15 Concept of Smart Grid and Its Applications

To dream the impossible dream,
To reach the unreachable star.

Joe Darion, in *The Impossible Dream*

An active field of science is like an immense anthills; the individual almost vanishes into the mass of minds tumbling over each other, carrying information from place to place, passing it around at the speed of light.

Lewis Thomas, in *Natural Science*

15.1 BASIC DEFINITIONS

Grid: The transmission system. It is the interconnected group of power lines and associated equipment for moving electric energy of high voltage between points of supply and points at which it is delivered to other electric systems or transformed to a lower voltage for delivery to customers.

Smart grid: The modernization of the grid by installing intelligent electronic devices in terms of sensor electronic switches, smart meters, and also advanced communication, and data acquisition and interactive software with real-time control that optimize the operation of the whole electric system and make more efficient utilization of the grid assets. It is such grid that is called the *smart grid*.

Legacy power systems: The presently existing power systems that have no smart grid applications yet.

Intelligent electronic device (*IED*): Any device incorporating one or more processors with the capability to receive or send data and control from or to an external source (e.g., electronic meters, digital relays, and controllers).

IED integration: Integration of protection, control, and data acquisition function into a minimal number of platforms to reduce capital and operating costs, reduce panel and control room space, and eliminate redundant equipment and databases.

International electrotechnical commission (*IEC*): An international organization whose mission is to prepare and publish standards for all electric, electronic, and related technologies.

Remote terminal unit (RTU): The entire complement of devices, functional modules, and assemblies that are electrically interconnected to affect the remote station supervisory functions. The equipment includes the interface with the communication channel but does not include the interconnecting channel.

Conventional RTU: Designed primarily for hardwired input/output (I/O) and has little or no capability to talk to downstream IEDs.

Remote access: Access to a control system or IED by a user whose operation terminal is not directly connected to the control systems or IED. Transport mechanisms typical of remote access include dial-up modem, frame relay, ISDN, Internet, and wireless technologies.

Protocol: A formal set of conventions governing the formal and relative timing of message exchange between two communication terminals; a strict procedure required to initiate and maintain communication. A communication protocol allows communication between two devices. The devices must have the same protocol (and version) implemented, otherwise the differences will result in communication errors. The substation integration and automation architecture must allow devices from different suppliers to communicate (interoperate) using an industry standard protocol.

Substation automation (SA): Deployment of substation and feeder operating functions and applications ranging from supervisory control and data acquisition (SCADA) and alarm processing to integrated volt/var control (IVVC) in order to optimize the management of capital assets and enhance operation and maintenance efficiencies with minimal human intervention.

Data concentrator: Designed primarily for IED integration and may also have limited capability for hardwired I/O.

Operational data: Also called SCADA, data and are instantaneous values of power system analog and status points (e.g., amps, volts, MW, Mvar, circuit breaker status, switch position). The operational data is conveyed to the SCADA master station at the scan rate of the SCADA system using the SCADA system's communication protocol, for example, DNP3.

Nonoperational data: Consists of files and waveforms (e.g., event summaries, oscillographic event reports, or sequential event records) in addition to SADA-like points (e.g., status and analog points) that have logical state or numerical value.

Home area network (*HAN*): The HAN stands for "home area network"; it is used to identify the network of communicating loads, appliances, and sensors beyond the smart meter and within the customer's property.

Security: The protection of computer hardware and software from accidental or malicious access, use, modification, destruction, or disclosure.

National Institute of Standards and Technology (*NIST*): Under the federal law of Energy Independence and Security Act of 2007, the National Institute of Standards and Technology (NIST) has been given the key role of coordinating development of a framework for smart grid standards.

Distributed network protocol (*DNP3*): A non-propriety communication protocol that is designed to optimize the transmission of data acquisition information and control commands from one computer to another.

CIGRE: An International Conference on Large High-Voltage Electric Systems. It is recognized as a permanent nongovernmental and nonprofit-making international association based in France. It focuses on issues related to the planning and operation of power systems, as well as the design, construction, maintenance, and disposal of high-voltage equipment and plants.

Cyber security: Security from threats conveyed by computer or computer terminals; also, the protection of other physical assets from modification or damage from accidental or malicious misuse of computer-based control facilities.

Intrusion detection system (*IDS*): A device that monitors the traffic on a communication line with the aim of detecting and reporting unauthorized users of the facilities. It is programmed to identify and track specific patterns of activities.

Port: A communication pathway into or out of a computer or networked device such as a server. Ports are often numbered and associated with specific application programs. Well-known applications have standard port numbers; for example, port 80 is used for HTTP traffic (web traffic).

Demand response (*DR*): *It defines the consumers' behavioral change to the changing rates.* It enables demand-side resources and improves the economic operation of electric power markets by aligning prices more closely with the value customers place on electric power.

Demand response management (*DRM*): It is similar to the old term known as "load management." It can provide competitive pressure to reduce wholesale power prices, increase awareness of energy usage, provide for more efficient operation of markets, mitigate market power, enhance reliability, and, in combination with certain new technologies, support the use of renewable energy resources, distributed generation, and advanced metering.

Distributed energy resources (*DER*): It is a phrase that refers to the new energy resources that are connected into a utility distribution network.

Plug-in hybrid electric vehicles (*PHEV*s): The vehicles that are designed and built to operate using either gas or electricity, by charging their batteries at night by plugging them into receptacles.

Wide area network (*WAN*): WAN is used to identify the network of upstream utility assets, including power plants, distribution storage, and substations. The interface between WAN and LAN and LAN and HAN is provided by smart meters.

Wide area monitoring/measurement system (*WAMS*): A monitoring/measurement system that is dedicated to monitor a WAN. It is based on a low latency networking.

Local area network (*LAN*): A local area network that facilitates for the enabled IEDs can be directly connected to the substation automation LAN. It is used to identify the network of integrated smart meters, field components, and gateways that constitute the logical network between distribution substations and customer's premises. The non-LAN-enabled IEDs require a network interface module (NIM) for protocol and physical interface conversion. A substation LAN is typically high speed and extends into the switchyard, which speeds the transfer of measurements, indications, control commands, and configuration and historical data between intelligent devices at the site.

Neighborhood area networks (*NAN*): The physical connections to the meter nodes change from WAN to NAN technologies. It is achieved by introducing one or more routers at the borders of the NAN that is connected to WAN, enabling bidirectional data streams between WAN and NAN.

Short-circuit analysis (*SCA*): It is used to calculate the short-circuit current to evaluate the possible impact of a fault on the network.

Active network: It is a passive network that has been converted to an active one by the connection of distributed generation in terms of, for example, CHP cogens and/or other renewable-based energy-producing units such as wind turbines or solar units.

Distribution management system (*DMS*): A system that uses voltage regulators or transformers with load tap changers (LTCs) to automatically raise or lower the voltage in response to changes in load. It also uses capacitor banks to supply some of the reactive power that would otherwise be drawn from the supply substations.

Substation automation (*SA*): Deployment of substation and feeder operating functions and applications ranging from SCADA and alarm processing to IVVC in order to optimize the management of capital assets and enhance operation and maintenance efficiencies with minimal human intervention.

Open systems: A computer system that embodies supplier-independent standards so that software can be applied on many different platforms and can interoperate with other applications on local and remote systems.

Data processing applications: The software applications that provide various users access to the data of the substation controller in order to provide instructions and programming to the substation controller, collect data from the substation controller, and perform the necessary functions.

Data collection applications: The software applications that provide the access to other systems and components that have data elements necessary for the substation controller to perform its functions.

Control database: All data reside in a single location, whether from a data processing application, data collection application, or derived from the substation controller itself.

Distributed network protocol (*DNP*): A comprehensive protocol to achieve open, standard-based interoperability between substation computers, RTUs, IEDs, and master stations (with the exception of inter-master communications) for the electric utility industry. The present version of DNP is version 3, that is, DNP3. Level 1 has the least functionality (used for simple IEDs), and level 3 has the most functionality (used for SCADA master station-communications front-end processors). Its advantages include the following: interoperability between multi-supplier devices; fewer protocols to support in the field; not needing protocol translators; reduced software costs; shorter delivery schedules; less need for testing, maintenance, and training; improved documentation; support for independent user group and third-party sources; easier system expansion; faster adoption of new technology; longer product life; and huge operational savings.

Distributed generation (*DG*): It refers to small generators that are connected to the distribution system network. Such generation is known as *distributed generation* (DG) or *dispersed generation*, or *embedded generation*.

Automated metering infrastructure (*AMI*): The network of communications between the substation and substation regulators, switches, capacitor banks, distributed regulators, real-time metering, alternative points of supplies, as well as active networks, if they exist.

15.2 INTRODUCTION

Today, there are many who do not like the usage of the term *smart grid*, but would have preferred to use *smarter grid*, because they feel that the existing grid is already plenty smart. What is needed is a "more efficient or advanced grid" in terms of the usage of advanced communication technology and information technology (IT) and other advanced technologies, and improved efficiencies. Arguably, because of that, it would have been the best to call the new perceived grid the "intelligent grid." Alas, the name is already coined for it. So, there it is.

Today's (legacy) electric grid is a one-way flow of electricity and according to the NIST [3]:

- Responsible for 405 of human-caused CO_2 production
- Centralized, bulk generation, mainly coal and natural gas
- Has controllable generation and predictable loads
- Limited automation and situational awareness
- Lots of customized proprietary systems
- Lack of customer-side data to manage and reduce energy uses

In that sense, the smart grid can simply be defined as "the grid with brain." It is a modernized grid that enables bidirectional flows of energy and uses two-way communication and control capabilities that will lead to an array of new functionalities and applications. The smart grid will permit the two-way flow of both electricity and information.

The move toward the smart grid is fueled by a number of needs. For example, there is the need for improved grid reliability while dealing with an aging infrastructure, and there is the need for environmental compliance and energy conservation. Also, there is the need for improved operational

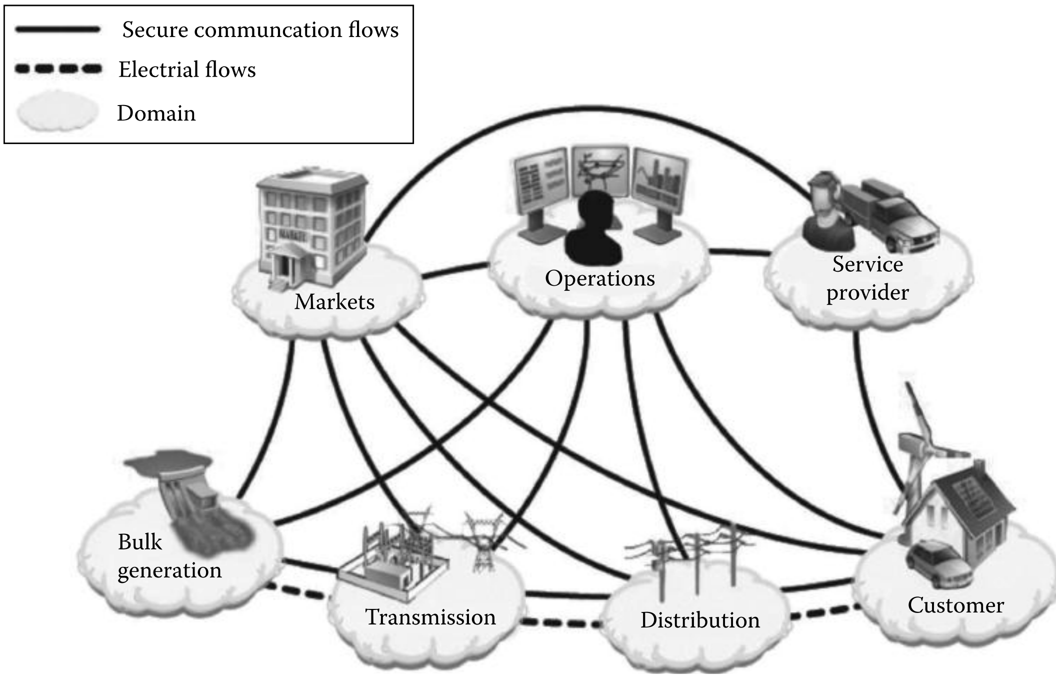

FIGURE 15.1 The conceptual representation of the smart grid network framework of NIST. (From *U.S. National Institute of Standards and Technology*: NIST framework and roadmap for smart grid interoperability standards, Release 1.0, September 2009, Washington, DC.)

efficiencies and customer service. Figure 15.1 shows the conceptual representation of the smart grid network framework of NIST. It represents the fundamental domains of the electric power system, namely, bulk power generation, transmission, distribution, customer operations, operation provider, customer, and markets. It also shows the electric flows and secure communication flows within the system.

Under the federal law of Energy Independence and Security Act of 2007, the National Institute of Standards and Technology (NIST) has been given the key role of coordinating development of a framework for smart grid standards. Thus, NIST's national coordinator for smart grid interoperability launched a three-phase plan to jump-start development and promote widespread adoption of smart grid interoperability standards [3]:

- Engage stakeholders in a participatory public process to identify applicable standards, gaps in currently available standards, and priorities for new standardization activities
- Establish a formal private–public partnership to drive longer-term progress
- Develop and implement a framework for testing and certification

Standardized architectural concepts, data models, and protocols are essential to achieve interoperability, reliability, security, and evolvability. New measurement methods and models are needed to sense, control, and optimize the grid's new operational paradigm. Today, the industry can benefit from similar large-scale experience-developing architecture and protocols for modernization of the telecom network and the Internet.

Furthermore, with an increase in regulating influence and the focus on smart grid advanced technologies, there is a renewed interest in increasing the investment in distribution networks to defer infrastructure build-out and to reduce operating and maintenance costs through improving grid efficiency, network reliability, and asset management (AM) programs. Thus, since the roots of power system issues are usually found in the electric distribution system, the point of departure for the grid overhaul is the distribution system [3].

The electric power grid is now focusing on a large number of technological innovations. Today, utility companies around the world are incorporating new technologies in their various operations and infrastructures. At the bottom of this transformation is the requirement to make more efficient use of present assets. Several utility companies have developed their own vision of future smart distribution systems to reach the smart grid objectives. Figure 15.2 shows such representation in terms of a smart grid tree. Notice that the trunk of the tree is the AM, which is the base of smart grid development. Based on this foundation, the utility company builds its smart grid system by a careful overhaul of their IT infrastructure, communication, and network infrastructure. Well-designed

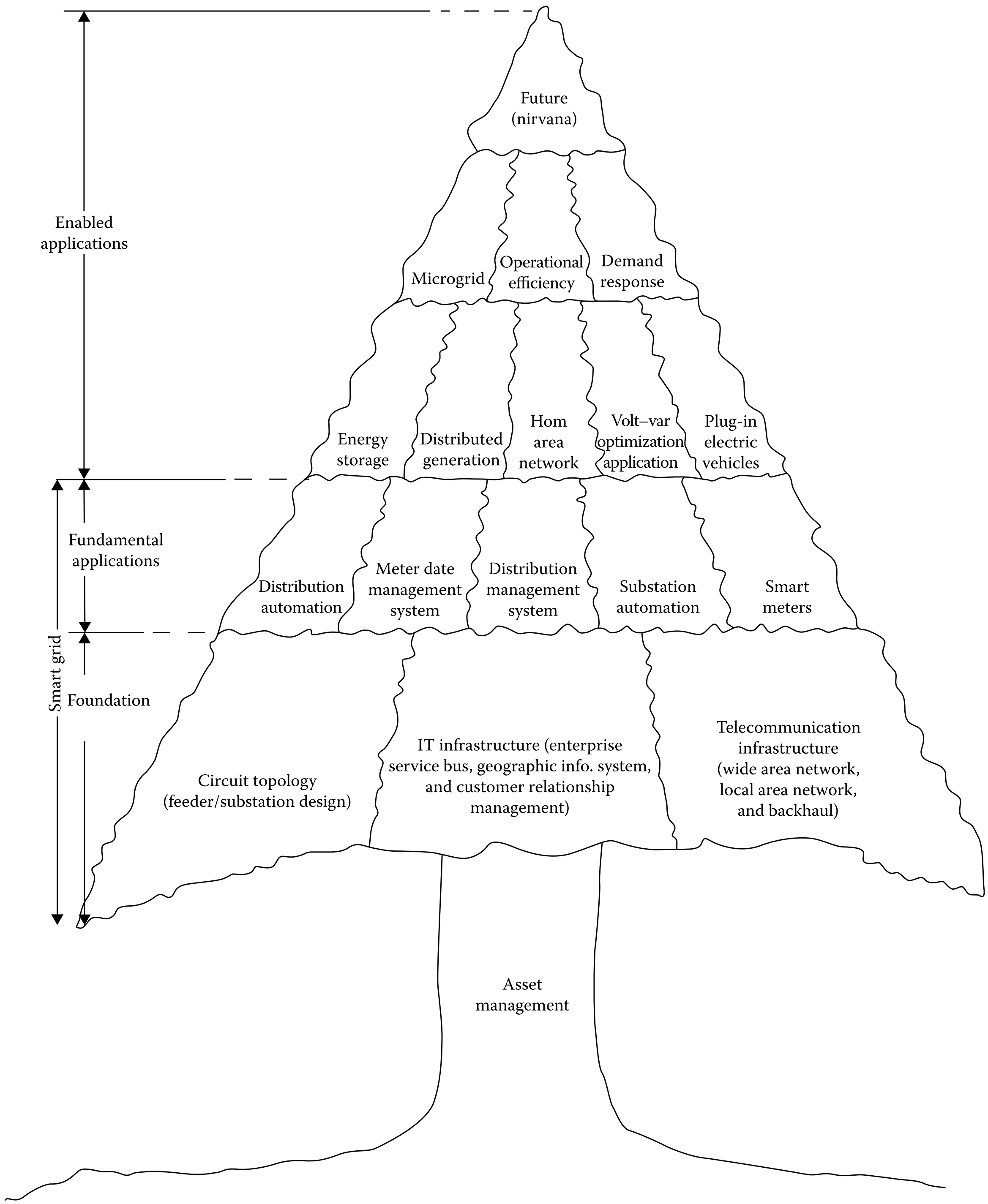

FIGURE 15.2 The representation of a smart grid as a tree.

layer of intelligence over utility assets that enables the emergence of the smart grid capabilities will be built on vertical integration of the upper-layer applications. For example, an important capability such as microgrid may not be possible without the integration of distributed generation (DG) and home area networks (HANs).

Thus, the emergence of the truly smart grid will require a drastic overhaul of the existing system. It will require the establishment of distributed control and monitoring systems within and alongside the present (legacy) electric power grid. Most likely, this change will be gradual but continuous.

The conventional methods of load management (LM) and load estimation (LE) in the traditional distribution management system (DMS) are no longer effective, causing other DMS applications ineffective or altogether useless. However, the impact of demand response management (DRM) and consumer behaviors may be mandated and predicted, from the utility pricing rules and rewarding policies for specific time periods.

As said before, most of the utilities believe that the biggest return on investment will be investing in distribution automation (DA) that will provide them with fast increasing capability over time. Thus, "blind" and manual operations, along with electromechanical components in the electric distribution grid, will need to be transformed into a "smart grid."

Such transformation is necessary to meet environmental targets, to accommodate a greater emphasis on demand response (DR), and to support plug-in hybrid electric vehicles (PHEVs) as well as DG and storage capabilities. Also, as succinctly put by Gellings [4], the attributions of the good smart grid are

1. Absolute reliability of supply
2. Optimal use of bulk power generation and storage in combination with distributed resources and controllable/dispatchable consumer loads to assure lowest cost
3. Minimal environmental impact of electricity production and delivery
4. Reduction in electricity used in the generation of electricity and an increase in the efficiency of the power delivery system and in the efficiency and effectiveness of end use
5. Resiliency of supply and delivery from physical and cyber-attacks and major natural phenomena (e.g., hurricanes, earthquakes, and tsunamis)
6. Assuring optimal power quality for all consumers who require it
7. Monitoring of all critical components of the power system to enable automated maintenance and outage prevention

Furthermore, the recommended renewable portfolio standard (RPS) mechanism generally places an obligation on the utility companies to provide a minimum percentage of their electricity from approved renewable energy sources. According to the US Environmental Protection Agency, as of August 2008, 32 states plus the District of Columbia had established RPS targets.

Together, these states represent for almost half of the electricity sales in the United States. The RPS targets presently range from a low 2% to a high 25% of electricity generation, with California leading the pact that requires 20% of the energy supply coming from renewable resources by 2010 and 33% by 2020. RPS noncompliance penalties imposed by states range from $10 to $25 per MWh.

On the average, a typical household in the United States uses 920 kWh of electricity per month with appliances accounting for 64.7% of electricity consumption.

The people who run the grid are generator owners and transmission owners. Also, from the system point of view, they are the independent system organizations (ISOs and RTOs). They monitor system loads and voltage profiles, operate transmission facilities and direct generation, define operating limits and develop contingency plans, and implement emergency procedures. Also, reliability coordinators play essential role. The North American Reliability Cooperation (NERC) develops and enforces reliability standards; monitors the bulk power systems; assesses future adequacy; audits owners, operators, and uses for preparedness; and educates and trains industry personnel.

Many states regulatory commissions have initiated proceedings or adopted policies for the implementation of automated metering infrastructure (AMI) to enable distributed resources. In this ruling on October 17, 2008, the Federal Energy Regulatory Commission (FERC) established a policy aimed at eliminating barriers to the participation of DR in the organized power markets (independent service operators [ISOs] and regional transmission organizations [RTOs]) by ensuring the comparable treatment of resources. In this ruling,

According to McDonald [5], FERC states that "the demand response can provide competitive pressure to reduce wholesale power prices: increases awareness of energy usage; provides for more efficient operation of markets; mitigates market power; enhances reliability; and in combination with certain new technologies, can support the use of renewable energy resources, DG, and advanced metering. Thus, enabling demand-side resources, improves the economic operation of electric power markets by aligning prices more closely with the value customers place on electric power."

Among other things, the order directs RTOs and ISOs to accept bids from distributed resources (DR) for energy and ancillary services, eliminate penalties for taking less energy than scheduled, and permit aggregators to bid DR on behalf of retail customers.

It is well known that the reliable supply of electric power plays a critical role in the economy. The new operating strategies for environmental compliance, together with our aging transmission and distribution infrastructure, constitute a great challenge to the security, reliability, and quality of the electric power supply.

When implemented throughout the system, intermittent energy resources, such as wind, will greatly stress transmission grid operation. The distribution grid will be also stressed with the introduction and, perhaps, rapid adaptation of on-site solar generation as well as PHEVs and plug-in electric vehicles (PEVs). Such plug-in vehicles could considerably increase the circuit loading if the charging times and schedules are not properly managed and controlled.

Major upgrades to distribution system infrastructure may flow patterns due to the integration of the DG and microgrids. Therefore, the existing power delivery infrastructure can be substantially improved through automation and information management.

As succinctly put by Farhangi [2], the convergence of communication technology and IT, with power system engineering helped by a number of new approaches, technologies, and applications, permits the existing grid to penetrate condition monitoring and AM, especially on the distribution system.

It is obvious that smart distribution system applications are at the core of the energy delivery systems between the transmission system and customers; all smart distribution applications target three main objectives:

1. Improving distribution network performance
2. Improving distribution system energy efficiency by increasing distribution network transit and capacity
3. Empowering the customer by providing choices

The smart distribution applications will have to integrate power system technologies such as DA, volt/var control (VVC), advanced distribution line monitoring with telecommunications, and data management technologies. The primary purpose of VVC is to maintain acceptable voltage at all points along the distribution feeder under all loading conditions. The purpose of using voltage regulators or transformers with *load tap changers* (LTCs) is to automatically raise or lower the voltage in response to changes in load.

It is often that there is a need that requires the use of *capacitor banks* to supply some reactive power that would otherwise be drawn from the supply substations. As penetration of intermittent renewable resource-based generating units increase in the future, high-speed dynamic load/var control will play a significant role in *maintaining power quality* and *voltage stability* on the distribution feeders.

Hence, as said before, electric utility companies believe that investing in DA will provide them with increasing capabilities over time. Thus, the first step in the evolution of the smart grid starts at the distribution side, enabling new applications and operational efficiencies to be introduced into the system.

15.3 NEED FOR ESTABLISHMENT OF SMART GRID

The electric power delivery system has often been referred to as the greatest and most complex machine ever built. It is made of wires, electric machines, electric towers, transformers, and circuit breakers—all put together in some fashion. The existing electricity grid is unidirectional in nature. Its overall conversion efficiency is very low, about 33% or 34%. In the United States, there are 140 million customers of electricity. They can be divided into three categories: *residential* (with 122 million customers and 37% of electricity sales), *commercial* (with 17 million customers and 35% of electricity sales), and *industrial* (with less than 1 million customers and 28% of electricity sales).

That means it converts only one-third of fuel energy into electricity, without recovering even its waste heat. Approximately 8% of its output is lost along its transmission lines, while 20% of its generation capacity exists just to meet its peak demand (i.e., it is being used for only 5% of the time). Furthermore, the existing electric system is vulnerable for domino-effect failures due to hierarchical topology of its assets.

The electric grid of today is one-way flow of electricity, as shown in Figure 15.3. According to NIST, its properties can be categorized as follows:

- Centralized, bulk generators, mainly coal and natural gas
- Responsible for 40% of human-caused CO_2 production
- Controllable generation and predictable loads
- Limited automation and situational awareness
- Lots of customized proprietary systems
- Lack of customer-side data to manage and reduce energy losses

The electric power grid infrastructure of the United States was built more than 50 years ago. It has become a complex spider web of power lines and aging networks and systems with obsolescent technology and outdated communications. In addition, there is a growing demand for lower carbon emissions, renewable energy sources, and improved system reliability and security. Figure 15.4 shows 2007 electric generation by source.

Increasing efficiency is a key priority. In that process, the following facts have to be taken into account [3]:

- Half of US coal plants are greater than 40 years old.
- Average substation transformer age is greater than 40 years.

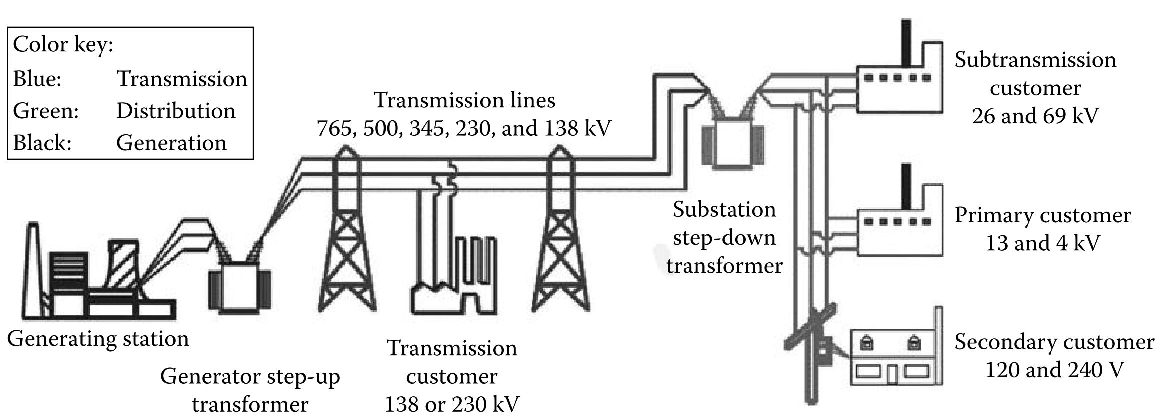

FIGURE 15.3 Legacy systems (today's electric grid). (From *U.S. National Institute of Standards and Technology*: NIST framework and roadmap for smart grid interoperability standards, Release 1.0, September 2009, Washington, DC.)

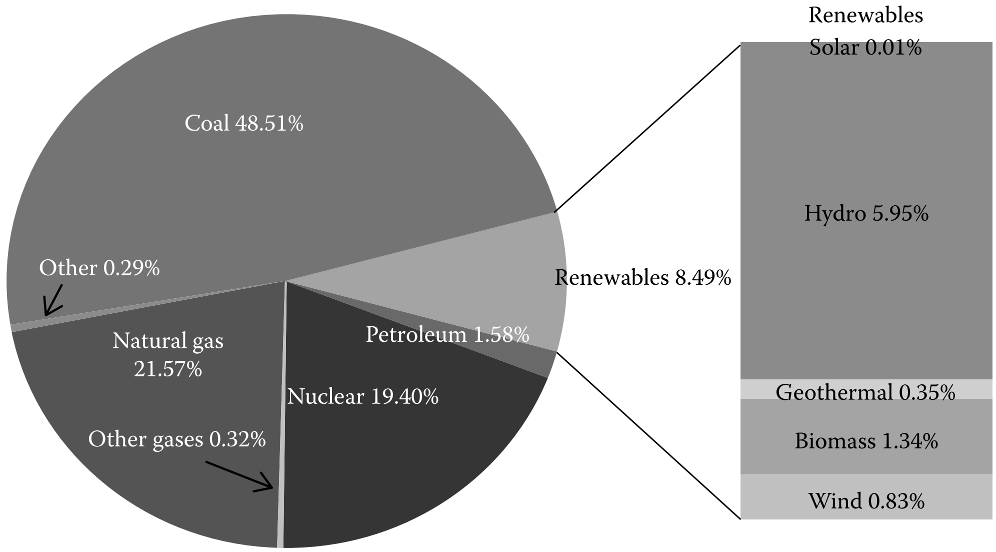

FIGURE 15.4 2007 electric generation by source. (From *U.S. National Institute of Standards and Technology*: NIST framework and roadmap for smart grid interoperability standards, Release 1.0, September 2009, Washington, DC.)

- Projected investment and expansion expenditure is predicted to be between \$1.5 and \$2 trillion by 2030.
- The US per capita annual electricity consumption is about 13,000 kWh that is largest among the industrialized countries. For example, Japan's per capita usage is 7,900 kWh.
- Smart grid helps utilities reduce delivery losses and average consumption and therefore reduce investment otherwise would be required.

The smart grid integrates IT and advanced communications into the power system in order to

- Increase system efficiency and cost effectiveness
- Provide customer tools to manage energy use
- Improve reliability, resiliency, and power quality
- Enable use of innovative technologies, including renewables, storage, and electric vehicles

All these requirements dictate the modernization of the grid by installing intelligent electronic devices (IEDs) in terms of sensor electronic switches, smart meters, and also advanced communication, and data acquisition and interactive software with real-time control that optimize the operation of the whole electric system and make more efficient utilization of the grid assets. It is such grid that is called the *smart grid*.

It is envisioned that such smart grid would integrate the renewable energy sources, especially wind and solar, with conventional power plants in a coordinated and intelligent way that would not only improve reliability and service continuity but would effectively reduce energy consumption and significantly reduce the carbon emissions. Based on a July 2009 Smart Grid Report of the United States Department of Energy [11], a smart grid has to have the following functions:

1. *Optimize asset utilization and operating efficiency*: The smart grid optimizes the utilization of the existing and new assets, improves load factors, and lowers system losses in order to maximize the operational efficiency and reduce the cost. Advanced sensing and robust communications will allow early problem detection, preventive maintenance, and correction action.
2. *Provide the power quality for the range of needs*: The smart grid will enable utilities to balance load sensitivities with power quality, and consumers will have the option of

purchasing varying grades of power quality at different prices. Also, irregularities caused by certain consumer loads will be buffered to prevent propagation.

3. *Accommodate all generation and storage options*: The smart grid will integrate all types of electric generation and storage systems, including small-scale power plants that serve their loads, known as *distributed generation*, with a simplified interconnection process analogous to "*plug-and-play*."
4. *Enable informed participation by customers*: The smart grid will give consumers information, control, and options that enable them to become active participants in the grid. *Well-informed* customers will modify consumption based on balancing their demands and resources with the electric system's capability to meet those demands.
5. *Enable new products, services, and markets*: The smart grid will enable market participation, allowing buyers and sellers to bid on their energy resources through the supply and demand interactions of markets and real-time price quotes.
6. *Operate resiliently to disturbances, attacks, and natural disasters*: The smart grid operates resiliently, that is, it has the ability to withstand and recover from disturbances in a self-healing manner to prevent or mitigate power outages, and to maintain reliability, stability, and service continuity. The smart grid will operate resiliently against attack and natural disaster. It incorporates new technology and higher cyber security, covering the entire electric system, reducing physical and cyber vulnerabilities, and enabling a rapid recovery from disruptions.

Therefore, the next-generation electricity grid, known as the "smart grid" or "intelligent grid," is designed to address the major shortcomings of the existing grid. Basically, the smart grid is required to provide the electric power utility industry with full visibility and penetrative control and monitoring over its assets and services. It is required to be self-healing and resilient to system abnormalities.

Furthermore, the smart grid needs to provide an improved platform for utility companies to engage with each other and do energy transactions across the system. The smart grids are expected to provide tremendous operational benefits to power utilities around the world because they provide a platform for enterprise-wide solutions that deliver far-reaching benefits to both utilities and their end customers. In 2009, "smart grid interoperability panel" (SGIP) was created. It has 1900 people, 750 member organizations; it is open to the public as well, with international participation. It coordinates standards developed by standards development organizations (SDOs). It identifies requirements and prioritizes standards development programs.

However, the development of the smart grid is not easy due to many reasons. First of all, the present power grid of the United States is a very large, fragmented, and complex system. For example, 22% of the world electricity is consumed by the United States. Accordingly, this country has 3,200 electric utility companies, 17,000 power plants, 800 GW peak demand, 165,000 miles of high-voltage lines, and 6 million miles of distribution lines; covers 140 million meters; has 41 trillion in assets; and creates $350 billion annual revenues.

Today, the utilities and their suppliers are already integrating IT and advanced communications into the power system in order to

- Increase system efficiency and cost effectiveness
- Provide customers tools to manage energy use
- Improve reliability, resiliency, and power quality
- Enable use of innovative technologies including renewables, storage, and electric vehicles

The development of new technologies and applications in distribution management can help drive optimization of smart grid and assets. Hence, the smart grid is the result of convergence of communication technology and communication technology with power system engineering.

The following are the NIST SG research and development (R&D) vision [3]:

- The smart grid is a complex system of systems that incorporates many new technologies and operating paradigms in an end-to-end system that functions very differently than the legacy grid in order to deliver power more efficiently, reliably, and cleanly.
- NIST develops the measurement science and standards, including interoperability and cyber-security standards, necessary to ensure that the performance of the smart grid—at the system, subsystem, and end-user levels—can be measured, controlled, and optimized to meet performance requirements, especially for safety and security, reliability and resilience, agility and stability, and energy efficiency.

Table 15.1 provides a comparison of features of the smart power grid with the existing power grid. In summary, a smart grid is the use of sensors, communications, computational ability, and control in some form to enhance the overall functionality of the electric power delivery system. In other words, a dumb system becomes smart by sensing, communicating, applying intelligence, exercising control, and, through feedback, continually adjusting. This allows several functions that permit optimization, in combination, of the use of bulk generation, and storage, transmission, distribution, distributed resources, and consumer end uses toward goals that ensure reliability and optimize or minimize the use of energy, mitigate environmental impact, manage assets, and minimize costs. In other words, the philosophy of the smart grid is a brand new way of looking at the electric power delivery system and its operation to achieve the optimality and maximum efficiency and effectiveness. Presently, it is hoped and expected that a smart grid will provide the following:

1. Higher penetration of renewable resources.
2. Extensive and effective communication overlay from generation to consumers.
3. The use of advanced sensors and high-speed control to make the grid more robust.
4. It will provide higher operating efficiency.
5. It will provide a greater resiliency against attack and natural disasters.
6. It will provide effective automated metering and rapid service restoration after storms.
7. It will facilitate real-time or time-of-use pricing of the electric energy.
8. It will provide greater customer participation in generation and selling of the energy generated by using renewable resources, such as the ones shown in Figures 15.5 through 15.9. Figures show various solar and wind applications as examples of DG.

TABLE 15.1
Comparison of the Features of the Smart Grid with the Existing Grid

Smart Grid	Existing Grid
Digital	Electromechanical
Two-way communication	One-way communication
DG	Centralized generation
Network	Hierarchical
Sensors throughout	Few sensors
Self-monitoring	Blind
Self-healing	Manual restoration
Adaptive and islanding	Failures and blackouts
Old-fashion customer metering	Intelligent customer metering
Remote checking/testing	Manual checking/testing
Pervasive control	Limited control
Many customer choices	Few customer choices

FIGURE 15.5 Solar and wind applications in the city of Kassel in the state of Hessen, Germany. (SMA Solar Technology AG.)

FIGURE 15.6 Solar and wind turbine applications in the state of Rheinland-Pfalz in Germany. (SMA Solar Technology AG.)

FIGURE 15.7 Solar installations in Germany. (SMA Solar Technology AG.)

FIGURE 15.8 Solar applications on the roof of Munich Temple in Germany. (SMA Solar Technology AG.)

FIGURE 15.9 Solar application in the city of Kassel in the state of Hessen in Germany. (SMA Solar Technology AG.)

In summary, a smart grid is an electricity network that can intelligently integrate the actions of all users connected to it, that is, generators, consumers, and those that do both, in order to efficiently deliver sustainable, economic, and secure electricity supplies.

A smart grid uses innovative products and services together with intelligent monitoring, control, communication, and self-healing technologies in order to

1. Better facilitate the connection and operation of generators of all sizes and technologies
2. Permit consumers to play a part in optimizing the operation of the system
3. Provide consumers with greater information and choice of supply
4. Deliver increased levels of reliability and security of supply
5. Significantly reduce the environmental impact of the whole electricity supply system

15.4 SMART GRID APPLICATIONS VERSUS BUSINESS OBJECTIVES

As in any successful organization, the smart distribution applications of a successful utility company have to match its business objectives. Otherwise, the result becomes a catastrophic failure.

Example 15.1

Consider the typical business objective of *improving distribution network performance* of a utility company, and match it with the following specific *smart distribution applications*:

a. Reliability
b. Power quality

Solution

1. The smart grid applications *for improving distribution system reliability* are as follows:
   A. Fault detection at distribution feeder devices
   B. DA
      a. Automatic reconfiguration of feeders
      b. Remote controlling of feeders, switches, and breakers
   C. Advanced distribution line monitoring
      a. Accurate fault location based on wave-shape analysis
2. The smart grid applications *for improving power quality* are
   A. Power quality measurements
   B. Advanced distribution monitoring

Example 15.2

Consider the typical business objective of *increasing distribution network transit and capacity* (i.e., *distribution system energy efficiency*) of a utility company, and match it with the typical and specific *smart distribution applications*.

Solution

The smart grid applications for *increasing distribution network transit and capacity* are as follows:

1. Distributed resource integration
   A. Dispersed generation and distributed energy resources (DERs)
   B. Storage
2. DR

Example 15.3

Consider the typical business objective of *empowering the customer* of a utility company, and match it with the specific *smart distribution applications*.

Solution

The smart grid applications for the typical business objective of *empowering the customer* of a utility company are as follows:

1. Integrated voltage and var control (IVVC)
   A. Voltage control from sensors on the distribution system
   B. Control of capacitors
2. Advanced distribution line monitoring and control
   A. Feeder protection settings

15.5 ROOTS OF THE MOTIVATION FOR THE SMART GRID

The electric power grid is now focusing on a large number of technological innovations. Utility companies around the world are incorporating new technologies in their various operations and infrastructures.

At the bottom of this transformation is the requirement to make more efficient use of present assets. Several utility companies have developed their own vision of future smart distribution systems to reach the smart grid objectives. Table 15.2 provides a list of enabled applications. Table 15.3 provides a list of smart grid applications.

Based on this foundation given in these tables, the utility company builds its smart grid system by a careful overhaul of their IT infrastructure and communication, and network infrastructure well-designed layer of intelligence over utility assets enables the emergence of the smart grid capabilities to be built on vertical integration of the upper-layer applications. For example, an important capability such as microgrid may not be possible without the integration of DG and HANs.

TABLE 15.2
Enabled Applications

- Microgrid
- Operational efficiency
- DR
- Energy storage
- DG
- HAN
- VVO application
- Plug-in electric vehicles

TABLE 15.3
Smart Grid Applications

1. Fundamental Applications of Smart Grid
   - A. DA
   - B. Meter data management system
   - C. DMS
   - D. SA
   - E. Smart meters
2. Smart Grid Foundation
   - A. Circuit topology
     - a. Feeder design
     - b. Substation design
   - B. IT infrastructure
     - a. Enterprise service bus
     - b. GIS
     - c. Customer relationship management
   - C. Telecommunication infrastructure
     - a. WAN
     - b. LAN
     - c. Backhaul

Thus, the emergence of the truly smart grid will require a drastic overhaul of the existing system. It will require the establishment of distributed control and monitoring systems within and alongside of the present electric power grid. Most likely this change will be gradual but continuous.

Such smart grids will facilitate the DG and cogeneration of energy as well as the integration of alternative sources of energy and the management and control of a power system's emissions and carbon footprint. Furthermore, they will help the utilities to make more efficient use of their present assets through a peak shaving DR and service quality control [2].

Here, the dilemma of a utility company is how to establish the smart grid to achieve the highest possible rate of return on the needed investments for such fundamental overhauls, the new architecture, protocols, and standards toward the smart grid.

However, as supply constraints continue, there will be more focus on the operational effectiveness of the distribution network in terms of cost reduction and capacity relief. Monitoring and control requirements for the distribution system will increase, and the integrated smart grid architecture will benefit from data exchange between the DMS and other project applications. The appearance of widespread distribution generation and consumer-demand response programs also introduces considerable impact to the DMS operation.

It is important to point out that smart grid technologies will add a tremendous amount of real-time and operational data with the increase in sensors and the need for more information on the operations of the system. In addition, utility customers will be able to generate and deliver electricity to the grid or consume the electricity from the grid based on predetermined rules and schedules. Using Ethernet TCP/IP sensors, transducers, and communication protocol, as illustrated in Figure 15.10, customers, through the use of smart meters, can control loads, such as washers and dryers, space heaters, air conditioners, electric stoves, refrigerators, and hot water tanks.

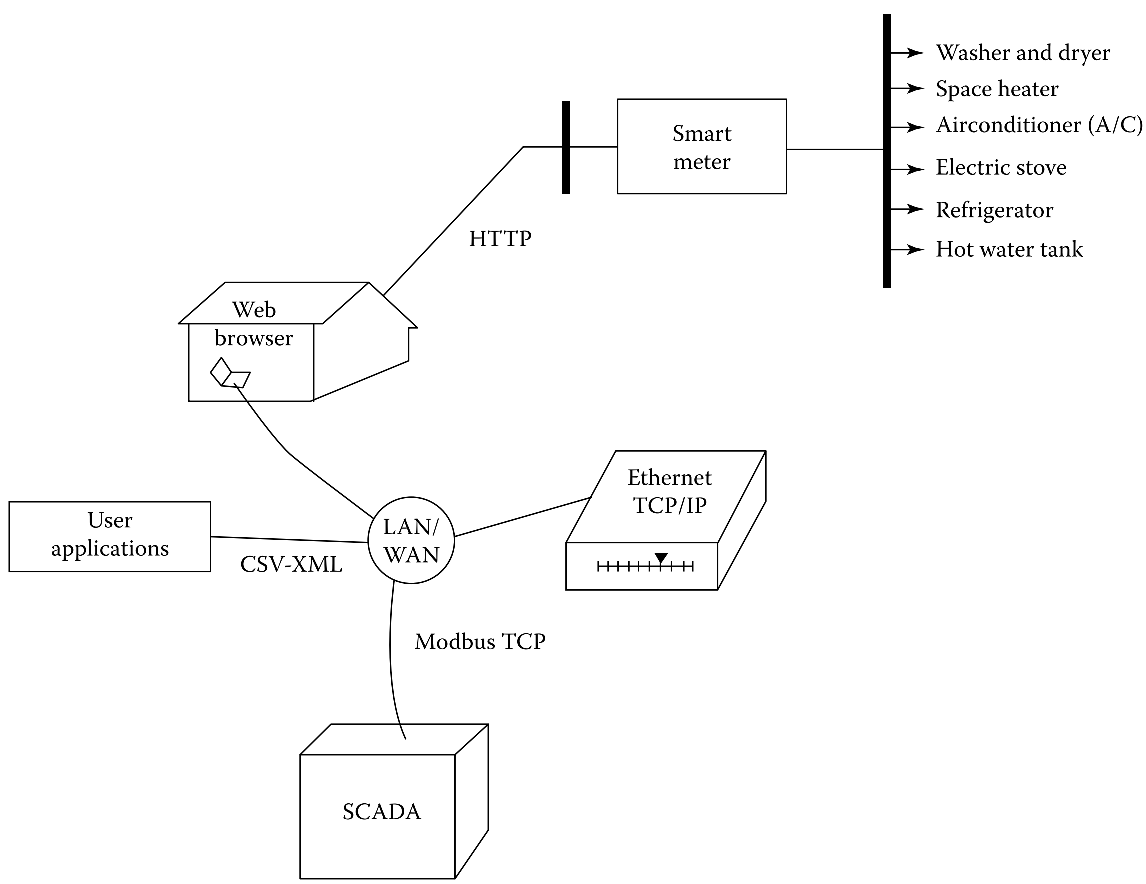

FIGURE 15.10 Application of Ethernet TCP/IP sensors, transducers, and communication protocol for load control.

Thus, the roles of the consumers have changed; they are no longer only buyers but are sellers and/or buyers, switching back and forth from time to time. This results in two-way power flows in the grid and the need for monitoring and controlling the generation and consumption points on the distribution network.

As a result of these changes, the distribution generation will be from dissimilar sources and subject to great uncertainty. At the same time, the electricity consumption of the individual customers is also subject to a great uncertainty when they respond to the real-time pricing and rewarding policies of power utilities for economic benefits.

The conventional methods of LM and LE in the traditional DMS are no longer effective, causing other DMS applications ineffective or altogether useless.

However, the impact of DRM and consumer behaviors may be mandated and predicted, from the utility pricing rules and rewarding policies for specified time periods. The fundamental benefits of automation applied to a distribution system are as follows:

1. Released capacity
2. Reduced losses
3. Increased service reliability
4. Extension of the lives of equipment
5. Effective utilization of assets

The drivers for advanced DA include the following:

1. Worldwide energy consumption is increasing due to population growth and increased energy use per capita in most developing countries.
2. Increased emphasis on system efficiency, reliability, and quality.
3. The need to serve increasing amounts of sensitive loads.
4. Need to do more with less capital expenditure.
5. Performance-based rates.
6. Increasing focus on renewable energy due to the increasing costs to extract and utilize the fossil fuels in an environmentally benign manner is becoming increasingly expensive.
7. Availability of real-time analysis tools for faster decision making.
8. Worldwide energy consumption.

In general, DA and control functions include the following [1]:

1. Discretionary load switching
2. Peak load pricing
3. Load shedding
4. Cold load pickup
5. Load reconfiguration
6. Voltage regulation
7. Transformer load management (TLM)
8. Feeder load management (FLM)
9. Capacitor control
10. Dispersed storage and generation
11. Fault detection, control, and isolation
12. Load studies
13. Condition and state monitoring
14. Automatic customer meter reading
15. Remote service connection or disconnection
16. Switching operations

15.6 DISTRIBUTION AUTOMATION

In a typical DA application, the included tasks are shown in Figure 15.11, which includes medium voltage (MV) regulator automation, MV post-type monitoring stations, MV switch automation, and MV recloser automation. However, in a smart grid development, there might be additional tasks that can be automated at the distribution level. For example, IEEE definition of the *DA* is "a system that enables an electric utility to remotely monitor, coordinate, and operate distribution companies in real-time mode from remote locations." The automation also includes the distribution system monitoring and AMI. Figure 15.12 shows the tasks involved in the distribution system monitoring. Figure 15.13 shows the tasks of an AMI. The figure illustrates the relationships between the communication network called the AMI and the components of a substation (i.e., substation regulators,

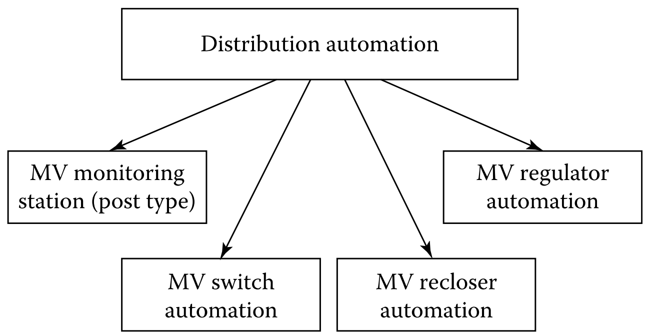

FIGURE 15.11 Tasks involved in the distribution level automation (at the MV level).

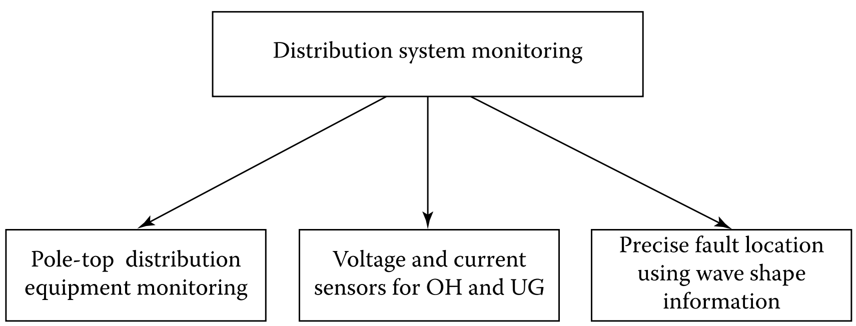

FIGURE 15.12 The tasks involved in the distribution system monitoring.

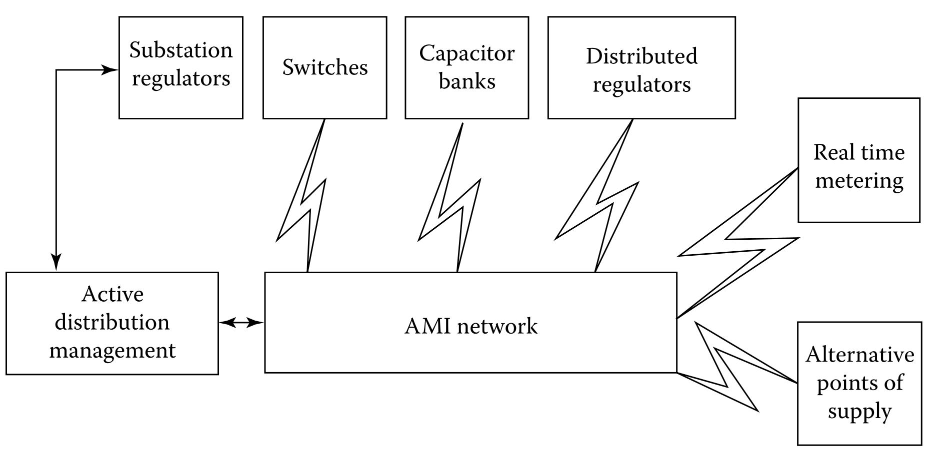

FIGURE 15.13 The tasks of an AMI.

switches, capacitor banks, distributed regulators, real-time metering, alternative points of supplies, as well as active networks [if they exists]) that have to be established.

For example, various distribution management system (MIS) applications that are commonly used today include the following:

1. *Fault detection, isolation, and service restoration* (*FDIR*): It is designed to improve system reliability. It detects a fault on a feeder section based on the remote measurements from the feeder terminal units (FTUs), rapidly isolates the faulted feeder section, and then restores service to the *unfaulted* feeder sections.
2. *The topology processor* (*TP*): It is a background, offline processor that accurately determines the distribution network topology and connectivity for display colorization and to provide accurate network data for other DMS control applications.
3. *Optimal network reconfiguration* (*ONR*): It is a module that recommends switching operations to reconfigure the distribution network to minimize network energy losses, maintain optimum voltage profile, and balance the loading conditions among the substation transformers, the distribution feeders, and the network phases.
4. *IVVC*: It has three basic objectives: reducing feeder network losses 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, as illustrated in Figure 15.14.
5. *Switch order management* (*SOM*): It is very useful for system operators in real-time operation. It provides advanced analysis and execution features to better manage all switch operations in the system.
6. *Dynamic load modeling/load estimation* (*LM/LE*): It is the base module in DMS. It uses all the available information from the distribution network to accurately estimate individual loads and aggregate bulk loads.
7. *The dispatcher training simulator* (*DTS*): It is used to simulate the effects of normal and abnormal operating conditions and switching scenarios before they are applied to the real system.

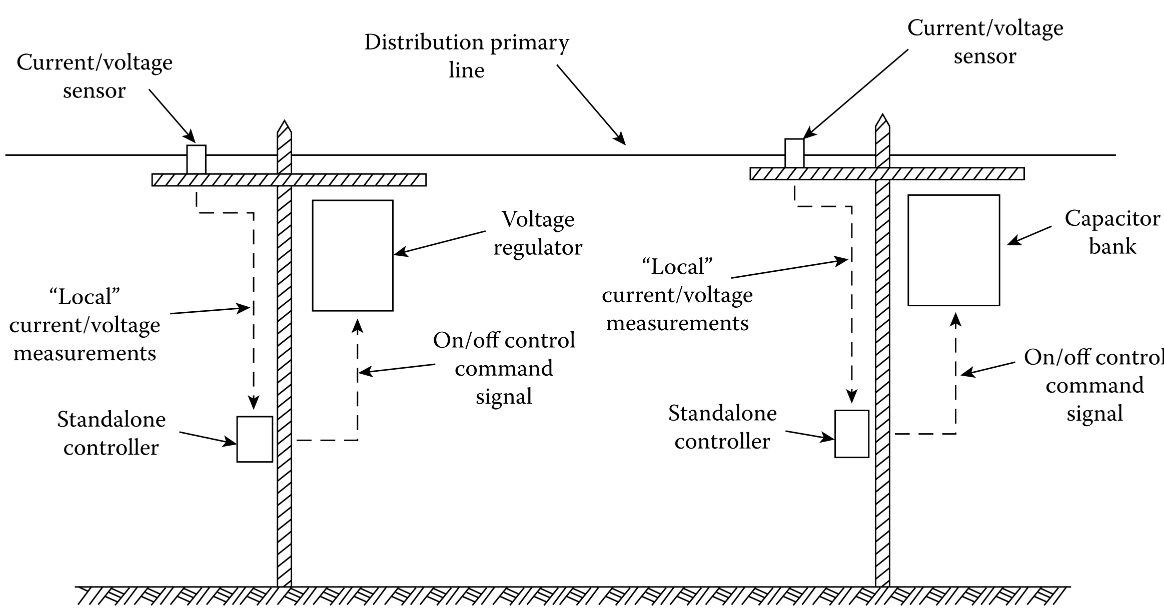

FIGURE 15.14 An illustration for how to control volt/var flows related to a distribution primary line using the individual, independent, stand-alone volt/var regulating equipment under the *traditional* VVC approach.

8. *Short-circuit analysis* (*SCA*): It is used to calculate the short-circuit current to evaluate the possible impact of a fault on the network.
9. *Relay protection coordination* (RPC): It manages and verifies the relay settings of the distribution feeders under various operating conditions and network configurations.
10. *Optimal capacitor placement/optimal voltage regulator placement* (OCP/OVP): It is used to determine the optimal locations for capacitor banks and voltage regulators in the distribution networks for the most effective control of the feeder volt/var profile.

15.7 ACTIVE DISTRIBUTION NETWORKS

An *active network* is a passive network that has been converted to an active one by the connection of DG in terms of, for example, combined heat and power (CHP) cogens and/or other renewable-based energy-producing units such as wind turbines or solar units, as shown in Figures 15.15 through 15.17.

The necessary monitoring, communications, and control in terms of both preventive and corrective actions are provided for such networks. They are flexible, adaptable (most likely autonomous

FIGURE 15.15 Solar applications in Bruchweg stadium- FSV Mainz 05, Germany. (SMA Solar Technology AG.)

FIGURE 15.16 Solar applications in the state of Crevillente in Spain. (SMA Solar Technology AG.)

FIGURE 15.17 Solar applications in Montalto di Castro in Italy. (SMA Solar Technology AG.)

such as the case with microgrids), and most likely intelligent. Hence, *active distribution networks* are the distribution networks to which renewable energy sources are connected. An active distribution network can be considered as an active network. Microgrids are *autonomous active networks*. The active network management is receiving considerable attention in the development of smart grid.

Also, in active distribution networks, the older style voltage regulators were often designed for hardly a pure radial situation, that is, power flow is always from the same direction (from the substation). They may not work correctly if power flow is from the opposite direction. For example, they could raise voltage during light load, creating higher voltage situation, or they could lower voltage during heavy load, creating low voltage situation.

Therefore, it is necessary to use *bidirectional* voltage regulator controller to handle feeder reconfiguration. Feeder reconfiguration may become a more frequent occurrence due to load transferred to another feeder during service restoration or due to having an ONR to reduce losses. In general, a distribution generation of sufficient size can reverse power flow.

To this day, there is no generally accepted definition of active network management yet. However, there is an acceptable definition of active network. By that definition, an active network includes the DG, renewables, monitoring, communications and control, and preventive and corrective actions; it is defined as flexible, adoptable, autonomous, and intelligent. Active network management includes dispatch, network reconfiguration, dynamic constraints, fault level management, demand-side management (DSM), and active voltage control.

15.8 INTEGRATION OF SMART GRID WITH DISTRIBUTION MANAGEMENT SYSTEM

Figure 15.18 shows the integration of the existing DMS with smart grid. The model involves planning and forecasting, outage management system (OMS), collection of outage data, AM, involving geographic information system (GIS), AMI, meter distribution management system (MDMS), customer information systems (CIS), as well as distribution system model. It also shows the DMS in terms of DA, the supervisory control and data acquisition (SCADA), VVC, efficiency, DSM, DG, and PHEV.

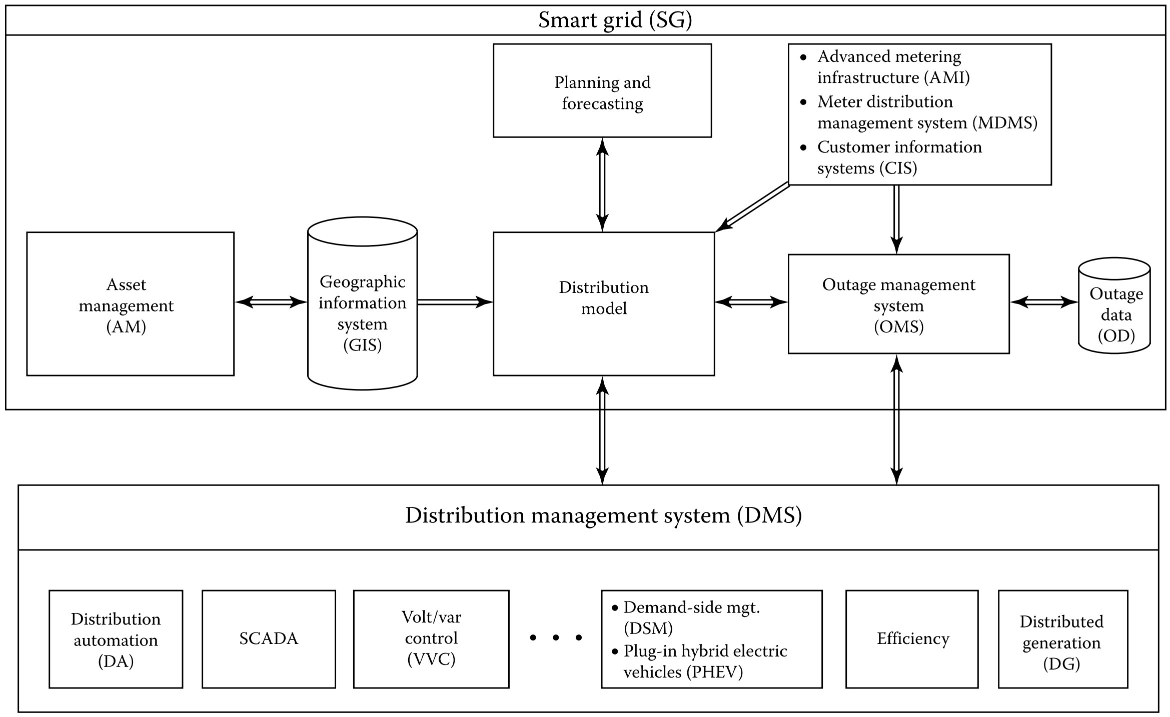

FIGURE 15.18 Integration of the existing DMS with smart grid.

15.9 VOLT/VAR CONTROL IN DISTRIBUTION NETWORKS

In general, it is agreed that the following are the three main approaches to VVC in the distribution systems:

1. Traditional approach
2. SCADA volt/var approach
3. IVVC optimization approach

15.9.1 Traditional Approach to Volt/VAR Control in the Distribution Networks

In the traditional approach to VVC in the distribution networks, the process is controlled by using individual, independent, and stand-alone volt/var regulating equipment such as substation transformer's LTC, by using line voltage regulators, and by using fixed and switched capacitor banks. Figure 15.14 shows an illustration for how to control volt/var flows related to a distribution primary line using the individual, independent, stand-alone volt/var regulating equipment under the *traditional* VVC approach.

Note that VVC is a fundamental operating requirement of all electric distribution systems. Its primary purpose is to maintain acceptable voltage at all points along the distribution feeder under all loading conditions, that is, under the full-load or light-load conditions.

Example 15.4

Conceptually illustrate how to manage a typical distribution primary line (i.e., feeder) volt/var flows by using the traditional VVC approach. Use the individual, independent, stand-alone volt/var regulating equipment such as substation transformer's LTC; line voltage regulators; and fixed and switched capacitor banks.

Solution

Figure 15.14 illustrates how to manage volt/var flows related to a distribution primary line using the individual, independent, stand-alone volt/var regulating equipment under the *traditional VVC approach*. Note that the current/voltage sensors located on the pole tops send the "local" current/voltage measurements to stand-alone controllers.

They, in turn, send out individual on/off control/command signal to the associated capacitor bank and/or voltage regulators, after using the substation transformer's LTCs. The process continues until appropriate voltage profile for the feeder is obtained. However, such traditional approach has the following limitations:

1. *Power factor correction/loss reduction*: Many traditional capacitor bank controllers have voltage control, that is, they switch on when voltage is low. This approach is good at maintaining acceptable voltage and has reactive power controllers, but it is expensive since it requires the addition of CTs. Also, the approach is good at power factor correction during peak-load times, but it may not come on at all during off-peak times. As a result, power factor is nearly unity during the peak-load times, but it is low during the off-peak times, causing higher electric losses.
2. *Monitoring of switched capacitor bank performance*: It is well known that switch capacitor banks are often out of service due to blown out fuses, etc. With the traditional approach, the switched capacitor bank could be out of service for extended periods without the operator knowing it. This results in higher losses due to the capacitor bank being out of service. As a result, it requires routine inspections that are costly.
3. *Voltage regulation problem when large DG unit is connected*: As a result of connecting a large DG unit, load current through voltage regulator will be reduced since the voltage regulator *thinks* the load is light on the feeder. Thus, the voltage regulator lowers its tap settings in order to avoid *light-load, high-voltage* condition. This, in turn, makes the actual *heavy-load, low-voltage* condition even worse.

These problems can be remedied by implementing DMS. Such system uses voltage regulators or transformers with LTCs that automatically raise or lower the voltage in response to changes in load. Also, capacitor banks are used to supply some of the reactive power that would otherwise be drawn from the supply substations.

However, today, utilities are seeking to do more with VVC than just keeping voltage within the allowable limits. System optimization is an important part of the normal operating strategy under smart grid.

Especially in the future, as penetration of intermittent renewable generating resources increases, high-speed dynamic VVC will be essential in sustaining power quality and voltage stability on the distribution feeders. But, the traditional approach has the previously mentioned limitations.

15.9.2 SCADA Approach to Control Volt/VAR in the Distribution Networks

Volt/var power apparatus is monitored and controlled by SCADA system. Such VVC is typically handled by two separate (independent) systems, that is, by var dispatch system that controls capacitor banks to improve power factor, reduce electric losses, etc., or by *voltage control* system that controls LTCs and/or voltage regulators to reduce demand and/or energy consumption, which is also known as *conservation voltage reduction** (CVR).

Operation of these systems is primarily *based on a stored set of predetermined rules*. For example, *if power factor is less than 0.95, then switch capacitor bank #1 off*. The overall objective of

* CVR is the practice of calibrating substation voltage regulating equipment so that system voltages are maintained. The US utilities average CVR factor is about 0.8. Here, CVR factor = $\Delta P/\Delta V$. The CVR performed during peak load period can be viewed as demand (capacity) reduction. The resultant annual energy savings due to CVR can be found from

$$\text{Annual energy savings} = \begin{pmatrix}\text{Average}\\ \text{load}\end{pmatrix}\begin{pmatrix}\text{Number of}\\ \text{hours per year}\end{pmatrix}\begin{pmatrix}\text{\% voltage}\\ \text{reduction}\end{pmatrix}\begin{pmatrix}\text{CVR}\\ \text{factor}\end{pmatrix}\begin{pmatrix}\text{Dollar value}\\ \text{from kWh sales}\end{pmatrix} - \begin{pmatrix}\text{Loss of revenue}\\ \text{from kWh sales}\end{pmatrix}$$

var dispatch is to maintain power factor as close as to unity at the beginning of the feeder without causing leading factor.

The *objectives of SCADA voltage control* are the following:

1. Maintain acceptable voltage at all locations under all loading conditions
2. Operate at a low voltage as possible to reduce power consumption through CVR

Example 15.5

Using the SCADA volt/var approach, conceptually illustrate how to manage a typical distribution primary line volt/var flows using var dispatch components. Use switched and fixed capacitor banks, capacitor bank control interface, communication facility, means of monitoring three-phase var flow at the substation, and master station running var dispatch software.

Solution

Figure 15.19 shows var dispatch components. Note that var dispatch processor contains rules for capacitor switching. There is a one-way communication link for capacitor bank control between the var dispatch processor and the capacitor bank controller. (Note that at the present time, the capacitor bank is de-energized by having the capacitor switch at off position.)

Substation remote terminal unit (RTU) measures the real and reactive power at substation end of the feeder; accordingly var dispatch processor sends commands to the capacitor bank controller. VAR dispatch processor applies the rules to determine if the capacitor bank switching is needed. If the reactive power is below the threshold, there is no need for any action, as illustrated in Figure 15.20. (*Note that there is no communication between the radios*.)

On the other hand, if the reactive power is above the threshold, action is required. Thus, var dispatch processor applies the rules to determine whether capacitor bank switching is needed.

The necessary communication is established between the radios, and the capacitor bank controller sends a command to capacitor switch, and it switches to the "on" position, and the capacitor bank is energized, as illustrated in Figure 15.21.

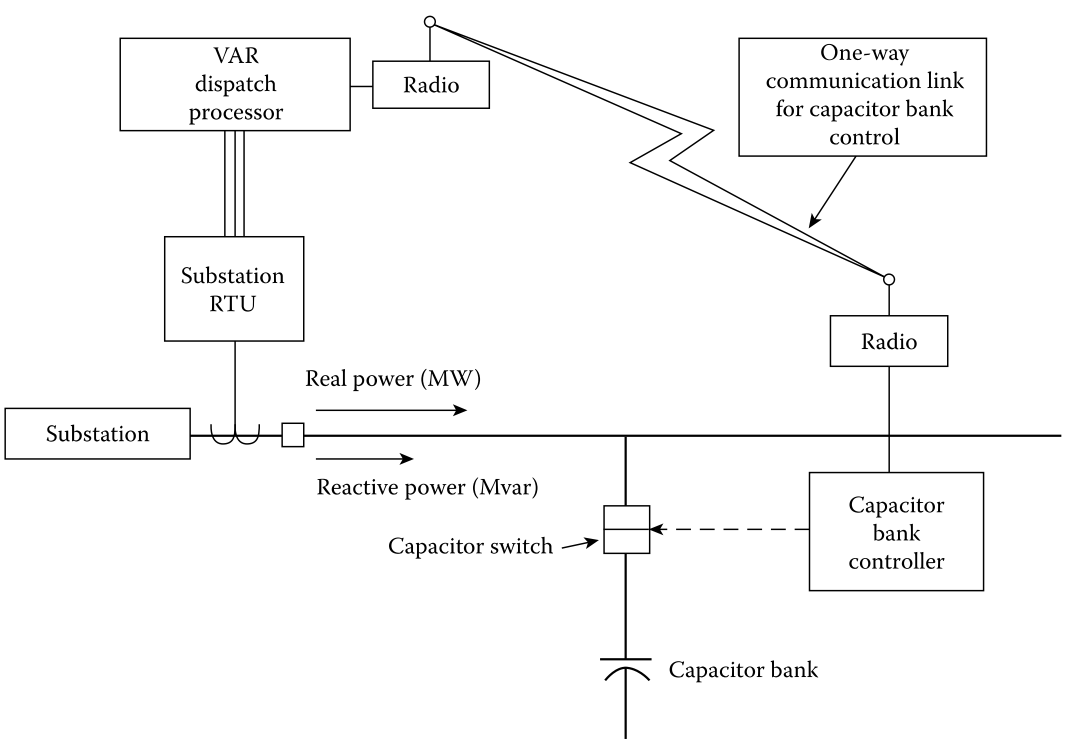

FIGURE 15.19 Var dispatch components of a SCADA system.

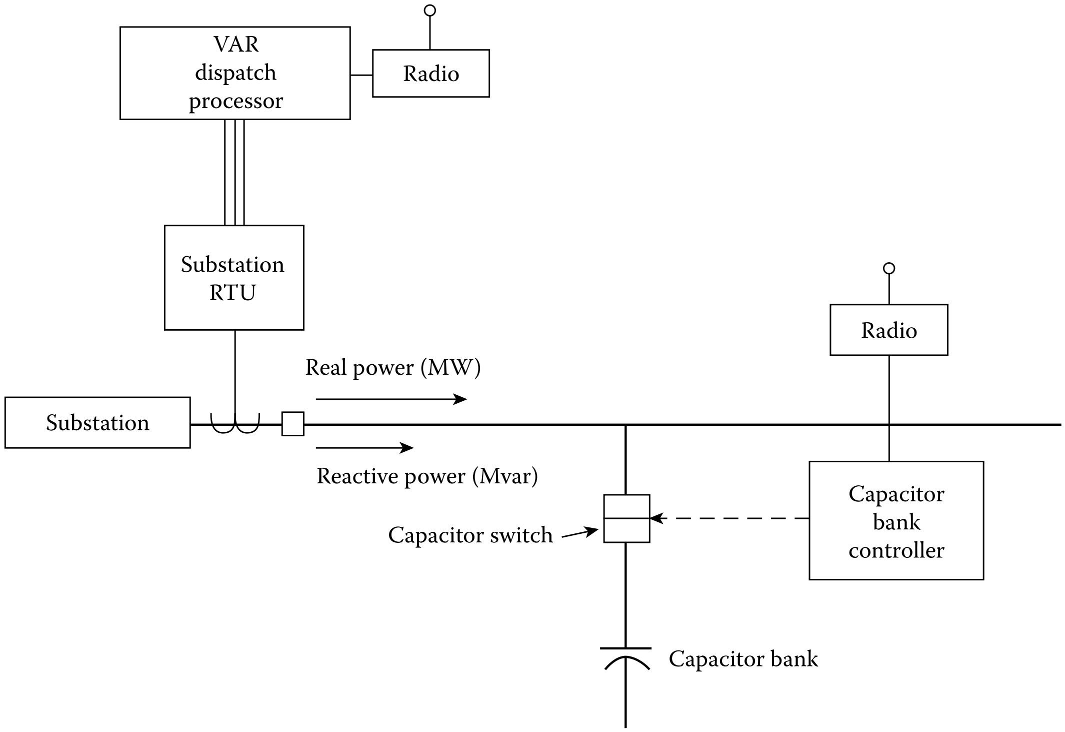

FIGURE 15.20 Var dispatch rules applied (and no action is required).

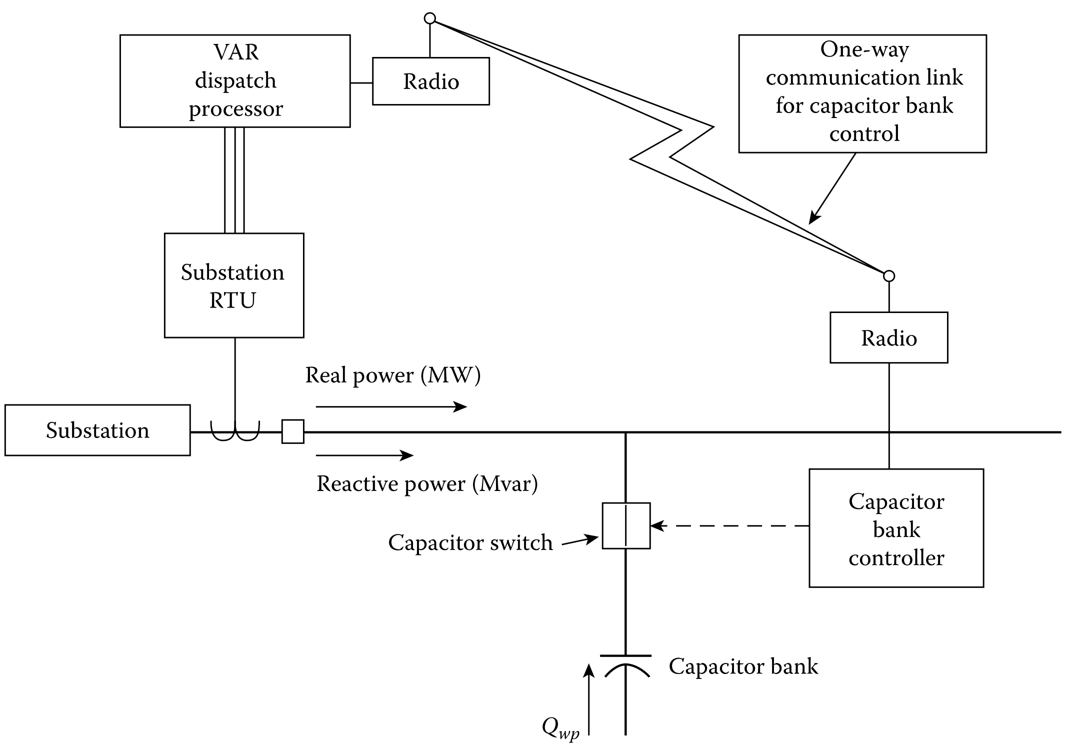

FIGURE 15.21 The capacitor bank is switched *on*.

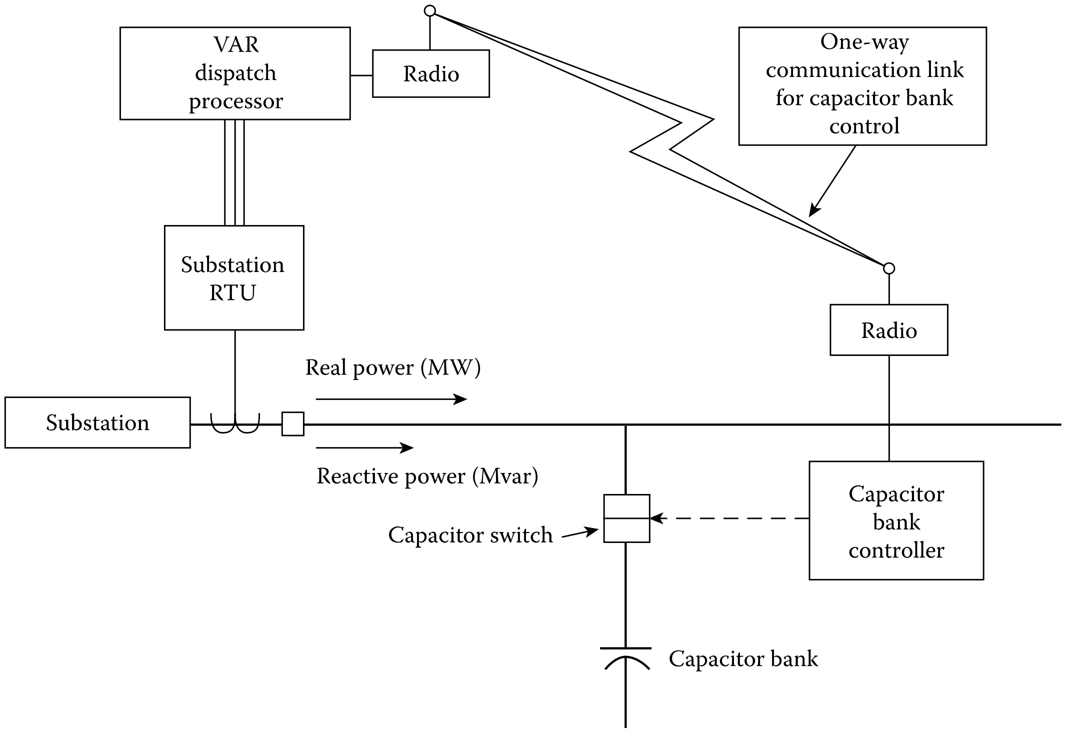

FIGURE 15.22 Change in reactive power is detected, and the capacitor bank is switched *off*.

Thus, the reactive power coming from the supplier is reduced. This change is detected by the substation RTUs. They measure real and reactive power at the substation end of the feeder. The var dispatch processor applies the rules for capacitor switching and sends a signal to the capacitor bank controller, which, in turn, de-energizes the capacitor bank by switching the capacitor switch to the "off" position, as illustrated in Figure 15.22.

At the substation end of the feeder, the var dispatch processor applies the rules for capacitor switching and sends a signal to the capacitor bank controller, which, in turn, de-energized the capacitor bank by switching the capacitor switch to the "off" position, as illustrated in Figure 15.22.

Note that such application of SCADA system provides (1) self-monitoring, (2) operator overrode capability, and (3) some improvement inefficiency. Here, the objectives of SCADA voltage control are (1) maintaining acceptable voltage at all locations under all loading conditions and (2) operating at as low voltage as possible to reduce power consumption, that is, CVR. However, SCADA cannot accomplish the following:

1. It does not adapt to changing feeder configurations (i.e., the rules are fixed in advance).
2. It does not adapt to varying operating needs (i.e., the rules are fixed in advance).
3. The overall efficiency with SCADA is improved with respect to the traditional approach, but it is not necessarily optimal under all conditions.
4. The operations of var/volt devices are not coordinated. It does not adapt well to the presence of modern grid devices such as DG.

15.9.3 Integrated Volt/VAR Control Optimization

What is needed is an IVVC optimization approach (i.e., centralized approach) that develops and executes a coordinated "optimal" switching plan for all voltage control devices based on an optimal power flow program to decide the plans for action.

In the process, it achieves utility-specific objectives as well, which include (1) minimizing power demand in terms of total customer demand and distribution system power losses, (2) minimizing "wear and tear" on the control equipment, and (3) maximizing revenue that is the difference between energy sales and energy prime cost.

Example 15.6

Consider the system given in Example 15.5, and conceptually design an IVVC optimization system configuration that develops a coordinated "optimal" switching plan for all voltage control equipment and execute the plan.

Solution

Figure 15.23 shows the integrated volt/var optimization (IVVO) system configuration. All the inputs from essential devices are fed to the VVC regulation coordination algorithm. They are provided through the communication links between the devices and the coordination algorithm.

Here, the volt/var regulation coordination algorithm manages tap changer settings, inverter and rotating machine var levels, and capacitors to regulate voltage, reduce losses, and conserve energy and system resources. The AMI, MDMS, and line switch provide inputs to distribution SCADA.

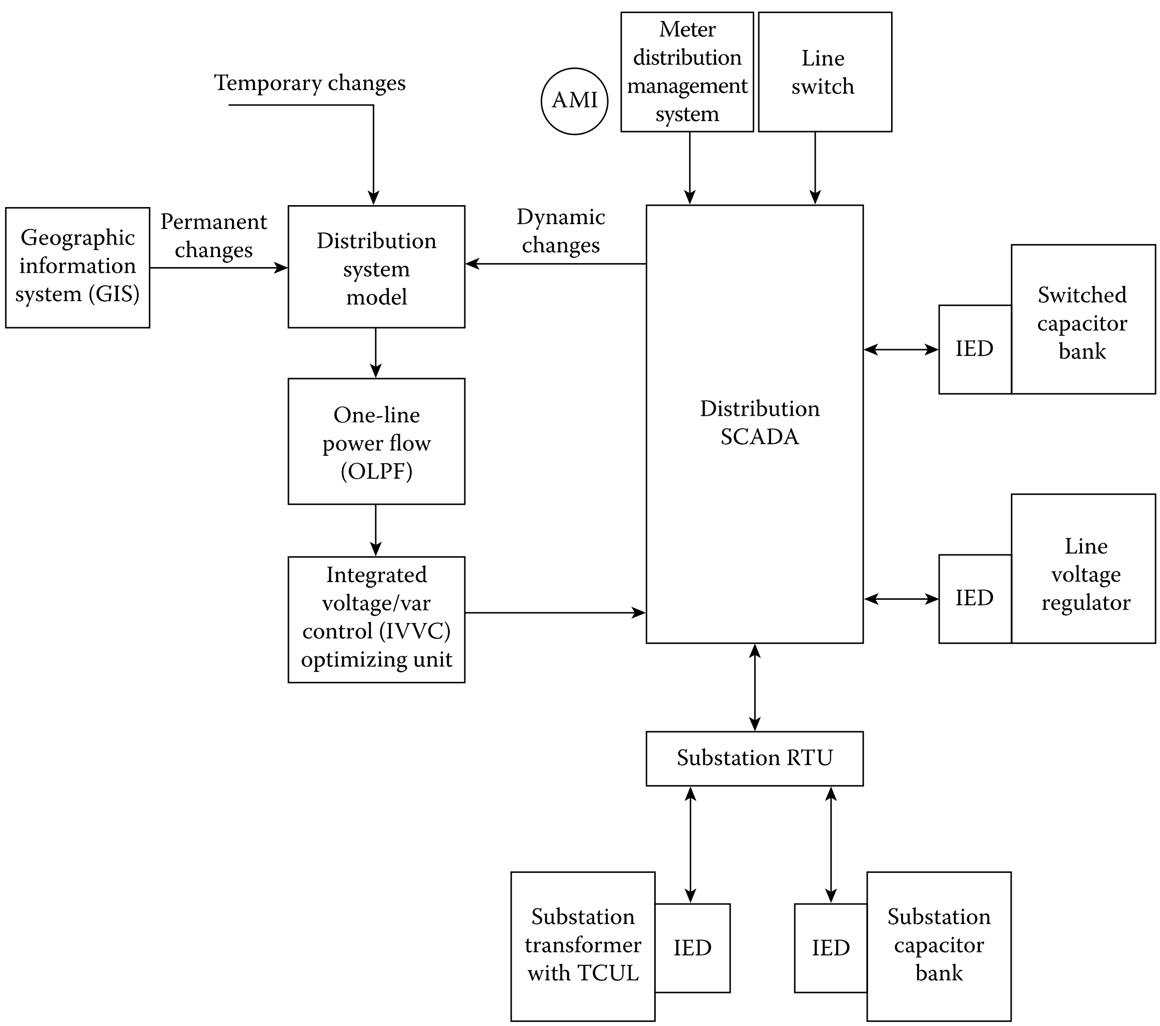

FIGURE 15.23 VVO system configuration.

The inputs of bank voltages and status, switch control are also provided by the switched capacitor banks and line voltage regulators. IVVC-optimizing engine develops a coordinated "optimal" switching plan for *all* voltage control devices and executes the plan. IVVC regulates an accurate, up-to-date electric model based on control of substation and feeder devices.

The AMI provides information on voltage feedback and accurate load data. The line switch provides information on switch status. The line voltage regulator provides inputs on monitor and control tap position and measure load voltage and load. The bank voltage and status, switch control of substation capacitor bank, as well as substation transformer with tap-charger under load (TCUL) are also used as inputs to the SCADA system.

Also, it is required that the substation transformer (with TCUL) to monitor and control tap position and measure load voltage and load. Temporary changes (i.e., cuts, jumpers, manual switching) as well as permanent asset changes (i.e., line extension and/or reconductoring) are inputted into distribution system model. Also provided are the real-time updates of dynamic changes. The necessary power flow results are provided by OLPF that calculates losses, voltage profile, etc. The IVVC determines optimal set of control actions to achieve a desired objective and provides the optimal switching plan to SCADA. In general, the IVVC has the following benefits:

1. When the network reconfiguration takes place, the dynamic model upgrades automatically.
2. The VVC actions are coordinated.
3. The system can model the effects of DG and other modern grid elements.
4. It produces the "optimal" results.
5. It accommodates varying operating objectives depending on present need.

15.10 EXISTING ELECTRIC POWER GRID

The present electricity grid is the result of fast urbanization and infrastructure development. However, the growth of the electric power system has been influenced by economic, political, and geographic factors that are utility specific. Nevertheless, the basic topology of the present power system has remained the same. As it can be easily observed, the basic topology is a vertical one.

Due to lack of proper communications and real data, the system is over-engineered to meet maximum expected peak demand of its aggregated customer load. Since the peak demand is infrequent due to its nature, the system is intrinsically vulnerable due to increase in demand for electric energy and decreased investments in plant and equipment, resulting in extensive blackouts.

In order to prevent it and maintain any expensive upstream plant and equipment without any damage, the utilities have established various command-and-control functions, such as SCADA systems that will be discussed in detail in the next sections. However, the application of the SCADA has remained not totally effective and has covered about 15%–20% of the distribution system. Primarily, the SCADA has been implemented into the transmission system.

15.11 SUPERVISORY CONTROL AND DATA ACQUISITION

SCADA is the equipment and procedures for controlling one or more remote stations from a master control station. It includes the digital control equipment, sensing and telemetry equipment, and two-way communications to and from the master stations and the remotely controlled stations.

The SCADA digital control equipment includes the control computers and terminals for data display and entry. The sensing and telemetry equipment includes the sensors, digital to analog and analog to digital converters, actuators, and relays used at the remote station to sense operating and alarm conditions and to remotely activate equipment such as circuit breakers.

The communication equipment includes the modems (modulator/demodulator) for transmitting the digital data and the communication link (radio, phone line, and microwave link, or power line).

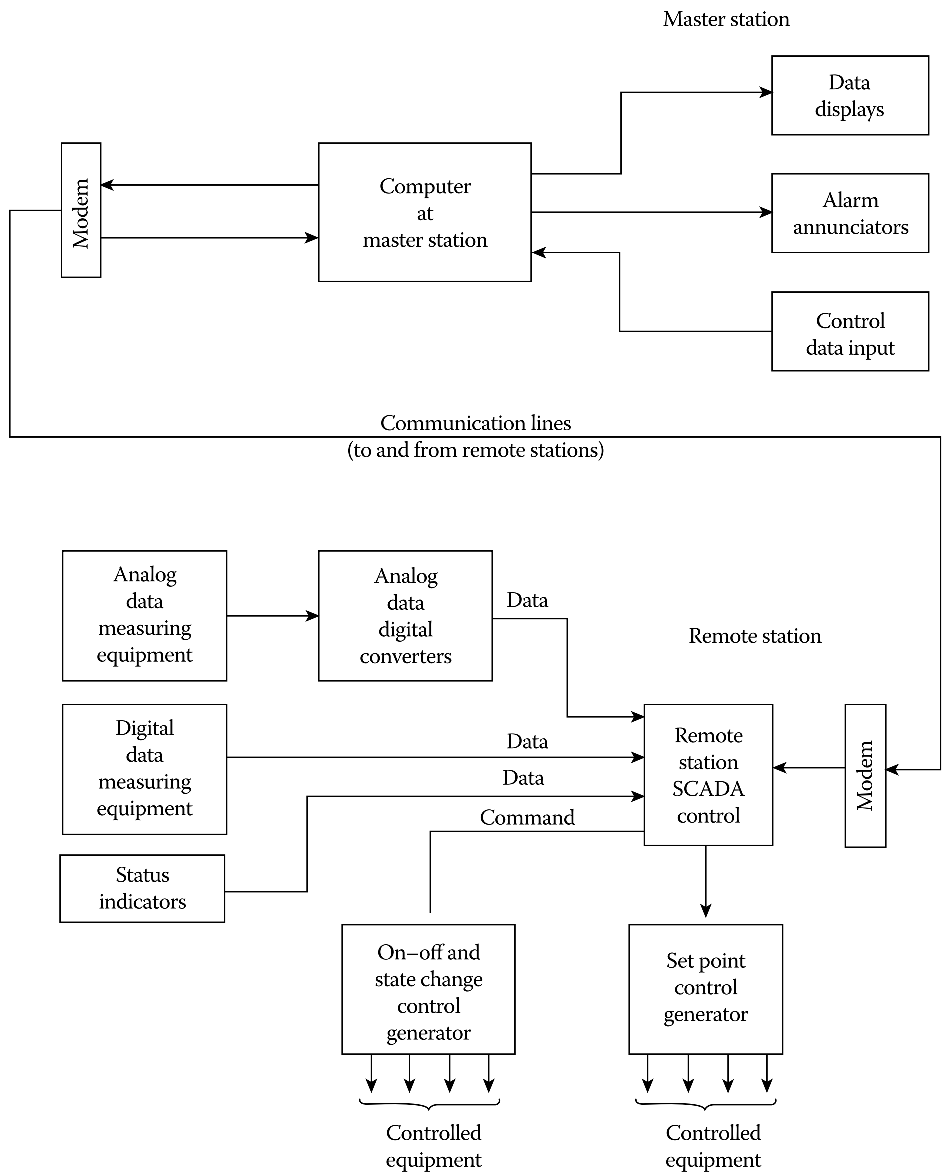

FIGURE 15.24 SCADA.

Figure 15.24 shows a block diagram of a SCADA system. Typical functions that can be performed by SCADA are the following:

1. Control and indication of the position of a two- or three-position device, for example, a motor-driven switch or a circuit breaker
2. State indication without control, for example, transformer fans on or off
3. Control without indication, for example, capacitors switched in or out
4. Set point control of remote control station, for example, nominal voltage for an automatic tap changer
5. Alarm sensing, for example, fire or the performance of a non-commanded function
6. Permit operators to initiate operations at remote stations from a central control station
7. Initiation and recognition of sequences of events, for example, routing power around a bad transformer by opening and closing circuit breakers or sectionalizing a bus with a fault on it
8. Data acquisition from metering equipment, usually via analog/digital converter and digital communication link

Today, in this country, all routine substation functions are remotely controlled. For example, a complete SCADA system can perform the following substation functions:

1. Automatic bus sectionalizing
2. Automatic reclosing after a fault
3. Synchronous check
4. Protection of equipment in a substation
5. Fault reporting
6. Transformer load balancing
7. Voltage and reactive power control
8. Equipment condition monitoring
9. Data acquisition
10. Status monitoring
11. Data logging

All SCADA systems have two-way data and voice communication between the master and the remote stations. Modems at the sending and receiving ends modulate, that is, put information on the carrier frequency, and demodulate, that is, remove information from the carrier, respectively.

Here, digital codes are utilized for such information exchange with various error detection schemes to assure that all data are received correctly. The RTU properly codes remote station information into the proper digital form for the modem to transmit and to convert the signals received from the master into the proper form for each piece of remote equipment.

When a SCADA system is in operation, it scans all routine alarm and monitoring functions periodically by sending the proper digital code to interrogate, or poll, each device. The polled device sends its data and status to the master station. The total scan time for a substation might be 30 s to several minutes subject to the speed of the SCADA system and the substation size. If an alarm condition takes place, it interrupts a normal scan. Upon an alarm, the computer polls the device at the substation that indicated the alarm.

It is possible for an alarm to trigger a computer-initiated sequence of events, for example, breaker action to sectionalize a faulted bus. Each of the activated equipment has a code to activate it, that is, to make it listen, and another code to cause the controlled action to take place.

Also, some alarm conditions may sound an alarm at the control station that indicates action is required by an operator. In that case, the operator initiates the action via a keyboard or a CRT. Of course, the computers used in SCADA systems must have considerable memory to store all the data, codes for the controlled devices, and the programs for automatic response to abnormal events.

15.12 ADVANCED SCADA CONCEPTS

The increasing competitive business environment of utilities, due to deregulation, is causing a reexamination of SCADA as a part of the process of utility operations, not as a process unto itself. The present business environment dictates the incorporation of hardware and software of the modern SCADA system into the corporation-wide, management information system strategy to maximize the benefits to the utility.

Today, the dedicated islands of automation gave way to the corporate information system. Tomorrow, in advanced systems, SCADA will be a function performed by workstation-based applications, interconnected through a *wide area network* (WAN) to create a virtual system, as shown in Figure 15.25.

This arrangement will provide the SCADA applications access to a host of other applications, for example, substation controllers, automated mapping/facility management system, trouble call analysis, crew dispatching, and demand-side LM. The WAN will also provide the traditional link between the utility's energy management system (EMS) and SCADA processors. The workstation-based applications will also provide for flexible expansion and economic system reconfiguration.

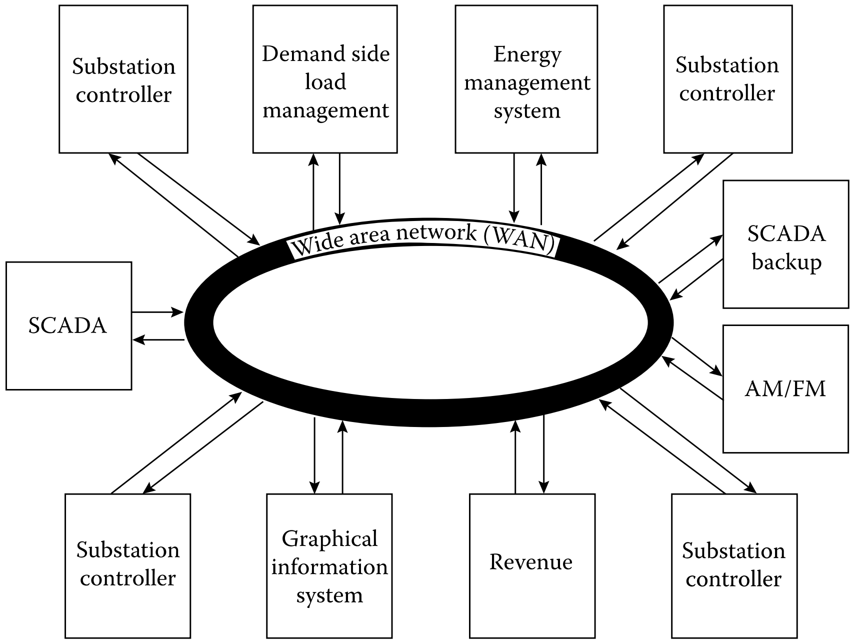

FIGURE 15.25 SCADA in a virtual system established by a WAN. (From Gönen, T., *Electric Power Transmission System Engineering*, 2nd ed., CRC Press, Boca Raton, FL, 2009.)

Also, unlike the centralized database of most existing SCADA systems, the advanced SCADA system database will exist in dynamic pieces that are distributed throughout the network. Modifications to any of the interconnected elements will be immediately available to all users, including the SCADA system. SCADA will have to become a more involved partner in the process of economic delivery and maintained quality of service to the end user.

In most applications today, SCADA and the EMS operate only on the transmission and generation sides of the system. In the future, economic dispatch algorithms will include demand-side (load) management and voltage control/reduction solutions. The control and its hardware and software resources will cease to exist.

15.12.1 Substation Controllers

In the future, RTUs will not only provide station telemetry and control to the master station but will also provide other primary functions such as system protection, local operation, *graphical user interface* (GUI), and data gathering/concentration from other subsystems.

Therefore, the future's RTUs will evolve into a class of devices that performs multiple substation control, protection, and operation functions. Besides these functions, the substation controller also develops and processes data required by the SCADA master, and it processes control commands and messages received from the SCADA master.

The substation controller will provide a gateway function to process and transmit data from the substation to the WAN. The substation controller is basically a computer system designed to operate in a substation environment. As shown in Figure 15.27, it has hardware modules and software in terms of the following:

1. *Data processing applications*: These software applications provide various users access to the data of the substation controller in order to provide instructions and programming to the substation controller, collect data from the substation controller, and perform the necessary functions.

2. *Data collection applications*: These software applications provide the access to other systems and components that have data elements necessary for the substation controller to perform its functions.
3. *Control database*: All data reside in a single location, whether from a data processing application, data collection application, or derived from the substation controller itself.

Therefore, the substation controller is a system that is made up of many different types of hardware and software components and may not even be in a single location. Here, RTU may exist only as a software application within the substation controller system. Substation controllers will make all data available on WANS. They will eliminate separate stand-alone systems and thus provide greater cost savings to the utility company.

According to Sciacca and Block [7], the SCADA planner must look beyond the traditional roles of SCADA. For example, the planner must consider the following issues:

1. Reduction of substation design and construction costs
2. Reduction of substation operating costs
3. Overall lowering of power system operating costs
4. Development of information for non-SCADA functions
5. Utilization of existing resources and company standard for hardware, software, and database generation
6. Expansion of automated operations at the subtransmission and distribution levels
7. Improved customer relations

To accomplish these, the SCADA planner must join forces with the substation engineer to become an integrated team. Each must ask the other, "How can your requirements be met in a manner that provides positive benefits for my business?"

15.13 ADVANCED DEVELOPMENTS FOR INTEGRATED SUBSTATION AUTOMATION

Since the substation integration and automation technology is fairly new, there are no industry standard definitions with the exception of the following definitions:

IED: Any device incorporating one or more processors with the capability to receive or send data/control from or to an external source, for example, digital relays, controllers, and electronic multifunction meters.

IED integration: Integration of protection, control, and data acquisition functions into a minimal number of platforms to reduce capital and operating costs, reduce panel and control room space, and eliminate redundant equipment and databases.

Substation automation (*SA*): Deployment of substation and feeder operating functions and applications ranging from SCADA and alarm processing to IVVC in order to optimize the management of capital assets and enhance operation and maintenance efficiencies with minimal human intervention.

Open systems: A computer system that embodies supplier-independent standards so that software can be applied on many different platforms and can interoperate with other applications on local and remote systems.

An SA project prior to the 1990s typically involved three major functional areas: SCADA; plus station control, metering, and display; and plus protection.

In recent years, the utility industry has started using IEDs in their systems. These IEDs provided additional functions and features, including self-check and diagnostics, communication interfaces, the ability to store historical data, and integrated RTU input/output (I/O). The IED also enabled redundant equipment to be eliminated, as multiple functions were integrated into a single piece of equipment. For example, when interfaced to the potential transformers and current transformers of an individual circuit, the IED could simultaneously handle protection, metering, and remote control.

As more and more traditional SA functions become integrated into single piece of equipment, the definition of IED began to expand. The term is now applied to any microprocessor-based device with a communication port and therefore includes protection relays, meters, RTUs, *programmable logic controllers* (PLCs), load survey and operator-indicating meters, digital fault recorders, revenue meters, and power equipment controllers of various types.

The IED can thus be considered as the first level of automation integration. Additional economies of scale can be obtained by connecting all of the IEDs into a single integrated substation control system. The use of a fully integrated control system can lead to further streamlining of redundant equipment, as well as reduced costs for wiring, communications, maintenance, and operation, and improved power quality and reliability.

However, the process of implementation has been slow, largely because hardware interfaces and protocols for IEDs are not standardized. Protocols are as numerous as the vendors, and in fact more so, since products even from same end or often have different protocols. Figure 15.26 shows the configuration of an SA system.

The electric utility SA system uses a variety of devices integrated into a functional package by a communication technology for the purpose of monitoring and controlling the substation. Common communication connections include utility operations centers, finance offices, and engineering centers.

Communications for other users is usually through a bridge, gateway, or processor. A library of standard symbols should be used to represent the substation power apparatus on graphical displays. In fact, this library should be established and used in all substations and coordinated with other systems in the utility, such as distribution SCADA system, the EMS, the GIS, and the trouble call management system.

According to McDonald [5], the *global positioning system* (GPS) satellite clock time reference shown in Figure 15.27 provides a time reference for the SA system and IEDs in the substation.

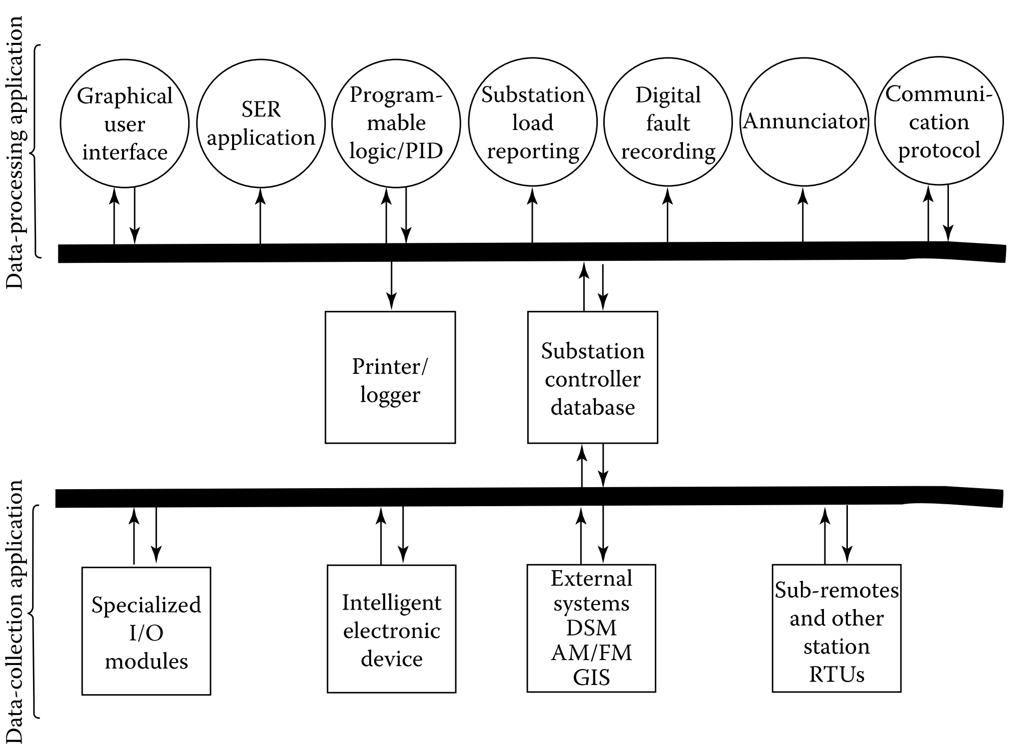

FIGURE 15.26 Substation controller. (From Gönen, T., *Electric Power Transmission System Engineering*, 2nd ed., CRC Press, Boca Raton, FL, 2009.)

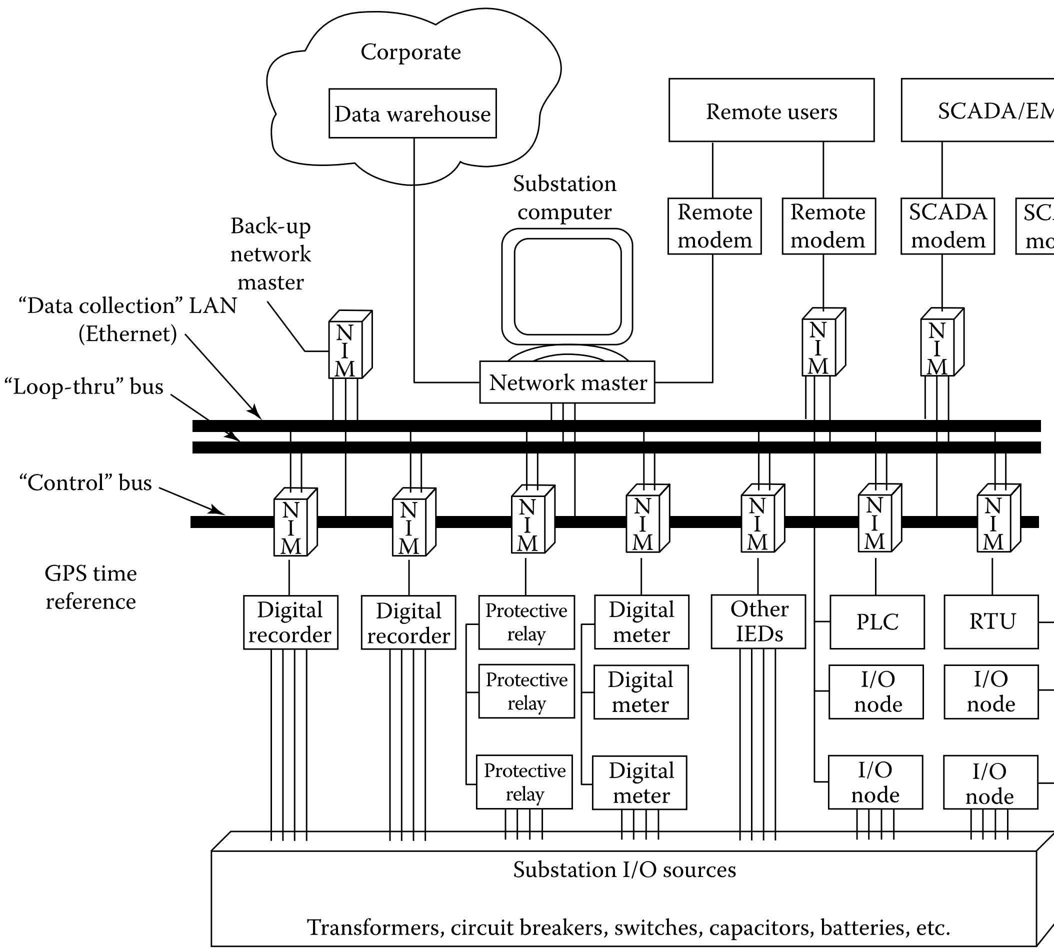

FIGURE 15.27 Configuration of SA system. (From Gönen, T., *Electric Power Distribution System Engineering*, 2nd ed., CRC Press, Boca Raton, FL, 2008.)

The host processor provides the GUI and the historical information system for achieving operational and nonoperational data.

The SCADA interface knows which SA system points are sent to the SCADA system, as well as the SCADA system protocol. The *local area network* (LAN)-enabled IEDs can be directly connected to the SA LAN. The non-LAN-enabled IEDs require a network interface module (NIM) for protocol and physical interface conversion.

A substation LAN has typically high speed and extends into the switchyard, which speeds the transfer of measurements, indications, control commands, and configuration and historical data between intelligent devices at the site.

This architecture reduces the amount and complexity of cabling currently required between intelligent devices. Also, it increases the communications bandwidth available to support faster updates and more advanced functions. Other benefits of an open LAN architecture can include creation of a foundation for future upgrades, access to third-party equipment, and increased interoperability.

In the United States, there are two major LAN standards, namely, Ethernet and PROFIBUS. Ethernet's great strength is the availability of its hardware and options from a myriad of vendors, not to mention industry-standard network-protocol support, multiple application-layer support and quality, and sheer quantity of test equipment. Because of these qualifications, Ethernet is more popular in this country, whereas PROFIBUS is widely used in Europe.

There are interfaces to substation IEDs to acquire data, determine the operating status of each IED, support all communication protocols used by the IEDs, and support standard protocols being developed. Besides SCADA, there may be an interface to the EMS that allows system operators to monitor and control each substation and the EMS to receive data from the substation integration and automation system at different time intervals.

The data warehouse enables users to access substation data while maintaining a firewall to protect substation control and operation functions. The utility has to decide who will use the SA system data, the type of data required, the nature of their application, and the frequency of the data, or update, required for each user.

A communication protocol permits communication between two devices. The devices must have the same protocol and its version implemented. Any protocol differences will result in communication errors. The substation integration and automation architecture must permit devices from different supplies to communicate employing an industry-standard protocol. The primary capability of an IED is its stand-alone capability, for example, protecting the power system for a relay IED. Its secondary capability is its integration capabilities, such as its physical interface, for example, RS-232, RS-485, Ethernet, and its communication protocol, for example, Modbus, Modbus Plus, DNP3, UCA2, and MMS.

To get all IEDs and their heterogeneous protocols onto a common substation LAN and platform, the gateway approach is best. The gateway will act not only as an interface between the local network physical layer and the RS-232/RS-485 ports found on the IEDs but also as a protocol converter, translating the IED's native protocol (like SEL, DNP3, or Modbus) into the protocol standard found on the substation's local network.

Two approaches can be used when using gateways to interface to the substation network. In one, a single low-cost gateway is used for each IED, and in the other, a multi-ported gateway interfaces with multiple IEDs. Which approach is more economical will depend on where the intelligent devices are located. If the IEDs are clustered in a central location, then the multi-ported gateway is certainly better.

The design of the substation integration and automation for new substations is easier than the one for existing substations. The new substation will typically have many IEDs for different functions, and the majority of operational data for the SCADA system will come from these IEDs. The IEDs will be integrated with digital two-way communications.

Typically, there are no conventional RTU in new substations. The RTU functionality is addressed using IEDs and PLCs and an integration network, using digital communications. In existing substations, there are several alternative approaches, depending on whether the substation has a conventional RTU installed.

The utility has three choices for their conventional substation RTUs: (1) integrate RTU with IEDs, (2) integrate RTU as another substation IED, and (3) retire RTU and use IEDs and PLCs, as with a new substation.

The environment of a substation is challenging for SA equipment. Substation control buildings are seldom heated or air-conditioned. Ambient temperatures can range from well below freezing to above 100°F (40°C). Metal-clad switchyard substations can reach ambient temperatures in excess of 140°F (50°C). Temperature changes stress the stability of measuring components in IEDs, RTUs, and transducers. In many environments, self-contained heating or air-conditioning may be recommended.

In summary, the integrated substation control system architecture (which is made up of IEDs, LANs, protocols, GUIs, and substation computers) is the foundation of the automated substation. However, the application building blocks consisting of operating and maintenance software are what produce the really substantial savings that can justify investment in an integrated substation control system.

15.14 EVOLUTION OF SMART GRID

As illustrated in Figure 15.28, the metering side of the distribution system has received most of the attention in terms of the recent infrastructure investments. The earlier applications in the distribution system included the automated meter reading (AMR). The AMR technology has facilitated utilities with the ability to read the customer consumption meters, alarms, and status remotely.

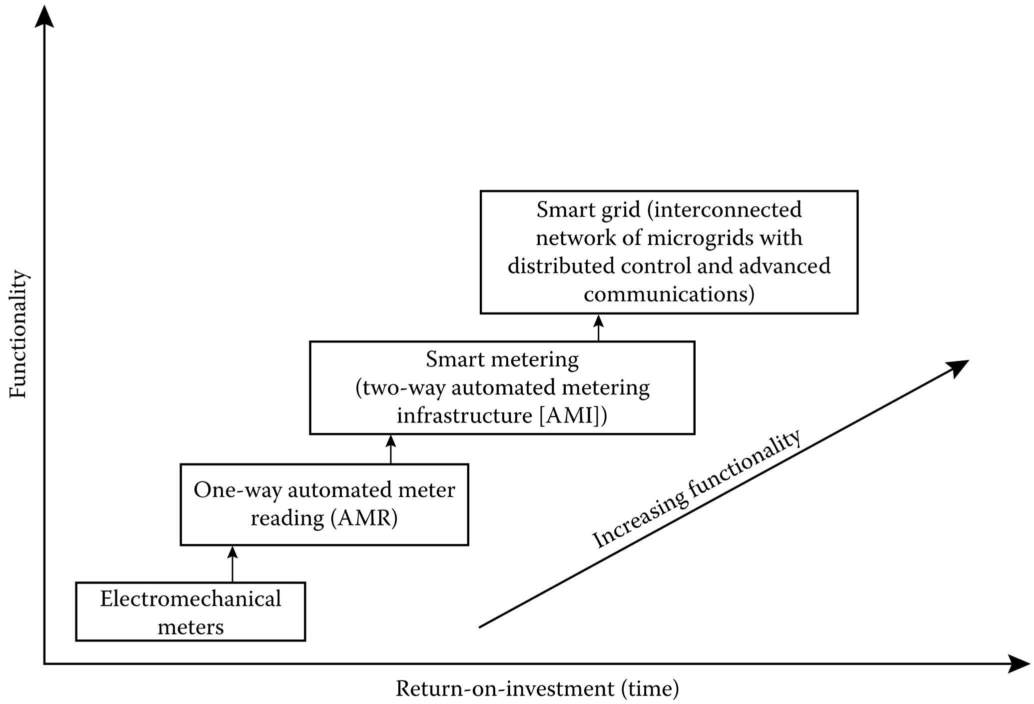

FIGURE 15.28 The evolution of smart grid as a function of return-on-investment versus time.

As shown in Figure 15.29, even though AMR technology has received a substantial attention initially, in time it became clear that AMR is not the answer for the DSM, primarily due to its one-way communication nature. It simply reads the customers' meter data.

It does not permit the transition to the smart grid where extensive control at all levels is essential [2]. Thus, AMR technology applications become extinct. It was replaced by AMI. This system provides utility companies with a two-way communication system to the customers' meters and the ability to modify customers' service-level parameters.

Hence, by using AMI, utilities can reach to their goals in load management and increased revenues. With AMI technology, power companies not only can collect instantaneous information about individual and aggregated demand but can also modify the energy consumption, as well as implement their cost-cutting measures. As said by Farhangi [2], the emergence of AMI started a concerted move by stakeholders to further refine the ever-changing concepts around the smart grid.

As a next step, according to Farhangi [2], the smart grid requires to leverage the AMI infrastructure and implement its distribution command-and-control strategies over the AMI backbone. The penetrating control and intelligent that are properties of the smart grid have to be located across all geographic areas, as well as components, and functions of the power system. The distinguished three elements mentioned in the preceding text, that is, geographic areas, components, and functions, determine the topology of the smart grid and its components.

Again, it is important to point out that smart distribution systems are essential part of the smart grid; here are the necessary steps to establish a smart distribution system:

Step 1: Design information models based on overall requirements of a smart distribution system.
Step 2: Establish substation data integration and associated applications, such as traditional SCADA and fault location.
Step 3: Add feeder automation for selected applications. For example, automatic reconfiguration and VVC.
Step 4: Add advanced metering integration. For example, state estimation and outage management.

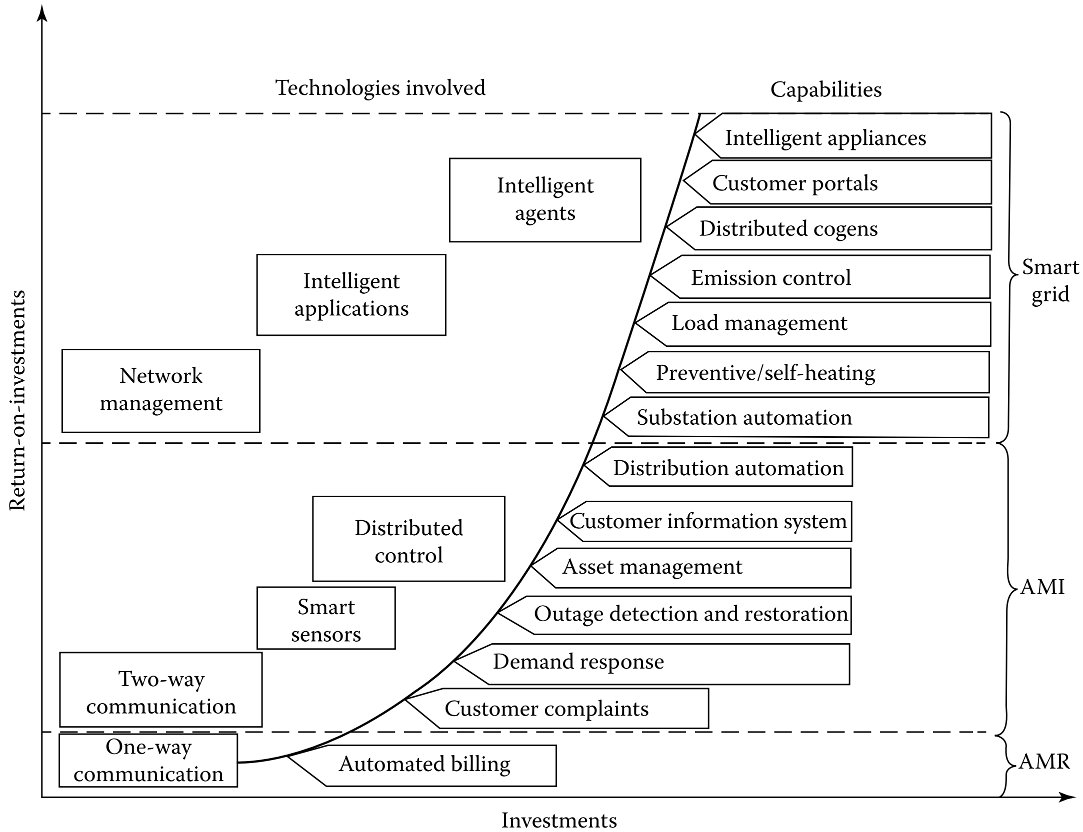

FIGURE 15.29 Return on investments for a smart grid.

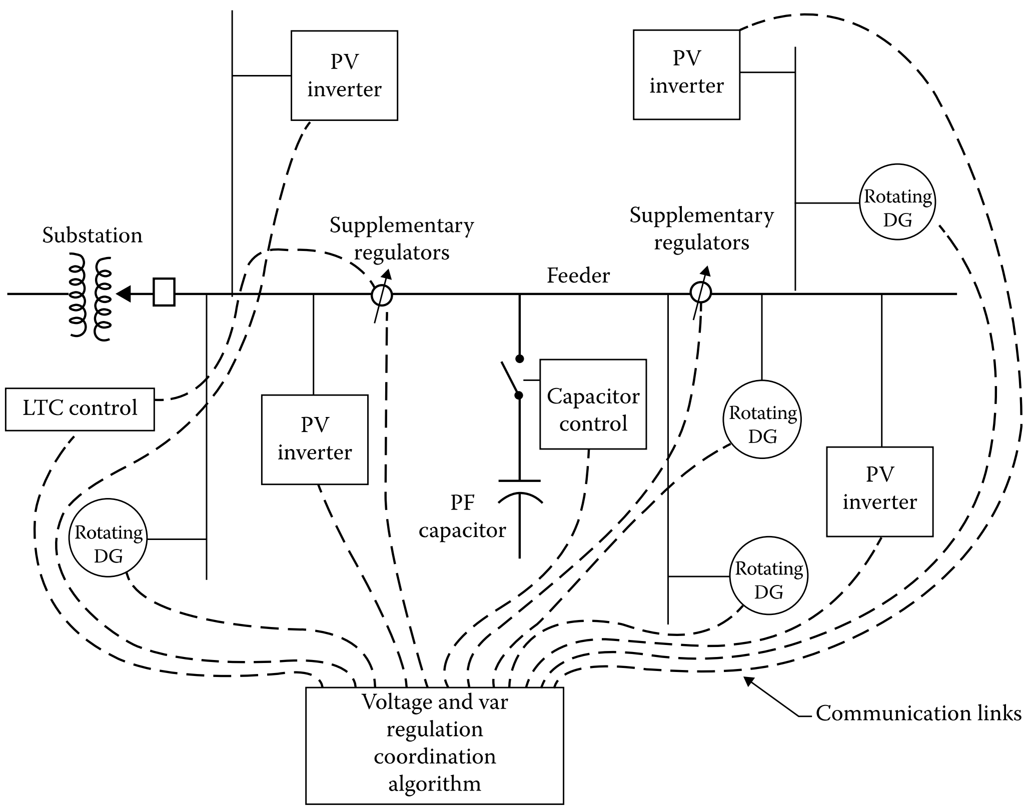

FIGURE 15.30 The additional steps that are necessary to achieve the VVO.

Step 5: Add integrated applications, such as energy management optimization, risk assessment, and advanced equipment diagnostics.
Step 6: Add interface to DERs as well as islanding, advanced energy management and optimization, and real and reactive power (PQ) management capabilities.

The necessary next steps to achieve the volt/var optimization (VVO) have been illustrated in Figure 15.30. The volt/var regulation coordination algorithm manages tap changer settings, inverter and rotating machine var levels, and capacitors to regulate voltage, reduce losses, and conserve energy and system resources. The necessary links between the algorithm and the individual components have been indicated in the figure.

15.15 SMART MICROGRIDS

As succinctly put by Farhangi [2], the smart grid is the collection of all technologies, concepts, topologies, and approaches that permit to maintain hierarchies of generation, transmission, and distribution to be replaced with an end-to-end, organically intelligent, fully integrated environment where the business processes, objectives, and needs of all stakeholders are supported by the efficient exchange of data, services, and transactions.

A smart grid is hence defined as a grid that accommodates a wide variety of generation options, for example, central, distributed, intermittent, and mobile. It provides customers with the ability to interact with the EMS to adjust their energy use and reduce their energy costs.

A smart grid also has to be a self-healing system. It foresees the forthcoming failures and takes the necessary corrective actions to avoid or mitigate system problems. A smart grid uses the IT to continuously optimize the employment of its capital assets while minimizing operational and maintenance costs [2].

However, the smart grid should not be seen as a replacement for the present electric power grid but a complement to it. Thus, the smart grid can coexist with the present electric power grid, adding to its capabilities, functionalities, and capacities by means of evolutionary path. This dictates a topology for the smart grid that permits for organic growth, the inclusion of forward-looking technologies, and full backward compatibility with the present systems [2].

The smart grid can also be defined as the ad hoc integration of complementary components, subsystems, and functions under the extensive control of a highly intelligent and distributed command-and-control system.

Furthermore, the organic growth and evolution of the smart grid is achieved by the inclusion of intelligent microgrids. Here, the *microgrid* is defined as interconnected networks of distributed energy systems, including loads and resources. So, it can function whether they are connected to or separated from the electric power grid [2].

As succinctly put by Keyhani [19], smart microgrid systems consist of renewable green energy sources with their associated power converters, efficient transformers, and storage systems.

According to Keyhani [19], a microgrid renewable green (MRG) energy DG system has to be also designed to provide an intelligent to act as grid optimization manager that would facilitate the control of various customer loads according to pricing trends and grid stress by altering customer's use of power. This is accomplished by smart meters in terms of shedding customer loads and permitting distribution generation to come online, if the price of power is above a set limit. The MRG system's EMS is in communication with all individual smart meters located at residential, commercial, and industrial customer sites. Here, the EMS is given information from the power grid and the open access same-time information system that is known as OASIS. Thus, the EMS has a two-way communication with the smart meters.

In addition, according to Keyhani [19], EMS can control power flow in microgrid according to load forecasts, weather forecasts, unit availability, and price fluctuations. Such MRG systems can facilitate the operation of clusters of load system and renewable DGs as a single controllable load

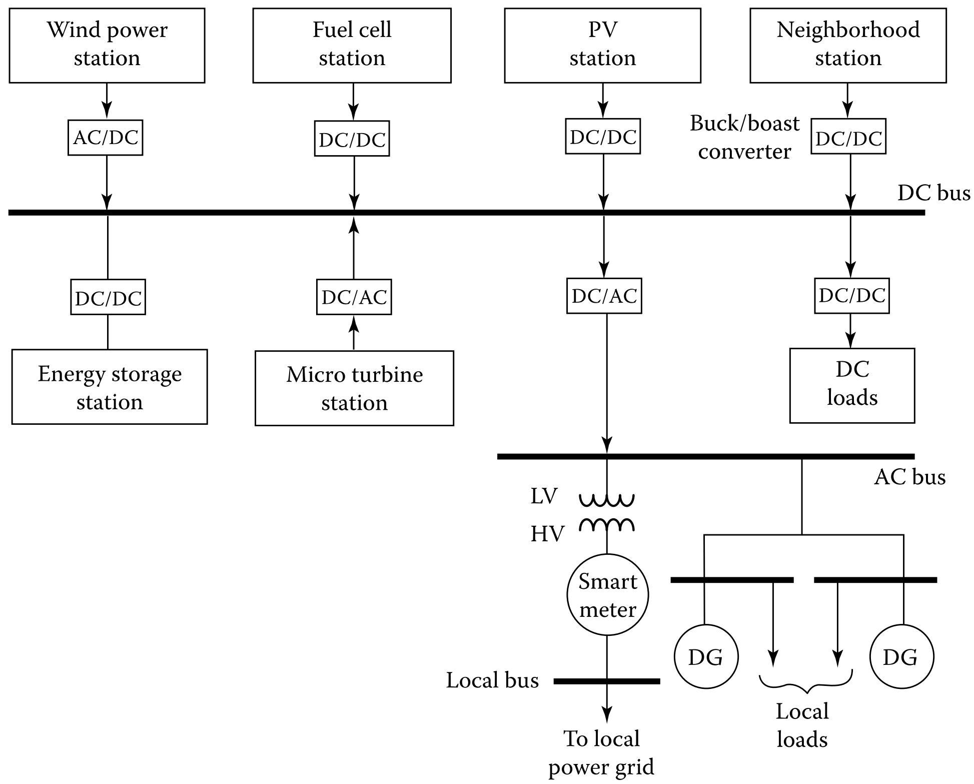

FIGURE 15.31 The dc and ac schematics of an MRG energy DG system.

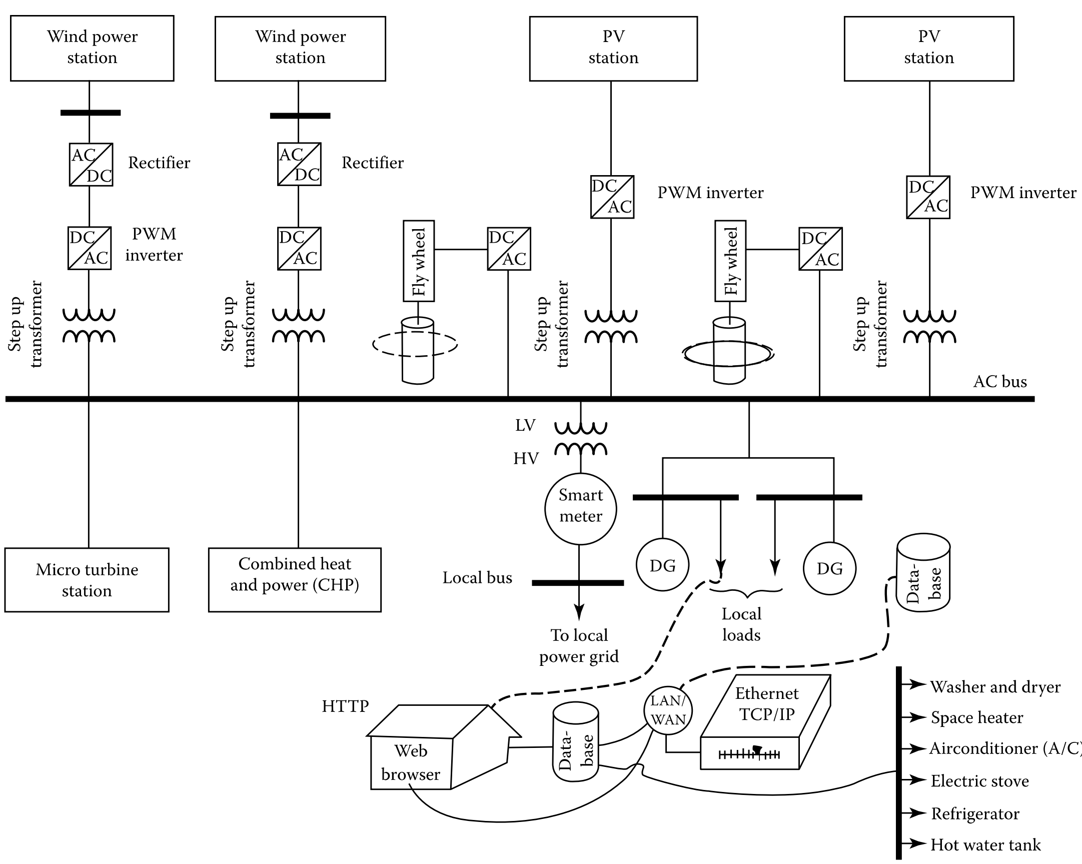

FIGURE 15.32 The ac schematics of an MRG energy DG system.

system and as a single dispatchable generation source, respectively. The interconnection point of the smart microgrid to the local power grid is represented by a node that is called locational marginal pricing (LMP). This cost represents the cost of energy at the location. Figure 15.31 shows the dc and ac schematics of an MRG energy DG system.

Figure 15.32 shows the ac schematics of an MRG energy DG system. Here, green energy sources of microturbines, fuel cells, or other renewable sources, for example, wind farms and solar generating stations, can be connected to a dc or an ac bus, employing standard interchangeable converters. The MRG systems have to be able to operate both in *synchronized operation* with the local power grid and in the *island mode* of operation. The MRG system inverter must be able to control active end reactive power at lagging, leading, or unit power factors. But, the voltage control, that is, the reactive power (*vars*) control, is left to the EMS of the local power grid.

15.16 TOPOLOGY OF A MICROGRID

As discussed in Section 11.13, a small microgrid network can operate in both grid-connected and islanded modes. The topology of a smart microgrid is illustrated in Figure 15.33. As said by Farhangi [2], a small grid integrates the following components:

1. It includes power plants capable of meeting local demand as well as feeding the unused energy back to the electric power grid. They are known as cogenerators and often use renewable resources, such as sun, wind, and biomass. Some microgrids have CHP thermal power plants that are capable of recovering the waste heat in terms of district cooling or heating in the vicinity of the power plant.
2. It employs local and distributed power-storage capability to smooth out the intermittent performance of renewable energy sources.
3. It services a variety of loads, including residential, commercial, and industrial loads.

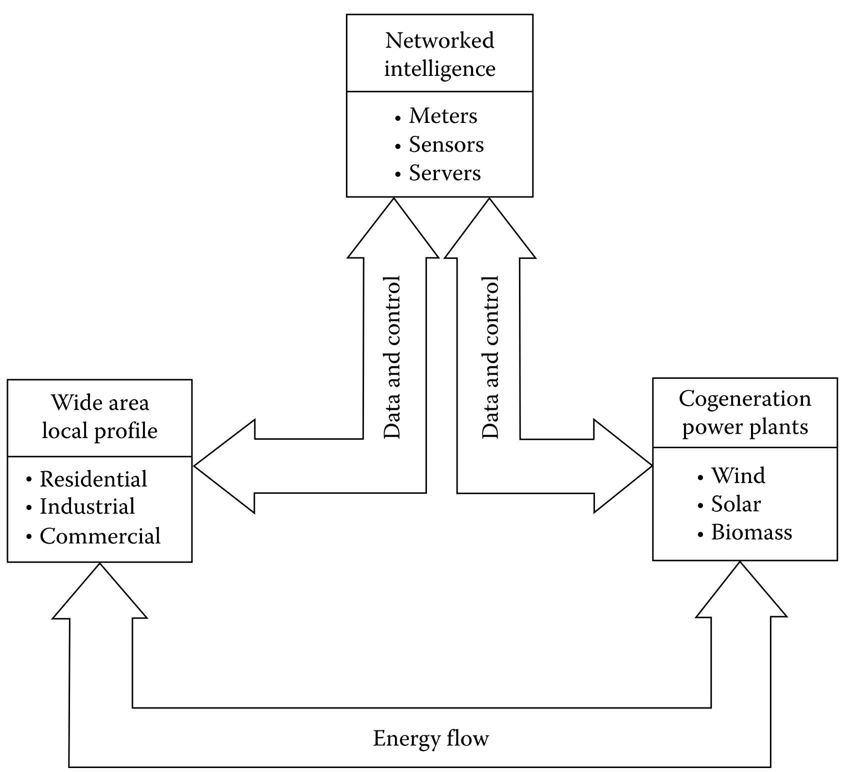

FIGURE 15.33 The topology of a smart microgrid with required microgrid components.

4. It has communication infrastructure that facilitates system components to exchange information and commands reliably and securely.
5. It employs smart meters and sensors capable of measuring a number of consumption parameters (e.g., real and reactive powers, voltage, current, and demand) with acceptable accuracy.
6. It includes an intelligent core, made of integrated networking, computing, and communication infrastructure elements, which appear to users in terms of energy management applications that permit command and control on all network nodes.
7. It includes smart terminations, loads, and appliances capable of communicating their status and accepting commands to adjust and control their performance and service levels according to consumer and/or utility requirements.

15.17 FUTURE OF A SMART GRID

Farhangi [2] predicts that the smart grid of the future will be interconnected through dedicated highways for power exchange, and data and commands, as shown in Figure 15.34. But, it is expected that not all microgrids will have the same capabilities and needs. It will be subject to the load diversity, geography, economics, and the mix of the primary energy resources.

The necessary AMI systems now being established will facilitate the evolution of the smart grid. However, due to the high costs involved, it is foreseeable that the new and the old grids may coexist for some time. Eventually though, it is expected that the system will replace the old grid.

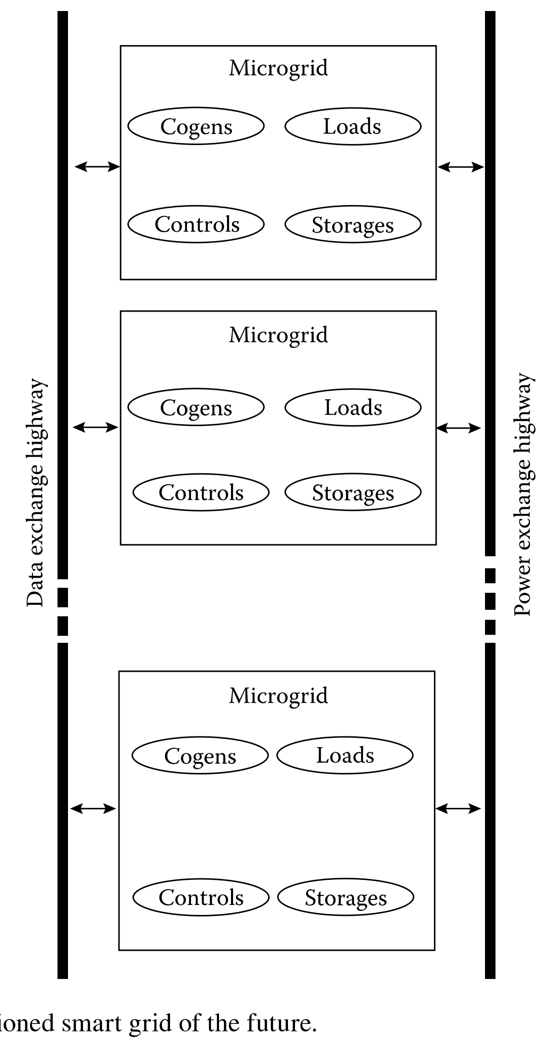

FIGURE 15.34 The envisioned smart grid of the future.

Thus, during the transition period, there will be a hybrid system. The new power grid will appear as a system of organically integrated collection of smart grids with extensive command-and-control functions implemented at all levels.

15.18 STANDARDS OF SMART GRIDS

It is very possible that some substantial problems emerge when distinctively different systems, components, and functions begin to be integrated as part of a distributed command-and-control system of a smart grid.

A part of the problem is the fact that at the present time, there are no commonly accepted interfaces, messaging and control protocols, and standards that would be abided by to ensure a common communication vocabulary among system components of a smart grid.

In order to assist the development of the required standards, the power industry is slowly adopting different terminologies for the purpose of segmentation of the command-and-control layers of the smart grid. The examples of this include HAN, LAN, and WAN.

The HAN stands for "home area network"; it is used to identify the network of communicating loads, appliances, and sensors beyond the smart meter and within the customer's property.

The LAN denotes the local area network. It is used to identify the network of integrated smart meters, field components, and gateways that constitute the logical network between distribution substations and customer's premises.

Finally, WAN is used to identify the network of upstream utility assets, including power plants, distribution storage, and substations. As shown in Figure 15.35, the interface between WAN and LAN and LAN and HAN is provided by smart meters.

In the United States, the US NIST is leading the effort for the standardization for smart grid [3]. In the United States, the most common standard that is used for substations is IEC 61850. It operates in real-time environment.

In Europe and other places, similar efforts indicate the need for the development of common information model (CIM) to enable vertical and lateral integration of applications and functions within the smart grid. CIM is a unified modeling language (UML) based on information model representing real-world objects and information entities exchanged within the value chain of the electric power industry. CIM is based on IEC 61970/61968 applications. It uses IBM's "rational rose" modeling tool. It is available in many forms, for example, cat, mch, html, xml, and owl. It enables

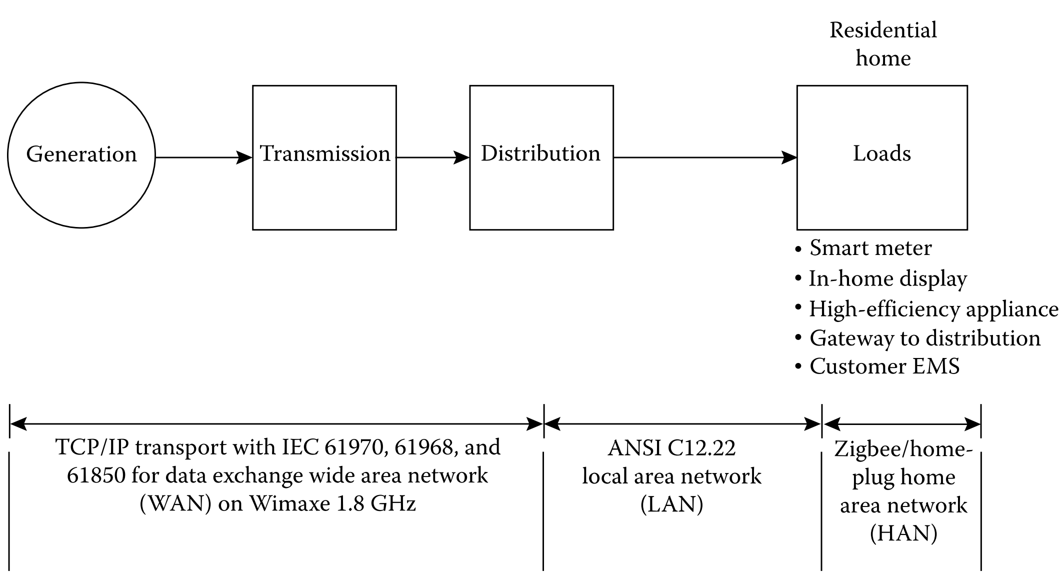

FIGURE 15.35 Development of standards for the smart grid.

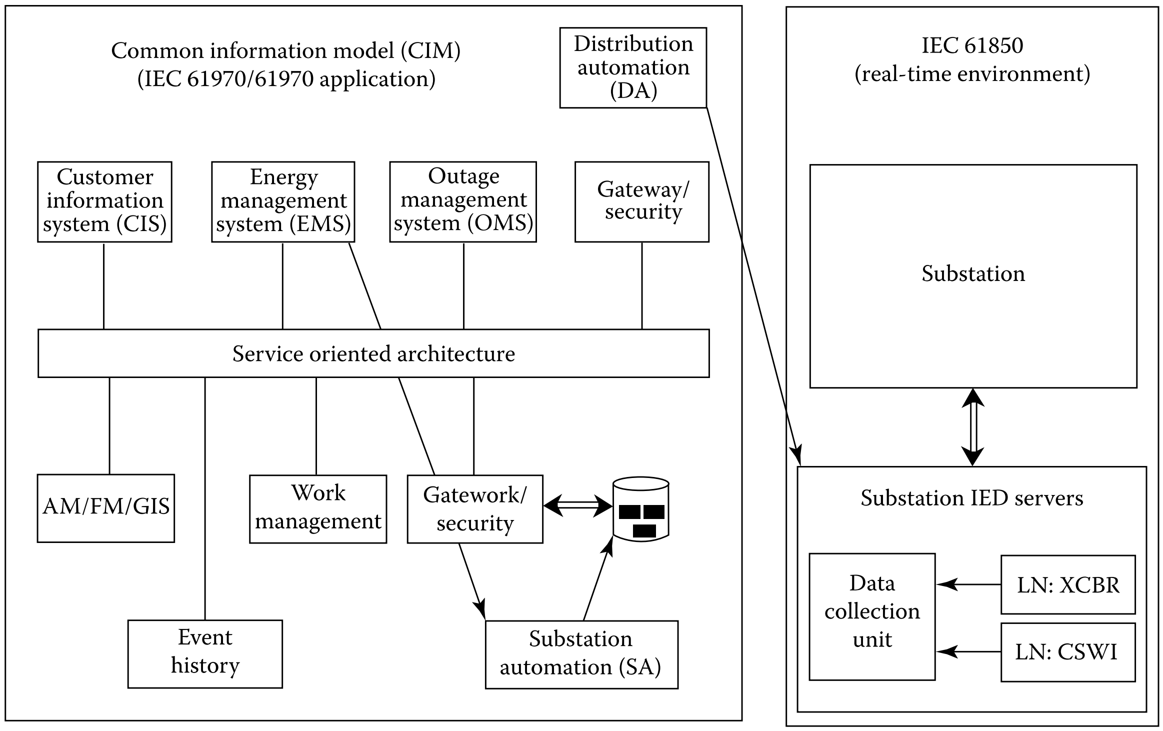

FIGURE 15.36 The application of IEC 61850 and CIM to a substation environment.

data access in a standard way. It also enables integration of applications and systems. It uses common language to navigate and access complex data structures in any database. It provides a common model behind all messages exchanged between systems. It is not tied to a particular application's viewpoint of the world.

Finally, it is the basis for defining information exchange models. It is being developed and standardized by IEC. Figure 15.36 shows the application of IEC 61850 and CIM to a substation environment. Figure 15.37 shows an example how to develop the CIM for distribution applications as well as its application to the field operations.

Figure 15.38 shows the application of the CIM in the interface reference model (IRM). It provides the framework for identifying information exchange requirements among utility business functions. The left-hand side of the figure represents the distribution management business functions, such as electric distribution network planning, constructing, maintaining, and operating. On the other hand, the right-hand side of the figure represents the business functions that are external to distribution management, such as generation and transmission management, enterprise resource planning, supply chain, and general corporate services. All the IEC 61968 activity diagrams and sequence diagrams are organized by the IRM.

Out of the proposed standards, IEC 61850 and its related standards appear to be favorites for WAN data communication, supporting TCP/IP, among other protocols, over fiber or a 1.8 GHz WiMax.

In North America, ANSI C12.12, and its related standards, is considered as the favorite LAN standard, facilitating a new generation of smart meters capable of communicating substation gateways over numerous wireless technologies.

Also, the European community is pushing for the development of the AMI standard for Europe, replacing the aging DLMS/COSEM standard. Thus, it is pushing for efforts to develop a European counterpart for ANSI-C12.22.

It appears that ZigBee with Smart Energy Profile is the favorite for HAN, partially due to the lack of initiatives by the home appliance manufacturers.

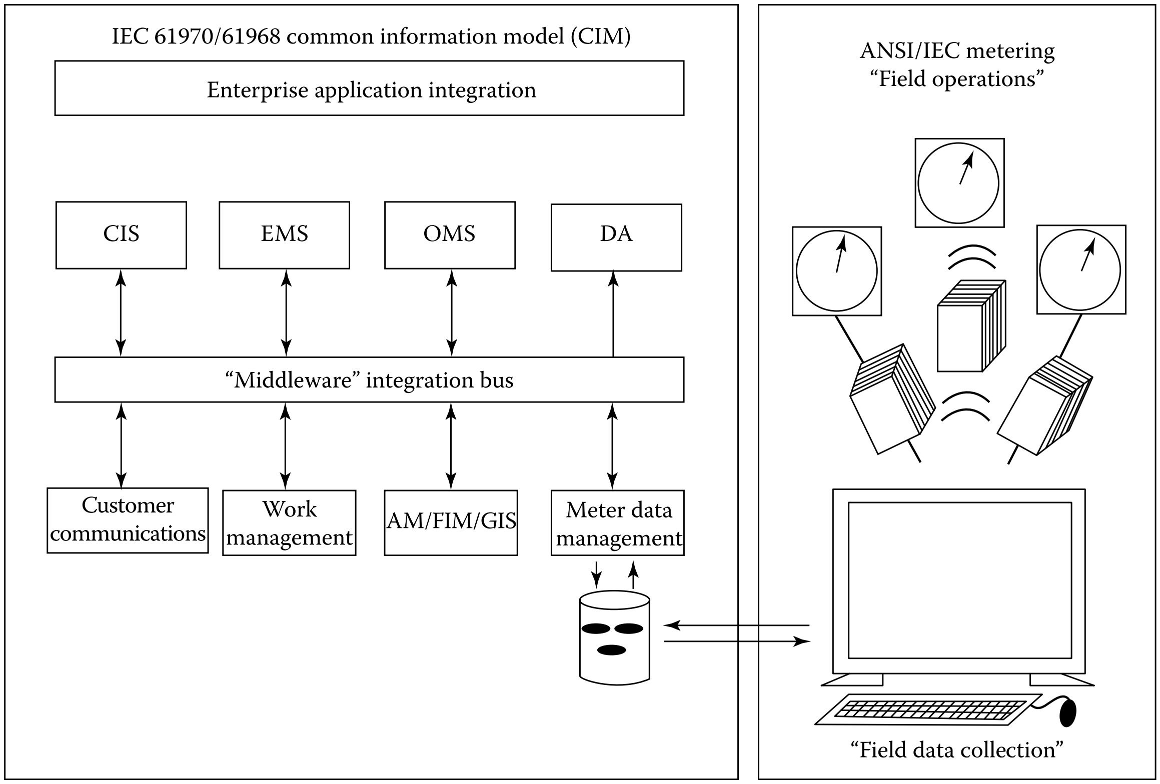

FIGURE 15.37 Developing the CIM for distribution applications as well as its application to the field operations.

15.19 ASSET MANAGEMENT

One of the major objectives of all utilities is to generate sufficient cash flow to cover their operating costs. As part of AM activities, a careful analysis of the substation equipment and operation can identify critical equipment that creates a significant fire hazard. Assets especially in substation control facilities are very critical and should be diligently reviewed to determine the adequacy of the planned fire protection.

As said before, with an increase in regulating influence and the focus on smart grid advanced technologies, there is a renewed interest in increasing the investment in distribution networks to defer infrastructure build-out and to reduce operating and maintenance costs through improving grid efficiency, network reliability, and AM programs.

Thus, since the roots of power system issues are usually found in the electric power distribution system, the point of departure for the grid overhaul is the distribution system. For example, proper loading, as well as overloading, issues of transformers should be considered as the careful application of AM principles. This will also address the risk of major outages in substations. As part of the application of AM principles, it will benefit the lives of substation transformers by establishing proper overloading principles to increase the useful life of the existing transformers.

In general, the smart grid optimizes the utilization of the existing and new assets, improves load factors, and lowers losses in order to maximize the operational efficiency and reduce the cost. Advanced sensing and robust communications will allow early problem detection, preventive maintenance, and corrective action.

Therefore, AM is very important for the utility companies in many respects. It will advance the applications of advanced DA. It will promote the constant monitoring of the conditions in the substations and other existing facilities. It will manage real-time loading of the plant and equipment. It will encourage establishing scheduled maintenance and will facilitate the increase in plant and equipment utilization.

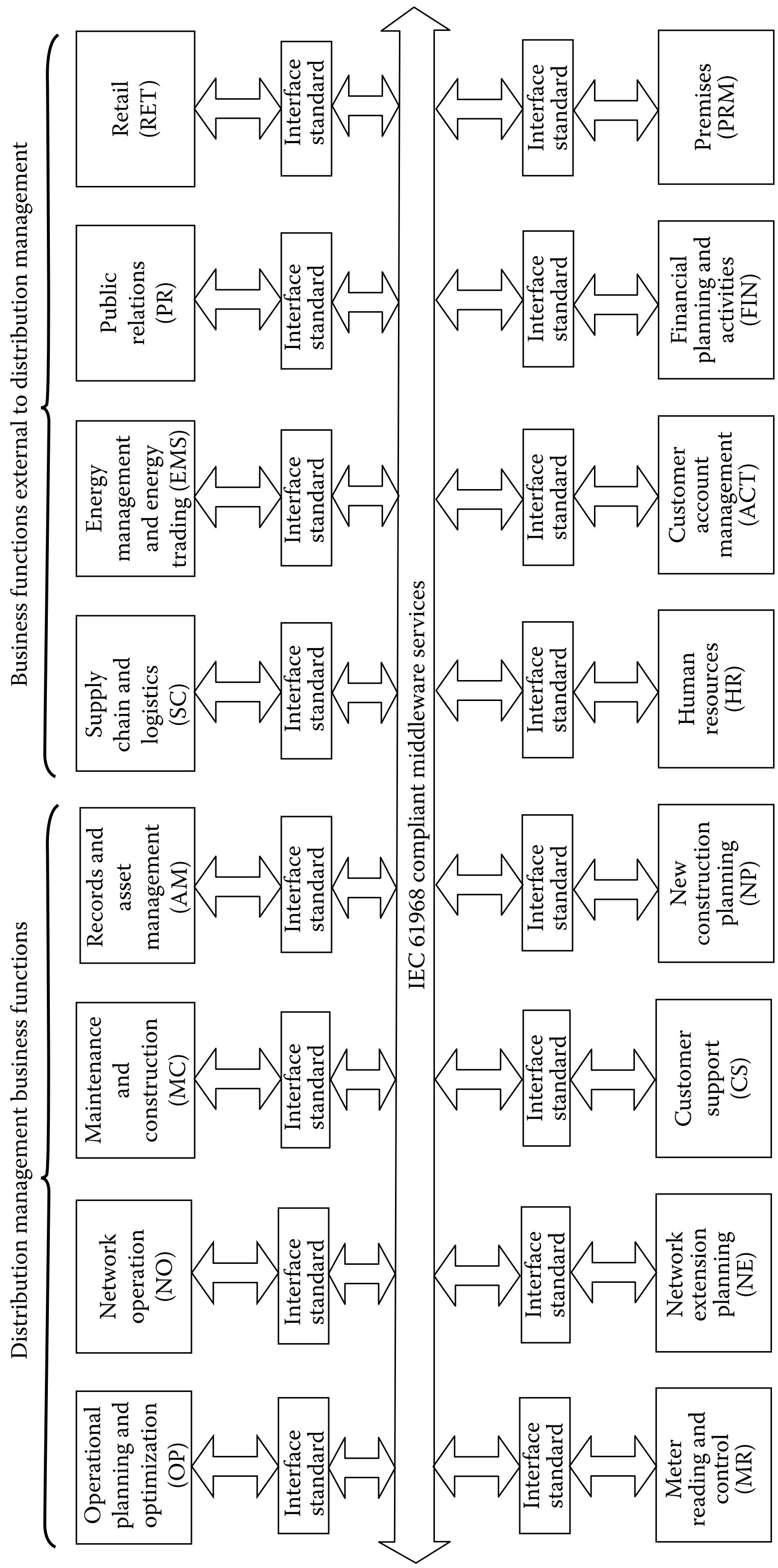

FIGURE 15.38 The IEC 61968 IRM showing activity diagrams and sequence diagrams that are organized by the IRM.

In summary, the proper application of the AM will increase the useful lives of the plant and equipment, delay the timing of the replacement of the plant and equipment, cause the increase in the net profit by decreasing the expenditures involved, and decrease the operational hazards to the plant and equipment as well as to the personnel involved.

15.20 EXISTING CHALLENGES TO THE APPLICATION OF THE CONCEPT OF SMART GRIDS

It is estimated that the electric power grid will make a transition from an electromechanically controlled system to an electronically controlled network within the next two decades. According to Amin and Wollenberg [5], there are some fundamental challenges to achieve this transition, namely,

1. The lack of transmission capacity to meet the substantially increasing loads
2. The difficulties of grid operation in a competitive market environment
3. The redefinition of power system planning and operation in the competitive era
4. The determination of the optimum type, mix, and placement of sensing, communication, and control hardware
5. The coordination of centralized and decentralized control

Smart grids are not really about doing things a lot differently than the way they are being done today. Instead, they are about doing more of what is being done, that is, sharing communication and infrastructures, filling in product gaps, and leveraging existing technologies to a greater extent while driving a higher level of integration to realize the synergies across enterprise integration.

A smart grid is not an off-the-shelf product or something that can be installed and turn on the next day. Rather, it is an integrated solution of technologies driving incremental benefits in capital expenditures, operation and maintenance expenditures, and customer and societal benefits.

A well-designed smart grid imitative build on the existing infrastructure provides a greater level of integration at the enterprise level and has a long-term focus. It is definitely a one-time solution but a change in how utilities look at a set of technologies that can enable both strategic and operational processes. It is the means to leverage benefits across applications and remove the barriers that are created by the past company practices.

15.21 EVOLUTION OF SMART GRID

Figure 15.39 illustrates the possible future application of the smart grid concept at the substation level as well as between substations. The figure shows the AMI infrastructure and implementation of distribution command-and-control strategies over the AMI backbone. Note that the penetrating control and intelligent that are the properties of smart grid have to be located across all geographic areas, as well as components, and functions of the power system. As said before, the distinguished three elements mentioned earlier, that is, geographic areas, components, and functions, determine the topology of the smart grid and its components.

Figure 15.40 shows the present and future research areas in the application of the smart grid concept into distribution systems. The areas can essentially be categorized into two areas, namely, the applications and technology, and the infrastructure. The area of applications and technology includes the new technologies; new applications and systems; technology transfer, industry coordination, technology watch, and application guides; PV integration; distribution efficiency; and PHEV integration. The area of infrastructure includes communication infrastructure, information system integration, and security.

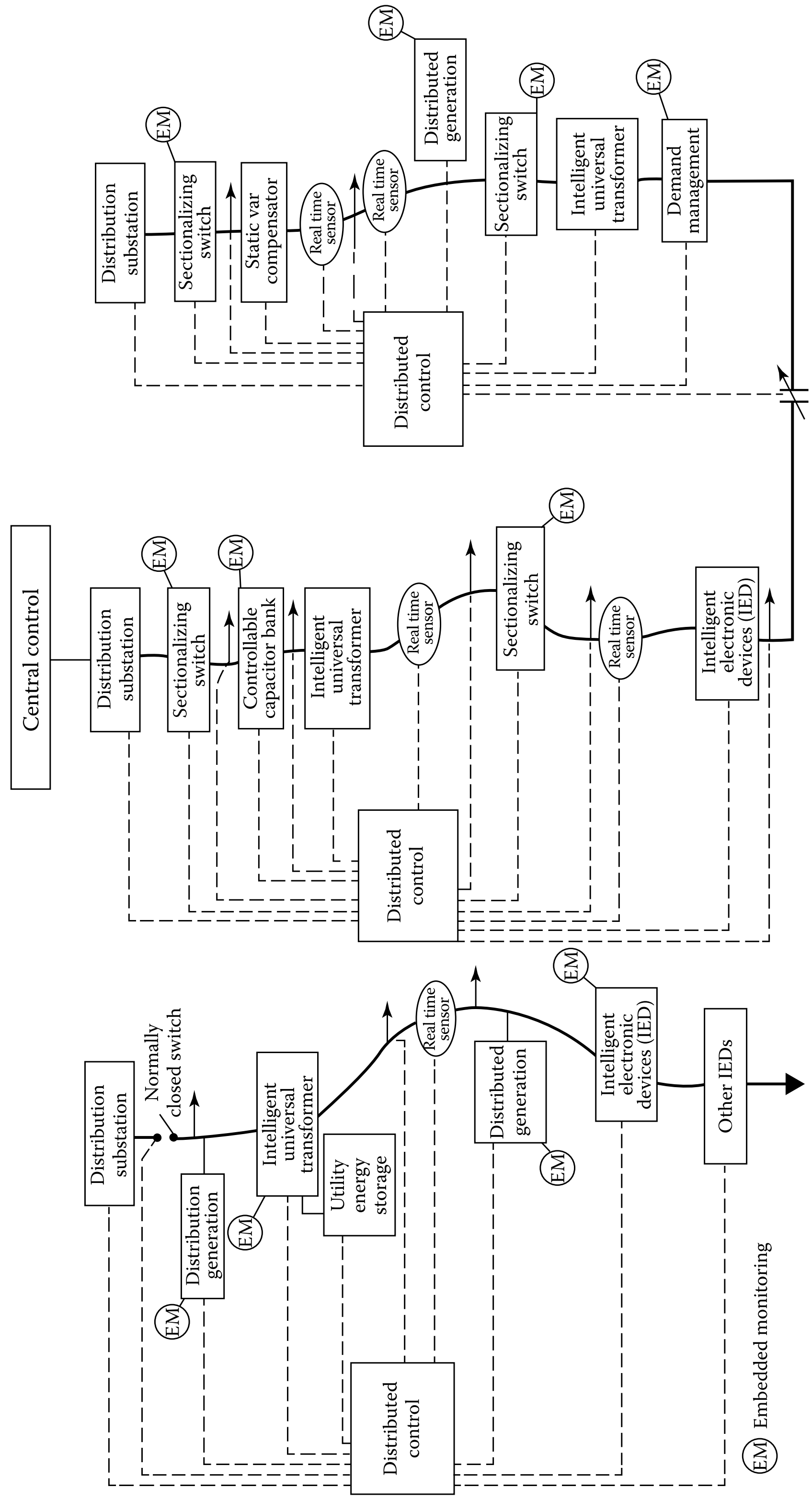

FIGURE 15.39 Illustrates the possible future application of the smart grid concept at the substation level as well as between substations.

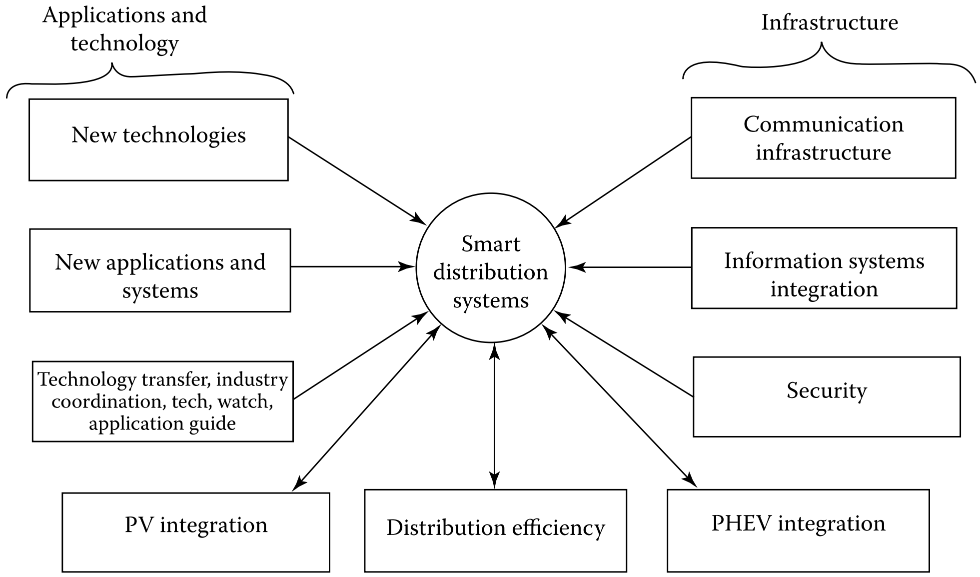

FIGURE 15.40 Present and future research areas in smart grid applications.

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