Smart Grid Technology in Bangladesh: An Overview and Implementation

This thesis report has been submitted to the Department of Electrical and Electronic Engineering in partial fulfillment of the requirements for the degree of Bachelor of Science in Electrical and Electronic Engineering (B.Sc in EEE).

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Finally, we beg pardon for our unintentional errors and omission if any.

DECLARATION

We hereby declare that this Thesis on "**Smart Grid Technology in Bangladesh: An Overview and implementation**" is submitted to Daffodil International University for partial fulfillment of the requirement of the degree of B. Sc. in Electrical & Electronic Engineering.

It has not been submitted to any other University or institution for the award of any degree previously. This project report does not breach any provision of copy right act.

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Dedication

This thesis is dedicated to our venerable parents and for the service to our Nation.

Abstract

The old electricity network infrastructure has proven to be inadequate, with respect to modern challenges such as alternative energy sources, electricity demand and energy saving policies. Moreover, Information and Communication Technologies (ICT) seem to have reached an adequate level of reliability and flexibility in order to support a new concept of electricity network—the smart grid. In this work, we will analyse the state-of-the-art of smart grids, in their technical, management, security, and optimization aspects. We will also provide a brief overview of the regulatory aspects involved in the development of a smart grid, mainly from the viewpoint of the Bangladesh.

Keywords: smart grids; energy; renewable; grid intelligence; energy efficiency; energy storage, Substation Automation.

Contents

Chapter 4 Information and Communication Technology for the Smart Grid

Chapter 6 Cyber security, Interoperability and Standard

Chapter 7 Implementation of Smart Grid in Bangladesh

Chapter 8 Conclusion and Recommendation

List of Figure

List of Tasble

List of Abbreviation

ATO	Advanced Transmission Operations
AMI	Advanced Metering Infrastructure
ADO	Advanced Distribution Operations
AAM	Advanced Asset Management
AC	Alternating current
AMM	Automatic Meter Management
AMR	Advance Meter Reading
ADR	Automatic Demand Response
AGC	Automatic Generation Control
APSCL	Ashuganj Power Station Co. Ltd
BPDB	Bangladesh Power Development Board
CPP	Critical Peak Pricing
CB	Circuit Breaker
CR	Cluster Router
CIS	Customer Information System
CCTV	Closed Circuit Television
DESCO	Dhaka Electric Supply Co. Ltd.
DPDC	Dhaka Power Distribution Co. Ltd.
DLR	Dynamic Line Rating
DFR	Digital Fault Recorder
DM	Demand Management
DSE	Distribution State Estimation
DCC	Data and Control Center
DVR	Digital Video Recorder
DMS	Distribution Management System
DER	Distributed Energy Resources
DR	Demand Response
DG	Distributed Generation
DA	Distribution Automation
DoE	U.S Department of Energy
FACTS	Flexible AC transmission system

EISA	Energy Independence and Security Act
EMS	Energy Management System
EVs	Electric Vehicles
EGCB	Electricity Generation Company of Bangladesh Ltd.
FAN	Field Area Network
FFD	Full Function Device
FACTS	Flexible AC Transmission System
GIS	Geographic Information System
GHG	Greenhouse Gas
GTO	Gate Turn-Off thyristor
HEMS	Home Energy Management Systems
HAN	Home Area Network
ISO	Independent System Operator
IEDs	Intelligent Electronic Devices
IP	Internet Protocol
IEC	International Electrotechnical Commission
IRs	Interior Routers
IPP	Independent Power Producers.
LAN	Local area Network
LCD	Liquid Crystal Displays
LED	Light Emitting Diodes
MEMS	Microgrid Energy Management System
MDM	Meter Data Management
MDMS	Meter Data Management System
MPLS	Multi Protocol Label Switching
NAN	Neighborhood Area Network
NETL	National Energy Technology Laboratory
NWPGCL	North West Power Generation Company Ltd.
NIST	National Institute of Standards and Technology
NWZPDCL	North West Zone Power Distribution Co. Ltd.
OMS	Outage Management System
RTU	Remote Terminal Unit
RTO	Regional Transmission Operator
PLC	Power Line Communications

PMU(s)	Phasor Measurement Unit
PLCNB	Power Line Communication over Narrowband Frequencies
PBS	Pallai Bidyut Samity
PGCB	Power Grid Company of Bangladesh Ltd.
PSTNs	Public Switched Telephone Networks
REM	Retail Energy Market
RTP	Real-Time Pricing
RPCL	Rural Power Company Ltd.
REB	Rural Electricity Board.
SA	Substation Automation
SA	Substation Automation
SD	Switch Disconnector
SCCL	Short-Circuit Current Limiters
SIPP	Small Independent Power Producers
SCADA	Supervisory Control And Data Acquisition System
SZPDCL	South Zone Power Distribution Company Ltd.
TCP	Transmission Control Protocol
ToU	Time of Use
TMS	Transmission Management System
VoIP	Voice Over IP
VVWC	Volt, VAR, Watt Control
WAN	Wide Area Network
WEMs	Wholesale Energy Markets
WAMS	Wide Area Measurement System
WPAN	Wireless Public Area Networks
WRs	WAN routers
WASA&C	Wide area situational Awareness and Control
WAMS	Wide-Area Measurement Systems
WZPDCL	West Zone Power Distribution Co. Ltd.

Chapter 1

Introduction

1.1 Introduction

Over the past 50 years, electricity networks evolved from the "local grid" networks in the beginning of the century to interconnected electric grids, based on generating stations of notable scale (1000–3000 MW) distributing power to major load centres that divided energy to a large number of individual consumers. The generating stations, or power plants, were built in order to provide massive amounts of energy, due to the nature of power generation technologies in use (hydroelectric, coal, oil, and

gas). By the end of the 20th century, however, this model proved to be unreliable and inadequate. First of all, the demand forecast techniques and the data processing technologies could not efficiently provide the desired energy at the desired time, thus power distribution was based upon rough average classifications.

Moreover, the emerging environmental issues and the geopolitical interdependence of power sources limited the development of economies of scale. The main challenges that a modern electricity network

Has to face are:

- Privacy issues between energy suppliers and customers;
- Security threats from cyber attack;

- National goals to employ alternative power generation sources;
- Significantly more complexity in maintaining stable power with intermittent supply;
- Conservation goals that seek to lessen peak demand surges during the day so that less energy is wasted in order to ensure adequate reserves;
- High demand for an electricity supply that is uninterrupted;
- Digitally controlled devices that can alter the nature of the electrical load and result in electricity demand that is incompatible with a power system that was built to serve an "analog economy".

These challenges require the development of an intelligent, self-balancing, integrated electric network that makes use of the modern ICT techniques to manipulate and share data. The smart grid technology tries to answer these needs. In this survey, we propose an overview of the main aspects of smart grids development and implementation. In Section 2, we give two different definitions of the smart grid concept. In Section 3 we will Study about smart grid technology. In Section 4, we will review its Information and communication aspects. In Section 5, we will see how smart meter deployed in smart grid and automation system of transmission and distribution system. In Section 6, we will review the cyber attack and cyber security of smart grid. In Section 7, we will see how smart grid is important and how the smart grid will be implemented in Bangladesh. In Section 8, some conclusions are given.

1.2 Background

Electricity has been a powerful driver of economic growth and wellbeing worldwide. Electricity consumption alone is causing 17% of anthropogenic greenhouse gas (GHG) emissions and as such should be one of the main areas of focus for mitigation of climate change.

Power is the pre condition for social and economic development. But currently consumers cannot be provided with uninterrupted and quality power supply due to inadequate generation compared to the national demand. To resolve the present shortfall and to meet the increasing demand for electricity, the government has taken an initiative to increase generation (installed) capacity to 13735 MW by 2015.

Energy demand continues to increase, while fossil fuel resources are shrinking and set to steadily become more expensive. At the same time, climate change and pollution have become issues of concern to Bangladeshi citizens.

The smart grid is hailed by regulators and industry players as one of the key opportunities to save energy and lower CO2 emissions, but deployment of the smart grid seems slow, as has been reported by numerous observers.

The smart grid is a complex concept, involving not only distribution of electricity, but also data generation and communication systems and complex management applications. It also involves a wide variety of players, from electricity producers, grid operators and electricity retailers to hardware and software producers, industry giants and start-ups, investors, regulators and 'prosumers' (consumer and micro-producer).

Ernst & Young (2010) recently identified ICT, Greentech and Electricity Utilities as leading growth areas over the coming ten years. It is the convergence of these three sectors that creates the smart grid, which makes this one of the most exciting sectors to emerge. The upgrading of old electricity grids with information and communication technology to modern 'smart' grids facilitates the integration of renewable energy and improves operational efficiency of the grids. It also enables savings in end-consumption of electricity and allows for shifting of demand load through the involvement of empowered consumers, thus reducing the need for construction of expensive extra peak capacity.

Energy efficiency measures generally have a lower GHG abatement cost than investment in nuclear or renewable power generation or carbon capture & storage (McKinsey, 2010). Smart grid technology and applications have the potential to increase the efficiency of electricity distribution as well as the efficiency of in-home electricity use. This is an incentive for policy makers, utilities and scientists to prioritize the development of the Smart Grid.

1.3 Literature review

For a complete analysis of drivers and barriers, as well as to deepen my understanding of smart grid technologies and applications and support my assumptions for the smart grid market forecast, I reviewed lots of website, journal, book, studied the interview and seminar of fellow person who work about smart grid, studied many pilot project that conducted in various country.

The literature analysis was conducted entirely over the Internet and included the following:

Yu, Y. X., and Wenpeng Luan (2009) described the drivers, characteristics and major technical components of smart grid on his research paper "Smart Grid and Its Implementations". He summarized the associated smart grid benefits, challenges and worldwide implementations by describing advanced transmission operations (ATO), advanced metering infrastructure (AMI), advanced distribution operations (ADO) and advanced asset management (AAM) integrated energy and communication system architecture (IECSA).

Xie, Kai, et al. (2008), to find direction of future power grid, defined the smart grid, its successful performance, characteristics, key technologies and business functions and the relations between them. He expressed The four components correspond to the future expected benefits, required special capability and related technologies support, the combination of technologies and businesses respectively.

Metke, Anthony R., et al.(2010) mentioned security key security technologies for a smart grid system, including public key infrastructures and trusted computing by describing require significant dependence on distributed intelligence and broadband communication capabilities, the access and communications capabilities require the latest in proven security technology for extremely large, wide-area communications networks.

S. M. Monjurul Hasan, et al, (2013) proposed a models using wind-mill software to reduce system loss and incorporate smart meter so that the power flow can reach easily to the consumers. He also proposed that inserting regulated voltage, regulator and capacitor into power grid would reduce the loss and make the effective and efficient power supply to the consumers.

Faysal Nayan, et al, (2013) discussed about the significance and a detailed feasibility study of practical implementation of Smart Grid in Bangladesh by analyzing the characteristics of Smart Grid and a comparative analy-sis with conventional grid system.

1.4 Significant of smart Grid/ Study

Since about 2005, there has been increasing interest in the Smart Grid. The recognition that ICT offers significant opportunities to modernise the operation of the electrical networks has coincided with an understanding that the power sector can only be de-carbonised at a realistic cost if it is monitored and controlled effectively. In addition, a number of more reasons have now coincided to stimulate interest in the Smart Grid.

In many parts of the world (for example, the USA and most countries in Europe including Bangladesh), the power system expanded rapidly from the 1950s and the transmission and distribution equipment that was installed then is now beyond its design life and in need of replacement. The need to refurbish the transmission and distribution circuits is an obvious opportunity to innovate with new designs and operating practices. Therefore some of the existing power transmission and distribution lines are operating near their capacity and some renewable generation cannot be connected. This calls for more intelligent methods of increasing the power transfer capacity of circuits dynamically and rerouting the power flows through less loaded circuits.

Any power system operates within prescribed voltage and frequency limits. If the voltage exceeds its upper limit, the insulation of components of the power system and consumer equipment may be damaged, leading to short-circuit faults. Too low a voltage may cause malfunctions of customer equipment and lead to excess current and tripping of some lines and generators. Modern society requires an increasingly reliable electricity supply as more and more critical loads are connected. The traditional approach to improving reliability was to install additional redundant circuits, at considerable capital cost and environmental impact.

A Smart Grid approach is to use intelligent post-fault reconfiguration so that after the (inevitable) faults in the power system, the supplies to customers are maintained but to avoid the expense of multiple circuits that may be only partly loaded for much of their lives. Fewer redundant circuits result in better utilization of assets but higher electrical losses.

1.5 Scope of Smart Grid

Energy shortage is a worldwide concern. Presently, more than 40 countries show power system instability and load-shedding due to electricity shortage. North American and European companies are presently working on building 'smart electrical grid' technologies to optimize energy flow using digital radios for more efficient electrical grid control and energy conservation. The need to build Smart Grid technologies is rising worldwide and Bangladesh can become a pioneer in this area of technology development. Since energy demand is increasing every year in Bangladesh, it is not possible to build power stations rapidly. Smart Grid system can minimize this problem. In the event of load-shedding, caused by electrical energy shortage in the country, the Smart Grid can automatically recalculate and distribute electricity to all consumers fairly.

The basic needs to implement Smart Grid are digital radios, circuit breakers etc. Both digital radios and circuit breakers are required to upgrade the operation of nation's electrical grid, which can be designed and manufactured in Bangladesh in large scale. With the help of expatriate Bangladeshi engineers, Bangladesh can start designing and manufacturing the electrical parts required to up-grade the electricity grid in Bangladesh so that, Bangladesh can be an early developer and adopter of the Smart Grid technology.

1.6 Methodology

The study was conducted mainly based on the data collected from the different secondary sources like Bangladesh power development board, power division, and power cell, U.S Department of Energy (DoE), Smart Grids European Technology Platform etc.

Different statistical reports, relevant research papers, books and many national and international journals have also been reviewed for this study.

Chapter 2

Conventional Power Grid and Basic review of Smart Grid

2.1 Introduction:

An electric grid is a complete interconnected network for delivering electric power through electric line also known as transmission line from generation station to end consumer. Electric grid also contains transformer (step-up, step-down, power transformer, current transformer etc), fuse, circuit breaker, relay etc. In electric grid, there are three main parts namely the generation station, the transmission line and the distribution system. A distribution system connects all the end users to transmission line. The transmission lines are the connecting link between the generation stations to distribution system. In the transmission line, two transformers are used to voltage up and down. Due to some technical problem, not possible to high voltage so to reduce transmission losses voltage is increased a possible level by step up transformer. Finally, last point of transmission line, voltage is downed a possible level by step down transformer and is supplied to distribution system is arranged by feeder, the distribution sub-station, distribution transformer, lighting arrestor, service line etc. In this grid system, there is little automation system where all safety devices are electro-mechanical which protect the grid lines and equipment during undesirable condition, and is bidirectional and manual data collection system. Now we want to introduce modernized electric grid where all system are controlled by automatically from central by computerized system known as "The Smart Grid Technology". The smart grid technology is evolution of conventional electric grid system. In this system major change will be in collecting data which sense automatically by using smart meter and communication technology is added to the grid to collect and analysis the data from smart meter and imposed sensor various point in all grid system. The main function of the smart grid technology is all data of end use and all grid system provides even any fault condition to center point by automatically and this system is able prevent the fault. In this chapter we showed basic introduction and characteristics of conventional grid and smart grid, comparison between smart grid and conventional grid. Also we showed why smart grid is important. [6]

2.2 Definition of electric power grid:

A power system network integrates transmission grids, distribution grids, distributed generators and loads that have connection points called busses. A bus in home circuit breaker panels is much smaller than those used on the grid, where bus bars can be 50 mm in diameter in electrical substations. Traditionally, these grid connections are unidirectional point to multipoint links. In distributed generation grids, these connections are bidirectional, and the reverse flow can raise safety and reliability concerns. Features in smart grids are designed to manage these conditions. A premise is generally said to have obtained grid connection when its service location becomes powered by a live connection to its service transformer.

A power station is generally said to have achieved grid connection when it first supplies power outside of its own boundaries. However, a town is only said to have achieved grid connection when it is connected to several redundant sources, generally involving long-distance transmission.

2.3 Conventional electric power grids:

The power grid system is the Electrical utility distribution system which provides power to the consumer (end-user.) Beginning at the Power Generation Plant continuing on through the transmission lines to the substation and local distribution network, finally to the individual consumer. Power grids are smaller distinct sections of this system which together make up the entire distribution network. [1]

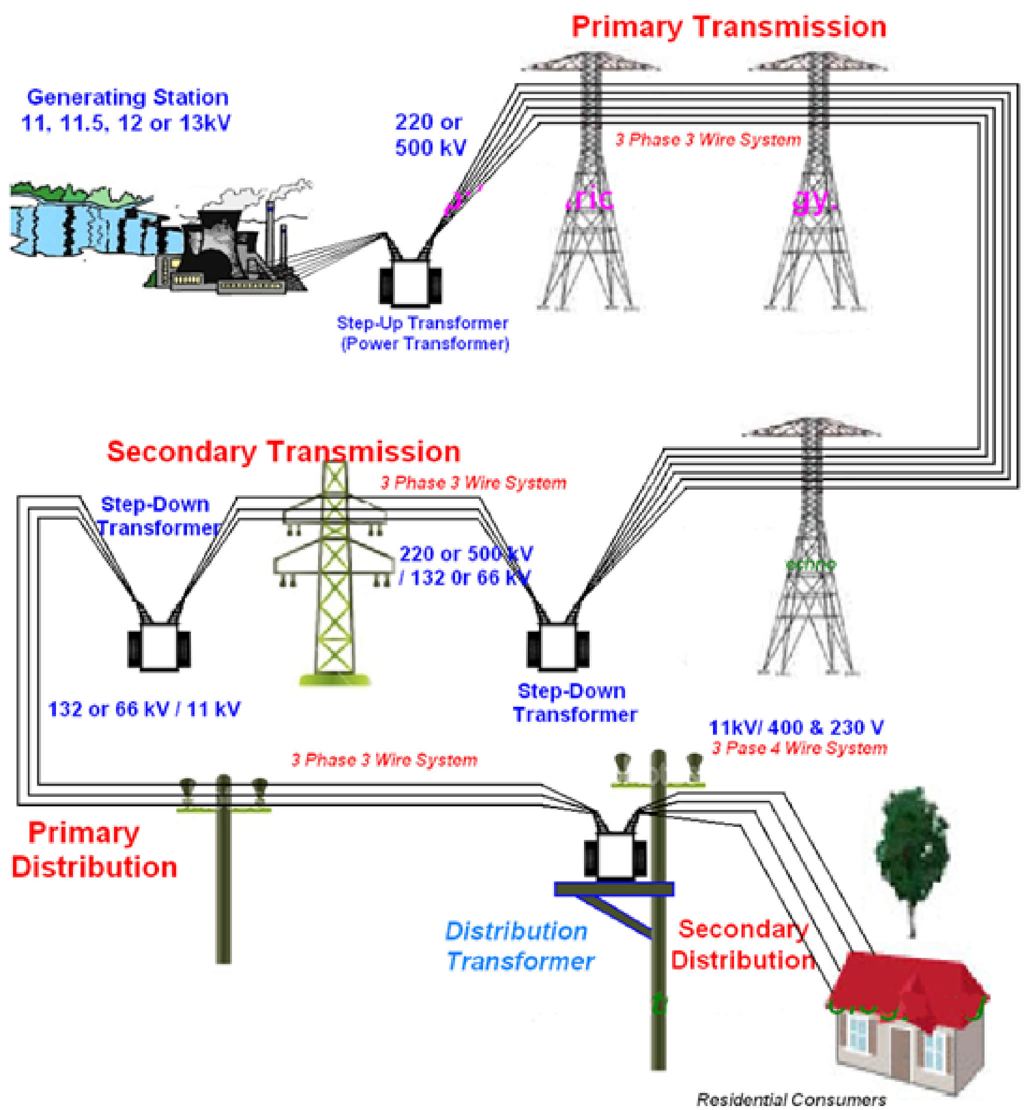


Figure 2.1 Conventional electric Grid

Operationally the conventional electrical grid starts at power generating systems such as power stations that generate 3 phase alternating current (AC) electricity. The 3 phase AC current is passed through a transmission substation that uses transformers to step up (increase) the voltage from thousands of volts to hundreds of thousands of volts. Increasing the voltage allows for efficient transmission of electricity over long distances. After being converted to high voltage, the 3 phase electricity is sent over long distance transmission lines through three lines, one for each phase. Before it can be distributed to end users, the electricity must pass through a power substation that steps down (decreases) the voltage with transformers so that it can be distributed to communities and used in homes and businesses at the correct voltage.

A 3 phase current is used because electricity is generated in a sine wave that has peaks and troughs, meaning that power strength for a single phase fluctuate between weaker and stronger moments. By generating three phases and offsetting them by 120 degrees, the moment of peak power is evenly distributed between the three phases, allowing for more consistent peak power output. Having consistent peak power output is important mainly for industrial purposes, e.g., industrial 3 phase motors.

Alternating current is used because it is easier to change voltages with it than with DC, and a very high voltage is fundamental to long distance electrical transmission because it reduces energy loss by lowering resistance in the wires. [2]

Today's electric infrastructure is comprised of a complex system of power generation, transmission systems, and distribution systems. The major components of this system include:

- **Power generation plants**, which are facilities designed to produce electric energy. Typical power generation plants are fueled by coal, natural gas, hydroelectric, or nuclear.
- **A substation** is a high-voltage electric system facility. It is used to switch generators, equipment, and circuits or lines in and out of a system. Some substations are small with little more than a transformer and associated switches. Others are very large with several transformers and dozens of switches and other equipment.
- **Transmission lines**, which can be hung overhead or underground, carry electric energy from one point to another in an electric power system. The main characteristics that distinguish transmission lines from distribution lines are that they are operated at relatively high voltages, they transmit large quantities of power, and they transmit the power over large distances.

- **A distribution system** originates at a distribution substation and includes the lines, poles, transformers and other equipment needed to deliver electric power to the customer at the required voltages. [3]

Even though current electric grid has efficiency reliability and controlling system enough, yet still has some significant issues:

❖ Limited delivery system:

The current electricity delivery uses a supervisory control and data acquisition system (SCADA) which suffers limited bandwidths and relatively slow data transmission rates that often require several seconds or more to respond to an alarm or system change and there is no visibility in the distribution network below the substation.

❖ High cost of power outage and power quality interruption:

It costs Americans $150 billion every year for power outage and interruption. The power goes out about 2.5 hours each year which leads to high economy loss especially in industries require high quality power.

❖ Inefficiency at managing peak load:

Electricity demands vary all the time, and the cost to meet these demands changes as well.

For the existing grid, supply has to change according to the demands continuously and the power grid will also need to maintain a buffer of excess supply, which results in lower efficiency, higher emissions, and higher costs. [4]

Given the issues above, the existing grid has to change to meet the demand proposed by this modern society.

2.4 Concept of Smart grid:

Smart Grid is developed by the European Technology Platform for 7th Frame Work Program. Since Smart Grid is still in research stage, there is no coincidence with the accurate definition for it, what features should it have, what goal should it achieve, what is the important point for develop it. Moreover considering the varying situations in different countries-economic development, developing strategies and policies, it is hard to obtain a unified definition. [5]

A modernization of the Nation electricity transmission and distribution system is to maintain a reliable and secure electricity infrastructure that can meet future demand growth.

The smart grid technology has:

- Advanced metering infrastructure (AMI)
- Flexible AC transmission system (FACTS)
- Distribution automation (DA)
- Distributed generation (DG)
- Substation automation (SA)
- Demand response (DR)
-

2.6 Comparison between Smart grid and Conventional Grid:

Table: 1-1 Comparison between conventional grid and smart grid [7, 8]

Characteristics	Conventional Grid	Smart Grid
Communication method	Unidirectional, Not Real-time	Bidirectional, Real-time
Technological base	Analog/Electromechanical	Digital
Power flow control	Limited	Pervasive
Power supply	Centralized power	Centralized and Decentralized

method	Generation	power Generation
Self-heals	Responds to prevent further damage.	Automatically detects and responds to actual and emerging transmission and distribution problems
Operation and Management	Artificial device calibration	Remote Monitoring
System topology	Radial structure	Network structure
Control system	Regional	Pan-regional
Motivates & includes the consumer	Consumers are uninformed and no participative with the power system	Informed, involved and active consumers.
Provides power quality for 21st century needs	Focused on outages rather than power quality problems.	Quality of power meets industry standards and consumer needs.
Accommodates all generation	Relatively small number of large generating plants.	Very large numbers of diverse distributed generation and plants. Storage devices deployed to complement the large generating
Enables markets	Limited wholesale markets still working to find the best operating models.	Mature wholesale market operations in place
Optimizes assets and operates	Minimal integration of limited operational data with Asset Management processes and technologies.	Greatly expanded sensing and measurement of grid conditions. Grid technologies deeply integrated with asset management processes to most effectively manage assets and costs.

Emergency recovery	Manual recovery	Self healing, Auto recovery
Price Information	Limited	All access price information
Customer choice	Limited choice of optional function	Wide range of optional function

Chapter 3

The Smart Grid Technology

3.1 Introduction:

Smart grid means “computerizing” the electric utility grid which includes adding two-way digital communication technology to devices associated with the grid. Each device used on the network can be given sensors to gather data (power meters, voltage sensors, fault detectors, etc.), plus two-way digital communication between the device in the field (e.g., end user, substation, transmission, distribution) and the utility’s network operations center. A key feature of the smart grid is automation technology that lets the utility adjust and control each individual device or millions of devices from a central location. [9]

As defined by the principal characteristics, OE has a vision of a smart grid that uses digital technology to improve reliability, resiliency, flexibility, and efficiency (both economic and energy) of the electric delivery system. Smart grid technology is an evolution of next decade power system not revolution so existing electric grid will still alike but some advanced technology, components is added to it and shamelessly add all possible power resource.

In this chapter we showed clear concept about “Smart Grid Technology” by defining smart grid, conceptual model of smart grid technology, technology used, function of smart grid technology etc.

3.2 Definition of the Smart Grid Technology.

When we are discussing about smart grid technology a question is what Smart Grid is?

Shortly we can say; Smart Grid = IT + Electric Grid

That means smart grid is nothing but the conventional grid with IT in order to achieve better reliability, flexibility, efficiency, resiliency and to give better service to end users.

The concept of Smart Grids was developed in 2006 by the European Technology Platform and they defined “smart grid is an electricity network that can intelligently integrate the actions of all users connected to it - generators, consumers and those that do both - in order to efficiently deliver sustainable, economic and secure electricity supplies. A smart grid employs innovative products and services together with intelligent monitoring, control, communication, and self-healing technologies in order to: [10]

- Better facilitate the connection and operation of generators of all sizes and technologies;
- Allow consumers to play a part in optimizing the operation of the system;
- Provide consumers with greater information and options for choice of supply;
- Significantly reduce the environmental impact of the whole electricity supply system;
- Maintain or even improve the existing high levels of system reliability, quality and security of supply;
- Maintain and improve the existing services efficiently;
- Foster market integration towards an European integrated market.

According to the U.S Department of Energy (DoE):

“Smart grid” generally refers to a class of technology people are using to bring utility electricity delivery systems into the 21st century, using computer-based remote control and automation. These systems are made possible by two-way communication technology and computer processing that has been used for decades in other industries. They are beginning to be used on electricity networks, from the power plants and wind farms all the way to the consumers of electricity in homes and businesses. They offer many benefits to utilities and consumers -- mostly seen in big improvements in energy efficiency on the electricity grid and in the energy users’ homes and offices.

According to U.S Department of Energy (DoE) the Functional Characteristics of smart grid are:

- Self-healing from power disturbance events

- Enabling active participation by consumers in demand response
- Operating resiliently against physical and cyber attack
- Providing power quality for 21st century needs
- Accommodating all generation and storage options
- Enabling new products, services, and markets
- Optimizing assets and operating efficiently

3.3 Working Principle of Smart Grid Technology:

With traditional utility technology, when a tree limb falls on a power line and creates an outage or a fault occurs on distribution line or customer side that's why creates an outage, for example, the utility finds out only when a customer calls to complain. With a smart grid system, devices along the network can automatically tell the utility exactly when and where an outage occurred, close the circuit at that location, to "island" the fault, re-route power around failed equipment and create a detailed "trouble ticket" for a repair crew.

Traditionally, electric utilities estimate that a certain type of equipment is likely to wear out after so many years and thus replaces every piece of that technology within that many years -- even devices that have much more useful life left in them. A smart grid system can spot failing grid devices before they give out, letting the utility use a much more cost effective replacement strategy.

When customers are given access to data about their own power use, they can change their habits to be more efficient and save money. Customers will eventually be able to see how the price of electricity changes depending on the time of day it is used, and they will be able to shift their use of the product to times when it is cheaper.

The biggest cost savings in using smart grid may be found in improved efficiency of electricity-delivery operations. For example, once the voltage is known and updated frequently all around a utility's grid, the utility can work much more efficiently. Rather than supplying extra voltage into the grid to cover possible dips somewhere on that grid, voltage drops can be identified and addressed remotely. Such a direct response lets the utility supply the minimum amount of voltage needed for smooth operations. Utilities testing this benefit in the real world are reporting big cost savings almost immediately. [11]

3.4 Why Implement the Smart Grid now?

The electricity systems all around world as well as Bangladesh face a number of challenges including ageing infrastructure, continued growth in demand, the integration of increasing numbers of variable renewable energy sources and electric vehicles, the need to improve the security of supply and the need to lower carbon emissions.

Smart grid technologies offer ways not just to meet these challenges but also to develop a cleaner energy supply that is more energy efficient, more affordable and more sustainable. [14]

The smart grid should be implemented to achieve following tasks and advantages:

- Increasing reliability, efficiency and safety of the power grid.
- Enabling decentralized power generation so homes can be both an energy client and supplier
- Flexibility of power consumption at the client's side to allow supplier selection (distributed generation, solar, wind, and biomass)
- Increase GDP by creating more new, green collar energy jobs related to renewable energy industry manufacturing,
- Enabling plug-in electric vehicles, solar panel, and wind turbine generation, energy conservation and construction.
- Give greater levels of information on electricity pricing and consumption to consumers, which will give them greater control over their consumption and help them reduce their bills.

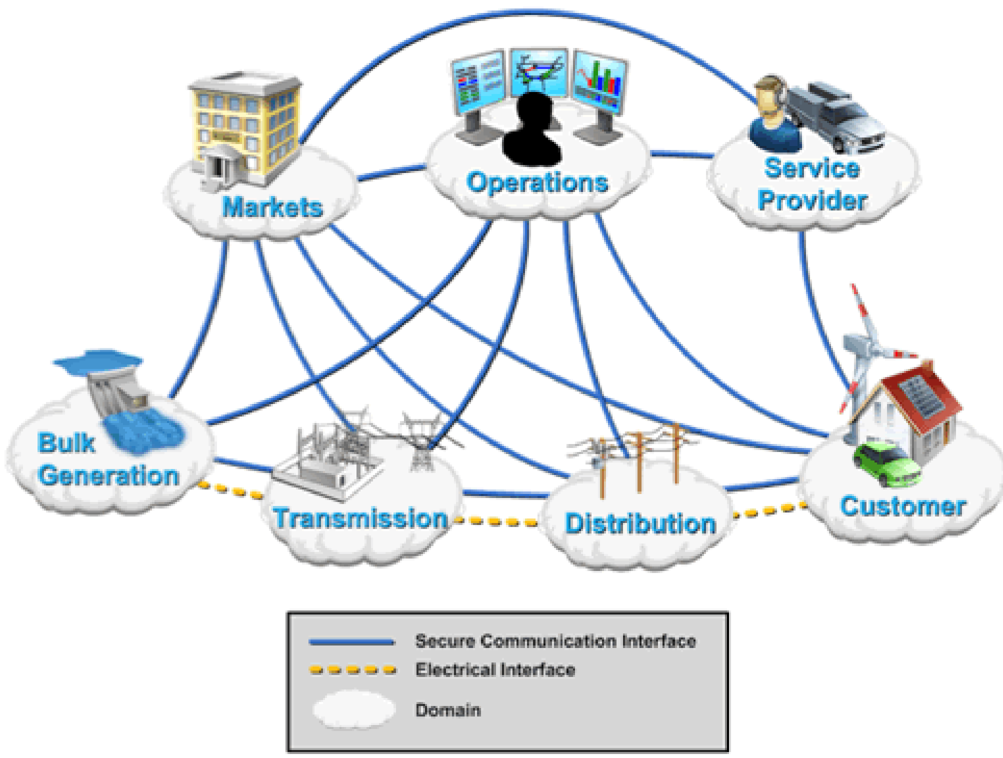


Figure: 3.1 Conceptual model of Smart Grid Technology in NIST

3.5 Smart Grid Conceptual model:

Under the Energy Independence and Security Act (EISA) of 2007, the National Institute of Standards and Technology (NIST) create framework using a systems approach to be flexible, uniform and technology-neutral, because no single technology developed will be able to satisfy all requirements for the smart grid. By building a framework based on possible application scenarios a robust model develops, the first release, a high-level conceptual reference model for the Smart Grid.

The NIST Conceptual Reference Model is descriptive, and is intended to be high level. The NIST conceptual Model can serve as a tool for identifying actors and possible communication paths in the Smart Grid. The figure below provides a high level grouping of what NIST has deemed as the smart grid domain. The seven Domains in the Smart Grid Conceptual Model include: [14]

- Bulk generation

- Transmission
- Distribution
- Customers
- Markets
- Service providers and
- Operations

It shows all the communications and energy/electricity flows connecting each domain and how they are interrelated. Each individual domain is itself comprised of important smart grid elements that are connected to each other through two-way communications and energy/electricity paths. These connections are the basis of the future, intelligent and dynamic power electricity grid.

The NIST Smart Grid Conceptual Model helps us to understand the building blocks of an end-to-end smart grid system, from Generation to (and from) Customers, and explores the interrelation between these smart grid segments.

At IEEE, the smart grid is seen as a large "System of Systems," where each NIST smart grid domain is expanded into three smart grid foundational layers: (i) the Power and Energy Layer, (ii) the Communication Layer and (iii) the IT/Computer Layer. Layers (ii) and (iii) are enabling infrastructure platforms of the Power and Energy Layer that makes the grid "smarter." [14]

❖ Bulk Generation:

Applications in the Bulk Generation domain are typically the first process in the delivery of electricity to customers. Electricity generation is the process of creating electricity from other forms of energy, which may vary from chemical combustion to nuclear fission, flowing water, wind, solar radiation and geothermal heat.

The Bulk Generation domain is electrically connected to the Transmission domains as well as communicating with the Operations and the Markets domain. Some benefits to the Bulk Generation domain from the deployment of the smart grid are the ability to automatically reroute power flow from other parts of the grid when generators fail. [12]

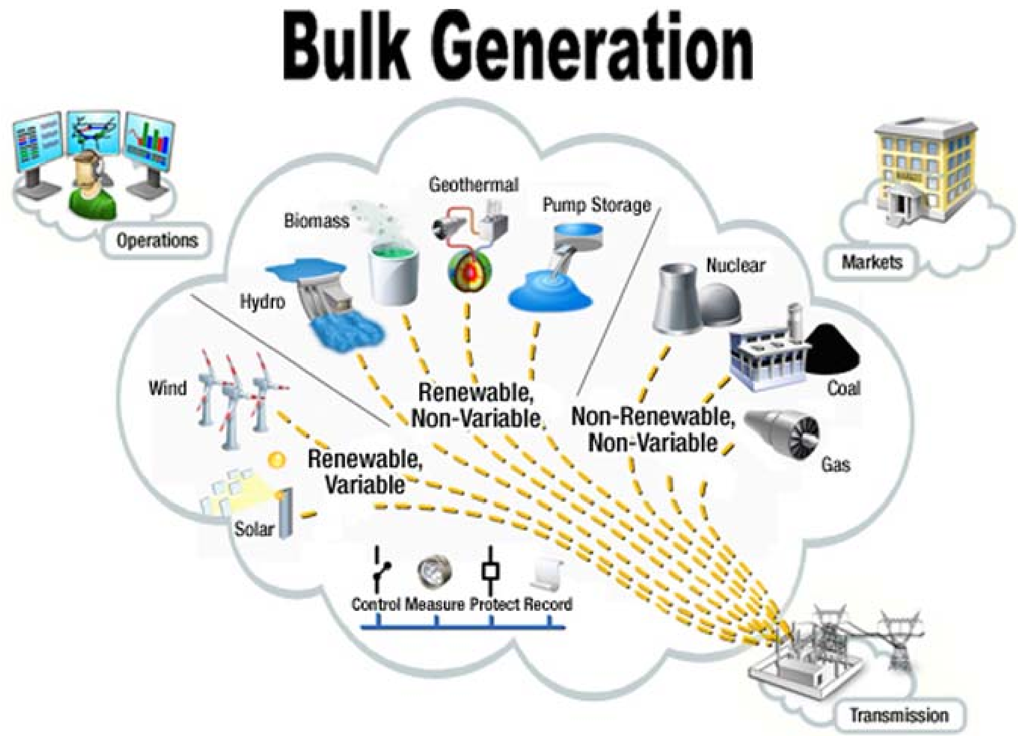


Figure: 3.2 Bulk Generation Domain (Conceptual Model of Smart Grid Technology)

The Bulk Generation domain of the smart grid generates electricity from renewable and non-renewable energy sources in bulk quantities. These sources can also be classified as renewable, variable sources, such as solar and wind; renewable, non-variable, such as hydro, biomass, geothermal and pump storage; or non-renewable, non-variable, such as nuclear, coal and gas. Energy that is stored for later distribution may also be included in this domain. [17]

Table 3-1 Typical Applications in the Bulk Generation Domain

Application Category	Description
Control	Performed by actors that permit the Operations domain to manage the flow of power and reliability of the system. An example is the use of phase angle regulators within a substation to control power flow between two adjacent power systems
Measure	Performed by actors that provide visibility into the flow of

	power and the condition of the systems in the field. In the future, measurement might be found built into meters, transformers, feeders, switches and other devices in the grid. An example is the digital and analog measurements collected through the SCADA system from a remote terminal unit (RTU) and provide to a grid control center in the Operations domain.
Protect	Performed by Actors that react rapidly to faults and other events in the system that might cause power outages, brownouts, or the destruction of equipment. Performed to maintain high levels of reliability and power quality. May work locally or on a wide scale.
Record	Performed by actors that permit other domains to review what has happened on the grid for financial, engineering, operational, and forecasting purposes.
Asset Management	Management performed by actors that work together to determine when equipment should have maintenance, calculate the life expectancy of the device, and record its history of operations and maintenance so it can be reviewed in the future for operational and engineering decisions.

❖ **Transmission**:

Transmission is the bulk transfer of electrical power from generation sources to distribution through multiple substations. The Transmission domain is electrically connected to the Bulk Generation and Distribution domains, as well as communicating with the Operations, and Markets domains.
A transmission network is typically operated by a Regional Transmission Operator or Independent System Operator (RTO/ISO) whose primary responsibility is to maintain stability on the electric grid by balancing generation (supply) with load (demand) across the transmission network.

The Transmission domain may contain distributed energy resources such as electrical storage or peaking generation units. Energy and supporting ancillary services (capacity that can be dispatched when needed) are procured through the Markets domain and scheduled and operated from the Operations domain. They are then delivered through the Transmission domain to the utility-controlled distribution system and finally to customers.

Actors in the transmission domain may include remote terminal units, substation meters, protection relays, power quality monitors, phasor measurement units, sag monitors, fault recorders, and substation user interfaces. [12]

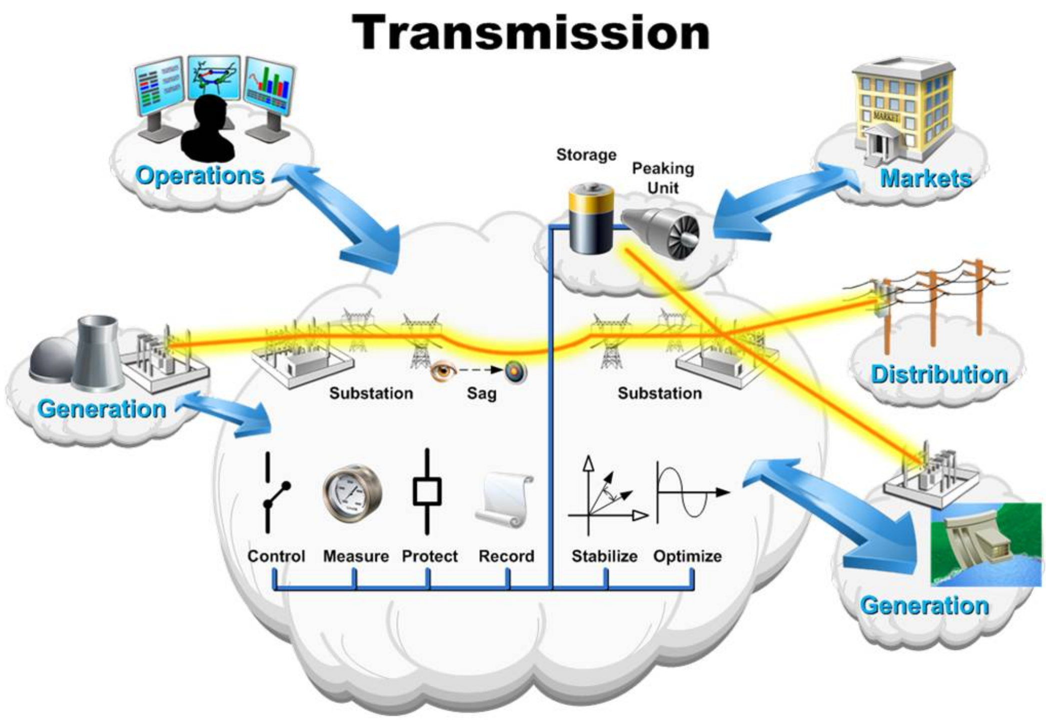


Figure: 3.3 Transmission Domain (Conceptual model)

Table 3-2 Typical Applications in the Transmission Domain

Application Category	Description
Substation	The systems within a substation.
Storage	A system that controls the charging and discharging of an energy storage unit
Measurement &	Includes all types of measurement and control systems to

Control	measure, record, and control with the intent of protecting and optimizing grid operation.

❖ **Distribution**:

The Distribution domain is electrically connected between the Transmission domain and the Customer domain at the metering points for consumption. The Distribution domain also communicates with the Operations and Markets domains. The Distribution domain distributes the electricity to and from the end customers in the smart grid. The distribution network connects the smart meters and all intelligent field devices, managing and controlling them through a two-way wireless or wireline communications network. [17]

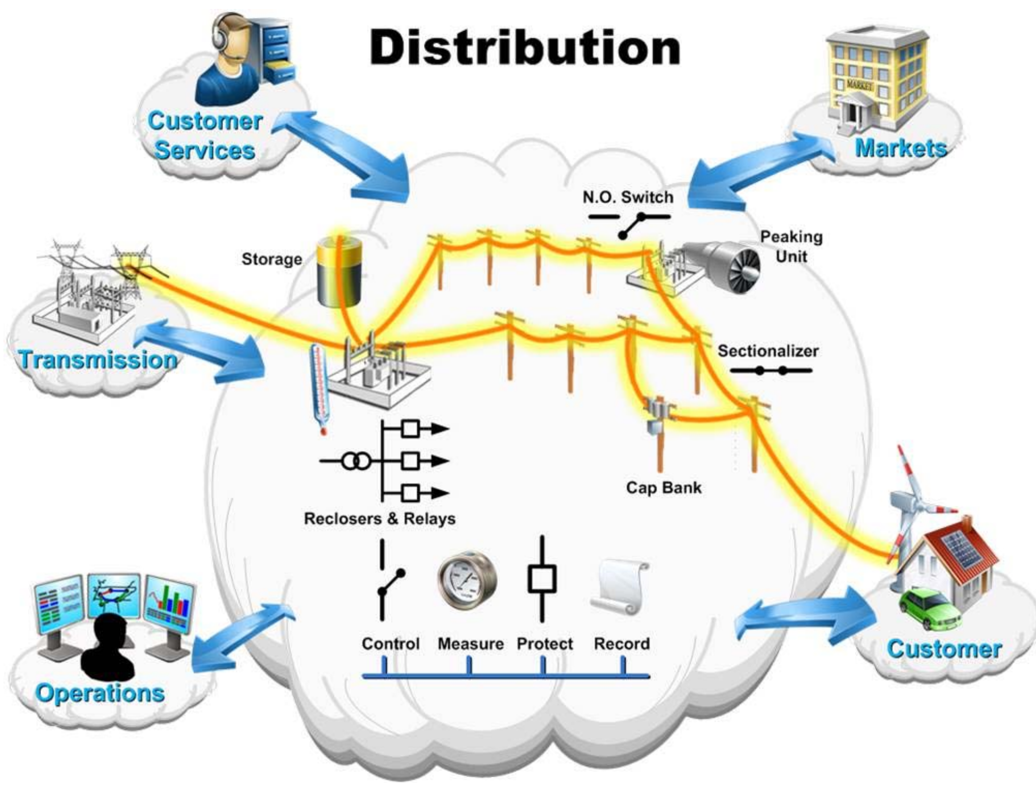


Figure: 3.4 Distribution Domain (Conceptual Model)

With the advancement of distributed storage, distributed generation, demand response and load control, the ability of the Customer domain to improve the reliability of the distribution domain exists. Distribution networks are now being built with much interconnection, extensive monitoring and control devices, and distributed energy resources capable of storing and generating power. Such distribution networks may be able to break into self-supporting "micro-grids" when a problem occurs and customers may not even be aware of it.

Actors in the Distribution domain may include capacitor banks, sectionalizers, reclosers, protection relays, storage devices, and distributed generators. [12]

Table 3-3 Typical Applications within the Distribution Domain

Application Category	Description
Substation	The control and monitoring systems within a substation.
Storage	A system that controls a charging and discharging of an energy storage unit
Distributed Generation	A power source located on the distribution side of the grid.
Measurement & Control	Includes all types of measurement and control systems to measure, record, and control with the intent of protecting and optimizing grid operation.

- **Customer**:

The Customer domain is electrically connected to the Distribution domain. It communicates with the Distribution, Operations, Markets, and Service Provider domains.

Actors in the Customer domain typically enable customers to manage their energy usage and generation. These actors also provide control and information flow between the Customer and the other domains. The boundaries of the Customer domain are typically considered to be the utility meter and/or an additional communication gateway to the utility at the premises. The Customer domain of the smart grid is where the end-users of electricity are connected to the electric distribution network through the smart meters. The smart meters control and manage the flow of electricity to and from the customers and provide energy information about energy usage and patterns.

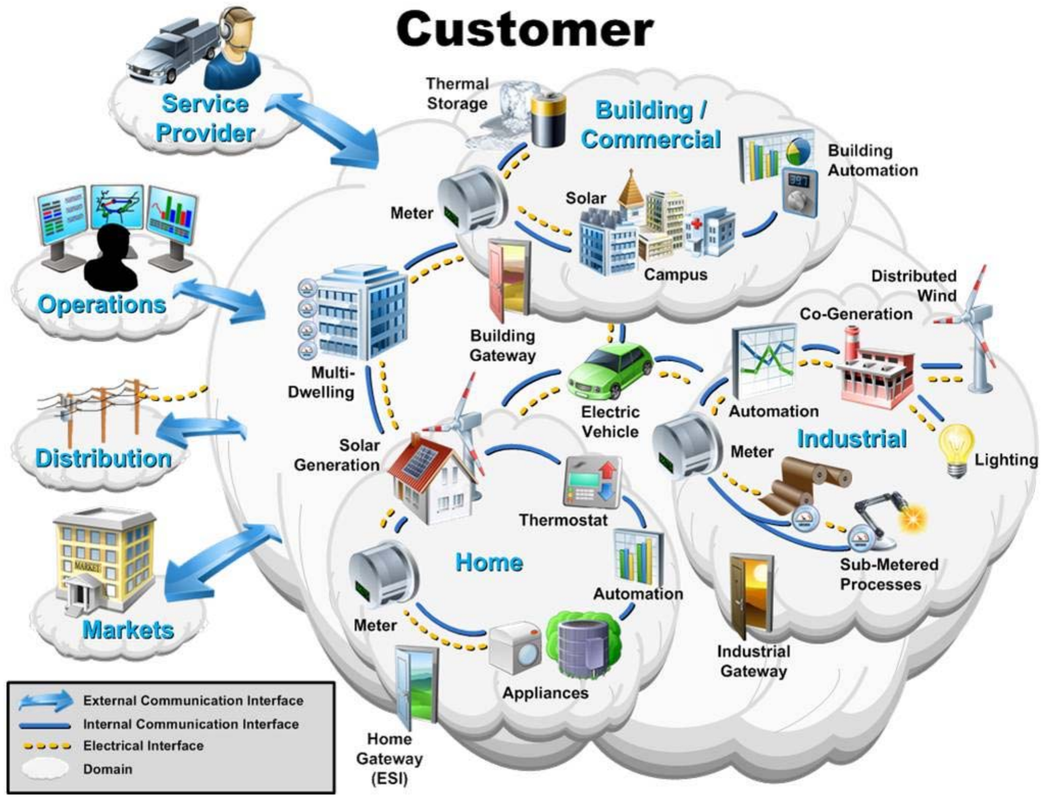


Figure: 3-5 Customer (Conceptual Model of Smart Grid Technology)

There are three types of customers within the Customer domain: **industrial, commercial/building, and home**. The limits of these domains are typically set at less than 20kW of demand for Home, 20-200kW for Commercial/Building, and over 200kW for Industrial. The electric vehicle is an example of an actor that interfaces with all three domains.

All three domains (industrial, commercial and residential) have a meter actor and a gateway that may reside in the meter or may be an independent actor. The gateway is the primary communications interface to the Customer domains. It may communicate with other domains via Advanced Metering Interface (AMI) or another method such as the Internet. It typically communicates to devices within the customer premises using a home area network or other local area network. The gateway enables applications such as remote load control, monitoring and control of distributed generation, in-home display of customer usage, reading of non-energy meters, and integration with building management systems. It may also provide auditing/logging for security purposes. [12]

Table 3-4 Typical Application Categories in the Customer Domain

Application Category	Description
Building or Home Automation	A system that is capable of controlling various functions within a building such as lighting and temperature control.
Industrial Automation	A system that controls industrial processes such as manufacturing or warehousing. These systems have very different requirements compared to home and building systems.
Micro-generation	Includes all types of distributed generation including; Solar, Wind, and Hydro generators. Generation harnesses energy for electricity at a customer location. May be monitored, dispatched, or controlled via communications.

- **Operation**:

Actors in the Operations domain perform the ongoing management functions necessary for the smooth operation of the power system. While the majority of these functions are typically the responsibility of a regulated utility, many of them may be outsourced to service providers and some may evolve over time. For instance, it is common for some customer service functions to be part of the Service Provider domain or Markets domains.

The typical applications performed within the Operations domain may include: network operation, network operation monitoring, network control, fault management, operation feedback analysis, operational statistics and reporting, real-time network calculation, dispatcher training.

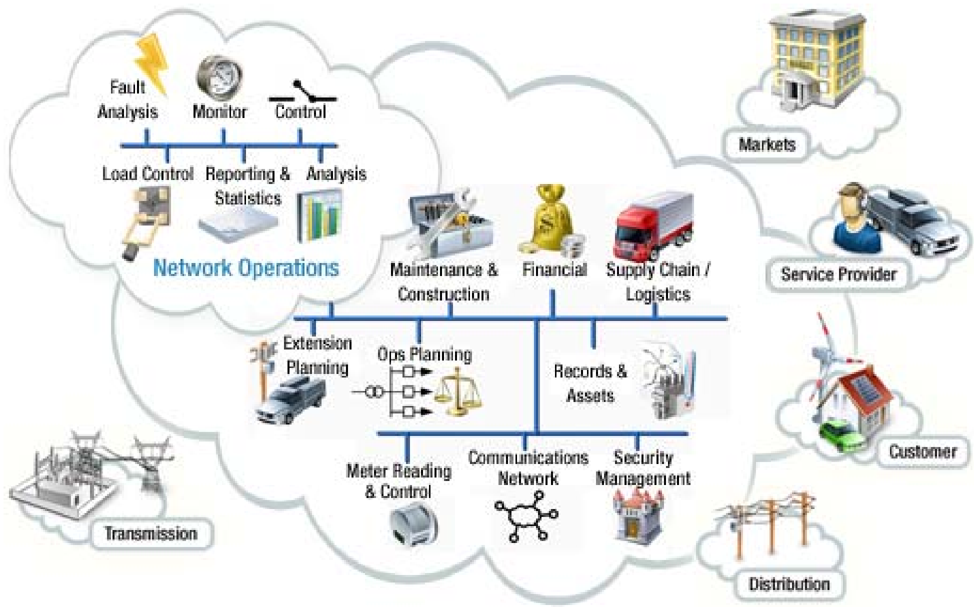


Figure: 3-6 Operation (Conceptual Model of Smart Grid Technology)

Table 3-5 Typical Applications in the Operations Domain.

Application Category	Description
Monitoring	Network Operation Monitoring actors supervise network topology, connectivity and loading conditions, including breaker and switch states, and control equipment status. They locate customer telephone complaints and field crews.
Control	Network control is coordinated by actors in this domain, although they may only supervise wide area, substation, and local automatic or manual control.
Fault Management	Fault Management actors enhance the speed at which faults can be located, identified, and sectionalized and service can be restored. They provide information for customers, coordinate with workforce dispatch and compile information for statistics.
Analysis	Operation Feedback Analysis actors compare records taken from real-time operation related with information on network incidents, connectivity and loading to optimize periodic maintenance.

Reporting an Statistics	Operational Statistics and Reporting actors archive on-line data and perform feedback analysis about system efficiency and reliability.
Calculations	Real-time Network Calculations actors (not shown) provide system operators with the ability to assess the reliability and security of the power system.
Training	Dispatcher Training actors provide facilities for dispatchers that simulate the actual system they will be using (not shown in Figure 9-5).
Records and Assets	The Records and Asset Management actors track and report on the substation and network equipment inventory, provide geospatial data and geographic displays, maintain records on non-electrical assets, and perform asset investment planning.
Operation Planning	Operational Planning and Optimization actors perform simulation of network operations, schedule switching actions, dispatch repair crews, inform affected customers, and schedule the importing of power. They keep the cost of imported power low through peak generation, switching, load shedding or demand response.
Maintenance and Construction	Maintenance and Construction actors coordinate inspection, cleaning and adjustment of equipment, organize construction and design, dispatch and schedule maintenance and construction work, and capture records gathered by field to view necessary information to perform their tasks.
Extension Planning	Network Extension planning actors develop long term plans for power system reliability, monitor the cost, performance and schedule of construction, and define projects to extend the network such as new lines, feeders or switchgear.
Customer Support	Customer Support actors help customers to purchase, provision, install and troubleshoot power system services, and relay and record customer trouble reports.

❖ Market:

Actors in the Markets domain typically perform pricing or balance supply and demand within the power system. The boundaries of the Markets domain are typically considered to be at the edge of the Operations domain where control happens, and at the domains containing physical assets (e.g. generation, transmission, etc).

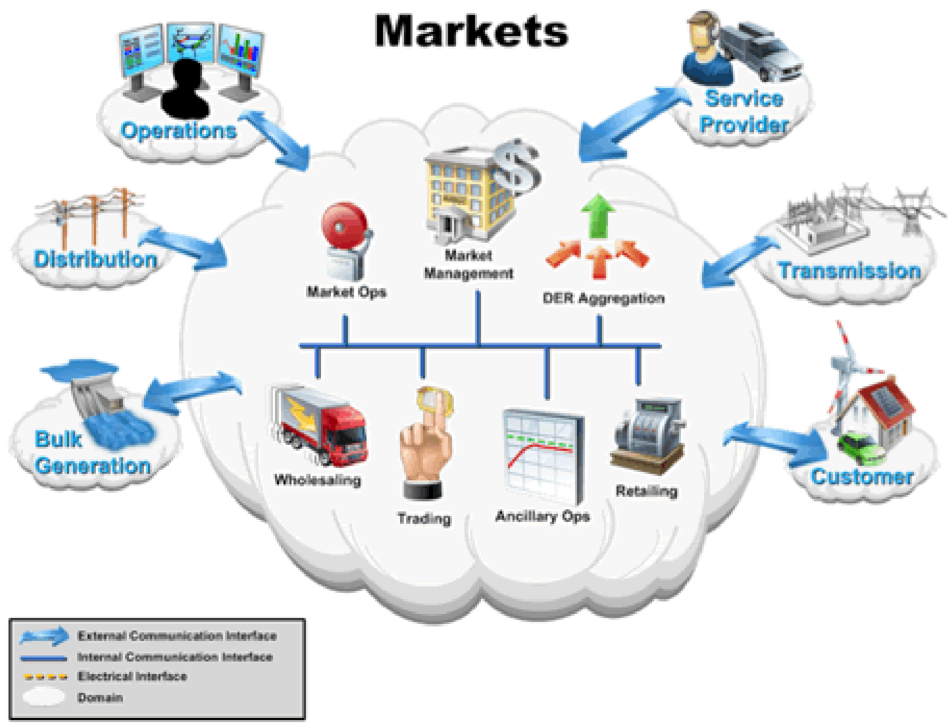


Figure: 3.7 Market (Conceptual Model of Smart grid Technology)

The interfaces between the Markets domain and those domains containing generation are most critical because efficient matching of production with consumption relies on markets. Besides the Bulk Generation domain, electricity generation also takes place in the Transmission, Distribution, and Customer domains and is known as distributed energy resources (DER). NERC CIPs consider suppliers of more than 300 megawatts to be Bulk Generation; most DER is smaller and is typically served through aggregators. DERs participate in markets to some extent today, and will participate to a greater extent as the smart grid becomes more interactive.

Table 3-6 Typical Applications in the Markets Domain.

Application Category	Description
Market Management	Market managers include ISOs for wholesale markets or NYMEX/CME for forward markets in many ISO/RTO regions. There are transmission and services and demand response markets as well. Some DER Curtailment resources are treated today as dispatchable generation.
Retailing	Retailers sell power to end customers and may in the future aggregate or broker DER between customers or into the market. Most are connected to a trading organization to allow participation in the wholesale market.
DER Aggregation	Aggregators combine smaller participants (as providers or customers or curtailment) to enable distributed resources to play in the larger markets.
Trading	Traders are participants in markets, which include aggregators for provision and consumption and curtailment, and other qualified entities. There are a number of companies whose primary business is the buying and selling of energy.
Market Operations	Make a particular market function smoothly. Functions include financial and goods sold clearing, price quotation streams, audit, balancing, and more.
Ancillary Operations	Provide a market to provide frequency support, voltage support, spinning reserve and other ancillary services as defined by FERC, NERC and the various ISOs. These markets function on a regional or ISO basis normally.

❖ Service Provider:

Actors in the Service Provider domain include the organizations providing services to electrical customers and utilities. That is, the actors in this domain typically perform a variety of functions that support the business processes of power system producers, distributors and customers. These business processes range from traditional core services such as billing and customer account management to enhanced customer services such as home energy generation and management. It is expected that service providers will create new and innovative services (and products) in response to market needs and requirements as the smart grid evolves. These emerging services represent an area of significant economic growth. Services may be performed by the electric service provider, by a third party on their behalf, or in support of new services outside of the current business models.

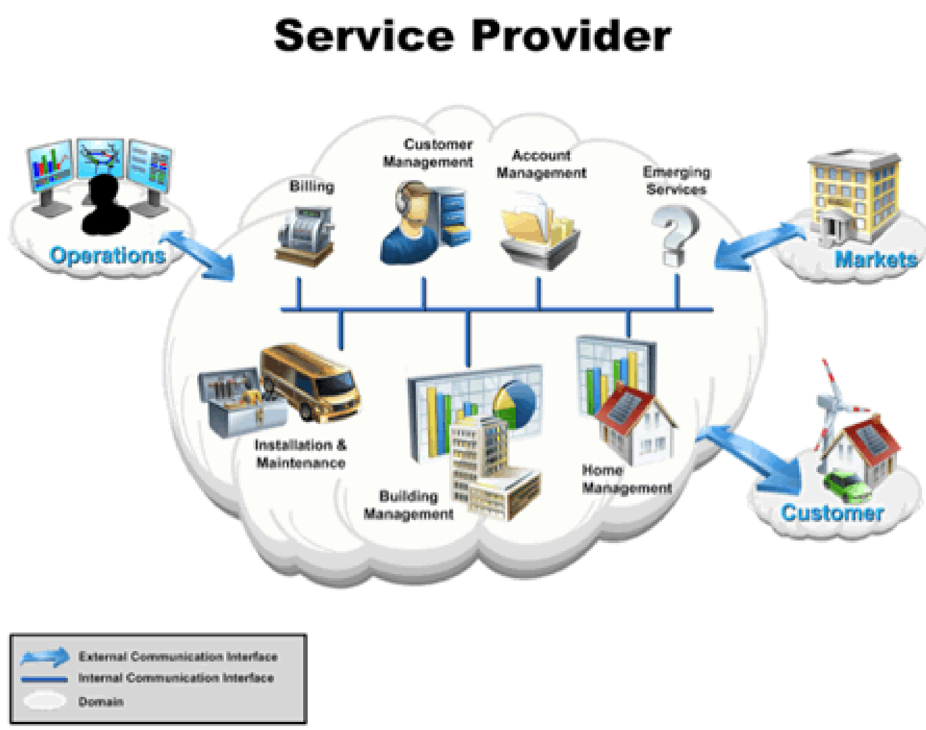


Figure: 3-8 Service Provider (Conceptual Model of Smart grid Technology)

The boundaries of the Service Provider domain are typically considered to be the power transmission and distribution network controlled by the Operations domain. Services provided must not compromise the security, reliability, stability, integrity and safety of the electrical power network.

The Service Provider domain is typically electrically connected at the Customer domain. It communicates with the Markets, Operations and Customer domains. Of these, the interfaces to the Operations domain are critical for system control and situational awareness but the interfaces to the Markets and Customer domains are critical for enabling economic growth through the development of "smart" services. The Service Provider domain may, as an example, provide the "front-end" connection between the customer and the market(s).

Table 3-7 Typical Applications in the Service Provider Domain.

Application Category	Description
Customer Management	Managing customer relationships by providing point-of-contact and resolution for customer issues and problems.
Installation & Management	Installing and maintaining premises equipment that interacts with the Smart Grid.
Building Management	Monitoring and controlling building energy and responding to Smart Grid signals while minimizing impact on building occupants.
Home Management	Monitoring and controlling home energy and responding to Smart Grid signals while minimizing impact on home occupants.
Billing	Managing customer billing information, including sending billing statements and processing payments.
Account Management	Managing the supplier and customer business accounts.
Emerging Services	All of the services and innovations that have yet to be created. These will be instrumental in defining the Smart Grid of the future.

3.6 Function of the Smart Grid Technology:

In leading a national transformation to a smarter grid, OE’s first step was to define not only a vision for the future electric delivery system but also the functional characteristics. Beginning in 2005, OE convened seven regional workshops across the country, involving regulators, utilities, vendors, legislators, research institutions, universities, and other stakeholders to forge a common vision and scope for the smart grid. This two-year effort resulted in identification of the principal smart grid functional characteristics that comprise the foundation of OE's smart grid program. [14]

- Self-healing from power disturbance events
- Enabling active participation by consumers in demand response
- Operating resiliently against physical and cyber attack
- Providing power quality for 21st century needs
- Accommodating all generation and storage options
- Enabling new products, services, and markets
- Optimizing assets and operating efficiently

The smart grid uses technological advancements to achieve its principal goals, which are summarized below.

3.6.1 Self-healing from power disturbance events.

A smart grid performs continuous self-assessments to detect and analyze issues, takes corrective actions to mitigate them and rapidly restores grid components or network sections as necessary. These digital technologies can also handle problems that are too large or quick for human intervention.

3.6.2Enabling active participation by consumers in demand response:

Customers are a key part of the electric power system. They have access to new information about electricity usage, pricing and incentives that in turn better motivates purchasing patterns in behavior. This leads to a more efficient and reliable operation of the overall grid.

3.6.3 Operating resiliently against physical and cyber attack:

A smart grid protects against outside forces by incorporating a system-wide solution that reduces physical and cyber vulnerabilities and enables fast recovery from disruptions.

3.6.4 Providing power quality for 21st century needs:

A smart grid provides power quality for the digital economy by helping to monitor, diagnose, and respond to power quality deficiencies. This dramatically reduces customers' losses due to poor power quality.

3.6.5 Accommodating all generation and storage options:

A smart grid enables power generation and distribution from multiple and widely dispersed distributed sources such as solar power system and wind turbines which create more efficient integration of renewable energy resources and other new technologies. Storage technologies can also be integrated into the electric power system to flexibly store electric power for later use in batteries, flywheels, super capacitors, and any other emerging storage technologies.

3.6.6 Enabling new products, services, and markets:

A smart grid enables new products, services, and markets by linking buyers and sellers together - from the consumer to the Regional Transmission Organization. It braces the creation of new electricity markets, from the energy management system at home to technologies that allow consumers and third parties to bid their energy resources into the electricity market.

3.6.7 Optimizing assets and operating efficiently:

A smart grid optimizes asset utilization and enables efficient operation by improving load factors, lowering system losses, and managing outages or faults in an enhanced manner.

3.7 Smart Grid Application:

3.7.1 Distributed Generation

Distributed Generation (DG) refers to power generation resources at consumer locations or stand-alone Distributed Generation (DG) plants, which are connected into the utility distribution system. DG sources deployed solely to support the energy demands of their owner and not connected into the grid are excluded from the discussion, since there is no connectivity of these DG sources to the Smart Grid network. Also excluded from discussion here are bulk energy generation sources connected directly into the transmission systems.

Many types of DG sources which impact on greenhouse gas reduction; large-scale deployment of DG is perhaps the most important component of the Smart Grid evolution. [16]

Distributed generation source may be including the following:

- Solar power
- Wind power
- Geothermal
- Small hydro
- Biomass and Biogas
- Fuel cell
- Combined heat and power

3.7.2 Distributed Storage

Electric energy storage has many advantages in utility operations. Many power plant technologies (bulk as well as DG) cannot easily or cost-effectively match generation and demand in real time. Energy drawn from electric energy storage can be used to compensate for variation in demand. Storage of large amounts of electric energy, however, is a challenging task. This task is particularly difficult when the energy must be stored over long periods of time (minutes, hours).

The term distributed storage (DS) is used to refer to an electric energy storage device connected to the grid that is able to store electric energy received from the grid (charging) and deliver the stored energy to the grid (discharging) when necessary. In DS, Discharge time should be as large as possible. [17]

Examples of DS technologies include the following:

- Battery
- Flywheel
- Super-capacitors
- Pumped-hydro

Distributed generation and distributed storages are collectively called Distributed Utility. The communication networking requirements associated with managing the grid connection for storage are similar to those associated with managing DG.

3.7.3 Electric Vehicles (EVs)

Use of electric vehicles can potentially reduce Green House Gas (GHG) emissions, provided the GHG emissions associated with electric power generation are lower than the emissions associated with internal combustion engines. Vehicles running on an electric motor are more efficient than internal combustion engines [18].

While all electric vehicles contribute directly or indirectly to GHG emissions, we limit our discussion to EVs that use power from the grid. These so-called *plug-in* vehicles may use gasoline, diesel, or fuel cells as additional fuel stored in the vehicle – in that case, the EVs are called plug-in *hybrid vehicles.* Thus, EVs that operate only from power supplied by fossil fuels or fuel cells in the vehicles (including many non-plugged-in hybrid cars) are excluded from this discussion. Also excluded are EVs that receive electric power from the grid or special-purpose power lines from a power plant but do not use batteries in the vehicle for storing the electric energy to run its motors (such as electric trains and some mass transit road vehicles).

EVs can also be considered distributed storage systems in their own right, provided the charged batteries in the vehicle are used to supply power to the grid. Therefore, when plugged into the grid (through power sockets at homes, businesses, or special-purpose *EV charging stations* such as at a parking lot), the EV batteries can be charged from the power supplied by the grid (Grid-Vehicle), and, based on agreement with the utility, the batteries can be discharged into the grid (Vehicle- Grid) as a DS source. EV owners may charge vehicle batteries when the energy rates are lower (if lower rates are offered by the utility during its nonpeak hours). The unused energy from the vehicle battery can be discharged into the grid during the peak hours, thus profiting from the higher rates of energy during the peak hours and, at the same time, supporting the utility in managing peak demands and reduction of power losses in transmission and distribution systems. Note that in most cases delivery of power is close to the point of consumption, thus reducing distribution system losses.

An Electric Vehicle Service Element (EVSE) provides the interface between the EV batteries and the grid (with EVSE connected into the power socket). An EVSE may be incorporated into the EV itself or provided as a stand-alone unit.

To facilitate billing, an EV must be associated with a utility or other ancillary service provider. (An EV may charge and discharge batteries at power sockets not owned by the EV owner.) Secure and reliable communication between the vehicle EVSE and the utility systems is needed to authenticate an EVSE for the purpose of billing. Secure and reliable communication is also needed for the management of the EV's grid connection when the EV is used.

3.7.4 Microgrids

A microgrid is simply a collection of individual consumers within a building, campus of buildings, or a community that are interconnected with each other and with at least one energy generation source, Shows in Figure. This collection of consumers and generation sources is a (small and independent) power grid. Microgrid consumers receive their energy supply from the utility grid as well as from the energy sources in the microgrid. [19]

Thus, a single home with rooftop PV solar panel is an example of a microgrid. Examples of more interesting microgrids include large businesses and campuses with local generation that is connected into the utility grid. With the deployment of DG, large residential buildings as well as new communities are becoming microgrids. A microgrid may be owned by a single organization, associations of consumers in a community or owners of large residential buildings. Generally, microgrids are autonomous from utility power grid. a microgrid being able to support the critical internal needs during power grid outage .

Microgrids as defined here are sometimes called prosumers (a term that means a combination of power producers and consumers).

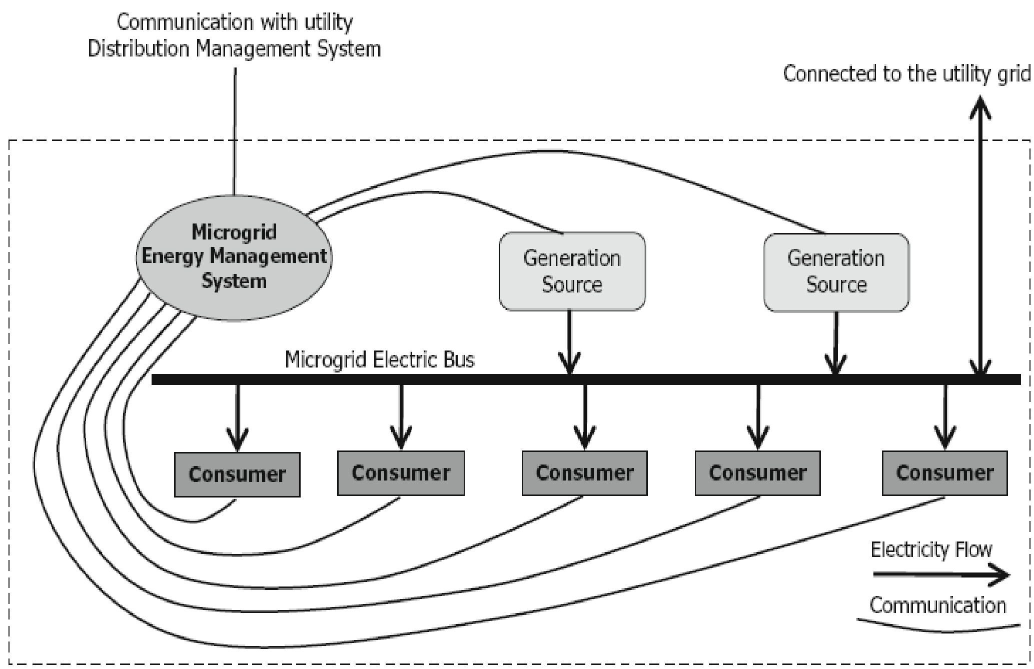


Figure 3.9 Schematics of a microgrid

In Fig. 3.9, an electric bus distributes the locally-generated power as well as the power received from the grid to all consumers in the microgrid. The bus may be conceptual, in that every consumer of the microgrid is able to receive electric power from every energy source in the microgrid as well as from the utility grid. When necessary, the direction of power flow between the microgrid and the utility grid can be reversed, allowing the microgrid to feed power into the grid. The microgrid may be connected to the utility grid at more than one point.

The microgrid energy management system (MEMS) is responsible for managing energy distribution within the microgrid as well as for managing energy transactions and electric connections with the utility DMS (including the utility EMS). The MEMS must monitor and control power generation as well as consumption. All consumption units and generation sources will need to be equipped with appropriate devices to communicate with the MEMS. The corresponding HAN with the home EMS will provide the network connections for the microgrid.

Finally, all functions related to connection of DG sources to the grid are relevant to connecting the microgrid generation to the utility DMS. (Note that we have assumed that generically the DMS includes utility EMS functions.) The utility may deploy IEDs at the microgrid for monitoring, control, and protection. In addition to communicating with these IEDs over the utility network, the utility DMS must communicate with the microgrid EMS for microgrid energy management, disposition of retail energy market transactions, and demand response. The latter two items will be described later in this chapter.

3.4.5 Teleportation

There are occasions when a fault in the transmission line (including at a transmission substation) requires the power supply to be disconnected by tripping a circuit breaker in either or both substations connected by the transmission line. Inter-substation communication between the (distance) relays for responding to a fault is called teleprotection. [20]

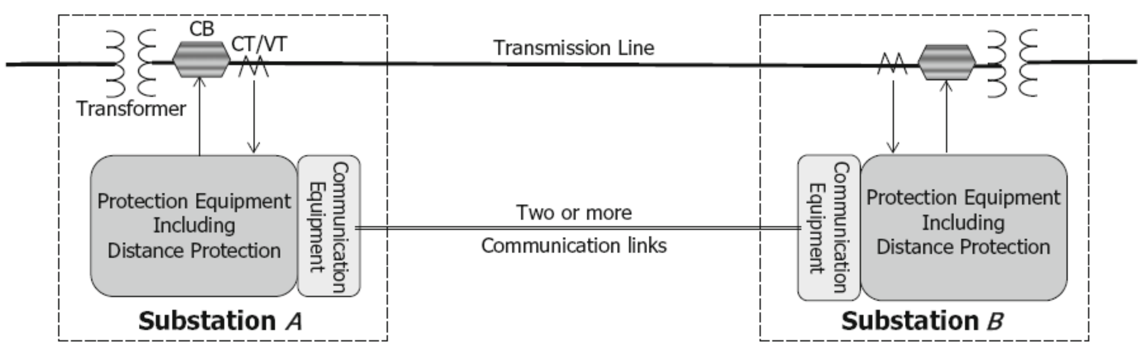


Figure 3.10 Teleprotection configuration

There are many teleprotection scenarios each requiring communication between substations. Consider an example scenario where there is a fault on the transmission line between substation A and B in figure. Based on the measurements received from the instrumentation connected to CT/VT at substation A, the distance relay at A determines that there is a fault and sends that information (permissive signal) to the relay in substation B through the communication line between the substations. If the relay at substation A also received the indication of that fault from substation B (based on the measurements by the protection relay at substation B), the relay at substation A sends the trip signal to the circuit breaker at substation A and the transmission line circuit is tripped at substation A. A variation of this scenario requires that the relay in substation A send the trip signal to the circuit breaker, if it does not receive the fault signal from B within a preconfigured time.

3.7.6 CCTV

Physical security of assets and buildings is extremely important for utilities, particularly at substations, DCCs, and other strategic locations. Equipment used to support physical security includes Closed Circuit Television (CCTV) cameras. Typical deployment of CCTV in a substation is illustrated in Fig. 3.11.

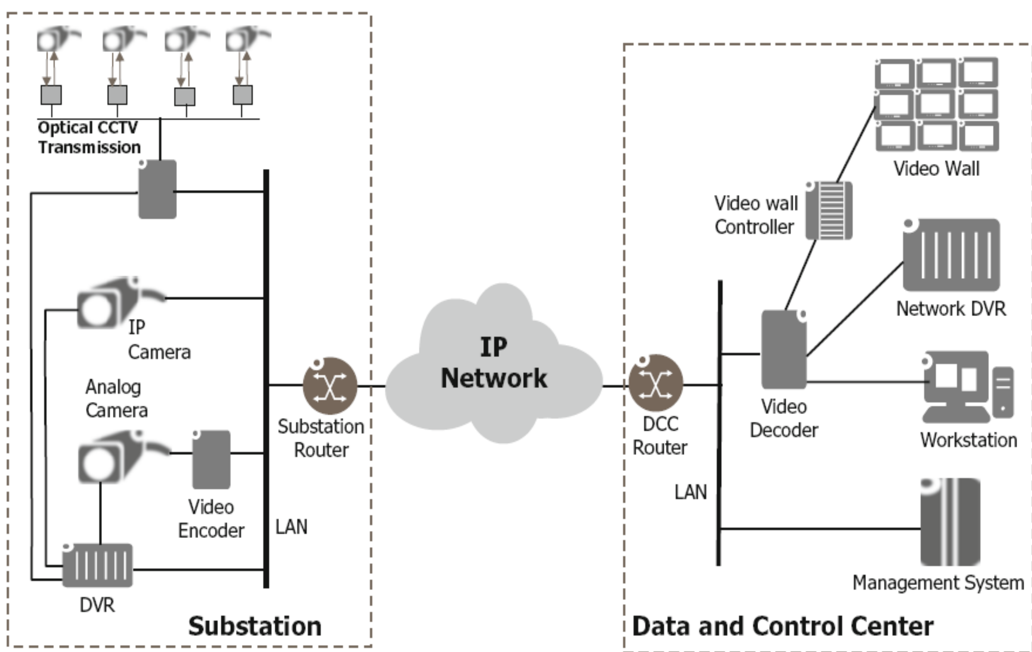


Figure 3.11 Components of a CCTV system

While some refer to CCTV systems as including only analog cameras, we include IP cameras with direct IP-based video output in CCTV systems. The number of cameras and their locations in the substation depend on the size of the substation yard, camera range, and camera capabilities such as focus and coverage. A Digital Video Recorder (DVR) deployed at the substation is used to locally record video streams from the cameras. Live video streams from cameras as well as recorded videos are transmitted to the DCC over a communication network. The video management system at the DCC determines the live video and the DVR video streams that need to be transmitted from the substation at a given time. A received video stream at the DCC may be fed into a collection of video monitors (video wall) that are monitored by DCC security staff. The security staff can control the video feeds displayed at the video wall at any time and may also control the video streams received from the cameras (in multiple substations) as well as their resolution. Optionally, the video streams can be stored by the network DVR.

The cameras as well as the video management system may use sophisticated video analytics to automatically control the camera movement and zooming to capture “interesting” images as well as for processing the received images to derive security-related inferences from video streams.

3.7.7 Business Voice and Data

As an enterprise, utilities need communication networks for their voice and data communication-both for communication within their enterprise as well as connecting to the outside world including connecting to the Internet and to the Public Switched Telephone Networks (PSTNs). Depending on the adoption of VoIP, business voice and data needs are served by an integrated “business” data network. This network may be distinct from the network used for utility operations for applications. However, the business network is also used for many utility operations-related data communication, such as for asset management and billing, thus requiring access to the utility operations systems in the DCC. Therefore, network security elements such as firewalls are deployed between these two (sets of) networks for the purpose of access control and secure data exchange. Utilities may already have an IP network that supports all their business application data needs and, possibly, also the voice communication needs on the same network with VoIP. In addition, CCTV cameras deployed at utility offices may use the IP network to communicate with security centers. Further, the business network may have unused excess capacity, particularly if the network is based on utility-owned fiber assets and/or microwave communication assets. Some utilities are looking to support communication for their existing operation applications such as SCADA and the future Smart Grid applications over the business network, assuming that the requirements of the mission-critical applications are met by the integrated network. The network architecture will provide support for traffic of the applications carried over the business network as well as traffic of the utility applications.

3.7.8 Retail Energy Markets

Utilities and owners of bulk energy sources are participants in traditional energy markets – referred to as wholesale energy markets (WEMs). In some cases, participation by a utility in the market may be indirect. In the case of indirect participation, the utility's interests are represented by another organization such as by Independent System Operators (ISOs), and Regional Transmission Operators (RTOs). A utility often has forward contracts with multiple bulk energy suppliers. These contracts are used to satisfy a large part of their demand (typically 50 % or more). The rest of the demand is met by buying power in the "day-ahead" markets or real-time spot markets. Utilities typically meet 60–95 % of their expected demand from a combination of forward contracts and day-ahead markets. The remaining demand is satisfied through participation in spot markets. While the energy prices for the forward contracts are predetermined, the prices for the day-ahead and spot markets are driven by supply–demand dynamics.[21]

Smart Grid brings with it informed consumers and large-scale deployment of DG – including DG deployed at consumer locations. It is expected that consumers will strive to meet their energy needs at the most competitive prices, possibly in real time. DG owners would also like to receive the best competitive pricing for their power generation. Prosumers (i.e., consumers with local DG connected to the utility grid) may need to sell locally generated excess power to the grid. Owners of EVs may want to buy power from the grid when prices are low and sell it back (if the battery still has remaining charge) when prices are high. There will be a larger number of DG owners wanting to sell their power compared with only a small number of bulk energy providers participating in the WEM.

These expected developments point to the establishment in the future of a retail energy market (REM). In REMs, DG owners along with individual consumers will participate in real-time energy trading to meet their energy demands at competitive prices. Figure 3.12 depicts a simplified REM architecture.

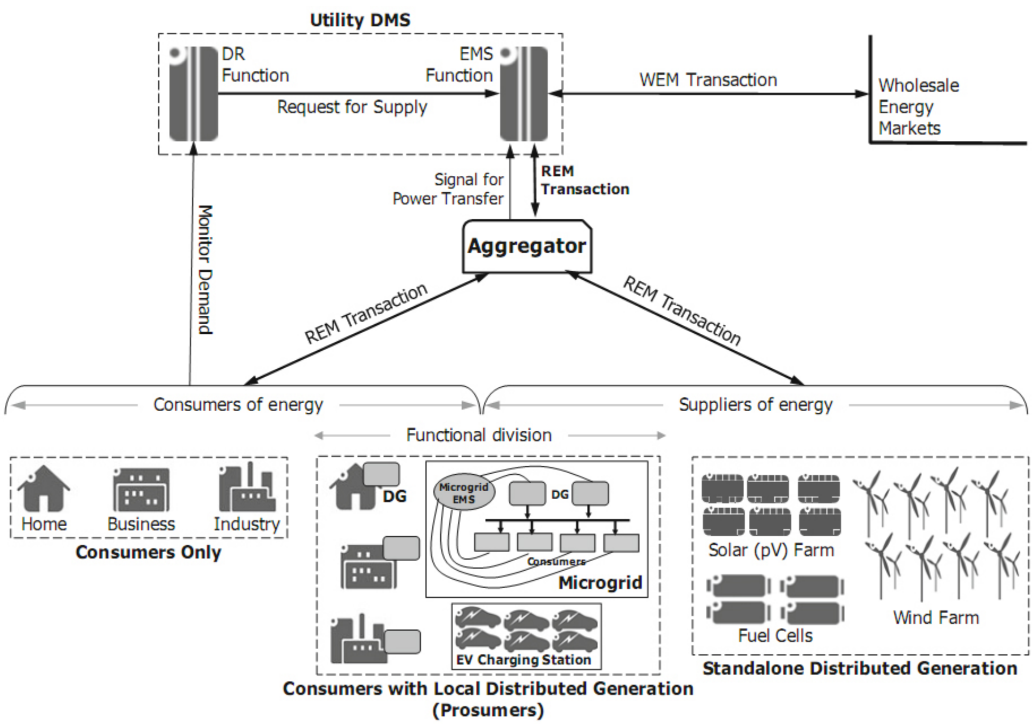


Figure 3.12 Retail energy market concept

Most prosumers as well as stand-alone DG owners will be REM participants. Many consumers would be incentivized to participate in REMs (even if they do not own any DG) to receive competitive energy prices. It is expected that the REM will be organized and managed by a third-party entity called an "aggregator." Aggregators will automate market transactions on behalf of thousands (if not millions) of REM participants. The aggregator will be responsible for receiving bids from the consumers containing parameters such as required demand, acceptable maximum price, and time horizon for that demand level. The aggregator will receive bids from REM DG participants containing parameters such as available supply, acceptable minimum price, and time horizon to maintain that supply level. To determine the optimal prices for consumers and suppliers, the aggregator may need to facilitate pricing negotiations. Finally, the aggregator must signal the utility EMS about the completed transaction to implement the energy transfer from the DG to the grid and from the grid to the consumer as necessary. Being a third-party entity, the aggregator belongs in the service provider domain of the NIST model. [22]

There may be more than one aggregator serving consumers and DG connected to a utility's grid, each organizing the market for a subset of consumers and DG. Note that the power quantity of an REM transaction is relatively small compared with the sellers and buyers in WEM. In addition, it is important to note that not every consumer will be an REM participant. Similarly, not every DG (particularly the prosumers) will be a market participant. Non-participants will continue to rely on utilities for pricing structure for buying and selling power.

It is clear that the Smart Grid communication network will be required to support REM transactions and associated traffic in real time.

3.8 Technology uses in the Smart Grid:

Various technologies that enable smart grid operation can be grouped into five key technology areas. According to the National Energy Technology Laboratory (NETL) Modern Grid Strategy, these categories are: [14]

1. Integrated communication Technology
2. Sensing and Measurement Technologies
3. Advanced Components
4. Advanced control methods
5. Improved interfaces and Decision support

3.8.1 Integrated Communications Technology:

Of these five key technology areas, the implementation of integrated communications is "a foundational need, required by the other key technologies and essential to the modern power grid. Integrated communications will create a dynamic, interactive mega infrastructure for real-time information and power exchange, allowing users to interact with various intelligent electronic devices in an integrated system sensitive to the various speed requirements (including near real-time) of the interconnected applications."

- Broadband Cable
- Power Line Communications (PLC)
- Broadband Power Line (BPL)
- Radio Frequency Identification Devices (RFID)
- Cellular (3G)
- Spread Spectrum (SS) Radio Systems
- Cellular (CDMA and TDMA)
- Three GPP (3GPP) Long Term Evolutions (LTE)
- Digital Subscriber Line (DSL)
- Fiber-to-the-Home (FTTH)
- Integrated Digital Enhanced Network (IDEN)
- Wi-Fi
- Internet Protocol (IPv4 and IPv6)
- WiFiber
- IPv6 over Low power WPAN (6lowpan)
- Wireless Interoperability for Microwave Access (WiMAX)
- Leased Lines & Dial-up
- Z-Wave, Zigbee for Home Automation
- Multiple Address (MAS) Radio

3.8.2 Sensing and Measurement Technologies:

Sensing and Measurement "is an essential component of a fully modern power grid. Advanced sensing and measurement technologies will acquire and transform data into information and enhance multiple aspects of power system management. These technologies will evaluate equipment health and the integrity of the grid. They will support frequent meter readings, eliminate billing estimations, and prevent energy theft. They will also help relieve congestion and reduce emissions by enabling consumer choice and demand response and by supporting new control strategies."

- Advanced Metering Infrastructure (AMI)
- Cable Monitoring System
- Circuit Breaker Monitoring System
- Current Sensor
- Fiber Optic Sensor
- Instrument Transformer
- Outage Management System
- Power Quality Monitoring System
- Sag Profile and VAR Monitoring System
- Temperature Monitoring System
- Transformer Monitoring System
- Wide Area Measurement System (WAMS)
- Wireless Condition Monitoring

3.8.3 Advanced Components:

Advanced components "Advanced components play an active role in determining the electrical behavior of the grid. They can be applied in either standalone applications or connected together to create complex systems such as microgrids. These components are based on fundamental research and development (R&D) gains in power electronics, superconductivity, materials, chemistry, and microelectronics."

- Narrow-band PLC Solutions
- Advanced On-load Tap-changer (OLTC)
- One Cycle Control Controller
- Advanced Protective Relays
- Programmable Communication Thermostats
- Controllable Network Transformer (CNT)
- Real-Time Demand Response and DER Control Device
- Short Circuit Current Limiter (SCCL)
- Current Limiting Conductor (CLiC)
- Smart Meter
- FACTS
- Solid State Transfer Switch (SSTS)
- Flow Control using HTS Cable
- Static Shunt Compensator (STATCOM)
- Static Synchronous Series Compensator (SSSC)
- Load Control Receiver
- Static Var Compensators
- Thyristor Controlled Series Compensators
- Unified Power Flow Controller (UPFC)
- Meter Data Management

3.8.4 Advanced control methods:

Advanced Control Method technologies are "the devices and algorithms that will analyze, diagnose, and predict conditions in the modern grid and determine and take appropriate corrective actions to eliminate, mitigate, and prevent outages and power quality disturbances. These methods will provide control at the transmission, distribution, and consumer levels and will manage both real and reactive power across state boundaries."

- Advanced Feeder Automation
- Advanced Substation Gateway
- Distributed Intelligent Control Systems
- Distribution Automation (DA)
- Energy Management System (EMS)
- Fault Locator for Distribution Systems
- Grid Friendly Appliance Controller
- SCADA
- Substation Automation (SA)

3.8.5 Improved interfaces and decision support:

Improved Interfaces and Decision Support are "essential technologies that must be implemented if grid operators and managers are to have the tools and training they will need to operate a modern grid. Improved Interface and Decision Support technologies will convert complex power-system data into information that can be understood by human operators at a glance. Animation, color contouring, virtual reality, and other data display techniques will prevent data overload and help operators identify, analyze, and act on emerging problems."

- Consumer Gateway and Portal
- Distributed Energy Resources Controller
- Grid Friendly Appliance Controller
- Micro grid Control Software
- Power Distribution Analysis Software
- Power Transmission Analysis Software
- Real Time Digital Simulator (RTDS)
- Smart Appliance Interface (SAI) Unit
- System Visualization Software
- Universal Power Interface

Chapter 4

Information and Communication Technology for the Smart Grid

4.1 Introduction:

Data communication systems are essential in any modern power system and their importance will only increase as the Smart Grid develops. As a simple example, a data communication system can be used to send status information from an Intelligent Electronic Device (IED) to a workstation (human–machine interface) for display (see Chapter 6). Any coordinated control of the power system relies on effective communications linking a large number of devices. Figure 2.1 shows a model of a simple point-to-point data communication system in which the communication channel is the path along which data travels as a signal. As can be seen from Figure 2.1, the communication channel could be a dedicated link between the Source and Destination or could be a shared medium.

Using the power system as an example, some possible components of this model and the associated physical devices are listed in Table 2.1. Communication channels are characterized by their maximum data transfer speed, error rate, delay and communication technology used.

Table 4-1 Examples of the physical devices in a power system communication system

Component	Physical device
Source	Voltage transformer Current transformer
Transmitter	Remote terminal unit (RTU)
Communication channel	LAN (Ethernet)
Receiver	Network interface card
Destination	Work station with graphic display IED for protection and control

4.2 Communication Technology for smart grid

4.2.1 IEEE 802 series

IEEE 802 is a family of standards that were developed to support Local Area Networks (LANs). For the Smart Grid illustrated in Figure 3.1, IEEE 802 standards are applicable to LANs in SCADA systems, NANs around the distribution networks and HANs in consumers' premises. Table 4-2 shows the different IEEE 802 standards applicable to commonly used communication technologies with their frequency band, bandwidth, bit rate and range.

Table 4-2 Different technologies specified under IEEE 802 [30, 31]

Protocol n	Descriptio	Frequency band	Bandwidt h	Bit rates	Range
IEEE 802.3 t	Etherne				
IEEE 802.4	Token bus – This is a LAN with each device in the network logically connected as a ring.			1, 5 and 10 Mbps	
IEEE 802.11a.2	Wireless LAN (WiFi)	5 GHz	20 MHz	6, 9, 12, 18, 24, 36, 48, 54 Mbps	Indoor: 35 m Outdoor: 120 m
IEEE 802.11b		2.4 GHz	20 MHz	1, 2, 5.5, 11 Mbps	Indoor: 38 m Outdoor: 140 m
IEEE 802.11g		2.4 GHz	20 and 40 MHz	1, 2, 6, 9, 12, 18, 24, 36, 48, 54 Mbps	Indoor: 38 m Outdoor: 140 m
IEEE 802.11n		2.4 and 5 GHz	20 and 40 MHz	varies between	Indoor: 70 m Outdoor: 250 m

				6.5 to 300 Mbps	
IEEE 802.15.1	Bluetooth	2.4 GHz		1–3 Mbps	Class 1 – 1 m Class 2 – 10 m Class 3 – 100 m
IEEE 802.15.4	This standard applies to low duty-cycle communication. It specifies and controls physical and MAC layers	868.3 MHz 902–928 MHz 2400–2483.5 MHz	600 kHz 2000 kHz 5000 kHz		
IEEE 802.16	WiMAX (Worldwide Inter-operability for Microwave Access)	2–66 GHz	1.25, 5, 10 and 20 MHz	75 Mbps (for fixed and 15 Mbps (for mobile)	50 km

4.2.2 TCP/IP/IP4/IP6

The Transmission Control Protocol (TCP)/Internet Protocol (IP) or TCP/IP is the most widely used protocol architecture today. It is a result of a project called Advanced Research Projects Agency Network (ARPANET) funded by the Defense Advanced Research Project Agency (DARPA) in the early 1970s.

The Internet layer uses an identifier called the IP address to identify devices connected to a network. There are two versions, IPv4 and IPv6, of IP addressing currently in use. IP version 4 (IPv4) is still the most commonly used and IP version 6 is becoming more widely used in the internet.

IP version 4

IPv4 addresses are 32 bits long. Usually these are displayed as a sequence of 4 octets(8 bits) with space between octets to make the addresses more readable. In order to make the address compact, a notation called dotted decimal notation is commonly used to represent an IPv4 address as shown in Figure 2.22.

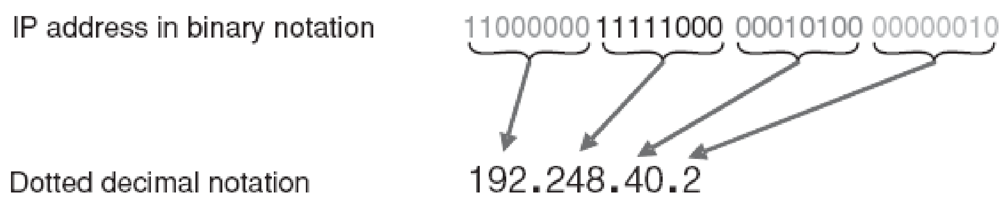


Figure 4.1 IPv4 address notations

IP version 6

IP version 6 also known as IP Next Generation (IPng) is a 128-bit addressing scheme. Therefore, it provides a much bigger address space compared to that of IPv4. The main advantages provided by IPv6 include:

1. Internet Protocol Security (IPsec) is mandatory for IPv6. It is a protocol suite for securing Internet Protocol (IP) communications by authenticating and encrypting each IP packet of a communication session.

2. Support for jumbograms which can be as large as 4, 294, 967, 295 (232 − 1) octets. In contrast, IPv4 supports datagrams up to 65, 535 (216 – 1) octets.

4.2.3 ZigBee and 6Lo WPAN

ZigBee and 6LoWPAN are two communication technologies built on IEEE 802.15.4. This is a low data rate wireless networking standard. Currently this standard is the most popular protocol for a Wireless Public Area Networks (WPAN) due to its low power consumption, high flexibility in networking and low cost.

A ZigBee device can be a Full Function Device (FFD) or a Reduced Function Device (RFD). A network will have at least one FFD, operating as the WPAN coordinator.

The FFD can operate in three modes: a coordinator, a router or an end device. An RFD can operate only as an end device. An FFD can talk to other FFDs and RFDs, whereas an RFD can only talk to an FFD. An RFD could be a light switch or a sensor which communicates with a controller. ZigBee networks can have star, mesh or cluster tree architecture.

6LoWPAN is a protocol which enables IPv6 packets to be carried over low power WPAN. The minimum transmission unit for an IPv6 packet is 1280 octets. However, the maximum MAC frame size defined by IEEE 802.15 is 127 bytes. When an RFD in a 6LoWPAN wants to send a data packet to an IP-enabled device outside the 6LoWPAN domain, it first sends the packet to an FFD in the same WPAN. An FFD which act as a Router in 6LoWPAN will forward the data packet hop by hop to the 6LoWPAN gateway. The 6LoWPAN gateway that connects to the 6LoWPAN with the IPv6 domain will then forward the packet to the destination IP-enabled device by using the IP address.

4.2.4 HomePlug

HomePlug is a non-standardized broadband technology specified by the HomePlug Powerline Alliance, whose members are major companies in communication equipment manufacturing and in the power industry.

HomePlug Powerline Alliance defines the following standards:

1. HomePlug 1.0: connects devices in homes (1–10 Mbps).
2. HomePlug AV and AV2: transmits HDTV and VoIP in the home – 200 Mbps (AV) and 600 Mbps (AV2).
3. HomePlug CC: Command and Control to complement other functions.
4. HomePlug BPL: still a working group addressing last-mile broadband (IEEE P1901).

4.3 Communication Standard for Smart Grid

4.3.1 IEC 61850

IEC 61850 is an open standard for Ethernet communication within substations. It is a function based standard which ensures interoperability of substation equipment. The functions are divided into:

1. **System support functions:** network management, time synchronization and physical device self-checking;
2. **System configuration or maintenance functions:** software management, configuration management, settings and test modes;
3. **operational or control functions:** parameter set switching, alarm management and fault record retrievals;
4. **Process automation functions:** protection, interlocking and load shedding.

4.3.2 Modbus

Modbus is a messaging protocol in the Application layer and provides communication between devices connected over several buses and networks. It can be implemented through Ethernet or using asynchronous serial transmission. Modbus over EIA 485 is used extensively in substation automation. Communication on a Modbus over EIA 485 is started by a Master with a query to a Slave. The Slave which is constantly monitoring the network for queries will recognise only the queries addressed to it and will respond either by performing an action (setting a value) or by returning a response. Only the Master can initiate a query. The Master can address individual Slaves, or, using a broadcast address, can initiate a broadcast message to all Slaves.

4.3.3 DNP3

DNP3 (Distributed Network Protocol) is a set of communication protocols developed for communications between various types of data acquisition and control equipment. It plays a crucial role in SCADA systems, where it is used by Control Centres, RTUs and IEDs. DNP3 has recently been adopted as an IEEE standard 1815–2010 [30]. The

DNP User layer can take analogue and binary inputs and output analogue and binary signals. A Master DNP3 station sends requests and typically the Slave DNP3 stations respond to these requests. However, a Slave DNP3 station may also transmit a message without a request. The DNP3 Physical layer most commonly uses serial communication protocols. Recently applications of DNP3 over an Ethernet connection can be found.[32]

4.3.4 Multi protocol label switching (MPLS)

Multi Protocol Label Switching (MPLS) is a packet forwarding technique capable of providing a Virtual Private Network (VPN) service to users over public networks or the internet. VPN provides the high quality of service and security required by Applications such as that associated with critical assets. Some anticipated Applications of point-to-point VPNs based on MPLS include Remote Terminal Unit (RTU) networks and backbone network to the System Control Centre. MPLS-based VPN is an attractive solution for wide area connectivity due to its relatively low cost and ability to be implemented rapidly using the existing network resources.

4.2 Conceptual reference model for Smart Grid Information Networks:

4.2.1 Description of conceptual Model

The conceptual model described here provides a high-level, overarching perspective. It is not only a tool for identifying actors and possible communications paths in the Smart Grid, but also a useful way for identifying potential intra- and inter-domain interactions and potential applications and capabilities enabled by these interactions. The conceptual model represented in Figure 3-1; it is not a design diagram that defines a solution and its implementation. In other words, the conceptual model is descriptive and not prescriptive. It is meant to foster understanding of Smart Grid operational intricacies but not prescribe how the Smart Grid will be implemented. [24]

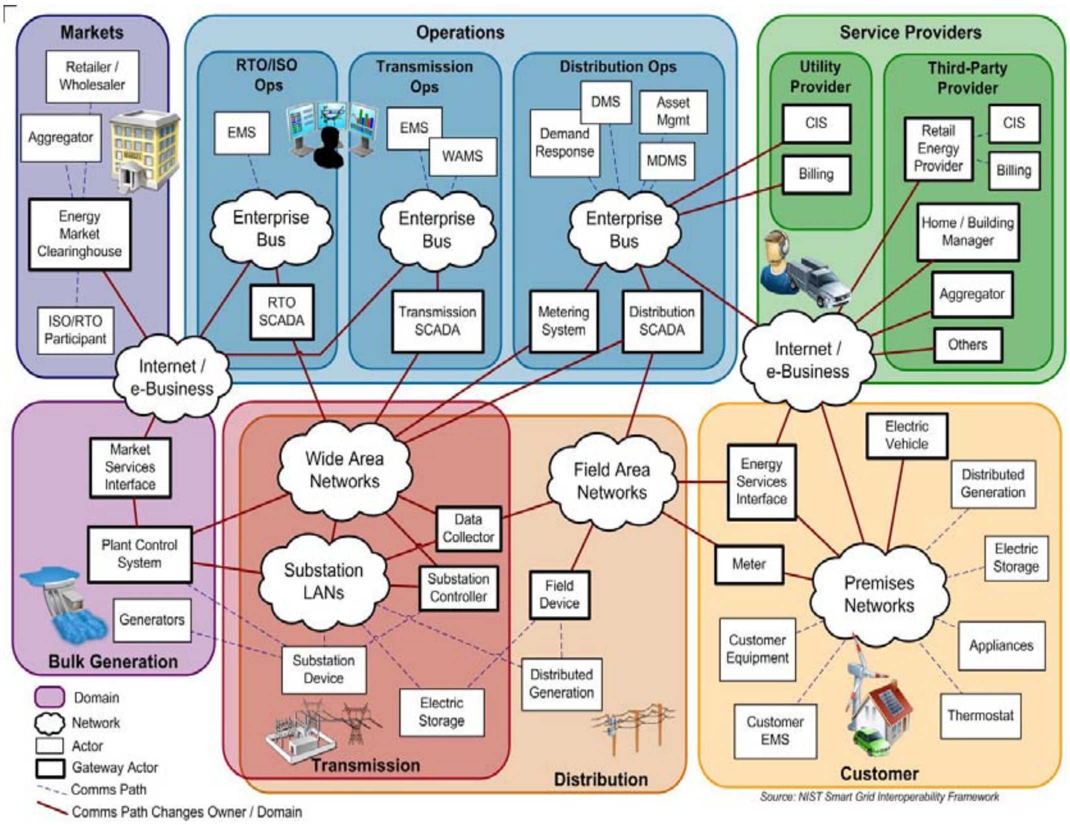


Figure 4.2 Conceptual Reference Diagram for Smart Grid Information Networks.

Domain: Each of the seven Smart Grid domains is a high-level grouping of organizations, buildings, individuals, systems, devices or other actors that have similar objectives and that depend on—or participate in—similar types of applications. Communications among actors in the same domain may have similar characteristics and requirements. Domains may contain sub-domains. Moreover, domains have much overlapping functionality, as in the case of the transmission and distribution domains. Transmission and distribution often share networks and, therefore, are represented as overlapping domains.

Actor: An actor is a device, computer system, software program, or the individual or organization that participates in the Smart Grid. Actors have the capability to make decisions and to exchange information with other actors. Organizations may have actors in more than one domain. The actors illustrated here are representative examples but are by no means all of the actors in the Smart Grid. Each actor may exist in several different varieties and may actually contain other actors within them.

Gateway Actor: An actor in one domain that interfaces with actors in other domains or in other networks. Gateway actors may use a variety of communication protocols; therefore, it is possible that one gateway actor may use a different communication protocol than another actor in the same domain, or use multiple protocols simultaneously.

Information Network: An information network is a collection, or aggregation, of interconnected computers, communication devices, and other information and communication technologies. Technologies in a network exchange information and share resources. The Smart Grid consists of many different types of networks, not all of which are shown in the diagram. The networks include: **the Enterprise Bus** that connects control center applications to markets, generators, and with each other; **Wide Area Networks** that connect geographically distant sites; **Field Area Networks** that connect devices, such as Intelligent Electronic Devices (IEDs) that control circuit breakers and transformers; and **Premises Networks** that include customer networks as well as utility networks within the customer domain. These networks may be implemented using public (e.g., the Internet) and nonpublic networks in combination. Both public and nonpublic networks will require implementation and maintenance of appropriate security and access control to support the Smart Grid. Examples of where communications may go through the public networks include: customer to third-party providers, bulk generators to grid operators, markets to grid operators, and third-party providers to utilities.

Comms (Communications) Path: Shows the logical exchange of data between actors or between actors and networks. Secure communications are not explicitly shown in the figure.

4.2.2 Enterprise Software Applications

The National Institute of Standards and Technology (NIST) has developed a Smart Grid Conceptual Reference Model as part of its Smart Grid Standards Framework and Roadmap. Figure 3-2 shows the specific logical architecture required to achieve the goals of this conceptual model.

Each box in Figure 4-2 is an actor. As far as the discussion of logical architecture is concerned, actors are software applications, with the exception of the meter in the Customer domain that acts as the gateway actor between the distribution utility operator and the customer. Software applications that potentially exchange data within an enterprise network are shown as being connected with heavyweight black lines. Such an exchange of data occurs across *interfaces*. Enterprise networks may be local area networks (LANs) or wide area networks (WANs) or a combination of the two. When software applications are connected together in such a manner that the data flows span NIST conceptual model domains (or sub-domains) then the communications path between the linked gateway actors is shown as a lightweight line. Table 4-2 describes each enterprise software application shown in Figure 4-2.

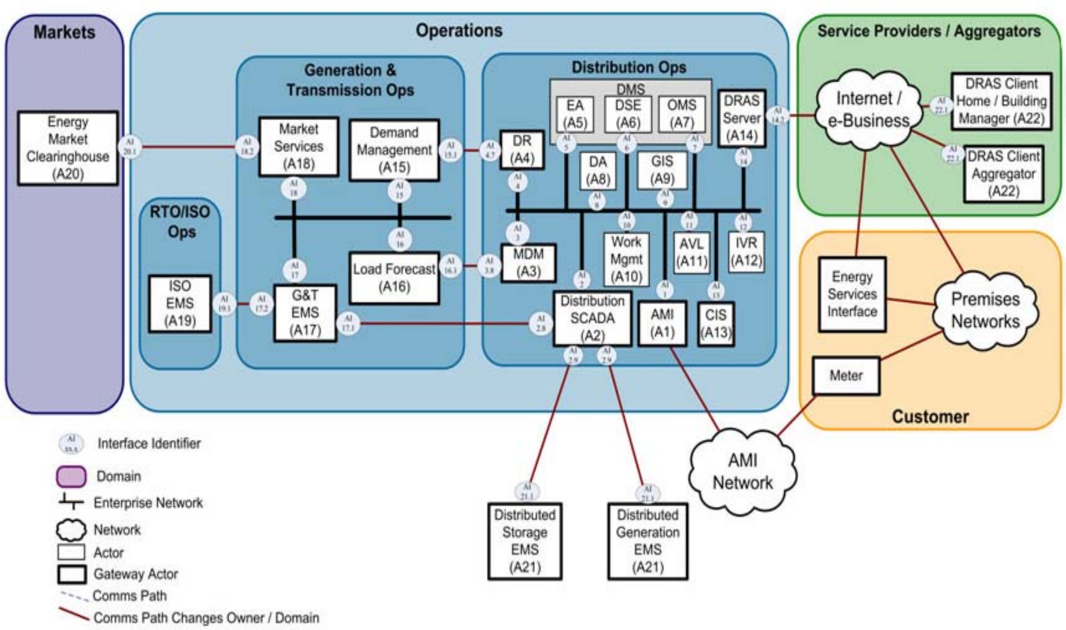


Figure 4.3 Logical Architecture for Enterprise Applications

Table 4-3 Description of Enterprise Software Applications [24, 25, 26]

Application	Interfaces With	Description
(A1) Advanced Metering Infrastructure (AMI)	A3) Meter Data Management A4) Demand Response A5) Engineering Analysis A6) Distribution State Estimation A7) Outage Management System A13) CIS	Advanced Metering Infrastructure (AMI). This system manages communications with meters, typically at customer locations. The AMI system also often acts to manage customer loads or to connect/disconnect/reconnect customer services.
(A2) Distribution SCADA	A3) Meter Data Management A4) Demand Response A5) Engineering Analysis A6) Distribution State Estimation A7) Outage Management System A8) Distribution Automation A9) GIS A17) G & T EMS A21) DER EMS	Distribution domain Supervisory Control and Data Acquisition (SCADA). Distribution SCADA systems control and obtain data about (typically) distribution substation equipment.
(A3) Meter Data Management (MDM)	A1) AMI A2) Distribution SCADA A4) Demand Response A5) Engineering Analysis A6) Distribution State Estimation A7) Outage Management System A13) CIS A16) Load Forecast	Meter data management (MDM) systems typically act as a centralized data management system to store meter readings and meter-related event data, such as customer outages, meter change-outs, or meter demand resets. MDM systems often are used to validate meter data, including estimating missing data. MDM systems may also include supplemental modules to filter, accumulate, or analyze meter data before it is sent to other systems. In the context of this project, the MDM system may be either (i) a shared system located on the generation and transmission operator network or (ii) a system on the network of a single distribution operator.
(A4) Demand Response (DR)	A1) AMI A2) Distribution SCADA A3) MDM A9) GIS A13) CIS	Demand response (DR) systems accept demand targets or market price signals from other systems, such as the Demand Management system (see A15, below), and send control or price signals to other systems, such as the AMI (see A1, above) or

	A14) Demand Response Automation Server (DRAS) A15) Demand Management	the Demand Response Automation Server (see A14, below) so that those systems can pass such control or price signals to other systems or to end devices.
A5) Engineering Analysis (ES)	A1) AMI A2) Distribution SCADA A3) Meter Data Management A7) Outage Management System A9) GIS A13) CIS	Engineering analysis (EA) accepts facility data and/or power system models from a geographic information system (see A9, below) and operational data such as metered data from AMI (A1, above) or system operations data from distribution SCADA or distribution automation systems (A2, above or A8, below) and perform off-line analyses of the data. EA systems are often used for system planning purposes. EA systems are sometimes deployed as a module of a distribution management system (DMS).
(A6) Distribution State Estimation (DSE)	A1) AMI A2) Distribution SCADA A3) Meter Data Management A7) Outage Management System A8) Distribution Automation	Distribution state estimation (DSE) systems are an emerging variety of engineering analysis system that are designed to perform real-time or near-real time analyses of power system models based on actual metered data and system operations data. DSE systems are often deployed as a module of a distribution management system (DMS).
(A7) Outage Management System (OMS)	A1) AMI A2) Distribution SCADA A3) Meter Data Management A5) Engineering Analysis A6) Distribution State Estimation A8) Distribution Automation A9) GIS A10) Work Management A11) Automatic Vehicle Location A12) Interactive Voice Response A13) CIS	Outage management system (OMS). The OMS accepts detected outage information from customer telephone calls, as well as from automated outage detection systems such as the AMI system (A1, above)or the interactive voice response system (A12, below). The OMS system then analyzes the pattern of detected outages based on a power system model and assists a dispatcher to manage crews to restore the affected facilities
(A8) Distribution Automation (DA)	A2) Distribution SCADA A6) Distribution State Estimation A7) Outage Management System	Distribution automation systems are similar to distribution SCADA systems (see A2, above) except that DA systems typically control or obtain data from devices down line of the distribution substation.
(A9) Geographic	A2) Distribution SCADA A4) Demand Response	Geographic Information System (GIS). The GIS stores and displays information about customers,

Information System (GIS)	A5) Engineering Analysis A7) Outage Management System A13) CIS	facilities and work in a geographic context. The GIS is often used as the central repository for the power system model that is subsequently provided to the EA (A5, above), DSE (A6, above), or OMS (A7, above).
(A10) Work Management (WM)	A7) Outage Management System A11) Automatic Vehicle Location A13) CIS	Work management (WM). The work management system generates and tracks work-related activities. The work management system is often integrated with (i) the AMI (A1, above) or MDM (A3, above) for managing work related to setting, replacing and retiring meters, (ii) the customer information system (A13, below) for managing service or construction work, and (iii) the OMS (A7, above) for managing outage restoration.
(A11) Automated Vehicle Location (AVL)	A7) Outage Management System A10) Work Management	Automatic Vehicle Location (AVL). The AVL system uses global positioning system (GPS) technology to locate utility-owned vehicles and display them in geographic context. AVL system output is often used in the GIS (A9, above), the OMS (A7, above) and the WM (A10, above).
(A12) Interactive Voice Response (IVR)	A7) Outage Management System A13) CIS	Interactive Voice Response (IVR). The IVR system automatically answers customer calls and routes them to the appropriate department or system for further action. In this context, the IVR is integrated with the OMS (A7, above) to manage customer outages.
(A13) Customer Information System (CIS)	A1) AMI A3) Meter Data Management A4) Demand Response A5) Engineering Analysis A7) Outage Management System A9) GIS A10) Work Management A12) Interactive Voice Response	Customer Information System (CIS). The CIS typically consists of several software modules that include a customer database, a bill calculation mechanism, plant inventory, and accounting systems. The CIS must be integrated with many of the systems listed here to provide customer information and to accept meter readings from the AMI (A1, above) or MDM (A3, above).
(A14) Demand Response Automation System (DRAS)	A4) Demand Response A22) DRAS Client	Demand Response Automation System (DRAS) Server. The DRAS Server is a system that accepts demand response targets or market price signals from the DR (A4, above) and implements the Open Automated Demand Response (OpenADR) protocol. OpenADR is used to coordinate demand

Server		response actions with DRAS Client systems (A22, below) at customer facilities or third-party service aggregators
(A15) Demand Management (DM)	A4) Demand Response A16) Load Forecast	Demand Management (DM). The DM system accepts demand response targets or market price signals from the Load Forecast system (A16, below) and manages appropriate demand response actions with the Demand Response (DR) system (A4, above) at each of the distribution utilities.
(A16) Load Forecast (LF)	A3) Meter Data Management A15) Demand Management A18) Market Services	Load Forecast (LF). The LF system accepts market signals from the Market Services application (A18, below), calculates the relative value of the output of generation assets and demand response resources, and send demand response management targets to the DM system (A15, above).
(A17) G&T Energy Management System (EMS)	A2) Distribution SCADA A19) ISO EMS	Generation and Transmission (G&T) Energy Management System (EMS). The G&T EMS is a system that collects data from and controls generation and transmission assets, acting in a manner similar to a SCADA system.
(A18) Market Services (MS)	A16) Load Forecast A20) Energy Market Clearinghouse	Market Services (MS). The MS coordinates market signals with the Energy Market Clearinghouse (A20, below) and sends market information to the Load Forecast application (A16, above).
(A19) RTO/ISO EMS	A17) G&T EMS	Regional Transmission Operator (RTO) /Independent System Operator (ISO) Energy Management System (EMS). The RTO/ISO EMS collects information on regional transmission assets and operational conditions and acts to control those transmission assets
(A20) Energy Market Clearinghou se	A18) Market Services	Energy Market Clearinghouse. The energy market clearinghouse is the market system that coordinates with market participants to exchange either price signals or bid and offer information. The energy market clearinghouse system in the market domain communicates with the market services application(s) (A18, above) in the generation and transmission system operator

		domain.
(A21) Distributed Energy Resources (DER) EMS	A2) Distribution SCADA	The distributed energy resources (DER) energy management system (EMS). This system acts to collect information about the operation of and to control the assets of a DER facility. In the context of this demonstration project, the DER may be either a distributed generation (DG) or distributed storage (DS) facility. In the context of this demonstration project, it is assumed that the DER EMS will coordinate with the distribution SCADA application (A2, above) in operation at the distribution operator.
(A22) Demand Response Automation (DRAS) Client	A14) DRAS Server	Demand Response Automation System (DRAS) Client. The DRAS Client implements the client portion of the Open Automated Demand Response (OpenADR) protocol, which is used to coordinate demand response actions with DRAS Server system (A14, above).

4.5 Architecture Framework

Most of the communication in a utility network is between utility endpoints distributed throughout the utility's service territory (deployed at locations such as substations, transmission towers, feeders, DG establishments, mobile workforce, and consumer locations) and control, monitoring, collection, dispatch, and other functions deployed at a few locations such as utility DCCs. Therefore, core-edge physical network connectivity is the fundamental basis for the Smart Grid network architecture.

The framework for the core-edge network physical connectivity architecture is presented in Fig. 4.4 [34].

Generally, a utility's core network is deployed in the portion of its service area where its data and control centers, headquarters, and business offices are located. These utility endpoints as well as substations in the vicinity of the core network connect directly into the core network. Deployment of Optical Ground Wire (OPGW) along the transmission lines may potentially allow core connectivity to be easily expanded to a large portion of the utility's substations. The size of the utility core network will vary. Core networks for large distribution and transmission utilities may interconnect hundreds of routers. Core networks for small distribution utilities, however, may only interconnect several routers.

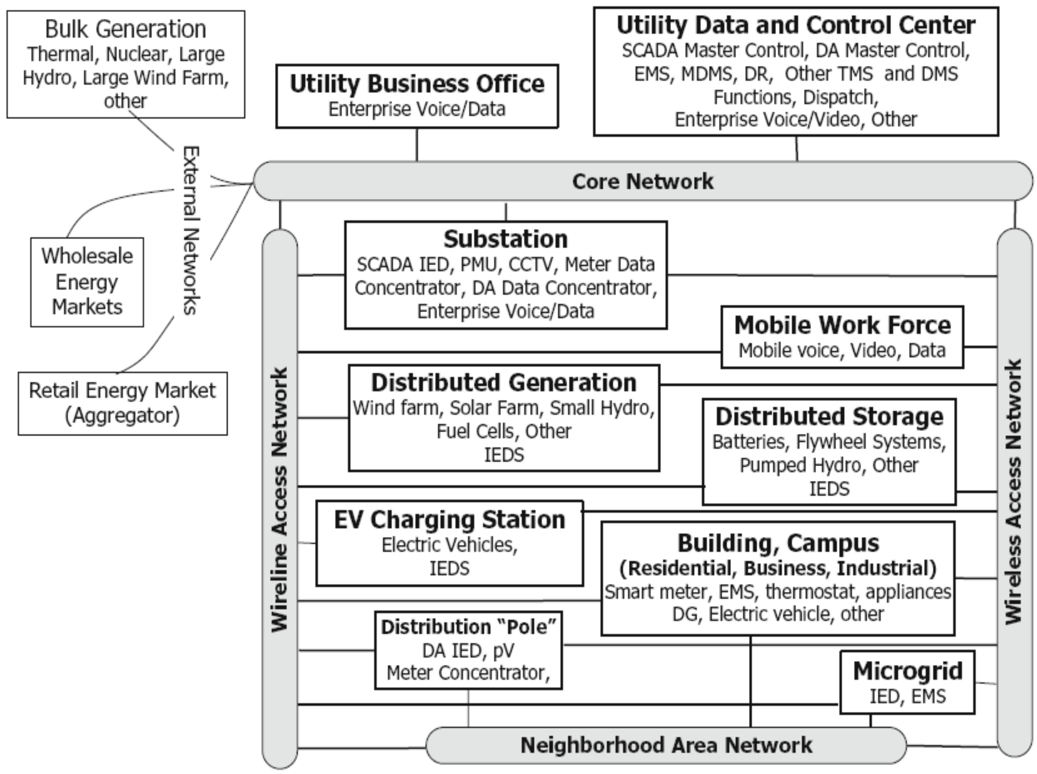


Figure 4.4 Physical architecture framework for Smart Grid network

In the utility community, the core network is called a Wide Area Network (WAN). We will adopt this terminology throughout the remainder of this book. A formal definition of the WAN in the context of utility network will be provided later in this chapter. Remote endpoints connect into the core network over one or more wireless and wireline access networks. These access networks are called Field Area Networks by the utility community. Therefore, we will call an access network connecting remote endpoints to the core network a FAN in the rest of this paper.

1. Communication endpoints at a substation include SCADA IEDs and CCTV cameras. PMUs may be deployed at transmission substations. Depending on

the AMI technology used (such as RF mesh NAN), meter data concentrators may be located at some of the distribution substations. In some cases, the distribution substation may also house data concentrators for the DA IEDs deployed on the feeders. Note that the meter data concentrators and the DA concentrators *may* be located in a transmission substation if that substation is more conveniently located in that "neighborhood." Finally, if a substation is staffed, their (business) voice and data network endpoints are located at those substations. We note that typically only a small portion of a utility's substations are staffed.

2. A distribution "pole" carrying a feeder may carry DA IEDs. Some utilities may deploy solar panels on these poles. Depending on the AMI technology (such as PLC–NB, NAN), meter concentrators may also be deployed at these poles. 3. Multiple IEDs may be deployed as needed at stand-alone DG, storage, or electric vehicle (EV) charging station facilities.
3. Smart meters are deployed at each consumer location.
4. The EMS at the HAN and/or LAN may be connected into the Smart Grid network.
5. For microgrids, the microgrid EMS and several IEDs may be connected into the network.

Instead of connecting each endpoint at a location over its own FAN (as is predominant in utility networks today), the architecture will provide aggregation of traffic for all endpoints at that location. This aggregated traffic will be carried over a single FAN connection.

The core network connects to external networks for communication with entities of other domains such as in the wholesale energy markets, bulk generation, and service providers.

4.4.1 Smart Grid Network Protocols

IP will be the network layer protocol for the Smart Grid communication network. From its inception, IP was developed for the purpose of connecting communication endpoints irrespective of the physical or logical connection technologies used. With the widespread support of IP, a wide variety of network products are available at competitive prices. Further, there has been a concerted effort to develop new standards, methodologies, and tools that increase efficiencies in engineering, operations, and management of the IP networks. Two of the most important advantages of using IP as the network layer protocol are:

(1) the ability to route individual data packets at each hop in the network and

(2) the ability to support priority and delay requirements of application packet streams that share network links.

These two properties of IP networks allow traffic to be aggregated from multiple endpoints without sacrificing efficiencies and network performance, thereby reducing network costs. In recent years, utilities have begun migrating SCADA networks from legacy serial connections to IP connections. Emerging Smart Grid applications such as AMI and DA also support IP connectivity to utility DCCs. New CCTV communication products are IP-based with legacy analog CCTV cameras connecting into IP networks through video encoders. It is expected that IP will be the networking protocol of choice for implementing new Smart Grid applications.

Using MPLS in the Smart Grid network provides many added benefits. In addition to supporting Smart Grid applications (such as teleprotection) where IP is not suited at the present time, MPLS services provide creation of closed user groups of applications, network endpoints, and/or users. Such closed user groups not only help facilitate network security with traffic isolation but can also provide Quality of Service (QoS) implementation targeted to individual groups.

4.4.2 Wide-area networks (WANs):

A WAN connects multiple distribution systems together and acts as a bridge between NANs and HANs and the utility network. A WAN gateway can use broadband connection (e.g., satellite) or possibly an IP-based network (e.g., MPLS and DNP3) to provide an access for the utility offices to collect the required data. Since information privacy and reliability are the major concerns for the customer, security and fault tolerance of these communication technologies are crucial issues.

We formalize the concept of WAN as an interconnection of WAN routers (WRs) as shown in Fig. 4.5. In this figure, no specific interconnection between the WRs within the WAN is shown or implied. In particular, the oval in the figure is only an iconic representation of the WAN and should *not* be misconstrued as a ring interconnection of the WRs. All network endpoints (including endpoints of utility applications-both traditional as well as the new Smart Grid applications) connect to WRs. Traffic between the pairs is routed by the respective WRs in the WAN. The end-to-end connection between endpoints of an application will be an IP connection.

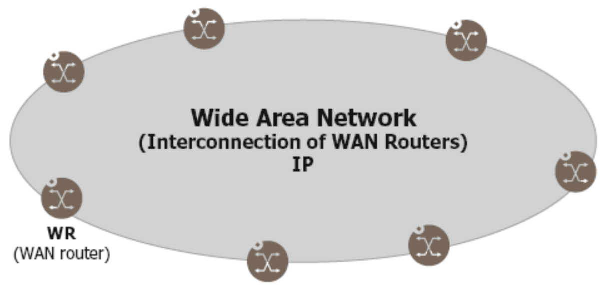


Figure 4.5 WAN is an interconnection of WAN routers

The network design will dictate the placement of WRs and the physical interconnections in the WAN. For network reliability, it is important that there be at least two disjoint physical paths between every pair of WRs. Additional routers called Interior Routers (IRs) may be deployed in the WAN (based on the design) for shorter paths between pairs of WRs (Fig. 4.6).

WRs not only serve the purpose of providing connectivity to the endpoints but also aggregating the traffic to/from these endpoints. Thus, traffic from one endpoint of an application connected to a WAN router WR1 may need to be routed to another router WR2 to which the other endpoint of the application is connected. The routed traffic may traverse the WAN from router WR1 to WR2 over zero or more intermediate WRs.

Generally, the WRs (and IRs) may be conveniently located at existing utility facilities such as DCCs and some substations. It may be necessary to deploy WRs and IRs at additional locations based on the overall network design of the WANs and the FANs for connecting the network endpoints.

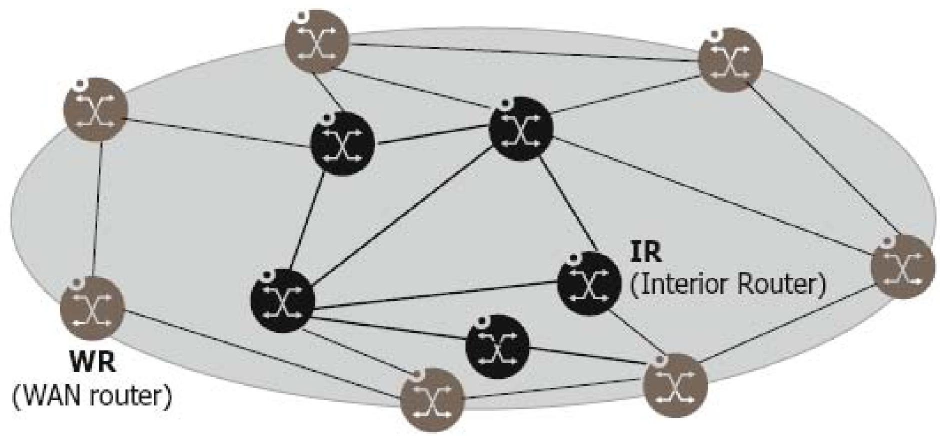


Figure 4.6 Reliable WAN with at least two physical paths between every pair of WAN routers WR/IR

4.5.3 Home-area networks (HANs):

One potentially beneficial function of the Smart Grid is management of residential energy consumption. Home energy management includes a wide spectrum of devices, including lights, appliances, heaters, air conditioners, local generation facilities (such as solar panels), and electric vehicles, if present. Home energy management systems (HEMS) are being developed and deployed to manage these energy consumption, storage, and generation devices. Communications among these devices are supported over a home area network. (Fig. 4.7)

HANs may include wireless networking technologies such as the ones defined by ZigBee standards. ZigBee is becoming a popular choice in contrast to wireline technology due to its low installation cost and better control and flexibility. [27]

PLC (Power line communication) is another networking technology used in HANs. The HomePlug networking specifications developed by the HomePlug Alliance and leverage existing home wiring are examples of a PLC technology that can be used in HANs.

Existing appliances and thermostats may be monitored and controlled using external devices specifically developed for the appliance. In addition to on/off control, such devices may also provide electric measurements such as consumption as well as the status of the appliances, thermostats, and lights. These attached devices may be connected to the HAN for the purpose of remote monitoring and control. Newer appliances, thermostats, and light switches may already be equipped with such control and communication functions. Homes with local DG (such as solar panels) and/or electric vehicles may also be connected to the HAN.

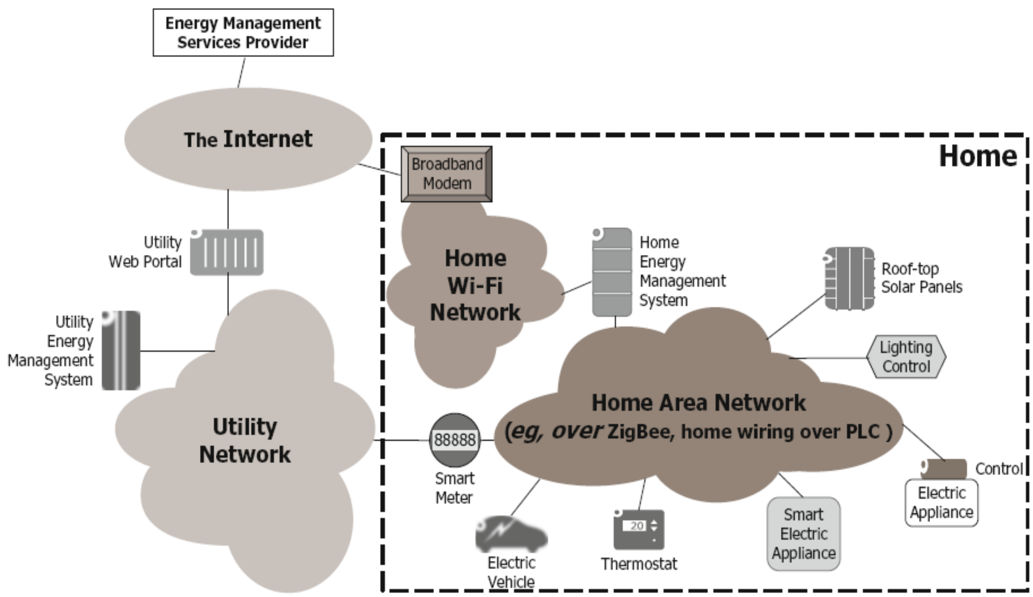


Figure 4.7 Home area network schematic

Depending on the functions supported, the HEMS remotely monitors energy consumption, storage, and generation units connected into the HAN. The HEMS monitors energy consumption/supply into and out of these systems. Further, HEMS may control their operation, turning them on and off as needed and managing their energy efficiency. If allowed by the utility, the (smart) meter may be connected into the HAN, allowing the HEMS to get access to meter measurements. HEMS may also provide access to the devices attached to the HAN from smart phones and PDAs from outside of the home.

HEMS can connect to the home Wi-Fi network to connect to the Internet. In this case, the HEMS may receive energy management services from a third-party provider of these services.

To support such functions as automated demand response (to be described later in this chapter), a utility may allow the HEMS to communicate with the utility EMS (UEMS). In addition, the UEMS may report to the HEMS information including past consumption, future consumption predictions, and consumption anomalies. The HEMS–UEMS communication *may* be carried through the meter connected into the HAN and the utility network. However, if the utility does not allow for such connection through the meter, the UEMS–HEMS communication will be carried over the Internet or other IP network through the utility Web portal.

4.5.4 Neighborhood-area networks (NANs)

A NAN connects multiple HANs and one or more networks between the individual service connections for distribution of electricity and information. As shown in Figure 4-3, all the data from HAN are collected to the data-aggregator unit (DAU). The NAN consists of HAN with smart meters to provide secure and seamless control of different home appliances. DAU consists of a NAN gateway to interface with the HAN and also with the WAN. The DAU communicates with the HAN gateway using network technologies such as PLC, ANSI C12 protocols, WiMAX, or ZigBee. The NAN acts as an access network to forward customer data to the utility local office. [27]

4.5.5 Field Area Network (FAN)

As was observed earlier, if a WR is placed at an existing utility location such as a DCC or substation, the FAN connection of the CR at that location to the WR reduces to simply a LAN connection. Such LAN connections are not considered FANs; thus, they are excluded from discussion.

While recommended, it is not necessary for a CR be deployed at every location with more than one endpoint. Collocated endpoints at a location without a CR connect directly to WR(s) over multiple FAN connections. For example, PVs and the meter concentrator at a distribution pole may have two different FAN connections to WR(s), and the DA IED at that pole may connect to the DA concentrator in a substation over a NAN.

4.5.6 Local Traffic Aggregation

Endpoints connect to the WR over wireline or wireless Field Area Networks. Traffic for collocated endpoints may be aggregated locally at a cluster router (CR) at that location. The CR, in turn, connects to a WR. Examples of locations with multiple endpoints include substations and DCC locations. Local aggregation reduces networking costs since only one FAN connection between the location (CR) and aWR is required. A few examples of local aggregation using CRs are presented in this section. [36]

(Note that if a WR is placed at one of the existing utility locations such as the DCC or a substation, the FAN connection of the CR at that location to the WR reduces to simply a LAN connection at that location.)

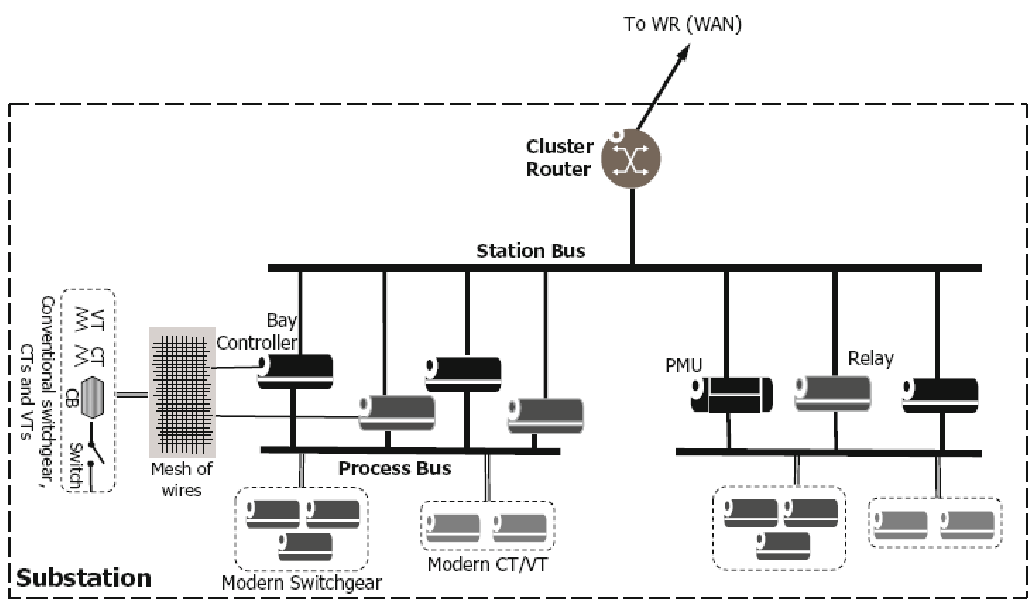


Figure 4.7 Local traffic aggregation at a substation

See Fig. 4.7 for an example of local aggregation at a substation. The substation internal network is similar to the substation architecture of process and station busses, with the exception that at a transmission substation, PMU(s) may be present. Further, the “substation router” is denoted as a cluster router in our network architecture.

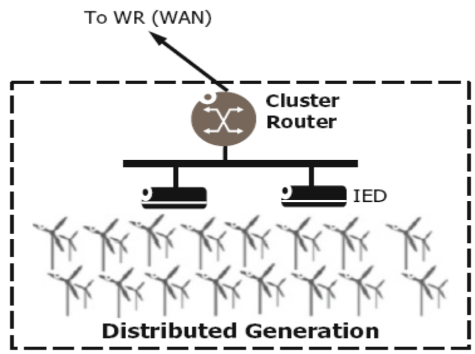


Figure 4.8 Traffic aggregation at a distributed generation site

An example of traffic aggregation at a DG site such as at a large wind farm is shown in Fig. 4.8.

There may be more than one IED at the DG site (and possibly, additionally a DG EMS) that must communicate with utility systems. The cluster router aggregates traffic from the IEDs and EMS (if present)

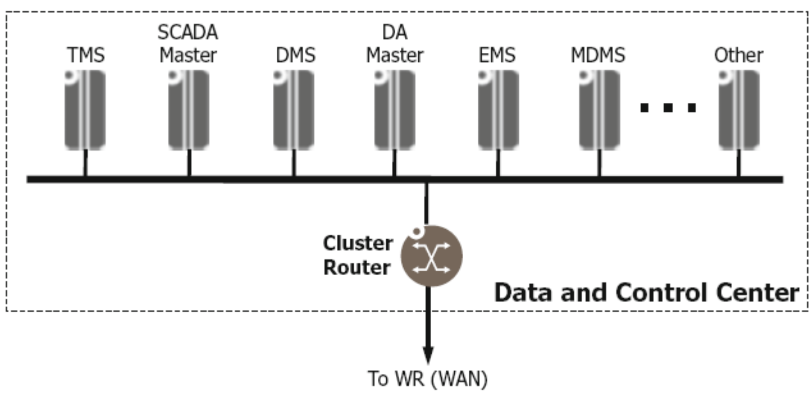


Figure 4.9 Traffic aggregation at utility Data and Control Center

Utility operations, data acquisition, control, energy management, meter data management, and other functions are hosted on the servers at one or more DCCs. Traffic for all severs at each DCC location can be aggregated at the cluster router. The CR in turn is connected into the DCC LAN as shown in Fig. 4.9

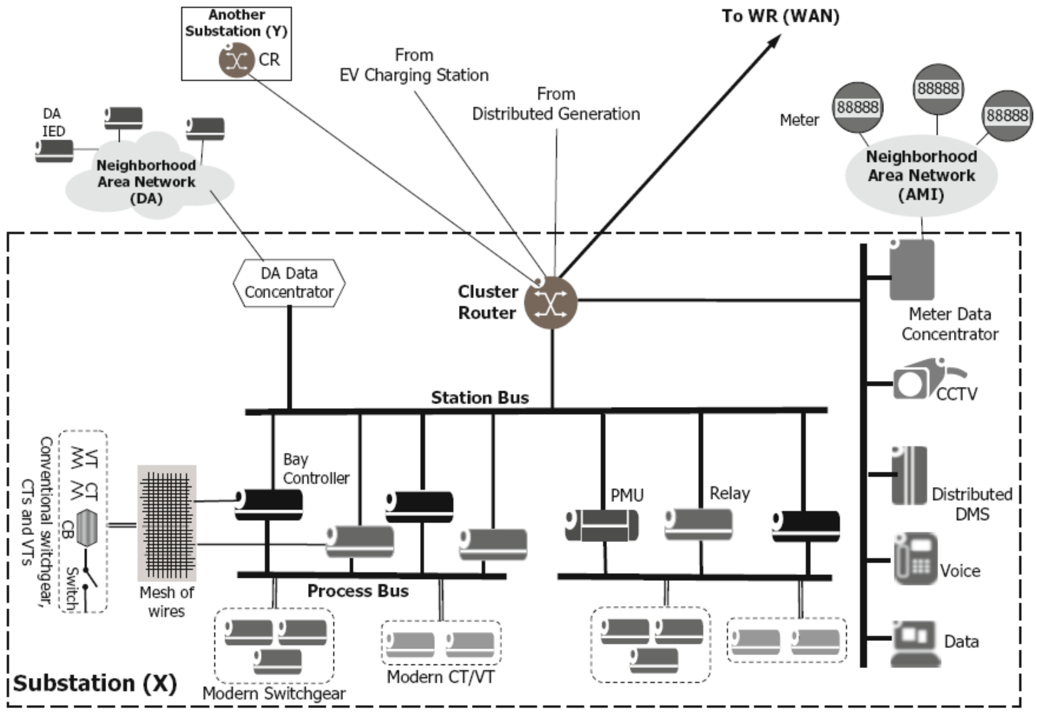


Figure 4.10 CR at substation X aggregates traffic from nearby locations and local traffic at X

Depending on the proximity of different endpoint locations, a network design may determine that further aggregation of traffic is beneficial. Additional aggregation is supported through deployment of a CR at a location (say, location X). This CR aggregates traffic from other locations in its vicinity, in addition to the traffic generated at location X. An example of this scenario is shown in Fig. 4.10.

In addition to SCADA traffic from the station bus, the CR at the substation also aggregates other application traffic generated at the substation such as CCTV traffic and business voice and data traffic if the substation is staffed. PMUs may be present in a transmission substation. If the utility deploys distributed DMS, some of the DMS functions may be located at distribution substations. Meter data concentrators and DA data concentrators, if present, also connect to the substation LANs. Their traffic is further aggregated at the CR. Note that these data concentrators connect to the respective AMI and DA NANs.

Traffic from other locations in the vicinity of the substation such as from DG and EV charging stations may also be aggregated at the substation CR. Finally, other (possibly smaller) substations such as substation Y in the vicinity may also be connected to the substation CR. For example, the CR in substation Y in Fig. 4.10 does not connect directly to a WR.

4.5.7 Putting It all together

An example of physical connectivity architecture for the Smart Grid network is illustrated in Fig. 11. [37].

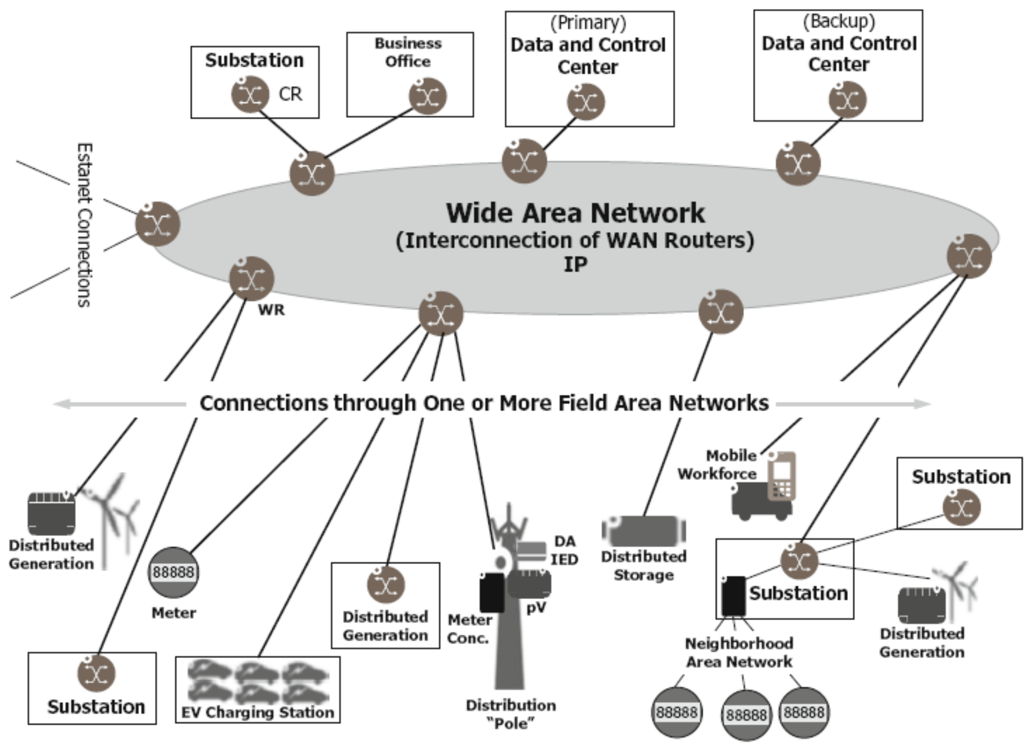


Figure 4.11 Smart Grid communication network architecture illustration

Physical connectivity for only some of the endpoints and applications is shown in the architecture illustration of Fig. 4.11. The actual placement of the WRs and individual FAN connections for the CRs and endpoints to connect to the WRs are determined by the network design. The design takes into account a variety of factors, including utility endpoint locations, supported applications and their traffic requirements, utility constraints on the placement of WRs, the planning period of network evolution, and costs. While a general core-edge network topology is reasonable – most applications require communication between the DCC and other endpoints – the final network may include additional and direct connections between endpoint locations due to delay and reliability requirements.

Traffic aggregation at WRs reduces network costs considerably. With aggregation, direct FAN connections between application endpoints, as is done in most utility networks today, are avoided. Additional aggregation at the CRs reduces costs further, since only one FAN connection is required between a location and the WR. In addition to reducing the capital and recurring operation costs associated with the leasing networking services from the NSPs, operation costs are further reduced by virtue of the smaller amount of network equipment and physical connections.

Chapter 5

Advance metering Infrastructure, Distribution, Transmission, and Automation

5.1 Introduction

The utility industry is on the move to modernize its meter reading and data collection system with advanced metering infrastructure. Driven by strong environmental, political and economic factors, and encouraged by legislative policies to conserve resources, utilities are launching demand response and dynamic pricing programs designed to reduce or shift energy consumption to non-peak periods. Consumers will receive real-time energy pricing and offers from the utility to manage their meter, Consumers benefit from lower bills, while utilities benefit from a stable load on the grid and less need to invest in expensive new capacity. Behind all of this is new technology, two-way communication between the meter and meter data management system, which allows utilities to remotely manage their metering assets and to reach inside the consumer's home through wireless sensor networks to display pricing information, collect hourly or more frequent usage information, and potentially to manage home appliances.

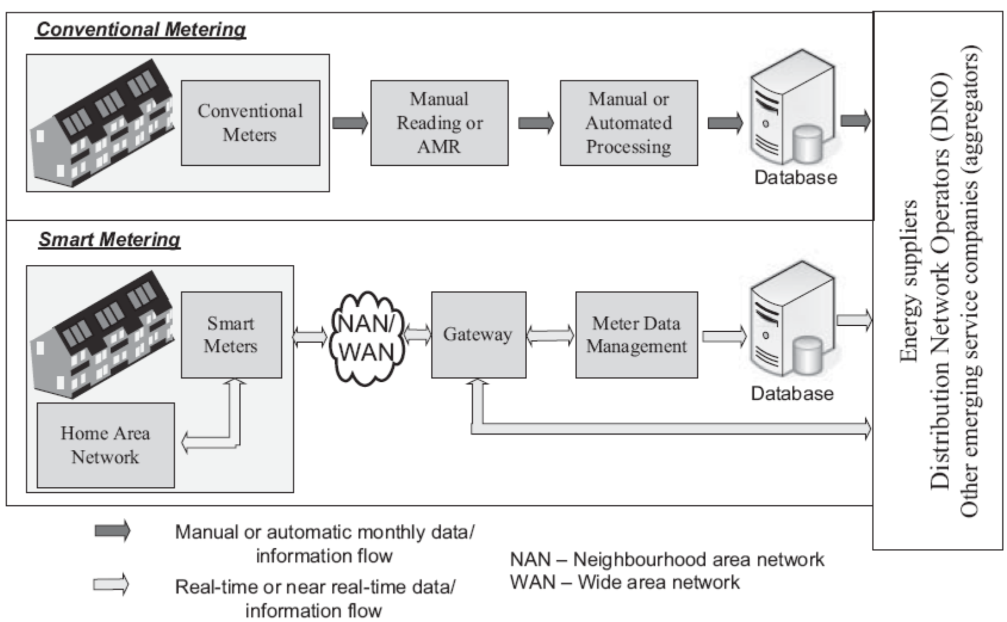


Figure 5.1 Conventional and smart metering compared

In order to aid the transmission and distribution system operators to monitor, control, and optimize the performance of generation and transmission systems, a suite of Applications collected into an Energy Management System (EMS) is used. As the monitoring and control functions for EMS are often provided by SCADA, these systems are also referred to as EMS/SCADA. The EMS is normally located in the System Control Centre and effective real-time monitoring and remote control exist between the Control Centre and the generating stations and transmission substations.

5.2 Conventional Metering and Smart Metering

The differences between conventional metering and smart metering are shown schematically in Figure 5.1. Smart meters have two-way communications to a Gateway and/or a Home Area Network (HAN) controller. The Gateway allows the transfer of smart meter data to energy suppliers, Distribution Network Operators (DNOs) and other emerging energy service companies. They may receive meter data through a data management company or from smart meters directly.

The benefits of advanced metering are listed in Table 5-1. Short-term benefits, particularly for the energy suppliers and metering operators, can be obtained from AMR and Automatic Meter Management (AMM). Longer-term benefits arise from the additional functions of smart metering that lead on to the use of smart meters in the Smart Grid.

Table 5-1 Benefits of advanced metering

	Energy suppliers and network operator benefits	All benefit	Customer benefits
Short-term	Lower metering costs and more frequent and accurate readings	Better customer service Variable pricing schemes	Energy savings as a result of improved information
	Limiting commercial losses due to easier detection of fraud and theft	Facilitating integration of DG and flexible loads	More frequent and accurate billing
Longer-term	Reducing peak demand via DSI programs and so reducing cost of purchasing wholesale electricity at peak	More reliable energy supply and reduced customer complaints	Simplification of payments for DG output

	time		
	Better planning of generation, network and maintenance	Using ICT infrastructure to remotely control DG, reward consumers and lower costs for utility	Additional payments for wider system benefits
	Supporting real-time system operation down to distribution levels	Facilitating adoption of electric vehicles and heat pumps, while minimizing increase in peak demand	Facilitating adoption of home area automation for more comfortable life while minimizing energy cost

5.3 Advance Metering Infrastructure (AMI)

AMI refers to the network infrastructure connecting smart meters deployed at consumer locations, the Meter Data Management System (MDMS) located at the utility DCCs, and other intermediate network elements supporting communication between the smart meters and the MDMS. The traditional electric meters at consumer locations are being replaced by smart meters Periodic measurements of electric quantities collected by the meters are used to support a large number of utility operations and business functions such as periodic monitoring of energy consumption, voltage, power, distribution of pricing information, and other consumer-centric functions in addition to billing the customers. AMI is one of the most prominent applications associated with the Smart Grid. AMI is also one of the most visible components of the Smart Grid.

5.4 Smart Meter Measurement

Smart meters provide periodic “interval measurements.” For meaningful operation of many distribution management functions such as demand response and volt, VAR, watt control (VVWC), interval measurements are required once every hour or once every 15 min or even at the rate of once every 5 min. Depending on the capabilities of the meter, some or all of the following measurements can be reported in every interval:

- Cumulative energy consumption (kWh) up to the end of the interval. Thus, the energy usage in the interval is the difference between the cumulative energy consumption measurements of the two consecutive intervals.
- Instantaneous rms voltage (V) measurement at the end of the interval.
- Instantaneous rms current (A) measurement at the end of the interval.
- Instantaneous power (W) measurement at the end of the interval.
- Average power measurement over the interval.
- Instantaneous reactive power (VAR) measurement at the end of the interval.
- Average reactive power measurement over the interval.
- Cumulative reactive energy consumption (kVARh) up to the end of the interval. Thus, the reactive energy usage in an interval is the difference between the cumulative reactive energy consumption measurements of the two consecutive intervals.
- Instantaneous power factor measurement at the end of the interval.
- Instantaneous (sine of the) phase angle measurement at the end of the interval.
- Whether dynamic pricing such as TOU, CPP, or RTP was in effect during the interval if the customer has subscribed to such a pricing program.

Additionally, voltage threshold alarms can be sent by the meter when the voltage falls below a utility-configured threshold. For 3-phase meters, these measurements are provided per phase, per line, and for the entire 3-phase connection, as appropriate. CTs and VTs may be needed for connecting higher voltage lines to the meters.

If a DG source is collocated with the consumer, the meter can provide the net energy flow. Such measurements can be used to determine whether the local DG is supplying power to the grid. In many cases, there may be two different meters at the consumer location – one for power drawn from the grid and the other for power delivered from the DG to the grid.

Additionally, AMI supports remote disconnection and reconnection of the meters, their (re-)registration with the MDMS after an outage, and remote upgrades of meter firmware and software.

5.5 Networking for AMI

Typical communications architecture for smart metering is shown in Figure 5.2. It has three communications interfaces: Wide Area Network (WAN), Neighborhood Area Network (NAN) and Home Area Network (HAN).

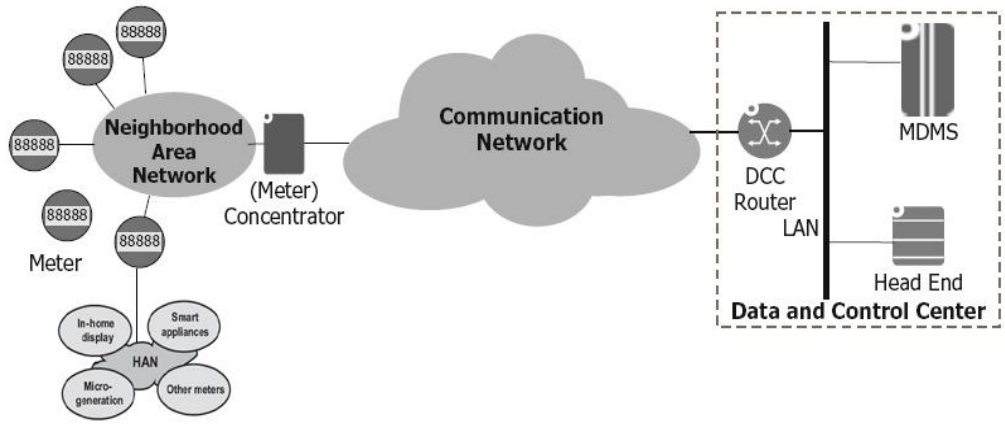


Figure 5.2 Typical communication architecture of smart metering

5.5.1 Home-area network

A Home-Area Network (HAN) is an integrated system of smart meter, in-home display, micro-generation, smart appliances, smart sockets, HVAC (Heating, Ventilation, Air Conditioning) facilities and plug-in hybrid/electric vehicles. A HAN uses wired or wireless communications and networking protocols to ensure the interoperability of networked appliances and the interface to a smart meter. It also includes security mechanisms to protect consumer data and the metering system.

A HAN enables centralized energy management and services as well as providing different facilities for the convenience and comfort of the household. Energy management functions provided by HAN include energy monitoring and display, controlling the HVAC system and controlling smart appliances and smart plugs. The services provided by HAN for the convenience of the household can include scheduling and remote operation of household appliances as well as household security systems. Home-based multimedia applications such as media centres for listening to music, viewing television and movies require broadband Internet access across the HAN. A separate HAN used for energy services can coexist with the broadband Internet system but there is some expectation that the systems will be merged in the future.

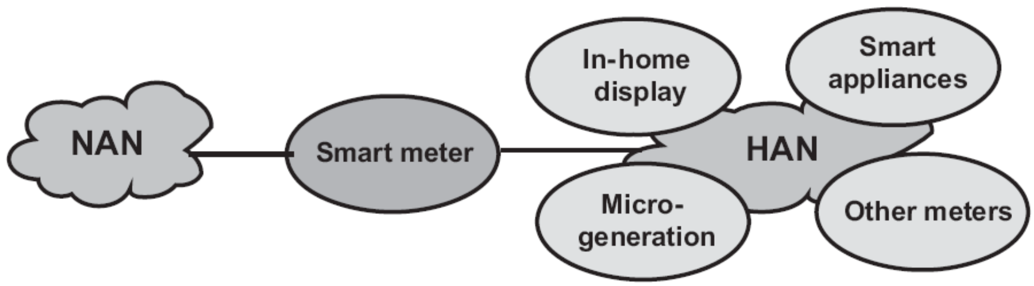


Figure 5.3 Interface between the HAN and NAN

It is expected that HAN will provide benefits to the utilities through demand response and management and the management of micro-generation and the charging of electric vehicles. [38]

5.5.2 Neighborhood area network (NAN)

The primary function of the Neighbourhood Area Network (NAN) is to transfer consumption readings from smart meters. The NAN should also facilitate diagnostic messages, firmware upgrades and real-time or near real-time messages for the power system support. It is anticipated that the data volume transferred from a household for simple metering is less than 100 kB per day and firmware upgrades may require 400 kB of data to be transferred. [39]

The communication technology used for the NAN is based on the volume of data transfer. For example, if ZigBee technology which has a data transfer rate of 250 kb/s is used, then each household would use the communication link only a fraction of a second per day to transfer energy consumption data to the data concentrator.

Also RF mesh and Power Line Communication over narrowband frequencies (PLCNB) technology are used in NAN. RF mesh is based on radio communication over unlicensed spectrum such as the 900 MHz Industrial, Scientific, and Medical (ISM) band States or the 2.4 GHz band. PLC uses the power line connecting the secondary of the distribution transformer to the consumer. In either case, the communication medium (air or power line) is available at no additional cost to the utility.

5.5.3 Smart meter

Meters support a communication interface to connect to the NAN. This interface may be integrated with the meter or attached to meters from different meter vendor models. The PHY and MAC layers for AMI communications over RF mesh and PLC-NB are being standardized, though particular AMI solutions may add their proprietary functions to these interfaces until the standards are widely accepted. IEEE 802.15.4g is a standard for PHY and MAC layers of RF mesh. Some of the PLC-NB standards are IEC/ISO 14908-3, IEC 61334, IEEE 1901.2, PRIME, G3-PLC, and IEC 9955/56

5.5.4 (Meter) Concentrator:

The meter concentrator, sometime called a collector, acts as a relay between the smart meters and the gateway. It manages the meters by automatically detecting them, creates and optimizes repeating chains, coordinates the bi-directional delivery of data, and monitors the conditions of the meters. The meter concentrator is responsible for supporting communication with the meters (in a neighborhood) over the NAN to collect periodic measurements and alarms generated at the meters as well as to send commands by the MDMs to the meters and receive the corresponding responses.

5.5.5 Head End

The head end is the AMI solution's meter management system. The head end communicates with the meter concentrator over an IP connection provided by the Smart Grid. However, the higher-level communication protocol between the head end and the concentrator is vendor-proprietary. The head end connects to the utility MDMS over an IP connection, typically over the LAN at the utility DCC where both are located. A standard protocol such as Extensible Markup Language (XML) is generally used for meter data exchange, commands, and responses between the head end and the MDMS.

5.5.6 Meter data management system (MDMS)

The core of a meter data management system is a database. It typically provides services such as data acquisition, validation, adjustment, storage and calculation (for example, data aggregation), in order to provide refined information for customer service and system operation purposes such as billing, demand forecasting and demand response. A major issue in the design and implementation of a meter data management system is how to make it open and flexible enough to integrate to existing business/enterprise applications and deliver better services and more value to customers while ensuring data security. Besides the common database functionalities, a meter data management system for smart metering also provides functions such as remote meter connection/disconnection, power status verification, supply restoration verification and on-demand reading of remote smart meters.

5.6 Smart meter Standard

While most of the current AMI deployment is based on proprietary solutions, AMI deployment based on direct meter-MDMS connections is expected to be more prevalent in the future as the AMI-related standards are developed and implemented by the AMI vendors. Vendors are already adopting the ANSI C12.19 specifications. The ANSI C12.19 standard provides common data structures (called tables) for transferring meter data between a meter and an MDMS. The ANSI C12.22 standard can be used for communication between a smart meter and the MDMS.

5.7 Smart Meter: An Overview of Hardware used

A traditional electro-mechanical meter has a spinning aluminum disc and a mechanical counter display that counts the revolutions of the disc. The disc is situated in between two coils, one fed with the voltage and the other fed with the current of the load. The current coil produces a magnetic field, φ_I and the voltage coil produces a magnetic field, φ_V. The forces acting on the disc due to the interaction between the eddy currents induced by φ_I and the magnetic field φ_V and the eddy currents induced by φ_V and the magnetic field φ_I produce a torque. The torque is proportional to the product of instantaneous current and voltage, thus to the power. The number of rotations of the disc is recorded on the mechanical counting device that gives the energy consumption.

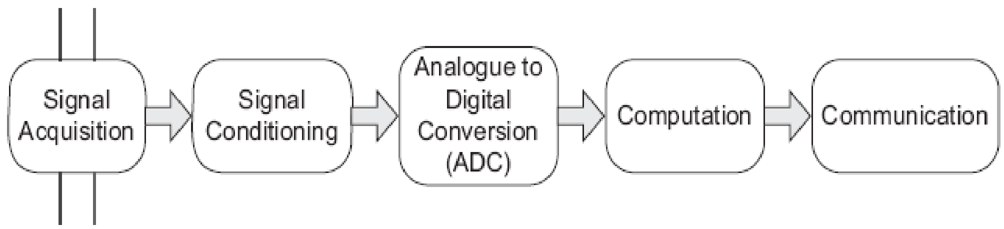


Figure 5.4 Functional block diagram of smart meter

The replacement of electro-mechanical meters with electronic meters offers several benefits. Electronic meters not only can measure instantaneous power and the amount of energy consumed over time but also other parameters such as power factor, reactive power, voltage and frequency, with high accuracy. Data can be measured and stored at specific intervals. Moreover, electronic meters are not sensitive to external magnets or orientation of the meter itself, so they are more tamperproof and more reliable. Early electronic meters had a display to show energy consumption but were read manually for billing purposes. More recently electronic meters with two-way communications have been introduced. Figure 5.4 provides a general functional block diagram of a smart meter. In Figure 5.4, the smart meter architecture has been split into five sections: signal acquisition, signal conditioning, Analogue to Digital Conversion (ADC), computation and communication.

5.7.1 Signal acquisition

A core function of the smart meter is to acquire system parameters accurately and continuously for subsequent computation and communication. The fundamental electrical parameters required are the magnitude and frequency of the voltage and the magnitude and phase displacement (relative to the voltage) of current. Other parameters such as the power factor, the active/reactive power, and Total Harmonic Distortion (THD) are computed using these fundamental quantities.

Current and voltage sensors measure the current into the premises (load) and the voltage at the point of supply. In low-cost meters the measuring circuits are connected directly to the power lines, typically using a current-sensing shunt resistor on the current input channel and a resistive voltage divider on the voltage input channel (Figure 5.5).

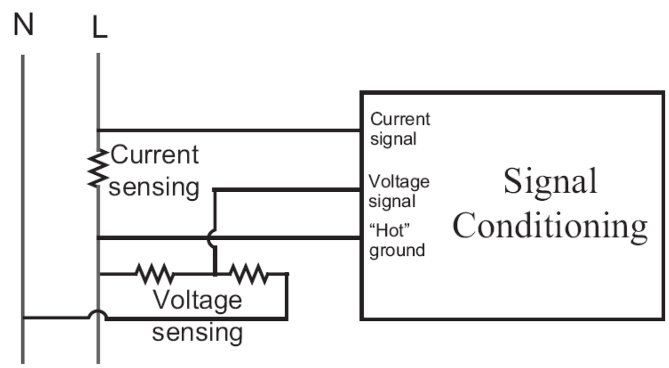


Figure 5.5 Current and voltage sensing

The current sensing shunt is a simple high stability resistor (typically with resistance between 100μΩ and 500mΩ) with the voltage drop across it proportional to the current flowing through it. The current rating of this shunt resistor is limited by its self-heating so it is usually used only in residential meters (maximum current less than 100 A). In order to match the voltage across the current sensing resistor (which is very small) with the Analogue to Digital Converter (ADC), a Programmable Gain Amplifier (PGA) is used in the signal conditioning stage before the ADC (normally integrated within a single chip with the ADC).

The voltage resistive divider gives the voltage between the phase conductor and neutral. The alloy Manganin is suitable for the resistive divider due to its near constant impedance over typical operating temperature ranges.

A Current Transformer (CT) can also be used for sensing current and providing isolation from the primary circuit. A CT can handle higher currents than a shunt and also consumes less power.

5.7.2 Signal conditioning

The signal conditioning stage involves the preparation of the input signals for the next step in the process, ADC. The signal conditioning stage may include addition/subtraction, attenuation/amplification and filtering. When it comes to physical implementation, the signal conditioning stages can be realized as discrete elements or combined with the ADC as part of an Integrated Circuit. Alternatively the stages can be built into a 'System on a Chip' architecture with a number of other functions.

In many circumstances the input signal will require attenuation, amplification or the addition/subtraction of an offset such that its maximum magnitude lies within the limits of the inputs for the ADC stage.

To avoid inaccuracy due to aliasing, it is necessary to remove components of the input signal above the Nyquist frequency (that is, half the sampling rate of the ADC). Therefore, prior to input to the ADC stage, a low pass filter is applied to the signal. The sampling frequency is determined by the functions of the meter. If the meter provides fundamental frequency measurements (currents, voltage and power) and in addition harmonic measurements, then the sampling frequency should be selected sufficiently high so as to obtain harmonic components accurately.

5.7.3 Analogue to digital conversion

Current and voltage signals obtained from the sensors are first sampled and then digitised to be processed by the metering software. Since there are two signals (current and voltage) in a single phase meter, if a single ADC is used, a multiplexer is required to send the signals in turn to the ADC.

The ADC converts analogue signals coming from the sensors into a digital form. As the number of levels available for analogue to digital conversion is limited, the ADC conversion always appears in discrete form. Figure 5.7 shows an example of how samples of a signal are digitized by a 3-bit ADC. Even though 3-bit ADCs are not available, here a 3-bit ADC was used to illustrate the operation of an ADC simply. The 3-bit ADC uses 23 (= 8) levels thus any voltage between −0.8 and −0.6 V is represented by 000 (the most negative range is assigned 000). In other word, −0.8, −0.75, −0.7, and −0.65 are all represented by 000. Similarly, voltage between −0.6 and −0.4 V is represented by 001, and so on.

The resolution of an ADC is defined as:
Resolution = Voltage range/2*n*; where *n* is the number of bits in the ADC.

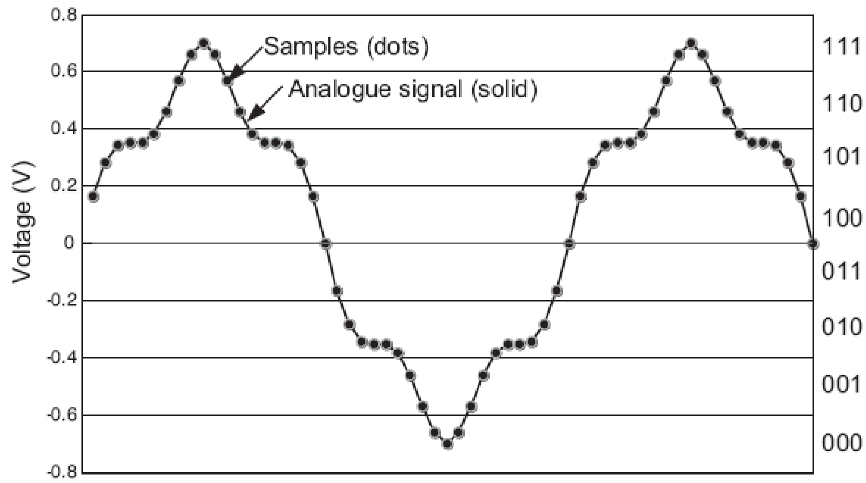


Figure 5.6 Operation of a 3-bit ADC

For the 3-bit ADC shown in Figure 5.7, the voltage range is 1.6 V (−0.8 to 0.8) and therefore the resolution is 1.6/23 = 0.2 V. The higher the number of bits used in the ADC, the lower the resolution. For example, if an 8-bit ADC (typically 8-, 16- and 32-bit ADCs are available) is used, the resolution is 1.6/28 = 6.25 mV

There are many established methods for conversion of an analogue input signal to a digital output. The majority of the methods involve an arrangement of comparators and registers with a synchronizing clock impulse. The most common ADCs for metering use the successive approximation and the sigma-delta method. [40, 41]

5.7.4 Computation

The computation requirements are split into arithmetic operations on input signals, time-stamping of data, preparation of data for communication or output peripherals, handling of routines associated with irregular input (such as payment, tamper detection), storage of data, system updates and co-coordinating different functions.

The block diagram shown in Figure 5.10 shows different functional blocks associated with the computation functions of a smart meter.

Due to the relatively large number of arithmetic operations (Table 5-2) required for the derivation of the parameters, a Digital Signal Processor (DSP) is used.

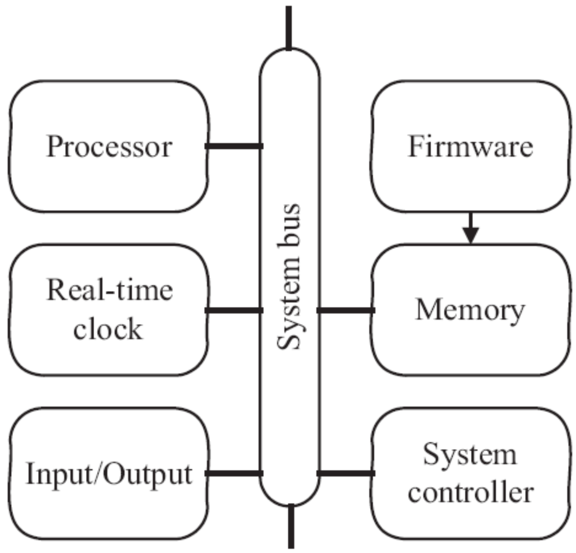


Figure 5.7 Computation overview block diagram

In addition to routine arithmetic operations, a meter deals with a large number of other procedures (that is, payment, tamper detection, system updates, user interactions) as well as other routine tasks (for example, the communication of billing information). Therefore, a high degree of parallelism (the ability to perform multiple tasks, involving the same data sets, simultaneously) and/or buffering (the ability to temporarily pause arithmetical operations so that other need can be attended to) is required.

Table 5-2 Arithmetic operation required for different parameters

Required parameter	Operation type
Instantaneous voltage	Multiplication
Instantaneous current	Multiplication
Peak voltage/current	Comparison
System frequency	Zero detection, Fourier analysis

RMS voltage/current	Multiplication
Phase displacement	Zero detection, comparison
Power factor	Trigonometric function
Instantaneous apparent power	Multiplication
Instantaneous real power	Multiplication
Instantaneous reactive power	Multiplication
Energy use/production	Integration
Harmonic voltage distortion	Fourier analysis
Total harmonic distortion	Multiplication and addition

For computation, volatile memory (where information is lost on loss of power supply) and non-volatile [40] memory is needed. Volatile memory is used for temporary storage of data to support the processor(s) as operations are undertaken. The amount of volatile memory used depends on the quantity, rate and complexity of computation and the rate of communication to/from ports. A certain amount of non-volatile memory is typically required to store specific information, such as the unit serial number and maintenance access key codes. Additionally data related to energy consumption should be retained until successful communication to the billing company has been achieved.

In order that the acquired data can be meaningfully interrogated, a time reference must be appended to each sample and/or calculated parameter. For this purpose a real-time clock is used. The accuracy of the real-time clock can vary with temperature. In order to maintain this function during system power losses or maintenance, a dedicated clock battery is typically used.

5.7.5 Input/Output

A smart meter has a display that presents information in the form of text and graphs for the human user. Liquid Crystal Displays (LCD) and the Light Emitting Diodes (LED) are preferred for their low cost and low power consumption requirements. Both display types are available in seven-segment, alphanumeric and matrix format. LEDs are relatively efficient light sources, as they produce a significant amount of light when directly polarised (at relatively low voltages: 1.2–1.6 V), and a current of a few milliamps is applied.

Smart meters provide a small key pad or touch screen for human–machine interaction, for instance, to change the settings of a smart meter so as to select the smart appliance to be controlled or to select payment options.

As smart meters require calibration due to variations in voltage references, sensor tolerances or other system gain errors, a calibration input is also provided. Some meters also provide remote calibration and control capability through communication links.

Energy consumption and tariffs may be displayed on a separate customer display unit located in an easily visible location within the residence (for example, the kitchen). This is to encourage customers to reduce their energy use, either throughout the year or at times of peak demand when generation is short. Research is ongoing to determine the most effective way to display information to encourage customers to take notice of their energy consumption, and/or the signals from the suppliers to restrict demand at times of generation shortage. Approaches that have been used include displays using:

- Three coloured lights (resembling traffic lights) or a globe that changes colour to signal changes in tariffs. This is used with a Time of Use Tariff to control peak demand.
- A digital read-out or analogue display resembling a car speedometer showing energy use;
- A continuously updated chart showing energy use and comparison with a previous period, for example, yesterday or last week.

It is hoped that customers will manage and reduce their energy consumption when they are provided with more accurate, up-to-date information, also that any reduction made soon after the display is installed will be maintained. Trials indicate that initial reductions in electrical energy use of up to 10 per cent may be possible but maintaining this level of reduction requires careful design of the displays and tariffs but also other interventions such as outreach programmes to customers that provide advice on how to reduce energy consumption.

5.7.6 Communication

Smart meters employ a wide range of network adapters for communication purposes. The wired options include the Public Switched Telephone Network (PSTN), power line carrier, cable modems and Ethernet. The wireless options include ZigBee, infrared, and GSM/GPRS/CDMA Cellular. These techniques are described in Chapter-2.

5.8 Distribution Management

We generically use the term Distribution Management System (DMS) to refer to systems that support functions for managing the distribution system, irrespective of whether the DMS is realized as one centralized system or a system distributed over multiple servers. Some of the distribution system applications and functions include the following:

- SCADA
- Digital Fault Recorder (DFR)
- Outage management system (OMS)
- Volt, VAR, WATT Control (VVWC)
- Meter Data Management System (MDMS)
- Distribution Operation Model and Analysis (DOMA)
- Multilevel Feeder Reconfiguration

Many of these functions and applications use SCADA data (described in this chapter) as well as data collected from other (Smart Grid) applications.

Further, we generically refer to the utility Data and Control Center (DCC) as a location where the TMS and DMS systems are located. However, the DCC may be centralized or distributed over multiple locations including for the purpose of backup. Some utilities have separate locations for Transmission Management System and for Distribution Management System.

5.9 Distribution Automation (DA)

The IEEE defines distribution automation as “a system that enables an electric utility to remotely monitor, coordinate, and operate distribution components in a real-time mode from remote locations”. We similarly define distribution automation as “any operation of device (or devices) outside the power substation that is triggered by an automatic response to any change in a power distribution network.” DA can function as centralized or decentralized intelligence as auto-operations in normal (load) and abnormal (fault, fault restoration) situations, with load transfers and two-way power flow for the distributed grid [43].

In its broadest context, distribution automation refers to the automation of all functions related to the distribution system using information collected from substation devices, devices deployed on feeders, and meters deployed at consumer locations. Thus, SCADA systems that monitor and control distribution substations are considered a DA function based on this broad definition. In addition, AMI could be considered a DA function since many new functions of Distribution Management Systems (DMS) use AMI data. However, a more widely accepted and practical definition of distribution automation is limited to the acquisition of data (measurements) from IEDs connected to the devices on the feeder and the control of those feeder devices. Under this limited definition, SCADA systems used to monitor and control distribution substations are excluded, as is AMI. [44]

5.10 Networking for Distribution Automation (DA)

Figure shows some of the devices that are included in distribution automation. Four different feeder device types are included in Fig.

1. Reclosers: A recloser monitors the feeder and breaks the feeder circuit if the current exceeds a preset threshold. In this sense, a recloser performs a function similar to a circuit breaker. However, the recloser also attempts to reconnect the circuit automatically after a short period of time after disconnecting it. The rationale is that many faults on a feeder are of a temporary nature (e.g., a falling tree hits an aboveground feeder wire before hitting the ground, thus creating a short circuit for only a short period of time, resulting in the recloser tripping that circuit). If a recloser is unable to reconnect the circuit at the first attempt, it attempts to reconnect several (preconfigured) more times with a short delay between successive attempts, before "concluding" that the fault is permanent. In the event a recloser declares a fault permanent, reclosers must be operated manually via a remotely executed command. (If that remote attempt is unsuccessful, a member of the mobile workforce may need to be dispatched for on-site repair).

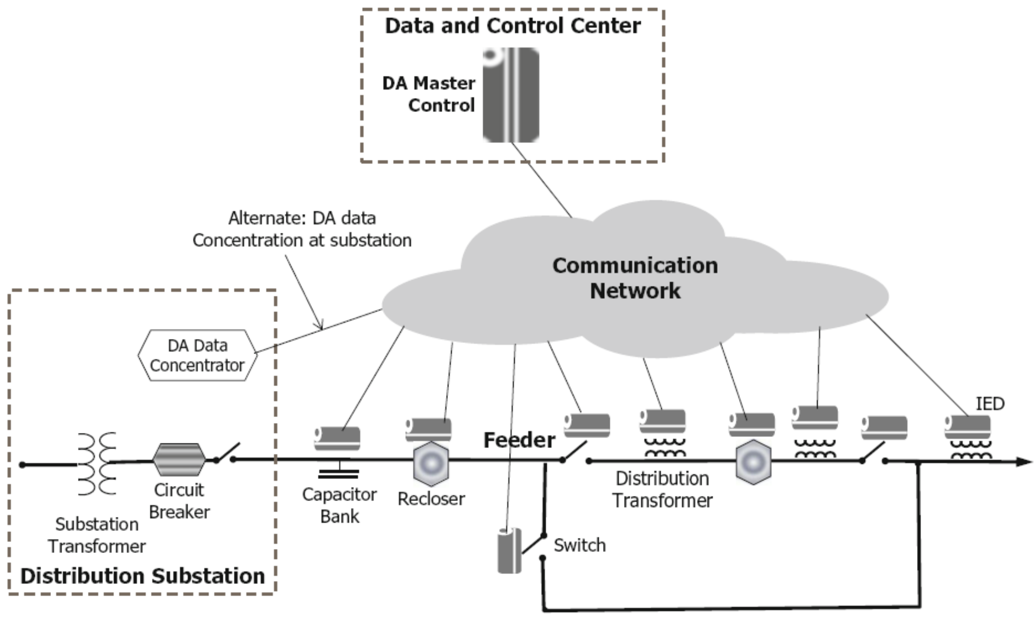


Figure 5.8 Examples of feeder devices included in distribution automation

2. ***Switches*:** Switches on feeders are deployed to "sectionalize" faulty sections of the feeders and to divert power around a faulty section (until the fault is repaired). Switches are operated manually or by using remotely executed commands.

3. ***Capacitor Bank*:** Capacitors are used to dynamically reduce the reactive current in an effort to maintain the power factor as close to 1 as possible. Traditionally, capacitors were deployed at substations. Deploying capacitors closer to the load (on the feeder), however, can reduce reactive current where it has the greatest impact (thus reducing the power losses at the feeders). In order to dynamically control capacitor banks, electric quantities must be measured in real time to determine the capacitors from a bank of capacitors that must be connected to (or disconnected from) the feeder circuit.

4. *Distribution Transformers*: In most existing deployments, distribution transformers are not monitored. Transformer loads can be estimated based on the power demands measured at the meters of consumers connected to the transformer. To improve the efficiency of the distribution system, however, it is becoming increasingly important to periodically measure the voltages and other electric quantities at the transformer primary and secondary. Further, transformer measurements can be used to estimate transformer (remaining) lifetime as well as to ensure that the capacity of distribution transformers is properly sized. In addition to the measurements of the electric quantities, accurate estimation of transformer lifetime requires frequent periodic measurements of the internal temperature of the transformer (such as the *top oil* temperature).

Each of these devices must include IEDs to support the required measurement, monitoring, and control functions. These IEDs communicate with the DA control system, called the DA master control. Depending on the available communication technology, it may be prudent to deploy a DA data concentrator at the substation. A DA data concentrator collects data from IEDs on one or more feeders and forwards the data to the DA master. In turn, commands and polls sent by the DA master to individual IEDs are relayed through the concentrator. The polling frequency for DA IEDs may be smaller (say, every 5–30 s) than the every 2–5 s typically used by SCADA systems to collect periodic measurements and status from the IEDs in a distribution substation. Both NAN can be used for DA. It is important that the more stringent (compared to AMI) performance, reliability, and security requirements of DA are satisfied by these NAN technologies.

5.11 Substation Automation (SA)

The term "substation automation" often refers to a combination of two modernization steps:

1. Deployment of microprocessor-based Intelligent Electronic Devices (IEDs) to replace conventional CTs, VTs, and RTUs and secondary equipment such as relays and bay controllers.

2. Development and deployment of new Distribution Management System (DMS) applications that take advantage of the enhanced monitoring and control functions provided by the IEDs.

A single IED may support functions formerly supported by multiple conventional devices in the substation, thus reducing the number of devices and the needed interconnections among them. With these advanced devices, new substation automation functions can be introduced, simplifying operations, improving performance, and providing support for newer communication technologies. These multifunctional IEDs are more powerful and smaller in size than the devices they replace, reducing the costs associated with SCADA operations. Some IEDs also support connectivity to conventional substation equipment using tunneling or gateway functions. These communication functions allow older equipment to be used for a period of time in the new communication technology environment.

As an intermediate step toward substation automation, the substation RTU may continue to be a single point of substation connection to the DCC as IEDs are deployed. In the final step, each IED will communicate directly with the master control in the DCC over the DNP3 protocol. The data to and from the IEDs can be aggregated at the substation at an IP router, with each individual DNP3 communication being carried over the IP connection between the corresponding IED and the SCADA master controller.

5.12 Substation Automation equipments

5.12.1 Intelligent Electronics Devices (IEDs)

The name Intelligent Electronic Device (IED) describes a range of devices that perform one or more of functions of protection, measurement, fault recording and control. An IED consists of a signal processing unit (as discussed in Sections 5.3.2 and 5.3.3), a microprocessor with input and output devices, and a communication interface. Communication interfaces such as EIA 232/EIA 483, Ethernet, Modbus and DNP3 are available in many IEDs.

***Relay IED*:**Modern relay IEDs combine a number of different protection functions with measurement, recording and monitoring. For example, the relay IED shown in Figure 6.12 has the following protection functions:

- three-phase instantaneous over-current: Type 50 (IEEE/ANSI designation);
- three-phase time-delayed over-current (IDMT): Type 51;
- three-phase voltage controlled or voltage restrained instantaneous or time-delayed overcurrent: Types 50V and 51V;
- earth fault instantaneous or time-delayed over-current: Types 50N and 51N.

The local measurements are first processed and made available to all the processors within the protection IED. A user may be able to read these digitised measurements through a small LED display as shown in Figure 6.13. Furthermore, a keypad is available to input settings or override commands.

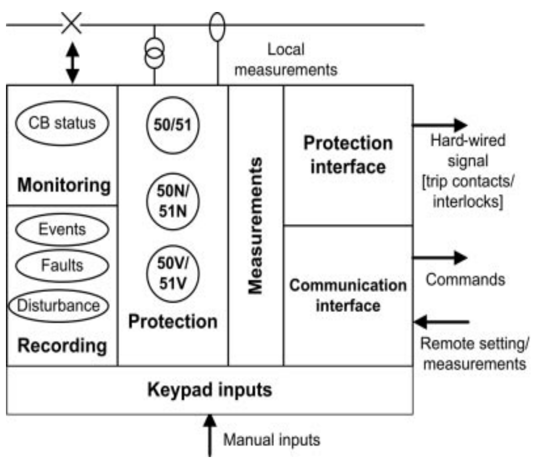


Figure 5.9 Typical configuration of a relay IED

Figure 5.10 Schematic of Relay IED

Various algorithms for different protection functions are stored in a ROM. For example, the algorithm corresponding to Type 50 continuously checks the local current measurements against a set value (which can be set by the user or can be set remotely) to determine whether there is an over-current on the feeder to which the circuit breaker is connected. If the current is greater than the setting, a trip command is generated and communicated to the Circuit Breaker (CB). IEDs have a relay contact that is hard-wired (in series) with the CB tripping coil and the tripping command completes the circuit, thus opening the CB.

Meter IED: A meter IED provides a comprehensive range of functions and features for measuring threephase and single-phase parameters. A typical meter IED measures voltage, current, power, power factor, energy over a period, maximum demand, maximum and minimum values, total harmonic distortion and harmonic components.

Recording IED: Even though meter and protection IEDs provide different parameters (some also have a data storage capability), separate recording IEDs are used to monitor and record status changes in the substation and outgoing feeders.

Continuous event recording up to a resolution of 1 ms is available in some IEDs. These records are sometimes interrogated by an expert to analyse a past event. This fault recorder records the pre-fault and fault values for currents and voltages. The disturbance records are used to understand the system behaviour and performance of related primary and secondary equipment during and after a disturbance.

5.12.2 Bay controller

Bay controllers (Figure 6.14) are employed for control and monitoring of switchgear, transformers and other bay equipment. The bay controller facilitates the remote control actions (from the control centre or from an on-site substation control point) and local control actions (at a point closer to the plant).

The functionalities available in a bay controller can vary, but typically include:

- CB control
- switchgear interlock check
- transformer tap change control
- Programmable automatic sequence control.

5.12.3 Remote terminal units

The distribution SCADA system acquires data (measurements and states) of the distribution network from Remote Terminal Units (RTU). This data is received by an RTU situated in the substation (referred to here as the station RTU), from the remote terminal units situated in other parts of the distribution network (referred to here as the field RTU).

The field RTUs act as the interface between the sensors in the field and the station RTU. The main functions of the field RTU are to: monitor both the analogue and digital sensor signals (measurements) and actuator signals (status), and convert the analogue signals coming from the sensors and actuators into digital form. The station RTU acquires the data from the field RTUs at a predefined interval by polling. However, any status changes are reported by the field RTUs whenever they occur.

Figure 5.12 Bay controller

Modern RTUs, which are microprocessor-based, are capable of performing control functions in addition to data processing and communication. The software stored in the microprocessor sets the monitoring parameters and sample time; executes control laws; sends the control actions to final circuits; sets off calling alarms and assists communications functions. Some modern RTUs have the capability to time-stamp events down to a millisecond resolution.

5.13 Supervisory Control and Data Acquisition (SCADA) systems

Supervisory Control and Data Acquisition systems have been in use for the last few decades to proactively monitor and control the power from the utility DCC using Remote Terminal Units (RTUs) deployed at the transmission and distribution substations. Monitoring (or data acquisition) refers to the measurement and reporting of voltages, currents, power (W), and reactive power (VAR) and reporting on the status of different systems in the substation such as the circuit breakers and switches. Control refers to the control of substation operations such as tripping of circuit breakers and adjusting taps on voltage regulators. [45]

SCADA (Supervisory Control And Data Acquisition) provides real-time system information to the modelling and analysis tools. Hence the data integrity and expandability of the SCADA database are critical. Data integrity should be independent of any DMS Applications and new functions should be able to be integrated easily with the SCADA system without affecting existing Applications.
SCADA has the following attributes:

1. ***Data acquisition*****:** Information describing the system operating state is collected automatically by Remote Terminal Units (RTUs). This includes the status of switching devices as well as alarms and measured values of voltages and currents. This information is passed to the control centre in close to real-time.
2. ***Monitoring, event processing and alarms*****;** An important function of SCADA is to compare the measured data to normal values and limits, for example, to monitor the overload of equipment (transformers and feeder circuits), and violations of voltage limits. It also detects the change of status of switchgear and operation of protection relays. An event is generated if there is change of switchgear status or violation of circuit limits. All events generated by the monitoring function are processed by the event processing function, which classifies and groups events and delivers appropriate information to the system operators through the Human–Machine Interface (HMI). Most critical events

will be sent to the operators as alarms, for example, flashing colour presentation or audible signals.

3. ***Control*:** Control through a SCADA system can be initiated manually or automatically. Control initiated manually can be the direct control of a particular device (for example, a circuit breaker or tap-changer). Some functions are initiated manually by the control room operator, but then follow local control logic to ensure the equipment is operated following a specific sequence or within specific limits. Control initiated automatically is triggered by an event or specific time.
4. ***Data storage, event log, analysis and reporting*:** Real-time measurements are stored in the real-time database of the SCADA system at the time received. Because the data update overwrites old values with new ones, the time-tagged data is stored in the historical database at periodic intervals, for example, every 5 minutes or every hour, for future use.

In order to analyze system disturbances correctly, an accurate time-stamped event log is necessary. Some equipment (for example, RTUs) is capable of recording events with millisecond precision and then delivering time-stamped information to the SCADA system. The sequence of events formed by time-stamped information is useful for the system operator to analyze an event to establish the reason for its occurrence.

5.14 SCADA Evolution with IEC 61850 Set of Standards

IEC 61850 is a 10-part comprehensive set of standards [46] encompassing communication networks and systems in substations. Many utilities across the world have begun or are planning to deploy substation devices (IEDs) and substation communication networks based on these standards. The standard formally defines an IED as any device incorporating one or more processors capable of receiving or sending data/control functions from or to an external source. Examples of IEDs include electronic multifunction meters, digital relays, and controllers; see IEC 61850-1.

The standards specify object models that characterize substation equipment and the information communicated between them. These object models formally describe IED functions that may be implemented by different IED vendors, providing a basis for multivendor interoperability. Further, a configuration language is defined for SCADA operations and maintenance functions. This allows for the use of standards-based tools from multiple application providers to support SCADA operations and maintenance functions. Of more relevance to the topic of this book, the standard specifies communication for substation automation.

The substation automation connectivity architecture developed in IEC 61850-7-1 is shown in Fig. 5.13.

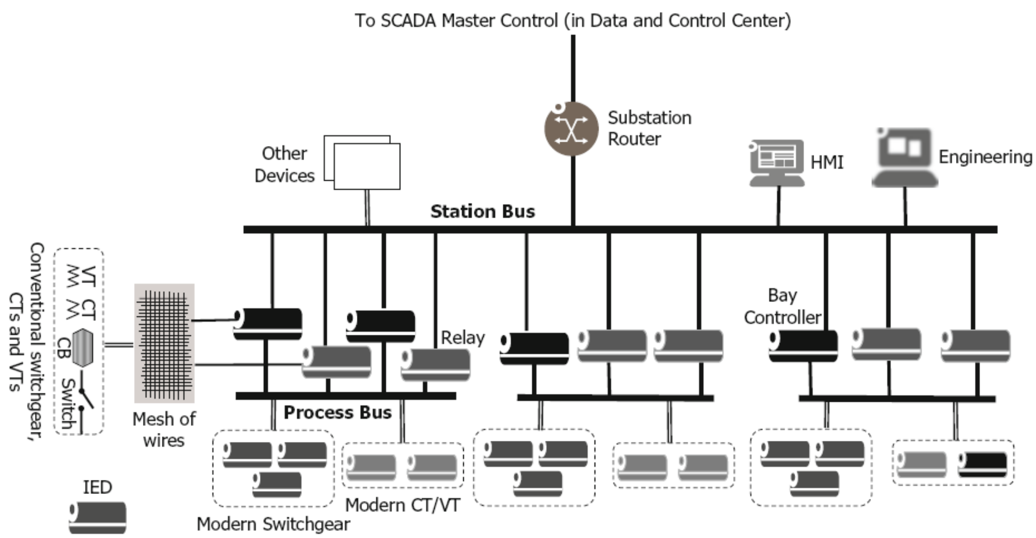


Figure 5.13 Substation architecture with IEC 61850-7-1

With IEC 61850, all substation devices are IED based. Each IED supports one or more functions including switchgear, CT, VT, bay controller, and relay. Traditional SCADA devices are shown in Fig. 5.13. Connectivity to conventional switchgear and instrumentation software may be maintained for a period of time by connecting them to IEDs that also simultaneously support such conventional equipment.

One or more process busses are deployed to support local interconnections of IEDs in several parts of the substation yard. A process bus is an Ethernet LAN, generally with a single Ethernet switch. Each IED communicates with other IEDs connected to its process bus. For example, a local multifunction meter can send measurements to relays connected to the process bus. Further, a bay controller can send trip signals to circuit breakers connected to the same bus. The number of process busses depends on the number and location of the switchgear and instrumentation transformers in the substation. Note that primary substation equipment is deployed at many different points of the power circuits in the substation, necessitating the use of multiple process busses.

The substation's station bus provides connections between IEDs and other systems in the substations. Thus, process busses connect into the station bus. The station bus is also an Ethernet LAN with one or more Ethernet switches. The local HMI and engineering station, if present, communicate with the IEDs over their connections to the station bus. The station bus provides LAN connections for other substation devices including IEDs that may provide functions other than the ones identified here. In the future, there may be other IEDs supporting additional functions. The station bus connects to the SCADA master controller in the DCC through the IP router connected to the station LAN.

As a target standard architecture, RTU functions for aggregating data or control functions from the IED are not defined. Each IED communicates directly with the SCADA master over protocols like DNP3 (carried over the IP connection between the substation router and the SCADA master). For IEDs (and legacy RTUs, if present in the substation during transition) with only serial network interfaces, the serial connection should be tunneled using IP.

An important aspect of IEC 61850 is the definition of the Generic Substation Events (GSEs). GSEs provide a fast (within 4 ms) and reliable mechanism for generating event notifications within a substation. Generic Object-Oriented Substation Events (GOOSE) defines a standardized mechanism for reporting event status and associated info.

The IEC 61850 standards were developed by the technical committee TC57 of the International Electromechanical Commission. TC57 has further extended these standards beyond substation automation to support communication between substations (such as for teleprotection to be discussed in Sect. 4.3) and to support communication between substations and generation sources – both bulk and distributed generation. To reflect the extension of the scope of the 61850 standards, they are now named communication networks and systems for power utility automation.

6.15 Faults in the distribution system

When a fault occurs in the transmission or distribution system, the power system voltage is depressed over a wide area of the network and only recovers when the fault is cleared. Transmission systems use fast-acting protection and circuit breakers to clear faults within around 100 ms. In contrast, the time-graded over-current protection of distribution circuits and their slower CBs only clear faults more slowly, typically taking up to 500 ms.

Fast clearance of faults is important for industrial, commercial and increasingly for domestic premises. Many industrial processes rely on motor drives and other power electronic equipment which is controlled by microprocessors. Commercial and domestic premises use ever more Information Technology Equipment (ITE). This equipment is becoming increasingly sensitive to voltage dips.

A sustained electricity outage may lead to severe disruption and economic loss, especially for industrial processes. Hence many Regulators impose penalties for the loss of electricity to customers.

In these circumstances, distribution network operators are concerned to increase the speed of isolating the fault and restoring supply. Increasingly they are applying automatic supply restoration techniques which use automatic reclosers, remotely controlled switches, remote measurements and sometimes local Agents (a piece of software running in a local computer).

5.15.1 Fault location, isolation and restoration

Figure 5.14 shows a typical 11 kV distribution network. When there is a fault on the network at the location shown, the over-current protection element in IED1 detects the fault and opens CB1. This will result in an outage at loads L1 to L5. Since there are no automated components in the network, supply restoration for a part of the network requires the intervention of a restoration crew and in some areas may take up to 80 minutes [57].

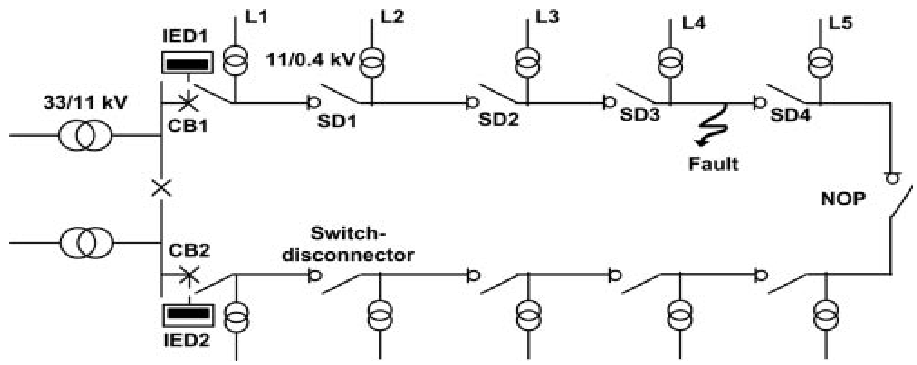


Figure 5.14 Typical distribution network section

Supply restoration is normally initiated by phone calls from one or more customers (in the area where outage occurred) reporting a loss of supply to the electricity supplier. Upon receiving these calls a restoration crew is dispatched to the area. It will take some time for the team to locate the fault and manually isolate it by opening SD3 and SD4. Then CB1 is closed to restore the supply to L1, L2 and L3. The normally open point (NOP) is closed to restore the supply to L5. Load L4 will be without supply until the fault is repaired.

A simple method to reduce the restoration time of loads L1, L2, L3 and L4 is using a pole-mounted recloser and sectionaliser as shown in Figure 5.15. When a fault occurs, the recloser will trips. Upon detecting the interruption, the sectionaliser, S, will increments its counter by 1.

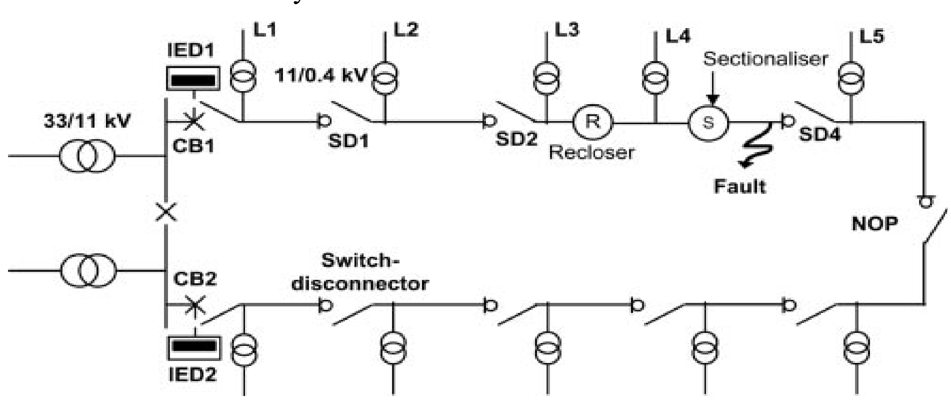


Figure 5.15 Distribution network with some degree of automation

After a short time delay, the recloser closes and if the fault persists, it will trip again. The counter of S increments again and it is then opened. The recloser then closes successfully. The operation of the sectionaliser facilitates restoration of supply to L1, L2, L3 and L4 within a couple of minutes. However, the restoration of supply to L5 requires the intervention of the crew. As this method does not need any communication infrastructure, it is reliable and relatively inexpensive.

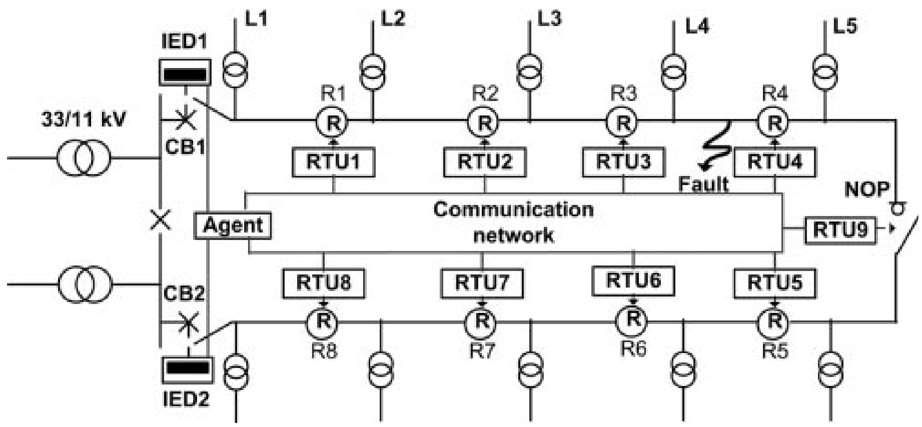


Figure 5.16 fully automated distribution network

A greater degree of automation may be introduced by using reclosers with RTUs, with communication infrastructure between them (Figure 5.16). In this scheme, an Agent is employed that gathers data from all the intelligent devices in the system. During normal operation, the Agent polls all the RTUs and IEDs to establish the system status. When there is a fault at the location shown, IED1 detects the fault current, opens the CB and informs the Agent. The Agent sends commands to RTU1 to RTU4 (remote terminal units up to the normally open point) to open them and requests current and voltage data from them in real time. A possible automatic restoration method is:

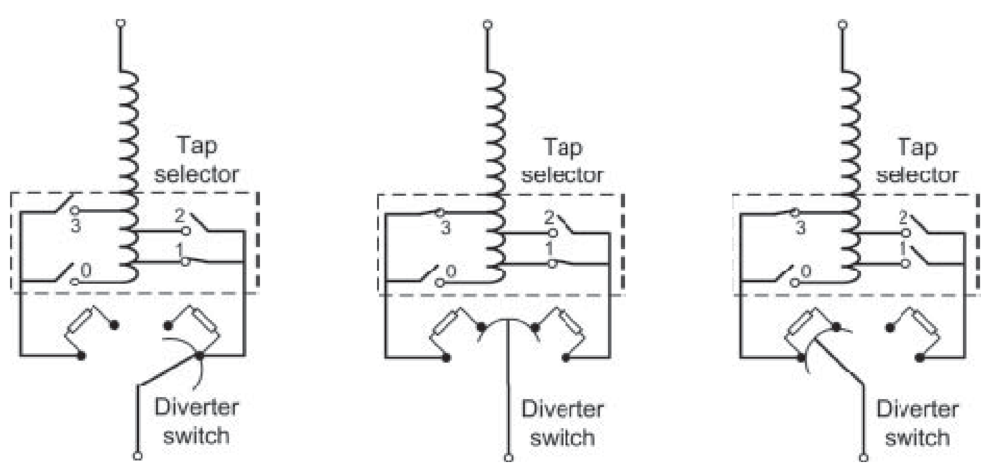
1. Send a command to IED1 to close CB1.
2. Send a command to RTU1 to reclose R1. If the fault current prevails, initiate a trip but as there is no fault current, R1 remains closed. Similarly send commands to RTU2, 3 and 4 to reclose R2, R3 and R4. When R3 is closed, fault current flows, thus causing R3 to trip and lock-out.
3. Then send a command to RTU9 to close the normally open point.

4. Finally, send a command to RTU4 to close R4. As the fault current flows, a trip command is initiated for R4. R3 and R4 thus isolate the fault and supply is restored to loads L1, L2, L3 and L5.

5.16 Voltage regulation

Distribution circuits are subject to voltage variations due to the continuous changes of the network load. At times of heavy load the voltage of the downstream networks is reduced and may go below the lower limit (voltage on the 230/400 V circuits should be maintained within +6 per cent and −10 per cent). Under light load conditions the voltage may go above the upper limit. The voltage variations may become severe when distributed generators are connected under light load conditions, the power flow may be reversed [47]

The sustained voltages above 10 per cent or below −10 per cent of the nominal voltage may damage or may prevent normal operation of IT equipment. As many consumers (domestic, industrial and commercial) are now heavily dependent on this equipment, regulating the voltage within the national limits is very important.



(a) (b) (c)

Figure 5.17 Operating sequence of an OLTC

Traditionally, an automatic tap changer and Automatic Voltage Control (AVC) relay, sometimes with line drop compensation is used on the HV/MV transformers to maintain the voltages on distribution circuits within limits. These transformers whose output voltage can be tapped while passing load current are referred to as having On-Load Tap Changers (OLTCs). The operation of the OLTC is achieved by operating a tap selector in coordination with a diverter switch as shown in Figure 6.30 a, b, c.[48]
In automatic arrangements (with a motorized tap changer), an AVC relay is introduced to maintain the MV busbar voltage within an upper and lower bounds (a set value ± a tolerance). The main purpose of introducing a tolerance is to prevent the continuous tapping up and down (hunting effect). A time-delay relay is also usually employed to prevent tap changing due to short-term voltage variations. In modern automatic on-load tap changers, the AVC software and time-delay relay are in a bay controller as shown in Figure 5.18.

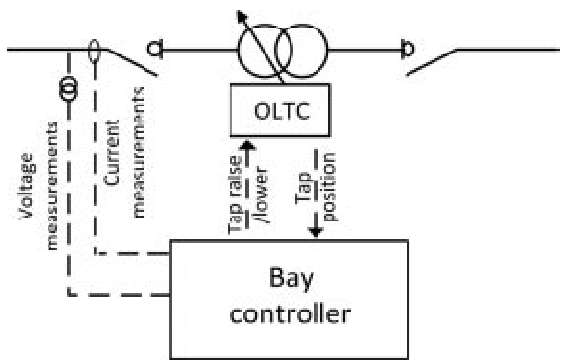


Figure 5.18 Automatic OLTC arrangement

In today's power system, pole-mounted capacitor banks are used in distribution circuits for voltage regulation. They provide power factor correction closer to load, improve voltage stability, increase the line power, flows are lower and reduce network losses. These capacitors may be fixed or variable. Modern pole-mounted variable capacitors come with current- and voltage sensing devices, data logging facility and local intelligence. Variable capacitors are essentially a number of switched capacitors where the number of capacitors that are switched in is determined by an intelligent controller fixed to the pole.

The location of the capacitor bank that provides reactive power and its value of reactive power support are critical to achieve the optimum voltage profile while minimizing network losses and maximizing line flows. In some cases coordinated control of the OLTC transformer, pole-mounted capacitors and any distributed generators in the network may provide enhanced optimization of different parameters.

5.17 Demand Side Integration (DSI)

Demand-Side Integration (DSI) is a set of measures to use loads and local generation to support network operation/management and improve the quality of power supply. DSI can help defer investment in new infrastructure by reducing system peak demand. In practice, the potential of DSI depends on: availability and timing of information provided to consumers, the duration and timing of their demand response, performance of the ICT infrastructure, metering, automation of end-use equipment and pricing/contracts.

The overall technical area of the efficient and effective use of electricity in support of the power system and customer needs is discussed under DSI. DSI covers all activities focused on advanced end-use efficiency and effective electricity utilization, including demand response and energy efficiency.

5.17.1 Demand Response (DR)

Due to the variability of supply and demand, meeting consumer power demands using available generation resources can be a challenging task. Demand response (DR) refers to management of increased demand by reduction in demand and/or increase in power supplied to the grid.

5.17.2 Services provided by DSI

Demand-side resources such as flexible loads, distributed generation and storage can provide various services to the power system by modifying the load consumption patterns. Such services can include load shifting, valley filling, peak clipping, dynamic energy management, energy efficiency improvement and strategic load growth [49]. Simple daily domestic load profiles are used to illustrate the function of each service, as shown in Figures bellow.

Load shifting, shows in Figure 5.19, is the movement of load between times of day (from on-peak to off-peak) or seasons. In Figure 5.13, a load such as a wet appliance (washing machine) that consumes 1 kW for 2 hours is shifted to off-peak time.

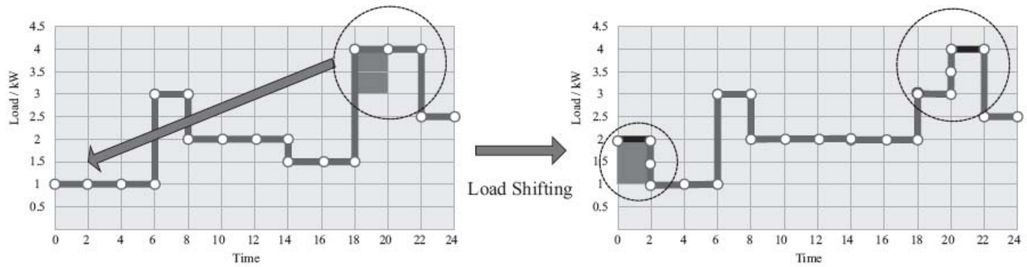


Figure 5.19 Load Shifting

Figure 5.20 shows the main purpose of valley filling, which is to increase off-peak demand through storing energy, for example, in a battery of a plug-in electric vehicle or thermal storage in an electric storage heater. The main difference between valley filling and load shifting is that valley filling introduces new loads to off-peak time periods, but load shifting only shifts loads so the total energy consumption is unchanged.

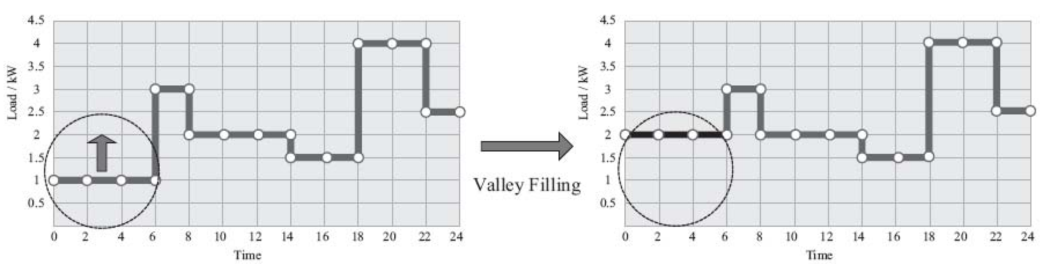


Figure 5.20 Valley Filling

Peak clipping reduces the peak load demand, especially when demand approaches the thermal limits of feeders/transformers, or the supply limits of the whole system. Peak clipping is primarily done through direct load control of domestic appliances, for example, reducing thermostat setting of space heaters or control of electric water heaters or air-conditioning units. As peak clipping reduces the energy consumed by certain loads (in Figure 5.21, 2 kWh of energy is reduced), often consumers have to reduce their comfort.

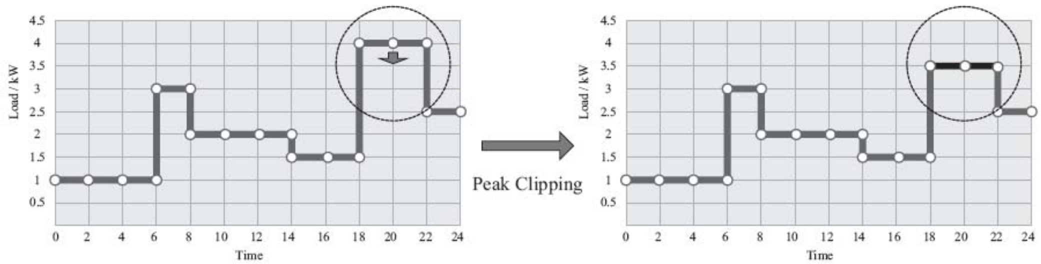


Figure 5.21 Peak Clipping

Energy efficiency programs are intended to reduce the overall use of energy. Approaches include offering incentives to adopt energy-efficient appliances, lighting, and other end-uses; or strategies that encourage more efficient electricity use, for example, the feedback of consumption and cost data to consumers, can lead to a reduction in total energy consumption.

Figure 5.22 shows the reduction in energy demand when ten 60 W filament lamps (operating from 18.00 hrs to 22.00 hrs) are replaced by 20 W Compact fluorescent lamps.

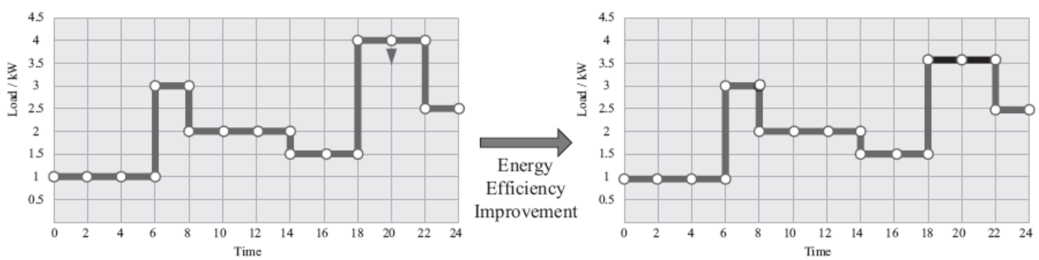


Figure 5.22 Energy Efficiency Improvement

With the deployment of smart metering and the development of home area automaton technologies, domestic appliances can be controlled in a more intelligent way, therefore bringing more flexibility to the demand side. The load shape is then flexible and can be controlled to meet the system needs. However, for the most effective DSI, the utility needs to know not only which loads are installed in the premises but which are in use. In this case two-way communication between the smart meter and network operators is necessary.

Demand-Side Integration describes a set of strategies which can be used in competitive electricity markets to increase the participation of customers in their energy supply. When customers are exposed to market prices, they may respond as described above, for example, by shifting load from the peak to the off-peak period, and/or by reducing their total or peak demand through load control, energy-efficiency measures or by installing distributed generation. Customers are able to sell energy services either in the form of reductions in energy consumption or through local generation.

Traditionally electric power systems were designed assuming that all loads would be met whenever the energy is requested. Domestic customers (and many other loads) use electricity at different times and this allows the design of the power system to benefit from diversity.

Demand-Side Integration has the potential to negate the beneficial effects of diversity. Consider a peak clipping control that sends a signal to switch off one hundred 3 kW water heaters that operate under thermostatic control. Although 100water heaters have been installed, only, say, 20 will be drawing power at any one time. Thus the peak will be reduced by 60 kW. When, after, say, two hours, the water heaters are reconnected, all the water tanks will have cooled and a load of 300 kW will be reconnected. Thus DSI measures must consider both the disconnection of loads but also their reconnection and the payback of the energy that has not been supplied. It is much easier to manage both the disconnection of loads and their reconnection with bi-directional communications whereby the state of the loads can be seen by the control system.

5.17.2 Implementations of DSI

The implementations of DSI can be through price-based schemes or incentive-based schemes [50].

Price-based DSI encourages customer load changes in response to changes in the electricity price.

Incentive-based DSI gives customers load modification incentives that are separate from, or in addition to, their retail electricity rates.

Various DSI programs are deployed and integrated within the power system core activities at different time scales of power system planning and operation, as shown in Figure 5.23.

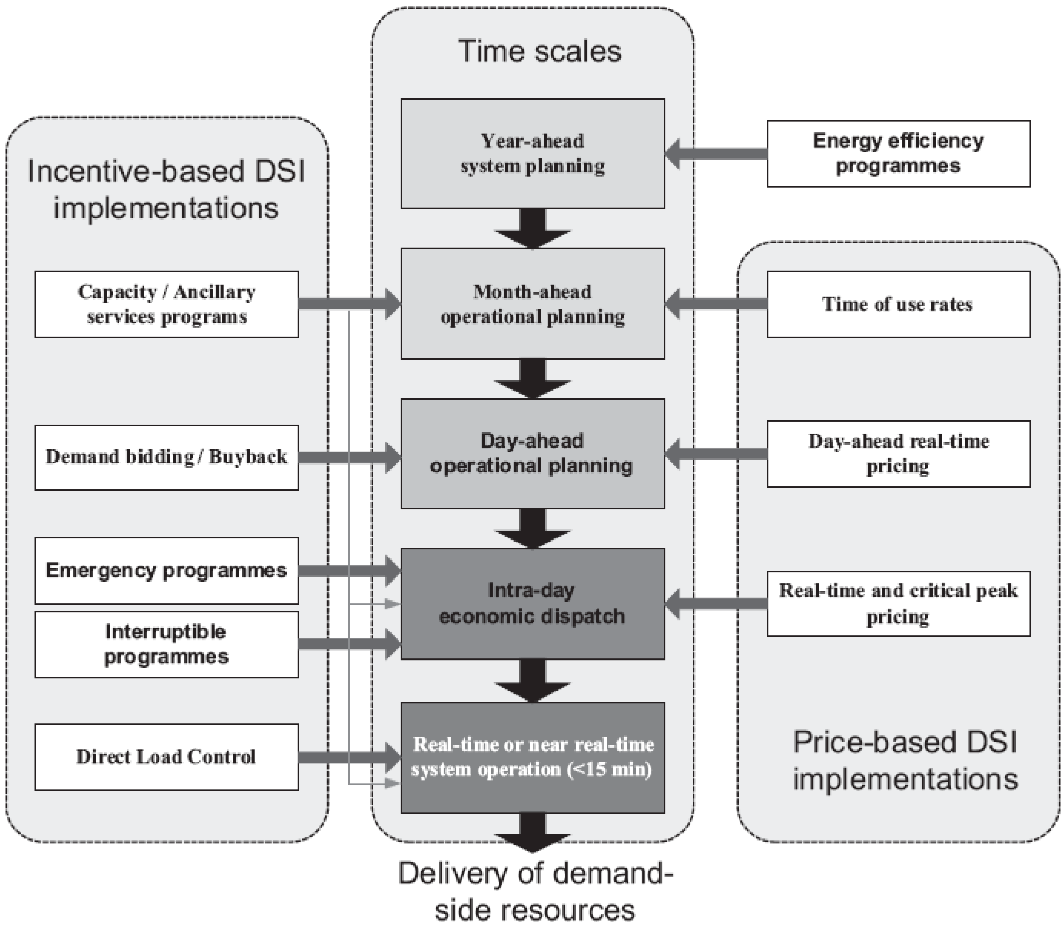


Figure 5.23 Deployment of DSI programs at different time scales

5.17.3.1 Price-based DSI implementations

Tariffs and pricing can be effective mechanisms to influence customer behavior, especially in unbundled electricity markets. Participation in pricing-based program is typically voluntary. For participating consumers, the energy price during peak periods (when the demand is high) is significantly higher than the price during nonpeak periods. Further, the nonpeak price for the participating customers is less than the (flat) price for the consumers not participating in the pricing based programs. The success of this DR method relies on consumer behavior. Note that in all dynamic pricing plans, consumers either know the schedule of higher pricing or are alerted of price increases hours in advance.Price schemes employed include time of use rates, real-time pricing and critical peak pricing:

a) ***Time of use (ToU)*:** ToU, in figure 5.24, rates use different unit prices for different time blocks, usually pre-defined for a 24-hour day. ToU rates reflect the cost of generating and delivering power during different time periods. The higher prices are in effect for a few hours during summer afternoons and, in regions where electric heating is used, during winter mornings and evenings. Peak prices are typically 2–3 times higher than nonpeak prices.

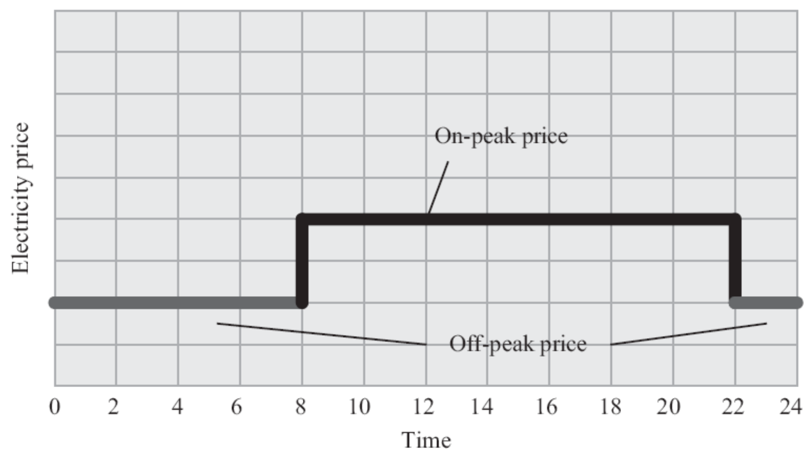


Figure 5.24 Time of use

b) ***Real-time pricing (RTP)*:** The electricity price provided by RTP, in figure 5.25, rates typically fluctuate hourly, reflecting changes in the wholesale electricity price. Customers are normally notified of RTP prices on a day-ahead or hour-ahead basis. The higher RTP prices are in effect for several hours at a time. Peak prices are typically 4–6 times higher than nonpeak prices. Instead of implementing a pricing program, a utility may offer its customers pricing incentives to curtail demand.

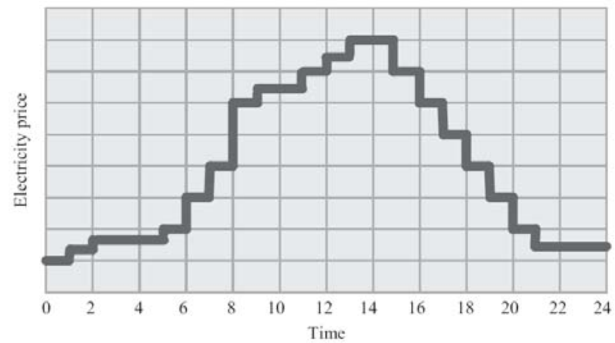


Figure 5.25 Real-time pricing

c) ***Critical peak pricing (CPP)*****:** CPP, in figure 5.26, rates are a hybrid design of the ToU and RTP. The basic rate structure is ToU. However, the normal peak price is replaced by a much higher CPP event price under predefined trigger conditions (for example, when system is suffering from some operational problem or the supply price is very high). Peak prices are typically 4–6 times higher than nonpeak prices. While participation in the CPP pricing can be planned in advance, consumers are informed of the impending CPP period 1 or 2 days in advance, based on weather forecasts.

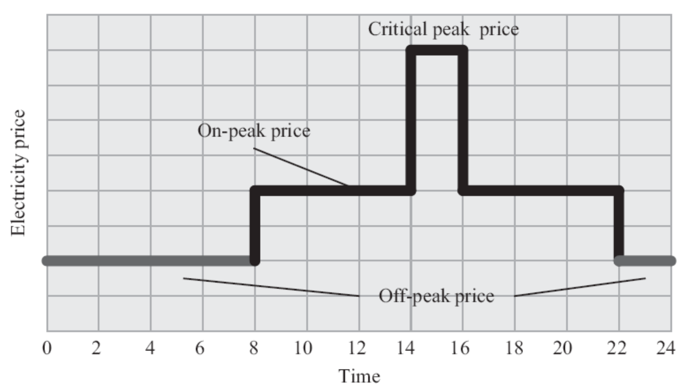


Figure 5.26 Critical peak pricing

5.17.3.2 Incentive-based DSI implementations

Table 5.6 lists various kinds of implementations of incentive-based DSI.

Table 5-3 Implementations of incentive-based DSI

Implementations	Description
Direct load control	Customers' electrical appliances (e.g. air conditioner, water heater, space heating) are controlled remotely (for example, shut down or tuned by the controller) by the program operator on short notice
	Direct load control programs are primarily offered to residential or small commercial customers
Interruptible/curtailable service	Curtailment options integrated into retail tariffs providing a rate discount or bill credit for agreeing to reduce load during system contingencies
	Penalties may be introduced for failing to curtail
	Interruptible programs have traditionally been offered only to the large industrial (or commercial) customers
Demand-side bidding/ Buy-back programs	Customers offer bids for curtailment based on wholesale electricity market prices
	Mainly offered to large customers (for example, one megawatt and over)
	For small customers, third parties (for example, aggregators) are needed to aggregate loads and bid in the market on behalf of

	them
Emergency demand response programs	Provide incentive payments to customers for load reduction during periods when the system is short of reserve
Capacity market programs	Customers offer load curtailment as system capacity to replace conventional generation
	Customers typically receive intra-day notice of curtailment events
	Incentives usually consist of upfront reservation payments, and penalties for customer failure to curtail

5.17.4 Automatic Demand Response (ADR)

When overall demand for energy exceeds supply, a utility may invoke demand response mechanisms. DR decisions are based on direct and indirect demand data from all possible sources. Such sources may include substation SCADA measurements as well as meter readings from individual consumers through the AMI system. If consumer participation is needed with ADR, the utility sends ADR signals to individual consumers. The utility's DR system determines which consumers should be targeted for ADR signals. Note that ADR is a part of the overall DR function; thus, the utility may invoke several different DR programs, including ADR. A logical end-to-end connection for ADR is illustrated in Fig. 5.27.

As discussed before, communications between the DR and consumer EMS may be supported in a variety of ways. Possible networking options to connect the utility DR function (which may be a component of the utility EMS) to consumer EMS include the following:

• Option 1: The utility DR function connects directly to the consumer EMS (such as the HEMS for a residential customer) over a managed IP network or the Internet.

• Option 2: The utility DR function signals through the meter deployed at that consumer location over the Smart Grid network. The meter, in turn, forwards the DR signals to the consumer EMS through HAN or local LAN.

• Option 3: The utility may outsource ADR management to a third-party energy management service. The third party may relay the ADR signals to the consumer EMS (such as the HEMS) over the Internet.

Finally, the consumer EMS must take appropriate action, shutting off or scheduling appliance operations and/or increasing the supply from the local DG. The EMS communicates with these local entities over the HAN or local LAN. Note that the WAN, several FANs, possibly a NAN, possibly an extranet connection (through the Internet), and a HAN are used to achieve these logical connections.

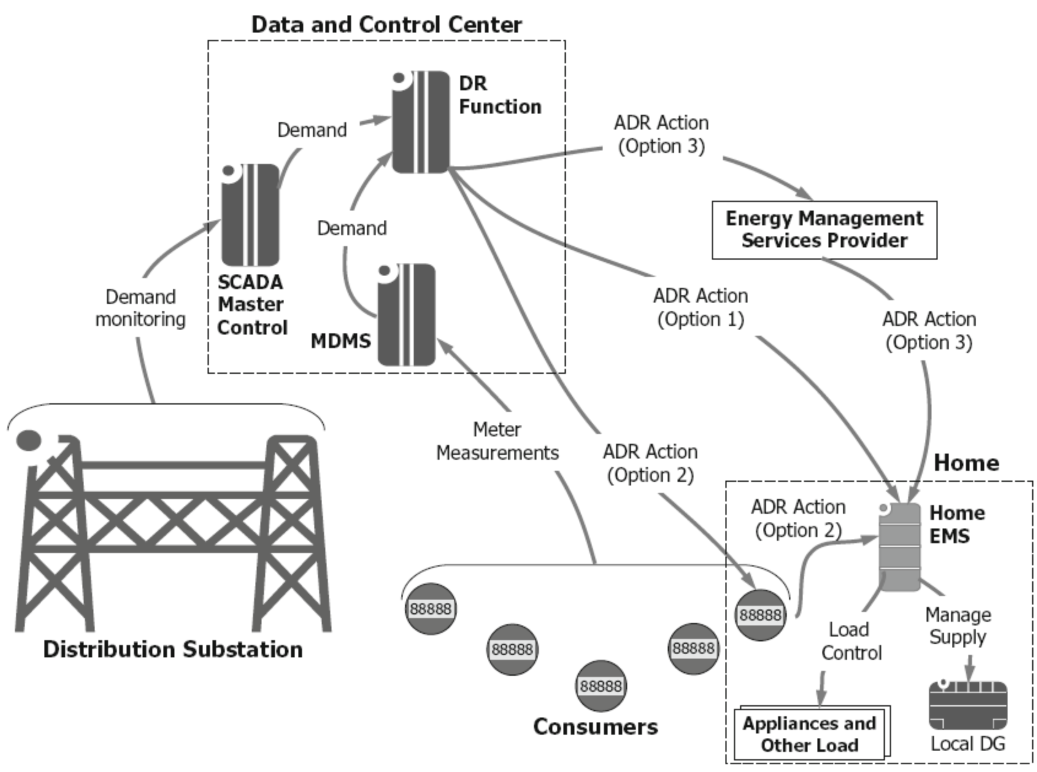


Figure 5-27 Logical end-to-end connection for ADR

5.17.5 Hardware support to DSI implementations

The essential ICT infrastructure required for DSI can be provided by smart metering. In addition, load control switches, controllable thermostats, lighting controls and adjustable speed drives are required. Such equipment receives signals such as alarms or price signals and controls loads accordingly

5.17.5.1 Load control switches

A load control switch is an electronic apparatus which consists of a communication module and a relay. It is wired into the control circuit of an air conditioning system, a water heater or a piece of thermal comfort equipment. The communication module is used to receive control signals from the DSI program operator (or a HAN). The time that the appliance will remain disconnected is generally pre-programmed (through an inbuilt clock).

5.17.5.2 Controllable thermostats

This type of apparatus combines a communication module with a controllable thermostat, and replaces conventional thermostats such as those on air conditioning systems or water heaters. The DSI program operator (or a HAN) can increase or decrease the temperature set point through the communication module, changing the functioning of the equipment and hence the electricity load.

5.17.5.3 Lighting control

Lighting control equipment is used to manage the energy used by lighting in a more efficient way. Lighting control strategies for energy consumption reduction are listed in Table 5.7. Estimated energy savings are presented for each case. These savings are based upon estimated average consumption, the time of use and user behavior.

Table 5-4 Lighting control strategies

Strategy	Description	Estimated energy savings
Planning program	Elimination or reduction of lighting during periods of low occupancy	10–30% with programmers 30–60% with personnel

Natural lighting	Deactivation or dimming of lighting according to the natural lighting in the building	10–17% for deactivation 17–35% for dimming
Constant light levels	Efficient compensation of low levels of natural light	10–17%
Tuning	Tuning the level of lighting according to the needs of the area	10–20%
Load shedding	Temporary lighting reduction to reduce peak demand	—
Light compensation	Modification of the level of lighting for increased visual comfort	—

5.17.5.4 Adjustable speed drives

Adjustable Speed Drives (ASDs) allow electric motors driving pumps, ventilation units and compressors to function over a continuous speed range. The loads of the majority of motorized appliances change over time and equipment is often operated at less than full load. ASDs allow the motors to satisfy the required functioning conditions and to economize power and energy use when the system is not functioning at its maximum load. Directly connected motors for pump and fans are often oversized and the fluid flow throttled for control. Replacement of this system by an ASD can yield considerable saving of energy.

5.18 Volt, VAR, Watt Control in Distribution System

The Volt, VAR, Watt Control (VVWC) function is responsible for ensuring that various electric quantities at different points in the utility grid remain within acceptable operational ranges. This includes regulating voltage (V) values, adjusting the reactive power (VAR) for power factor regulation, and controlling the overall power (W) delivered through the grid using different methods. ect. The VVWC functions are required in both the transmission system and the distribution system.

Transmission and distribution VVWC function may be integrated or independently deployed with close coordination between them. To control power, distribution VVWC functions need to coordinate with demand response. For example, *voltage control* (reducing voltage for the express purposes of reducing demand) associated with DR is related to watt control in VVWC.

A logical end-to-end connection for VVWC function in the utility distribution system is illustrated in Fig. 5.28

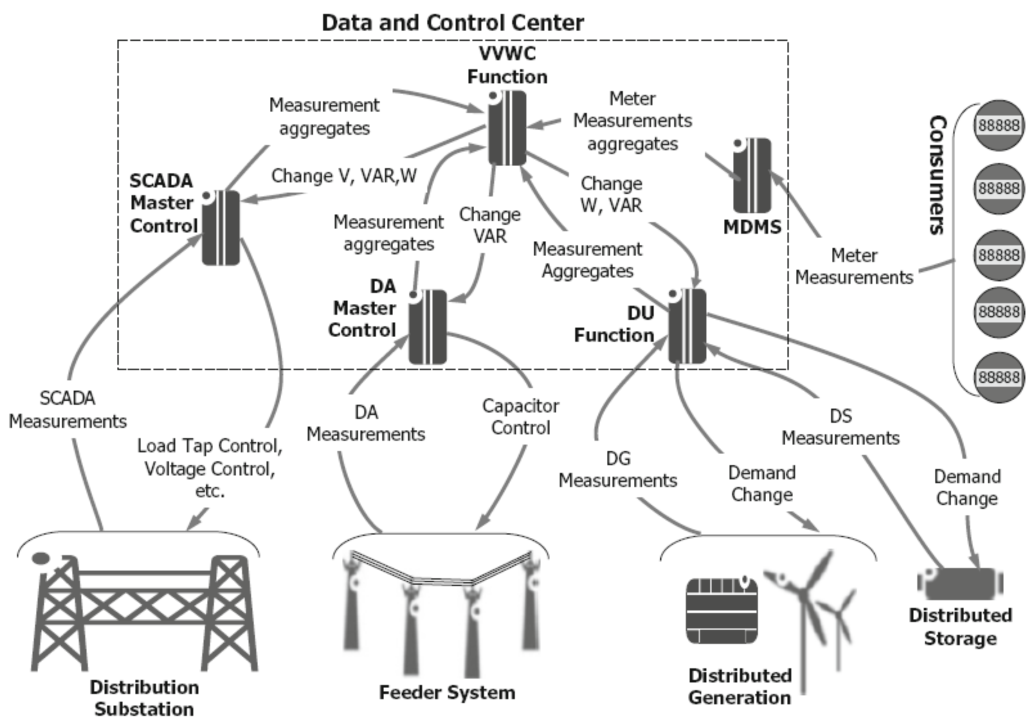


Figure 5.28 Logical end-to-end connection for VVWC in utility distribution system

For efficient VVWC operation, VVWC may collect measurements from a variety of sources including SCADA, DA, DG, DS, and AMI over the respective FAN connections. Relevant summaries or aggregations of these measurements may be derived at the respective management or control systems, or these raw measurements may be forwarded to VVWC function for processing.

The VVWC function, in turn, sends control messages to the monitoring and control systems to regulate voltages, reactive power, and (active) power. Examples include the following:

- The SCADA master control sends control signals to IEDs in the distribution substations, changing tap settings to adjust the bus voltages. If demand or control power needs to be reduced, voltage control signals are sent to the IEDs. If capacitor banks are deployed in the substation for the purpose of making an adjustment to VAR, signals are sent for controlling the capacitors.
- To adjust the capacitors for VAR control, the DA master control sends control signals to the IEDs at the capacitor banks.
- To meet increased demand, the DG and/or the DS function (possibly as a part of the utility EMS) sends control signals to DG and/or DS sources to increase the amount of power injection into the grid. If there is a DG/DS that can provide power at a leading power factor, the DU control function can signal that DG/DS source to connect into the grid for VAR control.

Note that the WAN, several FANs, and possibly NAN(s) are used to achieve these logical connections.

5.19 Transmission Management

We generically use the term Transmission Management System (TMS) to refer to systems that support functions for managing the transmission system, irrespective of whether the TMS is realized as one centralized system or a system distributed over multiple servers. Some of the transmission system applications and functions include the following:

- Supervisory Control and Data Acquisition (SCADA)
- Energy management system (EMS)
- Wide area situational awareness and control (WASA&C)
- Digital Fault Recorder (DFR)
- Flexible AC Transmission System (FACTS)
- Dynamic Line Rating (DLR)

5.20 Flexible AC Transmission System (FACTS)

Transfer of energy over a transmission line from generation to load is a function of the active power delivered to the load. (Recall that the active power is the product of voltage and the component of the current phasor in the direction of the voltage phasor, i.e., VI cosφ where φ is the phase angle between the voltage and the current phasors.). Many load types (such as electric motors) draw reactive power (VAR) for their operation (which is the product of voltage and the component of the current phasor that is at 90° lagging or leading the voltage phasor or VI sinφ). Most real-life loads requiring reactive power have the current phasor lagging the voltage phasor. The net effect is that the total current drawn by the load will need to be more than what is required for energy transfer. Note that reactive power is inherent in the generation, transmission, and distribution systems further increasing the current. Thus, the current passing through the transmission lines is more than that required solely for energy transfer. This increased current not only increases the voltage drop across the transmission line but also increases the power loss (I^2R) through the transmission line. Fluctuations in voltages are one of the main reasons for power system transients.

Reactive power compensation is an important component of transmission systems operation. Since reactive power is mostly lagging, capacitor banks are deployed as a shunt between the transmission line and ground or in series with the transmission line (or both) to provide "leading" reactance to improve the total reactance of the system close to zero. No-load synchronous motors, being able to provide leading reactance without significant power loss, can be used in addition to capacitors.

FACTS has been developed over the last decade to control the reactance of the capacitors (particularly those deployed in series with the transmission line) using semiconductor devices called thyristors. With FACTS, it is possible to dynamically change the capacitor reactance even during transient condition to dampen the level of the voltage and power transients [51].

In addition to reactive power compensation, FACTS provides other functions necessary for improving power flow and control of the transmission system. IEDs deployed at the FACTS (in transmission substations) provide for monitoring and control of the transmission systems from the TMS at the utility DCC. The Smart Grid communication network provides the required connectivity between the FACTS IEDs and the TMS.

5.21 Phasor Measurement Units (PMUs) in Distribution System

Figure 5.29 shows a PMU. It measures 50/60 Hz sinusoidal waveforms of voltages and currents at a high sampling rate, up to 1200 samples per second and with high accuracy. From the voltage and current samples, the magnitudes and phase angles of the voltage and current signals are calculated in the phasor microprocessor of the PMU. As the PMUs use the clock signal of the Global Positioning System (GPS) to provide synchronized phase angle measurements at all their measurement points, the measured phasors are often referred to as synchrophasors [52].

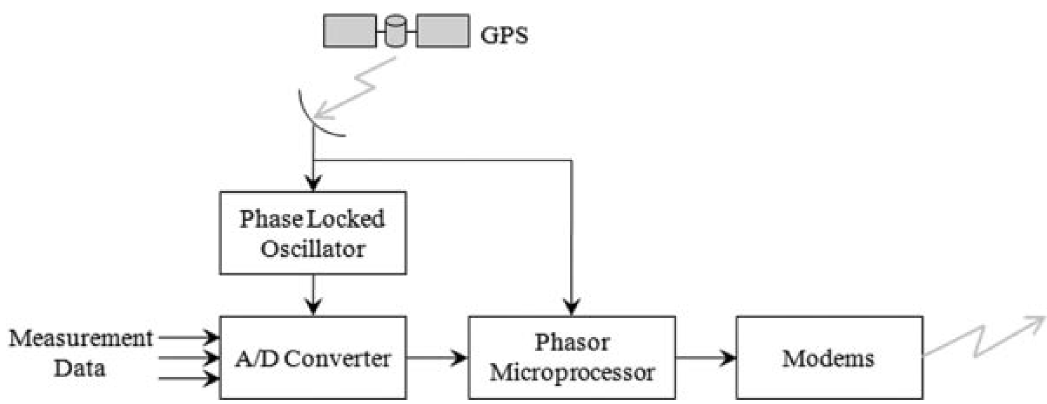


Figure 5.29 Phase Measurement Unit (PMU) device

Synchrophasors measured at different parts of the network are transmitted to a Phasor Data Concentrator (PDC) at a rate of 30–60 samples per second. Each PDC sends the data that is collected to a super PDC where there is Application software for data visualisation, storing the data in a central database and for integration with EMS, SCADA and Wide Area Application systems (Figure 5.30).

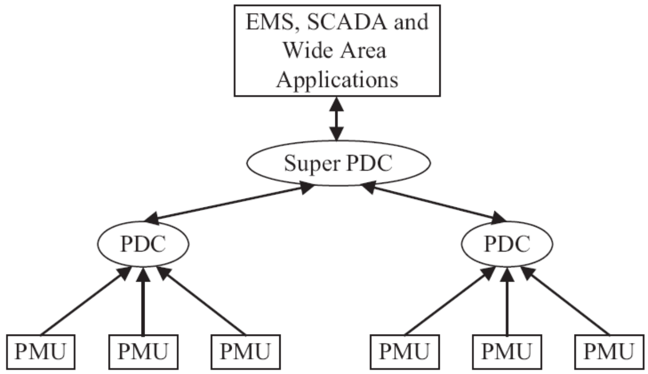


Figure 5.30 an example of a PMU connection

There are many advantages to deploying synchrophasors along feeders including at the DG locations of larger capacity for better state estimation of the distribution system as well as for accurately monitoring power quality (sinusoid at rated voltage and frequency) in the distribution system.

Deployment of PMUs at the feeders has the promise of increasing the distribution system reliability including maintaining power quality at the highest level. That is particularly the case for large-scale DG deployment. [54]

5.22 Dynamic Line Rating (DLR)

Transmission lines are generally rated (such as by the maximum current that it can carry) so that the rating is valid even under the worst possible conditions. For example, ambient temperature is one determining factor for the maximum current that is allowed to flow through a transmission line. As current increases, the power loss (*I2R*) increases; and since this "loss" manifests as heat energy, the transmission line conductor temperature increases with the heat generated. The actual temperature being the function of the ambient temperature, the maximum current rating is set so that the conductor temperature does not exceed the allowed value for the conductor material under the worst possible expected ambient temperature. It is possible for the transmission lines to carry currents exceeding the rating if environmental conditions are better than the worst condition assumed. This is particularly important, since deployments or modifications (such as replacing with better conducting material) of new transmission lines to meet increased power demand are costly propositions.

DLR provides for monitoring of environmental conditions at the transmission lines using IEDs deployed at or close to the transmission towers. These IEDs measure ambient temperature, wind, solar radiation, ice accumulation, and other parameters. For example, during nights and winters or under windy (including the wind direction) or cloudy conditions, ambient temperatures are lower. Thus, the line rating can be allowed to be increased for a period of time. According to, DLR has the potential to provide an additional 10–15 % transmission capacity 95 % of the time and fully 20–25 % more transmission capacity 85 % of the time. [56]

DLR IEDs are also deployed to monitor parameters that help compute the sag (the distance between the imaginary line connecting the endpoints of the transmission line section between two towers and the lowest point of the line on that span between the towers). This helps in monitoring the clearance below the transmission line over the ground for safety, say, for the clearance for a truck passing under the line or for the line touching the trees underneath. Temperature and ice accumulation increase the sag; thus, these measurements help in sag computation. There are new sensors that can actually monitor the tension for more accurate sag measurements.

Because of the large number of IEDs that must be monitored over large areas, wide area wireless networks are the most appropriate choice for communication between the IEDs deployed at the transmission towers and the TMS (possibly with an intermediate data concentration at a substation).

5.23 Short-Circuit Current Limiters (SCCL)

The short circuit current limiter (SCCL) is a technology that can be applied to utility power delivery systems to address the growing problems associated with fault currents. The present utility power delivery infrastructure is approaching its maximum capacity and yet demand continues to grow, leading in turn to increases in generation. The strain to deliver the increased energy demand results in a higher level of fault currents. The power-electronics-based SCCL is designed to work with the present utility system to address this problem. It detects a fault current and acts quickly to insert impedance into the circuit to limit the fault current to a level acceptable for normal operation of the existing protection systems.

The SCCL incorporates advanced Super GTO (Gate Turn-Off thyristor) devices for a higher-performing and more compact system that incorporates the most advanced control, processing, and communication components. This enables it to function as a key part of the Smart Grid.

5.24 Energy management systems

A typical EMS system configuration is shown in Figure 5.31. System status and measurement information are collected by the Remote Terminal Units (RTUs) and sent to the Control Centre through the communication infrastructure. The front-end server in the EMS is responsible for communicating with the RTUs and IEDs. Different EMS Applications reside in different servers and are linked together by the Local Area Network (LAN).

EMS Applications include Unit Commitment, Automatic Generation Control (AGC), and security assessment and control. However, an EMS also includes topological analysis, load forecasting, power flow analysis, and state estimation.

The purpose of Unit Commitment within a traditional power system is to decide how many and which generators should be used and to allocate the sequence of starting and shutting down generators. The inputs to the Unit Commitment Application include past load demand records, generator cost and emission functions, and accurate load forecasts. However, in a number of countries, market-based trading of electrical energy has superseded classical Unit Commitment. Then a number of forward markets operate to determine which generators should run. The system operator only arranges generator dispatch and the balancing of supply and demand during a final period (1 hour before real time).

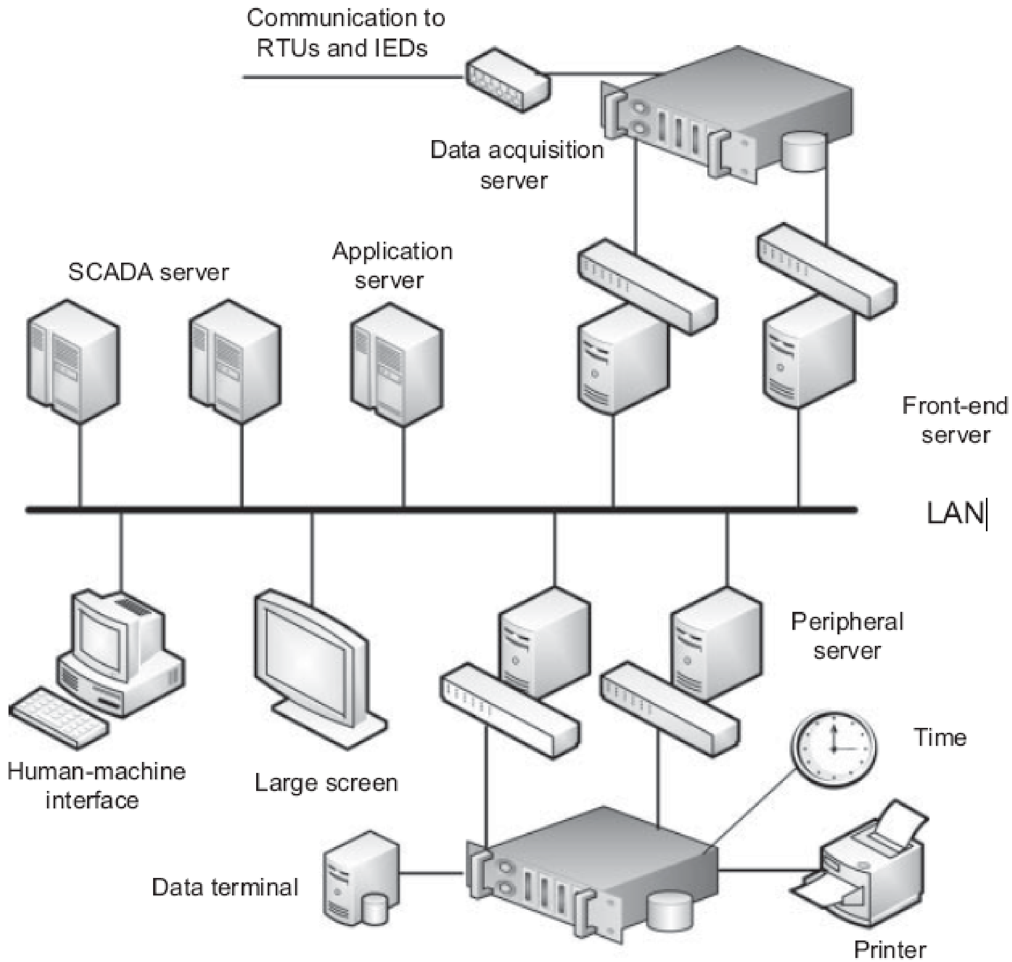


Figure 5.31 A typical EMS system configurations

Similarly, in a power system, AGC carries out load frequency control and economic dispatch. Load frequency control has to achieve three primary objectives to maintain:

- System frequency.
- Power interchanges with neighboring control areas.
- Power allocation between generators at the economic optimum.

AGC also performs functions such as reserve management (maintaining enough reserve in the system) and monitoring/recording of system performance. In a deregulated power system, many of these functions are managed through markets rather than directly by the system operator through an AGC.

Security assessment and control may be understood using the widely used framework proposed by Dy Liacco [55] (Figure 5.32). This Application exercises control to keep the power system in a secure state. The Dy Liacco framework considers the power system as being operated under two types of constraint: load constraints (load demand must be met), and operating constraints (maximum and minimum operating limits together with stability limits should be respected). In the normal state, both these constraints are satisfied.

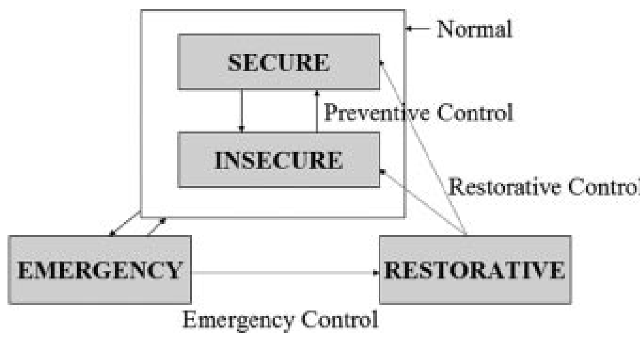


Figure 5.32 The Dy Liacco Framework for security assessment and control

The security assessment and control Application includes; security monitoring, security analysis, preventive control, emergency control, fault diagnosis and restorative control. The tools required include:

- network topology analysis
- external system equivalent modelling
- state estimation
- on-line power flow
- security monitoring (on-line identification of the actual operating condition – secure or insecure)
- Contingency analysis.

When the system is insecure, security analysis informs the operator which contingency is causing insecurity and the nature and severity of the anticipated emergency.

Besides these EMS functions, a training tool, the Dispatcher Training Simulator, is embedded within an EMS. Dispatch Training Simulators were originally created as a generic Application to introduce operators to the electrical and dynamic behaviour of a power system. Today, they model the actual power system being controlled with reasonable fidelity and are integrated within the EMS to provide a realistic environment for operators and dispatchers to practise normal, everyday operating tasks and procedures as well as experiencing emergency operating situations. Various training activities can be practised safely and conveniently with the simulator responding in a manner similar to the actual power system.

5.25 Wide-Area Measurement Systems (WAMS)

Wide-Area Measurement Systems (WAMS) are being installed on many transmission systems to supplement traditional SCADA. They measure the magnitudes and phase angle of busbar voltages as well as current flows through transmission circuits. This information, measured over a wide area, is transmitted to the Control Centre and is used for:

1. *Power system state estimation*: Since the phasor data is synchronized, the magnitudes and phase angles of voltages at all busbars in the grid can be estimated using a state estimation algorithm. These estimates can then be used to predict possible voltage and angle instabilities as well as to estimate system damping and vulnerability to small-signal oscillation.
2. *Power system monitoring and warning*: The phasor data allows the operating conditions of the power system to be monitored on a real-time basis, system stability to be assessed and warnings generated.

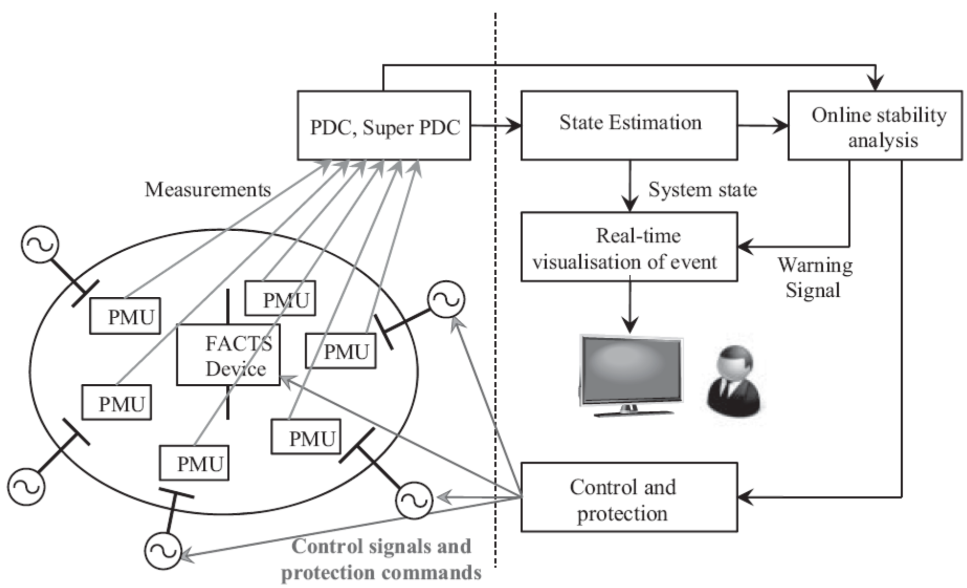


Figure 5.33 Simplified representation of WAMPAC

3. *Power system event analysis*: Synchronized phasor data of high accuracy is available before and after a fault or other network incident. This enables the system operators to study the causes and effects of faults and take countermeasures against subsequent events.

In future, it is anticipated that these Applications will be integrated into a Wide Area Monitoring, Protection and Control (WAMPAC) system [55]. Some examples of possible future WAMPAC schemes include:

1. To initiate actions to correct the system once a voltage, angle or oscillatory instability has been predicted. This may include switching of generators and controlling devices such as the Flexible AC transmission Systems (FACTS), the Power System Stabilizers (PSS) and HVDC converters.
2. To generate emergency control signals to avoid a large-scale blackout (for example, through selective shedding of load or temporary splitting of the network) in the event of a severe fault.
3.

A configuration of the WAMPAC is shown in Figure 8.9. The PMU (or synchrophasor) measurements collected from the different part of the network and state estimation are used for online stability analysis. When an event occurs, its location, time, magnitude (total capacity of generator or transmission lines outage) and type (generator outage or transmission line outage) are first identified. Real-time visualization of the event allows it to be replayed several seconds after it occurs. The future system condition is then analyzed using the information that has been gathered. An on-line stability assessment algorithm continuously assesses the system to check whether the system is still stable and how quickly the system would collapse if it became unstable. If instability is predicted, then the necessary corrective actions to correct the problem or to avert system collapse are taken.

5.25 An Example of Smart grid with possible communication and application

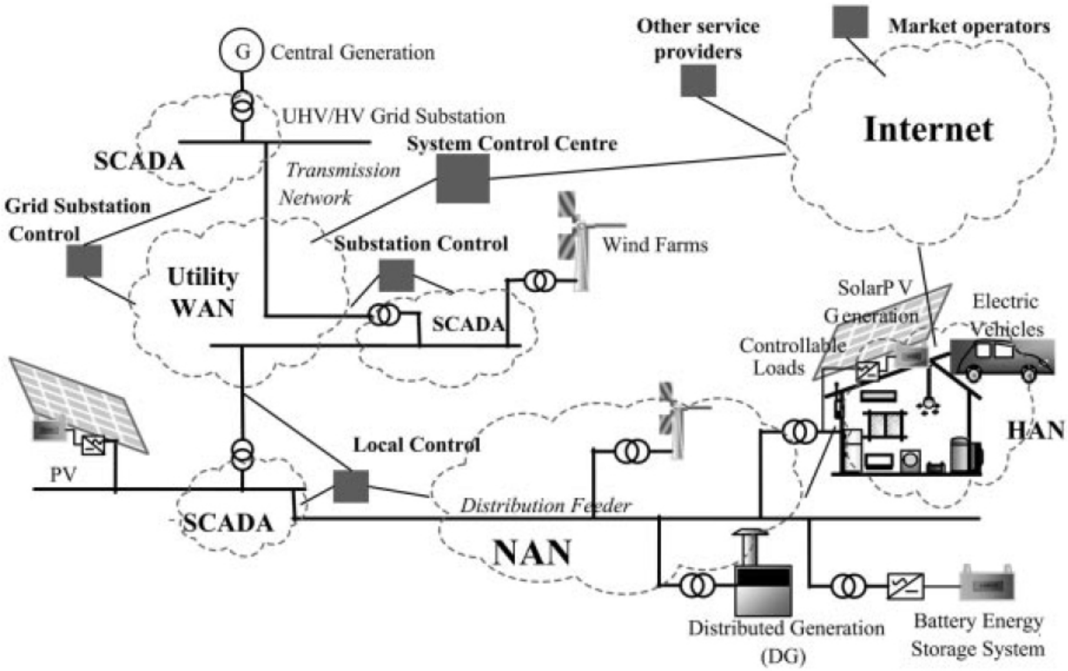


Figure 5.34 An Example of Smart grid with Possible communication and application

Chapter 6

Cyber security

6.1 Network Security:

The Smart Grid network should form a separate security zone from other networks and should support all security measures typical for any enterprise environment such as protection from external networks, including extranet connections to networks of utility partners and the Internet.

Although technology exists today to help utilities meet the enterprise-level security challenges, the complexity and the large number of smart devices required to connect seamlessly and provide the intelligence that makes the grid smarter also make the grid more vulnerable to attacks. According to Lockheed Martin, by 2015, the Smart Grid will offer up to 440 million potential points of attack also known as “attack surfaces” [58]. Additionally, depending on the utility, the Smart Grid network may carry utility business traffic, or there may be a separate utility business data network that must be connected to the Smart Grid network at one or more points to support data transfer between them. Smart Grid applications have very stringent requirements for security, since vulnerabilities can be exploited to destabilize the grid, potentially leading to outages across entire cities or regions. Thus, a security breach can negatively impact the critical requirement of electric service providers, namely, service reliability.

Utilities and regulators are acutely aware that grid modernization cannot move forward without a comprehensive and effective approach to security. The main objectives for grid security are to (1) minimize the attack surface, (2) increase the effort/time required to compromise the network, and (3) decrease the amount of time required to detect and respond a compromise.

The focus of this chapter is the development of a network security architecture. The architecture partitions the Smart Grid network into security zones. Network security elements within each security zone maintain the security requirements specific to individual zones in the presence of network interconnections with other zones.

6.2 Importance of Smart Grid Security

Energy security is a national security issue. Potential attacks may be launched by hostile foreign entities or individuals and the introduction of malware. With the use of communication networks to enable a more efficient transmission and distribution grid, there are growing concerns that the network (and therefore the grid) is becoming more susceptible to cyber attacks. For example, the number of cyber attacks against critical US infrastructure has grown dramatically in the recent years [59]. To address this need, the Smart Grid cyber security market is expected to exhibit huge growth before the end of the decade, climbing from a global value of $7.8 billion in 2011 to $79 billion in 2020 [60].

Examples of Cyber security Attacks on the Grid Critical infrastructure companies, more specifically utilities, are subject of frequent and increasingly aggressive denial-of-service attacks. These attacks are currently focused on the utilities' Internet interfaces. Advanced persistent threat attacks can also be launched by bypassing these Internet interface protections via phishing, etc. For example, Stuxnet bypassed the Internet interfaces. In addition, future cyber attacks could potentially be directed at application interfaces or internal systems using attack vectors such as smart meters, mobile workforce devices (mobile data terminals), or points within wireless FANs. As the Smart Grid rollout continues, there will be a growing number of utilities communicating in complex ways over a mix of public and private networks. Smart Grid evolution is extending communication networks to many DG locations including homes and businesses. With such a large number of FANs, supporting the growing number of endpoints, Smart Grid network protection will be infeasible without wide deployment of security infrastructure.

Telvent, Canada – provider of SCADA software systems to utilities in many countries – recently warned its customers of a breach of its company network that allowed a hacker to bypass its internal firewall, installing malicious software and stealing files related to SCADA control software. In 2007, researchers at the Idaho National Laboratory showed how to access a power plant's control system through the Internet. Running an emulator, the researchers simulated the destruction of a 27-ton power generator by power cycling the generator at very short intervals [61]. Many major cyber security events have already taken place, including Stuxnet, Aurora, RuggedCom, and smart meter hacks [62]. In 2009, there were news reports that the power grid had been penetrated by espionage agents who are suspected of having inserted rogue code in their target. Forty percent of critical infrastructure companies that responded to a McAfee survey reported finding Stuxnet in their systems, with the number increasing to 47 % in the electric sector. [63]

An illustrative example of the evolving threat landscape and the need for defense in depth is the Stuxnet attack: in 2010, the Stuxnet worm targeted SCADA systems used to monitor and control industrial processes. One of the ways the Stuxnet virus spread was by infecting project files in a grid control system made by Siemens. The Stuxnet malware is a graphic illustration of the potential risk of impairment of operations and even of physical destruction of equipment.

Breach of privacy is another major concern in utility networks since they manage customer-related information and other information that may be subject to privacy regulations. This information, if disclosed, could result in punitive penalties or at least damage to the utility’s corporate image. Confidentiality controls for privacyrelevant information are crucial and should apply to information in situ as well as in transit. A detailed consideration of these issues can be found in [64].

6.3 Smart Grid Security Architecture

An overarching principle for designing grid security is the separation of the operational grid network from the general business network in terms of both data sharing and network access. Whether the utility business network is integrated with Smart Grid network or they are two separate networks, separation of business application traffic and grid operations and control application traffic is an important principle. Even within the Smart Grid operations and control network, requirements for security may differ between applications, systems, and/or locations. Further, it may be necessary to isolate traffic subject to one set of security requirements from the traffic with a different set of requirements.

Therefore, the Smart Grid security architecture is divided into multiple security zones. We illustrate this concept with an example including five security zones: Enterprise Zone, Transmission Zone, Distribution SCADA Zone, Distribution Non-SCADA Zone, and the Interconnect Zone. Different levels of protection are required in each of these zones based on the criticality of application data for grid operations.

Since security requirements are based on the criticality of applications, it is generally the case that the security requirements apply across different physical networks and operational domains. (Depending on the utility and its security processes, a different classification is possible.)

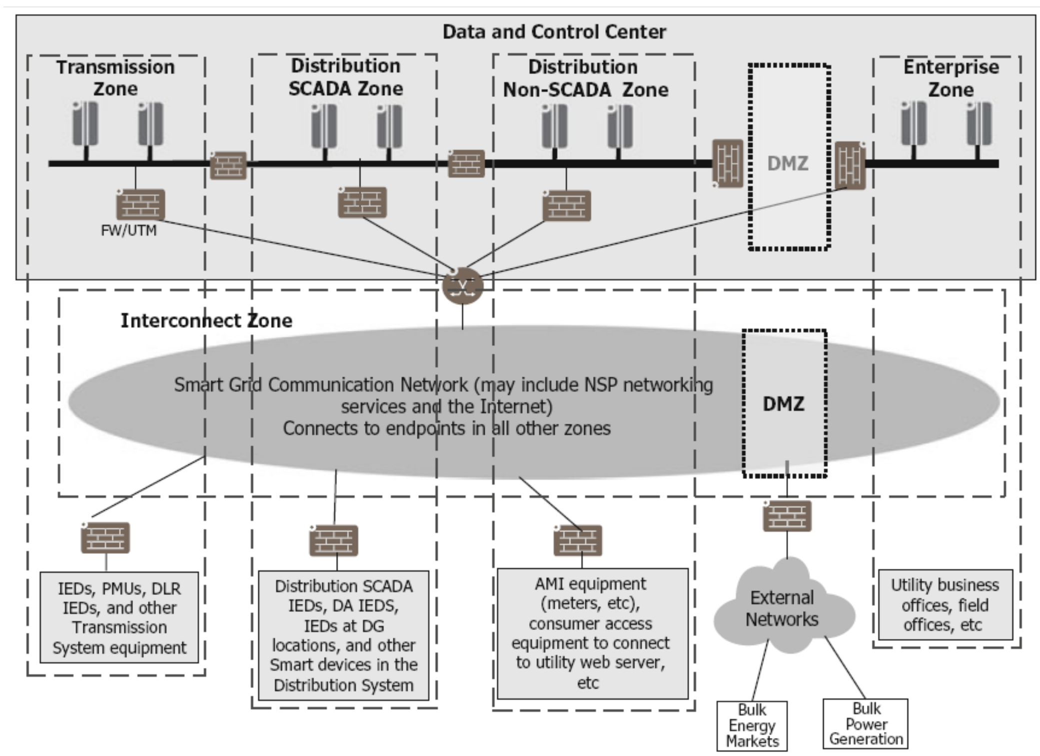


Figure 6.1 Security zones in Smart Grid communication network (an example)

Enterprise Zone The Enterprise Zone is comprised of the business systems, their users, traffic between these systems, and traffic between the systems and users. These business systems include servers and clients used for functions such as human resources, finance, information technology, customer service, billing, internal product development, and procurement. In the case of the integrated Smart Grid network that supports business traffic, the Enterprise Zone includes business traffic. Each business function should have its own security perimeter implemented via appropriate access controls for systems and assets. This security perimeter provides better visibility and accountability to information being transmitted on the enterprise network. It is possible that the business systems need to access operational data. Therefore, the Enterprise Zone is isolated from all of the other operational zones through the use of Demilitarized Zones (DMZs). The DMZ includes systems such as proxy servers to provide access to operational data without the need of directly accessing the operational zones themselves.

There are many different ways to design a network with a DMZ. For the Enterprise Zone, a dual-firewall DMZ is a security best practice. This approach employs two firewalls to create a DMZ: the first firewall is configured to allow traffic destined to the DMZ only, and the second firewall allows only the traffic from the DMZ to the internal network. In this setup, two sets of firewalls need to be compromised in a successful security attack.

Transmission Zone IEDs, PMU, and other transmission substation elements, IEDs deployed at transmission lines (such as DLR IEDs), the TMS systems at the DCC, and communication between all these entities are included in the Transmission Zone. Additionally, communication between the DCC systems and the bulk power generation, energy markets, and other external systems are also a part of the Transmission Zone. Traffic over these external systems must also be afforded the same security implementation as communication between the transmission elements within the utility. Note that extranet communication with bulk generation and markets, and even a utility's internal communication for some Smart Grid networks,may be carried over NSP networks and/or the Internet.

Distribution SCADA Zone SCADA IEDs in distribution substations, IEDs deployed at the feeders for distribution automation (DA), DMS systems at the DCC, and communication between these entities for SCADA and DA are included in Distribution SCADA Zone. Additionally, connections to other smart devices are also included. These smart devices include IEDs at DG locations (including at microgrids and other consumer locations). Increasingly, the Distribution SCADA Zone will be required to support communication for direct load control of consumer appliances such as air conditioners and electric water heaters. As with the Transmission Zone, communication between entities within the Distribution SCADA Zone may be carried over NSP networks and the Internet. For example, use of the Internet may be the only viable option for connecting the smart devices at residential locations to the utility communication network.

Distribution Non-SCADA Zone Distribution Non-SCADA Zone covers the communication aspects of the distribution system that are not critical to grid control. Such communication includes providing customers with data about electricity usage through the AMI infrastructure. Thus, the Distribution Non-SCADA Zone includes AMI devices such as meters, data concentrators, head ends, and the MDMS. A utility may provide web access to its customers for their individual energy management. Such web access (often over the Internet) is also a part of the Distribution Non-SCADA Zone. In addition to network security, user privacy is important to avoid revealing sensitive information, such as whether and when customers are at home, which could be inferred from energy utilization information.

Interconnect Zone The Interconnect Zone includes the interconnecting networks between the entities of different zones. These networks include the Smart Grid network, business network if separate from the Smart Grid network, and connections to external entities. With Smart Grid communication increasingly reaching a large number of devices deployed outside of substations and at consumer locations, the interconnecting communication network must support the necessary security mechanisms that will separate critical and noncritical data. Additionally, the Interconnect Zone also includes mobile workforce communication that needs interconnection with all other zones.

Although we can segment the interconnection network itself into these neatly defined security zones, in a practical implementation, such implementation will not be cost-effective. Many network links, network elements, and even the local area network (such as at the DCC) will need to carry traffic for more than one of these security zones. Fig. 6.1 for an illustration of the security zones defined above and secure separation between these zones. Note that the individual zone boundaries are logical and do not interconnect with each other. All connections carrying traffic between entities of different zones go through the Smart Grid network or the external networks shown, and through the security apparatus necessary for separation between the zones. For completeness, the separation (for security) of utility operations and business data traffic is shown, whether the business network is integrated with the Smart Grid network or it is itself a separate network.

Note that the DMZ may need to be implemented at different locations in the network. Some of the examples of DMZ placement are as follows:

1. ADMZ is placed between the DCC LANs connecting servers supporting the utility operations and control systems such as the TMS, DMS, and MDMS systems and the LAN connecting the data center systems.
2. At the WAN router (WR) locations collocated at the business locations, a DMZ is placed between the WR and the cluster router (CR) at that location.
3. ADMZ is used to separate the Internet connection (usually at the DCC) from the LAN(s) at that location.

Before describing the network security architecture for each of these security zones, we make some basic assumptions about the existence of security safeguards at the device, system, and organizational levels:

1. **Device-level protection:** Due to the large number of devices deployed in the Smart Grid network, isolation and protection between components (such as circuit boards) of these devices are necessary to prevent a failure or compromise in one component from affecting another. We also assume that in the event of an attack, the time and space separation of functions prevent the spread of malware among different systems. If one of the applications is compromised by an intrusion, the others will continue to perform unaffected. The affected partition can be disinfected and rebooted, while other virtual boards continue to run.
2. **System-level protection:** Physical security for grid elements including barriers, locks, access control, and CCTV must be provided.
3. **Organizational level protection:** In addition, for any security solution to be effective, it is critical that policies and mechanisms are enforced at the organization level. For example, the necessary access controls, firewalls, intrusion detection and prevention, cryptography, and anti-malware applications should be actively used, monitored, and managed. Further, personnel-related security considerations and

procedural policies are required, including screening, security awareness, and training.

4. **Incident management:** While risk management and vulnerability management can help reduce the frequency and impact of actual incidents, it is essential that there are procedures in place for managing security incidents when they do occur. Incident management includes detection, analysis, communication, correction, recovery, and retrospective assessment. Roles and responsibilities must be clearly defined and documented. Ideally, there should be an automated system to support incident management including the categorization, classification, communication, and escalation of incidents. In the extreme, an incident may require disaster recovery activities such as migration to a backup site. It is important to test incident management procedures with realistic scenarios.

6.4 Security Zones

6.4.1 Transmission Zone

Transmission substations are a key element of the Transmission Zone. While regulatory standards such as NERC CIP standards address only certain transmission substations (typically above 100 kV), bulk power plants, and DCC(s) supporting these locations, for simplicity and consistency, all substation security implementation should follow the regulatory standards even if formal compliance is not required.

Figure 6.2 illustrates the security architecture for the Transmission Zone as it is applied to the transmission substations and at the DCC location housing TMS servers.

All IEDs, PMUs, and other substation assets requiring communication are included in an ESP at the substations. The utility may choose to implement more than one ESP at a substation for operational purposes and for ease of compliance with regulatory standards. Note that there may be other substation equipment that is not included in an ESP. For example, CCTV cameras in the substation need not reside in an ESP, even if one or more cameras are used for regulatory compliance of the ESP security.

Unified Threat Management (UTM) appliances (also known as next-generation firewalls) combine multiple network security functions (e.g., firewall, DPI, IDS/IPS, encrypted IPSec VPN) into one integrated device, thereby simplifying network operations and management. The UTM manager function (in a security operations server) operates and manages firewall/UTM appliances that are deployed throughout the Transmission SCADA network. The UTM manager is responsible for updating security policies and signatures used by UTM appliances to detect threats to the Transmission SCADA systems as well as manage encrypted (IPSec) VPNs. UTM functions may be implemented in routers; otherwise, separate security appliances with UTM function must be deployed as shown. The (security) monitor is present to facilitate continuous monitoring to detect intrusions or traffic anomalies. The static nature of a SCADA network with its well-defined network flows can be leveraged by the monitor to provide situational awareness by monitoring LAN traffic for anomalous network flows in a nonintrusive manner. In addition to threat management

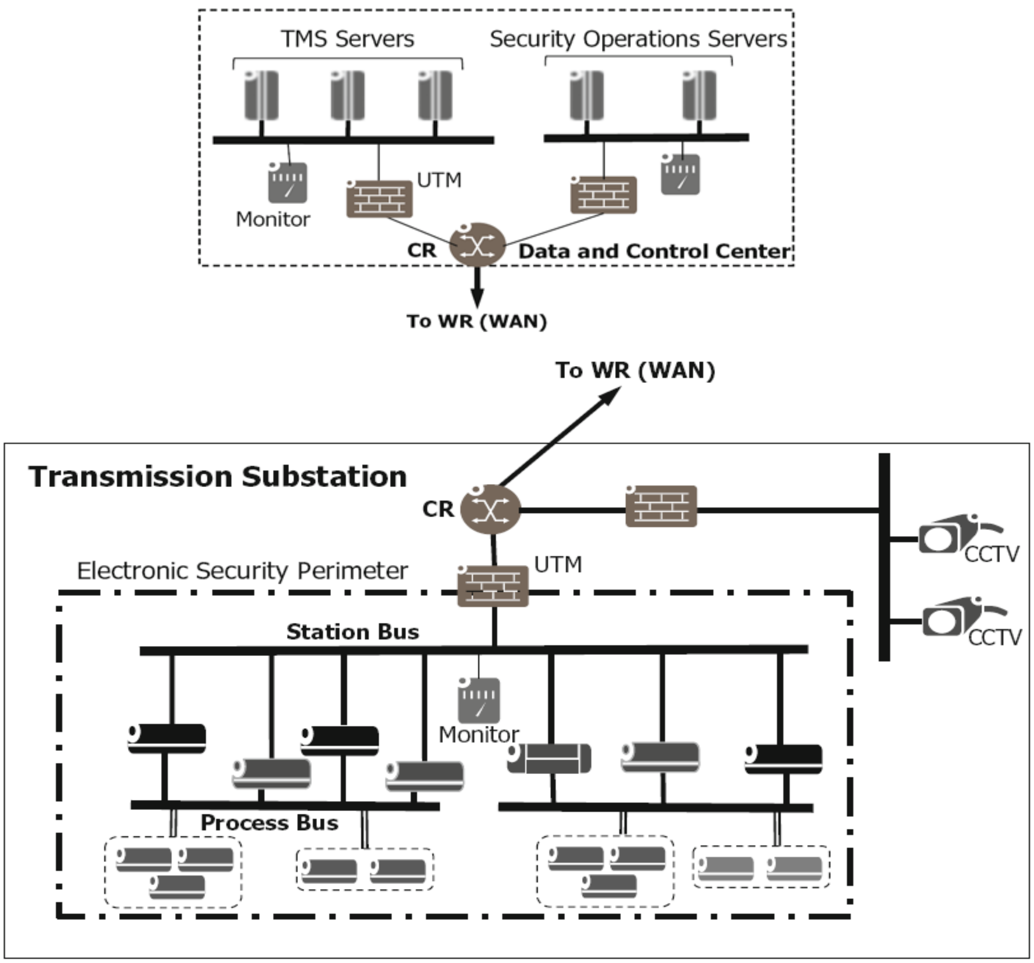


Figure 6.2 Transmission Zone security architecture (in substations) and DCC

and surveillance functions, the DCC includes one or more servers providing other security functions such as authentication.

(Note that we have used the term DCC to denote utility location(s) that houses utility grid management and control functions. Thus, the DCC includes the security operations function, even though the utility may deploy the security and operation servers at a DCC location that is separate from the DCC location housing the TMS function.)

Among these security management functions are maintenance of network and system logs (Syslog), UTM, and key management (used in authentication and encryption). Another required function is Next-Generation Security Information and Event Management (NextGen SIEM) to manage security monitors and to report and log any anomalous network flows observed by these monitors. The NextGen SIEM system provides real-time analysis and correlation of security alerts generated by Transmission SCADA devices and security appliances in order to reduce false positives and to allow security operations personnel to focus on highpriority threats. The NextGen SIEM system employs long-term storage of historical data to facilitate its analysis of data over time and to provide retention of correlation data for regulatory (such as NERC CIP) compliance. The NextGen SIEM can also be used to automatically generate reports required for regulatory compliance. This system also provides two capabilities that are useful for monitoring the security of the Transmission SCADA network. The first capability is the ability to correlate and analyze network flow information along with traditional Syslog information to manage threats. NextGen SIEM systems also include analytics engines that provide network-wide security intelligence to support multiple activities (e.g., threat detection, forensics, compliance) and to provide customized views of data to different people in an organization, depending on their roles.

6.4.2 Distribution SCADA Zone

Distribution management has extended beyond monitoring and controlling substation IEDs to the deployment of the DA IEDs and IEDs used for monitoring and controlling the DG connected to the distribution system. Similarly, in addition to the SCADA master control, DMS functions may include one or more of the functions.

While the trend is to use standards-based protocols such as DNP3 over IP networks, there may be distribution system functions that use proprietary protocols over purpose-built networks. The use of isolated networks eliminates many potential threats: however, it also limits the utility's access to their own information, increases the total cost of ownership, and brings additional data management overhead. Proprietary protocols also are not typically designed for comprehensive secure operations. Further, the distribution system functions may need to share data with applications and authorized users across the utility enterprise. This additional exposure to the enterprise network significantly increases the threat and vulnerabilities to the critical security controls of the distribution system. Some of these vulnerabilities can be effectively addressed via the DMZ between the operational zones and the enterprise zone.

Figure 6.3 shows the schematic of the security architecture for a Distribution SCADA Zone that includes substation and DA IEDs and the DCC with DMS systems.

Note that all DA IED traffic should be encrypted using, for example, IPSec VPNs. While DA traffic is concentrated using a substation-based DA concentrator as shown in Fig. 6.3, DA IEDs may be connected to the DA SCADA master directly over individual wire line or wireless FANs.

While regulatory agencies may not require an ESP at a distribution substation, enclosing the substation IEDs and other equipment in an ESP is recommended. Such an approach ESP will allow secure updates to the SCADA system without threatening the system's operational capacity. There should also be monitoring of transferred data to ensure that security enforcements are being implemented and to limit access only to authorized entities in the operational environment. All SCADA and DA data transfers should support encryption to preserve data integrity and confidentiality of

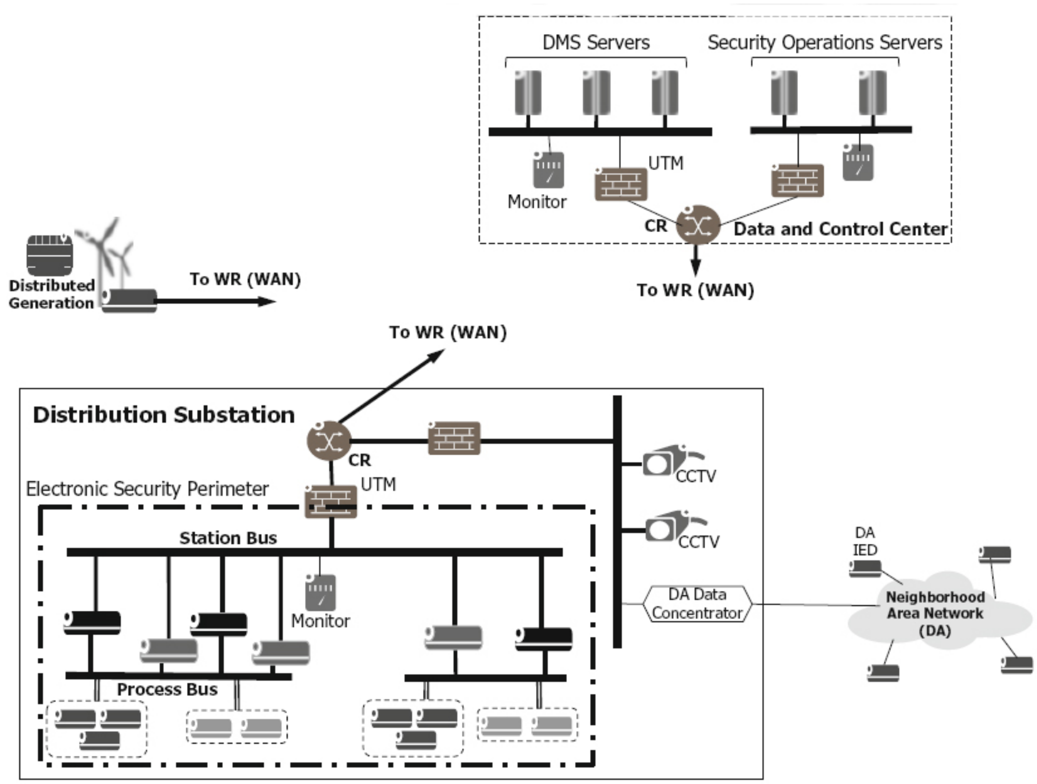


Figure 6.3 Distribution SCADA Zone (Distribution substation, DA, and DCC)

communications between servers and workstations without needing to alter operational procedures. IPSec encryption supports this requirement. Use of Transport Layer Security (TLS) is another option. In addition, the routers and UTM must be configured to screen critical communication ports on servers from external access. To limit the scope of SCADA security requirements, all applications not required for successful operation of the SCADA system should be external to the ESP. Thus, there may be entities (in addition to CCTV) that are outside of the ESP.

DG deployment including microgrids, particularly if connected to the MV distribution system, is also increasingly becoming a key element of the Distribution SCADA Zone. DG sources play a critical role since they can be managed as dispatchable generation sources. Note that IEDs deployed at the DG communicate with corresponding IEDs at the distribution substation, particularly for tele protection.

Since the Distribution SCADA Zone is still in the early phase of deployment, it is crucial that security solutions are scalable and extensible. For example, the system should readily support state-of-the-art antivirus packages and evolving authentication technologies, such as biometrics, persistent smartcards, and access tokens, allowing security administrators to use the most advanced tools available to combat potential new threats.

The security network architecture for this zone, with the use of the UTM functions and (security) monitors, is similar to that of the Transmission SCADA Zone in Fig. 6.2. The DCC function for security management (such as inclusion of NextGen SIEM and the UTM manager) is similar to the one for the Transmission SCADA Zone.

7.4.3 Distribution Non-SCADA Zone

The dominant non-SCADA application in the distribution network is AMI. In this section, we present AMI as a typical non-SCADA application; general requirements apply to many other distribution applications such as EV charging and retail energy markets.

Threats to AMI range in severity from power theft by a few consumers to network intrusion by foreign entities. Insider security attacks by individuals for financial gain are also not uncommon. Power theft is a relatively low-level threat. If unaddressed, however, power theft could leave the system vulnerable to attacks with greater impact on the grid. The primary vector for this type of an attack is physical access to the meters themselves. It may also involve using the network to modify meter firmware. Although AMI is not itself considered critical infrastructure, the data obtained from the AMI network may be used to control load. Thus, a cyber attack that tampers with AMI data could potentially impact grid operation. A more thorough threat analysis for the AMI network can be found in [65].

Drawing on parallels with AMI, the security vulnerabilities on the Distribution Non-SCADA Zone maybe classified based on the attack vector:

1. Device attack vector: Smart meters are physically accessible to many and therefore susceptible to several attacks that tamper with the device or the data they generate. It is also possible to launch configuration attacks through communication interfaces to the customer's appliance control equipment. One potential example is the reverse engineering attack on meters. A potential impact of this attack could be that AMI meters at consumer locations would underreport electric usage. Other impacts could include underreporting of ancillary services such as natural gas usage (if gas meters report through the electric smart meters) or failure to report correct status or outage information.

2. Network attack vector: Vulnerabilities in the AMI network could be used to launch denial-of-service attacks whereby the attacker could flood communications within the AMI network. The resulting bandwidth shortage would affect any utility communications using the same media. In particular, meters could have difficulty communicating status and usage information as well as receiving pricing information. The AMI network, along with the trust relationships between the various systems involved, and the commodity hardware and software that these systems use could also be leveraged to launch large-scale attacks on the grid itself. This could impact the entire power grid since the overall AMI system may provide connectivity from the balancing authority or regulating agencies (such as the ISO/RTU in the United States and Canada) all the way to individual meters at residential and small business customer locations.

3. Insider attack vector: Insiders with physical access to the systems involved or administrator access to either systems or networks such as the AMI headend system, the EMS, or the network infrastructure supporting these systems could perform attacks at either the computer or network level. The insider could potentially modify software or settings on any systems such that critical information is changed as it flows through that system.

We now present a security solution in the Distribution Non-SCADA Zone that implements the following security features:

1. In most cases, real-time monitoring of consumption can quickly detect many low-level attacks on meters. AMI solution vendors and utilities can mount an effective defense against rogue AMI devices by using a data transmission standard for AMI data and investigating abnormal usage patterns. This will

require encouraging AMI vendors to move from proprietary systems to an industry standards such as OpenAMI and to incorporate security requirements to the standard. One mitigation strategy for the consumer attack vector is to detect and investigate anomalies in power use. Such investigation involves checking configuration and firmware of the meters of suspected consumers. This can be automated at minimal expense to the utility while maximizing the likelihood that unauthorized modifications are detected. Cross-check mechanisms can also be implemented to detect and correct corrupted information before grid operations are impacted. Further, correlation of AMI data with SCADA meter data will allow for the detection of meter-level attacks that tamper with monitored data.

2. To address the insider threat, utilities need to exercise due diligence to show that insiders are not cooperating with other players in the energy sector. In addition, all communications from the head end to the customer endpoint should be treated as control traffic. As such, authentication of commands should be put in place. Good authentication processes will prevent person-in-the-middle and spoofing attacks by insiders with access to the AMI network. While head end systems are clearly not critical cyber assets in the sense of regulatory standards, the utility may want to treat them as such and implement personnel and system security management. Measures such as background checks and auditing will deter insiders who attack through physical access to AMI or related systems. Host-based intrusion detection with software integrity checking of the head end systems will detect changes to these systems by insiders. Utilities should conduct frequent, irregular audits of head end output. All user commands and actions in the head end systems should be repudiable, which will require logging and strong user authentication.

3. System maintenance tasks such as the application of system patches to address newly disclosed vulnerabilities must be completed in a timely manner. Standard exploits to well-known vulnerabilities will be openly available, making it easy for even unsophisticated hackers to exploit them. In addition, sophisticated adversaries may be able to exploit vulnerabilities that are not yet disclosed and for which no patch exists – so-called zero-day exploits. To

address zero-day exploits, it is important to have robust incident recovery mechanisms.

4. Since the AMI communication network will frequently share some or all communication links with other utility communication networks, there is a potential for attacks that take advantage of poor separation of communication channels. Bypassing such separation could impact the ability of TMS systems to communicate with bulk generation, resulting in possible attacks on the bulk electric grid. This attack depends on AMI connectivity. There are several AMI solution technologies, and vulnerability of an AMI network depends heavily upon the vulnerabilities in the communication technologies used.

5. Terrorist and nation-state threats are mitigated by all of the above measures because they make the target more difficult to compromise. Additional effective approaches to protecting against this threat are router access lists, firewalls, protected communication between the AMI network and other networks, strong communication authentication, and detection and halting of rapid market fluctuations.

6.4.4 Interconnect Zone

The Interconnect Zone that carries traffic for different operational functions must be logically separated based on the most stringent security requirements for the particular application. This logical separation can be achieved with MPLS services. Logical separation is more cost-efficient than physical separation, because it streamlines capital costs by avoiding multiple instances of physical devices and reduces associated operational costs. Using MPLS services at L1, L2, and IP layer (VPRNs), secure traffic isolation can be achieved, preventing attacks between MPLS services or from an MPLS service to the MPLS control plane. Networking products with MPLS services support will generally also provide device security (physical and logical access control) including security at administration and management interfaces. Note that MPLS services do not provide native data encryption. Therefore, it is necessary that the traffic be encrypted at higher layers (e.g., using IP or TLS).

6.4.5 Additional Security-Related Operations

Despite implementation of security architectures and security measures, it is inevitable that information and communication systems will have vulnerabilities. Often these are unknown (i.e., “zero-day”) vulnerabilities that have not yet been identified by vendors or utilities but that may have been discovered by malicious agents and may be actively used in zero-day attacks. Often vulnerabilities are known but have not yet been remediated. For example, patches may not be available or not yet deployed due to operational reasons (downtime, cost, risk of failure, etc.). The risks associated could be addressed via secure development and procurement of software and hardware and hardened configurations of systems, applications, and services. This includes disabling all unused components, ports, and services. It also can include enabling any optional security-pertinent features (e.g., encryption, logging) and configuring restricted access controls. Assets should be subjected to periodic vulnerability scanning using vulnerability scanning tools (e.g., Nessus). Vulnerability scanning has been known to cause operational systems to crash; therefore, scanning must be performed during a maintenance window. Log analysis and the security monitors mentioned previously can passively fingerprint OS versions, patch levels, and the extent of hardening performed on the system. Tools specific to functionality or protocols (e.g., SCADA) can also be used where appropriate. Often security vulnerability can be removed by a software patch, when the correction becomes available. However, patching of operational systems can be complex and risky. It is important to have a thorough inventory of systems to be patched, along with up-to-date versioning information. Patches must be tested before deployment. Patches must be deployed quickly and consistently and with a minimum downtime (ideally no downtime). Crucially, it must be possible to reverse a patch and return a system to the previous operational version should a problem arise. A patch management system can help with the complexity of this management task.

6.5 Cyber security standards

There are several standards which apply to the security of substation equipment and many are under development. For overall security assessment, the standard ISO 27001 is widely used and specifies the assessment of risks for a system of any sort and the strategy for developing the security system to mitigate those risks.

Furthermore, ISO 28000 specifies security management specifically for a supply chain system.

4.5.1 IEEE 1686: IEEE Standard for substation intelligent electronic devices (IEDs) cyber security capabilities

This standard originated from an IED security effort of the NERC CIP (North America Electric Reliability Corporation – Critical Infrastructure Protection). The standard is applicable to any IED where the user requires "security, accountability, and auditability in the configuration and maintenance of the IED".

The standard proposes different mechanisms to protect IEDs. The IED shall:

- be protected by unique user ID and password combinations. The password should be a minimum of 8 characters with at least one upper and lower cases, one number and one alpha-numeric character.
- not have any means to defeat or circumvent the user created ID/password. The mechanisms such as "embedded master password, chip-embedded diagnostic routines that automatically run in the event of hardware or software failures, hardware bypass of passwords such as jumpers and switch settings" shall not be present.
- support different level of utilization of IED functions and features based on individual user-created ID/password combinations.
- "have a time-out feature that automatically logs out a user.
- record in a sequential circular buffer (first in, first out) an audit trail listing events in the order in which they occur.
- monitor security-related activity and make the information available through a real-time communication protocol for transmission to SCADA."

4.5.2 IEC 62351: Power systems management and associated information exchange – data and communications security

IEC 62351 is a series of documents which specifies the types of security measures for communication networks and systems including profiles such as TCP/IP, Manufacturing Message Specification (MMS) and IEC 61850. Some security measures included in the standard are:

- authentication to minimise the threat of attacks, some types of bypassing control, carelessness and disgruntled employee actions;
- authentication of entities through digital signatures;
- confidentiality of authentication keys and messages via encryption;
- tamper detection;
- prevention of playback and spoofing;
- monitoring of the communications infrastructure itself

Chapter 7

Implementation of Smart Grid in Bangladesh

7.1 Introduction:

The phrase 'Digital Bangladesh' implies government's commitment to rapidly deploy computer and Information Technology (IT) across Bangladesh to improve efficiency of the service providing authorities. This concept can be extended to include use of digital technologies to transform the present dilapidated electricity distribution network of Bangladesh into a 'smart electrical grid'. Smart grid can prevent electricity outages and 'black-outs' that occur several times a day, causing work interruptions and economic losses to the nation. Smart digitally radio controlled grid enables step-by-step gradual load addition and removal. Under automatic remote digital radio and computer control, no section of the network will get overloaded and get protected from electrical damage by preventing excessive current flow. Such network operation automation through use of digital radio control of the Bangladesh electric grid will ensure stable power supply nationwide.

“Smart Grid” is a modern concept which refers to the conversion of the mainstream or typical electric power grid to a modern power grid. This new conversion is a foreseeable solution to the power system problems of the modern century. Rejuvenation of the current electric power distribution system is an important step to implement the Smart Grid technology. So, distribution system engineers should be acquainted with the knowledge of Smart Distribution System. Also the customers should acknowledge the benefits that they will be enjoying from this modernized power system. This paper gives a brief detail of Smart Grid. The focus of this paper is to familiarize with Smart Grid perspective to Bangladesh where the power system is very detailed, complex and quite aged. The distribution system loss is high and the customers face daily planned load shedding. To address the power crisis and other problems, the conventional distribution system should be restructured to smart distribution system which is a part of Smart Grid. Though it is a very new and expensive concept, yet Bangladesh Government has showed positive approach. The main objective of this paper is to discuss the Smart Power Generation, Transmission and Distribution System, its importance in Bangladesh power system and the progress & prospects. On the other hand, the scarcity of energy in Bangladesh is anticipated to endure for the next 50 years; as electricity demand is increasing every year surpassing generation capacity and distribution capabilities. New power stations cannot be built hastily enough. Moreover, there is lack of fuel energy in Bangladesh and power stations need wide amount of fuel every hour. This insufficiency of fuel will continue unless the nuclear power station becomes operational. When the neighbors have advanced much, Bangladesh is still at the elementary level in developing a smart grid. The country has only one national load dispatch center and a distribution load dispatch center, which is not working properly. Some pre-paid meters have been distributed under a pilot project. Bangladesh can get cooperation from amiable developed countries on smart grid. But initiatives have to be taken by the government and from the top level.

7.2 Present scenario of power sector of Bangladesh.

Bangladesh is a developing country. Its population is around 152 million in a land area of 1,47,570 sq km. The country has achieved worthy growth in recent years. A booming economic growth, rapid urbanization and continuing industrialization and development have increased the country's demand for electricity. Presently about 60% of the total population has access to electricity including renewable energy. Per capita power generation of 292 Kwh thru 8537 MW installed capacity.

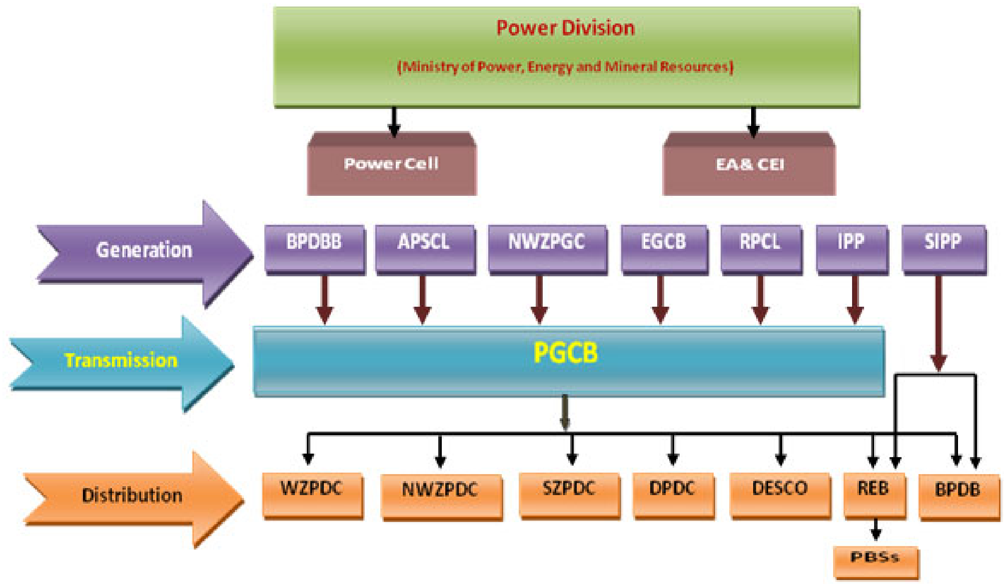
Present government has all along prioritized the power sector as a priority development sector. In this regard the government has set the vision to provide access to affordable and reliable electricity to all by the year 2021. The government is further focusing into its vision targeting the upcoming years up to 2030 and prepared the power sector master plan (PSMP) at 2010 This plan states that in 2030, the demand of power would be around 34,000 MW while the generation capacity is yet nearly 8500 MW which implies that endeavor is required to achieve the goal. Considering the country's future energy security, the government has given due importance on renewable energy, energy efficiency as well as energy conservation. [66]

Government's vision for power sector:

Vision 2021 : To provide access to affordable and reliable electricity to all

Vision 2030 : To delivery stable and high quality electricity to the people.

Fuel Vision 2030 : To establish the power system portfolio by fuel diversification



7.2.1 Generation of power in Bangladesh:

Bangladesh has small reserves of oil and coal, but potentially very large natural gas resources. Commercial energy consumption is around 71% natural gas, with the remainder almost entirely oil (plus limited amounts of hydropower and coal). Only around 18% of the population (25% in urban areas and 10% in rural areas) has access to electricity, and per capita commercial energy consumption is among the lowest in the world. Noncommercial energy sources, such as wood, animal wastes, and crop residues, are estimated to account for over half of the country's energy consumption. Consumption of wood for fuel has contributed to deforestation and other environmental problems in Bangladesh.

Bangladesh's installed electric generating capacity in 2000 was 3.8 gigawatts (GW), of which 94% was thermal (mainly natural-gas-fired), and the remainder hydroelectric, at 18 power stations. With only around 18% of the population connected to the electricity grid, and with power demand growing rapidly (10% annually from 1974-1994; 7% annually from 1995-1997), Bangladesh's Power System Master Plan (PSMP) projects a required doubling of electric generating capacity by 2010.

The Padma-Jamuna-Meghna river system divides Bangladesh into two zones, East and West. The East contains nearly all of the country's electric generating capacity, while the West, with almost no natural resources, must import power from the East. Electricity interconnection from the East to the West was accomplished in 1982 by a new, 230-kilovolt (kV) power transmission line. The vast majority of Bangladesh's electricity consumption takes place in the East, with the entire region west of the Jamuna River accounting for only 22% of the total. Greater Dhaka alone consumes around half of Bangladeshi electricity.

Discussions have been underway for several years about the possibility of Bangladesh connection its electric grid to those of India, Nepal, and Bhutan. Nepal and Bhutan have substantial untapped hydroelectricity potential. This power could be consumed in those two countries and also exported to India, Pakistan, and Bangladesh. In March 1999, it was reported that India's Power Grid Corporation had completed a feasibility study on possible exchange of 150 MW of power between Bangladesh and India. Interconnection points would be Ishwardi, Bangladesh-Farakka, India and Shahjibazar, Bangladesh-Kurnarghat, India. [67]

7.2.2 Distribution:

The PGCB supplies electricity to the distribution entities, which include: the Rural Electrification Board (REB), the BPDB, the Dhaka Power Distribution Company (DPDC), the Dhaka Electricity Supply Company (DESCO) and the West Zone Power Distribution Company (WZPDC). The table below presents the number of distribution lines and the capacity of substations by each of the distribution entities. DPDC and DESCO distribute electricity within the nation’s capital, Dhaka, they receive 42 percent of the electricity from the PGCB. REB provides electricity to the rural areas of Bangladesh and receives the most i.e. 40 percent of the transmitted electricity.

WZPDC covers the West Zone of Bangladesh and receives 6 percent of electricity. BPDB receives 23 percent of electricity and also distributes electricity to many rural areas and parts of the country that are not covered by the other companies. The market share of electricity of the distribution companies is illustrated in the following figure.

7.2.3 Transmission:

Power Grid Company of Bangladesh Ltd. (PGCB) is responsible for operation, maintenance and development of transmission system all over the country. Presently power generated in various power plants in Bangladesh is transmitted to the national grid through 230 kV and 132 kV transmission lines. In 1996 when PGCB was formed, the total lengths of 230 kV and 132 kV line was 8,500 ckt km. In June, 2013 length of 230 kV and 132 kV transmission lines stood at 9,250 ckt km. The total length of the OPGW installed in the transmission line from 1996 to June, 2007 was 2200 km. This has been increased to 4300 km up to June, 2013 after completing the NLDC project. This shows that the major parts of the country are covered by the PGCB optical fiber network. [68]

The PGCB took over about 1144 circuit km of 230 kV lines, 5255 circuit km of 132 kV lines, 6 nos of 230/132 kV substation and 63 nos of 132/33 kV substations from BPDB and DESA in different phases. Transmission lines of the company up to July, 2014 are stood at 164.70 ckt km of 400 kV lines, 3066 circuit km of 230 kV lines, 6125 circuit km of 132 kV lines and 1 nos of 400 kV substations, 18nos of 230/132 kV substation and 88 nos of 132/33 kV substations. The company has taken infrastructure development projects for further development of its operation. After successful completion of the projects the capacity of PGCB transmission network will enhance significantly.

7.2.4 Demand vs. Generation:

The average maximum demand for electricity was 3970 MW in 2007 which has increased to 4833 MW in 2011 (May, 2011) with an average increasing rate of 216 MW per annum. Under the business as usual scenario, the average demand might stand at 5696 MW by 2015. On the other hand, the average generation was 3378 MW in 2007 which has increased to 4103 MW in 2011 (May, 2011) with an annual average increasing rate of 181 MW. Continuation of this rate indicates that the average generation would be 4828 MW by 2015 which is far away from the vision of 11500 MW generations by 2015. Additionally, the average load shedding has been increased to 656 MW in 2011 (May, 2011) with an average increasing rate of 35 MW per year from 2007. If this increasing rate remains the same, the average load shedding might be stood at 795 MW by 2015. The lower increasing rate of generation (5.37 percent) than that of the demand (5.43 percent) has accelerated the rate of load shedding which has increased at a rate of 6.72 percent per annum during the same period.

The real demand for electricity could not be met due to the shortage of available generation capacity. A good number of generation units have become very old and have been operating at a much-reduced capacity. As a result, their reliability and productivity are also poor. Beside this, due to the shortage of gas supply, some power plants are unable to utilize their usual generation capacity. Therefore, there is an increase in the load-shedding over the years. The average maximum demand for electricity was 3970 MW in 2007 which has increased to 4833 MW in 2011 (May, 2011) with an average increasing rate of 216 MW per annum. Under the business as usual scenario, the average demand might stand at 5696 MW by 2015. On the other hand, the average generation was 3378 MW in 2007 which has increased to 4103 MW in 2011 (May, 2011) with an annual average increasing rate of 181 MW. Continuation of this rate indicates that the average generation would be 4828 MW by 2015, which is far away from the vision of 11500 MW generations by 2015. This increased demand over generation has resulted in increased load shedding (Figure 2). Additionally, the average load shedding has increased to 656 MW in 2011 (May, 2011) with an average increasing rate of 35 MW per year starting from 2007. If this increasing rate remains the same, the average load shedding might be stood at 795 MW by 2015 (Figure 2).

It is also observed that the demand for electricity has been increased with a rate of 5.43 percent per year whereas, the generation of electricity has been increased with a rate of 5.37 percent per year between 2007 and 2011. The lower increasing rate of generation (5.37 percent) than that of the demand (5.43 percent) has accelerated the rate of load shedding which has been increased at a rate of 6.72 percent per annum during the same period (Figure 3).

7.4 Challenges to implement smart grid

Switching to smart grid from conventional grid is not an easy task. Though energy consumption growth is high, generation is failing to meet demand rate. A global statistics on energy consumption is given below:

Challenges required to meet the implementation of smart grid can be divided into two different types; security challenges and integration challenges. [69, 70]

Security Challenges

1. Network security of distributed systems across meters, substations and in-home devices including authentication, detection, and monitoring.
2. Identity & access management for managing customer information.
3. Messaging and application security communications including data, network communications, and transactions.
4. Security policy management and implementing web services security standards.

Integration Challenges

1. Adoption of SOA architecture.
2. Web service enablement of legacy apps.
3. Format bridging, transformation and routing.
5. Handling wide variety of non-XML data formats.
4. Interfacing with partners and customers.

7.5 Prospect of Smart Grid in Bangladesh

Energy shortage is a worldwide concern. Presently, more than 40 countries show power system instability and load-shedding due to electricity shortage. North

American and European companies are presently working on building 'smart electrical grid' technologies to optimize energy flow using digital radios for more efficient electrical grid control and energy conservation. The need to build Smart Grid technologies is rising worldwide and Bangladesh can become a pioneer in this area of technology development. Since energy demand is increasing every year in Bangladesh, it is not possible to build power stations rapidly. Smart Grid system can minimize this problem. In the event of load-shedding, caused by electrical energy shortage in the country, the Smart Grid can automatically recalculate and distribute electricity to all consumers fairly [69, 70].

The basic needs to implement Smart Grid are digital radios, circuit breakers etc. Both digital radios and circuit breakers are required to upgrade the operation of nation's electrical grid, which can be designed and manufactured in Bangladesh in large scale. With the help of expatriate Bangladeshi engineers, Bangladesh can start designing and manufacturing the electrical parts required to up-grade the electricity grid in Bangladesh so that, Bangladesh can be an early developer and adopter of the Smart Grid technology[69, 72].

Integration of Renewable Energy

Since penetration levels of renewable energy are likely to continue increasing a rethink of the existing energy balancing paradigm may be required. Fortunately, an operational smart grid has the potential to mitigate some of the difficulties that are posed by high levels of renewable energy generation. A smart grid takes advantage of potential improvements that can be made to conventional operation through the use of communications and information. Current power system is unable to predict and detect such variability and therefore cannot support or control this. Besides effects on the grid varies with different penetration levels of wind and solar energy. Thus reliability is a major concern now. So, a sensitive control system is required which will consist efficient transmission, demand response and intelligent energy storage in other words a smart grid can be adapted.

An energy storage system is required to implement renewable energy sources. While renewable energy can-not necessarily be operated in a conventional manner, its behavior can be predicted and the forecast information is exactly the kind of information that a smart grid must use to improve system efficiency. So, simply we can see that renewable energy is an added advantage to Smart Grid [71].

Managing Distributed Generation

In smart grid system use small distributed generators that both make electricity and produce usable heat energy. They make more efficient use of the energy of the fuel that is used; they can relieve stresses on transmission and distribution systems; and, they can increase the reliability of power supply to local customers. In an emergency, it would sometimes be desirable to be able to disconnect a distribution feeder from the main power system. How-ever, with the right technology, control systems, and regulatory environment, there is no reason why we could not do this in a safe and efficient manner. Changes are needed to allow the development and wider use of distributed generation and small micro-grids.

7.6 Preparing a roadmap for implementation of smart grid

From the brief description above, it may be observed that smart grid is a transformation or journey from the present state of the grid towards adding a set of smarter systems/applications in a phased manner and according to the business priorities of each utility. In order to manage and achieve this transformation successfully, detailed planning and development of an implementation strategy, methodology and guidelines are required, covering processes, selection of technologies and standards, resource requirements and capacity building programs for utilities, regulators, implementation agencies and technology providers. A transparent and comprehensive plan and roadmap for the implementation of smart grids would help technology development, capacity building and investment planning. So first of all need a affective roadmap of smart grid, which may prepare by advisory and implementation committee or any technical team hired by government.

In every roadmap, there is time range in which time goal of project will be achieved. But we, in our study, suggest some conceptual theme without time range that will be added in a final roadmap.

Distribution (Including Distributed Generation)

1. Appropriate policies and programs to provide access to electricity for all with uninterrupted life line supply and electrification of 100% households by a selected year and continuous improvement in quality and quantum of supply.

2. Enabling programs and projects in distribution utilities to reduce Aggregate Technical and Commercial (AT&C) losses.

3. Integrated technology trials through a set of smart grid pilot projects; and based on outcome of the pilots, full rollout of smart grids in pilot project area; in major urban areas and nationwide..

4. Availability of an indigenous low cost smart meter. After successful completion of pilots, AMI rollout for all customers in a phased manner based on size of connection, starting with consumers with high voltage to medium voltage and gradually increase to all consumers deploying smart meters and necessary IT and communication infrastructure for the same. Innovative and sustainable financing/business models for smart meter roll outs may be developed.

5. Modernization of distribution sub-stations and conversion of sub-stations in all urban areas (starting with metro cities) to Gas Insulated Substations based on techno-commercial feasibility in a phased manner through innovative financing models.

6. Development of Microgrids, storage options, virtual power plants (VPP), solar photovoltaic to grid (PV2G), and building to grid (B2G) technologies in order to manage peak demand, optimally use installed capacity and eliminate load shedding and black-outs.

7. Policies for mandatory roof top solar power generation for large establishments, i.e., with connected load more than 20kW or otherwise defined threshold.

8. EV charging facilities may be created in all parking lots, institutional buildings, apartment blocks etc; and quick/fast charging facilities to be built in fuel stations and at strategic locations on highways.

9. Optimally balancing different sources of generation through efficient scheduling and dispatch of distributed energy resources (including captive plants in the near term) with the goal of long term energy sustainability

Transmission

1. Development of a reliable, secure and resilient grid supported by a strong communication

2. infrastructure that enables greater visibility and control of efficient power flow between allsources of production and consumption

3. Implementation of Wide Area Monitoring Systems (WAMS, using Phasor Measurement Units, or PMUs) for the entire transmission system. Installation of a larger number of PMUs on the transmission network sooner. Development of custom made analytics for synchrophasor data.

4. Setting up of Renewable Energy Monitoring Centre's (REMCs) and Energy Storage Systems to facilitate grid integration of renewable generation.

5. optical fiber cables to be installed over transmission lines by the year 2017 to support implementation of smart grid technologies
6. Enabling programs and projects in transmission utilities to reduce transmission losses to below possible range.

7. Implement power system enhancements to facilitate evacuation and integration.

Policies, Standards and Regulations

1. Formulation of effective customer outreach and communication programs for active involvement of consumers in the smart grid implementation.

2. Development of utility specific strategic roadmap(s) for implementation of smart grid technologies across the utility. Required business process reengineering, change management and capacity building programs to be initiated. State Regulators and utilities may take the lead here.

3. Finalization of frameworks for cyber security assessment, audit and certification of power utilities.

4. Policies for grid-interconnection of captive/consumer generation facilities (including renewable) where ever technically feasible; policies for roof-top solar, net-metering/feed-in tariff; and policies for peaking power stations.

5. Policies supporting improved tariffs such as dynamic tariffs, variable tariffs, etc., including mandatory demand response (DR) programs, starting with bulk consumers and extending to all 3-phase (or otherwise defined consumers).

6. Policies for energy efficiency in public infrastructure including EV charging facilities and for demand response ready appliances. Relevant policies in this regard to be finalized.

7. Development or adoption of appropriate standards for smart grid development in Bangladesh and continuous engagement in evolution of applicable standards relevant to the Bangladesh context. Active involvement of Bangladeshi experts in international bodies engaged in smart grid standards development if appear any.

8. Development of business models to create alternate revenue streams by leveraging the smart grid infrastructure to offer other services (security solutions, water metering, traffic solutions etc.) to municipalities, governments and other agencies.

9. Development of Skill Development Centers for smart grid development in line with the National Skill Development Policy.

Other Initiatives

1. Tariff mechanisms, new energy products, energy options and programs to encourage participation of customers in the energy markets that make them "prosumer"-producers and consumers.

2. Create an effective information exchange platform that can be shared by all market participants, including prosumers, in real time which will lead to the development of energy markets.

3. Investment in research and development, training and capacity building programs for creation of adequate resource pools for developing and implementing smart grid technologies in Bangladesh as well as export of smart grid know-how, products and services.

Chapter 8
Conclusion and Recommendation

8.1 Conclusion

Emission combined with resource and infrastructure constraints are dampers. Present installed power capacity may have to be doubled by the end of this decade to meet energy need of its growing population and expectations of a high GDP growth economy. An overview of Bangladesh Power Market along with brief analysis about the power system units is described. Power market in Bangladesh is generally characterized by the poor demand side management and response for lack of proper infrastructure and awareness.

Smart Grid Technology can intuitively overcome these issues. In addition to that, it can acknowledge reduction in line losses to overcome prevailing power shortages, improve the reliability of supply, power quality improvement and its management, safeguarding revenues, preventing theft etc.. Integration of RES is expected to play significant influence on the operation of the power system for sustainable energy in future. Grid codes are set up to specify the relevant requirements for efficient and secure operation of power system for all network users and these specifications have to be met in order to integrate wind turbine into the grid. Several technical and operational issues with increased power penetration has discussed for emerging Bangladesh power system.

In addition, Microgrids are creating new smart grid technology requirements in the areas of automation, management and control of alternative energy sources with energy storage devices. The report may guide future policies which to lead Bangladesh power system to take several steps to implement Smart grid with RES integration.

The thesis presents a discussion on Bangladesh Power Strategy along with its pitfalls in various technical and non-technical themes, with an organized approach to evolve the conceptualization of Smart Grid. Model taken by the government and many private bodies, are presented in the thesis. Further, various prospects of sustainable energy and off-grid solutions, Rural Electrification (RE) and evolution of Micro Grid along with various policies and regulatory affairs of Bangladesh is also presented here.

8.2 Recommendation

This study clearly indicates that there is potential for reduction of peak load and reduction of overall electricity consumption through demand response. Both types of reduction seem to depend a lot on consumer engagement. So participations with grid will be increased actively of consumer. Also, few more work related to micro grids and hybrid energy with energy storage systems are premeditated to complete by near future. Upon the finalizing of the entire study, the further research perspective would deliberately act as an advocate to discover the rank and strategy of nation's development in power and energy with respect to current and future energy demand.

The business case for smart grids is more obvious for society than it is for utilities alone. This implies that regulators should be forward-looking and play an important role in driving the development of the smart grid. Regulators can influence the development not only through technology mandates or financial incentives, but also through the promotion and communication of social norms and objectives.

From this thesis' review of consumer engagement theories and practical demand response studies, the following recommendations for regulators can be formulated:

1. Clearly communicate societal goals and regulatory targets, and provide incentives and education to end consumers. This will contribute toward individual consumers' alignment with these goals and will increase consumer engagement.

2. Design policies that align utility goals with societal and consumer goals, i.e. focus on service quality rather than quantity, giving incentives for electricity savings, rather than electricity sales.

3. Rather than focusing on the mandatory installation of smart meters, make it mandatory for utilities to provide consumers with frequent, accurate, timely consumption data (real-time and disaggregated, if possible) and historic comparisons.
4. Allow or mandate utilities to use “opt-out” schemes for dynamic pricing rather than “opt-in” schemes.
5. Ensure clear, stable and supportive regulatory conditions
6. Accelerate R&D and support evaluation efforts and sharing of results to ensure systematic learning and knowledge capitalization in this new area.

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