geospatial technology but by the transformation of the grid itself: the emergence of the smart grid.

How does geospatial technology contribute to planning, building, and operating the smart grid? In this section, we will examine the importance of these tools, reviewing a number of applications in the utility sector. One key in planning business-critical applications is to ensure a consistent base of geospatial data. The GIS is typically seen as the platform for managing these data—the "system of truth," which is synchronized with local data requirements for other enterprise systems. Close attention to interoperability is required. The stringent requirements of a smarter grid with constantly updated data may challenge the traditional abilities of GIS to continually exchange data with other applications.

11.3.1 Core Spatial Functionality

It used to be easy to equate geospatial applications with geographic information systems. After all, GIS was the tool of choice (and often the only tool) for any functions that required spatial data. That has changed dramatically; today, applications in virtually every part of the utility automation sector manage and display map-based data.

Here, the focus is on software applications. Although the division is somewhat arbitrary, the applications can be divided into categories that reflect how they are used.

The first group of functions includes those that are central to spatial data handling. They are traditionally the core components of the GIS.

11.3.1.1 Managing Spatial Data: The System of Truth

Geospatial tools, at a basic level, provide a common source of information for operating the grid. Since the operating system of a utility is spread out over a large geography, the data necessary to run it are spatial in nature, and managing these data spatially is critical to the business. This has been a major driver in the adoption of GIS within the utility sector. GIS, today, is often viewed as the "system of truth," the single trusted source for any data that are spatial. For many years, this viewpoint was hard to challenge. Almost any application of geospatial data was handled by the GIS software and managed by the utility's GIS group. It was clearly the single source of data because the data were not used anywhere else.

That has changed, however. As more operation functions have been automated, spatial data have made its way into other applications. Outage Management System (OMS)/Distribution Management System applications rely heavily on a spatial view of the grid. Who would have thought in the early days of a GIS "map" that we would see it presenting and interacting with SCADA? Work management systems now include map-based views of how work and crews are distributed over the service territory. Even planning and marketing groups in the utility employ geospatial data, using maps of current infrastructure in conjunction with demographic and land use data. It is due to these data codependence that the savvy spatial data manager recognizes the importance of data accuracy and strives for perfect data.

These applications must, therefore, use the same source of spatial data. They are, after all, covering the same geographic area. And they should reflect the same "reality" of the physical grid. For many years, all spatial data—anything with coordinates attached—were strictly the province of the GIS. It was argued that "spatial is special," or that the unique nature of geospatial data meant that only dedicated GISs were capable of handling and displaying these data. Now, however, many of these other systems have evolved to include spatial tools. So, where are the geospatial data? Which data sets reside in which system?

Advances in hardware and software technologies make these questions more difficult. Abundant storage means that keeping multiple copies of spatial data (perhaps in slightly different forms) is not cost prohibitive. The concept of cloud storage even eliminates the "where are my data" question—although it does raise other questions, like how to maintain security for critical infrastructure data. On the software side, database software, commonly used by other applications, may now include tools to manage these types of data (e.g., Oracle Spatial).

This spread of spatial functionality into other systems clearly has great advantages. It does raise a data management dilemma, however. If every application that uses geospatial data stores a copy of the data, how do we synchronize the systems to ensure that they are all operating on the same "truth"? A common approach is to keep the base data in the GIS and then feed to other systems as needed. As we will see in a later section, the changing requirements of the smart grid may make that method more difficult.

11.3.1.2 Geovisualization

Maps are used for a reason—they are the best means of communicating certain types of information. For the electric grid, this means a spatial view of the relationships between network, customers, and field crew locations.

We can refer to this process as geovisualization. It is a way of communicating spatial information in ways that support human decision-making. If done well, presenting a clear view of operating data supports situational awareness and improves decision-making.

One of the beauties of spatial technology is that the same data can be used in so many different ways. It can, in effect, produce a near, endless series of maps. At one scale, the data produce a wall map, an overview of a large area. The same data can also generate a series of larger-scale maps (or even schematics), with details for smaller areas. By managing scale, geospatial technology can produce the map that is most appropriate for the job at hand.

Today's computing technology can offer ways of visualization that go far beyond the static, 2-D paper map. GIS tools can quickly render views based on an almost endless combination of geographic and thematic filters.

The emergence of 3-D viewing also adds exciting possibilities. Most existing facility data, since they were created by converting paper maps, are 2-D. This has limited the use of 3-D viewing tools. New data collection methods, such as LiDAR, create point clouds that can be processed to build 3-D facility databases (Figure 11.4).

11.3.1.3 Queries and Reporting

Early automated mapping systems utilized special file structures to handle XY coordinates and attributes. In the late 1970s, the emergence of general-purpose relational databases offered a new storage paradigm. Soon, most GIS vendors offered databases as a way to manage the increasing volume of noncoordinate data. Over time, the ability to manage and manipulate geospatial data has become widespread in commercial databases (e.g., Oracle Spatial).

With this underlying database structure, it is, of course, very straightforward to perform queries and generate reports. The added geospatial element enables spatial filters that add to the power of data retrieval:

- A pure data query—"list all of my transformers"—usually yields too much information to be usable.
- Adding a filter by a landbase polygon—"list all of my transformers is this district"—is more useful but may still be too much information for most tasks.
- Adding a filter by proximity from a linear landbase feature—"list all of my transformers within 1000 ft of this road"—starts to focus an important subset of the data.

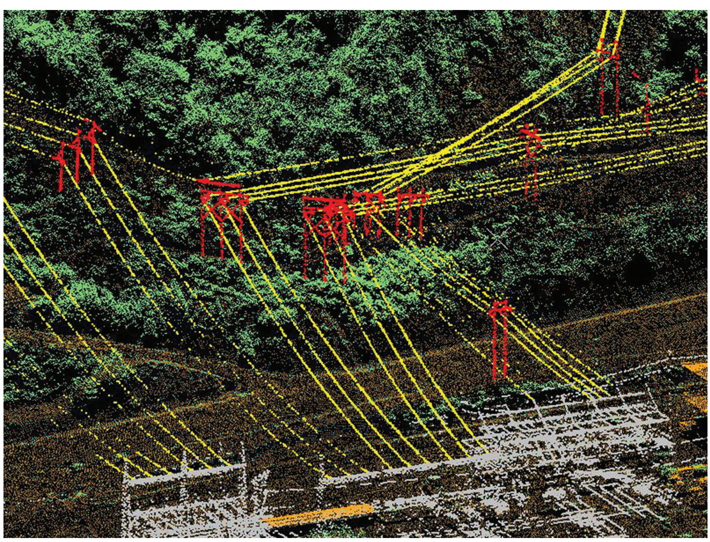

FIGURE 11.4 LiDAR point cloud. (Courtesy of LiDAR Services International, Calgary, AB, Canada.)

- The real power of spatial data may come from a filter based on connectivity—“list all of my transformers between these two points on this circuit.”
- More complex queries—“list the customers served by the transformers selected earlier”—can be designed to pinpoint data that are key for a certain task.

This query/report capability, combined with geovisualization, is often used to extend spatial data to settings where computers may not be appropriate. For example, work packets for a vegetation management crew can combine lists of tree-trimming work with maps that illustrate the work in a geographic context. This capability may also be useful as a way to provide data outside the company, such as contractor crews that may be validated for access to live data.

11.3.2 Planning and Designing the Grid

GIS and CAD systems have a long history of supporting the plan/design/build processes in electric utilities. A number of commercial systems are available for these tasks. While the spatial aspect of laying out facilities is native to these applications, the details of structural and electrical analysis and even work management must be considered for a design tool to be effective.

11.3.2.1 System Planning

Prior to detailed engineering design, utilities often have to perform long-range planning for service territory expansion or system improvements. This may involve projections of population growth used to predict future system needs or an analysis of environmental factors for a construction project. Defining a transmission corridor is a classic example of this type of project. The need for a new line may be established based on current demand and projections of future demand. Once it is determined that a new line is needed to connect a generation source with an area of demand, there may be an array of corridor choices that must be analyzed. This analysis will include factors such as terrain, environmental impact, current land use patterns, and cost. The selection process includes a bewildering mix of political and public interest actors—another case where geovisualization tools can have a major impact by communicating the spatial context.

While much of the data used in this process are spatial, they likely do not reside in the utility GIS. Land use and population data may come from local governments, while terrain, weather and wildlife patterns, and other geospatial technical data sets may be available from federal agencies. It is almost inevitable that multiple data sources, with data in multiple formats, will be needed. The tools used for utility system planning must be capable of handling this combination of data sources.

11.3.2.2 Grid Design

Detailed design of the electrical network is a category at the heart of the geospatial smart grid. These analysis and optimization systems, often including design layout tools (DLTs), are critical components for designing robust networks (Figure 11.5). When used well, they can also achieve significant cost savings.

Applications in this category have to handle the entire spectrum of the utility’s facilities:

- Both transmission and distribution
- Overhead as well as underground
- Linear underground (UG) facilities (ducts, trenches, conduits)
- UG structure nodes (manholes, handholes, vaults, pads)
- Substation internals

Fundamental capabilities of these applications include tracing by phase and circuit, schematic layout creation, and the ability to handle multiple levels of detail (e.g., showing a switch as a single element and the related internal view).

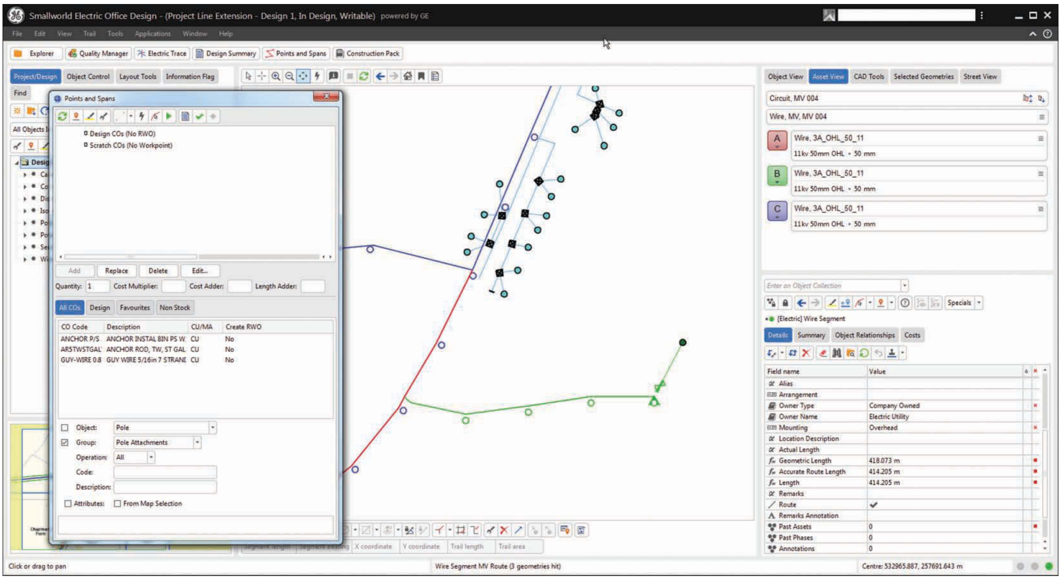

FIGURE 11.5 Grid design application.

A large component of the design system capability is optimizing conductor and transformer sizing. Flexibility is important. Results can be based on customer class data or spot load models. Tools have to consider load growth and check for allowable transformer overloading settings and potential voltage drop and flicker problems. Conductor sizing relies on both power factor and quality, considering both overloading and underloading.

Along with design of the core electrical network, these applications also may have tools for corridor management (right-of-way, vegetation, dam inundation), joint-use pole management, and streetlight layout.

11.3.2.3 Communications Network Design

One of the primary changes with smart grid is the addition of a communications network to the electric grid—a truly smart grid is as much about information flows as electron flows. This requires tools that enable efficient design of the communications network.

Communications design tools have to support an integrated view of the entire network. This includes both inside and outside plants, and both physical and logical networks (Figure 11.6).

The communications physical network model includes all of the ducts, cables (both underground and overhead), and support structures (street cabinets, manholes, splice closures, rack-mounted equipment) that compose the system. One of the challenges is the need to manage both extensive geographic areas and the details of buildings (including floor plans, rack locations, down to the communications port).

Communications design applications also have to manage the logical network (active network elements, customer circuits, and bearer circuits). Utilities have been utilizing grid design software for many years. What is different now is the need to manage the rollout of large communications networks. And, clearly, the key is integration of the engineering design of both electric and communications networks so that together they help manage a smarter grid.

11.3.3 Operating and Maintaining the Grid

Once the smart grid is designed and built, the emphasis changes to operating and maintaining it. Therefore, geospatial technologies are a core component of operational processes and applications.

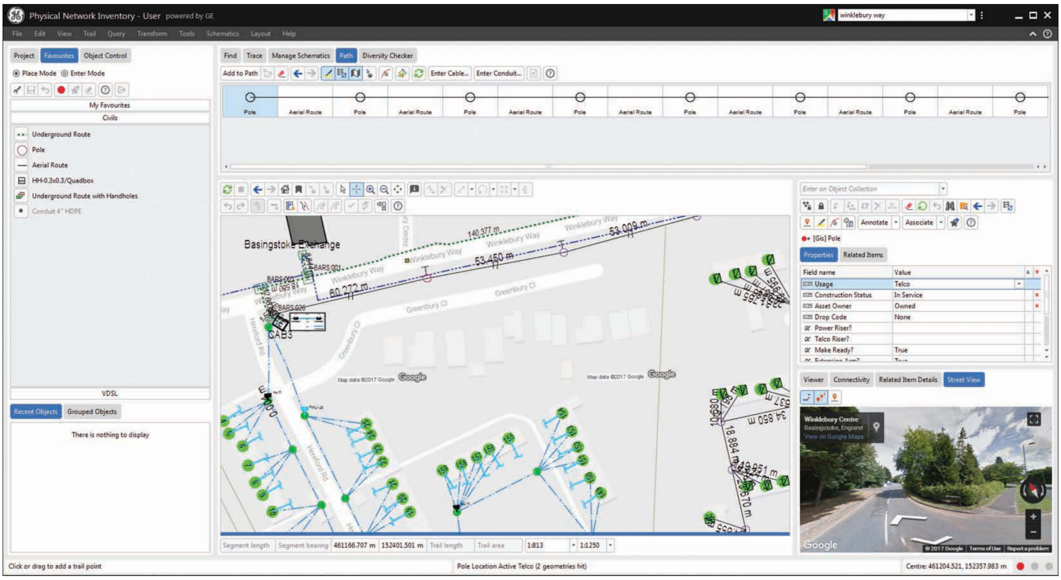

FIGURE 11.6 Communications network design application. (© 2016 General Electric. All rights reserved.)

11.3.3.1 Network Analysis

As the complexity of the grid increases, power system analysis tools will play an even larger role. These tools are used to manage circuit configuration, direction of flow, voltage, and phasing.

A major part of this functionality is transformer load management. By aggregating data from summer and winter peak loads for each customer (gathered from CIS billing data) and adding information about the performance specifications of individual transformers, these analysis applications can identify overloaded or underloaded transformers (Figure 11.7).

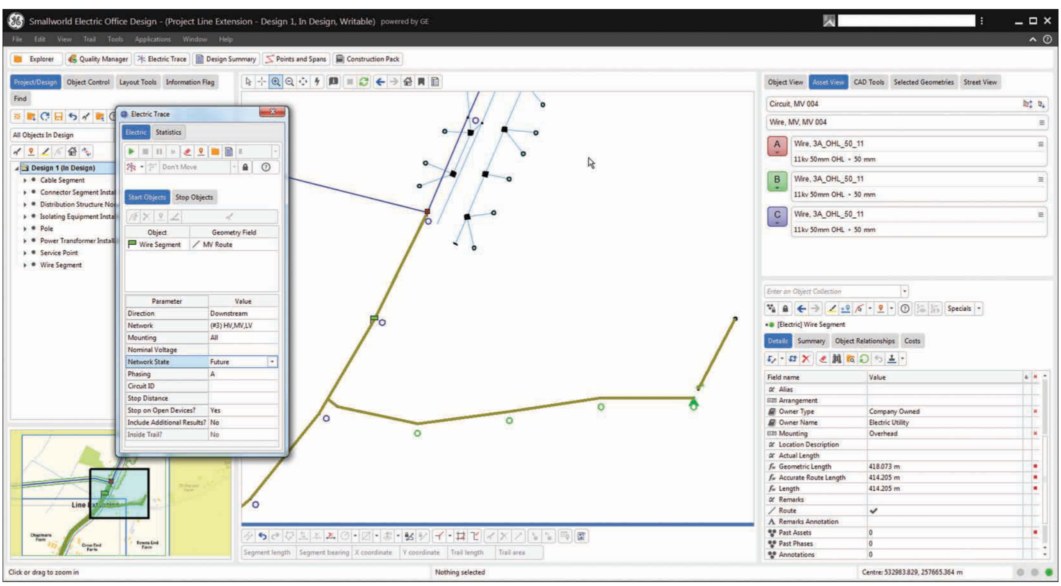

FIGURE 11.7 Network analysis software. (© 2016 General Electric. All rights reserved.)

11.3.3.2 Outage Restoration

The previous section described analysis tools that are used in the day-to-day operations of an electric utility. Another set of tools comes into play when things go wrong—the lights are out, impatient customers are waiting for answers, and the utility is facing significant monetary losses (both in lost revenue and penalties).

Outage management and work management systems are described in more detail elsewhere in this book. Here, we will just mention the key role of geospatial data in several parts of the outage process.

Much of the restoration process is driven by the utility's field crews. Here, it is vital to have a coordinated view of repairs between the OMS and work management systems. Communications between dispatchers and the field are very location-based; getting the right skills and equipment to the right place requires a detailed view of the network. As repairs are made, it is also important to record changes to the facility base and communicate those changes back to the GIS.

Responding to storms and other outages is a perfect example of the need for high performance in geospatial systems. It is truly a "high-stress GIS" situation. There are huge financial stakes in restoring critical infrastructure more quickly. Public perception, fueled by high-profile outages in the last decade, plays an increasingly important role. The GIS cannot be a roadblock, so it is crucial that it can manage large volumes of rapidly changing data.

Related technologies such as unmanned aerial systems (drones) are beginning to provide a rich set of tools for finding damage during storm restoration. Quickly navigating around the service territory to assess damage is a vital step, made more difficult in situations where roads are often blocked and other emergency personnel require access. The advent of drones, along with software that can tie aerial images to the facility database in the GIS, can greatly speed up the assessment process.

11.3.4 Mobile Geospatial Technologies

As noted earlier, one of the more recent steps in the evolution of utility geospatial technology is the ability to move map and facility data out of the back office and to the field worker. This trend has been enabled by major advances in mobile computing and related technologies such as GPS and wireless communications.

All field applications, of course, have to link closely to back-office systems. As noted in a later section, managing the data flows between office and field is a difficult, but necessary, element of geospatial design.

11.3.4.1 Map Viewing

A fundamental part of field capability revolves around viewing geospatial data. It is giving the field user answers to many of the "where" questions described earlier.

Early field automation systems were aimed at replacing paper. There are both productivity and cost advantages in eliminating the paper map books that utilities had relied on for decades. It is not hard to beat the functionality of paper. Instead of dealing with fixed scales, users can easily zoom in and out, getting the level of detail they need for the task at hand. Symbology can change with scale, so it is more easily read. And by grouping data into different layers, each with a display range tied to zoom levels, it is possible to reduce clutter and improve visibility.

There may even be useful view modes that take advantage of attributes linked to geometry, such as the ability to render circuits by color rather than a default mode of showing conductor color and line thickness by voltage or phase (Figure 11.8).

One of the primary advantages of a digital map viewer is the ability to search. Finding a specific facility on a paper map can be very time consuming, even if some assets, such as line poles, used a numbering system linked to a grid based on map sheets. Searching on objects other than the grid

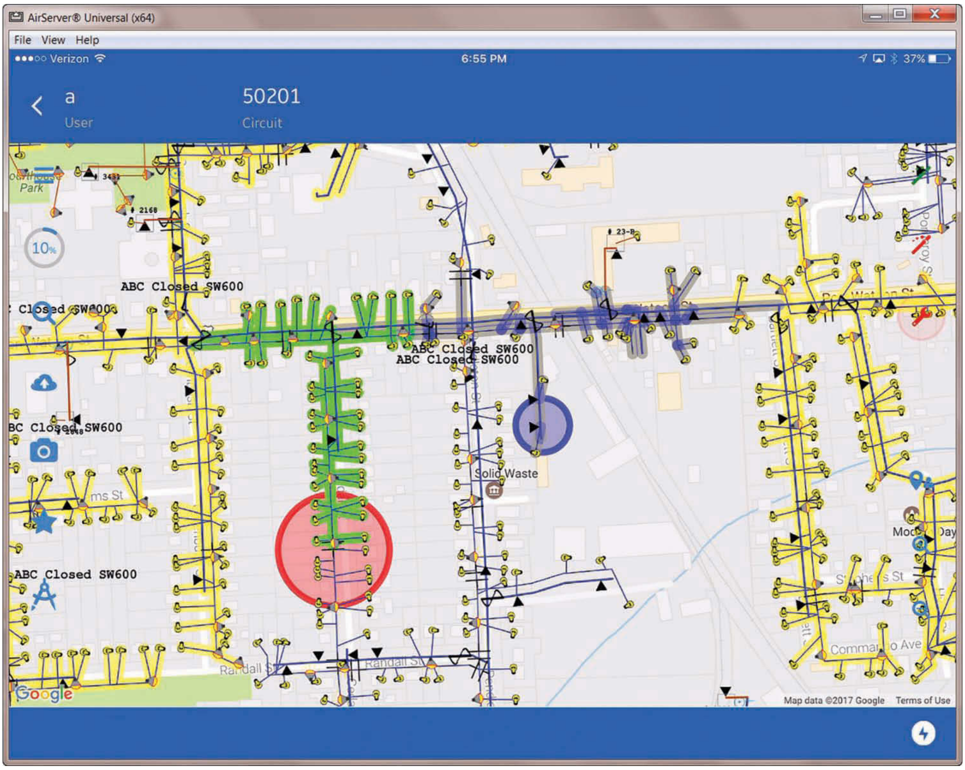

FIGURE 11.8 Displaying circuits by color. (© 2016 General Electric. All rights reserved.)

facilities is important, too. Landbase features (streets, intersections, points of interest) are useful in helping a crew navigate to work assignments—especially if they are in storm recovery phase and working in an unfamiliar area.

Searches can extend to external databases that can be linked to location. Customer data are a good example. Even if the customer (meter) coordinates are not part of the GIS data model, most utilities do link customer records to a transformer. This lets viewers zoom to a location that is in close proximity to the meter and even show lists of other customers served by the same transformer.

Most mobile viewers today include some analysis functions like circuit tracing (Figure 11.9), which takes advantage of the connectivity data present in the GIS. Tracing an electric circuit is a huge productivity gain in the field when field troubleshooting. The ability to designate an underground route through a building complex or urban setting with the connection to protective devices is impossible on paper. Similarly, the field crew cannot gain a clear picture of affected areas from an out-of-service protective device using a paper map.

11.3.4.2 Workforce Management

It is easy to forget the people element of smart grid. After all, much of what we hear is about the totally automated, self-healing nature of the future electric network. It is described as almost an "untouched by human hands" system. Although a great goal, we know that this will not always be the case. Smart meters will not be very smart when they are lying in the rubble of a house destroyed by a tornado, and the intelligent network will fail if vital components are damaged by falling trees. The bottom line is that people will always be a key part of running a utility.

Even though workforce management software has traditionally been a separate category, managed by a different group in the utility and provided by a different set of vendors, it is included here because

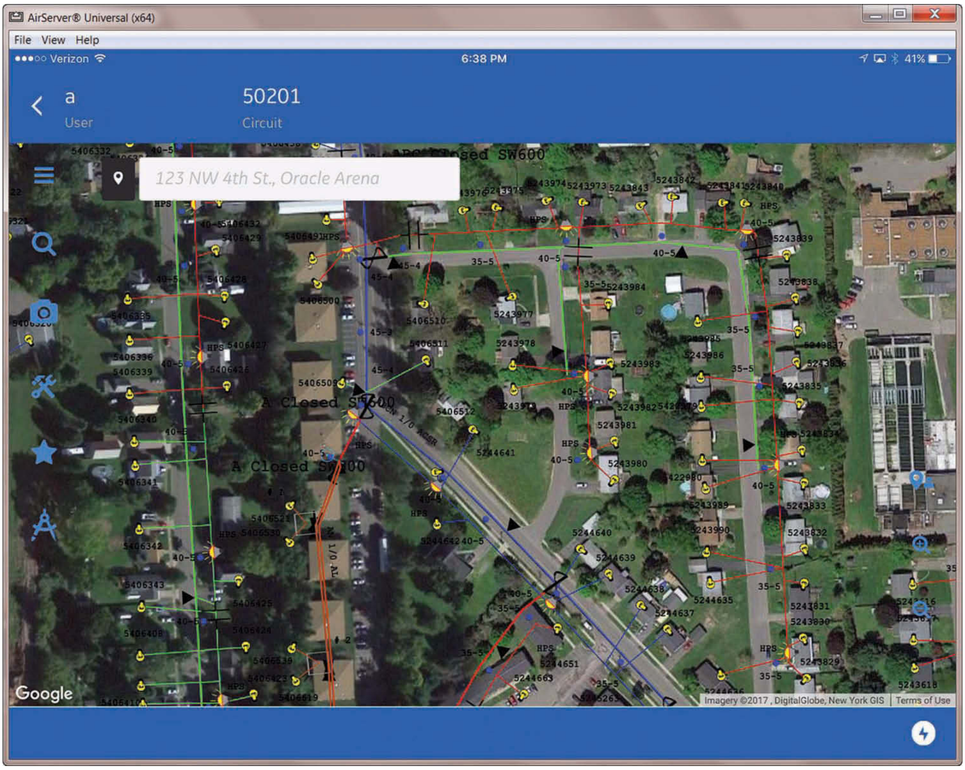

FIGURE 11.9 Circuit trace. (© 2016 General Electric. All rights reserved.)

of the strong geospatial link. The essence of these systems is to get the right people to the right place at the right time, so the space/time aspects of geospatial technologies are an essential component.

Work management systems come into play in almost all aspects of utility field work. These systems may, for example, schedule distribution designer field visits with customers and then manage the resulting construction work. After the system is built out, work management systems play a vital role in managing both the daily service work of the utility and the stressful periods of outages. Workforce systems may also play a role in special projects such as AMI deployment.

These applications typically have both back-office and field components. The back-office system manages the overall field workforce, tracking crews and equipment. As work is needed, the system creates service requests. It then assigns the task to a specific crew based on a complex mix of factors, including crew/vehicle capability, current locations, and expected task completion times. This drives the scheduling and dispatch of a given crew to each work task.

As the work is completed, the system tracks the progress, looking at current status and estimated time for completion. It may also manage parts inventory based on the materials used in each job.

The field component of workforce management takes a different perspective. Instead of managing multiple crews, the focus is on the assigned work of a single crew. Communicating with the back-office system is important to update assignments and job status. Although routing from one job to another is often handled in the office system, the ability to update routes in the field is useful since traffic conditions may affect the original path.

For many years, commercial work management systems tended to focus on a specific type of work. They were designed to handle either short-cycle (service) crews or long-cycle (construction) work. Today, as the utility workforce has evolved, much of that distinction has disappeared, and these systems use a “work is work” philosophy and take a unified approach to the entire mobile workforce (both in-house and contractor crews).

A relatively new capability in workforce applications is predictive analytics, forecasting how the utility's future workloads are most likely to be distributed over time and over the geography of its service area. This functionality utilizes historic trends and projected needs to help balance future demand (the amount and distribution of required work) and supply (crews, vehicles, materials).

11.3.4.3 Inspections

All utilities are required to periodically inspect facilities. Some inspections are self-imposed, and others are mandated by regulators. These inspections may focus on a specific facility type such as transformers, conditions that affect facilities like vegetation growth, or they may look at all facilities in a given area such as a circuit or a substation.

Special purpose categories include pole audits (looking at either the utility-owned poles themselves or updating foreign attachments), vegetation surveys, or storm damage assessment work (Figure 11.10). The back-office part of an inspection system schedules the work and manages historical data for the relevant facilities. The field application provides form display, validations, and editing capabilities, along with markup or sketching functions and attachments such as photographs. An additional advantage of digital inspections is the incorporation of GPS. GPS can be used with inspections to improve the "where" of mapped facilities as well as validate that the inspector was actually at the correct site when performing the inspection.

11.3.4.4 Routing and Navigation

As consumer navigation systems have proliferated, it is increasingly common to see navigation capabilities as part of a field automation suite (Figure 11.11). This can be an important capability even if a back-office system generates a preferred route as part of a work order since traffic or other real-world conditions might require changes in the original route.

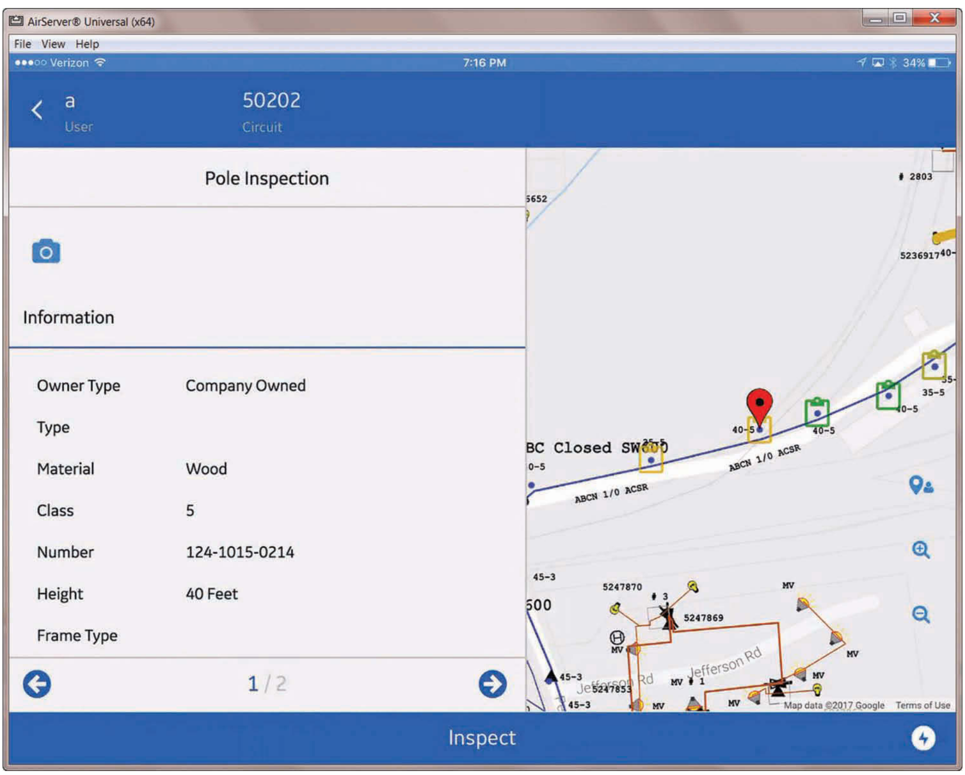

FIGURE 11.10 Field inspection application. (© 2016 General Electric. All rights reserved.)

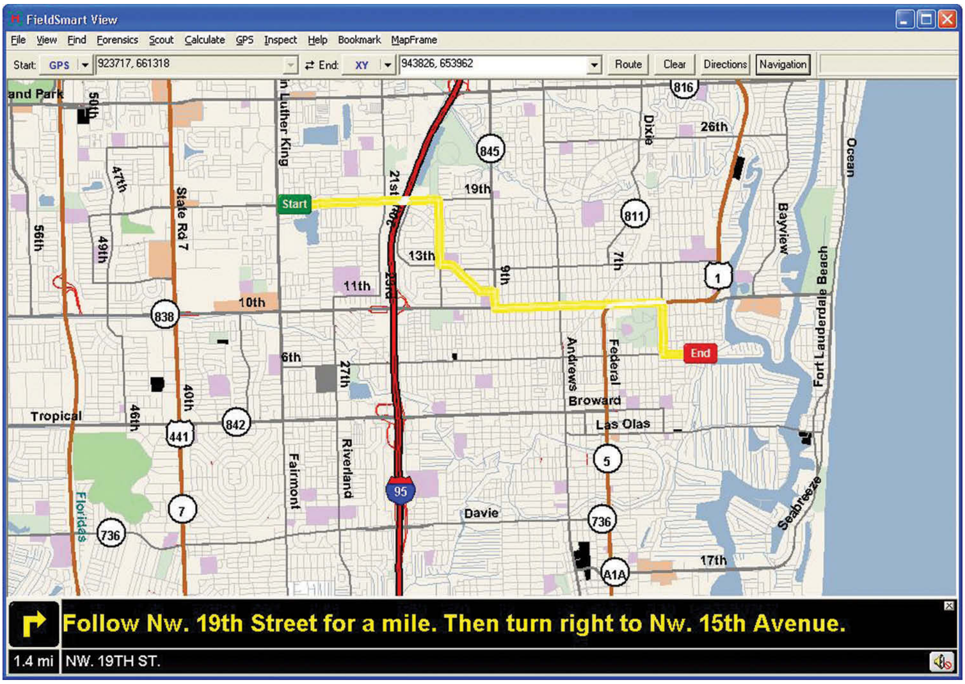

FIGURE 11.11 Navigation. (© 2016 General Electric. All rights reserved.)

The underlying technology is familiar: After the user defines a destination, the system uses GPS to determine current location, calculates point-to-point routing over an intelligent street network, and highlights the route with turn-by-turn directions. A utility setting adds some special requirements. For example, some bridges and underpasses might have restrictions that would prevent certain utility trucks from using them; the generated route has to take into account these restrictions. Similarly, some states constrain the use of driving directions on computer screens in certain vehicles, so the routing app has to communicate with verbal driving directions.

11.3.4.5 Data Collection and Update

Mobile applications that enable field data collection take advantage of the fact that utility field crews are in a good position to update the geospatial database. They are, after all, knowledgeable about the facilities and are often placed in close proximity to the objects in the field.

These capabilities can be used throughout the facility lifecycle. In some cases, they focus on collecting data that are not in the GIS such as dangerous trees or dig-in damage. They are also used as part of the construction process, capturing the differences between as-designed and as-built facilities. One of the more frequent uses of this capability lies in the ad hoc data updates that arise from a field crew seeing a discrepancy between what they see on the screen and what they observe in the real world.

There are several flavors of mobile data collection tools. Some are simple drawing tools, letting someone in the field draw on top of the map and submit the sketch to a mapping group for interpretation. Other redlining tools provide the ability to add notes and more complex drawing capabilities (text, symbols, and annotation) to the existing map. The most complex applications link to compatible unit databases and include data validation tools to help ensure that data collected in the field are usable in related systems.

Even if mobile applications support the field update of facility data, the back-office components must be able to capitalize by providing a rapid and secure process for inserting changes into the corporate GIS. The slow update process has been a source of frustration for many utilities. There are, of course, valid reasons for ensuring the validity of data before the "system of truth" is changed. In many cases, the legacy of paper mapping systems remains a roadblock. Given today's technology and the example of "crowdsourcing" tools (see next section), there is little excuse for an update cycle that is measured in weeks or months.

11.3.5 Engaging the Consumer

The applications discussed earlier are all aimed at the employees and contractors of the utility—the people who build and maintain the grid. What about the consumer, the end user of smart grid?

In most cases, there is no legitimate need for the consumer to access the detailed facility data in utility geospatial systems. Even if there is interest, security is a real concern. There are cases, however, where the customer would find it useful to have a spatial view of the grid. In a major outage, for example, many utilities post a Web page showing the extent of current outages. These data should, of course, reflect the more detailed view of current status that the utility is using internally.

The emergence of EVs may yield other examples. The driver of an EV, dealing with range limitations, has a vital need for updated locations of charging stations and perhaps even a count of the available outlets. If these data are present in the utility GIS, it should be in sync with what the consumer is seeing. These data need to be made available to the driver in the vehicle through an onboard system.

Other consumer-facing applications will undoubtedly emerge as we move into the smart grid era. Geospatial data will often provide a framework for these applications, serving as a common view of network assets and status.

11.4 SMART GRID IMPACT ON GEOSPATIAL TECHNOLOGY

In the previous section, we looked at how geospatial technology will help support the growth and management of smart grid. There is another interesting angle to that relationship: How will the emergence of the smart grid impact geospatial?

Today, GIS has been implemented in most utilities and is considered a successful example of technology implementation. Many in the industry, however, believe that the new grid will challenge current systems. After all, most current technology was designed to support the business processes that were rooted in the old grid—processes that, in some cases, may date to a century ago.

How does the shift to a smarter grid impact the geospatial systems now being used by utilities? Perhaps the most obvious change is that everything scales up—there are more data, tied together in more complex ways, and the need for speed and accuracy is dramatically increased. These factors will challenge almost every aspect of geospatial system design, forcing major changes in how spatial data are managed and distributed. The following sections describe potential problem areas and suggest how geospatial system design may evolve to handle these issues.

11.4.1 Coping with Scale

One of the clear differences with the geospatial smart grid is the change in scale—everything gets bigger. Even now, a spatial database for a large utility that contains detailed landbase and complex facility data for its entire service territory commonly exceeds 100 GB. That does not count related data from even larger systems (customer information, asset tracking).

Many observers estimate that there will be at least a thousand times as much data with smart grid deployment. Not all of that data, of course, will be managed by the geospatial systems, but we can anticipate a significant rise in volume.

For a large utility, the data volume is driven by the need for a lot of detail. This volume is multiplied by the large area that has to be covered, resulting in tremendous amounts of data. The GIS data models typically cover both the transmission system (power plant to substation) and the distribution network (substation to customer). In most cases, the model (or at least the populated database) does not extend to the actual customer premise (the meter) but ends at a transformer that may handle dozens of customers. Adding intelligence at the customer site will require handling data about the meter and the characteristics of the customer. (Are there solar panels on the roof? Is there an EV?) Not only are these data tied to a premise, but much of those are associated to the consumer (e.g., details on EVs and smart appliances). The historical aspect of these consumer data, as well as the need to keep it updated as the consumer moves or replaces items, all add to the data volume.

The smart grid will require more objects and more attributes for those objects that are in the facility "layer" of the utility GIS. It may also demand new sources of data (e.g., weather) and new analysis tools to dissect complex relationships among objects.

The key question here is whether current GIS architectures are optimal for these larger volumes. Data structures that have worked reasonably well in the current environment may not meet performance expectations as data needs scale rapidly.

11.4.2 Moving to Real Time

Even though a typical utility GIS now has thousands of changes every day, the system can be viewed as relatively static. New or changed facilities are reported through a review process and then validated by GIS staff before being added to the database.

GIS is often seen as a spatial data warehouse, a "system of truth" that is used as a trusted reference for the grid. Currently, the practice is to do periodic extracts for applications like outage management or mobile data; GIS is seen as a data source that feeds other, more time-critical applications. These operational systems are important for maintaining the grid and responding to power outages, and there are critical safety considerations when crews are doing work on the lines.

When the lights are out after a storm, data can start to change very quickly. For example, as the system is reconfigured to reroute power and resolve outages, the status of switches may change. The load on devices and conductors fluctuates, changing their working capacities. Some of the information about the grid is less likely to be valid if there is damage. Repairing the system takes precedence over recording the details of how those repairs were done. And public demand to get the lights back on adds to the time pressure, making this a true "high-stress GIS" situation.

The current slow change GIS cycle may not be adequate for a grid that is highly dynamic. In today's grid, even when object attributes and electrical flows change, location is almost always static. With EVs, that is no longer true; an EV is an active part of the network that can change location during the day. With solar generation rates changing as clouds pass across the sky, and wind turbine farms coming online and off-line based on wind speed, energy storage that absorbs system capacity can also move throughout the day and night. Managing these data will require the ability to handle moving objects in the spatial database.

Unless the GIS can support these near-real-time demands, it will not be able to retain its position as the single reference for the grid.

11.4.3 Supporting Distributed Users

One of the paradoxes of the smart grid is that even though the system is touted as being self-healing, its deployment puts even more burden on the people who maintain it. We not only need more information but we need it faster; we need to get it to the people who can act on the information. In a utility, that means the field crews—often spread out over a very large area and often (in situations like storm recovery) without consistent communications capability.

Data communications is a crucial design parameter for mobile applications. Utility crews have to be able to work anywhere within the service area, which means that there are almost always limited coverage areas for any large utility. Systems also have to allow for “no comm” situations, where storm damage to the grid may be accompanied by communications outages (or, at best, limited bandwidth). The bottom line is that field applications must be designed to support base functionality without any wireless connectivity. Critical applications have to work whenever and wherever they are needed.

There are many cases in grid maintenance where multiple crews, along with supervisors in an office, work together to handle a situation like a large outage. These users would benefit from a higher degree of interactivity with the back-office GIS (data input or sketches) to communicate changes; this can be seen as a need for geocollaboration (Figure 11.12) on a large scale.

11.4.4 Usability

The changes noted earlier—more data, changing faster, with distributed users—will lead to another challenge: How do users interact with the smart grid geospatial system? In an era with a more complex grid, user categories may be less distinct. Instead of a separate group of GIS professionals who maintain and control the system, we may find more of an operational bias, that is, electrical engineers viewing the system as a platform for applications.

An additional degree of difficulty is present in field settings. It is a challenging work environment; the display screen is typically smaller than is common in the office, and viewing conditions are rarely ideal. In events like storms, there is a great deal of pressure on the user (and consequently the system) to work quickly.

A design goal is to hide the complexity of GIS and CAD systems. The details of the application user interface should disappear. Ideally, users view the field application as a tool—something that helps them do their work and has an easily understood function.

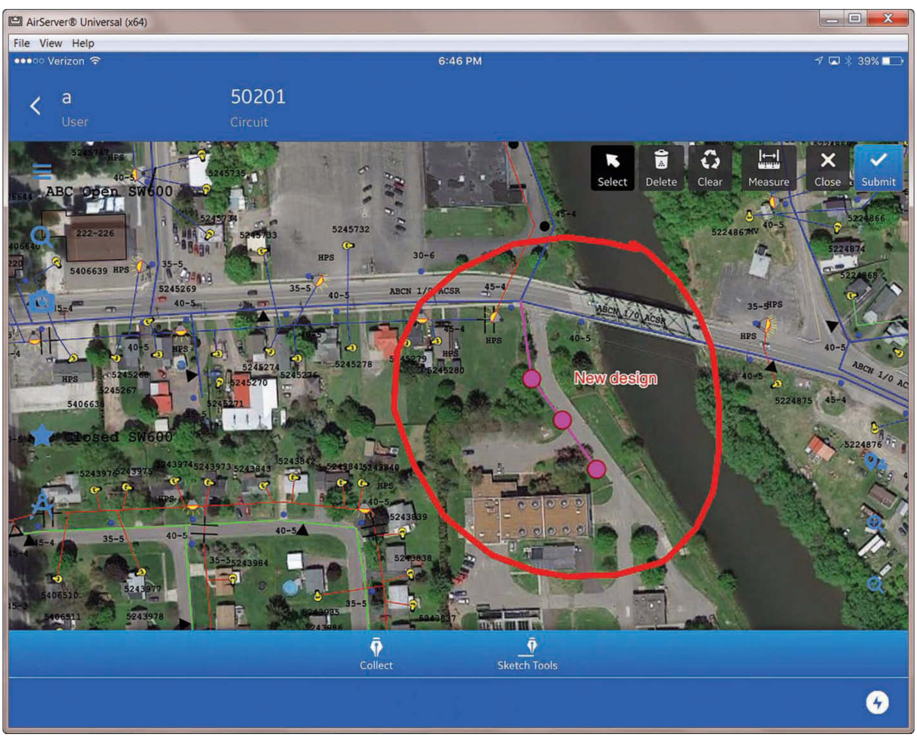

FIGURE 11.12 Geocollaboration. ()

There are several key questions regarding usability that must be addressed. How can we help users pick out key information in a system with more potential for clutter? Is it possible to define key data based on context (location, time of day, current user activity)? What design strategies are needed to support high performance?

11.4.5 Visualization

One of the design elements that relates to usability is visualization. One key advantage of a geospatial system is its ability to render maps in many different ways, depending on the audience and the intent. A GIS screen can act, if needed, like a wall map, giving operations staff in the control room a quick overview of system conditions, such as power flows and bus voltage levels by color combinations over a large service territory. It can, alternatively, display a detailed schematic of a transformer vault to help a crew safely make repairs.

It is important to remember that, in field settings, viewing maps is made more difficult by system constraints (typically a smaller screen size) and environmental conditions (glare from sunlight).

The increasing complexity of the grid will demand new forms of visualization. We may need to extend the GIS toolkit to take advantage of advances in other fields of computer graphics like 3-D entertainment systems.

One of the key aspects of visualization is helping the user quickly focus on what is important. How can we help users pick out critical information in a system that has more data, and consequently more potential for clutter? Symbology design and color will play important roles in this area. Another key to managing data display is the use of multiple layers. Given the vast amount of data that relate to the grid (especially if other networks, such as gas, water, or communications, are also present), the user can be overwhelmed by visual clutter. We can have the "fog of data" like the confusion of the "fog of war." By selecting groups of data elements that are job-specific and giving the user easy ways to select what they want to see based on the task they are performing, we can minimize information overload.

This problem can be mitigated with intelligent filtering of the data:

- Functional layers (e.g., landbase vs. facilities)
- Setting visibility (zoom) levels for each object type
- Symbology changes based on display scale
- Highlighting key objects

These techniques can be used together to create thematic views, where the goal is to present only the data related to the user's current task, using visualization techniques to highlight critical objects. For example, a field user may need an overview of an electrical circuit, where the conductor would be rendered with a thicker line, and devices like switches would be represented with larger symbols. Other aspects of data presentation drive from the environmental factors noted earlier. For example, using a light color line style to denote a high-voltage line may work fine in a controlled office environment but is likely to cause problems on field devices.

11.4.6 Standards

Given the vision of the smart grid as a vast interconnected network, having standards for all of the components is essential. Interoperability of software components moves from a goal to a requirement. Several organizations, notably NIST (National Institute of Standards and Technology) in the United States, have led the way with grid standards. Although there has been a considerable amount of work with GIS standards by the Open Geospatial Consortium (OGC) and others, the perception is that geospatial technology is less advanced in this area than in some of the "engineering" disciplines. There does seem to be momentum around ideas like Common Information Model, and discussion of GIS/grid standards appears to be growing. OGC has been involved in Smart Grid Standards Roadmap Workshops organized by NIST and the Electric Power Research Institute.

As we have seen in earlier sections, the need for spatial data is not confined to GIS. Many applications are driven by spatial data. It is vital, then, that these systems use common structures for managing and visualizing geospatial data.

11.4.7 Data Quality

What are the key characteristics of usable data for the geospatial grid?

- The data must be complete, covering all the relevant data types over the right geographic area. For example, the extents of the data must include all relevant parts of the electric grid that could be included in a network trace.
- Objects must be positioned accurately. This is often a challenge for utility data derived from old paper maps, which typically were not surveyed and were mapped in the pre-GPS era. Positional accuracy problems become more obvious when facility data from paper maps are overlaid with other data sources that were derived from imagery, GPS, or other more accurate methods.
- Objects have to be classified accurately and have to include attributes that support the utility's business processes (e.g., size of transformers, phases of electrical lines).
- The data must be reasonably current. The update cycle varies according to use. In some cases (e.g., switching status of operating devices on the grid), outdated or inaccurate data pose safety hazards.
- For data types that would be part of a network trace, topological relationships must be accurately captured. Connectivity may be explicit (i.e., driven by a table) or geometric (based on drawn location and proximity).

Information that passes these tests can form the basis of useful smart grid applications. Smart grid adds an element of uncertainty to current GIS practice. Where does the data model stop? Current distribution network traces, for example, cover the range from substation to transformer. As intelligence is added at the edge of the grid, other objects may come into play. Distributed generation sites and microgrids add complexity to power flows. On the customer side, do intelligent appliances and EVs need to be included?

In general, we can assume that there will be higher requirements for data quality to operate the smart grid than is true with the current grid. Control is more data-driven, and that requires complete and accurate data.

An ESRI survey of electric utilities published in August 2010 found that most companies were not ready for the increased demands of smart grid data. Only 15% of the respondents reported high confidence in their GIS data accuracy. A common issue highlighted in the ESRI report is the long lead time to update the GIS with data from the field. Lag times of several months are not uncommon. Part of the problem is that update processes in many utilities are still based on the age of paper maps, where a specific group in the utility has the sole responsibility for final changes to the database. This slow process creates problems today and could be a major issue in the faster changing world of smart grid. As suggested in a later section, concepts like VGI (volunteered geographic information) may offer a solution to this slow update cycle.

11.4.8 More Open: Sensors and Other Data Sources

Intelligent electronic devices, radio-frequency identification tags, and other types of sensors are being used more often in utilities. As the grid becomes smarter, more of its components will be digitally accessible and identifiable. The grid will be, in some ways, a perfect example of the "Internet of Things."

Although most of these devices are deployed to monitor and communicate specific measurements, their location—in terms of XY coordinates and relative to the topology of the grid—is an important element. In addition to these inputs that are controlled by the utility, there will be a need to integrate external data sources. Current and forecast weather data, for example, will be an important tool when trying to predict power flows from geographically dispersed solar and wind sites.

Research is needed to determine whether available GIS architectures can handle the flow of data from sensors and integrate with other data sources, such as weather feeds, into grid management applications.

11.4.9 More Closed: Security

Utility GIS has always been a very closed system. Part of this, of course, is based on security concerns, given the need to keep the grid (clearly an example of critical infrastructure) safe from malicious actions. This issue is an even more visible concern with smart grid since automating control of power flows means that physical security is not sufficient.

Another reason for the closed nature of utility systems has been a concern for data integrity. In most utilities today, GIS management has restricted change access to the database to trained personnel in the belief that it is necessary to maintain accuracy. A field user reports a change (which could result from an actual construction change or an observation that the existing map is incorrect) through a structured (and often time-consuming) process. A trained GIS professional validates the update and then makes the actual database change. This multistage process is frustrating to operations staff, since field employees are usually in a better position to compare the map with the real-world features that they are seeing.

How can these security concerns be addressed? There is considerable activity around security standards, made more challenging by the rapid pace of development in hardware and software technology. Because the stakes are so high, we can assume that security concerns will be a major filter on adoption of new approaches (such as cloud computing and crowdsourcing, covered in a later section).

North American Electric Reliability Corporation in the United States has implemented a Critical Infrastructure Protection program to establish a set of standards for all facets of utility security, including cyber assets. The IEEE is also very active in defining standards for grid data and applications.

11.4.10 More Closed: Privacy

The previous section looked at security from the perspective of the utility. It also works in the other direction: concerns about individual consumer privacy.

Given recent high-profile cases of hacking and identity theft, it is no surprise that many people have issues with any technology that collects and manages data about individuals. Smart grid, with its emphasis on data collection from tracking consumer usage habits to smart meters and sensors, fosters a growing concern about how to protect privacy rights.

The geospatial nature of much of the data adds another complication to the issue. Even if great care is taken to protect the most obvious aspects of individual identity (name, address, phone numbers), location information can be used as a link to find these data.

Legal challenges around the use of map-based tools (e.g., Google Street View) have resulted in the term "geolocation privacy." Safeguarding individual data becomes more difficult as data sources proliferate. Any utility applications that utilize geospatial data have to take into account these privacy concerns.

11.5 FUTURE DIRECTIONS

Geospatial technology—even when the technology was ink on paper—has always been an essential part of the electric grid. Tools have improved dramatically over the last decade, and GIS technology has become a business-critical force in helping utilities cope with a changing business environment. Utility geospatial tools will continue to evolve. They have moved from mapping to designing to managing in a relatively short period. As the GIS has grown in capability, we have seen the use of spatial data and spatial analysis tools in other applications. And now, as we enter a new era, we can see more clearly that the smart grid is about data—and much of that data are spatial. The need for these geospatial tools will continue to grow. At the same time, we see the need for new and better tools. As the electric network undergoes major changes, it seems clear that the technology being used today will not be adequate to support the increased size and complexity of a smarter, more connected grid. As the grid becomes smarter, systems that help manage the grid will have to be smarter, too. We can look forward to the continuing evolution of geospatial technology to meet these needs. The previous sections, while describing the key role of geospatial technology in running the grid, have also pointed out several gaps—areas where there are needs for future development to support a smarter grid. Here, we will look at several areas of development that may prove useful.

As the application of geospatial tools to electrical networks becomes more widespread, we see an interesting convergence of technologies. There are four major threads:

- Vendor-based GIS systems that have been the core of the growing geospatial industry for four decades
- Ancillary technologies, such as GPS, navigation systems, and drones, which focus on the value of location
- Consumer-oriented mapping tools such as Google Maps, offering toolsets for displaying data on map backgrounds
- Open-source tools and data (OSM, Ushahidi, the Map Kibera project), initially used for data collection, but now extending into visualization and analysis

11.5.1 Architecture

Looking at the geospatial grid automation picture as a whole, what is likely to be the predominant future architecture? Will this thing, called a GIS, continue to be the central repository for spatial data, feeding other applications as needed? Or will GIS disappear as other applications add the ability to store and manipulate spatial data?

It is likely that we will see something in between. With the rise of ubiquitous spatial capabilities, it seems clear that the preeminent role of corporate GIS will decline. Some planning functions, like grid design, are likely to remain within the domain of GIS and GIS vendors. Other operational tools, with the need for more real-time capability, will store and manipulate spatial data internally. In effect, the GIS will be embedded in multiple places.

The key is data integrity. It is vital that there is a single accurate and consistent view of the grid across all applications, and GIS still seems the most appropriate place to manage that “truth” for the utility.

11.5.2 Cloud

Cloud computing is one of the hottest areas of technology today. The appeal, in many ways, is obvious: Forget the details of managing hardware, storage, and software, and view applications as a service.

Does the cloud have a role in utility geospatial? (There is some irony in the fact that the cloud computing concept is often defined as a utility and is described by comparing it to the electrical grid.) Security concerns are often cited as a barrier. At this point, it is hard to envision a scenario where utilities turn over the management of critical infrastructure and operations data to a third-party storage provider. Some utilities are further constrained by regulations that govern the physical location of data storage. (Private clouds, utilizing the same concepts but maintaining physical custody of vital data, are more likely.) The tools to support the design and creation of the GIS data, however, may reside on a public cloud to reduce utility costs and allow the company to better leverage shared and contractor labor.

As we have seen with the grid, however, data needs extend far beyond the facility objects that represent the utility's assets. Other geographic data from other sources are needed for planning and designing. Renewable energy is subject to weather variations, so real-time weather data are needed for grid operations. These external spatial datasets are good candidates for the cloud approach.

11.5.3 Place for Neo-Geo

In the last few years, we have seen rapid progress in the "neo-geo" arena—companies and individuals using consumer tools such as Google Maps (or even open-source spatial toolkits), to solve significant real-world problems.

A great example is crowdsourcing or VGI. Fueled by grassroots efforts to help disaster recovery efforts in Haiti and elsewhere, VGI has proven to be a valuable tool. By supporting a larger group of users, it has been far more agile and more responsive than many of the traditional GIS efforts.

In some ways, communications and connectedness are the essence of a smarter grid. Can neo-geo play a part? There are security concerns and other barriers, but it does appear that these tools can help apply "people" intelligence to some utility processes, such as collecting damage information after a storm.

Geospatial technology, fueled by advances in computer hardware and software, will continue to evolve. The electric grid itself is in the early stages of a major transformation, and having the spatial understanding of that grid will be essential for those who build and manage it.

12 Mobile Workforce Management

Jessica Jensen
ABB Enterprise Software

CONTENTS

The majority of a utility's assets are distributed over thousands of miles of transmission lines and towers, city blocks of distribution poles and transformers, and hundreds of thousands of residential meters. To ensure safe and efficient operations, these distributed assets continually require maintenance and service, sometimes manual operation out in the field during outages, and also replacement after failure. The utility employees (or contractors) who perform this work in the field are typically referred to as a field or mobile workforce.

Often, one of the largest groups of employees at a utility is the field workforce, which includes line crews, trouble technicians, meter readers, construction crews, vegetation management crews, service installers, and more. Their main objectives are to ensure safe, reliable, and efficient delivery of essential services, such as electricity, gas, and water. This chapter focuses on electric utilities, but many of the points are also applicable for utilities that provide gas and water. Mobile Workforce Management (MWFM) is the system, software, devices, procedures, and workflows that enable the field workforce to meet their objectives, with their main activities focused on developing, operating, and maintaining a utility's assets.

Developing assets: building out or replacing the network; example: line extension or equipment replacement. Developing assets is typically a complex, multi-task undertaking involving carefully planned work, extended periods, multiple crew types and skills and, potentially, contractors.

Operating assets: day-to-day services in delivering electricity to customers; example: service connect/disconnect, meter reading, outage restoration and repair. Operating assets is typically a high-volume, short-duration activity, with mostly unplanned orders for individual field workers.

Maintaining assets: inspecting and repairing assets; example: pole or tower inspections, trimming trees, transformer maintenance. Maintaining assets is a combination of developing and operating assets with work that is planned and scheduled, involving individual technicians or crews working varying durations.

Some utilities categorize these activities as long-cycle work (developing and maintaining) and short-cycle work (operating).

- *Long-cycle:* typically planned work, often with long durations (even in the case of a quick patrol inspection, which are usually bundled into several days or weeks of work)
- *Short-cycle:* typically unplanned work, often with short durations

MWFM ensures that field resources have the information and tools they need to perform their work effectively and accurately. Field workers must ensure the safety of the public, other employees, and the utility infrastructure. This includes activities such as securing downed wires during a major weather event, monitoring and managing the condition of aging assets, or ensuring safe work practices on worksites. One of the most significant impacts to reliability is outage restoration, particularly restoration times. Absolute safety and constant delivery are crucial, but they are not sustainable without efficient operations. Getting the most out of assets and equipment, reducing driving time, eliminating rework and unnecessary repair costs, and ensuring accurate materials and labor accounting are all examples of how MWFM enables a utility to meet its objectives while remaining cost-effective.

12.1 MWFM SOLUTION AND COMPONENTS

More than just a set of software applications, MWFM enables the field workforce to complete their work efficiently and accurately, while providing status and detailed updates of work completed to the back-office. The main functions of an MWFM solution are summarized in Figure 12.1.

12.1.1 Planning

Encompassing both the work to be completed and the resources required to complete the work, planning can be further divided into planned and unplanned work. As noted earlier, some utilities also refer to these as long- and short-cycle work.

Planned work is typically created in the Enterprise Asset Management (EAM) system, based on inspection and maintenance schedules. It includes pole or transformer inspections, pole installation, corrosion prevention, painting, streetlight repairs, and vegetation management. Some utilities have dedicated inspection and maintenance crews, which allow them to plan the work based on 100% utilization. Crews often receive several days or even weeks of work at one time, and they self-manage the completion of the work within the time frame given.

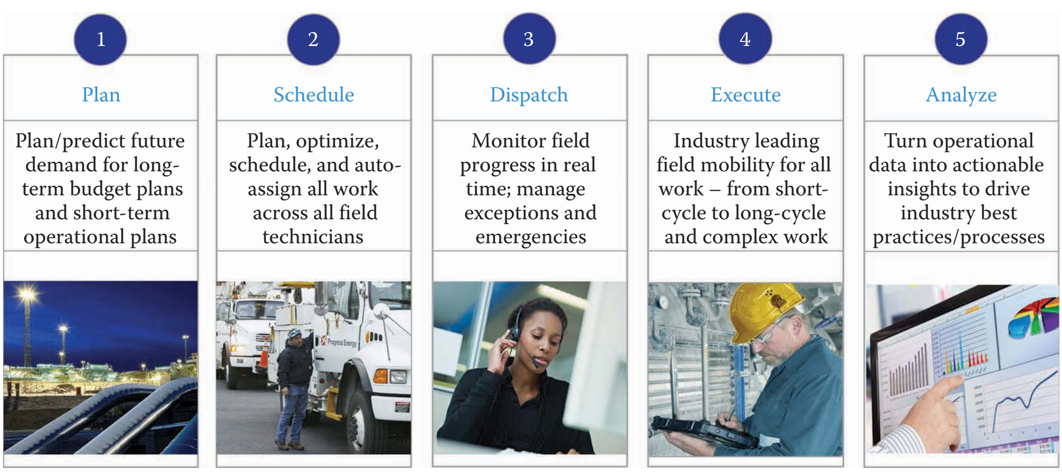

FIGURE 12.1 Main functions of an MWFM solution. (© 2016 ABB. All rights reserved.)

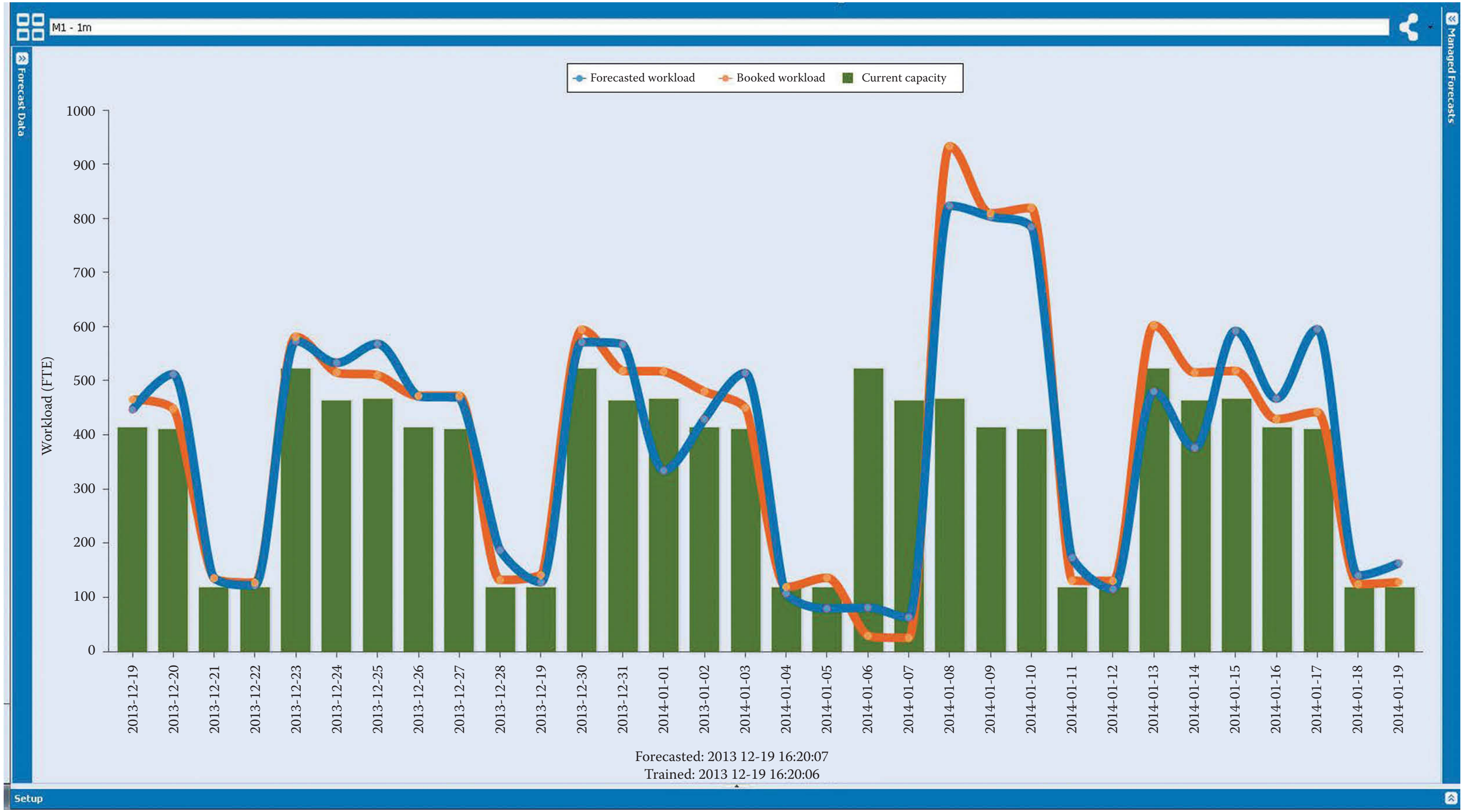

FIGURE 12.2 Workload and capacity planning. (© 2016 ABB. All rights reserved.)

Large, complex projects also fall into the planned work category, although this type of work typically involves multiple types of field resources—such as designers, supervisors, technicians, and crews, as well as involvement with nonutility personnel, such as city inspectors and contractors. These projects last often weeks, months, or even years in duration and require the coordination of resources, equipment, permits, and materials. Most projects are broken down into individual tasks, which can be assigned to field resources dedicated to the project or only work on the project when required.

Unplanned work includes customer service, such as turn-on, meter set, meter read, and nonpay disconnect, and also trouble or outage work, such as damage assessment, planned and unplanned switching, wire or line down, outage restoration, and outage repair. While a utility cannot predict the exact amount and timing of unplanned work, it typically has some method of forecasting the work based on historical data and seasonal patterns. Forecasting typically utilizes historical data and other inputs (such as known blocks of work) in a model to calculate workload demand up to a year in advance. Input data can then be manipulated through a series of "what-ifs" in an iterative process that eventually matches resource supply with work order demand. Output from this system can then be fed into subsequent scheduling processes.

Some types of unplanned work are known in advance—typically customer service requests. Utilities make commitments to customers when scheduling field resources to perform work, for example, installing new service or investigating flickering lights. To make the commitment, utilities need insight into the work currently scheduled (whether planned or unplanned), which resources are expected to be working, and whether those resources have the availability and capability to perform the work.

Combining the type and amount of planned work and the predicted unplanned work, planners can then estimate the number of field resources required to complete the work orders and tasks. Comparing the number of field resources required with the expected amount of work allows shift planners to define or update shift schedules. Shift schedules are based on the required number of field resources, and define who is working and when. They include plans for regular shifts, overtime shifts, on-call resources, training, vacation, and other working and nonworking time (Figure 12.2).

12.1.2 Scheduling

With the amount of work and field resource schedule defined, orders can now be scheduled and assigned. The process of assignment varies, but includes everything from preassignment by another system (e.g., specific maintenance crews selected in the EAM) to manual assignment by a supervisor or work planner, to automated assignment within the MWFM system.

Using scheduling, a utility can do the job right with the right resources the first time. Appointment scheduling is automated and immediate, using predefined scheduling parameters and rules. Call center representatives can initiate service requests and schedule service appointments, ensuring the right field personnel are at the right place and at the right time. The MWFM scheduling algorithms enable both the initial optimization and reoptimization of assignments and schedules to ensure the choice of a field resource to do a given job is, and remains, the most efficient possible. Scheduling allows a utility to:

- Define and adjust crew availability
- Negotiate and reserve customer appointments
- Automatically assign work orders to crews
- Reoptimize the schedule when the operational environment changes
- Sequence and optimize route work assignments
- Make manual adjustments to the schedule when conditions change

The rules of assignment vary, but typically include matching the skills, equipment, and working area of the field resource with the requirements of the work order or task, while also ensuring the field resource has the shift time available to complete the work. The time frame of the assignment also varies, from making assignment decisions months in advance for planned work orders to minutes after receiving an outage restoration task.

Utilities typically employ an automated assignment system to assign the bulk of the work, usually determining the next day's assignments overnight. That assignment includes all the known work for the next day, combining the planned and unplanned, and includes all types of work. The benefits of using an automated system to assign the majority of the work include optimal assignments and routes, reduced driving times, and ideal utilization of skilled resources.

Often, the most unknown aspect of work assignment is trouble or outage orders. While they can often be predicted based on weather, unforeseen circumstances (often something as simple as a vehicle hitting a pole) can require immediate assignment to assess the damage, initiate restoration, and, in some cases, carry out a subsequent permanent repair.

In the case of an outage, the most critical attribute is the time to restoration. When deciding which crew to assign the work to, the closest crew is often the best one—assuming, of course, they have the right skills and equipment. Knowledge of the nearby crews' members, skills, equipment, and current activities is crucial to making the right assignment. Many utilities rely on dispatchers to assign outage orders, although most MWFM systems can also assign these orders with an automated solution. In the case of manual assignment by dispatchers, it's important to ensure they have access to the information they need. Typically, this is via an MWFM dispatch application, which includes real-time status, geographical views, and details of the outage.

12.1.3 Dispatch

At some point before the work is due to be completed, the field resource needs to receive the work order or task details. Depending on the MWFM system used, this can be an automatic or manual process. For planned work, orders and tasks are typically dispatched in batches, for example, a week's worth of transformer maintenance tasks or a work order for the inspection of a section of transmission lines. Unplanned work is usually dispatched the day the work is expected to be completed. Once delivered, the work is ready to be executed by the field resource. Dispatch offers personnel a high-level and detailed look at the entire field service program in real time, in both Gantt chart (timeline) views, maps, and tabular windows (Figure 12.3). Dispatchers are given the flexibility to make modifications to assignments for technicians or crews, with the ability to adjust when there are conflicts or other conditions requiring their attention. With automated assignment, the MWFM system performs most of the dispatch functions needed during a shift, leaving dispatch personnel time to focus on those exceptions requiring personal intervention. Dispatch allows a utility dispatcher to:

- Monitor technician and order progress and status
- Be alerted to conditions that require a dispatcher's attention and action
- Monitor the position of the fleet using dispatch maps and GPS
- Enter status and complete orders on behalf of technicians who do not have operational devices
- Monitor the location of field resources compared to open orders
- View the geographical information system (GIS) representation of assets involved with open orders

Status updates are critical for providing an up-to-date view of events in the field, for example:

- Estimated restoration times during an outage
- Location of a field crew requiring assistance
- Expected arrival time to a customer appointment
- Number of pole inspections completed by a crew
- Current progress on a construction project

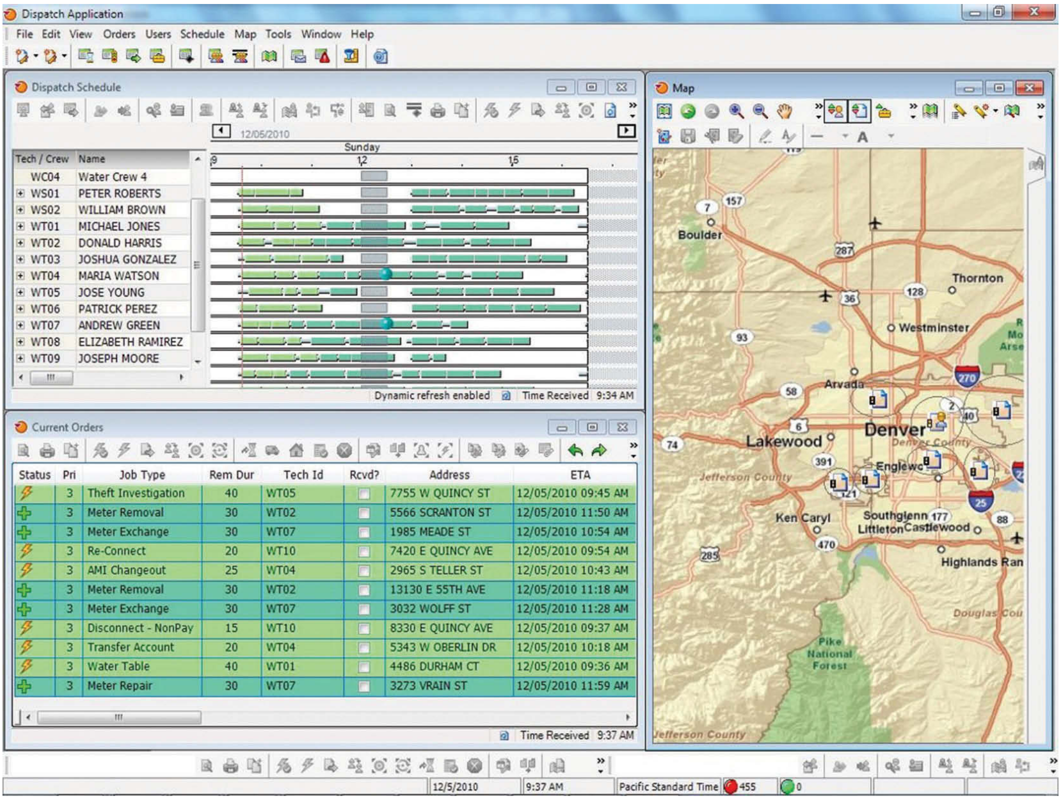

FIGURE 12.3 Assignment and dispatch of work to field resources. (© 2016 ABB. All rights reserved.)

Detailed work updates ensure that the field workforce's activities are accurately reflected in the utility's back end systems, for example:

- Repairs made to a transformer are noted in the asset's record in the EAM system
- Connecting service for a new residential customer is updated in the customer information system (CIS)
- As-built network information for a new subdivision is confirmed in the GIS and outage management system

12.1.4 Execution

The key word in MWFM is mobile, and it's critical during the execution phase. Mobile transforms the way all field workers process orders. Instead of receiving work orders on paper or over a voice radio, crews obtain and manage all of their work orders wirelessly on a mobile device. While smartphones didn't achieve mass adoption (especially for the consumer market) until partway through the 2000 decade, utilities have been using mobile devices to complete work in the field for more than 20 years. Even with more than two decades of mobile device availability, some utilities still track work in the field via pen and paper. That is, however, becoming an exception, as most utilities have deployed some type of mobility for their field workforce.

Mobile provides field workers with the tools, information, and wireless capabilities to receive work orders, complete the work, and send status updates and order completion information back to the enterprise—wirelessly and in real time. With integrated GPS-based mapping and street-level

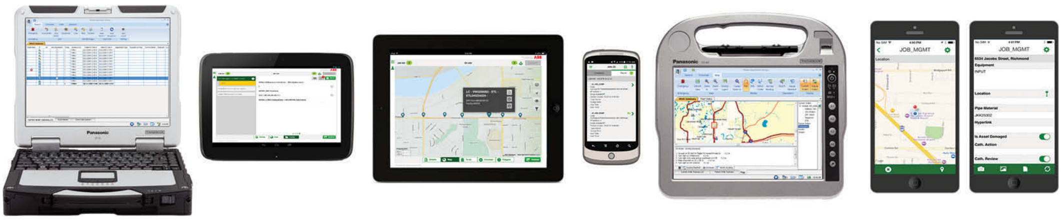

FIGURE 12.4 Utility workforce mobile technologies. (© 2016 ABB. All rights reserved.)

routing, mobile ensures optimal routes for traveling between assignments to minimize distance and time. Mobile allows a utility field worker to:

- Receive and execute work orders in the field
- Provide real-time status updates to dispatch and the back-office
- Request supplementary information from the back-office
- Review optimal driving directions
- Notify dispatch of potentially dangerous situations
- Complete, edit, and approve timesheets

With the right MWFM mobile application capabilities, utilities are able to provide field resources with further benefits, such as the ability to make ad hoc queries about their current task (e.g., the last five meter read values), take photos and video, use GPS and online maps to identify asset locations, and validate the work update information they enter against the utility's specific logic/rules (e.g., during outage restoration, the repair crew must enter the estimated time for restoration, what type of repair is required, whether they need assistance, and what materials they use.)

From a technology standpoint, the choice of device, platform, and capabilities depends on the type of work being performed (Figure 12.4). The standard technology was mostly ruggedized laptops, but with a much wider range of choices, utilities are now adding tablets and smartphones. The platform choice is often dictated by corporate policy, but Windows, iOS, and Android are by far the most popular choices. Selecting one or more devices is only the first step in what must be a comprehensive mobile device (and application) management plan. Utilities must also consider security (of both data and the devices themselves), connectivity, deployment, and updates of both the mobile devices and the mobile applications/data.

12.1.5 Reporting and Analytics

Learning from previous experience is the cornerstone for improvement, and it is crucial for a utility to understand field operations, confirm safety and compliance, and increase efficiency. Optimizing field service operations is possible with a performance reporting system within MWFM that provides critical visibility and insight into operational status, both at a tactical real-time level and at a strategic trending level. Easy Web access to multi dimensional analysis and detailed performance reports allows a utility to uncover the real drivers of workforce performance and make adjustments to maximize efficiency.

Reporting and analytics include information about all aspects of a utility's field operations and cover all time frames, from real time to years or even decades. Reporting typically comprises a knowledge warehouse, operations dashboard, and decision support capability. These integrated components provide a comprehensive, consistent view of operational data, addressing daily field tactics and providing in-depth views of past performance to assist with strategic analysis, planning, and forecasting. Input from reporting can be fed back into the initial step in the work cycle of forecasting, thus creating a self-referential loop of optimized field operations. Reporting allows a utility to:

- Obtain long-range trending views based on weeks and months of data
- Obtain short-term tactical views of current operations in the field
- Develop its own reporting structures based on the historical database
- Distribute reports automatically to target audiences
- Access all reporting through an easy-to-use Web interface

To ensure productive field operations, utilities use dashboards to monitor the current status of field resources and their work. Typical data points include number of open orders, average travel (drive) time, current or expected overtime, customer commitments met and missed, and emergency response times. These dashboards allow field managers to quickly respond to issues, for example, reassigning crews to areas with high volumes of open orders or dispatching on-call technicians.

To evaluate overall performance over multiple years, utilities use the same data as the above dashboards, but over longer time periods, and often with more detailed analysis of trends and patterns. Typical reports include work and travel time analysis, accuracy of work estimation, and average system and customer outage times (e.g., Customer Average Interruption Duration Index.) This information allows utilities to evaluate changes in the utility's business, how it is meeting regulatory requirements, or even the effectiveness of a newly implemented MWFM solution.

12.2 END-TO-END AND TOP-TO-BOTTOM BENEFITS

In the early days of utility workforce management, the primary order types supported were related to customer and meter services. Executing these high-volume, short-duration orders through MWFM soon proved to have powerful paybacks in terms of customer service and field workforce productivity, but this affected only part of the utility field workforce; there were still a substantial number of field technicians and crews doing more complex work in the field using only paper forms and voice radio.

Today, utilities operate in an ever-changing environment of rising costs, globalization, and mergers and acquisitions. They must meet customer expectations (which have increased with social media), ensure compliance with more stringent and complex industry regulations, understand how to use new emerging technologies and equipment, and consider the impact of renewable energy, all while reducing costs and ensuring sustainability. These modern requirements affect all types of work, field resources, and each functional step in the overall field operation process. Utilities have the opportunity to meet these requirements through the improved use of their MFWM system.

To gain these new benefits, an MWFM solution now must fully and truly support "end-to-end" processes and "top-to-bottom" functionality (Figure 12.5). If it does not, then new gains will become much more of a challenge and delay the required return on investment.

End-to-end means that, in doing field work orders, there is a natural progression of necessary functional steps. These begin with the process of forecasting both the workload and work resources needed over a projected period. Work orders must then be scheduled and assigned to specific resources; those orders should then be dispatched. Technicians and crews must then receive that work as they operate in a mobile state in the field. Finally, the results of such activity immediately and over time should be reported and analyzed. Such capabilities result in superior functional processes that support all construction, maintenance, inspection, outage/leak, and meter services work order types. In short, virtually everything a utility's workforce does and requires in the field is supported by such an approach to MWFM. The benefits of MWFM are summarized as follows:

Easier Access to, and Improved Accuracy of, Data

- Automate field collection and validate work results
- Deliver critical enterprise and customer and asset information to the field
- Provide real-time feedback on work progress

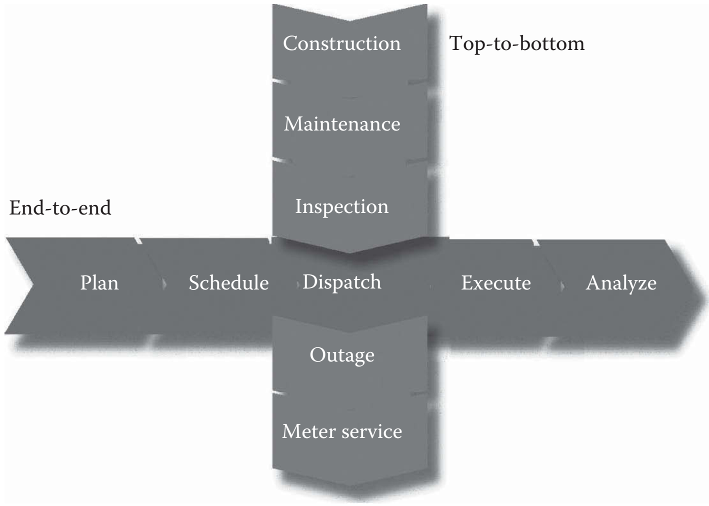

FIGURE 12.5 End-to-end and top-to-bottom benefits of MWFM. (© 2012 ABB. All rights reserved.)

- Validate data in the field to ensure correct information in back end systems
- Increase data accuracy with user-friendly graphical interface, context-sensitive drop-down lists, and auto-fill fields

See More and Control More in the Field

- Measure and analyze operational performance
- Access an enterprise-wide view of workforce and its workload
- Access Web-based, real-time tactical reporting tools
- Continuously optimize scheduling as daily changes occur
- Allow the user to configure, deploy, and modify the system

Consolidate Work and Save Time

- Eliminate manual work order sorting, bagging, and entry of completion information
- Consolidate geographically dispersed dispatch centers
- Reduce number of field technicians required
- Scale the system in response to changes in the organization
- Be flexible and adaptable through open, distributed architecture that supports an enterprise workforce management solution

Increase Customer Satisfaction

- Meet more customer appointment commitments
- Ensure workers have the right equipment, skills, and parts to finish the job in one visit
- Enable service agents to confidently offer narrower service appointment windows
- Provide real-time service order feedback to customers
- Meet regulatory requirements for customer appointments

Decrease Costs

- Reduce travel time and distance driven with geospatially optimized routing
- Reduce employee overtime

- Decrease operating expenses and overhead
- Optimize use of contractors
- Increase the number of technicians supported by each dispatcher

Increase Efficiency

- Eliminate voice and paper-based processes
- Increase volume of work orders and completion rates
- Improve service response times
- Improve monitoring and management of field resources
- Significantly reduce time needed for generating, reviewing, and changing schedules through optimized scheduling

12.3 MWFM IN A SMART GRID

Now more than ever, consumers and regulators insist on responsive and high-quality service from their utility service provider. To succeed, utilities need to optimize their field service delivery processes and improve the reliability of critical assets, while making efficient use of field workers and equipment.

Most MWFM systems in place today automate at least part of the field service workflow—from scheduling and optimization of order assignment to dissemination of work to the field, mobile order processing, and performance measurement. In the face of constantly changing investments and formidable field operations challenges, MWFM should provide a platform for managing work across much of the enterprise—regardless of the enterprise application from which the work is generated—and enable seamless, real-time data and communications flow between enterprise systems and mobile workers. However, are the systems that are in place today going to help build the workforce operation of tomorrow? Clearly there remain many obstacles to distributing work across organizational or geographic boundaries. As a result, utilities continue to look to further increase operational efficiencies and heighten productivity, while optimizing performance, improving internal controls, and reducing costs.

While utilities continue to look toward their MWFM systems as the primary platform for addressing new obstacles and gaining new benefits, the challenges include

- Improving end customer service and responsiveness
- Driving out operational and supply chain costs
- Meeting tougher regulatory compliance requirements
- Delivering system reliability in light of an aging field workforce and an aging asset infrastructure
- Supporting a progressive field asset management program
- Unifying fragmented technologies and lowering IT support costs
- Developing and enforcing utility-wide process standardization
- Increasing field force productivity
- Reducing the carbon footprint of field operations

The new types of assets and equipment that make up a smart grid require resources with a new set of skills, often specialized, for installation, inspection, and maintenance. With an ever-increasing number of smart grid initiatives around the world, the availability of these skilled resources will need to increase to meet the demands. For example, the Electric Advisory Committee recommended that the U.S. Department of Energy "[c]reate a workforce training program to ensure that working technicians have the skills needed to work with Smart Grid technologies" [1]. Utilities need to consider when, where, and how to recruit these resources, as well as what systems and tools they will need to be successful. These systems and tools should include an MWFM solution that can provide the field resources with the capability to perform their work, gather and capture information about their efforts, and optimize their daily routines.

Once a utility has the appropriate resources, the next challenge is ensuring they are used effectively and with maximum productivity, making the most of their skills and their available time. It's not cost-effective to have highly skilled resources idle or performing lower-skilled work when there is appropriate work available. This is where an MWFM solution with the ability to schedule resources based on their skill mix, availability, location, and equipment can be of significant benefit. Finding the optimal selection and sequence of work to assign to field resources can maximize their abilities while decreasing idle time.

Other smart grid technologies and solutions will help in the availability and immediacy of information to and from the field. With each smart device installed, including smart meters and smart appliances in the homes of consumers, a utility has the capability to collect and receive data on current operating status, warnings, error messages, and even requests for maintenance. Utilities can use these data to determine when to send a field resource to inspect, maintain, repair, or replace the equipment. During outage restoration, information provided to field resources can include predicted fault locations, equipment involved, and the number of customers affected. With the information they need, field resources can locate, confirm, and resolve outages faster. As they work through the restoration, field resources can provide real-time updates to the back-office, including estimated restoration times, severity of damage, potential temporary fixes, and follow-up work required. Knowledge of the current status of an outage is critical information for a variety of stakeholders, including dispatchers, operators, utility leadership, government, and the public.

The smart grid will also include access to, and use of, new technology, such as digitally connected assets and equipment, sensors, RFID, even drones and virtual reality. Utilities that have deployed an MWFM solution will be able to better incorporate the data provided by these technologies, for example, gathering current operating conditions from a transformer via Wi-Fi, RFID, or Bluetooth, rather than having to manually record it, or using augmented reality to view technical information (e.g., documents or videos) in the field while repairing a wind turbine. Incorporating these new technologies enables technicians to complete their work faster and with more accuracy.

While smart grid technologies will help in the MWFM process, the implementation of smart grid solutions will also require a new way of thinking in MWFM. A utility must consider the design and construction/installation of the smart grid components. From wind turbines to smart meters to solar panels, the coordination of field resources (not all of whom may be utility employees) and their tasks when constructing and installing new assets is best handed by an MWFM solution. Common requirements include assigning tasks to crews (ensuring they have the correct skills and equipment), ensuring related tasks are coordinated, providing as-designed specifications, and collecting as-built alterations to the design.

Once installed and operating, these new assets require appropriate inspection and maintenance. While utilities currently perform many traditional inspection and maintenance activities on the grid, areas such as renewable generation, energy storage, and microgrids require new skills and equipment. With the need for new, unique skills, utilities will likely bring on a new, specialized set of field resources. Augmented by smart sensors, the ability to monitor and diagnose equipment and predict equipment maintenance will ensure that the field workforce is used effectively, while also achieving optimal operations.

Smart meters are one of the core elements of a smart grid. With a network of smart meters, what was previously the most common field activity for a distribution utility, manual meter reads are no longer required (or at least significantly decreased). Replacing legacy meters with new smart meters requires a field workforce and, ideally, an MFWM system to manage the work and resources. While larger facilities require specialized resources, utilities already have the existing field workforce available, but will need to consider training and certification to add the skills required to install, troubleshoot, repair, and replace smart meters.

Few people in the utility business need convincing that the above- and below-ground asset infrastructure, be it electric, gas, or water, is a critical component that is showing unmistakable signs of age. And most utility managers understand that the field workforce tending to that infrastructure—and the customers attached to it—is also aging and retiring at an increasing rate. These issues of aging infrastructure and aging workforce are often examined independently in articles, papers, and presentations to industry forums. Although richly worthy of attention in their own right, it is the interaction of the two, the dual threat of asset infrastructure aging simultaneously with the workforce maintaining it, that should be of particular concern to utility management, regulators, employees, and customers.

Given various market drivers in play, mobilizing the asset-oriented/long-cycle work remains an untapped opportunity for utilities. Most utilities do not have a viable option across short- and long-cycle work and often manage multiple MWFM systems versus an enterprise application. An aging workforce continues to create challenges that highlight the importance of enterprise-wide technologies to support business process execution. In addition, aging infrastructure issues are driving companies to focus resources on asset-intensive work execution. These combined forces set the stage for companies to transition their focus toward improving field productivity through MWFM.

When a utility field technician or crew is dispatched to complete a series of inspections and maintenance orders at, for example, a substation, one can assume that they are experienced and fully trained to do so. With the median age of utility industry employees in the United States currently at 49, this would certainly be a valid assumption. Indeed, for the utility industry, there is a large group of well-experienced, well-trained current employees ranging in age from 45 to 54 years old. In executing the various procedures and tests involved in inspections and maintenance work, these employees are drawing directly on the considerable expertise and familiarity with the assets they have developed over some 25 years of work in the field.

Although inspections and maintenance procedures are well documented and the subject of frequent refresher training for crews, the personal knowledge component is just as important. Knowing the peculiarities of a given asset type, even down to the model number, is a valuable additional aid to properly conduct an inspection and, if necessary, make repairs. As these lead technicians and crew chiefs age, however, an increasing number is taking advantage of utility retirement packages to depart on or, in some cases, before their scheduled retirement dates. When such individuals leave, their individualized knowledge goes with them. And with strict cost controls in place at most utilities, hiring replacements is a lengthy and demanding process. Even when hired, the time needed to achieve the same level of personal knowledge is measured in many years, not months. With the increasing use of contractors (also exposed to the aging workforce factor), utilities might not even be in a position to hire new employees who will eventually be developing the in-depth skills needed for field work.

When a relatively new technician or crew goes out the following year to do that same inspection series at a substation, their personal expertise may be significantly less than the previous field resource. While they may have access to documented procedures and possibly be subject to on-site review by a field supervisor. However, the utility has lost the experienced resource with the innate ability to sense the status for a given piece of the asset infrastructure.

At the same time as this aging workforce factor is coming into play, those same assets and infrastructure being maintained are also aging, thus requiring more and lengthier inspections and maintenance procedures and, in some cases, replacement. Newspaper headlines and TV news stories the last five years have all too often featured a failure, sometimes spectacular, of a given piece of electric, gas, or water infrastructure that, at the very least, led to service interruptions or, more dramatically, produced significant damage and human injury as a result of its failure. Much of that infrastructure is composed of operating assets that utilities of all types must continually inspect, maintain, and replace to ensure reliable performance. And while a good portion of the nation's utility asset infrastructure is in satisfactory condition, an increasing percentage of it is nearing (or exceeding) its planned operating life and, therefore, requiring field work to maintain or replace it. In such work, a utility employee's personal knowledge of individual assets as well as the overall utility network is critical.

This work is typically generated in some form of utility asset management or work management system. Such a system consists of technology, certainly, as well as business processes, procedures, and even accounting practices, all of which come into play in operating a satisfactory asset management program. For many years, such systems were “siloized” by the type of asset being installed or maintained; thus, all meters would be managed by one system (often a spreadsheet), all transformers and related substation equipment managed in another, and so on. In recent years, however, there has been an increasing trend toward maintaining the history of all assets in a single enterprise-wide asset management system of record.

Ironically, this same silo approach has also been applied to the utility field workforce, with meter and customer service personnel managed by one workforce management system, inspection and maintenance personnel in another, construction crew with a third separate system, and outage technicians in still a fourth. Like asset management, however, the trend in recent years has been toward a common workforce management system covering the entire enterprise field force. With both of these consolidation trends, utilities have the ability to take a more holistic and integrated approach to asset management and workforce management, both as separate disciplines and now also as a useful synergistic point of operational excellence. Nowhere is this outcome more helpful than in addressing the problems posed by an asset infrastructure aging as fast as the workforce that maintains it.

While a clear strategy for achieving both business effectiveness and peak operational performance is the deployment of an enterprise-wide MWFM system, for this solution to be truly effective, it must be geospatially enabled across the board. With an enterprise MWFM solution that has full GIS capability, a utility can integrate enterprise applications, where mobility, scheduling, dispatch, and data transparency are carried throughout every layer of work. A key opportunity for organizations will be the enterprise MWFM functionality that can link the customer, meter, outage, inspection and maintenance, and construction work with GIS support in the field to decrease overall IT spending and increase company-wide productivity.

How would such synergy appear in a normal field environment? Consider the earlier example of a technician or crew going out to a substation for a series of inspection and maintenance tasks or orders. The composition of the crew is a good starting point, in that the enterprise workforce management system would have created a crew with the most appropriate skills, and structured the assignment of the work to achieve maximum efficiency. The orders to be completed would be generated by the EAM system, using a variety of triggers (time and condition based, and subject to regulatory requirements) to determine the specific asset items to be inspected and maintained. These orders would be passed electronically to the field resource’s mobile device. The device would display the details of the orders and assets, giving the field resource a clear view of what needs to be done, but not details on how it needs to be done. The “how” distinction would, in the past, have been left to the combination of training and personal knowledge that exists in the experienced employee. However, with the aging workforce and asset infrastructure issue, the “how” may not be known or as obvious to a less experienced technician. This challenge highlights how the abilities and benefits of an integrated approach to asset management and workforce management can complement less experienced field resources without sacrificing safety or productivity. In this scenario, in addition to sending the order details, the upstream system would also send a hyperlink or a file attachment - a clickable reference to the detailed inspection and maintenance procedure for that specific asset. The hyperlink can also provide graphical guidance, with detailed schematics of a given asset model, for example. The technician has specific and up-to-date guidance readily available on how to complete the work order correctly and efficiently.

Whereas a hyperlink reference would be largely generic to a group of similar assets, another possibility that is even more specific is the attachment capability. In this case, detailed information relevant to that particular asset and order, such as a digital photograph taken the previous day by the previous crew working on it, would be made available on the device. Any changes made that day can be captured via another digital photograph and sent back up as a file attachment as part of the order completion process. The difference between hyperlinks and attachments in this example, therefore, is largely one of specificity to the asset and order in question.

Another possibility would relate to a maintenance procedure (such as replacement of an asset grouping) that a crew might need to undertake following an inspection. Using software on the device and the wireless capability, the crew would be able to interface to other third-party applications that are resident on the device itself or accessible via the Web. For example, "compatible units" are a major component of new construction for the maintenance replacement of assets. With this third-party reference tool, the crew can access a library of available compatible units for the order in question and determine what materials and labor should ideally be expended in the procedure. Whereas in the past, this information would be on paper and well known to experienced utility or contractor employees, with this capability, they can easily and quickly reference compatible unit definitions that are always up-to-date and complete.

Utilities are continually looking to improve service, react effectively to emergencies, and identify opportunities in the field to improve service and operations. By definition, work consists of the day-to-day operations that define a utility. In the future, the work schedule will be intrinsic to the holistic operational plan. Responses to customer service inquiries, such as a new service hookup or a gas or water leak, can be combined and balanced with inspection and maintenance work.

For example, responses to customer care can be combined with managing other important assets in the field that are in close proximity to the customer care request. A mobile system with GIS can provide visibility into the field work scope and progress, along with the crew and contractor information. This increased visibility will result in better customer service, workforce efficiency, and, ultimately, cost savings. As much of the utility infrastructure is aging in parallel with a maturing and retiring workforce, utilities are entering a proactive phase of managing both assets and people with improved technology. For years, most work has been managed by silos of IT systems supporting only short-cycle (customer and meter services) work. With modern MWFM systems, utilities can now more directly accommodate, plan for, and have visibility into the status of inspection and maintenance duties. The next focus of development will be the successful management of construction in addition to improving customer, inspection, and maintenance works. Installing the next mile, managing new neighborhood designs and implementation, and maintaining this infrastructure will require enhanced MWFM capabilities with even stronger GIS components. MWFM combined with full-featured GIS capabilities is going to be a major field force transformative process that utilities and communications companies will face in the twenty-first century. It meets the challenges of increased customer service with lower costs that is and will be a hallmark of field operations, and at the same time provides significant configurable flexibility at the point of service provision in the field. Through a combination of software solution implementation and professional services on the organizational and procedural aspects of field operations, this MWFM/GIS solution can produce measurable and repeatable benefits to virtually all utility companies who deploy large and active field service organizations.

Through effective use of a MWFM system, information is accessible when and where needed to properly, efficiently and safely perform the work. MWFM augments the personal knowledge and experience of field resources by giving them the information and capabilities they need. The overall capability, achieved only through the proper integration and coordination of EAM and MWFM ensures that utilities can manage the dual threats of aging infrastructure and aging workforce.

Utilities are making significant investments in smart grid initiatives, and with those investments, they have the opportunity to ensure their field workforce and field activities make the most of those investments. An MWFM solution will ensure optimal operations for the construction, installation, inspection, and maintenance of the new types of equipment, assets, and facilities that make up the smart grid. With optimal operation of the smart grid, utilities will reduce costs with increased productivity and efficiency, diversify their business with access to new types of energy generation, delivery, and storage, and increase customer satisfaction with better response and restoration of outages.

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Robby Simpson
GE Power's Grid Solutions business

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Advanced Metering Infrastructure (AMI) is considered synonymous with smart meter systems. The use of the term AMI may be traced to a 2002 order instituting rulemaking by the California Public Utilities Commission [1] that defined an infrastructure to support demand response (DR) capabilities as including "advanced metering hardware; metering software including communications capability with the utility and/or the customer[1]; energy management control systems, smart thermostats, or other controls at the customer site; and any necessary software or communications to facilitate the integration of customer systems with the metering system and load dispatch infrastructure." Many industry experts consider smart meters as the foundation for smart grid because smart meters measure energy, demand, and power quality, and can communicate these parameters to the utility and (optionally) to the consumer via two-way wired or wireless networks [2]. Furthermore, the utility can send command and control messages down to the meter to manage the flow of power and energy to the consumer. As the name implies, AMI involves not only meters but also communications technologies and devices, software applications, and interfaces related to the exchange of data between the electric utility, the meter, and the consumer, and also authorized third parties in some cases.

AMI communications systems vary depending on the location, geography, utility company preference, business case, and the technology choices available. The various forms of communications are discussed in an earlier chapter of this book. This technology of remotely and automatically collecting diagnostic, consumption, and status information from the smart meter and then transporting that information (to a central database) for billing, analyzing, and operations is changing not only the way utilities do business but also the way the consumers behave.

Smart meters are defined by their functionality. A typical set of smart meter functions includes:

- Two-way communications between the utility and the meter
- Recording of energy consumption in configurable intervals of 15 min, 30 min, or 60 min
- Recording of power quality information, such as voltage and outages
- Sending data to the utility on a configurable (e.g., daily) schedule on demand, or via triggers
- Internal switch or interface to an externally operated switch to disconnect or reconnect service
- Home area network (HAN) interface for connection to consumer load control devices and what are known as in-home displays
- Functionality to ensure reliable and secure data communications

13.1 EVOLUTION OF THE ELECTRIC METER

The use of electricity meters expanded in the 1880s in order to properly bill consumers for the cost of energy. The electricity meter is a device that measures the amount of electric energy consumed by a residence, business, or an electrically powered device. Electricity meters are typically calibrated in billing units, the most common one being the kilowatt hour (kWh), which is the amount of energy consumed by a 1 kW load in 1 h. Billing of consumers relies on periodic readings of the electric meters to determine energy used during that period or cycle. In the Americas, most residential consumer meters are of the single-phase type, whereas most commercial and industrial consumers require two- or three-phase metering. For the latter, the electric meters often calculate energy (kWh), demand (kW), and power factor, since while most residential consumers are charged according to energy consumption only, commercial and industrial consumers are usually charged an energy rate, as well as a maximum demand rate, or sometimes according to their power factor.

Electric meters fall into two basic categories: electromechanical and solid-state (electronic). The most common type of electric meter currently in use today is the electromechanical induction watt-hour meter. An example of an electromechanical meter is shown in Figure 13.1.

The electromechanical induction meter operates by counting the revolutions of an aluminum disk, which is made to rotate at a speed proportional to the power through the meter to the load.

[1] Some use "customer" and some use "consumer." The latter will be preferred unless it is a direct quote from a cited source.

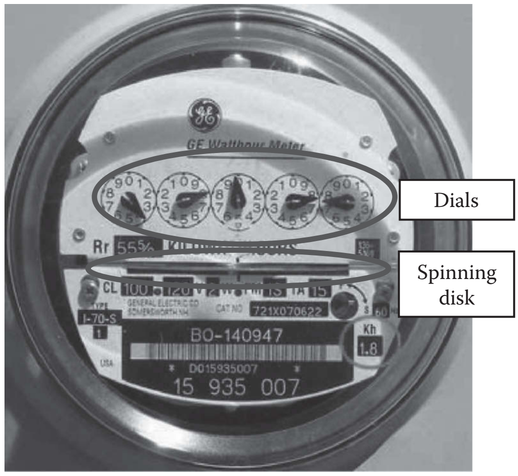

FIGURE 13.1 Typical electromechanical electric meter. (© 2016 GE Grid Solutions. All rights reserved.)

The number of revolutions is thus proportional to the energy usage. In addition to showing continuous power use via the rotating disk, these meters also show cumulative energy usage via the dials at the top of the meter. The cumulative energy usage is the total energy used since the meter was energized, which utilities use to determine how much energy has been used by the consumer. In order for a utility to obtain the information from purely electromechanical meters, someone must physically go to each meter to read it. The meters are read on a regular basis (monthly, quarterly, or annually, depending on usage and population density)—the difference between the two readings is how much energy (kWh) was used by the consumer between the readings. The readings are then entered into a consumer database for billing purposes.

There are several drawbacks to the electromechanical meter:

Inefficient: Sending utility employees to walk house to house (or business to business) to manually read each meter, or asking consumers to do this, is labor intensive, and can be expensive depending on the utility and location of the customers.

Inaccurate: All meters are prone to small measurement inaccuracies, and manual meter reading and manual data entry into the billing system are also prone to error. Any errors may require a significant amount of time to resolve, usually involving a separate visit to the consumer to read the meter again. This error-prone process led to the development of a software application called validation, estimation, and editing (VEE). These applications take into account historical patterns of use and validate readings to ensure that they were in the expected range and permit authorized utility personnel to edit (or correct) readings accordingly. Gaps in the meter readings can be filled by the use of estimating algorithms.

Tamper prone: Tampering with electromechanical meters to reduce the amount of energy registered may contribute to significant revenue losses for utilities if left unchecked. The meters themselves have different mechanisms susceptible to tampering; however, one benefit of these meters is that there are utility "eyes" on them once per billing period, and properly trained personnel can contribute to reducing losses due to identification of physical tampering at the meter.

No remote monitoring or control functionality: As part of the process of dealing with consumers moving residences (typically more frequently for apartments or high-turnover housing, such as near college campuses) and people not paying their electricity bills, utilities would need to send someone out to the consumer to turn the power off and back on for new consumers, as well as collect what are known as final and initial meter reads. Also, if a consumer reported loss of power, the utility would need to send someone to verify if the power supply on the utility side of the meter had failed (utility responsibility), or if it was an issue on the consumer side of the meter (consumer responsibility).

No consumer visibility of energy usage: Unless consumers physically read their own meters on a regular basis and more frequently than the billing cycle, or use third-party devices to accomplish the same, they have no visibility of their energy usage until they receive the bill. Without detailed or real-time information on energy usage and time-based energy pricing, consumers have much less ability to reduce or time-shift energy usage and save money on their bills. Note, however, there are some programs in place relying on educating consumers, which have proven to reduce energy and demand without additional technology [3,4].

As the needs of electric utilities progressed and technology advanced, the next generation of meters were developed using microprocessors, which included communications interfaces and data storage capability. These electronic meters brought the benefits of digital technology with no moving parts, more accuracy, much more functionality, and also software programmable features. Today, there are many solid-state meters available, and each with the capability to support numerous types of communications systems. An example of a smart meter is shown in Figure 13.2.

Electromechanical meters are still the most predominant type of electricity meter currently in use around the world. Replacing an entire meter population with a different type, say from electromechanical to solid-state, represents a significant investment by the utility for which a viable business case must be built. Some electromechanical meters have been in service for numerous decades, and electromechanical meters, as well as solid-state meters, can have a long service life. An advantage of solid-state meters over electromechanical meters is the ability of the former to potentially handle multiple meter configurations, say for different measurements, time periods, or rate structures, through firmware or programming changes.

As the smart meter communications capabilities evolved to support two-way communications, so did the functionality of the meters. Some of these functions include the capability of remotely connecting or disconnecting power to the consumer at the meter, notifying the utility when the meter loses power (remote power outage notification) or power is restored (remote power restoration notification), monitoring power quality, running remote diagnostics, communicating rates (pricing signals) to consumers, and remotely controlling appliances within the consumer's home to restrict usage at peak times (programs such as demand side management, or demand response). Smart meters are deployed not only in electric utilities but also in gas, water, and other utilities.

The standard business model of electricity retailing involves the electric utility company billing the consumer for the amount of energy used in the previous month or quarter. Some utilities offer prepayment metering (also known as payment metering) as an alternative to post-payment programs or to customers who wish to budget their electricity spending more closely. In a few countries, notably the United Kingdom, consumers who have not paid their bills are required to have prepayment metering [5]. This service requires the consumer to make advance payment (prepayment) before electricity can be used. If the available credit is exhausted, then

FIGURE 13.2 Example of a solid-state smart meter. (© 2012 Trilliant. All rights reserved.)

the supply of electricity is cut off at the prepayment meter. In the United Kingdom, mechanical prepayment meters used to be common in rented accommodations, and included a coin slot to collect payment!. The disadvantages of these included the need for regular visits to remove cash and risk of theft of the cash in the meter. Modern electronic electricity meters, in conjunction with smart cards, have removed these disadvantages, and such meters are commonly used for consumers considered to be a credit risk. One type of prepayment system relies upon rechargeable tokens that can be loaded with the amount of money that the consumer has available. In South Africa, Sudan, and Northern Ireland, prepaid meters are recharged by entering a unique, encoded 20-digit number using a keypad. This makes the tokens, essentially a slip of paper, very low in cost to produce. Smart meters enable the provision of prepayment service without any tokens at all, such as via a "central wallet" approach, as shown in Figure 13.3. In the central wallet approach, smart meters with remote disconnect and reconnect functionality are integrated without the need to access the smart meter, use physical tokens, smart cards, or keys to transfer credit to the meter. This is achieved with all customer accounts held in a central back-end system, unlike the traditional local wallet approach in which payment information is stored on the meter. The approach also provides customers with multiple engagement and payment channels, price plans, and incentives by providing enhanced customer service through web portal and smart phone self-service. A central wallet approach is also easier to manage, allows for changes to be made to the account instantly, and is more tamper-resistant, as well as being less expensive to implement and operate [5].

13.2 EVOLUTION OF METER READING

Utilities realized the inefficiencies in manual meter reading and started deploying systems that could automatically read meters, known as automated meter reading (AMR) systems. Another reason for deploying AMR is to minimize the use of technologies that require visiting each meter and physically connecting a reading device, such as a handheld computer, to a local infrared or wired serial port on a periodic basis, or using dial-up telephony to interrogate the meters remotely. These meter readings in the handheld computer were then later downloaded to a data collection or billing system when the meter reader returned to the utility office. This still required the meter reader to walk to each meter. AMR systems typically use short-range radio frequency

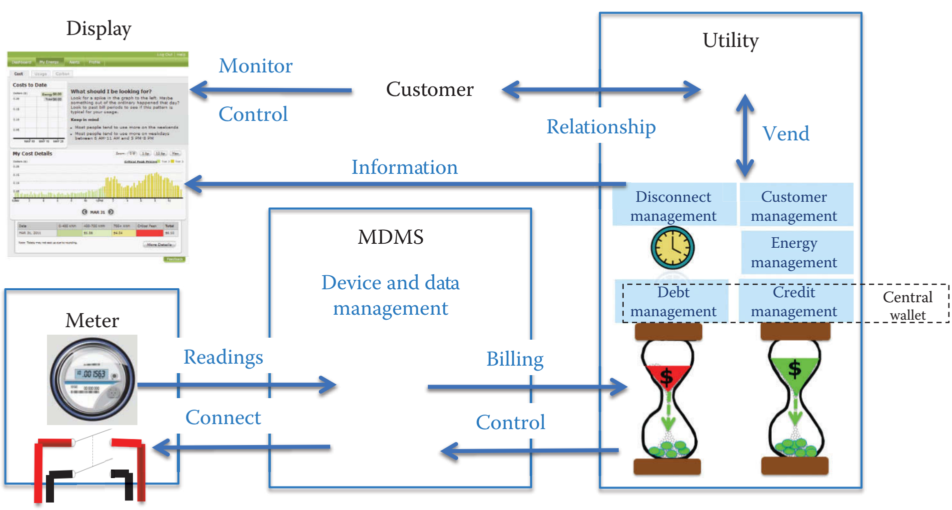

FIGURE 13.3 Data flows in the "central wallet" prepayment approach. (© 2012 eMeter, a Siemens business. All rights reserved.)

systems to communicate with the meters. This allows the meter reader to either "walk by" or "drive by" the meters rather than directly interrogate them. This approach allowed utilities to save on the cost of meter reading by increasing the speed of meter reading and avoiding issues with "hard to read" meters; i.e., either difficult for the meter reader to access the meter, or the meter reader was unable to enter the consumer premises due to locked gates, vicious dogs, and so forth. A single meter reader using a walk-by or drive-by system could "read" many more meters per route/day/shift. Despite the improved accuracy from the perspective of the meter reader and the savings in labor, there was still the cost of using the vehicle for "drive-by" meter reading, plus AMR offered no additional functionality; it simply replaced human meter readers. Drive-by meter systems are still in use today.

AMR evolved to include one-way fixed communications networks from the meter to a central data processing system without the need to "walk-by" or "drive-by" the meters. This provided utilities with significant operational savings in reading meters and integrating the meter readings directly into their billing system. It eliminated the vehicles and enabled the reading of meters every day. It also added alerts, such as theft alerts and outage alarms. As technology evolved and other requirements were added to metering communications, and functionality became prominent, two-way communications with the meters allowed the utilities to send messages and control commands to the meters, such as to remotely connect or disconnect service to a consumer. The advanced capabilities of the meters and the communications system, and the integration of the meter data into the utility billing and customer information systems (CISs) ultimately became known as "AMI."

A prototypical AMI system is shown in Figure 13.4. Within the utility data center is the AMI headend system, a meter data management system, a utility billing and CIS portal, a web portal for consumer engagement, and interfaces to third party systems (such as OpenADE), often connected through an integration platform. A smart meter communications network connects the headend to the smart meters and other AMI system equipment. The communications link to the customer is via a "home area network" (HAN)—an interface that is usually provided as part of the smart meter, which also supports utility, consumer, and third-party applications. The meter HAN interface is used to communicate with consumer thermostats, appliances, and other devices for consumer demand side

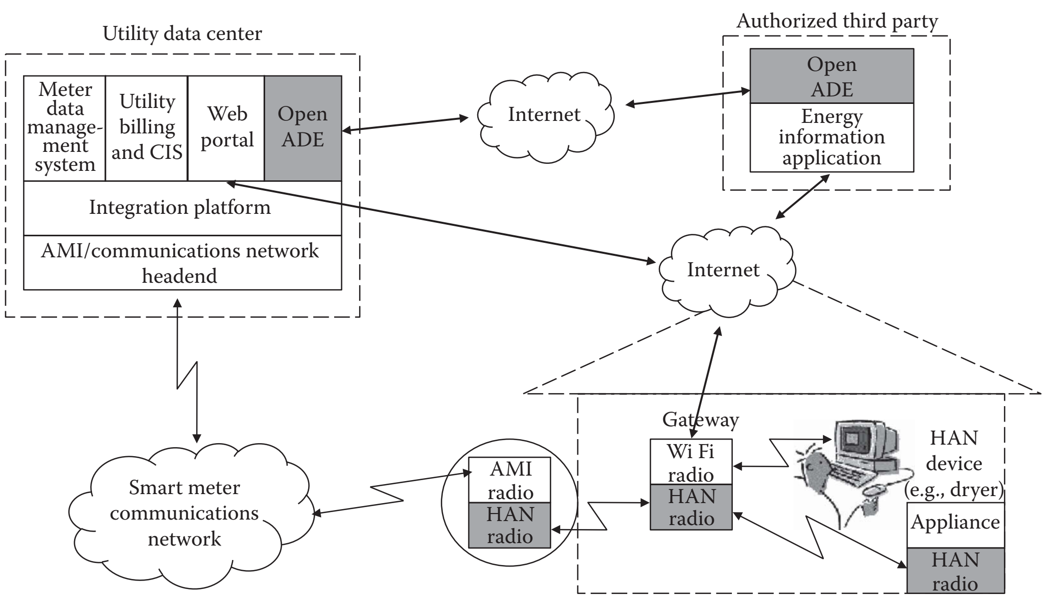

FIGURE 13.4 AMI functional components. (© 2012 eMeter, a Siemens business. All rights reserved.)

management/demand response, and to support communications to electric vehicle (EV) charging stations and other distributed energy resources.

The AMI network headend system monitors, controls, and manages the communications network hardware, firmware, software, and protocols for the exchange of data on the AMI network, including the provisioning[2] of the smart meters, sensors, and HAN devices, among others, on that network. The headend system, thus, enables the utility personnel to remotely monitor and maintain the health of the AMI network.

The MDMS is an application that is used by utilities to manage their meter population. This software application has several functions in the utility enterprise, but its core functions include data VEE. This is particularly useful where there is a large smart meter (and other AMI network device) population collecting data for billing and operational purposes. In some architectures, the MDMS serves as the enterprise application interface with the AMI network management system ("headend") in order to alleviate potential congestion issues. However, there are architectures where the headend system has MDMS functionality and is integrated with other enterprise systems and performs that role. The MDMS may also be the system of record for metering data—that is, the trusted source—for all other applications and systems. The CIS, an enterprise application that typically stores a broad set of consumer, location, service, asset, and financial information, is often used to produce the bill that is sent to the customer. This is accomplished by marrying the disparate pieces of validated information for the service locations from other systems, such as the MDMS, and combining them according to the necessary business rules within a single application.

As of late 2015, smart meter deployments were expected to reach 70 million devices in the United States, with more than 30 electric companies having fully deployed smart meters for their consumers; and then an estimated increase to 90 million devices by 2020 [6]. However, the penetration varies significantly by state. Table 13.1 lists the top 10 states by number of installed meters as of the end of 2015 [7], and for comparison purposes the values from 2011.

13.3 AMI DRIVERS AND BENEFITS

AMI is considered to be one of the technological underpinnings of a smart grid, and deploying smart meters is often the first step towards implementing a smart grid. The U.S. smart meter and AMI initiatives are a result of state initiatives (e.g., California and Texas), utility proactive steps

TABLE 13.1
Top Ten Smart Meter Deployments in the United States

State	2015	2011	State
California	12,649,000	10,017,553	California
Texas	8,854,100	4,934,632	Texas
Florida	6,153,200	2,096,453	Georgia
Georgia	4,068,700	1,638,500	Florida
Pennsylvania	3,690,200	1,403,000	Pennsylvania
Michigan	3,445,400	1,215,000	Arizona
Illinois	2,331,400	1,205,066	Alabama
Arizona	2,291,000	832,643	Oregon
Alabama	1,872,700	750,000	Nevada
Maryland	1,785,400	492,000	Idaho

[2] Provisioning is the process used to identify and validate devices on a network.

(e.g., Oregon, Idaho, Florida, Georgia, and Alabama), the Energy Independence and Security Act (EISA) [8], and Smart Grid Investment Grants [9] (e.g., District of Columbia and Nevada).

There has been much discussion recently regarding the advantages and disadvantages of smart meters. The main business drivers of AMI include reduction in costs related to manual meter reading and the manual connection and disconnection of consumers. Other benefits include the following:

- More precise outage detection data that can be integrated with outage management systems (OMS).
- Tamper and theft detection, and outage notification capabilities in utility revenue recovery.
- More accurate meter reads and improved billing, and a reduction in consumer complaints.
- A key facilitator for demand management programs: Consumers can receive price signals and more frequent and timely energy usage information so that they are aware of how much their energy use is costing and the value of conservation or efficiency investments.
- More consumer and asset information for the utility: The meter data that continuously stream in to the utility provide valuable information that can be used to make real-time operational decisions, as well as long-term decisions about planning and maintenance.
- The AMI communications link can also be used for other services to the consumer, such as Internet access.
- Real-time access to consumption and price data via in-home displays that connect to the smart meter HAN interface has been shown to reduce total consumption by an average of 8.7% [10].
- Some utilities are also trying to leverage the AMI communications system for other utility applications, such as communications for distribution automation, intelligent street lighting, and other safety-related purposes.
- Improvement in distribution system operations through collection and analysis of power quality information.
- AMI can enable renewables integration and net metering programs.
- The precise and real-time measurement of energy exchanged (consumed and generated) by customers at the grid-edge, which will allow the implementation of localized, marginal customer tariff structures that reflect the cost of consumption and generation specific to that point in the grid (discussed in more detail in the distributed energy markets chapter and the transactive energy chapter of this book).

Some potential, but so far unproven, disadvantages of AMI include the following:

- Loss of privacy since more detailed consumer energy usage information is available to the utility.
- Greater potential for monitoring or interception of consumer data by unauthorized third parties.
- Increased security risks from network or remote access to utility assets.

The business case for smart meters and AMI will continually evolve and be under intense scrutiny for years to come. An interesting use case for real-time AMI is that of the requirements for the United Kingdom in 2014, where a newly formulated data communications company (DCC) [11] for all utilities collected 15-min interval data for all residential and small business consumers. This is similar to the centralized meter data systems in Ontario (Canada) and Texas, which is shown in Figure 13.5.

13.4 AMI PROTOCOLS, STANDARDS, AND INITIATIVES

13.4.1 ANSI C12 Standards

Given the number of meter manufacturers and the utilities' desire not to be "locked in" or single-sourced to a specific meter manufacturer, a standardized configuration and interface protocol and

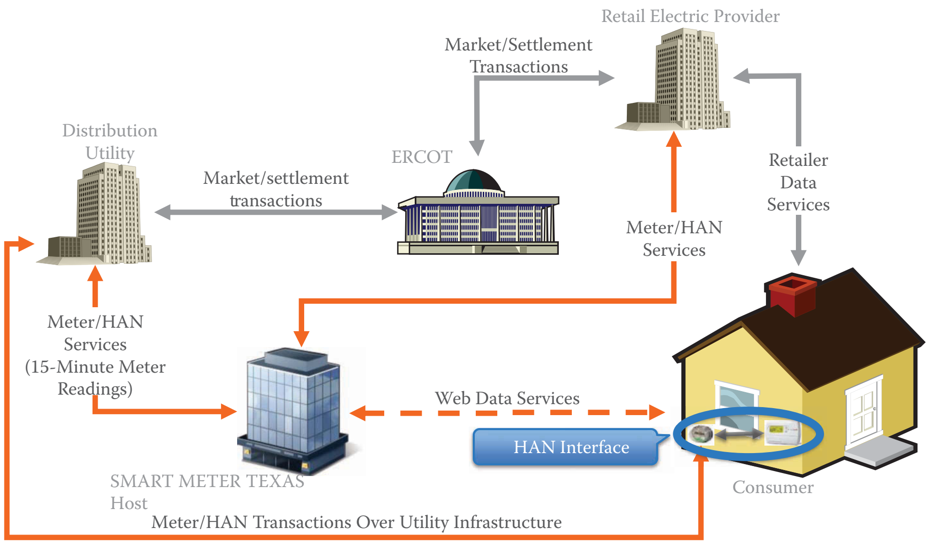

FIGURE 13.5 Smart Meter Texas portal. (© 2012 eMeter, a Siemens business. All rights reserved.)

data description standard were developed for meters. As a collection of four standards, ANSI C.12.18, C12.21, C12.22, and C.12.19 were formulated to standardize the configuration, data gathering, and link layer communication to the meter. Many utilities require metering products and systems to conform to these standards. For the data description, ANSI C12.19 is the American National Standard for Utility Industry End Device Data Tables and was first published in 1997. Since revised, this standard defines a set of flexible data structures for use when communicating metering information or interacting with the meter (sending commands). In particular, this standard defines a table-based data structure for utility application data to be passed between an electricity meter and another device, such as a handheld device carried by a meter reader or a meter communication module, which is part of an AMR system, or communicated over an AMI network. The standard organizes metering device data and operating criteria into standard tables that contain data common across all manufacturers, and allows for the additional use of manufacturer tables, which contain specific data to each manufacturer.

13.4.2 IEC 62056 DLMS/COSEM Standard

IEC 62056 (DLMS/COSEM)—Device Language Message Specification (DLMS)/Companion Specification for Energy Metering (COSEM)—is a suite of standards that specifies object models to represent the functionality of a meter, an identification system for all metering data, a messaging method to communicate with the model, and a transport method to carry information between the metering equipment and the data collection system. Technologies based on this suite of standards are most often found outside of the Americas, where the ANSI C12 standards are the foundation for the technologies.

13.4.3 Smart Energy Profile (SEP)

The ZigBee Alliance's Smart Energy Profile (SEP) is intended as a choice for bridging AMI and smart metering to HANs and was in use in Texas, Nevada, and Oklahoma—and in pilots in California—as of the end of 2011. It has since been deployed internationally, most notably in the UK. The second version of SEP (SEP2.0) has been adopted by the IEEE as IEEE 2030.5 and now supports other networking technologies in addition to ZigBee. SEP2.0 is also included in the US Department of Commerce National Institute of Standards and Technology (NIST) Framework and Roadmap.

13.4.4 IEC 61968/61970 CIM

The IEC Common Information Model (CIM) for power systems is defined and published by the Technical Committee 57 of the IEC. The CIM encompasses a semantic model to describe power system components within a software application or for sharing power system models, and is used as an extension for other business functions, such as asset tracking, meter reading, and control, as well as the data exchange needs of parties participating in electricity markets. The complete unified modeling language model provides consumable models through defined schemas, while the companion printed standards define the details for integration with other management models. The IEC CIM is also included in the NIST Smart Grid Framework and Roadmap [12].

In particular, the IEC 61968 series standards have been devised to facilitate inter-application integration for various software applications supporting the management of utility electrical distribution networks. IEC 61968 supports the integration of disparate applications (legacy and new) and is intended to support applications that are event-driven. It supports loosely coupled applications that have different run-time environments with heterogeneity in languages, operating systems, protocols, and management tools. Specifically, Part 9 of the IEC 61968 standard specifies the information content of a set of message types that can be used to support many of the business functions related to meter reading and control [13].

13.4.5 NERC CIP

The North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection (CIP) is the standard suite that covers system categorization, management controls, electronic security perimeters, physical security, incident reporting, response planning, recovery plans, configuration change management, vulnerability assessments, and information protection for cybersecurity as applied to the bulk power system.[3]

13.4.6 NIST

The NIST is developing key technical standards for Smart Grid and Cyber-Physical Systems (CPS). With respect to metering, ANSI C12 and IEC 61968 standards are part of their Framework and Roadmap for Smart Grid Interoperability Standards first released in 2009 and now available in its third revision [12]. NIST has also developed a Framework for CPS published in 2016, intended in part to coalesce prevailing thought leadership and pragmatic aspects of CPS [14].

13.5 AMI REQUIREMENTS

Smart meters and AMI aggregate data collected from the meters and provide the means to communicate data to the utility and the consumer. Within this context there are several requirements that must be supported by the smart meter and AMI.

13.5.1 Meter Data Reads

The systems must maintain a default schedule for uploading meter reads, and also to respond to on-demand authorized reads within a defined time frame.

[3] The bulk power system is defined as all transmission grid elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy. See http://www.nerc.com/pa/RAPA/BES%20DL/BES%20Definition%20Approved%20by%20FERC%203-20-14.pdf.

13.5.2 Internal Device Management

Each device must have the ability to perform internal self-monitoring and trigger alarms and/or AMI notifications based on configurable thresholds. The devices must also maintain an onboard history of log information that can be delivered to all authorized systems on demand.

13.5.3 Remote Configuration

Each device must support configuration for internal settings and processes remotely without requiring direct physical access to the devices. AMI meters should receive and process meter configuration files over the AMI network.

13.5.4 Firmware Upgrades

Each device must support the ability to handle remote firmware upgrades delivered from all authorized systems. The upgrade process should minimally impact the operation of the AMI system.

13.5.5 Time Synchronization

Each device must be required to maintain time synchronization with the AMI headend system by utilizing a time source, such as an NTP server. Systems may include global positioning system capabilities in each device.

13.5.6 Local Connectivity

The smart meter must allow local, direct physical connectivity from all authorized devices, which includes support for local handheld devices using, for example, wired or optical serial communications that are used by utility personnel in the event of an AMI network connection failure.

13.5.7 Testing and Diagnostics

Each device must perform self-diagnostic processing to identify both actual and potential issues and report these to the system in either real time, or on demand, depending on the criticality of the event.

13.5.8 Other Functions

The AMI system must interface with associated utility back-office business functions and event-driven processes that include the following:

- Service/load control
- Outage detection
- Service switching (connect/disconnect)
- Service limiting
- Tamper detection

13.5.9 Supporting the Consumer Interface

AMI will need to support DR functionality by responding to authenticated events and enabling delivery to HAN devices within the consumer premises. These will include the scheduling, cancelation, and rescheduling of demand management events. AMI must also be able to support EV billing. In the future, the concept of "point-of-use" metering may emerge where energy charges or credits would be managed and tracked across distribution networks for mobile devices, such as EVs (representing a load and a source). Above a calculable penetration level on a feeder or substation, this mobile load and source requires reexamining existing protection and control schemes that are commonly designed for one-way power flow in the distribution system. In the future, when utilities have dynamic localized rates and full support for two-way power flow in the distribution system, a vehicle owner could potentially participate in the wholesale and retail energy markets by finding low-cost points and times to charge and high-cost points and times to inject energy into the system in order to gain the most for their on-board energy. They could also connect and provide ancillary services, such as Volt/VAr or frequency support.

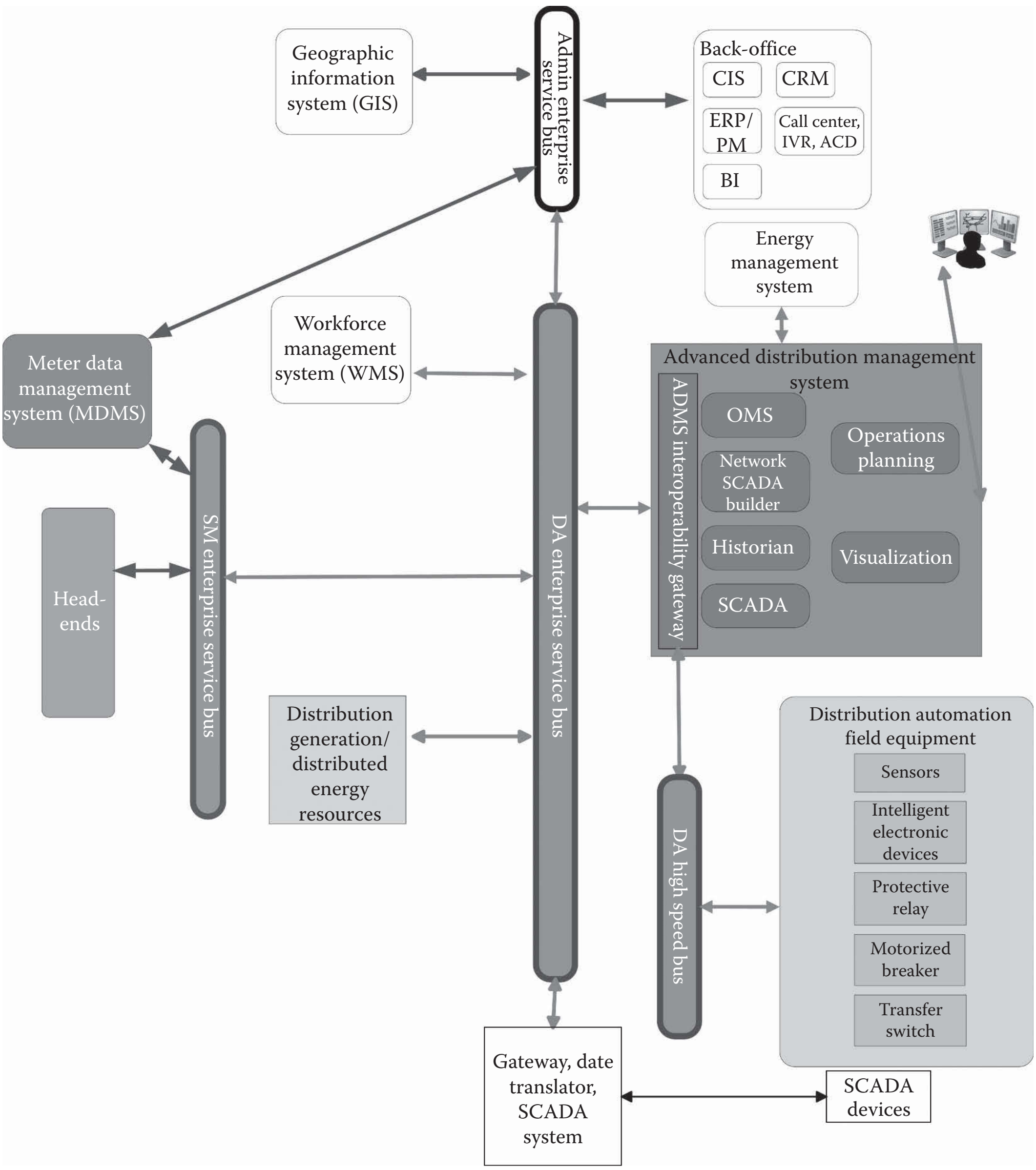

FIGURE 13.6 Typical Utility Enterprise Service Bus (ESB) architecture. (© 2016 EnerNex. All rights reserved.)

13.5.10 Integration with Utility Enterprise Applications

AMI must be able to integrate with other smart grid OT and IT enterprise applications in order to realize the full benefit of exchanging data between the AMI system, an OMS, and a distribution management system, for example, in addition to meter-related applications of billing and the CIS. One method of achieving this is through an "integration platform" using an architecture based on what is known as an enterprise service bus (ESB), where each enterprise application is loosely integrated, and provides "services" to the other applications using a data exchange model, such as publish/subscribe. Standards that facilitate this architecture and system integration include those discussed in section 13.4.4. In this application, the ESB serves as the information "highway" for both data and commands, and it manages and prioritizes the traffic between the enterprise applications. A typical ESB architecture for a utility application is shown in Figure 13.6.

13.6 AMI SECURITY

AMI security, similar to that applied across the utility enterprise, must take into consideration the costs of mitigating control techniques compared to the likelihood and risk scenarios of occurrence. While no security process, control, or solution can provide a 100% guarantee, utilities must keep in mind that consumption data read from the meters equates to the cash flow of the utility, and therefore utilities must provision for security mechanisms on par with any business financial transaction (e.g., the use of SSL, PKI, etc.) From this, methods to best identify security anomalies quickly, react accordingly, and segment where feasible, are all controls needed to lessen the impact, outages, and risks.

A complete development of AMI security requirements has been published by the UCA International Users Group AMI Security team and is a good starting place for an even deeper dive into this subject [15].

13.6.1 Requirements

AMI security requirements have been developed by government organizations, such as the US Department of Homeland Security, Department of Energy, NIST, and NERC, as well as industry groups, such as NEMA (National Electrical Manufacturers Association) and OpenSG AMI-SEC (Open Smart Grid Security Working Group). The AMI security requirements address the following cybersecurity-related domains:

- *Time synchronization:* Time synchronization is a critical function to nearly every component of the smart grid system. Accurate time synchronization across multiple systems is required to ensure proper record-keeping for control, measurement, and security system events. Those measurements then contribute to accurate billing. Further more, accurate time synchronization is essential to the proper implementation of certain cryptographic protocols and authentication schemes.
- *Logging and auditing:* These are common system functions that are required by many components of the smart grid system. There are three possibilities for a shared logging system. The first option is a centralized logging system, where all log records are transmitted to a central system on an immediate or "as soon as possible" basis. The second option is a decentralized logging system, where each system maintains logs separately, but the smart grid system provides an interface for querying remote system logs from a centralized location. The third option is a hybrid system, which allows each system to maintain its own logs of record, but those logs are transmitted on some periodic interval to a centralized logging service. The most appropriate option is ultimately based on the goals of the system. The ANSI C12 standard includes a secure logging function that can add an additional layer of security for the AMI system.

- *User management:* The process of managing users of the smart grid systems.
- *Role management:* The process of managing roles (or groups) that control access to various smart grid system functions. It includes, but is not limited to, the creation, modification, and deletion of roles, assigning users to roles, and determining the resources are available for each role.
- *Resource management:* The process of managing various resources, such as HTML or other pages or resources, in AMI communications equipment.
- *Authentication:* The process of proving that the requestor of an action is valid. A requestor may be a person, but also may be another system or service. This is typically accomplished through such mechanisms as passwords, token authentication, or certificates.
- *Authorization:* The process of proving that the validated requestor of an action is authorized to perform that action. A requestor may be a person, but may also be another system or service. This is typically accomplished through such mechanisms as role-based access control or directory group membership, and can include transaction level security.
- *Password management:* User passwords to the smart grid systems should be managed so that various complexity requirements can be met without having to redeploy any component. A password management process will provide the functionality to configure various complexity requirements for any or all users, and will provide functionality to reset or change passwords.
- *System account management:* System accounts that are used within the smart grid systems, such as username and password to connect to databases and certificate key stored passwords, should be configurable both at deployment and at any time during the lifetime of the smart grid system.
- *System and information integrity:* Smart grid systems exchange data within and outside of system boundaries, and may contain business-critical or confidential messages. It is highly important to protect the integrity of the data during transit.
- *System and information confidentiality:* Encryption technology is used to secure data while in motion or while at rest. Data in motion are considered particularly vulnerable, especially when passing from trusted systems to less trusted systems.
- *Cryptographic key management:* Cryptographic keys are used widely in smart grid systems, either symmetric encryption keys or public/private (asymmetric) key pairs of the certificates. The cryptographic keys typically have an expiration date and sometimes are mandated to be changed either at regular intervals or when there is any breach.
- *Firmware management:* Numerous smart grid components will contain firmware as an integral part of the component. How this firmware is managed represents a significant portion of the security related to the life cycle of hardware systems. There is a standard that defines requirements for firmware management published by NEMA for smart meters [16].

13.6.2 Threats

AMI systems are implemented over a wide variety of infrastructures. Designs include both wired and wireless communications, as well as a mix of public and private networks. The applications that run through these infrastructures are capable of implementing risk-appropriate security strategies in order to mitigate the impact of a range of threats. Security for information exchange between applications is supported by both the devices that either receive or provide the information, as well as any middleware. This is essential because the AMI as a whole may be exposed to several types of threats:

- Compromise of control
- Misuse of identity or authority to gain inappropriate depth of access (system intrusion)
- Exposure of confidential or sensitive information
- Denial of service or access
- Breach of system, import of errors (integrity)

- Unauthorized use (authorization)
- Unidentified use/misuse (authentication)
- Manipulation and destruction of records (auditability/proof)
- Delayed/misdirected/lost messages (reliability)
- System component cyber/physical damage, or loss

Because of the vast number of devices and technologies used in AMI deployments, layered security architectures are designed and implemented. Such architectures allow for a blending of different cost-effective technologies with suitable risk mitigation techniques, including using compensating controls when some system components are not inherently secured.

13.6.3 Applying Specifications

There are three predominant integration environments to consider for security purposes:

1. Utility mission critical operational systems and data access/exchange
2. Utility internal enterprise front and back-office applications and data/exchange
3. Utility external application and data access/exchange

Security measures are implemented in AMI implementations to support the specific needs of these environments.

13.7 OPPOSITION TO SMART METERS AND AMI

The deployment of smart meters and AMI is often predicated on any number of direct benefits to the utility, such as operational flexibility, revenue assurance, enhanced power quality, or minimizing personnel cost. These are often difficult to quantify on an individual basis for the end consumers; that is, will each consumer see a net benefit (reduced charge) on their monthly bill? There are already “socialized” costs built into the rates, such as costs for supplying reactive power and energy, voltage support, outage management, and the like, that can be challenging to articulate to the end consumer in an understandable fashion. Whenever the utility presents a new technology, especially one that touches every consumer, there is natural resistance to that change. Some of the oppositions to smart meters and AMI are related to:

- *Cost:* Will the monthly bill be higher, and if so, why?
- *Security:* Will the network be hacked and my service manipulated?
- *Privacy:* Will my information be stolen and used against me?
- *Safety:* Will the smart meter be as robust to overvoltage/overcurrent and other electrical conditions?
- *Health:* Will there be any impact from the wireless radio communications?

Cost: The relationship between meter and the monthly bill is composed of many parts. There is the cost of generation, the cost of the transmission and distribution networks, the amortized cost of the smart meter and AMI program itself, and the cost of the energy consumed. Often, the smart meter is more accurate (typically 0.5% versus 2% error) than the electromechanical meter it replaced, and it is capable of measuring lower levels of consumption, down to the tens of milliamperes versus amperes. Those two factors may contribute to a higher meter reading for the same load and, hence, a higher monthly bill. However, it is not always the case that the new smart meters increase other charges that make up the monthly bill, and consumers are encouraged to fully educate themselves on the business case and rates for their utility.

Security and privacy: The fear that the system will be compromised in some fashion dictates that the utility approaches security for the smart meters and AMI system using what is known as "layered security." From the chips used in the meters themselves up to the software applications at the utility, every component is individually and collectively secured. Most utilities program their smart meters to record the consumption (kWh) in what is called "intervals" of 60 min, 30 min, or 15 min. They may also choose to record what is known as a "daily snapshot" reading. Though the intervals are on the order of minutes, few AMI systems communicate this information at the same time interval today (though this may change in the future). The concern from the consumer that this information may let someone know which appliance is being used is valid as it is possible to examine the interval data and compare to known appliance signatures. Similarly, energy usage could be used to identify when a consumer premise is empty. However, this is not considered a catastrophic loss of privacy as one could use other known consumer information to arrive at the same conclusion. For a consumer's residence, if one knows it is a household of a certain size with two working adults and a few children, the load is expected to be higher in the weekday morning, say between 6 AM and 8 AM, with the load spikes being the refrigerator, water heater, the heating/air conditioning, and the electric stove. Then, there will be periodic spikes for the heating/air conditioning and refrigerator throughout the day until about 4–6 PM, when perhaps the electric stove, clothes washer, dishwasher, television, and clothes dryer are used. Once the household settles in for the night, the consumption will drop again, unless they are charging their EV overnight, and again with periodic spikes for the heating/air conditioning and refrigerator. For a commercial consumer, if one knows that the business hours are 8 AM–8 PM Monday through Friday, 8 AM–10 PM Saturday, and closed Sunday, it is not difficult, with knowledge of the type of business, to discern what might be the load makeup and when the building is occupied. In addition, for both examples, one could simply sit in a vehicle on the public street and observe the consumer habits and occupancy patterns. While access to energy usage data may be one of the concerns, if the consumer is connected to a HAN through the AMI system, there are more critical concerns with privacy of data regarding access to individual appliances if they are part of a DR control program, and even more so if the appliances can be accessed by an unauthorized user from the AMI system and remotely controlled. Integrated security, data privacy, and secured access are, therefore, crucial for smart meters and AMI networks.

Safety: Solid-state smart meters have different failure modes than electromechanical or hybrid meters. Smart meters may also have a service connect/disconnect switch and associated circuitry in addition to the metrology, the two-way AMI communication network, and any HAN communication interface. Meters typically have overvoltage protection built in to their circuitry, but not overcurrent protection. The consumer is protected from overcurrent events by their electrical distribution panel. There are some utility system conditions (such as lightning) or consumer side conditions (such as sustained high load) that may compromise the protective elements of the meter, though there is a collection of standards that were developed for the design and withstand requirements for the meters under those conditions. It is rare that meters fail in an unsafe condition, and the meter manufacturers are diligent to design the meters against this type of failure. The safety standards committees are composed of utility, manufacturer, consumer, and other stakeholders, who develop and publish standards with safety as the primary goal.

Health: Much has been discussed and researched concerning the potential health effects of smart meter communications. To date, there has been no peer-reviewed, scientific study that has unequivocally quantified the negative health effects of AMI communications. This does not mean that individuals are insensitive to AMI radio emissions; however, society-wide negative health effects are not proven. In addition, the radio emissions from the AMI meters are just one source in the crowded airwaves—there are radio waves, broadcast television, shortwave radios (police, fire, emergency, utility), cellular phones, and wireless Internet, to name a few, and it is scientifically doubtful that smart meters and AMI networks are the sole source of significant health issues.

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14 Convergence of Technologies and IT/OT Integration

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"Convergence" and "integration" are defined as the act or approach of making two or more independently designed things (e.g., systems, applications, databases, or processes) work together to achieve a common business goal. Today's typical utility IT systems took several years to install; they were expensive to deploy and are costly to maintain. They are often too complicated and difficult to use. These systems were built within the enterprise business operations silos, and were built for very specific purposes. These systems largely ignored the informational needs of the surrounding functional areas and were not designed to easily integrate with other systems. Within the last several years, as utilities look to implement new and improved business processes, they expect new systems to provide a revolutionary application platform that includes open-source, standard-based solutions. With smart grid, the new systems are ideally expected to be easy to use, highly adaptable, and responsive to the often changing needs. They are expected to have significantly lower total cost of ownership than the legacy systems. These systems are built to integrate with existing or future applications. As utilities are looking into these new systems, the focus should be on flexibility in configuration rather than on coding of the new systems. Contextually, if one considers how the utility does business, the idea of integration is establishing enterprise transactions that flow through the organization, crossing over from business area to business area. As utility companies continue to evolve with the types of services and delivery of the services to their customers, the need for defining and understanding enterprise transactions exponentially increases. In order to fully leverage the ability that a smart grid provides, the organization needs to fully understand its data, how the data transverse through the organization, and what the data mean at different points during their life, thus defining the enterprise transactions.

Within the utility enterprise, the majority of integration activity can be classified as either data or application integration, but data and application integration overlap. Bringing together data from two independently designed databases to create a third common database (physical or virtual) is an example of data integration. Creating a composite system by leveraging the functionality of two independently designed applications is an example of application integration. A common requirement is to ensure that two or more applications contain consistent data such that users interacting with these applications will see a single, consistent state of critical business entities (such as customers or products). While the end result of this activity is that the applications involved share the same perspective (i.e., application integration), achieving this state involves synchronizing the data between them (data integration) (see Figure 14.1). One of the key issues faced in integration projects is identifying and locating the data to be integrated, and understanding which users or applications need access to the data, and how often and in what format. Often, one may find that the data needed for a particular integration application are not even captured in any source. In other cases, significant effort is needed in order to understand the semantic relationships between data sources and convey those to the system. Addressing these issues requires both a framework for managing the metadata across an enterprise and tools for bridging the semantic heterogeneity between sources, subjects that are discussed later in this chapter.

The business side of the utility is responsible for decision-making, energy planning, operations planning, resource and asset allocation, and support of any activities required to facilitate the tasks of the operations group, such as trading, fuel nomination, field crew dispatch, and customer service. Decision-making at the enterprise level usually involves (directly or indirectly) multiple departments within the utility; for example, sending a field crew to repair a transformer will involve field

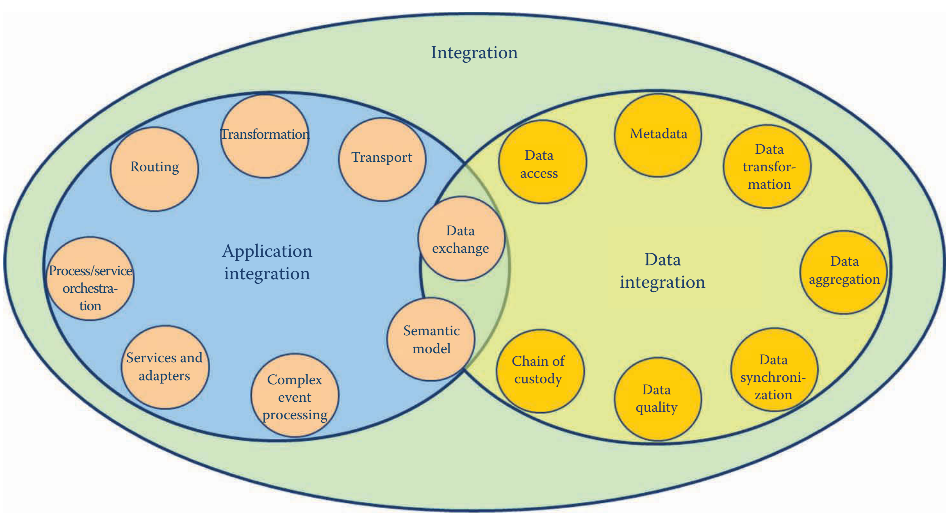

FIGURE 14.1 Conceptual integration of data and applications.

operations (personnel and vehicles), finance, human resources, inventory/warehouse, and customer service (if the maintenance task will affect end customers). The involvement of multiple departments in any process demands a seamless integration of systems and applications at the enterprise level that must be provided by a solid and consistent IT infrastructure. IT plays a major role in the success of effective decision-making in the utility. Data and application integration, business intelligence, hardware capabilities to run complex software and display mapping features, workflow coordination, and reporting are some of the elements that IT facilitates for the business groups for efficient operation.

The operations side of the utility is responsible for execution, monitoring, and control of the electric system, making sure the grid is operating within the allowed ranges of reliability, quality, and cost set by the regulations and parameters of the corresponding agencies (i.e., in the United States, NERC, Public Utility Commission, and FERC). Utility operations groups have control over the assets and infrastructure that are part of the electric system: power generation units, transmission grids, substations, distribution networks, feeders, meters, and so forth. Control and monitoring are executed via control and protection devices, such as relays, circuit breakers, switches, voltage regulators, capacitor controls, and feeder protection. Owing to the nature and properties of the electric power system, the decisions that the operations group make are aimed at (in priority order):

1. *Protecting the network*—Prevent a failure that can damage or destroy expensive equipment and infrastructure.
2. *Keeping the "lights on"*—Prevent outages and blackouts by ensuring that electric demand is met.
3. *Reducing cost of operation*—Ensure that demand is met in the most economical way.

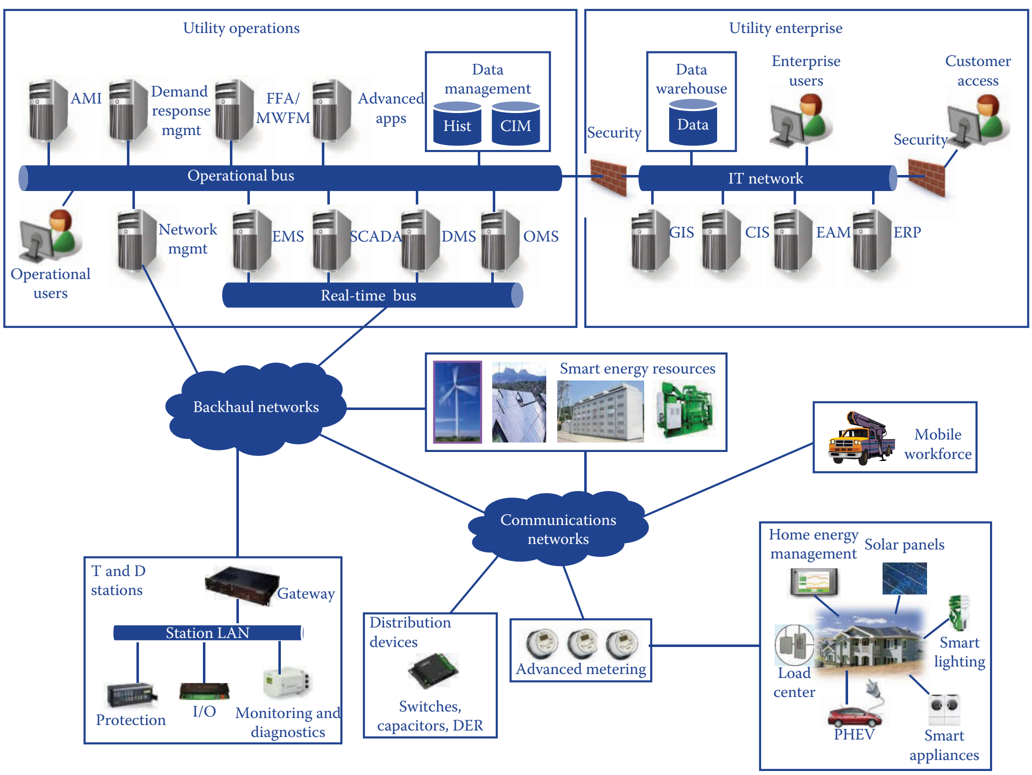

FIGURE 14.2 Dichotomy of utility operations and IT systems. (© 2016 GE Grid Solutions. All rights reserved.)

Historically, IT and OT systems reside in different parts of the organization and are implemented on separate data and communications infrastructures with limited connectivity and data exchange between the two systems (Figure 14.2). There are two current trends in utilities. One is the convergence of OT applications and processes, and the other is the integration of the operations applications with "enterprise" or "back-office" IT applications. Some major challenges emerge in this context. The first set of challenges relates to the adoption and integration of these new technologies, many of which are unproven in the utility industry. The second set of challenges relates to the complexity of applying evolving industry standards, protocols, and operational guidelines in an industry that has high requirements for reliability, security, and control. Another set of challenges relates to the existing gap between technical operations and business decision-making within the utility's organization.

Utilities should consider the synergies of smart grid technology deployment and sharing of infrastructure costs when planning smart grid programs. For accomplishing this and for obtaining regulatory approval, a good first step is to develop a well-thought out smart grid roadmap that articulates where and how industry standards will be employed to enable each component within the system of systems to work together in an optimal fashion. This will minimize the risk of future stranded investments resulting from tactical implementations of technologies that only gained isolated benefits. Therefore, each new component will fit within a longer-term strategic solution, yielding important additional benefits that will be realized when data is exchanged among the applications and processes.

14.1 SYNERGIES AND CHALLENGES

Today, while IT systems are well established and integrated in the utility enterprise, many of the utility operations centers for real-time grid management have a wide variety of software systems that are siloed according to specific applications, which result in islands of information. Compounding this problem, many of the software systems in the operations domain at utilities are often from different vendors, each historically with separate, independent data models, user interfaces, and incompatible and nonstandard security measures. As technologies and business applications continue to advance, tremendous opportunities exist to share data and information among utility business processes. The convergence of technologies in a utility maximizes the synergies of an integrated architecture and shared information with numerous cost and operational benefits, such as reducing duplicate hardware and databases, and the improved exchange of information and process visibility. These new applications and business processes will require a holistic solution to achieve seamless and secure interoperability of new and existing information sources in order to preserve the system quality attributes (performance, scalability, availability, security, etc.) that are mandatory to manage and control the electric power grid. While standard services are imperative for vendors to agree on the semantics behind interoperability of respective systems, the implementation and underlying security of these services in an operation-centric environment require an appropriate software infrastructure and governing framework.

It is clearly apparent that synergies in sharing and exchanging operating data can significantly enhance the integration of applications and drive toward a common platform of technologies. To date, sharing of data among applications has been mostly implemented as "point-to-point" solutions; software applications are still independent systems; and complexity of integration increases drastically as more systems are integrated. As smart grid moves forward, there will be a new generation of highly integrated applications supported by enterprise platforms and integration frameworks. There will always be some need to integrate new systems with legacy systems using some form of standardized integration adapters and services in order to reduce integration efforts.

The lines between what are seen as traditional operational or real-time applications, such as SCADA, DMS, and OMS, will start to blur as the applications merge into a single, highly integrated enterprise solution. Similarly, non-operational and what are currently considered "back-office" systems will be able to easily integrate with utility operational systems so that data can be freely exchanged across all utility operational and business applications. Much synergy in the sharing of data and an increase in the functionality and performance of applications can be achieved with the use of common standard data models and an integration framework. This enterprise level of integration will have a tremendous impact in the way a utility is operated and managed in the future—the following benefits are the ultimate nirvana of a smart grid realization:

Reduced operating expenses: Integration of operational and business systems allows utilities to benefit from reduced operating expenses through optimal process design, proactive maintenance programs avoiding emergency asset costs, improved technology investment programs, reduced theft, and significant gains in employee productivity.

Reduced working capital expenses: Integration of systems can assist utilities to lower working capital through improved inventory management targeting end-of-life components, slowed peak demand growth, support for distributed generation, and improved performance of existing assets.

Increased reliability and operating revenue: Through integration of systems, utilities can increase operating revenue through better customer experience, improved forecasting on asset utilization, increased capacity, and minimizing unplanned network downtime/blackouts.

Integrated and consistent vision fosters teamwork: Integrated solutions allow management, operational, planning, and backroom operations staff to truly operate as a team, with each having access to the same pool of information. This provides visibility of the goals of the entire business and how well they are performing at any given time. Enterprise data are available to the key business users with minimum human intervention. The business is provided with a complete and current view of the network and company assets with easy access to all functions and data. This allows informed real-time decision-making alongside strategic planning and network optimization. A common data model serving an integrated application suite provides improved data maintenance and integrity of data. This has direct productivity benefits for the business support system staff.

Fulfilling customer expectations: Customers demand a reliable and consistent high-quality service. An integrated solution supports and facilitates these expectations, which can be maintained even during severe storm events. Customers affected by supply failures are less upset when provided with substantive information relating to the fault—especially its likely duration. Integrated systems can help ensure that accurate information flows quickly between modules. Integration of OT applications, such as Volt/VAr control, can assist utilities with improving the quality of supply delivered to customers as well as improving network performance and reduced losses.

Regulatory performance: A fully integrated system is key to monitoring exposure to guaranteed standard payments by monitoring the progress of all network incidents and their potential impact on guaranteed standard payments to customers. The systems must be able to provide an accurate and auditable means of measurement, which can only be achieved through provision of data from a range of systems. In addition, it is becoming increasingly important for utilities to track performance against both a specific property and an individual. Systems need to be able to collect and report against such data.

Changes to business structure: Systems should be designed to manage change in business structure and accommodate mergers, acquisitions, organic growth, and separations. By implementing flexible, productized, and open systems, utilities can position themselves for the organizational turmoil of the utilities marketplace. For example, by implementing a DMS that can accommodate numerous legacy SCADA protocols, a newly combined business can continue to operate legacy SCADA systems without any impact on the control/operational user interface.

Media attention: With systems becoming strained to breaking point, high-profile failures are drawing increasing media and public attention. Through better decision support tools making use of increasingly voluminous and better quality data, utilities are better placed to avoid unwanted media attention through controlled management of both planned and unplanned outages.

The challenges of having consistent data flowing among systems are many and begin with the way systems are procured. Few companies define an effective enterprise-wide architecture framework before plunging into product selections. Ironically, the least of the costs is usually the actual purchase price of the product. A poorly designed or ad hoc architecture is a hidden liability that substantially increases overall costs with each application system that is procured. Vendors are driven by the procurement process to meet user requirements at lowest cost. Each of the procured systems will have its own unique mixture of platform technologies, databases, communications systems, data formats, and application interfaces. As a result, the same information is stored and maintained on many separate systems throughout the utility's enterprise. This results in integration anarchy, which is a chaos of duplicated logic, duplicated data, duplicated effort, newly acquired integration difficulties, lack of ability to easily create new application functionality from services, and lack of ability to support business processes with applications. This integration anarchy will, therefore, result in higher costs and an inflexible system of systems. True integration is achieved by systematically managing information as an enterprise asset. Challenges to this include:

Complexity of installation: Both the business and operations groups will face significant challenges in terms of infrastructure, communications, business processes, and coordination. Integrating the entire suite of business systems is a complex problem that requires open, yet secure, applications that are productized and flexible to global customer requirements. The foundation of an intelligent grid must be an open, systems-based comprehensive reference architecture that can integrate intelligent equipment and data communications networks into an industry-wide distributed computing system. There is also the need to integrate and manage large quantities of new types of assets/agents and make them "operational ready," taking into consideration all the complexities of data in near real time that will be available to the operations and business groups within the utility.

Data and application integration: Data and application integration are key for implementing advanced technologies and solutions in the smart utility environment. With the multiplicity of applications involved, the same asset may have different identifiers in each of the applications. For example, a circuit breaker represented in a SCADA system may not have the same identifiers in an asset management system. An integration framework and data model are required for successful integration.

Adoption of standards: Although there has been a recent move toward standardization of technologies, protocols, and architectures, adoption of such standards is a complex undertaking as these standards, particularly data standards, are continually being revised. Furthermore, interpretation can still differ. The smart grid has too many moving parts for any single vendor to offer a complete solution, so moving toward consistent interpretation of standards across product solutions and vendor implementations is important.

Performance and availability: The performance and availability requirements of real-time control systems have historically differed from back-office applications. With integration between the back-office applications and real-time control systems, consideration should be given to availability of data from back-office applications. In the longer term, with advances in hardware performance and availability, particularly with industry initiatives like Smart Grid Interoperability Panel's OpenFMB, such issues are likely to become less important.

Business process improvement: Business processes have often been at odds with technology, where technology is an enabler, while business process can often lag behind. A common example is the single network model concept that requires the master data repository to be maintained in time to ensure that the real-time network model always accurately reflects the actual construction in the field.

Volume and rate of data acquisition: With dramatic changes expected in communications networks and vastly increased volumes of data becoming available, the challenge will be to optimize usage of the data in assisting the system to make rapid and intelligent decisions.

Change management: Possibly the most important yet least addressed issue in integrating systems is managing organizational change. With safety at the core of every control room decision, utilities have historically been conservative in their approach to adopting new technologies and processes. The concept of change management describes a structured approach to transitions in individuals, teams, and organizations that moves the target from a current state to a desired state. Change management is a process for managing the people side of change.

14.2 STRATEGY AND FRAMEWORK

Utilities are seeking to create more flexible businesses and are weary of plans being hindered by their complex and brittle IT systems. Effectively using data wherever they needed throughout the enterprise requires an architecture and strategy to deal with how utilities collect, use, and act upon it. This data goal leads the utilities to an integration strategy that is based not only on standards but also on Enterprise Information Management (EIM) concepts to give the standards a proper context. Gartner states,

> Enterprise Information Management (EIM) is an organizational commitment to structure, secure and improve the accuracy and integrity of information assets, to solve semantic inconsistencies across all boundaries, and support the technical, operational and business objectives within the organization's enterprise architecture strategy.

The main show-stopper for large-scale integration is that data reside in tens of thousands of incompatible formats and cannot be systematically managed, integrated, or cleansed. Integration infrastructures suffer from data errors and ambiguities that arise with different interpretations about the intended meaning of information exchanged between applications, such as (1) confounding conflicts, where information appears to have the same meaning but does not; (2) scaling conflicts, where different reference systems measure the same value; and (3) naming conflicts, where naming schemes differ significantly.

With the smart grid, the types and also the volumes of data are growing dramatically. Traditional approaches and already strained legacy systems will simply not support information exchange requirements of utilities implementing advanced smart grid systems. EIM is of strategic importance because it establishes the framework of data and information as business enablers rather than inhibitors. EIM does this by resolving information to a single version of the truth, thereby reducing the risk of misinformation and increasing the efficiency of system and human interactions [1].

Many tools and industry standards exist to facilitate process integration and business intelligence. An EIM-based methodology embraces these tools and standards as a way to resolve the semantic differences that make data difficult to exchange, analyze, and understand. In an IT environment where utilities have dozens of representations of the same information, resolving these differences by creating common meaning across the enterprise is of utmost importance. This methodology manages business semantics as the foundation for supporting common understanding, transparent flow, and usage of information across an enterprise. It decouples applications so that data can be used throughout the enterprise as a true information asset. This not only insulates applications from changes to data sources and application interfaces but it also enables utilities to dramatically reduce redundant data sources, migrate systems much more easily, and free utilities from vendor lock-in.

There are numerous challenges with integrating systems, and as mentioned previously, they begin with the way systems are procured. Since vendors are driven by the procurement process to meet minimum user requirements at lowest cost, each of the procured systems has its own unique mixture of platform technologies, databases, communications systems, data formats, and application interfaces. While utilities prefer products that support industry standard interfaces, another high priority is for product vendors to supply application interfaces that remain relatively stable across product releases. In that fashion, once an application is interfaced to the utility's enterprise integration infrastructure, incorporation of future product upgrades will be easier, charges for custom interface development will be decreased, and the risk of errors will be reduced during installation and maintenance of each product release. Success will depend on how well EIM is defined before the procurement process begins, and then used as proposals are evaluated and selected, and then ultimately through implementation.

A well-designed EIM strategy requires business units and IT to look at enterprise data and information as assets in an effort to understand the nature of the information and how it is used and controlled. This effort includes addressing key issues around data generation, definition, quality, integrity, security, compliance, access, management, integration, and governance. These issues are interrelated and systemic in nature and require business units and IT to work together to understand and catalog information and data to build a robust model that can be leveraged across the enterprise. This is an iterative process that requires a holistic and evolutional EIM strategy and framework to ensure a consistent and effective approach.

EIM frameworks and strategies provide a clear roadmap for utilities to establish the necessary governance and technology solutions to drive and enable the convergence of OT and IT, which is key for the ultimate realization of a smart grid. An example of such a framework can be seen in Figure 14.3.

EIM enables raw data to be turned into information, intelligence, knowledge, and wisdom. As information systems are becoming critical to the success of business, information management must be addressed holistically. In summary, EIM:

- Enables utilities to take ownership, responsibility, and accountability for the improvement of data quality and information accuracy and consistency
- Enables utilities to establish a single version of truth for data over time
- Improves utility process and operational efficiency and effectiveness
- Provides a strategy and technique to mitigate the risks as well as maximize the value of implementing commercial packaged applications
- Reduces the number and effort of integration over time
- Enables the control of unnecessary data duplication and proliferation
- Enables a more flexible and scalable process integration
- Improves the data quality, integrity, consistency, availability, and accessibility over time
- Maximizes the return on investment of integration technologies
- Establishes a critical component of the enterprise architecture
- Provides guidance and services and enables consistent implementation of integration technologies and information management across major programs

Figure 14.4 highlights a 10-step approach to IT/OT integration with key activities, sequences, and focus areas, leading toward an end goal of a shared organizational understanding and commitment of value as well as the investment needed for EIM. While the approach is strategic, the execution of this approach needs to be tactical and flexible to support the short- and long-term needs of the utility. Therefore, it is suggested that steps 1 and 2 be conducted first, and the findings evaluated, then followed by necessary adjustments to the remaining steps [2].

14.3 DATA MODELING

At the core of an EIM methodology is the development and use of an enterprise semantic model (ESM), which serves as the logical representation of the information assets and enterprise uses to manage and facilitate business processes. When governance, for example, is established by a utility in the absence of an overarching semantic life-cycle design, governance will provide little return on

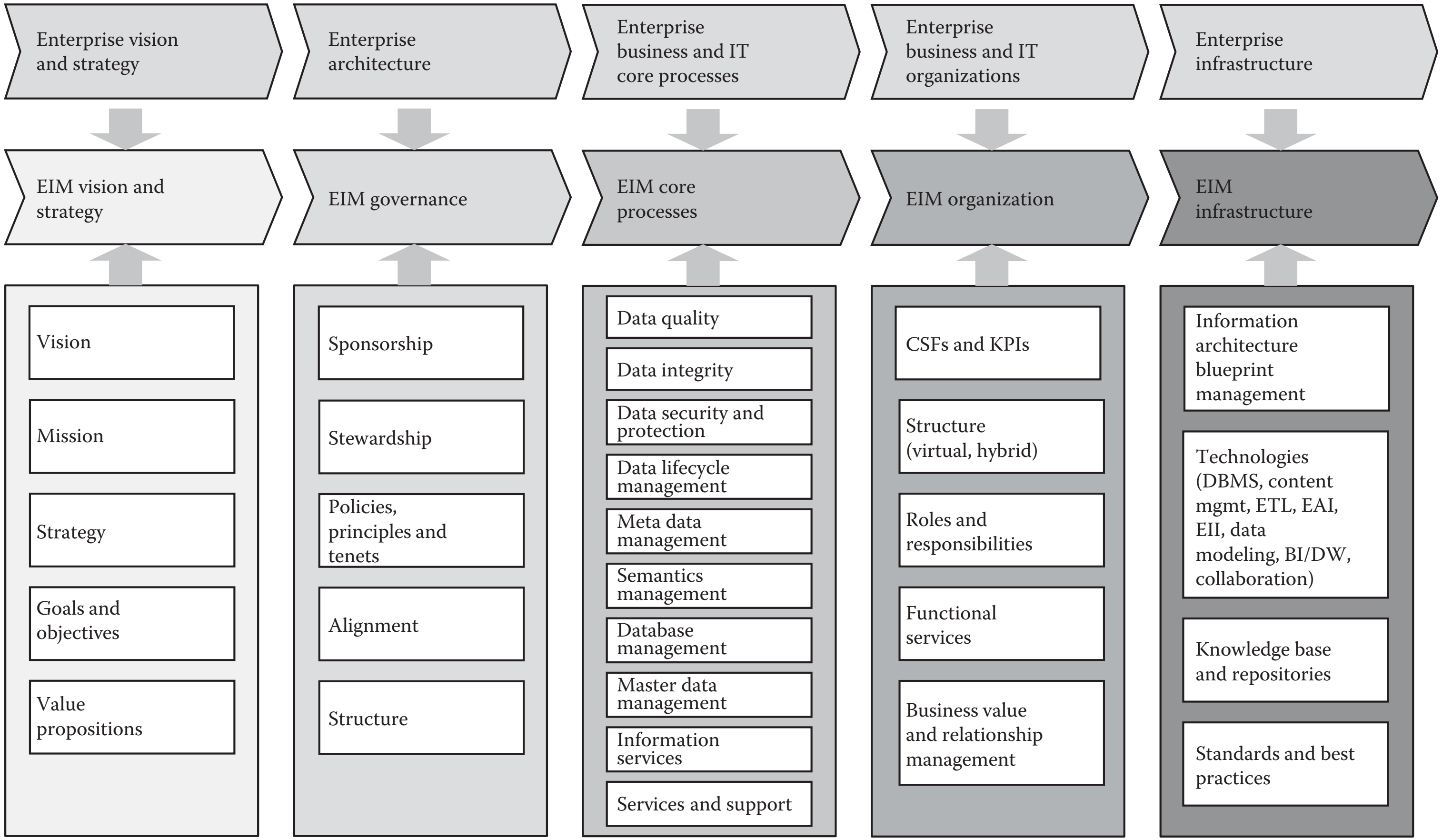

FIGURE 14.3 II/OT integration framework. (© 2016 Xtensible Solutions. All rights reserved.)

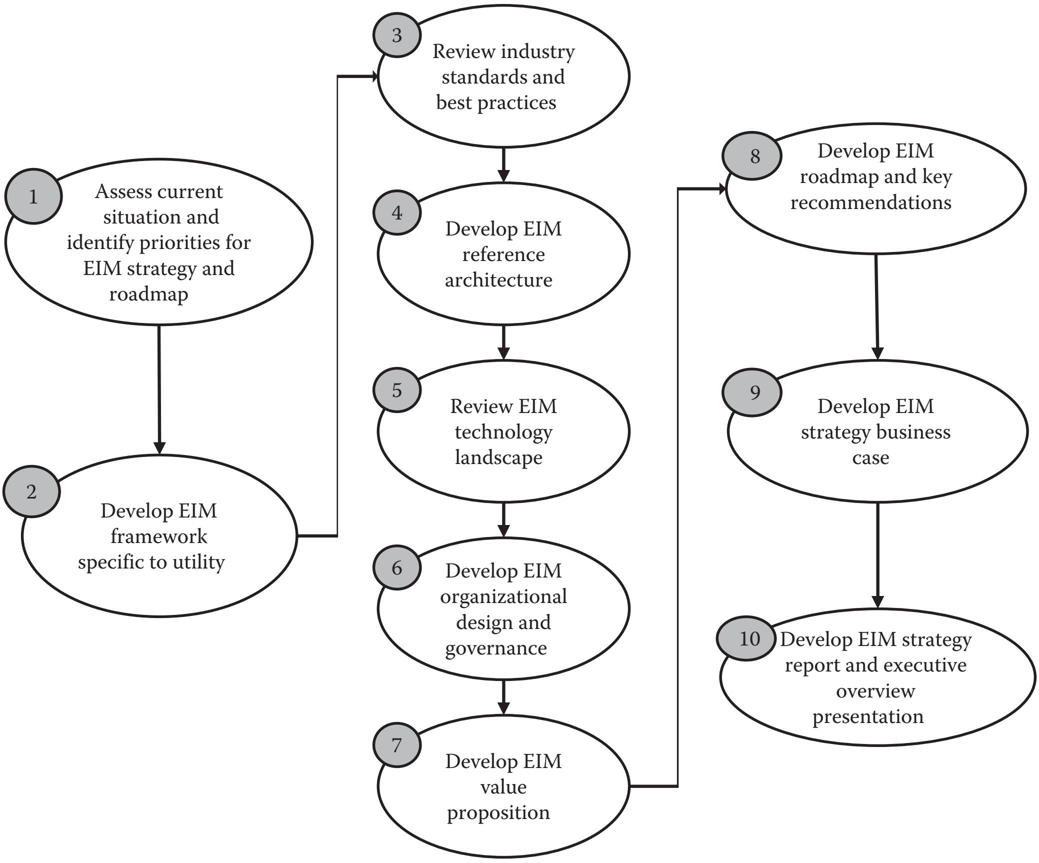

FIGURE 14.4 Integration strategy and roadmap approach. (© 2016 Xtensible Solutions. All rights reserved.)

investment because the opportunities for effective reuse of project artifacts will be greatly diminished. Basic ESM goals include the following:

- *Enterprise information driven:* The ESM utilizes internal models, metadata, and terminology already in use in the enterprise. Existing models and common vernacular, whether or not they are documented, are the most important sources for ESM development.
- *Enterprise owned:* The enterprise owns the ESM, including its terminology, semantics, and implementation. The enterprise has the final word on if and when externally controlled semantics are introduced.
- *Stable:* The ESM must be stable, keeping established semantics clear and unambiguous.
- *Nonstatic:* ESMs are nonstatic in nature and must allow semantics to evolve toward greater clarity as existing business information evolves or new information is introduced.
- *Openly accessible:* The ESM must provide open access to business-critical information about semantics, data restrictions, entity refinement, and constraints targeting specific business contexts.
- *Semantic traceability:* Semantic traceability and lineage are important to enterprises that require or desire traceability and correlation across internal information or to non-ESM semantics.
- *Industry standards aware:* By providing mechanisms to systematically take advantage of applicable industry standard models, data types, and code lists as input, a robust ESM incorporates standard and broadly adopted semantics.

- *Multiple standards capable:* An ESM must be capable of incorporating multiple external reference models, even allowing for referencing more than one standard from a single business entity.
- *Concise enterprise semantics:* By benefiting from both internal sources and available industry standards, an ESM provides concise enterprise semantics appropriate for business information across the enterprise.
- *Business context capable:* The ESM must support data exchange and information sharing within a particular business context.
- *Leverage available methodologies:* When appropriate, any existing modeling methodologies should be used in order to avoid reinvention or introduction of proprietary concepts. Proprietary methods limit choices of service providers, which indirectly will drive up maintenance and enhancement costs.

A utility needs to resolve semantics across information sources scattered around the enterprise to support consistent system development, integration, and analysis. A common approach to resolving enterprise semantics is to map information sources to each other. Key challenges with this approach include

- Difficulty arriving at common agreement of semantics across all uses
- Varying formats and change rates of mapping sources (i.e., inconsistencies due to revisions, upgrades, and replacements)

As a means for resolving these issues, industry standard information models are often employed. However, this initially adds standard terminology to enterprise semantics. Therefore, this adds further challenges:

- Additional semantic mappings to develop and maintain
- Complexity of understanding and using multiple standards
- Differences in format of mapping sources
- Possible internal model vulnerability to external model changes

The ESM provides the means to leverage commonly defined business semantics—see Figure 14.5. The ESM serves as the logical model on which all semantically aware design artifacts are then

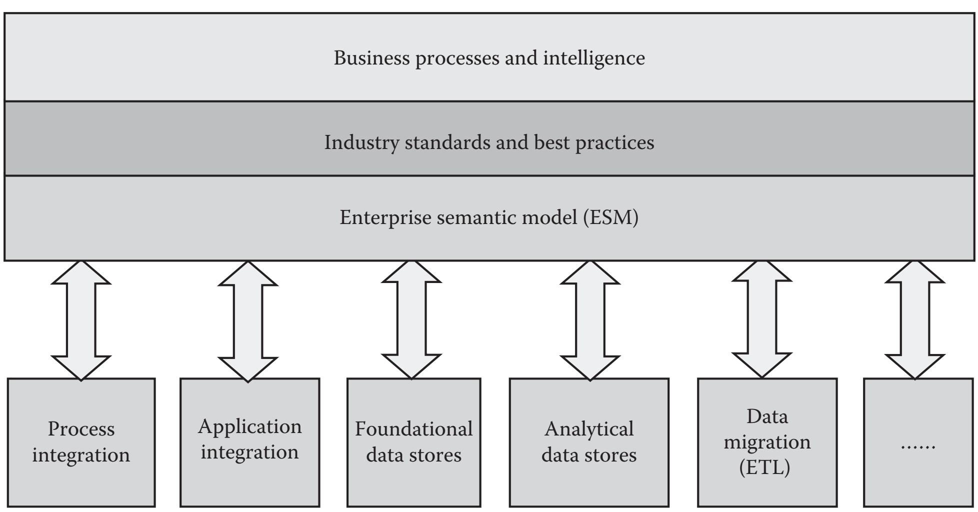

FIGURE 14.5 Logical data model. (© 2016 Xtensible Solutions. All rights reserved.)

based, such as those for integration services, data warehouses, analytic data stores, reporting, and business process automation and monitoring. In reference to Figure 14.6, the first step is to identify existing enterprise concepts through analysis and collaboration. Semantics already in use in the enterprise are not necessarily documented and agreed upon. As with all steps in this process, the information analyzed should only cover areas of interest and go as deep as initially required. This step may also be "seeded" with terminology from a standard reference model. The content represents terminology agreed upon by business stakeholders that is implementation agnostic, meaning that the terminology can be represented in any modeling tool or development environment.

Once a set of enterprise terms and basic definitions is identified and chosen, it needs to be formalized to whatever degree is determined appropriate for the project. The formalized semantics are then implemented in a modeling environment suitable for transforming the formal semantics into canonical models, which are used by projects to generate implementation artifacts (e.g., DDL, XSD, WSDL). Most utilities are already using Unified Modeling Language (UML), which works well for this purpose.

An effective integration strategy allows utilities to embrace industry standards and, more importantly, enables utilities to create their own information model by organizing metadata and models from their existing applications. This is a critical component of an enterprise strategy for creating reusable data services. While many industry models may be helpful, at the core of the ESM for most utilities will be IEC's CIM (Common Information Model), which was designed for the purpose of integrating disparate utility applications (IEC 61968 and IEC 61970 series of standards). However, ERP and supply chain are largely outside of the scope of the CIM, so additional industry or proprietary models will be employed for these aspects. For communicating with intelligent electronic devices, IEC 61850 contains a rich model that can be incorporated into the ESM. The CIM is a large information model and requires that a systematic and model-driven methodology be followed to achieve desired benefits. There are common misconceptions and concerns about using the CIM, some of which are summarized as follows:

1. *The CIM is too large:* For the common system language, the CIM can be thought of as the unabridged dictionary. It is important to note that projects only use the portion of the dictionary relevant to their implementation. But since the dictionary is much richer, there will be consistency and congruity for other areas that must interface with the CIM implementation.

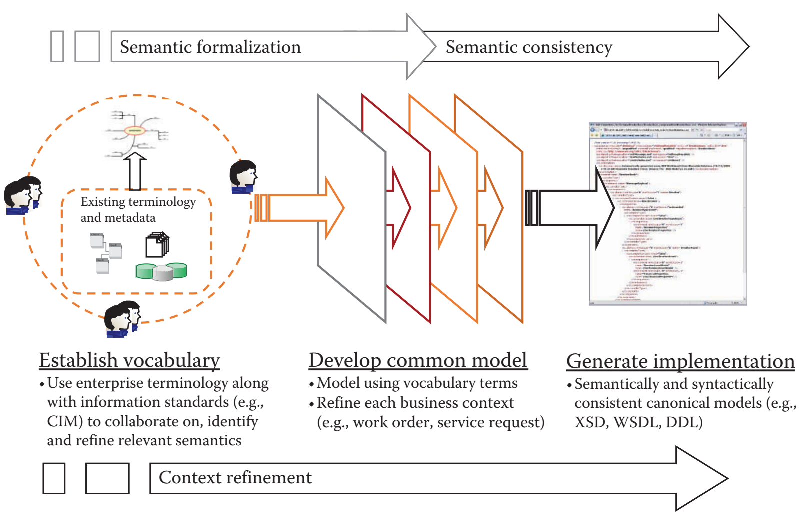

FIGURE 14.6 Developing and implementing a common data model. (© 2016 Xtensible Solutions. All rights reserved.)

2. *The CIM inhibits innovation:* Because people do not have to waste time reinventing things that have been well vetted in the utility community, they can leverage the existing dictionary while focusing more energy on their innovative concept. Not only is this more efficient for the innovator but it is also much more efficient for the people with whom the innovators want to share their ideas. The community is already educated on how to use the well-vetted language.
3. *The CIM is too slow:* This is like saying the English language is slow; it is based on the speaker's command of the language and the choice of media used. When a person communicates with someone, he or she must (1) articulate the information for the receiver to comprehend it, and (2) provide this information through the U.S. Postal Service, through e-mail, through phone calls, directly in a conversation, and so forth. In a similar fashion, the system may provide this information over many types of middleware (messaging, file transfers, database, etc.).
4. *The CIM is too abstract:* This quality enables the CIM to continue to be relevant and valid even as technology continuously changes. The ability to properly convey unambiguous information primarily boils down to one's skills in applying the common system language.
5. *The CIM is not a best practice data model:* For any individual purpose, one can always invent a model that is superior to any other existing model. The CIM has not been developed for only one functional area; rather, it was created by a wide range of domain experts for integrating disparate applications. So, for interapplication integration purposes, a superior model does not exist and would be difficult to achieve.
6. *The CIM is too hard to implement:* Specialized models are often biased for a particular implementation and are used with a specific implementation technology. If the implementation never had to interface with other systems, this would be easier. As the CIM is an information model that is technology-neutral, using the CIM does require following a process that restricts the general information model for particular contexts and then generates the appropriate design artifacts. The CIM community has been doing this for some time, and many tools are available for automating the process [3].

As evidenced by the aforementioned concerns, it is time-consuming and resource-intensive for project teams to fully understand all of the necessary details to correctly and optimally apply relevant industry standards. So, as a means of lowering both costs and risk, it is recommended that the enterprise architects and data modelers supporting smart grid projects be involved with industry user groups, such as those of the Utility Communications Architecture International Users Group (UCAIUG).

14.4 ARCHITECTURE

A key goal of EIM is to enable the information to be used in a semantically consistent way across disparate technologies and business functions. This is depicted in Figure 14.7. Whether starting at the top with business process models or at the bottom with interfaces to systems, the goal is to represent each concept precisely in the ESM. Concepts may then be utilized properly and consistently wherever they show up, for both "data in motion" and "data at rest." To avoid carrying today's baggage into tomorrow's systems, transformation is used where necessary to interface ESM-based canonical models to legacy and other nonconforming systems.

Figure 14.7 depicts four major components of how to introduce consistent semantics into the enterprise architecture at both design and run times:

1. *Business modeling and design layer:* Typically, business process management and design are done on a project-by-project basis, governed, if available, by a corporate IT lifecycle process. What is often missing is how to introduce and manage consistent business

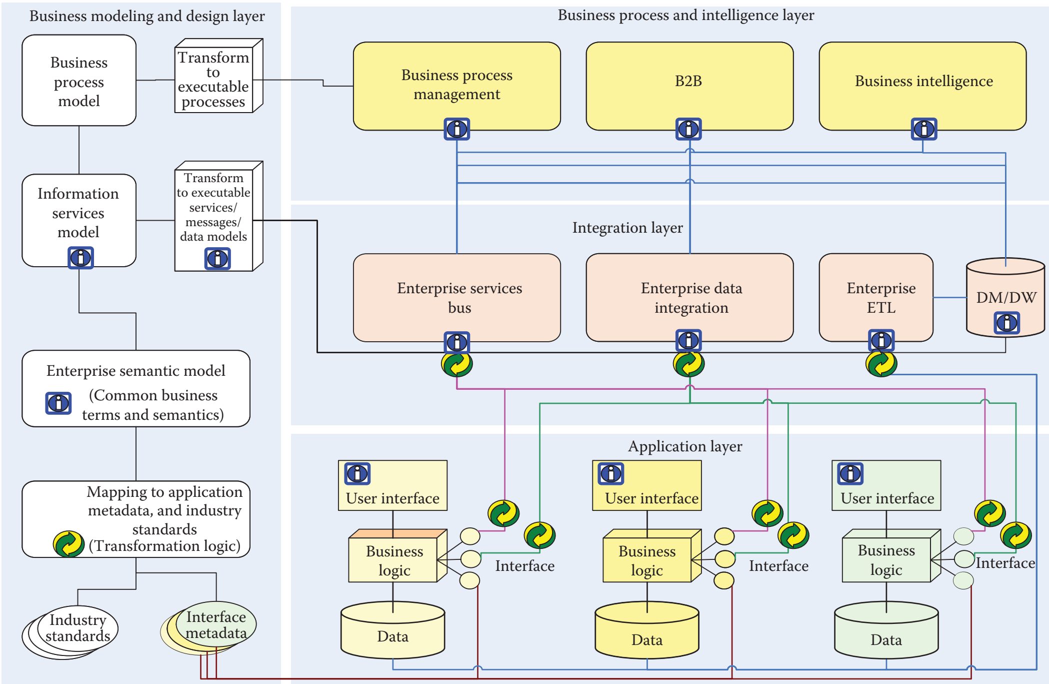

FIGURE 14.7 IT/OT integration architecture. (© 2016 Xtensible Solutions. All rights reserved.)

semantics at design time. The business modeling and design layer show that business process models will drive information service models, which are supported by an ESM. The information service models are collections of the services, operations, and messages utilized for information exchange. The ESM is developed through a combination of industry standards, internal application metadata, business terms and definitions, and is defined using UML constructs. This model is transformed into WSDL and XSD definitions for transaction message exchange or DDL for database design and data integration. The output of the process and information service models will drive the run-time environments in the three layers on the right.

2. *Application layer:* With the increasing amount of commercial off-the-shelf (COTS) applications being implemented at utilities, the ability to dictate how application internal data and information are modeled and represented is eliminated. Utilities can enforce consistent semantics on applications within an enterprise that need to exchange information and provide services outside of the application boundaries. Additionally, applications today are capable of being configured with fields that represent how a utility wants to see their data, thus enforcing consistent semantics at the GUI and reporting levels.
3. *Integration layer:* It is common for several integration technologies to coexist at utilities. For example, the Enterprise Service Bus (ESB) for process and services integration and EDI/ETL for data integration often coexist in an enterprise. The key to introducing consistent semantics is to have an ESM to drive both the design of integration services (typically in WSDL/XSD format) and the design of the data services (ETL transformations) and database models (DDL). This ensures that what is exposed to the enterprise is a consistent representation of the data and information.
4. *Business process and intelligence layer:* At the business process level, there are needs for orchestrating multiple applications to accomplish process automation or process management. There is also the need to exchange data with applications or users outside of the

enterprise (B2B), as well as to present business data in a way that business intelligence can be mined. All these speak of the necessity of a consistent representation of business meaning (semantics) [4].

Data integration is typically implemented with an ESB, which is the middleware that allows systems to integrate with each other through standard protocols. The ESB provides an infrastructure view, in terms of the middleware layer that supports and manages the run-time business and infrastructure services, and facilitates their creation from existing assets. The ESB contains the enterprise integration components. Typical enterprise integration components include:

1. *Message transport:* Moves data from the application to broker and vice versa
2. *Transformation engine:* Translates messages from one format to another
3. *Process management:* Provides ability to apply business logic to events
4. *Routing:* Route requested data to the application or events
5. *Application adapter:* Forms the bridge between integration layer and application layer

MultiSpeak and the IEC CIM standards provide a set of industry standard canonical messages types (described in XSD) for utility applications to interoperate. Since the ESM can be built on these industry standards models, utilities can use their ESM as the semantic base to expand the interoperability of utility systems beyond the standards, thus enabling more utility systems to be interoperable. Furthermore, utility systems with vendors that already support these standards can provide data in standard format, which will be much easier to integrate with the rest of this architecture.

These components are typically used with a concept called enterprise service-oriented integration (SOI) based on a service-oriented architecture (SOA). SOA is a software design and application architecture based on discrete pieces of software that provide application functionality as services. SOI uses the guiding principles of an SOA to construct an ecosystem of services that business users can dynamically combine and compose into higher-level processes that meet continuously evolving and changing business requirements. The overarching goal of SOI is to better leverage existing systems and achieve a better ROI within the IT ecosystem by applying service-oriented principles. Technically, the ultimate goal is to enable the assembly of composite applications, with little or no custom coding, that include capabilities sourced from existing systems. Composite applications are applications that pull together data, functionality, and process from multiple existing sources to solve a business problem or create new business value. The key principles of this approach are [5]:

- Component-based architecture, which separates the interface into components with low coupling and high cohesion.
- Layered architecture that places components into well-defined layers, which enforce separation of concerns.
- Must support incremental adoption of an SOA.
- Component sequencing, which separates the component sequencing from the components themselves.
- Canonical message models, which standardize the semantics of the messages.
- Declarative programming, which separates the "what" we want to do from the "how" we are going to do it.

Service classifications, or taxonomy, pertain to the logical function they perform, such as infrastructure, security, data access, business, presentation, and orchestration. The Open Group's approach [5] is to represent the integration problem space using five functional layers:

1. *Consumer services.* The Consumers layer is the top level of the reference architecture and defines where users interact with the functionality being exposed by the integrated solution. It represents consumers of business services or orchestrated business processes.

Service and process consumers may be either internal or external to the organizations. The services in the Consumers layer include: System Consumers (e.g., procured and legacy GMS Subsystems), User Interaction Services, and Composite Applications.

2. *Business process services.* SOA is heavily premised on the ability to model and represent business processes and their associated activities. The Business Process layer typically takes a number of business services, together with data/connectivity services, and groups these services into an orchestrated flow of operations. The purpose of the Business Process layer is to create higher value by providing a separation between the implementation of specific activities and their orchestration into independent architecture layers. The services in the Business Process layer include Process Services and Decision Services.
3. *Core services.* This layer contains the services required to implement business requirements as defined in the service catalog and provides a classification framework for services to support service definition and discovery. This layer also describes how the ESM supports service interactions, service definitions, contracts, and policies. Included in the Core Services layer are coarse-grained Business Application Services that may group together a number of Information or Access services and some light-weight, short running business logic to deliver the capabilities of the service. Typically, these services are coarse-grained, atomic, and as such deliver a full set of functionality in a single operation. It is critically important to ensure that services defined at this layer are as reusable as possible. The single most important contributor to ensuring reuse is to make Business Application Services as course-grained as possible. The services in the Core Services Layer include Access Services (dedicated to integrating legacy applications and functions into the SOA solution), Information Services, and Business Application Services.

   Information services are particularly relevant to data management because they contain the data logic of business design. The service implementations that provide the data logic have three major responsibilities:

   - *Data access:* The data access information service implementations can include query statements for retrieving information or referential integrity checks on the information manipulated by these service implementations. Information services for data access incorporate federation of multiple data sources.
   - *Data composition:* The data composition information service implementations compose information in a way that matches the composition of services in the business design. This is analogous to the kind of refactoring that can occur with legacy applications to get them to fit better with the business design. In addition, it is common practice to implement these services to separate the database design from the application design to achieve the level of performance and scalability required in many enterprise computing environments.
   - *Data flow:* The data flow information service implementations manage the movement of information from one part of the enterprise to another. The movement of data is needed to satisfy its own data flow and life-cycle requirements. This may involve the use of Extract-Transform-Load (ETL) mechanisms to process and enrich data in bulk, batch processing activities involved in bulk transaction processing, and migrating data from master-data-of-record databases to information warehouses that can be used to perform postprocessing and business intelligence, analytics, and content management functions—which, in turn, are made available to the business application as services.

From an architectural perspective, an Information Service is a data abstraction layer sitting above a set of underlying data sources. The purpose of these services, built on SOA principles, is to provide a single point of access for all read and write operations, and to shield the underlying data's physical structure and access mechanisms from consuming applications. To accomplish this, the Information Services provides an interface, independent from the underlying data sources, that exposes a standard set of reusable data services for reading and writing data.

Business application services are a category of services that implement core business logic. These are service implementations that are created specifically within a business model and that represent the basic building blocks of business design. These services are not decomposable within the business model, but can be composed to form higher-level services. Architecturally, Business Application Services begins the representation of two key paradigms, consolidation and rationalization. Consolidation refers to the ability to reduce or eliminate business functionality that is duplicated partly or wholly in different parts of an enterprise. Rationalization refers to the standardization of business functionality, not just at the interface level but at the semantic and usage levels. In other words, the Business Application Services provides a mechanism to standardize the way the business does its business.

4. *Service Components*. Service Components are those components that realize or implement SOA services; they provide access to the smart grid applications. There are a variety of technologies and products that can be leveraged to connect to existing Information Systems. Generally, both synchronous and asynchronous techniques are employed by this layer to provide connectivity.
5. *Operational Systems*. The Operational Systems layer consists of the core IT systems that make up the operating environment. The services in the Operational Systems layer include Utility Services and Infrastructure Services.

14.5 DATA MANAGEMENT

Figure 14.8 depicts some key data notions that are necessary for successfully integrating IT and OT systems in a way that is adaptable and flexible. At the foundation is the ESM, which enables a common data model with the same meaning for the same names across all of the functions depicted in this diagram. An SOA provides for well-described service interfaces, which allow the use of services without the need to understand their implementation details. As such, SOA is ideally suited for smart grid implementations so long as semantics are congruent across services. Therefore, this section begins with a discussion of services-based integration. Then, building upon the earlier EIM discussion, this section provides additional data management considerations that are key to achieving these architectural principles.

The Design-Time Data Management enables business models to drive information service and persistence models. The information service models are collections of the services, operations, and messages utilized for information exchange. As described earlier, the ESM is developed through a combination of industry standards, internal application metadata, and business terms and definitions, and is defined using UML constructs. This model is transformed into canonical message models (typically expressed in XSD format) for transaction message exchange or canonical data models (typically expressed in DDL format) for database design and data integration. The output of the process and information service models will drive the run-time environments in the layers on the right of the diagram.

To have the same terms used in the same way across interfaces among systems and data stores, the ESM must be decoupled from particular serialization formats. This has the benefit of making it easier to understand the data within the system as abstract entities rather than being a particular line or column of text within a file, or as one or more columns and tables in a database. This also allows the same data to be serialized in multiple different formats without impacting its structure and definition.

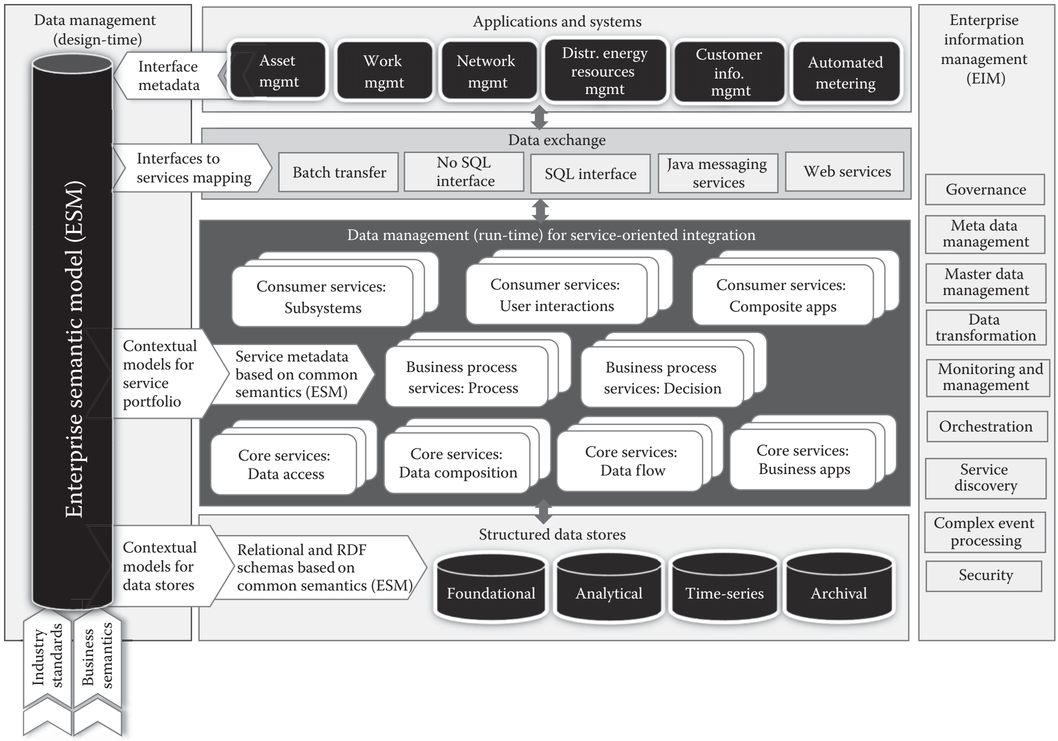

FIGURE 14.8 Data management for service-oriented integration. (© 2016 Xtensible Solutions. All rights reserved.)

The ESM will be used to derive all forms of information exchange and storage, including database schemas, file formats, documentation, and interfaces automatically. A foundational aspect of achieving congruent semantics is to have an inheritance hierarchy that ensures common attributes and relationships (UML associations) are inherited from super-classes. Master data management goals will be facilitated with a common identity scheme that is inherited by most classes. For example, the majority of CIM classes inherit from the Identified Object class, yielding common attributes for identification, such as a universally unique identifier known as the Master Resource Identifier (mRID), human readable names, and support of aliases. To ensure the semantic model can be simultaneously effective across its subsystems requires a careful structuring of relations among classes, each relation being at the correct place in the respective hierarchies. While these relationships can be further restricted (e.g., changing a "zero to many" to a "zero to one"), the relationships must never be allowed to be broken during the creation of integration and data storage artifacts.

Care must be taken as different reference models are used for the ESM because many industry models are reverse-engineered from old databases (schemas) and interface definitions (XSDs, APIs, CSVs, spreadsheets, etc.), with the unfortunate side of having "designed in" many unnecessary constraints that existed in the original implementation. This is in contrast to models designed top-down to support information exchange requirements across domains.

Furthermore, the ESM must simultaneously address multiple perspectives such as: As forecasted; As planned; As designed; As contracted; As built; As maintained; and As operated. Accordingly, modelers must also resist the temptation to view various reference models as containing merely Lego blocks that they can mix and match as needed. They must also take care during creation of the ESM to ensure that essential relationships are maintained from the reference models, as the industry standard (i.e., CIM, MultiSpeak, 61850), vendor, and home grown models are integrated together. Proper relationship management will enable clean navigation of perspectives across different scenarios and time horizons. They will also enable each measurement to have many sources (from SCADA, from AMI, from third parties, manually entered, calculated [e.g., optimal power flow], etc.), each with its own time stamp, quality, and trust rating. Furthermore, by maintaining instance data in a graph database based on the ESM, the many types of business intelligence and analytics that would have been too complex are instead straightforwardly performed through SPARQL (SPARQL Protocol and RDF Query Language) queries. While this will be beneficial for many known and future business requirements, it will likely be essential for performing optimizations across the many perspectives and scenarios dependent upon the electrical connectivity network.

The schemas used for the structured data stores are defined during the design phase in the ESM, driving the design of the data services (e.g., ETL transformations) and database models (e.g., DDL, RDF). This ensures that what is exposed to the enterprise is a consistent representation of the data and information.

Data persistence will continue to require a tool box of capabilities since the Smart Grid service will be interfacing with some legacy systems and because of limited capabilities of some newly acquired products as vendors migrate their products to newer technologies. For example, ETL/ELT and DCC (data change capture) technologies are likely to continue to be needed for transactional data in relational databases. Furthermore, to support reporting and analytics, intra-ETL will likely be used (e.g., Oracle Utility Data Model) to move data from the foundation layer (in third normal form) to the analytics layer (e.g., based on star schemas). Data staging is often performed between the data source(s) and the data target(s). Data-staging areas are often transient in nature, with their contents being erased prior to running an ETL process or immediately following successful completion of an ETL process. When services are being provided by service providers, a staging area may be used as an intermediate storage area for data processing during the ETL process.

The structured data stores will likely need to support the notion of an operational data store, which is a database designed to integrate data from multiple sources for additional operations on the data. Unlike a master data store, the data are not passed back to operational systems. It may be passed for further operations and to the data warehouse for reporting. Because the data originate from multiple sources, the integration often involves cleaning, resolving redundancy, and checking against business rules for integrity. This capability is usually designed for low-level or atomic (indivisible) data with limited history that is captured “real time” or “near real time” as opposed to the much greater volumes of data stored in the data warehouse generally on a less-frequent basis.

The structured data stores contain a Foundation Layer that gathers information and serves up data to the Analytic Layer. This foundation layer may be in third normal form and contains reference entities and tables (used to store master reference entities, nonchanging or infrequently changing data), base entities (store transactions from systems of record, contains data at atomic level, and is required to perform detailed analysis, and uncover causal effects and associations), and lookup entities and tables.

The Time-Series Data Store is optimized for handling time series data, arrays of numbers indexed by time (a date time or a date time range). A time series of energy consumption can be used for understanding a load profile. A database that can correctly, reliably, and efficiently implement query operations is typically specialized for time-series data. Software with complex logic or business rules and high transaction volume for time series data may not be practical with traditional relational database management systems. Flat file databases are not a viable option either, if the data and transaction volume reach a maximum threshold. Queries for historical data, replete with time ranges and roll ups and arbitrary time zone conversions, are more difficult in a relational database. Database that joins across multiple time series data sets is typically only practical when the time tag associated with each data entry spans the same set of discrete times for all data sets across which the join is performed.

The Archival Data Store moves inactive data out of the production databases to improve overall performance without losing critical historical. The ESM is used for data integration following the SOA principles to avoid unnecessary data transformations. The concept is to use the same logical data model for both XSD and DDL generation. The XSD will be used for data integration, and the DDL is used for database design.

EIM encompasses many important aspects that are key to SOI. For example, with Master Data Management (MDM) provided as a service, the data will not get jumbled up as the data traverse the enterprise. The composite services from the ESB can get the reference data as needed, thus making the messaging services more agile and reusable. The Complex Event Processing (CEP) engine can reference master data to develop more enriched rules for event processing. MDM functionality can be achieved in different ways: consolidating data from multiple sources and integrating into a single hub for replication to other destination systems, federating by having a single virtual view of master data from one or more sources, and data propagation, which is the process of copying master data from one system to another. However it is constructed, the foundation of the MDM solution will be the master data model, and this model will be unnecessarily complicated to build and maintain if it is not directly based on the ESM.

14.6 SMART GRID EXAMPLES

14.6.1 Convergence of Distribution Operation Applications

The isolated operational systems of the 1980s and 1990s have now become increasingly integrated, through various interfaces such as file transfers, application programming interfaces (APIs), middleware, and, most recently, Web services. As electric utilities look to the future with the intense pressure to improve reliability, operational efficiencies, and customer satisfaction, they will require advancements in real-time grid management systems to meet the growing demand. Integration of distribution operations systems will be critical to the success of the smart grid.

Utilities are experiencing an increase in automation and the amount of data collection points being applied to customer premises and utility grids. The ability of network operators to proactively manage large and complex networks requires new advanced tools that can turn grid data into useful information in order for safe, timely, and effective operational decisions to be made. One current trend is the integration of the Supervisory Control and Data Acquisition (SCADA) system and Distribution Management System (DMS) with the Outage Management System (OMS) in order to provide a more comprehensive and integrated approach to managing the operation of the distribution system and to responding to outages on the system.

Figure 14.9 shows an integrated distribution operations environment using a single network model and integrated operator functionality. Benefits of integrating SCADA with DMS/OMS include the following:

- Improved operations by close integration of DMS applications with distribution SCADA
- Increased operator efficiency, eliminating the need for multiple systems with potentially different data
- Integrated security analysis for substation and feeder operations to check for tags in one area affecting operations in the other
- Streamlined login and authority management within one system
- One network model for OMS and DMS analysis
- Consolidated system support for DMS/OMS and distribution SCADA

Such an architecture is also modular in order to effectively meet the needs of different distribution organizations that are in different phases or have different strategies of smart grid implementation. This modular distribution operations platform permits organizations to incrementally add particular software modules, such as OMS capability and advanced DMS network applications, as their business needs change.

The components of the integrated distribution operation environment include the following.

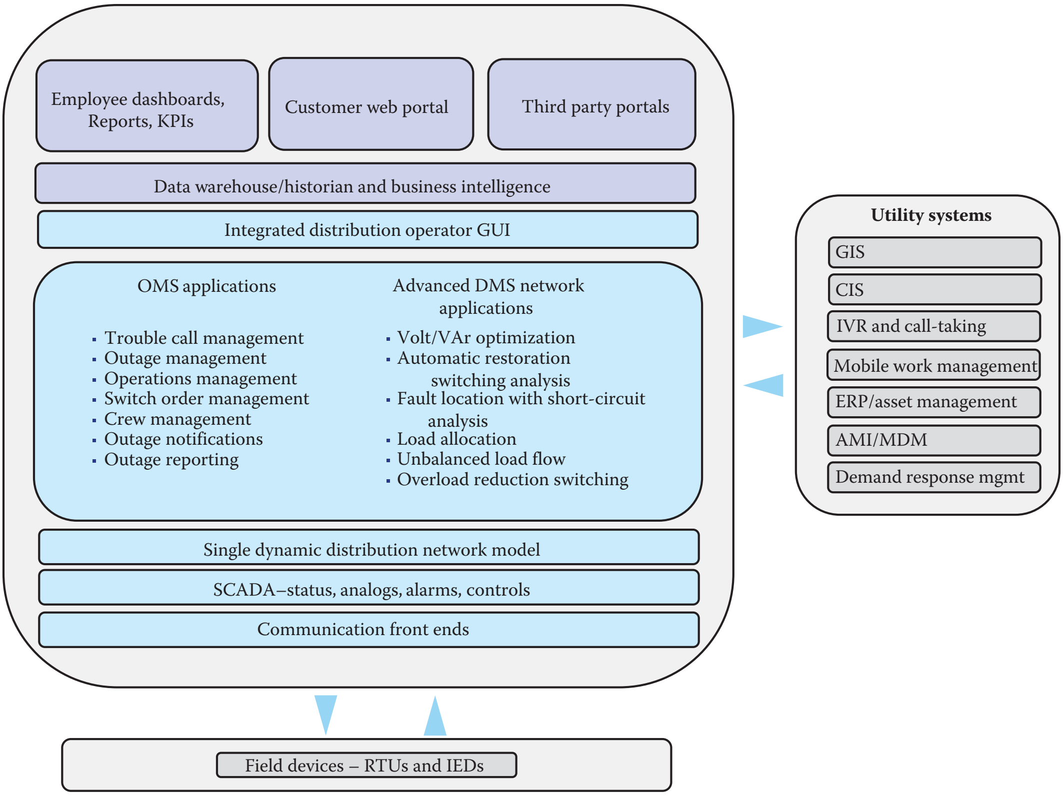

FIGURE 14.9 Integrated distribution operations environment. (© 2012 ABB. All rights reserved.)

14.6.1.1 Integration of SCADA, DMS, and OMS

The distribution SCADA infrastructure is shown at the bottom of Figure 14.9. SCADA collects analog and status data from RTUs and IEDs and provides basic monitoring and control functionality including alarms, events, and tagging. The OMS and DMS network applications can integrate with the SCADA application in a single platform, or they can be integrated with a third-party SCADA solution using the intercontrol center protocol (ICCP) or other types of integration interfaces. Integration of DMS and OMS with SCADA is an increasing trend. While the inclusion of real-time SCADA status in the OMS has been used for outage detection for years, recent business challenges have driven a more comprehensive integration between the systems. In this example, available functionality can include the transfer of status/analog points from SCADA to the DMS/OMS and sending supervisory control and manual override commands from the DMS/OMS to the SCADA. This integration will require the ability to resolve the disparate identifiers used in each application for the same physical device or network resource.

14.6.1.2 Single Dynamic Distribution Network Model

As shown in the center of Figure 14.9, this example utilizes a common distribution network model for DMS applications and OMS applications. It greatly simplifies system maintenance as it eliminates the need to build, maintain, and synchronize multiple data models. An additional benefit is the ability to coordinate planned and unplanned outages by adding system changes in the form of temporary lines and line cuts, and manually operated switches and other operations carried out by field crews. The single dynamic distribution model also means that the DMS network applications always utilize the as-operated state of the distribution network, with the current connectivity and state of switching devices, capacitor banks, and customer loads.

14.6.1.3 Integrated Operator User Interface

This example depicts a consistent user interface across the operational functions. This can include distribution SCADA, DMS applications, OMS, and transmission SCADA. Operator workstations consist of tabular displays, in combination with geographic and schematic displays that provide fast response during storms. The result is improved operator effectiveness and flexibility, as well as reduced maintenance and training costs.

14.6.1.4 Advanced DMS and OMS Functionality

This example integrates OMS and advanced DMS network applications. The OMS functionality includes the identification and resolution of outages throughout the distribution network, the management of field crews, and the tracking of corrective work, including temporary line cuts and line jumpers. This allows more accurate representation of the distribution system with advanced DMS applications, such as load allocation and unbalanced load flow analysis; switch order creation, simulation, approval, and execution; overload reduction switching; and capacitor and voltage regulator control. Other applications, such as fault location and restoration switching analysis, permit operators to reduce customer interruption durations during outage management. Applications such as load allocation, unbalanced load flow, and line loading permit improved asset utilization and operation closer to equipment thermal limits.

14.6.1.5 Business Intelligence for Distribution Operations

Varying degrees of packaged business intelligence solutions are available from product suppliers. This enhances an organization's reporting, situational awareness, and business intelligence needs, and allows individuals across the distribution organization to understand what is happening through the use of standard KPIs, dashboards, and out-of-the-box reports. By having one common environment integrating distribution operations, the reporting and dashboards are easier to generate and maintain, and there is one common database without the need to verify and integrate operations data from separate systems.

14.6.2 Integrating OMS with Mobile Workforce Management

Integration between OMS and MWFM is often done to improve work flows in the outage management process. Functionality that is typical includes the following:

- Transmittal of outage assignments directly to the mobile data terminal (MDT) from the OMS
- Receiving of crew assignment status updates from the MDT (en route, arrived)
- Updating of assignments automatically to MDT as the OMS outage engine predicts outages
- Verification and completion of outages in the OMS from the MDT
- Display of crew login status in the OMS, as entered from MDT

There are other advantages of closer integration between the control center and field operations. Switch order management and execution can be more efficient. Resources can be dispatched and managed more efficiently. Figure 14.10 illustrates benefits from improved integration between control center and field operations functions.

14.6.3 Integrating AMI with Distribution Operations

Smart meters and AMI (Advanced Metering Infrastructure) are key components of many distribution organizations' smart grid plans. Business cases are being built on the premise that AMI systems with the right functionality can help to improve system operations. There are many ways AMI data can improve the outage management process (Figure 14.11). If the AMI meters are so equipped, the

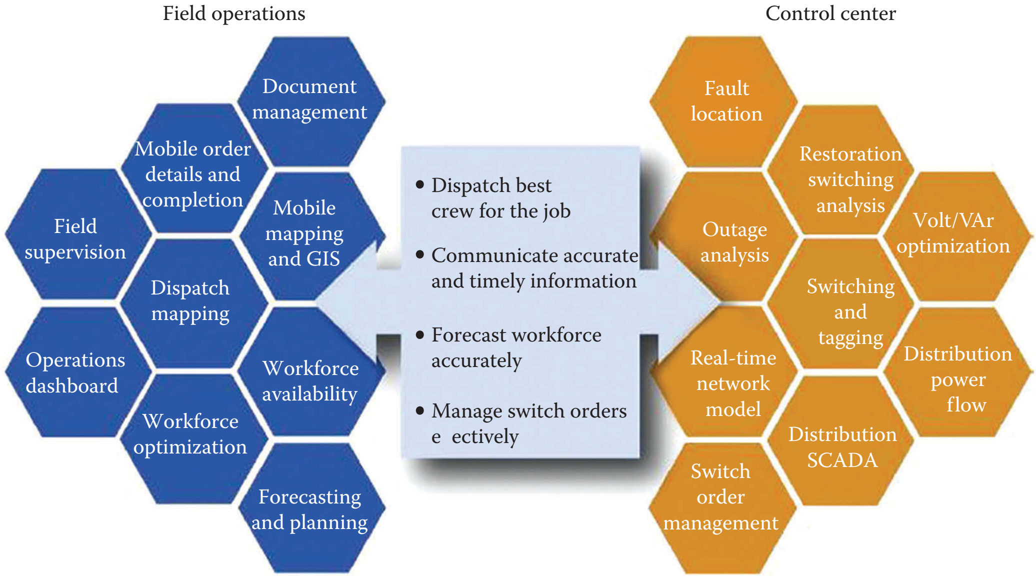

FIGURE 14.10 Integrated outage management and field operations. (© 2012 ABB. All rights reserved.)

OMS can receive a last-gasp or outage notification message from the meter when it loses voltage (i.e., a customer outage event has occurred). That way the OMS is notified of any customer outages even if the customer does not report it. (In the past, utilities relied heavily on receiving calls from customers reporting outages.) These messages are particularly useful when no one is at a property where an outage occurred or when people there are asleep. The outage notification message can provide the granularity of identifying individual customer outages at the meter and help with outage management algorithms to more accurately predict the source of the outage and, therefore, reduce customer interruption times and result in a more efficient dispatch of repair crews.

With the proper integration between the OMS and AMI system, and the right communications infrastructure and meter, a message can be sent from the OMS to query if a meter is in service. This is sometimes referred to as "pinging the meter." The meter can be pinged directly, or the Meter Data Management (MDM) can be queried to determine the status of a meter. The meter can be pinged either by a customer service representative or an operator. The value in pinging the meter is that many customer outages are the result of problems on the customer side of meters. Utilities commonly report that 50%–67% of single-customer-call outages are the results of the problems on the customer side of the meters (OK on arrival), and not a distribution system outage. By remotely interrogating the meter, the utility can inform customers if any loss of service issues requires further investigation by the customer on the customer side of the meter. If personnel can ping a meter to determine it has voltage despite a customer's reports of no power, responding troubleshooters and crews could save time and vehicle miles. Utilities can also take advantage of other measurements available in the smart meter, such as power quality (e.g., sag and swell) data, and identify and respond to any service issues well before the customer calls to complain. An additional value in meter querying is in the ability to perform outage scoping or define the outage area by pinging select meters. This can lead to a faster definition of the outage area.

Another area in which the integration of the OMS and AMI systems can provide value is through restoration notifications. They provide confirmation to distribution operators that customers have been restored downstream of a particular protective device. Restoration notification can be done through a restoration notification message transmitted from the restored meter to the OMS, or

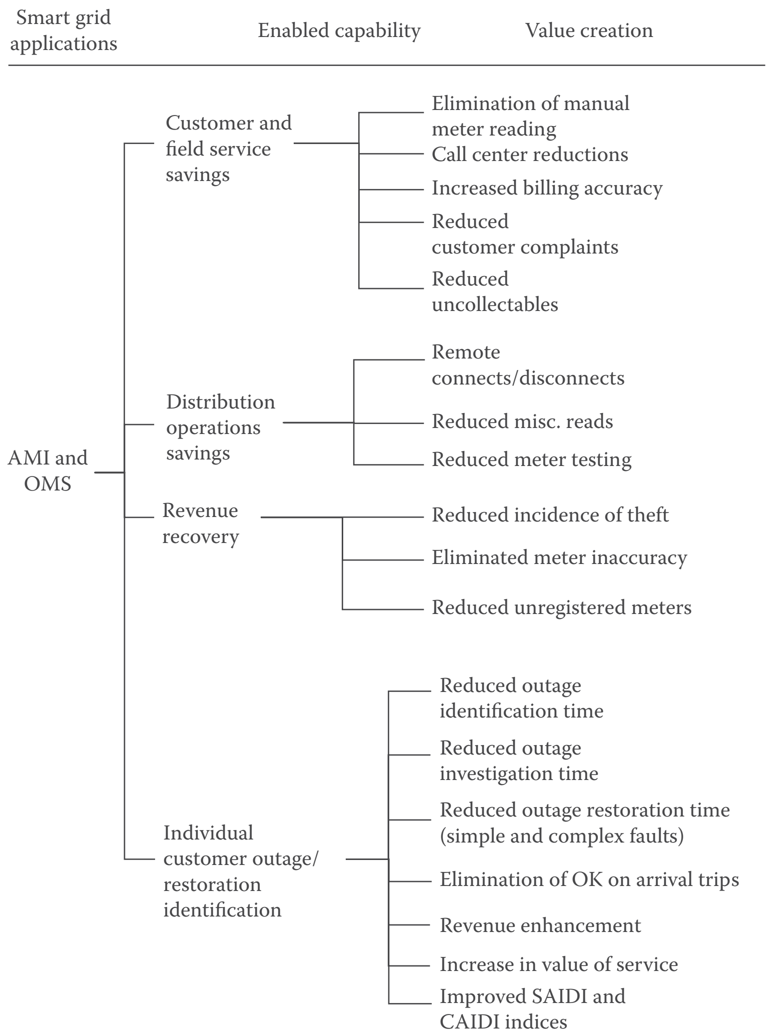

FIGURE 14.11 AMI and OMS integration synergies. (© 2016 GE Grid Solutions. All rights reserved.)

through pinging of meters that presumably have been restored. The value of restoration notifications is that, if all customers have not been restored because of a nested outage within the larger outage area, field personnel can be notified of additional problems before they leave the area. This reduces the need to redispatch crews during multiple outages and reduces crew costs and travel time. The smart meter can, therefore, further reduce the duration of extended outages as part of the improvement in customer service.

Other ways of using the AMI infrastructure for outage notification and system planning are also being used, such as the use of interval demand data and voltage violations. Customer load profile information, obtained from AMI data, is being used in load flow programs instead of customer-class load profile estimates that are currently developed for typical day types. This means that more accurate loading information can be applied to each distribution transformer before load flow calculations on the system are performed. The results are improved understanding of the actual power flows and voltages on a distribution system.

Voltage violation alarms and other power quality measurements from the AMI system can also be sent to the DMS so that system operators are notified of system problems. With this additional voltage measurement data at the customer, Volt/VAr control can then be adjusted to compensate for the voltage problems, either by the operator or directly by the automated Volt/VAr control application. This will be especially important for utilities that aim to reduce customer demand by operating their systems in the lowest levels of the permissible voltage bandwidth.

14.6.4 Integrating Asset and Workforce Management with Distribution Operations

Projects involving the field installation of grid assets (such as building new substations and replacing failed equipment) are typically a complex undertaking involving carefully planned work, extended time, multiple crew types and skills, and, potentially, contractors. Operating the assets, however, is typically a high-volume, short-duration activity, with mostly orders for individual field workers. Maintaining assets is an amalgam of the two, with work that is planned and scheduled for individual technicians or crews working varying durations. Supporting smart grids involves these very same breakdowns of work, yet the tools, scheduling, skills, and durations can significantly vary from current utility practices. What is particularly new is the amount and types of data these new assets produce, and the need to make the data available to the right people, at the right time, in the right format. Utilities can approach these challenges by leveraging an integrated platform for distribution operations, asset management, and work force management (Figure 14.12).

In this integrated platform, field work can originate in either the Enterprise Asset Management system, or in the distribution operations (SCADA/DMS/OMS) systems, and immediately, without intervention, flow to the Enterprise Workforce Management system, an actionable work order. Any work completed in the field can be reflected back to the originating system; for example, if a new substation is constructed, or if a switch is replaced, it will be updated automatically in the asset database as well as in the SCADA system and operations database. Integration of field work data with the OMS will allow more timely information to be shared with customers, and utilities can

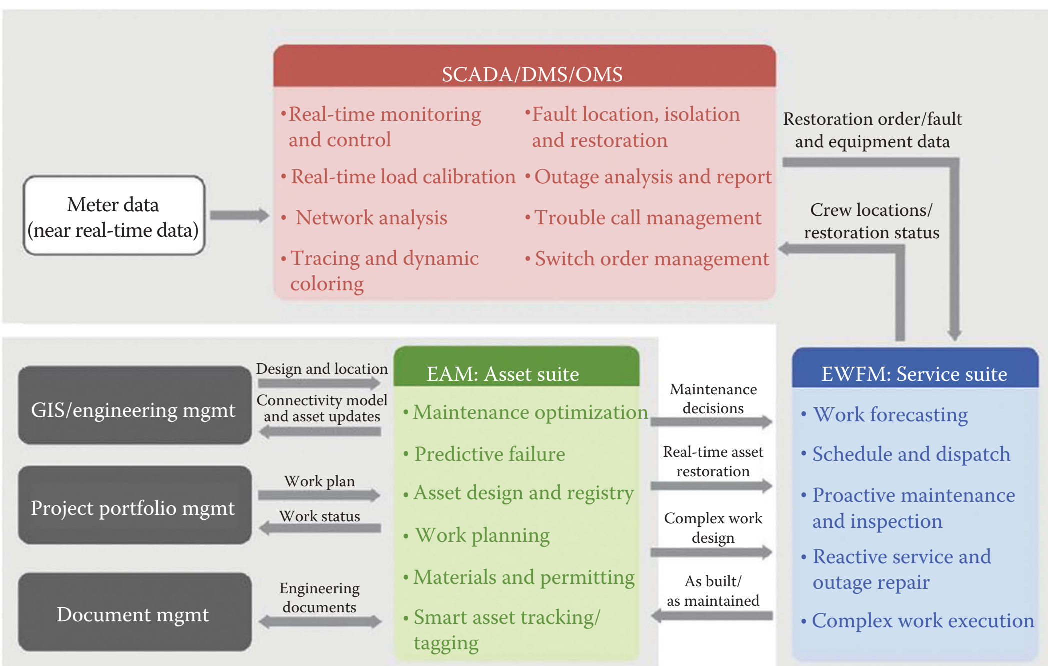

FIGURE 14.12 Operations, asset management, and workflow in a utility-centric view. (© 2012 ABB. All rights reserved.)

provide detailed explanations of what is occurring in an outage, and when customers can expect power to be restored.

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15 Data Analytics for the Smart Grid

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15.1 THE ANALYTICS VALUE CURVE

The term smart grid analytics is used to refer to a suite of data analytics and applications that can benefit almost every aspect of a utility business and processes, with particular areas of interest including outage management, asset management, and energy management. There is a great deal of market hype about using data analytics to create new insights for better business decisions, meaningful actions, and result-oriented outcomes. However, utilities should focus on using analytics to:

- Enhance existing processes, such as asset management, work management, customer information, protection, and so on.
- Solve new problems arising from major market, regulatory, and technology changes, such as those associated with maintaining a stable and cost-effective grid in the midst of growing numbers of electric vehicles, distributed generation, distributed storage, energy efficiency, and customer equipment that can respond to demand response signals.
- Eliminate the time, bandwidth, and expense required to transport the data necessary for centralized solutions by extending analytical solutions out to the field, and even to the "grid-edge."
- Empower business users so that they can be "citizen data scientists," taking advantage of analytical tools using accurate information that spans business silos. This makes it possible for the right person to take more immediate action in response to business insights.

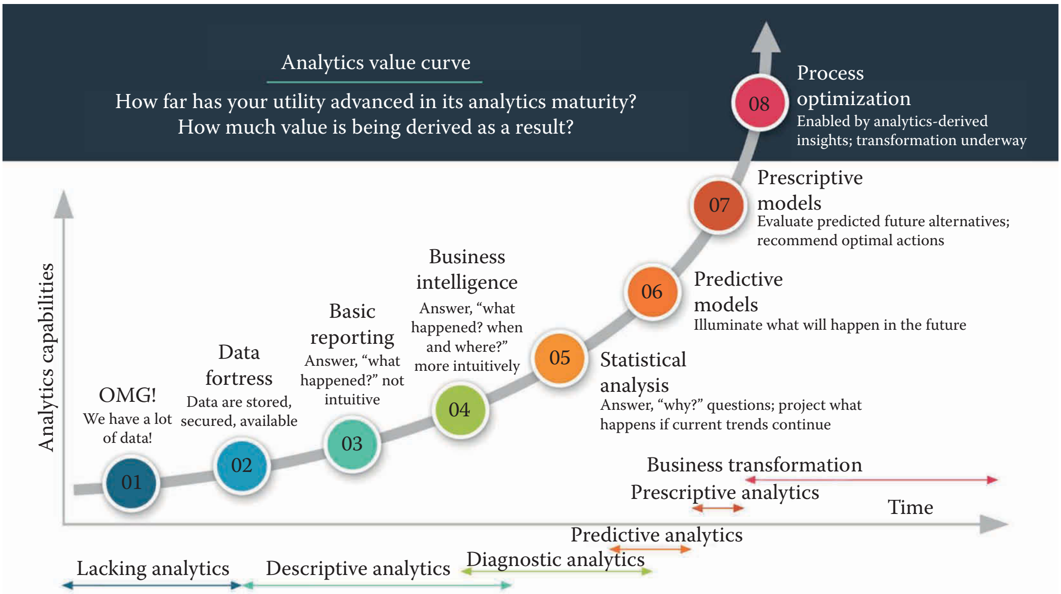

FIGURE 15.1 Utility analytics value curve. (From the Utility Analytics Institute (UAI), http://www.energycentral.com/sites/default/files/ec-core/nodes/227281/new_value_curve_-_oct_2015_-_final.jpg. With permission.)

Analytics applications are not a new occurrence in the utility business. In some form, utilities have used analytics for many years even before the advent of computers. However, many utilities are only at the point where they realize there is great value from analytics and the technologies exist to store and analyze large amounts of data. Figure 15.1 from the Utility Analytics Institute (UAI)[1] depicts a value curve for analytics for the utility industry. The primary levels of analytics are:

- *Descriptive*—reporting that describes what happened (aka hindsight or oversight) with actual analytics left to human evaluation. Many utilities are primarily at this level.
- *Diagnostic*—"why did it happen" analytics. Most utilities are currently moving to this level.
- *Predictive*—analytics that are used to determine "what will happen." This is where the leaders are moving.
- *Prescriptive*—identifying the optimal actions given predicted future outcomes.
- *Business Transformation*—insights used to optimize processes and transform the business.

However, the convergence of technologies and business process benefits with smart grids has brought a new focus on competitive advantage and the urgency to apply grid analytics. Advances in sensor technologies and the drive to extend monitoring and control further down the grid to the customer ("grid-edge") are making operational and nonoperational data available to the utility at a much higher rate and magnitude than the data collected from traditional grid management systems. Operational data are data related to the real-time monitoring and control of the grid, for example, SCADA (Supervisory Control and Data Acquisition). Nonoperational data are not directly related to real-time monitoring and control, but field data are available from the protection, monitoring, and control devices in the field. Nonoperational data include, for example, the number of circuit-breaker operations, the maximum current measured on a transmission line, the oil temperature of a

[1] The Utility Analytics Institute (UAI) (http://www.energycentral.com/c/ua), a corporate membership-based organization that strives to accelerate the adoption of analytics in utilities.

transformer, and the low voltage measured by a smart meter at a customer. Nonoperational data also include sets of measurements captured by field devices, such as digital fault records (oscillographic data), meter records, trends, load profiles, power quality data, and sequence of events.

Amid all this complexity and evolution, the high-level core elements of grid analytics stay the same: the right data need to be collected, processed, and turned into actionable insight and information, and made available to the right person or application at the right time, and in the right format. As the adage goes, the devil is in the details, and the biggest challenge is to move away from being data-rich to being information-rich and impactful with grid analytics solutions.

A successful grid analytics solution sits on the foundation of a solid business case with three supporting legs of analytics, communications, and grid hardware (Figure 15.2). Weaken the foundation or any of the legs and the solution starts to fail. This was, however, not the norm from the start. For most utilities and for the right reasons, the question did not start with a recognized need and business case around it. It was more about "we have the data, what can we do with it," which is more of a discovery phase, oftentimes formalized as "descriptive analytics," which involves mining the data for value streams and insights.

As the organizational knowledge and structures mature toward capturing the full value of smart grid analytics, the technology focus will transition from descriptive analytics to predictive and eventually prescriptive analytics, where recommended actions are also an expected deliverable from the analytics solution. The bulk of the smart grid industry is still in the discovery phase trying to uncover new value streams and use cases from the influx of operational and nonoperational grid data.

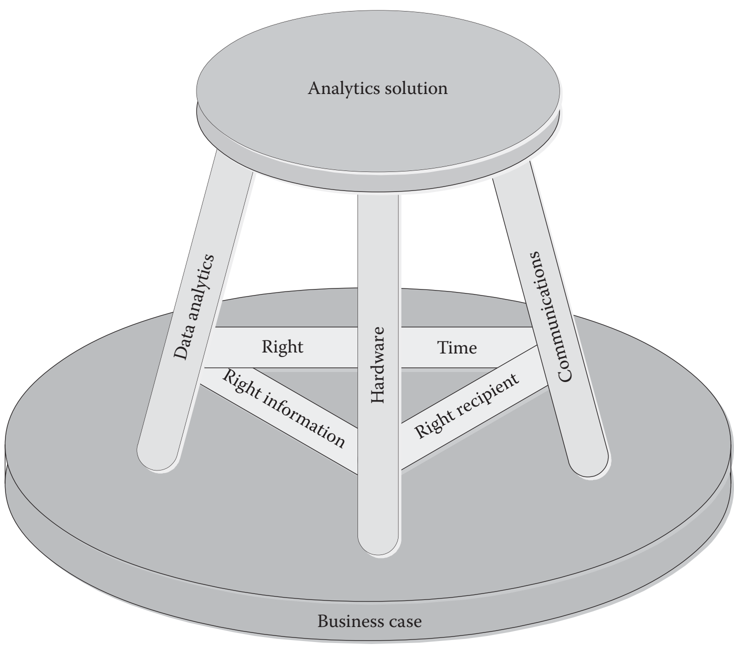

FIGURE 15.2 Foundational elements and requirements of a grid analytics solution. (© 2016 ABB. All rights reserved. With permission.)

Owing to the historical lag in the adoption of automation technologies, the need for data analytics is more pronounced in distribution operations than anywhere else on the electric grid. Utilities are more than ever expected to do more with less, and this is where data analytics is going to make the single biggest impact. Existing and new architectures and digital systems provide a great quantity, variety, and veracity of grid data from a subset of key components through sensors, meters, and IEDs (Intelligent Electronic Devices). Nonoperational data are the opportunity areas for grid analytics. Some utilities have migrated to a more integrated collection of operational, equipment failure, and event data. With the additional data comes the need for specialized data analytics tools and technologies to realize the full potential of these investments. As utilities face shrinking budgets and reduced and retiring workforces, the integration of data analytics into business processes and planning tools becomes imperative.

While there are many good analytic solutions from vendors, these solutions become increasingly cumbersome and marginally effective when they are extended beyond the functionality of their original purpose. This leads companies to ask the tough questions about how they're going to scale their solutions and about the suitability of the various associated technologies. Whether to share data across systems for process automation or aggregate data to drive business intelligence (BI), it is clear that data integration and management must deal with many disparate data types used in a variety of ways.

15.2 "BIG DATA"

Big data problems are characterized by challenges that aren't easily or economically solved by conventional data warehousing approaches. To name a few of these challenges and their implications:

- The large *volume* of the working dataset necessitates storing the data across many nodes.
- The high *velocity* of the data necessitates streamlined and distributed processing of the data—that is, scaling horizontally by means of cluster computing approaches.
- The large *variety* of the data necessitates schemaless databases and machine learning approaches
- The *veracity* of the data necessitates front-end validity checking and "scrubbing" to ensure the data accurately and reliably reflect the measurement from the field, or whether they have been degraded by time, format conversion, or are bad or missing measurements due to a defective sensor, device, or communications path.

The most challenging of these is the variety and veracity. While utility enterprises are somewhat accustomed to volume and velocity, which they have addressed effectively through specialized solutions like historians and phasor data concentrators, such solutions typically process a single type of data. Emerging applications, such as strategic asset management, require the use of multiple types of data. The variety is a challenge that resists solving by a specialized solution. Since various types of analytics can be performed on various subsets of data, a general, flexible solution is needed to address this problem, so that each analytic could access the data it needs without a custom integration effort. The validity of the data is always a common problem with real-time systems that vary over time. While grid management systems include ways to verify SCADA system data, the use of the data throughout the enterprise requires additional measures to verify the data in terms of the user and the analytics application; for example, the change in state of a circuit breaker is critical for SCADA measurements, but may not be as critical for measuring total circuit-breaker operations over a period of time for an asset management application.

While not all data associated with smart grid fit the definition of big data, due to the increase in the use of sensors, IEDs, and AMI, as well as other technologies creating vast amounts of data resulting in the "OMG we have a lot of data" depicted in Level 0 in Figure 15.1, big data technologies have a significant role to play.

Big data technologies transform data into information and intelligence. While smart grid data are mostly from field sensors, IEDs, and AMI, data sources external to the operational systems can also be very valuable. Social media can be a valuable source of important information during natural disasters and emergency situations, where anyone with a mobile phone can post pictures or updates to social networks.

The key strength of big data technology is to turn unstructured and semistructured data into structured data, that is, to mine specific information from vast amounts of data in a linear fashion. Any data and algorithms that can be broken down into parallel processing and be scaled linearly would be a good candidate for big data technologies. For example, a PMU (Phasor Measurement Unit) is a good candidate for postprocessing and analysis using big data technology. Some big data may be stored in their original forms on a big data appliance for future analysis without a substantial effort to design and implement an Enterprise Data Warehouse (EDW) solution ahead of time.

15.3 HIERARCHY

The overall theme in smart grid analytics involves continuous data transformation into actionable information, which, in reference to Figure 15.3, can take place at multiple levels of the grid management hierarchy.

Level 0 is the "distribution field device" level, which captures data from monitoring and control devices outside the substation down the distribution feeder to the customer interface. Analytics at this level is typically done by embedding dedicated algorithms into field IEDs, controllers, monitors, and meters. For example, a solar inverter controller could host specific algorithms to perform real-time waveform analytics on the value streams it receives from local sensors and turn that into an asset health index or production performance index for the associated solar panels.

Level 1 is the "substation device" level. It includes applications and algorithms implemented in each individual substation IED, controller, monitor, and meter. An example use case for this could be to develop an overall feeder vulnerability index based on disturbances that impact the substation bus measurements.

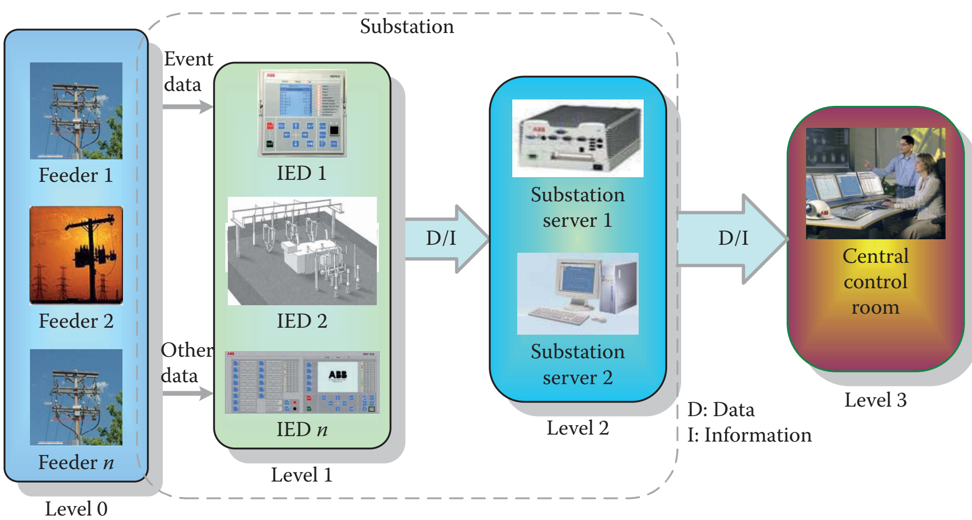

FIGURE 15.3 Grid analytics hierarchy. (© 2016 ABB. All rights reserved. With permission.)

Level 2 is the "substation system" level that includes applications and algorithms for extracting information from multiple IEDs (inside and outside the substation) via a substation computer or gateway. This is where the results from Level 1 can be aggregated, filtered, and analyzed.

Level 3 is the "control center" level. It includes the data warehouse/historians along with applications and algorithms in control centers, some being regional control centers. Grid analytics at this level include use cases related to outages, asset health, and energy management, and start to exhibit the characteristics of big data (volume, variety, velocity, and veracity).

Level 4 (not depicted in Figure 15.3) is the "enterprise" level and aggregates data and information from multiple regional control centers for system-wide decision-making and planning. Monitoring and improving overall grid resiliency and enforcing cyber security of the utility operational and information systems are prime candidates for analytics at this level, which also benefit the most from big data technologies.

As the data/information flow up from field devices to the next level, the ratio of raw data to information should ideally be reduced. In other words, by utilizing data analytics at each step of the process, raw data are filtered and turned into information, which is, in turn, used to derive the next level information in the next upper level. For example, feeder IEDs can host algorithms that use waveform analytics to identify an abnormal operation, such as a fault, or the IEDs can monitor field communications to detect a malicious cyber attack. Based on this local analysis, IEDs can take an appropriate action, such as operating appropriate circuit breakers or switches, and forwarding the fault/event information to the next higher level of the hierarchy (which can be a substation computer). This minimizes the amount of data that must be sent up to the substation or control center, and has the additional positive impact of reducing the communications bandwidth required.

15.4 ARCHITECTURE

Understanding the general latency differences and relationship between data acquisition and analytical processes is an important consideration in designing a robust architecture that integrates and analyzes data with suitable performance, speed, and scalability. Figure 15.4 depicts these relative latency differences while highlighting typical components for implementing big data, data integration, and analytics into a utility enterprise for smart grid applications.

Big Data Capture and Integration: A Big Data Appliance is a converged hardware and software platform for big data that can be used to capture and analyze data from a wide variety of sources. Big data integration and analysis should support all enterprise data, whether the data are structured or unstructured, which are often collectively referred to as the "Data Lake." Data access refers to software and activities related to storing, retrieving, or acting on data housed in the overall data repository system. Solutions are usually a hybrid of technologies, with each component using different methods and languages. It is noteworthy that many of these individual repositories will store their content in different and incompatible formats. Big data solutions provide data scientists with tools to access data from multiple heterogeneous (i.e., relational or nonrelational) data sources. These distributed data can then remain housed in the type of store most optimal for its volume and variety. Big data integration usually occurs over a distributed file system that enables files to be divided into large blocks and distributed across a cluster of nodes. The Hadoop Distributed File System (HDFS) is an example of a storage solution that can address long-term data storage needs for files, including waveform, telemetry, and events.

Data Integration: ETL (extract transform load)/ELT (extract load transform) and CDC (change data capture) technologies are needed for many utility systems, including back-office, operations, and front office, that store their transactional data in relational databases in order to support analytical data movement into the EDW for reporting and analytics.

Enterprise Service Bus (ESB): The ESB is the middleware that allows systems to integrate with each other through standard protocols. The IEC CIM (Common Information Model) and its related standards already provide a set of messages for utility applications to interoperate.

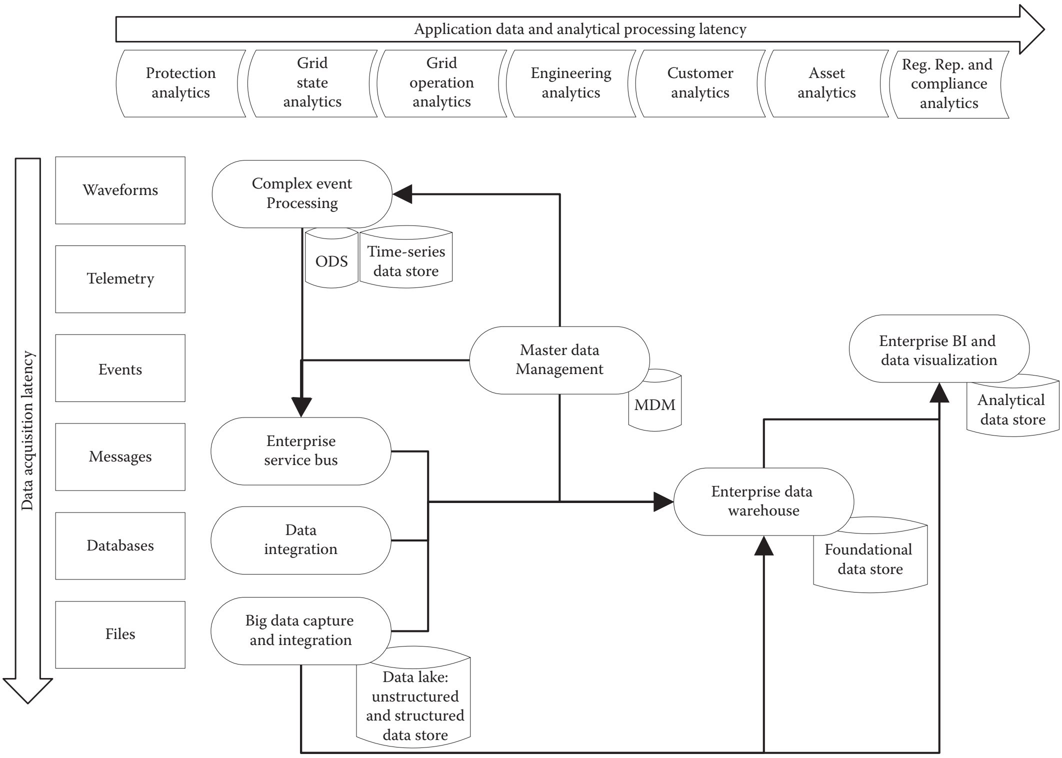

FIGURE 15.4 Latency considerations in big data and analytics solutions. (© 2016 Xtensible Solutions. All rights reserved. With permission.)

Complex Event Processing: The Complex Event Process (CEP) engine manages complex events in real time, such as from field devices as well as the demand for decision-making. A CEP engine usually integrates with time series data that can be stored in an ODS for the short term.

Operational Data Store (ODS): An operational data store is a database designed to integrate data from multiple sources for additional operations on the data. Unlike a master data store, the data are not passed back to operational systems. It may be passed for further operations and to the EDW for reporting. Because the data originate from multiple sources, the integration often involves cleaning, resolving redundancy, and checking against business rules for integrity. An ODS is usually designed to contain low-level or atomic (indivisible) data with limited history that is captured "real time" or "near real time" as opposed to the much greater volumes of data stored in the data warehouse generally on a less frequent basis.

The Time-Series Data Store: This data storage is optimized for handling time series data, arrays of numbers indexed by time. A time series of energy consumption can be used for understanding a load profile. Business rules and high transaction volumes can make it difficult for traditional relational database management to efficiently implement query operations, so these types of data are often stored in specialized databases. For example, integration of multiple time series data sets may only be practical when the time tag associated with each data entry spans the same set of discrete times for all data sets across which the integration is performed.

Master Data Management (MDM): Gartner defines MDM as "a technology-enabled discipline in which business and IT work together to ensure the uniformity, accuracy, stewardship, semantic consistency and accountability of the enterprise's official shared master data assets. Master data is the consistent and uniform set of identifiers and extended attributes that describes the core entities of the enterprise including customers, prospects, citizens, suppliers, sites, hierarchies and chart of accounts" [1]. With master data managed and provided as a service, the data will not get corrupted as they traverse the enterprise. MDM is key to supporting the single version of the truth architectural goal. System of record data and data relationships are needed to navigate through the various domains on anything beyond a small scale. With MDM, the Foundational Data Store can consume the data and then establish shared dimensions of all the data. MDM functionality can be achieved in different ways: providing a registry for information about an object and cross-references for disparate object identifiers, consolidating data from multiple sources and integrating into a single repository for replication to other destination systems, federating by having a single virtual view of master data from one or more sources, and data propagation, which is the process of copying master data from one system to another. However it is constructed, the foundation of the MDM solution will be the master data model, and this model will be complicated to build and maintain if it is not based on a common data model.

EDW: The EDW is critical for accurate and repeatable data analytics. A data staging area exists between the data sources and data targets and is typically supported in data warehouse appliances. Inbound staging supports the transmission from external systems and transformations, such as cleansing, decoding, harmonization, and changed data capture. Data staging areas are often transient in nature, with their contents being erased following successful completion of a transfer process. The Foundational Data Store gathers information and serves up data to the analytic layer. This foundation layer contains reference entities and tables (used to store master reference entities, nonchanging or infrequently changing data), base entities (store transactions from systems of record, contain data at atomic level, and are required to perform detailed analysis, and uncover causal effects and associations), and lookup entities and tables.

BI, Data Mining, and Visualization: BI, data mining, and visualization tools are critical to making analytics work for end users. Key requirements that drive the tools' adoption at utilities are ease of use, integration with geographical data and visualization, and ease of data access and manipulation for analysis. Some of the analytical data will be transformed and stored in the Foundational Data Store of the EDW. While foundational and analytical data stores are shown separately from a functional and processing latency perspective, they are often part of the same physical EDW. The analytical data store is typically used for operational reporting and data mining. This data store also contains aggregate entities that provide information to analyze and summarize, and enables dimensional analysis on a wide variety of subject areas.

Data Management and Common Data Model: Big data technology is excellent at answering a few questions using a large amount of unstructured data that express the same thing. A data model is often not used for big data because a big data algorithm is typically applied to a very narrowly defined dataset. However, a utility requires many types of analyses that span multiple datasets. These types of analyses are best achieved using congruent information maintained in structured data stores. The Enterprise Semantic Model (ESM) (also discussed in Chapter 14 of this book) is the suggested approach for providing the necessary common data model and data relationship across utilities' business domains. Big data analysis results will then be integrated and have capabilities beyond those provided with individual business systems. Figure 15.5 represents a reference architecture for analytics data. The ESM is used to establish a common vocabulary for both services and data stores, and ensures that all enterprise analytics is performed with a common vocabulary. Data are understood and accessed consistently regardless of the source.

This data management approach enables the following benefits to be achieved:

- Establishes a single version of truth for data
- Enables the control of unnecessary data duplication and proliferation
- Improves data quality, integrity, consistency, availability, and accessibility
- Provides flexible and scalable process integration and automation
- Reduces life-cycle costs for integrating systems and data stores

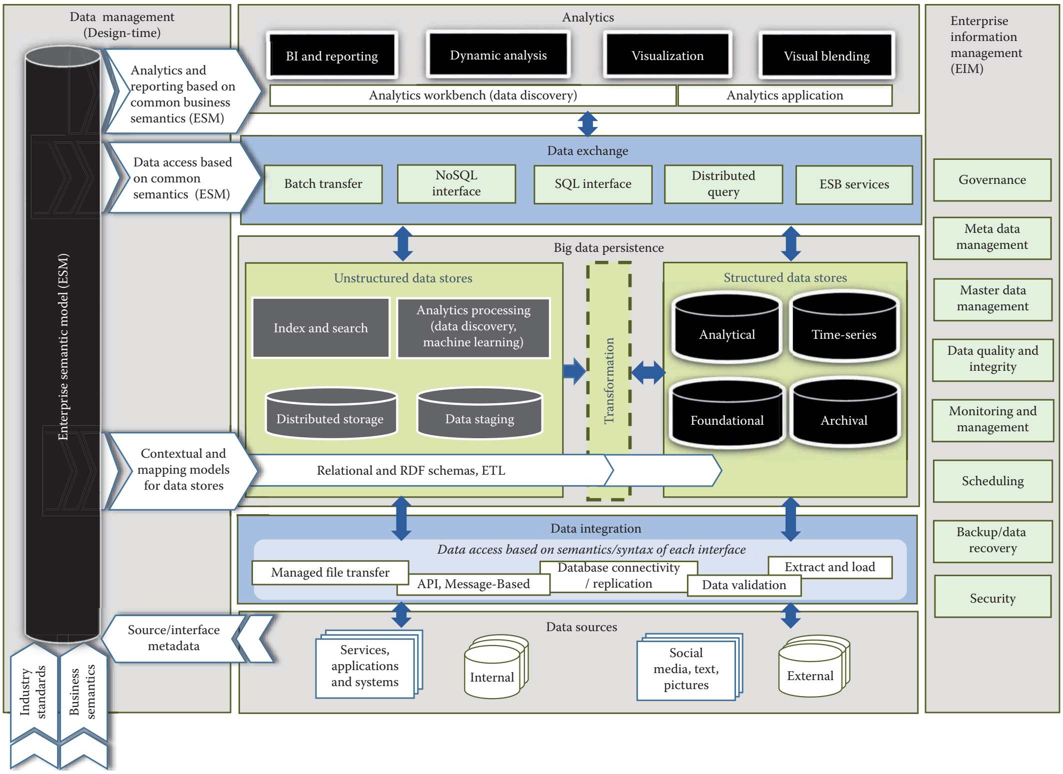

FIGURE 15.5 Data management for big data and analytics. (© 2016 Xtensible Solutions. All rights reserved. With permission.)

- Enables integration and analytics to be performed in step with business needs, while ensuring that each increment of functionality aligns with the overall solution.
- Minimizes impact on existing systems and data stores when replacing a system.
- Allows the assimilation of data required for holistic decision-making, analysis, planning, risk management, reporting, and so on.
- Allows for the development of new reports and functionality not previously available in any of the off-the-shelf applications.

Broad categories of analytics utilities use (shown in Figure 15.4) include:

- *Protection and Control Analytics:* Power systems protection and control can be automated and driven by human decision-making, both of which require data acquisition and decision-making in real time, ranging from milliseconds to seconds, depending on the application and human intervention required. For example, protection and control analytics could be used to optimize the coordination of control and protection schemes during reconfiguration of the grid (e.g., after a fault), or in response to the varying levels of distributed energy resource (DER) supply on the grid.
- *Grid Operational Analytics:* Operation of the grid requires a constant feed of data and analysis, from historical data to real-time monitoring to predictive analysis. This is an area where opportunities to combine data from various systems and devices exist to provide more insight into the current state of the grid, as well as to provide more predictive and prescriptive analytics to assist grid operations. The purpose of monitoring operating states is to observe and analyze the behavior of the overall power system, such as steady-state

power flows and incipient voltage collapse, and disturbances caused by dynamic swings of machines, power quality distortions, or switching transients. Different recording devices, such as dynamic disturbance recorders (also known as swing recorders or phasor measurement units), power quality meters, and high-performance data loggers for transient recording, provide data that can be made available for historical and predictive analysis.
- *Asset Analytics:* Asset analytics make an increasing amount of historical and real-time asset health data available to asset managers so that asset performance predictions are more accurate. Meter data analytics is a key part of asset management. Assets also must be installed and maintained with an awareness of both environmental impacts on the assets (salt corrosion, ice, water, sand, etc.) as well as impacts on the environment by the assets. The latter is subject to many forms of government regulation. Asset risk management is used to monitor, understand, and manage the risks involved in business activities, and ensure that policies, processes, and practices are followed accordingly.
- *Engineering Analytics:* Engineering analytics uses historical data to assist with capacity planning and load forecasting to ensure optimum network upgrades and expansions. This includes the ability to model customer load profiles using smart meters and provide load aggregation and forecasting starting at the customer level of the grid.
- *Consumer Analytics:* Understanding and analyzing consumer demographics, consumer behavior, and consumer DER choices facilitate efficient and proactive customer support. Consumer analytics requires integrating utility internal customer data with external data sources, as well as linking the data sources to the operational and engineering sides of the business.
- *Enterprise Performance Analytics:* Enterprise performance analytics includes the majority of back-office functions, such as financial, human resource, supply chain, and project management functions.
- *Regulatory Reporting and Compliance Analytics:* This is another area of utility business that will see increased reporting for compliance purposes and will require data from many areas of the business.

It is noteworthy that COTS (commercial off-the-shelf) analytical products are fragmented as they each focus on a different segment of analytical users. Within each of the aforementioned broad categories, there are many types of analytic products that focus on a small subset of the overall category. This problem is minimized when utility analytical models are based on the data management approach described earlier. While a utility's ESM typically includes the IEC CIM, it also used to expand the interoperability of utility systems beyond the IEC standards. A benefit of having "CIM inside" is that because many vendor systems already support the CIM-based interfaces, it is easier to integrate those systems with other utility systems and data stores. Furthermore, a utility can utilize their ESM to develop a standard "event model" for events coming from a utility's various field devices (from IEDs, to communication devices, to consumer devices). With a standard event model, out-of-the-box event-processing rules can be pre-configured as the starting point for a CEP-based solution for real-time operational analytics. Events expressed in a standard format using the ESM will also be easier for downstream processing using big data technology and an EDW.

15.5 SMART GRID EXAMPLES

15.5.1 Asset Management

Asset management is a domain that spans the utility enterprise, stretching from the customer premise meters to substation assets to lines and poles, and involving disparate functional areas of planning and procurement, maintenance, and operation. Moreover, given the large installed base of assets and the significant replacement costs, many assets are routinely in service beyond their nominal lifetime. The asset-management decisions that play out on a daily basis are varied and complex and are, therefore, best made on the basis of a dispassionate analysis of relevant data. For instance, high-value assets, such as power transformers, are routinely kept in service beyond their nominal lifetime. From a planning and procurement perspective, the analysis for the repair versus replace decisions for such assets is driven by risk-management calculations. From a maintenance perspective, right-sizing the maintenance program requires an accurate assessment of the asset condition, which is made on the basis of asset health analytics. From an operational perspective, the smart trade-off between use-related deterioration against revenue is a key aspect of maximizing efficiency of the asset. These are some of the considerations in what constitutes a multidimensional problem.

The use of financial and risk management principles for asset management is gaining momentum. The crux of this approach is to use analytics that, on the basis of all available data pertinent to the assets, computes health scores, ranks the assets, and provides actionable intelligence. There is a range of such analytical solutions being deployed in utilities, ranging from ones that focus on a particular asset category to comprehensive Asset Risk Management System (ARMS) solutions that span multiple asset classes and incorporate multiple analytics packages. The focus of ARMS on optimally and sustainably managing assets, their performance, risks, and expenditures differs from and complements the procurement planning and work-centric viewpoints of Enterprise Asset Planning (EAP) and Work and Asset Management (WAM) systems.

Organizationally, the implementation of a strategic asset management program, as embodied in the British standard PAS-55 and the International standard ISO 55000, enables the institutionalization of asset management best practices and consistent outcomes in this era of aging workforce and ever-increasing demands on the assets. As illustrated in Figure 15.6, analytics systems, such as ARMS, would be a key element of such a strategic asset management program.

Data sources within utility enterprises recognized as valuable for asset health assessment include:

Online Monitors and IEDs: Examples of online monitors are Dissolved Gas Analyzers (DGAs) and IEC 61850 Intelligent Electronic Devices (IEDs). In addition to the measurements, such devices may also provide additional information. Device characteristics, such as the sensor accuracy, are helpful information in terms of assessing measurements from such devices. An analytic that utilizes online monitoring data may obtain the data directly from the device by way of the native protocol that the device uses to communicate the measurements, for example, DNP3 or MMS-mapped 61850, or from a database system, such as a SCADA Historian that receives and archives the data from the device. In addition, new data sources are being investigated for asset analytics purposes. For instance, the use of Phasor Measurement Unit (PMU) data will help to assess incidents in

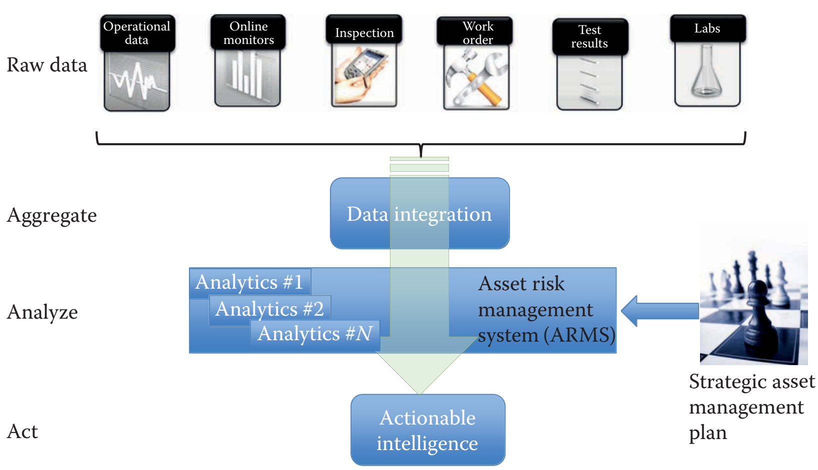

FIGURE 15.6 A strategic asset management program. (© 2016 Doble Engineering. All rights reserved. With permission.)

generators, oscillations in wind plants, and failure modes in transmission equipment, and ultimately be able to predict and protect against them. With the advent of MicroPMUs, which are low-cost units designed for distribution networks, the prevalence of these types of data is expected to increase rapidly. PMUs and MicroPMUs can produce immense amounts of high-velocity data. A MicroPMU typically makes 120 measurements per second for 60-Hz systems and may produce on the order of 1 MB of data per minute, or about 500 GB of data per year. When critical line segments and transformers are monitored with such devices, it is easy to see the high data volume and velocity from this data source alone.

Field Test Results: Examples of field tests are dielectric loss/power factor tests on transformers. For such tests, there are test plans describing, for instance, between what points measurements are to be taken: high winding to low winding, high winding to ground, low winding to ground, and so on. The outcome of the tests includes the measurements as well as the conditions under which the measurements were taken. The measurement outcomes are typically stored in a relational database. An analytic that utilizes these data also needs the details of the test plan, which may be in the form of a document, and the nameplate details of the asset, which may be in a different system.

Inspection Results: Inspection data typically involve the filling out of a paper or electronic form. Examples are substation inspections with a handheld data capture device. The data captured could include numerals such as readings from dials, Boolean such as switch status, and free-form text such as the description of animal activity. Such data could be stored in a relational database or, in case of the need for a multiplicity of forms with custom fields, a schemaless database.

Survey Results: Examples of surveys are aerial LiDAR surveys of transmission corridors, IR thermography of substation assets, and partial discharge surveys of insulation systems. The measurements from such surveys are typically held in self-contained systems, such as the LiDAR data in a GIS, and these systems may have some built-in data processing and exploration capabilities. In a strategic asset management setting, such data should be made accessible, either through an application programming interface (API), or by storing in a database for wider use in analytics.

Lab Test Results: Lab tests are most commonly performed on oil samples, which may be tested for dissolved gases, oil quality, and contaminants. The tests are intended to evaluate the condition of the oil and its ability to perform its function. Considerable contextual data are also generated for these tests: for instance, when was the sample collected and when it was brought to the lab, the ambient conditions during the sample collection, the standard according to which a particular test was conducted, the equipment that was used in the test, the temperature at which the test was conducted, the lab that conducted the test, and so on. These data could be delivered in a report, stored in a relational database, or stored in an oil analytic system from which the data are accessible for the asset analytics application.

Other Utility Systems: Other applications and systems used by the utility are also very useful sources of information for asset management. These other sources include:

- SCADA Historian for online monitoring and telemetered data, and electrical configuration and connectivity
- Geospatial Information System (GIS) for physical configuration and connectivity
- Work and Asset Management Systems (WAMS) for work and maintenance history, and, in some cases, inspection, survey, and field test results
- Databases that store results of diagnostic field tests

Consumer and External: Various submeter data, such as from electric vehicles (EVs) and customer-reported information on social networks, such as Twitter, are being investigated as well.

Some data are held in ad hoc forms and are not in persistent storage systems. For example, test results could be in spreadsheets or flat files. Also, data from an online condition monitor may be stored in the device itself, and only the alerts from the device are manually checked. In such cases, it makes sense to put in place data persistence systems to extract value from the data. With the maturation of cloud-based technologies and the strengthening of security measures around them, it may make sense to consider cloud-based systems for such ad hoc data sources. There is clear movement in this direction in the electric power industry, with many utilities developing well-considered security policies that address the types of data that could be hosted in the cloud, which typically include asset condition assessment data and the security controls required. Dealing with a variety of data sources without extensive and expensive replication of data is a challenge.

Taken together, the data sources used in asset analytics constitute volume, velocity, and variety not seen in legacy utility applications. The various data systems identified as valuable for asset management are owned by different entities within the utility enterprise. Owing to organizational, data ownership and security barriers, it is typically very challenging to bring together the disparate datasets. But there is substantial value in being able to access the data together for analytical purposes. An advantageous approach to doing so is to leverage an international standard, such as the CIM, developed by the IEC Technical Committee 57 (TC57). Ideally, the CIM would be used as a core part of the ESM discussed earlier. Because the CIM standards clearly identify the data profiles that are needed for a business use case or process of interest, the utilities could implement role-based access control (RBAC) or attribute-based access control (ABAC) schemes to allow the access of only the data necessary for their use cases. By sharing only the necessary data and no more, the utilities can realize the value in their data while ensuring overall information security.

One manifestation of a CIM-based implementation in a distributed environment is the implementation of a discovery database that has some basic classifying information about the assets and pointers to various information objects available about the assets. Some asset classifying information of interest include type, life-cycle state, nameplate ratings, location, criticality, and ownership. Such an asset database is depicted as an Asset Registry in Figure 15.7. In addition to classifying information, the asset registry would likely also be involved in the resolution of the different identifiers used to identify assets either directly or in conjunction with a business data registry. It would also need to be able to reconcile the different views of an asset (e.g., assets that are viewed in terms of their components where information is also maintained at a component level versus assets that are viewed as a single entity, which would be typical in an Enterprise Asset Management [EAM]) system.

If, as shown in Figure 15.7, the data exchange is CIM-based, the information objects can instead be more effective in the form of asset management profiles. In this case, it could be implemented as

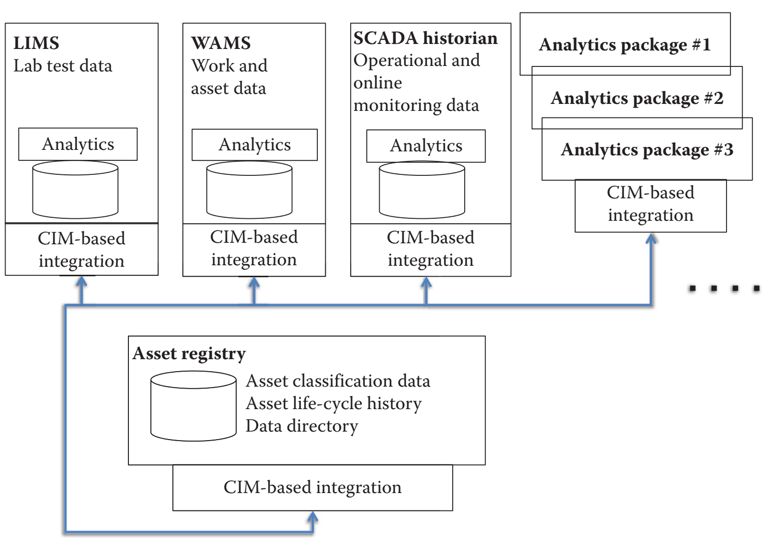

FIGURE 15.7 Illustration of Asset Registry-based data exchange and aggregation. (© 2016 Doble Engineering. All rights reserved. With permission.)

a simple lookup table. For example, one profile in the IEC 61968-4 CIM standard is AssetCatalogue, which is intended for exchanging product model information. This profile is shown in Figure 15.8. Any system that implements this profile can be identified on the Asset Registry. An analytic that is interested in catalog model information could obtain such data by issuing a GET request to the systems that implement this profile. It is possible that multiple systems have different subsets of information in this profile; for instance, a catalog system might have the catalog information (catalogueNumber, corporateStandardKind, etc.) and the ratings information (one of BusbarSectionInfo, BushingInfo, etc.), whereas a different system might have the list of assets (Assets) that are of the said model. Given such a flexible data-sharing environment, the asset analytics packages are able to obtain the data they need, and the challenge then shifts to being able to process the data in a timely fashion. To solve the challenges of volume and velocity in processing the data, mature technologies could be leveraged. For instance, big data processing infrastructures, such as ones using Apache Hadoop and Apache Spark, may be commissioned and shared between multiple analytics packages. Infrastructure as a Service (IaaS) and Platform as a Service (PaaS) cloud technologies have elucidated the commissioning of such environments.

A flexible data-sharing environment and a big data processing infrastructure form the underpinnings of strategic asset management, as well as the other big data applications within utilities. The crux of asset analytics and, in particular, the Asset Risk Management Systems (ARMS) is that, on the basis of all available data pertinent to the assets, they must compute health scores, rank the assets, and provide actionable intelligence. The objective is to provide strategic asset management by enabling optimal and sustainable management of assets, their performance, risks, and expenditures. Typical information exchanges for such applications include:

- Asset data from enterprise data sources to ARMS
  - Asset list and characteristics provided by EAM to ARMS
  - Asset location data provided by GIS to ARMS
  - Asset measurements and test results provided by historian and test databases to ARMS
  - Asset inspection and maintenance data provided by EAM/WAMS to ARMS
- Actionable intelligence from ARMS to various enterprise systems
  - Risk-ranked asset list provided by ARMS to EAM for replacement planning
  - Asset health and condition assessments provided to GIS for provision to the field force
  - Work request provided to WAMS on the basis of deteriorating health indicators

A specific realization of ARMS focused on substation assets may comprise the following elements:

- Online condition monitoring devices for power transformers, circuit breakers, and batteries provide data to a historian.
- Diagnostic test results and inspection results are stored in database systems.
- An analytic suite continuously assesses the data to determine asset condition. For instance, in the case of a power transformer:
  - Among the analysis would be the monitoring of dissolved gases in the transformer oil for the presence of any fault condition indicators.
  - If the assessment predicts a health event, such as a high risk of bubble formation, an actionable intelligence alert is provided to designated systems and persons.
- An analytic suite periodically assesses and helps optimize the asset use.

Similar such analytics packages could be deployed for other asset categories, such as lines and structures. Other analytics applications may include the management of distributed generation and alternative energy sources, self-healing wide-area protection and monitoring, demand response and real-time pricing, and energy market participation.

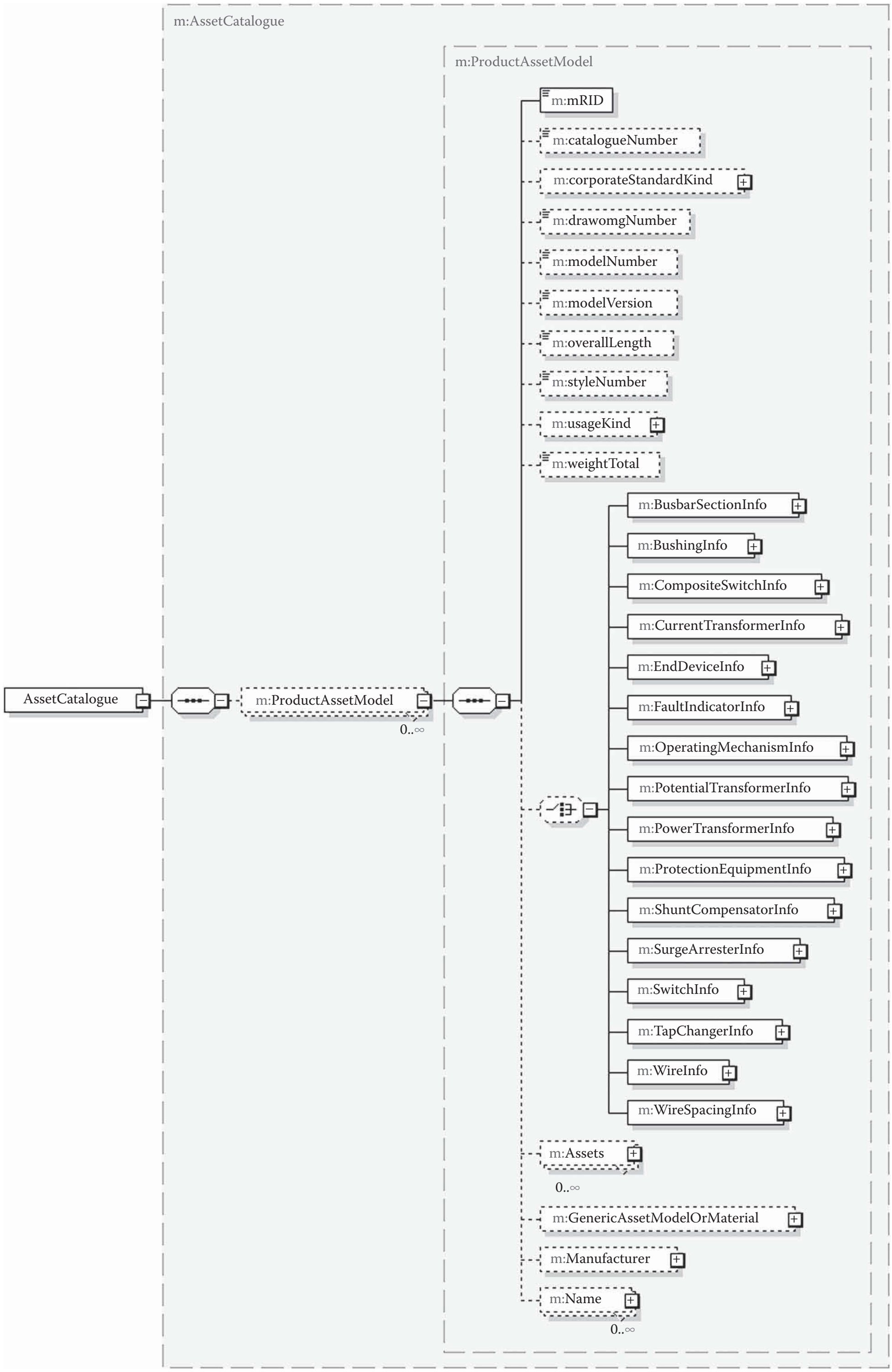

FIGURE 15.8 IEC CIM profile for exchanging asset catalog information. (© 2016 Doble Engineering. All rights reserved. With permission.)

15.5.2 Waveform Analytics for Enhanced Outage and Reliability Management

Areas that can benefit significantly from feeder-level real-time analytics include outage detection, confirmation, notification, and crew dispatch. Electrical faults and the resulting outages on distribution feeders result in loss of revenue and adversely affect customer satisfaction and reliability. Such events contribute significantly to customer-minutes-out and ultimately impact the utility's performance. For example, some feeder faults do not cause the substation breaker to operate and, if there is no remote monitoring of the feeder downline outside the substation, the fault does not generate a reportable SCADA event. As a result, the utility has to rely on customer calls or customer meter reports for notification of sustained outages on the distribution system. This type of delayed, reactive response can become a thing of the past if appropriate data analytics technologies are deployed.

Waveform (oscillography) data can be helpful in real-time event analysis to reduce the time required to respond to an outage by enabling the operators to address the problem before an outage report is received, or by avoiding the outage altogether by detecting incipient faults. Furthermore, this level of analytics improves the utility's preparedness for outage calls and provides an effective tool to confirm the reported nature of the incident. In particular, by detecting incipient faults that are on the verge of escalating into full-blown failures, asset and reliability managers can optimize the annual maintenance and reliability improvement expenditures.

Figure 15.9 shows a schematic of a feeder with the overlaid data flows to enable waveform analytics. Data from field IEDs and sensors are captured in the form of disturbance waveforms, aggregated at the substation level and analyzed for operator decision-making with respect to the appropriate

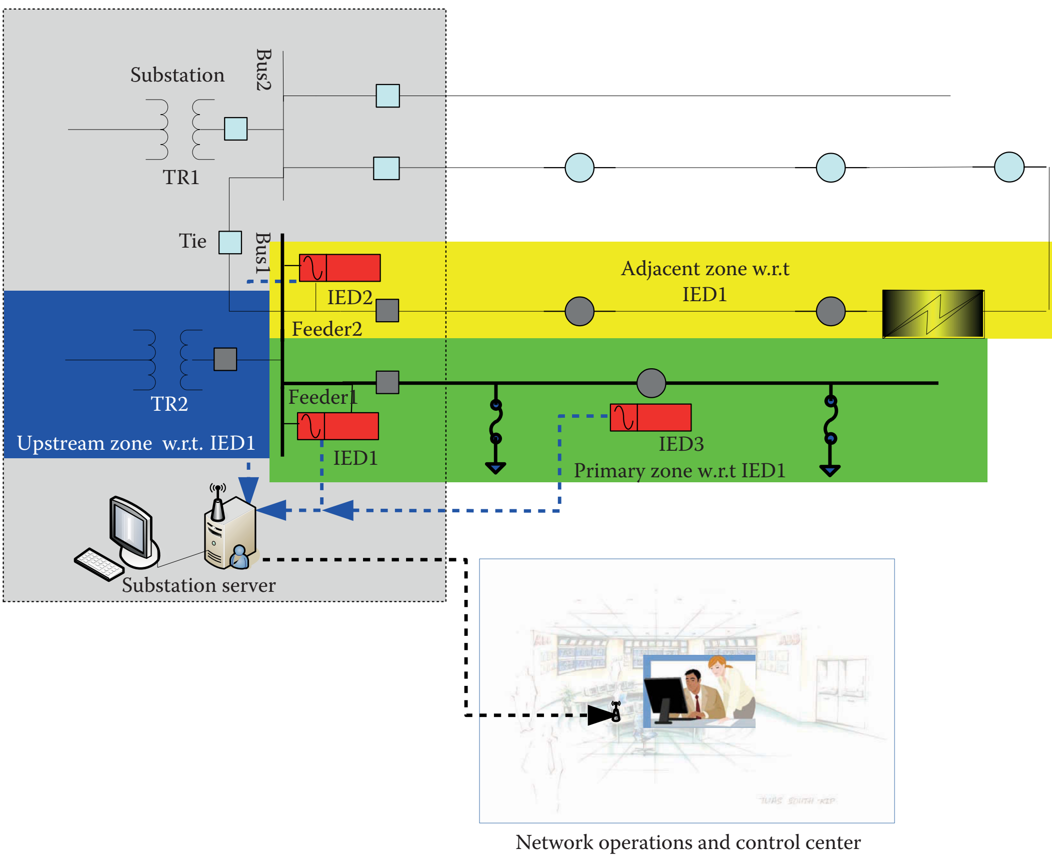

FIGURE 15.9 Waveform analytics applied to feeder IEDs. (© 2016 ABB. All rights reserved. With permission.)

response. Waveform analytics in this case drives the process, turning digital fault signatures into operational intelligence meaningful to human operators as illustrated in Figure 15.10.

Compared to traditional SCADA alarms and meter reports, data analytics provides an in-depth evaluation of the disturbance. The primary value delivered by the analytics engines running in the field IEDs, substation controllers, or control center computers is knowledge or situational awareness. The dispatchers will have more knowledge when a feeder fault/abnormality occurs that is either self-clearing, incipient, or is cleared by a device not monitored by SCADA, for example, reclosers or switches further down the feeder, or cleared by an unintelligent device, such as a fuse. This information, if delivered in a timely manner, enables the utility to reduce the duration of sustained outages or avoid problems that will eventually lead to sustained outages and reliability degradation. As a minimum, the information delivered by the analytics system should include substation and feeder identification, faulted phase, magnitude, type, zone, and time of occurrence.

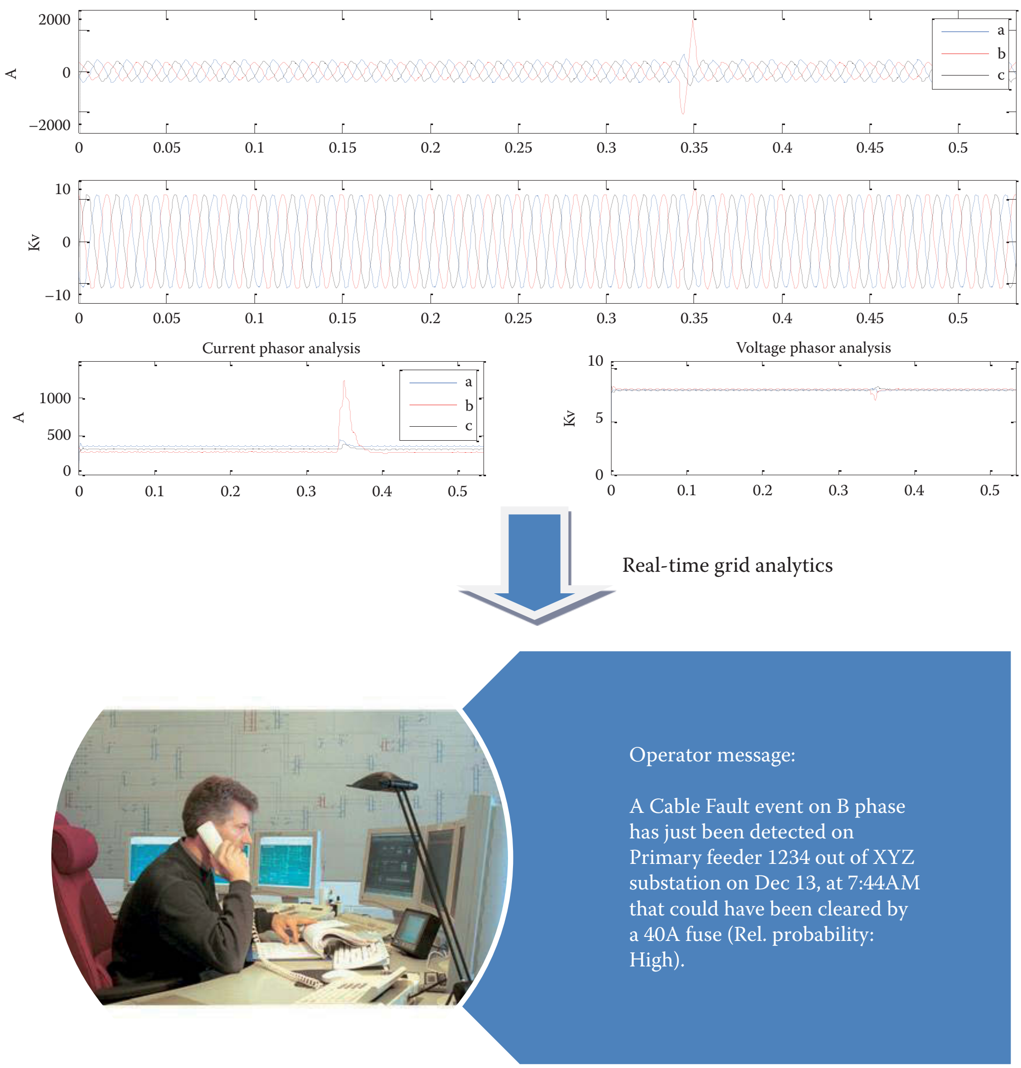

FIGURE 15.10 Real-time grid analytics turn waveform data into intelligence meaningful to operators. (© 2016 ABB. All rights reserved. With permission.)

TABLE 15.1
Example of Waveform Analytics Data Improving Outage Management

	Analytics Engine	OMS
Case # 955	**Predicted**	**Actual**
Time of event	12/13, 7:44 am	12/13 8:02 am
Substation	XYZ	XYZ
Feeder number	1234	1234
Phase	B	B
Event classification	Short-duration feeder fault (high probability)	Cable fault
Infrastructure	UG (80% probability)	UG
Clearing device	Fuse	Fuse
Clearing device size	Range: [10A, 65A] estimate: [40A, 0.981]	40A
Location	Primary zone, segment X	Primary feeder
Time of restoration	N/A	9:45 am

Waveform analytics can be predictive with respect to an outage management system. An example comparison is provided in Table 15.1 where the waveform analytics prediction is approximately 20 min ahead of the outage detected by the outage management system, which, when scaled across the utility over time, could lead to a significant boost in reliability with respect to outage metrics, such as SAIDI. Furthermore, the information derived from the fault record goes well beyond a pure indication of a fault. This level of intelligence is where grid analytics makes a clear impact.

The technical approach in real-time grid analytics draws upon statistical decision theory, machine learning, pattern analysis, and signal processing techniques, harvesting the latest tools and methodologies developed in computer science, statistics, and mathematics disciplines. The design process generally involves all or some of the five step cyclical process depicted in Figure 15.11.

The general design process starts with the data collection and integration/cleansing phase. Data collection was originally the greatest challenge in real-time grid analytics. With the proliferation of sensors, meters, and other data sources in smart grids, data collection is no longer a major impediment. Data access, sharing, cleansing, and integration, however, remain an industry challenge. Next is the data mining phase where insights are drawn from a seemingly random sequence of numbers and characters. The outcome of this crucial phase is a set of initial characteristics that best describes the behavior or model under study. If the use case is fully developed, this step can be straightforward and may be the terminal point. Feature extraction is where dimensionality reduction takes place in which potential redundancies in the initial attributes are removed, leading to a lean model selection in the subsequent step for classification, regression, and so on. Once an appropriate descriptive model is found, the final step involves testing and verification. This process continues until a satisfactory performance is achieved based on the specifics of the use case. Once the design is completed, the deployment phase uses the configuration set determined during the design process in an open-loop process from data to actions.

The ultimate design is often a trade-off between accuracy and complexity. For field implementation, such as in a substation computer, the design process cannot be decoupled from the host platform attributes and hardware requirements. For that reason, an analytics solution that is intended to be deployed on field controllers enabling edge analytics will have different performance targets and design than a solution that is intended for control room or centralized applications (cloud or mist analytics). The available spectrum for innovation and business impact is wide and continues to widen with the proliferation of sensors, ubiquitous computing, communications, and connectivity. It is only the beginning of a new digital era for the utility industry and beyond.

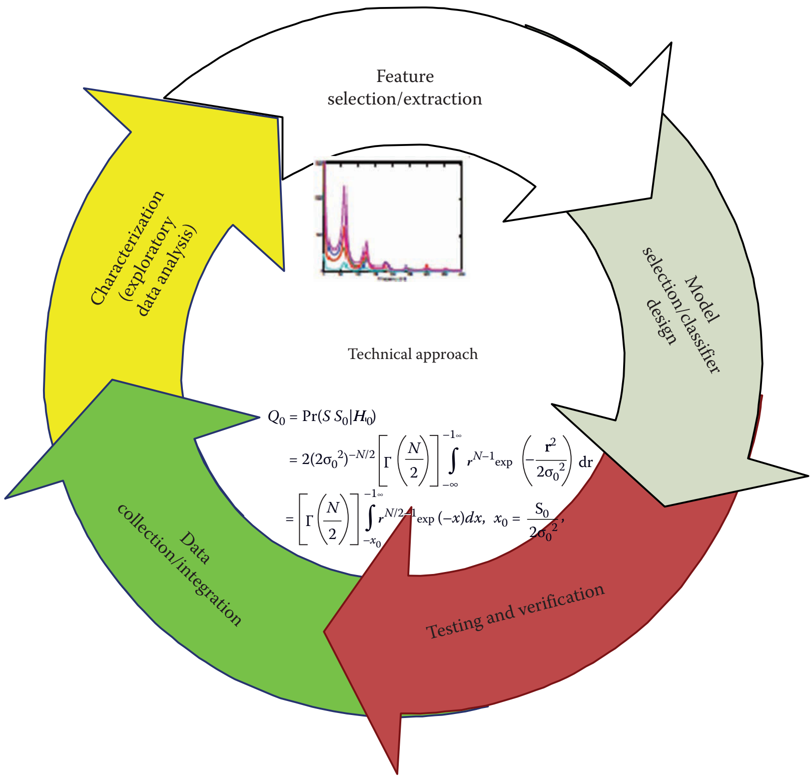

FIGURE 15.11 Cyclical design process in grid analytics. (© 2016 ABB. All rights reserved. With permission.)

15.5.3 Use of Environmental Information

Utilities have traditionally utilized environmental information, primarily weather, in areas such as load forecasting, customer usage inquiries, and operations. Some use cases related to environmental information reflect simple queries and descriptive or diagnostic analytics, such as temperatures over a billing period, to respond to a customer high bill complaint; others, such as load forecasting, are more closely associated with predictive analytics. Typically, predictive analytics such as this utilizes simple algorithms and weather forecasts that cover broad areas. In some cases, "rule of thumb" analytics are primarily used. Historically, sources for weather information were limited, applied to broad geographic areas and not available through automated services. Even with the advent of the World Wide Web and the availability of weather information through that media, utility meteorologists still had to write the information down or utilize screen prints and then manually enter it into whatever analytics applications they might be using. In recent years, that landscape has changed. Many governmental agencies (e.g., NOAA, National Weather Service [NWS], USGS) now provide environmental information through automated services. Commercial weather providers also provide environmental information as automated services, with some allowing tailoring of information received to a fairly granular level. While in general the improved availability is positive, there is also a downside. Because the information is so available, some utilities have found that they are using similar information from multiple sources across various organizations in the utility. In some cases, where it is provided by commercial service providers, they may even be paying for the same information more than once. Just like data internal to the utility, data from external sources should be managed through data integration and governance.

Another issue is the proprietary nature of the automated services through which the information is obtained. While some standards do exist, such as the Weather Information Exchange Model (WXXM), they do not address the broad spectrum of environmental information and tend to be focused toward a particular use. With this in mind, a U.S. utility recently initiated a collaborative project with the Electric Power Research Institute (EPRI) to incorporate environmental information into the IEC CIM. Although the project was initially focused on weather, it quickly expanded to include other environmental factors that are useful for utility analytics. Four categories of environmental information were identified (see Figure 15.12 below):

- *Atmospheric*—this includes what is typically thought of as weather, including wind, rainfall, snowfall, lightning, and so on, but would also include other factors such as volcanic ash.
- *Hydrospheric*—this includes events such as floods, tsunamis, and other events occurring on or in water.
- *Geospheric*–this includes earthquakes, fires, landslides, snowpack, and other events on or beneath the ground.
- *Space*—this primarily addresses solar flares.

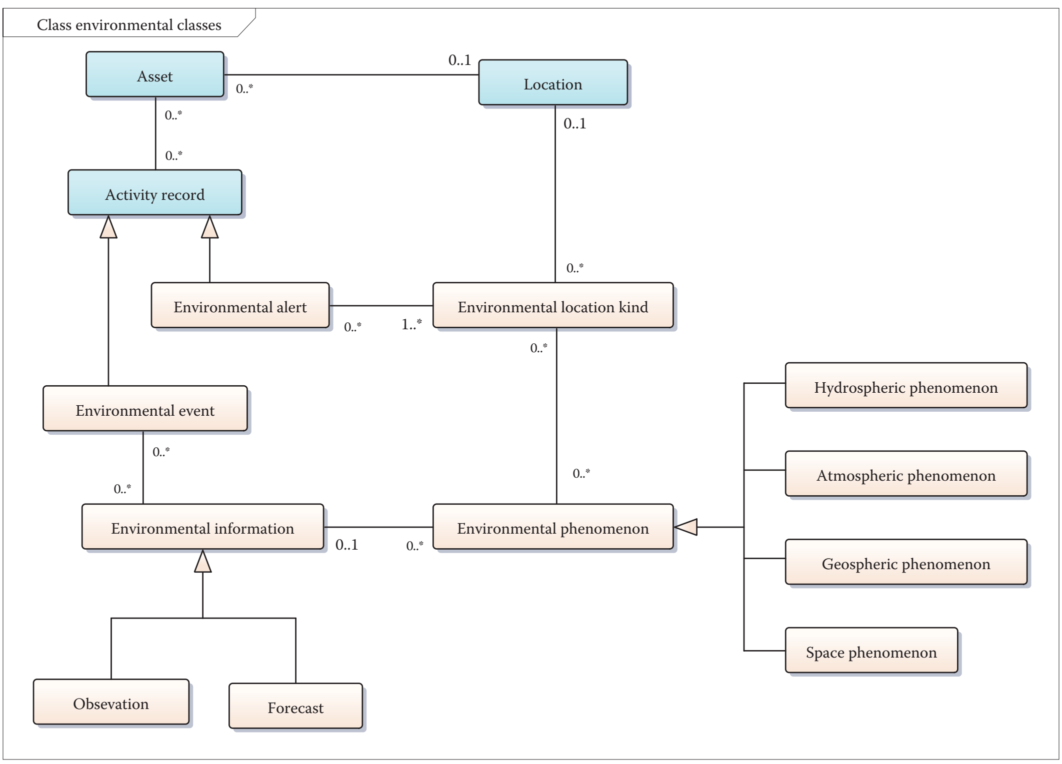

FIGURE 15.12 Categories of environmental information for utility analytics. (Courtesy of Strateture Solutions.)

While ideally all organizations providing environmental information for utilities would conform to the CIM standard, that is not likely to happen. This leaves the utility with the need to implement a new application, a Utility Environmental Data Service (UEDS). Designed using the approach described previously on Enterprise Information Management (EIM), the UEDS would provide the connections to the external data services and the adapters necessary to transform from other standards and proprietary formats. It would also provide the ESM-based services (which includes CIM) for applications to use. This could include providing such capabilities as aggregation, computing averages over time periods, or minimums and maximums and other statistical operations. It might also provide an additional level of intelligence, such as evaluating the relevance of incoming alerts for further distribution. Depending on the need, it would also provide both subscription services (e.g., subscribing to alerts of a specific nature or location) and publishing services.

While the attributes applicable to each environmental category and also within a category may vary, they can be represented in a semantically consistent manner, which allows for the development of standard profiles or messages that can be used by applications regardless of the category. Information across the categories is modeled as environmental forecasts and observations. Environmental observations can be current (e.g., current temperature) or historic. Current observations can be utilized in analytics that can affect real-time operations. An example of this would be the inclusion of real-time lightning strike information in an outage management system and utilizing that information as part of the analysis to enhance outage management. Current observations on fires could also be used to assess impacts to assets, determine resource requirements to replace or repair assets, and determine the necessity for curtailing power. Through the use of standard messages, the same analytics could be applied to other environmental events, such as floods or earthquakes.

Historic environmental observations can be utilized in multiple use cases. An example of a simple use case is the comparison of customer usage to the daily temperatures over the usage period. This could be extended to broader load profiling by customer segments. A more complex area where historical environmental observations come into play is in predictive analytics. Historical environmental observations are typically utilized as an input to determine correlations that form the basis for predictive analytics.

Environmental forecasts are also utilized in multiple use cases. A forecast for rain may affect the scheduling of utility field work, for example. With a more detailed environmental forecast specific to times and locations, then only field work scheduled for those times and locations would be affected. With the increased implementation of DER, forecasts of cloud cover and wind affecting the generation from DERs and analytics will play a significant role in daily operations of the grid. Environmental forecasts are also used as inputs to predictive analytics, such as load forecasting.

Two other components of the environmental model are alerts and events. An example of an alert would be a message emanating from the NWS warning of flash floods. Alerts tend to be fairly general and would trigger subsequent analytic activities, such as retrieving and using forecasts to assess the potential impact of the alert. Alerts could also be generated internal to the utility as an output of analytics. An NWS alert might trigger analytics that would result in the utility issuing an alert to its customers who will most likely be affected. The other component is an event. The event provides the capability to give a "name" to an environmental event (e.g., typically forest fires and hurricanes are given names by governmental agencies), associate both forecasts and observations to the event for both operational and subsequent analytic purposes, and associate affected assets to the event.

When a major storm (rain, wind, snow) is on the horizon, utilities will attempt to prepare for it in advance, possibly staging crew and material, notifying mutual assistance utilities of the potential need, and other proactive activities. However, the determination of how much, who, when, and so on is often based on “seat of the pants”’ or past experience, rather than true analytics. This is an example where predictive analytics can provide value.

The data that may help for this area of analytics include:

- Environmental events (historical)
- Observations (historical associated to the events)
- Outages (historical associated to the events)
- Work tasks/labor hours/resources (historical associated to the outages)
- Asset replacements/repairs (historical associated to the outages)
- Forecasts

Utilizing the environmental forecasts, prior events with observations similar to the forecast would be used to identify the resultant outages and the work and assets associated with them. This would result in the prediction of what type of resources would be required, the number of assets by type likely to be replaced or repaired, and an expected duration. For utilities with large, diverse service territories, the location of the events is also a significant factor as it may affect crew travel time, availability of materials, and so on. Based on this analysis, the utility is better prepared to stage crews and material, as well as proactively provide alerts to customers. The predictive analytics would not be a one-time use, but would be repeated as necessary as additional forecasts are received and while work is completed in order to provide updated estimates.

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16 High-Performance Computing for Advanced Smart Grid Applications

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CONTENTS

The power grid has been evolving over the past 120 years, but it is likely to see more changes over the next decade than it has seen over the past century. In particular, the widespread deployment of renewable generation, smart load controls, energy storage, and plug-in hybrid vehicles will require fundamental changes in the operational concepts and principal components of the grid. Encouraged by aggressive public policy goals, such as the U.S. State of California's push to generate 33% of its energy from renewable sources by 2020, this evolution will continue at an accelerated speed. Within the next decade, it is estimated that more than 15% of electricity will be supplied by intermittent renewable sources, and the U.S. Energy Information Administration estimated 33% of the demand side would have significant uncertain behaviors (Figure 16.1). Distributed generation will supply power directly to the distribution grid, and electric vehicles (EVs) will be able to serve as both mobile and roving electricity consumers and electricity suppliers. The traditional one-way power flow, from generation to transmission to distribution and to consumer, will be fundamentally changed to a two-way power flow. This will result in stochastic operating behaviors and dynamics that the grid has never seen nor has been designed for. To plan and operate such a grid with sufficient reliability and efficiency is a fundamental challenge.

As smart grid evolves and the number of smart sensors and meters on the grid increase by orders of magnitude, the information infrastructure will also need to drastically change to support the exchange of enormous amounts of data. With the significant increase in the number of data sources and the

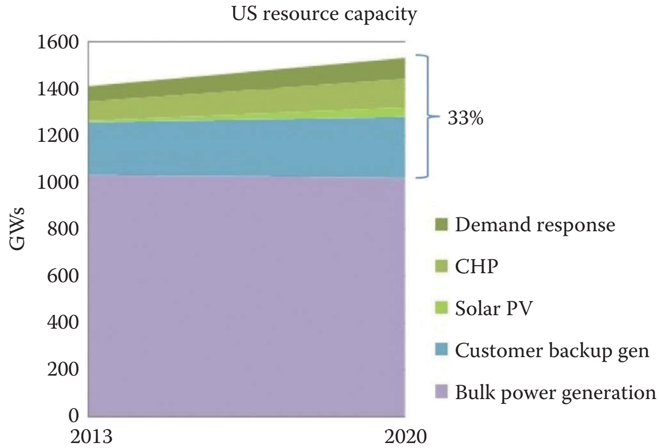

FIGURE 16.1 Estimated participation from the consumer side versus traditional bulk generation. (From EIA, EPA, DOE, FERC, Carnegie Mellon, GlobalData. With permission.)

amount of data, smart grid applications will need the capability to collect, assimilate, analyze, and process the data. In particular, operation applications of the smart grid will need to process data at rates that satisfy the real-time requirements of functions that monitor, control, and protect the grid. Not only will smart grid sensors and meters generate an unprecedented volume of data (estimated at a million times more data), they will also have distinct attributes that differentiate them from traditional power grid measurement devices. For example, sensors that use high sampling rates (30 samples per second or higher) provide an opportunity to more accurately monitor transmission grid dynamics. Other types of sensors will become more prevalent in monitoring the distribution system and the end users, providing transparency into the demand side of the grid. In the traditional scenario of one-way power flows, only limited digital information is required to operate and manage the traditional grid. In contrast, the future grid will have two-way information flow to monitor and control the two-way power flows. This requires not only fundamentally changing the way information is generated, transferred, and managed but also (and more importantly) how the information will be utilized. The challenge is how to take advantage of this information revolution in terms of capturing and processing the large amounts of data. Without addressing this challenge, the grand aspirations of smart grid evolution will remain unfulfilled.

New techniques and computational capabilities are required to meet the demands for higher reliability and better asset utilization, including advanced algorithms and computing hardware for large-scale modeling, simulation, and analysis. High-performance computing (HPC) is considered one of the fundamental technologies in meeting the computational challenges in smart grid planning and operation. HPC involves the application of advanced algorithms, parallel programming, and computational hardware to drastically improve the capability of handling data analysis, modeling, and computation complexity in software applications.

In addition to being driven toward HPC from the complexity due to internal smart grid development, power grid applications are also driven toward HPC by external forces in computer development. Computer processor hardware has been significantly improved over the last decade from about 300 MHz in 1997 to about 4 GHz today. However, the single processor speed (i.e., clock frequency) is reaching a plateau and no longer follows Moore's law [1], due to thermal limitations with the current Complementary Metal-Oxide Semiconductor processor technologies. To further increase the processor speed, computer vendors are offering multicore processors, while the performance of each core remains relatively flat. With this trend, essentially all computers are going to be parallel computers ranging from a few cores in desktops to hundreds of thousands of cores in a large-scale high-end computer. Power grid software tools, designed traditionally as sequential codes for single central processing unit (CPU) personal computers, are essentially running on only one core in the multicore computers. The easy gains of the past in which sequential applications simply got faster due to increased performance and clock frequencies on newer processors are long gone. Any performance gains for applications must be realized through the use of parallelism across multicore processors. It is imperative to redevelop power grid software tools with explicit parallelization for such a parallel computing platform. Only such parallelized software tools can take advantage of the multicore parallel computers.

16.1 COMPUTATIONAL CHALLENGES IN A SMART GRID

Power grid planning and operation rely heavily on modeling and simulation. Owing to the large size and high complexity of a power grid, experimentation with the system in real time is very limited, and, for most cases, infeasible. Simulation becomes almost the sole means to understand how a large-scale power grid would behave and how a control method or operation procedure would affect such a large system. Simulation requires accurate representative models, real-time data for situational awareness, and computational algorithms and hardware for timely execution. State estimation (SE) is a traditional example of such a simulation function that combines the use of system models and measured data to provide real-time knowledge of a power grid using computational methods. SE typically receives telemetered data from the supervisory control and data acquisition (SCADA) system every few seconds and extrapolates a full set of grid conditions based on the grid's current configuration and a theoretical power flow model. SE provides the current power grid status and drives other key functions, such as contingency analysis, optimal power flow (OPF), economic dispatch, and automatic generation control (AGC) (Figure 16.2) [2].

Mathematically, the functions shown in Figure 16.2 are built on complex algorithms and network theories in combination with optimization techniques (Figure 16.3) [3]. The recent increase of uncertainty due to intermittent renewable generation, responsive loads, and other new smart grid developments adds statistical techniques to the mathematical foundation for grid functions. Given the sheer size of some power grids, all these mathematical problems require significant time to solve. The computational efficiency in grid operations is low, which can lead to the inability of grid operations to respond quickly to adverse situations and eventual instability and voltage collapse of the grid within a matter of seconds [4].

Advanced smart grid applications will create an enormous computational challenge. On the one hand, the information revolution offers opportunities for full transparency with tremendously larger real-time data sets made available through the information system. The challenge is that a computational platform needs to be in place to handle such data. On the other hand, the grid evolution introduces new dynamic and stochastic behaviors into the power grid. Simulating such a smart grid will require enhanced modeling techniques and computational tools to solve the models. There are several computational challenges that result from the complexity of data, modeling, and computation.

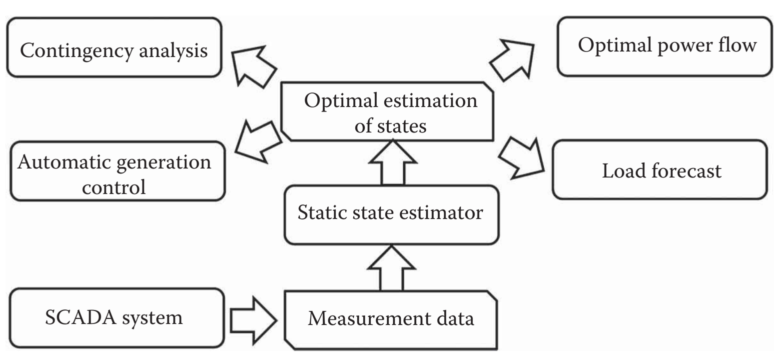

FIGURE 16.2 Functional structure of real-time power grid operations. (Reproduced from Chen, Y. et al., *International Federation of Automatic Control (IFAC) Proceedings*, 44(1):12162–12170, 2011. © 2011 IFAC. With permission.)

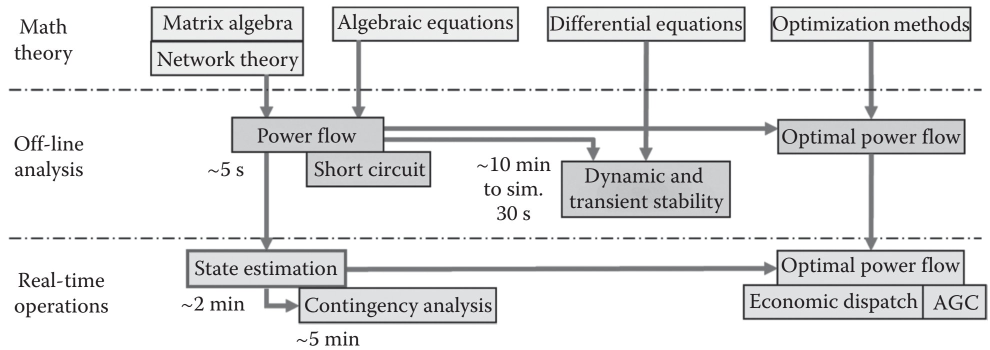

FIGURE 16.3 Grid computational paradigm. (From Huang, Z. and Nieplocha, J., Transforming power grid operations via high-performance computing, *Proceedings of PES-GM2008—The IEEE Power and Energy Society General Meeting 2008*, Pittsburgh, PA, 2008. With permission.)

16.1.1 Data Complexity

The primary source of real-time operational data for today's grid is through the SCADA system. Typically, the scan rate is once every few seconds. The future power grid is expected to contain millions of smart sensors and meters with various data transfer speeds ranging from once every few seconds to many samples per second. These new sensors and meters will result in significantly larger amounts of data compared to the traditional power grid data infrastructure. One significant category of sensors is the phasor measurement unit (PMU). PMUs generate high-speed time-synchronized measurements at a typical data rate of 30 samples per second. Currently, there are approximately 250–300 PMUs installed in North America (Figure 16.4).

Major phasor efforts are coordinated by the North American SynchroPhasor Initiative (NASPI) [7] supported by the U.S. Department of Energy (DOE) and the North American Electric Reliability Corporation (NERC). For the deployment of a full-scale phasor system in the future North American power grid, the phasor data volume is estimated to be at the order of terabytes per day. Consider the following:

$$\begin{aligned}\text{N\_PMUs} \times \text{N\_Phasors} \times \text{N\_Bytes} \times \text{N\_Samples} \times 24\ \text{h} \times 60\ \text{min} \times 60\ \text{s} &= 50{,}000 \times 8 \times 4 \times 30 \times 24 \times 60 \times 60 \times 4.15 \times 10^{12}\ \text{bytes/day} \\ &= 4.15\ \text{terabytes/day}\end{aligned}$$

where

- N_PMUs is the total number of PMUs in the system, estimated at 50,000—the number of transmission-level buses in North American power grids
- N_Phasors is the number of phasors each PMU will generate (assumed to be 8)
- N_Bytes is the total number of bytes each phasor sample has (assumed to be 4)
- N_Samples is the data speed, assumed to be 30 samples per second

If considering other data, such as time stamps and higher data rates, the data volume would be several times larger.

Another major category of data is the smart meter data. Smart meter data are available through technologies such as automatic meter reading (AMR) and automatic metering infrastructure (AMI). Beyond energy measurements for billing, smart meters increase visibility of the distribution network for planning and operation and help improve demand management. There are already millions of smart meters installed in the U.S. power grid. The American Recovery and Reinvestment Act of 2009 fostered significant investment in the United States through various Smart Grid Investment

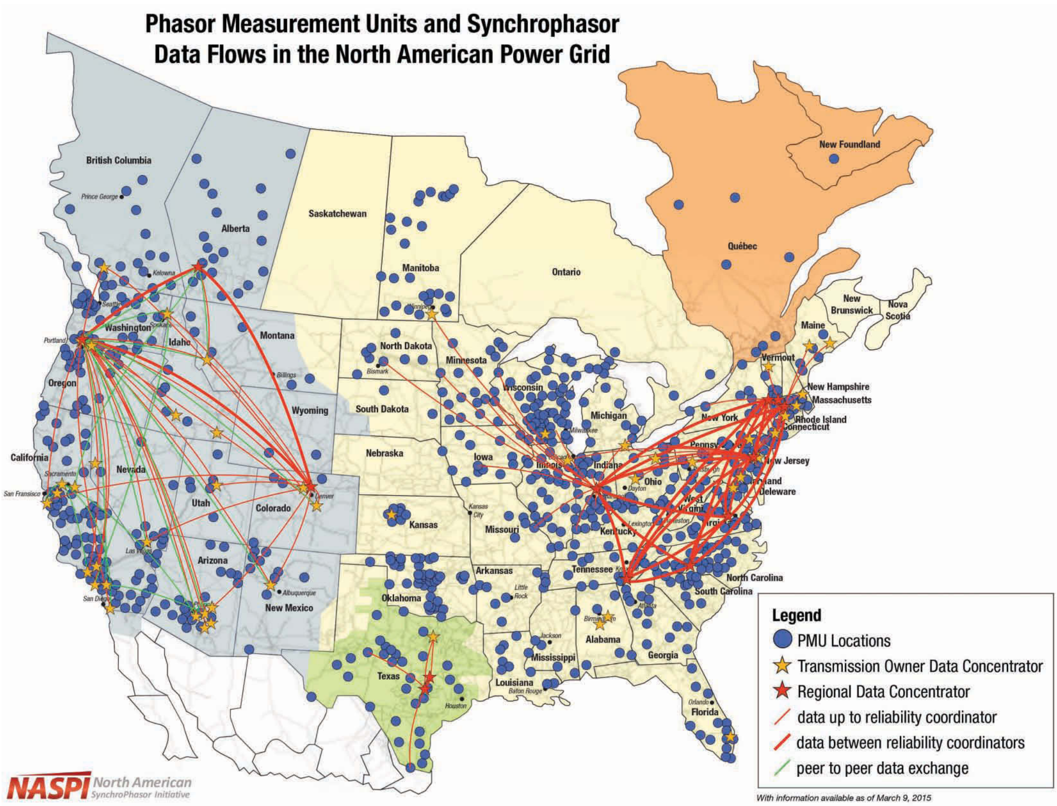

FIGURE 16.4 Installed PMUs in North American power systems. (Courtesy of the North American SynchroPhasor Initiative (www.naspi.org) and the U.S. Department of Energy.)

TABLE 16.1
Estimated Amount of Smart Meter Data for 1 Year

Number of homes	100	1k+	10k+	100k+	500k+	1 Million
Compressed data size	2.5 GB	38.5 GB	366.3 GB	2.9 TB	13.6 TB	27.3 TB

GB, gigabyte, 10^9 bytes; TB, terabyte, 10^{12} bytes.

Grants and Smart Grid Demonstration Projects. Deployment of smart meters results in large volumes of data (Table 16.1) [8]. There are over 140 million households in the United States with electricity. If they all had smart meters, the resulting data volume could be at peta-scales over a time period of 1 year even at today's relatively low data acquisition speeds (e.g., one sample every minute) for smart meter data.

The challenges posed by the increase in data are twofold: high data volume and high data speed. Power grid planners and operators need to explore options for rapid retrieval and analysis of large volumes of data. Power grid operators rely on the data to make real-time decisions; hence, the data need to be transferred and managed in very short time intervals over large geographical areas, and the analysis functions need to have high computational speeds to keep up with the large volume and the high data rates. Large-scale problems combined with requirements for real-time data collection, categorization, and processing pose a unique challenge for data-intensive computing.

16.1.2 Modeling Complexity

Modeling of grids today is typically performed on a first-principle-based[1] approach to describe the grid connectivity and associated parameters at the bulk transmission level (69 kV and above). The model size is typically on the order of 10^4 components for an interconnection-scale grid. The assumption when modeling only the bulk transmission system is that loads residing in the low-voltage-level grid (distribution system) are passive devices and the majority of their behaviors are predictable; the distribution system is at most approximated using simple models for special studies that involve identification of voltage stability behaviors.

This assumption is no longer true with the penetration of smart loads and distributed generation (especially small wind turbines and rooftop photovoltaic panels). The grid load is actively participating in and responding to grid dynamics and incentive signals, and the electricity flows bidirectionally between the transmission grid and the distribution grid, instead of one way, as in the traditional grid paradigm. The need for modeling of some of the lower voltage levels in the grid becomes apparent. However, inclusion of modeling of the distribution system would increase the order of the model size significantly. Figure 16.5 shows the complexity of the power grid and the number of devices at different levels.

Given the sheer number of devices to be modeled and the complexity of each of them, it is apparent that the traditional first-principle-based modeling approach will no longer suffice. For example, it is not feasible to model air conditioning units based on the electrothermal conversion equations in more than 200 million homes and businesses in the United States. A fundamentally new modeling approach must be developed to achieve higher modeling resolution while retaining the feasibility of solving the models. There is a need to explore statistical approaches and behavior modeling to characterize the stochastic nature of smart grid devices and an increased level of human intervention. The model will be aggregated at a level that is feasible for mathematical and numerical solutions. Even with aggregation, the number of components in the model will inevitably increase, probably from 10^4 to 10^5. For example, the composite load model has recently been developed by the Modeling and Validation Work Group of the United States. Western Electricity Coordinating Council (WECC) extends the traditional 1-component load model to a 10-component load model that includes a transformer, a feeder line, four motors of different types, an electronics load, a ZIP (constant impedance, current, and power) load, and two capacitors. Considering dynamic models of both traditional centralized power plants and distributed energy resources, the model size would increase by another order of magnitude to 10^6.

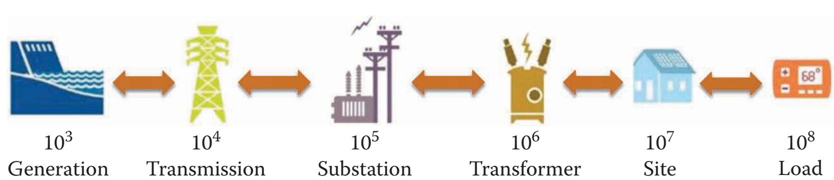

FIGURE 16.5 Example of power grid modeling complexity (Western USA). (Courtesy of Pacific Northwest National Laboratory, Richland, WA.)

[1] First-principle-based modeling relies on creating a block diagram model that implements known differential algebraic equations governing dynamics of the system.

16.1.3 Computational Complexity

Computational complexity used in this context describes the order of computational operations required to solve a specific modeling equation. "Big-O" notation is used as the measure of computational complexity that reflects how much computational capacity is required to solve a specific problem. Note that it does not consider computer memory requirements. Some key equations used in power grid modeling and analysis include power flow solution and contingency analysis, SE, dynamic simulation and dynamic contingency analysis, small signal stability, and dynamic SE.

The aforementioned data rates, system size, algorithmic complexity, and required time to solution determine the computing power required. In particular, the types of real-time simulations and analyses discussed earlier drive the need for HPC power. Table 16.2 estimates the computing power required to solve the key equations to meet expected operational requirements with various model sizes and expected times to solution.

With the complexity of data, modeling, and computation, it is clear that advances in smart grid applications will present significant challenges in planning, analyzing, and operating the grid. The analysis tools employed in today's power grid planning and operation using serial computing[2] significantly limit the understanding of power grid behaviors and responsiveness to emergencies, such as the 2003 U.S.–Canada Blackout [3]. The information revolution provides an opportunity to enhance grid planning and operation functions and enable new ones. But challenges exist in terms of large volumes of high-speed data, unprecedented modeling granularity, and large-scale computation. These challenges call for the exploration of HPC technologies to transform today's grid functions using improved computational efficiency and functionality.

16.1.4 Parallelized SE

Power system SE is a core EMS function that is used to estimate grid states based on field measurement data. The SE outputs are critical for system operations and subsequent EMS functions.

The weighted-least-squares (WLS) algorithm is the most widely used solution method in SE. It involves solving a large and sparse system of linear equations at every iteration. In each cycle of WLS SE, a large and sparse system of linear equations is being solved. There are two types of solvers to solve this kind of linear equation: direct method and iteration method. Direct methods factorize the gain matrix using different decomposition methods, such as LU, QR, and Cholesky, followed by the backward and forward substitution [1]. Iterative methods typically start with an

TABLE 16.2
Computing Requirements for Modeling the Power Grid

Model size	10^4 (major transmission elements)	10^5 (+ major renewable and major loads)	10^6 (+ renewable, loads, distributed generation)
Time to solution	2–4 min	2–4 s	10 ms–1 s
State estimation	100 MFLOPS	10 GFLOPS	10 ExaFLOPS (dynamic)
Contingency analysis	100 MFLOPS	1 TFLOPS	100 TFLOPS
Dynamic simulation	1MFLOPS (10× slower than real time)	100 GFLOPS (10× faster than real time)	10 TFLOPS (10× faster than real time)
Small signal stability	10 GFLOPS	10 TFLOPS	1 ExaFLOPS

FLOPS, floating-point operations per second; MFLOPS, MegaFLOPS = 10^6 FLOPS; GFLOPS, GigaFLOPS = 10^9 FLOPS; TFLOPS, TeraFLOPS = 10^{12} FLOPS; PFLOPS, PetaFLOPS = 10^{15} FLOPS; ExaFLOPS, 10^{18} FLOPS.

[2] Serial computing uses only one CPU (processor) to perform all the simulation computation tasks sequentially.

initial approximation of the solutions and update the approximations until the process converges within a predefined tolerance [2].

A good candidate for iterative method is preconditioned conjugate gradient (PCG) algorithm [9] because it exhibits a high degree of coarse-grained parallelism[3] and is often used on parallel computers for applications that require sparse linear solvers. PCG-type methods theoretically yield exact solutions within a finite number of steps. Evaluation of the CG algorithm by modeling the 14,000-bus U.S. WECC system achieved a 5-s solution time for the full SE problem, a speed comparable with SCADA cycles [10–13].

Recently, a new adaptive sparse matrix solver of NICSLU [3,4,7] has been found to perform the best among the tested direct solvers and iterative solvers. The NICSLU solver is developed to handle extremely sparse matrices for parallel circuit simulation, which is suitable for power grid modeling and simulation. A parallel SE (PSE) program with the NICSLU solver has been tested with Bonneville Power Administration (BPA) SE data for 47 hourly snapshots. The BPA system has approximately 7500 buses and 9300 branches. The number of measurements is around 27,000. The results show that the solver can help execute all 47 SE cases within 1 s. This subsecond performance is sufficient to complete SE process with today's SCADA cycles. The SE solution time for these cases using NICSLU solver on one thread is shown in Figure 16.6 [14].

This subsecond SE solution time is not only much less than the tested PCG Hypre solver but better than a commercial SE solver. A benchmarking case study has shown that it took 4–7 s to solve the 47 BPA SE cases, which is more than 10 times longer than the developed PSE program with NICSLU solver. The fast SE computational time helps improve wide-area situational awareness and operators' decision support process.

The scalability of the NISCLU solver on these BPA models and data has been further evaluated. Because the size of BPA model is not large enough to take advantage of multithreading technique, using more threads does not improve the computational time significantly with the testing cases. However, with the fast development of smart grid techniques, the size of SE problem is increasing. An advanced parallel SE solver will be soon required to solve large SE problems. A better scalability with more threads is expected when handling the future large systems. Such scalability would be

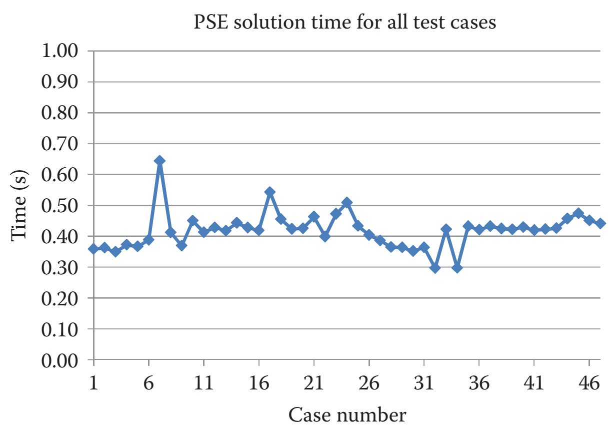

FIGURE 16.6 Solution time for the 47 BPA SE cases using NICSLU solver (one thread). (From Chen, Y. et al., Sub-second state estimation implementation and its evaluation with real data, *Proceedings of PES-GM 2015—The IEEE Power and Energy Society General Meeting 2008*, Pittsburgh, PA, 2008. With permission.)

[3] An application exhibits fine-grained parallelism if its subtasks must communicate many times per second; it exhibits coarse-grained parallelism if they do not communicate many times per second.

very important in future smart grids. Model sizes for a smart grid may be significantly larger due to the need to model the grid with more granularity in order to capture additional system dynamics and stochasticity.

16.1.5 Parallel Contingency Analysis

Contingency analysis assesses the ability of the power grid to sustain various combinations of component failures based on SE outputs. The results of contingency analysis are used to provide the basis for preventive and corrective operation actions and ensure the grid reliability. Contingency analysis is also extensively used in power market operation for feasibility testing of market solutions.

Owing to the extensive computation involved, contingency analysis is currently limited to mostly selected "$N-1$" scenarios. Power grid operators manage the system in a way that ensures that *any single credible contingency (i.e., $N-1$) will not propagate into a cascading blackout*, which approximately summarizes the "$N-1$" contingency standard established by NERC [15].

Although it has been a common industry practice, analysis based on limited "$N-1$" cases will not be adequate to assess the vulnerability of future power grids due to the high penetration of smart grid technologies. Variable renewable energy introduces more-frequent, higher-amplitude energy imbalances to the power grid. In addition, smart loads and plug-in hybrid vehicles cause new dynamics and random behaviors, while new market development puts the grid close to its capacity and requires more frequent contingency analysis. NERC moves to mandate contingency analysis from "$N-1$" to "$N-x$" in its grid operation standards [16]. All this calls for a massive number of contingency cases to be analyzed. This would result in a huge number of contingency cases. As an example, the WECC system has about 20,000 elements. Full "$N-1$" contingency analysis constitutes 20,000 cases, "$N-2$" is roughly 10^8 cases, and the number increases exponentially with "$N-x$." If the uncertainties of renewable energy forecast are considered for look-ahead contingency analysis, the required computational workload will be largely increased. It is obvious that the computational workload is beyond what a single personal computer can accomplish within a reasonable time frame. Parallel computers or multicore computers emerging in the HPC industry hold the promise of accelerating power grid contingency analysis.

Because the communication between contingency analysis calculations is minimal as the cases are relatively independent of one another, contingency analysis is inherently a parallelizable process and can easily be parallelized. The performance of parallel contingency analysis relies heavily on computational load balancing to optimize the scalability.

A straightforward load balancing of parallel contingency analysis is to preallocate an equal number of cases to each processor, that is, static load balancing. The master processor only needs to allocate the cases once at the beginning. Because of the different execution times for different cases, each power flow run may require a different number of iterations and, thus, take more or less time to finish. The extreme case would be diverged cases, which iterate until the maximum number of iterations is reached. The variations in execution time result in unevenness, and the overall computational effort is determined by the longest execution time of any of the individual processors. Computational power is not fully utilized as many processors are idle while waiting for the last one to finish. A better load balancing scheme is to allocate tasks to processors based on the availability of a processor, that is, dynamic load balancing. In other words, the contingency cases are *dynamically* allocated to the individual processors on demand, so that the cases are more evenly distributed in terms of execution time by significantly reducing processor idle time. One implementation of the scheme is based on a shared variable (task counter) updated by an atomic fetch-and-add operation [18]. The master processor does not distribute all the cases at the beginning. Instead, it maintains a single task counter. Whenever a processor finishes its assigned case, it requests another task from the master processor, and the task counter is updated by one, as shown in Figure 16.7a. In contrast

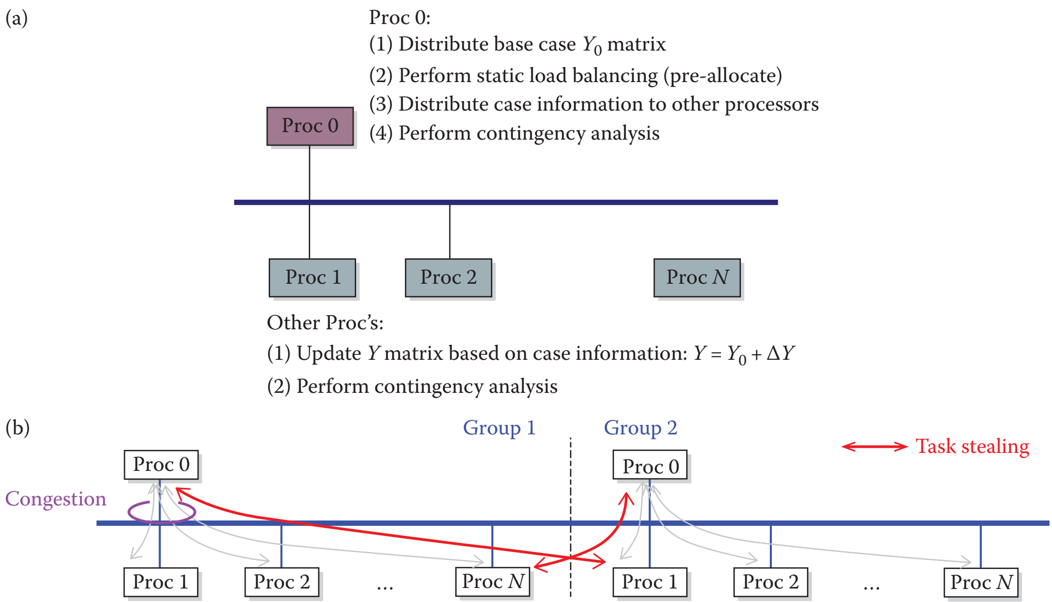

FIGURE 16.7 Framework of parallel contingency analysis: (a) single-counter dynamic load balancing, and (b) multicounter dynamic load balancing with task stealing. (From Chen, Y. et al., Performance evaluation of counter-based dynamic load balancing schemes for massive contingency analysis with different computing environments, *Proceedings of the IEEE Power and Energy Society General Meeting 2010*, Minneapolis, MN, 2010. With permission.)

with the evenly distributed number of cases on each processor with the static scheme, the number of cases on each processor with the dynamic scheme may not be equal, but the computation time on each processor is optimally equalized.

This dynamic load balancing scheme can be further improved by extending it to multiple counters to avoid congestion for the master processor. Figure 16.7b shows a two-counter example. An equal number of cases is preallocated to the two-counter groups. Each group has its own counter. Within each group, the dynamic load balancing scheme is applied based on the availability of processors. When the preallocated tasks are finished in one group, the counter in this group *dynamically* "steals" tasks from the other group to continue the computation until all tasks are done. By implementing the multicounter dynamic load balancing scheme, counter congestion can be reduced, and further speedup is achieved. Such a multicounter scheme is particularly well suited for a computing environment, with a large number of processors connected by relatively slow communications links [16].

Using a test system that has a size and structure equivalent to the U.S. Western Interconnection, the aforementioned load balancing schemes were tested and compared to demonstrate the performance of parallel computing. The test system has 2748 generators, 14,000 buses, and 17,346 lines. For this test, 512 "$N-1$" contingency cases, representing a typical scenario of today's practice, were selected. Obviously, much better linear scalability is achieved with dynamic load balancing as shown in Figure 16.8a. Figure 16.8b further compares the processor execution times for the case with 32 processors. With dynamic load balancing, the execution time for all the processors is within a small variation of the average 23.4 s, while static load balancing has variations as large as 20 s or 86%. The dynamic load balancing scheme successfully improves evenness.

The single-counter dynamic load balancing scheme was further tested with massive numbers of contingency cases. Three large sets of contingency cases were computed using 512 processors: (1) 20,094 full "$N-1$" cases, which consist of 2748 generator outage cases and 17,346 line outage

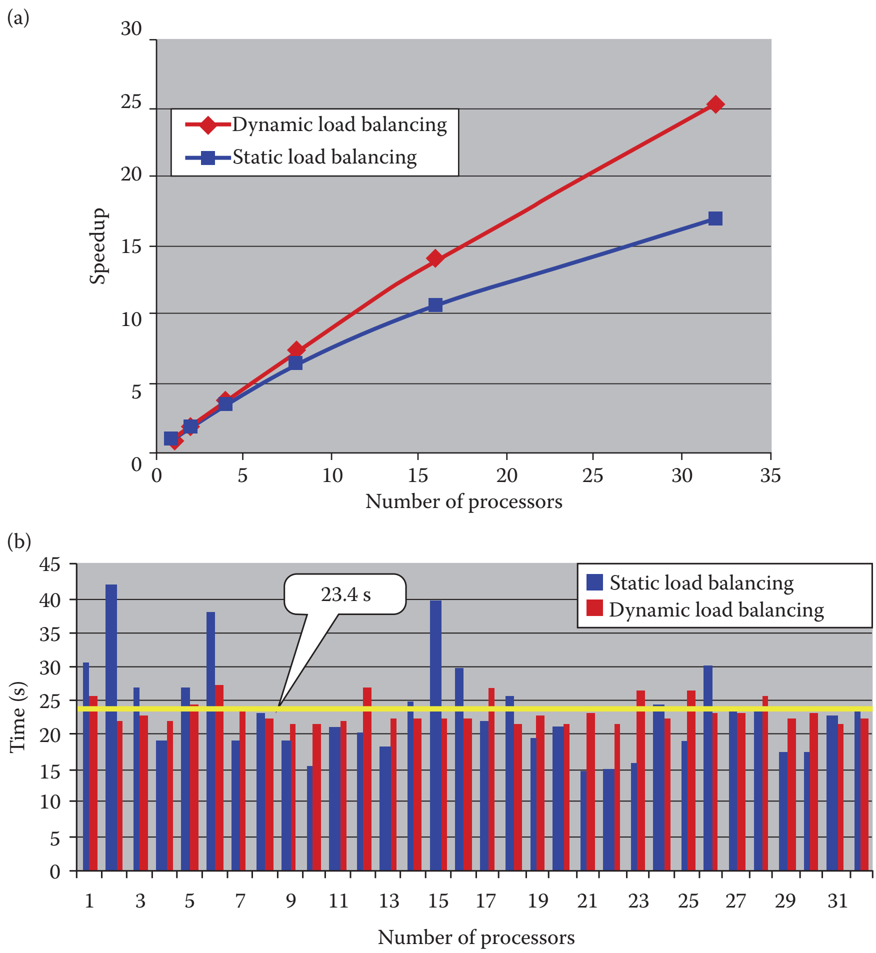

FIGURE 16.8 Comparison of computational performance with static load balancing and single-counter-based dynamic load balancing: (a) speedup performance comparison, and (b) computational evenness comparison. (From Huang, Z. et al., Massive contingency analysis with high performance computing, *Proceedings of PES-GM2009—The IEEE Power and Energy Society General Meeting 2009*, Calgary, Canada, 2009. With permission.)

TABLE 16.3
Summary Results of Massive Contingency Analysis

512 Processors Used	Total Time with Parallel Computing (s)	Total Time with Serial Computing (s)	Speedup
20,094 $N-1$ cases	31.0	14,322.2	462
150,000 $N-2$ cases	187.5	94,312.5	503
300,000 $N-2$ cases	447.9	227,085.8	507

cases; (2) 150,000 "$N-2$" cases, which randomly chose 50,000 cases from each of three combinations: double-generator outages, double-line outages, and generator-line outages; (3) 300,000 "$N-2$" cases, including 100,000 cases from each of the three combinations mentioned earlier. The results are summarized in Table 16.3, showing excellent speedup performance is achieved—about 500 times with the "$N-2$" scenarios and slightly less with the "$N-1$" scenario.

To evaluate the performance of multiple-counter-based dynamic load balancing scheme, the parallel MCA code has been mitigated to the Olympus machine that has about 20,000 cores. This time, 1 million $N-2$ cases were used with 512-core, 1024-core, and up to 10,240-core on the Olympus machine with the single-counter and two-counter dynamic load balancing schemes. This is the first time the contingency analysis has been scaled up to more than 10,000 cores. The performance of the dynamic load balancing scheme with 1 million contingency cases has been summarized in Table 16.4 [8]. The speedup curves of these two schemes are shown in Figure 16.9.

Figure 16.9 shows that the performance of single- and two-counter schemes is close when the number of cores is less than 2018. However, when the number of core is larger than 4096, the two-counter scheme is much better for this particular case. This observation validates the effectiveness of multicounter dynamic load balancing scheme.

The contingency analysis framework and dynamic processor load balancing schemes described earlier are generally applicable to more complex analyses. In the smart grid environment, renewable energy and other smart solutions will require faster and more extensive contingency analysis of larger systems. In addition, greater dependence on data and data networks requires contingency analysis to consider failures beyond the power grid. It needs to consider failures in the data network or manipulations of the data. Such data-induced contingencies will certainly increase the

TABLE 16.4
Performance of the Counter-Based Dynamic Load Balancing Scheme with 1 Million $N-2$ Contingency Cases

Number of Cores	Time (s) (1-Counter)	Time (s) (2-Counter)	Speedup (1-Counter)	Speedup (2-Counter)
512	1023.4	1021	511.3	512.5
1,024	517.4	512.7	1011.41	1020.7
2,048	250.07	250.1	2092.6	2092.0
4,096	163.4	132	3202.1	3964.3
10,000	75.1	72.8	7017.2	7239.2
10,240	74.3	66.9	7040.0	7877.0

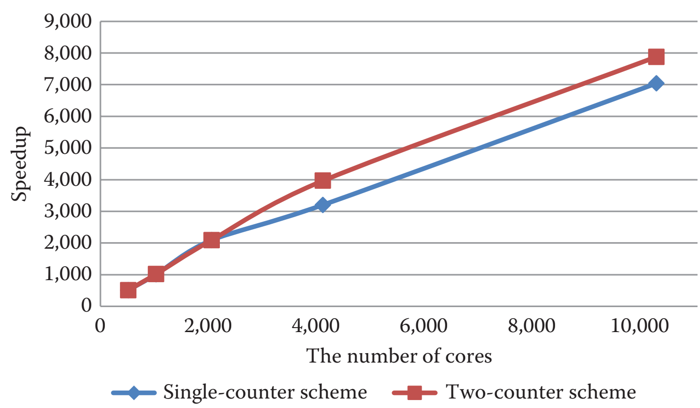

FIGURE 16.9 Scalability comparison of 1-counter and 2-counter dynamic load balancing schemes. (From Chen, Y. et al., Evaluation of counter-based dynamic load balancing schemes for massive contingency analysis on over 10,000 cores in SC companion: high performance computing, *Networking and Analysis (SCC 2012)*, Salt Lake City, UT, pp. 341–346, 2012. IEEE Computer Society, Los Alamitos, CA. With permission.)

complexity and size of the analysis. HPC-aided contingency analysis is therefore essential. This dynamic load balancing scheme can be extended to other scenario-based applications to help optimize the speedup performance.

16.2 NEW FUNCTIONS ENABLED BY HPC

Over the years of developing computational methods for power grid analysis, certain assumptions and compromises were introduced to make sure the methods are practical within the constraints of limited computational resources. Typical in power grid planning and operation are modeling assumptions, quasi-steady-state assumptions, and compromises of efficiency for reliability.

As mentioned earlier, a modeling assumption is made in today's transmission models that loads are predictable with simple equations. This assumption reduces the size of the model and, thus, makes the computation feasible with standard single-processor computers. Another modeling assumption is the reduction of a substation model to a single-bus model, which results in the difference between an operational model (i.e., circuit-breaker-oriented model) and a planning model (i.e., bus-oriented model). This modeling assumption, in turn, results in a significant divergence of methods and tools between planning and operation. This assumption does significantly simplify the computation for planning studies; however, it is limited in that many scenarios cannot be easily studied in planning, such as breaker failure contingencies. A more profound impact is that planning and operation are typically in separate organizational silos, and the difficulties in communication between these two important functions cause significant grid reliability issues when emergencies arise.

A quasi-steady-state assumption is applied to operation studies. Today's operation is based primarily on a model that largely ignores dynamics in the power grid; electromechanical interaction of generators and dynamic characteristics of loads and control devices are not included in operational models. This assumption reduces the computation by several orders of magnitude and enables the operation studies on standard computers to be feasible within the required operational intervals. The problem with this assumption is that many studies cannot be performed in the operational environment. Development of the smart grid makes the grid much less quasi-steady-state, as compared with the power grid in the past. Furthermore, this assumption widens the divergence between planning and operation, as mentioned earlier.

One example of compromising grid efficiency for reliability is today's path rating studies. To support grid reliability, path rating studies are performed to determine transfer capabilities of transmission paths and apply a margin so the actual power flow will not exceed the predetermined limits. Path rating studies are typically performed in an off-line mode months ahead of time using the most conservative scenarios. This compromise makes the studies feasible with limited computational resources. The consequence is that the predetermined limits are conservative by definition; transmission capacity is underutilized, which results in reduced grid efficiency. This consequence will be more significant with smart grid development. Owing to intermittency and stochasticity of new generation and loads, the most conservative case will be so conservative that it would render the path limits unreasonably low. With the increased complexity in the smart grid, there may be situations where the predetermined limits do not maintain adequate reliability in the grid.

These assumptions and compromises were reasonable and historically have contributed significantly to the development of power grid computational methods and tools. However, they no longer make sense in the much-evolved power grid. New energy resources and new load consumption devices make the power grid more dynamic and stochastic, which requires more granular analysis and more timely response.

With much-improved computational resources, there are no reasons to continue applying these assumptions in power grid planning and operation. Models for planning and for operation can be merged into one: operation can include dynamic models as in planning, and planning studies can be done in a more real-time manner to improve grid efficiency while still maintaining reliability. HPC will enable new functions that are much needed for smart grid development. Two examples of HPC-enabled new functions are presented in the following: dynamic SE and real-time path rating.

16.2.1 Dynamic State Estimation

Dynamic SE (State Estimation) introduces dynamic models for real-time power grid operation. Traditional *static* SE only estimates static states, that is, bus voltages and phase angles. Power grids are inherently dynamic systems. A full dynamic grid view needs to estimate dynamic states, for example, generator speeds and rotor angles. This is possible with high-speed phasor measurements in the power grid [19]. Dynamic SE would then enable real-time dynamic simulation and dynamic contingency analysis to foresee the grid status with more transparency for better reliability and asset utilization. This is especially important given the increasing penetration of variable renewable energy sources and smart loads into the grid. However, bringing dynamic information into real-time grid operations is extremely challenging due to its computational demand. The dynamic model of a power grid consists of a set of differential and algebraic equations; solving such a set of equations in the time domain using numerical integration techniques is far more time consuming than solving static power flow equations.

One approach for dynamic SE is to formulate the problem as a Kalman filter process. Both extended Kalman filter (EKF) [20] and ensemble Kalman filter (EnKF) [21] techniques have been applied to dynamic SE. EKF and EnKF are capable of dealing with nonlinear equations [20] used in power system SE. Given a power system modeled as a set of difference equations, the dynamic SE is a two-step prediction/correction process [22]. The prediction step is a time update using the difference equation, which predicts the state variables of the next step based on the values of the previous step. The correction step compares the predicted values against actual measurements and uses the error to correct state variables.

Tests with a 16-generator system demonstrated good tracking performance of an EnKF-based dynamic SE. The test system consisted of 16 generators, 86 transmission lines, and 68 buses [23]. A 0.05-s disturbance of a three-phase-to-ground fault at a bus was simulated at 1.1 s with 3% noise added to all simulated voltages. The test results are shown in Figure 16.10. Initial errors in the state variables affect only the state variable tracking for the initial time period. After a short time, for example, about 1 s, there is no significant discrepancy for the state tracking. The disturbance does cause some deviation in the tracking. The Kalman filter can correct itself with continuous data and track the states again. Overall performance indicates that once the EnKF is locked into tracking, the performance is consistently good for the continuous tracking.

Achieving tracking accuracy is just the first step for the dynamic SE function. Performing the function fast enough for real-time purposes is another important aspect. The Kalman filter has high computation demands, especially for large algorithm solution systems such as the power grid. The EnKF computational complexity in "Big-O" notation is O(M2N). For large power grids, the computation is prohibitive for achieving real-time performance without HPC. For example, a 1081-bus system, representing regional power systems such as the U.S. California grid, would require 1.57×1011 FLOPS to complete one tracking step within 0.03 s (the phasor measurement cycle), and a 16,072-bus system equivalent to the WECC power system would require 5.60×1014 FLOPS. These FLOPS numbers translate to HPC computers with thousands to hundreds of thousands of processor cores. Implementing and parallelizing codes on such HPC computers is a fundamental challenge. An initial attempt (Figure 16.11) has shown a promising path forward to achieve the required computational performance. Figure 16.11a is the time used to compute one step of the EnKF dynamic SE. The parallel codes are based on the global array programming model [22,24]. Several computers are used to perform the test. Although the best time at 128 cores is still about 1000 times longer than 0.03 s, the execution time decreases

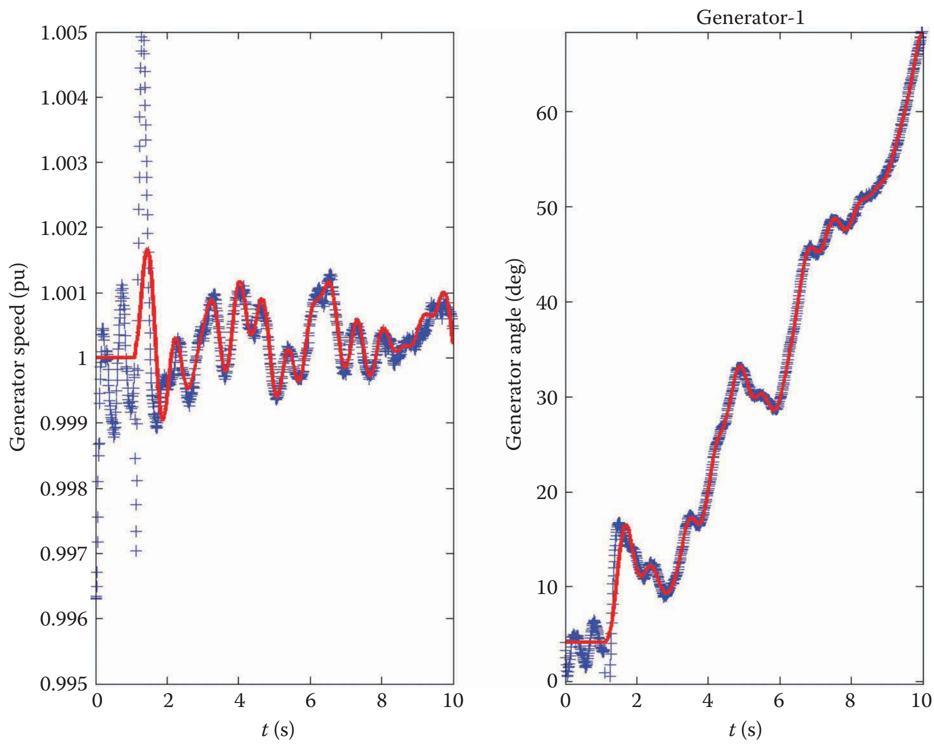

FIGURE 16.10 State tracking of generator 1 in the 16-generator system. The solid line is the true value from simulation. The scattered crosses are the estimated states from EnKF. (From Li, Y. et al., Application of ensemble Kalman filter in power system state tracking and sensitivity, *Proceedings of the 2012 IEEE Power and Energy Society Transmission and Distribution Conference and Exposition*, Orlando, FL, 2012. With permission.)

consistently as more processor cores are applied. This is confirmed by the speedup curve in Figure 16.11b. The speedup curve also reveals potential saturation issues with parallelization. To prevent the overhead associated with parallelization that diminishes the benefits of using more cores, further improvements with the parallelization approaches are probably needed. With such improvements and larger-scale HPC, dynamic SE is very attainable, especially for regional power systems.

16.2.2 Real-Time Path Rating

Transmission grid path flow is limited by the lowest of three criteria: the thermal limit, the voltage stability limit, and the transient stability limit for all critical contingency scenarios. Figure 16.12 shows the U.S. California-Oregon Intertie (COI) ratings as an example [25]. The contingency rating is determined by stability studies using the worst-case scenario. The difference between the thermal rating and the contingency rating is significant, and it presents an opportunity for improvement if the analysis can be done in real time with realistic power flow scenarios from online EMS snapshots. According to Bonneville Power Administration studies in the United States, a 1000-MW rating increase would generate $15 million revenue even if only 25% of the increased margin can be used for 25% of a year. One fundamental challenge that limits conduction of path rating studies in real time is the solution time that is needed to perform transient stability simulation. With today's commercial software packages, it takes hours or days to perform transient simulation for one path

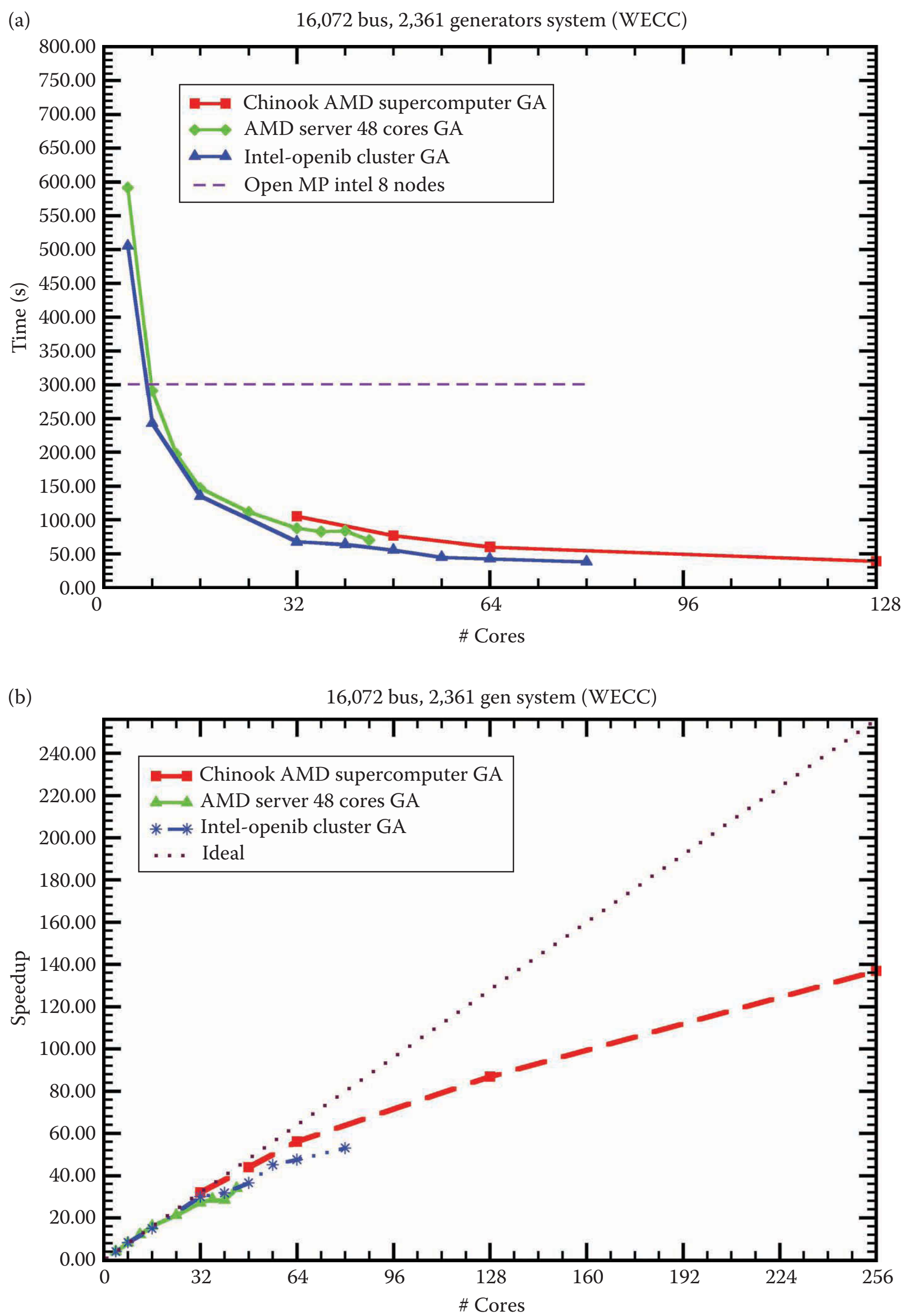

FIGURE 16.11 Computational performance of EnKF-based dynamic SE with a 16,072-bus system: (a) execution time, and (b) speedup. (Courtesy of Pacific Northwest National Laboratory Richland, WA.)

rating. The objective of path rating is to search for the maximum power transfer capability that will not violate stability criteria. One typical scheme is the binary search or its variations. As illustrated in Figure 16.13, at each loading level (1, 2, 3, 4, …), a set of contingency scenarios is simulated to test for stability limits. This is a serial process because the direction of the search depends on the results of the previous loading level.

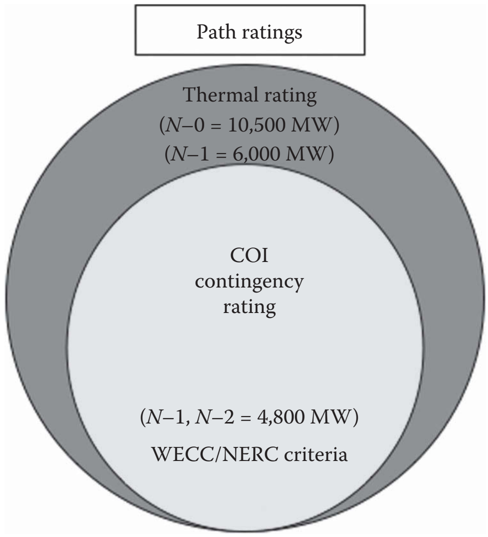

FIGURE 16.12 COI path rating—an example of underutilized assets. (From Western Interconnection 2006 Congestion Assessment Study, Prepared by the Western Congestion Analysis Task Force, 2006.)

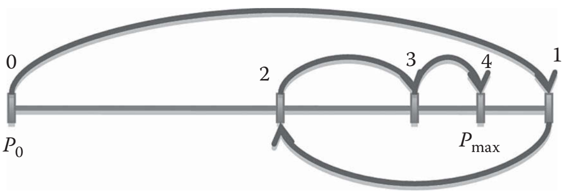

FIGURE 16.13 Binary search for maximum power transfer capability. (Courtesy of Pacific Northwest National Laboratory Richland, WA.)

The computational process is shown conceptually in Figure 16.14. A number of dynamic simulation cases need to be performed at each loading level. Since serial computing uses only one CPU to perform all the simulation sequentially, the total solution time increases when the number of contingencies or the number of search iterations increases. It usually takes a very long time. This serial computing is typical in current practice and renders the path rating studies to be off-line. Distributed computing has been applied to speed up the computation of multiple contingency cases by distributing the cases to multiple computers, but the solution time for each case remains the same, as shown in Figure 16.14b. The total solution time no longer depends on the number of contingencies, assuming enough processors are available. But due to the time it takes to solve each dynamic simulation case, the total solution time is still in the range of hours or more. It improves the performance, but it does not address the issue of computation time with the sequential search process. The key to further reducing the solution time is to parallelize the computation of individual simulation cases. Figure 16.14c shows the approach with parallelized computing. With enough processors and a scalable implementation of parallelized dynamic simulation, the total solution time can be kept short enough to enable real-time path rating analysis.

A version of parallel dynamic simulation was implemented on a 128-core HPC computer using OpenMP application program interface (API). This 128-core computer belongs to the shared-memory HPC family, which has a large block of memory accessible from multiple processing cores. Several test systems of sizes ranging from small to medium were used to test the parallel dynamic

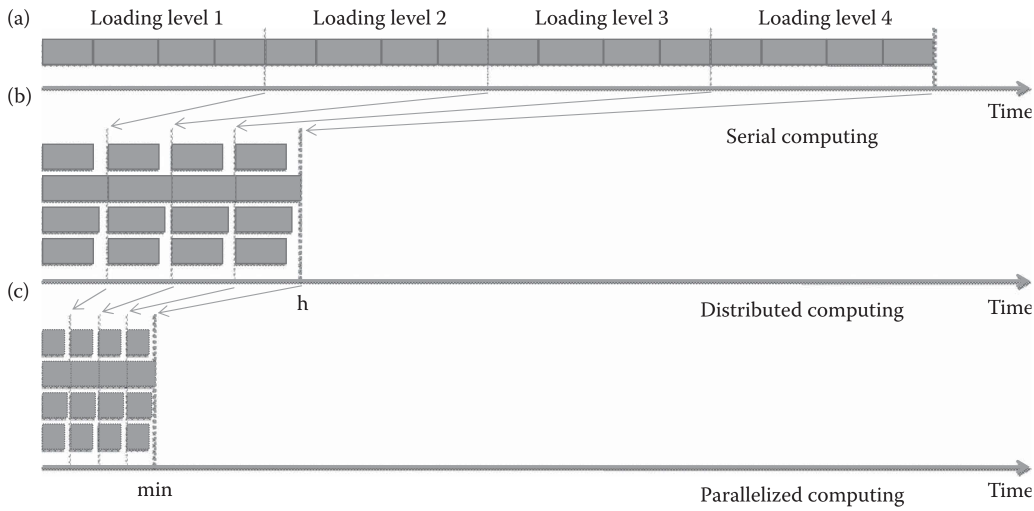

FIGURE 16.14 Conceptual computational processes of dynamic simulation for path rating with three different approaches: (a) serial computing, (b) distributed computing, and (c) parallelized computing. Each block represents a dynamic simulation case for a contingency scenario. (Courtesy of Pacific Northwest National Laboratory Richland, WA.)

simulation implementation. Figure 16.15 shows the results of speeding up the transient simulation in a research setting. The overhead required to coordinate the parallel computation among processors quickly dominates the simulation. Thus, the speedup curve saturates at a relatively small number of processors. However, as the system size increases, better speedup performance is observed, and saturation occurs at a larger number of processors. For example, the 400-machine test system achieved 14 times speedup with 32 processors. Speedup performance is expected to be even better with larger system sizes (e.g., the WECC system has 3000 generators). Figure 16.15 shows that HPC can run transient simulation much faster and enable real-time path rating for better grid asset utilization.

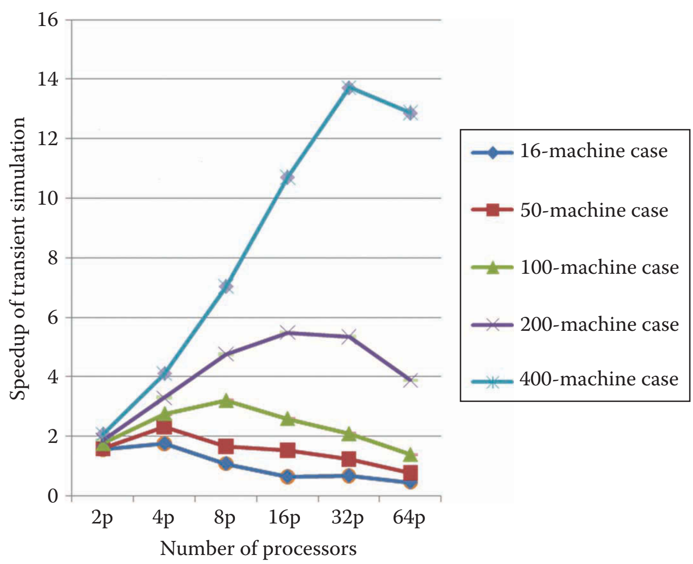

FIGURE 16.15 Speedup of transient simulation with an HPC computer. (Courtesy of Pacific Northwest National Laboratory Richland, WA.)

Voltage stability limit is another critical factor for path rating. Traditionally, the process of calculating voltage stability limit is to calculate voltage stability boundary under different contingencies along different stress directions and identify the most limiting one, step by step. Applying HPC-based technologies is one way to speed up. Because the communication between each calculation is minimal, this parallelization mechanism is similar to the mechanism for massive contingency analysis, that is, assign different powerflow/contingency analysis cases to different computer cores based on their availability using dynamic load balancing scheme. Recently, a new direct method was developed at PNNL, which is to find voltage stability regions using a non-iterative computational method [10]. This approach can quickly locate the most limiting voltage and thermal violations for different stress directions and multiple contingencies. Continuation power flow (CPF) is used to find the location where thermal violation and voltage violation happen first. Then, an orbiting method is used to calculate the voltage stability boundary points along different stress directions. Figure 16.16 illustrates the process of identifying the voltage boundary points, which are the most limiting voltage boundary points among all contingencies (yellow curves in Figure 16.16).

This non-iterative method has been tested with the full 2014 Western Interconnection planning model. Figure 16.17 shows the process of finding the voltage stability boundary points with the direct method. It took 36.8 s to find the voltage boundary points on nine stress directions, while the traditional method needs 129 s, about four times slower.

Once the voltage boundary points are identified, a dynamic simulation testing can be performed at these voltage boundary points to check their transient stability conditions. If the test passes at one point, then voltage stability limit is the path rating; otherwise, the test fails, the system stress level has to be adjusted to lower levels and rerun dynamic simulation at these internal levels using

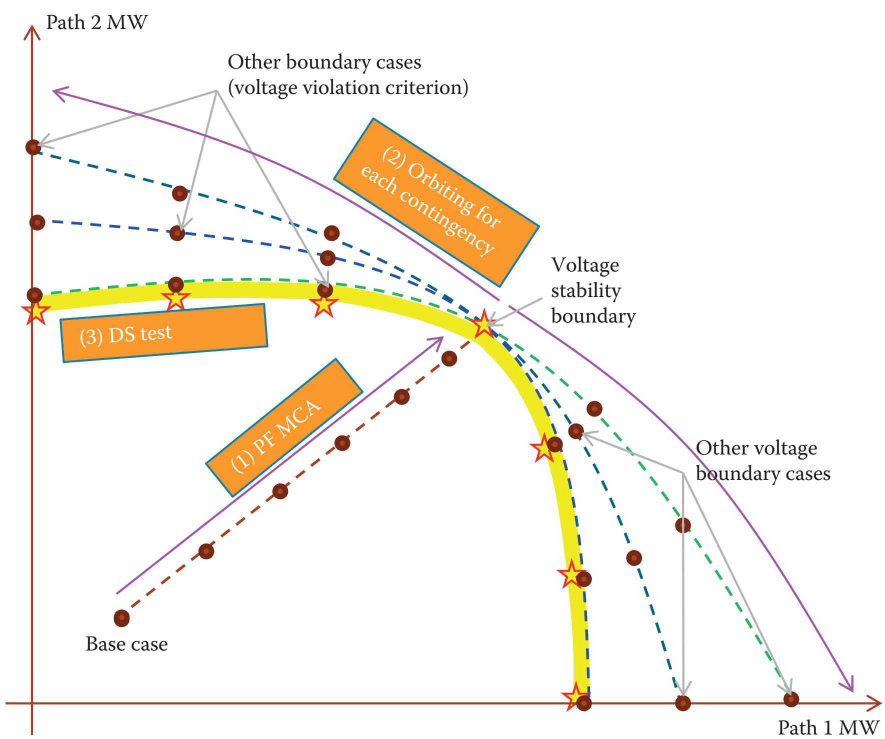

FIGURE 16.16 The process of finding voltage stability boundary points using the non-iterative method. *PF*, power flow; *MCA*, massive contingency analysis; *DS*, dynamic simulation. (Courtesy of Pacific Northwest National Laboratory, Richland, WA.)

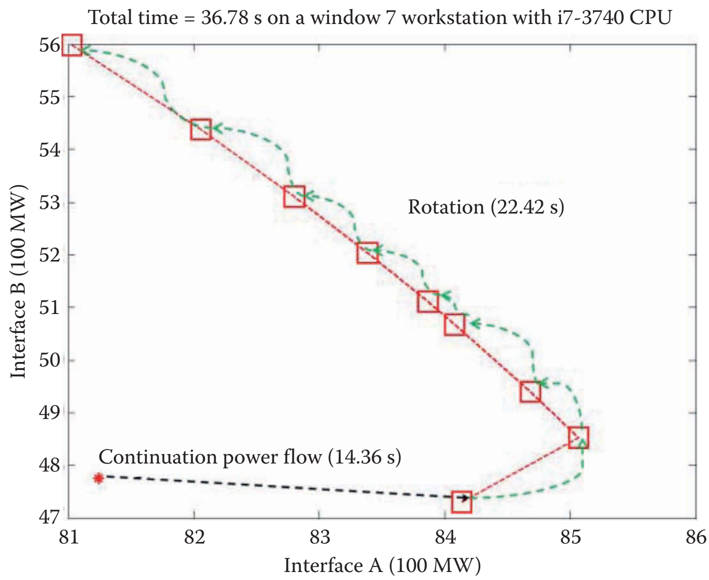

FIGURE 16.17 Noniterative method test using the 2014 Western U.S. Interconnection planning model. (From Makarov, Y.V. et al., Direct methods to estimate the most limiting voltage level and thermal violations in coordinates of power transfers on critical transmission paths. *Proceedings of the 2016 49th Hawaii International Conference on System Sciences*. With permission.)

the HPC technologies to calculate system's transient stability limits, which will be the path rating for this scenario. Two-level parallelism can be applied to running multiple dynamic simulations with multiple contingencies to further increase computational performance. In this case, the tasks of dynamic simulation with multiple contingencies can be assigned to a different group of cores as first level of parallelism; within each group, multiple cores will be used to speed up the computation of dynamic simulation. This is the second level of parallelism.

With the help of non-iterative voltage stability method and HPC technologies, computing the path rating near-real-time is achievable. A recent test on a BPA model with 405 contingencies and 4 nomogram point shows that it took about 6 min to complete RTPR for one case using 125 cores. This computational performance is far better than today's tool. It provides more decision support to help address the coming challenge of 15-min dynamic scheduling for dealing with uncertainties, and improve the efficiency of utilizing transmission assets.

16.3 HPC IN THE SMART GRID

Driven by the deployment of smart grid technologies, the complexity of the power grid is increasing significantly. The complexity lies in three major aspects: data, modeling, and computation. The future smart grid will have significantly larger sets of data available from smart meters and sensors, and will require more granular models to describe the grid behaviors with new dynamics and stochasticity. Large amounts of data and complex grid models drive up the scale of computation in smart grid applications.

Smart grid applications need to explore HPC technologies for two main reasons. First, the computational requirements cannot be satisfied by serial computing; the slow responses to adverse grid conditions lead to inability to prevent failures and grid instability. Second, computations need to adapt to the trend in the computer industry, which is undergoing a significant change, from the traditional single-processor environment to an HPC era with multiprocessor computing platforms.

HPC has been shown to improve today's grid operation functions, such as SE and contingency analysis. Study results show that these functions can be solved much faster when adapted to appropriate HPC computing platforms. Solution times can be reduced from minutes to seconds—comparable to SCADA measurement cycles. HPC also enables the development of new smart grid applications by integrating dynamic analysis into real-time grid operations and by moving offline analyses to online applications. Dynamic SE and real-time path rating are two examples of new HPC-enabled applications. With HPC improving the computational performance of smart grid modeling and simulation, more studies and faster analyses will be possible, and that will generate much larger amounts of data in a shorter time frame. To convert such big data into actionable information, especially for real-time grid operation, computer-driven analytics and visualization would be essential and would be another application that is enabled by and can take advantage of HPC technologies. When the information is used for decision-making in controlling, operating, or managing smart grid devices, HPC can exert its value in smart grid development.

This chapter focused, for the most part, on power system computation. However, there are additional areas that should be developed to further support HPC applications in smart grid. Beyond individual HPC applications, an HPC-compatible numerical library would significantly accelerate the development and adoption of HPC in smart grid applications. GridPACK[4] [11] is such a library example. It contains a suite of data and function modules that hide the details of HPC programing and are reusable by various applications; beyond computation, a computing architecture is necessary to bring data to computation and convert large amounts of computing results into usable and actionable information through analytics and visualization. The GridOPTICS Software System (GOSS)[5] [12] has gained traction in enabling such workflows. Beyond the smart grid, the dependency on other systems, such as communication systems, requires a co-simulation framework to study the impact among the systems. The Framework of Network Co-Simulation (FNCS) [13] is starting along this direction. FNCS uses a middleware approach to automatically manage time synchronization and data exchanges among simulators of subsystems.

HPC in smart grid is still in its infancy. Significant research and development are needed to adapt power grid computations to HPC platforms, and eventually bring HPC technology into other areas of utility planning, operation, and maintenance.

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[4] GridPACK is a software framework consisting of a set of modules designed to simplify the development of programs that model the power grid and run on parallel, high performance computing platforms.

[5] GridOPTICS (Grid Operation and Planning Technology Integrated Capabilities Suite) Software System (GOSS) is a middleware framework that facilitates the deployments of new applications for the future power grid. It easily integrates grid applications with sources of data and facilitates communication among them.

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17 Cybersecurity for the Smart Grid

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CONTENTS

Cybersecurity relates to technologies, processes, and measures taken to protect data, communications networks, information technologies, and computing systems against unauthorized access or attack. Cybersecurity for the smart grid is essential to ensure the resiliency of the supply and delivery of electrical power.

Cybersecurity for the utility's electrical grid monitoring and control systems provides the actions required to preclude the unauthorized use of, denial of service to, modification to, disclosure of, loss of revenue from, or destruction of, critical system or informational assets [1].

17.1 THE CYBERSECURITY PROBLEM

In this modern world, where remote operations are common, where physical changes can occur through the click of a button or because of the logic programmed into a device, the questions that need to be asked are:

- If the utility operator can control the grid remotely, who else can?
- What happens when the information that the operator receives is not correct?
- What happens when equipment starts to act and react differently than expected?
- Is it possible for cyber attackers to navigate their way into a utility's control network, and take control of the system?

Unfortunately, it is possible for a cyber attack or malware (malicious software) to infiltrate utility networks and cause unexpected events. It has already happened in isolated instances. Cyber attacks and viruses have caused power disruptions, and malware has caused factories to manufacture bad products and even destroy product components.

17.1.1 Cyber-Physical Systems

For the physical processes in the utility, such as the generation or transmission and distribution of electricity, sensors are added to measure various parameters within the process, such as pressure, temperature, flow rate, voltage, amperage, and power factor. The cyber part is the microprocessor-based computer system used to monitor and analyze the data, and then send control commands to modify the physical process to achieve the desired outcome. Together, this cyber-physical system can achieve new levels of efficiency, as processes can be monitored and adjusted to meet the demand, or react to changes in the operation of the grid. Such is the case with transmission and distribution lines. There is a limit to how much power can be transferred from the generation source to the point of distribution and use. An example of a cyber-physical system is a flexible alternating current transmission system that monitors and optimizes the power transfer capability and voltage stability of a transmission system [2].

A cyber-physical system is dependent upon receiving accurate information from the sensors and upon being able to communicate to the equipment that makes changes to the physical process. It is a precarious balance of trust. Trust that the data received by the system is describing the physical condition accurately, trust that the right field equipment is receiving and executing the commands properly, and trust that the computer (cyber) is working properly and making the right decisions.

- Could this precarious balance be tilted and put off-balance? (Yes)
- Have sensors ever failed or gone out of calibration? (Yes)
- Have communications been disrupted or garbled in transmission? (Yes)
- Have computer systems ever failed or become compromised? (Yes)

Borrowing from the words of Forrest Gump, "It happens." In this world of cyber-physical effects, where through cyber means, physical things are made to happen, cybersecurity is an essential component to keeping our electrical grids safe and operating correctly.

17.1.2 Information Technology versus Operational Technology

For the purpose of this discussion and throughout this chapter, the term Information Technology (IT) refers to the practices and equipment used in maintaining and operating the enterprise or corporate networks, and the term Operational Technology (OT) refers to the practices and equipment used in maintaining and operating the utility real-time grid management systems.

Years ago, as the electric industry began to move from electro-mechanical to digital devices, these digital devices and systems used proprietary communication protocols and very specialized hardware and software. In this environment, the OT network was physically separated and isolated from the business computer network, or IT system. However, as OT solutions matured, IT solutions were adopted into the OT environment to enhance Supervisory and Data Acquisition (SCADA) communication capabilities between the control center and the remote substations. Then, the corporate and SCADA system networks were connected. This connection between the business and the operational worlds provided new capabilities and efficiencies, but it also provided much less isolation between the OT systems and corporate networks. The SCADA systems of yesteryear were designed and built for operation in isolation, where security was not a consideration in their design and implementation, and the focus was on operational availability, efficiency, and safety. Advances in SCADA and the development of other grid management applications [such as energy management systems, substation automation systems, distribution automation systems, distribution management systems (DMS)] were accompanied by advances in the grid monitoring and control devices, and the use of more open-standard communication interfaces, such as Transmission Control Protocol/Internet Protocol (TCP/IP). The more widespread use of advanced monitoring and control devices on the grid, and the increased need for more advanced OT systems to exchange data with traditional utility IT systems [such as outage management and advanced metering infrastructure (AMI)] created a need for security to be introduced into the OT environment.

There are marked differences in characteristics of a grid management system in an OT environment with that of a traditional IT system. In order to highlight many of the differences between the two systems, the reader is invited to examine the following table, initially produced in the National Institute for Standards and Technology (NIST) Special Publication 800-82, Guide to ICS security [3] (Table 17.1).

17.1.2.1 Confidentiality, Integrity, Availability versus Availability, Integrity, Confidentiality

Information security focuses on achieving three key objectives: confidentiality, integrity, and availability (CIA). In IT security, CIA is the order of priority that governs the way it is managed. That is, confidentiality is the primary focus, with Integrity a close second. Availability, although important, is not as essential as ensuring the privacy of the data exchange and validating that the transaction is accurate; thus, some delay is acceptable. The policies, procedures, and equipment developed for the IT environment support this priority.

In the OT environment, the order of priority is reversed, that is, availability, integrity, and confidentiality (AIC). Most agree that availability has the highest priority. The supply of electricity is expected and even demanded to be available at all times. It supports and drives other controlled processes that also require a 24/7 operation. Integrity is a close second, as operations and maintenance rely on the information coming from the field. If the data are wrong, then a bad decision could be made, which could affect the safety of personnel and the environment. Confidentiality is not as important. In fact, OT systems were historically designed with no confidentiality, as the data were available to anyone who needed to see it, whether it was the operator, the engineer, the maintenance team, or the management.

With this discussion as a preamble, let’s now take a closer look at each of the three key objectives.

17.1.2.2 Availability

Smart grid systems are required to have reliability levels as high as the reliability of the overall electric grid. Availability is the measure of the system being available to do the work it was designed

TABLE 17.1
Summary of IT Systems and ICS Differences

Category	Information Technology System (IT)	Industrial Control System (OT)
Performance requirements	• Nonreal time • Response must be consistent • High throughput is demanded • High delay and jitter may be acceptable • Less critical emergency interaction • Tightly restricted access control can be implemented to the degree necessary for security	• Real time • Response is time-critical • Modest throughput is acceptable • High delay and jitter are not acceptable • Response to human and other emergency interaction is critical • Access to ICS should be strictly controlled, but should not hamper or interfere with human–machine interaction
Availability (reliability) requirements	• Responses, such as rebooting, are acceptable • Availability deficiencies can often be tolerated, depending on the system's operational requirements	• Responses, such as rebooting, may not be acceptable because of process availability requirements • Availability requirements may necessitate redundant systems • Outages must be planned and scheduled days/weeks in advance • High availability requires exhaustive predeployment testing
Risk management requirements	• Manage data • Data confidentiality and integrity are paramount • Fault tolerance is less important—momentary downtime is not a major risk • Major risk impact is delay of business operations	• Control physical world • Human safety is paramount, followed by protection of the process • Fault tolerance is essential, even momentary downtime may not be acceptable • Major risk impacts are regulatory noncompliance, environmental impacts, loss of life, equipment, or production
System operation	• Systems are designed for use with typical operating systems • Upgrades are straightforward with the availability of automated deployment tools	• Differing and possibly proprietary operating systems, often without security capabilities built-in • Software changes must be carefully made, usually by software vendors, because of the specialized control algorithms and perhaps modified hardware and software involved
Resource constraints	• Systems are specified with enough resources to support the addition of third-party applications, such as security solutions	• Systems are designed to support the intended industrial process and may not have enough memory and computing resources to support the addition of security capabilities
Communications	• Standard communications protocols • Primarily wired networks with some localized wireless capabilities • Typical IT networking practices	• Many proprietary and standard communication protocols • Several types of communications media used including dedicated wire and wireless (radio and satellite) • Networks are complex and sometimes require the expertise of control engineers

(*Continued*)

TABLE 17.1 (*Continued*)
Summary of IT Systems and ICS Differences

Category	Information Technology System (IT)	Industrial Control System (OT)
Change management	• Software changes are applied in a timely fashion in the presence of good security policy and procedures. The procedures are often automated	• Software changes must be thoroughly tested and deployed incrementally throughout a system to ensure that the integrity of the control system is maintained. ICS outages often must be planned and scheduled days/weeks in advance. ICS may use OSs that are no longer supported
Managed support	• Allow for diversified support styles	• Service support is usually via a single vendor
Component lifetime	• Lifetime on the order of 3–5 years	• Lifetime on the order of 15–20 years
Access to components	• Components are usually local and easy to access	• Components can be isolated, remote, and require extensive physical effort to gain access to them

Source: From NIST SP 800-82 r2, Table 2-1, as Public information.

to do, at the time it is needed. A portion of the system may be up, running, and processing commands 100% of the time, and, therefore, very reliable, but if the performance is not adequate to the needs of the system, and critical command windows are missed or delayed, then the system cannot be said to be available. In fact, a denial of service cyber attack can simply be causing the data flow rate to slow down enough to where the process cannot respond appropriately, and thus affect the availability of the system. Risk to the availability of the control system could potentially come from any system, any communications-handling device, any message-handling process, or any service that is invoked.

17.1.2.3 Integrity

The integrity of the data that are exchanged by smart grid systems is critical. Operations could be negatively impacted if the data are manipulated (intentionally) or corrupted (unintentionally) and systems are fed inaccurate operational data. In extreme circumstances, this could lead to the compromise of critical systems or to grid instability.

The entry points that introduce integrity risk are any interfaces where data are handed off from one system to another. The security of the handoff is important, but of more importance is how the system that is receiving the data ensures the validity (integrity) of the message. If the data can be manipulated, or if the data are corrupted while the data in motion between two systems, the potential exists that the receiving system will take action based on the manipulated/corrupted data. This is the intent of a "Man-in-the-Middle" cyber attack. The attacker inserts himself/herself into the traffic stream between two communicating systems or devices. The intent is to control the information going to, and being received by, the systems or devices. This makes ensuring the integrity of the data of critical importance to ensure stable operations.

Historically, integrity was the amount of trust that the data received came from the actual source. Before the advent of the Internet and the proliferation of networking environments, it was a safe bet that the data came from the expected source. In today's world, we should follow the adage of "trust, but verify."

Integrity is the process of verifying or ensuring that the source of the data, and the data itself, are authentic. It could be argued that ensuring message integrity is the most critical operational security function that the smart grid must support. The answers to solving the integrity problems are rooted in the security functions of auditing, authorization, nonrepudiation, and message-signing. These functions will be discussed in more detail later in this chapter.

17.1.2.4 Confidentiality

Confidentiality includes the traditional concerns of privacy between two (or more) hosts. Confidentiality in the smart grid is needed to protect sensitive information, such that if the data were exposed, the data could have the potential to have a negative consequence on the operation of the system. Alternately, the operational data may also be deemed confidential for competitive reasons. If the data were known to a competitor, the data may allow that entity to obtain an unfair advantage in a specific supply area or within the overall market.

There is certainly consumer, as well as regulatory, expectations that the data regarding the use of electricity within a private residence remain confidential. For example, advanced metering enables greater data accuracy, such that it could show if there is anyone home, and what appliances/devices they are using.

The entry points that introduce the confidentiality risk are any location where data are stored (at rest) and any mechanism by which data are transmitted (in motion). For data at rest, whether on a smart grid device or within an operational data center, the data have the potential to be read, copied, and distributed to persons other than the intended recipients of the data. For data in motion, whether on a private, utility-owned network, on a service provider-shared private network, or on a public network, such as the Internet, the data have the potential to be intercepted, just like "tapping" a phone call, and then recorded, copied, and distributed.

The answers to solving the confidentiality problem are rooted in the security functions of encryption and access control. By providing the appropriate level of data encryption, data can be protected from observation by anyone who is not an intended recipient. Access controls are the technical measures that are put in place to protect information from those with access to the system from obtaining data that are not relevant to their job function, thereby further protecting the data from accidental or intentional disclosure. The functions of encryption and access control will be discussed in more detail later in this chapter.

17.1.3 Threats

Threats to an electric utility include adverse weather conditions, animals chewing through cables, falling trees, human error, and cyber attacks. Some of these threats can be predicted with some accuracy, such as weather disruptions and falling trees, but threats that are human based, such as cyber attacks, disgruntled employees' malicious actions, or accidents and mistakes, are unpredictable. We will focus our attention on the cyber attack threats.

A threat is credible when the threat actor has the capability to perform the attack, has the intent or motivation, and has the opportunity to execute the attack.

Threat actors can be grouped into three categories (see Figure 17.1) [4]:

- Group 1—Mainstream threats
- Group 2—Organized threats
- Group 3—Terrorists and nation state threat

Group 1—Mainstream Threats This is the largest threat group. This group is unorganized, or rather their efforts are not well coordinated. They consist of individuals whose skills vary from beginner to advanced. Their motivation generally flows into the desire for notoriety,

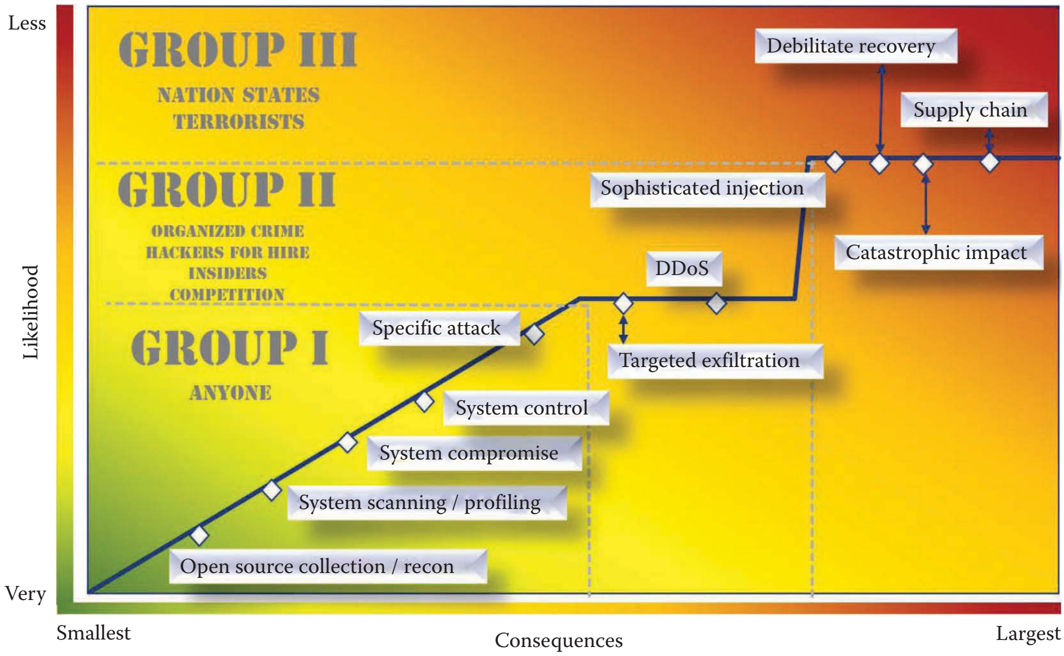

FIGURE 17.1 The risk curve. (Reprinted from ICS-CERT Virtual Learning Portal, 210W-06 Cybersecurity for Industrial Control Systems-Current Trends (Threats), page 22, as public information.)

or just to see if they can accomplish something. Some consider themselves to be cybersecurity researchers and will attack systems to either improve their knowledge on how systems work, or demonstrate their capabilities to potential employers.

The consequences that could come from this group ranges from inconsequential actions, such as open source collection, to gaining access to a control system and causing unintended actions.

Group 2—Organized Threats Organized threat actors generally include groups, such as disgruntled employees, insiders, criminal groups, political or environmental activists, or corporate espionage. Their intent may be financial rewards, drawing attention to a cause by disclosing sensitive information, blackmail, or gathering information and trade secrets. The attacks are more organized and sophisticated as there is usually a hierarchal organization, with individuals working together to enhance the cumulative skill of the group. It is common for this group to pull from the membership of the mainstream threat actors.

The consequences that could come from this group include targeted exfiltration of data, denial of service, or taking control of the control system and performing nefarious actions.

Group 3—Terrorist and Nation-State Threats This final group of threat actors is very sophisticated and structured. They are well organized and well funded as they have the backing of a nation-state or a terrorist group. Many of these groups have active cyber-warfare programs and exercise their skills regularly. The goal of these groups is to steal classified information, and disrupt, terrorize, or eliminate major aspects of society. This group may also recruit group 2 organizations, and group 1 individuals.

The consequence of a terrorist or nation-state cyber attack will be major or even catastrophic.

17.1.3.1 Identifying Specific Threats and Mitigations through Attack Tree Analysis

The purpose of an attack tree is to define the possible attack vectors to reach a desired attack outcome. This is a common exercise performed to assess the vulnerability of a system under test. Once an attack tree has been built, an attacker looks at the vectors on the attack tree to determine the least effort required that results in an exploit. The effort to accomplish an attack is measured against the expenditures, such as cost of equipment or personnel. It also factors into account the need for specialized tools or knowledge. Finally, effort is measured against the time needed to carry out an attack. For each of the attack outcomes, there is a graphical attack tree. The root node represents the goal of the attacker. The tree lists possible ways to reach the goal. The nodes of the tree represent potential attacks. The children of the nodes represent refinements of the attack.

As an example of the benefit of this methodology, we will look at a specific attack on an AMI system [5]. The attack that is analyzed below has the goal of interrupting the electricity flow. There are multiple attack vectors that could be analyzed through attack trees. A list of attack tree analyses that flow from the AMI system that communicates with electric meters, that have remote access and control capabilities, and that delivers usage data to the utility for billing purposes includes:

- Interrupt electricity flow
- Denial of service
- Information gathering—preattack
- Modifying meter data
- Compromise head-end system
- Compromise take out point
- Disable take out point
- Disable the head-end system
- Hijack smart grid devices
- Spoof smart grid devices
- Privacy attacks

The attack tree to interrupt electricity flow is primarily based on attacks on the disconnect switch that resides in the meters. Local digital attacks can be accomplished with a detailed knowledge of the meter metrology and design. These methods could include the use of physical means to modify or force the meter electronics circuitry to operate the disconnect switch (Figure 17.2).

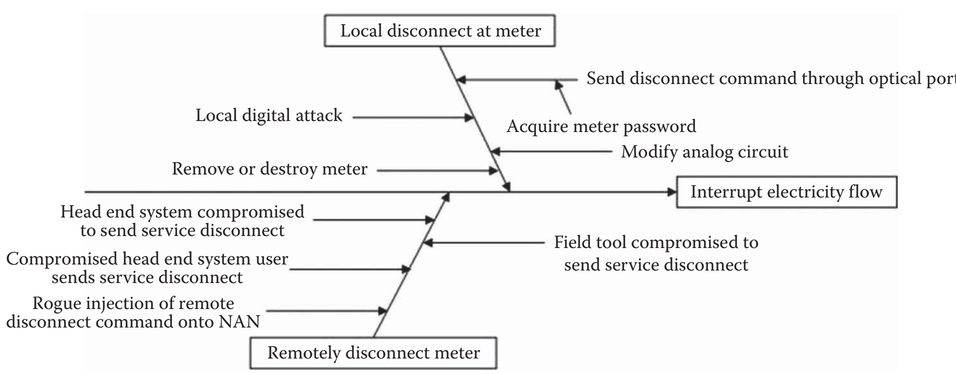

FIGURE 17.2 Attack tree to interrupt electricity flow through a meter. (From Chasko, S. and Demeter, M., Attack Tree Analysis of Advanced Metering Systems, Landis and Gyr, 2016. With permission.)

The meters often have a local communications interface (e.g., optical port) for field configuration and maintenance. If an attacker has compromised the required meter password, they might be able to send a disconnect command through the local communication interface.

With remote attacks, a compromise of the metering software system or an authorized AMI user might also allow for the remote disconnect of a meter over the AMI communications network. One could also use the field tools that are used to remotely interact with the meters to attack the disconnect switch. There are field tools that communicate over the AMI network that are used to interact with the meters. If an attacker could compromise the authentication mechanisms utilized by the AMI networked field tools, this could allow an attacker to operate as a rogue field tool user within the system. Finally, it might be possible to create a rogue message that is injected or replayed issuing a disconnect command onto the AMI communication network.

17.1.4 Common Vulnerabilities

A vulnerability is a flaw or weakness in the design, implementation, or operation and management of a component that can be exploited to cause a security compromise [1]. It is important to note that the existence of a vulnerability in a system, device, or software program does not mean that the utility has been compromised. A utility has been compromised only when a vulnerability has been exploited, and unauthorized disclosure, modification, substitution, or use of information has occurred.

Where are the potential vulnerabilities within a utility OT system? Figure 17.3 is an example of potential vulnerabilities that could be found in a utility OT architecture that includes the main control center, transmission and distribution substations, customer meters, loads, generation, as well as mobile devices used by the utility workforce. The potential vulnerabilities can be found in trusted access to the network, software programs, embedded firmware on hardware devices, and communication protocols.

In 2015, the US Department of Homeland Security, Industrial Control System-Cyber Emergency Response Team (ICS-CERT) performed 112 security assessments of varying degrees and intensity across the USA [6]. ICS-CERT performs these assessments as a service for all 18 critical infrastructure sectors, including the Energy sector. However, there is usually a high degree of similarity between a control system in one sector to that in another. From those assessments,

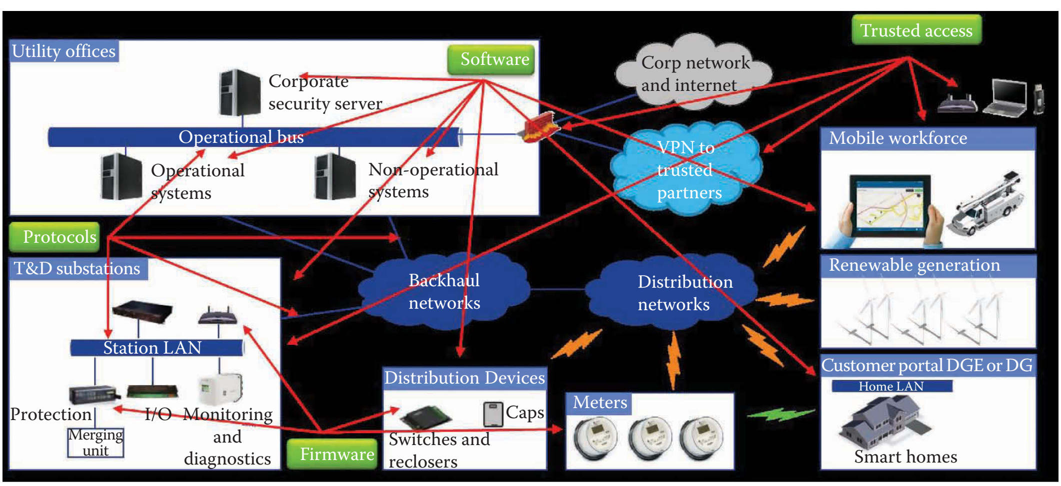

FIGURE 17.3 Potential vulnerabilities in a SCADA system. (© 2016 General Electric. All rights reserved. With permission.)

a total of 638 weaknesses were identified. The most common issue was insufficient protection at the network boundary. Control and monitoring of communications are essential as they can slow attack progress and provide records for detection and analysis of unauthorized activity. It is important to know what is going into and out of the utility OT networks. Without strong boundary protection, it is easier for attackers to gain access to critical assets and information, and potentially manipulate the systems being controlled. Second on the list was least functionality, or rather the concept of minimizing the computing resources of system functions, ports, protocols, and services to only those required to support system essential operation. Restricting the device or service to allow only what is needed for operation reduces the attack surface and makes it more difficult for the attacker. Table 17.2 summarizes the top six weaknesses identified by the US Department of Homeland Security.

Communication protocols commonly used in utility OT applications do not have built-in security features, such as authentication, authorization, or tamper-checking capabilities. Utility protocols, such as Modbus and DNP3, were first developed as proprietary serial protocols. They were then standardized and many vendors began supporting them. With the addition of TCP-IP functionality and commercial off-the-shelf IT components, these protocols were given a TCP-IP wrapper, but the basic functionality of the protocol, including the lack of security features, were not changed. Without authentication or authorization, the software or hardware device must assume that the command is coming from a trusted source and it will execute the command. An attacker can take advantage of this. All the attacker needs to do is gain access to the network, and then send his/her own commands to the controller. Or, as another example, the attacker could intercept the information, modify it, and send it on, providing false information.

Any software or hardware that processes, stores, or transmits information digitally is potentially vulnerable to cyber attack. It is important to recognize that the products used in the OT world have

TABLE 17.2
Top Six Weaknesses Discovered in FY 2015

Area of Weakness	Consequence/Risk
Boundary protection	• Cannot detect unauthorized activity in critical systems • Increased risk to critical assets with weak boundaries between ICS and enterprise networks
Least functionality	• Creates vectors for malicious party access to critical systems • Rogue internal access could be established
Authenticator management	• Unsecured password communications can easily be compromised • Password compromise could allow trusted unauthorized access to systems
Identification and authentication	• Results in lack of accountability and traceability for user actions if an account is compromised • Increases difficulty in securing accounts as personnel leave the organization, especially sensitive for users with administrator access
Least privilege	• The more authorized users with elevated privileges, the larger the attack surface for an intruder to steal account credentials with elevated access rights to access and compromise critical systems
Allocation of resources	• Understaffing impedes organizational cybersecurity monitoring and response capability to a critical system cyber incident increasing the potential impact to the company

Source: From DHS NCCIC/ICS-CERT Industrial Control Systems Assessment Summary Report, Table 2, as Public Information.

a much longer life span than those found in the IT world. The average life of an OT component is 15–20 years, whereas the average life of an IT component is only 3–5 years. That means utilities are working with products that were potentially designed over 20 years ago, before the need for cybersecurity was generally accepted in the control system world. What used to be considered good coding practices are now potentially insecure coding practices.

Times are changing and vendors of OT system products, both software and hardware, are making changes. New products are being designed with security built into the product. Existing products are being modified, replacing vulnerable code with secure code, and updating the products to include security features. However, this is a process and not a one-time event. For example, Microsoft provides a monthly security patch for the Windows operating system. They are continually finding vulnerabilities, fixing them, and providing patches to us, their customers. The same is true with OT vendors and their products.

Product vulnerabilities are found by vendors, security researchers, national Computer Emergency Readiness Teams (CERTs), and customers. The ICS-CERT receives vulnerability reports and facilitates the issues found with the applicable vendor. When the vendor has created a patch or firmware update that fixes the vulnerability or provides other mitigations, ICS-CERT will issue an Advisory. The Advisory provides relevant information about the vulnerability and the recommended actions to take; often it includes the announcement of the release of the patch that fixes the vulnerability. Figure 17.4 shows that this is a very active program, for, in 2015 alone, 427 vulnerabilities were reported to ICS-CERT [7].

The types of vulnerabilities being reported are shown in Figure 17.5 [7]. The two types of vulnerabilities that have consistently been more that 50% of the issues discovered are improper input validation, and permissions, privileges, and access control. ICS-CERT acknowledges that this trend may indicate a cybersecurity gap, or that it reflects the type of vulnerabilities that are targeted by researchers reporting to ICS-CERT. Improper input validation vulnerability occurs when the software does not properly validate the data being input by the user. An attacker could potentially use this vulnerability to provide unintended input and cause altered control flow, arbitrary control of a resource, or arbitrary code execution. Permissions, privileges, and access control vulnerabilities occur when an attacker is able to bypass a defined authorization policy. For example, an attacker might be able to elevate his/her privileges from User to Administrator, or find a way to bypass the access controls and gain unauthorized access, permissions, and capabilities.

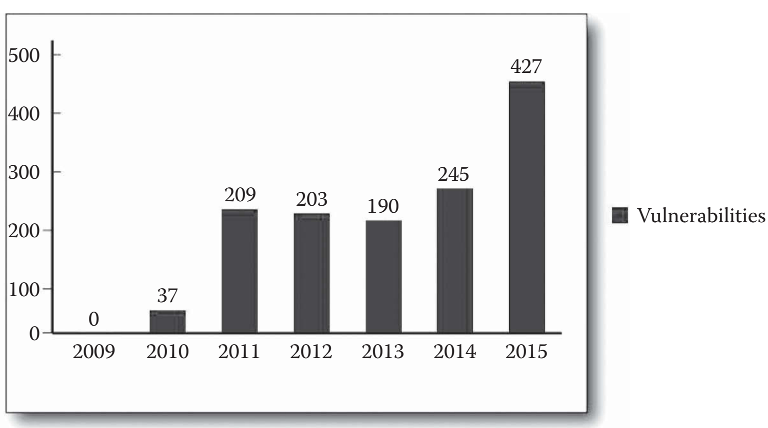

FIGURE 17.4 Number of vulnerabilities reported to ICS-CERT 2009 through 2015. (Reprinted from DHS NCCIC/ICS-CERT FY 2015 Annual Vulnerability Coordination Report Figure 3, as public information.)

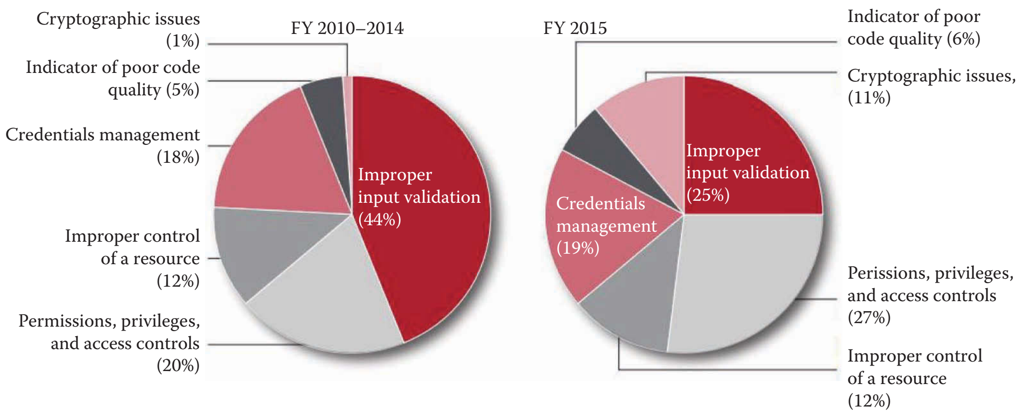

FIGURE 17.5 Categories of all vulnerabilities reported to ICS-CERT. (Reprinted from DHS NCCIC/ICS-CERT FY 2015 Annual Vulnerability Coordination Report Figure 9, as public information.)

17.1.5 Examples of Cyber Attacks

In this section, we will review few well-known cyber attacks and some of the lessons that can be learned from each.

17.1.5.1 Aurora—Simulated Cyber Attack Destroys Diesel Generator

17.1.5.1.1 Overview

In 2007, the Idaho National Laboratory under the direction of the Department of Homeland Security ran the Aurora Generator Test in order to demonstrate that a cyber attack could destroy the physical components of the electric grid. This vulnerability is referred to as the Aurora Vulnerability [8].

The Aurora Vulnerability, not to be confused with the Aurora-Google attack, affects rotating equipment. The test setup consisted of a 2.25-MW diesel-powered generator supplying power to the grid. The attack was not on the generator itself, but on a device that operated a circuit breaker. The circuit breaker was in a nearby substation and connected the generator to the grid. The attack consisted of rapidly opening and closing the circuit breaker. When the circuit breaker is opened, the grid load on the generator is removed and the generator speeds up. When the circuit breaker is closed, the generator is not in phase with the grid frequency, which creates a massive torque on the equipment as it regains synchronicity with the grid. A video of the Aurora test was released to the media and shown by CNN and others. The video, which is still available on YouTube.com [9], showed the 2.25-MW diesel generator bouncing and shaking each time the cyber attack opened and closed the breaker. After a few hits, black smoke billowed from the exhaust stack, and parts of the generator and the coupling between the diesel motor and the generator could be seen flying off. Some parts of the generator landed as far as 80 feet away from the generator. The Aurora Generator Test was the first full-scale demonstration, showing how a cyber attack could physically damage equipment.

It is important to note that the Aurora vulnerability does not just affect electrical generators, but could affect any large synchronous rotating equipment, for example, motors.

17.1.5.1.2 Lessons Learned

The Aurora Vulnerability takes advantage of the command and control protocols, such as Modbus and DNP3, that are used in utility control systems, which do not have security protections, such as authentication, authorization, confidentiality, or replay protections. This means that if an attacker can gain access to the substation network and communicate with the device controlling the breakers, he/she can also control it. Mr. Perry Pederson was the Director of the DHS Control Systems Security Program in 2006. It was under his leadership that the Aurora test was developed and conducted. In 2014, Mr. Pederson wrote a blog that revisited the Aurora project.

> It's about time that we learn the lesson that Aurora tried to teach us seven years ago. Obviously, I am not speaking to those involved in the project, but to those who completely missed the point. You can continue to canvas the masses and run another survey or attend one more ICS cyber security conferences and you will continue to hear a range of opinions on Aurora. You can argue the test was fake, you can argue that the problem does not exist, you can even argue that mitigation efforts have been 100% successful. What has been glossed over countless times in this debate is the approach used to discover Aurora in the first place. Those who first postulated Aurora and then set about to fully assess the vulnerability knew this:
>
> "Effective defense against cyber-physical attacks is based on thorough system analysis and engineering principles, not on consensus" [10].

17.1.5.2 Stuxnet—Cyber Attack Destroys Uranium Enrichment Centrifuges

17.1.5.2.1 Overview

Stuxnet is a malicious computer worm created specifically for the purpose of sabotaging Iran's nuclear Uranium enrichment program, making it appear to be a series of unfortunate accidents. The worm itself was approximately 500 kb in size, included four "zero-day" exploits, contained over 4000 functions, and employed sophisticated evasion techniques [11]. Stuxnet was probably introduced to the system by a USB stick.

In June 2010, Stuxnet was discovered. Over the ensuing weeks and months, researchers discovered how this masterful piece of malicious software worked. It attacked in three phases. First, it targeted Microsoft Windows machines using valid digital certificates and bypassing automated malware detection systems, repeatedly replicating itself across the network(s). Second, it sought out Siemens Step7 software (also Windows-based) that is used to program ICS and determined whether a specific programmable logic controller (PLC) was part of the control system. If the computer was not part of the targeted control system, Stuxnet did nothing. It was benign to all but the intended target; however, if it was part of the targeted system, then the worm attempted to access the Internet and download the latest version of itself. Finally, it used "zero-day" vulnerabilities (i.e., vulnerabilities that are unknown to everyone but the attacker) to compromise the PLC. It then monitors the operation of the system before executing its malicious control programs [12].

In earlier versions of Stuxnet, it controlled the gas flows of the Uranium enrichment process to result in much lower than expected products. The later versions of Stuxnet controlled the speed at which some of the centrifuges spun. It would spin very fast, then slow down, then speed up until the centrifuge failed. While the centrifuges are spinning out of control, Stuxnet would provide false data to the control room, which would show optimal operation. It must have been very frustrating for the engineers and scientists who were trying to make the process work, for while the control room showed everything worked as it should, centrifuges were randomly failing, at a much higher than normal rate. International inspectors discovered numerous failed centrifuges. It was estimated that Stuxnet ruined almost one-fifth of Iran's nuclear centrifuges [13].

17.1.5.2.2 Lessons Learned

Every control system site is vulnerable to a cyber attack, even those that are not directly connected to the Internet. Many people mistakenly believe that, as long as there is a firewall between them and the corporate network or the Internet, they are not connected. Some sites even go as far to say that they are "air-gapped" or that there is no connection to another network. However, USB sticks, laptops, and external hard drives are commonly used to update software, firmware, and configuration files in a control system. Stuxnet was most likely introduced to the system on a USB stick. After the initial infection, it passed through firewalls on SQL server connections and compromised the PLC. There is always a way that a system can be compromised.

It is not easy to discover whether your system is compromised by an external hacker. The earliest version of Stuxnet was from 2007. Stuxnet was discovered in July 2010. This means that the Iranian system was compromised for at least 3 years. The US Department of Homeland Security, Industrial Control System—Cyber Emergency Response Team (DHS ICS-CERT) has discovered through their forensic investigations of compromised U.S. critical infrastructure control systems, that some system were compromised up to 2 years before it was discovered. It is a best practice to include monitoring systems to look for anomalous and inappropriate network traffic.

17.1.5.3 Cyber Attack on Western Ukraine Power Grid

17.1.5.3.1 Overview

On December 23, 2015, three different electric energy companies were victims of a cyber attack that caused a power outage affecting approximately 225,000 customers. Operator stations and controllers were rendered unusable by a malicious software called KillDisk, and serial to Ethernet converters were rendered useless after the attackers uploaded new firmware to the devices. This made it impossible for the utility to operate remotely. The power was restored within 6 hours by sending technicians to the substations to manually reconnect the power.

To better understand the full scope of the attack, we will review what happened, step by step [14]. Please refer to Figure 17.6 when reviewing the following steps. *Note:* Based on the reports given through System Administration, Networking, and Security Institute and DHS ICS-CERT, an attempt has been made to define actions as they happened in a serial fashion. However, it is possible that the order of some events is not exactly as it happened.

- Step 0. The attackers gather publicly available information about the utility and its people from Internet Web sites, for example, LinkedIn and Job Postings.
- Step 1. They craft a malicious Microsoft Word document with macros that will install BlackEnergy3, a remote access Trojan, when run.
- Step 2. They send an email to a number of utility employees in a phishing campaign based on the information gathered in Step 0.
- Step 3. Some of the recipients open the email and its attachment and run the macros, which installs the malware. The malware is used to steal user credentials.
- Step 4. These credentials are used to access the Domain Server, which contains many other usernames, passwords, and information about other machines in the network.
- Step 5. The additional information from Step 4 is exfiltrated for further analysis and potential use.
- Step 6. The attackers need to get to the Control System network. This would typically be done by pivoting through the firewalls and DMZ separating the Business Network from the Control System, but in this case, they find an easier method. They discover a VPN access point that does not require two-factor authentication and are able to use previously stolen credentials to login.
- Step 7. Now in the Control System network, the attackers spend around six months studying the environment, gathering information about connections to field devices, and so on. It is likely that some of this time was spent building a mock control system and testing attacks against it that would result in an outage and hamper restoration efforts.
- Step 8. One of the first actions taken was to schedule a power outage on network-connected uninterruptible power supplies (UPS) for the main control room.
- Step 9. The attackers also loaded the KillDisk malware on some of the SCADA servers.

Step 10. Ready to begin their attack, the attackers launch a telephone denial of service to block customers reporting outages as well as hamper communication between the regional control centers once the attack begins.

Step 11. They proceed to lockout the keyboards and mice connected to the operator workstations, preventing operators from regaining control when malicious actions are performed.

Step 12. They changed a number of passwords for key systems.

Step 13. The attackers used remote access tools (such as Remote Desktop) to manipulate the DMS (distribution management system) user interface from their remote location. *Note:* Remote Desktop was a functionality implemented by the energy company, not software installed by the attacker).

Step 14. Using standard DMS functionality, the attackers tripped breakers at more than 50 regional substations. While the operators could see it happening, they were unable to intervene because their mice and keyboards were locked out. This caused approximately 225,000 customers to lose power.

Step 15. In order to prolong the outage, the attackers installed KillDisk on some of the remote terminal units in the substations.

Step 16. They uploaded malicious firmware to some of the serial-to-Ethernet converters, rendering them unusable. This prevents any remote monitoring or operation of the devices in the field.

Step 17. The previously scheduled (Step 8) UPS outage takes place, removing power to the servers in the control room.

Step 18. Without power to the SCADA servers or a way to communicate with field devices, the utility has no choice but to send crews to the field to manually operate breakers in the substations, thereby restoring power to the customers and to the control center.

Step 19. The servers at the utility begin to come back online, but the previously loaded KillDisk component wipes some of the control systems, rendering them unusable. It also wipes other machines in business functions (management, HR, finance).

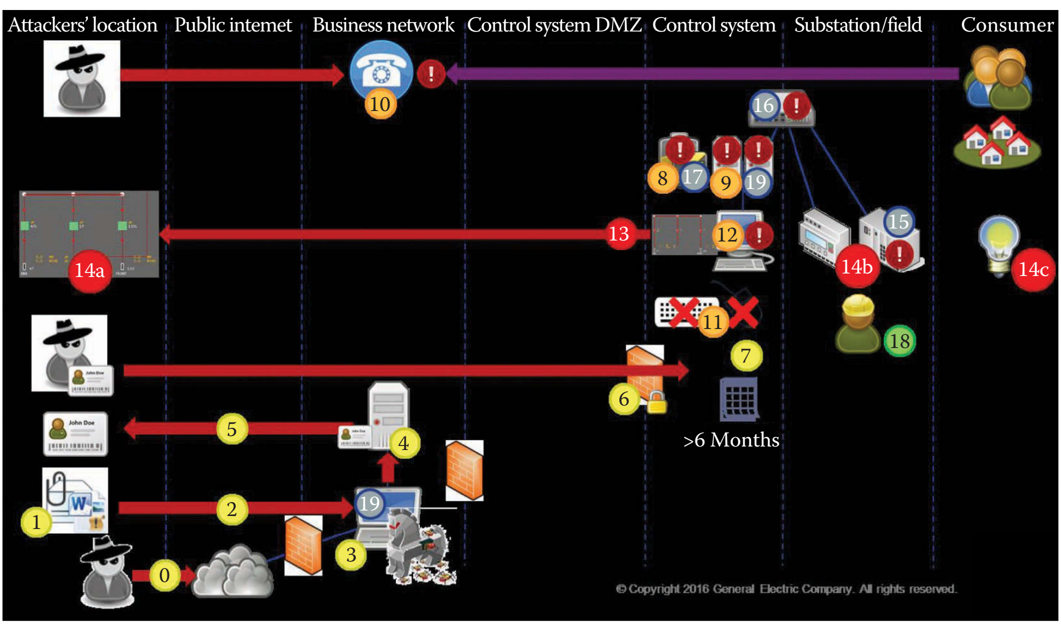

FIGURE 17.6 Summary of the Ukraine distribution cyber attack. (© 2016 General Electric. All rights reserved. With permission.)

Although the power was restored in a relatively short amount of time, the real problem was that the energy company now had no remote access capability, and was forced to operate in manual mode for months, while the serial-to-Ethernet devices were replaced and commissioned, servers were restored and verified clean of infection, and the control software was reinstalled and tested [15,16].

17.1.5.3.2 Lessons Learned

This is an interesting case because the attackers used the features of the system to perform the power outage attack. The only exploitation that was accomplished was the phishing email and the opening of the compromised Microsoft Word document. Everything else was done using standard features and capabilities of the system. For example, the attackers accessed the control system through an established VPN, using valid credentials that they had stolen. The control system functionality enabled new software and firmware to be uploaded to the systems. The energy company used remote desktop to enable their operators and engineers to login remotely and control the system. Therefore, it is essential for each system to be reviewed with the "evil eye" or through the viewpoint of an attacker. Then, simple mitigations can be implemented to prevent attacks, such as dual authentication for VPN access, role-based access control, least user privileges, services that ensure authorization, authentication, and auditing (e.g., RADIUS – Remote Authentication Dial-in User Service), and a monitoring and event correlation program (e.g., Intrusion Detection System and Security Incident and Event Management program).

Could this type of attack happen elsewhere? Yes, indeed. In the spring of 2015, a Washington state utility executive Benjamine Beberness had invited a "red team" of National Guard cyber experts to test the utility's defenses [17]. Within 22 min, the National Guard red team had broken into the utility. "The cyberattack chain that the National Guard used against us, it's almost verbatim what happened in Ukraine," said Beberness, the utility's chief IT officer. At this utility and at the Ukraine power companies, employees recklessly clicked on a phishing email with concealed malware that took the attackers inside the utility's business computers. "It only took one click for somebody to get in," Beberness said of his utility's fate. Once in, the National Guard cyber experts found pathways into a test operations network that mirrored the utility's control system. This cyber exercise prompted new cybersecurity strategies to be implemented at the Washington state utility.

This exercise and the Western Ukraine cyber attack prove that this is not a unique incident. The threat is real. The capability of the adversary is sufficient. The smart grid needs improved cybersecurity strategies.

17.2 THE CYBERSECURITY SOLUTION

In deference to the Lone Ranger, there is no "silver bullet" in the world of cybersecurity. That is, a single security product, technology, or solution cannot adequately protect a utility system by itself. Cybersecurity is not a single defensive measure, but rather multiple overlapping security layers and a governing framework to provide the required level of defense. The sections and subsections that follow will discuss frameworks, standards, and regulations that provide a model for securing the utility environment in the smart grid.

17.2.1 Security Standards, Regulations, and Guidance

Governments and industry organizations have defined several security standards, guidelines, and recommended practices. These documents provide recommendations and requirements, some of which are enforced through penalties and fines. As already discussed, there are marked differences between the traditional IT and OT operations. These standards, guidelines, and recommended practices have evolved over the years, from taking a traditional information security approach to addressing industry challenges directly and thoroughly.

We will review the most widely recognized and referenced security standards for the smart grid, as well as a couple of ICS standards that are relevant to the electric industry. There will be some standards and regulations that will not be addressed through this review; however, as will be discovered through our review, many of the concepts, categories, and requirements addressed in one standard will also be addressed in another standard. In fact, there is value in referencing standards, guidelines, and recommended practices, and performing a crosswalk to compare the similarities between them. The U.S. Department of Homeland Security developed such a document to help subject matter experts as they were writing standards for ICS security [18]. In some cases, crosswalks will be provided within the security standard to show concurrence with other authoritative documents.

17.2.1.1 Compliance versus Security

Being in compliance with regulatory security standards does not necessarily mean that you are in fact secure. For example, if there is a requirement to have a firewall between the OT and IT networks, what would be the most secure? (1) A firewall that has the same rules as that protecting the business enterprise IT network? or (2) A firewall that is properly configured for the OT environment? (*Note:* (2) is the correct answer.)

Regardless of the security standard your organization is using, it is important to remember that standards were all written for a large and diverse audience. They do provide guidelines, make recommendations, and impose requirements for specific cybersecurity controls. However, a single security standard cannot address the intricacies and nuances of any one individual company or environment. No two environments are the same. Even the same processes within the same utility could differ from site to site due to commissioning dates, system updates and migrations, and general maintenance. Therefore, each recommendation should be given careful consideration, taking into account the specifics of each unique environment [19].

17.2.1.2 NERC CIP

The North American Electric Reliability Corporation (NERC) was designated the Electric Reliability Organization (ERO) in 2006 by the Federal Energy Regulatory Council in accordance with the Federal Power Act, enacted by the Energy Policy Act of 2005. With this ERO designation, NERC was given the authority to develop and enforce compliance with mandatory reliability standards in the United States. These mandatory reliability standards include Critical Infrastructure Protection (CIP) [20], which consists of 10 standards designed to address the security of cyber system and cyber assets essential to the reliable operation of the Bulk Electric System (BES). In July 2016, NERC CIP version 6 became effective (i.e., enforceable), and currently includes the standards listed in Table 17.3.

The BES, which generally covers the generation and transmission services, is expected to comply with the NERC standards, or face severe financial penalties.

TABLE 17.3
NERC CIP v6 Standards Effective July 1, 2016

NERC CIP Standard	Title
CIP 002-5.1	Cyber security—BES cyber system categorization
CIP 003-6	Cyber security—security management controls
CIP 004-6	Cyber security—personnel and training
CIP 005-5	Cyber security—electronic security perimeter(s)
CIP 006-6	Cyber security—physical security of BES cyber systems
CIP007-6	Cyber security—system security management
CIP 008-5	Cyber security—incident reporting and response planning
CIP 009-6	Cyber security—recovery plans for BES cyber systems
CIP 010-2	Cyber security—configuration change management and vulnerability assessments
CIP 011-2	Cyber security—information protection

The NERC CIP standards can be categorized into three types: documentation, policy/procedure, and technical. Compliance to CIP-002 and CIP-003 shows that the utility has developed the documents, policies, and procedures that are required. Compliance to CIP-008 and CIP-009 are policy/procedure standards, where the utility must demonstrate that they have implemented the procedures. The rest of the standards are a hybrid of policy/procedure and technical requirements. Compliance to these standards requires that the utility shows they have implemented and followed the documented procedure, and have incorporated a minimum level of technical security for the cyber system or cyber asset.

Note: Compliance to the NERC CIP standards is the responsibility of the utility. Vendors, integrators, and security contractors can provide products that meet the technical requirements, provide guidance of how to implement the products or systems securely, and even help with the development and implementation of the policies and procedures. However, NERC looks to the utility, for it is the utility that is ultimately responsible, and it will be the utility that passes or fails the NERC CIP audit.

17.2.1.3 NIST IR 7628

The NIST Interagency Report 7628 Revision 1 titled "Guidelines for Smart Grid Cybersecurity" is comprehensive, consisting of three volumes—all of which are meticulously researched and articulated—that outline the requirements of inter relationships between bulk generation, transmission, distribution, customer, service provider, operations, and marketing actors [21]. This report presents an analytical framework that organizations can use to develop effective cybersecurity strategies tailored to their particular combinations of smart grid-related characteristics, risks, and vulnerabilities. Organizations in the diverse community of smart grid stakeholders—from utilities to providers of energy management services to manufacturers of electric vehicles and charging stations—can use the methods and supporting information presented as guidance for assessing risk and identifying and applying appropriate security requirements. This approach recognizes that the electric grid is changing from a relatively closed system to a complex, highly interconnected environment. Each organization's cybersecurity requirements should evolve as technology advances and as threats to grid security inevitably multiply

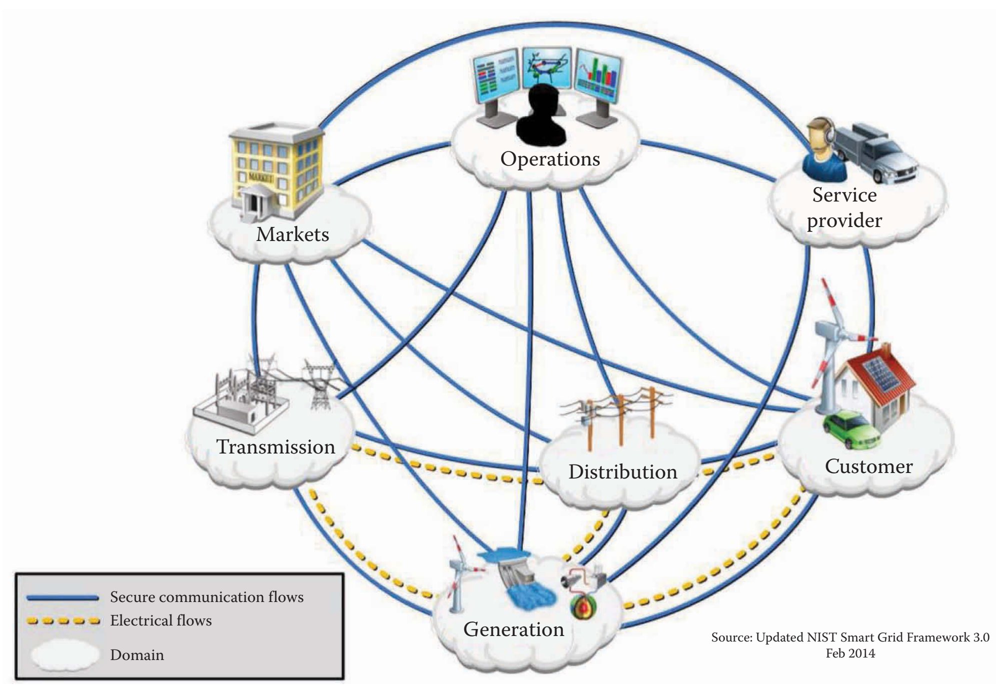

FIGURE 17.7 Interaction of actors in different smart grid domains through secure communication flows. (Reprinted from the NIST Interagency Report 7628 Revision 1, Figure 2-1 as public information.)

and diversify. In order to enable smart grid functionality, actors from one domain (e.g., Operations, Distribution, Generation) often interact with actors in other domains, as shown in Figure 17.7 [22].

Figure 17.8 expands each domain and identifies a high-level view of the actors within each of the smart grid domains. Actors are devices, systems, or programs that make decisions and exchange information necessary for executing applications within the smart grid. To further complicate matters, these actors do not operate in isolation. Figure 17.9 further illustrates the complexity of the smart grid by mapping the interconnections and communication channels between systems [22].

Security requirements are detailed in Volume 1, Chapter 3, of the NIST Interagency Report 7628. The security requirements listed below are an amalgam from several sources: NIST SP 800-53, the DHS Catalog, the NERC CIPs, and the NRC Regulatory Guidance [22]. Those interested in viewing a crosswalk of these cybersecurity documents against the Smart Grid Cybersecurity Requirements are encouraged to go to the NIST Interagency Report 7628, Appendix A. The categories addressed by the Smart Grid Cybersecurity Requirements are:

- Access control
- Awareness and training
- Audit and accountability
- Security assessment and authorization
- Configuration management
- Continuity of operations
- Identification and authentication
- Information and document management

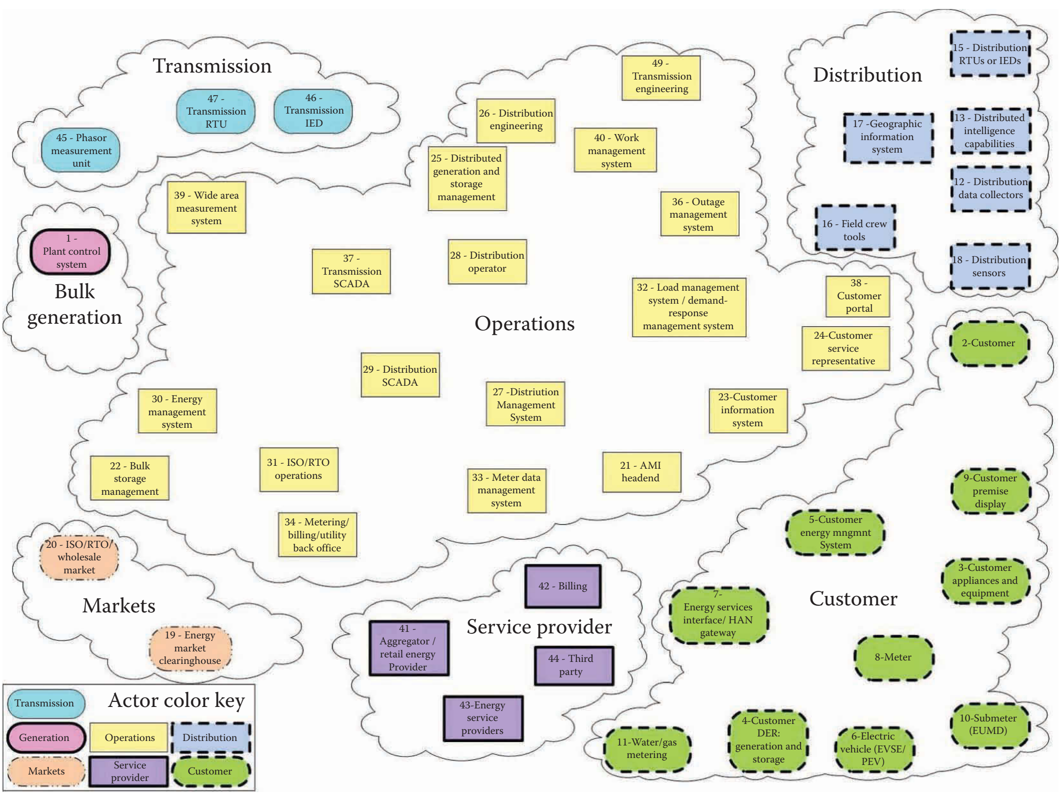

FIGURE 17.8 Composite high-level view of the actors within each of the smart grid domains. (Reprinted from the NIST Interagency Report 7628 Revision 1, Figure 2-2 as public information.)

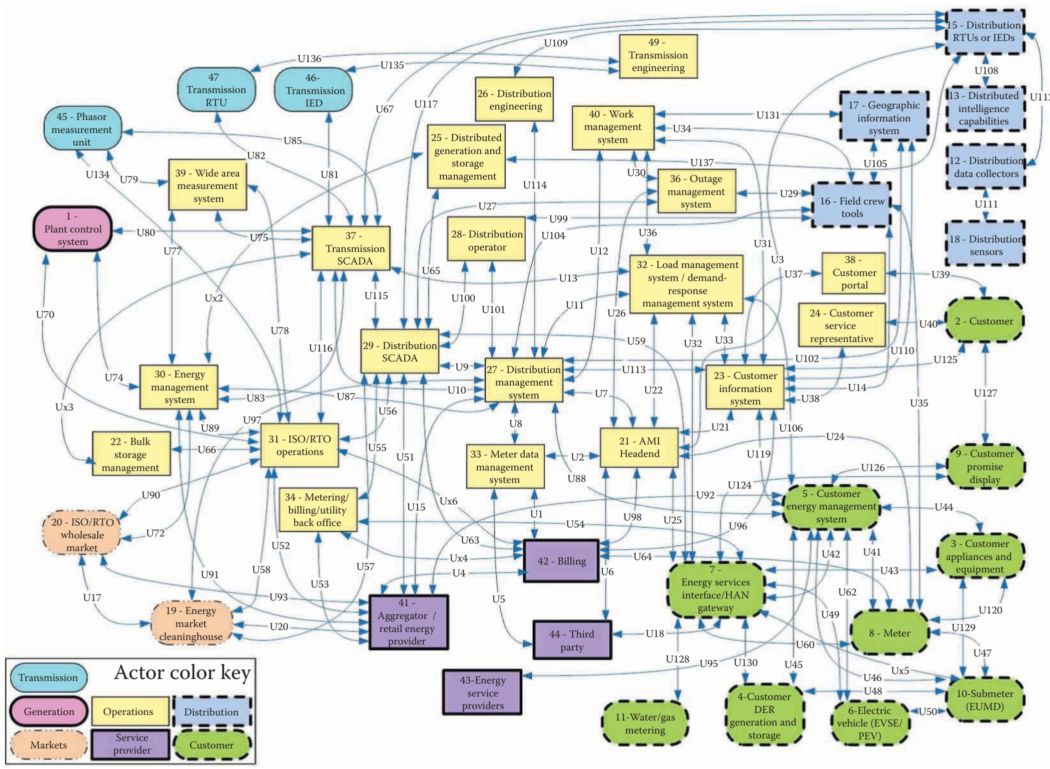

FIGURE 17.9 NIST's smart grid logical reference model. (Reprinted from the NIST Interagency Report 7628 Revision 1, Figure 2–3 as public information.)

- Incident response
- Smart grid information system development and maintenance
- Media protection
- Physical and environmental security
- Planning
- Security program management
- Personnel security
- Risk management and assessment
- Smart grid information system and services acquisition
- Smart grid information system and communication protection
- Smart grid information system and information integrity
- Testing and certification of smart grid cybersecurity

17.2.1.4 International Society of Automation (ISA)/International Electrotechnical Commission (IEC) 62443

ISA 62443 is a series of standards, organized into four groups that address a broad range of topics necessary for the implementation of a secure Industrial Automation and Control System (IACS). This effort originated through the ISA-99 standards development committee, which brings together over 500 worldwide Industrial Control System Cybersecurity Experts from industry, governments, and academia, and is now being aligned with the IEC 62443 standard. The ISA/IEC 62443 standards define policies and requirements for implementing electronically secure Industrial and Automation Control Systems security practices. It is applicable to the asset owner, the component developer, and

TABLE 17.4
IEC 62443 Organization Structure

Document Number	Title	Status	Date
	General		
IEC 62443-1-1	Terminology, concepts, and models	Published	July 1, 2009
IEC 62443-1-2	Master glossary of terms and abbreviations	In development	
IEC 62443-1-3	System security conformance metrics	In development	
IEC 62443-1-4	IACS security life cycle and use-cases	Planned	
	Policies and Procedures		
IEC 62443-2-1	Establishing and IACS security program	Published	Janurary 18, 2011
IEC 62443-2-2	Implementation guidance for an IACS security management system	Planned	
IEC 62443-2-3	Patch management in the IACS environment	Published	June 1, 2015
IEC 62443-2-4	Security program requirements for IACS service providers	Published	June 1, 2015
	System		
IEC 62443-3-1	Security technologies for IACS	Published	October 10, 2013
IEC 62443-3-2	Security risk assessment and system design	Out for comment/vote	
IEC 62443-3-3	System security requirements and security levels	Published	April 1, 2014
	Component		
IEC 62443-4-1	Product development requirements	Out for comment/vote	
IEC 62443-4-2	Technical security requirements for IACS components	Out for comment/vote	

the manufacturer. Table 17.4 identifies the IEC 62443 standards, organized into their four groups, along with their status, as some are still in the planning or development stage.

These standards do not only address the smart grid, but all critical infrastructure sectors that use industrial automation systems. Consider the generation, transmission, and distribution of electricity. Industrial automation is used extensively throughout it. Therefore, IEC 62443 is highly relevant.

IEC 62443 addresses the architecture of the communication network through applying the Purdue Model for Control Hierarchy (Figure 17.10). The Purdue Model uses the concept of zones and conduits. Zones are created by subdividing the IT enterprise and OT network(s) into logical segments performing similar functions. Conduits are created by defining or allowing devices in a network segment (zone) to communicate with devices in a zone that is directly above or directly below it. Implementing this zone and conduit methodology greatly increases the difficulty for an attacker to navigate from the IT enterprise network to the OT network.

17.2.1.5 NIST 800-82

NIST 800-82, Guide to Industrial Control System (ICS) Security, does not address the smart grid specifically; however, it is often considered the baseline or de facto security standard for many in the ICS world. It is referenced extensively in many other publications, and often, other standards will map their requirements to it. NIST 800-82 is a comprehensive ICS security standard that should be considered as both a reference and valuable resource [19].

NIST 800-82 provides guidance for securing ICS, including SCADA and distributed control systems, and other systems performing control functions. It provides a notational overview of ICS, reviews typical system topologies and architectures, identifies known threats and vulnerabilities to these systems, and provides recommended security countermeasures to mitigate the associated risk.

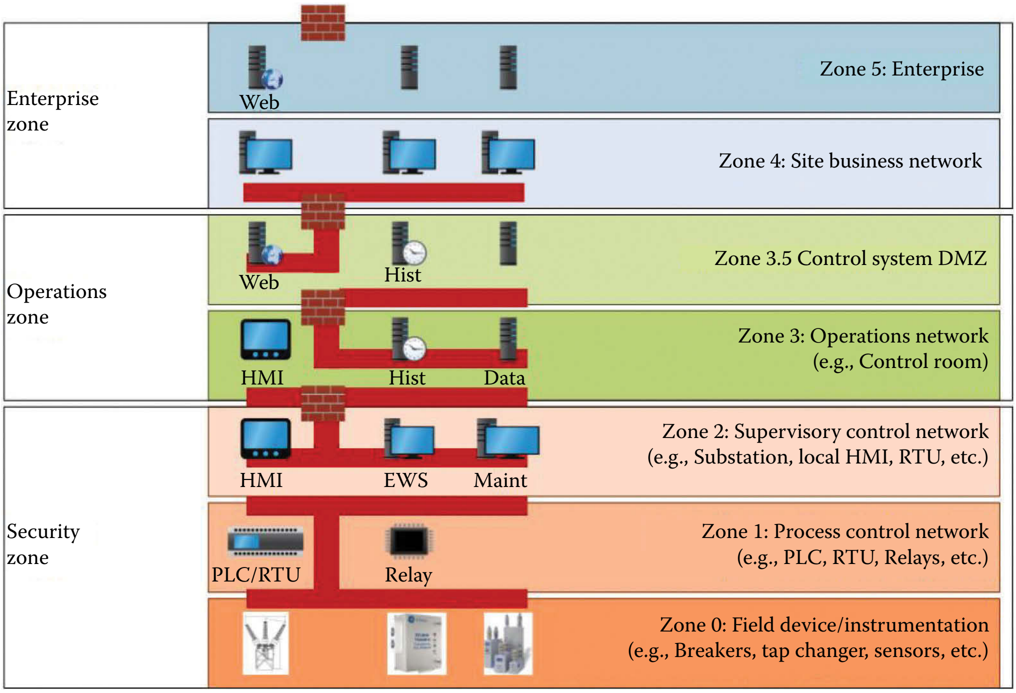

FIGURE 17.10 Purdue model—showing zones and conduits. (© 2016 General Electric. All rights reserved. With permission.)

In addition, it presents an ICS-tailored security control overlay, based on SP800-53 rev 4 (Security and Privacy Controls for Federal Information Systems and Organizations) to provide a customization of controls as they apply to the unique characteristics of the ICS domain [3].

17.2.2 U.S. Cybersecurity Framework

In February 2013, the United States President issued Executive Order 13636, "Improving Critical Infrastructure Cybersecurity," which established that "[i]t is the Policy of the United States to enhance the security and resilience of the Nation's critical infrastructure." It called for the development of a voluntary risk-based Cybersecurity Framework—based on existing standards, guidelines, and practices [23].

The smart grid contains a web of privately and publicly owned networks. It includes large investor-owned utilities, small municipalities, governmental generation and transmission organizations, and more. Some are regulated by the NERC CIP standards, some are not. The Cybersecurity Framework is not a one-size-fits-all approach to managing cybersecurity risk. Different organizations within the electrical critical infrastructure will have unique risks—different threats, different vulnerabilities, and different risk.

The Framework enables organizations—regardless of size, degree of cybersecurity risk, or cybersecurity sophistication—to apply the principles and best practices of risk management to improving security and resilience. The Framework provides structure to today's multiple approaches to cybersecurity by assembling commonly used and referenced internationally recognized standards, guidelines, and practices.

The Framework consists of three parts: the Framework Core, the Framework Profile, and the Framework Implementation Tiers. The Framework Core is a set of cybersecurity activities, outcomes, and informative references. Through use of the Profiles, the Framework will help the organization align its cybersecurity activities with its business requirements, risk tolerances, and resources. Profiles can be used to identify opportunities for improving cybersecurity posture by comparing a "Current" Profile (the "as is" state) with a "Target" Profile (the "to be" state). The Tiers provide a mechanism for organizations to view and understand the characteristics of their approach to managing cybersecurity risk. The Tiers characterize an organization's practices over a range, from Partial (Tier 1) to Adaptive (Tier 4).

The Framework Core consists of five concurrent and continuous Functions—Identify, Protect, Detect, Respond, Recover. These Functions provide a view of the life cycle of an organization's management of cybersecurity risk. To each Function, it maps "informative references" that are existing standards, guidelines, and practices. We will discuss each of these five Functions in greater detail.

17.2.2.1 Identify (Risk Assessment)

Utilities need to manage cybersecurity risk to system, assets, data, and capabilities. Risk is often expressed as the probability that a particular threat will exploit a particular vulnerability resulting in a specific consequence. Therefore, risk is a function of threat, vulnerability, and consequence, where consequence is the negative impact the organization experiences due to the specific harm to the organization's assets by the specific threat and vulnerability. The threat and vulnerability components can be expressed in terms of likelihood. Likelihood is the probability that a specific action will occur.

The key objectives of security, that is, confidentiality, integrity, and availability, are predicated on there being a reason to secure the system at all. What is the risk to the overall smart grid system if the system itself, or any one of its components, is compromised? This risk, and the potential cost of this risk, drive the economics of security design decisions.

How risk acceptance is determined is a business decision, not a technical decision. A business choosing to employ a particular risk analysis methodology will have its own key input variables that drive the decisions, which are usually tied to a financial risk that the business assumes based on their own competitive analysis of the market or regulatory conditions under which they operate. There are reasons other than financial ones that may drive risk acceptance. For example, a business using a strictly financial-based risk analysis model may be willing to accept the financial implications of their risk. However, industry regulations or law may dictate that a business may not accept that risk, or the industry-governing organization may have the authority to assign penalties that drive behavior that may not otherwise be financially justified. These factors may drive security behavior even in the absence of a strong economic incentive to add additional security capabilities.

It is important to recognize that no security decision should be made without considering risk. Where are the risks in the system? How much will a failure of the system cost? How much will a failure of the security of a system cost? Not all risks are created equal. A business must understand the risk and must be able to make informed and intelligent decisions about how to address it.

17.2.2.2 Protect (Defense in Depth)

The Protect function supports the ability to limit or contain the impact of a potential cybersecurity event. This requires that appropriate safeguards are implemented to ensure delivery of critical infrastructure services. As mentioned earlier, cybersecurity is not a single defensive measure, but rather multiple overlapping security layers, providing defense in depth. The concept of a layered security model is not a new concept. It has been the defensive strategy employed by armies and navies for centuries. Operating systems and microprocessors have been using this architecture for decades to control access to privileged resources. It is not difficult to imagine this same concept applied to smart grid systems. The defense in depth layers can be categorized into four groups:

- Security management policies, procedures, and awareness
- Physical security

- Network security
- Software and hardware security

Each defensive layer is as important as the next, and without all areas coordinating and working together, it can leave gaping holes in the defensive shield.

17.2.2.2.1 Security Management Policies, Procedures, and Awareness

Security management includes the policies and procedures that address how the employees are expected to act and react. Policies and procedures, such as Hiring Qualifications, Acceptable Use, Access Control, Change Control, and Incident Management and Response, are needed to set the expectations and standards of who will be on the network, what permissions and authority they have, how updates and changes are made and recorded, and when something is identified as a concern or if something goes wrong—what happens then? It is important that companies train their employees to be knowledgeable about these policies and have drills or exercises to practice them.

The employee is the first and often the last line of defense. Security awareness training needs to be provided to all employees. Those within strategic roles need specific training for their roles and responsibilities. Third-party stakeholders should also be provided security training for their roles and responsibilities.

17.2.2.2.2 Physical Security

The 3 Gs of physical security (guards, gates, and guns) are an important part of cybersecurity. It is important to monitor and maintain positive control of who accesses sensitive or critical areas. The level of physical security should vary depending on the criticality of the information that needs protection. Physical security policies and procedures should answer the following questions. Who can access the computer server room? Who is allowed into the operations room or into the plant? And what areas of the facility are critical? Appropriate technology should be used to limit access. For example, cipher locks are used to limit access to only those who know the code. However, if the code is written on the side of the door, just in case someone forgets the code, then the cipher lock is useless, and could be replaced with just a simple door knob. Monitored video surveillance is also important, especially for remote/nonmanned areas. Physical access measures should be put in place and revoked when necessary and appropriate.

17.2.2.2.3 Network Security

Network security is the protection that is designed into the architecture and operation of the network. It includes Access Control, Data Security, and Protective Technology.

17.2.2.2.3.1 Access Control Access to assets and associated facilities is limited to authorized users, processes, or devices, and to authorized activities and transactions [23]. In order for users to access a resource, they must first prove who they say they are (identification), have the necessary credentials (authentication), and have been give the necessary permission, rights, or privileges to perform the actions they are requesting (authorization). When these steps are completed, the user can access and use the network resources. Tracking the user's activities and recording them provides the accountability for actions taken [24]. There are several components to access control as follows.

Identity Database An identity database is required for authentication. It can take many forms, such as a commercially available user directory, or database table, or other mechanisms. These data sources contain the information necessary to determine who, or what, is attempting to access a system. The identity database is likely to contain user names and passwords, but it will also hold information about devices and certificates. These certificates can be used in place of user names and passwords to facilitate machine-to-machine communication. Certificates will be discussed in more detail in a later section.

Identity Management System An identity management system is designed to be a central repository of all resources that require authentication services. It might be compared to an asset management database, except that instead of physical equipment, the assets are identities. The identity management system tracks resources, such as user accounts, systems, and permissions and is capable of tracking these resources throughout their life within the business environment.

When personnel are first hired, they are entered into the identity management system. When their first email account is created, it is also entered into the same system. When they are granted remote access or access to any other specific systems, these requests are logged and possibly even processed by the identity management system. The same process is true for machine access, allowing machines and applications to be tracked as well as people. This creates a central place for access to resources to be tracked over the life cycle of personnel or systems within the organization. When an organization has invested in an identity management system, it will find that its ability to complete meaningful audits is greatly enhanced by the existence of this centralized repository.

Authentication Authentication is the process of verifying the identity of the person or service requesting access to another resource and answers the question, "Who are you?" A robust authentication mechanism may require a number of subcomponents, each of which will serve a particular function in system authentication. We are very used to thinking of authentication in terms of user names and passwords, and this is correct. However, authentication is also between systems, or between applications, or between hardware components. Each of these may have a different way of achieving authentication, but it is a necessary process to ensure security.

Many of the devices in today's smart grid infrastructure use legacy communication protocols, such as DNP3 and Modbus. These protocols are authentication-less, or in other words insecure by design. The device receives and executes commands, and sends information based on the information it received. These insecure protocols have no method to ensure the integrity and authentication of the message, nor the ability to validate that the host that sent the message has the authority to issue the command. Therefore, there is an inherent trust by the receiving device that the message was sent by a user or device that has the appropriate authorization. Some efforts have been made to update legacy industrial control system protocols to include security, such as DNP3 Secure Authentication. However, in order for a device to support the new secure protocol, hardware changes may be required that include updated processors and additional memory. So, until those devices are replaced with modern devices, conversion to the secure protocol will be delayed.

Authorization When a user has been appropriately identified and authenticated, the system needs to determine whether the subject has been given the necessary rights and privileges to perform the requested actions. The system will look at an access control matrix or something similar to learn if the user has been provided those rights. If the system determines that the subject is allowed to access the resource, it authorizes the subject [24].

Simple systems often have two authorization modes: read-write and read-only. More complex systems might be capable of more specific authorization rules that control access on a very specific attribute basis, such as the ability to update one field, but not another, only at certain times of day, and only when logged in from certain machines. This is often referred to as granularity. There are benefits to a very granular authorization system, but it does come with the added complexity of managing the many potential roles and responsibilities across all the users of the system.

Network Integrity Network integrity ensures that users and devices that are either on the network or that have access to the network are authorized, and that the activities on the network are appropriate. The network architecture should be designed to support and enhance security, yet also enable the flow of information to the appropriate persons and groups who need it. OT networks and business IT networks should not be all on the same network. Rather, these networks should be segregated into logical business and operational groups, separated by firewalls with appropriate rulesets. The use of Demilitarized Zone (DMZ) should be employed to store operational data that the business network needs. There should be no direct access from the business network into the control system network. Network segmentation, using the concepts of zones and conduits, plays a large role in this as discussed earlier.

The separation of systems using networking technologies is an extremely strong tool in securing the network-dependent smart grid. The services available at the network layer are among the most well-proven security technologies in use today. These services include networking equipment, such as routers and firewalls that establish the electronic security boundary. The logical network separation of one set of systems from another can prevent a significant number of the vulnerability concerns. This logical separation can be with virtual LAN (VLAN) technologies or a physical break in the wire between critical systems and networks. In addition to VLAN technologies, smart grid solutions will make heavy use of protected network segments, commonly referred to as DMZ segments. These DMZ segments are usually used as a buffer zone between a secure network and a less-secure network.

When these networking technologies are combined into a well-managed system, they provide an extremely strong defense against network-borne attacks. In addition, network-based security services can be tied to the other security services, such as authentication, authorization, and certificate services. When all of these services are tied together, the beginning of a true end-to-end solution for smart grid security is now in sight.

17.2.2.2.3.2 Data Security Information and records (data) are managed consistent with the organization's risk strategy to protect the confidentiality, integrity, and availability of information [23]. There are several components to data security as follows:

Cryptography Message Integrity and Confidentiality Cryptography is the science of secret writing that enables an entity to store and transmit data in a form that is viewable only by the intended individuals. Cryptosystems involves software and hardware implementation of cryptography, which can provide the following services: Confidentiality renders the information unintelligible (encryption), except by authorized entities; Integrity ensures the data (message) has not been altered in an unauthorized manner since it was created, transmitted, or stored; Authentication verifies the identity of the user or system that created the information; Authorization proves that the individual or device has the key or password that will allow access to the resource; and Nonrepudiation ensures that the sender cannot deny sending the message [24]. Nonrepudiation also means that you can have confidence that the message is authentic. Nonrepudiation also means that the message has been logged and that the log file is marked with the times of the transaction. This level of integrity checking ensures that the system can be extremely confident in the validity of the message and its ability to be audited.

One-Way Hash Hashing is a one-way process for taking a variable length string, such as data or a message, and producing a fixed length value called a hash value. The value of the one-way hashing function is that the hash value cannot be used to calculate the message. Thus, if a message was sent, and at the other end the user hashed the received message and compared it to the hash value from before it was sent, the user can be confident that the message was not modified during transmission.

There are methods available to ensure that the message and the hash value can be sent together, without concern that an attacker can intercept the message, decrypt the message, then modify the message and provide a new hash value, and then send the message and new hash on to the intended receiver [24].

Attacking one-way hash values is possible through brute force attacks, or through hashing a message, then comparing it to the original hash. If the initial and the newly hashed values are the same, the odds are that the original message has been discovered. Brute force is a single character at a time, trial, and error operation. Obviously, this could take a lot of calculations. With today's computers that are getting faster, it is getting easier to perform the requisite number of computations in a reasonable amount of time. This is one reason why passwords are now recommended to be complex, for example, using more than eight characters that consist of upper and lower case, numbers, and special characters. Eventually, any password or message can be discovered. The goal is to make the effort and time required to crack the message greater than its value. There are open source software programs that will perform the brute force attack, if the initial hash value is provided. The utility should ensure that the complexity of the algorithms used is proportional to their risk and security needs.

Encryption The purpose of encryption is to ensure that a message is not able to be read by any person or system for which the message was not intended. In order for two entities to communicate via encryption, they must use the same algorithm, either the same key (symmetric keys) or different but related keys (asymmetric—public and private keys). There are benefits to both symmetric and asymmetric encryption, and the one that should be used is left to the architect of the system to fully understand the benefits and drawbacks of each method.

Public Key Infrastructure (PKI) is a hybrid system of both symmetric and asymmetric key algorithms and methods that provide authentication, confidentiality, nonrepudiation, and integrity. The infrastructure uses digital certificates that positively identify the subject, and through asymmetric encryption, to exchange keys. PKI contains the pieces that will identify subjects, create and distribute digital certificates, maintain and revoke certificates, distribute and maintain encryption keys, and enable all technologies to communicate and work together for the purpose of encrypted communication and authentication [24].

Digital Signature When a message is sent from one system to another, there is an authentication process, to prove an identity, followed by an authorization process, to check what that identity is allowed to do. Once those two things have happened, messages may be exchanged between the two systems. To prevent communication tampering, another layer is recommended, and that is a process of message signing. There are two main reasons for digitally signing a message. The first is to ensure that the message contents have not been modified while being sent between systems. The second reason is to verify the identity of the sender independently of the authentication process.

Digital Certificates Certificates can be thought of as identification tokens that can be assigned to a user, a piece of hardware, or an application. When any of these want to trade data with another, they can use certificate services to validate each other's token, safely grant access, and exchange encrypted information. How certificates are created, distributed, and verified is a detailed topic, but the basic function of certificates is a means of verifying identity between two systems and encrypting communications between those systems.

Certificate services act in concert with an identity management system. The identity management system database or directory would typically store the certificates, which can then be retrieved as needed by the certificate services to validate the authenticity of a certificate that is presented by another system.

Certificates are not the only mechanism for achieving positive identification and encryption, but certificates are a very robust mechanism. There are deployment considerations when using certificates, such as the management of millions of unique certificates, the keys associated with maintaining them, and the processes for issuing and expiring certificates. These are all well understood, but thought must be given as to how to handle each of these deployment requirements.

Key Management In cryptography, "keys" are used to encrypt and decrypt the message. These keys are used to establish identity and to ensure message integrity when sending commands between systems. Whoever has the key can decode and read the message. Cryptography is based on a trust model. In an OT network, users and devices must trust each other to protect their own key, trust the administrator who maintains the keys, and trust a server that holds, maintains, and distributes the keys. If the keys are captured, modified, corrupted, or disclosed to unauthorized individuals, the message or data are at risk of being revealed [24].

Key management is the process that governs how keys are securely issued to users, applications, and devices. An automated process is recommended, especially when there are many devices that require them, and when messages are frequently sent. The frequency of use of a cryptographic key is directly proportional to how often the key should be changed. The more a key is used, the more likely it is to be compromised. The level of security needed, as shown in risk assessments, and the frequency of use can identify how often the keys should be updated. As more smart grid devices are being deployed that use cryptography, secure methods of distributing keys is very important. Key management is the most challenging part of cryptography and also the most crucial [24]. Every key in the system must be able to be updated or revoked on demand.

17.2.2.2.3.3 Protective Technology Technical security solutions are managed to ensure the security and resiliency of systems and assets, consistent with related policies, procedures, and agreements [23]. There are several components to protective technology as follows.

Network Protection The electronic security boundary of a system is defined by the firewalls, routers, or unidirectional gateways that protect them. Firewalls are used to restrict access from one network to another. Routers enable traffic between networks, but can have access control lists that are used to restrict traffic. Unidirectional gateways are used to ensure one-way traffic only, either into the network or out of the network, but never both. Firewalls and routers by their design and use of the TCP protocol allow two-way traffic. The ruleset in any firewall used for OT environments should implicitly deny all traffic that is not explicitly allowed. Careful attention should be made to those rules that are written to allow traffic through the firewall, to make sure it is absolutely necessary. Many firewalls can perform deep packet inspections to evaluate the type of information flowing through it. Therefore, firewall rules can become very specific and detailed. Some vendors are producing next generation firewalls made specifically for ICS. These firewalls can inspect the OT network communications, create and enforce policy for OT based processes, and either alert or block known cyber attack traffic [25].

A common security risk is when a computer has two network interface cards, and it can bypass the security protections established by a firewall and pass network traffic directly from one network to the other. For example, if an engineer's computer has two network interface cards, one could be connected to the enterprise network for email and Internet access, and the other network interface card could be connected to the SCADA network. If this engineer is sent a phishing email, and the engineer clicks on the malicious link or opens a document that has an embedded malicious file, it compromises the computer and gives remote access control to the attacker. Then, the attacker has direct access to the SCADA network, and the firewall has no ability to stop the attack.

Auditing The heart of any risk analysis and security program is its auditing program. Without periodic audits to validate the efficacy of the security controls that are in place, there can be no assurance that the system is secure. A good auditing program should be executed on a periodic basis to test the controls that the business has determined to be essential for the secure operation of the system. In some cases, regulations, such as Sarbanes-Oxley (SOX), or organizations such as NERC, may dictate the frequency of the audits and the data that must be audited.

Logging The generation and management of log files are not only essential for grid operations but may even be required by regulation. In general, log files must record every access to a critical system, as well as record every change made to the system. It is quite easy to imagine smart grid systems generating significant amounts of data in log files, and this represents yet another challenge with a system of the scale and complexity of the smart grid. When these log files are distributed across hundreds of different systems, there must exist a mechanism for centralizing the log file when needed. This can represent a challenge from a communications perspective, a data storage perspective, and an analysis perspective. Companies will need to have a process in place for log aggregation and analysis to ensure that audits can be done successfully, and so that analysis can be done after significant events.

Time Synchronization As a minor sub-function to logging, but as a larger function to security as a whole, time synchronization is an essential function. Not only is time synchronization critical for event analysis, it plays an important role in other security functions, such as message validation and session management. In a unified smart grid system, it is important that all devices share an authoritative time source.

Time synchronization is especially important to other advanced smart grid devices, such as synchrophasors, which require a sub-microsecond, or less than 1×10^{-6}s, level of precision in order for them to fulfill their function. While this is not strictly a security aspect of time synchronization, it serves as a representative example of why time synchronization is essential to smart grid systems.

17.2.2.2.4 Software and Hardware Security

At the heart of a control system is the software and hardware that operate, manage, and control the process. The vendor or manufacturer is responsible for the software application and device security. Appropriate security features should be designed and built into the hardware devices and software solutions. The design team should follow a Secure Development Life Cycle process that will ensure that the product is designed, developed, tested, and manufactured with appropriate cybersecurity features and processes. There are several components to software and hardware security as follows.

17.2.2.2.4.1 Secure Development Life cycle Building security into the products and systems that govern and monitor our electrical generation, transmission, distribution, and maintenance is not done by accident, nor is it a one-time event. After a product has been commercialized and is in operation, a vulnerability can be discovered that could compromise the integrity of the system. Therefore, the development team needs to be able to fix the errant code and provide a patch or update to the users in order to eliminate the vulnerability. Building secure products and systems must be built into the development cycle of the product and that cycle must be repeated continuously and religiously. The secure development life cycle guides the process from the beginning of the product design through the development and testing stages, and onto the release of the product, including monitoring and responding to incidents after the product has been released and is in use (Figure 17.11).

At the beginning of the design process, requirements for the project are gathered. This must include any cybersecurity requirements that need to be implemented into the product. Requirements can come from customer requests, industry standards (e.g., NERC CIP 002–011, IEC 62351, IEC

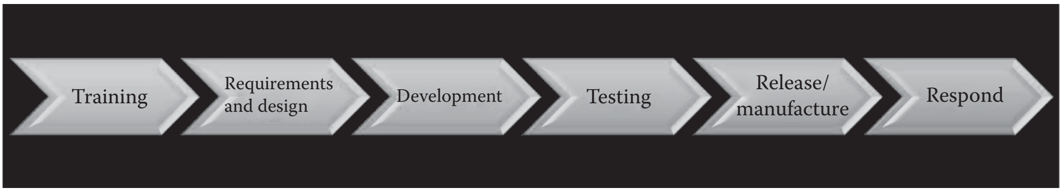

FIGURE 17.11 Secure development life cycle.

62443), best practices, and so on. Security features that could be considered part of a minimum security requirements list are:

- Ports and Services—Shutdown unnecessary network ports and services. Identify and document ports and services the product uses and the reason that each port or service is active.
- Cryptography–All cryptographic components should be up to a current state of complexity (i.e., the product meets regulatory and customer requirements).
- Least Privileges—All product components use least privilege (i.e., every user or software component runs with the least system privileges required to perform its function).
- Encryption Keys and Certificates—If keys/certificates are in use, encryption keys/certificates should not be shared across the installed base (i.e., product will utilize unique encryption keys/certificates upon activation of each product as it is installed).
- Back Doors—Ensure that back-door interfaces have been removed.
- Role-Based Access Control—Provide access control for interactive access to products or systems.
- No Hard-Coded Passwords—Ensure all hard-coded passwords are removed (i.e., all passwords should be changeable by the customer).
- Logging Security Events—Provide logging capabilities using an industry standard format.
- Time Stamping—Use standard time synchronization.
- Protect Sensitive Information—Protect the confidentiality and integrity of sensitive information.
- Secure Deployment Guide—Each product should have a document that provides the information necessary to deploy it securely in a control system environment.

Threat modeling is also part of the design process in order to analyze the security of an application. It is a structured approach that enables the design team to identify, quantify, and address the security risks associated with an application. Looking at a system from a potential attacker's perspective, threat modeling allows the reviewer to see where the entry points to the application are and the associated threats with each entry point, as opposed to a defender's viewpoint.

Development should be done using secure coding and development practices. Using a static code analysis tool is essential to develop a high quality and secure code, and it will identify vulnerabilities that can be resolved immediately.

A testing plan must also be developed and followed. This includes dynamic security testing or fuzzing to ensure a robust communication stack. An example of this is the Achilles Communication Certification for devices and regression testing for software. This testing validates a robust communication stack, and tests specifically against DDoS types of attacks. Security assessments, such as penetration tests and defense-in-depth reviews, are essential in identifying unknown vulnerabilities and missed security strategies. Security testing is not the same as quality testing. Quality testing validates that the product does what it should do. Security testing evaluates the product from an attacker's perspective and works to find ways to compromise the product/systems availability, integrity, or confidentiality. These assessments are often limited in scope and resources, but provide valuable insight into unrealized product vulnerabilities.

The respond process of the secure development life cycle is essential and should be a formal process for the product or system vendor that implements a process consisting of receive, assess, and resolve phases.

Receive: Ensure a timely and appropriate acknowledgment of externally identified incidents and vulnerabilities.

Assess: (1) Investigate the reported issue, (2) reproduce if possible, (3) determine the impact to the reported product by ranking based on severity and risk of exploit, and (4) identify other potentially affected products.

Resolve: Fix the vulnerability and communicate to customers.

17.2.2.3 Detect (Intrusion Detection and Prevention System)

An OT network is dissimilar to an IT network in that most of the OT network traffic is predictable. The OT network has specific users, specific communications paths between devices and between devices and the control software, and also specific protocols used for communications.

One of the most important security features of the OT network is the Intrusion Detection System (IDS). It is important to "know the network," or in other words, know what is happening on the network at all times. The Department of Homeland Security, ICS-CERT, has helped many critical infrastructure asset owners recover from being compromised. Their forensic analysis has revealed that the adversary has been on their system for sometimes up to 1 or 2 years. This gives a new meaning to the term "Advanced Persistent Threat." In large measure, the reason why an advanced threat is persistent is because an attacker was able to stay on their network for a long time, and there was no specific search for such a threat. Thus, after doing all that you can to protect the network, you need something that will monitor it and identify what isn't right. A network IDS monitors all the traffic in the network and can alert to either identified bad traffic, or to unexpected traffic. For example, rules can be set up to identify the known good or expected traffic. Anything left over is unexpected and potentially suspect.

When you have done all that you can do to protect the network, you need to monitor it. There are smart people out in the world with various incentives for breaking into an OT network. New vulnerabilities are often found, and there are vulnerabilities that are only known and used by the researcher(s) who found them. Therefore, the task of protecting the network is never completed. It can be "pretty good," but never "perfect." That is why it is important to have a system that gathers and correlates event logs and monitors the traffic for unauthorized events. Unless you are constantly looking for signs of compromise, you'll never see them.

17.2.2.4 Respond

What do you do when something goes wrong? Each utility should have a plan that is documented and that employees rehearse. NERC CIP 008-5, Cyber Security—Incident Reporting and Response Planning, addresses the importance and requirements of documenting the incident reporting and response procedure, and in exercising the process. The respond function supports the ability to contain the impact of a potential cybersecurity event [23].

17.2.2.5 Recover

Each utility should have a documented plan that implements the appropriate activities to maintain plans for resilience and restore any capabilities or services that were impaired due to a cybersecurity event [23]. Resiliency is the ability to adapt to stress and adversity. A common misconception is that systems that are resilient do not experience negative or stressful events, such as cyber attacks, or viruses. Contrarily, resiliency is demonstrated in systems that can effectively navigate their way around crises and utilize effective methods of coping. A resilient control system is one that maintains state awareness and accepted levels of operational normalcy in response to disturbances, including threats of an unexpected and malicious nature. Like a rubber ball when pressure is put on it, it deforms as it is stressed, but it remains intact and returns to its original shape when that pressure is removed. Utilities have operated in harsh weather, and dealt with accidents and equipment failure. The utility is resilient against these pressures. However, as modern computer and communications networks are overlaid onto the grid and interconnected to the Internet, there arises a new force that needs to be dealt with. Cybersecurity adds resiliency to the smart grid [26,27].

LIST OF ABBREVIATIONS

ACC	Achilles communication certification
AIC	availability, integrity, confidentiality
AMI	advanced meter infrastructure
BES	bulk electric system
CERT	computer emergency readiness teams
CIA	confidentiality, integrity, availability
CIP	critical infrastructure protection
DHS	Department of Homeland Security
DOE	Department of Energy
DoS	denial-of-service
DMZ	demilitarized zone
FACTS	flexible alternating current transmission system
FERC	Federal Energy Regulatory Commission
HAN	home area network
HMI	human machine interface
ICS	industrial control systems
ICS-CERT	Industrial Control System-Cyber Emergency Response Team
IEC	International Electrotechnical Commission
IT	information technology
NERC	North American Electric Reliability Corporation
NIST	National Institute of Standards and Technology
NIST IR	National Institute of Standards and Technology Interagency Report
OT	operation technology
PKI	public key infrastructure
PLC	programmable logic controller
RTU	remote telemetry unit
SAML	security assertion markup language
SCADA	supervisory control and data acquisition
SGIP	smart grid interoperability panel
VLAN	virtual local area network

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18 FACTS and HVDC

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CONTENTS

The development of electric power supply began more than 100 years ago. Residential areas and neighboring establishments were at first supplied with DC via short lines. At the end of the nineteenth century, AC transmission was introduced, using higher voltages to transmit power from remote power stations to the consumers.

In Europe, 400 kV became the highest AC voltage level, in Far East countries mostly 550 kV, and in North America 765 kV. The 1150 kV ultrahigh voltage (UHV) level was anticipated in some countries in the past, and some UHV lines have already been built in China. Figure 18.1 depicts these developments and prospects.

Examples of large synchronous AC interconnections are systems in North America, Brazil, China, and India, as well as in Europe (installed capacity 631 GW, formerly known as UCTE—now CE, Continental Europe) and Russia (IPS/UPS—315 GW). IPS/UPS and CE are planned to be interconnected in the future.

It is an unfortunate consequence of increasing size of interconnected systems that the advantages of larger size diminish for both technical and economic reasons, since the energy must be transmitted over extremely long distances through the interconnected synchronous AC systems. These limitations are related to problems with low-frequency inter-area oscillations [1–3], voltage quality, and load flow. This is, for example, the case in the CE (former UCTE) system, where the 400-kV voltage level is, in fact, too low for large cross-border and inter-area power exchange.

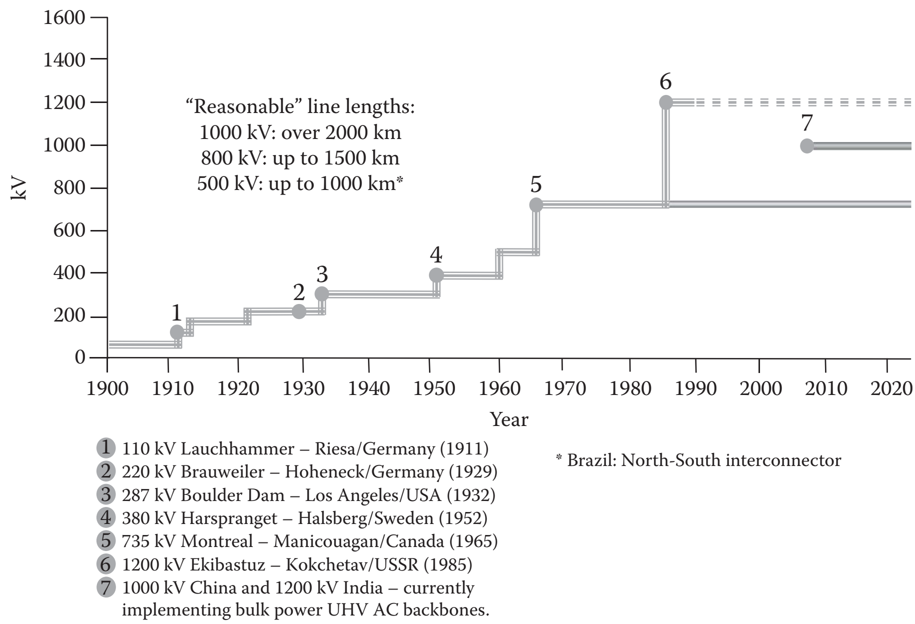


FIGURE 18.1 Development of AC transmission—milestones and prospects. (© 2012 Siemens. All rights reserved. With permission.)

One basic function of electricity networks is that the amount of power produced at any given moment must match the amount of power consumed. In the middle of this balancing act is the infrastructure that must carry the power from its place of production to its point of use, that is, the transmission network. In a typical AC power system, the transmission network performs this service through transmission lines, transformers, circuit breakers, and other common equipment. The flow of electricity through the transmission system follows the basic laws of physics. For a given voltage and line impedance, one can calculate the amount of current that will flow. This current flow may be more (overloaded) or less (underutilized) than desired by the transmission operator. A transmission device that is able to change the electrical system response to a given condition is obviously a useful element in creating a smarter grid. While adding this equipment alone does not constitute having a "smart grid," measurement devices and software that calculates optimum situations are only helpful to the extent that something can be done about the situation. The ability to control the flow of real and reactive power, the voltage and the frequency, and other aspects of the transmission system can be key elements in optimizing the grid. Those devices that can assert control over the real or reactive power flow in a specific line or node or even region of a network are the following:

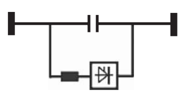
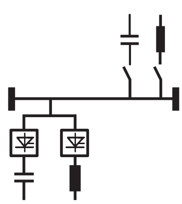
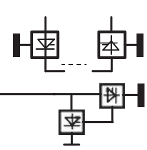
- Synchronous condensers
- Flexible AC transmission systems (FACTS) devices
- High-voltage direct current (HVDC)

These devices have the ability to implement aspects of smart control under normal, steady-state operating conditions, as well as under transient or fault events, and depending on their speed of response, may be able to automatically prevent a fault from propagating or speed up the recovery from faulty situations. In particular, the group of high-voltage power electronics devices, such as FACTS and HVDC, provide features that avoid problems in heavily loaded power systems; they increase the transmission capacity and system stability very efficiently and assist in preventing cascading disturbances. As load increases and changes, some system elements are going to become loaded up to their thermal limits, and wide-area power trading with fast varying load patterns will contribute to increasing congestion [4,5]. In addition to this, the dramatic global climate developments call for changes in the way electricity is supplied. Environmental constraints, such as loss minimization and CO_2 reduction, will play an increasingly important role. Consequently, network planners must deal with conflicting requirement between reliability of supply, environmental sustainability, as well as economic efficiency [6,7]. The power grid of the future must be secure, cost-effective, and environmentally compatible. The combination of these three tasks can be tackled with the help of ideas, intelligent solutions, as well as innovative technologies, such as HVDC and FACTS, which have the potential to cope with the new challenges. By means of power electronics, they provide a versatile range of features that are necessary to avoid many operational problems in the power systems; they increase the transmission capacity and system stability very efficiently and help prevent cascading disturbances. Features of a future smart grid, such as this, can be outlined as follows: flexible, accessible, reliable, resilient, and economic. Smart grid will help achieve a sustainable development.

Table 18.1 summarizes the impact of FACTS and HVDC on load flow, stability, and voltage quality when using different devices. Evaluation is based on a large number of studies and experiences from projects. For comparison, mechanically switched devices [mechanically switched capacitor/reactor (MSC/R)] are included in the table.

The developing load and generation patterns of existing power systems will lead to bottlenecks and reliability problems. Therefore, the strategies for the development of large power systems go

TABLE 18.1
FACTS and HVDC: Overview of Functions

			Impact on System Performance		
Principle	**Devices**	**Scheme**	**Load Flow**	**Stability**	**Voltage Quality**
Variation of the line impedance	FSC (fixed series compensation)		●	●●●	●
			●	●●●	●
Series compensation	TPSC (thyristor protected series compensation)		●	●●●	●
			●●		
	TCSC (thyristor controlled series compensation)				
Voltage control	MSC/R (mechanically switched capacitor/reactor)		○	●	●●
Shunt compensation	SVC (static VAr compensator)		○	●●	●●●
Shunt compensaton	STATCOM (static synchronous compensator)		○	●●	●●●
Load-flow control	HVDC–B2B, LDT HVDC VSC		●●●	●●●	●●●
	UPFC (unified power flow controller)		●●	●●●	●●●

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Note: Influence (based on studies and practical experience):?, No or low, ●, small; ●●, medium; ●●● strong.

clearly in the direction of smart grid, consisting of AC/DC interconnections and point-to-point bulk power transmission “highways” (UHV or super-grid solutions). FACTS technology is also an important part of this strategy, and hybrid systems offer significant advantages in terms of technology, economics, and system security.

FACTS and HVDC also have an important role to play in the integration of large-scale, transmission-connected wind farms and solar fields into a smart transmission grid [8,9]. These connections are provided for both offshore and land-based wind and solar energy production. In order to proceed with offshore wind power production, FACTS and HVDC technologies are crucial for interconnecting long offshore cables with the offshore wind farms. For high levels of wind power integration into the AC grid, several factors need to be considered; these may include voltage ride-through, mitigating transient and voltage stability problems, regulating power flows, and compensating for harmonic and reactive power in the long cables.

There are already areas in Europe that are very highly penetrated with intermittent wind generation. These include the northern German and Danish transmission systems where over 100% wind penetration is common under low loading conditions. Under these conditions, a flexible AC and DC transmission grid, provided by FACTS and HVDC technologies, is crucial for reliable operation.

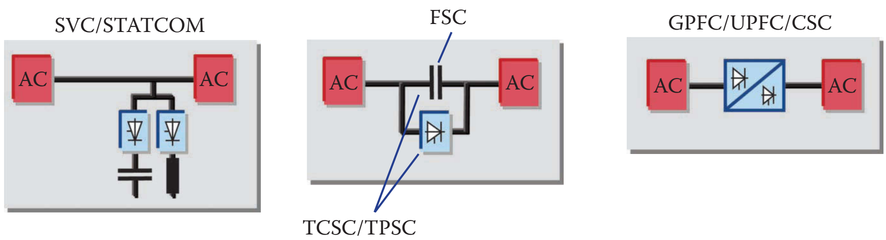
FACTS and HVDC applications will play an important role in the future development of smart power systems. This will result in efficient, low-loss AC/DC hybrid grids, which will ensure better controllability of the power flow and, in doing so, do their part in preventing “domino effects” in case of disturbances and blackouts. By means of these DC and AC, ultrahigh-power transmission technologies, the “smart grid,” consisting of a number of highly flexible “microgrids,” will turn into a “super grid” with bulk power energy highways, fully suitable for a secure and sustainable access to huge renewable energy resources such as hydro, solar, and wind. The state-of-the-art AC and DC technologies and solutions for smart and super grids are explained in the following sections.

In addition to these relatively complex systems using power electronics, there are other lower cost features, which may be incorporated into the equipment installed in future power networks. These offer varying extents of functionality to add to the overall intelligence of the smart grid of the future, such as monitoring of transformers and switchgear, which provide real-time analysis of transformer oil and other status information. Maintenance management systems can monitor and analyze this information and determine increased wear-and-tear rates, predict failure modes, and identify the need for preemptive maintenance before the next scheduled maintenance activity.

18.1 FACTS

Reactive power compensation has been regarded as a fundamental consideration in achieving efficient electric energy delivery system. Reactive compensation may be categorized into series compensation, shunt compensation, and combined compensation, representing the intentional insertion of reactive power-producing devices in series or in parallel in the power circuit, either capacitive or inductive. Further flexibility can be achieved with dynamically controllable compensation to provide the required amount of corrective reactive power precisely and promptly. A family of such controllable compensation devices based on power electronics technology is often referred to as FACTS devices.

FACTS technology, based on power electronics, was developed in the 1960s to improve the performance of weak AC systems, make long-distance AC transmission feasible, and help solve technical problems within the interconnected power systems [10]. The technology, proven in various applications, became a first-rate, and highly reliable. Figure 18.2 shows the basic configurations of FACTS devices. FACTS systems can be used in various configurations in order to control load flow and to improve dynamic conditions on the grid: in a parallel connection (SVC, STATCOM); in a series connection [fixed series compensation (FSC), thyristor-controlled series compensation (TCSC), TPSC; or as a combination in both a parallel and series connection [GPFC, unified power flow controller (UPFC), current source converter (CSC)].



- SVC–static VAr compensator
- STATCOM–static synchronous compensator, with VSC
- FSC–fixed series compensation
- TCSC–thyristor controlled series compensation
- TPSC–thyristor protected series compensation
- GPFC–grid power flow controller (FACTS-B2B)
- UPFC–unified power flow controller (with VSC)
- CSC–convertible synchronous compensator (with VSC)

FIGURE 18.2 Transmission solutions with FACTS.

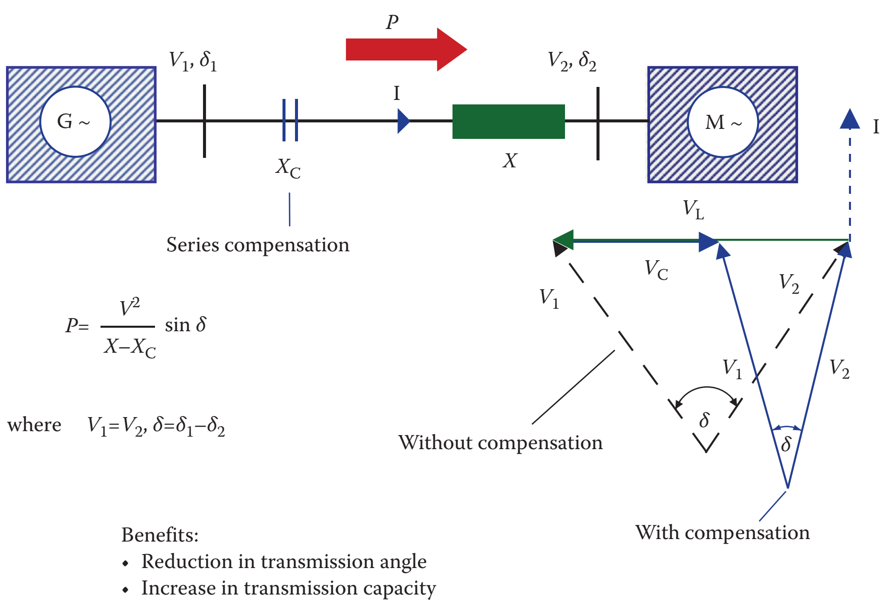


FIGURE 18.3 FACTS—influence of series compensation on power transmission.

In Figure 18.3, the impact of series compensation on power transmission and system stability is illustrated, and Figure 18.4 depicts the increase in voltage quality by means of shunt compensation with SVC (or STATCOM).

18.1.1 Series Compensation

The conventional or FSC is a well-established technology and has been in commercial use since the early 1960s. The basic concept of series-capacitor compensation is to reduce the overall inductive

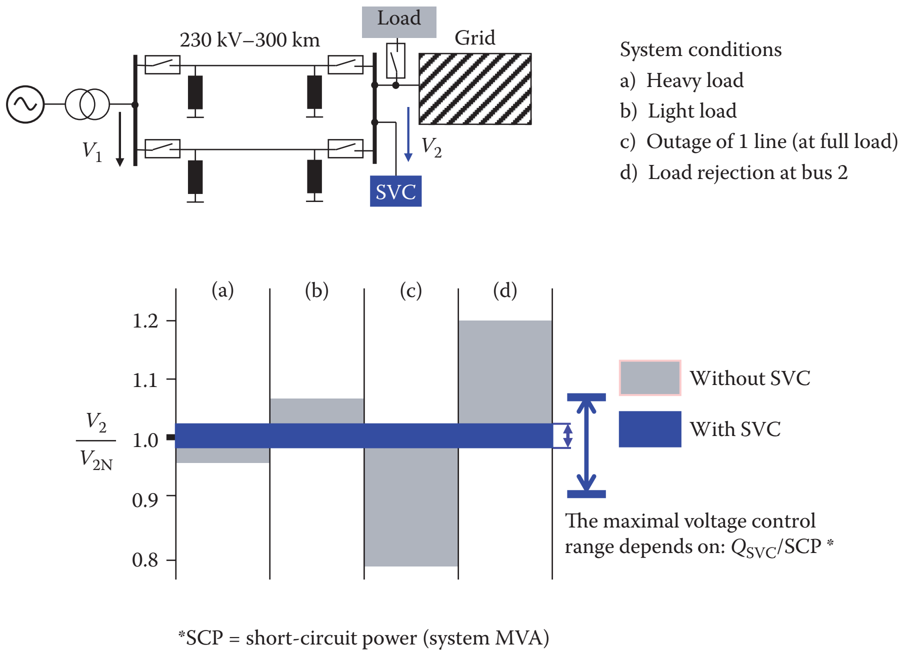


FIGURE 18.4 FACTS—improvement in voltage profile with SVC. (© 2012 Siemens. All rights reserved. With permission.)

reactance of power lines by connecting series capacitors in series with the line conductors. As shown in Figure 18.5, the series-capacitor compensation equipment comprises series-capacitor banks, located in the line terminals or in the middle of the line, and overvoltage protection circuit for the capacitor bank. A photograph of a series compensation installation is shown in Figure 18.6.

Incorporating series capacitors in suitable power lines can improve both power system steady-state performance and dynamic characteristics. Series compensation has traditionally been used associated with long-distance transmission lines and with improving transient stability. In a transmission system, the maximum active power transferable over a certain power line is inversely proportional to the series inductive reactance of the line. Thus, by compensating the series inductive reactance to a certain degree, typically between 25% and 70%, using series capacitors, an electrically shorter line is realized and higher active power transfer and improved system performance can be achieved. In recent years, series capacitors are also applied on shorter transmission lines to improve voltage stability. In general, the main benefits of applying series compensation in transmission systems include the following:

- Enhanced system dynamic stability
- Desirable load division among parallel lines
- Improved voltage regulation and reactive power balance
- Reduced network power losses

TCSC is an extension of conventional series compensation technology, providing further flexibility of series compensation in transmission applications (Figure 18.7).

18.1.2 Shunt Compensation

A static VAr compensator (SVC) is a regulated source of leading or lagging reactive power. By varying its reactive power output in response to the demand of an automatic voltage regulator, an SVC can

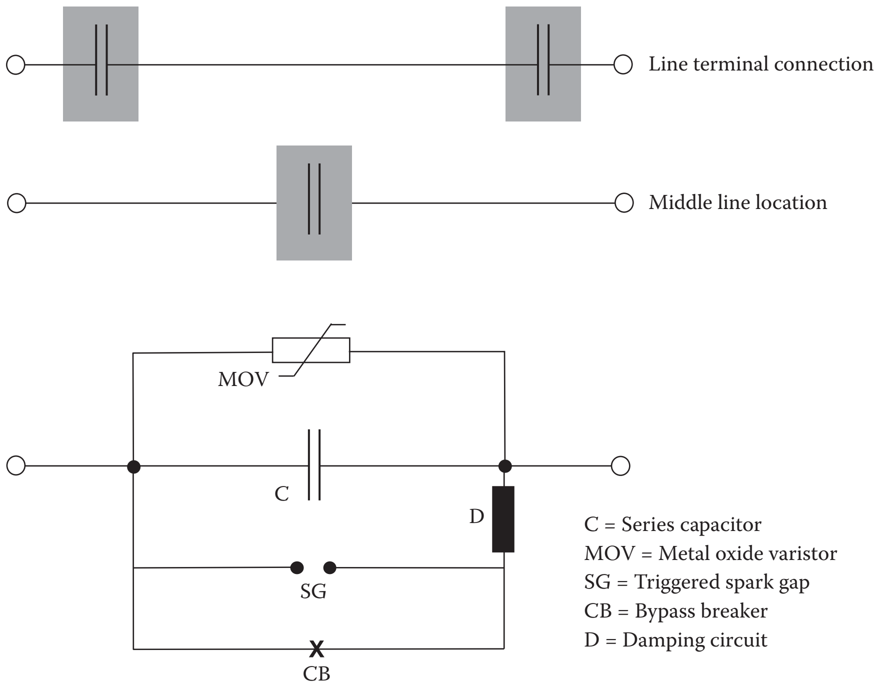


FIGURE 18.5 Common FSC locations and main circuit diagram. (Courtesy of Siemens. With permission.)

FIGURE 18.6 A series compensation installation. (© 2012 Siemens. All rights reserved. With permission.)

maintain virtually constant voltage at the point in the network to which it is connected. An SVC comprises standard inductive and capacitive branches controlled by thyristor valves connected in shunt to the transmission network via a step-up transformer. Thyristor control gives the SVC the characteristic of a variable shunt susceptance. Figure 18.8 shows three common SVC configurations for reactive power compensation in electric power systems. The first configuration consists of a thyristor-switched reactor and a thyristor-switched capacitor (TSC). Since no reactor phase control is used, no filters are

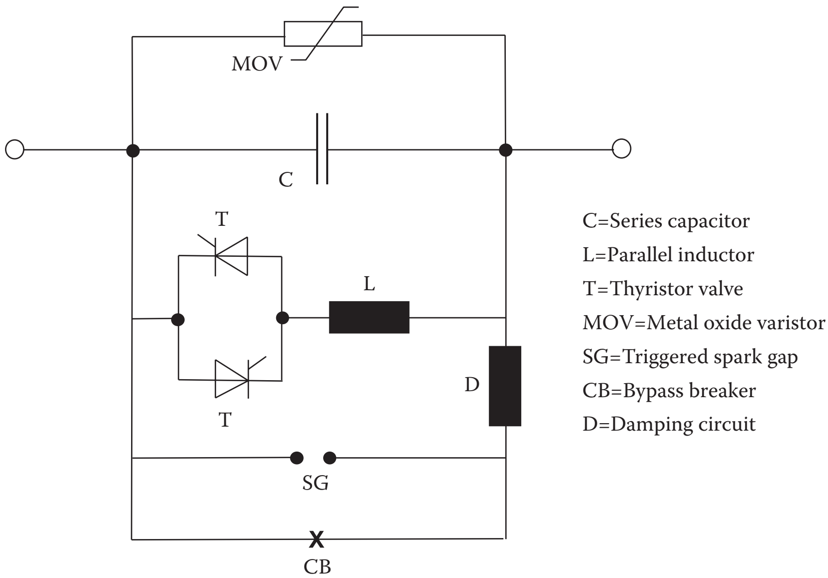


FIGURE 18.7 TCSC main circuit diagram. (Courtesy of Siemens. With permission.)

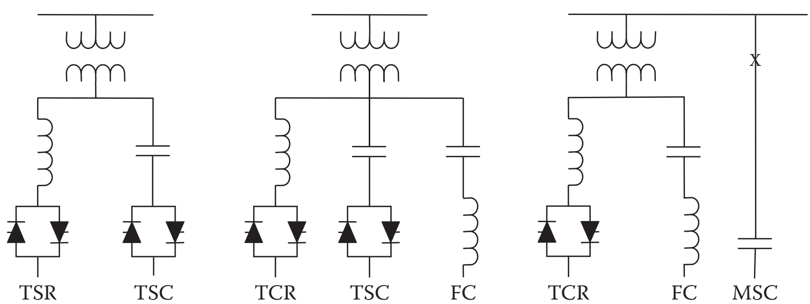


FIGURE 18.8 Common SVC configurations. (Courtesy of Siemens. With permission.)

needed. The second consists of a thyristor-controlled reactor (TCR), a TSC, and harmonic filters (FC). The third consists of a TCR, mechanically switched shunt capacitors (MSC), as well as FC.

For example, with the TCR/TSC configuration, flexible and continuous reactive power compensation can be obtained by appropriate switching of TSCs and accurate controlling of TCR, from the full inductive rating of the TCR to the full capacitive rating of the TSCs and the FC.

An SVC installation is shown in Figure 18.9. SVC technology has been in commercial use since the early 1970s (with over 1000 systems in service), initially developed for the steel industry to address the problem of voltage flicker with arc furnaces. The SVC is now a mature technology that is widely used for transmission applications, providing voltage support in response to system disturbances and balancing the reactive power demand of large and fluctuating industrial loads. The installation can be in the midpoint of transmission interconnections or in load areas. In general, the main benefits of applying SVC technology in power transmission systems include the following:

- Improved system voltage profiles
- Reduced network power losses
- Stabilized voltage of weak systems or load areas
- Increased network power delivery capability
- Mitigated active power oscillations

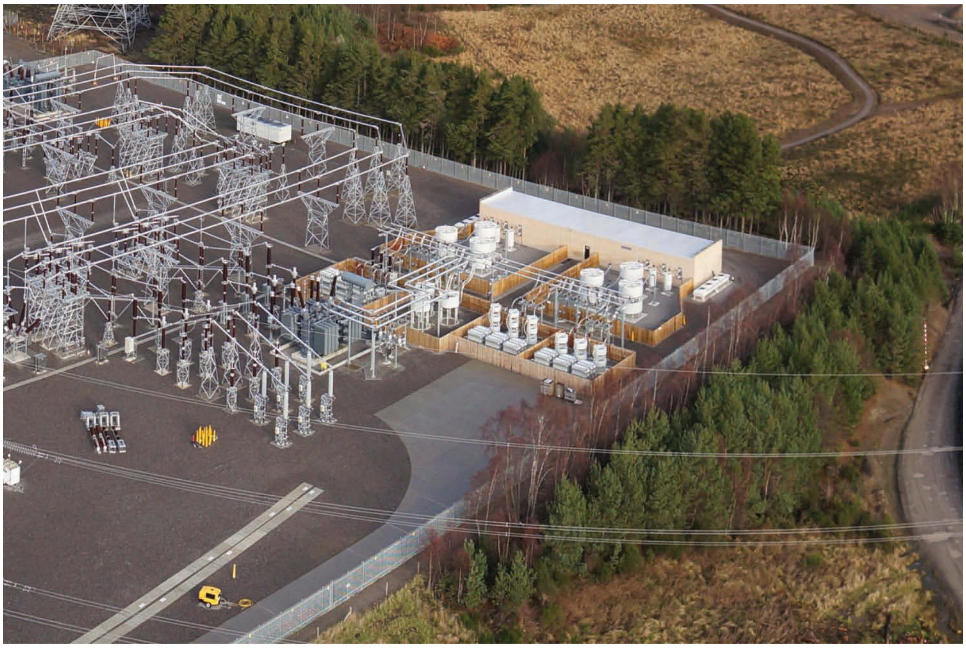


FIGURE 18.9 An SVC installation. (© 2016 GE Grid Solutions. All rights reserved. With permission.)

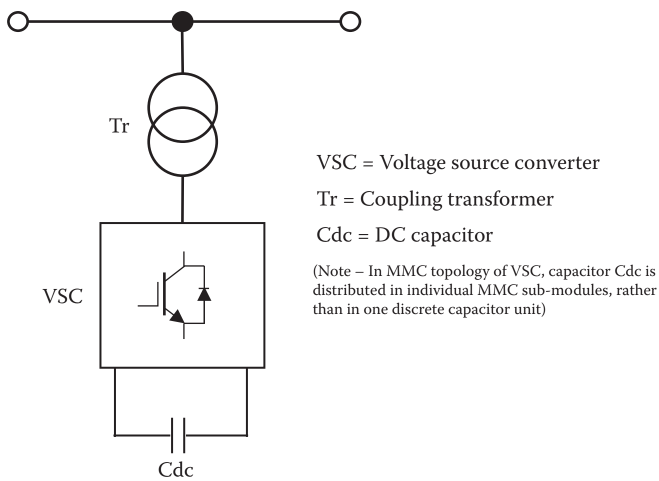


FIGURE 18.10 STATCOM main circuit diagram.

STATCOM technology is based on the power electronic concept of voltage-source conversion (Figure 18.10), where the shunt-connected voltage-source converter (VSC) is comprised of solid state switching components with turn-off capability with anti-parallel diodes. Performance of the STATCOM is analogous to that of a synchronous machine generating balanced three-phase sinusoidal voltages at fundamental frequency with controllable amplitude and phase angle. The device, however, has no inertia and does not contribute to the short-circuit capacity.

The STATCOM consists of a VSC operating as an inverter with a capacitor as the DC energy source. It is controlled to regulate the voltage in much the same way as an SVC. A coupling transformer is used to connect to the transmission voltage level. In this application, only the voltage magnitude is controlled, not phase angle. By controlling the converter output voltage relative to the system voltage, reactive power magnitude and direction can be regulated. If the VSC AC output voltage is lower than the system voltage, reactive power is absorbed. If the VSC AC output voltage is higher than the system voltage, reactive power is produced.

The functions performed by the STATCOM in a transmission network are quite the same as an SVC, such as steady-state and dynamic voltage support and regulation, improved synchronous stability and transfer capability, and improved power system damping. In addition, the STATCOM is also installed for power quality applications. These include the following:

- Improved dynamic load balancing
- Improved flicker control
- Mitigate low-order harmonics
- Provide voltage ride-through
- Faster response for load compensation

STATCOM with energy storage is an enhancement of STATCOM consisting of batteries as shown in Figure 18.11. Energy storage enables the STATCOM to generate and consume active power for a certain period. One typical application of STATCOM with energy storage is for integrating a renewable energy source, such as a wind farm or solar farm that has a strongly fluctuating power production. The load balancing function provided by energy storage delivers active power at a scheduled power level and reactive consumption/production within operational limits, according to the power and voltage setting demands from the system operator. With energy storage connected to the DC-link, the STATCOM can also provide emulated inertia in the power system of the future where loss of inertia may be a common problem with the retirement of fossil generation [11–13].

These devices will form an increasingly important component of the future smart grid as a result of the increasing use of variable generation sources, such as wind and solar, as the stored energy may be used to fill in the nongenerating periods from these diverse renewable sources and provide

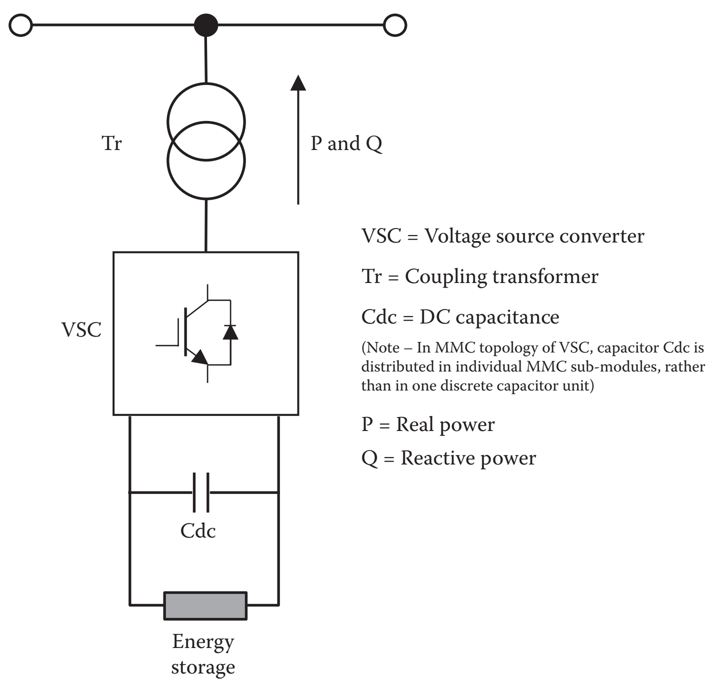


FIGURE 18.11 STATCOM with energy storage.

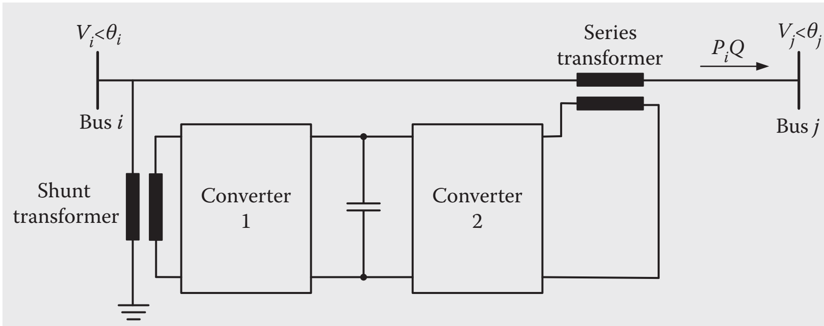


FIGURE 18.12 UPFC. (© 1999 ABB. All rights reserved. With permission.)

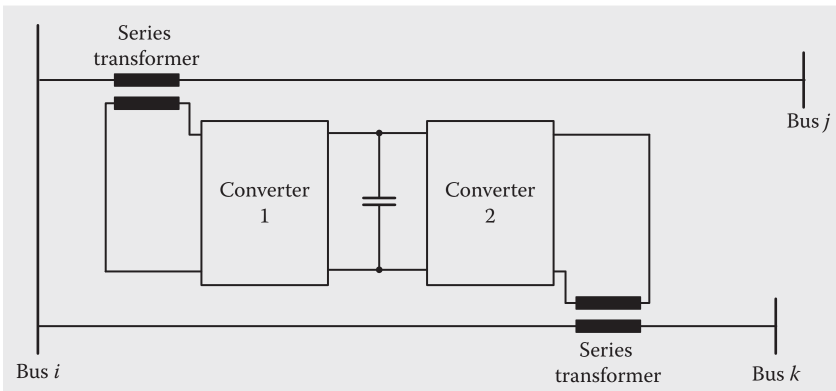


FIGURE 18.13 IPFC. (© 1999 ABB. All rights reserved. With permission.)

inertia with increased use of nonrotating renewable generation [11–13]. The capacity of the storage system must clearly be suitably rated to substitute the energy normally provided by the renewable source; but for short periods, this is a viable solution.

18.1.3 Combined and Other Devices

More sophisticated systems to control power flow in transmission lines may be formed by combining series and shunt devices. The STATCOM described previously is a shunt-connected voltage-sourced device that can regulate voltage at the point of connection through control of reactive power flow by injecting reactive current. Another device called the static synchronous series compensator (SSSC), which is similar to the STATCOM except it is series-connected, controls the magnitude and phase of an injected voltage independent of the current in the line.

In the UPFC configuration, STATCOM and SSSC are combined on a transmission line as shown in Figure 18.12, and they can regulate both real and reactive power in a line, allowing for rapid voltage support and power flow control. These devices require two converters in a back-to-back (B2B or B-B) configuration and may use the same DC capacitor in much the same way as an HVDC link.

The interline power flow controller (IPFC) is another configuration of the combined VSCs, except that the two converters are inserted on different transmission lines. The IPFC consists of two SSSC converters as shown in Figure 18.13. In this configuration, the IPFC is able to control both real and reactive power in both lines *i*–*j* and *i*–*k* by exchanging power through the DC link between them.

The SSSC, UPFC, and IPFC are applications of VSC converters, and presently these systems are not in common use; those that are in operation have been constructed as development projects [14].

18.1.4 Variable Frequency Transformer

A relatively new transmission device is the variable frequency transformer (VFT). A VFT is considered by many to be a "smart" device as it has the ability to control the amount of power flowing through it. Similar to an HVDC system, the VFT can interconnect asynchronous grids, with the key difference being that the VFT provides a true AC connection. The first asynchronous AC transmission using a VFT appeared in 2003 at Hydro-Québec's Langlois Substation.

The VFT absorbs reactive power since it is an induction machine. It is normally applied with shunt banks to supply reactive power per the application's needs. As a true AC connection, the VFT allows reactive power to flow from one side to the other. As in any AC circuit, reactive power flow is a function of the system voltages and the series impedance. Figure 18.14 is a simplified one-line diagram of a VFT interconnection.

While many designs are theoretically possible, the present technology consists of one or multiple parallel 100 MW, 50/60 Hz machines. There are currently five machines in commercial operation. In addition to providing flexibility in moving a controlled amount of real power between two points, which need not be synchronized, adding a VFT has also demonstrated improvements to power system dynamic performance and generator damping.

The ability of the VFT to control the flow of power through it offers network operators a transmission device that can be dispatched similar to generating assets. This can assist with operation of the power grid in a more optimized manner. The power flowing through any given transmission path may be higher or lower than operators prefer. Changing the system to adjust the flow of power through one point may have unintended consequences through another transmission path.

18.1.5 Synchronous Condenser

While the synchronous condenser is not a new, high-tech device invented to contribute to the modern smart grid, it is worthy to consider that this may be the original Volt/VAr controller. Once commonly found in both industrial and utility applications, the number of synchronous condensers in operation has been on the decline. Simply put, the synchronous condenser is a synchronous motor without a load connected to its shaft. Or viewed in a way more familiar to the utility industry, a condenser is similar to a generator without a prime mover. The field is under- or overexcited to absorb or produce reactive power. The machine will absorb a small amount of real power to overcome losses. When equipped with a modern generator field exciter, the speed of response is reasonably fast.

Although slower than a STATCOM and more costly than SVC, the synchronous condenser demonstrates a number of advantages over electronic solutions, including significant overload capability,

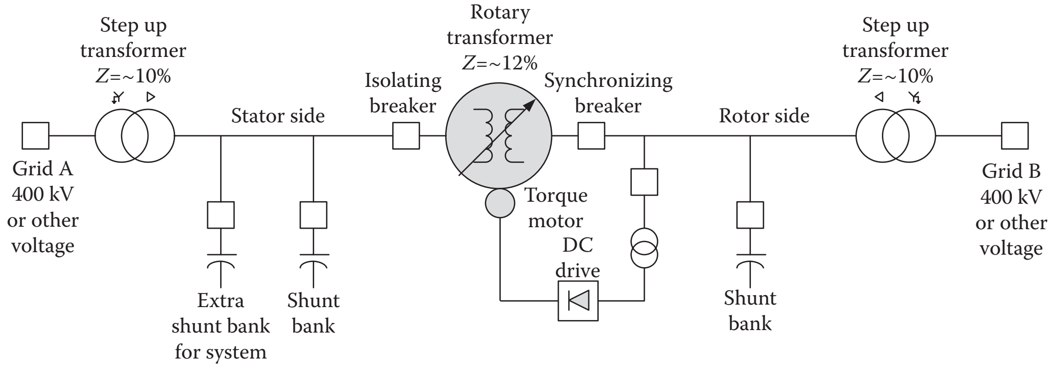


FIGURE 18.14 One-line diagram of a variable frequency transformer. (© 2016 GE Grid Solutions. All rights reserved. With permission.)

short circuit level, and real rotating inertia. It is relatively compatible with harmonic issues and can even act as a harmonic sink. As more renewable sources of energy, such as wind and solar, have displaced traditional thermal machines, some grids have experienced a decline in rotating inertia. In other applications, synchronous condensers are required on the receiving end of large thyristor-based HVDC systems to ensure proper inverter operation. This has prompted a renewed interest in the application of synchronous condensers as part of the overall smart grid solution.

The synchronous condenser's usefulness in the smart grid is not unlike modern FACTS devices. Controlling voltage through injecting or absorbing reactive power at key points in the transmission system can allow more precise control of power flow and optimized transmission grid operation.

18.2 HVDC

In general, for transmission distances above 600 km, DC transmission is more economical than AC transmission (≥1000 MW). In the second half of the last century, high-power HVDC transmission technology was introduced, offering new dimensions for long-distance transmission. This development started with the transmission of power in a range of less than 100 MW and was continuously increased. HVDC power transmission of up to 600–800 MW over distances of about 600 km has already been achieved with submarine cables, and cable transmission lengths of up to approximately 1000 km are in the planning stage. The state-of-the-art for many years settled at 500 kV DC rating, and there are many examples of links with transmission ratings of 3 GW over large distances. More recent developments have achieved transmission ratings of 6 GW and higher over even longer distances in China, India, and other countries using only one bipolar DC transmission system. HVDC is now a mature and reliable technology (Figure 18.15).

Typical configurations of HVDC are depicted in Figure 18.16. The first HVDC commercial applications were cable transmissions. For AC cable, transmission over more than 80–120 km

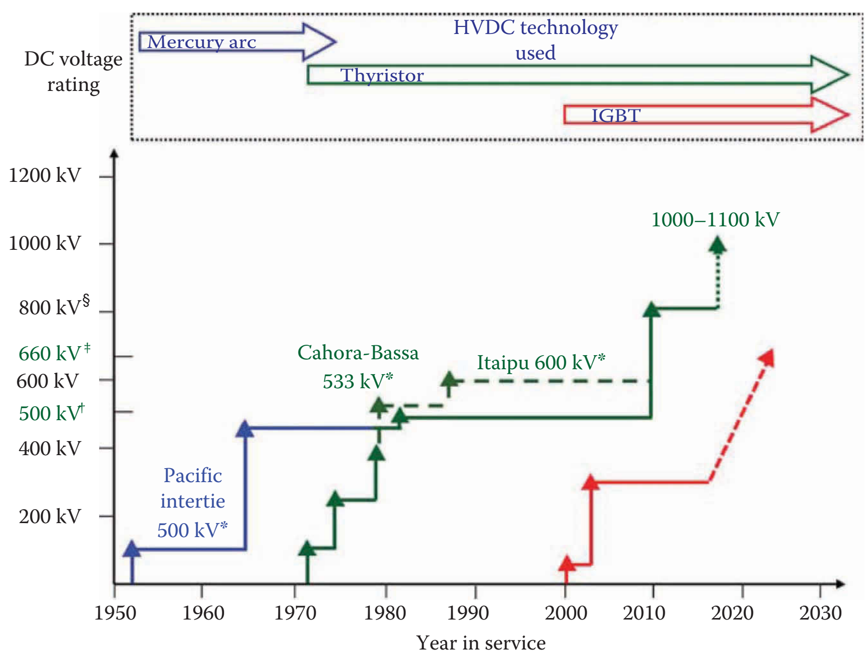


FIGURE 18.15 Evolution of HVDC voltage rating and technology. *Multiple bridges per pole; †500 kV becomes *de facto* standard for single 12-pulse bridge per pole; ‡660 kV used as "standard" in China; §800 kV used as "standard" in China and India. (© 2012 Siemens. All rights reserved. With permission.)

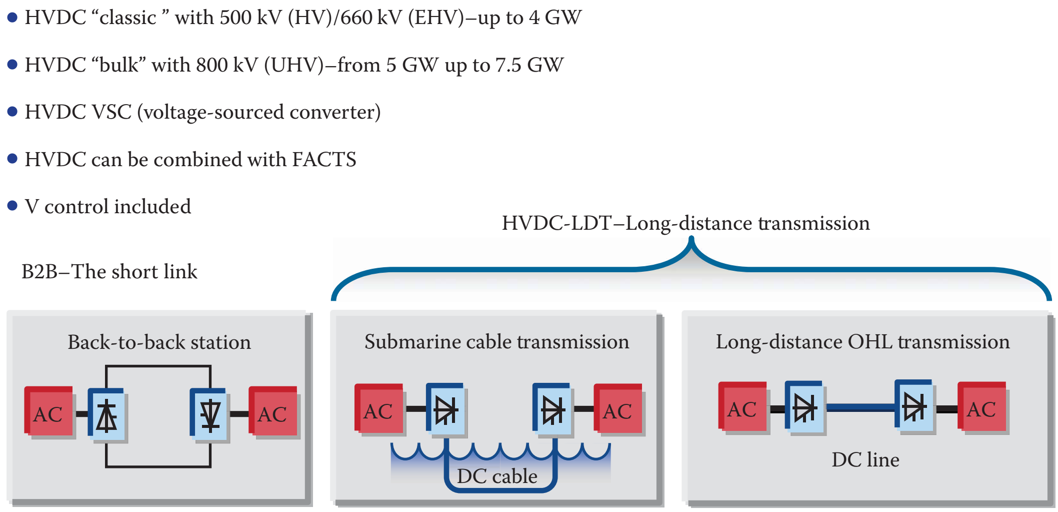


FIGURE 18.16 HVDC configurations and technologies.

is technically not feasible due to reactive power limitations. Then, long-distance HVDC transmissions with overhead lines were built as they are more economical than transmission with AC lines [15]. To interconnect systems operating at different frequencies (asynchronous), B2B schemes were applied. B2B converters can also be connected to long AC lines. A further application of HVDC transmission that is highly important for the future is its integration into the complex interconnected AC system. The reasons for these hybrid solutions are basically lower transmission costs as well as the possibility of bypassing heavily loaded AC systems. Further information on the application of HVDC to handle large-scale transmission to overcome the difficulties encountered by the conventional AC networks may be found in Barker et al. [16] and MacLeod et al. [17]. HVDC transmission systems offer many benefits over their AC counterparts, including the following:

- Improved system stability margins through the ability to rapidly change power transfer. Power flow through the link can be precisely controlled in both magnitude and direction, either through operator action or through automated response.
- Voltage and frequency in the two AC networks can be controlled independently of each other, again either through operator action or through automated response.
- The HVDC link can be used to assist one (or even both) of the AC networks in responding to disturbances (e.g., power swing damping, by modulation of the transmitted power). This is normally fully automated since the operator is unable to respond in this timescale.
- No increase of the short-circuit level of the system.
- No transfer of faults across the interconnected systems.

Originally, the HVDC power flow control device was based on mercury-arc technology, though these systems have now all been decommissioned. Modern HVDC systems have been based on the use of thyristors as the controlled device [referred to as line commutated converter (LCC), CSC, or conventional HVDC] for over 50 years, and more recently in the last 15 years or so, the use of the transistor (referred to as VSC) has been increasing. The power ranges of VSC-HVDC have been improved rapidly in recent years. In the upper range, the technology now reaches 1200 MVA for symmetric monopole schemes with cables, which can be increased to 2400 MVA for bipole schemes with overhead lines.

The intelligence incorporated into the control and protection system can be made to provide fully automated responses to all of these scenarios, such that the situation is detected and the response carried out without the need for human intervention. In this way, the HVDC system can be considered as an essential component of the smart grid. The HVDC control system is designed to automatically respond to stimulus events from many sources, including the following:

- Operator input
- Routine changes in AC network conditions
- Routine network switching events
- Disturbance caused by faults within the DC system, or in the AC network

VSC-HVDC technology is now emerging as a flexible and economical alternative for future transmission grid expansion. VSC-HVDC is the preferred technology for connecting islanded grids, such as offshore wind farms, to the power system [18]. This technology provides the "black-start" feature by means of self-commutated VSCs [19]. VSCs do not need any "driving" system voltage; they can build up a three-phase AC voltage via the DC voltage at the cable end, supplied from the converter at the main grid. Embedded VSC-HVDC applications, together with the wide-area monitoring system, in meshed AC grids could significantly improve the overall system performance, enabling smart operation of transmission grids with improved security and efficiency. VSC-HVDC transmission also offers a superior solution for many challenging technical issues associated with integration of large-scale renewable energy sources, such as offshore wind power.

Figure 18.17a shows the results of a simulation study based on two AC networks (A and B), which are interconnected and synchronized by a line rated at 500 MW. A short circuit fault occurs in network B at about 0.3 s; it can be seen that after about 7 s, the angular displacement of the rotors of selected generators in network A, relative to a reference generator, is increasing, that is, they cannot regain synchronism and the system is unstable. Exactly the same fault is applied in Figure 18.17b, but in this case an HVDC B2B link has been introduced between the two networks, that is, the link is now effectively asynchronous. It can be seen that within about 4 s, the rotor angle swings have been damped and stability has been maintained; the power flow through the link is virtually unchanged once the fault had been cleared. This is just one example of the way that networks, which incorporate the controllability of HVDC, can be made more intelligent, self-healing, and an integral, essential part of the smart grid of the future.

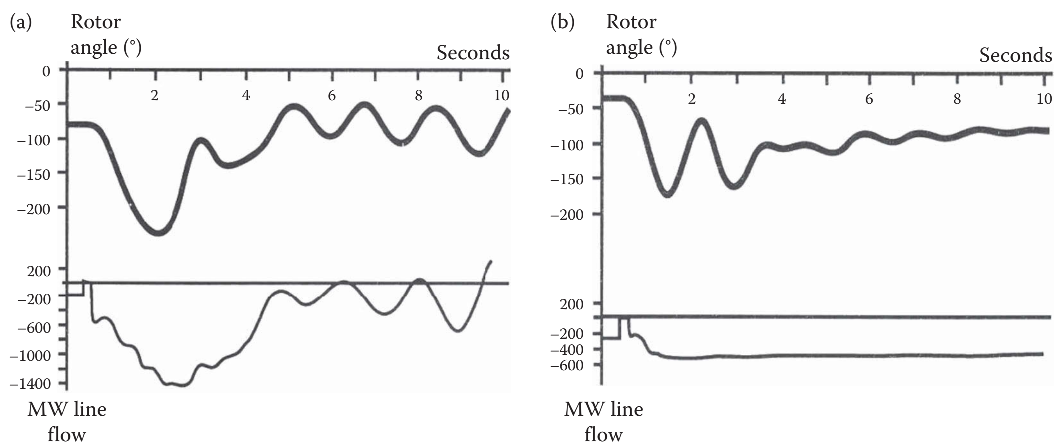


FIGURE 18.17 Post-fault response of two AC networks interconnected with (a) AC link and (b) HVDC B2B link.

Smart grid intelligence requires both functionality in individual equipment or subsystems and communications between these subsystems to allow other components of the network or hierarchy to see what is going on and, in turn, allow them to make other intelligent decisions and take controlling actions.

HVDC is one of the most intelligent subsystems within a network, since it is able to carry out precise control of power flow based on internal and external information, since it is customary for HVDC systems to pass information at a very detailed level to remote centers for monitoring, protection, and control at other locations. By coordinating the action of the HVDC control system and other control systems in the network (generators, switching, and transformer substations, FACTS devices, etc.), it is possible to build up a complete control hierarchy for the network made up of these discrete and dispersed subsystems. Intelligent systems, such as this are obviously capable of responding to events much faster than the human operator, and the rapid response to most faults or other events is critical to allow the system to recover and restabilize quickly. For example, the power flow on the VSC-HVDC systems can be optimally scheduled based on system economics and security requirements. It is also feasible to dispatch VSC-HVDC systems in real-time power grid operations. Such increased power flow control flexibility allows the system operators to utilize more economic and less polluting generation resources and implement effective congestion management strategies.

18.2.1 Thyristor-Based "Conventional" HVDC

Conventional HVDC, also known as LCC systems, is based on thyristor switching technology. Figure 18.18 shows a simplified circuit diagram of the main components that make up the power circuit of a typical conventional HVDC system: these are the thyristor valves, the converter transformers, and the AC filters. The most common configuration of conventional HVDC is using the 12-pulse bridge arrangement, which offers the best compromise of least cost and least harmonics. The AC filters perform the dual roles of (1) maintaining reactive power balance with the AC network, and (2) preventing harmonics generated by the HVDC from reaching the AC system. A photograph of a conventional HVDC installation is shown in Figure 18.19.

Figure 18.20 shows a typical HVDC thyristor valve hall for one end of an HVDC scheme. There are two different configurations of HVDC, a point-to-point system, where the DC connection is an overhead line or insulated cable, and a B2B system where the DC connection has zero length. The

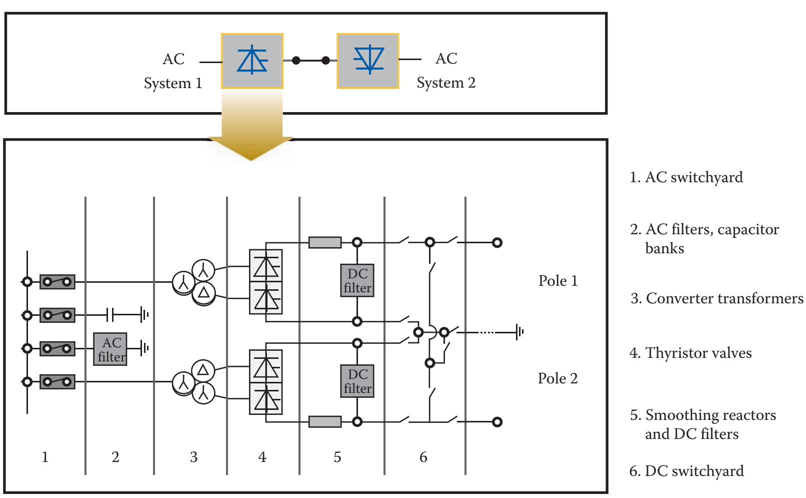


FIGURE 18.18 Conventional HVDC single-line diagram. (© 2012 Siemens. All rights reserved. With permission.)

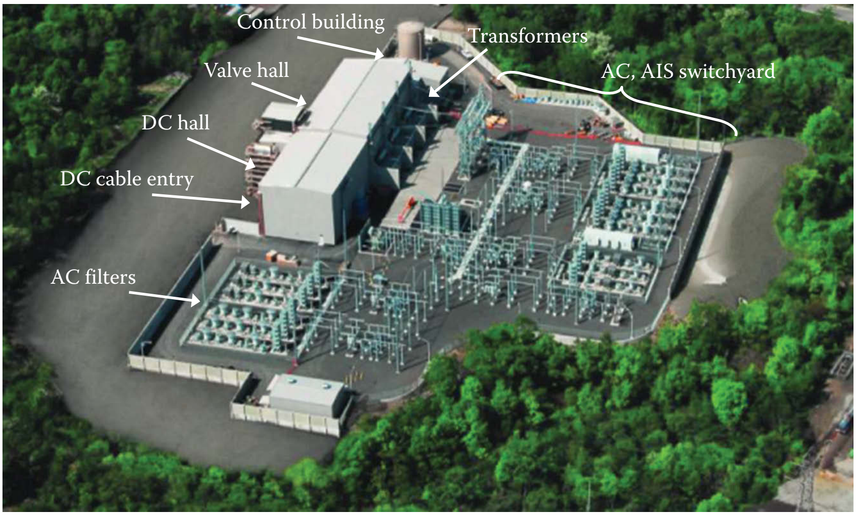


FIGURE 18.19 A conventional (thyristor) HVDC installation. (© 2012 Siemens. All rights reserved. With permission.)

FIGURE 18.20 Conventional HVDC thyristor valve hall. (© 2012 Siemens. All rights reserved. With permission.)

point-to-point system is used for the economical transmission of power over long distances. The B2B system can be used to isolate systems that are normally asynchronous to prevent the spread of cascading faults and increase the stability limit on an AC line.

18.2.2 VSC-Based HVDC

VSC-HVDC is a transmission technology based on VSCs (voltage source converters) and insulated gate bipolar transistors (IGBT). The converter operates by creating its own AC waveform and thus has the capability to rapidly control both active and reactive power, independently of each other. In particular, VSC-HVDC systems are attractive solutions for transmitting power underground and underwater over long distances. With extruded DC cables, power ratings from a few tens of megawatts up to more than 1000 MW are available. Figure 18.21 shows a simplified circuit diagram of main components that make up the power circuit of a typical VSC-HVDC system, which include IGBT converter valves, converter reactors, soft-start resistors, DC cables, and transformers.

The first VSC-HVDC schemes were based on a two-level topology, where the output voltage is switched between two voltage levels using pulse-width modulation techniques, which resulted in relatively high switching losses in converter operation. However, the most common VSC valve configuration being currently implemented is the modular multilevel converter (MMC), as this offers significant improvements in operating efficiency. The MMC converter topology consists of individual "half-bridge" IGBT submodules using two IGBTs. These submodules are connected in series to make up the converter, and are individually switched in sequence to synthesize an AC waveform. Each phase has two valves, one between the positive potential and the phase outlet, and one between the outlet and the negative potential. Thus, a three-phase converter has six valves, with each valve having a reactor in series. The valve reactor permits continuous and independent control of active and reactive power, as well as provides fault current limiting impedance. The fundamental frequency voltage across the reactor defines the power flow (both active and reactive) between the AC and DC sides. The transformer is an ordinary single- or three-phase power transformer, and may or may not be fitted with a tap changer according to the specific requirements of the system. The secondary voltage is controlled with the tap changer to achieve the maximum active and reactive power from the converter. Figure 18.22 shows a VSC-HVDC converter station.

One attractive feature of VSC-HVDC systems is that the power direction is changed by changing the direction of the current and not by changing the polarity of the DC voltage. This makes it easier to build a VSC-HVDC system with multiple terminals. These terminals can be connected to different points in the same AC network or to different AC networks. The resulting multiterminal VSC-HVDC systems can be radial, ring, or meshed topologies.

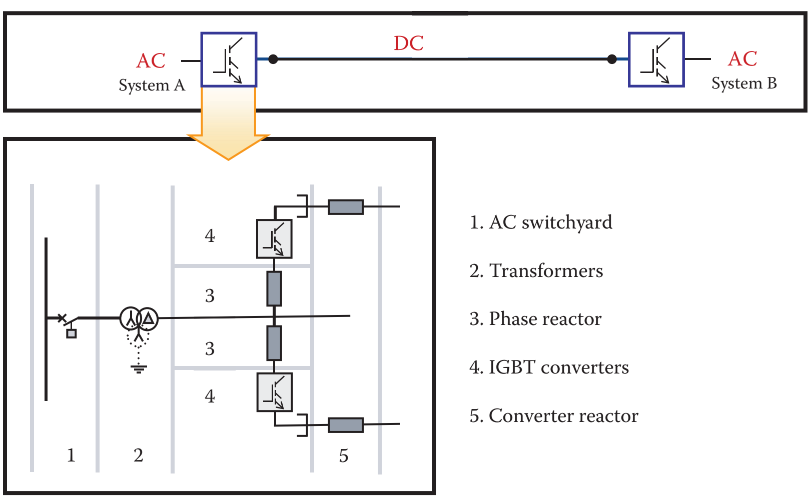


FIGURE 18.21 VSC-HVDC single-line diagram. (© 2016 GE Grid Solutions. All rights reserved. With permission.)

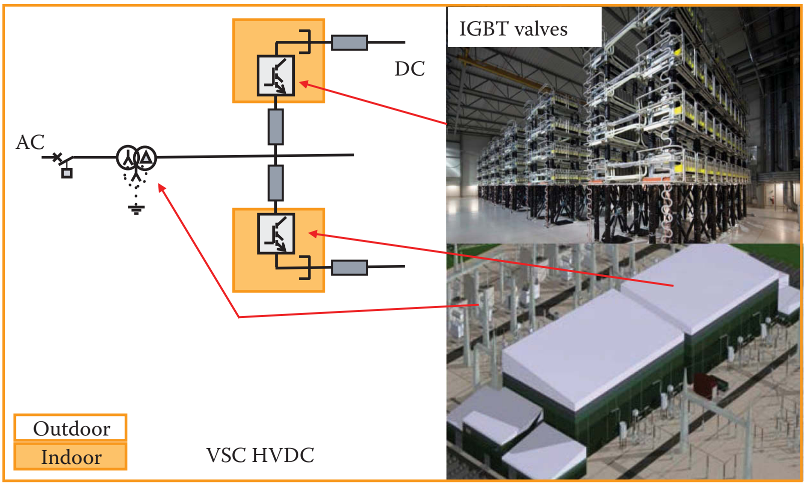


FIGURE 18.22 HVDC station with VSCs. (© 2016 GE Grid Solutions. All rights reserved. With permission.)

Standards have been developed by bodies such as the IEC, CENELEC, and CIGRE to define the various characteristics of the VSC converters necessary to create DC grids in the future. Product development work is under way to create new topologies of VSC converters, such as:

- "Full-bridge" submodules to provide DC side fault protection, which the half-bridge submodules cannot provide
- DC circuit breakers—to enable the creation of DC grids with the ability to segregate the DC circuit in response to faults in the same way as conventional AC breakers and protective devices
- DC-DC converters—to allow the interconnection of DC circuits operating at different direct voltages

VSC-HVDC is ideal for embedded applications in meshed AC grids. Its inherent features include flexible control of power flow and the ability to provide dynamic voltage support to the surrounding AC networks. Together with advanced control strategies, these can greatly enhance smart transmission operations with improved steady-state and dynamic performance of the grid. Fast control of active and reactive power of VSC-HVDC systems can improve AC power grid dynamic performance under disturbances. For example, if a severe disturbance threatens system transient stability, fast power runback and even instant power reversal control functions can be used to help maintain synchronized power grid operation.

18.3 ROLE OF TRANSMISSION SYSTEMS IN THE SMART GRID

Renewable energy generation is a key topic of today's power systems, in all countries. Driven by the need to reduce CO_2 emissions to stop or at least reduce the global warming effect, new "CO_2-free" technologies are investigated to fulfill the energy requirements of the future. Based on the Kyoto protocol and its subsequent conferences, most countries have committed to specific CO_2 reduction and renewable energy targets within the next 10–30 years.

Large synchronous power grids, for example, in the Americas and in Europe, continue to develop in complexity and were not originally designed to serve the purpose they are expected to carry out nowadays, and this progression will continue into the future. Originally, the conventional power plants, which are very easy to control, were mostly built in the vicinity of cities and load centers, and the grid around them was designed to provide the required capacity. The power demand has been growing over the years, and the ever-increasing amount of power capacity had to be brought from the adjacent grids over large distances. In addition to this, in the course of deregulation and privatization, a great number of power plants had to change their location; in the meantime, plenty of volatile wind power has been installed in many countries, causing parts of the grid, which may already be overloaded, to become even more overloaded.

18.3.1 Integrating Intermittent Power

For power grids, wind and PV solar energy are the most difficult to integrate into the power grid due to their inherent variability, whether they are located onshore or offshore [8,9]. These fluctuations create great difficulties for the grids, for in this case not only the power flow, that is, the power supply, but also the voltage of the grids is affected. This results in fluctuations of both active and reactive power on the transmission system. This deteriorates voltage and power quality; the corresponding grid code can no longer be adhered to, and the adjacent loads as well as the grid itself are affected detrimentally. Moreover, in the event of grid faults, larger power outages referred to as “voltage collapse” can easily occur due to cascading tripping of wind or solar generators at low voltage levels. Because of this, in a large number of countries, the grid codes have been significantly tightened in order to both fix the voltage within exact, time-dependent ranges of tolerance and protect the grid.

Integrating offshore wind power at an onshore substation provides possible risk factors that can be mitigated by FACTS and advanced VSC-HVDC links. These are summarized below:

- Long offshore AC cables connecting the wind farms are an additional risk due to the large additional cable capacitance added to the system. Even though the capacitance could be compensated with shunt reactors at the line frequency, the reactors cannot compensate for the higher order 2nd to 25th harmonic system resonances. This cable capacitance negatively impacts the harmonic impedance and can result in filter capacitor overheating and possible breaker tripping in substations connecting adjacent colocated HVDC and generator tie-lines [12]. A STATCOM may be included to mitigate the reactive power without adding more harmonic resonances, as well as any unacceptable low-order harmonic currents at the same time.
- The use of MMC VSC topologies reduces the risk of significant harmonic distortion, which might otherwise be encountered with two-level or similar converter types. These early generation VSC converters create increased levels of harmonics, which may interact with the other harmonic sources in the offshore AC network, since the network mostly comprised submarine AC cables and converter-fed wind turbine generators, containing little in the way of damping.
- Owing to the additional network resonance points associated with the offshore AC cable and HVDC capacitance, unacceptable temporary overvoltages (TOVs) during switching conditions at the substation may result. In such cases, the amplification at especially the 2nd harmonic is of concern due to transformer inrush currents. A STATCOM may help mitigate the TOVs [20].
- Offshore wind generator facilities and other closely connected generating facilities may be impacted by voltage sags due to switching events and system faults. STATCOMs can also provide the required voltage ride-through support.

18.3.2 Grid Security and Blackout Prevention

The security of power supply in terms of reliability and blackout prevention has the utmost priority when planning and extending power grids [8]. The availability of electric power is the crucial prerequisite for the survivability of a modern society, and power grids are virtually its lifelines. The aspect of sustainability is gradually gaining in importance in view of such challenges as the global climate protection and economical use of power resources are running short. It is, however, not a means to an end to do without electric power in order to reduce CO_2 emissions. A more appropriate way is to integrate renewable energy resources to a greater extent in the future (energy mix) and, in addition to this, to increase the efficiency of conventional power generation as well as power transmission and distribution without loss of system security. The future power grids will have to withstand increasing stresses caused by large-scale power trading and a growing share of fluctuating regenerative energy sources, such as wind and solar power. In order to keep generation, transmission, and consumption in balance, the grids must become more flexible, that is, they must be controlled in a better way. State-of-the-art power electronics with HVDC and FACTS technologies provide a wide range of applications with different solutions, which can be adapted to the respective grid in the best possible manner. DC current transmission constitutes the best solution when it comes to loss reduction for transmitting power over long distances. The HVDC technology also helps control the load flow in an optimal way. This is the reason why, along with system interconnections, the HVDC systems become part of synchronous grids increasingly more often—either in the form of a B2B for load flow control and grid support or as a DC energy highway to relieve heavily loaded grids.

18.3.3 Super Grid Developments

HVDC technology allows for grid access of generation facilities on the basis of availability-dependent regenerative energy sources, including large onshore and offshore wind farms, and compared with conventional AC transmission, it suffers a significantly lower level of transmission losses on the way to the loads.

Based on these evaluations, Figure 18.23 shows the stepwise interconnection of a number of grids by using AC lines, DC B2B systems, DC long-distance transmissions, and FACTS for strengthening the AC lines. These integrated hybrid AC/DC systems provide significant advantages in terms of technology, economics, as well as system security. They reduce transmission costs and help bypass heavily loaded AC systems. With these DC and AC ultrahigh-power transmission technologies, the "smart grid," consisting of a number of highly flexible "microgrids," will turn into a "super grid" with bulk power energy highways, fully suitable for a secure and sustainable access to huge renewable energy resources, such as hydro, solar, and wind, as indicated in Figure 18.24. This approach is an important step in the direction of environmental sustainability of power supply: Transmission technologies with HVDC and FACTS can effectively help reduce transmission

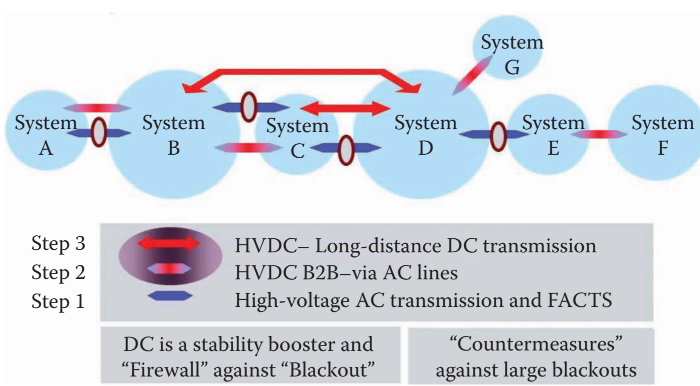


FIGURE 18.23 Hybrid system interconnections—"Super Grid" with HVDC and FACTS. (© 2012 Siemens. All rights reserved. With permission.)

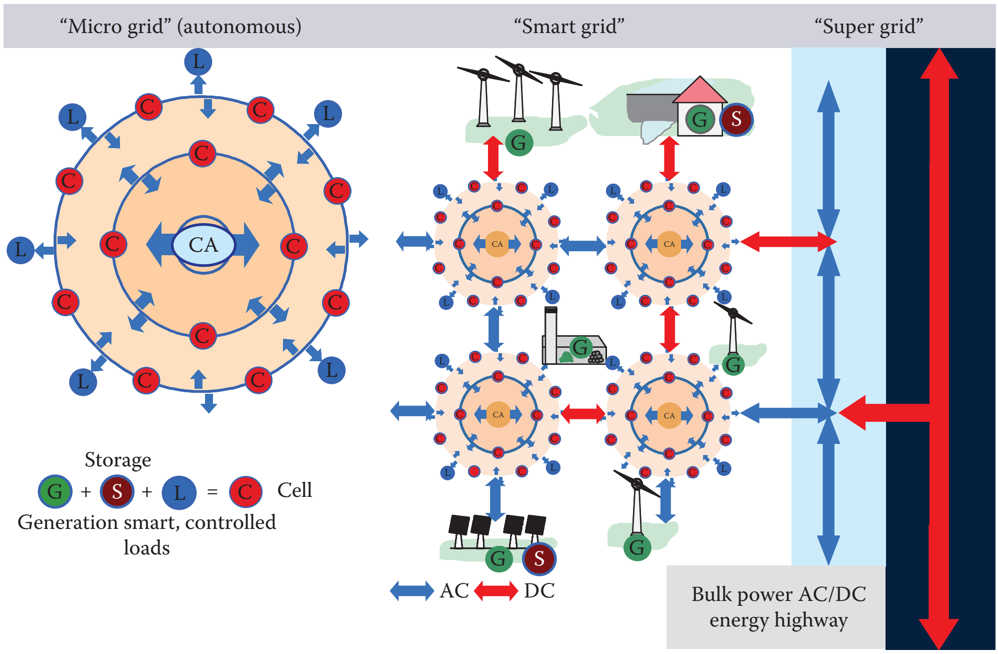


FIGURE 18.24 Prospects of smart transmission grid developments. (© 2012 Siemens. All rights reserved. With permission.)

losses and CO_2 emissions. Despite a significant share of wind power, the stability of the grid has to be maintained, that is, grid access solutions are needed, which provide both sustainability and security of electric power supply. This can be made possible by means of power electronics with dynamic fast control, which makes the grid more flexible and subsequently able to take in more regenerative and distributed energy sources. The solution of choice to tackle this complex task is FACTS and HVDC technology, for they can be controlled on demand, which takes a conventional grid to the "smart grid."

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19 Microgrids

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CONTENTS

Microgrids have become a concept much talked about within the smart grid evolution. The microgrid market is steadily growing, but it is difficult to clearly estimate its size and potential. According to Pike Research [1], the worldwide market for microgrids is expected to grow from 349 MW of generation capacity in 2012 to over 1.1 GW by 2017. Predictions for microgrid markets by Transparency

Market Research [2] show what was a $9.8 billion market in 2013 is expected to rise to $35.1 billion in 2020.

In addition to their ability to operate free of the grid, the microgrid market is growing mainly because of rising demand for secure, emissions-free, and reliable power. Microgrid growth is also spurred by the lower barrier to market entry for renewables (through regulation, renewable targets, tax credits, and lower technology costs) and an increase in energy storage technologies.

According to Microgrid Knowledge [3], most of the market growth is occurring in the grid-connected microgrid market, with campuses and institutions leading the way, thanks to government funding for renewables at these facilities. In North America, the military also is playing a key role in driving growth. After North America, the fastest growing markets are in Asia Pacific and Europe.

19.1 DEFINITION

A microgrid is an integrated energy system consisting of interconnected loads and DERs (distributed energy resources) that can operate connected to the grid or in an island mode. The objective is to ensure better energy reliability, security, and efficiency. Some microgrid solutions have been used for improving energy reliability and efficiency in industrial plants, commercial buildings, and military or university campuses. A new breed of microgrid is now becoming a reality for utilities wanting to integrate local generation or to implement grid relief solutions in areas that are poorly served by the transmission grid. Microgrids may be a quick alternative to the building or reinforcement of transmission lines. The main challenges for utilities are to guarantee grid reliability, stability, and security and also optimize energy efficiency.

Scale and location of the microgrid are important factors. Microgrids are typically constructed at the low-voltage (LV) or medium-voltage (MV) levels. The key defining characteristics of a microgrid are as follows:

- Provides sufficient and continuous energy to a significant portion of the internal demand
- Has its own internal control and optimization strategy
- Can be islanded and reconnected with minimal service disruption
- Can be used as a flexible controlled entity to provide services/optimization for the grid or the energy market
- Applicable to various voltage levels (usually <20 kV)
- Has storage capacity

So as not to be confused with other grid components, a microgrid is defined as NOT

- One micro-turbine/generator at a commercial or industrial site [this is only distributed generation (DG)].
- A group of individual generation sources that are not coordinated, but run optimally for a narrowly defined load.
- A load or group of loads that cannot be easily separated from the grid or controlled facility/building management, for example.

A microgrid's capacity to self-manage and define operational strategies concerning islanding mode and self-reorganization makes it the ultimate smart grid offering.

19.2 DRIVERS

Several drivers are pushing toward strong and quick deployment of microgrids:

- *Environmental incentives:* Owners and operators of microgrid generation capacities should benefit in most countries from governmental incentives to help renewable implementation. This makes microgrids a new and efficient way to develop renewable energies and attain emissions goals set by many countries (e.g., the European Union 2020 plan).

- *Cost-effective access to electricity:* Microgrids could constitute a relatively low cost and efficient step toward rural electrification. For many emerging countries, low rural population density and high electrical infrastructure prices represent too big of a hurdle to supply electricity to an entire territory. Microgrids could be a more gradual solution to solve this issue.
- *Reliability:* In areas where generation and grid load is a problem and causes blackouts or brownouts regularly, microgrids could offer a solution to alleviate energy supplies without heavy investment in large-scale power plants and high-voltage power lines. This, in turn, would give the end consumer a more reliable electricity supply.
- *Security:* The islanding capacity is also one way to improve grid resilience in case of unforeseen difficulties, an important factor for several sensitive end consumers, such as military bases, hospitals, or server farms.
- *Energy efficiency:* The localized energy resources provided by microgrids have the benefit of reducing electrical losses from long-distance transmission.
- *Renewable energy implementation:* Microgrids could be a strong accelerator toward renewable energy implementation. Many countries have set ambitious goals. Microgrids constitute one way to achieve those goals and accelerate the development of smart grids due to easy integration with the grid.
- *Progress in energy storage technologies:* Energy storage is a vital part of the microgrid system. GTM Research [4] forecasts the annual U.S. energy storage market will cross the 1-GW mark in 2019, and by 2020 will be a 1.7 GW market valued at $2.5 billion. A combined solar and storage solution can be configured to enable an islandable microgrid for a commercial or industrial facility with the potential to power critical loads indefinitely. Combining a clean energy solution can reduce project development costs, including permitting installation and grid interconnection. Also, the increase in electrical vehicles can be seen as a plug-and-play storage capacity, and for this reason, can have a large impact on microgrid development and research in the coming years.

19.3 BENEFITS

It is clear that microgrids offer many benefits, especially when renewable energy is generated and consumed locally. Microgrids can reduce electrical losses, increase grid stability and security, and, as a whole, reduce spending for both consumers and utilities. Microgrids benefit the utility, consumer, and DER owners. The DERs may be owned by the utility, consumer, or a third party (Figure 19.1).

19.3.1 Economic Benefits

- *Consumer benefits:* Microgrid systems can encompass relatively complex price setting mechanisms. It is possible to imagine systems in which dynamic pricing software calculates in real time the lowest cost source of energy to the consumer: from either the main grid or local generation sources [e.g., rooftop photovoltaic (PV) panels or wind farm integrated to the microgrid].
- *DER benefits:* Many countries have introduced incentives to accelerate the implementation of renewable energies. Such schemes usually include a subsidized price for the owner of a renewable energy generation system (PV, wind, small hydro, biomass) to sell back to the electric company the electricity produced at higher than market price. This can also be considered as a microgrid benefit.
- *Grid spending reduction:* In areas where the existing infrastructure is under high demand, or where there is no existing electrical infrastructure (e.g., rural areas in developing countries),

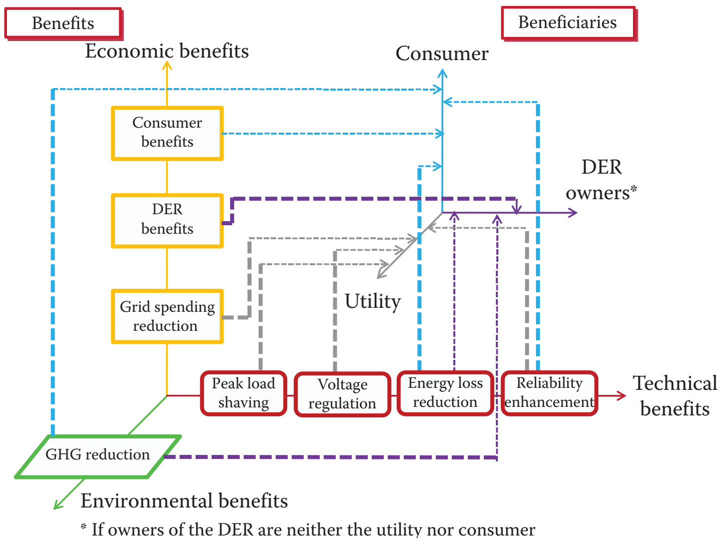

FIGURE 19.1 Microgrid benefits. (EU More Microgrids project highlights, December 2009, www.microgrids.eu.)

microgrid implementation could represent a much cheaper alternative to transmission infrastructure costs. Network spending is in that respect reduced, or at the very least postponed.

19.3.2 Environmental Benefits

- *Greenhouse gas reduction:* Microgrids may rely heavily on local renewable energy sources. Furthermore, local energy sources drastically reduce electrical losses incurred on the grid, which can be translated into CO_2 emission reduction.

19.3.3 Technical Benefits

- *Peak load shaving:* Dynamic pricing coupled with the availability of local generation may be a powerful tool to shave or shift loads. It has been shown that dynamic load shaving can reduce peak load demand by 10% and general consumption by up to 15%.
- *Voltage regulation:* Local energy supplies can help to improve the voltage quality of electricity at the consumer level, provided that the proper microgrid control and automation solutions are in place.
- *Energy loss reduction:* As explained earlier, local generation reduces the need to transmit electricity across the grid, thus reducing electrical energy losses.
- *Reliability enhancement:* Thanks to their potential local automation capabilities, microgrids can improve general grid stability and electricity reliability.

Obviously, identification of microgrid benefits is a multiobjective and multiparty coordination task, which will strongly depend on business structure and models. However, it seems clear that microgrids have a lot to offer to all stakeholders on the electrical grid.

19.4 BUILDING BLOCKS OF A MICROGRID

A typical microgrid will contain physical systems, control and automation systems, and interfaces with other utility systems.

19.4.1 Physical System

A microgrid is composed largely of off-the-shelf physical components. None of the physical components discussed here are specific to a microgrid application. In fact, most of these same physical systems are used in other ways by utilities. It is the combination of the physical systems under an advanced control scheme that creates a microgrid application. Nonetheless, it is worth understanding the basic building blocks of the system. These include the following:

- *Sensors:* Sensors, and more generally information input, are required to determine whether criteria for islanding or reconnecting have been met.
- *Switches:* Intelligent switches are a vital part of the microgrid because they allow quick reconfiguration of the components in the microgrid. Switches allow the microgrid to electrically disconnect or reconnect with the grid, section-off areas of the circuit, or bring various DER components online or off-line.
- *Power electronics:* Power electronics allow for DC-to-AC and AC-to-DC conversions, as well as voltage changes for DER components. This allows DERs, such as energy storage or microturbine generators, to be grid-connected despite nongrid-conforming generating modes.
- *Energy storage:* Energy storage helps smooth rapid changes due to external events or characteristics of DER in the microgrid. For example, in the event of a blackout, energy storage can help to support the system for a few minutes while generators start up. In order to perform these functions, the storage must be sufficiency large and able to respond quickly.
- *Dynamic resistors:* This could come as a large resistive load, which can be varied rapidly in order to absorb excess wind generation rather than spill it by shutting down or throttling back wind turbines. As the resistor can be adjusted rapidly, this effectively converts spilled wind into "spinning" reserve that can be used to supplement diesel generation. Maintaining the power balance between generation and demand in this way allows the resistor to maintain system frequency [5].
- *Generators:* Generators can take a variety of forms, but are most commonly diesel- or natural gas-based combustion engines. These generators are necessary even when renewable alternatives are available because they provide energy that can be relied on with relatively high certainty.
- *Protection and control equipment:* Protection equipment is always necessary, regardless of whether or not the DER is configured in a microgrid. Nonetheless, there are special precautions that must be taken in a microgrid because of the added level of complexity involved with becoming a separate electrical entity. Specifically, the major issues that must be accounted for are protection when disconnecting and reconnecting with the grid, and ensuring that there is an appropriate level of fault detection and protection in each part of the islanded microgrid system. Control systems for protection equipment will also have to be modified to fit the operating paradigm of the microgrid.
- *Metering:* Advanced metering must be in place at the substation and preferably in the residential neighborhood so that conditions and power flow can be monitored in real time.

19.4.2 Control and Automation System

Three basic functional levels of microgrid control and automation can be identified (Figure 19.2). The control and automation architecture is functional and may have to be adapted depending on the size of the microgrid and the regulatory constraints. However, it is mandatory that the following functions are fulfilled somewhere in the microgrid:

- Manage exchange with the main grid (disconnection, reconnection, market functions, and emergency control, if required).

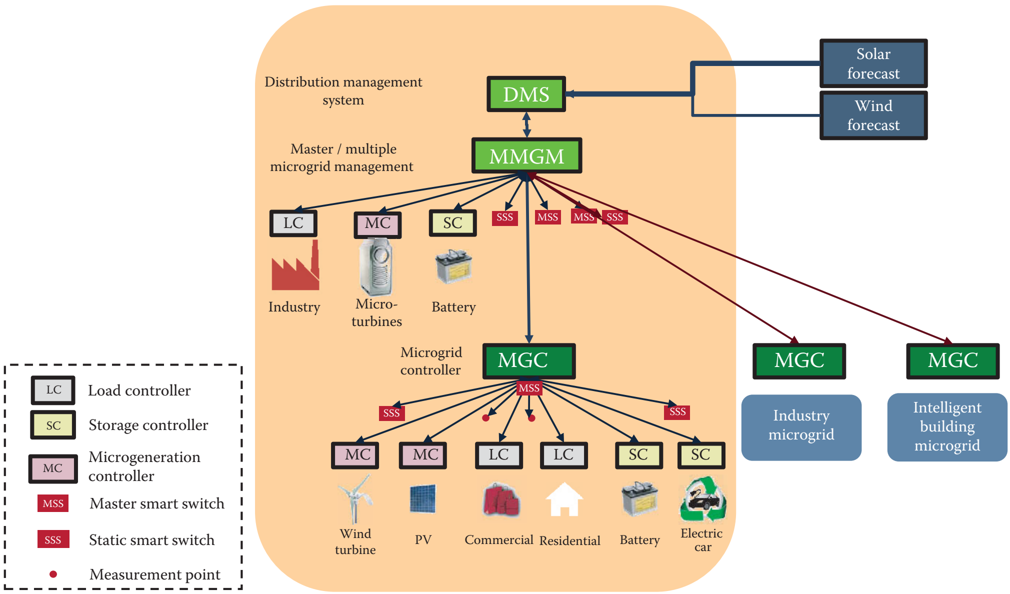

FIGURE 19.2 Typical microgrid control and automation architecture.

- Operate reliably for microgrid consumers in islanded mode and in connected mode.
- Optimize asset utilization (DER, load, transformers, etc.) within the microgrid while in islanded mode or in connected mode.

Local device controllers necessary to control individual components of the microgrid: load controllers, energy storage controllers, and micro-generation source controllers. These local controllers respond to control signals sent by the microgrid controller and react to real-time conditions (detection of a fault, etc.) in order to guarantee the reliability of the different components. Protection relays and smart switches are also part of this level of automation.

Microgrid controllers provide real-time monitoring and control functions for all the components within their control boundaries. Their main objective is to ensure power reliability and quality. It may bear some basic local optimization functions based on economics of local generation and storage.

The master microgrid management system optimizes the overall microgrid or collection of microgrids under its control. It defines set points for all the loads and generation in order to optimize the efficiency of the microgrid depending on electricity prices and local generation cost. It also provides forecast and real-time estimation of loads and generation to the distribution management system (DMS). The master microgrid management system is also responsible for the disconnection/reconnection to the main grid. It may also interact directly with the market or with curtailment service providers.

19.4.3 Interfaces with Other Systems

The microgrid controller relies on other grid control systems to deliver information or commands to it, as well as execute some of its requests. Though it can operate independently, the microgrid controller is of most use to the grid when it understands the external grid conditions and reacts accordingly. Interfaces with the utility DMS/outage management system (OMS) and the advanced metering infrastructure (AMI) system are particularly important.

19.5 MICROGRID TYPES AND EXAMPLES

Current operational microgrids are mostly pilot programs, generally small scale and with no proven return on investment. However, these various projects should be seen as the first steps to prove the business model and the technical feasibility on a large scale.

Three main areas in the world have started implementing several microgrid programs: Europe, Japan, and North America.

Europe subsidized a major research program called More Microgrids (budget of €8.5 million) during the 2006–2010 period. Partly funded by the European Union, and partly funded by the private sector, the project implemented eight microgrids in various locations in Europe, both North and South. Most microgrids are small-scale, LV pilot projects to research on technical issues and feasibility. Two of these programs are operated in laboratories. However, one project stands out by it size: Bornholm Island in Denmark. Bornholm is a Danish Island with 28,000 inhabitants. Electricity is generated locally through local sources in LV and MV (oil, coal, and wind). It is also linked to an underwater high-voltage cable from Sweden. After an accident, this underwater cable was cut, and the grid became islanded, becoming in effect a microgrid for several months. This is, up to now, the only "microgrid" of this size and voltage levels in the world. The next step in European research is to develop projects of larger scale to identify and solve size-related issues. In 2010, the European Commission launched a call for demonstration program within the Framework Program 7 (Energy 2010—7.1.1—large-scale demonstration of smart distribution networks with DG and active customer participation). Two ambitious projects called Ecogrid and GRID4EU started at the end of 2011. One example of a subproject of GRID4EU is the NiceGrid project: specification and deployment of a MV microgrid in a new area of Nice (France) with strong concentration of PV generation.

In *Japan*, the main research institute in charge of microgrid research is the New Energy and Industrial Technology Development Organization. Japan is the world leader in pure numbers of microgrids, but again, most of them are very small, and they focus mostly on the integration of renewable energies. Private research is led by Mitsubishi Electric Corporation, which has already developed several specific microgrid products (inverters and management system).

North America probably has the most advanced research when it comes to microgrids. Canada, through the CANMET Energy and Technology Research Center, has several pilot microgrid programs focusing on DER integration standards and codes, and also net-metering. In the United States, the Consortium for Electric Reliability Technology Solutions and Power Systems Engineering Research Center are two main research institutes. With the bailout grants given out by the Obama administration, the total budget for smart grid research increased to approximately $8.1 billion in 2009. About 10%–15% ($800 million) was allocated to various microgrid research projects. Research in the United States is mostly developed for institutional projects (military or university campuses).

The *rest of the world* is not as advanced in microgrid research. However, other countries in Asia and in the Middle East have started investing in this type of technology. Several projects, some of which are highly ambitious, such as the Masdar Smart City in Abu Dhabi, have been launched. Microgrids have also gained a lot of interest over the past years in China.

While islands, remote villages, and large ships have many of the same features as microgrids, and meet some of the definitions of microgrids, modern microgrid definitions include the ability to connect to, and disconnect from, larger main grid systems. Among the modern definition, microgrids can be broken down by their types of ownership, the types of load they support, or by their voltage level of connection in the distribution grid.

The largest number of identified types of microgrids are, in decreasing order, institutional microgrids (hospitals, university, or military campuses), followed by commercial/industrial grids (factories, server farms, commercial malls, business towers), and finally, community grids (multiple houses or apartment buildings, some commercial buildings). The latest is very small today, but a huge increase is expected when regulatory and business barriers are lifted.

One possible microgrid segmentation is the following:

1. *Blue ocean:* This segment consists of areas not yet connected to the country's main grid. In this case, there is no preexisting infrastructure. One of the main drivers in this case is the possibility to supply good-quality electricity without building transmission lines and other grid infrastructure.
2. *Network relief:* Areas where the main grid is saturated and, hence, has problems with voltage stability and peak demand are the key markets for this segment. Microgrids will increase stability and defer expensive investments in large-scale infrastructure upgrades.
3. *Energy security:* This particular segment deals with all institutions where it is strategically important to obtain stable and good-quality electricity without any interruption. Hospitals, military campuses, refineries, and the like can potentially be islanded for long periods in the case of main grid outages. Within this category, it is possible to define subcategories depending on the criticality: Typically, hospitals need a higher level of service (a few seconds of interruption can cost a life) than industries.
4. *Energy efficiency:* This particular segment's main motivations are environmental concerns and profits made by the sale of renewable energies. In this particular case, a microgrid is only one solution since the islanding characteristic that defines a microgrid is optional. This segment may include university campuses, office buildings, small communities, and so on.
5. From a technical point of view, different categories of microgrids can also be defined along different levels of voltages. Depending on the microgrid architecture, level of voltages impacted, and components included (substations, feeders, etc.), control and automation processes and telecommunication tools may differ greatly. Figure 19.3 shows four possible categories.

Typical owners of large, complex pieces of electric distribution grids, such as universities and hospitals, tend to be the earliest adopters of microgrid equipment and system configurations because they have single owners. Either for research purposes or for economics or resilience, these owners decide to invest in generation, storage, load control, or energy efficiency and management systems. More recently, multiple consumers have been grouping together to share district systems and form what are called community microgrids [6]. While not currently abundant, these tend to be focused on something like a shared community water source, colocated equipment, or existing district heating

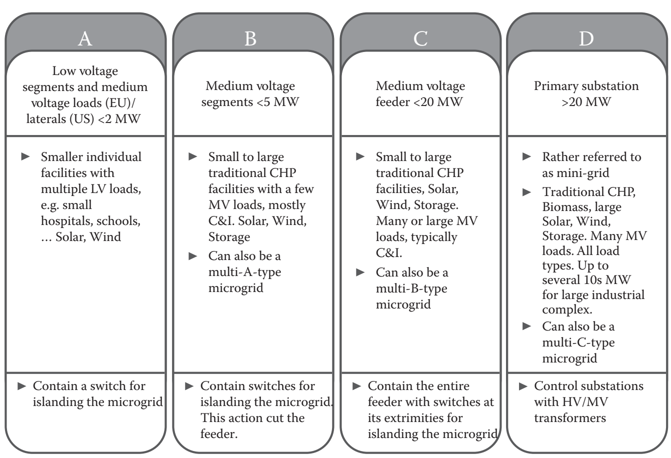

FIGURE 19.3 Microgrid application categories. (From U.S. DOE/CEC Microgrids Research Assessment, May 2006.)

or cooling. When communities are interested in the benefits of shared microgrid resources, but the interested parties' electrical distribution infrastructure does not allow for cost-effective isolation or islanding of all of the buildings, together then they can design and install clustered or cluster-based microgrids.

19.5.1 Single User—Campus Microgrids

This type of microgrid refers to islandable sections of distribution grid that serve multiple buildings and have a single owner/operator. The term "campus" is broader than just college campuses and can refer to hospitals, office complexes, military bases, federal facilities, and any single owner that manages the electrical infrastructure of multiple buildings. These types of microgrids can be broken down further into independent, which are owned by third parties that are not end users of the microgrid; public, which are owned by government organizations; utility, which can be municipal electric departments or investor-owned utilities that operate microgrids for economic or resilience purposes; and hybrid, which have shared ownership.

Example: Illinois Institute of Technology (IIT), USA

The microgrid is based on hierarchical control via supervisory control and data acquisition software to ensure reliable and economic operation of the IIT microgrid. It also coordinates the operation of high-reliability distribution system controllers, on-site generation, storage, and individual building controllers (Figure 19.4). Intelligent switching and advanced coordination technologies of the master controller (MC) through the communication system facilitate rapid fault assessments and isolations of the IIT microgrid [7].

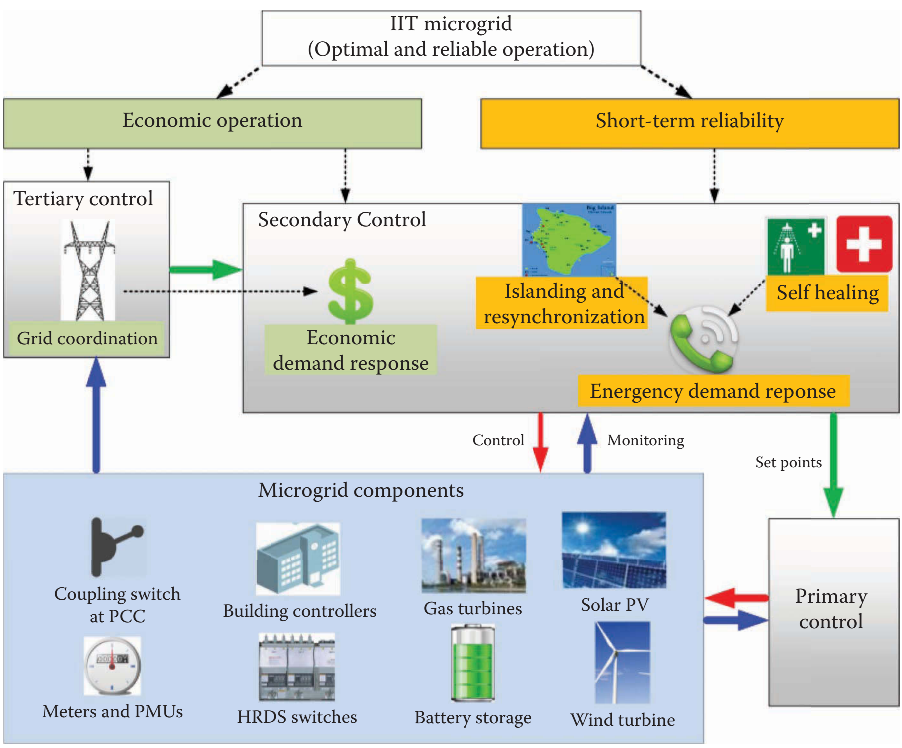

FIGURE 19.4 Illinois Institute of Technology (IIT) microgrid operation overview. (© 2016 Willdan Energy Solutions. All rights reserved. With permission.)

A major element of the IIT microgrid is its MC. The MC monitors and controls all loads and resources, and performs day-ahead and real-time optimal scheduling for the IIT microgrid. An overview of microgrid operation including different types of control, functions, and components is shown in Figure 19.5. The MC economically optimizes the energy flow at three levels—campus, DER/building, and subbuilding. Building meters provide the MC with individual building load profiles, enabling it to communicate with, and adjust subbuilding loads through building controllers. The MC also receives the day-ahead price of electricity, weather data, wind speed, cloud coverage, and other data for utilizing the renewable sources in the microgrid. The MC then runs a day-ahead scheduling optimization algorithm to optimize the use of microgrid local generation and balance the hourly demand response (load curtailment and shifting of nonessential microgrid loads) in order to minimize the cost of supplying the microgrid load [8].

19.5.2 Multiple Users—Community Microgrids

The most recent investments of state and federal government research into microgrids have been into the concept of multiowner and multiuser microgrids that can cross city, county, and industry boundaries. Community microgrids may also be the best solutions for small- and medium-sized cities that want to support critical city infrastructure clustered in city downtown areas. These can be structured similar to district heating cooperatives that serve a few permanent customers with the potential to add or remove additional customers. These types of microgrids can also be broken down similarly to campus microgrids by independent, public, utility, and hybrid specifications, and have the most potential for growth as they have the largest potential market for new investments.

Example: Bronzeville, Illinois, USA

For the Bronzeville community in Illinois, USA, the MC provides a hierarchical control strategy to ensure reliable and economic operation of the microgrid. It also coordinates the operation of switch controllers, and DG and storage controllers. An overview of the microgrid control architecture is shown in Figure 19.6. The hierarchical control approach in the MC is implemented in a distributed fashion. This approach was chosen to maintain major control capability during communication failure. The proposed microgrid will be deployed in the Bronzeville neighborhood of the City of Chicago, and will tie into the IIT microgrid and to ComEd's electric grid at two substations. The proposed interconnection will allow the two microgrids to work in conjunction with each other and share resources, thus forming a clustered microgrid.

Example: San Diego Gas and Electric, Borrego Spring, California, USA

The San Diego Gas and Electric microgrid project, with support from the Department of Energy (DOE) and the California Energy Commission (CEC), has one of the largest-scale microgrid demonstration projects in the United States. The project, which is implemented in the desert city of Borrego, will combine distribution-side technologies with consumer-side technologies, improve system reliability, and reduce peak load by more than 15%. These technologies include DER resources, advanced energy storage, residential solar panels, and demand response resources. The project received about $10 million in federal and state funding, and projects a total project cost of about $15 million over 3 years. The project incorporates an advanced microgrid controller that will integrate and optimize the utility-side DER with consumer-side resources, such as demand response. The microgrid controller will also coordinate with other utility systems, such as the DMS, OMS, and AMI. This kind of integrated microgrid controller program could potentially be expanded to the rest of the utility's distribution system to improve DER management across the utility's service area.

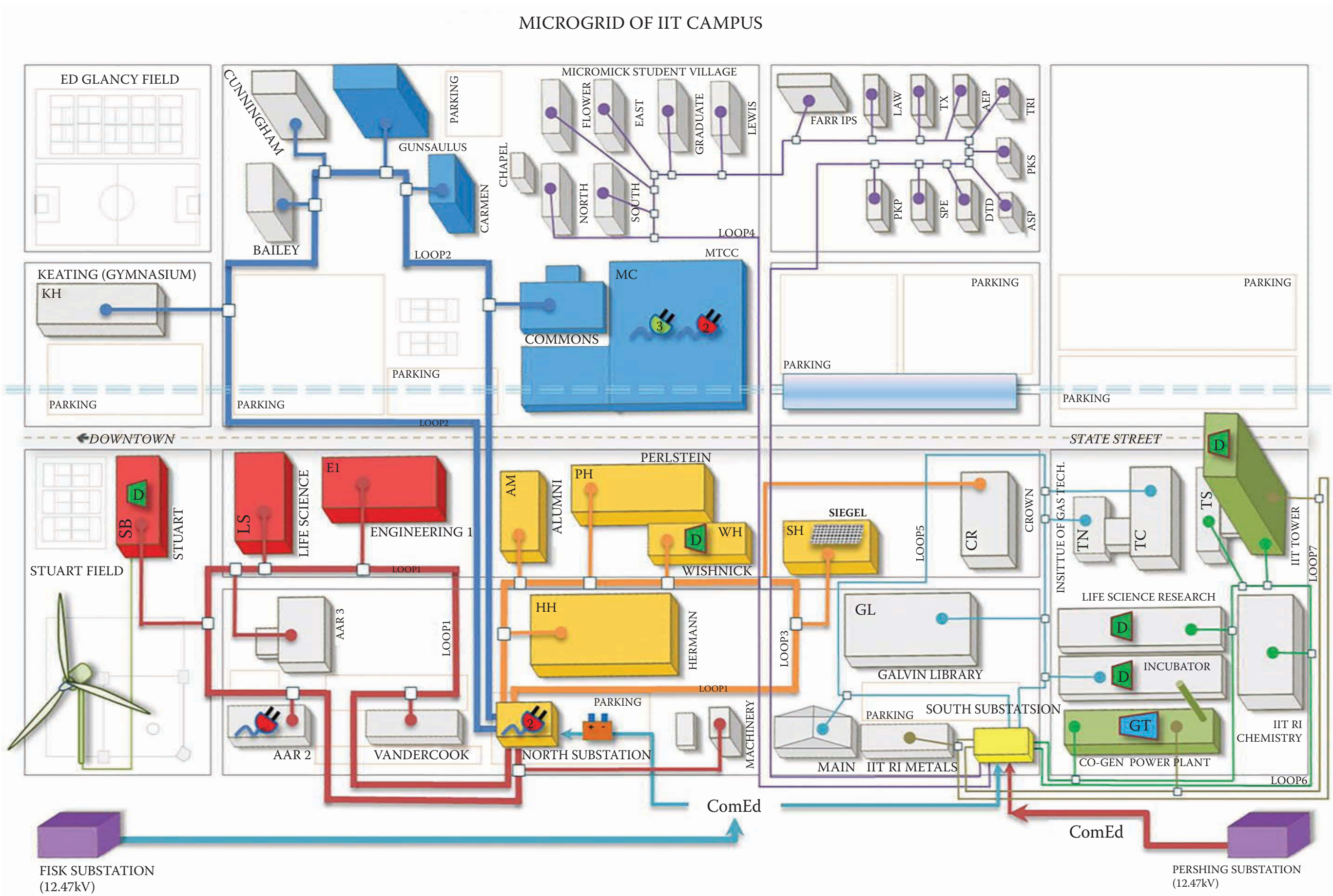

FIGURE 19.5 Illinois Institute of Technology (IIT) microgrid control [9]. (© 2016 Willdan Energy Solutions. All rights reserved. With permission.)

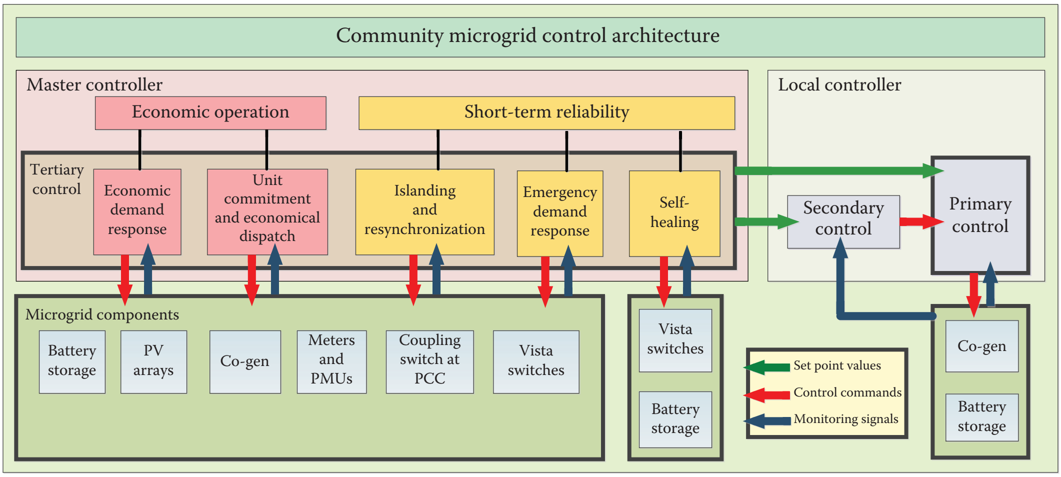

FIGURE 19.6 Overview of the Bronzeville community microgrid control architecture. (© 2016 Willdan Energy Solutions. All rights reserved. With permission.)

19.5.3 Clustered Microgrids

Similar to the community microgrid structure, clustered microgrids involve multiple owners and complex load types, and leverage innovative configurations of generation and load control to provide maximum benefits to all of the customers. The difficulty and expense of connecting and isolating neighboring loads and complex distribution networks are offset by the potential to separate community microgrids that will provide the maximum benefits to customers while remaining economical. This often involves grouping the most critical loads, such as fire departments, hospitals, jails, and other facilities that are well-positioned, based on electrical distribution layout, and installing generation and load control to support these individual clusters in the event of an outage, and to also provide economic benefits to less critical loads. The key aspect of supporting multiple small clusters is to aggregate the load and generation resources and provide better electricity prices to the group of customers while also making participation in ancillary services simpler and more cost-effective [10].

19.6 CHALLENGES TO THE DEVELOPMENT OF MICROGRIDS

A certain number of factors can slow down the development and deployment of microgrids.

19.6.1 Technical

One technical challenge concerns the balance management between load and generation. To improve grid efficiency, it is important that the DERs and demand be optimally controlled, and that systems and securities are implemented to control when local generation is consumed or stored. All these imply that the grid must be able to forecast energy production and make "smart" decisions based on the forecasts. The microgrid must also be able to evaluate its energy reserves very precisely so as to make good control decisions at multiple horizons: "a week, a day, 15 min, a few seconds."

Protection and safety represent other technical issues. Pilot programs are currently designed to see how a grid reacts when it is switched from a normal mode of operation to an islanded mode (and vice versa). Research has not yet tried to evaluate precisely the consequences of unplanned outages and the consequent reconfiguration required in the microgrid. Another concern is "black start," the process of restoring a generation station to operation without relying on external energy sources. The final challenge concerns two-way electricity flows. One idea concerning microgrids is that if one was to regroup multiple microgrids, they could feed each other with energy. For this system to function, there needs to be two-way power flows on the distribution grid. In most current cases, this is not a possibility due to security rules and equipment capability.

Another technical challenge concerns everything to do with the microgrid and main grid interconnection. There needs to be real-time monitoring of power flow, precise measurement tools to calculate and monitor key electrical characteristics (voltages, flows, angles), Volt/VAr analysis, control of frequency and harmonics in islanded mode, and the reconnection procedures after an islanded event. Currently, pilot programs do not emphasize these various technical challenges, but as microgrid complexity and size increase and microgrids are subject to realistic grid operating experiences, difficulties may arise that will need to be addressed.

An additional technical challenge concerns the information and communication parameters linked to the electrical aspects of the microgrid. It is important to design a data management system capable of handling all the data generated by a complete microgrid, but, at the same time, the management system must be economical in proportion to the size of the microgrid.

One last idea concerning microgrids would be to create a dynamic peer-to-peer market to transfer electricity (and perform the money settlement) inside the microgrid between the various generators/consumers of electricity. This last point bears various technical issues, and many more tests have to be conducted before an operational peer-to-peer microgrid can be created.

19.6.2 Rate Design

In a regulated utility, retail electric rates usually comprise three parts: generation, transmission, and distribution. Net metering was introduced as a balance between the full bundled cost of imported electricity against electricity produced and exported onsite. A local power producer can execute a power purchase agreement (PPA) with a customer and provide that customer with power that is generated locally at a competitive rate. The proposed rate by the power producer can make this PPA economically beneficial to the customer due to the fact that the proposed rate can be noticeably lower than the full bundled rate typically offered by the utility. In a community microgrid, various energy resources can be owned by different owners and will generate electricity to be shared among multiple consumers through the combined electric distribution system. Rates can be much more complicated for community microgrid customers due to limits on how much individual onsite resources can export, including existing regulations that limit the customer's ability to purchase electricity from providers other than the utility. Depending on the type of customer and the services provided, such as demand reduction, energy arbitrage, and energy security, these rates may change.

19.6.3 Regulatory

Microgrids as nonutility energy providers may fall under traditional utility regulation of the state's public utility commission due to having their assets cross public streets. Therefore, microgrid billing, rates, and services quality can be heavily regulated. Consequently, extra costs and risks are added to the already large microgrid investment and operations and maintenance costs. Microgrid permitting and interconnection requirements and their associated costs may vary depending on the type of DER assets and the availability of net metering programs. These procedures add additional legal requirements that involve more cost and effort for project developers.

Although some government efforts support the deployment of microgrids, most legacy regulations are designed for a standard operating distribution grid, rather than pockets of high-reliability, resilient, flexible microgrids. Because of this, third-party owned and operated microgrids functioning as small-scale utilities do not have much regulatory support. Utility franchise rights significantly constrain third-party providers from developing larger projects that may be more economically attractive. Therefore, a nonutility provider may have legal challenges in order to use existing utility distribution lines or take over ownership of existing customers.

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20 The Dynamics of Wholesale and Distributed Energy Markets

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Decades ago, the basic idea behind wholesale electricity markets was to allow large-scale generators to have open, nondiscriminatory access to high-voltage transmission in order to sell power at competitive prices. The use of open-access high-voltage transmission, thus, defines the context for competitive wholesale markets. The smart grid ensures access to wholesale markets, which are important to monetize and make economic decisions for energy resources. Wholesale markets now include demand-side management (demand response, DR) and other forms of smart grid energy resources beyond large, central station generators. Still, wholesale electricity markets are but one part of the value chain to fully integrate smart grid resources. Retail and distributed energy markets are also critical to enable energy resources to be monetized and fully used on the distribution grid. Integration and optimization of all energy resources should be achieved across both wholesale and retail markets in order to capture the full value and all related costs for the transmission grid, distribution network, and customers, including distributed energy resources (DERs).

20.1 WHOLESALE MARKETS FOR WHOLESALE AND RETAIL RESOURCES

At the wholesale level, the Federal Energy Regulatory Commission (FERC) has approved processes to establish nondiscriminatory open access transmission [1]. In the mid- to late 1990s, FERC Orders 888 and 889 provided the rules of engagement for Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs). During this time, the term "ISO" was prominently used and "RTO" was later defined to focus more on integrating transmission grids, though these two kinds of organizations remain very similar.

The general aims of FERC's precedent setting Orders 888 and 889 were for appropriate, authorized ISO/RTO institutions to achieve the following:

1. Improve efficiencies in transmission grid management
2. Improve grid reliability
3. Remove remaining opportunities for discriminatory transmission practices
4. Improve market performance
5. Facilitate lighter-handed regulation [2].

FERC Order 888 established 11 foundational principles for ISOs/RTOs to administer open access transmission services, which are as follows:

1. The ISO's governance should be structured in a fair and nondiscriminatory manner.
2. An ISO and its employees should have no financial interest in the economic performance of any power market participant. An ISO should adopt and enforce strict conflict of interest standards.
3. An ISO should provide open access to the transmission system and all services under its control at "nonpancaked" rates pursuant to a single, unbundled, grid-wide tariff that applies to all eligible users in a nondiscriminatory manner.
4. An ISO should have the primary responsibility of ensuring short-term reliability of grid operations. Its role in this responsibility should be well defined and should comply with applicable standards set by NERC (National Electricity Reliability Corporation) and the regional reliability council.
5. An ISO should have control over the operation of interconnected transmission facilities within its region.
6. An ISO should identify constraints on the system and be able to take operational actions to relieve those constraints within the trading rules established by the governing body. These rules should promote efficient trading.
7. The ISO should have appropriate incentives for efficient management and administration and should procure the services needed for such management and administration in an open competitive market.
8. An ISO's transmission and ancillary services (AS) pricing policies should promote the efficient use of, and investment in, generation, transmission, and consumption. An ISO or

Regional Transmission Group (later designated RTO) of which the ISO is a member should conduct such studies as may be necessary to identify operational problems or appropriate expansions.

9. An ISO should make transmission system information publicly available on a timely basis via an electronic information network consistent with the Commission's requirements.
10. An ISO should develop mechanisms to coordinate with neighboring control areas.
11. An ISO should establish an Alternative Dispute Resolution process to resolve disputes in the first instance [3].

Based on these ideas and principles, a group of ISOs and RTOs have been authorized to operate in the USA and Canada. Presently, over 60% of all electrical power supply is provided by ISOs/RTOs in the USA [4]. The U.S. operational requirements for RTOs and ISOs are now quite well established through additional FERC Orders [5]. ISOs/RTOs must also act consistently with NERC requirements, reliability, and safety standards for the operation of all high-voltage systems in the USA. Expanding this reach, compliance with ISO/RTO and NERC requirements has allowed for relatively seamless competitive power transactions with many of Canada's wholesale transmission organizations.

20.1.1 Primary Wholesale Products—Transmission, Energy, Capacity, and Ancillary Services

The primary products in virtually all ISOs/RTOs include the following:

- Access to the transmission system by large generators and consumers of electricity and power
- Energy as a commodity (firm and nonfirm)
- Capacity availability, though these requirements differ substantially between ISOs/RTOs

Access to the transmission grid, for buyers and sellers of electricity, requires compliance with specific technical requirements. A grid access fee is typically charged, separate from the costs charged and prices paid for electricity from an ISO/RTO.

Open access to transmission is essential for all buyers and sellers at the wholesale level. This has been extended to include *comparability* or comparable access by all market participants, including those that bring demand-side resources to the grid. Demand-side response to electricity needs at the retail and wholesale levels can be aggregated, managed, and provided as comparable services that reduce the need for competitive energy and capacity sources.

Buyers and sellers, as well as transmission owners, must pay and be paid. Systems for physical and financial settlement of electricity- and capacity-related services have been developed.

The basic products and services in the wholesale energy market are energy, capacity, and AS. Energy is the basic commodity sold through ISOs/RTOs, on an MWh basis. Firm energy is "backed" by the standard package of AS, including operating reserves (spinning and nonspinning reserve), and frequency regulation. Operating reserves, as they represent availability of power, can also be considered capacity, and are bought and sold on an MW basis. Regulation or frequency regulation is very fast response to ensure that grid frequency (Hz) is maintained at nominal frequency, 60 Hz in North America and 50 Hz in most other regions of the world.

After more than two decades, a multi-settlement market design with nodal market models is generally used in North America, with individual market variations [6]. Australia uses a one-settlement market system [7]. Figure 20.1 shows the high-level multi-settlement U.S. design, with the time frame ranging from periods that allow for planning to real-time (RT) grid operations [8].

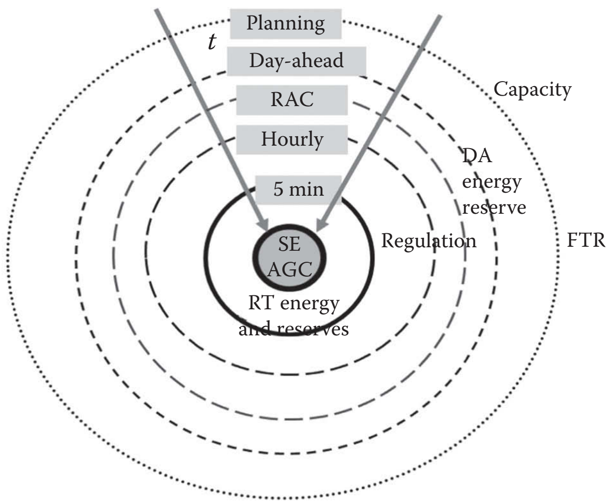

FIGURE 20.1 High-level design of the multi-settlement market in the USA. (H. Chen, *Power Grid Operation in a Market Environment: Economic Efficiency and Risk Mitigation*. © 2016. Wiley-IEEE Press. All rights reserved. With permission.)

20.1.2 Wholesale Energy Markets

Energy is typically bought and sold at a "competitive price," called the locational marginal price (LMP). The generator is paid the LMP, and the customer pays the LMP. The general model used to operate the grid is summarized as a process of *security-constrained economic dispatch*. This means that the energy resources (generators, demand-side management, DERs, etc.) must be operated to ensure that reliability (grid security) is maintained, while the energy resources are committed and dispatched (turned on/off, and ramped up/down) based on economics. The economics can be simplified to the case where progressively higher priced resources, each with a bid-price, are placed in a *bid-stack* from least to most expensive. Least-cost (bid price) energy resources are dispatched first. The ISO/RTO uses the bid-stack of available energy resources as needed in order to meet the constantly varying loads on the grid. In a given day, particularly when peak loads are relatively low, the highest bid-price generators may not be used at all. There are a set of dispatch rules promulgated in each ISO/RTO to provide sufficient transparency for market participants.

The differences in LMPs for energy, depending on the costs to provide the energy at specific grid locations, are subject to reliability requirements. The so-called criteria violations that would violate NERC rules must be avoided, as these would jeopardize reliability, most typically by overloading a transmission line or other transmission facilities, such as transformers. To avoid criteria violations, typically lower-priced generators must reduce output (or be taken off-line), while other more expensive generators must increase output (or be added to the grid), in order to avoid threats to grid reliability. This is called redispatch, since least-cost dispatch cannot be achieved for such grid configurations and energy resource locations. The difference in price between the preferred lower cost resource and the required higher cost resource, the delta, serves as a measure of increased costs, in grid terms a "congestion price." This congestion price, resulting from redispatch of the generation mix, is then the reference competitive price that "clears the market" for that location. Absent congestion at a location, redispatch is not required, and the congestion price component is zero. Grid losses are also added to the price at this location to represent "all-in" LMPs at each price-node (P-node).

LMPs are locational, time-specific, and generally have three components: energy, losses, and congestion. If the grid is not congested, the congestion component is zero. Under marginal cost pricing, there is also a loss component in LMPs.

The LMP drivers are then defined based on (1) the extent to which a particular P-node requires electricity, that is, the load at this location, (2) the availability of transmission (capacity) to serve the customer(s) at that P-node, and (3) the cost (bid-price) of generation that can satisfy local grid reliability needs. When congestion prices are consistently high at a particular location, it usually signals that additional transmission investment can eliminate these congestion prices.

This then presents an investment trade-off between the extent that congestion occurs and the costs to resolve the transmission constraint or potential criteria violation. It shows that ultimately transmission investments are a direct substitute for generation, and unregulated transmission investments can compete with unregulated generation investments [9].

In a summary, LMPs encourage the efficient use of the system and enhance reliability. In the long run, this market structure enables new generation sources to be located in areas where they will receive higher prices, signals large new users of electricity to locate where they can buy lower-cost power, and encourages the construction of new transmission facilities in areas where congestion is common in order to reduce the financial impact of congestion on electricity prices.

Under two-settlement systems, energy markets have both day-ahead (DA) markets and RT balancing markets. DA markets are cleared before each operating day, based on bid-in demand submitted by market participants. Both physical bids (generation offers and demand bids) and pure financial bids, known as "virtual bids," participate in DA markets. Virtual bids help with the convergence between DA markets and RT markets.[1] The cleared DA hourly real power schedules and prices represent binding economic commitments to market participants. DA markets secure the majority of the resources for the operating day. The market clearing timelines vary for individual markets. Rules for generation offers may also vary in different markets. Generation offer information includes availability, price and cost offers, operating parameters, such as ramp rates, startup time, shut down time, minimum run time, minimum down time, minimum and maximum generation, and so on. The system topology is based on scheduled transmission outages.

RT markets often co-optimize energy and reserves (such as regulation, primary reserves, contingency reserves) by sending out dispatch and price signals approximately every 5 min. The dispatch is based on current system status, represented by a State Estimator (SE) solution, forecasted load, generators' offer information, scheduled transactions, and system topology. There is no virtual bid in the RT market. The resulting dispatch and price signals are sent to market participants to balance system load, maintain system reserves, and resolve transmission congestions.

Both DA and RT market clearing are otherwise termed bid-based Security Constrained Unit Commitment (SCUC) and Security Constrained Economic Dispatch (SCED) processes. The objective is to ensure total production cost minimization, or total social (economic) surplus maximization, based on power balance constraint, branch flow limits, transfer interface limits, and other transmission-related limits, such as transmission security constraints. Reserve requirement constraints are also included to align with system reliability criteria and practices.

Economic unit scheduling and feasibility analysis are the two key components of the DA market. Feasibility analysis is required to ensure the physical deliverability of the 24 hourly DA schedules, and checks the network security of the economic scheduling results. Once a limit or criteria violation is identified, the corresponding constraints are then enforced into the next SCUC/SCED run. The hourly constraint sensitivities are inputted to the SCUC/SCED. These markets also determine the amounts of marginal electricity losses. To do this, hourly loss sensitivities are fed into the SCUC/SCED as well. The iteration between SCUC/SCED and the feasibility analysis is complete when no more limit violations are detected. The solution method details can be found in the study by Chen [8].

In the RT market, based on the SE solution, an AC power flow is performed for RT contingency analysis. The constraint sensitivities and loss sensitivities at the current system operation point are provided to SCUC/SCED. Binding transmission constraints indicate whether generation redispatch is actually required to relieve the congestions.

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[1] There is controversy over virtual bidding for power as some claim this invites opportunistic market gaming.

In both the DA and RT markets, LMPs are generated as part of the SCED process and determined by the shadow prices of the power balance constraints and transmission security constraints.

20.1.3 Wholesale Capacity Markets

Capacity markets were created to make sure that there will be sufficient capacity to meet future peak load plus reserve margin [10–13]. They address the "missing money" issue, and create long-term price signals that attract investments for both maintaining existing capacity resources and encouraging the development of new capacity resources. To reflect limited transfer capabilities, locational capacity requirements are often set for capacity zones. Some markets, for example, PJM [10] and New England [4], have long-term forward capacity markets (3 years forward) to provide greater information into the reliability situation with sufficient lead-time so that new entrants can compete against each other and avoid overbuilding. Long-term capacity markets could also lead to higher prices because generators face a higher risk in committing to produce electricity many years in the future.

Performance-based capacity markets were recently implemented to better reward well-performing power plants and demand-side resources, which also penalize those that fail to perform when needed most [10,11]. This is to ensure that a reliable supply will be available during extreme weather or other system emergencies.

Some regions do not have capacity markets, but have resource adequacy (RA) programs, and rely on market price response, called *scarcity pricing*, to ensure long-term reliability [14,15,16]. The extent to which scarcity pricing can reduce grid loads—through price response—depends on price caps in the energy market. Higher price caps allow price response to have a greater impact on load reduction, ideally creating a "self-regulating" capacity response.

20.1.4 Wholesale Ancillary Service Markets

Specific ASs are required by NERC, including operating reserves and frequency regulation. ASs are important to support the transmission of electric power and maintain reliable operations of the system. These services generally include frequency control, spinning reserve, nonspinning reserve, replacement reserve, voltage support, and black start. Voltage support and black-start capability (from system collapse) are also unbundled as ASs in some ISOs/RTOs. Currently, these two services are still cost-based and do not use market-based price determination.

Maintaining operating reserves is essential in system operation to mitigate uncertainties caused by unit tripping, sudden load changes, and so on. Reserve markets are created to provide a market-based mechanism for the procurement of reserves on the system. Transparent price signals incentivize resources to provide flexible capability to the grid. In most U.S. markets, reserves are jointly scheduled with energy in the DA markets and RT markets. Different markets have different types of reserve products co-optimized with energy [17].

Reserve requirements are mostly predetermined based on historical data, corresponding to operation practices, for example, $N-1$ or $N-2$ contingency criteria. To address reserve deliverability issues, some markets have zonal reserve requirements, either statically or dynamically, based on actual interface flow and limits. Reserve clearing prices are derived from the shadow prices of the reserve requirement constraints. Reserve demand curves are usually defined for pricing reserves under scarcity [18].

To be in compliance with FERC Order 755 [19], performance-based regulation markets have been implemented. Resources are not only paid for their regulating capacity, they are also paid for their actual performance.

In February 2015, FERC issued a notice of proposed rulemaking (NOPR) to allow third-party provision on Primary Frequency Response Service to Balancing Authorities that may have a need for such a product to meet NERC Standard BAL-003-1 obligations [20,21]. This opens the door for market-based Primary Frequency Response products.

20.1.5 Demand Response and Storage—From Wholesale and Retail Perspectives

Wholesale markets enable retail participants to compete directly with DR, storage, and even energy efficiency (EE) in some ISOs/RTOs. The retail grid-edge, on the customer side of the meter, is increasingly leveraged by smart energy management systems that optimize customer loads and supply costs using DR, storage, EE, and PVs with smart inverters. Retail grid-edge optimization then aims to reduce wholesale supply costs, which will increasingly use strategies to reduce wholesale peak, ramping, load-following, and AS costs. This direct competition from the retail grid-edge bodes to make traditional large-scale fossil generation less economic. At the same time, DR, storage, and optimized retail grid-edge providers look to be sources of flexible wholesale grid needs.

Customer-based DR and storage can be used as multifunctional tools in wholesale competition as they have option value and can satisfy a host of functions. Dispatch of DR to precool and preheat buildings, for example, provides *virtual storage*, which will at times compete with battery storage. With greater deployment of variable renewable resources, especially solar PVs and wind, grids will need to accommodate more flexible load and storage resources. DR has been used to reduce and shift loads, but with newer technologies it can provide ramping, load-following, and even more rapid frequency response. The California DR potential study shows that there will be at least 5.2 GW of RA and 5.7 GW of DR for peak load shedding available in the state by 2025 [22]. As that study explains, a host of new DR capabilities will be needed, which can be categorized as services to provide "Shape, Shift, Shed, and Shimmy" [22]. Shape reshapes DR load profiles through price response or behavioral programs. Shift is the movement of energy consumption from times of high demand to times when there are surplus renewables. Shed is curtailment of loads to provide peak capacity, system emergency, and respond to contingency events. Shimmy is dynamic adjustment of demand ranging from seconds to an hour, to address ramping, load-following, and disturbances. While the study focuses on DR services for the wholesale market, it also takes into account DR for the retail market. The study findings, using their service categories of "Shape, Shift, Shed, and Shimmy," is summarized as follows:

- The Shape-Shift DR potential is approximately 1.8 gigawatt-hours (GWh) per day for 2025.
- Under a "conventional system peak DR" price referent cost-effectiveness framework, our findings suggest that Shed DR resources could provide ~4.2 GW of RA credit capacity in 2025.
- The Shape-Shed DR results are additive and provide an additional 1 GW of reduction (labeled "TOU/CPP"), for a total of 5.2 GW.
- Our results indicate that Shimmy load following resources are cost-competitive for ~350 MW at about $50/kW-year. Shimmy regulation DR is shown to be cost-competitive up to approximately $85/kW-year in a medium scenario, resulting in a DR potential of ~450 MW across all three California Investor Owned Utilities (IOUs).

These magnitudes of DR are substantially greater than what has been shown in prior studies of traditional DR potential. Certainly, this suggests that wholesale and distribution markets will be increasingly focused on bringing DR to customers through market platforms.

Certainly, this also demonstrates that the portfolio of behind-the-meter DR and storage-like resources is expanding for use in both wholesale and retail markets. Strategic charging of plug-in electric vehicles (PEVs), a different form of demand-side management, also shows major promise. PEVs are seen as resources that can provide vehicle-to-grid storage services, using the batteries deployed in these vehicles. Storage batteries also look promising for wholesale competition as storage costs continue to decline, much as the costs of photovoltaic panels, which can be used with batteries, have plummeted. Grid-based DR and storage will increasingly be used *comparably*—directly compared with, and valued with, supply-side generation. Smart-grid systems, big data, digitization, high-performance computing, and software developments will further enhance the use of DR and storage, both directly in wholesale grids and on the customer-side of the meter.

With the advancement of storage technologies and attractive market design, energy storage has become an excellent frequency control resources, especially in the markets where they are compensated correspondingly for their fast response performances [3]. In order to maximize the value of battery storage, however, its *option value* needs to be exercised, which requires that the resource be used for multiple market and retail applications.

20.1.6 Wholesale Market Response to Net Load—Distributed and Large-Scale Impacts

Where large amounts of variable renewable resources are interconnected to an ISO/RTO, as in California and Midwest ISO (MISO), benefits are found with grid expansion to more economically absorb these variable resources. In general, larger grid systems simply have more flexible resources that can be deployed when variable renewables either under or overproduce. Increasingly the focus then is on net load, including the load net of the renewable, self-generation, and customer management that occurs during each period.

In California, for example, from spring to fall, the net load ramps up early in the morning and then rapidly declines as the solar PV production comes on line. This eliminates the traditional peak load (noon to 6 pm), but then causes a later peak from 7 to 9 pm. It is not the traditional load that must be balanced against supply, but the net load that must be balanced against all other supply and available demand-side resources. An important consequence is that the high summer peak season (noon to 6 pm) no longer exists in California. This creates major impacts on traditional thermal electric generators that count on high-peak wholesale market prices to provide profits that accrue only during traditional summer peak periods.

20.1.7 Response to Supply–Demand in Terms of Net Load

The supply-demand market response to the changing net load conditions is most troublesome for fossil fuel generation. The net-load condition is now being used in places, such as California, where renewable sources are increasingly prominent. Fossil resources have significant variable costs, even now with dramatically lower fossil fuel prices. Variable renewable resources have very little, if any, variable costs. Moreover, variable energy resources are in essence *infra-marginal*—produce power at costs that are below the marginal costs of fossil generation when fossil resources are *on the margin*. Persistent reductions in the costs of variable renewable resources suggest there will be a much greater need for flexible resources that can respond when solar and wind do not perform. Solar and wind generation create highly variable conditions, which require more ramping and flexible resources to respond. Flexible resources are then directly compared to the net-load curve to determine feasible schedules for an ISO/RTO. Of significant concern to ISO/RTO grid operators are intra-hour (within-hour) conditions when ramping resources may be insufficient in specific circumstances. These conditions adversely impact grid reliability.

20.1.8 Market Response to the Retail Grid-Edge—Smart Grid Engaged

Wholesale markets enable retail participants in DR, storage, and even EE in some ISOs/RTOs, to compete directly. The retail grid-edge, on the customer side of the meter, is increasingly leveraged by smart energy management systems that optimize customer loads and supply costs using DR, storage, EE, and PVs with smart inverters. Retail grid-edge optimization then aims to reduce wholesale supply costs, which will increasingly use strategies to reduce wholesale peak, ramping, load-following, and AS costs. This direct competition from the retail grid-edge bodes to make traditional large-scale fossil generation less economic. At the same time, DR, storage, and optimized retail grid-edge providers look to be sources of flexible wholesale grid needs.

20.1.9 Ramping and Load Following Where Renewables Dominate?

With the increased penetration of intermittent renewable resources, such as wind and solar, which are highly variable, difficult to dispatch for the various wholesale market services, and hard to forecast as well, the smart grid will need the capability to ramp supply quickly to accommodate the increased uncertainty caused by highly variable renewable resources. In some systems, cloud covering could become the largest contingency.

To align with system operation needs, some markets are considering new reserve products, such as fast-ramping products—in seconds to one minute—to ensure sufficient ramping capability to handle expected contingencies and uncertainties, particularly in CAISO and MISO, which have large amounts of variable renewable generation.

Planning adequate reserves is important to system control, especially with increased renewable penetration. For example, the regulation reserve requirement may need to be increased to account for a larger amount of fluctuating wind power or solar power. In ERCOT, forecasted wind output is factored in setting the regulating and contingency reserve requirements. Reserve requirements are being reevaluated and adjusted in ISOs/RTOs. Dynamic reserve requirements have also been extensively discussed to capture updated system needs.

20.1.10 Market Sustainability Where Distributed and Other Renewable Resources Dominate

Where distributed and other renewables become a large part of the resource mix, thermal generation will cease being *on the margin*, and will no longer determine market prices. This is occurring in California where solar PVs are the predominant resource during what was previously the summer peak period. Bidding into wholesale ISO/RTO markets, zero-priced, even negatively priced bids on the margin severely depress market prices. Alternatively, based on the net load curve (discussed earlier), the demand for electricity during these times becomes much lower, which likewise will depress market prices. This brings into question the sustainability of fossil-based generation in ISO/RTO markets when the proportion of variable renewables becomes large, at least during traditional peak periods.

The question is whether the *writing is on the wall*—will wholesale markets continue as we know them? LMP markets were largely designed to resolve market prices based on marginal costs of thermal generation. LMPs have and will increasingly decline as more variable renewable resources are integrated into ISOs/RTOs. How can we use existing ISO/RTO market design to monetize other resources, including smart grid resources that are behind-the-meter? If thermal resources are not on the margin, since zero-variable-priced renewable resources are *infra-marginal* by comparison, how will fossil resources continue to be economic, that is, fully monetized?

Similar questions should be raised about monetizing demand-side resources, which are measured against fossil resources both in terms of LMPs and capacity prices. PJM's capacity market is largely based on the capital cost of a market-based combustion turbine (CT) proxy. With greater use of DR and DERs, the question will be asked: Why use a CT proxy to value these demand-side resources? With greater use of carbon-free or GHG-free resources, use of a CT proxy to monetize DER value may also be considered suspect. Hence, both for LMPs and for capacity, the question is whether wholesale electricity markets must be fundamentally redesigned.

Discussions about monetizing DERs at the retail level raise similar but possibly more complex questions when ISO/RTO markets must be part of the cost minimization equation. Also related are dialogs about *transactive energy*, which is meant to enable integration of the so-called *platform economics* that enable plug-and-play solutions at the customer and distribution levels. These transactive energy topics are discussed in more detail in the next chapter of this book.

20.2 DISTRIBUTED ENERGY—RESOURCE PLANNING AND MARKETS

With smart grid, the planning, investment, and operation of the distribution system change dramatically. Historically, utility investment in distribution systems ensured circuit capacity was adequate to deliver power from the bulk grid to the customer. Now, customer-owned solar PV delivers power to the distribution system, and DR from customers provides energy and capacity reduction at the bulk grid level. A host of other distributed resources, including fuel cells and energy storage, provide power that is injected at the low-voltage level and may create reverse power flows on the grid, moving power away from the customer. Platforms are being designed to host DERs at lower voltage levels to explicitly supply customers at the distribution level and to wholesale markets. An immediate objective is to monetize the *option value* of DERs, which translates to more flexible DER uses in multiple markets. Multiple opportunities have emerged, and more will result as DER needs increase across the grid. We examine both the current context and future opportunities to provide greater understanding of these new resources.

20.2.1 Context for New Distribution Planning—"Nowcasting" to the Next Decade

We first analyze what is currently in place that can form the basis for a transition to a more complete smart grid future. Utility web sites now offer smart rates, comprehensive energy upgrades, smart DR, a point system to calculate customer incentives, and financing for certain DER packages [23]. There are a multitude of demand-side energy resources, but they are organized in silos–EE, rate options, DR, and storage options are all presented independently in separate utility programs [24].

These separate silos are largely unchanged over the last 5 years or more. Information from smart meters has been available and is little used by the utilities. Capabilities include "stream-my-data" and use of home area network devices—smart thermostats, control equipment, and itemized energy usage. At the same time, utilities more than ever need grid *situational awareness* and greater control of DERs at the customer level. The array of DER options is already large and soon would be dizzying. The software to use them is here, but the communications and other capabilities are not quite at hand to choreograph clean energy results.

Many utilities are surrounded by a plethora of big data—AMI data, SCADA data, and market data. Data management, modeling, analytics, and *right metrics*[2] can enable DER and grid optimization. There is increasing awareness that additional benefits are available from increased smart grid granularity, which more fully defines grid physical limits and accordingly the economic benefits and costs. New methods are needed for assessing benefits and costs, especially in defining locational DER benefits. In California, Distribution Resource Plans are being offered to first define some of the operational characteristics of the distribution grid. This is an essential first step in maximizing the value of DERs. For example, integration capacity analysis (ICA), based on load-flow analysis, can be used to define *hosting capacity*—the amount of DER capacity that can be added to the system. A key consideration in evaluating the ICA is that when ICA incorporates tailored packages of DERs, including EE and DR, hosting capacity can be further increased. This potential for greater hosting is being ignored, however, in the haste to define locational advantages as soon as possible.

One critical question is how to specify location-specific DER packages for customers, fully valued to enable "one-stop customer shopping." This would be a tool to enable consumers to choose from packages of DERs, as well as to have a full suite of choices, incentives, and financing. In this light, what immediate steps seem appropriate? A critical step in the California agenda is to use Locational Net Benefit Analysis (LNBA) to fully define the economic value of DERs at all grid locations. Integration and optimization of the full suite of benefits at the customer level results in

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[2] These can include the fully integrated and optimized net locational benefits from planning and from operations.

200% to 500% (2× to 5×) greater benefits from DERs compared to traditional spreadsheet formulations of average DER cost-effectiveness. This requires greater data granularity, use of customer-specific AMI data, and more detailed customer load-curve analysis.

These more granular results reveal additional benefits, in significant part, by "de-averaging" inputs and results.[3] Targeted focus on high-use and high-peak customers further "de-averages" to enable capture of greater benefits. Beyond these steps, the targeting of packages of DERs to specific distribution locations can solve grid constraints (load-flow), reduce capital costs, and add 100%–200% in net benefit terms. To compound these benefits, a statistical approach can be used to capture the correlation (covariance) of weather, loads, prices, and DER performance. Conservatively, this is shown to net up to 60% greater benefits, for example, for dispatchable DR in Nevada [25,26]. And finally, with distributed locational optimization of the DER portfolio both in planning and in operations, another 1× to 2× (100%–200%) in added net benefits is expected.

For these reasons, the calculation of LNBA results, including portfolio optimization in operations, should be based on granular load-flow and properly stacked locational marginal costs, which are discussed later in this section. Significant advances in valuation methodology reflect greater granularity and advanced computational methods. These methods significantly improve upon previously used spreadsheet models. The net benefits of operationally coordinated, locationally optimized, DER packages, targeted to customers at specific grid locations, seem to exceed most expectations. In contrast, current spreadsheet practices continue to use average deterministic (single-point assumption) benefits, siloed DER programs, ignore additional benefits due to integration and operational coordination, rely on average inputs, and hence fail to more fully reflect specific locational benefits.

The future calls for the acceleration of DER adoption, particularly in light of the need to more rapidly reduce greenhouse gas (GHG) levels. As greater value (such as carbon pricing) is attributed to GHG mitigation, these added benefits will further drive DER cost-effectiveness.

More complete monetization of DER integration and optimization is a critical next step. This can be accomplished by fully and assiduously defining a standard practice that incorporates the *all-in* granular, locational, incremental, and marginal costs to fully reflect appropriate values [27]. DERs at locations, including integrated and optimized DER packages, can then be directly used to value each resource (CapEx and OpEx) decision at the planning stage.

This is consistent with California's SB350 legislation that requires integrated resource planning. The intent of this legislation is to collapse the clean energy silos, accelerate renewables (to be 50% of the portfolio), double the use of EE and peak load reduction, determine the value of air quality costs and benefits, and accelerate pollution mitigation.[4] The integrated resource planning of old (1980s) was based on the best case of hourly generation marginal costs, where average transmission and distribution marginal costs were added [28,29]. Implied in the SB350 legislation is the assessment of interactive impacts among DER resources, reflected in distributed marginal costs (DMCs), which can be more fully defined with more granular data and analytics that are increasingly available.

There are a specific set of actions that should be taken now in order to maximize the benefit of DER and speed its deployment in optimal locations. These actions include:

- Optimize customer constraints, distribution constraints, and bulk grid conditions in order to fully define appropriate co-optimization benefits and costs.
- Deployed AMI systems should provide communications access for the operational coordination of DERs.

[3] California cost-effectiveness and resource valuation generally use only 16 average load shapes per year in DER cost-effectiveness calculations. Spreadsheet calculations severely limit the use of data, in contrast to more expansive computational methods. More modern cost-effectiveness calculations use at least 576 custom load shapes, and include multiple covariance effects.

[4] https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB350. This legislation, in part, creates the California Public Utilities Code Section 454.52, which requires an integrated resource plan.

- Refinements are needed to allocate customer DER incentives, which must also work in conjunction with customer financing of DERs. The approach proffered in EE to use rolling portfolios most likely needs to be applied to DER integration and optimization, at the customer level.

20.2.2 Real Innovation in Stacked Value Compiled as All-In Distribution Marginal Costs

The formulation of DMCs is necessarily a bottom-up process. It is based on “all-in” incremental cost differences, and comparison with DER and without DER scenarios. The net effects of DERs depend directly on the forecasts and the analytics at the grid-edge, which is at the customer premise, and extend through the distribution and bulk power systems. These forecasts begin at distribution line-sections or nodes and proceed to substations and subtransmission. This suggests the analytics directly reflect loads at the service transformer or the customer’s premise. DMCs provide the equivalent of avoided (deferral) cost-based measurements that are locational, geospatially specific, with resolution down to the customer or the line-section level. To estimate net benefits in future years, all future costs must be determined as part of a base case, pre-DER scenario.

The savings from DER adoption—determined in a *with-and-without* analysis—can then be put into net-present-value or Economic Carrying Charge Rate terms. Other components are the forecasted distribution costs in the base case. These are the equivalent of locational future cost curves, analogous to those used on the supply side. Instead of power plants being deferrable, here we focus on deferrable substation capacity, circuit capacity, voltage impacts, impacts from power factor changes, and other engineering-oriented cost-based factors that determine DER hosting.

Load-flow analysis is also used to determine DER hosting capacity, and identifies the physical grid capabilities, which include conditions when reliability, voltage, and VAr limits are exceeded. Based on load-flow analysis, marginal (incremental) cost analysis is required to determine the most economic, least cost mix of DERs, with reference to the line segment, circuit, or substation, that provides the least cost outcomes, within the technical limits of the DER load-flow results. In some cases, additional spending on the grid may be optimal, such as to mitigate overvoltage with clustered PVs. These and other trade-offs can be directly analyzed to determine the overall least cost plan for implementing optimal DER portfolios.

DMCs can be separately defined, or combined, to capture value in kWh, kW, and kVAr terms. As with supply-side marginal costs, DMCs are needed to define variable short-term needs (5 min, hourly) and long-term capacity needs (1–20 years). To be accurate, DMCs require granular load forecasting coupled with software and data to predict the timing and magnitude of all related grid needs. Locational integration through power flow modeling must be coupled with economic optimization methods to determine the least cost DER mix with greater certainty. The use of DMCs enables direct comparison of the options to address specific grid needs, either through a DER-based solution or a traditional utility solution. Packages of DERs can then be integrated and optimized directly with use of respective DMCs. In this case, we are comparing the respective DMCs for each resource option based on the classic *with-and-without* analysis.

Fully formulated DMCs—which are entirely situation-specific—represent the marginal or avoided cost of alternative DER resources. Complexities remain to fully optimize alternative DER packages that can defer more costly distribution equipment. But this process can be automated and improved over time, just as simpler supply side comparisons to DERs became more advanced in the 1980s and 1990s. An advantage with this approach is that the revenue and earnings implications of DERs are easily defined with greater certainty. This can streamline the calculation of potential utility and third-party earnings, which seems especially useful to evaluate optional business models and programs. Earnings can be simply estimated as a percentage of shared savings, an approach used to define earnings for EE.

Recent analysis shows that optimal locational DER packages can directly defer major distribution capital costs (planned assets) by operating in specific ways over specific hourly periods [30–34]. There is complexity in optimizing alternative packages of DERs, though this is much simplified by the direct comparison of DMCs for resources that may defer more costly distribution/supply options. In short, this optimization can be more easily automated and transparent with the use of DMCs. DER will be viewed more positively if it is both the *least-cost* option from the utility perspective[5] and is cost-effective based on the *Total Resource Cost* test. More generally, we can use DMCs to provide a natural *loading-order* based on lowest net marginal costs to build DER packages and portfolios. This will ensure that the most economic options are deployed [35], consistent with grid reliability needs and customer-driven needs to maximize value.

Though termed locational *Distribution* Marginal Costs, the full set of *wholesale* locational components that represent kWh and kW values should also be fully included to determine total DMC values.[6] This is critical as almost all DERs have direct supply-side impacts. The combination then enables distribution grid options and wholesale supply options to be directly compared and jointly co-optimized. With the use of fully compiled DMCs, all stakeholders can benefit from more accurate distribution of resource planning decisions. The expected benefits of the DMC approach include more effective locational investments, full management of electric vehicle charging, more effective rate-design, optimized DER programs for customers and the grid, greater reliability and unbundled reliability services, and enhanced customer adoption [37,38].

DMCs can be split into two types and four categories: fixed versus variable and grid versus supply (Figure 20.2). Fixed costs are analogous to capacity credits and variable costs are analogous to energy credits. Supply costs generally remain as per KW/KWh values; however, grid costs can occur in per KVA or per kVAr terms. There is no single DMC value, per se, though one could foresee a context where 2 DMCs were feasible, a long-run fixed cost ($ per KVA) and a short-run hourly or 5 min ($ per KVAh value). These would include both the real and reactive components.

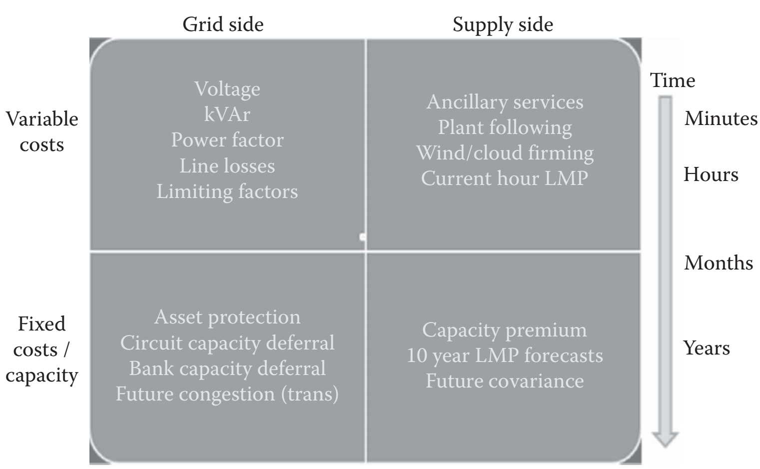

FIGURE 20.2 Four dimensions of DMCs. (From T. Osterhus, Distribution marginal prices (DMPs)" Update #6, *Integral Analytics,* 2014; R. Stevie and T. Osterhus, *DMP Methodology Applied to Value of Solar,* New York REV Proceedings, Matter No. 15-02703, Case 15-E-0751; © 2016 Integral Analytics. All Rights Reserved. With permission.)

[5] In California Standard Practice Manual terms, this means the Program Administrator Test from the utility revenue requirements perspective.

[6] Wholesale kVAr can also be added to DMC kVAr, though it will be fairly small in comparison, except for the most exceptional circumstances, such as where Reliability Must Run (RMR) generation is prescribed for Volt/VAr support.

Fully formulated DMCs can be used in the short term, as minute-by-minute values for market trading, or forecasted out many years to provide forward curves.[7] As shown in Figure 20.2, based on the four DMC dimensions, a spectrum of complementary valuation methods can be used. In different terms, we can combine DMCs that represent corresponding DER values to directly compare these options with underlying *but-for* distribution values or combined distribution and wholesale (delivered energy/power) values. This allows nuanced locational and broader wholesale values to be accurately compiled and used to compare all competing resources on a level playing field.

Geospatial distribution values and broader locational wholesale values can be accurately compiled and used to compare all competing resources on a level playing field. In different terms, nuanced locational DMC values can be used to compare all competing resources on a level playing field, based on a common framework. The potential is to combine DMCs that represent corresponding DER values to directly compare these options with underlying *but-for* distribution values or combined distribution and wholesale (delivered energy/power) values. This further enables most all related energy choices to be directly compared and thus rationalized.

Accurately compiled DMCs can be compared *with and without* DER customer incentives, rate options, and even broader scale tariff structures. Compiled DMCs, with various DER options, can also be used to value the use of microgrids within an otherwise contiguous distribution system.

20.2.3 The Components of DMC

Had utilities used DMC as the basis for Heating, Ventilation, and Air Conditioning (HVAC) incentives a decade ago, it is likely that HVAC manufacturers would not have chased the higher kW/kWh efficiency SEER levels, at the expense of costing utilities more in kVAr via the poor power factors caused by the redesigned systems. The utility rebates were solely kW/kWh focused, and the HVAC industry followed the money in their equipment designs. It is not clear if net energy savings is now occurring at the expense of the increased “hidden” costs of the poorer power factor caused by the newer HVAC units.

Using the DMC, optimal PV, DR and storage locations and the magnitude of each deployment can be identified for service transformers, line sections, or regions across the circuits. This level of specificity is only possible using actual, granular load data, and consistent with proven methods and probabilistic characterization of risk (covariance) using actual load history, weather data, and prices.

The physical and operational characteristics of the locational distribution system determine the manner in which DERs can benefit or harm the existing infrastructure. There are a number of characteristics that determine the overall DER impact including, but not limited to:

- The voltage class, radial versus networked arrangement, conductor type, impedance, geographic topology of the feeder, regulation equipment used, and operating characteristics such as reactive power management and protection schemes
- The amount, location, and timing of the DER—when it should be installed—relative to network infrastructure investments
- The DER characteristics, such as inverter-based versus machine-based DER, fixed versus variable output, and the time at which the DER provides power or energy to the grid (coincidence with load)

Several core elements are needed to fully measure the integrated benefits of DER. The primary element of the analysis is an accurate spatial forecast of energy demand by class, DER adoption, and other expected changes to the system. This forecast is needed to identify and quantify the impacts

[7] When DMCs are forecasted out for 10 years, they become the “forward tenders” often described by transactive energy advocates. DMC methods depart from transactive energy propositions, however, in that DMCs are largely cost-based, not market-based.

of various levels of additional DER on the distribution system and on the bulk power system. The analysis also includes an assessment of hosting capacity or the level of DER interconnection that can be locally accommodated without exceeding distribution system safety or power quality limits. Additionally, several categories of avoided cost are required to optimally site DERs. The analysis will consider energy, capacity, and reliability costs, both at the bulk power level from the generator to the substation, and distribution level benefits from the substation to the meter.

Simple rules can be used to further the dimension DMCs. The proper dimensioning of DMCs is essential to establish comparable *apples-to-apples* valuations across resource options and across locations. DMCs are currently used to enable granular optimization, particularly to identify specific resource needs down to the circuit or customer level. This is possible through the integration of both supply-side and distribution-side marginal/avoided costs, including kVAr (power factor and voltage), which is required to resolve distribution needs.

The appropriate value capture represented in DMC is directly related to the cost avoided. In 1970, Alfred Kahn [39] explained a set of problems with defining marginal costs that are still relevant: (1) proper specification of the time perspective and primary causality, including integration of short-run and long-run components, (2) proper specification of the incremental block/unit, and (3) how to identify the marginal costs in terms of the incremental, causal cost responsibility, particularly if significant costs are common (with functions of joint supply and separate demand).

In the case of DMCs, the distribution expansion plan largely serves as the guide to determine potentially avoidable grid and market costs, provides the time dimensions (up to 20 years) to capture respective avoided cost values, uses a consistent incremental block/unit, and defines causal cost responsibility. It should be based on granular load forecast and related power flow results. As many utilities update their 10-year distribution plans at least yearly, the distribution components of DMCs seem to be reasonably well defined. This importantly allows for adjustments to utility, customer, or vendor incentives to better motivate pursuit of the desired least cost outcomes. DER resources, such as PV and storage, are 20-year decisions. To intelligently establish policy surrounding these resources, a long-term forecast of their benefits and costs are required. Ignoring these long-run cost impacts, particularly at times when the nature and use of the existing grid are in flux, is risky to say the least. Even a guess at the long-term forward cost curves for the distribution impacts is better than existing policy, which largely motivates siloed PV adoption via the use of existing tariffs (past costs). It is analogous to driving forward with only the use of a rear view mirror. The wholesale or supply components, likewise, will change and evolve significantly through this process. Importantly, the DMC analysis can enable joint co-optimization around both the distribution grid and bulk-grid supply.

Still, the application of specific DMC components for kWh, kW, and kVAr requires careful parsing, which requires proper matching of the specific avoidable resource needs identified. The wholesale energy/power (kWh/kW) cases present little issue. The newer world of distribution-related marginal or avoided costs, however, presents little in terms of track record to go on. The easy cases are with proposed distribution resource plan solutions, which are more operationally focused on DER integration at the hourly level, or next day, at most. The more important and consequential need is to get ahead of the risks, and signal locational value to DERs, where more than 20-year-old equipment and resources are being permanently placed. These cases call for separate DMC metrics, but the long-run locational capacity value may well be the most important dimension.

Intuitively, where solar and storage are in place, the energy from solar is largely for "free" from the sun—with little or no short-run marginal cost—leaving the bulk of the utility planning problem to be a focus on long-term capacity planning. To be sure, short-run DER integration at the operational level is critical, but much of the current focus and discussion seems disproportionately on short-term operational integration; it lacks focused considerations on long-run avoidable capacity costs. Both, of course, matter.

When two or more of these dimensions are combined, in concept the concerns of Alfred Kahn may arise. This suggests concerted focus on the time frame (short-term variable and long-term fixed costs), the increment involved, and direct causality. Direct causality must be properly derived from engineering models tied to load forecasting, long-term cost estimation, and the economics of cost-benefit optimization. To capture the avoided costs of a specific distribution resource, it may make sense to combine two or more of the respective DMC values (e.g., kW and kVAr), for ease of implementation or market fluidity. With hourly or subhourly DMCs that represent a specific avoidable locational distribution resource, this combination of attributes amounts to a locational asset-specific DMC. For PVs, the long-term forward tender value will differ from that of storage, EE, and other DERs.

To test whether a package of DERs can avoid a specific distribution asset, merely compare the DMC for the package (*ex anti*) to the DMC for the distribution asset (*ex post*). With the extensive data bases and new modeling available, asset-specific DMCs can be accurately compared with DMCs for tailored DER packages with right dimensioning. Geospatial DMC modeling and optimization enable dimensional checks to ensure comparable value comparisons, which enable fast and accurate resource plan development.

The proper compilation of DMCs requires that each *with-and-without* case be comparable and accurately represent the "*but-for"* circumstances. This is essential to properly determine the DMC differences that will drive primary results, and, even more so, optimization results. Importantly then, two critical conditions must be satisfied:

1. Traditional resources must indeed be deferrable by DER resources, using accurate forecasting and cost analysis methods (comparable or better than traditional supply-side avoided cost-estimates) with causality, using correct dimensions to net this value.
2. Deferral value must be properly represented over time, time periods must match between traditional and alternative resources, and magnitudes must match, such that hourly load shape or savings shapes are made to be comparable, and new cost factors unique to the grid are standardized, including ramp rates, intermittency, voltage, power factor, and reach/protection.

At locations, this requires comparable well-designed matching of the traditional distribution and supply-side resources avoided compared to the appropriate package(s) of DER resources, and possibly the addition of new costs from new smart grid equipment (e.g., overvoltage mitigation from "too much solar" in a location). These are the modern requirements that extend Alfred Kahn's much earlier recommendations on marginal cost pricing. Just as Kahn and many others have suggested, with proper compilation of marginal costs, resource options can be directly compared and chosen, either for short-term purposes or to determine long-term choices.

The principles remain unchanged. As with traditional integrated resource plans, one must forecast loads and costs, conduct least cost optimization analysis, and use the appropriate cost at the margin-to-signal pricing and value. These same principles underlie supply cost forecasting, network power flow optimization modeling, and the derivation of wholesale LMPs at the substation. With distribution-based marginal costing, all of the costs incurred between the substation and the customer must now be considered. This is particularly critical with the influx of new grid-edge resources behind the meter or along distribution circuits. The process and methods are the same in the derivation of marginal distribution costs. The data complexity and granularity levels are necessarily greater, but these challenges are surmountable with modern computation, modeling, and data management.

20.2.4 Customer Value-of-Service to Further Optimize Planning and Markets

A conceptual methodology to integrate value-of-service for DER projects is recommended based on six steps [30,40,41,42]. The first step, as we have explained earlier, is to define the benefits for a project. This exercise requires a map of each project function into standard benefit categories. The second very critical step is to define the baseline or *but-for* case and how it is estimated. The third step is to determine the data available to quantify the benefits. The fourth step requires calculation of the quantitative estimates (from engineering, SAIFI, etc.). The fifth step is monetizing the benefits with use of economic conversion factors. The sixth step requires comparison of the baseline or *but-for* case to the proposed project case, comparing the full stack of benefits to costs. To perform this work in detail, the general benefit categories are first defined based on principal characteristics and mapped to grid/DER functions.

The second step, to define the baseline (*but-for*) case, can be very challenging. What are the baseline conditions in each case in terms of engineering or other metrics/criteria, which can then be monetized using economic metrics? What are the benefit categories, who benefits (customer, distribution grid, bulk-power), and how is each baseline indicator defined? For example, the case for circuit switching may posit the number of existing circuit switches in place and explain the impacts of current and future circuit switching given the number of circuits. Another example is to define the grid impacts of the *status quo* case on future DER hosting.

The third step is to define data available to quantify the benefits. How will the distribution grid be impacted? In some cases, outages and declines in power quality must be defined. The reliability (SAIDI/SAIFI) and power quality (Volt/VAr criteria violations) data provide direct implications, such as where new circuit switching *is not provided*, especially with greater use of DERs.

The fourth step is to provide relevant results, including calculation of the quantitative estimates (from engineering calculations, SAIFI, etc.) that can be used. A comparison of the with and without cases, based on technical parameters, is needed to reflect the change in conditions. These conditions will manifest as changes in electricity bills, customer costs, distribution costs, bulk-grid costs, power interruptions, power quality, resiliency, safety (accidents) and security, emissions, and other results. Per the example in the prior paragraph, one can define the grid impacts for the current and future cases, related to the grid expenditure (project), to increase DER hosting. These kinds of results can be compiled and explained.

Importantly, customer value of service (VOS) can be defined based on reliability benefits, and used as the metric to test the economics of distribution upgrades as well as DERs. The impact of reliability on customers is typically based on "outage costs" [43]. Without this kind of measure, it seems difficult to define the full value of grid modifications that ensure reliability. This can be a major limitation on the valuation of grid modifications. Reliability value can, however, be defined and used to define how best to balance customer reliability and grid value. As Electric Power Research Institute (EPRI) explains:

> Customer outage time could be logged by smart meters or outage management systems. These data could be compared with typical hourly loads to estimate the "load not served" during the outage. The value of the decreased load not served as a result of smart grid functions must be allocated based on the function's contribution to reducing outage minutes. By applying a VOS metric (i.e., by customer class and geographic region), the value of the load not served can be estimated as follows:
>
> $$\begin{aligned}\text{Value (\$)} = {} & [\text{Outage Time (h)} \times \text{Load Not Served (kW estimated)} \times \text{VOS(\$ / kWh)}]_{\text{Baseline}} \\ & - [\text{Outage Time (h)} \times \text{Load Not Served (kW estimated)} \times \text{VOS(\$ / kWh)}]_{\text{Project}}\end{aligned}$$
>
> An estimate of the load not served may be provided by the project at the time of reporting, or could be obtained from the baseline estimate generated when the project is established.

Overall, the marginal customer value-of-service should equal the marginal cost of service, including relevant grid costs [44]. Estimated grid interruption (outage) costs from the Lawrence Berkeley National Laboratory (LBNL) study are shown in Table 20.1.

The final step in this overall approach to monetize grid modernization and DERs is to compare the baseline or *but-for* case benefits and costs to the proposed project case. Correlation of weather, loads, and prices further adds to the robustness and valuation.

TABLE 20.1
Estimated Customer Interruption Costs per Electricity Supply Interruption Event—Average kW and Unserved kWh (U.S. 2013$) per Duration and Customer Class

Interruption Cost	Momentary	30 min	1 h	4 h	8 h	16 h
	Interruption Duration					
Medium and Large C&I (Over 50,000 Annual kWh)						
Cost per event	$12,952	$15,241	$17,804	$39,458	$84,083	$165,482
Cost per average kW	$15.9	$18.7	$21.8	$48.4	$103.2	$203.0
Cost per unserved kWh	$190.7	$37.4	$21.8	$12.1	$12.9	$12.7
Small C&I (Under 50,000 Annual kWh)						
Cost per event	$412	$520	$647	$1,880	$4,690	$9,055
Cost per average kW	$187.9	$237.0	$295.0	$857.1	$2,138.1	$4,128.3
Cost per unserved kWh	$2,254.6	$474.1	$295.0	$214.3	$267.3	$258.0
Residential						
Cost per event	$3.9	$4.5	$5.1	$9.5	$17.2	$32.4
Cost per average kW	$2.6	$2.9	$3.3	$6.2	$11.3	$21.2
Cost per unserved kWh	$30.9	$5.9	$3.3	$1.6	$1.4	$1.3

Source:

20.2.5 Software and Computation Enable DER Integration and Optimization

A primary objective for DER resources is to maximize value for customers, the distribution system, and the bulk grid. DERs are usually situated, however, within the distribution system connected to customers and lower voltage. To maximize the value of DERs requires two things: (1) long-term DER use must be planned and optimized, and (2) short-term DER use must be appropriately dispatched in order to maximize operational value, a second level of optimization.

In order to achieve maximum value and realize these two levels of optimization, DERs must be fully integrated into both distribution and bulk grid use, and they must achieve the maximum deferral and avoided cost possible. These are major challenges. Moreover, the traditional use of DERs has been as separate resources, largely in silos. Each DER resource is unique and has different characteristics. EE is relatively permanent and has a specific impact on customer load curves, which translates to specific load reductions when aggregated. Likewise, DR is unique, but has relatively limited use in terms of the number of hours of the year when it can be exercised. Distributed generation, such as solar PV, can generate only when the sun shines. Storage batteries are available only during specific hours, though they can be used flexibly, and must be charged, which provides for energy management during the discharge and charging cycles. More importantly, specific customer loads are key in determining the type of DERs required to reduce load, improve Volt/VAr, and serve frequency regulation needs.

DER value can be increased substantially if used to defer major distribution and bulk grid costs, largely capital expenditures, but also operating expenditures. When used and operated separately, each DER has different hourly impacts. This, in many cases, limits the deferral capability and value of individual DERs. When DERs are used in the right combination, with the right sizing and certainty, DERs can directly defer high-cost resources. To achieve this, however, specific packages of DERs must be configured, installed, and operated at specific locations on the grid.

DER optimization is generally more challenging than supply-side optimization. Supply-side optimization typically considers customer loads at a higher level of aggregation, at the subtransmission or price-node (P-node). Large-scale generators have specific operating characteristics (start-up, ramping, and operating costs), which enable capacity expansion and security-constrained economic dispatch to be well defined. The dynamics of transmission power flow must also be considered, especially to understand voltage constraints and possible loop-flow.

In contrast, DERs are more specific, depend on underlying customer loads, and must reflect both the physical grid architecture in detail and the integration and operation of the DER portfolio. This is significantly more complex than supply-side integration and optimization. To fully integrate and optimize DERs, each specific customer load profile must first be defined, which typically requires smart metering (AMI) data. The distribution system load flows must be accurately modeled to create the basis for underlying changes in distribution deferral (CapEx) and operations (OpEx). Wholesale grid impacts must also be determined. Specific DER packages must be designed for individual customers to achieve the desired deferral and operational benefits. And the DER portfolio must be operated to maximize the value for both the distribution and wholesale grids. This seems like *a tall order* to achieve, to fully integrate DER planning, much less to optimize both DER investment and operations.

The latest uses and capabilities of software and computation now enable these results. Big data can be managed and analyzed to resolve these objective functions, and system-wide results can be well-defined. The composite hourly and subhourly impacts of DERs can be determined based on appropriate stacking and resolution of physical grid characteristics and incremental or marginal benefits. Detailed locational load forecasting, power flow analysis, DER package determination, portfolio optimization, and DER operational optimization can all be integrated in a new process, the DER-centric distribution planning process.

The “DER-centric” distribution planning process starts with locational demand forecasting that uses acre level planning granularity and customer-specific AMI data. Customer-specific targeting of high peak demand use, high energy use, and combined effects are possible, as well as the overlay of customer-specific electricity end uses. Distribution load-flow analysis is then calibrated to determine distribution loads down to the customer line-segment level. Distribution planning assumptions for load growth are used to define specific future CapEx- and OpEx-related projects. The needs identified in the distribution planning process provide the basis for distribution deferral analysis.

Installed DER costs and locational bulk grid supply curves are needed as inputs to determine composite locational “all-in” incremental, marginal, and avoided costs. DMCs, as described earlier, encapsulate these costs. Operational optimization of selected DER packages for each location is also needed. The results of these steps are then projected forward for the duration of the planning cycle. By iterating between all-in DMCs, customer-specific loads, and DER options, customized DER packages can be determined for specific customer locations on the grid. These methods enable DER integration and optimization at the customer level.

20.2.6 Distribution and Bulk Grid—Four Steps to Iterate and Integrate

A four-step method has been developed for DER integration and iteration through research with a set of U.S. utilities. This points to progress with best practice techniques to capture maximum benefits, use new data, and fully integrate and optimize DERS with the smart grid. A 2× to 5× increase in portfolio value can be demonstrated when customers are offered the full spectrum of DER options. These four steps explain how this optimal approach is used.

When examined in detail, DERs may defer or avoid major utility grid capital and variable costs, netting very substantial benefits. Where ISOs/RTOs are in place, generation has largely become competitive, removing generation capital costs from rate base. Transmission may, for many utilities, be a significant component of the regulated utility rate base. But distribution investment has remained one of the largest fixed investments in capital, and thus a large component of the rate-base.[30]

DER investments that directly impact distribution investments are of critical concern if they have implications for reliability. Moreover, with major use of DERs, many utilities become very concerned about three directly related matters: (1) net decreases in investment (rate base) occur, (2) lost revenue (from reduced sales) results, and (3) the costs of many DER options are less than the conventional resources they are designed to replace, thereby reducing rates. With expansive use of cost-effective DERs, this now threatens to be disruptive from the utility view.

Locational DER modeling can be overlaid on distribution load flows to provide T&D assessment and enable targeting of integrated DERs. Of note, this enables the utility to identify specific (actual) distribution system capital investment deferral opportunities. It also identifies distribution assets at risk, both with and without the proposed DERs. In this way, DERs can be spatially allocated to achieve maximum benefit. Recent California legislation, AB327, adds a Public Utilities Codes Section 769, which states that electric utilities are to provide "*distribution resources plan proposals to identify optimal locations for the deployment of distributed resources cost-effective methods to maximize the locational benefits and minimize the incremental costs of [these resources].*" A key to this step is verification of locational engineering assumptions and of existing demand-side features to establish the base case. Utilities will need to get agreement from local distribution and transmission engineers about expected load flows and dynamic operations, which are then reconciled with modeling.

We now have the data, modeling, and computation capability to target DERS at the feeder and customer levels. These same capabilities also enable more granular demand forecasting. A geospatial planning approach can enable the use of map-layer hierarchies, such as those shown in Figure 20.3. Electricity load flows then are provided with geospatial mapping, consistent with customer locations, circuit maps, per-capita growth assumptions, transportation corridors, specific DERs at specific customer locations, and future land use.

The approach can then identify specific (actual) distribution system capital investment deferral opportunities down to the customer feeder level, which then allows identification of capacity and energy deferral opportunities at the specific customer building level. This includes spatial identification of distribution assets that are at risk for loss of load, and identification of the specific mix of DER and distribution assets that will provide the reliability level desired. In short, DERs can be spatially allocated to achieve maximum benefits. This approach, already being used at Duke Energy, and starting to be used at PG&E [46,47], provides distribution feeder level and customer level granularity through a series of steps. These include use of local planning assumptions and economic growth plans on a locational basis to identify asset/planning areas that have capacity surplus as well as deficiencies. Where there are deficiencies, mitigation projects can be planned and specific areas can be identified for candidate T&D project deferral opportunities.

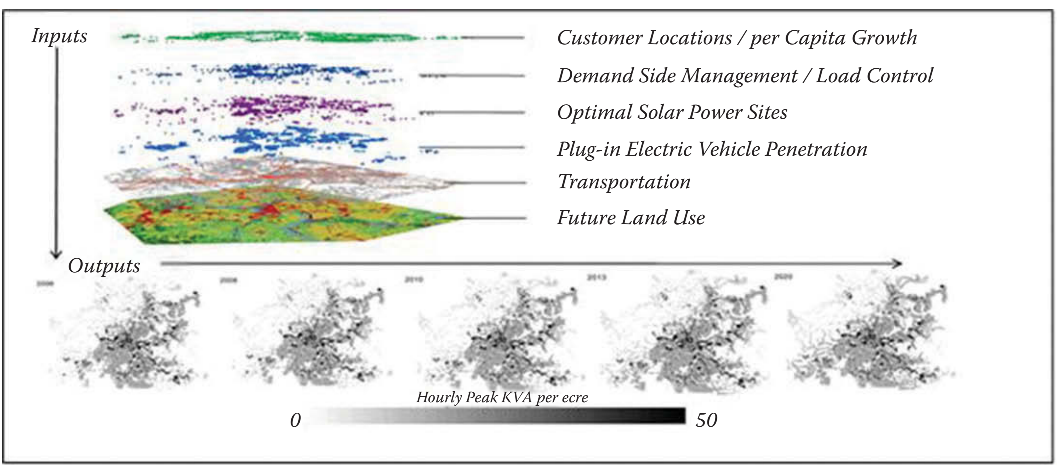

FIGURE 20.3 Map layer hierarchies for DER geospatial planning. (© 2016 Integral Analytics. All rights reserved. With permission.)

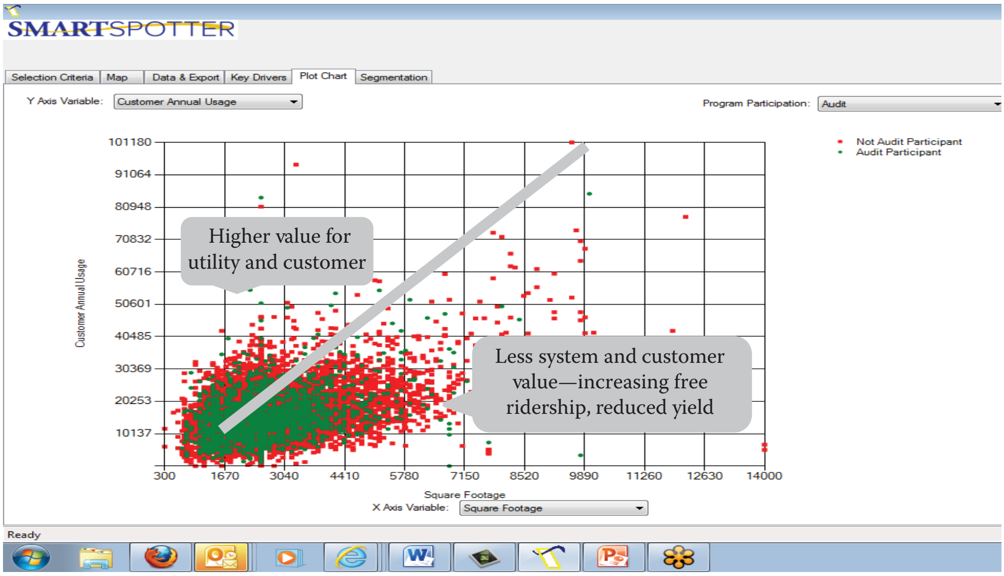

FIGURE 20.4 Locational assessment value of T&D capital cost deferral in DER planning. (© 2016 Integral Analytics. All rights reserved. With permission.)

With these areas targeted, the required DER technologies can be determined, as well as the specific savings required to defer T&D capital projects. From this, DER project portfolios can be designed to transform significant grid and generation costs into more cost-effective DER investments. This creates the specific opportunity to calculate the avoided capacity and energy cost for the specific context, at what amounts to the microgrid level, and to tailor the DER remediation to achieve the desired capital and variable cost deferral with certainty. This locational assessment then flows into the cost-effectiveness analysis to define the larger value proposition. In Figure 20.4, the areas in green signify locations where the capital cost deferral from DERs would be valued at zero, while the areas in red show capital cost deferral would be $280/kW-year. Although the regional average project cost may be consistent with field utility information, with greater granularity we can identify the higher avoided cost areas and enable targeting of DER projects that provide major benefits.

There are four main steps in evaluating the locational value of T&D capital cost deferral in DER planning:

Step 1: *Target Marketing and Consumer Engagement*—Identify the high value participants and target-specific DER packages to these customers using interval (load-profile) and "big data." Data-driven targeting enables focus on the right customers who can deliver highest value. This method leverages vendor and usage data to increase brand lift, customer satisfaction, savings, lower average marketing costs, lower free ridership, and enables higher quality consumer engagement. Results are dramatically enhanced compared to traditional "shotgun" methods from siloed solutions.

Step 2: *Locational Distribution and Transmission Benefits*—Customer-specific impacts from transmission to the distribution feeder level show the deferral of major capital and operating costs. The portfolio can be spatially allocated across the distribution and transmission systems to achieve maximum benefit. This level of granularity enables hourly and subhourly mapping of existing and future loads. Load growth plans define distribution and transmission areas with capacity surplus and deficiencies. The portfolio can defer specific distribution and transmission project costs. This customer-level granularity increases the benefits achieved. An example based on locational capacity targeting is shown in Figure 20.5.

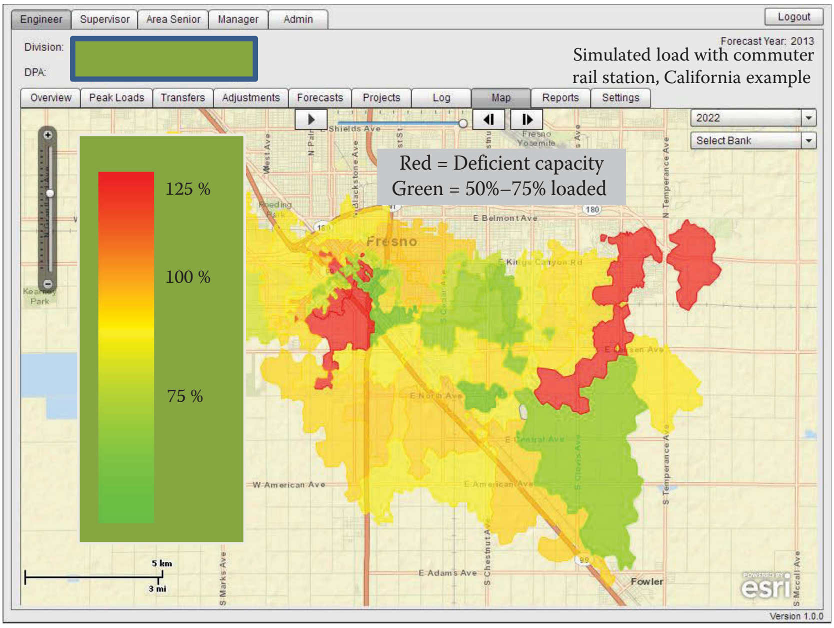

FIGURE 20.5 Locational capacity targeting. (© 2016 Integral Analytics. All rights reserved. With permission.)

Step 3: *Locational Uncertainty, Hedge, and Option Value*—This captures deviations (covariance) in expected demand, weather, demographics, commodities, prices, and combined value to reflect the probability of expected uncertainty and the benefits of reducing uncertainty. This is a major advance over use of point-source (deterministic) assumptions, based on approximate averages and linear models that largely ignore uncertainty. The results from this analysis appropriately show substantial value added.

Step 4: *Distributed Optimization to Maximize Benefits*—The ultimate optimal use of DER and smart grid measures, what is equivalent to the *Holy Grail*, is the dispatchable virtual power plant. This enables optimization of individual resources and the portfolio. This includes scheduling and dispatch of distributed resources, injection of reactive power, voltage control, loss compensation, load following, and system protection. These methods proactively predict loads, control their shapes, and manage demand. With this higher level of resource optimization, system costs are dramatically reduced for customers.

Distributed optimization enables the value of load leveling, peak shaving, load-shifting, and load reduction to be captured at the substation, transformer, feeder, and wholesale grid levels. This can, in part, be achieved across an ISO, as shown in Figure 20.6. This further enables efficiencies from the three steps previously explained.[8]

20.2.7 Option Value and Optimization

The question is how to fully define the value of optionality—availability to serve in multiple markets—from dispatchable DR capacity. In 2002, the California Public Utilities Commission directed its utilities to use option value methods to evaluate all major electricity procurement transactions.[9] Each of California's investor-owned energy utilities has continued to use option value

[8] Further explanation can be found in Reference [48].
[9] California Public Utilities Commission, D. 02-12-074, p. 17.

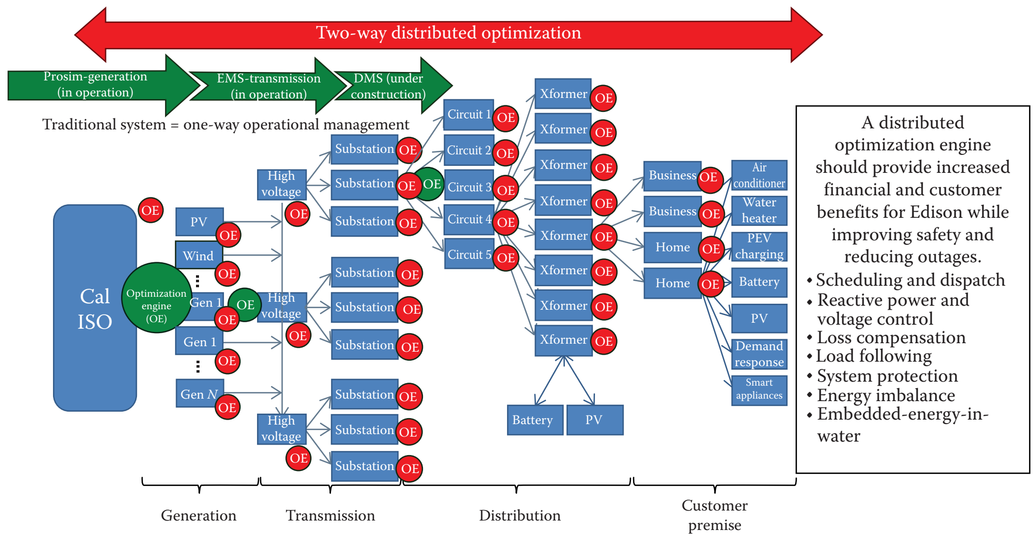

FIGURE 20.6 Optimization across CAISO. (© 2016 Integral Analytics. All rights reserved. With permission.)

methods to evaluate long-term procurement options in the CPUC's long-term procurement plan. The results are kept confidential, protected by Nondisclosure Agreements, and reviewed by a stakeholder-based Procurement Review Group.

Option value represents the availability of a resource to participate in multiple markets concurrently. A resource that can be available for use during the highest price hours and the times when reliability is most threatened is simply more valuable than a resource dedicated to a single narrow use (e.g., grid-wide emergency service). Full option value implies that the full set of benefits is available and that each potential use is valued. Option value has been used for years to value fossil generation.[10] This approach can be used to directly quantify the market benefits of dispatchable capacity. With variable wind or solar resources, dispatchable capacity must increase (or decrease) immediately to fill the gaps in order to avoid a grid outage. These supply changes result in more price volatility and greater congestion. Option value can also be extended to the distribution level, for example, where electric vehicle charging requires load-management that is provided by DR.

To fully value DR, option models are typically used that rely on traded forward curves (contracts) for energy and related price volatility at specific delivery points. Option models can be designed to directly reflect load changes, hours of availability, and price volatility. A primary assumption of traded forward contracts is that future prices converge to the prevailing energy spot price upon maturity. The value of optionality in multiple concurrent markets is based on hours of resource availability, the market value of energy, the value of reduced market volatility, and contract length. In contrast, a single snapshot of avoided capacity and energy costs cannot capture the optionality of dispatchable capacity.[11] For example, utilities often use dispatchable DR only as emergency capacity, but it can be used more widely as an *option contract* to serve multiple purposes and maximize its value [51]. Building on Table 20.1, a subset of the multiple uses of dispatchable DR includes:

- Ramping capacity (for grid needs and to integrate more renewables)
- RA and operating reserves
- Reduce capital costs
- Lower electricity prices

[10] The genesis of this is the *spark-spread* option. See References [49,50].
[11] Monte Carlo techniques can be used to augment valuation in order to capture elements of DER optionality.

- Reduce congestion costs
- Mitigate market power
- Locational arbitrage (in nodal markets)
- Reduce fuel risk
- Remove counterparty risk
- Distribution load management

20.2.8 Dynamic Capabilities Will Be Essential for Smart Grid Adaptation[12]

It is increasingly clear that dynamic capabilities are needed to develop resources that can adapt and gain competitive advantage in the smart grid space, especially to enable more effective integration and optimization. Simply put, dynamic capabilities will be essential to succeed in this new arena. New smart grid business models are and will increasingly be at the forefront. Successful firms must design and provide new products and services that reflect new competencies. These steps will, in turn, require new smart grid stakeholders to innovate in response to exogenous events (e.g., business cycles, enhanced competition, and regulatory changes), fully embrace integrated systems (that remove siloed barriers), leverage new technologies and collaborative efforts, and all of these must proceed at the speed of the market. With greater change in the business and technology environment, the advantages conferred of dynamic capabilities will be critical. Integration and optimization of electricity with water, gas, and other platform economics will become essential to enable stakeholders to gain competitive advantage. In this intense setting, dynamic capabilities will result from inimitable capabilities, rapid adaptation, flexibility, and innovation.

Five specific dynamic capabilities seem critical to capture and synthesize needed advantages. First, as in IT and electronics, specific processes are needed to define, manage, streamline, and adapt to enable smart grid product development, quality control, knowledge transfer, and technology transfer. These routines must be well orchestrated to enable dynamic efficiencies. Further development of dynamic capabilities will be essential in these areas.

Second, improved smart grid business models must be a focus, an area of continuous improvement. This is how value is delivered to customers, and it will compel customers to pay for value and convert this value into profits. New revenue and cost structures must be designed to meet customer needs, and leverage the use of market segments and channels and specific mechanisms to capture value. Smart grid-related business models will require articulation of the value proposition in terms of its scope, scale, differentiation, and consumer engagement. The related value chain structure must also realize value, revenue, and profits. Each business plan must ultimately define the way that a vendor "goes to market," including the scope and extent of the vendor's market presence. Business model adjustments must be anticipated and well executed as conditions change in the competitive landscape. These are essential business realities, and the smart grid space is no different.

Third, as David Teece explains, dynamic investment choices create competitive advantage when value chain elements are complementary, reinforce each other, and increase value [53]. This is where *cospecialized* assets can be used strategically in conjunction with each other. This is one of the integration functions that will enable greater smart grid value to be leveraged as service options and technology scope increase. Properly bundled and managed, the integration of key smart grid operations will enable new services that are further differentiated, provide greater benefit capture, and yield significant cost savings. *Cospecialized* assets will be combined to achieve system integration and innovation benefits. These smart grid systems will increasingly need to be designed, built, and sized to meet specific smart grid needs (e.g., at the substation or microgrid level). A number of smart grid integration and optimization benefits are likely to be found bundled within specific subsystem needs and opportunities. Innovation routines should be exploited that can be used to develop new cospecialization technologies. A critical outcome from this is greater focus on scope-based advantages in the smart grid.

[12] This entire section borrows heavily from the work of David Teece, including Reference [52].

Fourth, dynamic smart grid adaptation capabilities can be forged through informed orchestration of assets, new knowledge, and coordination with value chain partners. The vendor's assets, knowledge, and value chain partners can be further orchestrated to create new dynamic capabilities that generate greater value for customers and other stakeholders. A focus on consumer needs and value chain capabilities can be approached strategically to enable the vendor to use proactive smart grid adaptation and deployment.

Fifth, dynamic smart grid capabilities will originate from efficient learning and technology development across different parts of innovative vendors. The sharing of knowledge and capabilities reflects "silo busting," to monetize otherwise untapped potential. The outsourcing of functions and joint development across smart grid vendors will enable new capabilities and differentiation, and with it greater value. Thus, the development and improvement of dynamic capabilities are especially valuable, though it may be difficult at times, particularly to imitate potentially competing services and products.

With this backdrop, what do we expect by 2020 and in another decade? Contemplated are interactive smart grids that enable *plug-and-play* DERs that are fully integrated and optimized. More work is required to further develop new utility business models and exhibit tomorrow's dashboards. Transactive energy is expected to both enable trading of long-term DER forward positions and short-term interactive trades. *Superforecasting* techniques are likely to be well developed to provide greater knowledge about best future options.

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21 Transactive Energy

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CONTENTS

21.1 TRADING OF LOCATIONAL ENERGY RESOURCES

Many believe that smart energy resources, whether they are DERs (distributed energy resources—distributed generation, energy storage, and electric vehicle-to-grid supply), demand response (DR) programs, or utility connected resources, may best be fully harnessed and monetized through transactive energy (TE) frameworks. The ultimate aim of smart grid and TE is to provide a *plug-and-play architecture* that enables DERs, smart applications, software, and services to transact energy via an interactive, open-access platform. TE has been defined by the Gridwise Architecture Council as follows:

> A system of economic and control mechanisms that allows the dynamic balance of supply and demand across the entire electrical infrastructure using value as a key operational parameter.

The Gridwise Architecture definition seems to be overly broad; therefore, the following definition from the National Institute of Standards and Technology (NIST) TE Challenge Business and Energy Models Working Group, may be more appropriate, and would allow for a greater number of TE model [1]:

> Transactive Energy engages customers and suppliers as participants in decentralized markets for energy transactions that strive towards the three goals of economic efficiency, reliability, and environmental enhancement.

Albeit difficult to define and admittedly speculative, this chapter provides an overview of how TE markets for DERs may be developed to enable trading in future short- and long-term settings.

TE aims to fully monetize distributed and wholesale energy resources, but from this a set of challenges arise. Customers care about lower bills, and will increasingly benefit from DERs that can be fully monetized by providing co-benefits that *buy-down* the costs of DERs. These DER packages are increasingly aimed to maximize benefits for (1) the customer, (2) the distribution location, and (3) the bulk-grid location. On a day-to-day basis, the distribution grid is generally focused less on kWh and kW and more on voltage and VAr (volt-amps reactive) levels. The bulk-grid is more about kWh and kW, but also about frequency regulation and voltage management. Customer and distribution needs, however, are highly locational. Bulk grid needs are more focused on regional or subregional solutions. Distribution and bulk-grid needs are many times non-coincident.

DERs can provide significant benefits for all three value categories. Hence, there are a set of objectives and benefits that targeted DERs can focus on optimizing. A general challenge with *right-sized* locational DERs is that each building and premise will have an idiosyncratic DER solution, that is, a specific package or mix of DER resources with a characteristic set of interactive effects. In contrast, the best-known market solutions require standardized energy services and specific performance.

Nonstandard bilateral contracts typically enable customized energy services to be provided, but are not easily tradeable in uniform markets. Still, the related challenge is to use TE to monetize the value of integrated and optimized DERs. Integrated and optimized DER solutions are, however, again idiosyncratic, as they are sized and configured to be optimal for the customer and grid setting, and reflect specific individual customer load curves.

In contrast, standard market solutions rely on relatively uniform commodities or uniform asset characteristics. Electrical energy and capacity typically have standardized market dimensions. Energy in kWh is defined as firm (with operating reserve backup) or nonfirm. Capacity has hourly kW availability and a required duration. The two main wholesale energy market exchanges are the spot market, for short-term trading, and the forward market, where the delivery of electricity takes place at a future date. Forward energy (future energy reservations) can be purchased over-the-counter, and at a delivery point based on uniform contracts.

Intercontinental Exchange has led the industry in standardizing over-the-counter energy contracts and listing them on a widely distributed electronic trading platform. This has enabled physically settled bilateral contracts for North American natural gas and power markets to satisfy the hedging and trading objectives of a diverse range of market participants [2]. A number of other over-the-counter market providers have developed similar markets.

Proposed TE market structures anticipate (1) bilateral trading, (2) exchange at the wholesale level and exchange at the retail level, and (3) *peer-to-peer* transactions. The use of short-term spot markets are familiar practice in organized wholesale electric markets, but have yet to be formulated for distribution retail markets in the USA. TE involves both wholesale and distributed energy trading in the retail market.

ISO/RTO trading in short-term wholesale energy and ancillary services in so-called *spot markets* is typically based on uniform bid-based markets.[1] Energy is typically traded according to an economic bid-stack of available resources. These trades are based on reliable physical delivery of energy to a location, which includes the cost to dispatch energy, and around any transmission congestion (constraints).

ISO/RTO energy markets are based on *security-constrained economic dispatch* and provide uniform wholesale participant bids and delivery of uniform energy. In many ISOs/RTOs, delivery of energy during the hour or subhour is monitored, if not controlled. *Uninstructed deviations* from ISO/RTO signals may warrant penalty for lack of energy delivered within limits in each period. Such deviations are all taken into account in *ex post* economic settlements. Similarly, specific wholesale ancillary services, including operating reserves (spinning and nonspinning), frequency regulation, and regulation up/down, rely on uniform bid-based markets.

Short-term trading of electricity at the distribution level, behind-the meter, or in front-of-the meter is possible through the aggregation of energy, DR, and energy efficiency,[2] at least in some wholesale electric markets. Aggregated customer DR can be bid-in as energy reduction, or as forward capacity in some ISOs/RTOs. In the U.S. PJM RTO, a total of nearly 11,000 MW of DR is committed as capacity resources for the 2016/2017 delivery year [4]. DR in different forms can also be bid-in to markets in CAISO (California), ISONE (new England), MISO (mid-continent USA and Canada), and NYISO (New York) markets.

[1] The type of auction is also typically specified, such as lowest-losing bid, or as-bid.

[2] Energy efficiency is defined in the US PJM as expected energy reduction during specific scheduled hours. See Ref. [3].

21.2 DER VALUATION CHALLENGES

As discussed in the previous chapter on wholesale and retail market dynamics, locational DER solutions are defined in the distribution planning process with the intention of deferring fixed distribution capital-cost projects. The distribution deferral value is but one part of the value chain that DERs can provide. Other needs in the value chain, including energy commodity, capacity, and volt/VAr support, present additional opportunities to further monetize DERs. These added values represent optionality, and accordingly more value for DERs and for customers.

A critical question is whether separate DER market options can be "peeled off" and monetized through TE or through other markets? For example, can DERs be used to defer a distribution capital project, and also be used in energy commodity markets? In some cases, the answer is yes. This second use of DERs would be separately compensated based on the metered settlements in ISO/RTO energy markets. In addition, the DER provider may negotiate a bilateral contract with the distribution company to provide Volt/VAr compensation (based on specific performance goals) to further monetize its value. Solar roof-top photovoltaics (PVs) may, however, at least in the short term, be subject to net-energy-metering policies that restrict further commercial energy trades through wholesale or retail markets.

In order to legitimately capture full DER value, actual DER performance and availability must be assured, and double counting of benefits must be precluded. In different terms, *incrementality*—additional incremental or marginal value—must be assured. A fundamental question then is how can TE markets be designed to more fully monetize optional DER and commodity values—capture co-benefits—such as from aggregated sources, and minimize transaction costs? Also important, the related *transaction costs*—the full costs to do the deal (including negotiation, monitoring, enforcing "contracts," and related remedies)—must be carefully examined [5]. If transaction costs are significant, those incurring these costs will need to identify how these costs can be counterbalanced by the transaction, including co-benefits.

The economic and financial valuation of energy resources and assets is usually based on comparative incremental or marginal cost. In simple terms, the most expensive resources to meet a specific need or set of needs are stacked in relation to the least expensive resources. This forms the *supply-curve* for the required resources or asset. A future demand curve is then overlain to determine an expected market price. Ranges of values may be used. In all cases for North America, and for most parts of the world, projections show the costs of solar PVs and storage batteries continue to decline, which will make fossil-fired generation noncompetitive and, thus, obsolete. DER and other supply resources should be valued in comparison to each other—based on their incremental or marginal cost differences. In times past, supply-side resources have generally been used as proxy values for DERs. This looks to be a problem sooner than many think. Known expert opinions suggest that coal- and gas-fired electricity will be rapidly replaced with solar PVs, wind, and batteries in less than a decade, if not by 2020. The logic is as follows:

- There will be no "golden age of gas" as the costs of solar, storage, and wind are falling too fast; *You can't fight the future [as] the economics are increasingly locked in …*
- Renewables attract $7.8 trillion, which dwarfs fossil fuel investments ($2.1 trillion); *solar will soon dominate … and battery storage will be as ubiquitous as rooftop solar is today.*
- Electric cars rescue power markets and go mainstream, allowing for increased grid efficiencies (but disrupt oil markets).
- Battery storage joins the grid with scale, driving prices lower and enabling widespread storage of solar and wind power.
- Solar and wind prices plummet. For every doubling of the world's solar panels, costs fall 26%. Likewise with wind doubling, there is a 19% cost reduction. Solar and wind will be the cheapest forms of electricity in most of the world before 2030.

- Renewable capacity factors dramatically increase as technologies advance; this is a focus when the marginal cost of renewable electricity production is virtually zero [6].
- With the erosion of markets that support reference fossil plant values, how can we take up the slack with TE markets to effectively value DERs?

21.3 DER VALUATION—THE BASICS OF AVOIDED, INCREMENTAL, AND MARGINAL COST

Let's briefly recount traditional resource valuation basics. Avoided costs typically represent the utility costs deferred based on *but-for* decisions that utilities or alternative suppliers make. Differences in costs between competing market options are typically based on market prices. In both of these cases, *incremental costs* also seem relevant. Marginal costs are, like incremental costs, the change in costs for a given change in demand or energy use. With DERs, the costs to produce required voltage and VAr changes can also be expressed in avoided cost, incremental cost, or marginal cost terms. What matters most in all of these cases is the increment in question. Is the incremental based on locational kW or MW, kWh or MWh, kVAr or MVAr, or maybe an incremental plant such as a combustion turbine? In all cases, *apples-to-apples* comparisons are needed to define comparable and meaningful economic valuations.[3]

Proponents of TE propose forms of bilateral contracts and the use of standard offers to monetize electrical capacity. Bilateral contracts are also referred to as *peer-to-peer* transactions. More customized DER solicitations are expected to provide voltage- and VAr-related resources. Markets for fixed electricity infrastructure provide generation capacity, transmission capacity, and, to a lesser extent, distribution capacity. To finance power plants, typically project developers request investors to sign long-term contracts for power and energy. Similarly, natural gas transportation (pipeline) infrastructure has used *open-season* procurements to solicit customer demands, which are executed as standard-form contracts. The argument is that short-term electricity capacity offers can also be structured through competitive solicitations, such as for locational capacity reservations or resource adequacy. The question is how to step beyond the DER planning and solicitation framework to monetize DERs to defer long-term infrastructure with TE?

Traditional spot and forward markets are uniform, of one dimension, and are treated as a discrete stream of variables. The much discussed convergence theory for specific assets holds that forward markets will, over time, converge to prevailing spot prices. *It is assumed that at expiration, the futures price converges to the spot price*, or in different terms, *all forward contracts are linked to the same driver: the initial spot price* [7]. Forward energy prices can be correlated to traded forward curves. A difficulty, however, is to understand how forward energy prices relate to forward capacity prices? Forward capacity prices can be calculated with traditional Black-Scholes models, accepting the known limitations.[4] Monte-Carlo models can also be used to estimate the capacity prices that apply to traditional power plants. Without use of traditional generation capacity price proxies as avoided costs, it remains difficult to define longer-term DER capacity prices. In this light, how can TE be designed to monetize DER capacity prices?

The question for TE markets is how to value DERs and supply-side resources in terms of multidimensional value-stacks? In these cases, some combination of incremental utility (avoided) and marginal (market) costs seems important to combine meaningfully. For distribution systems, maintenance of voltage and provision of VArs may be critical. On an incremental basis, added value may certainly exist in corresponding energy and capacity components. These added dimensions further complicate what should be defined as the increment in question. Hence, which incremental

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[3] While economists are famous for embarrassing and practically meaningless disagreements about these definitions, multidisciplinary professionals can usually understand these rather minor differences.

[4] Often discussed are the limitations with less-liquidly traded forward energy curves and the normal distribution assumption (with Brownian motion) in Black-Scholes models. See Refs [8,9].

dimension(s) should be used, even in simple cases? We can ask, for example, where does the total value reside with incremental kW, kWh, and kVAr? (In this example, we can ignore voltage mitigation, up, or down).

How can we define the incremental value of DERs that exhibit three dimensions of value—kW, kWh, and kVAr? At the hourly level, kW and kWh become the same, though they sum differently, as one is capacity (instantaneous peak) and the other is energy (over a duration). kVAr injection may require a short-duration response to provide value, if not near instantaneous, power-factor correction. Therefore, with kVAr, the increment is different. This makes *slicing and dicing* DERs, or simply adding and multiplying DER values, more complicated at the distribution level. Accordingly, the optimization of DER use and value becomes even more complex with kVAr value added to the mix. On the other hand, in some cases it seems essential.

Simply put, traditional spot markets, which require uniformity, are less able to monetize DERs. This is because many DERs have disproportionately high capital costs, minimal variable costs, and must be valued in highly customized situations. While TE markets aim to overcome these challenges, can they?

With further consideration, we must acknowledge that solar PVs, wind generation, battery storage, and electric vehicles have substantial capital cost and almost zero variable costs. Resources that have little or no variable cost cannot be readily valued if the basis is short-run incremental or marginal cost. Most spot markets for energy are based on short-term bids or offers that reflect incremental or marginal values. If DERs bid in as *inframarginal* resources, that is, at zero or very low prices, they will always be scheduled or dispatched to operate, regardless of existing grid conditions. Then, what happens when resources must be dispatched or used to avoid grid criteria violations? DERs are, in this way, anomalous compared to fossil generation resources that are bid into wholesale spot markets based on marginal or incremental costs.

When DERs are *scheduled*, or bid at zero or low prices, into wholesale markets, the resulting wholesale ISO/RTO market clearing prices decline.[5] Over time, as DERs and wholesale solar and wind resources become a larger part of the mix, major difficulties arise. DER pricing based on short-run marginal cost becomes, in short, meaningless, and market failure should be expected.

California's net load *duck curve* exhibits peak-period prices that reduce the cost recovery of traditional fossil generators. Ultimately, this will make traditional fossil generation uneconomic. With relatively low load growth, increased use of DERs, and declining fossil prices, financial valuations of traditional fossil generation suggest further decline.

21.4 DER PACKAGES—RIGHT COMBINATIONS OF DIFFERENT RESOURCES—AND OPTION VALUE

The need for various resources at the distribution level, where customer service is a priority, will involve custom DER packages with a set of resources that are sized to provide optimal benefits. Distribution system needs can be first defined by the equipment and upgrades required to maintain reliability, power quality, protection, and safety. Capacity needs on distribution systems are usually determined with reference to thermal overloads of lines, transformers, or circuits. Voltage and VAr needs are related to keep distribution voltages within required operating limits, and optimize load flows.

Smart inverters used with solar photovoltaic and storage systems can also be used to address voltage, VAr, and frequency issues, though much of this remains to be further tested and analyzed. Grid protection limits can be complicated and can involve protection switching to isolate circuits or line segments, which may not operate with reverse flows that DERs may create. And safety may also

[5] In ISO/RTO markets, resources are either scheduled or bid-in. Behind-the-meter resources, such as solar PVs, are "scheduled" to the extent that the change in the expected load curve for the day, which includes net load of the solar PV generation, is represented.

be compromised when protection cannot be provided, which is much discussed when reverse power flows occur on the distribution system. In short, distribution grid needs can be extensive, and may not always be mitigated through the use of DERs and related smart grid equipment, and therefore more traditional infrastructure upgrades may be required.

Where DERs can be used for multiple purposes, multiple benefit streams may be realized. In simple terms, a set of co-benefits may be gained. Multiple optional uses of DERs will buy-down the cost of DERs. Accepting that resource overcommitment and double counting must be avoided, more benefits are generally preferred over the siloed use of a resource. The optionality of DERs may span multiple benefit streams through (1) use to lower customers costs, (2) use to reduce distribution costs (e.g., equipment deferral), (3) wholesale grid benefits, (4) retail and wholesale market benefits, as well as hedging.

The capture of DER option value will be a goal of TE markets. The DR industry by itself has shown that it can capture option value benefits, as explained in a recent California DR Potential study.[6] These DR option values are based on the following four key capabilities or resource types:

Shape resource: The umbrella term used to describe load-modifying resources. This resource consists of TOU (time-of-use) and CPP (critical peak pricing) DR rate programs, and is analyzed separately from other resources (i.e., cluster end-use loads) as it affects the baseline load, does not fit within the propensity scoring framework, and does not require enabling technologies. The Shape resource is different from the "Service Types" in that it is not a grid service for which supply and demand curves are generated. Instead, it is a resource that is able to provide other DR services, namely, Shift and Shed.

Shed service: A reduction in load that provides relief to the grid during times of peak demand. This service includes conventional DR products as well as the peak load reduction that is realized through Shape (TOU/CPP) resources.[7]

Shift service: An energy-neutral movement of load from times of peak demand (typically evenings) to times of very low net load (typically midafternoon when solar generation is high). This service benefits the grid by reducing peak load, curtailment of renewables, and evening ramping requirements.

Shimmy service: Load that is able to follow a fast dispatch signal in order to either increase or decrease load in order to make real-time generation match demand. This service supports frequency and voltage management on the grid and reduces the need for conventional generation to provide these services. Shimmy service can be provided on either a 5-min or 4-s dispatch signal, in which case it is referred to as Load Following or Regulation, respectively.[8]

These new market products and services—shape, shed, shift, and shimmy—are expected to form at least some of the core of future TE markets. These same products and services seem certain to be developed in energy storage solutions. Moreover, these new services and products suggest new opportunities for unbundling and rebundling to maximize option value. DERs that can be used to meet multiple needs will be more valuable.

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[6] See option value for DR explained in Refs [8,10,11].

[7] Shed fraction represents the fraction of end-use load that can be shed (i.e., reduced) by the technology during a DR event. There are four shed fractions defined for each technology: Peak, 1-h, 2-h, and 4-h, which capture the potential "fatigue" of end uses when asked to shed load for longer durations. For example, a 4-h shed for an HVAC technology may be lower than its peak-shed because shedding the full amount for 4 h would reduce the end-use's ability to serve its basic function.

[8] Final Report on Phase 2 Results 2015 California Demand Response Potential Study, *Charting California's Demand Response Future, Final Draft*, Lawrence Berkeley National Laboratories, November 14, 2016, pp. 3-13 to 3-20.

21.5 AUCTION AND BILATERAL MARKET CONDITIONS—DIFFERENT THRESHOLDS

Some wholesale auction markets separately trade short-term energy (kWh) and capacity (kW). ISOs/RTOs may also co-optimize market price determination for both energy and ancillary services. Long-term capacity is not traded in many ISOs/RTOs. PJM and ISONE are exceptions in the USA, both of which have capacity markets. In general, there are two major dimensions of short-run spot markets, energy and capacity. Ancillary services are also traded in spot markets, though at far smaller volumes. As previously explained, there is some growth in financial forward and future markets, as derivatives of physical spot markets that have significant uniformity and liquidity. From these examples, how can we build linkages to value TE markets with auctions?

One challenge is to extend physical spot energy market auctions to define the value of longer-term capacity that can then be traded. Black-Scholes and Monte-Carlo modeling can be used to extend forward energy contracts and transform these values into capacity, but these techniques seem to have limited appeal. These advanced modeling techniques are not that well known and require what some see as *black-box modeling*—lack of transparency given the complexity—and, thus, are not used extensively in DR or DER industries.[9]

An implication for TE may be the use of competitive procurements and bilateral contracts in lieu of auctions. As bilateral contracts can be customized, this will satisfy a number of specific market conditions, such as to provide specific packages of DERS at particular customer locations. The question remains: Would auctions work to trade the energy-only component in these markets? A similar question is: Will there be sufficiently liquid auctions in some circumstances to ensure that spot market auctions will provide workable competition? In many local situations, there are likely to be few sellers and few buyers, which would not fulfill the deep liquid market condition commonly desired to satisfy the need for real competition. Markets based on bilateral contracts would then seem appropriate.

The use of bilateral contracts to serve in organized TE markets seems difficult to predict. This raises at least these two specific questions:

1. Does sufficient market uniformity and market liquidity exist to support auction markets?
2. What are the competitive needs of both the customer and the provider?

A benefit of bilateral contracts is that they need not be uniform; they can be customized. This allows for specific performance to be defined based on customers' needs, and for producer performance to be incentivized. Accordingly, bilateral contracts can diverge from expected spot market behavior to reflect negotiated performance, risk sharing, short- or long-term value trade-offs, and desired hedge value. That said, there are two principles in energy markets and planning.

First, there is the need to provide significant certainty about the value of auction and bilateral markets going forward. Can either of these market models better identify (define) the value of customer reliability? The basic theory of short-term spot markets is that spot-prices will, over time, converge to long-term bilateral contract values, assuming that performance conditions are roughly the same in ensuing duration. In other words, traded long-term energy forward contracts should converge to future short-term spot prices for energy, assuming the same asset type at the same margin (e.g., natural gas fired generation) and delivery point. There is some reciprocity in this arrangement; bilateral contract values can be used, if known to be relatively uniform or average, to indicate expected future spot market prices.

Second, the customer can be used as the reference point to demarcate capacity value, based on customer outage (shortage) costs. The general rule in planning for economic reliability is to ensure that the marginal or incremental cost of supply is less than or equal to the marginal or incremental

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[9] Examples of this analysis have been used in a number of applications, such as to value long-term renewable generation contracts and demand response contracts. See Ref. [12].

customer value-of-service (VOS), where VOS is the cost of an outage to that specific customer [13]. Each customer has its own VOS, though this can be generalized in specific situations for specific customer groups [14].

These and other metrics can be used to value and calibrate market results, where levels of uniformity and liquidity are evident, whether they are based on spot markets or bilateral markets. More directly, bilateral contracts and spot markets have common trend lines and are expected to exhibit specific relationships. Moreover, customer outage costs can be used as a proxy for capacity value. Accordingly, average customer outage costs, for a defined set of customers, can be used to define the market characteristics of capacity value. Any specific customer, however, may have outage costs that deviate significantly from the average, suggesting customized needs to best serve such individuals.

The implications of these two reference points, bilateral contracts (vs spot markets), and customer outage costs strongly suggest that when customer needs are not average, or sufficient levels of market liquidity do not exist, idiosyncratic results should be expected. In these less uniform cases, markets are less likely to be successful. The direct implications for TE reinforce the lessons learned in bulk wholesale electricity markets. If market conditions (characteristics) are not uniform, or if deep liquid market conditions are not found, market failure can be expected. In cases where the demand is significant to customize bilateral contracts, or customer reliability needs are unusual, TE markets would seem to struggle. Others may more simply ask, *where is the demand for TE*?

The primary needs at distribution voltage levels are to maintain voltage, VArs, and serve locational capacity needs. These primary distribution needs contrast with those of wholesale markets, which are to maintain energy and capacity levels, as well as frequency. While voltage is managed at the wholesale level, there has been little or no trading of this service.[10] The primary market trading of voltage and VAr services in wholesale markets has been through bilateral contracts, as there is little uniformity in, and less than a liquid market for, these products and services. The dimensions to use in trading voltage and VArs are also unclear. For VArs, would it be kVArs? For voltage, what would it be? Trading of locational capacity may be possible if DERs can be installed as needed at specific locations. But again, each DER capacity solution would seem to be specific to the distribution location and the connected customers. This suggests that, even with well-defined "all-in" marginal or avoided costs at a customer's location, masking of these market metrics would be needed to avoid gaming or rent-*seeking*—excessive profits that result from taking advantage of the market conditions. The utility, or an independent administrator, may be used to define locational, all-in distribution marginal costs (DMCs) and administer competitive procurements to ensure DER packages can satisfy specific needs at costs that are less than, or equal to, the DMC. However, the "other side" of the market must also be satisfied, which includes the actual customers that own and operate the DERs.

As recently experienced in California, a new planning challenge is to ensure sufficient dispatchable and ramping resources to counterbalance the higher levels of variable renewables on the wholesale grid.[11] The traditional wholesale grid has assumed the existing fossil and hydro fleet would be "moved"—turned up or down—from preferred operating points (POPs) to less optimal operating points, based on a master file of ramping capabilities for each plant. A relatively large number of load-following and ramping resources could be tapped so that most individual plants would not need to move much from their respective POPs. With greater reliance on variable renewable resources, such as solar PVs and wind, the need for ramping resources has dramatically changed. Both the amount and the speed of required ramping and load-following are now far greater. This suggests that a market for fast ramping capacity will be needed, at least at the wholesale level. A number of ISOs/RTOs have considered, and even adopted, both short-term ramping energy products and ramping capacity products.[12]

[10] Must-run generation may be contracted at specific interconnection points on the wholesale grid, but this is, at most, a very "thin" market.

[11] Energy and Environmental Economics, *Resolve Modeling Overview*, CPUC IRP Workshop December 16, 2016, slide 4, in California Public Utilities Commission Rulemaking 16-02-007.

[12] In CAISO, for example, this is called Flex-RA (Flexible Resource Adequacy).

21.6 QUESTIONS FROM MARKET LITERATURE FOR TE MARKETS

In the evolving smart grid context, what are the major market opportunities, limitations, and constraints? As when wholesale electricity markets are developed, a set of primary questions for TE markets seem germane. The market development literature offers a set of questions that may be used to direct further discourse about TE. A first set of questions is: How can we achieve economically efficient TE markets, enable price revelation, use auctions, and use competitive bidding? As Hayek pointed out in the 1940s, price formation of some kind is essential, which may include pricing to organize information, particularly for commodities, and structured activities to recognize constraints [15]. Uniform auction markets classically use price and quantity pairs to enable signaled preferences for sellers and buyers to transact. Bidding is typically used, based on symmetrical dimensions (uniformity), in order to link one bidder's price to others who are competing. The general aim of dynamic competitive markets is to maximize gains from trade for all participants based on efficient market clearing—price determination.

A key requirement for economically efficient market clearing—price formation—to occur is that each participant's benefit be maximized given prices that clear the market. With many sellers (buyers), each one competes to lower (increase) its price to win in an auction, absent conditions that encourage tacit collusion. Typically, so-called "sealed bid" or "double auctions" are thought to be economically efficient, even optimal trading rules, given sufficient numbers of buyers/sellers. The primary requirements for efficient market clearing price determination are market liquidity—sufficient buyers/sellers—uniformity of service/product traded, and absence of tacit collusion [16].

The conditions to ensure robust competition and avoid collusion are less well known in the smart grid literature, but are essential to understand. *Incentive compatibility* basically requires that each market participant follow the rules, but, more specifically, a market is incentive compatible if every participant will achieve their optimum outcome by acting in accord with their own true preferences [17]. This then would directly preclude a set of *gaming* strategies that enable manipulated results.[13] Incentive compatibility is a requirement in the formulation of market rules if markets are to accomplish larger group and societal goals (*fair-play*).

Markets also need to avoid *adverse selection*, which can be simply explained as avoiding the sale of inferior products/services, as compared to the sale of acceptable products/services.[14] This then points to the practical need to ensure uniformity of good products/services, which is potentially difficult when multiple services are bundled as packages, as in the case of DERs that are needed at specific customer locations.

With this backdrop, a set of primary questions are posed about prospects to formulate efficient and effective TE markets for the smart grid, as follows:

- Is there sufficient local market liquidity—enough buyers and sellers—to enable an exchange auction for products such as energy, capacity, kVAr, or combined products?
- Are the products to be traded in TE sufficiently uniform (in quality and dimension) to ensure that pricing will be accurately enabled, with the uniformity needed to ensure competition?
- Can TE markets be formulated to trade just energy and capacity, per hour, not unlike a regional/local version of retail access?
    - What level of granularity will be needed to enable sufficient competition from buyers/sellers?
    - Should this be based more on a uniform exchange auction or bilateral agreements?
- Can "all-in," fully formulated distribution marginal costs (DMCs), based on wholesale and distribution grid conditions, enable optimal DER and supply-side procurement?
    - Will DMCs need to be kept confidential as they will otherwise preclude incentive compatibility and encourage adverse selection?

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[13] To avoid manipulative gaming, as in wholesale electric markets, see Ref. [18].

[14] Adverse selection is also seen more expansively as a manifestation of *moral hazard* [19].

    - If DMCs are kept confidential, can other market information be used to structure competitive bidding among DER providers, with bilateral contracts to follow?[15]
- Can sufficient uniformity in bilateral contracts be achieved to enable forms of competitive exchange (e.g., a bulletin board) so that effective competitive trading will result?
- Should DMCs remain confidential to enable competitive bidding in the procurement of DERs?
    - Are there ways to reveal DMCs to DER providers and ensure incentive compatibility, which is a prerequisite to enable efficient market allocation?
- Can TE markets be formulated that sufficiently lower the transaction costs for participants, leaving adequate benefits to encourage vigorous trade and avoid market failure?

With further resolve to answer these and other related questions, a structured path for TE exchange in the smart grid is expected to emerge.

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22 Smart Grid Standardization Work

In Memoriam: Erich Gunther (1958–2016)

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CONTENTS

A simplifying factor in addressing the smart grid standards and technology problem is to find a manner to decompose the interconnected power system and its underlying standards and technologies into coherent parts that allow targeted research to be applied, while exposing the barriers that have precluded solution development. To accomplish this, four fundamental questions related to standards and technology are often asked by the various stakeholders:

- What new and emerging technologies are on the horizon that impact the smart grid of the future?
- How do asset owners avoid incompatible systems being fielded that result in costly replacements ahead of projections (i.e., stranded assets)?
- What drivers exist to help foster open access, competition, and commercial growth of new and exciting technologies that offer energy consumers new ways to meet their energy needs while at the same time saving them money?
- Where can government help and where should government let the private sector initiate efforts (i.e., "public" vs "private")?

22.1 INTRODUCTION TO STANDARDS AND TECHNOLOGY

Standards development can be thought of as a continuum ranging from a single-company's proprietary solution, to a multiparty agreement, then to a dominant organization's set of technologies or market requirements, to regional specifications, to a national standard, and finally to an international standard (see Figure 22.1).

Agreements, requirements, and specifications are defined by single or multiple entities, alliances, or organizations. Often proprietary in nature, they are quickly developed to design and measure

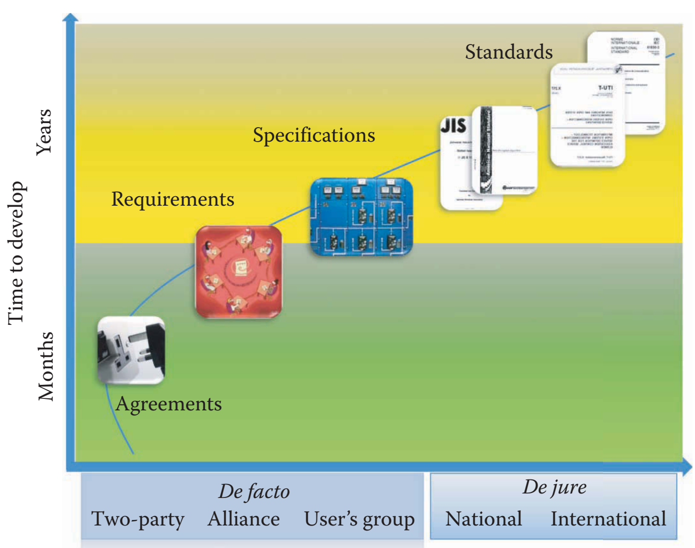

FIGURE 22.1 Standards continuum. (© 2012 EnerNex. All rights reserved. With permission.)

elements, products, and systems, usually over a period of months. They are effective to solve immediate requirements, but are not generally expandable.

A single-organization example drawn from the computing industry is the Microsoft set of application programming interfaces (APIs). These publicly available interfaces are used by developers in combination with the Microsoft Windows software development kit (SDK) to create applications intending to work under the Windows framework. Microsoft has mechanisms to incorporate feedback from developers and customers for their software, APIs, and SDK—also hosting conferences to increase awareness and information exchange among the entire ecosystem. There is a certification program (the "designed for" sticker/logo) to inform customers of the relative capabilities of hardware and software conforming to this set of practices. This approach usually means that these technologies work together well and that users are locked into the organization's products.

Alliances are a group of entities and individuals that recognize the value of a particular technology and form a formal "interest group" to promote, for example, the codification of design and marketing of that technology. One of the primary goals of most alliance efforts is demonstrable product interoperability within the framework of a defined certification program. Extension of the interoperability and certification efforts may even include joint work with other alliances to meet market needs. Multiparty in nature, the difference between an alliance and a formal standards group lies within both the rules and the work products. Since any number and balance of interested parties can form an alliance, the rules under which they operate vary widely, as do their premises and promises.

Alliances often focus on developing *de facto*[1] specifications based on work performed by their members. These *de facto* specifications and requirements may be written in a manner that facilitates work by formal standards groups to develop, modify, and enhance *de jure* standards. Since an alliance may not be required to have a balanced membership or may have limited participation, the work products cannot be considered as standards as such but could be submitted to a recognized, or accredited, standards development organization (SDO) in order to become true *de jure* standards. Another path to standardization would be to change the operating rules and become accredited as an SDO. The following are a few well-known alliances related to the utility industry:

- HomePlug Powerline Alliance (www.homeplug.org)
- Wi-Fi Alliance (www.wi-fi-org)
- ZigBee Alliance (www.zigbee.org)
- G3-PLC Alliance (www.g3-plc.com)
- Open Smart Grid Protocol (OSGP) Alliance (www.osgp.org)
- MESA Alliance for Energy Storage Systems communications (mesastandards.org)

Another type of organization relevant to this discussion is a "user group." A differentiator between user groups, alliances, and formal standardization organizations is that user group formulation and participants emphasize the challenges of actually implementing standards and specifications. An example of a very active user group is the Common Information Model (CIM) Users Group (http://cimug.ucaiug.org), or "CIMug," which meets both to provide tutorials on CIM and to identify additional requirements that could be added to the series of CIM standards.

SDOs operate under similar rules worldwide. A clear distinction from an alliance or user group is that strict control is maintained of the candidate voter pool for balloting as a rigorous measure of fairness and balance. As an example, the American National Standards Institute (ANSI) has three primary categories, producer, user, and general interest, and for balloting purposes, no single category can exceed one-third of eligible voters.

In general terms, the members of the committees doing the actual development work are limited by antitrust rules or laws from engaging in anti-competitive behavior, such as market division and pricing discussions. Also, intellectual property is treated as a potential source for standards language and requires disclosure standards by the holder [1,2].

[1] Journalist's Guide to the Federal Courts: "Something that exists in fact but not as a matter of law."

Formal standards (and many specifications) often begin as *de facto* "standards," that is, enough commonality among enough producers to call the product/approach/protocol "standard." Beyond this, SDOs actually author *de jure* standards—those that are codified in a manner similar to laws. Given the careful attention to balloting balance, open rules, and open participation, standards may be adopted in place of laws in certain jurisdictions. To move beyond standards that are regional in scope, there are copublication (or "dual logo") pacts in place between the SDOs, such as International Electrotechnical Commission (IEC) and Institute of Electrical and Electronics Engineers (IEEE), ANSI and IEEE, and others. Copublication is the first step toward true harmonization, whereby a standard is in place for a broader market. The following are examples of relevant SDOs for the utility industry:

- Internationally recognized SDOs:
  - IEC International Electrotechnical Commission (www.iec.ch)
  - IEEE Institute of Electrical and Electronics Engineers (www.ieee.org)
  - IETF Internet Engineering Task Force (www.ietf.org)
  - ISO International Organization for Standardization (www.iso.org)
  - ITU International Telecommunication Union (www.itu.int)
  - W3C World Wide Web Consortium (www.w3.org)
- Regional or nationally recognized SDOs:
  - ANSI American National Standards Institute (www.ansi.org)
  - BSI British Standards Institution (www.bsigroup.com)
  - CEN European Committee for Standardization (www.cen.eu)
  - CENELEC European Committee for Electrotechnical Standardization (www.cenelec.eu)
  - DIN Deutsches Institut für Normung, German Standards Institute (www.din.de)
  - ETSI European Telecommunications Standards Institute (www.etsi.org)
  - AFNOR Association Française de Normalisation (www.afnor.org)
  - NAESB North American Energy Standards Board (www.naesb.org)
  - UL Underwriters' Laboratories (www.ul.com)

Table 22.1 summarizes the standards continuum with respect to the elements described earlier.

Standards attempt to meet the goal of creating a basic understanding of how to use a technology in a common manner. Unless interoperability tests or guidelines exist for a standard, at best a technology would be in compliance with the standard. In electronic and power technology, unlike physical technology (say, for dimensions of a device), interoperability is the highest aspiration of the

TABLE 22.1
Standards Continuum Summary

	Level	Defined by	Recognized	Example	Time Frame
De Facto	Proprietary	One vendor or user Two vendors or users	Market dominance Market acceptance	File formats, API	Months
	Consortia Industry Alliance	Group of vendors and/or users representing an industry or market segment	Members of the alliance, consortium	ASHRAE, DNP, EIA, IETF, ZigBee	Months/years
De Jure	National	National standards body	Within one country or group of countries	ABNT, ANSI, CEN, CSA, DIN, JSA	Years
	International	International standards body	Worldwide	IEC, IEEE, ISO, ITU	

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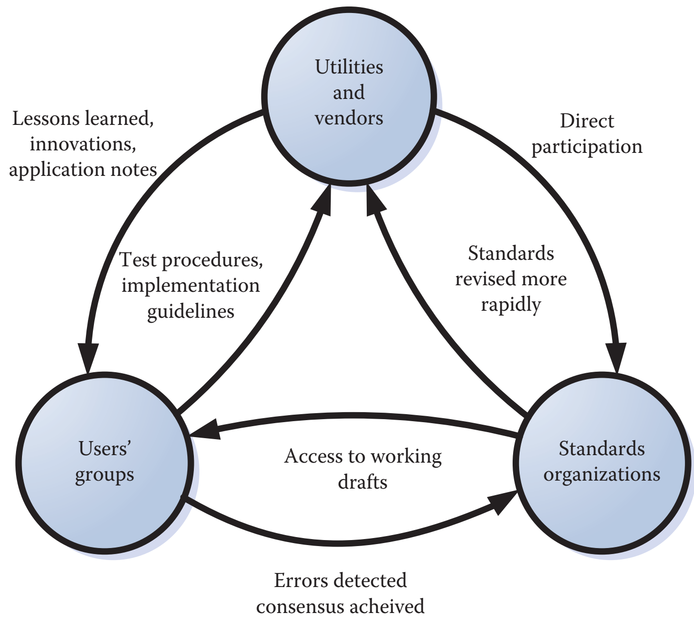

FIGURE 22.2 Successful standardization interaction. (© 2012 EnerNex. All rights reserved. With permission.)

community that developed the standard. This highlights the need for a dedicated user's community tasked to identify interoperability challenges (requirements), write tests to validate products, and certify those results.

A robust and desired relationship between the principal participants of successful standardization efforts is depicted in Figure 22.2. Utilities and vendors provide input into user groups and SDOs in the form of lessons learned, technical innovations, and application notes, and through direct participation. User groups, with early access to SDO drafts, can review and debate errors and propose other changes in a manner that provides a quicker consensus result. This results in the utilities and vendors more quickly receiving developed standards that address oft-desired implementation guidelines and test procedures, providing a higher degree of technology confidence and less "buyer's remorse."

One group that can be identified as laying the foundation for true interoperability is the GridWise Architecture Council (GWAC). The GWAC defined an interoperability context-setting framework [3] that provides a high-level perspective for identifying and debating interoperability issues. This framework defines eight interoperability categories across the utility business from the lowest of Basic Connectivity to the highest at Economic/Regulatory Policy. In addition, a number of cross-cutting issues are enumerated, thus identifying the interdependencies. These concepts are shown in Figure 22.3.

In a partnership with National Institute of Standards and Technology (NIST), from 2007 to 2012, the GWAC sponsored the Grid-Interop [4] conference, with the goals of achieving system-to-system interoperability, achieving business process interoperation, preparing for a sustainable electricity system, developing policies for integrated smart energy, and achieving a holistic view of generation to consumption.

Another method to move beyond standards and technology driven by a single interest group is to use rules and regulations from governments and governmental agencies. The best of these are targets or guidelines with appropriate incentives and penalties without too much prescription. An example from another industry is the corporate average fuel economy (CAFE) standard for automobile manufacturers codified in the U.S. Code [5]. This is a target for the entire production, without specifying which particular models. The market for vehicles (that is, what is being sought

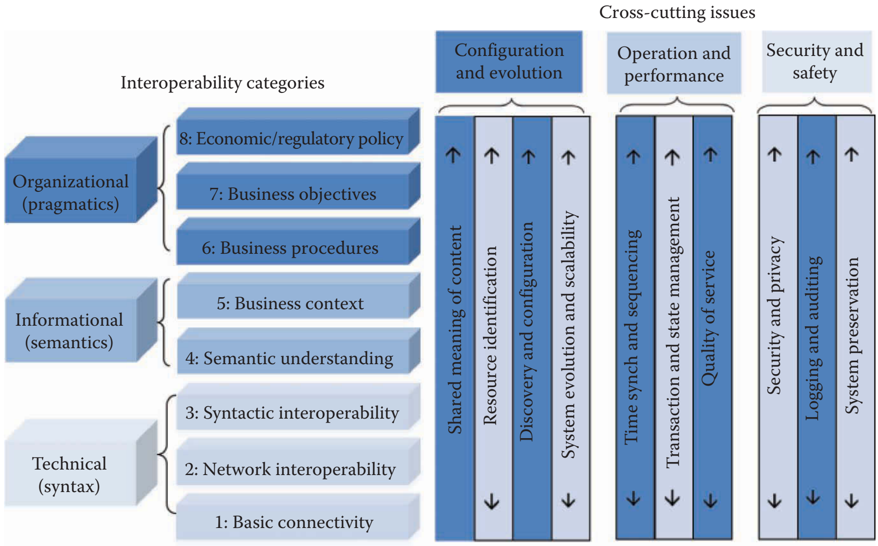

FIGURE 22.3 Interoperability framework. (© 2008 GridWise Architecture Council (GWAC). All rights reserved. The smart grid interoperability maturity model is a work of the GridWise Architecture Council. http://www.gridwiseac.org/about/imm.aspx. With permission.)

and bought) then signals to the manufacturers which vehicle and what volumes are needed, allowing them to develop technologies (engines, combustion techniques, etc.) to meet the government standard measurement.

The term "standard" is truly only applicable in certain situations. It is advocated here to reserve the use of "standard" for *de jure* standards, especially when employed without the "*de jure*" modifier. There may appear to be little harm in referring to *de facto* "standards" simply as "standards," but this dilutes and confuses the definition in the manner that the term "engineer" is often misapplied to functions requiring no engineering education or certification. It is recommended to employ the applicable term of "specification," "requirements," and "requirement specification" instead of "standard."

22.2 ORGANIZATIONS FOCUSED ON SMART GRID STANDARDS

22.2.1 NIST

In 2009, the United States NIST began a three-phase smart grid interoperability plan to expedite development of key standards that incorporate and align the results of efforts by industry players and research institutes. In September 2009, NIST released a report expanding their initial 16 preferred standards to a list of 77 standards, which are all available for review in the full report [6]. However, there were about 70 other broad sectors of the smart grid where NIST has yet to come up with specific recommended standards. At that time, NIST focused on 14 priority areas where key regulators—namely, the U.S. Federal Energy Regulatory Commission (FERC)—said they need them sooner rather than later. The initial set of "action plans" driven by the Smart Grid Interoperability Panel (SGIP) resulted in a number of new or modified standards for the utility industry and has since been expanded to address new technological innovations, such as the Green Button, the Orange Button, and the application of Internet of Things (IoT) devices at the so-called grid-edge through the Open Field Message Bus (OpenFMB) effort led, in part, by the Smart Grid Interoperability Panel (SGIP)[2]. At the time of this writing, 73 standards are part of the NIST release 3.0 framework and the SGIP Catalog of Standards (CoS) [7].

[2] The SGIP merged with SEPA (www.sepapower.og) in April 2017.

22.2.2 IEC SyC Smart Energy

As power utilities have to cope with the complex mixture of ever growing demand, the integration of intermittent sources from renewables, and aging infrastructures, the need for intelligent electricity networks or smart grids, which integrate the actions of all users connected to them, has emerged. The IEC has been at the forefront of smart grid standardization through the work of many of its technical committees (TCs) and of a dedicated Strategic Group (SG), Systems Evaluation Group (SEG), and, very recently, Systems Committee (SyC Smart Energy).

In 2012, the European Union (EU) sponsored the development of a three-dimensional Smart Grid Architecture Model (SGAM), based on GWAC stack, organized with a smart grid architecture plane having five domains, six zones, and five interoperability layers as illustrated in Figures 22.4 and 22.5.

The SGAM concept, along with cross-cutting nonfunctional areas, is used by the IEC as a framework for categorizing its standards. For instance, to help grid managers find their way through the smart grid standards ecosystem, the IEC has developed an interactive Smart Grid Standards Map (http://smartgridstandardsmap.com/). This map provides an overall view of the smart grid architecture and lists of relevant IEC, ISO, and ITU standards (with previews). Users can select to view all standards associated with a particular domain or can single out any given standard in relation to its role within the smart grid.

The IEC has also established a few system committees for different areas, such as smart energy [8]. SyC working groups are aimed at the systems level instead of the product level, and focus on defining reference architectures, use cases, and appropriate standards and guidance on the interfaces, functionality, and interaction of a system within the scope of their charter. The SyC working groups span multiple TC/subcommittees and external organizations, although they have no authority to dictate to any of them. They can produce IEC deliverables and have a system-orientated secretariat provided by IEC Central Office.

Recently, the IEC established the SyC Smart Energy. The status as a Systems Committee provides SyC Smart Energy with the operational capability of engaging and supporting TCs. It is also able to publish IEC Systems Reference Documents (SRD) that can be referenced by interested

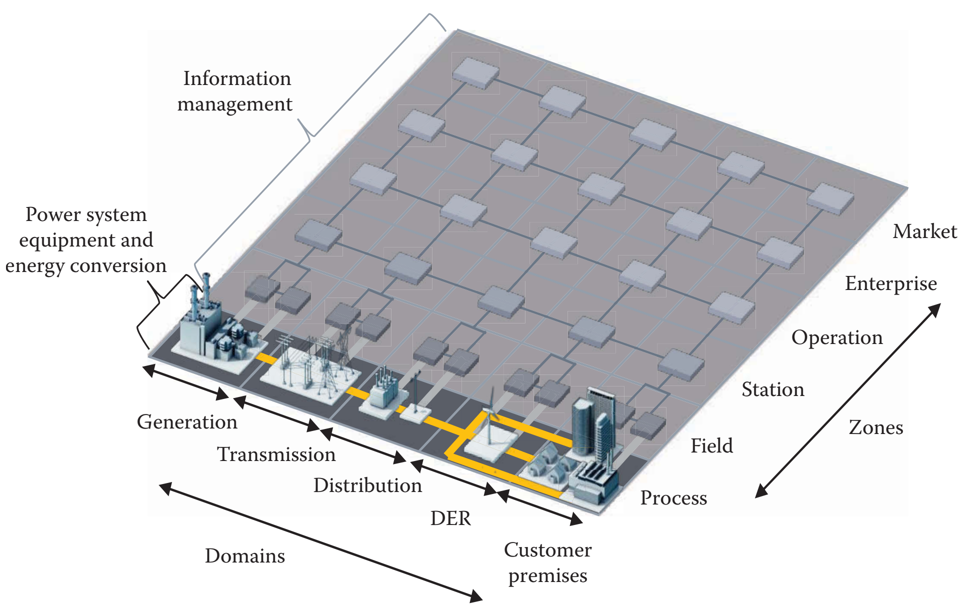

FIGURE 22.4 Smart grid architecture plane. (© 2012 CEN-CENELEC-ETSI. All rights reserved.)

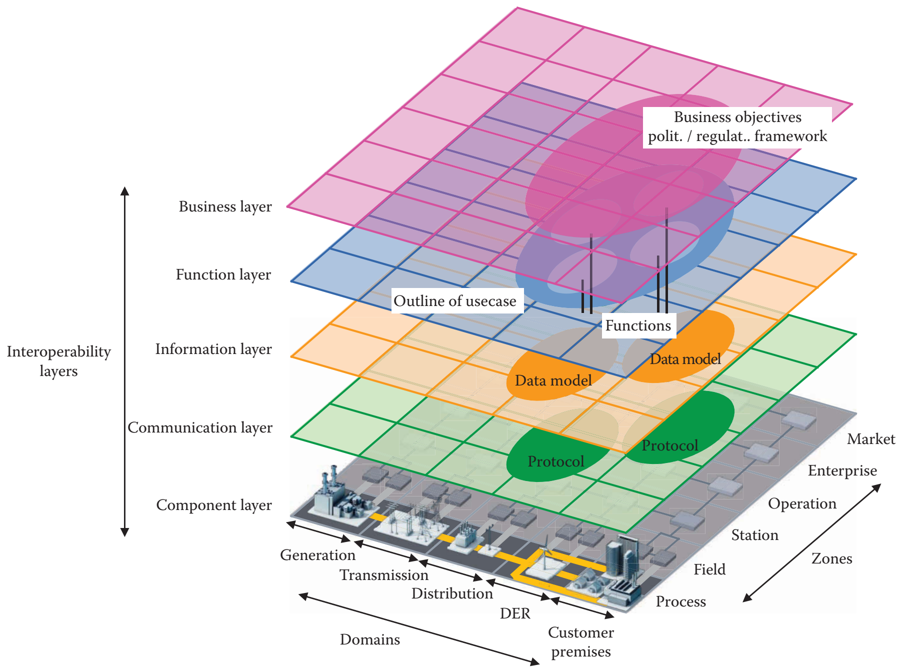

FIGURE 22.5 Smart grid architecture model (SGAM) framework. (© 2012 CEN-CENELEC-ETSI. All rights reserved.)

parties, thus providing enhanced consistency of approach for generic use cases and roadmaps, to name two examples. The scope of the new SyC on Smart Energy includes the following:

- Standardization in the field of Smart Energy in order to provide systems-level standardization, coordination, and guidance in the areas of smart grid and smart energy, including interaction in the areas of heat and gas
- Wide consultation within the IEC community and the broader stakeholder community to provide overall systems-level value, support, and guidance to the TCs and other standard development groups, both inside and outside the IEC
- Liaison and cooperation with SyC Smart Cities, SyC Active Assisted Living and SEGs (Low Voltage Direct Current Applications, Distribution and Safety for use in Developed and Developing Economies, Non-conventional Distribution Networks/Microgrids, Smart Manufacturing) as well as with the Systems Resource Group (SRG). The SRG is a group of systems methodology experts whose purpose is to guide the development and use of specialized tools and software applications for systems, and encourage the use of these tools and sharing of best practices within the Systems Committees.
- Cyber Security and Resilience Guidelines for Cyber-Physical Systems. This effort covers the concepts of cyber security for smart energy, such as risk assessment, defense-in-depth, and different requirements for Operational Technology (OT) versus Information Technology (IT).

Figure 22.6 describes the SyC Smart Energy organization and dynamic workflow with TCs that allow the identification of standards situation at system level.

Liaisons are established with user groups and with regional organizations (named as Ad hoc Groups). New smart grid requirements are gathered via a rigorous Use Case methodology in Working Group 6, in close cooperation with Technical Committees. These use cases are formalized by Working Group 5 and populate a Use Case Repository. Roadmaps are established by Working Group 3, and prioritization plans are established by Working Group 2 in coordination with TC

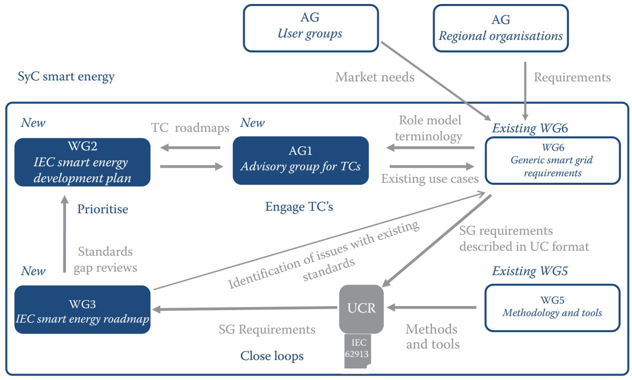

FIGURE 22.6 IEC SyC smart energy overview.

by the means of Advisory Group 1. Leveraging the success of this approach, the IEC has created another SyC on Smart Cities [9].

22.2.3 IEC TC57

IEC Technical Committee 57 (TC57) [10] is member of SyC Smart Energy. Its scope is to prepare international standards for power systems control equipment and systems including energy management systems (EMS), supervisory control and data acquisition (SCADA), distributed energy resources (DER), distribution automation, teleprotection, and associated information exchange for real-time and non-real-time information, used in the planning, operation, and maintenance of power systems. Power systems management comprises control within control centers, substations, primary equipment, and DER systems, including telecontrol and interfaces to equipment, systems, and databases, which may be outside the scope of TC57. TC57 develops key smart grid standards IEC 61850 and CIM. The CIM (IEC 61968, IEC 61970, and IEC 62325 series) and the IEC 61850 series have been recognized as pillars for realization of the smart grid objectives of interoperability and device management. These series define the semantic domains of power system management. Figure 22.7 depicts the application coverage of CIM and IEC 61850 in the SGAM.

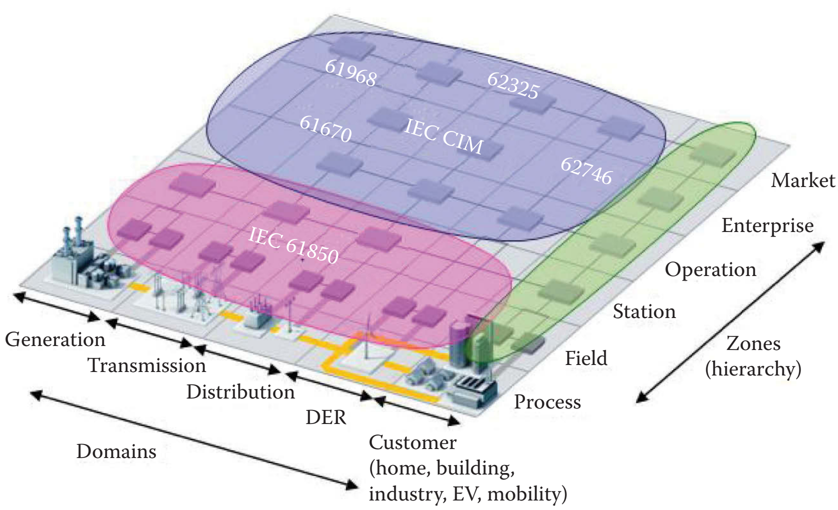

FIGURE 22.7 IEC TC 57 overview.

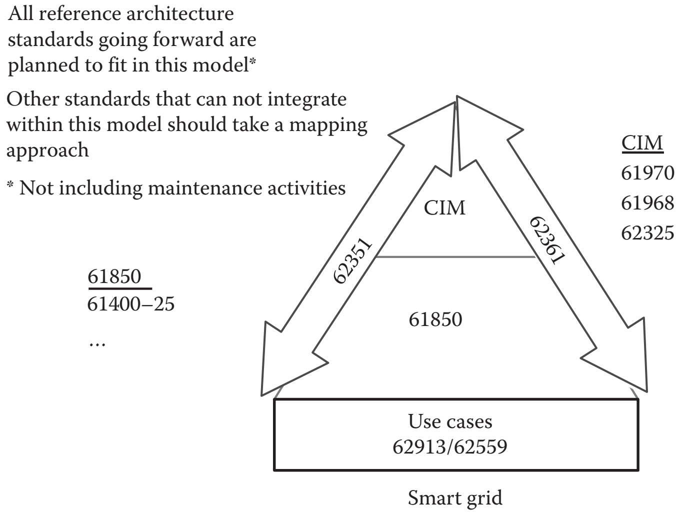

FIGURE 22.8 Core domain of the TC57 reference architecture. (From IEC/TR 62357-1 ed.2.0. © 2016 IEC Geneva, Switzerland. www.iec.ch. With permission.)

TC57 controls development of IEC 61850 and CIM in its application domain, and supports other TCs to develop core standards in their own application domains (e.g., extension of IEC 61850 for wind turbines in TC88 and electric vehicles in TC69). Its reference architecture, published officially in 2016 (IEC 62357-1), defines the core standards, as shown in Figure 22.8, namely, IEC 61970 (CIM for power models), IEC 61968 (CIM for Distribution), IEC 61850 (for substation automation, hydrogeneration, distribution automation, and DER), and IEC 62351 (cybersecurity). These standards meet the requirements that are being developed by the SyC working groups in IEC 62913 as per the use case specification in IEC 62559.

A more detailed diagram is shown in Figure 22.9.

22.2.4 IECEE Certification Body (CB)

The CB scheme of the IECEE (IEC System for Conformity Testing and Certification of Electrotechnical Equipment and Components) is a strong example of international cooperation; it encourages efficient international trade by slowly abolishing technical barriers and identifying national differences. The IECEE CB has obligated participating countries to conform to IEC standards for various electronic components, equipment, and products while providing evidence (CB Test Certificates) that applicants have successfully passed the requirements of IEC standards. If national standards do not adhere entirely to IEC standards, variances are permitted after formally declaring and detailing these to the IECEE [11].

22.2.5 ENTSO-E and IEC Standards

ENTSO-E, the European Network of Transmission System Operators for Electricity, represents 42 electricity transmission system operators (TSOs) from 35 countries across Europe. ENTSO-E was established and given legal mandates by the EU Third Legislative Package for the Internal Energy Market in 2009, which aims at further liberalizing the gas and electricity markets in the EU, and established grid codes for DER in 2016. The role of TSOs has considerably evolved with the Third Energy Package. Because of unbundling and the liberalization of the energy market, TSOs have become the meeting place for the various players to interact on the market place. ENTSO-E members share the objective of setting up the internal energy market and ensuring its optimal

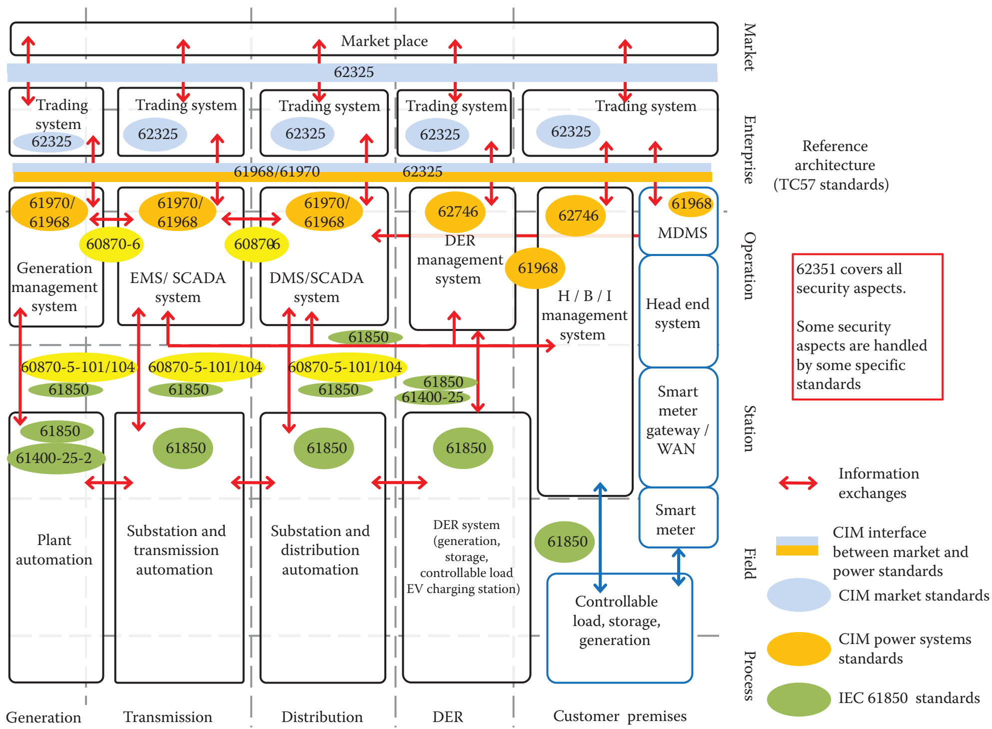

FIGURE 22.9 TC57 reference architecture. (From IEC/TR 62357-1 ed.2.0. © 2016 IEC Geneva, Switzerland. www.iec.ch. With permission.)

functioning, and supporting the ambitious European energy and climate agenda. ENTSO-E has actively worked with the IEC to develop communication standards for this marketplace, defining their requirements in the CIM-based IEC 62325, IEC 61970, and IEC 61968.

ENTSO-E will also work with the IEC to ensure that the IEC 61850-7-420 standard meets all of the new DER grid code requirements. That standard is currently being updated to meet both the new ENTSO-E grid code interconnection requirements and the North American IEEE 1547 DER interconnection and interoperability requirements, which are currently being revised. These new requirements include many autonomous functions as well the possibility of direct or indirect control of DER capabilities, including:

- Disconnect/connect function
- Cease to energize/return to service function
- High/low voltage ride-through (fault ride-through) mode
- High/low frequency ride-through mode
- Dynamic reactive current support mode
- Frequency watt emergency mode (frequency sensitivity mode)
- Volt-watt mode
- Fixed power factor mode
- Set reactive power mode
- Volt/VAr mode
- Watt-VAr mode
- Active power limiting mode
- Low frequency-watt emergency mode for demand side management (fast load shedding)
- Low voltage-watt emergency mode for demand-side management

ENTSO-E is committed to develop the most suitable responses to the challenge of a changing power system while maintaining security of supply. Innovation, a market-based approach, customer focus, stakeholder focus, security of supply, flexibility, and regional cooperation are key to ENTSO-E's agenda. ENTSO-E contributes to the achievement of these objectives through:

- policy positions,
- the drafting of network codes (a form of standards) and contributing to their implementation,
- regional cooperation through the Regional Security Coordination Initiatives,
- technical cooperation between TSOs,
- the publication of Summer and Winter Outlook reports for electricity generation for the short-term system adequacy overview,
- the development of long-term pan-European network plans, and
- the coordination of research and development plans, innovation activities, and the participation in research programs such as Horizon 2020.

Three main system committees are part of ENTSO-E: the System Development Committee (SDC), the System Operation Committee (SOC), and the Market Committee (MC). The SDC is in charge of TSO cooperation regarding network development and planning. Its main mission is to coordinate the development of a secure, environmentally sustainable, and economical transmission system with the aim of creating a robust European grid that can facilitate the creation of a well-functioning European electricity market and, from the planning point of view, a high standard of interoperability, reliability, and security.

The SOC is in charge of ENTSO-E system operation activities. System operations is the core activity of any TSO and covers the actions taken to ensure the optimal and secure operation of the grid in real time.

The MC objective is to ensure that the objectives of the Third Internal Energy Market package are realized and facilitate the development of a well-functioning European electricity market. This is achieved by contributing to market design and developing market-related network codes in cooperation with ENTSO-E's 42 members, and in close consultation with stakeholders.

ENTSO-E's members, through its main committees (SDC, SOC, and MC), are implementing IEC CIM standards in order to improve the quality of network models and increase the efficiency of data and model exchanges among the member TSOs and with the secretariat. A major reason why this standard is important for ENTSO-E is that different TSOs use different tools with different input formats for power system studies. ENTSO-E agreed on a roadmap for the implementation of future updates of the CIM-based format for exchanges of system operations and system studies.

The interoperability of the applications used by TSOs for operational and system development exchanges is crucial, and ENTSO-E has the objective to ensure the interoperability via compliance of those applications with the Common Grid Model Exchange Standard (CGMES) requirements. Thus, ENTSO-E approved the CGMES Conformity Assessment Framework, which establishes services:

- to facilitate the elaboration of the CGMES,
- the implementation of the European network codes, and
- the elaboration of the system development studies, specific power system analysis software and IT systems (both hereafter referred to as Applications) that are used to ensure smooth data exchanges between TSOs.

ENTSO-E is organizing interoperability (IOP) tests to demonstrate interoperability using the ENTSO-E CIM-based data exchange format and the IEC CIM-based standard. The tests are also designed in order to allow vendors to verify the correctness of the implementation of the updated CIM standard and support ENTSO-E processes toward achieving the objectives given to ENTSO-E by the EU's Third Energy Package.

The adoption of the ENTSO-E CIM interoperability tests and the CIM/eXtensible Markup Language (XML)-based data exchange format is a direct contribution to the ENTSO-E tasks defined by the EU. The experience gained from the process of developing and implementing CIM-based standards will directly contribute to the future networking code development as data exchange processes will be part of several network codes.

Since 2009, ENTSO-E has organized large-scale IOP tests for grid model exchange. The CIM for grid model exchange enables exchanges for the data necessary for regional or pan-European grid development studies, and for future processes related to network codes.

In 2012, ENTSO-E organized the first IOP on CIM for energy market and began a series of IOPs related to the CIM for European market style. The European style market profile, as defined in IEC 62325-351, provides the core components for use in the IEC 62325-451-‘X’ standards, which target specific core business processes within Europe’s internal electricity market, such as scheduling, settlement, capacity allocation and nomination, and acknowledgment. ENTSO-E is also committed to 61850 interoperability tests [12–15].

22.3 SMART GRID STANDARDS ASSESSMENT

Although the vast majority of engineers working on the smart grid understand the importance of standards in the deployment of smart grid technologies, a big concern is how long it takes to develop standards and have them adopted by national or international standards bodies. Standards usually have a cycle of adoption from two to five years. The industry cannot develop smart grid standards using current methods and hope to match the pace of technology evolution. What then are the approaches to standards that the industry should take? First, luckily, there are already many standards adopted by international standards bodies, which are fully applicable to the smart grid of today and tomorrow.

Figure 22.10 provides a high-level overview of the smart grid landscape through identified, network-centric domains. Ideally, each of the domains, members, and technologies would interact

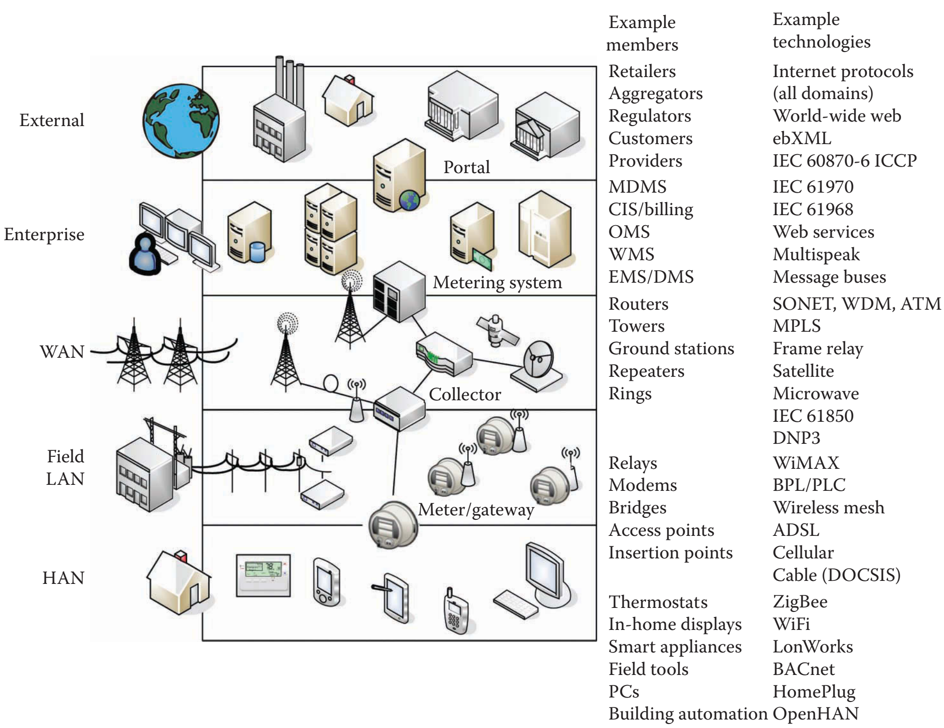

FIGURE 22.10 Smart grid domains of interoperation. (© 2012 EnerNex. All rights reserved. With permission.)

in a manner that empowered all actors (utilities, customers, etc.) to participate in meeting any of the business, technology, and societal goals. From the home area network (HAN), where consumers would be able to purchase and install monitors and controls, through the utility network formed of communications and power system infrastructure to the enterprise applications, data would be transformed into useful information wherever and whenever necessary. In reality, each of the horizontal domains (field area network, wide-area network, etc.) represents a zone of interoperation where there may be competing and complementary standards and technology, often focused on a specific technology or partner technologies and developed without consideration for the requirements of any other domains.

Figure 22.11 is a more complex representation of the hurdles to achieving interoperability (seamless information exchange) between devices and systems using the advanced metering infrastructure (AMI) enterprise as an example. One can easily trace from the HAN, through a LAN and WAN, and into the utility enterprise. Orthogonal to this view, there are seven layers displaying the open system interconnection (OSI), layered communications model [4]: application, presentation, session, transport, network, data link, and physical. To be properly integrated, any two devices/systems must agree on standards and protocols for each of the seven layers.

Layer 1, the physical layer, identifies the media (hardware) by which bits are exchanged. Layer 2, the data link, or media access control layer, is where the exchange of frames (multiple bits) between hardware and software is performed. Layer 3, the network layer, is where paths are determined and logical addressing is applied for packets (multiple frames). Layer 4, the transport layer, is where end-to-end connections are formed and segments (multiple packets) are exchanged. Layer 5, the session layer, deals with interhost communication. Layer 6, the presentation layer, deals with data representation and encryption. Layer 7, the application layer, is where data are used and information is created and where users connect interface devices.

Communications protocols (the name given to a specific instantiation of the seven-layer OSI stack) may not explicitly define all seven layers of the OSI stack. These "short" stacks may only

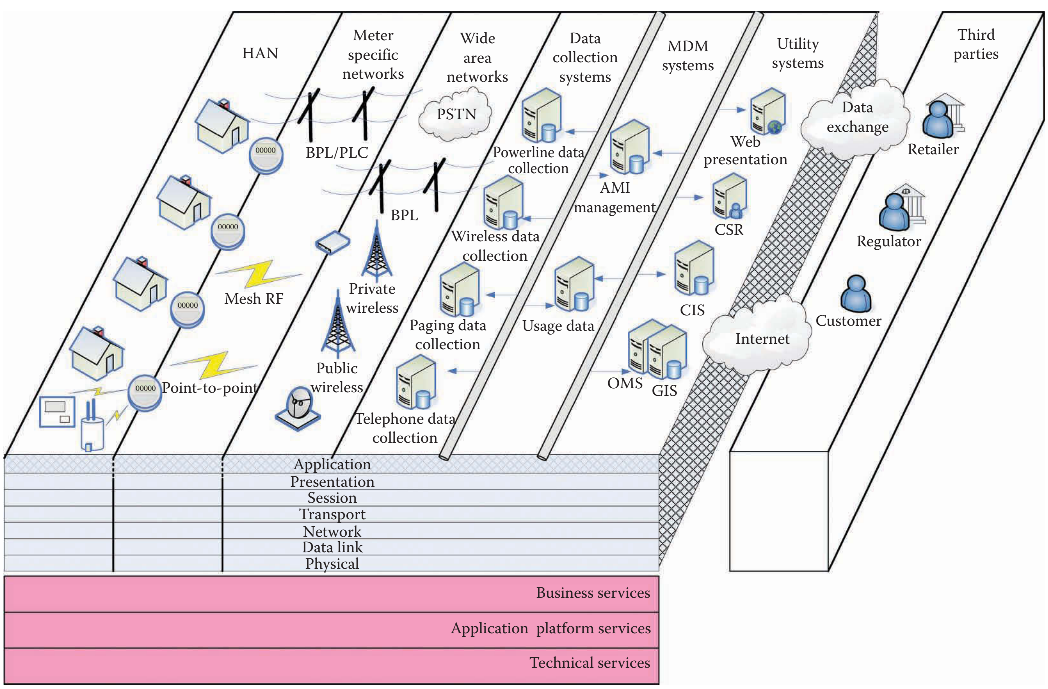

FIGURE 22.11 Interoperability hurdles in the AMI enterprise [16]. (© 2012 EnerNex. All rights reserved. With permission.)

explicitly reference three or four layers; however, the functionality of all seven OSI layers is typically bundled somewhere in the protocol even though some layers are only implicitly defined. The OSI model is generally accepted as the most detailed practical representation of communications functionality.

22.4 SMART GRID GAP IDENTIFICATION AND DECOMPOSITION

The utility landscape can be decomposed into discrete domains, along different philosophies. One relevant version is that from the NIST framework, shown in Figure 22.12. The highest level is shown here with the markets, operations, service provider, generation, transmission, distribution, and customer domains.

Most of the existing utility business process systems have been designed, tendered, installed, and operated for a single application, in what are known colloquially as "silos." The most common application that may cross operational and communications domains is a SCADA system, which is used by a control center to operate elements in the substation domain across a WAN. Despite this internal isolation, a significant amount of utility research and development effort has been devoted to advanced applications, usually with the presumption of some sort of high-speed communications network being available. Examples of these advanced applications are a broadly deployed power quality monitoring and control system or a phasor measurement monitoring system. The former often requires feature-rich monitoring devices (large quantities of data, to the oscillographic level) and extremely high-speed communications to leverage the system under operational conditions (sub-second to minutes). The latter may represent fewer data elements but still necessitates high-speed communications with low total elapsed time (latency) for its most useful applications of system protections (a few seconds) to system state calculation (a few minutes).

As much as the utility business is still composed of internal silos of operation, the product domain exhibits the same characteristics. It is rare for companies to have a broad portfolio of solutions for more than two of the domains. Even if one abstracts the problem further, one finds the standards and user communities also typically focus their efforts on one domain, one integrated solution, or one particular product or suite of products.

With the plethora of standards available in the utility space in each "network" domain as well as through the OSI layers, it is often beneficial to juxtapose existing standards against actual

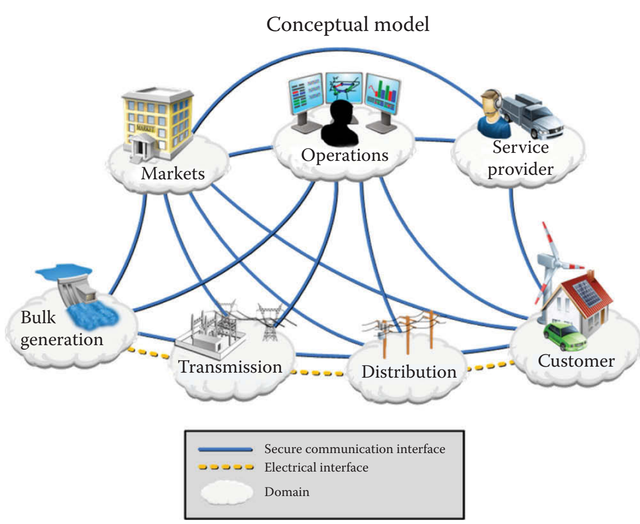

FIGURE 22.12 NIST conceptual model defining domains. (© 2009 NIST. All rights reserved. With permission.)

requirements, resulting in a “gap” analysis. A gap analysis is facilitated by preparing annotated requirements against applicable technologies. An approach that derives requirements from use cases is one of the best methods to develop lists of functional requirements [17].

22.4.1 Generation

For generation power equipment, this is a well-defined space, with mature standards and regulations. However, technology in the generation area will always evolve, and new standards will always be developed.

22.4.2 Transmission

For transmission power equipment, this is also a well-defined space, with mature standards and regulations. For communications between utility operations applications and transmission equipment, the same is generally true. Technology in the transmission area will always evolve, and new standards will always be developed. Representative standards, specifications, and technologies are categorized by application domain in Table 22.2.

TABLE 22.2
Transmission Standards and Technology

Domain	Standard/Specification/Technology
Control centers	• IEC 61970 CIM • IEC 60870-6 Intercontrol Center Communications Protocol (ICCP) • National Rural Electric Cooperative Association (NRECA) MultiSpeak
Substations	• IEEE C37.1 SCADA and Automation Systems • IEEE C37.2 Device Function Numbers • IEC 61850 Protocols, Configuration, Information Models • IEEE 1646 Communications Performance • IEEE 1815 Distributed Network Protocol (DNP3) • Modbus • IEEE C37.111-1999 COMTRADE • IEEE 1159.3 PQDIF
Outside the substation	• IEEE C37.118 Phasor Measurement • IEC 61850-90 (in development) • IEEE 1588 Precision Time Protocol • Network Time Protocol
Security	• IEEE 1686 IED Security • IEC 62351 Utility Communications Security • NERC Critical Infrastructure Protection (CIP) Standards • ISO/IEC 27002/27019 • IEC 62443 Series
Hardening/codes	• IEEE 1613 Substation Hardening for Gateways • IEC 61000-4 Electromagnetic Compatibility • IEC 60870-2 Telecontrol Operating Conditions • IEC 61850-3 General Requirements

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22.4.3 Distribution and DER

For typical central generation supply and typical substation designs, this is a well-defined space, with mature standards and regulations. For legacy utility communications, the same is true. However, distribution and DER are areas where much of the innovation is expected to occur. A paradigm shift is occurring where the smart grid is moving away from the central generation supply model, and toward a distributed model with DER (generation, storage, and controllable load) supplying significant amounts of power and requiring widely dispersed management at the distribution level.

IEC 61850-7-420 has been developed over the last years to address the communications requirements, focusing on developing an information model of the sophisticated DER functions, and recently including IoT technologies to better reach the DER systems spread throughout utility territories. These DER functions include "high/low voltage ride-through" (in which DER systems attempt to remain operational even during short voltage spikes and sags), "high/low frequency ride-through," "Volt/VAr" (in which DER systems counteract voltage rises and falls by modifying their reactive power), and "frequency-watt control" (in which DER systems modify their active power to counter frequency increases and decreases). These autonomous functions, enabled as needed by utilities, provide the kind of power system management that used to be provided only by bulk generators under direct utility control—a situation no longer possible with the installation of millions of DER systems.

Cybersecurity has become increasingly important as utilities need to interact with DER systems that are not under their direct control or within protected boundaries. IEC 62351 is a series of security standards covering key cybersecurity requirements and providing guidelines for power system operations with these new communication requirements. The SyC Smart Energy cybersecurity guidelines provide additional understandings and references to the key cybersecurity standards for the power industry.

In many countries, IEC 61850 is being used both as the information model and as the protocol. In North America, the IEC 61850 information model is considered as the source for DER communications, but other protocols are used. In particular, IEEE 2030.5 (SEP2 – Smart Energy Profile 2.0) has been developed to support many of the DER functions, and IEEE 1815 (DNP3) is mapped from IEC 61850 to be used by utility SCADA systems.

In North America, IEEE 1547, which is used by most jurisdictions to establish the regulations for interconnecting DER systems, has also undertaken a revision to make many of the key DER reliability-related functions mandatory. Without such mandates, utilities with high penetrations of DER systems would soon not be able to manage their grids, given the fluctuations of renewable sources and the fact that DER systems are not directly under the control of the utilities. UL 1741 has been updated to cover testing these sophisticated DER functions, to make sure they can work reliably when interconnected with the power grid.

The IEC also has developed the CIM standards (IEC 61968) for use in exchanging information about the distribution system within the control center. Additional efforts work on harmonizing the interfaces between the IEC 61850 information model, which is focused on DER functions and device communications, and the CIM, which is focused on interactions between control center applications that need to model and study power systems with DER.

Other examples of protocols in this domain include the IEEE 1815/DNP3 and Modbus for what is known as distribution automation products, and ANSI C12.19 (table-based data model) and ANSI C12.22 (networked communications) standards for electricity metering products. A series of standards produced by the IEC in the 62052/62053/62056 series provides a competing set of metering protocols standards to ANSI C12.

22.4.4 AMI Communications Technologies

Vendors are currently building "last mile" AMI communications solutions around five technologies: wireless star, wireless mesh, power line carrier (PLC), broadband over power line (BPL), and fiber optics. Wireless star technologies are typically available in both licensed (200 MHz, 900 MHz) and unlicensed spectra (900 MHz, 2.4 GHz). Advantages of licensed technology include greater allowable transmission power (2 W vs 1 W) and blocking of interference sources in certain jurisdictions. The principal disadvantage is the need to obtain a jurisdiction-by-jurisdiction license to operate. The desired frequency may also have been already allocated. Advantages of unlicensed technology are elimination of licensing requirements due to the use of the "free" spectra and more choices of a set of frequencies to use within the spectral bands. These two aspects often offset the potential interference and lower allowable transmission power. For wired technologies, the principal hurdle is propagation of the signal across power system equipment, such as transformers. Transformers act as natural filters to the radio-frequency signal. Another difficulty is maximizing the bidirectional communications rate. For BPL technologies, the communications rate is solved by choice of the frequency band; however, power line communications equipment often interferes with other wireless communications technologies (amateur radio). None of the aforementioned limitations apply to fiber optic technologies. However, it is often difficult to cost-justify "fiber to the home" for a single purpose use (such as advanced metering). Smaller utilities, such as municipalities have sometimes successfully invested in this medium as they may then be able to offer cable television, phone service, and Internet service first (depending on competitive legal issues) with enough bandwidth still remaining for their utility operations.

The major disadvantage of wired technologies is that they are often incompatible with water and gas meters due to their use of the electrical distribution wires as the transmission media. A wireless technology is needed to reach any device not receiving electric service. Sometimes, utilities will adopt a hybrid approach, utilizing different technologies to accomplish heterogeneous functional objectives.

22.4.5 Consumer

For the consumer, equipment standards are generally driven by product safety codes and regulations, especially for electricity-consuming products. UL and the Canadian Standards Association (CSA) are the main bodies that develop safety standards, with the National Fire Protection Agency (NFPA) responsible for the National Electric Code (NFPA 70), a version of which is used to judge installations. Another safety-oriented standard is IEEE C2, known as the National Electric Safety Code. For communications signals and interference, the Federal Communications Commission (FCC) has jurisdiction over products according to Code of Federal Regulations Title 47 Part 15. Most consumer devices are tested and certified to accept any incoming interfering signals and continue operations and do not generate any interfering signals in a certain frequency band. Communications standards and specifications have historically failed to gain widespread application (and product adoption) due to the variety of products in this market space at all levels. Industry-facing efforts include the specifications developed by the ZigBee and HomePlug alliances, standards such as BACnet (building automation and control network communications protocol), LONWorks, IEEE 2030.5 Smart Energy Profile 2, and ANSI/ASHRAE/NEMA 201. In certain cases, an alliance will coalesce around a standard to deal with the certification and marketing of products conforming to the standard. An example of this is the Wi-Fi (short for wireless fidelity) Alliance, formed to address the market needs of products conforming to the IEEE 802.11 series of standards.

22.4.6 Enterprise Integration

Enterprise integration identifies the connection of disparate applications needed to drive the utility business needs. This typically includes applications with "system" in their name, such as outage management systems, graphical information systems, distribution management systems, energy management systems, customer information systems, meter data management systems, or even an enterprise resource planning system. Common practice is for each of these systems to be supplied by a different vendor, leading to difficulties in managing the data needed to run the utility business. The industry is moving toward CIM IEC development and away from proprietary integration development.

22.4.7 NERC CIP Standards

The NERC Critical Infrastructure Protection (CIP) standards received the force of law in the United States in 2008 when the FERC approved their use. These standards dictate measures utilities must take in identifying and protecting critical cyber assets. However, jurisdictional issues complicate the matter for distribution-oriented smart grid technologies, such as DER and AMI. The primary point of contention over whether or not the CIP standards should apply to DER and AMI has to do with one of the criteria explicitly delineated as requiring consideration for designation as a critical asset. CIP 002 states that utilities shall give consideration to “systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more.” If an AMI deployment includes integrated disconnects in the meters, this threshold is easily surpassed by distribution networks even in the 100,000 home range. For larger deployments with significant distributed energy resources and demand response program enrollment, it is possible this threshold may even be surpassed without disconnects in the equation. The takeaway point here is that significant smart grid technology deployments, such as distribution automation or advanced metering have the ability to dramatically affect load if compromised and used improperly or for malicious intent. Furthermore, the automation capabilities of these systems may provide the ability to drop load suddenly or rapidly enough to impact overall system stability, including causing problems for transmission and generation, and possibly even causing a cascading blackout. This is a case of technological development having simply outpaced the relevant regulatory structures. By law, NERC has jurisdiction over generation and transmission as they frequently involve interstate commerce. Most distribution technologies including AMI do not involve interstate commerce and, therefore, fall under the purview of individual state utility commissions. As of this writing, the NERC CIP standards do not apply to DER, AMI or any other smart grid technology deployed in the distribution domain.

22.5 ONGOING ISSUES WITH SMART GRID DEPLOYMENTS

22.5.1 Interoperability Weak Spots

Several of the key smart grid communications standards, notably ANSI C12, IEC 61850, and IEC 61968/61970 (CIM), follow a similar pattern:

- Committees have developed them over a long time, perhaps a decade or more, and the standards, therefore, represent heroic efforts on the part of multiple stakeholders to compromise. The fact that some of them exist at all is remarkable.
- Nevertheless, the process in which they were developed means the standards contain options for most of the possible ways that vendors have implemented these utility applications over the years.
- The standards, therefore, contain many implementation choices with few mandatory items, and implementations are difficult for utilities to specify without significant internal expertise.
- Utilities use these standards in areas that have traditionally been dominated by single-vendor implementations, and for economic reasons, *unfortunately continue to be so dominated* despite the use of the standards. Therefore, significant multivendor interoperability testing in real-world situations is slow to arrive, and sometimes painful when it does.
- In some cases, such as ANSI C12, no organization exists even to provide certification testing. Although it is less effective than true interoperability testing, certification would at least represent a major step toward interoperability.

- Devices implementing the standard typically can establish basic communications and exchange simple information very easily. However, when trying to deploy more advanced functions, utilities discover that vendors follow differences in philosophy that cause them to not work well together. The GridWise Interoperability Framework [3] would identify these philosophical differences as a lack of interoperability at the level of semantic understanding, business context, or business procedures.

The traditional solution for these problems is to let more time pass and let the standard mature. Implementers discover the weak spots in the standard, and utility users eventually begin to demand more mandatory items. The industry eventually develops guidelines for implementation that restrict the number of ways a vendor can implement the standard to a minimum set. IEC 61850, for instance, has released a second edition, including additional amendments, addressing many of the "tissues" (technical issues) in the first edition. In addition, profiles of these standards are being developed that focus on specific requirements. IEC 61850 also includes a system configuration language that allows vendors and utilities to configure their equipment in a consistent and verifiable manner, thus avoiding some of manual steps previously required to configure the equipment in a substation.

However, the regulatory and economic realities of smart grid deployment mean that some utilities do not have the time to wait for the standards to mature. It may be necessary for groups of utilities to step in and impose guidelines for interoperability. Nevertheless, to do so, assume that someone knows what the best guidelines should be!

22.5.2 No Pervasive HAN Standard

In attempting to deploy smart grid applications such as AMI and DR to the home, utilities have necessarily entered the volatile home and building automation markets. These industries have implemented a huge variety of networking technologies, open and proprietary, wired and wireless. The leaders in this area include HomePlug 6LoWPAN and ZigBee, plus semi-proprietary solutions like LonTalk, Insteon, and Z-Wave; more traditional (but costly and power-hungry) open standards like Ethernet and Wi-Fi; and popular legacy protocols, such as X10. Such diversity and lack of interoperability have presented difficulties to the vendors in these markets previously, but the problem has been exacerbated by the deployment of AMI and other smart grid applications. Utilities would prefer to implement a single networking technology across every premise in their service area, a possibility that was previously very unlikely in this market.

There are a few promising efforts in this area. Among them was the swift creation of IEEE 2030.5 (SEP), an application layer object model dedicated to electric utility functions. In addition, OpenADR has been developed to provide market information for demand response. Another promising sign is the agreement between the ZigBee Alliance and HomePlug PowerLine Alliance to develop a common application layer across their respective wireless and broadband-over-power line technologies.

However, any standards effort takes time. Utilities that must deploy customer-oriented smart grid applications are continually forced to either commit to a particular technology, provide services only to customers who already have Internet access, or defer applications that require the use of HAN until some future release. In the latter case, they may be faced with higher upgrade costs later.

The reality is that the promises of smart grid for the average consumer will require both voluntary, nontechnical changes in their consumption behavior, or that and the installation of some technology in their home that enables their desire to participate to be enacted on their behalf. For the latter case, the reality of a retail friendly experience is not yet realized, except perhaps for Wi-Fi connected devices. There are challenges beyond what for many is a daunting part of their home life … becoming a network administrator for their Internet service and pool of computing devices. The installation, commissioning, and maintenance of a sensor network to obtain actionable data blend electrical knowledge, business skills, and somewhat advanced information technology capabilities to make this a reality [18].

22.5.3 Gateway Definition Between Utility and Premise

Although the EPRI and others have been studying the idea of a "consumer portal" for several years now, the technological shape of the gateway between the utility and each customer has never been well defined. For instance, consider a system using ANSI C12 over the WAN and distribution LAN and the ZigBee Smart Energy profile on customer premises. There is no specification that clearly defines how the functions of these two technologies should be mapped to one another. For instance, which object or message on the HAN implements a demand response event expressed in ANSI C12?

22.5.4 Legacy Transmission and Distribution Automation

Utilities that attempt to deploy smart grid applications universally across their service area must first deal with the automation they have already deployed. Most utilities have several "islands of automation" in place, developed on a project-by-project basis over the years. Automation projects have tended to be "spotty" and incomplete due to a lack of a business case, especially in the distribution environment. Now that the business environment for widespread automation is improved, system engineers must find ways to incorporate these legacy systems into the new smart grid.

An important factor is that many of the technologies used in these legacy systems are becoming obsolete and are no longer supported. The "technology time warp" in the power industry is such that many technologies considered "advanced" by utilities are already considered to be aging and on the way out in general computing environments. Examples of such technologies are SONET, Frame Relay, 10 Mbit Ethernet, trunked radio, and even leased telephone lines. Many older technologies are now essentially *only* found in utility automation. Smart grid deployments must find a way to either integrate or replace these systems. For example, the IEC 61850-420 standard is addressing feeder automation and other distribution automation capabilities, but this standard is not yet deployed.

22.5.5 Poor Business Cases in Isolation, High Initial Investment When Integrated

In the metering and distribution automation environments, basic smart grid functions tend to have poor business cases by themselves. Examples of such functions are simple automatic meter reading or feeder fault location and auto restoration. While nobody can deny their intrinsic value, these functions typically do not provide enough return on investment to justify building the communications networks needed to deploy them over a wide area.

Many early adopters of smart grid philosophy have discovered, however, that when several smart grid applications are deployed together, the integrated business case becomes viable. For instance, when basic meter reading is combined with meter-aided outage management, theft detection, and prepayment and real-time pricing, it is easier to justify an AMI deployment. Similarly, when fault location is combined with phasor measurement and real-time state estimation, the business case for transmission or distribution automation becomes clearer.

Nevertheless, these more advanced features and holistic integration of security, network management, and data management (see Figure 22.13) require a larger up-front investment. The higher initial investment of integrating advanced smart grid applications may present a challenge to many utilities.

22.5.6 Merging Applications and Organizations

One of the biggest challenges facing utilities wishing to implement integrated smart grid applications is that the integrated applications force previously isolated organizations to communicate with each other and perhaps merge. Some examples include the following:

- *Merging SCADA and protection:* For several years now, it has become apparent that substation automation using intelligent devices and modern LAN technology requires the integration of substation functions. Protection devices must be capable of controlling and

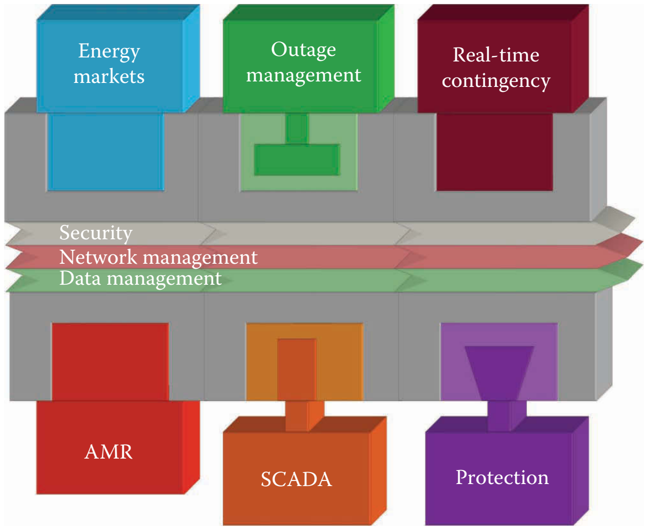

FIGURE 22.13 Holistic application integration. (© 2012 EnerNex. All rights reserved. With permission.)

monitoring, and SCADA devices must take some part in protection. Similarly, the parent organizations of these devices must learn to communicate with each other.

- *Merging information technology (IT) and operations:* As utilities deploy enterprise bus technologies, the traditional separation between corporate IT and utility operations organizations must narrow, especially to address security issues.
- *Merging metering and distribution automation:* These two systems previously had nothing to do with each other although they shared a common geographic area of responsibility. Soon they will likely make use of a common, ubiquitous distribution communications network. Similarly, their respective organizations must now integrate operating procedures to realize some of the advantages of an integrated smart grid, such as advanced outage management.
- *Merging power and industrial:* As more customer-centric applications like real-time pricing, distributed generation, and microgrids are deployed, utilities must take more of an interest in the industrial automation world. What was previously a one-way relationship must become a partnership as customers become active contributors to the operation of the power system.

22.5.7 Applying Holistic Security

Even if they applied to distribution-oriented smart grid technologies, the NERC CIP standards clearly specify that utilities must integrate information system security into all aspects of their automation systems: not just devices, computer systems, and technologies but also policies, procedures, and training. This is sound practice, and utilities would be well advised to follow this guidance even if the force of law does not apply. In order to be effective, utilities must apply these measures consistently and in an integrated fashion across their entire organization. ISO/IEC TR 27019, IEC 62443, and IEC 62351 series of standard can be used by utilities to support their power system security management.

The IEC 62351 standards address the scope and purpose to "Undertake the development of standards for security of the communication protocols defined by the IEC TC 57, specifically the IEC 60870-5 series, the IEC 60870-6 series, the IEC 61850 series, the IEC 61970 series, and the

IEC 61968 series. Undertake the development of standards and/or technical reports on end-to-end security issues."

The IEC 62351 standards consist of:

- IEC/TS 62351-1: Introduction
- IEC/TS 62351-2: Glossary
- IEC/TS 62351-3: Security for profiles including TCP/IP
- IEC/TS 62351-4: Security for profiles including MMS
- IEC/TS 62351-5: Security for IEC 60870-5 and derivatives
- IEC/TS 62351-6: Security for IEC 61850 profiles
- IEC/TS 62351-7: Objects for network management
- IEC/TS 62351-8: Role-based access control
- IEC/TS 62351-9: Key management (under development)
- IEC/TS 62351-10: Security architecture
- IEC/TS 62351-11: Security for XML files (under development)
- IEC/TR 62351-12: Resiliency and security recommendations for power systems with distributed energy resources (DER) Systems (under development)
- IEC/TR 62351-90-1: Guidelines for using Part 8 roles
- IEC/TS 62351-100-1: Conformance test cases for IEC 62351-5 and companion standards
- IEC 62351-14: Cybersecurity event logging
- IEC/TR 62351-90-2: Deep packet inspection
- IEC/TR Part 90-19: Using role-based access control (RBAC) and IEC 61850 (joint with WG10)
- IEC/TR 62351-90-3: Guidelines for network management

There is not a one-to-one correlation between the IEC TC57 communication standards and the IEC 62351 security standards. This is because many of the communication standards rely on the same underlying standards at different layers. In addition, some security documents cover broader concepts rather than specific cryptography. The scopes and interrelationships between the IEC TC57 standards and the IEC 62351 security standards are illustrated in Figure 22.14.

The smart grid vision of information flowing automatically throughout the utility provides great opportunities for efficiency, reliability, and cost-effectiveness. However, it also provides many more opportunities for attackers. The challenge for most utilities will be to build their smart grid systems in an evolutionary fashion, integrating security, network management, and data management into each smart grid application as it is deployed.

22.6 LEGISLATION AND REGULATIONS

One area that is difficult to navigate is legislation and regulations. The utility space is rife with conflicting constraints, including obligation to serve, monopoly franchising, right-of-way reclamation and defense, primary fuel source considerations, environmental, legal, rate of return, and many others. An example of this is provided by the attempt to mandate programmable, controllable thermostats (PCTs) in all new construction in California. These PCTs would enable the customers to determine a program that met their comfort and financial (and, in some cases, environmental) goals, while providing utilities a touch point to limit peak demand (among other capabilities). Clearly, nondiscriminatory in application (all new houses were required to have one), however, the perceived discrimination in operation (temperature and wind speed variance across a service territory might lead to a certain population "suffering" while another did not) provided a means to eliminate this law and regulation. One of the root causes of such vehement opposition is the flat consumption rate/tariff that was in place for the majority of electricity consumers. The fear of changing to another pricing model adds the potential for every single consumer to increase the cost of consumption. This

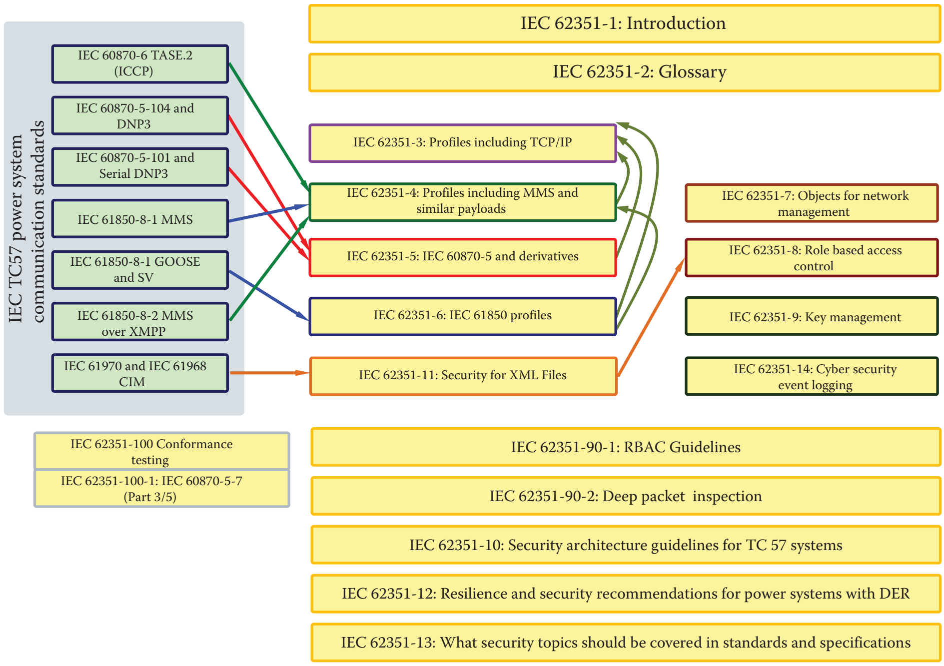

FIGURE 22.14 Mapping of TC57 communication standards to IEC 62351 security standards. (From IEC/TR 62351-13 ed.1.0. © 2016 IEC Geneva, Switzerland. www.iec.ch. With permission.)

is particularly unpalatable if one perceives others to be benefitting at one's expense, no matter what the "greater good" might dictate.

Clearly, there was no lack of vision in this example. Rather, the legislation was defeated by good counter-marketing press. As demand response, smart grids and even AMI are difficult concepts for the general public to grasp, and fear of change drives efforts to understand, accept, and agree. A suggestion for strategy in the legislative and regulatory environment would be one of continual engagement with the general public at every stage. Communities of experts in industry organizations, such as the GWAC, and the collaboration of regulators, such as the Mid-Atlantic Distributed Resources Initiative, provide models for public engagement by leveraging the expertise in the industry.

As mentioned previously, cybersecurity also poses a particular challenge for legislation and regulation. While a uniform cybersecurity vision and strategy across the system may make sense from a technical standpoint, there is a hurdle in the way that our government is fundamentally structured. States still hold the trump card when it comes to legislation, and from a regulatory standpoint, the U.S. states operate more like 50 separate markets—each with their own rules and procedures. As long as state regulatory commissions determine how rates are figured, this issue is not likely to go away.

More recently in California, the Smart Inverter Working Group (SIWG) convened weekly calls with over 250 DER stakeholders, including utilities, DER manufacturers, integrators, aggregators, consumer groups, and many other interested parties. The results were ultimate agreement by the key stakeholders on the updating of California's Rule 21 on DER interconnections to include seven critical DER functions. The California Public Utilities Commission (CPUC) reviewed and approved these recommendations, and these DER functions will now be mandatory by late 2017. In addition, SIWG recommendations on communications and additional DER functions are under review by the CPUC. This California effort triggered the revising of the national DER interconnection standard, IEEE 1547, which is expected to be finalized late in 2017.

In Europe, in order to harmonize and liberalize the EU's internal energy market, three consecutive legislative packages of measures were adopted between 1996 and 2009, addressing market access, transparency and regulation, consumer protection, supporting interconnection, and adequate levels of supply. As a result of these measures, new gas and electricity suppliers can enter member states' markets, while both industrial and domestic consumers are now free to choose their own suppliers. Other EU policies related to the internal energy market address the security of the supply of electricity, gas and oil, as well as the development of trans-European networks for transporting electricity and gas.

In February 2015, the European Commission published a communication on the Energy Union Package entitled "A Framework Strategy for a Resilient Energy Union with a Forward-Looking Climate Change Policy." The package states that the goal of the Energy Union is "… to give EU consumers—households and businesses—secure, sustainable, competitive and affordable energy." In order to achieve these goals, five mutually reinforcing and closely interrelated dimensions were set out in the package: energy security, solidarity, and trust; a fully integrated European energy market; energy efficiency contributing to moderation of demand; decarbonizing the economy; and research, innovation, and competitiveness.

The European Commission, together with many stakeholders, has established that greater effort is needed to create a secure, competitive, and low-carbon European energy sector and a pan-European Internal Energy Market. Network codes are intended as a tool to reach this objective by complementing existing national rules to tackle cross-border issues in a systematic manner. Network codes are sets of rules, which apply to one or more parts of the energy sector. The need for them was identified during the course of developing the Third Energy Package. More specifically, Regulation (EC) 714/2009 sets out the areas in which network codes are developed, and a process for developing them.

22.7 ADVANCING SMART GRID STANDARDS

The first is a commitment to drive stakeholders from use of open standards to demonstrations of interoperability within the deployed systems. Stagnation at the standards developer level can ruin a good standard (see IEEE P1901). If compliance tests are not defined and moderated, the standards themselves are both too strict and too interpretable for each implementer. If interoperability tests are not defined and moderated, it is nearly impossible to provide any assurance of field compatibility.

A holistic approach (technical, communications, environment, regulation, security) is difficult but feasible. Clearly defined requirements in all of the areas allow system designers and integrators to develop, test, and deploy solutions that have a chance for success.

Finally, simple single-entity rate of return is often a poor measure of project value. As an example, AMI projects are built to leverage benefits beyond meter control and data collection. It may be the case that a utility can jump from all human-read to fully automatic reading, piggy-back on a significant existing communications infrastructure, or take advantage of favorable population density or terrain to minimize equipment investment. Looking outside of core metering aspects leads a utility to enhance outage management programs and perhaps improve on customer relations, to name a few areas.

In the same manner, smart grid projects should look to provide benefits beyond core system operations improvements. For instance, in California, not only is there a goal of 50% renewables by 2030, utilities are also required to take DER systems as possible elements in planning for increased electrical use from population growth and electric vehicles. For instance, they may defer construction costs on a feeder by incentivizing the installation of DER systems, particularly energy storage systems, to provide grid services to provide local generation and voltage support. This win–win situation allows utilities to reduce their construction costs while allowing consumers to benefit from selling grid services.

Another shift is that utilities can benefit from the use of standards based on Internet standards, rather than special utility-only standards, such as IEC 60870-5-101/104 and IEEE 1815 (DNP3). For instance, a standardized profile of DNP3 based on IEC 61850-7-420 provides interoperability for interactions between utility SCADA systems and larger scale DER systems. In California, IEEE 2030.5 (SEP2), using RESTful Internet technology, has been selected by the SIWG as the default protocol, and IEC 61850 has also developed an Internet-based protocol, IEC 61850-8-2, which uses the XMPP protocol as transport.

The systems engineering approach assists a utility with finding multiple benefit streams for a project deployment and helps to eliminate the siloed or "my project" syndromes that plague many large projects in many industries.

An excellent domain-specific system engineering reference is the IEC Publicly Available Specification (PAS) 62559, which includes the IntelliGrid methodology for project definition decomposed into a five-phase project approach. The PAS also includes a use case development guide with three different (transmission synchrophasors, distribution automation, consumer) domain examples. Complementary to this open standard, third-party metrics, such as the GridWise Architecture Interoperability Checklist and the Smart Grid Scorecard [19], provide an independent means for project teams to self-evaluate systems and products, leading to more transparent benefit derivation. IEC PAS 62559 became a set of IEC standards (62559 series), which are managed by IEC SyC Smart Energy.

For large systems, such as AMI and "smart grid" deployment, it is no longer the case that a "boutique" approach is viable: purchasing the latest and "greatest" components and stitching them together to construct a system. The process is reasonably clear for determining and acting upon requirements:

- Legislation and regulations (and markets) will determine targets for utilities.
- Utilities will use specifications and standards (and proprietary information) to procure and deploy equipment from vendors, within the legislative and regulatory constraints.
- Vendors will use specifications and standards (and utility information) to develop equipment.

None of this approach is unknown; however, the final steps are not always followed:

- Appropriate parties should construct compliance tests (e.g., vendors and third parties).
- Appropriate parties should construct acceptance tests (e.g., utilities and vendors).
- Appropriate parties should construct interoperability tests (e.g., vendors, third parties, and utilities).
- Appropriate parties should construct security tests (e.g., independent third parties and utilities).

Standards groups are ill-equipped to partake in these efforts as often the scope of the group or its ground rules preclude the open communication necessary to properly expose issues with technology as it is measured against the standard. However, the vendors participating in those groups are, with proper moderation and oversight, well-equipped to perform exactly these tasks. The other parties need to resist the "single vendor, end-to-end is better," which, while true initially, leads (and has led) to incompatible products, poorly defined systems, and widespread buyer's remorse in the utility industry.

Research should be conducted to accelerate the development of standards that fill existing gaps, including those for security, smart grid network and device management, information privacy management, and FAN interoperability. Appropriate private and public sector funding and organizations are needed to address these needs. Security, network, and device management and field interoperability touch on both technology and policy in that order. It is not enough to develop secure, manageable, and interoperable technology if policies, rules, and regulations inhibit its use in the power system.

Information privacy management also touches both policy and technology, though likely policy first. Best practices on developing policies are most likely not centered on the "terms of use" model from Web sites: long, legalese-filled missives that often inhibit understanding by the casual user. For example, this is an area where some discomfort may be found in the answer where the end consumer is the owner of the data collected and permits the utility, and only that utility, to use the data to provide the service. Permission is not granted to release the information to any entity, regardless of situation. This is not the current model nor is this a proposed solution; rather, it is an example of an issue regarding information privacy management. This particular subject area requires legal research as well to examine what liability limits each party owns.

There are many mature standards and best practices already available that can be readily deployed to facilitate smart grid deployment. The main problem with adoption seems to be a lack of awareness of those standards and best practices by those involved in designing smart grid systems at a high level and regulatory guidelines for applying them.

Key recommendations include the following:

- Regulations should be developed that encourage utilities and product vendors to support standards-based technologies over proprietary solutions, in particular Internet-based transport communications.
- Regulations should avoid mandating specific standards or technologies where possible in favor of specifying desired outcomes and important characteristics of the standards to be employed ("what" vs "how"), including cybersecurity requirements (but not necessarily the cybersecurity technologies).
- Research should be conducted to accelerate the development of standards that fill existing gaps, including those for security, resilience, smart grid network and device management, information privacy management, and interoperability.

22.8 RECENT ADVANCEMENTS

While this section will provide an introduction to a few recent advancements in the smart grid technology arena, it should be noted that these advancements tend to leverage what is called the system engineering approach first applied in recent times in the utility industry smart grid efforts for AMI. This approach brings together personnel from various groups impacted by the different aspects of metering (e.g., meters, communications, IT, system planning, system operation, customer interface, maintenance, reliability, and business operations) to discuss on an abstract level the use of such a system, and capturing the responses via a "use case" is the first step. Included in the system engineering approach is the customer via a variety of mechanisms through direct workshop participation, consumer advocacy groups and focus groups, to name a few. From these use cases, it is possible to eliminate spurious actors and requirements (both functional and nonfunctional) through the documentation step. Functional requirements and nonfunctional requirements are then enumerated. Further discussion with utility personnel allows them to target high-impact (low-hanging) returns, making for a solid business case. Applying a ranking system to the requirements provides the utility personnel a tool with which to evaluate the relative maturity of any technology with respect to the cross-paired requirements and business goals. The vendors are then given a clear signal against which to develop (or modify) candidate elements and systems to meet the utility needs.

This is a laborious process, but all stakeholders derive considerable benefit. The utility has several points along the process against which to test both their system and goals and candidate technology. The vendors have a relatively static target that facilitates development investment, and this static target also creates "vendor tension"—that is, competition—which the utility can leverage in either a performance or financial manner (or sometimes both). The customer is connected with the right technology that demonstrates value to them.

22.8.1 Transactive Energy

Over the past decade, the use of DER for market efficiency and grid reliability has grown dramatically. Federal and state policy objectives point to an important role for customers' loads, generation, and storage in the management of an increasingly unpredictable power system. The addition of DER on the distribution system requires changes to operation, control, and markets for those resources. From this need is a focus on an area of activity called "Transactive Energy" defined as "a system or economic and control mechanisms that allows the dynamic balance of supply and demand across the entire electrical infrastructure using value as a key operational parameter" [20]. This seemingly brings together different disciplines within the utility related to economic optimization, multiobjective controls, adaptive protection, supervisory control, and data acquisition, among others. One other applied element is the differing time scales involved in the different problems being solved; for example, protection tends to be in the tens of milliseconds, meter data intervals on the order of minutes, and market operations on an hour-ahead or day-ahead schedule [20].

22.8.2 Field Message Bus and the Internet of Things

Duke Energy defined the concept of a Distributed Intelligence Platform (DIP) for energy systems [21] that is intended to extend the concept of an Enterprise Service Bus (ESB) to the "edge" of the grid (the "edge" is defined as the hand-off point between responsibility of the utility and that of the customer, usually the electric meter connection, and sometimes referred to as the point of common coupling, or PCC). They named this the Field Message Bus (FMB). The FMB is envisioned to support peer-to-peer publish/subscribe messaging using widely available, economical Internet technologies. Devices using technologies in this fashion can be referred to as being part of the Internet of Things (IoT).

The published framework includes distributed intelligent nodes interacting with each other through loosely coupled, scalable, peer-to-peer messaging for field devices and systems at the grid-edge. The specification provided by the framework gives power systems field devices the ability to leverage a nonproprietary and standards-based reference architecture, which consists of Internet protocol (IP) networking and IoT messaging protocols. As defined in the framework, DER communications are supported and operate on a common schematic definition. Data can be processed locally without a round trip to "enterprise applications" hosted in a central data center. The framework and specification support field-based applications that are data-centric, rather than device-centric and distributed as well as centralized logic. This work was codified by the North American Energy Standards Board, and development continues through an industry group under the OpenFMB moniker [22].

22.8.3 Consumer Access to Data and Green Button

Green Button is an industry-led effort that responds to a White House call-to-action: provide electricity customers with easy access to their energy usage data in a consumer-friendly and computer-friendly format [23]. This concept unifies the presentation and availability of a standardized collection of energy data as provided by any electricity meter by any vendor in a secure, privacy-enveloped format. The goals of providing this include enabling energy consumers to better understand their own consumption patterns and how those patters are reflected in their billing, enabling authorized third parties to market services to energy consumers to help those consumers better manage their consumption, enabling application providers and providing a consistent presentation of energy data on utility and other party Web sites. A few standards underpin this effort, such as the North American Energy Standards Board's (NAESB) REQ 21—Energy Service Provider Interface (ESPI), and technologies built on those standards permit open exchange of metering data not reliant upon proprietary conversions.

22.8.4 Interoperability Processes and Recommended Practices

The smart grid requires interoperable products, devices, applications, and systems. Conformance to a standard is often the only step for vendors when asserting interoperability, and the use of alliances bringing the vendors together to demonstrate both conformance and interoperability and earn a certification is one solid step to delivering on the promises of smart grid. The SGIP considers the Interoperability Process Reference Manual (IPRM) to be a key foundational element. The SGIP Smart Grid Testing and Certification Committee (SGTCC) initially developed and issued the IPRM (versions 1 and 2) to detail its recommendations on testing and certification processes and best practices that enhance the introduction of interoperable products in the market place. These recommendations build upon international standards-based processes for interoperability testing and certification.

Published now as an ANSI/NEMA standard "version 3," the strongly held belief by the SGIP stakeholders is that implementation of the IPRM by Interoperability Testing and Certification Authorities will increase the quality of standards-based, secure, and interoperable products in the smart grid marketplace. The IPRM stakeholder community also believes that implementation of the IPRM will lead to reduced deployment costs of smart grid systems and devices, and to enhanced product quality with respect to interoperability and conformance, ultimately providing increased end-user customer satisfaction and confidence to the buyer through meaningful certification programs.

The use of the IPRM enables the adoption of consistent and measurable certification and testing policies and procedures across standards-based smart grid products based on the conformance, interoperability, and cybersecurity testing experience and expertise of SGTCC participants, and the widely accepted International Organization for Standardization (ISO)/International Electrotechnical Commission (IEC) 17025 and ISO/IEC 17065 international standards for testing laboratory and certification body management systems [24].

LIST OF ABBREVIATIONS

6LoWPAN	IPv6 over Low-power wireless personal area networks
ADSL	asymmetric digital subscriber line
AMI	advanced metering infrastructure
AMI-SEC	AMI security
ANSI	American National Standards Institute
ATM	asynchronous transfer mode
BACnet	building automation and control networks data communications protocol
BAN	building area network—synonym for HAN
BPL	broadband over power line
CDMA	code division multiple access
CDPD	cellular digital packet data
CFR	code of federal regulations
CIM	common information model
CIP	critical infrastructure protection
CIS	customer information system
COMTRADE	common format for transient data exchange
CORBA	common object request broker architecture
COSEM	companion specification for energy metering
CSA	Canadian Standards Association
CSR	customer service representative
DER	distributed energy resources
DIN	Deutsches Institute für Normung

DLMS	device language message specification
DMS	distribution management system
DNP	distributed network protocol
DOCSIS	data over cable service interface specification
DOE	Department of Energy
DRBizNet	demand response business network
ebXML	electronic business using eXtensible Markup Language
EMS	energy management system
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
FAN	field area network
FCC	Federal Communications Commission
FIPS	Federal Information Processing Standard
FRCC	Florida Reliability Coordinating Council
GID	generic interface definition
GIS	graphical information system
GPRS	general packet radio service
GWAC	GridWise Architecture Council
HAN	home area network
HTML	hypertext markup language
HTTP	hypertext transfer protocol
HTTPS	hypertext transfer protocol over secure socket layer
ICCP	Intercontrol Center Communications Protocol
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers
IPSec	Internet Protocol Security
IPv6	Internet Protocol version 6
ISO	International Organization for Standardization
IT	information technology
ITU	International Telecommunication Union
LAN	local area network
LEED	leadership in energy and environmental design
MAC	media access control
MAS	multiple address systems
MDMS	meter data management system
MPLS	multiprotocol label switching
MRO	Midwest Reliability Organization
NEC	national electric code
NERC	North American Electric Reliability Corporation
NESC	national electric safety code
NFPA	National Fire Protection Agency
NIST	National Institute of Standards and Technology
NPCC	Northeast Power Coordinating Council

NRECA	National Rural Electric Cooperative Association
OLE	object linking and embedding
OMS	outage management system
OPC	OLE for process control
OSGi	open services gateway initiative
OSI	open systems interconnection
PAN	premise area network—synonym for HAN
PAS	publicly available specification
PC	personal computer
PCT	programmable, controllable thermostat
PHEV	plug-in hybrid electric vehicle
PKI	public-key infrastructure
PLC	power line carrier
PMU	phasor measurement unit
PQDIF	power quality data interchange format
PSTN	public switched telephone network
PTP	precision time protocol
RFC	reliability first corporation
RFID	radio-frequency identification
RMON	remote network monitoring
SAE	society of automotive engineers
SAN	substation area network
SCADA	supervisory control and data acquisition
SDH	synchronous digital hierarchy
SDO	Standards Development Organization
SERC	SERC Reliability Corporation
SNMP	simple network management protocol
SOAP	simple object access protocol
SONET	synchronous optical networking
SPP	southwest power pool
SQL	structured query language
SyC	System Committee Smart Energy
TLS	transport layer security
TRE	Texas regional entity
UCAIug	UCA International Users Group
UL	underwriters laboratories
USB	universal serial bus
USC	U.S. code
VLAN	virtual local area network
VPN	virtual private network
WAN	wide area network
WDM	wavelength division multiplexing
WECC	Western Electricity Coordinating Council

Wi-Fi wireless fidelity
WiMAX worldwide interoperability for microwave access
WMS work management system
WPA2 Wi-Fi protected access 2

Annex: Technology Enumeration

A nonexhaustive list of technologies that straddle the identified decomposition is enumerated as follows:

Standard	Enterprise	LAN	WAN	SAN	FAN	HAN
Internet Protocol version 4 (IPv4)	Y	Y	Y	Y	Y	Y
Internet Protocol version 6 (IPv6)	Y	Y	Y	Y	Y	Y
Multiprotocol Label Switching (MPLS)	Y	Y	Y	Y	Y	Y
X.509 Public-Key Infrastructure (PKI)	Y	Y	Y	Y	Y	Y
Federal Information Processing Standard (FIPS) encryption	Y	Y	Y	Y	Y	Y
Federal Information Processing Standard (FIPS) authentication	Y	Y	Y	Y	Y	Y
Internet Protocol Security (IPSec)	Y	Y	Y	Y	Y	Y
Transport Layer Security (TLS)	Y	Y	Y	Y	Y	Y
Common Management Information Protocol	Y	Y	Y	Y	Y	Y
OSI (Open Systems Interconnection) network management	Y	Y	Y	Y	Y	Y
IEC 62351 Security	Y	Y	Y	Y	Y	Y
Simple Network Management Protocol (SNMP)	Y	Y	Y	Y	Y	Y
Remote Network Monitoring (RMON)	Y	Y	Y	Y	Y	Y
IEEE 1588 Precision Time Protocol (PTP)	Y	Y	Y	Y	Y	Y
IEC 61334-4-41 DLMS (Device Language Message Specification)			Y		Y	Y
IEC 62056 COSEM (Companion Specification for Energy Metering)			Y		Y	Y
ANSI C12.18 Optical Port and Protocol Specification for Electric Metering						Y
ANSI C12.19 Utility Industry Data Tables			Y		Y	Y
ANSI C12.21 Telephone			Y		Y	
ANSI C12.22 Networking			Y		Y	Y
ANSI C12.23 Testing			Y		Y	Y
Building automation and control networks (BACNet)						Y
HomePlug						Y
IEEE 802.15.4 with ZigBee						Y
IEEE 802.11 b/g “Wi-Fi”						Y
IEEE 802.15.1 “Bluetooth”						Y
Radio-frequency identification (RFID)						Y
IEEE 802.11i Wi-Fi Protected Access 2 (WPA2)						Y
IEEE 802.3 Ethernet						Y
LonWorks						Y
X10						Y
6LowPAN (IPv6 over low-power wireless personal area networks)						Y

(*Continued*)

Annex: Technology Enumeration (*Continued*)

A nonexhaustive list of technologies that straddle the identified decomposition is enumerated as follows:

Standard	Enterprise	LAN	WAN	SAN	FAN	HAN
Insteon						Y
WirelessHART (Highway Addressable Remote Transducer Protocol)						Y
Open Services Gateway initiative (OSGi)						Y
IEEE 802.1Q Virtual LANs (VLANs)						Y
Fieldbus			Y	Y	Y	
Profibus			Y	Y	Y	
IEEE 1390 Telephone Meter Reading			Y	Y	Y	
Cellular Digital Packet Data (CDPD)			Y	Y	Y	
IEEE 802.16 WiMAX			Y	Y	Y	
Multiple Address Systems (MAS)/Trunked Radio			Y	Y	Y	
IEC 60870-5-101/104 Telecontrol			Y	Y	Y	
Modbus			Y	Y	Y	
DNP3			Y	Y	Y	
IEC 61850 Substations			Y	Y	Y	
2G Wireless (1×RTT, GPRS)			Y		Y	
HomePlug Access BPL (Broadband over Power Line)			Y		Y	
X-Series Networking	Y		Y	Y		
Frame Relay	Y		Y	Y		
Synchronous optical networking (SONET)	Y		Y	Y		
Synchronous digital hierarchy (SDH)	Y		Y	Y		
Asynchronous transfer mode (ATM)	Y		Y	Y		
Wavelength division multiplexing (WDM)	Y		Y	Y		
Virtual private networks (VPNs)	Y		Y	Y		
IEC 60870-6 Intercontrol Center	Y					
IEC 61970 Common Info Model	Y		Y	Y		
IEC 61968 Distribution Interfaces	Y		Y	Y		
OpenGIS (Open Geographic Information Systems)	Y					
MultiSpeak	Y		Y	Y		
HTTP/HTML	Y					
Common Object Request Broker Architecture (CORBA)	Y					
Web services	Y					
Structure Query Language (SQL)	Y					
OPC (Object Linking and Embedding for Process Control)	Y					
Web services security	Y					
HTTPS (Hypertext Transfer Protocol over Secure Socket Layer)	Y					
IEC 62325 Energy Markets						
ebXML (Electronic Business using eXtensible Markup Language)						
Point-to-point microwave	Y		Y			
Licensed point-to-multipoint radio			Y	Y	Y	Y
Unlicensed point-to-multipoint radio			Y	Y	Y	Y
Licensed mesh radio network			Y	Y	Y	Y

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23 The Smart Grid IoT

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CONTENTS

23.1 WHAT IS THE INTERNET OF THINGS?

The Internet of Things (IoT) has a number of definitions. However, the major tenets of the IoT definition involve connecting individual physical devices with each other, with larger groupings of objects (e.g., buildings), and with people, such that the connected devices are networked and are able to collect and exchange data. The Global Standards Initiative on Internet of Things (IoT-GSI) defines IoT in Recommendation ITU-T Y.2060 (06/2012) as, "A global infrastructure for the information society, enabling advanced services by interconnecting (physical and virtual) things based on existing and evolving interoperable information and communication technologies."

Given these definitions, in a strict sense, the IoT is not a new concept. For decades, devices have been able to collect data, exchange data, react to data, and issue commands to produce an action. However, what is more recent is the rapid advancement of processing and connectivity across multiple communication technologies at reduced power levels, smaller form factors, and lower cost. These advancements enable devices to be connected more reliably, at lower cost, and more efficiently than ever before. Improvements in data warehousing and analytics now enable software platforms to transform the massive amount of data generated by networks of connected devices into useful business intelligence—consider the extensive number of uses and applications that could be realized if "thing A" were able to talk to another "thing B." Gartner conservatively estimates that the IoT will consist of over 20 billion connected things by 2020 [1]. As an analogy, consider the growth of Internet usage in the world, driven by infrastructure buildout and ever-dropping costs of connection (Figure 23.1).

Or consider the explosion of cellular subscribers, driven by the enabling technology of allowing people to talk to other people when they may not be near a traditional wireline telephone (Figure 23.2).

Based on recent market activity, technology advances in the smart grid can be considered as one of the main drivers and initial volume market for the IoT—a segment that we shall term the "Smart Grid Internet of Things" (SG-IoT).

The SG-IoT involves aggregating sensors, controllers, and other intelligent electronic devices together via decision-making intelligence and communications technologies to collect, process, and

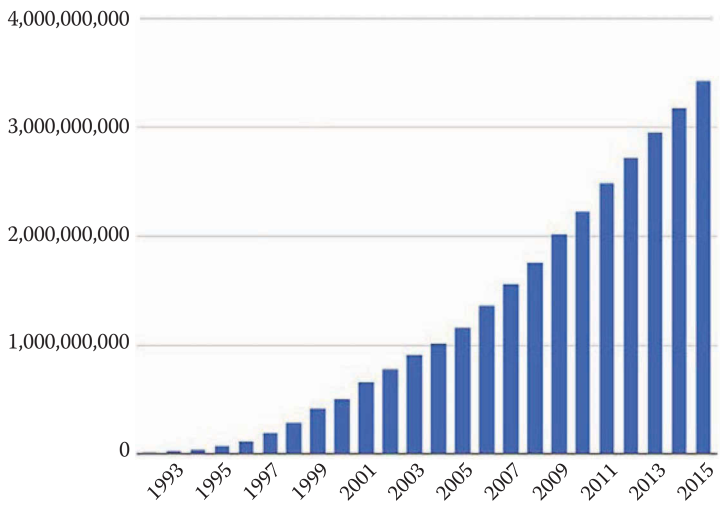

FIGURE 23.1 Worldwide Internet users. (From Internet Live Stats, December 2016, http://www.internetlivestats.com/internet-users/. With permission.)

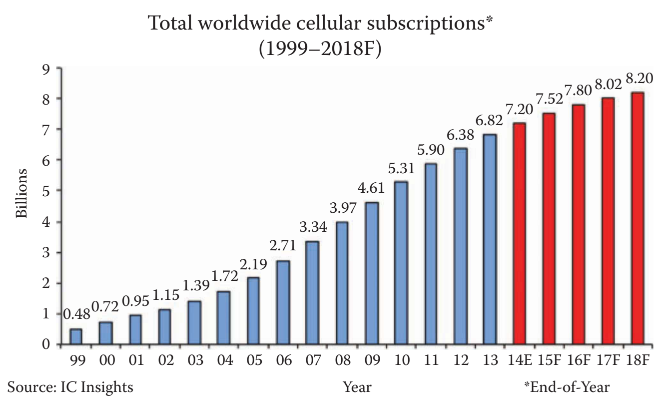

FIGURE 23.2 Worldwide cellular subscriptions. (From IC Market Drivers, IC Insights, 2015, www.icinsights.com. With permission.)

exchange data over a network. While "connected devices" with communications capability have been used by electric utilities for several decades for remote monitoring, control, and data acquisition, the utility industry was slow to adopt Internet Protocol (IP)-based communications for several reasons, including network security and data privacy concerns, and unfamiliarity with the use of Internet protocols in real-time applications. IP-based utility communications has been critical in enabling grid monitoring and control devices to network (communicate peer-to-peer) and share data in real time—real-time data exchange is an important requirement for the SG-IoT.

The SG-IoT can apply to all types of utilities—electric, gas, water—from supply down to the consumer interface, and within the consumer premises. It is an enabler to creating new models for improving delivery, efficiency, safety, and reliability. IoT for the smart grid integrates technologies with existing assets, new assets, data, operational tools, and advanced decision-making intelligence to achieve improvements in operational practices and economics. With technological advancements that make it increasingly easy and inexpensive to enable the smart grid, we can predict a tremendous growth of smart grid IoT buildout, followed by the deployment of new uses and applications, which further drives more technological advancement and IoT buildout, resulting in billions of interconnected devices.

23.2 IOT COMMUNICATIONS

Devices would not be valuable sources of data without the means to communicate. The key to SG-IoT is networking, preferably using IP-based communications. As with other industries and communicating devices, numerous communication systems are available to provide widespread coverage, and the devices themselves must be able to support the different communications interfaces or there must be a sufficient small subset of standards and practices that allow interoperability at all levels in the communication layers, from the physical medium to the application protocol and data modeling within the device. As with other industries and communicating devices, numerous communication systems are available to provide widespread coverage, and the devices themselves must be able to support the different communications inter-faces or there must be a sufficient small subset of standards and practices that allow interoperability at all levels in the communication layers, from the physical medium to the application protocol and data modeling within the device. A prominent use case for the smart grid IoT is to provide alternate communication paths for various data and application types. For example, monitoring data from one device could traverse one communication technology, while its control data could simultaneously traverse another, low-latency network.

A large number of uniquely addressable devices must be supported by a single utility network and, hence, the suitability of using the Internet Protocol address space. If one considers the grid-edge device population, smart appliances, and new assets to be deployed over time, the permutations and combinations of connectivity architectures become a vast landscape. For example, the DNP3 address space is limited to 65,535 addresses prior to having to reuse addresses and remap identities into a database, while the IPv6 address space is virtually unlimited. While support for IPv6 is still building in the device space, IPv4 can be deployed with various techniques used to provide scaleability. Utility networks are by definition mission-critical infrastructure and, therefore, require the highest levels of security, reliability, availability, and serviceability. Data privacy from a consumer and utility perspective is also included in this requirement. If these requirements look familiar, they should—the Internet has the same characteristics; hence, the appeal for using IP-based protocols and architectures for the smart grid. These problems have all been solved before (often by the IEEE or IETF). However, SG-IoT requirements differ from Internet requirements in five important areas:

- SG-IoT devices typically do not produce or consume much data. Therefore, bandwidth requirements are much lower than exhibited by PC, tablet, or cell phone users.
- SG-IoT devices often operate in real time, so their latency requirements are far more stringent than those of Internet users.

- Most SG-IoT devices will likely operate from battery power and so, communications protocols must support quiescent or "dormant" device operation, and be very efficient with bandwidth and protocol overhead.
- SG-IoT devices have expected operating lifetimes of 5–15 years or longer, as opposed to consumer devices that can be switched out much more quickly. They, therefore, require a very high level of device robustness.
- SG-IoT devices are typically not mobile. The requirement to operate wireless devices from a fixed location requires a very high level of communications reliability.

The first three requirements influence communications protocol design and selection, resulting in some deviations from the standard IP protocol stack (e.g., the emergence of 6LoWPAN). The last two requirements influence device design and qualification strategies, as well as product costs.

23.2.1 Standards

IoT connectivity technologies can be divided into five major areas, as a function of coverage. These include:

- *Personal Area Network (PAN):* typically distances of 10–100 m, for example, devices within consumer premises (HAN—Home Area Network), devices on a distribution feeder (same span), within a substation yard, or other applications requiring limited bandwidth and connection density
- *Local Area Network (LAN):* typically distances of 100 m–1 km, for example, within large buildings or between buildings of a campus
- *Neighborhood Area Network (NAN):* typically distances up to 5 km, for example, from pole-top to multiple consumer revenue meters and distributed energy resources (DERs), or communications between devices in a substation and devices down along the distribution feeder
- *Metropolitan Area Network (MAN) or Field Area Network (FAN):* typically 5–10 km
- *Wide-Area Network (WAN):* typically above 10 km per link

NAN, MAN and FAN are terms typically included to differentiate the common understanding of WAN and LAN in IT terms from communication networks specific to the geographic layout of utility systems or smart cities. Communications for the smart grid is discussed in detail in another chapter of this book, but it is important in the context of the IoT to track the cellular performance

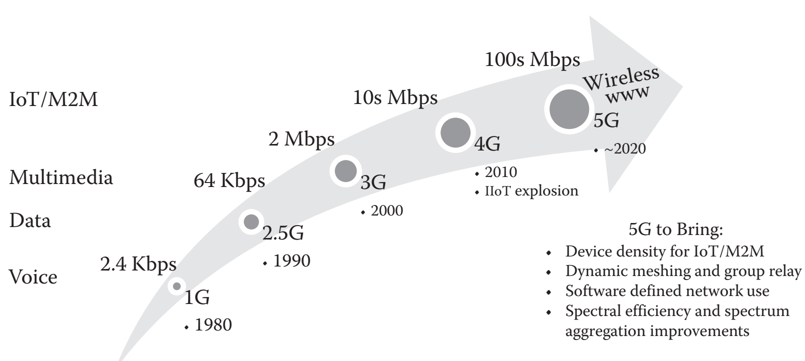

FIGURE 23.3 IoT and the cellular generation evolution. (© 2016 S&C Electric. All rights reserved. With permission.)

evolution from the second generation (2G) to today's 4G networks (Figure 23.3). Many IoT networks run on 2G and 3G networks today, within required coverage and performance parameters.. The 4G latency and device population support has enhanced IoT over cellular, and 5G is poised to bring improvements in device density for SG-IoT applications, for example, group relay, advanced multicast, and improved latency. Much concern has been expressed over the more rapid cellular life cycles, with the necessity to exchange modems or network interface cards to the next generation. In reality, cellular generations tend to evolve every 10 years, and are kept in service for about 20 years. Most cellular service providers will keep the older technologies around for telemetry and IoT opportunities, to maximize return from their infrastructure and spectral assets. Note, however, that when spectrum is refarmed to new-generation cellular technologies, the ability of the legacy technology to continue supporting IoT applications is diminished.

As the penetration of IoT devices and lower power networks continues to advance, existing and new (cellular and other) communication service providers have also emerged that aim to build, provide, and manage wireless networks to connect low energy devices. Their operational models enable power providers and potentially consumers to offload their communication deployment and operations expenditures to others to manage their network for a recurring fee per device per unit time of usage. Traditional cellular service provider data plans have also sharply reduced over time as the race to connect devices is attractive to their average revenue per unit, which is a metric of total revenue divided by the number of subscribers on the network.

RF Mesh has gained significant popularity in North America, Australia/New Zealand, and Asia for PAN and LAN/NAN deployments due to its low cost, resiliency, and decent bandwidth and latency characteristics. Power-line carrier has been deployed broadly in southern Europe and China due to its low cost, and the high home-to-transformer ratio in those geographies. In the FAN/WAN, a combination of cellular, long-range wireless, and WiMax has been used for both PAN/NAN backhaul and distribution automation.

The proliferation of low-power wireless connectivity technologies is making the use of long-life batteries and energy harvesting technologies more achievable, which is driving down costs of sensing and other connected devices, making them much more attractive from a total cost of ownership versus operational benefit comparison.

Machine to machine data exchange and control protocols have been used since early telemetry and proprietary control systems. The increase in the number of wireless technologies, their low power requirements, low cost, near ubiquitous coverage, and decent throughput capabilities have made it possible to connect things previously not connected. However, as these technologies are adopted and device density increases, special attention is paid to the protocol efficiency as a function of the data it must transmit, the data exchange frequency, and available power. The predominant communication standards that enable modern-day-defined IoT connectivity in the smart grid are illustrated in Figure 23.4. The landscape of the protocols consists of both incumbent protocols and newer, packet-based, and IP-based capable protocols. The figure includes the predominant smart grid data exchange and control protocols above the connectivity protocols.

As new standards, technologies, and products are introduced, the recommended communication profiles and standards will continue to evolve. As expected, the IEEE and cellular standards dominate the physical and data link (or media access control) layers, while various IETF RFCs dominate the adaptation and convergence layers.

The key objective of SG-IoT protocols is to deliver the right data to the right place at the right time and in the right format. Consequently, object-oriented models are preferred, wherein the complexity of different data sources and tasks can be abstracted from the application, while the common attributes are all inherited in uniform fashion. For example, voltage data can be collected at any point in the transmission and distribution network, and exchanged or forwarded across the SG-IoT network to enterprise applications, where the same data objects can persist and be managed and processed simultaneously by multiple applications, as Volt/VAr optimization, outage monitoring, and energy theft detection.

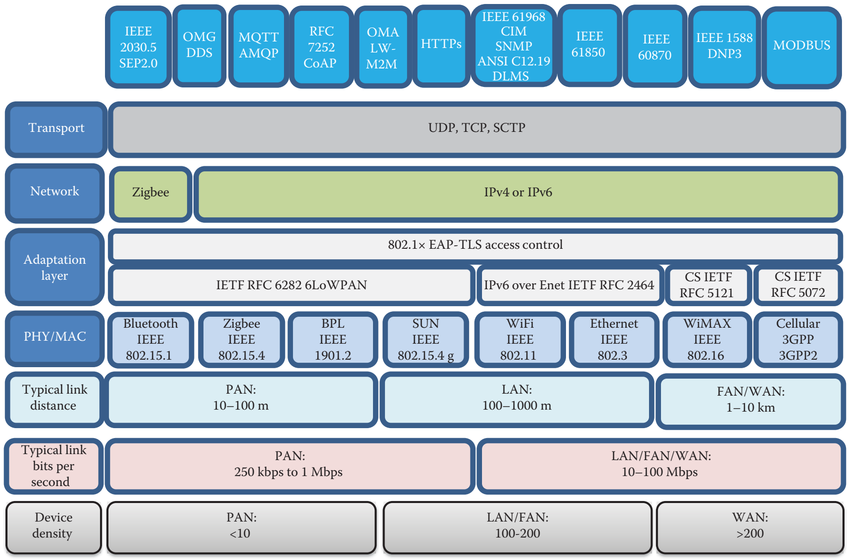

FIGURE 23.4 Predominant smart grid M2M and IoT connectivity technologies and standards. (© 2016 S&C Electric. All rights reserved. With permission.)

23.2.1.1 IEEE 2030.5 Smart Energy Profile 2.0

Smart Energy Profile 2.0 is defined in IEEE 2030.5–2013, and provides support for a number of HAN applications (Figure 23.5). It mostly serves the purposes of exchanging pricing and energy usage data, but is also able to exchange control actions for demand-response grid support, such as the operation of smart appliances behind the consumer's meter.

The access into the HAN is typically through an Energy Service Interface, which serves as the gateway, and could be the revenue meter, or the home's broadband connection. In general, it enables increased consumer engagement with the utility. The HAN can also provide visibility and management of DERs, while leveraging much of the pricing and energy usage data.

23.2.1.2 Object Management Group Data Distribution Service

The Data Distribution Service is a middleware protocol that integrates communication system network elements together, but in a data-centric manner using a real-time publish/subscribe abstraction.

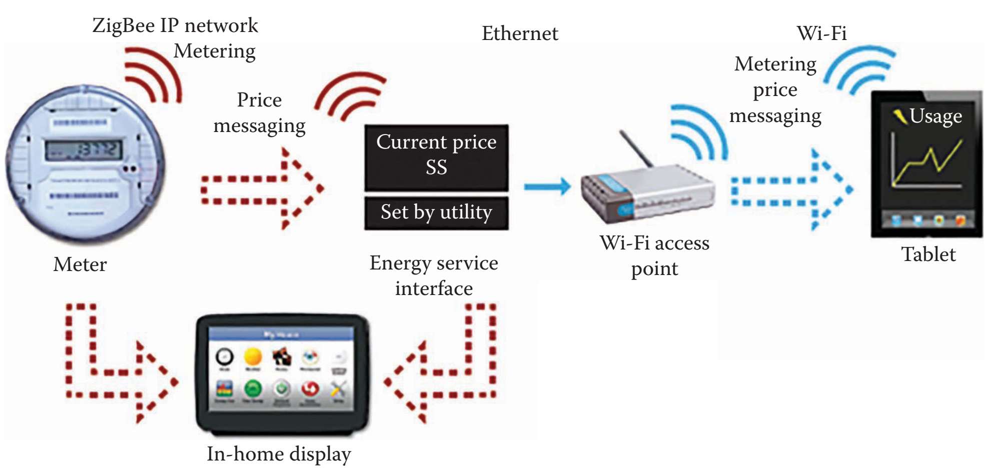

FIGURE 23.5 IoT behind the meter. (Courtesy of Texas Instruments, 2016.)

It is a scalable architecture in that it can operate between devices in a domain at the grid-edge in peer-to-peer form, yet facilitate computing on a regional domain level, which can then integrate into a central domain level. This enables data and control functions to remain autonomously at the grid-edge, closest to where it is needed, while providing data exchange efficiency in sharing only the data that are needed with the layers above. DDS has been used in smart grid demonstrations involving advanced SCADA applications.

23.2.1.3 Message Queuing Telemetry Transport (MQTT)

The MQTT protocol provides a lightweight publish/subscribe model where small code footprints, network bandwidth, and power availability are limited. Because MQTT provides enhancement of data delivery reliability and works over connection-oriented and reliable protocols, such as TCP/IP, it may not be suitable for lower cost and small microcontroller applications, such as sensors.

23.2.1.4 Advanced Message Queuing Protocol (AMQP)

The AMQP is an open standard for message-oriented middleware. It predominantly focuses on message queuing, routing, and orientation. It has publish/subscribe capabilities but is a binary layer protocol to support many messaging applications atop it. Like MQTT, AMQP is a connection-oriented protocol and relies on TCP/IP to help provide the message exchange reliability. Therefore, network bandwidth, latency, and microcontroller memory footprint and processing power may be more demanding than some other lightweight protocols.

23.2.1.5 RFC 7252 Constrained Application Protocol (CoAP)

RFC 7252, the Constrained Application Protocol (CoAP), is a predominant IETF Constrained RESTful environment protocol, which has been gaining popularity due to its target for lightweight processing, a small memory footprint and code space, and very low power demands. It is ideal for smart grid sensors, grid-edge devices, and other constrained nodes, and is able to transfer very small, efficient message structures. Unlike MQTT and AMQP, it is designed to work over UDP rather than TCP, pushing messaging reliability to the higher application level layers. Given its RESTful primitives, CoAP is easily translated with an adaptor or gateway module to HTTP, and from there, integration is easily facilitated to other protocols (such as DNP3), and back-end enterprise systems via Web Services.

23.2.1.6 Open Mobile Alliance Lightweight Machine-to-Machine (M2M)

The Open Mobile Alliance Lightweight protocol is used to provide expedient deployment of client-server applications in the machine to machine space. It is primarily a device management protocol, but can be used to facilitate other services and application data exchanges.

23.2.1.7 RFC 2818 HTTPs

RFC2818 is a secure version of HTTP and is also in the domain of RESTful services. It is listed here since it is not only popular for Internet Web applications but is also able to integrate and translate CoAP and L2M2M to other back-end applications and Web services via its similar defined workload primitives.

23.2.1.8 IEEE 61968 Common Information Model (CIM)

IEEE 61968 is a series of standards that define data element exchange structures between electricity distribution systems. The CIM is also used together with other interoperable data element and management definitions, such as IEEE 61850. Like other protocols in this section, it is a middleware service that facilitates the exchange of data elements and their associated messages between various higher level applications.

Similar protocols in this data element space include ANSI C12.19, which defines and organizes data elements between electric meters and computers for data sharing and management purposes. ANSI C12.22 defines the communication of the C12.19 data element structures over a communication subsystem. In the metering space, Device Language Message Specification (DLMS) and

Companion Specification for Energy Metering (COSEM) can be used together to define meter data exchanges across AMI systems. The Simple Network Management Protocol (versions 1 through 3) defines data element structure and management specific to many communication subsystem devices, and has been in broad use for more than 30 years.

23.2.1.9 IEEE 61850

IEEE 61850 is discussed in detail elsewhere in this book. It has the capability to support publish/subscribe and many of its functions to make use of the Ethernet and IP network layer communications.

23.2.1.10 IEC 60870

IEC 60870 is the standardized version of SCADA (supervisory control and data acquisition) that has been the ubiquitous monitoring and control protocol used for decades within transmission and distribution networks. SCADA will benefit from the scaleability, interoperability, and security improvements offered by tunneling IEC 60870 over IPv6-based protocols.

23.2.1.11 IEEE 1518 (DNP3)

The IEEE 1518 DNP3 protocol has been deployed in electric utility networks for decades. It can be exchanged over IP networks, and is a legacy fixture in both the serial and IP datagram world.

23.2.1.12 Modbus

Like DNP3, Modbus is a legacy device protocol that must be accommodated in the IoT system. Modbus is more predominant in commercial and industrial device applications. Modbus can be encapsulated into IP datagrams, which makes its inclusion into the IoT world a possibility.

23.3 MAKING IOT A REALITY IN SMART GRIDS

Key to widespread deployment of the SG-IoT is not only the low cost of the devices but also the ease and cost to install the devices. For ease of installation, especially when installing IoT devices on existing assets, the devices should also have the option to be powered by battery with low power requirements.

Utilities and electric grids operate over city, state, and national scales, and over different terrain (urban, suburban, rural) and deployment models, so both high-density and long-distance communications connectivity is required. It is, therefore, important to have options for a pervasive, low-cost, and secure communications network (preferably wireless) that is based on open-standard protocols. A combination of various types of communication networks may be necessary, so it is critical that the SG-IoT supports seamless connectivity between different types of networks, using adaptive or convergence layers where needed to translate between heterogeneous network protocols.

While the current structure of the IoT is focused more on communicating with devices in order to send data to centralized applications for processing, the ultimate value of the IoT is connectivity, interoperability, and the ability to exchange data among devices. As more and more devices are added to the SG-IoT, the key challenge we see for the SG-IoT is the need to manage, process, filter, store, and control the vast amount of data at the IoT level in order to reduce the amount of data exchanged between devices and communicated to centralized, enterprise-level applications and systems, especially if low data latency is critical. The ideal SG-IoT should, therefore, be able to implement functions autonomously at the device level by means of distributed intelligence or fog computing, while also supplying meaningful data to a centralized software platform or cloud for collection and analysis. This distributed computing ability will bring additional value to the SG-IoT, particularly now with the focus on the grid-edge, where there will be a vast number of devices on the distribution grid and at the customer interface. There has been discussion about avoiding the need for any centralized control or brokering of data by using blockchain to enable true autonomous smart devices [2]. Fog computing, also known as fog networking or fogging, is a decentralized computing infrastructure in which computing resources and applications are distributed in the most logical, efficient place at any point along the data source continuum [3]. The goal of fog computing is to improve computational and communications efficiency by reducing the amount of data that needs to be transported to a central location (or to the cloud) for data processing, analysis, and storage. Fog computing is also used to reduce the latency of response between the application and the connected devices. Fog computing may also be carried out for security and compliance reasons. The choice of the word "fog" is meant to convey the idea that the advantages of cloud computing should be brought closer to the data source—in meteorology, fog is simply a cloud that is close to the ground. Fog computing is about processing close to the data's location and taking decisions as close to the data as possible [4].

This distributed intelligence and fog concept may also lend itself well to "machine learning" at the device level. Machine learning is the ability of computing devices to learn to function in ways that they were not specifically programmed to do [5]. The philosophy behind machine learning is to automate the creation of analytical models in order to enable algorithms to learn iteratively and continuously with the help of available data. Therefore, machine learning allows computing devices to find hidden insights without being explicitly programmed where to look. Machine learning can be applied in cases where the desired outcome is known (guided learning), or the data are not known beforehand (unguided learning), or the learning is the result of interaction between a model and the environment (reinforcement learning) [6]. Machine learning can be a significant driver in taking IoT in the smart grid to the next level of applications that require minimal interaction (or are autonomous), and for applications that can adapt to various conditions, for example, Volt/VAr control on a distribution system that contains DERs.

While the access to enormous amounts of field data may be an obvious benefit, utilities may be challenged with the business case in building out the SG-IoT if they do not clearly identify and define the objectives in using the data and how the data will be collected, stored, and analyzed by applications and solutions that will provide benefits to the utility, customer, and environment. As with smart grid technology and solution deployments, there must be a comprehensive strategy and plan for IoT adoption, and to identify the shared costs and benefits of multiple, complementary solutions enabled by the increase in field devices in the smart grid IoT; otherwise, it may be difficult to justify the cost and secure budgets for the implementation. Equally as important are the applications and systems that will be using, analyzing, and acting on the data from the IoT network. The smart grid IoT discussions should include both technology and business goals.

There is a perceived lack of IoT expertise in the utility industry; this is also true for data analytics in the context of utilities and smart grid. This is not expected to be a significant barrier to IoT adoption in the smart grid as expertise and experience in smart grid implementations continue to ramp up. Innovation and expertise will need to come from both utilities and vendor partnerships. With new technologies, there is also the need for testing and standards to ensure interoperability and widespread adoption, which help to reduce costs at scale. As part of the overall digitalization trend in utilities, IoT will be a significant part of the change in utility thinking, and utilities can look to each other and to other industries in helping to guide the transformation.

While the SG-IoT is arguably in its infancy, there is a clear technology trajectory and need for IoT in this space. New IoT protocols, technologies, and use cases will continue to penetrate the industry and other similar vertical industries in the next several years, and at an accelerated pace. IoT technologies from other industries and adjacent markets, such as wearables (health monitors, virtual/augmented reality), drones, and RFID, will also prove to be beneficial in the utility realm.

23.4 SMART GRID IOT APPLICATIONS

According to a recent SAS survey [7], 63% of responding utilities indicated that IoT was critical to their companies' future success. Top uses of IoT today include metering and meter data management (55%) and cybersecurity (49%); however, the biggest growth areas are customer-facing. In all, 73%

of the respondents in SAS' survey indicated that customer engagement will be IoT-enabled in the next three years. The same survey reported that an average of 25% of the respondents have machine learning initiatives currently under way, increasing to over 40% planned in the next 3 years.

As the utility industry moves forward with smart grid applications and IoT, there will be an increased focus on both the consumer and the grid-edge, with the need to communicate with third-party-owned devices, such as DER controllers, and provide marketplace interaction for transactive energy exchanges. As with smart grid deployments, we will see pilots and proof-of-concept projects focusing on IoT networks and initial levels of some form of distributed intelligence, fog computing, and machine learning. The sections that follow summarize some of the focus areas in SG-IoT today and envisioned for the near future.

23.4.1 Smart Metering and Consumer Engagement

In recent years, smart metering and advanced metering infrastructures (AMIs) have been the initial smart grid technologies to benefit from recent IoT technological advances in embedded intelligence and communications. It is this explosion of cost-effective devices that has provided utilities and consumers with more data and energy usage awareness, and creates business value and justifies the buildout of smart grid infrastructure. Outage notification is one of the initial benefits of using real-time data from smart meters, where the meter is able to automatically notify the utility after a customer loses power. Real-time data from the meter can also be used to manage and verify Volt/VAr management schemes. Measurements from customer meters and corresponding measurements of load on distribution transformers can be used to identify non technical losses (theft).

Perhaps one of the most revolutionary enablers is the ability to further connect the consumers with their utilities or service providers in real time to provide better customer service. Home automation technology also falls in this category. As expected, the consumers' smart phone is a key part of the SG-IoT with mobile applications that may connect directly to the utility or service provider (such as outage notification), or with their meter and devices to manage energy usage. Such connections can result in new services and applications that enable a better way of life.

While tamper detection and fraud analysis are common centralized functions as part of the meter data management system, such applications are prime candidates for machine learning implementation in devices at the consumer interface, such as within the smart meter itself. Machine learning is also a great fit for demand response management, allowing utilities to determine the optimum demand response plan and expected participation from each consumer.

23.4.2 Reliability and Outage Management

With a strong focus on SG-IoT at the grid-edge and consumer interface, there is opportunity to leverage the data for applications related to the operation of the distribution grid. A good example is the use of IoT for reliability and outage management. While automatic restoration and outage management technologies and applications are discussed elsewhere in this book, the IoT perspective could be extended to include communications to sensors for fault detection and the controllers for fault isolation. The additional IoT component is from communicating directly with customers via their mobile devices (text, application, social media), such as outage reporting by the customer and outage status (expected time to restore) notification from the utility. Mobile devices do not limit customers to reporting outages at their home location, and customers will be able to report any abnormal grid conditions (with photographs or videos), such as arcing insulators on a distribution line. Distributed intelligence, fog computing, and machine learning would allow devices in the field to share data and learn over time which parts of the distribution system are more prone to failure or faults and help make the grid more resilient. During storms where the grid can be susceptible to widespread damages and outages, the smart grid IoT can help with prioritization of field work and quicker restoration.

23.4.3 Asset Management and Tracking

SG-IoT provides utilities with connected sensors across the transmission and distribution grid, which can provide real-time data on equipment health and performance. Physical parameters, such as voltage, current, temperature, humidity, pressure, and vibration, can be measured by a distributed sensor network, communicated back to the utility, and analyzed by algorithms in real time in order to establish baseline performance and detect excursions from normal behavior (Figure 23.6). Cameras can be placed in substations to detect break-ins and theft, and the images or video uploaded to the utility. Furthermore, all of these data can be integrated with other data sources (such as weather) to gain further insights into asset health.

23.4.4 Predictive Maintenance

Utilities can use the data collected by the SG-IoT to measure the loading and wear on grid assets, which can then be compared with device specifications to predict useful asset life. For example, 15-min interval data collected from smart meters located downstream from a given transformer can be aggregated over time to monitor the transformer loading profile and identify times of peak loading. The transformer can then be resized if appropriate, and maintenance or replacement schedules can be calculated based on actual operating conditions. This knowledge helps the utility optimally deploy both capital resources and maximize return on assets.

While integrated monitoring and diagnostics devices are currently available, machine learning can further drive the value-curve of asset management to predict and optimize the operation of the asset in real time in the field in order to minimize the amount of data sent back to a centralized system. A centralized asset management application is still required to archive the data and analyze trends across similar fleets of equipment or service areas, and provide integrated reporting and asset health dashboards.

23.4.5 Fleet and Mobile Workforce Management

SG-IoT can be used to optimize the utility's use of labor resources as well as capital. The predictive maintenance capabilities of IoT will reduce the labor and travel time required to replace assets before their operational life has expired, or respond to emergencies when assets have failed.

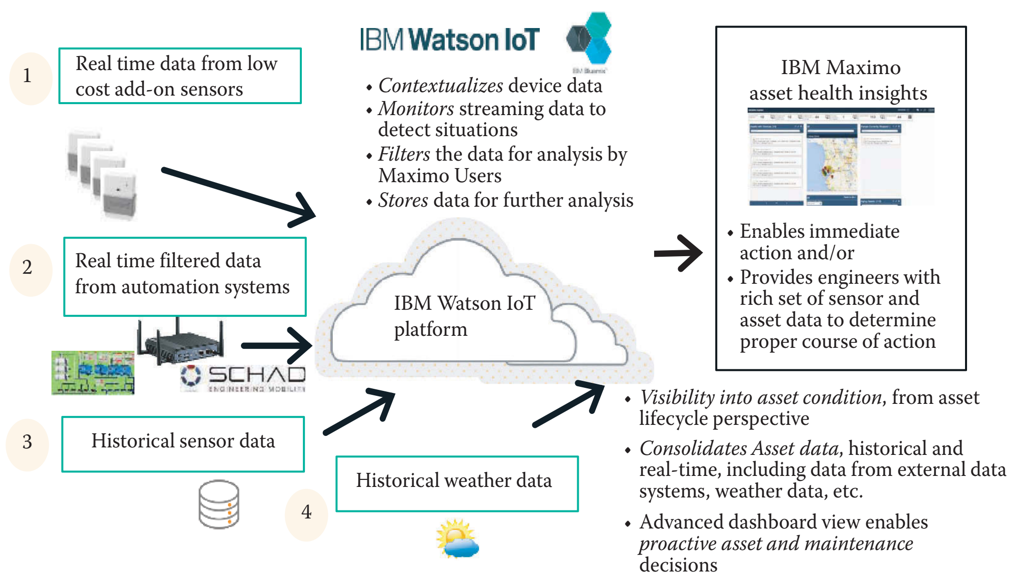

FIGURE 23.6 IBM Watson IoT platform. (From International Business Machines (IBM) Corporation, 2016.)

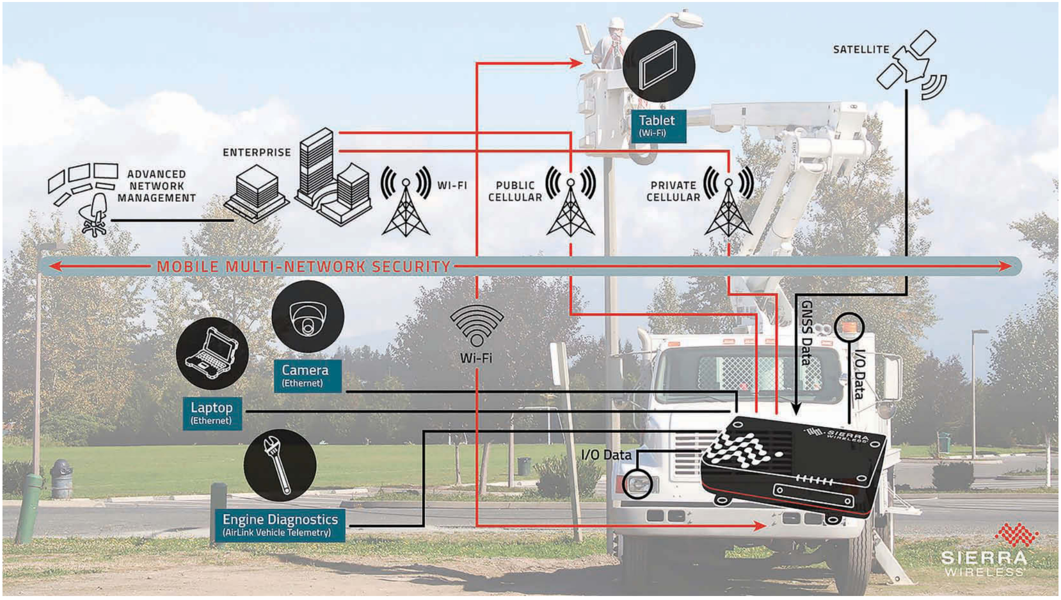

FIGURE 23.7 IoT for fleet and workforce management. (Courtesy of Sierra Wireless, 2017.)

High-bandwidth backhaul networks can provide the workforce with inexpensive voice and broadband data access for work order dispatch, tracking field work, directly accessing and updating geospatial information in the field after work is complete, and accessing equipment maintenance manuals and supporting photos or videos, if required (Figure 23.7). The field vehicles can be tracked and diagnosed remotely (e.g., to identify maintenance requirements) in order to improve vehicle fleet management. The vehicles can also be outfitted with sensors and communications to manage and enhance workforce performance.

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24 Smart Cities

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CONTENTS

Cities are places of opportunity and economic growth. People are attracted to cities to find higher paying jobs, to be closer to friends in smaller neighborhoods, and to enjoy the faster-paced culture and the multitude of convenient amenities of urban life. Today, more than half of the world's population lives in towns and cities. With an estimated one million people moving into cities each week, this figure is expected to rise significantly in coming years. Between 2011 and 2050, the world's urban population is projected to rise by 72% (from 3.6 billion to 6.3 billion) and the population share in urban areas is expected to increase from 52% in 2011 to 67% in 2050 [1]. Though cities occupy only 2% of the land mass, they consume 75% of all energy and produce 80% of all CO_2 emissions [2]. This requires an increase in more cost-effective, smartly planned, and timely solutions to provide cities with an integrated infrastructure and services, such as transport, energy, health care, water, and waste. Information and communications technologies (ICT) will play an important role in connecting these resources to the people who use them in order to ensure economic, social, and environmental sustainability. The development of smart cities requires the joint participation by several stakeholders—government, private industries, and citizens.

The goal of smart cities is to answer such questions as: "How are cities improving urban life through sustainable integrated solutions? And how are they developing good quality services for citizens and businesses?" These are some of the challenges for cities when becoming "smarter." Smart cities can provide great opportunities for suppliers and users to prove innovative technologies. Becoming "smarter" is also about identifying and testing new business and financing models to be able to deploy and scale up new technologies in cities. And there are no "smart cities" without "smart citizens," adding challenges around engaging and empowering citizens to help make their cities "smarter." Becoming a "smart" city is not an end goal for urban development, but a continuous process for cities to become more resource-efficient while also improving quality of life.

24.1 WHAT IT TAKES TO RUN A CITY

Every city navigates not only its particular geographical challenges, but also the history that endows it with a particular kind of culture and government. In many parts of the world, city leaders have relatively little power to make decisions on their own. In India, for example, urban policy is typically set by the state and national governments, under the influence of a city's residential and business communities. In the United Kingdom, city governments can implement many policies on their own, but are often forced to engage with the national government to push through any large ideas, while there is no equivalent to state governments. In the United States, cities must navigate a federal system that gives different powers to the city, state, and federal governments.

Though many of the challenges and practices of particular smart and would-be smart cities are unique, there are some common traits. The following section provides a broad overview of the types of city stakeholders and some of their distinctions, and the decision-making process.

24.1.1 Stakeholders

A city consists of three main types of stakeholders: the public, which lives and works in the city; the business community that drives its economy; and the government, whose decisions can have a transformative effect on a city. The stakeholders rely on each other, while simultaneously wielding significant amounts of power on the others. A government would struggle to maintain legitimacy without a functioning business community, or the political power without the support of the population. A business community needs the government to provide it a structure within which to function, and the population to buy its products, while the broader population needs the business community to provide it employment, and the government to provide essential services. A truly smart city capitalizes on the synergy that exists between each of the types of stakeholders.

Within each of these stakeholder categories, community members, the business community, and the government, there are numerous subcategories. In the United States, for example, smart cities have to navigate a federal system that gives different powers to the city, the state, and the national government. Though much of the implementation is typically entrusted to the city governments, they are often reliant on funding provided by the state and national governments. When cities receive funding from other governmental bodies, they are required to demonstrate that it is properly spent, which can often mean showing it is the most economical use of government resources.

24.1.2 Making the Decisions

Though government agencies are, by definition, not-for-profit entities, they do seek returns on their investment. They expect to see growing economic outputs and improving levels of quality of life for residents, including those from communities that have been historically deprived. These two foci reiterate the importance of being constantly attentive to the needs of the business and popular communities.

Within the business community, there are, of course, large divides. For every company whose profits increase with added investment in clean energy, there may be another company whose profits decline. Speaking broadly, however, economic growth is ideally associated with increased governmental efficiency, more services provided at lower cost, and with less impact to the environment. A smart city that is committed to leveraging the local business community's skills in accomplishing those tasks will be in an advantageous position.

Simultaneously, a smart city must maintain deep contacts with a wide range of the population so as to ensure it is attentive to their needs. This includes actively interacting with the citizens and understanding and responding to their individual concerns, while also paying special attention to those groups, including those ideologically motivated, who represent swathes of the city's residents.

A cautionary tale of a smart city that failed to pay enough attention to the political challenges is Boulder, Colorado. In 2007, Xcel Energy chose to focus on that city with an ambitious smart grid plan that would give the city's residents access to the most advanced technological services. Though they succeeded in many respects, Xcel Energy failed to explain to the city's residents why the usage of renewable resources did not meet the city of Boulder's expectations, which cost the smart city project valuable popular support. Meanwhile, Xcel Energy's inability to justify to members of the Colorado Public Utility Commission the value from their investments lost them continued financial support from the state government, which ultimately resulted in significant losses for the company.

Contrast this with what happened in Barcelona, Spain. They focused on smart city initiatives in four groups: smart governance, smart economy, smart living, and smart people; and implemented effective programs, such as developing innovation clusters, where companies, universities, and citizens can collaborate, thereby strengthening the economy, and provided training programs in digital literacy to ordinary residents so as to make it easier for them to access government services. Barcelona also focused intensely on preserving public support. They developed a 22@Barcelona district that helped make it very clear, using marketing and branding, what was being done for residents. They also maintained deep connections, particularly with members of the Barcelona City Council, so that they were aware of the policies being implemented, and how they were helping accomplish their broader, shared goals.

24.2 CHARACTERISTICS OF A SMART CITY

Making a city "smart" focuses on mitigating the problems generated by the urban population growth and rapid urbanization by:

- Integrating services and making them more efficient
- Attracting more businesses, jobs, and visitors to the city

- Ensuring a better, healthier, and safer place to live and work
- Improving public services, including education and transportation
- Improving the efficiency of the underlying infrastructure
- Social, economic, and environmental sustainability

Smart cities that can better use existing resources through improved monitoring, controls, and coordination of services and infrastructure can improve the quality of life of residents and attract more businesses. There are several approaches to identifying the needs of smart cities. Some definitions of smart cities are based on the various services and stakeholders—the public services, the utility services, transportation, building energy management, and so on. One approach is to consider the five basic elements or characteristics shown in Figure 24.1. Common to all smart city elements is the need for an ICT infrastructure that has the capability to interface and exchange data within all of the elements of the smart city, most notably able to handle the different data types and data

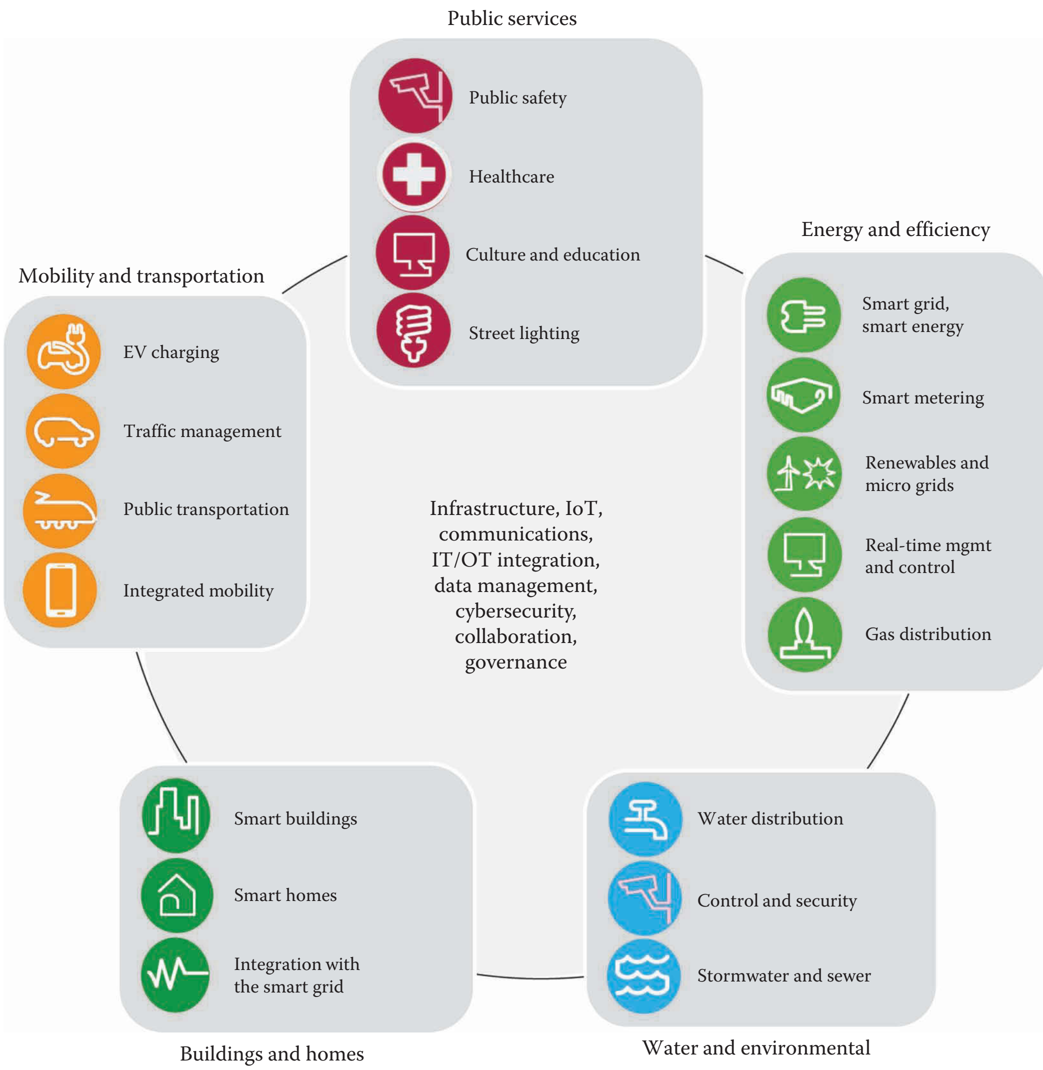

FIGURE 24.1 Dimensions and elements of smart cities. (© 2017 Stuart Borlase. All rights reserved. With permission.)

exchange requirements. Also across the smart city elements is the need for physical and cybersecurity measures and a common platform for data integration and management.

Different cities in different geographies and at different stages of development may wish to tailor these characteristics to suit their local context and priorities. Hence, a smart city could be described as one that

- Dramatically increases the pace at which it improves its sustainability and resilience.
- Fundamentally improves how it engages society, how it applies collaborative leadership methods, how it works across disciplines and city systems, and how it uses data and integrated technologies.
- Provides better services and quality of life to those who live in the city and to those involved with the city (residents, businesses, visitors).

Energy efficiency and sustainability are typically the near-term aspects and objectives of smart cities. Significant progress has been made on these fronts. Use of, and interface with, smarter energy systems (electric and gas) is a crucial component in this process. A second major area is mobility and intelligent transportation, which are critical to living and working in cities, reducing GHG levels and lowering medical costs. In a third major area, there is a focus on safe water supplies, waste, emissions, green living, and environmental management. Clean water and its reuse, environmental pollution control, and the related set of topics are all critical to cities. A fourth major area is big data, communications, and processing. This is where smart system analytics—planning, integration, and optimization—largely reside. And the fifth major area is cyber-physical security and information privacy. This is, of course, critical to ensure preservation of smart system operations and data security. Critically important are the interactions between these five major areas, as well as the scale that can be achieved, which jointly drive major innovation. Scope and scale are critical to enable new innovation to be economical, such as by reducing overall smart system costs.

To succeed on the political side, there are two key components that deserve close attention, public administration and services, and culture and education. A smart city should strive to produce an efficient government that delivers clear benefits to its residents. Second, it must endeavor to promote an urban culture that highlights the growing appeal of the smart city, and publicizes the available resources to its entire population.

24.2.1 Public Administration and Services

Efficient provision of services is the mark of an effective government, and smart cities are no exception. In contrast to other forms of government, however, smart cities have a very clear benchmark of success—solving resident needs. Smart cities are radically resident-centric. They are attentive and responsive to the particular needs of their populations, offering solutions from the best of available technology.

Even within a single city, not all groups will have the same needs. Research on Munich's Smart City reforms, for example, found that many government officials conceptualized it as increasing responsiveness to citizen needs, and were less focused on the environmental effects [3]. Environmental activists might focus on different advantages of the broader strategy.

In different cities across the world, we have seen how an intelligent appreciation of the unique needs of their residents has often led to dramatically different solutions. Water, for example, would seem like a basic need for every population, and all smart cities are committed to improving the distribution of water. Not all residents, however, need the same kind of water services. This is why in some cities, there is a greater emphasis on increasing the availability of potable water, by only cleaning the water that requires it and identifying which water needs to be recycled, while in other cities, more effort is invested in delivery and cost-efficiency, such as reducing leaks and theft.

Though every city is different, there are broad trends important in the design and deployment of smart city services.

24.2.1.1 Health and Public Safety

A smart city collects, analyzes, and then reacts to a wide range of information in order to better maintain the health and safety of its residents. The U.S. Department of Energy, for example, recommends that the newest distributed electricity systems should reflect and respond to data about weather concerns, such as earthquakes and even fire hazards on the electric grid. But these kinds of data may be even more relevant when the danger is high in particular areas of the city.

Key examples include air quality sensors and gunshot detectors. More and more cities are deploying air quality sensors across their territory, which can collect key data about a particular location and send that information back to a central location for analysis in order to identify precisely where a response is needed so as to optimize the use of government resources across the city.

Similarly, gunshot detectors now exist that can distinguish between loud, but harmless, noises, such as firecrackers, from those that can threaten the lives of city residents. Providing this information to emergency responders can help them avoid responding to false alarms, and respond even faster where time is of the essence.

24.2.1.2 Culture and Education

The best smart cities also make sure that their populations are as smart as possible. This entails maximizing the government's investment in education and culture. The increased availability of low-cost (or free) and high-speed Internet makes it possible to give every school child access to the best educational resources anywhere, to have access to a dizzying array of newspapers and books, see famous teachers deliver lessons, or to improve their language abilities by speaking to a native speaker across the globe. By digitizing exhibits from museums and galleries, and promoting them using social media, for example, Instagram and YouTube, smart cities can increase the reach of their local cultural resources, potentially enhancing industries like tourism. Internet access and digitization also allow smart city residents to be part of a global conversation with those who may have grown up seeing them in person, and with those who could only have imagined it in the predigital era.

24.2.1.3 Street Lighting

Modern cities began lighting their most prominent streets with electric lights after the development of the arc lamp and its installation in Paris in the late 1800s [4]. By 1890, over 130,000 arc lamps were installed as streetlights across American cities. Once Thomas Edison commercialized the incandescent light bulb in the early twentieth century, it signified a major step in the progress of keeping urban spaces safer with electric streetlights. Mercury vapor (MV) fixtures quickly took over in the mid-twentieth century due to significantly higher light output, with some still in use today [5]. High-pressure sodium (HPS) lamps, which have a familiar orange glow, were a common replacement for the MV lamps 30–40 years ago due to their simpler and more efficient technology that could often be retrofitted into MV fixtures. HPS lamps are still the current technology in many major cities across the USA. More modern installations use metal halide lamps, which produce a more natural white light, but is often less efficient than its HPS counterpart, making it less cost-effective for public lighting. In most cities, there is a balance between utility-owned streetlights, city-owned path lighting and roadway lighting, and state-owned highway lighting. Municipalities and counties can also own streetlights, making the complete retrofit of a city's lighting infrastructure a much more complicated project. HPS fixtures rely on ballasts, a starting mechanism, and bulbs require replacement every 5–7 years.

Since many of the major cities performed major overhauls of their public street lighting between the early 1960s and late 1980s, their infrastructure is now due for an upgrade. This opens the door for new lighting technologies, and light emitting diodes (LEDs) are quickly becoming ubiquitous. LEDs have advanced to a point where they can provide the same lumen output as other light sources while consuming half the power. The energy savings alone are sufficient to justify an upgrade. LEDs also have the added benefit of longer service life, 20 years or more. Furthermore, as opposed to much of the current lighting stock, LEDs are solid-state and do not require starting ballasts or capacitors, use digital components, and have the capability to be dimmed. Many new streetlight fixtures have been upgraded from a simple on/off photocell control, to a seven pin photocell that has onboard communications technology, metering, dimming capability, and has extra pins to include future sensors or features. Dimmable lighting opens up a huge range of possible applications, many of which have never been explored because the capability to do so was simply not present. For example, dimming applications may include complementing the setting sun by ramping up light levels over time; doing the same in reverse and ramping down during sun rise; and by providing low-level, supplemental light during particularly overcast days. Additionally, whole sets of lights can be dimmed during low-use periods to save additional energy, and sensors can be integrated to help cities with parking, street cleaning, snow removal, and safety.

Simply swapping one light fixture for a more efficient one does not provide the city with any additional visibility into their lighting system, nor does it give it any additional control over its lights. In most major cities, streetlights are typically only replaced when citizens report lighting issues to the city, or when utilities or city workers drive around to visually check the operation of the streetlights. Major cities can spend as much as 40% of their budgets on public lighting [6]. When a lighting issue is reported, a crew in a truck is sent out to determine the problem. The use of advanced communications, often forming a mesh network among light fixtures, and integrating with existing utility smart grid networks, allow for vastly improved lighting controls and management. With smart streetlights, a city can detect, in real time, any problems with the lights, and then schedule crews to repair the lights, depending on the type of problem and the urgency. This cuts down on operations costs, maintenance costs, and even legal costs, as cities and municipalities dramatically reduce their liability for accidents and crimes that occur under broken streetlights. The connections between lighting, city management, public safety, and smart cities form a tight web, represented in Figure 24.2. A University of Chicago study showed that, in that city, when three streetlights went out at the same time on a city block, crime on that block

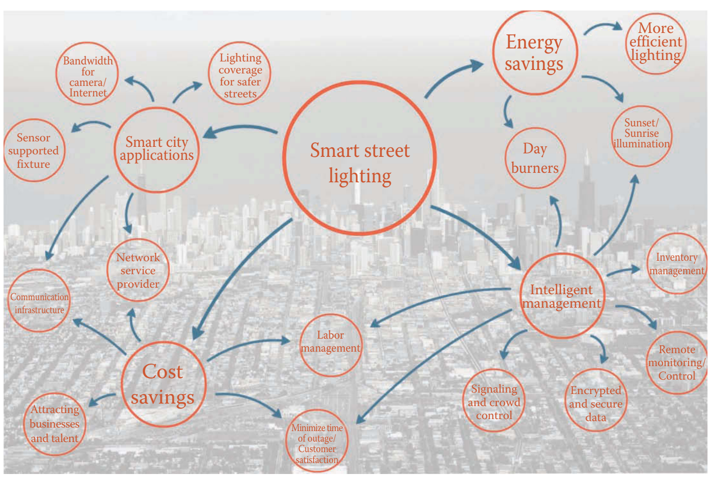

FIGURE 24.2 Smart street lighting benefits. (© 2016 Willdan Energy Solutions. All rights reserved. With permission.)

spiked 7.4%, including an 18.6% increase of violent battery crime [7]. By immediately reporting when smart streetlights fail allows relevant authorities to identify precisely where their attention is most needed.

Smart streetlights can also represent a particularly valuable component of a region-wide AMI communications network because the communication nodes can be placed at a sufficiently high elevation, creating a clear communication pathway between nodes. Not only do networked streetlights dramatically improve energy efficiency of a city's lighting program and reduce the operations and maintenance costs of that program, but they can also serve as the skeletal backbone for networking other infrastructure in the future. When all other forms of communication fail, this network can allow emergency responders to comprehend the situation across the region.

Even beyond communicating with other devices on the network, networked streetlights also allow for improved systems integration, or tying together operations that were previously independent. For example, ambulances dispatched in response to 911 emergency calls occasionally have difficulty identifying a correct street address, wasting precious time for someone who may be in need of serious medical attention. The 911 system could automatically send a signal via the network to flash the streetlight nearest to the caller's address, acting as a beacon for ambulance drivers rushing to the location. Another opportunity in emergency response is to equip the networked streetlights with acoustic sensors to detect gunshots, and relay an alert to emergency responders. Police could therefore be dispatched without depending on an individual reporting the incident.

In off-grid scenarios, LED street lights can provide even greater benefits due to their low energy consumption, simplicity of operation, and long-lasting components. Companies are beginning to offer off-grid LED streetlights powered by solar panels and small wind generators that charge batteries integrated into the light [8]. Currently, 18% of the world's population (i.e., 1.2 billion people) live without access to electricity, and LED fixtures can help illuminate the lives of these people, reduce negative health effects from burning fuels for light and cooking, allow for cellphone and device charging, and provide nighttime studying, meeting, and celebration opportunities. These off-grid lighting units can be controlled by direct cellular access to each individual unit, but this can be expensive and can prove difficult in remote areas where cellular service is not reliable. However, if streetlights on highways or roadways are upgraded with communications capability, then the individual lighting nodes can be used to form a communications and information highway to connect cities with villages across the country. These communication networks could also be used for emergency communications, control of streetlights or other generation resources, communications for transactive power, and other innovative services to improve the lives of everyone.

One of the first steps in smart street lighting applications is developing sensors that can identify when a moving object (person or vehicle) is approaching the streetlight. Streetlights can be individually controlled so that when there is no movement nearby, the streetlight can either be turned off, or dimmed, depending on the location of the streetlight, in order to save energy. Prototypes have been developed containing a series of potential options. Computer vision presence detection, for example, entails installing a video camera and then using computer vision analysis software to identify human presence in the area. This has shown to be fairly accurate, but also requires a significant investment in terms of power and communications bandwidth. Passive infrared (PIR) sensors measure the infrared radiation in an area to identify when somebody is moving in the vicinity. These sensors have, however, relatively little range, and can only be tuned during the manufacturing process, limiting their adjustability. PIR plus ultrasonic sensors incorporate the latter to increase their range, but can still only be modified while being manufactured. X-band radar detection is another option that sends waves of X-band pulses and uses the Doppler effect of the echoes to identify the presence of a human or other moving object [9].

Another important step in smart street lighting development is identifying what other types of data can be collected from the streetlight. For example, additional sensors can be installed on the streetlight fixtures in order to measure local air pollution as well as noise levels. Once the additional sensor data are collected, they can be conveyed to the cloud where the data can be processed, analyzed, and made available to the relevant authorities [10]. In the small port city of Santander in Spain, they have begun to use a wireless communication module based on IEEE 802.15.4 to create a mesh network for relaying the sensor information to the IoT Network Gateway. A 3G link is used to transmit information back to a light intensity sensor in the smart street light to determine when the light should be turned on [9].

Street lights are one of the permanent assets of cities today. They illuminate downtowns, parks, and public gathering places, industrial centers and malls, alleys, and residential neighborhoods. It's sometimes in ordinary pilot studies that we can see the initial inklings of the next generation of technology. In a broader sense, city lighting allows residents to live their lives as they would like to live. Researchers have suggested that good outdoor lighting has a wide range of positive effects, including even encouraging residents to exercise more [11]. Using some of the most advanced technology for streetlights is, in some ways, the first step to ensuring that the entire city is truly smart.

24.2.2 Energy and Efficiency

Energy is the lifeblood of modern cities, illuminating streets and parks, moving goods and people, and heating and cooling the indoor environment. It is an essential resource for cities to maintain to ensure that residents and businesses prosper. Cities and their local utilities have a responsibility to work together to deliver cost-effective, sustainable energy to the urban ecosystem. Through initiatives that integrate DERs (Distributed Energy Resources) (e.g., energy efficiency, renewable energy, demand response, and zero-emission vehicles), cities and utilities can modernize the grid, reducing greenhouse gas (GHG) emissions and increasing resiliency and reliability.

Local, state, and federal mandates are driving GHG emission reduction goals across the USA. For example, in 2014, the state of California created a target of doubling energy efficiency and ensuring that 50% of the power delivered by utilities was from qualified renewables by 2030. At the local level, the city and county of San Francisco, a nationwide sustainability leader, has set a goal to reduce GHG emissions 80% below 1990 levels by 2050. To achieve this, the city is working toward ensuring that 100% of the electricity supplied to residents and buildings is from renewables by 2030.

San Francisco has two electric utility providers: the San Francisco Public Utilities Commission (SFPUC), and the Pacific Gas and Electric Company (PG&E). The SFPUC is the city's municipal power utility, which owns and operates the Hetch Hetchy Power System, San Francisco's clean energy backbone. For over 100 years, the Hetch Hetchy power network has supplied 100% GHG-free electricity to all municipal facilities, services, and customers, which includes the airport, hospital, police and fire departments, residences, and businesses. Collectively, this accounts for approximately 17% of the city's electrical load.

PG&E is an investor-owned utility, providing electric and gas services within San Francisco. It currently serves approximately 73% of the city's commercial and residential customer load, and is committed to achieving California's Renewable Portfolio Standard (RPS) requirements (33% by 2020 and 50% by 2030). In 2015, PG&E's portfolio included 27% renewables, and it is on track to achieve the 2030 RPS goal with 37% renewables currently under contract. In January 2016, PG&E also launched Solar Choice, a renewable energy program that enables PG&E retail electricity customers—including renters, homeowners, and businesses—to purchase up to 100% renewable energy without installing solar photovolatics (PV) on their roofs.

The city of San Francisco is continuing its path to 100% renewable energy with the launch of CleanPowerSF [12] (Figure 24.3), San Francisco's new Community Choice Aggregation program. Launched in May 2016 by the SFPUC, CleanPowerSF, which was authorized under State law (AB117 in 2002), allows the city to collaborate with PG&E to provide an additional choice in the sources of electricity generated and delivered to residents and businesses. Under CleanPowerSF, PG&E will continue to maintain the grid, respond to outages, and collect payments. For CleanPowerSF

FIGURE 24.3 CleanPowerSF overview. (From the San Francisco Public Utilities Commission.)

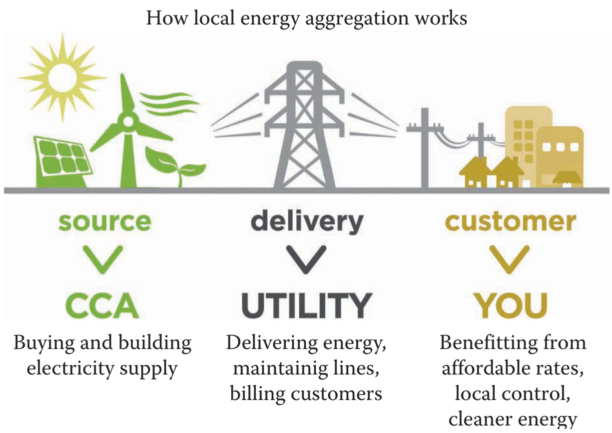

FIGURE 24.4 How community choice aggregation (CCA) works. (From LEAN Energy US, http://www.leanenergyus.org/. With permission.)

customers, the city will make decisions about the supply of electricity, and replace PG&E supply choices and charges with a new charge that pays for cleaner energy. The city is offering electric generation rates to CleanPowerSF customers that are competitive with PG&E generation rates. Furthermore, CleanPowerSF will exceed the state's 2020 RPS goal of 33% by providing a default "Green" product that is 35% renewable and a premium "Super Green" product that is 100% renewable, using California sourced renewable energy.

Community Choice Aggregation (CCA)[1] is a relatively simple concept involving group purchasing. CCA allows local governments and some special districts to pool (or aggregate) their electricity load in order to purchase and develop power on behalf of their residents, businesses, and municipal accounts [13]. CCA is an energy supply model that works in partnership with the region's existing utility, which continues to deliver power, maintain the grid, and provide consolidated billing and other customer services (Figure 24.4). Choosing to develop a CCA enables local governments the option to procure renewable power, empowering customers with choice, local energy generation, and the ability to reduce energy costs. Throughout the United States, many states have passed CCA laws as part of electric restructuring legislation in the late 1990s and early 2000s, including California, Illinois (2009), Massachusetts (1997), New Jersey (2003), Ohio (1999), New York, and Rhode Island (1997).[2] A major benefit is that utilities still utilize their transmission and distribution

[1] Sometimes also referred to as municipal aggregation and government energy aggregation.

[2] CCAs in CA and IL are permitted to develop power projects as well as contract for power. Some states (e.g., OH) also allow for gas aggregation.

systems to deliver the electricity supplied by a CCA in a nondiscriminatory manner. Utilities must provide these delivery services at the same price and at the same level of reliability to CCA customers as it does for its own full-service customers.

ICT help cities integrate and optimize its energy systems and services, making them more efficient and resilient. An integrated energy system will also help preserve natural resources, ensure energy security, and provide residents and businesses a host of ways to monitor and control their energy consumption to save money. ICT integration enables cities to collect and analyze data, perform demand forecasts, and optimally manage load and procure energy. Distributed sensor deployment in cities, such as smart street lighting and residential, commercial, and industrial smart meters, enables cities to collect real-time and granular energy consumption data. Collected data can be securely stored and analyzed to help cities gain a better understanding of their aggregated demand. Currently, cities can visualize their energy cost trend, but usually only at a high level and only after the fact by reviewing bills from a previous period. Using data integration and data analytics to calculate or estimate energy use down to the asset or device level could improve understanding of how energy is being used and how it relates to the energy bill. Additionally, good data collection can lead to the creation of metrics, such as energy and cost calculations, to measure asset use and efficiency helping to meet goals. Analytics also helps cities to optimally balance energy consumption and production with real-time energy market prices.

24.2.3 Mobility and Transportation

New and renovated airports are one of the leading indicators of city growth, which make the cities an ideal candidate to becoming a smart city. Some current examples include:

- Masdar City, a sustainable, zero-carbon, zero-waste, car-free city in the UAE is adjacent to the ever growing Abu Dhabi International Airport.
- Guangzhou Knowledge City, a 42-square kilometer Eco-City is in between the new Guangzhou International Airport and the Central Business District (CBD) of Guangzhou.
- Shanghai, this most international of all Chinese cities, recently expanded its predominately domestic airport into a transportation hub called Hongqiao International Airport, which, in addition to new terminals and runways, includes a bullet train terminal, subway terminal, and plans for a CBD.
- King Abdullah Economic City, a new smart city just north of Jeddah, Saudi Arabia, recently had its closest airport at Jeddah International Airport renovated and expanded with new terminals and transportation distribution centers.
- Singapore, a model of a modern urban environment, recently completed renovations to its Changi International Airport terminals to accommodate the newer aircraft from Airbus and Boeing.
- New York, the international gateway to millions of visitors to the USA, recently completed renovations to all its terminals at John F. Kennedy airport, and has a new connection to rail transportation.
- San Francisco, one of the most innovative cities in the USA, recently completed renovations to terminal 2 of its airport, which also has a new international terminal that seamlessly connects to rail transportation.

As a gateway, airports are an early indicator that a city is creating the environment for an exchange of ideas, trade, and people. As a hub, airports are anchoring multimodal transportation centers that allow people to efficiently get from one place to another. As a symbol, airports are providing people an opportunity to first experience the city, setting the tone for the rest of their journey. And as an indicator, early smart city spending currently centers on spurring multimodal transportation policies, mostly because it is easier for cities to control investments in transportation projects, such as airports.

According to Pike Research,[3] global spending on smart transportation solutions, such as infrastructure that links electric vehicle charging with other transit options, or intelligent traffic management systems involving congestion pricing and traffic flow sensors, is estimated to reach U.S.$5.5 billion annually by 2020, which represents a compounded growth rate of about 20% between now and 2020. Pike Research predicts that most of this investment will be focused on intelligent traffic management systems, as this sector has room to expand and is relevant to virtually all cities. Smart transportation programs and projects can include:

- Public transit management
- Smart parking meters
- Smart parking locators
- Traffic congestion management
- Vehicle information and communication system (VICS)
- Advanced cruise-assist highway systems
- Contactless smart transit passes/tickets
- Fixed road sensors
- Mobile data probes
- Driverless cars

24.2.4 Water and Environmental

Water and energy are essential for everyday life. Although energy is typically the center of focus in struggling to meet the rising demand from growing populations, city administrations also face water issues, such as water quality, flooding, drought, and aging infrastructures. The water industry that manages the full water life cycle has been using control and automation systems for many years. However, with recent advances in technology, low cost and prevalent sensors and information services are available to better monitor water and wastewater systems in real time to drive smarter, informed decisions. Smart sensors that monitor water quality and smart meters that measure water consumption, flow, and pressure provide a real time and much more detailed view of water management. The increasing sophistication and declining cost of digital technologies will become a platform for economizing resources and sharing physical space in ways that are both economical and more convenient. The entire value chain of water can now be monitored with sensors, and data and information can be shared among communities of stakeholders.

There are many areas where smart sensors, analytics, and services are making a difference, such as water quality, flood management, and environmental protection. Soft sensors and analytics have helped water utilities improve water quality, meet environmental regulations, reduce sewer overflows, and forecast floods in advance to reduce damage and save lives. The city of Calgary in Canada is a good example where they used real-time weather forecasts, rainfall meters, river levels, dam levels, and snow pack melt data to forecast a major flood event. They immediately took action and evacuated the downtown core, preventing harm to their citizens.

Three areas with a lot of activity in the water and environmental elements of smart cities are energy management, asset management, and water loss control. In any major city, the water utility that manages water and wastewater is typically the largest power consumer. A lot of electricity and energy is needed to treat and pump water and wastewater. At the same time, a lot of water is needed to create power. Managing this water-energy nexus is critical to ongoing sustainability. Coal and nuclear plants, for example, may draw 20–60 gallons of water for every kilowatt-hour of electricity they produce, depending on how they are cooled. Largely because of older power plants using this approach, electric power generation is responsible for more than 40% of freshwater withdrawals in the United States, primarily for cooling [14]. It also takes a lot of electricity to pump and treat water.

[3] Pike Research Smart Cities—Technology Annual Revenue—Global Transport: 2012–2020.

Worldwide, an average of 7% of the total electricity generated is used to pump and treat water and wastewater [15]. Data from real-time power monitoring on major pumps, motors, blowers, and other assets, along with weather forecasts, water demand, and time of use or demand response electricity rates, are integrated to generate forecasts to decide when water should be pumped to reservoirs and when/if secondary energy sources like digester gas (anaerobic digestion in wastewater treatment as applicable), solar, and wind should be used to reduce demand from the power grid as well as reduce electrical costs. A small utility in California has reduced their power costs by 15% each year since 2008, and a large wastewater utility in England has saved $1.2 million per year since 2013.

In the area of assets, water and wastewater management vendors are providing services to their customers by monitoring their assets in real time to ensure optimal performance, uptime, and reduced maintenance costs. This information or data as a service model not only helps the vendor track their products' performance but also ensure the customer is getting the most from the asset. With sensors, utilities are becoming smarter at maintaining their assets. For example, water utilities are shifting to condition-based maintenance by looking at run time hours, start/stops, and specific energy (energy consumed per units of water pumped) to drive maintenance work orders. In San Francisco, this shift for 100 major water pumps is expected to save $1.7 million annually [16]. In the past, regularly scheduled maintenance was the norm, and, in many instances, the assets are overserviced.

Smart water meters and automatic meter reading and advanced metering infrastructures (AMIs) that provide the utility two-way communications to the meter are being deployed at customers' sites to provide real-time visibility of water consumption and demand through mobile applications. These applications identify when water is being used and have the ability to compare customer usage with similar households. This, in turn, fosters water conservation. Smart water meters in the water distribution network and at customer premises also enable real-time water loss control by identifying leaks. Globally, 15%–35% of water treated is lost as nonrevenue water [17]. Nonrevenue water is the difference between the volume of water supplied to a water distribution system and the volume that is billed to customers. Nonrevenue water comprises three components: physical (or real) losses, commercial (or apparent) losses, and unbilled authorized consumption. In physical losses alone, approximately 32.6 trillion liters of water is lost annually through leaky pipes before it gets to homes, businesses, and hospitals. Put another way, if you could detect those leaks and plug them, you could almost fill China's Three Gorges Dam to the brim every year with clean, treated water.[4] The "leaky pipe" problem highlights one of the biggest challenges we face in the coming decades. The good news is more and more utilities are proactively reducing their leaks. Consider the experience of a large water utility in Manila, Philippines [11]. They serve millions of customers over 540 km^2: it manages nearly 7500 km of water and sewer pipes and 19 reservoirs. In 2007, nearly 20% of the citizens in its service territory could not even obtain water service, roughly half did not have 24-h service, and over half did not have sufficient water pressure to support basic functions and services. As part of an upgrade using smart meters, this utility pursued an aggressive program to monitor the entire water system with metrics such as real-time water flows, while mapping consumption patterns in different geographies. By 2013, it was servicing 94.7% of its customers; 97% had 24-h service and 99% had sufficient water pressure. At the same time, they recovered 640 million liters of treated water. In another example, through smart meters and analytics, Vitens in the Netherlands has the ability to detect a leak within 5 min [19]. Recently, innovative companies have technologies to convert regular mechanical meters into smart, electronic meters to measure leaks, verify proper meter sizes, and identify lost revenue. Cities are not the only proving ground for water management technologies. Lawrence, Kansas, a college city with a population of 90,000, is currently experimenting with using software to reduce the cost and energy involved in treating wastewater by shifting treatment procedures to off-peak hours.

[4] Here is the math on Three Gorges: 32.6 trillion liters lost = 32.6 billion cubic meters. Three Gorges holds 39.3 billion cubic meters of water [18].

With more data and technologies, such as machine learning ("edge" computing and intelligence), the entire water life cycle will be better managed, reducing costs and consumption, increasing quality, lowering environmental impact, and reducing water scarcity. This is not an easy task, but utilities and their stakeholders are already tackling these challenges with successes. The growth and distribution of the population in various economies will impact the amount of generated emissions and the limited natural resources [20]. Cities are increasingly seen as central to the fight against climate change, and are the keys to a sustainable future. Only by making cities more efficient, equitable, and healthful can expanding human populations be accommodated in ways that protect the environment. Finding sustainable solutions in smart cities requires integrating all facets of science, technology, and design. Water and power utilities, consumers, and regulators are sharing data to collaborate and drive sustainability. More community and collaborative solutions through services based on data and the billions of new sensors are being deployed. The next decade will be a time of trial and error, but will drive sustainable outcomes, and the technology platforms will be a key component of every smart city and village.

24.2.5 Buildings and Homes

For over 20 years, many buildings have moved toward automating facility management processes to provide a quality environment for inhabitants and streamline operational and maintenance tasks while conserving resources. The sophistication of certain building systems, such as lighting, heating, ventilation, and air conditioning (HVAC); conveyance systems (elevators, escalators); and security has created robust solutions, but has also created deep silos of operation. The challenge for many building operators is to try and integrate these systems so their buildings become smarter by having operational data "talk" to each other to implement greater gains in efficiency and effectiveness. It is a daunting task, as there is massive complexity inside buildings with both proprietary and open protocols and systems, leading to a resource-intensive process just to have disparate systems communicate with each other.

Residential loads are responsible for more than a third of the total U.S. electric energy consumption. This amount has increased by 10% during the last 2 years, mostly due to the increase in home technologies. In all, 27% of this residential energy use is from HVAC loads [21]. To deliver energy to the customer efficiently while minimizing generation, transmission, and distribution system upgrades, utilities are focusing on more accurate monitoring and forecasting of individual customer loads, and the measurement of local weather conditions. Inadequate behind-the-meter load monitoring systems, combined with the lack of capability to schedule and control individual residential loads according to the customer's level of comfort, prevents utility companies from being more efficient. While industrial and commercial customers have been the main focus for energy management and efficiency in the past due to their large combined load on the system, utilities are now looking for additional savings from residential customers and smart home technologies. Customers are also seeing the benefits, both economic and environmental, in being able to monitor and control their energy usage.

Demand-side management systems alleviate problems with load uncertainties, intermittent renewable energy resource integration, and demand overestimates. A demand-side management system typically relies on two main load management techniques: direct load control, and dynamic and real-time pricing. Using direct load control, utilities can centrally control interruptible loads, such as HVAC, in order to maintain a balance between electric supply and demand during system peaks. Nowadays, different electricity pricing schemes are often available for customers, including dynamic-pricing and real-time pricing. Customers are charged with the same fixed rate during all hours of the day in a fixed-rate plan, which is the standard pricing most customers are familiar with today. In dynamic pricing, hourly rates are sent to the customer to encourage the customer to decrease their energy consumption when generation costs are high, and shift load to times when prices are low. This arrangement includes a day-ahead market price forecast. Real-time pricing requires an energy price calculated every 5 min that is set by the market price at the beginning of each hour. All of these current pricing options require the individual customer to manually change their behavior in response to a centrally distributed energy price, which is not an optimal approach for residential applications. Ideally, demand-side management programs should interface and integrate with smart home technologies, and provide the means to individually control appliances and other loads in homes based on price signals, appliance load usage profiles, customer behaviors, and desired levels of comfort. With digital models and real-time measurements and control, buildings and homes can leverage these data to perform at an optimal level, and smart cities can integrate and analyze the data to identify ways to improve the efficiency of customer energy, gas, and water usage while helping customers reduce their utility bills.

With the emergence of the Internet of Things (IOT), utilities are more optimistic about deploying smart home solutions. The availability of off-the-shelf IOT devices allows for a wider range of home applications, not only for energy management but also for solutions that improve the security and control of customer gas and water consumption. As more vendors produce IOT devices, the presence of a system-wide integrator that can install and manage these devices through one single system becomes more critical to deliver system-wide benefits to individual customers. Recently, security, Internet, and cable providers have taken further steps toward the integrated deployment of these solutions; however, full smart home deployment is still in the pilot phase. As an example, the Illinois Institute of Technology (IIT) smart home pilot project commenced in Spring 2014 and is the combination of different technologies, such as plug-level load control, wireless appliance and HVAC monitoring, smart lighting, wireless EV charging, and a home energy management system that provides its residents real-time monitoring and control functionality (Figure 24.5).

Integrated solutions to allow disparate building systems to communicate and work together have matured in recent years, breaking down this resource-intensive task into affordable solutions. Equipment management control companies like Siemens, Johnson Controls, and Schneider Electric have provided the market with innovative Building Automation Systems in many configurations that are creating the framework and environment for the emergence of truly smart buildings. While smart buildings and smart homes are key initiatives to consider in smart city programs, the current level of technology maturity brings the opportunity to look beyond the individual building or home and capture value at the data transaction level. The logical next step is to have buildings and homes begin to communicate together to share mutually beneficial data.

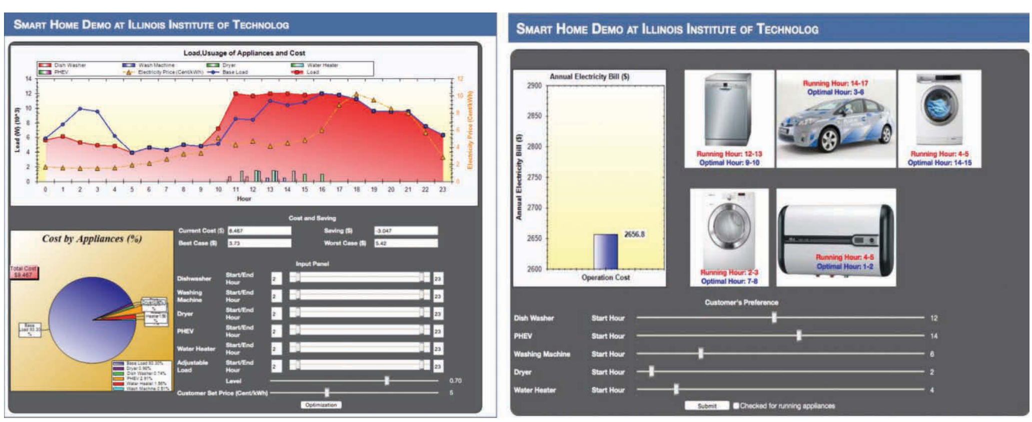

FIGURE 24.5 Illinois Institute of Technology (IIT) smart home demo real-time dashboard and monitoring system. (Courtesy of the Illinois Institute of Technology, 2016.)

24.2.6 Data and Communications

24.2.6.1 Machine to Machine and the Internet of Things

ICT is being used to better comprehend the connections between people, places, and things in urban environments. From GPS-enabled school buses sharing locations with a parent's smartphone, to sensors that monitor and report on building conditions, smart cities and their systems are becoming increasingly connected with their inhabitants with a promise of urban intelligence and resiliency like never before. This network of connections is known in the market today as the IoT, sometimes called machine-to-machine (M2M) communication, where objects communicate with the ability to transmit and receive data. Connectivity is the key ingredient of how M2M and the IoT will grow and fulfill the vision of a truly interconnected world.

There are nine existing methods of how M2M/IoT communicates:

1. Radio frequency identification
2. Sensor nodes
3. Gateways
4. Cloud management
5. Near-field communications (NFC)
6. Complex event processing
7. Supervisory control and data acquisition (SCADA)
8. Zigbee
9. Information and discovery services.

To provide some perspective, according to Cisco Systems, as many as 50 billion devices will be connected to the Internet by 2020, creating a U.S.$14.4 trillion market [22]. The M2M/IoT communication market in 2011 was worth $44.0 billion, and is expected to grow to $290.0 billion by 2017 [23].

24.2.6.2 The Cloud

Cloud solutions use the Internet to remotely access software and store data. Smart city cloud applications enable the migration, integration, and interoperability of complex city data. This is of high value to cities as their organizational structures were never designed to share information since each city department typically operates in "silos." This situation led to an accumulation of existing city information in various formats, locations, and states of quality. Smart city solutions promise to dive into these silos, identify and acquire sought-after data, and share it across other silos to provide solutions that used to be too resource-intensive to implement. Cloud-based solutions for smart cities are catching the wave faster than incumbent technology products due to low cost, easy scalability, and the big data functions of these products. Cloud solutions lower the barrier to entry by being inexpensive compared to traditional software offerings, require little to no additional technology infrastructure, and are very secure. Planning for the cloud for a smart city involves a higher resource allocation to connectivity than in the past. Having higher bandwidth provides a better experience for cloud-based solutions. XML protocols also assist in tagging and managing city data by making it easier to find, manage, and distribute city information from silos to platforms. As the cloud's many attributes become more mainstream to city government operations, expect a plethora of solutions to become ubiquitous in how a citizen communicates and interacts with his or her city.

24.2.6.3 Platforms and Apps

Some initial smart city efforts focused on the "city as a platform" approach, which was copied from large-scale IT programs and thinking. Platforms are software systems, usually vendor proprietary, that force users to use the vendor's methods of software management, development, and distribution based on strict software licenses. Platforms can be cloud-based, or located within a secure, on-premise network. Traditional software platforms usually require a proprietary Application Programming Interface to create unique views of data or functions to manipulate these data. Most smart cities are shying away from these centrally controlled system designs and embracing an open, online platform approach, leveraging the concept perfected by Apple with its iPhone and iPad products of developing Apps and downloading these Apps from iTunes or the Apple App Store. Smart city Apps need to be developed fast and inexpensive and focus on simple tasks, giving end users the flexibility to interact with their urban environment in their own unique way, instead of learning a more formal, strict system that may or may not be easy to use, free or accessible. Apps for smart cities will allow citizens to have two-way communications with the various stakeholders and service providers. For example, an App that allows a citizen to take a photo of a pothole in the road, report it to the city, and then track the process until the pothole is fixed, is but one simple example of how smart city Apps can break down the communication barriers between city stakeholders. Citizen engagement is an important function that cities are implementing in order to lay the groundwork for a better trusting relationship between elected officials and city workers, and also between the city government and its urban inhabitants. A breakthrough in citizen engagement has come in the form of crowdsourcing. Crowdsourcing solicits services, ideas, and content contributions from a large group of online and connected people, usually developed and managed by Apps and Blogs. By inexpensively and quickly being able to start a movement, activists and traditionally inactive citizens can participate in discussions with a city, and provide suggested solutions to streamline decisions and actions that used to be too long and too expensive with limited input from citizens. Proper crowdsourcing in a smart city enables bottom-up community building with top-down empowerment from city government. The value of crowdsourcing is in not just using M2M/IoT technologies and solutions as the only data points to make informed decisions but to introduce the wisdom of many human users. The proper balance of technology and human interaction provides a strong foundation for a smart city.

24.2.6.4 Mobile Communications and Devices

Our current generation of ICT tools and solutions is having the most impact on the average urban citizen in the form of mobile communications and devices. Breaking free of a wired world that forces a person to have to sit in one place to communicate, compute, and manage their lives, the world of smartphones, tablets, Apps, and a series of protocols and standards has been embraced by the market in meaningful and important ways. Urban citizens are emerging as people with a "connected life," a life that has the expectation that information about everything should be immediate, accurate, and accessible. Free Wi-Fi connections, public transportation and map Apps, and mobile payments are already bars that have been set for cities to even begin to think of themselves as smart. The emerging standard of NFC is one area that is fast enabling an urban connected life to emerge as a standard way of life in a smart city. NFC is a set of standards for mobile devices that establish communication between devices by either touching them together or having them in close proximity to each other. NFC-enabled environments and Apps on mobile devices support mobile payment transactions and seamless data exchange, and create the opportunity to access the cloud as a temporary, wireless, mesh style network. The instant network feature of NFC environments brings a host of opportunity for new style Apps to be used by urban citizens in a smart city.

24.2.6.5 Big Data and Data Management

As we identify the challenges of living in a highly connected and resilient world, it is comforting to relate to our cities as organisms. If the city is an organism like a human body, then we have seen its evolution from the agrarian society to the Information Age to today's interconnect world through the development of systems. Each city has its own cardiovascular system (traffic, mass transit), skeletal system (infrastructure), respiratory and digestive systems (energy, waste), and even a primitive nervous system (telecommunications). In order for a city to provide access to its intelligence behind the knowledge and become a smart city, the development of the intelligence system that connects the central nervous system to a brain is required. Feeding the vast amounts of data into this brain will require a measured and thoughtful process to take into account the proper planning of a city's brain. Does a city create an uber system that consolidates all data and functions of a city into a nice compact solution, but runs the risk of having such a system be vulnerable to hackers, terrorists, or other negative situations? Or does a city emulate the open system approach prevalent in the IT industry and creates a dispersed framework of interconnected exchanges that allow important data to flow freely to the end user, but runs the risk of technology complexities and a "too open source" way of working that makes a system so resource-intensive to be unrealistic?

So just what data are valued and relevant for cities that are looking for pathways to becoming a smart city? It is important to learn what cities already possess to properly answer this critical question. Owing to the implementation of vast information technology (IT) solutions over the past few decades by cities, the world has created varied and enormous amount of data in both digital and paper formats. These data come in all shapes and sizes and enable an enormous amount of tasks to be conducted more effectively and efficiently. The issue is not if the city has the proper data to become a smart city; the issue is how. The media and marketing people are calling this emancipation of data being freed from their silos, big data. The job of today's cities IT department is not to just secure people from getting into a city's system, but how to control and manage the glut of data that will be trying to get out. Think of what happened to sensitive data that were set free in the Wikileaks scandal a few years ago and you get the picture of big data's effect on the free flow of data. So, a major issue for a city's IT department is how to manage big data, now that it can be set free so easily. The cities that solve this issue will be on the correct path to being a smart city.

The focus on big data and a city's behavior toward its data's management is a critical element toward being a truly smart city. A smarter, efficient city that can encompass aspects of intelligent transportation, security, energy management, CO_2 emissions, and resiliency is contingent on the implementation of a big data strategic plan to enable decision-makers and authorities to perform their jobs. In response, some cities have taken an "open data" approach to assist in making their data available to the general public, which has spawned an emerging market for the development and sale of Apps to enable these open data to come alive and provide value to a user. Some cities have also begun programs to leverage their existing data of the environment found in their building departments, zoning departments, and utilities. Programs, such as smart permitting called Corenet in Singapore and Quick Response (QR) tagging of Building Permits in New York City and Smart Metering/Wi-Fi in Santa Clara, California, are leading their citizens into the next generation of their relationship with their city. A relationship that fosters two-way communications built on trust, while acquiring and building the digital DNA (big data) of the city's environment, is a winning combination for the transformation of smart cities.

24.2.6.6 Gamification

Although the cloud is the environment and the driver behind many smart city initiatives, the use of gaming technologies is providing internal and external value in the art of storytelling. Gaming is a broad term that describes the technologies, processes, and strategies that are used by video/computer games. In the context of business, gaming is also described as the use of game design techniques, game thinking, and game mechanics to enhance nongame use in the context of software applications and processes. This "gamification" encourages people to adopt them, or to influence how they are used. Gamification works by making technology more engaging, by encouraging users to engage in desired behaviors, by showing a path to mastery and autonomy, by helping to solve problems, and by taking advantage of humans' psychological predisposition to engage in gaming. The technique can encourage people to perform chores that they ordinarily consider boring, distant, or unchallenging, by playing diverse roles in competition and collaboration with others, in search of a reward. A more pragmatic use of gamification is when 3D graphics and objects can be imported into an online gaming environment to provide a user with an accurate 3D geospatial world that can be used to navigate, analyze, and manage vast amounts of data in an easy-to-use environment. For example, by providing a design in a gaming tool, an architect can quickly get feedback from an owner or engineering consultant earlier in the process, leading to a better solution. Also, by addressing a field condition in the context of a detail in a gaming tool, a contractor can quickly and accurately solve the issue without losing time or having to learn new software. By viewing their city's operations in the form of a 3D gaming "dashboard," city managers can be more effective and efficient in their decision-making. The gamification industry is in its infancy, but is being nurtured to a fast maturity by implementations across a broad spectrum of solutions.

24.2.6.7 Buildings as Servers, Cities as Networks

Consider a smart city as a network, with each building acting as a server. When individual building data are connected to the city network, likely through an open data policy or as an ordinance, interesting things begin to happen. The data that a city captures through this process or already possesses become the digital DNA of smart cities. In a similar way that there is latent valuable data in each building, cities possess an amazing amount of data in various forms, sizes, and accessibility. The benefit of utilizing these valuable data to make better decisions lies in identifying, locating, and reporting these latent data into actionable data. With advances in ICT, such as cloud-based technologies, there has been great improvement in a city's ability to gather vast amounts of data in a cost-effective manner. ICT advances becoming commonplace in cities today include:

- Ubiquitous sensors enabling authenticated data collection
- Low-cost and open communications protocols and systems to simplify and reduce costs
- Pervasive video devices that assist in public safety programs
- Real-time management systems for traffic, water, sanitation, and public transportation that control, automate, and optimize performance
- 3D visualization analytic tools that translate all of these data into actionable intelligence

With both new and existing cities, this data intelligence process begins with a proactive approach of identifying, capturing, and managing a city's digital DNA. Because the outcome is to enable city stakeholders with tools to make better decisions, 3D visualization analytic tools are emerging as the preferred method due to their ability to take highly complex amounts of data and show results in context with the actual city. 3D visualization tools need accurate, authenticated data to "build" a 3D view of the city. These data reside today in a city's Building Department, Engineering Department, Land Department, Planning Department, Sanitation Department, Tax Departments, Postal Services, or any other department where they collect and manage vast amounts of data that, when viewed as a whole, create the virtual representation of the smart city. The building blocks to effectively and efficiently use these city data will ultimately reside in a city's ability to repurpose its existing data and documents. The accuracy, authentication, validation, and integration of these city data are the key to a proactive approach to entering a path to becoming a smart city.

Once this foundation of a digital visualization of a city is in place, cities have the ability to leverage this "front end" to begin viewing the data behind the digital, smart buildings. Today, cities acquire most of the data of a building through some basic communication of paper and digital reporting, which can be resource-intensive. What is emerging in both new and existing cities is the automation of this reporting process through programs and systems like smart meters (water and power), cable television, and telecommunication boxes and building "black boxes" that can house and report on the "health of a building" from structural integrity to Building Automation System data. This can be viewed as buildings becoming servers of data, like in a computer network. Best practices of buildings as servers use the core of the building mechanical room as the location where these building data can best be captured, managed, and reported. The building will essentially contain an intelligent operations center (IOC) where the building data can be analyzed using the city model for quick, intuitive results. A simple example is the capturing of a building's power consumption, which is reported in real time to the IOC and measured against benchmarks and then reported with a color-coded status, such as green, yellow, and red. The IOC can then provide more details on the status, if required. Lessons learned and best practices from operating and maintaining computer networks will be required for many city stakeholders to realize the benefits of having immediate access to authenticated building data. Easily mapped to a computer network, the city as a network brings many unexpected results that cities are only beginning to discover. Using buildings and infrastructure assets as a visualization and data foundation, the use of sensors, video, and mobile devices to assist with city management becomes an easier process.

24.2.7 Cybersecurity and Data Privacy

As cities move forward with the integration of smart city solutions, the concepts of information and communication security are critical in order to protect the confidentiality, availability, and integrity of a city's services.

According to the Institute of Electrical and Electronics Engineers (IEEE), "a smart city brings together technology, government and society to enable the following characteristics: a smart economy, smart mobility, a smart environment, smart people, smart living and smart governance." This can be interpreted as an integration of multiple connected systems to process and transfer data between various stakeholders. Therefore, with the increase in the number of communications networks and system connections in a smart city and smart grid, there is a greater need to evaluate the security risks to ensure that an appropriate plan is in place to mitigate the risks for each connected system.

It is important to remember that smart city technology solutions consist of hardware components, such as edge devices and gateways, and also software components, including operating systems, application software, and messaging and communication protocols. Therefore, guidelines are required for smart city authorities to select and validate technologies in terms of risk and security. Cities should consider security and privacy guidelines proposed by technology vendors, but should also identify additional requirements specific to the smart city's needs and technologies deployed, and the need for security and privacy governance across multiple, integrated solutions. This process should be performed considering cybersecurity controls and protection requirements, while guaranteeing their desired functionality, and ensuring the balance between the level of security and ease of access.

In the design and planning phase of a smart city, basic security requirements should be considered. These requirements include strong cryptography to protect data, both at rest and in transit, authentication, authorization, automatic and secure updates of software and firmware, auditing, alerting, and logging capabilities, anti-tampering capabilities, nonbasic functionality disabled by default, fail safe/close, secure by default, and no backdoor/undocumented/hardcoded accounts [24]. Also, vulnerability history of the technologies, such as vendor security, should also be checked. Technologies with a powerful data and security management interface should be favored. The selected technologies should be tested and verified for security vulnerabilities, weak security protections, and basic security requirements compliance.

In the implementation phase, cities should ensure the technologies satisfy the selection requirements and can be administrated by a single entity to perform all targeted actions accessed through a strong authentication process. In the operation and maintenance phases, vendors must provide continuous support, and operators have to track and monitor the technologies operation and status. Finally, when technologies are replaced after reaching their targeted lifetime, or they are upgraded to other technologies with more capabilities, they should be disposed of properly to remove sensitive or private information.

24.3 PLANNING, DESIGNING, AND IMPLEMENTING A SMART CITY

There is no one recipe for making a city smarter, but a close look at past efforts, successful and otherwise, in cities across the globe shows the importance of four sets of smart city strategies: proposing and implementing resident-centric solutions, forming partnerships, executing a robust communications strategy, and being mindful of all potential funding routes.

24.3.1 Resident-Centric Solutions

Smart cities must be radically resident-centric, focused primarily on solving their residents' needs. Because so many of these technologies are new, not only to the cities, but also to the residents, it is often difficult for them to know which development will truly be helpful. Active listening at the early stages is necessary in order to determine what technical solution might solve a tricky problem, but continued listening after the plans have been put into place, paying close attention to unintended consequences, both positive and negative, is crucial. A smart city is never completed, but always getting smarter, and so developing feedback loops between residents and city leaders is an important strategy.

24.3.2 Robust Communications

A smart city should be more than just a service provider; it should also ensure that all of the stakeholders of a smart city understand the value provided. To that end, a culture of shared leadership is advisable, making the public aware of the available services using branding, partnerships, and a robust communications strategy.

Branding refers to developing a cohesive message about what the city is trying to accomplish. This is helpful both internally, in providing clear guidelines for all stakeholders about the best direction, and externally, to strengthen the city's image in the public eye. Researchers have discussed how branding a city as "smart" can help build up hype, which can be crucial both in preserving local public support for such reforms and in attracting outsiders who might be curious to live and work there, too [25]. This can help push cities into a virtuous circle, where not only does it benefit from the reforms but the arriving talent helps their economy become more globally competitive, while strengthening industries like housing and tourism, providing benefits to the entire city.

To make sure that these groups are aware of the potential partnership opportunities and the available services, a smart city needs to engage in a robust communications strategy. This includes making press releases and events available to a wide range of the media, including social media, as well as holding frequent meetings with a wide range of stakeholders to convey to them personally the broader strategy and how specific programs can benefit them.

24.3.3 Partnerships

Forming partnerships is the key to accomplish smart city goals and attract participation of the various stakeholders. For some companies, the immediate benefit is more obvious. Many ICT companies found that investing in smart city technology was a wise strategic choice, particularly during an economic recession, because it allowed them to develop new revenue streams in a difficult financial climate [26]. Once they start on this path, however, it can help commit the stakeholders to backing a broader project. For-profit companies that recognize smart cities are the right direction for investment can help produce a narrative that appeals to a broader audience [27].

Other types of stakeholders might be interested in different forms of partnerships. Within the U.S. federal government, there are agencies that are focused on testing new clean energy technologies, improving the efficiency of transportation methods, and protecting the public from security threats. Within the broader population, labor unions are often especially attracted to new programs that entail new jobs, such as by expanding current infrastructure. Environmental activists, however, might be more attracted to plans that help reduce the city's carbon footprint. Local community groups might prefer plans that help expand government services or limit government waste. A smart city will do its best to avail itself of the right combination of partnerships to solve its residents' unique challenges and needs.

24.3.4 Funding

As with any new major investment, smart city programs often require a significant initial capital outlay to gain the benefits. Cities generally rely on a mix of public and private funds. Therefore, it is often beneficial to look for a wide range of funding opportunities, both to reduce the reliance on any one type of source and expand the buy-in from those who could form valuable partnerships.

Though much of this will depend on the particular smart city program, one can distinguish two main types of sources: for-profit, and not-for-profit. For-profit sources of funds are generally looking for a monetary return on their investment. Not-for-profit sources of funds are typically trying to either provide a service for customers, or promote a cause, such as expanding research in a crucial study area.

For-profit sources of funds can come from a wide range of industries. In the past, this has included anything from ICT companies, which have been deeply involved in providing resources for cities to improve their technological infrastructure for a wide range of programs, to utilities that have focused more on programs like electric grid modernization and making water provision more efficient.

Not-for-profit funds traditionally come from the government, whether from a city's regular budget or that of the state or federal government. These funds can be in the form of providing a service to constituents, but it can also come in the form of payment for research or a pilot study to prove viability. Additionally, universities, research institutions, and foundations also contribute to research into new technologies as well as pilot studies.

Each of these types of funding sources can play key roles at different stages in the development of a smart city, and being mindful of all of their potential contributions is crucial.

24.4 SMART CITY STANDARDS AND INITIATIVES

The creation of smart cities will only be achieved with a holistic approach, supported by standards to achieve interoperability. Standard bodies still operate in industry-specific silos, developing standards that are not easy to understand by nonspecialists, for example, city managers. Standards are facilitators for city planners who need to incorporate them in planning and procurement. Therefore, there is a need to reform the way standards are produced for smart city deployments and ensure that they are adapted to the needs of the city planners and other service operators within the city.

There is a need for close collaboration between standard bodies themselves and collaboration with outside organizations, and particularly the city planners. A precondition for the considerable investment in, and successful deployment of, smart city solutions is the need for substantial global agreement on the *what* and *how* of smart cities among the key stakeholders. Smart city stakeholders need to recognize that standardization efforts will involve the development, promotion, and deployment of standards and also conformity assessment schemes in order to enable the implementation of smart city solutions.

The multiplicity of technologies and services within a city now demands a top-down approach to standardization. This requires new coordination approaches between standards development organizations, in which all the parts of the city are jointly considered by the several technical committees involved by the different organizations. This methodology is essential as systems level standards will enable the implementation and interoperability of smart city solutions.

Several standards activities and initiatives are under way worldwide to address the need for specific and appropriate standards and guidelines for smart city deployments.

24.4.1 IEC, ISO, and ITU World Smart City Forum

In 2016, a World Smart City Forum [28] was organized by the IEC, ISO, and ITU that addressed the key points of smart city elements and related technologies, such as mobility, water, energy, cybersecurity, and privacy that could hinder smart city development.

24.4.2 IEC System Committee for Smart Cities and Communities

The IEC launched a System Committee for Smart Cities and Communities. Its scope is to foster the development of standards in the field of electrotechnology to help with the integration, interoperability, and effectiveness of city systems.

24.4.3 CEN-CENELEC-ETSI Smart and Sustainable Cities and Communities Coordination Group

In Europe, CEN-CENELEC-ETSI created a Smart and Sustainable Cities and Communities Coordination Group [29] (SSCC-CG) to provide advice on European interests and needs for the standardization of smart and sustainable cities and communities, foster collaboration, and make recommendations for future standardization activities. The SSCC-CG published a report [30] in January 2015 where it also addressed relevant international work at global level.

24.4.4 British Standards Institute Smart City Framework

In the UK, the British Standards Institute in collaboration with the Department for Business, Innovation, and Skills released a report in February 2014 on the smart city framework, which is a guide to establishing strategies for smart cities and communities [31], and a proposal on regulation and standardization of smart cities.

24.4.5 German Standardization Roadmap Smart City

In Germany, the VDE, responsible for the daily operations of the DKE German Commission for Electrical, Electronic, and Information Technologies of DIN and VDE, published the German Standardization Roadmap Smart City in April 2014.

24.4.6 ANSI Network on Smart and Sustainable Cities

In 2014, the United States ANSI launched the ANSI Network on Smart and Sustainable Cities as a one-stop shop where city authorities and others can network in researching their standardization needs. ANSI is the U.S. member of the ISO.

24.4.7 ISO Sustainable Development in Communities

The ISO Technical Committee 268 is responsible for standardization in the field of Sustainable Development in Communities [32], which will include requirements, guidance, and supporting techniques and tools to help all kind of communities, their related subdivisions, and interested and concerned parties to become more resilient and sustainable and demonstrate achievements in that regard. The proposed series of International Standards will, thus, encourage the development and implementation of holistic, cross-sector, and area-based approaches to sustainable development in communities. As in the program of work, it will include Management System Requirement, Guidance, and Related standards.

24.4.8 IEC Systems Evaluation Group on Smart Cities

More than ever before, many different organizations will need to collaborate to help make cities smarter; technology integration is a special challenge that requires broad cooperation in a systems approach. The IEC Systems Evaluation Group (SEG 1) on Smart Cities is currently preparing a reference architecture and standardization roadmap in cooperation with many different organizations.

The aim is to identify and close standards gaps, and develop relevant International Standards as building blocks for tailor-made solutions.

24.4.9 European Parliament's Committee on Industry, Research, and Energy

In 2014, the European Parliament's Committee on Industry, Research, and Energy commissioned a study named "Mapping Smart Cities in the EU." This report was commissioned to provide background information and advice on Smart Cities in the European Union (EU) and explain how existing mechanisms perform. In exploring this, a working definition of a smart city for Europe was established, and the cities fitting this definition across the EU member states were mapped. An analysis of the objectives and Europe 2020 targets of smart city initiatives finds that despite their early stage of development, smart city objectives should be more explicit, well-defined, and clearly aligned to city development, innovation plans, and Europe 2020 in order to be successful.

ICT is a key enabler for cities to address these challenges in a "smart" manner. In this report, a smart city is considered as one with at least one initiative addressing one or more of the following six characteristics: Smart Governance, Smart People, Smart Living, Smart Mobility, Smart Economy, and Smart Environment. ICT links and strengthens networks of people, businesses, infrastructures, resources, energy, and spaces, as well as provides intelligent organizational and governance tools. Thus, a smart city is defined by the European Parliament's Committee on Industry, Research, and Energy as follows: "A Smart City is a city seeking to address public issues via ICT-based solutions on the basis of a multi-stakeholder, municipally based partnership [33]."

24.4.10 European Commission R&D Projects

The European Commission (EC) is the executive of the EU and promotes its general interest. The Innovation and Networks Executive Agency (INEA) is the successor of the Trans-European Transport Network Executive Agency (TEN-T EA), which was created by the European Commission in 2006 to manage the technical and financial implementation of its TEN-T program. INEA officially started its activities in 2014 in order to implement the following EU programs:

- Connecting Europe facility (CEF)
- Parts of Horizon 2020—Smart, green, and integrated transport, and secure, clean, and efficient energy
- Legacy programs: TEN-T and Marco Polo 2007–2013

INEA's main objective is to increase the efficiency of the technical and financial management of the program, which includes parts of Horizon 2020, the EU's €77 billion research and innovation program for 2014–2020 in the areas of transport and energy. Smart Cities and Communities [34] represent €131.5 million of the Horizon 2020 program's budget in 2016–2017. The Smart Cities and Communities effort will focus on the sustainable development of urban areas, which will require new, efficient, and user-friendly technologies and services, in particular, in the areas of energy, transport, and ICT. However, it is recognized that these solutions need integrated approaches, both in terms of research and development of advanced technological solutions and as deployment.

24.4.11 European Innovation Partnership for Smart Cities and Communities (EIP-SCC)

The European Innovation Partnership for Smart Cities and Communities (EIP-SCC) combines ICT, energy management, and transport management to come up with innovative solutions to the major environmental, societal, and health challenges facing European cities today [35]. The EIP-SCC is a partnership with the EC that consists of two governance bodies: (1) a High Level Group advising the EC, made up of senior representatives from industry, cities, and civil society, and (2) the Smart Cities

Stakeholder Platform. While the High Level Group focuses on bottlenecks in the development of smart cities and societal needs, the Stakeholder Platform focuses on identifying the solutions and needs of practitioners, that is, developers of technologies and specialists in the implementation of technical solutions. It is a bottom-up platform designed to develop integrated technology approaches and develop a technology roadmap for the EC based on identified smart city needs.

The Smart Cities Stakeholder Platform is essentially about promoting innovation. It aims to accelerate the development and market deployment of energy efficiency and low-carbon technology applications in the urban environment. The Platform supports the EU toward its goal of an 80% reduction of GHG emissions by 2050, and the Europe's primary energy technology strategy, the SET-Plan. Emphasis will be on technology integration in the areas of energy, transport, and ICT. Integration across these areas is one of the key challenges for SET-Plan technologies, and notably for smart city technologies. To achieve its goal, the Smart Cities Stakeholder Platform set up five working groups. The main stakeholders are technical experts, allowing the platform to draw on expertise from those directly involved in developing, testing, and demonstrating new technologies. The working groups operate using a bottom-up approach, and the overall themes are fine-tuned by participants based on guidance and the framework provided by the working group chairs.

In 2014, EDSO (European distribution system operators) for Smart Grids recommitted to playing a role in the new activities of the EIP. EDSO for Smart Grids gathers leading EDSOs for electricity, cooperating to bring smart grids from vision to reality in Europe, and is focused on guiding EU R&D, policy and member state regulation to support this development.

A call for proposals is currently open in 2017 for Smart Cities and Communities Lighthouse projects. *Lighthouse* cities should develop intelligent, user-driven, and demand-oriented city solutions that could be replicated in other urban districts across Europe, with the involvement of *follower* cities. The total budget is €69.5 million, of which €12 to €18 million will be allocated to individual projects (indicative). The focus on these smart cities Lighthouse projects proposed by the EC will result in integrated commercial-scale solutions in the field of energy, transport, and ICT with a high market potential.

24.4.12 Eurocities

The members of Eurocities [36] are a network of elected local and municipal governments of major European cities. Eurocities was founded in 1986 by the mayors of six large cities: Barcelona, Birmingham, Frankfurt, Lyon, Milan, and Rotterdam. Today, it brings together the local governments of over 130 of Europe's largest cities and 40 partner cities, which represents 130 million citizens across 35 countries. Through six thematic forums, and a wide range of working groups, projects, activities, and events, Eurocities offers members a platform for sharing knowledge and exchanging ideas. Eurocities influence and work with the EU institutions to respond to common issues that affect the day-to-day lives of Europeans. Its objective is to reinforce the important role that local governments should play in a multilevel governance structure. It aims to shape the opinions of stakeholders and ultimately shift the focus of EU legislation in a way that allows city governments to tackle strategic challenges at the local level. The Eurocities' strategic framework 2014–2020 identifies some of the challenges and opportunities in cities that are closely linked to developments at the EU level. It sets out five focus areas to guide their work, which largely align with the EU's strategic priorities and provide a strong strategic operational framework:

- Cities as drivers of quality jobs and sustainable growth
- Inclusive, diverse, and creative cities
- Green, free-flowing, and healthy cities
- Smarter cities
- Urban innovation and governance in cities

24.4.13 TU Wien Smart City Model

TU Wien, one of the major universities in Vienna, Austria, has been working on the issue of smart cities since 2007 [37]. TU Wien helped develop the European Smart City Model in cooperation with different partners on specific projects financed by private or public stakeholders and actors. The work by TU Wien provides an integrated approach to profile and benchmark European medium-sized cities and is regarded as an instrument for effective learning processes regarding urban innovations in specific fields of urban development.

24.5 SMART CITY EXAMPLES

According to ABI Research, $8.1 billion was spent on smart city technologies in 2010, and by 2016 that number was projected to reach $39.5 billion [38]. At that time, there were 102 smart city projects worldwide, with Europe leading the way at 38, North America at 35, Asia Pacific at 21, the Middle East and Africa at 6, and Latin America with 2. Each smart city has different drivers and needs that lead to different dimensions, elements, and solutions, but ABI notes that currently, the largest spending on smart city technologies is for smart grids; however, over the last 5 years, there has been a significant increase in spending for smart transportation technologies, such as automatic vehicle ID, and smart governance systems, such as e-ID and ID document systems.

Some of the key and influential smart city projects include:

- Vienna, Austria
- Toronto, Canada
- Paris, France
- New York
- Amsterdam, the Netherlands
- London, UK
- Tokyo University, Japan
- Seattle, WA
- Berlin, Germany
- Copenhagen, Denmark
- Hong Kong, China
- Bogota, Colombia
- Chicago, Illinois
- Barcelona, Spain
- Boston, Massachusetts
- Sydney, Australia

24.5.1 Amsterdam, the Netherlands

One of the areas in which Amsterdam decided to invest significant funds was in soccer stadiums. The municipality partnered with AFC Ajax and Huawei, a major Chinese company, to make the Amsterdam Arena as smart as possible. They installed 50,000 sensors around the stadium in order to monitor the actual state of the infrastructure and ensure that repairs are done precisely when necessary. They attached sensors to their lawn mower to measure agronomic data, which are analyzed to ensure that the playing field soil is healthy and predict dry areas that might affect the grass. They also used sensors to identify in real time precisely where the players are during the game in order to provide the coaches a spatial representation and record of their team during each game to ensure that they remain one of the best teams in the world.

24.5.2 Seattle, WA

The city of Seattle focused on improving the energy efficiency of smaller buildings. Working with Microsoft and Seattle City Light, the city developed the 2030 District Imitative, outfitting sensors to buildings, such as hotels, which would monitor critical HVAC, electrical, and other mechanical systems. They then used Microsoft's cloud solution to analyze the building data, and additional environmental data, such as weather conditions, in order to identify ways that building owners could optimally manage their buildings.

24.5.3 Bogota, Colombia

In Bogota, they instituted an Infrastructure of Spatial Data for the Capital District with established rules to allow residents to access GPS data of the city. They then made an app called Tu Bogota that shows how much it would cost to buy land in different parts of the city, identify landmarks for tourists, and alert the relevant authorities when city services are required.

24.5.4 Tokyo University, Japan

Twenty-five minutes from Tokyo, a new campus of Tokyo University was built in Kashiwanoha, where urban leaders have spearheaded initiatives with partners ranging from government agencies, to research institutes and for-profit corporations, to ensure that energy is used in the wisest way. Hitachi helped implement the Area Energy Management System, which identifies the detailed energy footprint of the campus and its effects on the environment, and allows the campus to review strategies to improve and optimize their energy usage. An energy visualization tool was installed that allowed them to focus on accurate measurements of the changes in CO_2 emissions. But all of this might only be the beginning, as these systems can be used as the framework to create new options, like ambient lighting and pay-as-you-go services, which might make life more affordable for their residents while improving the environment.

24.5.5 Illinois Institute of Technology (IIT)

The Galvin Center for Electricity Innovations at the IIT worked on a smart streetlights project that involved the integration of the streetlights with the existing microgrid on campus, the development of IIT's SCADA system and the integration of streetlights into this system, and the development and application of a cyber-physical system for the newly implemented networked streetlights at the IIT Microgrid [39]. The project was implemented in three phases.

24.5.5.1 Phase I

Phase I of the smart streetlight pilot program began with the installation of 15 networked and high-efficiency LED lights at the IIT Microgrid and the development of a monitoring and control system based on the OSIsoft PI software, which allowed the project team to remotely monitor and control the lights at the IIT microgrid.

24.5.5.2 Phase II

Phase II was primarily concerned with the effect of smart streetlights on the resilience of the overall distribution grid, and cybersecurity measures for the intelligent streetlight devices and monitoring and control system. Phase II focused on answering the following questions:

- What drawbacks or security vulnerabilities exist in wireless networked lighting control systems in smart cities, and what can be done to mitigate the vulnerabilities?
- What are the economic drivers and other benefits of LED streetlights and wireless networked control systems in smart cities?

- What are the advantages and disadvantages of different control and communication strategies for enhancing cybersecurity in smart cities?
- What are the applications of wireless networked LED streetlight control technology that are not explored in smart cities, and how can they be advanced further?

Answers to these questions have been explored through comprehensive cyber-physical security testing, analyses of the pilot system's actual measured benefits, configuration testing of the pilot system, and student- and faculty-led research exploring new opportunities available with this exciting technology at IIT.

24.5.5.3 Phase III

Phase III of the smart streetlight pilot program will expand the network of LED streetlights across the campus to test the scalability of the network and of the software as a pilot for large-scale implementation in the ComEd service area. In addition to scalability, the system will monitor and report on the measured benefits of the pilot to fortify the business case for networked LED streetlight expansion, and build support for what is considered a necessary step that businesses, municipalities, and local governments must take toward more efficient lighting. Throughout this phase, the monitoring and control system will integrate controls into the IIT facilities energy management system and public safety's security systems, and include maintenance email alerts and scheduled maintenance notifications, and allow the streetlights to automatically respond to certain campus safety alerts or public safety searches or drills. The goal of the IIT Smart Cities Pilot Project is to modernize the street lighting system and provide a readily reproducible model for larger scale cities. In addition, the project team research into system resiliency will help improve the environmental, financial, and security benefits of similar systems.

24.5.6 ComEd Community of the Future, Illinois

A smart city is continuously getting smarter, which makes it of the utmost importance to identify and leverage developing trends. Technologies can be divided into two categories: new, emerging technologies that are being tested and will soon be implemented; and existing technologies that are used as benchmarks, references, and best practices. One important example is a single neighborhood called Bronzeville in Chicago, Illinois. Although Bronzeville is not one of the top tourist attractions in Illinois, it has played a significant role in Chicago's history, and is also the site of a number of significant public buildings, including the Chicago Police Department headquarters, community centers, churches, and universities. ComEd, a local electric utility in Illinois, is attempting to leverage many of the existing technological developments demonstrated in cities across the world, and which are developed by the company itself, in order to give this neighborhood access to the best available services, both as a proof of concept of what a smart neighborhood could be in the United States and also as an initial building block to extend the same level of services to the entire city.

ComEd's first step was, and continues to be, to engage deeply with various parts of the community. It invested significant time and resources in understanding what smart city capabilities were needed for a smart city. This includes engaging with local community leaders and businesses to obtain a better idea of what services would be most appreciated, and by installing smart meters and analyzing the community's energy usage. From this research, a few significant needs became apparent. There was a widespread concern about inefficient use of electricity, which both increased costs for local residents and had detrimental effects on the environment.

ComEd also played a key role in helping local youth obtain jobs in the energy sector, thereby boosting the local economy. ComEd also provided public Wi-Fi networks so that the entire community could benefit from readily available Internet access. Additionally, the presence of critical public infrastructure, such as the police headquarters, made the resilience of the electric grid a primary requirement.

ComEd then performed extensive research into the available technologies that had been implemented in other cities, as well as potential innovations that it could develop in-house. ComEd is looking to engage additional partners that can help to ensure highest quality services and also form a unified front to make the neighborhood smarter. Some of the ways to improve energy efficiency, for example, required individual residents and businesses to embrace best energy usage practices from other successful smart city initiatives worldwide. Other ideas, however, required buy-in from larger partners. With the financial support of the federal Department of Energy, and collaborating with both local universities and for-profit technology companies, ComEd is developing and testing a microgrid master controller that would make it possible to interconnect and manage multiple microgrids across the city.

By focusing solely on a single neighborhood, ComEd avoids some of the challenges—and opportunities—of having to deal extensively with the city government. In the long-term, ComEd will likely have to invest more to engage with the wider media, and with stakeholders across the city, many of whom may not immediately experience the benefits of a smart city as the programs are rolled out neighborhood by neighborhood. Even within the neighborhood, however, after implementing some of the new ideas, continued engagement with the local community is crucial in order to explain advantages of the programs, hold follow-up meetings to get a better sense of how effective the programs were, and determine if any unintended consequences had emerged that needed to be considered.

ComEd's effort, however, is showing that even large and complex American cities with long histories can be made much smarter. The long-term success of this effort will require continued and expanding interactions and partnerships at multiple geographical levels with the government, the business community, and the broader population, so as to commit them to continue making changes that benefit all involved. The goal is to produce a model that can be expanded upon, adapted from, and hopefully improved in a wide array of smarter cities across the globe.

24.5.7 San José, CA

As the capital of Silicon Valley, San José is the "center of the universe" for innovation and disruptive technologies powered by the Internet economy. The San José metro area is the most connected region in the United States according to the 2015 American Communities Survey [40]. That same year, Bloomberg cited San José as America's richest city [41], based on its high median income. San José, however, is very much a tale of two cities with significant inequality for income and connectedness. San José's income inequality gap is one of the largest in the nation, ranking 22nd out of 19,500 cities in 2015. This gap continues to widen according to a December 2016 report issued by the National Bureau of Economic Research [42].

Despite San José being the capital of Silicon Valley and the richest city in the United States, more than 12% of their households have no household Internet access, and more than 40% of their residents with incomes below $20,000 have no household Internet access. This represents 100,000 people, a significant digital divide that cannot be overlooked, and one the city of San José is actively taking steps to reduce. The key factor that influences the digital divide is affordability. Given San José's income inequality, not only have people become lost in the statistics, they have also lost practical opportunities to participate in this intensely connected world of learning, jobs, public and commercial services, and civic engagement. Since President Clinton identified the issue in 1998, the nation has made significant progress to address the digital divide on a national level to reduce long-term implications for social equity and stability. More recently, President Obama pursued many policy initiatives toward the vision of achieving greater digital equity that provides better access and opportunity to digital tools, resources, services, and skills. This progress could reverse, however, both as the income gap widens and as more educational, workforce, healthcare, and civic engagement opportunities move online. For example, the "homework gap" in San José reveals too many students attempting to do their homework assignments on smart phones while clustering around school buildings after hours looking for Internet access. And not just students are affected. Seniors, small businesses, entrepreneurs, recent immigrants, the unemployed, the homeless, and other underserved community segments also struggle for inclusion in today's digital world, whether they are applying for jobs, signing up for Social Security, or emailing to their families.

San José has taken the initiative to be among the first major U.S. cities to successfully confront the interconnected challenges of digital inclusion and digital infrastructure for the benefit of the community. Tackling digital infrastructure, broadband, and digital inclusion strategy together is critical to optimize San José's efforts because these issues are tightly linked. The development of a broadband strategy will focus on how the city might expand, enhance, and fill gaps in the digital infrastructure, ideally through public–private partnerships since public resources are severely constrained. In parallel development, the city's digital inclusion strategy will identify how it can leverage existing resources and develop new programs and improvements for underserved community segments to overcome the barriers of access, affordability, and digital literacy.

Digital inclusion is most effective when the private sector builds and operates digital infrastructure; San José is not proposing that the city compete with the telecom industry; however, the city can intervene strategically when the market fails to meet minimum performance expectations, such as affordability, location, bandwidth, throughput, and latency. San José's digital inclusion strategy addresses all aspects of digital inclusion—access, affordability, and literacy—but iterates by community segments. San José will first focus on low-income families with students, as well as seniors aged more than 65—the two segments most digitally excluded. Since local data are not available, "street surveys" are being conducted by a nonprofit research company and Stanford University to identify Internet usage and digital inclusion barriers in low-income neighborhoods. Future iterations will focus on digital inclusion for small businesses, entrepreneurs, and other underserved segments of the community.

In early 2017, San José aimed to launch "SpeedUp San José," which will allow residents, visitors, and workers to test out real-world Internet speeds from various providers and provide feedback on pricing and satisfaction. These data will shine a light on private sector market performance at a granular level, and will help identify San José's geographic and segment strategies for digital inclusion and infrastructure. The city of San José is also partnering with the East Side Union High School District to pilot the deployment of free outdoor Wi-Fi for students, their families, and other members of the community. The pilot schools will provide Internet access to students and will provide additional equipment for any households unable to access the Wi-Fi. The students will become the "digital inclusion force" that will provide better access, affordability, literacy, and adoption for households on the wrong side of the digital divide. This partnership was driven by the school district, which secured $2.7 million in funding for the design and installation of infrastructure for the first three attendance areas through Technology Bond Measure I approved by San José voters in 2014. San José is hopeful that this model partnership can be replicated in other San José school districts, as well as in other cities.

As part of their digital inclusion efforts, San José is also partnering with Facebook, which is installing its "Terragraph" technology as a proof-of-concept project in the downtown area (Figure 24.6) [43]. Terragraph is a 60-GHz, multi-node wireless system for dense urban areas that uses radios based on the WiGig standard. Facebook said Terragraph will deliver gigabits of data capacity. Terragraph will incorporate commercial off-the-shelf components and aim for high-volume, low-cost production. Facebook noted that up to 7 GHz of bandwidth is available in the unlicensed 60-GHz band in many countries. The US regulators are considering expanding this to a total of 14 GHz. Terragraph will also leverage an SDN-like cloud computer controller and a new modular routing protocol that Facebook optimized for fast route convergence and failure detection. Terragraph is already in operation at the Facebook campus in Menlo Park, California, where it delivers 1.05 Gbps bidirectional (2.1 Gbps total throughput) per distribution node in point-to-point mode, up to 250 m away [44]. San José will be the first large-scale trial of Terragraph. Facebook's Terragraph could lead to an extended deployment by the city and ultimately enable San José to

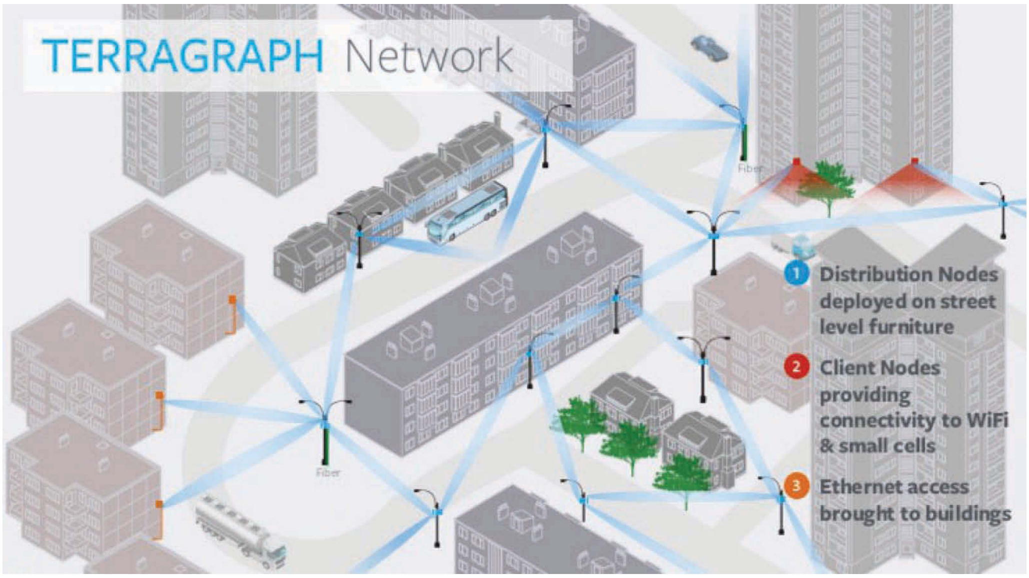

FIGURE 24.6 City of San Jose Terragraph network. (From Facebook, 2017.)

provide affordable or free broadband service at the street level, benefiting thousands of residents, businesses, and visitors, both downtown and in underserved neighborhoods. San José is well positioned to successfully confront the interconnected challenges of broadband and digital inclusion so that access to top-quality high-speed networks can spur innovation and growth while ensuring these opportunities are available to everyone.

24.6 SMART CITY CHALLENGES AND SUCCESS FACTORS

Smart cities are being created mostly due to economic conditions, availability of next-generation ICT tools, and an increase in urban migration that requires new and existing cities to respond with powerful new programs, solutions, and relationships between people, places, and things. Smart cities require not only smart technologies and systems, but also smart thinking. The basic goal of smart cities is to improve the quality of life and the well-being of its citizens, as human capital far outweighs any other measure of a successful urban environment. Both large and small smart city solutions have the opportunity to assist in creating an urban environment for people to prosper in a welcoming, inclusive, and open manner. Living a connected life is transforming into living an "interconnected life" for people in today's urban places. When people, places, and things begin to seamlessly and transparently communicate, interesting things begin to happen. This is the promise of smart cities. As the research, development, and implementation of smart cities emerge as a primary objective for urban environments across the globe, in addition to sustainability and livability, there are several factors important in the design and implementation of smart city programs.

24.6.1 Stakeholder Participation

For a city to become a "smart city," it needs full engagement of its stakeholders and users—they need to be aware of the importance of the environmental, social, and economic challenges in order to address them. Smart city stakeholders are not just people living in the city and businesses operating in the city but also include the people, businesses, and organizations involved in the management, operation, and maintenance of the city. Ensuring the participation of all stakeholders in the planning and design phases of smart cities is critical to determine the ideal programs and integration of services required to make each city smarter while delivering benefits to all the users. Stakeholders may include:

- Political leaders, managers, and operators of the local government.
- Service providers—public or private: water, electricity, gas, communications, transportation, waste, education, and so on.
- End users and prosumers: inhabitants and local businesses.
- Investors: private banks, venture capitalists, pension funds, and international banks.
- Solution providers: technology providers, financiers, and investors.

Smart city initiatives have an impact on the quality of life of citizens and aim to foster more informed, educated, and participatory citizens. In addition, users and residents of the city have the opportunity to become more active in the management and governance of the city, and can influence the success or failure of smart city programs. While individual needs are important for the success of a smart city, it is just as important to identify the specific needs of groups and communities, but not to the extent that it will unnecessarily detract or be a detriment to balancing the needs of individual users and stakeholders. Citizen engagement in terms of gaining public support and trust in new processes and tools, such as crowdsourcing, mobile phone applications, and report tracking, is a primary objective of many cities on the path to becoming a smart city. Transformation from an ordinary city to a smart city also requires addressing external pressures, such as legal agendas and regulatory barriers that may affect the outcomes of smart city initiatives.

24.6.2 Vision and Collaboration

The various stakeholders of a smart city will have different goals and expectations. The challenge is to determine which components of each smart city should be implemented to provide the most benefit to all stakeholders versus individual stakeholders. In addition, the vision should include the ability to deploy a smart city in various phases while keeping the same goals, but allowing for any refinement or update of goals over time. Since there is no single owner of the smart city, suitable committee accountability and oversight with representation by the various stakeholders are key success factors. ICT technology breakthroughs, insightful policies, and urban designs are intersecting in a manner that calls for collaboration at a rate that we have not been accustomed to before. These points of intersection are fertile ground for innovation within organizations and between organizations.

There is a high level of interdependence and organizational and social interaction within the city, and the politics of working with numerous and diverse services and stakeholders. The goals and objectives of a smart city should, ideally, include [45]:

- people-centric (citizens, businesses, workers, residents, visitors, etc.);
- well-led and governed;
- inclusive and open (to all people and new ideas);
- transparent in communications and operations;
- enabling the security of personal information;
- supported by integrated services and infrastructure;
- proactive in learning and developing.

If a smart city program is not carefully planned, funded, and managed, the sheer size of the project may be the fundamental detriment to any successful smart city deployment. It is therefore necessary to have multidisciplinary project teams from the various stakeholders involved in the process. The smart city programs will include physical technology aspects, operational and real-time requirements, and the integration of digital and back-office systems and software, with an overall cybersecurity and data privacy framework and governance. There is a need for a central vision and alignment of the various goals of the smart city program. The goals must be realistic and achievable. There must also be clear milestones and measurable deliverables, as with any other well-managed program.

When cities contemplate new ways to deliver basic services, support from citizens is essential for success. Citizens who are uninformed or disengaged cannot support, and may actively oppose, even the best policies. The public needs easy, open, and continuous access to a wide variety of data and planning information, and people must be brought into a project early so they can participate in designing it.

Cities are complex organizations, and decisions that involve multiple departments tend to take time and are often at odds with the sales cycles of companies. Procurement cycles for cities can take several years, which can prevent innovative, under-resourced companies from participating in smart city development opportunities. Coordination within the city's services and operational silos can be challenging; introducing the private sector to that equation compounds the complexity. As with any major initiative with various stakeholders, there is the challenge of resistance to change and conflicting ideas. Not only does the change need to be managed but also business processes may need to be improved to support the new goals of the smart city.

Knowing a city's needs, expanding the conversation about smart cities, realizing that Internet is a necessity, and financing were just some of the major issues discussed during 2016 Smart Cities Week event in Washington, DC [46]. What makes a city smart can be difficult and differs from region to region and even within the same country. What technology is implemented, whether air quality sensors on streetlight posts, sensors on garbage dumpsters to help sanitation departments, or public Wi-Fi networks, will determine that city's definition of being "smarter." Current smart city implementations are gaining momentum and represent widely different goals and implementations, but are great resources for reviewing best practices and technology comparisons.

Since a prosperous and low-crime city will largely center around jobs—that's a given—many smart cities are being designed around business parks, with the hope of attracting global or regional business headquarters to the cities that will provide plentiful skilled jobs. Many social engineers are unhappy about the idea of future "smart" cities growing up entirely around corporate power and money [47].

Smart city strategies and solutions must be considered in the context of a city's entire operations infrastructure processes and workflows. This holistic-system view will assist in identifying which isolated projects will have limited impact. The concept of "smart cities" must conjure up mental images in all of us, from urban utopias to sci-fi inspired urban dystopias, and sometimes a little of both. A smart city, also called a "digital city" or a "connected city," is a concept that has been defined as "embedding intelligence in objects" and then filling a town or city with those intelligent, connected objects: cars, parking meters, parking lots, police equipment, smart cards for public services, alternative energy sources, "smart" electric grids, and intelligent networked telecommunications equipment. The ultimate goal is "smart life," whereby urban life becomes easy, enjoyable, clean, green, and safe because it relies less on human whim and error and more on information and next-generation energy [47]. Cloud-based, 3D gaming style solutions are proving to be successful in telling this vital story.

24.6.3 Economic Viability

The economy of the city is naturally a major factor in driving the extent and magnitude of smart city programs. A city with a high level of economic wealth will attract more stakeholders and have the luxury to be more innovative. Similarly, the economic outcomes of smart city initiatives will help to attract more businesses, residents, and visitors to the area, help create jobs, and improve the overall productivity and sustainability of the city and surrounding areas.

One of the underlying concerns for cities is how to afford smart technology. While there will be significant cost savings in synergies of services and smart city programs, there is still the need to set realistic expectations for costs and funding required from each of the stakeholders. This may require an increase in service costs to the citizens and the service providers.

When it comes to smart cities, most challenges are financial and infrastructural. Several questions arise: how will the investment be financed, what return can be expected, and in which time frame? Many of today's cities are suffering from years of disinvestment in basic infrastructure, and especially technology infrastructure. These gaps, which are due, in part, to budgetary pressure but also to the regular turnover of leadership, have kept cities, their leaders, and citizens from realizing their full potential, slowing economic development and constraining their ability to make informed, data-driven decisions [48].

A well-developed city is usually constrained by existing infrastructure (transport, smart buildings, energy generation plants, etc.), which might compromise its sustainable development; therefore, significant financial resources are needed to adapt new technologies to existing facilities. It is also important to understand the operational costs of the infrastructure with high costs of installation, operation, and maintenance of ICT systems, including the cost of training.

The sole focus on economic gains in the short term, a fear of higher investment costs, and delayed visibilities of benefits are the key challenges with the economic viability of smart cities. Improvements on conventional city services and solutions typically become increasingly clear only in the medium to long term. Investors need to be aware of all the benefits that a smart city can provide, both tangible and intangible. It is also important to identify the benefits of proposed smart city programs to each of the stakeholder groups, as shown in Table 24.1.

Here investment subsidies for particular elements, for example, solar power, are crucial to encourage active participation in smart city co-creation. Many cities adopt a myopic view of integrated smart grid programs by only considering tangible economic benefits. While this may simplify investment decision-making, it lacks the richness and diversity of life in the city. Economic value is only one of many ways for public investments to create value. Smart cities must also consider

TABLE 24.1
Smart City Stakeholder Benefits

Stakeholder/Benefit	Metering	Sensor Networks	Data Storage/Visualization	Network (ICT)	Intelligent Grid Management
Residents	Fair billing, insight into real-time data usage	Access to city data for research, improved quality of life	Train and bus tracking, crime maps, attractive to tech entrepreneurs and startups	More efficient electric distribution	Less outage frequency and duration, lower cost electricity, improved safety during storms
City managers	Fair billing of public resources, insight into usage and costs	Environmental, usage, traffic, crime data, easier maintenance	Private and publicly funded research, city management with traffic, crime, electric, gas, and water dashboards for rapid city understanding	Opens opportunity for sensor networks	Maintenance and planning systems can be integrated with real-time equipment status
Utility	Demand response, accurate billing	Network as a service option, utility of the future	Analytics, granularity for management and planning, real-time operations and grid restoration	Network service provider, smart grid network, lower costs	Lower costs, improved employee safety, fewer truck rolls, better customer satisfaction

intangible or noneconomic benefits. The challenge is to establish a framework for identifying, measuring, and expressing value that resonates with citizens and enables politicians to articulate how they are enriching everyday life in many ways.

The scope of smart cities is almost limitless with the acceleration of technologies. It is not always clear to administrators how smart technologies will resolve the issues faced by the population on a day-to-day basis. The technology descriptions can be quite abstract (cloud computing, data analytics, etc.) and can often obscure the true impact of the technology. The challenge is to explain to stakeholders in the city how an average day in their lives will change with the adoption of smart solutions. In the near term, smart cities are certainly constrained by the economics of integrated and optimized systems and the overall challenges of working with various stakeholders and across different service types to develop a cohesive plan and infrastructure. A key question is: What are the economically feasible scope opportunities for smart cities? There is a need to determine all the cost factors and potential benefits and identify the business plan that can be funded by the various city services. There are several synergies in an integrated framework for smart cities, such as a shared communications infrastructure, and shared information, but a well-developed deployment plan is required to ensure maximum benefits are realized at the end of the smart city implementation. The sheer magnitude and complexity of smart city projects can be overwhelming, so incremental deployments that are specific to the needs of cities and delivering measurable results at each phase will likely be the path moving forward for most smart city deployments.

In order to invest in the new technologies that will make the urban information economy possible, cities will need to take an innovative approach to how they deliver services (operating model), how they charge for them (business model), and how they finance it all (finance model). Smarter city engagements all over the world are demonstrating how the right investments in infrastructure can introduce long-term efficiencies and dramatically transform a city's prospects for growth. Large-scale trials of smart cities should focus on business models and deployment, not just technologies.

24.6.4 Technology and Data Integration

Smart grid technologies and innovations have a significant influence in driving the integration and optimization of the various services of a city and making them smarter. In particular, wireless sensors as part of IoT; pervasive communications infrastructures and device connectivity; the digital transformation, including big data and data analytics; microgrids and energy conservation and sustainability; the increase in cybersecurity awareness; and the increased focus on the customer; all provide a strong foundation for smart city deployments.

Some of the challenges in implementing common infrastructures within a smart city include the integration, compatibility, and interoperability of hardware and software technologies, and the overall security and data privacy governance required. The key to becoming a smart city is also knowing which of those smart technologies a city actually needs. Implementing technology simply because a private sector vendor makes it available is not always beneficial to citizens.

The underlying ICT infrastructure is a critical technological aspect of a smart city. ICT infrastructure includes a combination of technologies for the various types of users, data types, and data exchange requirements, such as bandwidth, availability, latency, and priority. Therefore, a combination of communications technologies is expected from high bandwidth redundant optical backbone networks to wireless infrastructure to support mobile communications, Wi-Fi, and so on. While ICT use in cities can improve the quality of life for citizens, it can also increase inequalities and promote a digital divide [49].

Smart cities require a pragmatic approach to technological development and deployment that is based on open standards and interoperability, but needs to be vendor-neutral and focused on the needs of cities, citizens, and businesses. One particular challenge in the context of smart cities relates to the interoperability between products and services across very different domains or elements. This also relates to the integration and interoperability of the various related software platforms and databases. Future interoperability can only be guaranteed through the existence of international standards ensuring that components from different suppliers and technologies can interact seamlessly. Continued best practice sharing and development of common standards to ensure that data can flow freely between systems is essential, while maintaining the need to protect confidentiality and individual privacy. With smart cities, there are various other services and organizations, and technologies will be required from a multitude of markets that come with their integration and communication challenges.

Open data and data sharing are also requirements for smart cities; however, these requirements for open data create another challenge. As with smart grids, the overall priority must be to establish user confidence in the upcoming technologies; otherwise, stakeholders will hesitate to accept the services provided by smart cities. Personal data contribute to a better monitoring of the city environment providing real-time data, but still keeping users and citizens owners of their data. To make people willing to contribute, they must be assured of the safety of their personal information.

Working across city government agencies and with the academic and private sectors is important in moving from pilot programs to integrated and scalable solutions. Research done on smart city technology should not happen in ivory towers, but must foster better citizen engagement. Without citizen access to reliable, high-speed broadband and Wi-Fi, the participation rates in studies to determine what gaps smart cities technologies can fill may not be accurately identified [46].

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25 Refining a Holistic View of Grid Modernization

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CONTENTS

This chapter takes stock of changes in the power industry over the past 5 years, where it stands as of 2016, and addresses, as pragmatically as possible, prospects for the next 5 years. Grid modernization is a journey, a continuum, not a destination. Rational investments made with a holistic approach to a robust, flexible, scalable grid will return benefits that will increase over time and meet future needs. Today, the three pillars of progress—technology, policy, and standards—offer most if not all the tools for creating the foundation of grid modernization. Certainly, each pillar presents ongoing challenges, but those challenges are being defined and acted upon. The various utility business models, too, are under pressure to change and keep pace with market developments. Now, every utility must thoroughly review its approach to grid modernization, understand industry's best practices and lessons learned over the past 5 years, and take a proactive stance to succeed in the face of changes sweeping the landscape.

By the time the first edition of this book was written in 2010, the power industry's outlook had already shifted from bolting on technology piecemeal to the development of a holistic vision of grid modernization. By 2016 and the writing of this second edition, a fundamental challenge remained for many, if not most, utilities: how to methodically move ahead with a sound technology roadmap and adaptable business model to create a sustainable enterprise. This challenge is daunting, and inertia is understandable. Myriad forces have pressured utilities over the past 5 years and show no signs of abating over the next 5 years. These forces include regulation/policy-making, standards development, and disruptive market forces, including the rise of distributed energy resources (DER), third-party service providers, the transformation of "ratepayers" into actual consumers, and the increased frequency of extreme weather events, to name but a few.

Technology and related tools, as is often the case, appear to have raced ahead of the policy-making and standards development curves. Yet, policy-making and standards are catching up with technology due to widespread recognition of the stakes involved. Dire predictions notwithstanding, a centralized grid has a critical role to play in our collective energy future, and utilities' survival is fundamental to every nation's social order and economic and national security. A policy shift in support of a holistic vision of grid modernization emerged a decade ago and has been accelerating ever since.

25.1 U.S. POLICY FOUNDATIONS

In the United States, for instance, the Energy Independence and Security Act of 2007 (EISA 2007) Title XIII laid the groundwork by articulating the federal government's explicit support for grid modernization. Title XIII directed the Secretary of the Department of Energy (DOE) to coordinate federal agencies and stakeholders in pursuit of research and development, standards, and interoperability. Title XIII also encouraged the states to require proof that utility investments would be cost-effective, secure, improve reliability, and benefit society. Two years later, the federal American Recovery and Reinvestment Act of 2009 (ARRA 2009) provided the DOE with $4.5 billion to modernize the grid through cost-sharing with industry and taxpayers. Through the largest program, the Smart Grid Investment Grant (SGIG), these stakeholders—including more than 200 utilities and related organizations—jointly invested about $8 billion in 99 projects involving smart grid technologies, strengthening cybersecurity, improving interoperability, and collecting data on the results. Soon thereafter, California passed Senate Bill 17, which in part required the state's investor-owned utilities (IOUs) to create and submit smart grid deployment plans and submit them to the California Public Utilities Commission (CPUC) for review. These IOUs were instructed to deploy smart grid technologies in an incremental manner to maximize the benefit to ratepayers. As state regulators around the country followed suit, in fits and starts, the "ratepayer" became the "consumer." Fundamental policy changes were under way. This momentum has continued as state regulators, legislators, and organizations such as the National Association of Regulatory Utility Commissioners (NARUC) have grappled with enabling utilities to develop a rational path to a sustainable future.

Policy makers have to balance utility interests and public interests, and that means weighing utility operational benefits and return-on-investment (ROI) outcomes as well as ensuring that consumers' and taxpayers' monies are well spent on improvements in reliability, resiliency, and efficiency.

25.2 UTILITY LEADERS AND GRID MODERNIZATION

To meet policy mandates, utility leadership also has to balance the success of the enterprise and the pursuit of operational benefits and ROI with the public good. Fortunately, the lessons learned since the first edition of this book was published underscore that utility leaders pursuing grid modernization have the power to:

- Define their organization's strategy and operating model, and pursue a progressive and accelerated technology migration, rather than follow a defensive, incremental, reactive migration
- Define measurable outcomes that strike a clear balance between customer/societal benefits versus utility/grid operational benefits
- Establish partnerships among public, private, and education-related stakeholders that promote the best outcomes
- Design a modern grid based on solutions (not just technology) supported by scalable, flexible, and open standards that serve long-term goals
- Enable speed-to-value by building support and momentum for concepts that rapidly accelerate to full-scale deployments
- Set an example for innovation in infrastructure not only in energy but in water, health care, safety, transportation, buildings, and waste systems as well

To be sure, these are high-level, perennial prerogatives of utility leadership facing the future. More specific to the goal of grid modernization, creating a robust, flexible, scalable grid meets both utility and public goals:

- Ensures adequate infrastructure and contributes to avoiding the cost of new generation, improves reliability, and produces more efficient utilization of existing assets
- Improves energy productivity, which reduces energy demand through active management
- Manages electricity costs and mitigates environmental impacts, which defers or avoids the construction of new-generation and transmission facilities
- Contributes to mitigating environmental impacts by enabling the increased penetration of distributed renewable resources

25.3 BUILD A "STRONG" GRID FIRST

In order to realize these grid modernization benefits, utility leadership has the added challenge of propelling organizational and cultural change. A practical path includes championing utility priorities and establishing a culture of cooperation across the organization, eliminating traditional siloes that threaten the success of a holistic approach to grid modernization. Though it has been said that "culture eats technology for breakfast"—meaning that cultural change is a much greater challenge than merely implementing new technology—the two can be combined. Two real-world examples of foundational technology implementation and the opportunity they present for changes in traditional utility culture illustrate this point.

The importance of a foundational communication network that seamlessly ties together all operational and enterprise aspects of a utility business is virtually a prerequisite for grid modernization. Of equal importance is a holistic, robust, and seamless information technology infrastructure that ensures no disconnects in the enterprise that would hinder enterprise-wide data management. Establishing a foundational communication network and IT infrastructure may be thought of in terms of building a "strong grid" before creating a "smart grid." The tandem of communication network and information technology (IT) infrastructure will enable and support full information flow, data management and analytics, and monitoring and control. It is also the basis for future functionalities that inevitably will include new consumer services, accommodation of DERs, and as-yet unforeseen needs. Ensuring that both operational and nonoperational data are captured and exploited by both operations and the enterprise requires cooperation between the formerly siloed operations technology (OT) and IT groups. The divide of the OT and IT silos has no place in a forward-looking utility.

Our second example focuses on the benefits of distribution automation (DA)—visibility, fault detection and isolation, energy efficiency and asset management—that are creating a "second wave" of smart grid investments, following the widespread adoption of advanced metering infrastructure (AMI). The operational benefits are obvious, and the business case for DA is better than for any other single system in the phased steps of grid modernization.

In those phased steps, a foundational communication network and IT infrastructure would come first and, perhaps, AMI would follow. Owing to the ARRA funding for AMI, however, some utilities adopted it with the traditional utility approach that assigned its implementation to, perhaps, the metering group alone. Now those utilities may find that their data network and IT choices do not allow DA integration, or require a costly, disruptive work-around.

In the past, AMI implementations typically belonged to a metering group inside the utility, while a distribution engineering group in operations would handle DA. That arrangement will result in redundant efforts, duplicative expense, and two separate data streams—when the two systems share a need for a service territory-wide communication network. In fact, DA relies on AMI's end-of-line sensors, aka "smart" or interval meters, to enable its benefits.

The simplest way to avoid this misstep is to have executive leadership, sometimes aided by a third party, bring together the metering group and the distribution engineering group to jointly determine their mutual, functional requirements for a common communication network. AMI and DA integration is an early rudimentary example of holistic thinking about the technology roadmap. Demands on that foundational communication network will only grow with time. Furthermore, when a utility adopts new technologies that inevitably impact operations, business processes must change and new skill sets are required. For instance, relays, remote terminal units (RTUs), and communication networks operate today as a seamless whole; thus, new super Intelligent Electronic Device (IED)-specialists are needed to extract the new technology's full benefits.

Indeed, a general rule of thumb for a technology roadmap and resulting utility investments is to develop them with a horizontal organizational structure that results in cost-effective investments and integration-friendly systems. Gone are the days when a utility could devote a department to each major grid function. Today, multiple, formerly discrete technologies have been combined such that organization-wide requirements must be considered to realize the value of any and every investment in the scoping, design, purchase, implementation, and operation of new technologies. As this becomes a more widely recognized best practice in grid modernization, a horizontal organizational structure will replace the old tendency to build silos. And regulators will come to expect this approach as a basis for their decisions as they balance utility and consumer interests.

25.4 MACRO CHALLENGES

A holistic approach to grid modernization, as described in this high-level view, sounds clear-cut. And the guiding principles and pragmatic processes enumerated earlier can inform methodical actions and successful outcomes. But it's realistic to acknowledge the macro-challenges taking place well beyond the individual utility's purview and that are nearly ubiquitous across the power industry landscape:

- An aging infrastructure calls for fresh investment, a need which is as pervasive as it is daunting in scale. Fully 70% of the existing grid is more than 25 years old.
- Severe weather events, which have spiked dramatically in the period 1992–2012, are the primary cause of power outages in the United States. The cost to the U.S. economy in that period was an inflation-adjusted annual average of \$18 to \$33 billion [1]. (Figure 25.1).
- Consumer expectations are changing in a cloud-based world of information and options. They seek to manage their energy use and costs, and are attracted to self-sufficiency and alternative service offerings. Extreme weather events have opened some consumers' eyes to the need for grid resiliency and hardening.

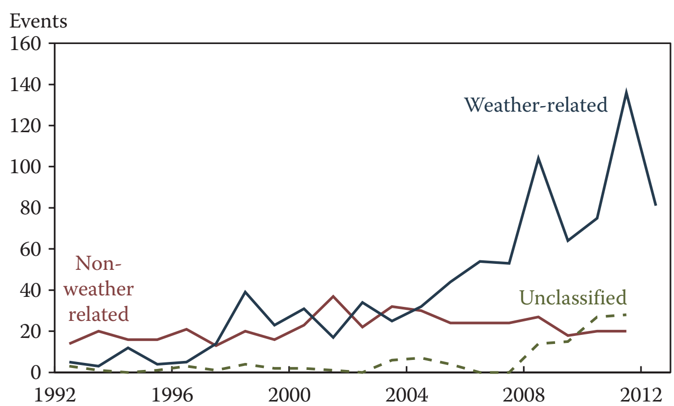

FIGURE 25.1 Observed outages to the bulk electric system, 1992–2012. (From *Economic Benefits of Increasing Electric Grid Resilience to Weather Events*, Executive Office of the President, August 2013.)

- Growth in renewables prompted by federal and state policy and regulation—including the Clean Air Act, 111d, which seeks to reduce carbon pollution from the power sector—and ambitious Renewable Portfolio Standards (RPSs), coupled with the increasing efficiency and lower costs of renewables, presents technical and revenue challenges.
- Increased emphasis on energy efficiency, particularly in developed countries, and demand-control technologies increase the risk of long-term erosion of demand.
- Third-party, disruptive business models challenge legacy utility business models and the latter's domination of the power industry.
- An aging utility workforce is retiring, with 60% of utility executives and 40% of employees projected to leave the workforce by 2018. And new skill sets are in rising demand [2].

25.5 POTENTIAL SOLUTIONS

Solutions to these challenges will fall to individual, affected utilities, and they will require concerted industry-wide effort where the impacts are more universal. Readers can best determine which of the following solutions might apply to their utility and which might require their contribution to industry-wide efforts. In answer to the foregoing list of challenges, the following proposed solutions may provide food for thought:

- Fresh investment should be directed to logical steps in grid modernization to maximize value and manage capital and operational expenses.
- The advent of more frequent, extreme weather events calls for parallel investments and measures to harden the grid and make it more resilient when temporarily overwhelmed by the forces of nature.
- Consumers and their needs and expectations must be understood. Consumers must be engaged, educated, and empowered to manage their energy use and costs and presented with an attractive, design-driven user experience. Utilities will have to develop the expertise to do this or seek partners possessing this expertise.
- The growth of renewables and DER—both utility-owned and operated as well as resources owned by consumers or third parties—must be met by utilities with a proactive stance that strikes a balance between plant integration optimization, control, and protection technologies. Policy makers must understand the technical implications of RPSs.
- That same proactive stance is needed to support energy service choices that will require an advanced technology platform, energy domain-driven analytics, and new business models. Differentiated service offerings must appeal to consumer psychographic segments revealed by industry research.
- Finally, addressing skilled workforce shortages can be accomplished by improving workforce productivity through mobile data dispatch and field force automation. On a longer time horizon, the industry must attract students and young professionals, perhaps emphasizing challenges, such as the digitization of power equipment, the design of an engaging consumer experience, and the role of power and DER in economic and national security. (In fact, the two most important considerations of electrical engineering university graduates, upon attaining their first full-time job, are to serve society and protect the environment.)

If the power industry understands the challenges ahead in implementing grid modernization, and the implications for utility business models and organizational change, meeting those challenges will usher in a new, sustainable energy future. A "day in the life" in 2020 may be characterized by a flexible, optimized energy system that is secure and reliable, features a robust central grid, distributed home/neighborhood power systems, and an elastic, distributed balance between supply and demand. Smart devices, appliances, electric vehicles, homes, buildings, communities, and even cities will generate and consume power when and where it's needed, all based on an innovative, flexible, infrastructure platform that delivers resiliency and efficiency made possible by a productive workforce and empowered consumers.

Now, let's turn to market enablers and drivers that will propel this transformation.

25.6 MARKET DRIVERS AND ENABLERS

Of the numerous factors enabling and driving the market for grid modernization, many familiar, high-level factors have been identified in this chapter's introduction on opportunities and challenges in grid modernization. Those factors include aging infrastructure, increasing frequency of severe weather (the leading cause of widespread outages), policy mandates, the new role of the consumer, environmental concerns and its corollary, a rise in DERs, and the increased efficiencies and dropping costs of the latter.

The transformation of passive "ratepayer" to "consumer," with all that the shift entails in a digital age, imbued by high expectations for transparency, information, and service options, is another major factor driving a particularly unpredictable segment of the grid modernization market. Thus, Section 25.7 covers consumers as market drivers for technology, products and services, utility programs, and third-party offerings.

Let's examine each of these factors from the perspective of their role as market enablers and drivers.

As noted earlier, federal and state policies, funding, and incentives in the USA have played a major role in establishing and growing the grid modernization market. This is particularly true in cases where policy is based on environmental concerns. One major goal for sustainable power practices, driven by concerns about climate change and air quality, has become low-carbon emissions. In the USA, the market has embraced low-cost natural gas, recovered largely through hydraulic fracturing, over coal as a power source due both to cost and limits on emissions. Utility adoption of renewables and DER is often mandated by legislation or ballot initiatives for RPS targets. But market forces are driving solar and wind installations as well, as renewable kilowatt-hour (kWh) costs arguably approach parity with fossil-fuel generation and renewables technology efficiency increases as its cost drops. Thus, DER—both utility-owned and customer-owned—is on the rise. As we'll see, the rise in DER can impact electromechanical controls, which are driving research and development (R&D) and commercialization of power electronics for certain, formerly electromechanical means of control [3].

The evolution and adoption of a holistic approach to grid modernization and the ARRA-funded, widespread installation of AMI have turned the power industry's attention to foundational communication networks and a holistic, robust, and seamless IT infrastructure. That foundation and AMI's widespread integration have also brought a focus to the next logical upgrades in substation automation (SA) for more granular visibility, monitoring, and control in real time and in DA for reliability, resiliency, and quality of service (QoS).

The industry's shift from its historic, sole focus on generation to meet demand to also controlling demand—even isolating demand through the use of microgrids—is driving the market for sensor and control technologies. The success and growing sophistication of sensor and control technologies are, in turn, supporting the use of microgrids in various grid applications, from supporting poorly performing feeders to offering the ability to shed load by sending a microgrid into island mode.

The transformation of formerly stand-alone control and protection technologies, such as relays into IEDs with expanded data outputs, must be recognized as a market-enabler driving replacement of aging equipment and upgrades in functionality. IEDs' ability to support condition-based over time-based maintenance offers a major transformation in asset management and, therefore, added value that drives IED uptake as well.

Certainly, as standards are written for interconnecting intermittent renewables and DER to the transmission and distribution systems as well as for SA, DA, and IEDs, interoperability is ensured, which grows markets and enables economies of scale, lowering costs and reducing barriers to modernizing the grid.

An aging workforce and the need for operational efficiencies appear certain to drive the uptake of mobile data dispatch and field force automation applications.

The uncertainties resulting from the rise of renewables and DER, increases in severe weather, adoption of new technologies, and other factors may be placing renewed emphasis on scenario planning—how does mitigating risk across the spectrum of scenarios mesh with a utility's grid modernization roadmap?—and turning it into a market driver as well.

Let's examine each of these drivers/enablers.

25.6.1 The Rise of Renewables and DER

For context, let's look at the scale of DER. At the transmission level, solar photovoltaics (PV), concentrating solar power (CSP), and wind plants must be integrated into the grid at 69 kV and 138 kV. At the distribution level, typically solar power enters the grid at 13.8 kV and 34.5 kV. Then, there are customer-scale renewables and DER, which encompass solar PV, small-scale wind, bio-gas, advanced- and micro-turbines, batteries, and fuel cells, connected at much lower voltages. The consumer role in adding DER, electric vehicles, and storage is driving markets for those technologies. And the consumers and large utility customers' increasingly important role in controlling demand through microgrids, uninterrupted power supplies, micro-turbines, and demand response programs also drives a market for grid modernization technologies and standards on the utility side.

In seeking to address the impacts of DER, grid operators must understand the similarities and differences between solar and wind, which present distinctly different challenges.

PV exists at all levels—transmission, distribution, and customer sites—and is more likely to be distributed and located closer to the load. Wind typically enters at the transmission level and is usually sited farther from the load. Both solar and wind are renewable, but also are highly variable and difficult to forecast. Both have grid integration requirements that must be met. And both use similar power electronics for operation, monitoring, and control. Wind has its own complex aeromechanical systems and controls that PV lacks.

Because of renewables and DER's variability, one major application of energy storage systems is to capture and store power when renewables and DER production is high and load is low. In determining whether and how energy storage should be part of a DER-related solution, utilities must ask themselves: What is the intended application from a time perspective? Two points must be made; The first point is not often considered and the second typically is not well understood.

If the desired application is "power" (kilowatts), it's instantaneous (a point on the power curve), like what's needed to ride through intermittency in a DER application. If the desired application is "energy" (kilowatt hours), it's the integral or area beneath that curve. An example of an energy application is a situation in which a utility might park trailers full of batteries next to a substation for a "peak deferrals" application. The substation can't handle all the load on a peak day, so batteries are used over a longer time frame to handle the peak above the substation's capacity.

The second point utility engineers need to understand is that different battery chemistries are not optimal across different time-related applications. Figure 25.2 shows that if instantaneous power is needed in a DER application, lithium-ion is appropriate. If the application is over a longer time frame for an energy application, sodium-sulfur is more likely to be the optimal battery chemistry.

As for the energy storage business case, it remains true that multiple value streams typically must be captured to create a cost/benefit ratio that makes sense. At the time of writing in mid-2016, the energy storage business case is not as strong as it could be, and more research is required to optimize the cost-effectiveness of battery energy storage chemistry. Because battery energy storage technology (i.e., beyond hydroelectric power) holds the promise of breaking power's traditional use-it-or-lose-it limitations, research on battery chemistry is sure to continue in a search for one of the power industries' holy grails.

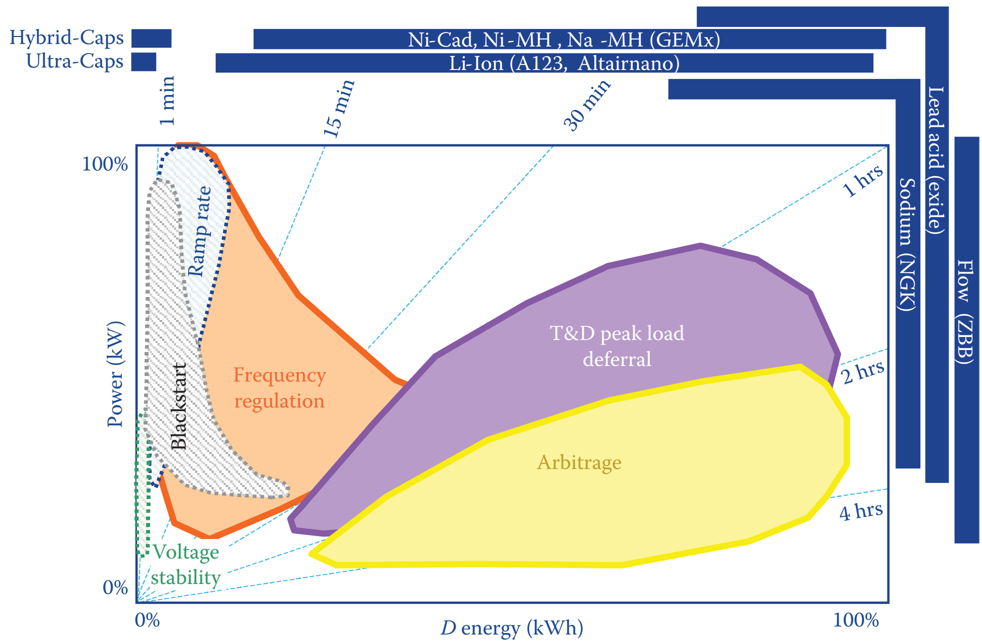

FIGURE 25.2 Storage landscape. (From *The Impact of Renewables on the Grid*, John D. McDonald, Byron Flynn, GE Digital Energy, September 28–30, 2015.)

25.6.2 Substation Automation

SA essentially integrates IEDs for improved visibility, situational awareness/remote monitoring, and real-time control and automation functions using supervisory control and data acquisition (SCADA) gear inside a substation, and facilitates improved reliability and condition-based asset management. The most effective way to approach SA is to develop a business case that makes costs and benefits—monetary and strategic—clear before a project is undertaken and that the costs and benefits support company business drivers. Monetary benefits mean ROI measured in years, while strategic benefits are not directly quantifiable, such as a reduction in customer outages.

Improvements in IEDs and in communication infrastructure and standards and protocols, such as International Electrotechnical Commission (IEC) 61850, are driving IED integration in SA projects. Cost-effective investments in SA will allow the enterprise to exploit the full value of operational and nonoperational data and, thus, realize the full ROI for IEDs and IED integration. Operational data are routed to the control center for operators maintaining power quality and the integrity of the grid itself. The nonoperational data can reveal, for instance, the level of energy associated with the breaker arc that needs to be quenched when a relay trips and it can record how many times a breaker has operated—both are factors of interest to a utility's maintenance group. Capturing and analyzing nonoperational data can represent as much as 80% of the value of every IED investment.

An effective SA design addresses current business drivers while laying the foundation for additional functionalities needed in the future. Cost/benefit analysis determines which SA functions are justified in a positive business case.

Proper IED integration requires a substation automation plan and a system architecture that allow a utility to reap the full monetary and strategic benefits aligned with key business drivers, such as reliability and QoS, cost of service, and customer loyalty. Among the functionalities gained are online equipment condition monitoring, dynamic transformer ratings, adaptive relay settings, power system disturbance analysis, and automatic load restoration. Thus, factors such as reliability, QoS, cost of service, and customer loyalty drive the market for SA.

It's important to note that as utilities upgrade the legacy equipment in the substation and on their distribution systems, an opportunity arises to capture more value from the resulting hybrid configuration of new and existing technology. Avoiding stranded assets is a critical aspect of value to be captured in an SA business case [4].

25.6.3 Distribution Automation

By 2016, few utilities in the USA had completed DA projects. Generally speaking, optimizing the distribution system provides the strongest grid modernization-related business case and the ROI for DA is attractive—if approached with careful analysis. This is another case where improvements in reliability, resiliency, QoS, and maintenance costs (in terms of field analysis of faults and truck rolls) drive the DA market.

DA for each feeder must be modeled for the benefit/cost ratio (BCR) that determines effective investments for the greatest improvements in reliability. Feeders are all different, in terms of loads (what's the mix of residential, commercial, and industrial customers?) and geographic location (are they subject to lightning?). Utilities all have their list of "10 worst-performing feeders," but they need to be quantified and analyzed to justify an investment. An accurate model will help further a utility's understanding of the relationship between manual and automatic control to be applied to rural and urban areas and help develop a DA road map.

Since sectionalizing is a necessary part of a DA project, determining the optimum number and location for switches that enable fault location, isolation, and service restoration should also be subject to modeling and BCR analysis. The goal is to sectionalize to effectively isolate faults, but too many switches and the payback drops precipitously.

A simple graph illustrates these points (Figure 25.3).

The reliability expectations of customers and regulators must also be considered, as regulatory approval of such projects must be sought and rates may be affected. In a 2014 survey of utility customers by Harris Poll on behalf of GE, Harris Poll found that 41% of people living east of the Mississippi River would be willing to pay a $10 or more per month rate increase for improved reliability. These customers had experienced three times more storm-related outages in the prior 12 months than those living west of the Mississippi, who had fewer outages, would still be willing to pay a $10 or more per month rate increase for improved reliability [5]. In a global example of customer attitudes, the blackout in India in 2012 affecting twice the population of the United States appears to have caused relatively little concern, as such blackouts generally are more frequent in that country.

A DA performance improvement modeling tool can assess costs (estimated net capital and maintenance costs) and benefits (improvement to outage minutes) for an appropriate level of technology

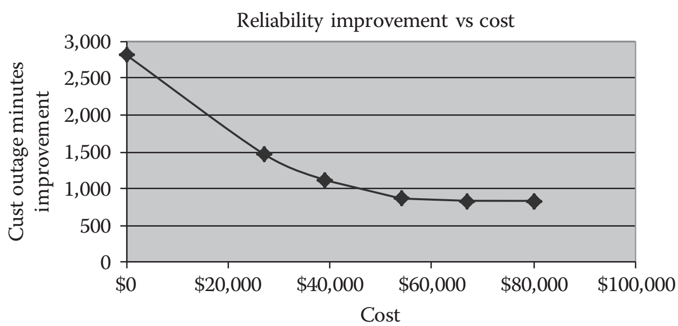

FIGURE 25.3 The challenge of diminishing returns: Additional reliability improvement benefit declines dramatically as more switches are added. (From *Justifying Distribution Automation*, John D. McDonald, Byron Flynn, GE Digital Energy, September 28–30, 2015.)

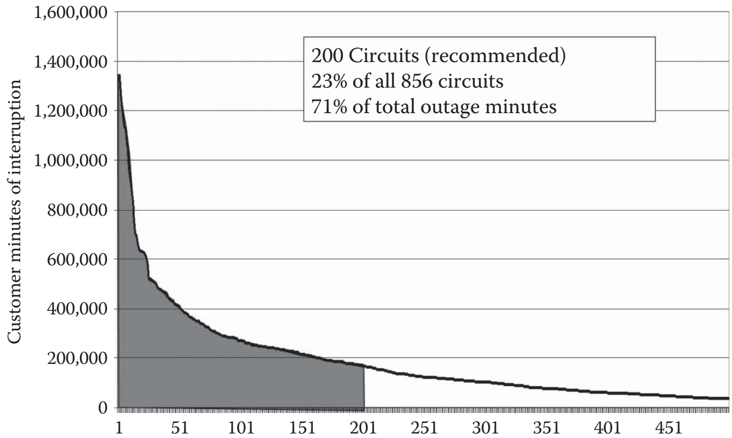

FIGURE 25.4 DA prioritization based on SAIDI. (From *Justifying Distribution Automation*, John D. McDonald, Byron Flynn, GE Digital Energy, September 28–30, 2015.)

for various feeders by weighing varying factors, such as load density, fault exposures, response times, and the level of existing technology.

As with all grid modernization projects, creating a DA strategy and roadmap is a multidisciplinary exercise. In the case of DA, the pertinent utility departments include Distribution Planning, Distribution Operations, Engineering Maintenance, Distribution Reliability, System Protection, and Telecommunications Engineering.

A DA performance improvement modeling tool should assess factors that include assumptions, critical path analysis from fault to restoration by feeder segment, typical response times, common input variables, and estimated net costs.

Figure 25.4 is another simple graph that illustrates the results of DA prioritization based on the System Average Interruption Duration Index (SAIDI), where 200 circuits (23% of an individual utility's total 856 circuits) were recommended for DA investment, which account for 71% of the utility's total outage minutes.

It is important to note that DA is designed to improve reliability in everyday circumstances—the so-called blue sky weather days. DA's greatest value lies in its ability to support consistent, year-round service. DA functionalities focus on restoring power after typical interruptions, such as vehicle-utility pole accidents, grid equipment failures, and other mundane events. Although extreme weather's physical destruction of grid assets can impact DA components, such as switches and sectionalizers, DA components that remain in service definitely aid subsequent service restoration [6].

25.6.4 Controls and Sensors

The industry's shift from its historic sole focus on generation to meet demand to also control demand—even isolate demand through the use of microgrids—is driving a market for sensor and control technologies. The success and growing sophistication of sensor and control technologies are, in turn, supporting the use of microgrids in various grid applications, from shedding load by sending a microgrid into island mode, to supporting under performing feeders.

Today's shift to control demand may be referred to more broadly as resource optimization in real time. Resource optimization demands reasonably accurate forecasts for both generation and load. Think of a utility's portfolio of resources, including traditional, nonvariable generation, variable generation (renewables), plus demand-side management. In the "old days," if load increased and frequency dropped, traditionally we'd increase generation output. Today, we might dial up demand response. We have different resources available now to optimize and orchestrate, and that puts a focus on control technologies, sensors, communication networks, and software analytics.

Utilities and their customers are adopting microgrids for a variety of applications, including poor feeder performance or islanding customers or facilities during outages, which seem likely to expand the market as utilities become more experienced with implementing them or accommodating customer- or third-party-sponsored microgrids. Policies encouraging the safe integration of microgrids for utility personnel, as well as for reliability and resiliency on the customer sides during grid outages, are another market driver. Standards to enable smart inverters and utility-microgrid interconnections are driving the market as well.

Meanwhile, electromechanical means of control are increasingly being replaced by the use of power electronics. In some cases, this is driven by the impact of renewables on legacy electromechanical control devices. In one particular case with future, potentially widespread implications, policy-driven, consumer uptake of rooftop solar PV on certain feeders in San Diego Gas & Electric's (SDG&E) and Arizona Public Service's (APS) service territories have led to extensive voltage variability [3]. That variability triggered overoperation of voltage regulation devices, such as load tap changers, reducing their life cycles.

The search for mitigating technologies ranges from the conventional, such as resizing feeder lines and installing dynamic VAr (Volt-Ampere reactive) devices, to the unconventional, which includes energy storage and the application of power electronics to technologies that today rely on electromechanical means of operation. In fact, the subject highlights why the currently separate disciplines of power electronics and power system automation should be integrated. Once that happens, the resulting devices would be more cost-effective to implement and, therefore, represent an attractive benefit/cost ratio, driving a market for uptake.

Power electronics have the ability to use distributed intelligence to assess many more variables in power quality on distribution feeders and calibrate a device's response to minimize automated, mechanical actions. Power electronics also have the ability to react in exponentially swifter time frames than electromechanical devices that can shut down from excessive operation in the face of rapid swings in voltage.

The introduction of power electronics in this context to reduce the number of mechanical operations to within a device's design parameters may well provide a solution; in fact, in this case, SDG&E used dynamic VAr devices that are assisted by power electronics installed on the low-voltage network. Major vendors are doing R&D on prototype LTCs employing power electronics. So, despite the perils of generalization, an underlying challenge is apparent and the nature of power electronics lends itself to a solution, though cost remained a concern as this book was published. Other mitigating technologies, some of which also rely on power electronics, are being explored. In both cases, however, it may be presumed, based on historical trends, that standards-based power electronics will find an expanding market that brings down costs.

As rooftop solar PV panels gain in efficiency and drop in price, these early cases in California and Arizona are a foreshadowing of impacts on many utilities across the USA over the coming decades. So, instead of remaining in reactive mode, utilities need to look ahead and be aware of what's coming, if present trends continue.

The bottom line is that the future grid will be more volatile, and thus the way we control it has to evolve. Mechanical means of control will give way to power electronics, and three new applications of power electronics will eliminate moving parts: (1) load tap changers on transformers, (2) low voltage network dynamic grid-edge controllers, and (3) smart inverters.

Power electronics and LTCs have just been discussed. Low voltage network, dynamic, grid-edge controllers will be needed at the ends of feeders to handle the potentially frequent voltage volatility expected as DER becomes widespread. The speed and durability of power electronics is ideal for such an application. Smart inverters, relying on power electronics, have expanded the inverter's primary role of converting DC power to AC power for consumption or injection into the grid to include myriad functionalities including modulating reactive power output so that grid-edge DER can provide voltage regulation services.

Certainly as standards are written for interconnecting intermittent renewables and DER, as well as for SA, DA, and IEDs, the level of interoperability will help grow markets and enable economies of scale, thereby lowering costs and reducing barriers to upgrading the grid.

An aging workforce and the need for operational efficiencies drive the uptake of mobile data dispatch and field force automation. Because the majority of utility personnel are field-based, wireless communications coupled with vehicle-based or handheld computer terminals save time, boost productivity, and cut costs by enabling more efficient dispatch of crews focused on operating and maintaining the grid. Field force automation typically leverages mobile applications to provide field crews with maps, routing directions, and service intelligence drawn from, for instance, control room outage management systems (OMS).

The uncertainties resulting from the rise of renewables and DER, increases in severe weather, adoption of new technologies, and other factors may be placing renewed emphasis on scenario planning—how does mitigating risk across the spectrum of scenarios mesh with a utility's grid modernization roadmap?—and that may be considered a market driver as well.

In the strategic planning process, certain assumptions must be made; for example, low cost of natural gas, adherence to specific U.S. Environmental Protection Agency (EPA) emissions requirements, policy on decoupling and rates, superstorms, EV adoption rates, consumer participation in system load reduction (DR, dynamic rates), and the impact of implementing new standards and new technologies. These assumptions are subject to sensitivity analysis. What could change and to what degree? These assumptions and the variables that affect them will likely impact a utility's technology roadmap, its strategic plan, and its business plan. Thus, the results of scenario planning may well impact grid modernization decisions. In this section, we've illustrated how developments in policy, technology, and standards have, in general, enabled a market for utilities pursuing grid modernization and, in particular, the market-driving force for infrastructure spending.

25.6.5 Next Few Years

Newton-Evans Research Company has completed updates of its prior studies of smart grid-related market components since the first edition of this book was published in 2013. Informing this new edition is primary research (i.e., interview- and survey-based studies) and secondary research projects completed between 2013 and mid-2016.

The topics covered in these studies include Distribution Automation; Increasing Role of Third Party Consultancies; Need for T&D Equipment Testing; Protective Relay Trends; Substation Automation and Modernization; Gas Insulated Switchgear and Substations; Global Study of Transformer Maintenance and Diagnostics; HV Underground Cable; and two major studies of EMS, SCADA, DMS, and OMS Systems Trends. Most studies were completed for individual clients, while the rest were multi-client reports [7].

Newton-Evans Research frequently holds additional smart grid-related discussions with equipment manufacturers, systems integration specialists, OT/IT consultants, and engineering firms (including engineering, procurement, construction, architects and engineers (A&E), and T&D consultants), and these discussions inform the analyses shared here. Specifically, the consensus views of this mix of sources had yielded insights that have led Newton-Evans to develop updated estimates and forecasts of smart grid-related expenditures by electric power utilities.

Newton-Evans Research's findings suggest a slowdown in growth of smart grid-related spending from the outlook we had developed in 2012 for the first edition of this book. Reasons for the slowdown in capital investments in smart grid programs include depletion of the ARRA program funding of $4.5 billion, sluggish economic growth in both advanced and developing countries, and anemic growth in electricity consumption, delaying some power construction projects in Western nations. Nonetheless, smart grid investments continue to outpace many other areas of the modern electric power industry.

At the global level, 2011 is noted in Table 25.1 as the year in which the "basket" of smart grid-related expenditures likely reached $10 billion for the first time. The expenditure estimates and projections found in Table 25.1 exclude internal utility spending ("soft dollar" expenditures) allocated for staff resources applied in both the developmental and operational stages of a smart grid project. Other costs not included in the table include the cost to construct and furnish operations control centers, ongoing O&M costs of operating and maintaining telecommunications networks, or post-installation costs of equipment and systems maintenance and diagnostic programs. Note the expectation in this table for the doubling of annual smart grid expenditures from 2008 to 2020. Over the entire span of this period, the total expenditures for this grouping of smart grid technology are forecasted to approach $160 billion.

Newton-Evans Research has found that several smart grid business opportunities will likely continue to flourish in the coming years, including:

- Increased use of "automated" or computer-assisted design tools
- Increased reliance on third-party smart grid technical consultancies
- Rapid growth in smart infrastructure equipment utilization
- Enhancement of physical security of substations, switchyards, and power-generating facilities
- Acceleration of cybersecurity investments into operational and enterprise OT/IT systems
- Market introduction of robust data analysis tools and systems (analytics)
- Advanced communications networks having greater bandwidth and lower latency, which serve as enablers for several smart grid components (such as phasor measurement implementations in transmission and for some distribution applications, metering data acquisition, and distribution automation)
- OT/IT convergence to better integrate and link utility operational technology with enterprise information technology
- Integration of renewable resources in the power generation mix and in the associated transmission and distribution of electricity
- Brownfield upgrades of generating stations, switchyards, and substations with gas-insulated technology taking hold in many application areas

Figure 25.5 provides one view of global smart grid and IT expenditures in 2020 and in 2025. Note the inclusion of "overlap" portions of administrative IT investments and certain operations IT investments as well as "pure" smart grid-related spending in the formulation of what may grow to become a $21 billion portion of the electric power industry by 2020, and perhaps $25 billion by 2025. If the world economy picks up steam, smart grid-related investments are likely to rise as well.

25.6.6 Technical Innovation

Significant advancements have been made in smart grid-related technology since the first edition of this book was published nearly 5 years ago. Some then-current challenges have been met and new areas of innovation have been identified and, in some cases, commercialized.

Though an inventory of recent innovation may be useful, all technology decisions and implementations—regarding either familiar or new technologies—should be governed by a holistic approach to grid modernization. The most fundamental development of the past 5 years has been in how to think about technology decisions and implementations, not necessarily the technology itself. A holistic approach encompasses a set of technology components integrated together to address the business needs of the utility. Technology innovation in itself is meaningless unless its implementation aligns with a utility's business drivers and is accompanied by business process and organizational changes that wring full value from the technology investment. Technology innovation is

TABLE 25.1
Global Spending for Major Components of Smart Grid, 2008–2020 (in Millions of U.S. Dollars)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
Control systems	$665.0	$630.0	$740.0	$830.0	$885.0	$945.0	$1,010.0	$1,050.0	$1,095.0	$1,165.0	$1,215.0	$1,250.0	$1,295.0	$12,775.0
Systems+ integration	$525.0	$495.0	$580.0	$650.0	$690.0	$740.0	$775.0	$800.0	$830.0	$880.0	$895.0	$910.0	$930.0	$9,700.0
Third-party Sw/Svcs/ maint	$140.0	$135.0	$160.0	$180.0	$195.0	$205.0	$235.0	$250.0	$265.0	$285.0	$320.0	$340.0	$365.0	$3,075.0
Outage management	**$90.0**	**$90.0**	**$98.0**	**$120.0**	**$145.0**	**$175.0**	**$190.0**	**$225.0**	**$245.0**	**$265.0**	**$280.0**	**$305.0**	**$325.0**	**$2,553.0**
Substation automation	**$1,900.0**	**$1,780.0**	**$1,885.0**	**$2,090.0**	**$2,220.0**	**$2,380.0**	**$2,560.0**	**$2,820.0**	**$2,890.0**	**$2,960.0**	**$3,120.0**	**$3,175.0**	**$3,265.0**	**$33,045.0**
SA programs	$300.0	$275.0	$290.0	$325.0	$355.0	$380.0	$475.0	$635.0	$645.0	$660.0	$675.0	$685.0	$715.0	$6,415.0
RTUs and 1EDs	$1,350.0	$1,280.0	$1,320.0	$1,455.0	$1,540.0	$1,645.0	$1,700.0	$1,760.0	$1,810.0	$1,850.0	$1,975.0	$2,010.0	$2,050.0	$21,745.0
Monitoring and diagnostics	$250.0	$225.0	$275.0	$310.0	$325.0	$355.0	$385.0	$425.0	$435.0	$450.0	$470.0	$480.0	$500.0	$4,885.0
AMI-AMR	**$2,150.0**	**$2,350.0**	**$2,610.0**	**$3,100.0**	**$3,350.0**	**$3,575.0**	**$3,800.0**	**$4,025.0**	**$3,950.0**	**$3,910.0**	**$3,870.0**	**$3,850.0**	**$3,870.0**	**$44,410.0**
Protection and control	**$1,750.0**	**$1,775.0**	**$1,900.0**	**$2,020.0**	**$2,065.0**	**$2,100.0**	**$2,125.0**	**$2,155.0**	**$2,180.0**	**$2,210.0**	**$2,255.0**	**$2,270.0**	**$2,295.0**	**$27,100.0**
Utility telecomms	**$510.0**	**$525.0**	**$545.0**	**$565.0**	**$590.0**	**$625.0**	**$660.0**	**$695.0**	**$710.0**	**$740.0**	**$785.0**	**$830.0**	**$865.0**	**$8,645.0**
Telecoms for control systems	$350.0	$345.0	$375.0	$380.0	$385.0	$400.0	$415.0	$430.0	$435.0	$450.0	$465.0	$485.0	$500.0	$5,415.0
Telecoms for AMI	$160.0	$180.0	$170.0	$185.0	$205.0	$225.0	$245.0	$265.0	$275.0	$290.0	$320.0	$345.0	$365.0	$3,230.0
Distribution automation	**$1,440.0**	**$1,600.0**	**$1,735.0**	**$1,940.0**	**$2,085.0**	**$2,365.0**	**$2,540.0**	**$2,765.0**	**$2,880.0**	**$2,960.0**	**$3,095.0**	**$3,195.0**	**$3,265.0**	**$31,865.0**
DA software and platforms	$125.0	$130.0	$145.0	$170.0	$195.0	$225.0	$260.0	$300.0	$335.0	$365.0	$400.0	$430.0	$445.0	$3,525.0
Smart distribution equipment	$1,125.0	$1,250.0	$1,325.0	$1,475.0	$1,550.0	$1,775.0	$1,900.0	$2,060.0	$2,130.0	$2,165.0	$2,250.0	$2,310.0	$2,350.0	$23,665.0
Telecoms for DA	$190.0	$220.0	$265.0	$295.0	$340.0	$365.0	$380.0	$405.0	$415.0	$430.0	$445.0	$455.0	$470.0	$4,675.0
Total	**$8,505.0**	**$8,750.0**	**$9,513.0**	**$10,665.0**	**$11,340.0**	**$12,165.0**	**$12,885.0**	**$13,735.0**	**$13,950.0**	**$14,210.0**	**$14,620.0**	**$14,875.0**	**$15,180.0**	**$160,393.0**

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Note: Bold titles are subtotals of any non-bold line items directly below.

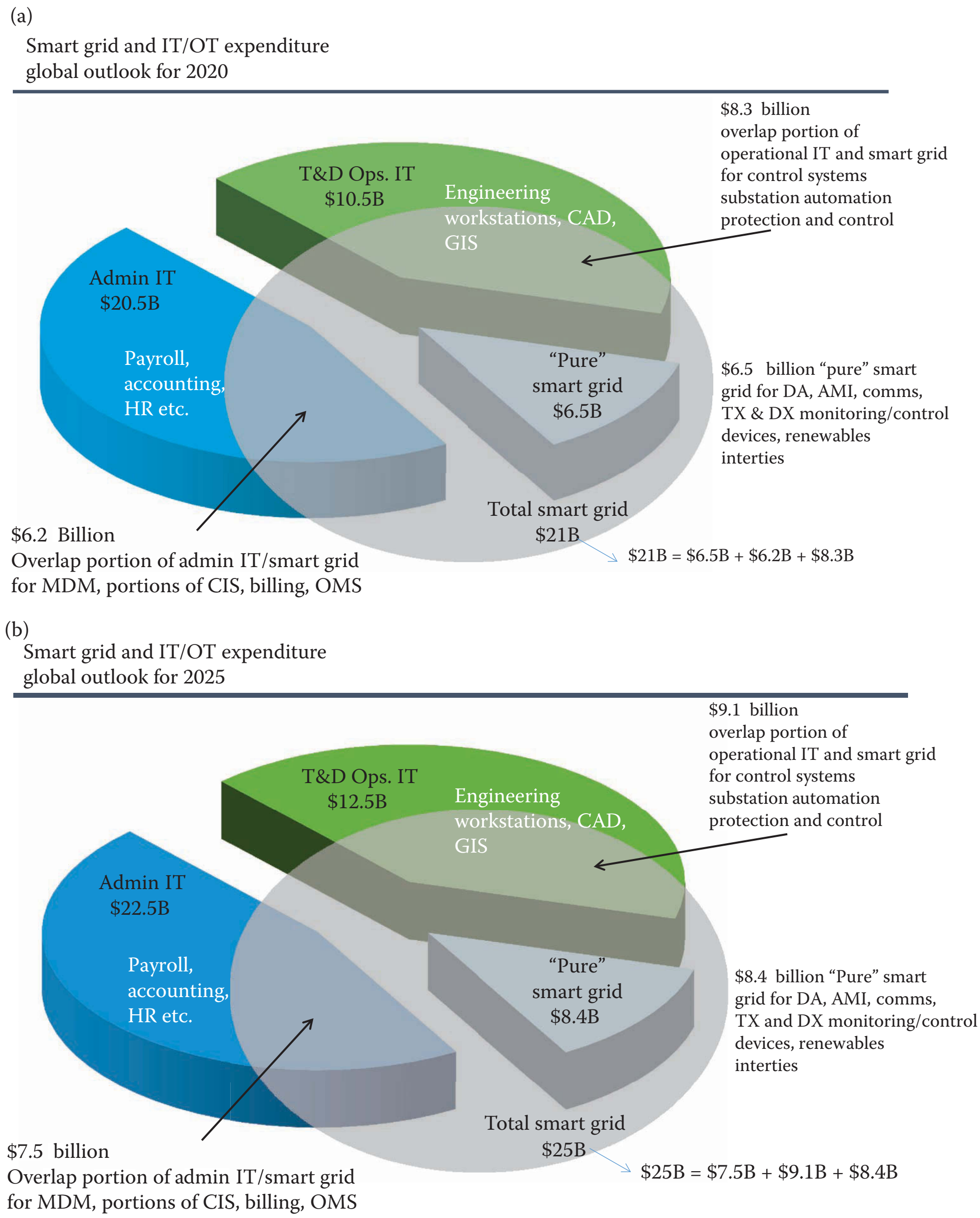

FIGURE 25.5 One view of global smart grid and IT expenditures in 2020 and in 2025. (© 2016 Newton-Evans Research Company. All rights reserved. With permission.)

constant and ever-changing, but in recent years the power industry has developed a better understanding of how to adapt to a landscape of constant change and manage that process [8].

To begin thinking in terms of holistic solutions, utility leadership should review their organization's business model in light of current and anticipated policy changes and incentives, growing consumer participation, disruptive market and technology forces, new emphases on sustainability, and shareholder and stakeholder concerns. This review includes taking stock of where a utility's technology stands today. A utility's technology foundation must be sound before innovations are introduced. One mantra serves here: Build a strong grid before building a smart grid.

As noted, current, near-, and mid-term business drivers should shape holistic solutions that include a technology roadmap. The vast majority of grids will be hybrids that integrate old and new technologies, and preserving the value of legacy equipment and preventing stranded assets call for thoughtful analysis. The process of integrating old and new technology inevitably requires a sea change in a utility's organizational culture and business processes. Simply put, a utility should make significant organizational and cultural changes before or in tandem with technology decisions to obtain the full value of such investments [4].

This theme of holistic solutions, which ties together the business, the organization, and the technology, runs throughout this section as we discuss the foundational grid, the smart grid, and current and near-term technology innovations. The following discussion covers both currently available innovations as well as innovations needed in the near- and mid-term.

25.6.6.1 The Foundation

The foundation of a "strong" grid comprises an information and communications technology (ICT) infrastructure that supports the functional requirements of current and future technology and application implementations. The foundation should be supported by an open information architecture based on industry standards. The creation of that foundation depends on—and may drive—the convergence and cooperation of personnel in IT and OT—two traditionally siloed domains. Cooperation between IT and OT is merely the first step in an organization-wide cultural shift toward inclusive, horizontal interactions among IT, operations, and enterprise groups in the utility that should precede and inform technology decisions and implementations.

IT and OT and the personnel that support them must be integrated to properly design and implement the strong grid foundation that will align with business drivers and enable smart grid technology implementations. The details of the IT/OT foundational architecture and technology are covered in prior chapters of this book. Suffice to say here, that foundation must support a communications infrastructure with the response requirements, bandwidth, and latency metrics to meet all automation needs [9]. In most cases, a utility's communication infrastructure is a hybrid of communications technologies and protocols across the grid and that arrangement must be analyzed to ensure that it seamlessly supports current and future automation needs.

25.6.6.2 Exploiting Operational and Nonoperational Data

A strong grid foundation will also enable a utility to realize the full value of its investments in IEDs. One of the fundamental areas of innovation over the past 5 years has been the integration of IEDs with nearly every device in the distribution system. This is relevant because IEDs produce both a constant stream of operational data and an array of nonoperational data sources that have great value to various business groups within the utility. Operational data have been a traditional staple of SCADA monitoring and control schemes. Nonoperational data have immense but still largely untapped value to the enterprise. With a strong ICT foundation, nonoperational data must be collected, concentrated, routed across the operations firewalls, processed, and made available to stakeholders on-demand on the corporate network, in a presentation format or dashboard that suits their purposes.

Because IEDs produce both types of high-value data, no individual operations or enterprise group within a utility should be allowed to purchase technology without an organization-wide review of the potential needs of, and benefits to, all stakeholders. Every technology purchase and implementation must be viewed from the perspective of a holistic strategy to maximize IED benefits and ROI. Simply approaching the acquisition of new technology should trigger a flattening of a utility's organizational structure and the mapping of operational and, especially, nonoperational data to all internal stakeholders for value creation. It is estimated that failure to exploit the value of nonoperational data from IEDs leaves perhaps 70%–80% of an IED's value on the table. With hundreds of IEDs, each costing $5,000 to $10,000 and producing immensely valuable nonoperational data, such a lost opportunity should be unacceptable. Thus, technology innovation and implementation and utility cultural change go hand-in-hand [10].

Ignoring a holistic approach to technology innovation and implementation can have costly consequences in terms of money, time, and lost opportunities. For instance, utilities that implemented smart meters and AMI without considering and integrating the future requirements of distribution automation have been faced with expensive, laborious, inefficient workarounds. Conversely, cooperation between a utility's metering group and its distribution engineering group in this integration opportunity can avoid duplicative efforts and unlock the value in both systems [11].

The implementation of multifunctional IEDs may also lead to organizational and staffing changes. As more, formerly disparate functionalities are combined within each IED, the need for new skill sets arises and former organizational distinctions may blur. For instance, the integration of communications, protection, and RTU functionalities in a single IED may require a shift from having three separate departments to the need for a "super-IED specialist."

25.6.6.3 Managing Big Data

As IEDs proliferate—their functionality is increasing and costs decreasing—and add intelligence to the grid, a utility must manage the resulting onslaught of data. Though the production and use of operational data are somewhat static at this point, the current trend toward adding phasor measurement units (PMUs) on the distribution system adds a new challenge. And this step allows a utility to run a state estimation application at the distribution substation level rather than using that app only on an energy management system (EMS) in the control center for generation and transmission visibility [12]. Instead of SCADA-like data whose frequency is in the 2–4 s range, PMUs produce data with a frequency measured in fractions of a second, and this granularity improves visibility. How this improved visibility at the distribution substation can benefit a utility remains an area ripe for advanced analytics and technology innovation.

The more impactful technology innovation in this area is the development of IEDs and their diverse and increasing ability to output valuable nonoperational data. One challenge lies in the cultural shift that would aid in data management and subsequent value creation—holistic data management practices, which often require utility leadership and a third-party catalyst/consultant to manage the process. If technology implementation is challenging, cultural shifts in an organization demand even greater effort [13].

A few points on forward-looking, holistic data management practices are appropriate here. Different types of data must be managed differently. Operational data are routinely routed to the control center, archived, and presented to operators to inform real-time decisions. A subset of operational data is also sent across the operations firewalls for querying and data mining by business units to augment their analysis of nonoperational data. Nonoperational data produce the most value when it is routed across the operations firewalls to an enterprise data mart for processing and on-demand availability to business groups for value creation.

The process of creating a data mart begins with the end user/stakeholder and his/her data needs to create a data requirements matrix, which also documents the frequency, accuracy, formatting, and timeliness needed for each data point. All data-producing devices are inventoried and their outputs mapped to the stakeholders who can benefit and create value from specific data sources. Both operational and nonoperational data can then be routed in the most efficient manner to a data warehouse, which houses, processes, and makes data sets available for third-party applications for processing and presentation. Strict authentication and access controls are used to ensure that only the right people get the right data at the right time. Dashboards and other presentation media can be designed to present useful outputs to end users [14].

Commonwealth Edison (ComEd) was an early adopter of nonoperational data to rationalize operations and maintenance work in an approach commonly referred to as "condition-based asset management," and that program informed a carefully prioritized capital investment plan—a good example of value creation from nonoperational data.

ComEd wisely articulated success factors at the inception of its project a decade ago. Data management and analytics and new technology had to "reduce system stress, enhance security, reduce costs and improve reliability." The utility also decided that grid analytics should yield insights into an optimal operational philosophy, determine whether a new application would scale from pilot project to service territory, possess a positive business case, show customer value, and improve service reliability. These disciplined metrics and requirements appear to have contributed to realizing ComEd's goal to use electricity more efficiently, improve system reliability, strengthen system infrastructure, and drive regional economic development. And ComEd's success in condition-based asset management has put it in the vanguard of such efforts nationwide [15].

25.6.6.4 Managing the Hybrid Grid

These points on the addition of IEDs and managing disparate data flows underscore the need to effectively manage a hybrid grid as technology innovations become available and are integrated with legacy infrastructure.

Upgrading legacy distribution system equipment provides an opportunity to capture more value from the resulting, hybrid configuration, although a new data network architecture may be needed. In the case of a distribution substation's automation gear, the integration of IEDs with an existing array of RTUs—both in the substation and downstream on distribution feeders—can create more value than either set of devices running alone.

To realize that added value, a utility should assess which applications will run at the substation level for optimal operation of the substation and downstream, distribution feeders, and which applications will run at the control center or within the enterprise. At first, IEDs were simply integrated with legacy RTUs, but that arrangement failed to deliver full value. The development of a family of products referred to as data concentrators, however, enabled the collection and routing of nonoperational data from IEDs to the enterprise, the key to fuller value.

A transition from an RTU-centric arrangement to a distributed network architecture with IEDs and data concentrators offers far greater value than a legacy, serial, point-to-point communications-based architecture. With a distributed network architecture, legacy RTUs perform as an IED until they can no longer be maintained.

Standards have created an opportunity to move from proprietary architectures and equipment to an open architecture that supports further technology innovation. IEC 61850—a global standard for substation automation communications—provides the benefit of standard variable nomenclature instead of the unique variable nomenclature typically employed by individual vendors, which unfortunately is endemic to legacy systems. Standards also apply to data extraction, concentration, and storage, which provide much of the value of automation to grid operators. The standards efforts of the past 5 years include supporting the backward compatibility of IEDs and continued use of legacy RTUs as automation is improved.

Developing a new distributed network architecture with IEDs and data concentrators will yield high value by delivering operational and nonoperational data to enterprise business groups. This improves ROI for IEDs, requires IT/OT cooperation, and produces enterprise-wide value to the utility. The integration of new technologies with legacy systems in the manner described, particularly in substation automation, will result in significant value creation by business groups, in addition to the expected operational benefits [4].

Optimal integration of key distribution system components, programs, and applications is the key to unlocking value, containing costs, improving resiliency, and supporting new technology innovations.

A holistic DA system comprises five main components, including smart meters, AMI, an OMS, an advanced distribution management system (ADMS), and a GIS. Properly integrated, these five components create value greater than their sum. A DA application runs on the SCADA platform, enabling a suite of distribution software applications, such as fault detection, isolation, and restoration (FDIR), integrated Volt/VAr control (IVVC), optimal feeder reconfiguration, and distribution power analysis. The SCADA platform and the suite of applications running on it comprise the ADMS.

Smart meters and AMI provide not only usage and billing data but also premise-level voltage readings and a "last gasp" signal reflecting an outage. An OMS hosts the network model (populated by GIS data on utility assets and their geographic location), which provides operators with the specific locations of affected customers. An ADMS, supplied by meter data, addresses voltage and VArs.

One advanced application that resides on the ADMS is FDIR, whose logic can be centralized at the operations center, substation-based, or peer-to-peer among IEDs residing on feeders. The application's logic must first be tested and approved by an operator but, eventually, it is automated to increase the speed of restoration. Obviously, whether on "blue sky" days or in a storm, automation provides the speed to improve a utility's reliability performance as measured by the SAIDI and SAIFI indices [6].

The topic of FDIR underscores an important, developing technology innovation: how power electronics-based components are likely to replace electromechanical functions, as illustrated at SDG&E and APS in recent years [3]. The driver—policy incentives that encourage residential, rooftop solar PV—led in both cases to relatively high penetration of renewables (up to 35%) on specific distribution system feeders. That led to voltage volatility at certain times of day as intermittent PV generation injected onto the grid rose and fell and midday loads were low. While this voltage volatility may eventually occur at many utilities not yet experiencing high rooftop solar PV uptake, it's possible that such volatility is taking place at utilities that simply aren't examining feeder voltage data in highly granular form and remain unaware of the issue.

The load tap changers (LTCs) designed to cope with such volatility were designed to operate perhaps five times per day. The voltage volatility introduced by high penetration of rooftop solar PV at SDG&E and APS, however, caused LTCs at both utilities to operate up to 90 or 100 times per day, reducing their life expectancy from decades to perhaps 5–10 years.

Challenges such as those experienced by SDG&E and APS have led to the ongoing development of power electronics-based LTCs for distribution networks, as well as smart inverters for solar PV arrays and microgrids, and dynamic low-voltage network grid-edge controllers for DER integration. Power electronics can use distributed intelligence to assess more variables in power quality on distribution feeders and calibrate a device's response to minimize automated, mechanical actions. Power electronics also react in exponentially more rapid time frames than electromechanical devices, which may simply shut down from excess operation, for example, in response to voltage volatility.

The efficacy of this approach is likely to expand the market for power electronics-equipped components, reducing costs through standards and, thus, economies of scale. As we've documented, the challenge is real and likely to impact more utilities over time. The efficacy of power electronics in different distribution substation components and elsewhere also underscores why the power industry should more closely integrate the currently separate disciplines of power electronics and power system automation. This area, today, is virtually a green field in technology innovation.

25.6.6.5 Microgrids: Valuable Utility Tools

Microgrids have moved into the utility toolkit in recent years, though they were originally viewed as a means to grid independence by military installations, university and corporate campuses, schools and hospitals. The trend toward mainstreaming microgrids by utilities has gained momentum since the first edition of this book.

For instance, in the aftermath of Hurricane Irene and a freak winter storm in fall 2011, the state of Connecticut studied microgrids as a means of increasing power reliability and resilience, and it created a state-sponsored, ongoing loan program for both private and public (utility) microgrids. After Hurricane Sandy struck the northeastern USA in 2012, microgrids got a fresh look by the northeastern states and IOUs and municipal utilities seeking power reliability and resilience. In 2013, Minnesota studied microgrids' potential role in energy assurance, a policy pillar of the state's approach to a sustainable economy.

Utilities have piloted and applied the use of microgrids for several reasons: as a means to integrate and manage intermittent renewables, as a means to provide grid resiliency on problematic feeders, and even as a means to divide the central grid into microgrid-controlled sectors, like a honeycomb, for reliability and resilience.

Other developments have added to this momentum. The evolution of standards such as IEEE 1547–Standard for Interconnecting Distributed Resources with Electric Power Systems—has softened utility concerns about how microgrids potentially affect the central grid, enabled by the development of power electronics-aided smart inverters. The emergence of results-based regulation is contributing to policy shifts that will also encourage the adoption of microgrids by utilities [16].

One of the major technology innovations enabling utility microgrid deployments is the utility's increasing ability to manage how microgrids connect with the main grid via a local substation and the utility DMS. From a control center point of view, a utility can manage the entire grid holistically, while optimizing operations at the substation level and downstream using a self-contained microgrid. The means to do so is a topology processor, an application running on the DMS, which can take into account microgrids that are either connected or islanded. The topology processor encompasses a three-phase load-flow program, which can analyze power system conditions just for one microgrid, a series of microgrids, or the whole grid.

The emergence of ADMS applications to enable utilities to manage microgrids is a major enhancement over past practices. Managing the dynamics of generation and transmission has been simpler from a SCADA point of view, because generation and large transmission substations have a plethora of data-producing "points" to inform their management.

In contrast, a distribution system has many more substations, but each substation has fewer "points," producing less data for management purposes. Downstream of substations, on the feeders, a number of switch and capacitor locations need to be tracked, and each has status, analog, and control points. Compared to managing generation and transmission, the number of substations in a distribution system makes the latter an exponentially greater (more than 10×) challenge.

So, an ADMS can analyze and optimize, but it needs a certain amount of information from the field, from substations and feeders and IEDs along those feeders. And ADMS analysis is done on a full, three-phase, unbalanced basis—an added complexity. (With generation and transmission we assume a three-phase, balanced power system; so, typically, we perform only a simpler, single-phase analysis.)

In sum, an ADMS and its applications still face challenges in providing optimal management functions, and this is an area of technology innovation today. Consider the system being analyzed: It has many small, geographically dispersed loads (single- and three-phase). Typically, real-time data on each of those small loads is not available. A load estimation tool can be applied to determine existing, available measurement points and how those data points can be processed by an allocation-type algorithm to produce a good estimate of load values across the system. With dynamic microgrids and intermittent DER, in addition to relatively static loads, it's a significant challenge to assess and manage a low-voltage network.

25.6.6.6 Automation and Alarm Filtering

Another area in need of technology innovation is "intelligent alarm filtering" in the SCADA and substation automation systems. Though alarm-filtering software is available for SCADA (EMS and DMS) and substation automation systems, improvements are still needed [17].

Originally, the SCADA approach sent field data to operators, who had to determine which alarms were important and which could be safely ignored. With the advent of automation, a transient fault—say, a tree branch touching a feeder line—might result in several alarms where none need to be sent to the operator, as the fault was temporary and an automated recloser did its job. In the case of major storms, operators are often overwhelmed by the frequency and scale of alarms, hindering an effective response.

Prioritizing, filtering, and suppressing alarms that don't require immediate attention will support better decision-making by eliminating distractions. This is true because one alarm often represents several other secondary alarms, which are irrelevant functions of the first alarm. For instance, if a feeder breaker in a distribution substation trips, seven alarms could be issued. One alarm is the status change on the breaker—and that's all that's necessary. An operator doesn't need the confusion of seeing three low-voltage alarms (one for each phase) and three low-current alarms (one for each phase). The latter secondary alarms can be routed to an archive for later evaluation.

Readers can expect to see improved alarm-filtering applications on the market in the near- and mid-term future.

25.6.6.7 Integrating Social Media

Customer engagement—indeed, consumer engagement—is likely to shape future utility practices and business models. If utilities embrace it, that engagement can be put to practical use for improving system reliability and resiliency, among other things.

Consider the trends under way. In a 2014 GE survey in the USA, 70% of utility customers said that social media is their preferred means of communicating with their utility. By 2020, "millennials"—a demographic group that no longer relies on landline phones—over the age of 25 will make up 20% of the U.S. population and will be responsible for 30% of retail purchases [18]. So, utilities' current reliance on landline phones for customer phone calls to report outages, which connect phone numbers to physical addresses in the customer record, is nearly obsolete.

The technology innovation here is recently commercialized software that enables a utility to tie a customer "handle" from their Twitter account to that customer's record and physical address. (In fact, the entire household's Twitter accounts can be so connected.) This means that the customer doesn't need to be home to report an outage. And newly developed software can analyze tweets for input into an OMS, creating a more rapid sense of an outage's location and, possibly, its cause [19].

Increasingly, utilities may also use images from customers' GPS-enabled smartphone cameras of grid damage, which will provide visual information on which to base field crew dispatching.

It has been well established by Smart Energy Consumer Collaborative (SECC) surveys that customer involvement improves customer satisfaction. Utility incentives could boost customer participation in programs that tie their social media information to their customer record. A utility can point to larger customer benefits for their involvement: faster service restoration. The utility, in turn, benefits from improved reliability indices and more satisfied customers. Once engaged in this manner, utility customers may be more likely to participate in other utility programs, such as demand response.

The current and potential future roles of the customer/consumer are explored at length in Section 25.2.

25.6.7 Policy and Regulatory Priorities and the Role of Electricity Markets

Fundamental shifts in technology and market forces have accelerated since the first edition of this book was published nearly 5 years ago. Smart grid-related and consumer-facing technologies have rapidly gained in functionality and efficiency while, in many instances, costs have dropped. The term demand-side management (DSM) is being replaced with DERs, which include energy efficiency (EE), demand response (DR), distributed generation, storage, and strategic charging of electric vehicles. At the same time, the landscape has dramatically changed as a result of two forces: (1) the economic rationale for DERs is being better understood, and (2) a global embrace of environmental values, largely by a consensus to reduce greenhouse gas (GHG) emissions.

Though policy is often the driver of technology uptake—for example, California's incentives for efficient flat screen TVs—the speed of technology innovation and simple economics now appear to be outpacing policy development. Though a generalization, by 2017 and beyond, in many regions policy is expected to play catch-up with market forces. First-hand experience in 40 countries suggests that the two main drivers of power-related policy and practices today are the economics that enable a focus on DERs in the near-term—to achieve an optimized, integrated, distributed energy paradigm—and global efforts to reduce GHG emissions [20].

25.6.7.1 Changes in Supply and Demand

On the supply side, the use of coal—based on its end-to-end cost of extraction, transportation, and combustion, initially due to its environmental and public health impacts—is decreasing. Less expensive, less impactful fuels, such as natural gas and renewable energy are replacing it. Fewer coal-burning generators are being built; many are converting to natural gas. New natural gas generators are being built, and renewable energy from sun and wind, in particular, is reaching cost parity with fossil fuels. Though nuclear power offers a low-emissions fossil fuel source, siting, nuclear waste storage, and cost considerations have largely pushed nuclear power projects out of the picture or to developing countries. Even the International Atomic Energy Agency has forecasted (in September 2013) that nuclear power will increase globally by only 1.2% per year out to 2030 [21].

On the demand side, DERs have become economically attractive, capital and operationally efficient alternatives to building out traditional, central station generation and, more recently, building out distribution assets. In many utility grids, opportunities abound to match supply—to defer generation, transmission, and distribution—by managing packages of DERs. Several factors provide momentum to this shift in emphasis. The benefits of DERs are being recognized for their relatively high impact and low cost. DER efficiencies are increasing while costs fall, most notably for solar PV panels and storage batteries. Technology developments that enable DERs include the availability of system-wide and AMI data, and the increasing capabilities of data analytics, software, computational resources, and distributed controls. DERs can be installed incrementally, such as at the true “grid-edge” in commercial buildings, while large central station, transmission, and distribution assets are “lumpy” investments [22]. Packages of DSM/DERs now look to be especially potent to defer traditional generation and distribution resources. Policies, standards, and economies of scale and scope are enabling factors in such scenarios [23].

25.6.7.2 Policy Shifts

In many, if not most, regions of the world, the speed of innovation, the spread of mindshare, and the pressures of unregulated market forces are increasingly outstripping the ability of policymakers to keep pace. Policy expertise has been siloed, like the respective DER technologies themselves, largely as regulatory and utility organizations have used separate proceedings and separate organizations to develop these technologies. Perhaps, not surprisingly, energy efficiency experts do not work with solar experts. DR experts are only recently beginning to work with storage battery experts. Now far greater benefits can be realized with integrated and optimized technologies, using systems thinking, to construct packages of smart resources at locations and between locations, particularly to defer the addition or upgrade of traditional distribution assets. Perhaps the most potent driver of change in this combined policy and technical arena is the rise in importance of the consumer—in traditional economics, the driver of markets—and the resulting moves in the electricity sector to enable a prosumer, market-oriented approach.

Many countries are moving swiftly to enact or embrace clean energy policies—officially, ad hoc, or by simple consensus—that promote DERs. India, for instance, is placing greater emphasis on microgrids and DERs, largely to leverage distributed solar PV and wind power. This shift has obvious advantages with the linkage of supply and load in the same proximity. This can virtually eliminate the capital and operational costs to build and maintain an extensive high-voltage transmission and lower-voltage distribution infrastructure. India’s approach exemplifies the many challenges and opportunities that abound for developing nations. Undoubtedly developing nations face challenges to amass capital and extend new grids reliably, given the demands for sustainable electric power by urban and rural populations. Distributed systems, however, can provide the comforts and economic prosperity that electricity offers, particularly with integrated packages of DERs.

New, commercially available DER-based solutions enable less-developed regions to “leapfrog” past the buildout of traditional electricity infrastructure maintained by developed nations. Distributed systems can be more economical, particularly—though applied differently—in dense urban settings and in dispersed rural settings. Conversely, developed nations face the inertia of past and now outdated regulatory and economic practices in power development. These traditional practices present major challenges, costs to upgrade legacy systems, and the potential for stranded assets, especially as DER costs continue to decline. In light of these trends, the respective approaches to energy challenges will drive national, regional, and local policy, and, of course, future outcomes.

This generalized view, of course, remains nuanced. Developing nations’ policies are driving grid modernization and, in places, provide forward-looking, market-based practices. Based on best practices, the use of local centers of innovation brings major new improvements. Developed nations need not simply struggle with updating legacy electricity infrastructure. In many locations, both economic and policy drivers will move to more rapidly support DERs to enable integrated, optimized solutions.

Most consumers in developed nations—small- and medium-sized enterprises (SMEs), the C&I sector and large corporations—are digitally savvy and exposed to third-party DERs that make economic and environmental sense. Many consumers and SMEs seek greater control over energy costs by implementing smart thermostats, solar PV, and a host of other clean energy options. C&I businesses that have long participated in dynamic rates and DR now are adopting microgrids and solar PV to supplement reliability and manage energy costs. Large corporations, focused on expanding their profit margins and attracted by the cachet of environmental responsibility, see the economic and social advantages of managing a sustainable energy future, embracing DERs by design and through advanced building controls. The global Internet of Things (IoT) sector, as it expands to support a more digital society and economy, is also actively addressing the need to manage its energy consumption. “Green IoT” has become a major area for research, development, and demonstration [24].

The juxtaposition of electricity challenges and opportunities in both developed and developing nations is creating further local synergies. Multinational corporations, entrepreneurs, philanthropic and nongovernmental organizations (NGOs) in all realms are pursuing the profit and the common good that arise from mindshare and technology transfer in the private and public sectors. Innovative applications now grow separate DER areas, but even more emphasis is being placed on integrated, optimized solutions and practices. Developing nations are eager to pursue opportunities to leapfrog traditional and siloed electricity solutions.

25.6.7.3 Developments in the USA

Policies and technology developments enable new market forces that, in turn, influence new policies, particularly to grapple with the speed of innovation and markets. Developments in the USA illustrate this dynamic. As noted at the beginning of this chapter, federal policy in the USA has established support for grid modernization. At the wholesale level, EISA 2007 Title XIII directed FERC to not only support the implementation of advanced technologies but also support policies that enable DERs, dynamic rates, and other distributed services and capabilities, including vehicle-to-grid (V2G). EISA 2007 Title XIII also required the National Institute of Standards and Technology (NIST) and other stakeholders to develop an interoperability framework that would enable transmission and distribution utilities and systems and consumers to interact in market-based transactions. These policies, in turn, support the use of “transactive energy” market models. This federal legislation further directed states to consider the cost-effectiveness, reliability improvements, security, system performance, and societal benefits of utilities investing in smart grid technology in lieu of traditional technology.

Since that time, and the publication of the first edition of this book, FERC has issued Rule 745, which required transmission organizations—independent system operators (ISOs) and regional transmission organizations (RTOs)—under federal jurisdiction to provide equal access to both traditional and nontraditional generation resources, including those enabled by DERs, and require supply and demand resources to be considered comparably. The Electric Power Supply Association (EPSA), on behalf of its traditional generation membership, initiated court action to block FERC Rule 745 based on the Federal Power Act (FPA). In 2016, the U.S. Supreme Court ruled to support FERC's authority under the FPA, to establish "nondiscriminatory open access" policies, ensure "comparability" of supply-side and demand-side resources, and use retail DR to enhance grid reliability and security [25].

ISOs and RTOs have approached implementation of DER policies differently. In general, except during this recent U.S. Supreme Court controversy, the use of DERs at the bulk-grid level—particularly DR—has been encouraged. The results have been to capture market benefits on the bulk grid by avoiding or deferring the need for energy (at locational marginal pricings or LMPs), operating reserves, frequency regulation, and other ancillary services.

25.6.7.4 State-Level Policy-Making

Looking forward, these policy and technology trends provide strong support for future policymakers at the state level. These trends also forebode major issues for states less inclined to support these policies. A related controversy has been customer privacy protection. Still, in some states, customer energy data are made available by customers to their designated third-party service providers. AMI costs for new smart meters and the related business case justification have been controversial as well. As a result, some state policymakers have been slow to support or require AMI at the retail level. Other states, such as Texas and California, have gone full-bore with the use of customer-facing AMI capabilities, including dynamic rates. Some states even seem interested to test "transactive energy" markets. New York, a sudden convert to AMI, sees the extraordinary benefits that can come with integration and optimization of DERs, enabled by advanced customer AMI data.

Efforts are under way in several states to create policies that drive or support new utility business models in the face of unregulated third-party service providers that appeal to consumers' desire for energy self-sufficiency and cost management. Significant momentum is gathering in several U.S. states, such as California, New York, Minnesota, Massachusetts, and Hawaii, to provide a policy basis for shifting to a more optimized and integrated DER-based distributed power system, with possible shareholder incentives to encourage utilities to install DERs. An overarching goal is to enable consumers and transactive energy markets that unlock maximum value. The ultimate goal is to gain alignment across three major value buckets: consumers, the distribution system, and the bulk-grid (high-voltage transmission and generation systems). California, New York, and Hawaii are leading these related, multifaceted, policymaking, and market-leveraging endeavors.

25.6.7.5 New York and California

A synopsis of the New York REV (Reforming the Energy Vision) program appears later in this chapter under Section 25.2. One brief paraphrase from that synopsis will serve here: REV seeks to boost reliability, resiliency, and energy efficiency by supporting customer empowerment, DR, and clean, distributed generation in a comprehensive strategy … resulting in a consumer-centric approach to energy provisioning that will include consumer participation in the market and encourage load management opportunities such as DR and distributed generation. The goal is to bring massive, systemic efficiencies to the electricity market.

In California, a more selective experiment is called the Demand Response Auction Mechanism (DRAM), in which third parties procure and price DR capacity for bulk-grid reliability, using new click-through methods to automatically register customers and obtain billing data. The DRAM allows third-party DR providers to package demand-side services and be paid as-bid prices for peak load reduction delivered year ahead. California has proposed that the DRAM approach be used much more broadly for a set of DR needs [26].

More broadly, a Distribution Resource Planning approach is also used that relies on load-flow analysis to define DER hosting at specific locations on the grid, a process called Integrated Capacity Analysis (ICA). The economics of planned DERs at the distribution level are further shaped by Locational Net Benefits Analysis (LNBA) and procured by third parties in a Competitive Solicitation Framework [27]. A next step, not yet fully achieved, is to provide dispatch for DERs consistent with distribution operations. Pilot and demonstration projects are being pursued for DRAM, ICA, and LNBA. It has been estimated that 2× to 5× greater benefits are available from DERs targeted to specific customers as a result of the integration and optimization that can be enabled by ICA, LNBA, competitive solicitation, and distributed dispatch [28].

As a result, the old utility business model that relied on volumetric sales of kWh and a "reasonable return" on prudent infrastructure investment is being supplanted by new frameworks that encourage higher levels of performance, greater efficiency in resource investment and use, competition among third-party providers, and use of consumer-driven market forces. There is increasing urgency in current and future situations as unregulated market pressures on regulated utilities grow stronger, approaching disruptive proportions, largely as a result of third-party service providers.

Simply put, third-party providers are aggregating EE, DER, and DR by soliciting individual utility customers and providing these resources in wholesale, distributed, and retail energy markets. Other third parties are offering packages of solar PV and batteries for consumer self-sufficiency. Both trends cut reliance on utility-delivered kWhs and, thus, on fixed and volumetric utility cost recovery. As investment in distributed resources comes to far outweigh centralized power infrastructure, utilities may be precluded from earning rates of return on infrastructure investment.

25.6.7.6 Shareholder Incentives for Distributed Energy

The pressure is on policymakers and utilities to shape the latters' future while it's still possible to proactively do so and before third-party disruption forecloses the remaining options. In light of this pressure, "dashboard indicators" and other utility shareholder incentives are being proposed. Utilities will need policy support to make this transition and implement workable policy solutions [29]. In a May 2015 address at an "Advanced Workshop in Regulation and Competition" at Rutgers University, Eric Woychik made the following points.

"Analytics and valuation show, for example, how and where demand side management (DSM) and distributed energy resources (DER) can defer more costly utility assets. With more granular data, new models show how to construct best practice utility solutions, and operationalize what otherwise are third-party service provider threats…"

"Of most concern are threats that customers will go 'off-grid' (e.g., EV charger+battery, or rooftop PV+battery solutions). These threats further highlight the gaps in analytic understanding and in the dialog about what utility business models are needed to manage risk and reward…" [30].

"Huge efficiency gains are now possible with customer and locational targeting, right-sizing of resources, and orchestration of the virtual clean energy system. Over time, distributed optimization seems likely to replace traditional utility distribution, transmission, and generation investments. Choreographed locational benefits can be 2× to 5× greater [than previously anticipated]. Customer pull and smart technology push will make this the dominant business model, largely because massive benefits can be found while greening the planet. The race then is to further incentivize utilities, engage the customer, demonstrate the huge benefits available, and transform the industry. A 2030 vision for 100% clean energy certainly seems within reach in many places" [29].

Thus, state-level policy making in the USA is increasingly likely to seek to enable and support new, performance-based utility business models that reward utilities for empowering consumers and markets, while enabling and supporting more distributed resources for reliability, resiliency, as well as operational and economic efficiencies [31].

25.6.7.7 New Tools, Models, and Methods

To do so, as noted, policymakers and utilities will need enhanced tools, models, methods, and refined goals. Five features, in particular, are likely to be addressed by state public utility commissions (PUCs) moving forward:

- LNBA
- Transactive energy markets
- Scope/scale benefits for DERs
- New shareholder incentives
- Dashboards

Of note, LNBA is the method, along with software modeling capabilities, which defines the "stacked value" in layers of locational marginal cost. Moreover, LNBA allows utilities to integrate the three value buckets of consumer benefits, distribution system benefits and transmission, and bulk grid benefits. LNBA provides the analytics to define where investments across the distribution and transmission systems will yield the greatest system-wide value and, conversely, where that value is limited or nonexistent. LNBA, therefore, provides new visibility into an active electricity market, which heretofore has been opaque. This tool can provide granular, house-by-house analyses to determine the most economically beneficial DER package that would work best over a defined time frame—whether sponsored by utility, third party, or customer. And LNBA can provide data on optimizing its operations and dispatch into the market. This tool can effectively defer capital investments, optimize and integrate DER, manage load profiles, and meet customers' needs.

An extension of the LNBA is being widely discussed as part of transactive energy markets. These markets present opportunities to purchase and sell DER packages at specific locations on the grid as long-term investments, and have these DER resources optimally dispatched in near real time. Transactive energy markets could make a standard practice of DER integration and optimization, both for longer- and shorter-term investments. Peer-to-peer transactions between customers and DER providers would be priced and dispatched at the local level, to further enable direct tradeoffs with the bulk-grid. Customers who want greater amounts of renewable and DER use can make that happen. Neighbors would sometimes contract with each other. Resolving the grid transportation costs for these local transactions will be critical to their enablement, especially if they interface directly with the bulk grid. Another critical need is to create a system for the financial settlement of each transaction.

Scope and scale benefits are also available through the integration of utility assets and third-party DER providers that bring innovation at the speed of the market. Utilities can capture major economies where scope and scale benefits are derived, largely through use of big data, coordination of distribution assets, and operations to achieve the more fully integrated and optimized, distributed resource vision. To reduce capital costs in distribution and DER energy transportation, the virtual demand-side power plant can be planned for, designed, and choreographed for optimal operations. The benefits of scope and scale come from the ability to use distribution, customer loads, the bulk grid, and DERs together, right-sizing of each of the components, joint communications, monitoring and control, and optimizing both the investment and operations, as well as maintenance. Locational granularity is a major source of efficiency gains, which requires best-practices integration of third-party DER and smart grid resource providers [32].

In order to move forward with these innovations, utility shareholder incentives are needed. Currently, shareholder incentives rely on rate-base—the undepreciated capital assets times authorized rate-of-return. This approach requires transformation. Rate-base rate-of-return regulation has been used for nearly a century.

Compelled by new technologies, the changes requested by policymakers now dramatically alter the duties and responsibilities assigned to the utility, suggesting changes in compensation are needed. DSM/DER bode to usher in the use of less capital intensive resources, which defer the need for highly capital-intensive generation, transmission, and distribution investments. At present utilities have few incentives to invest in DERs but for needs to satisfice regulators and legislatures. The lack of management incentive then diminishes the company desire to support and provide DERs.

"The California Public Utilities Commission (CPUC) has initiated a proceeding, Integrated Demand Response Energy Resources, Rulemaking 15-10-003, to integrate the separate, siloed features of the industry, notably DERs, rate-making, rate design, and the supply-side. It explains seven relevant problems in the industry, as follows:

1. *Current efforts are not forward looking:* Integrated demand-side resource policies and incentives must meet tomorrow's customer and system needs.
2. *Current efforts are too focused on rate-based versus performance-based:* The existing regulatory framework rewards utilities for installing traditional infrastructure … a disincentive for utilities to acquire DSM.
3. *Demand-side resources do not adequately impact system planning, investments, and operations:* Currently DSM and DER are only partially considered when planning generation, transmission … distribution infrastructure [and] system operations… Demand-side resources must be integrated into system planning and operations for their full value to be properly assessed and captured.
4. *Current efforts do not address grid needs:* DSM policies and incentives do not align with the needs of transmission and distribution system operators. The integration of DSM should resolve problems for the grid and, ideally, reduce grid revenue requirements.
5. *Lack of access to data:* Third-parties are limited in their ability to identify and serve customers because they lack the data needed to understand where the electric system needs demand-side solutions, which integrated or demand side service can provide those solutions, and which customers are eligible and should be targeted.
6. *Integration is divorced from rate-making:* Rate design for customers has not been coordinated with integrated DSM policies, limiting the motivation a customer has to take action. If customers have the right economic signals, they will be better motivated to take the right integrated actions.
7. *Market failure of revenue streams:* A party who invests in demand-side resources (usually the building owner) typically cannot fully capture the full value of the bill reductions that flow from that investment … This also strongly deters third-party investment in otherwise cost-effective measures, especially energy efficiency, due to the inability of the investor to fully capture the related benefit stream [29]."

The CPUC proceeding aims to produce a pilot project to test alternative shareholder incentive mechanisms, and produce an outcome that will accelerate use of DERs.

An innovative alternative is to use dashboards for performance-based incentives:

- An outcomes-based set of dashboards compels the question: What are the most important desired outcomes that are relevant, quantifiable, verifiable, and controllable?
- Many have focused on dashboards that utilities seek to use. Synapse Energy Economics has offered a utility performance incentive mechanisms handbook to provide examples of performance metrics that focus on customer needs, including stakeholder engagement, effective resource planning, carbon intensity, and system load factor. There are a number of other examples of performance-based-ratemaking in the USA and abroad.
- The focus here is on dashboards that represent desired outcomes for customers where new integrated DER/DSM markets and services—preferred resources—are the priority. In response to California's customer, utility, and regulatory challenges, eight possible outcomes or dashboards indicators are listed:
    1. More economically efficient—cost causative—price signals

2. Faster DER/DSM resource adoption and less use of traditional (rate-based) utility assets
3. More effective, and more complete, integration and optimization of DER/DSM resources
4. Greater innovation through utilities and third-party providers moving at market speed
5. Greater use of community (microgrid) energy options and zero-net-energy buildings
6. Reduced GHG in energy and transportation
7. Increased reliance on renewable energy
8. Reduced customer bills [33]

"[In summary] outcome-based dashboards [are proposed] that can be calibrated to deliver efficient outcomes, increasingly as new data and more granular methods are used. Certainly this approach can be consistent with the results doctrine, to enable greater utility efficiencies to be directly rewarded. This also shows how rate-of-return can be decoupled from risk, allowing lower risk and higher returns where suitable performance is achieved. The proposed approach offers one possible path to increased profitability and adaptability for utilities in this decade. It further offers a mutually reinforcing system to use dashboards and to carry out current roles. At this juncture it bodes a road less traveled though with less risk and more reward [34]."

The California and New York approaches to advance DERs and new utility business models differ in many ways but are similar in others. New York has taken a top-down approach, looking at business models, characterizing grid and DER services, and searching for a model that uses regulatory incentives in some situations and private incentives in others. New York has discussed the use of unregulated affiliates and has undertaken a set of comprehensive pilot projects, while at the same time requiring DER business plans. California meantime has taken a bottom-up approach, starting with distribution planning, the distribution assets that may be deferred by DERs, use of an ICA and LNBA approach, with procurement of DERs in a competitive bidding scheme. California has proposed DER shareholder incentive mechanisms as pilots, and a set of ICA and LNBA pilots is in process. All the while, California and New York have a cooperative agreement and are collaborating to share lessons learned and findings. In both settings, the DER future looks bright, the roles for regulation remain uncertain, and the roles for markets seem encouraging. It seems that only a few conclusions can be drawn at this point.

25.6.7.8 An Economic Tipping Point

The potential to deliver and use DERs more economically than traditional bulk electricity is now at a crossroad, compared to traditional electricity resources. Compared to traditional electricity, DERs appear to be less expensive, with fewer environmental trade-offs. California and New York, to be clear, have significant environmental requirements and building standards, and they are shying away from even clean natural gas generation at this point. By 2020, and sooner in places, a new, distributed, clean energy future is possible, along with enhanced reliability and greater customer choice. Integration of DERs with traditional electricity resources has become well understood. As DERs achieve greater scale, integration and optimization will be standard best practices to achieve the 2× to 5× greater benefits, compared to the siloed use of DERs we have seen in the past. With DER benefits on this scale, in comparison to traditional energy resources, the path to clean energy seems obvious to many, but may remain mired in the politics of entrenched interests. Third-party DER providers will become the service providers that bring innovation at market speed. The distribution grid will be a true "plug-and-play" automated platform, a system-of-systems to enable peer-to-peer and other multi-sided transactions. In the new DER world, choice of reliability will become routine, as will the extent that customers interface with transactive energy markets, which seems certain to use brokers that offer simple interface options. The utility role would at a minimum be as a distribution wires provider, with metering and reliability services. But that role could be expanded if the utility chooses to be a DER enabler with dashboard-based (light-handed) regulation that more fully aligns shareholder incentives and customer needs. In this broader role, the utility can leverage inherent scope and scale advantages as a distribution wires provider, interface to the bulk (wholesale) grid, and enable third-party DER and distribution grid innovation. Technology, policy, and market advancements have created this bold new world.

25.6.8 Standards: Milestones (2010–2016) and Gaps

Technical standards have always played an important role in the electric power industry, particularly given the single-provider and regulated nature of the industry. With the tie between the funding provided by ARRA 2009 in the USA and smart grid standards, the importance of technical standards increased dramatically.

While an increased push for technical standardization received pushback from some quarters, it was largely successful, resulting in a plethora of smart grid standards. These standards cover a wide range of topics, from utility back-office systems to DERs to physical communication technologies. In many cases, there is overlap or even direct competition between various standards. Some consolidation of overlapping standards is likely, resulting in the emergence of dominant, widely adopted standards.

The first phase of smart grid standards development began prior to ARRA and dramatically increased as a result of ARRA funding. It focused on the creation of standards in an area lacking them. In the USA, NIST was tasked with the coordination of smart grid standards to meet such gaps. In response, NIST published the NIST Framework and Roadmap for Smart Grid Interoperability Standards [35]. NIST also led the creation of the Smart Grid Interoperability Panel (SGIP) that, among other activities, maintains the Catalog of Standards [36]. Similarly, many other global regions also focused their attention on the development of smart grid standards. Stakeholders who pushed back gradually recognized the benefits of standardization—interoperability, market development, and innovation. Stakeholders generally have benefitted from the increased functionality of technology as a result of Moore's Law—which literally says that the number of transistors in a dense integrated circuit doubles approximately every 2 years but, more generally, predicts rapid advances in functionality in the digital electronics increasingly applied to power applications.

This focus on smart grid standards development has led to the current (as of 2016) phase, which is characterized by a plethora of sometimes competing standards. However, the industry has converged on one standard globally for control center-to-control center communications (IEC 60870-6/TASE.2), two standards for control center-to-field communications (IEEE 1815 and IEC 60870-5-101/104), and two standards for communications within field equipment (IEC 61850 and IEEE 1815).

Simultaneously, other industries have begun to focus on standards for machine-to-machine (M2M) communication, resulting in the IoT trend. While IoT is not focused solely on smart grid or even smart cities, it is certainly a trend that affects the smart grid industry and one that cannot be overlooked. Going forward, much of the technology and standards development activities for smart grid will attempt to fit the IoT paradigm, including near-ubiquitous use of the Internet Protocol (IP).

The IoT trend has also resulted in a plethora of standards, with multiple standards development organizations and related consortia vying to capture mind and market share.

Going forward, we are likely to enter a third phase of smart grid standards development in which we see consolidation of various overlapping standards and the emergence of fewer dominant, widely adopted standards. This process will likely be organic and market-driven. The global power industry will determine which standards and technologies are most effective for various application domains.

At the time of writing (mid-2016), several focus areas of standardization had surfaced. Many were relatively new domains and, given the time frame typical of standards development, probably remain under development as you read this chapter. Standardization work in other, better-known domains continues apace.

In the more traditional grid operations domains, efforts are ongoing to achieve semantic interoperability. The International Electrotechnical Commission (IEC) is working to harmonize the semantics of its two popular suites of standards for smart grid [37]: IEC 61968/61970 (Common Information Model [CIM]) and IEC 61850. There are also many other standards where increased harmonization of semantics would be useful, such as DLMS/COSEM [38] and the ANSI C12 suite [39].

For the underlying communications technologies, the Institute of Electrical and Electronics Engineers (IEEE) has created the 802.15.4g standard for smart utility networks [40]. This standard has now been adopted by several consortia for profiling, testing, certification, and commercialization, including Wi-SUN [41] and the JupiterMesh activity of the ZigBee Alliance [42]. This standard will likely see adoption worldwide for use in mesh networks supporting smart meters and other field devices.

With the maturation of LTE, cellular technologies are proving to be of greater interest for utility networks. Given the focus on IoT and M2M communication for the upcoming 5G cellular technologies, these technologies will likely be of even greater interest for smart grid communication in the near future.

Standardization of power line carrier (PLC) communication technologies remains an area of interest, with the IEEE publishing IEEE 1901 [43] and IEEE 1901.2 [44] and the International Telecommunication Union publishing G.hn [45] and G.hnem [46] standards.

In the past, communication between smart grid devices in the field and the utility back office system took place in a centralized fashion. Going forward, however, increased interest focuses on distributed intelligence, with little to no interaction with utility back-office systems. For instance, the SGIP, whose mission includes identifying standards gaps, is working on the Open Field Message Bus (OpenFMB) [47]. The OpenFMB framework uses IoT standards to facilitate communication directly between smart grid devices in the field, eliminating the need for centralized communication and freeing the devices to make local decisions. Taken further, distributed intelligence holds the promise of enabling entirely new paradigms in the operation and use of the smart grid, such as transactive energy [48].

Yet, another domain of increased standards efforts is that of the interaction of consumers and third parties (such as aggregators) with the utility-controlled smart grid. Many standards that facilitate information sharing as well as control of non-utility assets have been developed or remain under development. For instance, the U.S. DOE-sponsored Green Button initiative [49] is now standardized as NAESB REQ.21 [50] and focuses on providing energy usage information to consumers via traditional Internet connections. The use of Internet connections to engage consumers in the smart grid is continuing to increase in popularity, including many interactions that were previously reserved for private networks, such as demand response. Likewise, dedicated consumer devices such as in-home displays are increasingly becoming obsolete, in favor of devices consumers already own. Home energy management standards remain an area of contention, with wireless communications such as Wi-Fi possibly competing with ZigBee and a variety of application standards and frameworks also competing. That nascent market and the standards to support it will undoubtedly receive more attention going forward.

The integration of DER, such as consumer-owned or third-party-leased solar PV panels, will only grow in importance. Standards, such as IEEE 2030.5 [51], IEEE 1547 [52], and UL 1741 [53], are enabling consumer and third-party interactions with distribution utilities to not only enable feed-in of energy from consumer generation but also maintain grid stability and safety.

The emergence of plug-in electric vehicles (PEV) has become a long-anticipated reality, with several automotive firms offering models, and consumer uptake gradually increasing. Though standards exist for charging PEVs, future work will focus on applications, such as vehicle-to-grid (V2G) energy transfer and standards for higher voltage DC charging.

The trend toward consolidation of existing standards and increased efforts at standards development in power and related domains such as IoT will, over the long run, promote interoperability and its benefits, which include market development, cost reductions, and resulting market growth and benefits to the people being served.

25.7 ROLE OF CONSUMERS/CUSTOMERS

In recent decades, many market-based industries have grown or perished from advances in ICT. The electric power industry may be an anomaly. Its IOUs are regulated monopolies, and their systems still operate in much the same way as in the early twentieth century. Central generating stations produce power that is transmitted via high-voltage transmission lines to step-down substations, where a distribution system delivers power to homes and businesses. This structure is under transformative pressures from many forces. Perhaps the most significant force is the shift in the role of end users from "ratepayers" to "customers" and "consumers." We can define "customers" as those who hold utility accounts and "consumers" as everyone else who consumes electricity. As the regulated monopoly model gives way to a more market-based approach, the distinction will disappear and, therefore, we'll henceforth use "consumer" as our term of choice. We know from market data and from surveys that consumers aspire to more closely manage their energy use, participate in new programs, and adopt rooftop solar and other DERs. Yet, studies also show that consumers are not a monolithic group. Psychographics have revealed at least five major categories of consumers, each with their own aspirations, motivations, and characteristics.

While utility system technology has inched forward, based on advances in ICT and other areas, consumer use of digital technology, such as mobile smart devices, and their expectations for instant, transparent information, participation, and options has grown rapidly. Meanwhile, two primary forces have led to increasing consumer interest in renewable energy: broad societal concerns over the environmental impacts of electric power production, transmission, and distribution, and the simple economics of increasing renewables efficiency and falling prices. Third-party energy service companies, capable of providing information, insight, control, renewable energy, and other products and services, threaten disintermediation of the utility-consumer relationship. These forces and resulting shifts have irrevocably changed the utility-consumer relationship and are forcing utilities to recast their business models as they seek to maintain or improve their legacy role as energy providers. The days of passive ratepayers who know nothing about their role in the energy ecosystem but their monthly electricity bill are coming to an end, as consumers become active participants in a smarter, modernized grid.

25.7.1 Consumer Engagement

In order to create sustainable business models and retain consumers' interest in their services, utilities are evolving to integrate ICT in order to modernize the grid and provide enhanced consumer services, enabling greater consumer control over their energy use, cost, and even their own production. The electric power industry, however, with its legacy of regarding consumers as homogeneous ratepayers, has had to play catchup in order to engage consumers based on their interests and values, and adopt more traditional up-to-date marketing approaches. Many, if not most, utilities grasp that change is afoot for all the reasons enumerated, and they are now pursuing solutions to these challenges. Meanwhile, the three pillars of technology, standards, and policy are shifting as well, driven by the recognized rise in importance of the consumer. New consumer-friendly technologies are constantly hitting the market. Standards to support both sides of the utility-consumer relationship are emerging. And policies are changing to allow more market-based, retail utility activity and more third-party providers of products and services. Policy reviews and revisions are under way in several U.S. states to place the consumer at the center of a transactive energy paradigm, something unheard of 5 years ago.

As utilities respond to consumer-based pressures and seek to engage consumers, they need to know who their customers are and what they want. This is a sea change for the electric power industry. As a result, in 2010, industry stakeholders founded a 501c3 nonprofit dubbed the Smart Grid Consumer Collaborative (SGCC)—rebranded in 2017 as the Smart Energy Consumer Collaborative (SECC)—to study consumers and conduct foundational research into their values, interests, and awareness around energy usage and technology. Since then, SECC has published numerous research studies focused on understanding consumers and their aspirations, motivations, and perceptions, and how to best engage consumers around their values and attitudes regarding energy.

SECC research has established that a critical, foundational element for engagement is consumer segmentation. Segmentation matters because people are not all alike; they differ in many ways. Consumer segmentation is done in nearly all other business sectors and is widely acknowledged to be critical to successful consumer engagement. While slow to come to the utility industry, a few utilities are now creating programs and messaging according to the consumer segments identified in their service territories, while others are considering adopting a segmentation-based approach.

Traditional consumer segmentation by utilities has relied on demographics and divided consumers into groups based on similarities/differences perhaps drawn from available data, such as how much electricity they use, their location, age, income, and household size. Although helpful for certain purposes, this is not as useful for consumer engagement in the smart grid era because consumer motives, priorities, lifestyles, and behaviors identified through recent segmentation studies often do not align with traditional demographics.

SECC findings divide residential consumers into five distinct segments, each defined holistically in terms of attitudes, values, behaviors, motivations, lifestyles, technology adoption, and so on, in the context of smart grid issues. These findings are based on systematic and objective research relevant to utilities and other stakeholders involved in grid modernization, rather than outdated perceptions, anecdotal “evidence,” impressions, or best guesses. (See Figure 25.6 for a graphic representation of the five consumer segments.)

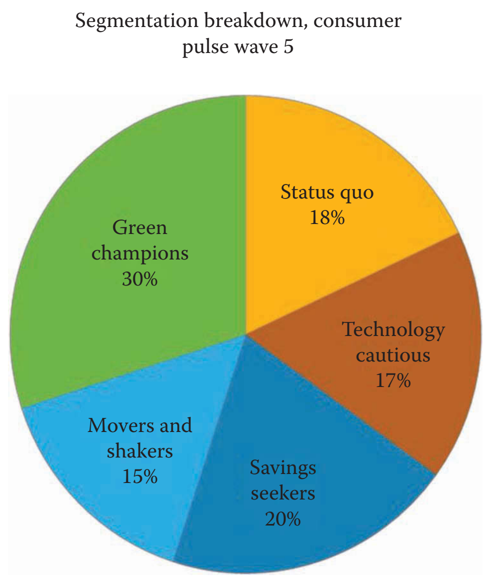

FIGURE 25.6 Consumer segmentation framework in SECC’s “consumer pulse and market segmentation study—wave 5.” (© 2016 Smart Grid Consumer Collaborative. All rights reserved. http://smartgridcc.org/research/sgcc-research/sgccs-wave-5-consumer-pulse-and-market-segmentation-study-summary/. With permission.)

The five consumer segments are defined as follows, with primary statements of their interest and supporting details:

1. *Green champions:* "Smart energy technologies fit our environmentally aware, high-tech lifestyles."
   Green champions comprise the largest single segment, at 30% of the population. They demonstrate the strongest interest in new utility services and smart energy programs. They are early technology adopters and the most environmentally conscious consumers. This is the youngest segment, with half under the age of 35, and they are the second-highest income group.
2. *Savings seekers:* "How can smart energy programs help us save money?"
   This is the lowest-income segment, which seeks information on how to be frugal energy users. Awareness and favorability toward "smart grid" and "smart meters" are low, but they do see the benefits of the smart grid as important. Despite income constraints, Savings seekers are to a degree willing to pay for smart grid-related benefits.
3. *Status quo:* "We're okay; you can leave us alone."
   This segment has lower interest in smart energy programs than any of the other segments. It's a relatively older segment, with many retirees and small households. Comfort and ease are more important to this segment than conservation.
4. *Technology cautious:* "We want to use energy wisely, but we don't see how technologies can help."
   Similar to *status quo* demographically, this group is more knowledgeable about smart grid programs, but doesn't grasp how technology on their or the utility side can help. They claim knowledge of how to save energy and indicate concern about the environment, but are more focused on comfort and ease of use.
5. *Movers and shakers:* "Impress us with smart energy technology and maybe we will start to like the utility more."
   This is the highest-income segment, with larger homes and the highest average electric bills. Smart grid awareness and favorability are high, but utility satisfaction is low. This segment includes early technology adopters and has high interest in new energy technologies but, so far, only moderate interest in smart energy programs and new utility services.

25.7.2 Lessons Learned/Best Practices in Community/Consumer Engagement

Developing a customer- or consumer-centric engagement plan for smart grid means creating a multifaceted, integrated road map that addresses how technology and new products and services will intersect with consumer interests and needs. The DOE's Office of Electricity Delivery and Energy Reliability discusses such a road map in its 2013 report, "Voices of Experience: Insights on Smart Grid Customer Engagement [54]." Some highlights are provided here.

Because smart meter installation is generally a customer's first experience with new utility technology, this has been the impetus for many utilities to actively engage with their customers. The challenge has been to help them understand the technology and its immediate, planned, or potential benefits. Other challenges include determining relevant, consumer-friendly metrics that measure project success and value, as well as countering irrational but influential opposition to technology changes. Most of the ideas in this section are applicable to customer engagement in general, but others are specific to AMI deployments. Basic steps in shaping a consumer engagement plan include:

- Start stakeholder engagement planning 12–18 months prior to the technology deployment to lay the groundwork. Ensure internal and external stakeholders are on board.

- Create a comprehensive plan that covers all phases of the deployment, including what happens after the technology is installed. Explain how the utility will handle customer data.
- Allow time in the plan for delays and unexpected events. The ability to be flexible and respond to changing conditions is critical.

25.7.3 Stakeholder Engagement

Consumers (in general), customers (in particular), community-based organizations, consumer advocates, politicians, and religious organizations are all stakeholders, as are consumer advocates, regulators, utilities, and civic/business leaders. The benefits of proactively engaging stakeholders as partners cannot be overstated. Input from a broad range of stakeholders with varying experiences leads to greater understanding of customer wants that can be used to educate and engage consumers. Informed, engaged stakeholders who see the value in smart grid investments and participate in a collaborative process can become advocates and sometimes the best voices to counter unsubstantiated pushback.

Consider creating an advisory panel consisting of regulatory and other interested stakeholders that meets regularly to discuss plans for deploying technology and engaging consumers. Whether established voluntarily or through regulatory mandate, advisory panels are very successful in building trust and communicating with key stakeholders.

Inadequate stakeholder engagement can lead to misunderstandings and lack of support that may negatively impact outcomes. Collaborative efforts help reduce tensions and ease adversarial relationships.

25.7.4 Metrics for Successful Programs

Metrics in this context are useful to measure how well outcomes match goals. They can also be used to explain challenges, quantify benefits, and tell a success story. Consumers, regulators, and utilities often assess the success of smart grid programs based on different criteria, which require different metrics.

As the utility-consumer relationship changes, metrics used to evaluate the success of engagement will change, too. For example, utility call centers were once assessed, in part, by the call duration. Going forward, the consumer satisfaction gained from call center operators taking the time to listen and respond to a concern may become more important. A consumer engagement program that includes metrics to measure consumer satisfaction and other community goals over utility-centric criteria is an important step in managing the changing relationship.

Possible metrics for an AMI project, for instance, include measuring desired customer attitudes (neutral to positive), an acceptable number of opt outs for installation of a smart meter, and the adoption rate of applications and tools, such as online energy use dashboards. Engagement with stakeholders can help develop broadly relevant and stakeholder-specific metrics that build community support and stakeholder satisfaction.

As noted, a consumer engagement program may need to focus on direct, consumer-centric impacts such as what smart meters will do for them, now and in the future. However, smart meters also have utility-centric operational benefits that indirectly, but materially, affect the consumer, and these should be explained via consumer engagement. Therefore, consumers should be engaged and informed on operational benefits (savings due to avoided truck rolls, etc.); capital savings (avoided T&D infrastructure costs); societal savings (reduced GHG, reduced energy theft, etc.); project execution (meters installed versus target); safety record (Occupational Safety and Health Administration recordable incidents).

The foregoing points on metrics for success were confirmed as best practices during a Commonwealth Edison AMI deployment. The utility's work with the Environmental Defense Fund (EDF) and Illinois Citizens Board (IL CUB) produced one of the few known performance metrics programs created for a successful AMI deployment. In March 2016, the parties agreed to track how smart meter installations will reduce GHG emissions outlined in a "GHG Metric for Smart Grid Advanced Metering Infrastructure Deployment Plan [55]," which had not been finalized by mid-2016. The metric is intended to capture GHG reductions resulting from a variety of clean energy and smart grid efforts tied to AMI, including enabling energy efficiency and conservation; reducing peak electric demand; enabling demand response; and enabling the integration of clean, renewable generation sources, like rooftop solar.

25.7.5 Countering Smart Meter/Smart Grid Opposition

All the elements of consumer and stakeholder engagement elucidated here apply not only to building support for smart grid deployments, in general, and smart meter deployments, in particular, but also countering outright opposition. The time frame needed for consumer and stakeholder engagement and education underscores the importance of a forward-looking strategy, at least 12–18 months out. Engagement and support should be in place well before public awareness of a project begins.

These points were confirmed when the largely ARRA-funded AMI deployments began at about the time the first edition of this book was written in 2010–2011. At the time, various utilities announced their smart meter/AMI projects, small but vocal anti-smart meters groups formed across the country, aided by the Internet's speed, amplification of messaging (positive and negative), and tendency to make online groups appear credible. One California-based group, Stop Smart Meters!, reinforced its views with an online video filled with misinformation titled "Take Back Your Power." Going forward, utilities will need to decide whether and how to publicly address misinformation. For its part, SECC developed a "Stop Smart Meters Response Campaign" to provide utilities and stakeholders with a means to address opposition to smart meters using techniques and resources to refute misinformation.

Opposition groups often promote misinformed arguments about the risks of radio frequency (RF) emissions from digital meters, the loss of personal privacy from utilities gathering data on home energy usage, and the risk of cyber attacks and security breaches. SECC resources developed over the years can assist utilities going forward with meeting such informational challenges, such as [56]:

- "Separating the Facts from Fiction" video
- An educational website at www.WhatIsSmartGrid.org
- A series of printed and online fact sheets
- Draft op-ed templates that can be utility-customized for local media
- Success stories of AMI deployments from utility customers including consumer testimonials on how they've saved energy or enjoy more energy budget control
- A package of consumer-facing fact sheets and short multimedia videos to address consumer concerns with topics such as "RF Emissions," "Myths vs Truths," "Cybersecurity," "Smart Grid Benefits" and more
- A list of subject matter experts to consult on these issues in real time
- A set of talking points to provide to industry stakeholders to use when tasked with answering similar concerns from around the country
- Methods to create a rapid response team that includes technology experts to answer media questions on topics raised by smart grid opposition groups
- Methods to create a platform to promote smart grid awareness through social media including Twitter, a YouTube channel with search engine optimization, and Facebook

25.7.6 Consumer Participation

Going forward, utilities will need to understand consumers and the many ways in which they want to participate in their energy-related experience and future. This participation can take many forms and will range from consumer adoption of new utility services and programs to activities that are utility-neutral, or utility-agnostic, or even perceived by a particular utility as counter to its interests. In fact, consumers are making choices that do not necessarily align with utility plans and preferences. Some of these choices also reduce overall electric load, which is a major concern for utilities whose revenue is directly tied to energy sales.

Often, consumer participation will be boosted by policy changes and mandates; sometimes, it will be a response to the availability and affordability of new technology and, in many cases, technology and policy will supported by the development of new standards.

At the time the first edition of this book was written in mid-2010, consumers had already demonstrated an increasing interest in shaping their energy future based on multiple motivations, including managing and reducing their electric bills, a desire for "energy independence," perceived deficiencies in grid reliability (especially during storms and natural disasters), pursuit of cleaner energy options, and enthusiasm for new technologies.

Smart thermostats are an example of new technology that could benefit utilities or have a neutral impact on them. DER in the form of rooftop solar PV arrays is an example of technology seeing increasing adoption as policies encourage implementations through tax credits and other means. Solar PV adoption is also increasing as its efficiency rises, prices fall, and smart inverters allow this technology to remain in operation even when the central grid is down. Utilities appear divided on whether rooftop solar PV is a net benefit to the grid, a cost or even a threat to their business models.

Consumer preferences are also shaped by third parties. Solar developers, energy efficiency installers, electric vehicle manufacturers, "smart home" equipment and software vendors and other new market entrants are committing significant resources to marketing, policy advocacy, and building customer relationships. Currently, and into the foreseeable future, utilities will need to acknowledge, analyze, and plan for how to deal with consumer options and preferences, and DER is a prime example where grid operations and business models will inevitably be affected.

In some regions, DER penetration already is reaching levels that have a measurable impact on grid planning and operations. Solar PV, in some areas the most prevalent DER technology today, is expected to continue its steep growth trajectory for many more years. A significant driver of solar PV growth is the Federal Investment Tax Credit, which was extended through 2021 by Congress in December 2015 [57].

25.7.7 Consumers, Social Media, and Improved Reliability Metrics

An integrated system of outage detection and power restoration that includes a role for the consumer can help utilities improve critical reliability indices while contributing to customer engagement and satisfaction. This approach takes advantage of existing technologies as well as innovative software reaching market as this book went to press.

Making this approach part of a distribution automation project that includes FDIR and IVVC typically creates a strong business case. For utilities that have installed AMI and interval smart meters, this is a logical next step, but the approach outlined here can be accomplished without AMI. Distribution automation's business case improves when it is focused on speedy outage detection and power restoration.

Smart meters play several roles, including emitting a last gasp as they and the feeder they're on lose power. That gives a utility almost instant notification of an outage, which is quicker and more precise than awaiting a customer call. The time difference between the two methods could be the difference between an outage being classified as momentary under Momentary Average Interruption Frequency Index and a sustained outage under SAIFI, both of which are key metrics evaluated by regulators to determine utility performance.

To achieve this functionality for utilities without smart meters and AMI, voltage-sensing meters can be strategically placed at the ends of feeders to measure compliance with American National Standards Institute (ANSI) standards for delivering 114–126 V of power—and play a role in outage detection, though less granular than with AMI.

In the past, a utility could trace a customer phone call to a location by linking their landline phone number to a physical address by tapping its customer information system. Today, however, many people do not have landline phone numbers (especially "millennials"), and every physical address is likely to have several mobile device accounts. Multiple tweets about an outage, for example, will provide greater accuracy in locating outages. The utility benefits by improving reliability metrics and customers get their power restored more quickly.

As with other consumer engagement efforts discussed in this chapter, consumer involvement will require outreach. A utility could incentivize its customers and their household members to link their Twitter tags to their utility account or turn on their mobile devices' geo-tagging functions, which provides the latitude and longitude of a tweet. A commercial software platform with geospatial coordinates for automated systems can connect those data with an OMS.

Crowdsourcing the cause of an outage is also possible by leveraging consumers' still and video images from their mobile devices. Consumers' images, posted to a utility's Facebook page, can be analyzed by automated image-assessment software to inform field crews prior to truck rolls.

It's easy to see how these utility-consumer interactions support the fundamental messaging around consumer participation in a smarter grid and, thus, could lead to participation in other utility programs such as demand response [19].

25.7.8 Consumer Data: Who Owns It, Consumer, and Third-Party Access

"Digital empowerment" means providing consumers convenient access to their own energy usage and pricing information, and it has emerged as a central strategy for addressing one of the most important energy challenges: how to engage consumers to significantly reduce energy use in buildings. The plummeting cost of computing power and the availability of detailed consumption data are now enabling development of software and hardware tools to give consumers new opportunities to better understand, manage, and control their energy options. Going forward, utilities will need to understand how these tools may impact their operations and business models.

Examples of consumer-facing tools include:

- "no-touch" energy audits that recommend efficiency measures for homes and businesses
- EnergyStar benchmarking, facilitating compliance with building consumption energy transparency laws
- tools to optimize the operation of home appliances, as well as home and building heating/air conditioning, and on-site generation or storage
- recommendations for sizing solar and other clean energy installations
- inexpensive verification of efficiency and demand response measures
- real-time analytics and alerts—the ability to detect patterns in real time, using energy analytics, for example, detecting a space heater is on when no one is home

The savings to consumers are particularly promising in the states that have deployed smart meters and AMI. Millions of older generation meters can also collect data that are valuable to consumers and yield data that can drive many energy applications as well. The insights a consumer can gain from his or her ongoing energy consumption data are very powerful, enabling energy savings estimated by the American Council for an Energy Efficient Economy at up to 12% or more.

Almost half of U.S. households have, or soon will have, advanced meters capable of providing detailed energy usage data, potentially the single most powerful tool to save energy. By some estimates, 40% or more of the entire benefits of smart meters are consumer savings. Providing consumers easy, convenient access to their own energy usage and pricing data can be accomplished at low cost, a small fraction of the cost of the new meters themselves.

To ensure that consumers have the widest selection of energy management tools, access to their energy use data should be provided via widely adopted standard formats, avoiding local or proprietary solutions that impede the use of products and services built around national standards. Home area network/Premise area network (HAN/PAN) capabilities can be enabled as soon as advanced meters are deployed. Whether HAN/PAN capabilities are enabled is a utility choice that must be considered in the context of a particular utility's evolving business plan and technology road map as they relate to their customers (in particular) and consumers (in general).

Three states that are leading the effort to empower consumers with access to their energy data include California, Illinois, and Texas. More details on these examples are available in a report that is the source for the foregoing section titled "The EMPOWERed Consumer" by Mission: Data [58].

On a national level, the Green Button initiative is an industry-led effort that responds to a White House call-to-action to provide utility customers with easy and secure access to their energy usage information in a consumer-friendly and computer-friendly format. Customers are able to securely download their own detailed energy usage with a simple click of a literal "Green Button" on electric utilities' websites [49].

Throughout the USA, intelligence is being added to the grid through the deployment of advanced technologies and grid modernization efforts. This increased intelligence has led to concerns regarding consumer data access and the privacy of consumer energy consumption data. Historically, utilities have taken very seriously the job of protecting customers' privacy, and privacy and security protections will remain fundamental objectives. However, with the new technologies being deployed today, these fundamental protections warrant new attention. Consumers must feel secure that their data will be protected and treated responsibly. Therefore, the DOE has worked with electric industry stakeholders to develop a voluntary code of conduct for utilities and third parties providing consumer energy use services—known as Data Guard—that addresses privacy related to data enabled by smart grid technologies [59].

25.7.9 Consumer-centric Standards

Standards help accelerate grid modernization through the promotion of interoperability in devices and energy management systems. This interoperability enables consumers to have the widest possible selection of energy technology and the ease of use that comes with purchasing different solutions or parts of solutions at different times from different vendors. Without standards, consumer adoption of energy technology will be slower and lead to consumer frustration and dissatisfaction, because disparate systems based on proprietary technologies will not work together.

As the smart grid continues to evolve, standards will clearly impact the next generation of electric delivery systems and their reliability, resiliency, and consumer-related interfaces, such as HAN/PAN, PEVs, and solar PV systems. Every day, more smart devices and distributed sources of generation are connected to the grid. At some point in the future, the electrical grid may resemble the Internet, connecting consumers and devices to data they need for productivity and comfort in their daily lives. Some are calling this the Energy Internet of Things. Standards are crucial to keeping this connectivity and technology interoperable and, thus, customer satisfaction high.

25.7.10 Consumer Information Standards

Four sets of consumer standards related to the smart grid have been introduced. See the SECC's online guidebook, "Consumer Information Standards," which links the standards to further resources [60].

These standards provide data to the consumers regarding their interaction with the smart grid, including energy usage information, pricing information, billing information, demand response events, and prepayment functionality.

25.7.11 ZigBee Smart Energy 1.x

ZigBee Smart Energy 1.x is an application for providing consumer information to devices in a HAN, often via a smart meter. ZigBee Smart Energy 1.x is designed to work with ZigBee technology, a low-power wireless networking technology. This standard is not necessarily limited to transmission of energy usage information from the smart meter and can support many other types of information (e.g., pricing information, demand response events) and commodities (e.g., natural gas, water).

25.7.12 Smart Energy Profile 2.0/IEEE 2030.5–2013

Smart Energy Profile 2.0 (SEP 2.0) is an application for providing consumer information to devices in a home or a HAN, often via a smart meter. SEP 2.0 is an evolution of ZigBee Smart Energy 1.x, designed to work over any technology that supports the IP. This standard is not necessarily limited to transmission of energy usage information from the smart meter and can support many other types of information (e.g., pricing information, demand response events, billing information, prepayment information) and commodities (e.g., natural gas, water). SEP 2.0 is also used for communication between an electric vehicle and a charging station.

25.7.13 Green Button/Energy Services Provider Interface (ESPI)/NAESB REQ 21 (NAESB)

Green Button is the common marketing name for the ESPI standard. This standard is an application for providing customer information from a "data custodian" (e.g., utility) to an authorized third party or customer. Green Button is designed to work on top of IP.

25.7.14 Demand Response Standards

The following standards provide information to the consumers to enable their participation in demand response programs:

- OpenADR is an application for providing demand response (DR) information and events to customers. OpenADR is designed to work on top of IP. OpenADR is primarily used by commercial and industrial (C&I) customers.
- ZigBee Smart Energy 1.x is designed to work on top of IP.
- Smart Energy Profile 2.0/IEEE 2030.5–2013 is designed to work on top of IP.

25.7.15 Solar and Other DER Standards

These standards specify how and what information is needed to connect solar and DER to the smart grid.

IEC 61850 specifies both physical interconnection requirements and information elements for grid-connected solar and DER.

IEEE 1547 specifies physical interconnection requirements for solar and DER.

UL 1741 specifies physical interconnection requirements for solar and DER.

SEP 2.0 has been initially recognized in California for the provisioning of data and grid/market signals and information for grid-connected solar facilities.

25.7.16 Electric Vehicles

SAE J1772 specifies the physical connector or plug between an electrical vehicle and a charging station.

25.7.17 Time-varying Rate Plans

The widespread implementation of smart meters and AMI accelerated by ARRA grant funding has, in many cases, enabled consumers to see and, in some cases, use their energy use data for managing energy use for the first time. By mid-2016, however, the use of those data to optimize energy use and costs via time-varying rates (TVR) remained low. More and better research is needed on how TVR might benefit both utilities and consumers, and could potentially lead to more progress in TVR implementation, which is widely seen as important to improving grid efficiency and realizing the value of smart meters.

In May 2016, the SECC released "The Empowered Consumer" report, which presents research findings on how consumers in the USA are engaging with their energy providers in a post-ARRA era [61].

The report explored consumers' awareness of, preferences for, and interest in, nine smart energy technologies and services. Two conjoint statistical analyses were conducted to provide an in-depth understanding of what elements consumers value in a smart thermostat program that utilizes time-varying rate plans. This choice-based methodology simulated real-world decision-making, requiring respondents to make "trade-off" decisions when evaluating features and services. Smart thermostat programs emerged as a convenient gateway for utilities to introduce and foster consumer engagement with energy technology.

SECC surveyed consumers in "advanced states" with AMI deployed and "control states" with no AMI. The study analyzed survey respondents through the lens of the consumer segmentation framework described earlier and each segment's awareness of and preferences relating to smart grid-enabled programs and technologies.

SECC's findings revealed that up to 55% of consumers are interested in enrolling in a TVR plan when given the option over a standard rate plan. Up to 60% of consumers are interested in enrolling in a TVR plan when they are presented with the opportunity to choose from an offering of three various TVR plans alongside a standard rate plan. Consumers are interested in these programs as a means to save money, reduce pressure on the grid, and protect the environment. Whether consumers were given the opportunity to choose a single TVR plan or from the three variations tested, consumers exhibited a strong preference for a nighttime rate discount. This plan, in particular, is easy for consumers to understand because the time frame is a simple 12 h on-peak and 12 h off-peak, the peak charge premium is modest in scope, and it limits their financial risk.

Using a conjoint analysis, the study implemented a holistic approach to understanding consumer preferences for the various elements that comprise a TVR plan. The findings revealed that consumers placed the greatest importance on kWh pricing by more than a 3:1 margin, as detailed in Figure 25.7. As the kWh pricing scheme is the only element that significantly affects predicted participation rates, other tested rate plan elements (maximum bill limits, contract duration, and how usage

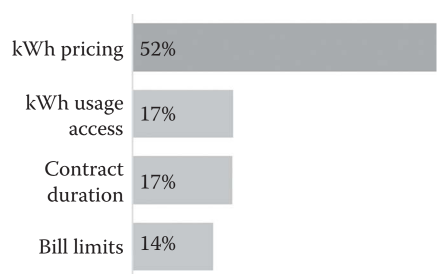

FIGURE 25.7 An SECC survey revealed that consumers placed the greatest importance on kilowatt-hour (kWh) pricing by more than a 3:1 margin. (From SECC's "The Empowered Consumer" report. © 2016 Smart Energy Consumer Collaborative. All rights reserved. With permission.)

is tracked) are predicted to have a minimal effect on rate plan preferences. Thus, energy providers have a degree of flexibility with these non-kWh pricing elements when designing TVR plans.

One of the insights from the study that could guide utilities in developing future rate plans is that an increasing number of consumers expressed an interest in enrolling in a TVR plan when they were presented with a choice of multiple options as opposed to a single option. Consumers prefer choices so they can select the program that best fits their needs and lifestyles.

Another valuable insight arose when the study analyzed the demographic characteristics of consumers who preferred one of the TVR plans versus a standard rate plan. Among the majority that preferred the "night-time rate discount" option, openness to a TVR plan varied by demographic characteristics. More than two-thirds of younger (18–44 years old), college educated, and wealthier consumers ($100,000 or higher incomes) preferred TVRs over standard rates. Among older, less educated and low-to-moderate income consumers, half prefer a TVR. As TVR programs are inevitably rolled out, these findings indicate which consumer segments and demographics represent an initial target audience for marketing and outreach efforts to achieve enrollment target success.

Conversely, the study found that 40% of consumers have no interest in TVRs. If nearly half of all consumers do not want to adopt TVRs, a program design must take that into account. Yet, successful peak load reduction can be achieved with far less than 60% enrollment; depending on the goal, some utility program models suggest that 10%–12% participation is sufficient [62].

Time-based rates, enabled by utility investments in AMI, are increasingly being considered by utilities and policymakers as tools to augment incentive-based programs for reducing peak demand and enabling customers to better manage consumption and costs. In addition, there are several customer systems that are relatively new to the marketplace that have potential for improving the effectiveness of these programs, including in-home displays (IHDs), programmable communicating thermostats (PCTs), Web portals, and a host of new and novel software and data applications, including the U.S. DOE-originated Green Button.

Under the U.S. DOE's Smart Grid Investment Grants (SGIG) program, several utilities have taken part in a Consumer Behavior Study effort that has developed information on time-based rates and incentive-based programs including impacts, benefits, and lessons-learned that can assist utilities and policy and decision-makers with the design and implementation of new rate and technology offerings.

The foregoing discussion addresses TVR from the utility to the consumer. As energy technologies continue to advance and offer more options to customers, developing effective rate designs for consumers with DER, such as solar PV, is also important. With the advent of DER that contributes to bidirectional flows of power, utilities and consumers must assess their respective cost/benefit ratios to inform policies that fairly compensate consumers for adding energy to the grid while compensating utilities for the infrastructure that enables this consumer practice. Studies by both "sides"—and sides are being taken on this issue—purport to demonstrate that DER in the form of solar PV is either a net benefit or net cost to the utility and its grid. Myriad studies have argued both sides, and the results of state-level regulatory hearings have sometimes favored either utilities or consumers on this issue.

According to a well-respected study by the Regulatory Assistance Project (RAP), "Designing Tariffs for Distributed Generation Customers," (February 2016), striking a fair balance should lead to policies that include the following elements [63]:

- A customer should be able to connect to the grid for no more than the cost of connecting to the grid.
- Customers should pay for grid services and power supply in proportion to how much (and when) they use these services and how much power they consume.
- Customers who supply power to the grid should be fairly compensated for the full value of the power they supply, no more and no less.
- Tariffs should fairly balance the interests of all stakeholders: the utility, the DG customer, and the non-DG customer.

Evaluated through this prism, several rate designs currently under debate are not optimal or fair. For example, a rate design based on high-fixed customer charges may satisfy a utility desire for guaranteed revenues, but it is not fair to all customers. It does not answer the objectives of energy conservation and efficiency policies. Also, it is not based on cost-causation, the traditional basis for fixed charges.

An important consideration going forward on this issue is independently determining the value of the power provided from DER. The relationship between the value of the DER unit to the grid as compared to the retail rate will determine whether customers are being over- or undercompensated for the power they provide to the grid. If the value provided is higher than the net-metered rate, then the customer may be under-compensated. If the value provided by the customer's DER is lower than the net-metered rate, then the customer may be overcompensated.

For regulators, the challenge lies in balancing short-term customer costs with long-term system benefits and getting the price signals correct. In establishing rate designs, RAP advises that regulators should consider the following points:

- Does the rate design fairly allocate costs in accordance with who is causing the cost? Does the rate provide the proper price signals so that appropriate attention is paid to system costs and needs so as to avoid uneconomic investments?
- Does the rate provide proper price signals so that customers pay in accordance with the costs they are causing on the system?
- Is there fair and reasonable compensation for those providing a service/benefit to the grid?
- Does the rate fairly consider the energy burden for low-income customers?
- Are there policies in place to address utility revenue shortfalls and to reward the utility for implementing practices that increase its operating efficiency and advance public policy goals?

Rate designs that can affirmatively answer these questions will have a higher likelihood of success as DER alternatives continue to gain traction.

25.7.18 The Road Ahead

The global energy industry faces unprecedented, fundamental change in technology, policy, and standards, much of it led by the increasingly critical role of the consumer. Rapid advancements and widespread adoption of distributed generation, smart technologies, and connected home products and services are just a few of the game changers affecting energy providers and consumers. At the same time, digital consumer technologies are rapidly breaking down barriers and creating new opportunities for utilities and nontraditional players. As the fast-moving world becomes increasingly social and connected, more consumers are seeking added value, personal relevance, and societal meaning—all of which extend beyond simply selling energy. In short, energy is increasingly becoming a foundation on which innovative value propositions and new products and services can be sold. Utilities can either remain service and commodity providers, or move beyond that role to become energy and service option providers. While technology may attract new players and value propositions, Accenture's New Energy Consumer research program has shown that, ultimately, it will be consumer preferences that change the energy landscape. Utilities must decide whether to get in front of and proactively manage these opportunities or simply react amid market upheaval. Disruptive technology can be an enabler as energy providers look to address distinctive consumer needs.

To thrive in the next-generation energy ecosystem, energy providers need to move forward with increasing speed to build new capabilities that enable them to scale quickly, seize new opportunities, tap into unconventional markets, and architect a future-proof foundation of simplicity and flexibility. According to Accenture [64], these new capabilities include:

- Addressing a spectrum of energy perspectives—driving simplified, agile customer solutions as consumer preferences run the gamut from "energy agnostic" to "energy literate"

- Enabling interconnection and short cycle innovation—demonstrating innovation in energy diversity through multiproduct value, partnerships, and brand extension
- Delivering seamless experiences—leveraging digital technologies to enable a social-centric yet individualized customer experience for the "always-on" customer
- Reinventing customer operations—rethinking and creatively addressing the preferences and behaviors of the current and future new energy consumer

25.7.19 New York's Policy Plunge

While California, Texas, Hawaii, and other states have sought to create a new energy/utility paradigm by increments resting atop legacy policies, a new effort by New York—Reforming the Energy Vision (NY REV)—is seeking to create a complete transformation of the utility-consumer relationship to one that is consumer-driven and consumer-centric.

NY REV is a process undertaken in 2014 that sets out concepts and processes for revamping New York's distribution utilities and retail markets. The goals of REV are to boost reliability, resiliency, and energy efficiency by supporting customer empowerment, DR, and clean distributed generation in a comprehensive strategy. This process will result in a consumer-centric approach to energy provisioning that will include consumer participation in the market and encourage load management opportunities, such as DR and distributed generation. NY REV's goal is to bring massive, systemic efficiencies to the electricity market, including the reduction or elimination of capital-inefficient, stand-by generation required to meet peak demand on only a few days each year. This effort appears to be the first state-level approach to energy that goes well beyond smart grid to not only engage and empower consumers but make them a significant market force.

One important goal of NY REV is to create a platform that will serve as a place for market-based, sustainable products and services. Another important goal is to create tariffs that empower customers to reduce and optimize their energy usage and electric bills and that will further stimulate innovation and new products.

NY REV (in its own words) "is motivated by the observation that the electricity industry has remained fundamentally unchanged for nearly a century. While other industries and sectors have embraced revolutionary technological advances in the past decades, the electricity system today would be familiar to Thomas Edison himself. The system is built to support the few hours each year when demand is highest, resulting in dramatic inefficiency. The burdens placed upon customers by this archaic model include" [65]:

- Financial cost: Electricity bills have risen 32% for the average New York ratepayer since 2004. As the system is sized to meet 'peak' demand during the hottest summer days, it is idle nearly half the time. Paying year-round for this idle capacity costs customers around $2 billion a year. And while overall demand for electricity is flat, 'peak' demand continues to increase, resulting in even higher costs to customers. Maintaining the power grid cost New Yorkers an additional $17 billion over the past 10 years, and if trends are not addressed, $30 billion will be spent in the coming decade.
- Environmental cost: Electricity generation is a leading cause of greenhouse gas emissions in New York state. To protect the health and welfare of New Yorkers and our environment, we must diversify our sources of energy and accelerate deployment of clean, low-carbon technologies.
- Resilience: Superstorm Sandy and Tropical Storms Lee and Irene left millions of New Yorkers without electricity. A more resilient energy system will be better able to power our homes, businesses, and economy in the face of these increasingly common extreme weather events. Hospitals, first responders, community centers, and other places of refuge will also be better prepared to address emergency and safety issues with more resilient power sources."

Clearly, a new utility emphasis on the role of the consumer—empowered by standards, energy use data, apps, utility programs, and third-party offerings—can be supported by *bona fide* SECC research into consumer behavior and perceptions. Creating a consumer-centric, more market-based, distributed energy paradigm will take years. The foregoing section on consumers and the changing utility-consumer relationship, however, illustrates that a fundamental shift is under way.

25.8 ECONOMIC GROWTH AND CHANGES IN THE GLOBAL ELECTRIC POWER MARKET

The U.S. Energy Information Administration's (EIA) International Energy Outlook (IEO) for 2016 (IEO 2016) divides the world's countries into members of the Organisation for Economic Cooperation and Development (OECD) and nonmembers to present energy-related data and projections.

OECD members are divided into three basic groupings: OECD Americas (United States, Canada, and Mexico/Chile), OECD Europe, and OECD Asia (Japan, South Korea, and Australia/New Zealand). Non-OECD countries are divided into five separate regional subgroups: non-OECD Europe and Eurasia (which includes Russia), non-OECD Asia (which includes China and India), Middle East, Africa, and non-OECD Americas (including Brazil) [66].

(The OECD studies drivers of economic, social, and environmental change, and measures productivity and global flows of trade and investment. The organization also performs analyses to predict future trends.)

The IEO 2016 projects 2% annual gross domestic product (GDP) growth in OECD countries and 4.2% for non-OECD countries through 2040. Generally speaking, mature, developed economies grow more slowly than developing economies. According to the IEO, however, these differences in growth rates are expected to narrow, as growth in non-OECD countries slows, and they shift from reliance on production in energy-intensive industries to more service-oriented industries.

Overall, global GDP growth is projected to average 3.3% per year from 2012 to 2040. That growth rate is expected to slow over 2012–2014, peaking at 3.8% per year in 2018, then declining to 3.0% per year in 2040. Slower global growth after 2020 is due to expected slower growth in emerging economies, particularly China.

The fastest-growing OECD countries from 2012 to 2040 are projected to be Chile and Mexico, whose combined GDP is projected to increase by an average of 3.1% per year. In mid-2016, Newton-Evans projected a short-term downside for North America, including a slowdown in hiring, decreased corporate profits, lower industrial production; and an upside, which includes relatively upbeat consumer spending and some degree of wage growth.

Among non-OECD countries, India has the world's fastest-growing economy. It is projected to grow on average 5.5% per year from 2012 to 2040.

According to the IEO 2016, much of the global increase in energy demand is driven by strong economic growth and expanding populations in the developing non-OECD nations (Figure 25.8). Specifically, non-OECD demand for energy is projected to rise by 71% from 2012 to 2040. In contrast, in more mature, energy-consuming and slower-growing OECD economies, energy use is projected to rise by only 18% from 2012 to 2040. Clearly, economic growth is a major influence on energy consumption.

More than half of the projected increase in global energy consumption from 2012 to 2040 takes place in non-OECD Asia, which includes China and India—not incidentally, the two most populous countries in the world, with 1.4 billion and 1.3 billion people, respectively. (The United States is the third most populous country, with 321 million people.) Both China and India are among the world's fastest-growing economies over the past decade [67].

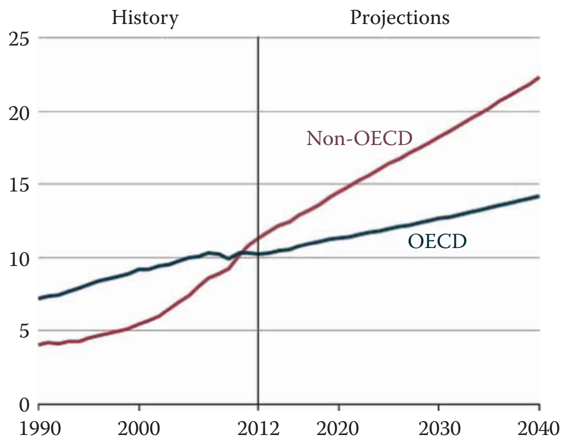

FIGURE 25.8 A rough, graphical depiction of OECD and non-OECD growth in electricity generation, 1990–2040. (From the U.S. Energy Information Administration's (EIA) International Energy Outlook (IEO) for 2016 (IEO 2016).)

In the future, however, the differences in economic growth rates between OECD and non-OECD nations are expected to narrow, as economic growth in non-OECD countries moderates, and as their industrial structures move from reliance mainly on production in energy-intensive industries to more service-oriented industries.

Based on seven studies on smart grid-related topics in 2013–2016, encompassing more than 600 surveys of utility executives in 34 countries [68], Newton-Evans forecasts relatively slow growth in transmission and distribution (T&D) spending (and smart grid products, services, and systems) among OECD nations over the next 5 years. This forecast correlates closely with the 2% Average Annual Growth Rate (AAGR) outlook for OECD countries made by the EIA. That rate may rise to 5% or 6% in 1 or 2 years during this 5-year outlook. This outlook may be characterized as market stability with relatively slow to moderate growth.

The following points are culled from the IEO 2016's executive summary [66], to provide a sense of specific trends not reflected in the foregoing high-level view of the global market.

- Global energy use is projected to rise for three decades, fueled by Asia, specifically China and India.
- By 2040, nearly two-thirds of the world's primary energy will be consumed in non-OECD countries.
- Strong projected economic growth rates in non-OECD countries drive growth in future energy consumption in those countries.
- Renewables (except for hydropower) are projected to be the fastest-growing energy source worldwide between 2016 and 2040, with renewables consumption increasing by an average 2.6% per year.
- Nuclear power is the second fastest-growing energy source worldwide; consumption is projected to increase by 2.3% per year, 2016–2040.
- Many OECD countries have adopted environmental policies and regulations to reduce GHG emissions from electric power plants by cutting the use of fossil fuels, leading to a declining role for coal. Projections show that by 2040, generation from renewables will equal generation from coal on a global basis.
- Fossil fuels, though outpaced by the growth in renewables, will still account for 78% of energy use in 2040.

- The fastest-growing fossil fuel is natural gas, and global consumption is projected to increase by 1.9% per year.
- Coal shows the slowest growth, rising by 0.6% per year. Coal will be surpassed by natural gas by 2030.
- The electric power sector continues to be one of the most dynamic growth areas among all energy markets. Electricity remains the world's fastest-growing form of end-use energy consumption, continuing a decades-long trend.
- Global, energy-related CO_2 emissions increase 34%, 2016–2040, driven by non-OECD countries, which rely on fossil fuels to meet the fast-paced growth in demand for energy.

25.9 LOOKING AHEAD

The second edition of this book has spelled out the thinking, the tools, and the methods by which power industry stakeholders can advance grid modernization, particularly in the area of adding intelligence, automation, and situational awareness.

The many contributing authors have provided insight into the current status of the three pillars of progress, namely, in random order, technology, policy, and standards. This chapter has placed particular emphasis on articulating and illustrating the reasoning behind current best practices that will inform the near-term future. Perhaps the most influential change since the first edition of this book was published is the power industry's recognition that traditionally regulated monopolies will gradually, inevitably, transition to more market-based businesses. As such, they will be buffeted by market forces, challenged by third-party energy service companies and subject to the demands of former "ratepayers" who have become "customers" and, more to the point, savvy "consumers." A cornerstone of this chapter is devoted to the consumer, who is likely to emerge as the most dominant force in a market-based, twenty-first century power paradigm. It will behoove utilities to explore, as suggested, the potential for consumer use of social media to engage them for mutual benefits.

Stakeholders recognize that the ground is shifting. The question moving forward is how to best navigate a changing environment. The future of power utilities as currently constituted is by no means guaranteed and the centricity of "the grid" as we know it is evolving. A centralized grid can and probably should continue to serve society, though it may share its traditional role with new players and empowered consumers. Power utilities, just to meet their current, traditional obligations and, looking ahead, remain relevant, will need to adopt an energetic, proactive approach to deliver their established value and create new value streams. As the industry becomes more market-based, utilities will need to innovate, partner, and create sustainable practices and business models to thrive. The forces of change from all quarters are too strong and persistent to do otherwise.

This concluding section on "Looking Ahead" is an opportunity to review the key benefits of grid modernization, suggest an open-ended, nonprescriptive approach for how stakeholders might proceed in order to realize those benefits, and, finally, gaze into the crystal ball on likely mid-term and long-term outcomes.

25.9.1 A Recap of Current Conditions

As noted, utilities today face a very different future than they did just two decades ago. In addition to meeting traditional performance metrics on reliability, safety, and emissions, new policy mandates often include goals for RPSs, energy efficiency (EE), and even restrictive emissions. Integrating high levels of DERs introduces new technical challenges, particularly when those DERs are sponsored and owned by large customers, nonutility players, and consumers. Widespread implementation of nonutility DER and energy efficiency goals will at some point impact utilities' volumetric sales-based revenue. Third-party energy service companies have seized technically feasible business opportunities to disintermediate utilities and their customers. Digitally savvy consumers expect energy use data transparency and benefits and other service options. The advent of more frequent, extreme weather events has had enormous impacts on utilities' physical assets as well as awakening consumers to the perceived advantages of some form of energy self-reliance. In many countries, though national policy and some degree of funding has often been supportive of grid modernization, typically, local policymakers have been slower to recognize and accommodate these new realities, leaving some utilities between the proverbial rock and a hard place.

At the same time, utilities have never had more experience, lessons learned, well-defined best practices, and a deeper toolkit of technology and standards with which to face current and future challenges. Utility leadership retains the ability and prerogative to define their organization's strategy, operating model, and desired outcomes, while building stakeholder support—elements that will serve them well in the face of future uncertainties.

25.9.2 Grid Modernization Benefits

In the big picture, realizing grid modernization and its benefits should create a robust, flexible, scalable grid that meets both utility and public goals that include the provision of adequate infrastructure, energy productivity, management of electricity costs, and mitigation of environmental impacts. On the ground, an individual utility should achieve improved reliability and resiliency metrics, as measured by SAIFI and her "sisters," via improved visibility, situational awareness, monitoring, and control. Demanding enterprise-wide participation in technology requirements and outcomes should level the organizational structure, eliminate silos (especially between OT and IT), and propel enterprise culture change to embrace organization-wide outcomes and benefits.

Utilities should focus on creating a "strong" grid—that is, one based upon a foundational ICT investment that delivers all available data to anyone in the enterprise who can benefit from it—before considering a "smarter" grid. Then, modernization projects should map a utility's business drivers to AMI, SA, DA, and other improvements that together, synergistically, provide even greater benefits than any one project alone. How any individual utility navigates this admittedly overgeneralized, nonprescriptive approach will depend on their location, business drivers, legacy assets, customers, service territory characteristics, and myriad other factors. Internally, workforce efficiencies through the use of mobile data dispatch, field force automation, and DA will be needed as the current, knowledgeable workforce retires. Externally, building stakeholder support should be an immediate and ongoing priority to gain trust and consensus for moving forward. Doing so as a project is announced is too little, too late.

As we pointed out in this chapter, federal policymakers in the USA have, over time, laid the groundwork for grid modernization, funded widespread investments in technology deployments and pilot projects, and suggested guidelines for state regulators to gauge the cost-effectiveness and public benefits of utility projects. State PUCs' responsibilities have grown from relatively simple oversight of utility efforts to deliver safe, affordable power and preside over rate cases to a more complex role in determining whether a given utility is on a rational path, with public benefits, in grid modernization. Understanding the principles and perils at stake in deregulation, de-coupling (volumetric sales from revenue), and devising revenue models that reward innovation for public benefit, such as reducing emissions, increasing efficiency, and moving to a more market-based business model, will in the long-run pay dividends. It will simplify the regulator's role, clarify utility rights and responsibilities, and ensure that the public has service options and control over their energy future. PUCs will need to clear the way for utility- as well as third party- and customer-owned DER and reward those who benefit the system as a whole.

Vendors and system integrators/consultants compose another major stakeholder group that ultimately will see benefits from grid modernization. In a standards-based world, offering clients expensive, proprietary solutions cannot compete in a market that increasingly favors innovation based on standards and interoperability. If utilities and their regulators demand standards-based solutions as the basis for awarding contracts, vendors and system integrators/consultants will be forced to produce standards-based technology and systems integration. The market and its participants will benefit because standards and interoperability support a virtuous cycle of expanded markets, economies of scale, lower end-user costs, and higher adoption rates.

25.9.3 The Consumer

Though "stakeholders" can encompass innumerable segments of society, the most fundamental stakeholder in a market is always the consumer. Consumers will benefit from grid modernization in ways both small and large. Individual consumers will see greater reliability of service, fewer and shorter outages, more efficient use of capital expenditures (capex) and operations expenditures (opex), and, thus, more rational rates and charges. Net metering policies should encourage an orderly adoption of DER that will mutually benefit consumer and utility. The availability of energy use data and management options, whether provided by a utility or third party, should further encourage energy conservation and efficiency. These factors will contribute to a larger set of benefits for society as a whole, including reductions in GHG emissions that contribute to climate change and carbon emissions with impacts on public health. In the mid- to long-term, sustainable energy practices aided by grid modernization will provide the foundation for comfort and productivity that equate to economic prosperity and security.

25.9.4 The Path Forward

What do utility leaders and their stakeholders need to do to create a path forward in grid modernization to realize these benefits? Simply put, it's a proactive, holistic approach that includes awareness, education, participation, and anticipation.

Utility leaders, in particular, should set an example by personally belonging to and participating in industry organizations, conferences, and publications relating to technology, policy, and standards. Leaders should require their team to do the same so that all bases are covered. Though such participation can require significant commitments of time outside the day-to-day challenge of running a utility, broad outreach is invaluable in informing the direction a utility takes in grid modernization.

In terms of technology, such organizations include the IEEE Power and Energy Society and its technical activities efforts and the International Council on Large Electric Systems and its technical activities (16 Study Committees).

In terms of policy, we've noted the U.S. example of the federal FERC and NERC, which govern generation and transmission. Distribution and the customer are governed by 51 (50 states and the District of Columbia) PUCs. The commissioners in the 51 PUCs are members of National Association of Regulatory Utility Commissioners (NARUC). The national associations for IOUs, municipal, and cooperative utilities are, respectively, Edison Electric Institute (EEI), the American Public Power Association (APPA), and the National Rural Electric Cooperative Association (NRECA). Understanding a utility's policy needs and positions and advocating them is not only fair but desirable. Do not neglect a liaison with the National Association of Utility Consumer Advocates (NASUCA) and consumer advocates; understanding and benefitting consumers—from traditional protections for vulnerable populations to the public benefits of grid modernization rate cases—pays dividends in the long run.

A designated utility official should participate in or monitor standards development organizations, such as the IEEE Standards Association (IEEE-SA) and the IEC, as well as groups that identify gaps in standards such as SGIP.

All of these organizations hold regular conferences, sponsor-related professional networks, and publish relevant periodicals. Awareness, education, and participation will contribute to anticipation of future developments that provide the context for sound decision-making.

25.9.5 A Glimpse of the Future?

Looking into the future is always fraught with peril. But a few observations might be appropriate. Currently known technologies and best practices, applied with a holistic approach, will likely guide the majority of utilities into the near-term future of the next several years. When the benefits of the current phase of grid modernization are realized, power industry stakeholders will have the credibility and confidence to discern the next steps, and those, in turn, will inform the mid-term future. The insights, tools, methods, and models currently at our disposal, or soon to be commercialized, will likely carry the power industry to the mid-term horizon of the next 5 years.

At that point, the crystal ball slips from transparent to translucent, if not opaque. It is not abundantly clear what new utility business models will look like or if they will take distinctly different forms based on national or regional policy or other factors. Cautiously worded statements about the near- and mid-term future give way to a litany of questions about the long-term future. Will utilities retreat to a focus on asset management of the grid and leave the consumer and retail interface to marketing and service entities? Or will they partner with such entities and become vertically integrated energy providers? Will mergers and acquisitions or divestitures characterize the market? Will policies favor third parties who will succeed in disintermediation of utilities and their customers? Will consumers, tempted by rising DER efficiencies and falling prices, seek energy self-sufficiency and become the dominant market force? Or will a dynamic hybrid of these forces and factors lead to shared ownership, operations, and benefits? How do the traditional divisions of generation, transmission, and distribution change and the markets and regulations associated with each category change over time?

Certainly, advances in ICT, power electronics, and their integration into known technologies and monitoring/control systems appear poised to play a role in a future shaped by sometimes cooperating, sometimes competing stakeholders. Perhaps the "grid" will cease to be considered an entity of its own and, instead, become part of a continuous energy "fabric" that relies on distributed rather than central generation nodes, with a bi- or multidirectional power network at various voltage levels extending down to pervasive, localized, energy producing or harvesting components, from homes and businesses to devices and sensors that alternately produce or consume energy depending on the time of day or season of the year, with payments and credits flowing in multiple directions—a scenario of fluid, multidirectional energy flows and financial or other value transactions, reliable in its diversity and distribution, resilient due to its mesh/web design, efficient due to proximity of supply and load, and sustainable due to a greater shift to renewable energy sources. Ownership and control may accrue according to the value produced. A million possibilities present themselves. Perhaps in 5 years, and the next edition of this book, this future will be more visible.

LIST OF ABBREVIATIONS

A&E	architects and engineers
AAGR	average annual growth rate
ACEE	American Council for an Energy Efficient Economy
ADMS	advanced distribution management system
AMI	advanced metering infrastructure
ANSI	American National Standards Institute
APPA	American Public Power Association
APS	Arizona Public Service
ARRA 2009	American Recovery and Reinvestment Act of 2009
BCR	benefit/cost ratio
CBS	consumer behavior study
CI	commercial/industrial

CIGRE	International Council on Large Electric Systems
CIM	Common Information Model
CIS	customer information system
ComEd	Commonwealth Edison
CPUC	California Public Utilities Commission
CSP	concentrating solar power
DA	distribution automation
DER	distributed energy resource
DG	distributed generation
DOE	U.S. Department of Energy
DPA	distribution power analysis
DR	demand response
DRAM	demand response auction mechanism
DRP	distribution resource planning
DSM	demand-side management
EDF	Environmental Defense Fund
EE	energy efficiency
EEI	Edison Electric Institute
EIA	U.S. Energy Information Administration
EISA 2007	Energy Independence and Security Act of 2007
EPA	U.S. Environmental Protection Agency
EPC	engineering, procurement, construction
EPSA	Electric Power Supply Association
ESCO	energy service company
ESPI	Energy Services Provider Interface
FDIR	fault detection, isolation and restoration
FERC	Federal Energy Regulatory Commission
FLISR	fault location, isolation and service restoration
FPA	Federal Power Act
GDP	gross domestic product
GHG	greenhouse gases
GIS	geographic information system
HAN	home area network
ICA	Integrated Capacity Analysis
ICT	information and communications technology
IEC	International Electrotechnical Commission
IED	intelligent electronic device
IEEE	Institute of Electrical and Electronics Engineers
IEEE-SA	IEEE Standards Association
IEO	International Energy Outlook
IHD	in-home display
IL CUB	Illinois Citizens Utility Board
IoT	Internet of Things
IOU	investor-owned utility
IP	Internet protocol
IT	information technology
ITU	International Telecommunications Union
IVVC	integrated volt/VAr control
kWh	kilowatt hour
LMP	locational marginal pricing
LNBA	Locational Net Benefits Analysis
LTC	load tap changer

MAIFI	Momentary Average Interruption Frequency Index
M2M	machine-to-machine
NARUC	National Association of Regulatory Utility Commissioners
NASUCA	National Association of Utility Consumer Advocates
NGO	non-governmental organization
NIST	National Institute of Standards and Technology
NRECA	National Rural Electric Cooperative Association
NY REV	New York – Reforming the Energy Vision
OECD	Organisation for Economic Cooperation and Development
OMS	outage management system
OpenFMB	Open Field Message Bus
OSHA	Occupational Safety and Health Administration
OT	operations technology
PAN	premise area network
PCT	Programmable communicating thermostat
PES	IEEE Power & Energy Society
PEV	Plug-in electric vehicle
PLC	power line carrier
PMU	phasor measurement unit
PUC	public utility commission
PV	photovoltaics
QoS	quality of service
R&D	research and development
RAP	Regulatory Assistance Project
RBROR	Rate-base rate-of-return regulation
RF	radio frequency
ROI	return on investment
RPS	renewable portfolio standard
RTU	remote terminal unit
SA	substation automation
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SDG&E	San Diego Gas & Electric
SECC	Smart Energy Consumer Collaborative
SGIG	Smart Grid Investment Grant
SGIP	Smart Grid Interoperability Panel
SME	small- and medium-sized enterprises
TVR	time-varying rates
V2G	vehicle-to-grid
VAr	Volt-Ampere reactive

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