Chapter 2
Distribution Management System

National policies on the Electricity Supply Industry of Thailand, either an introduction of more competition to improve efficiency or more reliability and quality of services, impose different performance pressures on utility and its management. As a consequence, utility is required to improve its internal business practices and inevitably acquire more technologies to assist in the operation, monitoring and maintenance of its assets. These can be seen for examples the Power Quality obligation to guarantee the service quality to end customers, the Asset Management framework/system to translate technical information to economic and business decisions, and/or network automation and control. All these new advance technologies and frameworks mentioned above are complicated and typically large system. Hence, they are usually outsourced and implemented by international consultants, and the utility acts as the project manager.

A new type of control system is emerging, as utilities focus more attention on their distribution operations. Distribution Management System (DMS) is regarded as one of the new paradigm to manage and control the distribution network driven by advance in ICT technology. The DMS includes conventional SCADA capabilities for distribution substations and feeders, closed-loop control functions for substation and feeder operations, and analytical tools to support distribution operators and operations planners. Besides, the DMS can be interconnected with several other utility computer systems in a synergistic configuration that exploits the strengths of each system in an efficient manner. The benefits of DMS functions include reduced O&M costs, reduced losses, and deferral of capital investment. The type and amount of benefits are highly utility dependent. Although DMS is implemented and utilized by modern utilities around the world to help the system operators in their decision making processes, especially when emergencies occur, the system can vary from utility to utility. This is due to the complexity of each organization and primary distribution system.

2.1 Chapter Overview

This chapter provides rationales why DMS or SCADA/DMS is needed by modern power utilities. It starts with a basic of the real-time control system which is the fundamental requirement of the network operation and control. Then, the definition of DMS is explored. Furthermore, the evolution of advanced control system from SCADA to DMS is presented as well as its life-cycle assessment. Finally, the problem faced by the utility in the designing and implementation of the DMS is stated and explained in this chapter.

2.2 Basic of Real-Time Control System

Many market survey and review confirms the increasing acceptance and implementation of distribution automation. A survey in 1999 confirmed that over half of the 40 United State utilities questioned were actively deploying, and had planned to continue installing. The survey in 2000 was again shown a significant adoption of remote-controlled switches or reclosers. They had implemented automation on both substation and feeder switches. [20] According to a survey conducted in the USA, while the load is increasing, the number of backup connections has to be increased accordingly, which also brings more automation to the network. Especially in the medium-voltage, the network automation, based on the control of reclosers and disconnectors (sectionalizers) at the distribution substations located at points of strategic importance for the network management, minimizes the effects of faults and interruptions with respect to the area and duration. It could be a particularly efficient way to improve the availability of electricity distribution in metropolitan area. [21]

A total of 145 North American electric utilities are represented in the 2008 Newton-Evans research. Among the 145 participating utilities, 95% of the respondents indicated their utility has at least one control system installed for use in operating the transmission and/or distribution network. Almost all utilities with 25,000 or more customers also reported having a SCADA (or EMS) system in operation. A lower number of mentions were received for installations of “stand-alone” distribution management systems, as most distribution utilities incorporate at least some distribution grid management functions within their SCADA system. Only 17% of respondents reported having a distinct DMS in operation.

The 2008 International survey has found that 40% of the 70 respondents indicated that outage management (OMS) is currently a separate system from EMS/SCADA, while 31% stated that OMS is or will be integral to SCADA. Seven percent were planning to implement as a separate system by 2010 while 21% cited no use and no plans for any OMS. European and Asia Pacific respondents were more likely to indicate that OMS is or would be a separate system than were their peers in Latin America, the Middle East/Africa or in Eastern Europe. It is also found that current linkages and plans for additional links between EMS, SCADA and DMS systems to other systems: Ties or links to historical files were the most common link (about 84%). Another 56% reported having links already in place with enterprise WANs and 47% cited linkages to plant control systems (DCS).

The above mentions the importance of the basic real-time control system which is fundamental to every network operation system, also known as network automation. Hence in order to understand the rationale behind the designing and implementation of the DMS, this section then explains the basic real-time control system. Typical network control hierarchy is shown in figure 2.1 which is comprised of 5 layers. [22]

Layer 1 Utility covers all the enterprise wide IT, asset management, and the energy trading system

Layer 2 Network has controlled the bulk power transmission networks, including the economic dispatch of the generators

Layer 3 Substation has controlled all circuit breakers inside substation with the communication of all protection relay status

Layer 4 Distribution covers the medium voltage feeder systems and reflects the expansion of the real-time control capability through remote control and local automation of the feeder devices located below the primary substations

Layer 5 Consumer is where the delivery system directly interfaces with the consumer where more flexible metering system are required to allow the revision of tariff and load control

Normally, distribution systems have needed little real-time control because initially the distribution network was designed as the redial network. Furthermore, these redial type network were predominantly designed to operate within the specified voltage limits and a range of anticipated loads. Hence, reliability improvement could be met with network reconfiguration activity which is one of a few alternatives. Switching of the network outside substation boundary was performed manually by line crew sent out to locate, isolate, and repair the fault before restoring full service. Fault isolation can be achieved by local automation or by direct remote control; however, supply restoration by remote control using operator decision making, rather than automated logic, is the most accepted approach. Fully automated restoration schemes using local automation are possible but require the complete confidence of the operating staff before acceptance.

Similar to other aspects within the ESI, Deregulation or introduction of more competition in the industry has also had its impact on the distribution network. This is particularly from the reliability and quality of supply perspectives, emphasizing the need to reduce outage times. As a result, automation of the feeder system has emerged as one of the strategies to improve operation performance. [20]

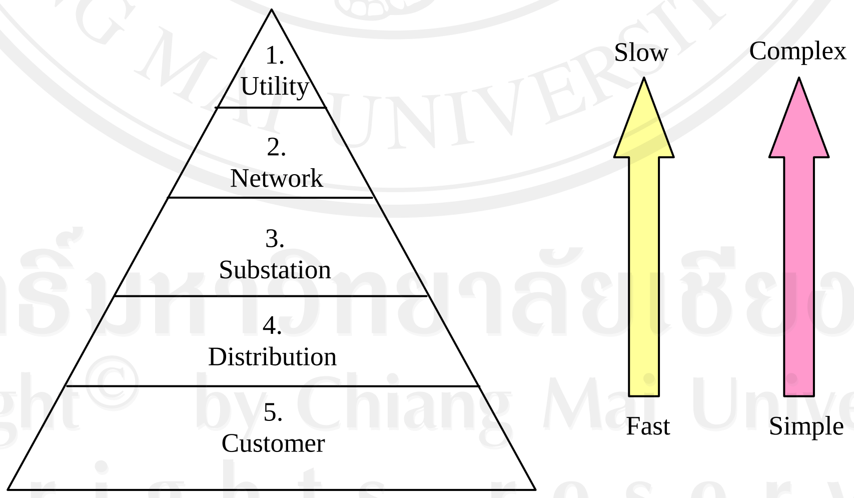

Figure 2.1: Control Hierarchy Level

Figure 2.1 illustrates the different level of the control hierarchy of the utility. There are five layers which each layer are described above. The highest control system can control the overall. The higher one can control the lower one but the priority of the lower one is more important. This is served for safety operation purpose. For example, there are not able to control from the network control center to the switch in the substation that is locally operated for maintenance. Moreover, the lower layer control system requires the system speed faster than the higher one; conversely, the system in the lower layer is less complex than the higher one.

The operation of the typical power system can be divided into four states. In order to manage and control distribution network efficiently, the operation requires the balance among security, economy, and quality perspectives. This is shown in Figure 2.2.

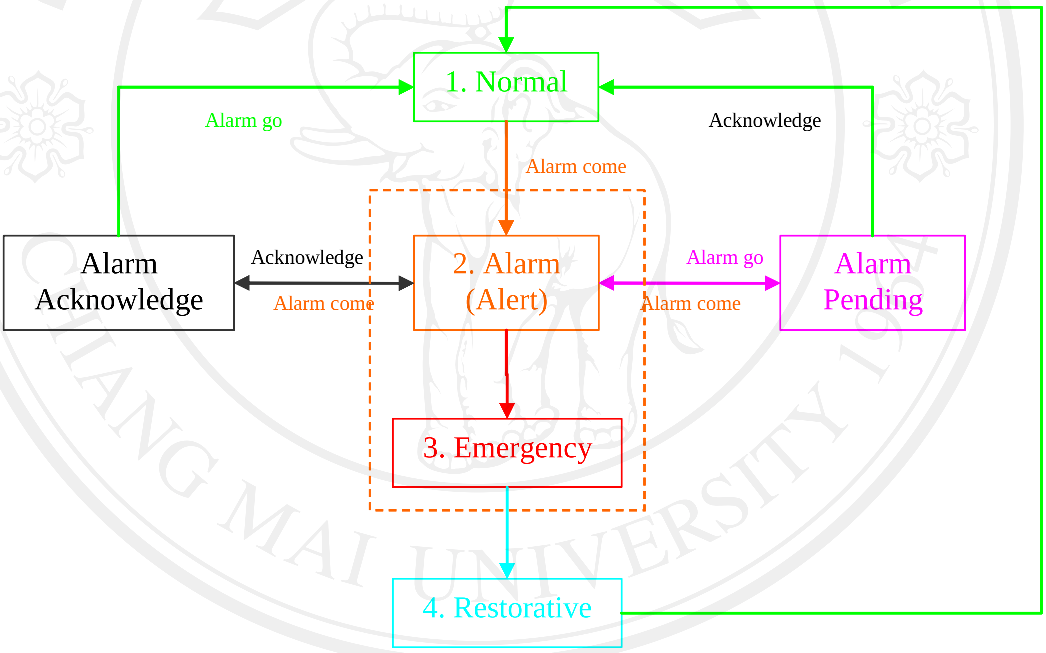

Figure 2.2: Typical Operation Stages

Figure 2.2 shows the different states of the power system operation. These include the normal operation, the alarm (alert) state, the emergency state and the restorative state.

The normal state is the most operation preference. The emergency state is reflecting the collapse of power system generally from cascade trip as a consequence of major transmission or generation loss. The alarm (alert) state is the state (automatically by the automated system or manually by the operator) that a disturbance has occurred and action should be taken directly to relieve the situation before it is going to the alarm state. This state is the most significant state for system operator highlighted in Figure 2.2 to acknowledge and respond with an appropriate decision. In the bulk supply system, the alarm (alert) state can move very fast into the emergency state which is impossible for an operator to prevent system collapse. The objective of automation system is to keep the power system within the normal state or return it to the normal state as soon as possible via the restorative state.

To serve end customerr, the distribution network is inevitably built and expanded to cover as many load areas as possible with regard to the relevant economic and technical constraints. As a result, the distribution network becomes large scale system with long distance feeders. Hence, to be able to operate and control the network efficiently, local system operators are divided and assigned to many different control centre across the distribution network. The system operation functions required at control center can be split into three groups:-

- *Instantaneous operation*: involves the real-time monitoring and control of power system. The load demand, power generation, network power flow, and current and voltage level are continuously monitored and controlled. Any limits or violations should be reported in alarm state and responsed in order to restore the system back into the normal state which the defined operating values are within the limit.
- *Operation planning*: is both short (few hours) and longer (few months) planning period. An accurate short-term forecast is very important for economic dispatch of generation plant. It is the key for system operation in deregulation environment especially in the generation-deficient markets where the excess of maximum contract value will get the penalty to the operation. The load shedding strategy may come into the consideration.
- *Operation reporting*: is the need to keep statistics on performance, disturbances, and loadings as input to planning and accounting functions. Post-mortem analysis is a key to determining disturbance causes. The report of quality is usually a regulatory requirement.

Power system operation depends on the state of the system, which requires proper forecasting and planning methods. These methods have to be supplied with a wide set of data measured from the real power system in strictly define interval of time. This means that in power system operation, one of the problems is data acquisition. This measured data is the basis for all operational activities in power systems, which include the following operational problems:-

- Load and voltage control
- Fault diagnosis
- Environmental protection
- Dispatcher training
- Research and development

Computer applications in power systems have been used from the beginning of the computer age, and the following indicate the area of application:

- Calculation and computer aided design (CAD)
- Computer-aided manufacture (CAM)
- Digital relay protection

Development of the computer in power system led to supervisory control and data acquisistion (SCADA) and subsequently to energy management system (EMS) and distribution management system (DMS)

The last decade of computer application in power systems has witnessed a significant number of Intelligent Knowledge Base System (IKBS) developments. The first IKBS in this domain was developed to monitor vibrations in order to diagnose faults in large pumps in nuclear power station, and has been in operation since 1980. the accident at the Three Mile Island nuclear power station in 1979 highlight the human limitations in the operation of such complex systems, and as a result started the age of knowledge based system application in power systems. Since then, the field of expert system applications electric power engineering has grown at a significant rate. Data concerning IKBSs in power system in Europe is collected in Germond and Niebour [23]. According to this paper, the percentage spread of the 40 projects described is:-

- Alarm reduction and system diagnosis (27.5%)
- Environments for operational aids (12.5%)
- Steady-state security and dynamic security (15%)
- Management, scheduling and planning (15%)
- Component diagnosis (2.5%)
- Remedial controls (10%)
- Restoration (10%)
- Substation monitoring and control (7.5%)

Another interesting perspective, which is based on responses received from 24 organizations all over the world, is presented in Lui and Van Son [24] and will be briefly report below. The motivating issues behind IKBS application, as indicated by respondents, was said to be:-

- To prevent human error (4)
- To maintain system knowledge (3)
- To standardize actions (5)
- To reduce operator burden (11)
- To test IKBS techniques (17)
- To improve inefficient analytical programs (5)

This same survey found that IKBSs were applied for:-

- Fault diagnosis (11)
- Restoration (9)
- Alarm processing (6)
- Operation assistant (3)
- Remedial control and security assessment (5)

The basic of real time control system is Supervisory Control and Data Acquisition (SCADA) system. The SCADA systems allow dispatchers to monitor and control primary equipment remotely from a central location. The systems, using an RTU to interpret code message between control center and primary equipment, have the ability to display changes in the operating status of a system as soon as they occur and also have alarm monitoring capabilities to alert dispatchers to problems. [22] The level of SCADA implementation in distribution networks has historically controlled around 10% of switching devices and has been limited to circuit breakers at the large primary substations. A typical SCADA system is shown in figure 2.3 which comprised of hardware and software. SCADA hardware may consist of:-

- Control center
    - Human-machine interface (HMI)
    - Workstation
    - Server having particular function
    - Communication subsystem
    - Peripheral
- Communication Media
- Field Level
    - Remote Terminal Units (RTU) with marshalling terminal
    - Field level instrumentations and control devices

A flexible redundancy such as hot and standby server should be provided to fulfill the time critical function. The communication among hardware is usually via Local Area Network (LAN) with an international standard protocol, where the code message may be sent to field level by radio, telephone lines, or even by power line. [19] Currently some utilities including MEA change this communication media from radio to fiber optic.

The key features of SCADA software in control center are:-

- User interface
- Graphics displays
- Alarms
- Trends
- RTU interface
- Scalability
- Access to data
- Database

- Networking
- Fault tolerance and redundancy
- Client/server distributed processing

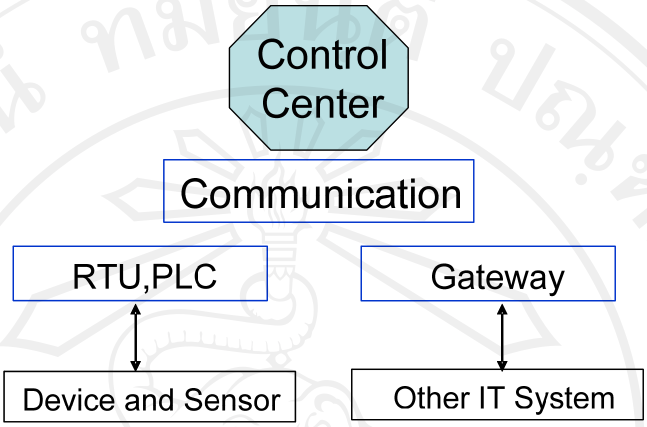

Figure 2.3: Typical SCADA systems

A thorough understanding of the software package, which can be developed by experienced in-house group or external source with consultant service, is essential to provide solutions to meet specific requirements. Basic of real-time control system (SCADA) is configured around the following standard base functions:-

1. Data acquisition
   - Status indications
     a. Single point
     b. Double point
   - Measured values
     a. Time stamp
   - Energy values
     a. Pulse counter
2. Monitoring and event processing
   - Status monitor
   - Limit value monitor
   - Accurate Time-stamping of event (for analyze system disturbance)

- Sequence of events
- Trend monitor

Quality attributes need to apply to data. A method of flagging the data either a particular color or symbol in operator's display console is used. The following are typical attributes:

- Nonupdated/updated
- Manual
- Calculated
- Blocked for updating
- Blocked for event processing
- Blocked for remote control
- Normal/non-normal state
- Out of limit
- Alarm
- Unacknowledged

3. Control
   - Individual device control: close, open
   - Control messages to regulating equipment: command from central control, conduct by local logic
   - Sequential control: a set of control actions
   - Automatic control: triggered by event
4. Data storage archiving and analysis
   - Time tagged data (TTD)
   - Post-mortem review (PMR)
5. Application-specific decision support
6. Reporting

Previously, SCADA (figure 2.4) was applied only in the primary substation not in distribution feeder. Its advance feature is automation, which normally implemented at the top of the control hierarchy, where integration of multifunction gains efficiencies across the entire utility organization. However, downstream automation system, like separated distribution automation system, requires more difficult justification and it is usually site specific to the area where the improved performance can be measured. These are now extended to device along the feeder and even down to the meter.

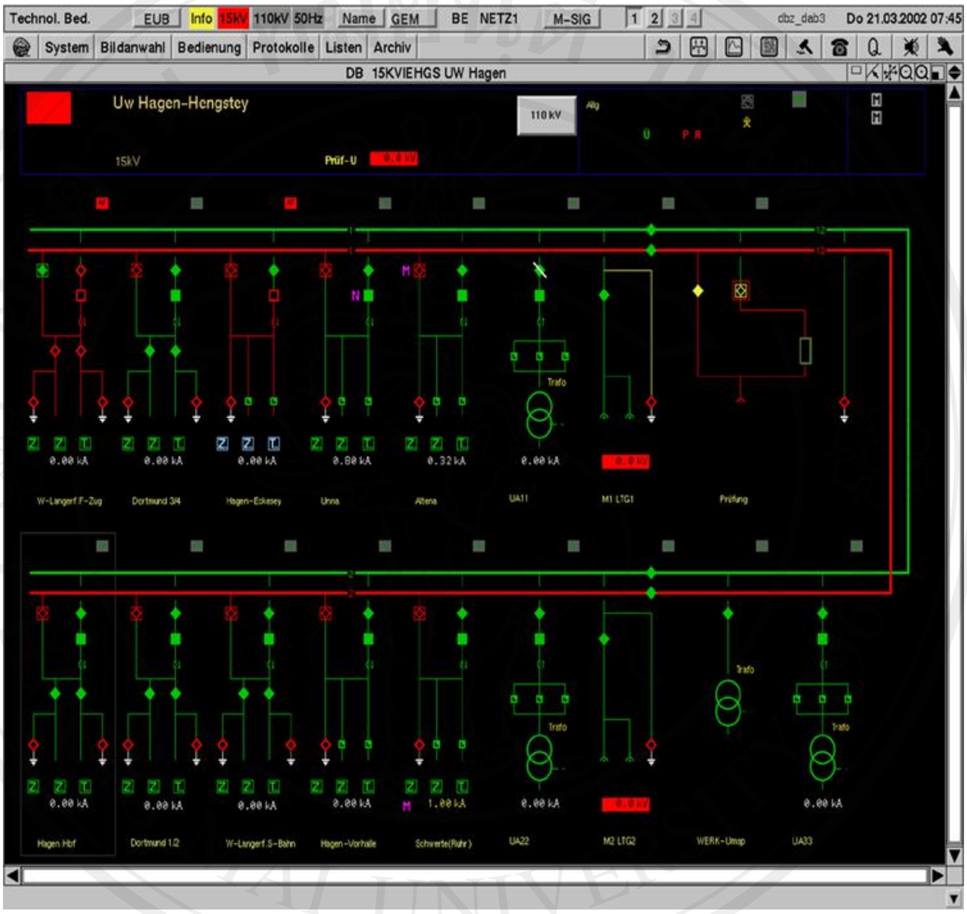

Figure 2.4: SCADA Application [25]

Modern trend for any automation system is open architecture which equipment of different manufacturers may be functionally integrated in a manner that makes the particular characteristics of individual devices transparent to the system. The other is distributed architecture that is flexible from the point of view of system extensions and upgrading. However, the system openness is not guaranteed by the distributed architecture itself, but rather by the use of an international standard throughout the entire system design and procurement process.

According to present technology, automation includes many functions (such as control, protection, communication, and so on). Hence it provides the necessary information to the right person at the right time which has the key areas of benefits as follows [22, 26]:-

- Reduce O&M cost by automatic development of the switching plan, fast fault location, reduce crew travel time, reduce loss by switching the normally open points (NOPs), dynamic control voltage, condition monitoring of the network, planned outage to reduce impact on customer.
- Capacity project deferral by operating with real-time loading analysis to reduce the margin.
- Improved reliability by reduce frequency and duration of outages especially in overhead feeder system with well maintained and automated
- New customer services by more flexible tariff, selectivity and control of the consumption
- Power quality include voltage regulation, unbalance, sags, swells and harmonics contents
- Improved information for engineering and planning by more visibility for the planner and operator of the network

Moreover, DMS which focus more in control room will be described in the following section.

2.3 The Challenge for Utilities in Modern Environment

In the new world of power distribution, every distribution utilitiy meets new challenges and has to improve productivity and reduce operating and maintenance costs whilst providing customers with a reliable quality supply and a broad range of services. Moreover, utility in the future need to consider the variety of prosumer (consumer and producer) which may especially have a distributed generation. The benefits of distributed generation to the power system need to be investigated, and are summarised as follows;

- Decentralisation of supply.

- Reduction in electrical losses on the transmission network level.
- Improvement in the voltage profile
- Lower emissions from the production process.
- Deferment of the investment in the network assets.
- Better choices of investments for the investors in new generation assets

Today the environment consideration in the three Es (Engineering, Economics, and takes the most attention around the world. This is obviously taken care by 'Kyoto' protocol in the way that to reduce the global warming effect from carbon dioxide (CO_2) by the appropriate production and consumption management. However, many utilities still confront of the three coinciding critical issues;

- The age of infrastructure assets that may be over 50 years
- The asset has matured and required some form of life extension
- The need to increase capacity of the existing infrastructure

The total asset: Physical asset, financial asset, human asset, information asset, and intangible asset should be considered and identified the critical one. By using the specification for the optimized of physical infrastructure assets that was mentioned in PAS-55. The principle benefits of asset management which support continuous improvement and compromize among cost, performance and risk can be achieved. These are:

- Enhance customer satisfaction
- Improve health, safety and environment performance
- Optimized return on investment
- Demonstrate best value for money within a constrained funding regime
- Evidence to demonstrate legal, regulartory and statutory compliance
- Improve risk management and corperate governance
- Improve corperate image
- The ability to demonstrate sustainability

The most challenge of every utility is to supply their power in good quality. By definition, power quality can be identifies into interruption, surge, voltage drop, harmonics, voltage sag, voltage swell, and overvoltage which the good service quality mean to supply with these value in the standard limit.

Interruption (Outage) is completely loss of voltage supply from thirty cycles to several hours. It is usually caused by the fault that makes the protection to trip the related power system. It can be classified as temporary if the system can be restored back or permanent if the system can not.

Surge (Lightning or Switching Surge) is a transient voltage or current that has very high in magnitude but in the short duration. These surges are caused by lightning strike or switching operation (especially capacitors, reactors, power transformer, generator, load, and so on)

Voltage Drop (Undervoltage) is the long duration (several seconds or longer) of service voltage that lower than the limit. This may cause from overload or poor voltage regulation system.

Harmonics are the nonfundamental frequency component of a distorted waveform. Normally they are not generated by utilities, but rather by cusromers' equipment. For example, a large non linear industrial load may produce a significant harmonics magnitude that can travel back into the power system and affect other customer. The triplen harmonics should be precisely concerned with the system grounding in order to make the protection system operates properly.

Voltage sag is a momentary voltage dip that last for a few seconds. It may cause by a temperary fault on the transmission or distribution system or by switching a large amout of load or transformer. It is very serious for a sensitive load such as computer and some electronics devices.

Voltage swell is the voltage relative to ground of the phase that fault does not occur. It has durations of several seconds or less, but can last as long as a minute.

Overvoltage is classified as any steady state voltage that over than the standard limit in several seconds or longer. It usually occurs as a result of improper regulation practices.

Figure 2.5 shows the typical voltage disturbances which we are described as previous. Good power quality should be to supply the voltage with these disturbances within the standard limits which will not cause any users' equipment damage.

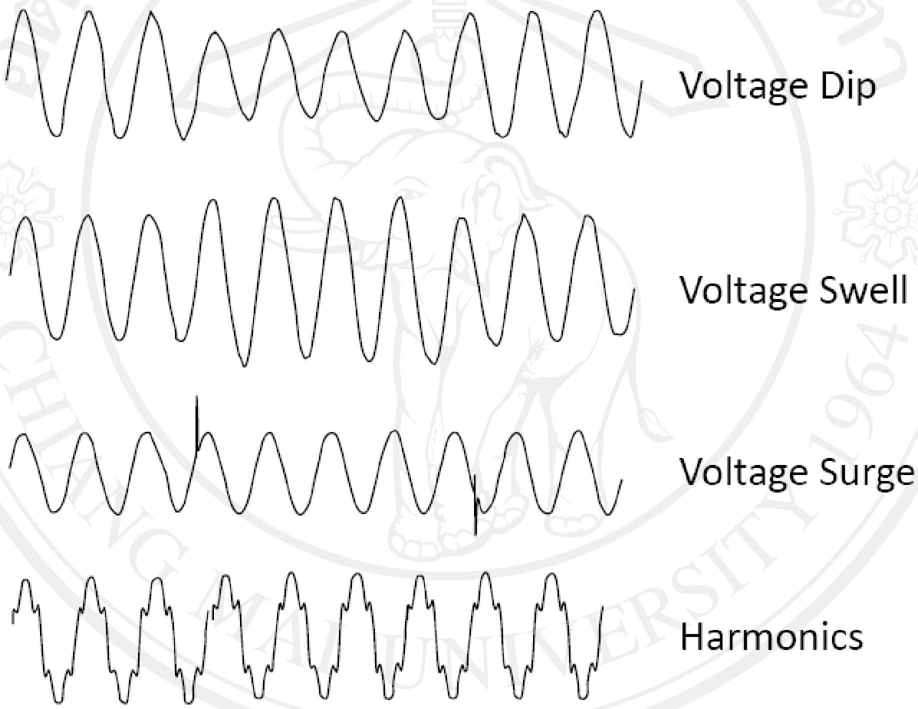

Figure 2.5: Typical Voltage Disturbances

Typical voltage profile of heavy and light load is shown in figure 2.6. The utilities need to maintain their supply voltage within the standard limits. These can be achieved by applying the regulator into an appropriate point of the system. However, the difference of over and under voltage for heavy load is larger than light load. However, the voltage supply to all customers is still within the limits by using Load Tap Changer (LTC) with approprited setting voltage regulator in substation and on the feeder.

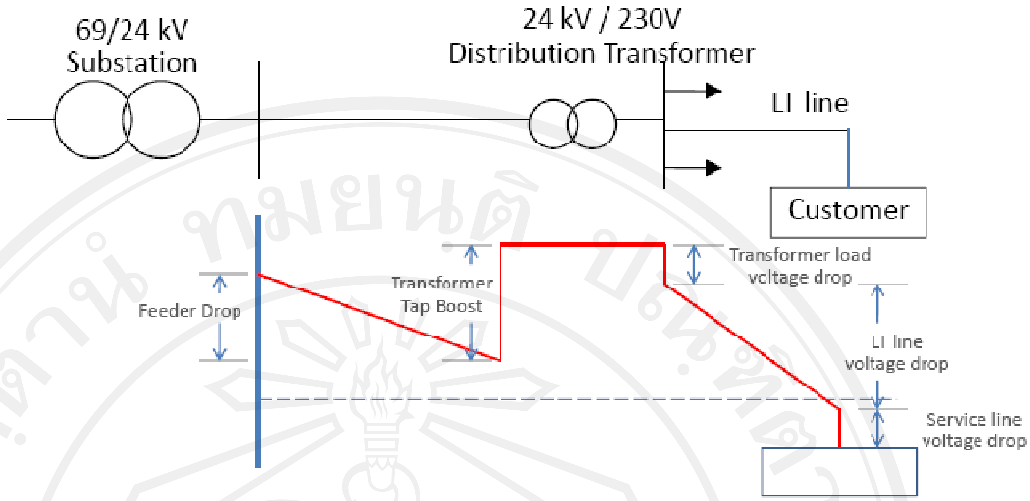

Figure 2.6: Voltage Profile during Heavy and Light Load

In addition to LTC, many utilities apply shunt capacitor banks to improve feeder voltage profile (figure 2.7) and supply reactive power to a circuit. This application may help utility to control their voltage profile and reduce their resistive loss. However, regulator and capacitor may overcompensate at the light load and create an overvoltage that last for many hours.

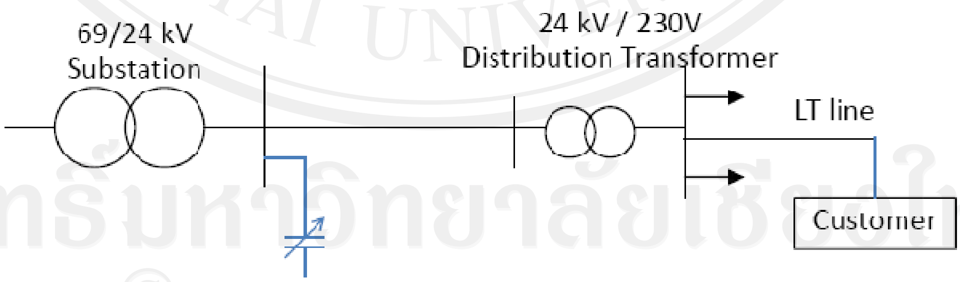

Figure 2.7: Voltage Profile with Capacitor

For example, the existing of DG brings the system into bi-directional monitoring and control with very much needing an appropriate voltage and var control. To achieve rapid success the effective use of Information Technology is essential. One of the most popular solutions is the extension of SCADA application like SCADA/EMS for energy transmission and SCADA/DMS for energy distribution.

2.4 DMS and its evolution

Supervisory Control and Data Acquisition for Distribution Management System (SCADA/DMS) or DMS with many functional tools, as shown in figure 2.5, will help their system operators to control the distribution system effectively. The features allow simplified management for large distribution networks with frequent modifications and updating operations. Utility will focus on system reliability, power quality, system losses, customer communications and customer billing. The DMS functions [27] can be grouped into:-

- SCADA: data acquisition, data processing and supervisory control
- Substation Automation: control device within the substation such as service restoration, bus voltage control, parallel transformer control, automatic reclosing etc.
- Feeder Automation: control device on the feeder such as fault location, fault isolation, service restoration, feeder reconfiguration etc.
- Distribution System Analysis: basic distribution power flow and advance functions such as contingency load transfer, load and voltage profile, and distribution losses etc.
- Interface to other computer system: such as Customer Information System (CIS), Geographic Information System (GIS), Energy Management System (EMS) via, Middleware, a software layer that provides a level of interconnection.

Standard hardware architecture can be centralized or distributed (multi-center), redundancy workstation (vendor UNIX or Linux) or personnel computer (Window or Linux). The software can be proprietary or open. The communication in metropolitan area is mainly fiber optic. Specific or open protocols and error detection philosophies are used for efficient and optimum transfer of data. [28] This research will focus on DMS hardware and software focusing on the control room.

Figure 2.8 illustrates a typical SCADA/DMS which focuses on hardwares in control room and in the distribution system. In control center, the hardware consists of SCADA server, DMS server, and many application servers to support many operator consoles. Each console has the operator console window which operator can see the schematic diagram, alarm, and historical report on the separate screen. The system must communicate to each installed *R*emote *T*erminal *U*nits (RTUs) which are in substations and distribution feeders via the selected communication media and protocol.

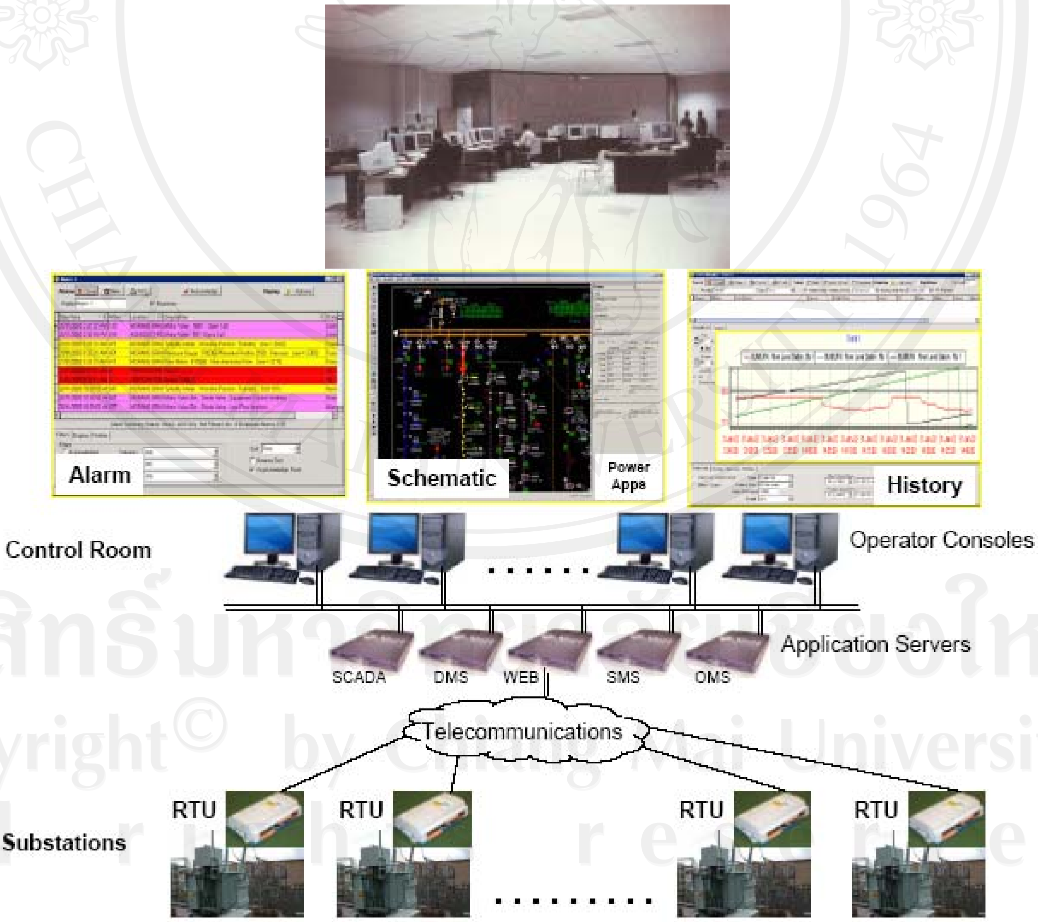

Figure 2.8: Typical SCADA/DMS [29]

There are many SCADA/DMS implementation around the world according to SNC-Lavalin project profile in table 2.1. In Thailand, Provincial Electricity Authority (PEA) was also their customer for this first system. PEA power system serves more than 10.9 million customers in Thailand. The peak load is 9,900 MW and is increasing by more than 5.9% per annum. The system covers 510,000 square kilometres, approximately 99% of Thailand's total area. SNC-Lavalin Energy Control Systems delivered six SCADA/EMS/DMS systems arranged in a hierarchical configuration in 2005. The System Management Centre (SMC) is linked via TASE.2 ICCP links to five Area Distribution Dispatch Centres (ADDC), which in turn communicate with over 2,300 remote terminal units and Substation Automation Systems. The RTUs communicate with each ADDC using the DNP3 protocol over a combination of digital microwave, TDMA, telephone lines and UHF radio links. The SMC supervises the entire power system operations from PEA headquarters in Bangkok, whereas the ADDCs perform their power system operations within their own service territories.

Table 2.1: SCADA/DMS Implementation

Source: http://www.snclavalin.com/ecs/en/dmsproj.htm

Utility Name	**Country**	**Completion Year**
Energex	Australia	2002
Public Utilities Commission of Scarborough	Canada	1996
-	China	-
Alexandria Electricity Distribution Company	Egypt	2000
-	Finland	-
Reykjavík Electricity	Iceland	1997
Elektro Gorenjska	Slovenia	2002
Taiwan Power Company	Taiwan	Ongoing
Provincial Electricity Authority	Thailand	2005
Hawaiian Electric Company	United State	1997
Electricidad de Caracas	Venezuela	1994

2.4.1 DMS definition

A distribution management system is a system of computer-aided tools used by operators of electric distribution networks to monitor, control, and optimize the performance of the distribution system. [30] DMS is also regarded as the decision support system that helps utility to efficiently operate its distribution system in both normal and emergency situations. It allows simplified management for large distribution networks with frequent modifications and updating operations of the network. The DMS functions can be grouped into Supervisory Control and Data Acquisition (SCADA), substation automation, feeder automation, distribution system analysis, and interface feasibility to other computer system.

The DMS scope may vary depend on each utility [31]-[34]. The variety of DMS application function in electrical utilities is shown in table 2.2.

Table 2.2: DMS function in electrical utilities

Source: http://www.snclavalin.com/ecs/en/dmsproj.htm

Utility Name	**DMS Application**
Energex	SCADA system Distribution Network Model Connectivity Analysis Demand Estimation Load Flow Fault Level Analysis Switching Management Subsystem Service Call Management Load Control functions.
Public Utilities Commission of Scarborough	Connectivity analysis Distribution power flow Load forecasting Demand allocation Power loss minimization Energy loss minimization Load balancing Load shedding

	Feeder voltage control distribution network model Geographic displays
Alexandria Electricity Distribution Company	SCADA system Distribution Network Model Connectivity Analysis Demand Estimation Load Flow Fault Location Analysis Load Control functions
Reykjavík Electricity	Connectivity analysis Distribution power flow Fault level analysis Loss minimization Dispatcher training simulator Distribution network model Geographic displays
Elektro Gorenjska	SCADA applications Distribution network analysis Trouble call management Service order management Outage management applications.
Taiwan Power Company	Fault Detection, Isolation and system Restoration (FDIR)
Provincial Electricity Authority	SCADA applications Distribution network model Connectivity analysis Power flow Fault isolation and system restoration Trouble call management Volt/var control Distribution network and graphical displays
Hawaiian Electric Company	Connectivity analysis Three-phase unbalanced distribution power flow Load forecasting Demand allocation Loss minimization Load balancing

	Load shedding Feeder voltage control Interface to corporate Power Outage Management Systems (POMS)
Electricidad de Caracas	Connectivity analysis Three-phase unbalanced distribution power flow Load forecasting Demand allocation Loss minimization Load balancing Load shedding Feeder voltage control Distribution network model Geographic displays

Considering its significance, the scope of DMS in this research covers primary distribution equipments (12 or 24kV system from substation transformer to distribution transformer), remote terminal units, control center, DMS hardware, DMS software, and communication system as shown in figure 2.6. The primary distribution equipments are for both overhead and underground system which the configuration can be radial, loop, primary selective, and special spare line. It should be noted that substation automation is not in the scope of this research.

Smart grid concept covers for the overall power system that included generation, transmission, distribution, and consumer (or producer at distribution level). There are SCADA/GMS for generation system, SCADA/EMS for transmission system, and SCADA/DMS for distribution system. Figure 2.9 shows the primary network and service area that cope with SCADA application in each level. For example, SCADA/EMS application at load dispatch center is used to control transmission network at 115 or 69kV. And SCADA/DMS at distribution system control and district control center, the scope of this research, is used to control distribution network at 12 or 24kV.

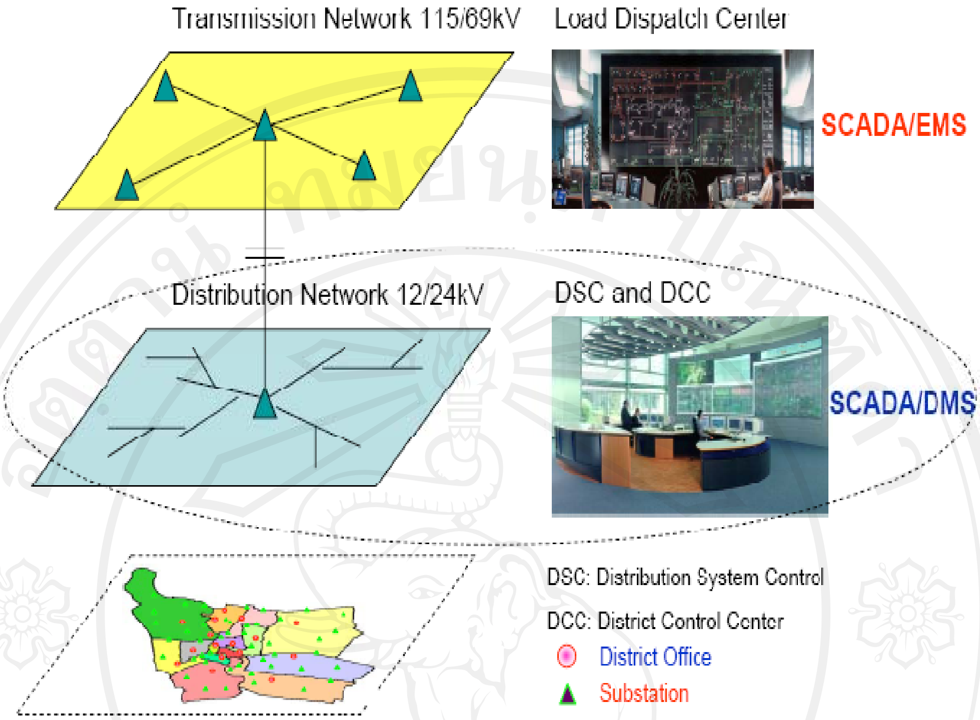

Figure 2.9: Scope of SCADA/DMS

2.4.2 SCADA/DMS concept

Main concept of SCADA/DMS is not only reliability but power quality and economics improvement through optimum responses to changing operating conditions in real time and maximize utilization of real time operational tolerances. By extending traditional SCADA capabilities, SCADA/DMS will provide more typical and advance function especially to medium voltage distribution system. Figure 2.10 shows the operator console and wall display of SCADA/DMS which operator can visualize the system easily and have a capability to look at many views of the system at the same time.

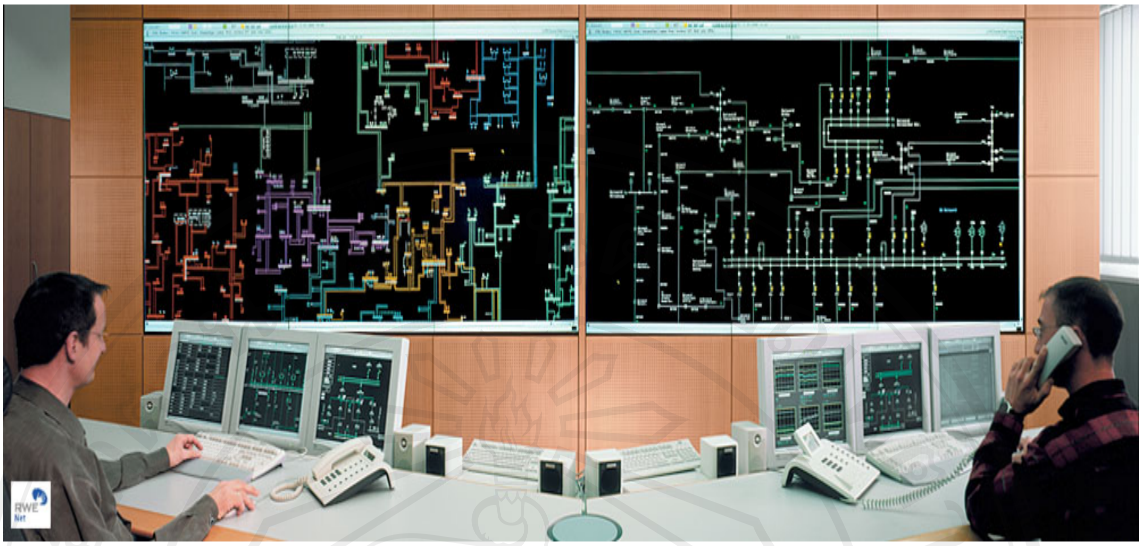

Figure 2.10: Operator Console and Wall Display

Source: PSI-CNI [25]

Typical functions can be described into:-

- Geospatial network diagram (Figure 2.11)
  - Zooming
  - Coloring
  - Tagging
- Distribution operation model and analysis (three phase)
  - Connectivity model and checking
  - Load Modeling
  - Power Flow Modeling (Figure 2.12)
  - Voltage and load limit checking
  - Loss and voltage quality analysis
  - Determination of available load reduction
  - Report preparation
  - Run periodically and by event
- Contingency Analysis (for study)
  - Faults in each switching section are considered
  - Restoration objectives:

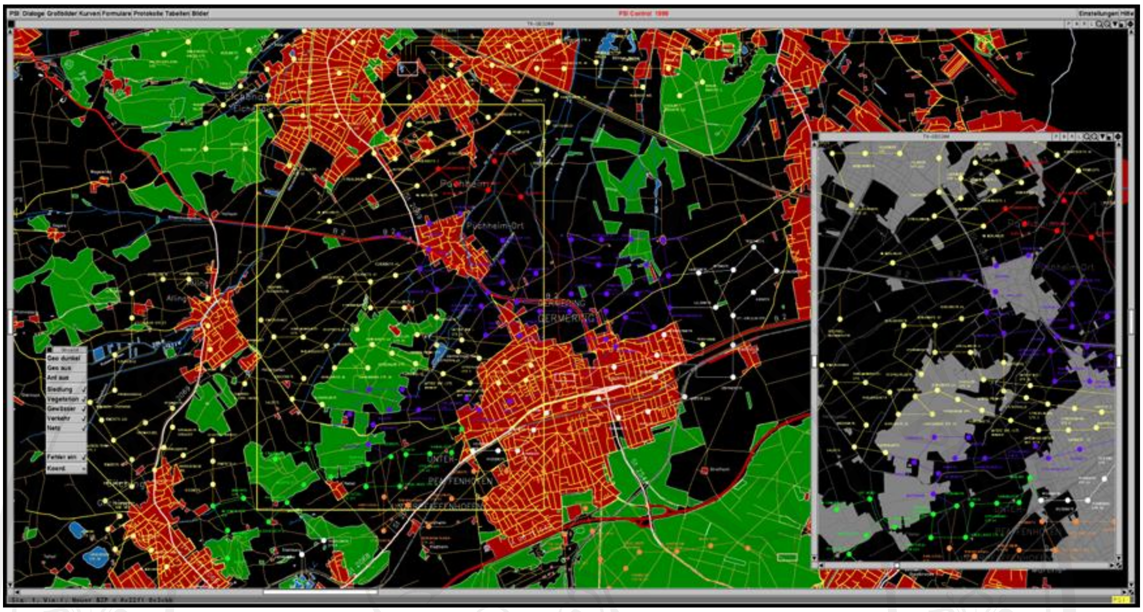

Figure 2.11: Geospatial Network Diagram

Source: PSI-CNI

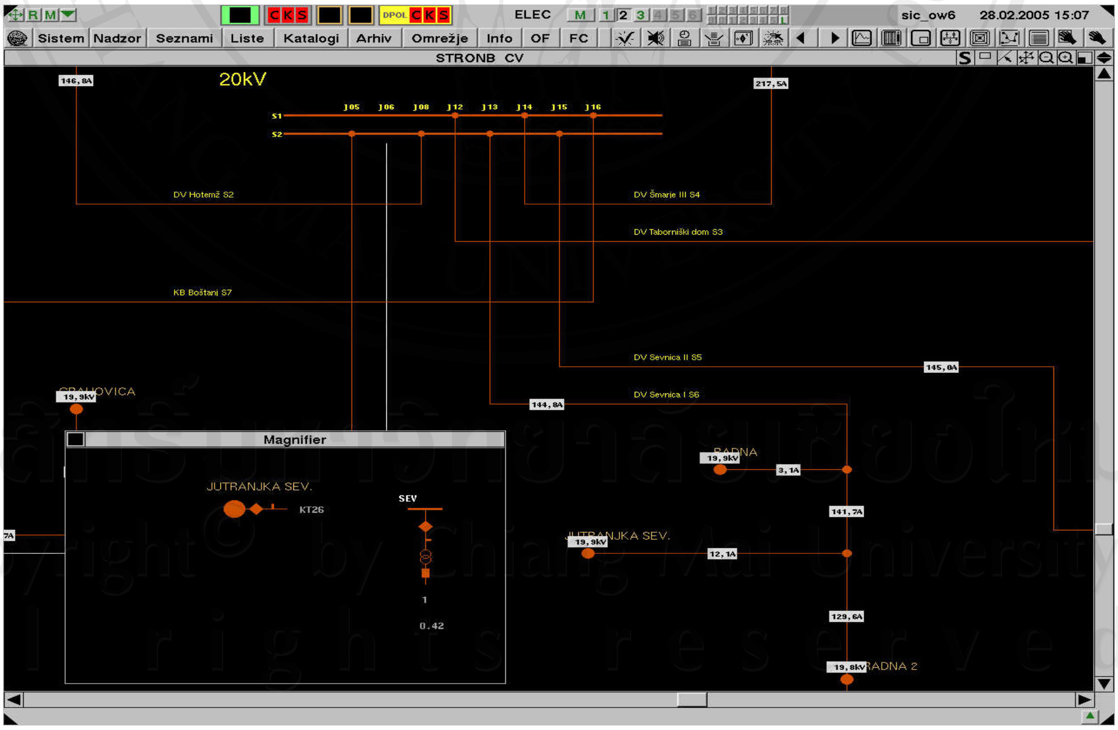

Figure 2.12: Distribution Load Flow Calculation

Source: PSI-CNI

        - Max. customers restoration
        - No overload in backup feeders
        - Min. switching operations
        - Acceptable voltage
        - Min. losses
    - Pre and post fault power flow calculations
    - Reports
    - Runs periodically and by event

- VVWC (Coordinated Volt Var Watt Control)
    - Objectives:
        - Power Quality
        - Load reduction
        - Economic (reaction on real time pricing - very high energy price – lower voltage for load reduction)
    - Constraints:
        - Voltage limits at customer load center
        - Voltage limits at substation buses
        - Voltage limits in sub transmission
        - Loading limits in distribution
        - Loading limits in sub transmission
        - Capacitor operation limits (e.g. no.of switchings/day)
        - LTC regulation ranges
            - Advisory mode
            - Close loop mode

- MFR (Multi-level Feeder Reconfiguration)
    - Optimization of normally open points in multiple feeders
    - Objectives:
        - Service restoration

- Overload elimination (in distribution feeders, substation transformers, transmission facilities)
- Loss minimization
- Voltage balancing between feeders
- Reliability improvement

o Dimension:

- Hundred of interconnected feeders
- Thousand of switches

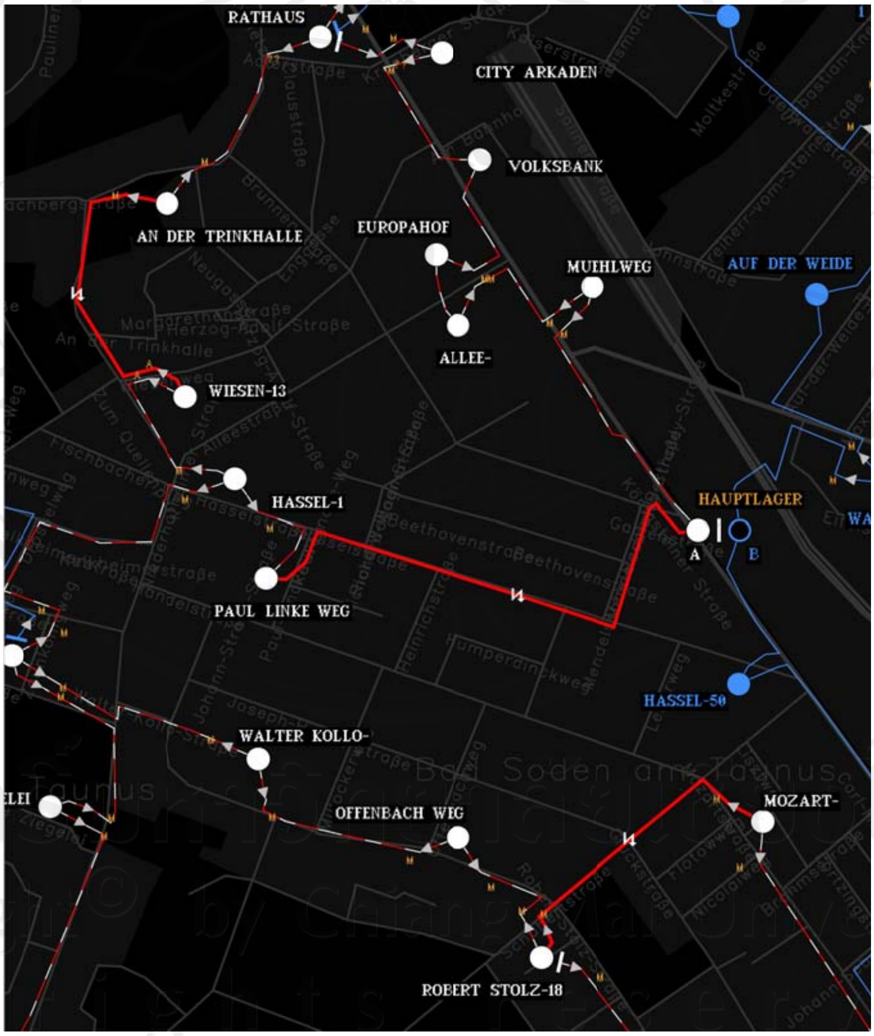

Figure 2.13: Fault Location, Isolation and Service Restoration

Source: PSI-CNI

- PLOM (Planned Outage Management) in Figure 2.14
  - o Analysis of outage requests:
    - Look-ahead operation modeling and analysis

      Takes into account future authorized maintenance jobs
    - Look-ahead contingency analysis with restorability assessment
      - Calculates the probable number of un-restored customers
  - o Switching orders preparation

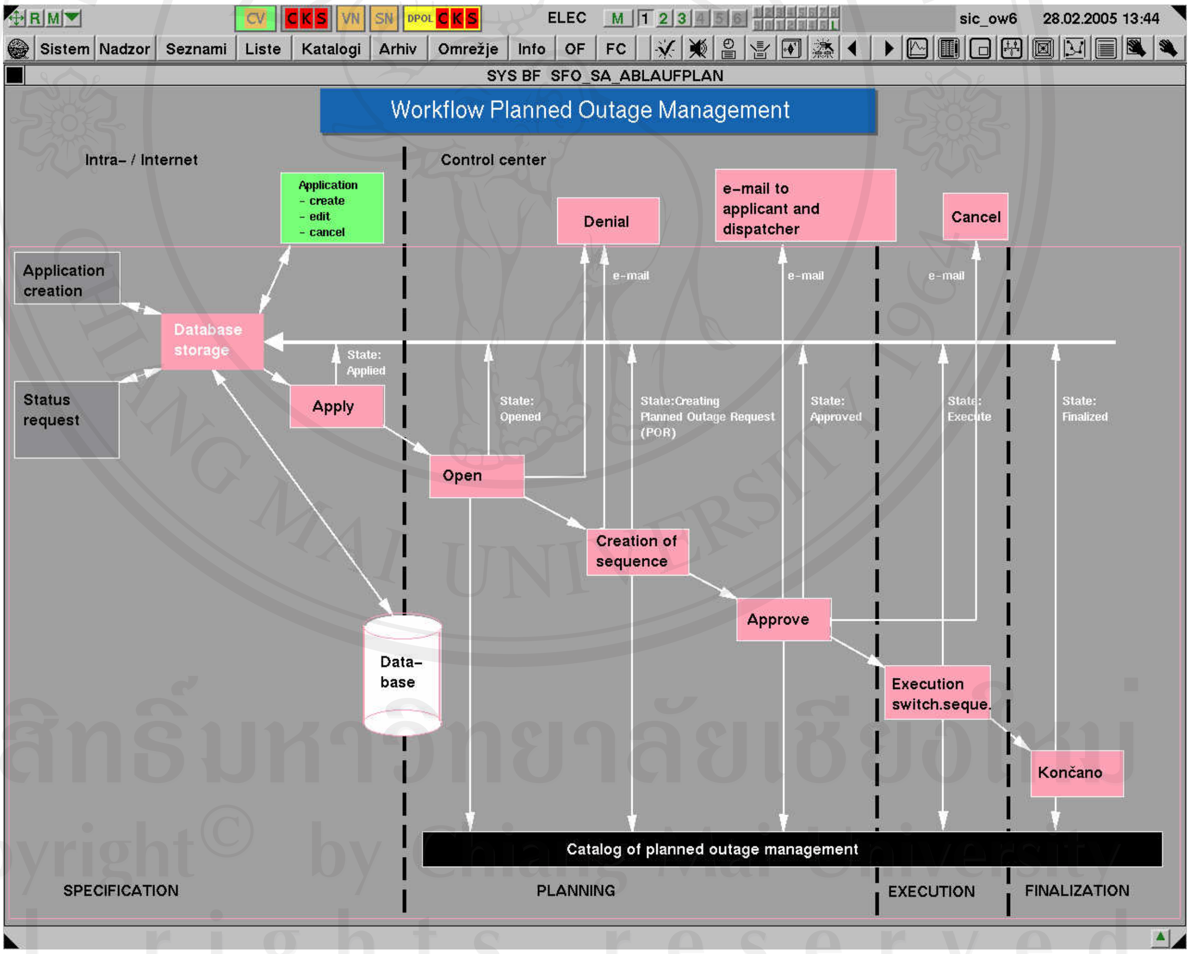

Figure 2.14: Work Order Management (Planned Outage)

Source: PSI-CNI

Other system component that may interface with advance DMS function:-

- OMS (Outage Management System) in Figure 2.15
- SMS (Switching Management System)
- WMS (Work Management System)
- AMS (Asset Management System)
- CIS (Customer Information System)
- AMR (Automatic Meter Reading)
- LMS (Load Management System)
- DAS (Distribution automation system)

This integration of different system can be achieved by using an international standard such as IEC 61968 (Common Information Model for Distribution System). Although Common Information Model (CIM) can be used to create central database which all applications are linked, this is not a solution. Generally there are different data structures existing in various applications both in data center such as SCADA, DMS application, GIS, and external such as CIS and ERP.

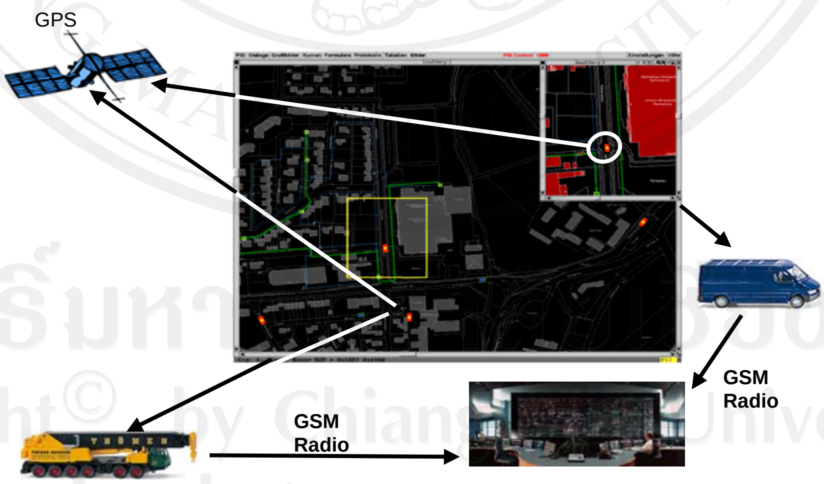

Figure 2.15: Outage Management System

Source: PSI-CNI

Data interface between these applications can be done via messaging middleware where common interfaces or wrappers attach each application to message bus as shown in Figure 2.16. And XML language is used to create self description message.

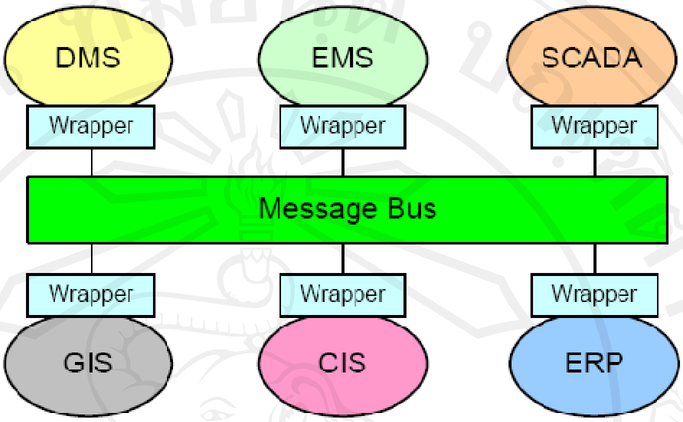

Figure 2.16 Message bus and wrappers

Moreover, after updating the database with other system, the database switcher in figure 2.17a will switch future database into current database in figure 2.17b in order to keep the speed of CPU.

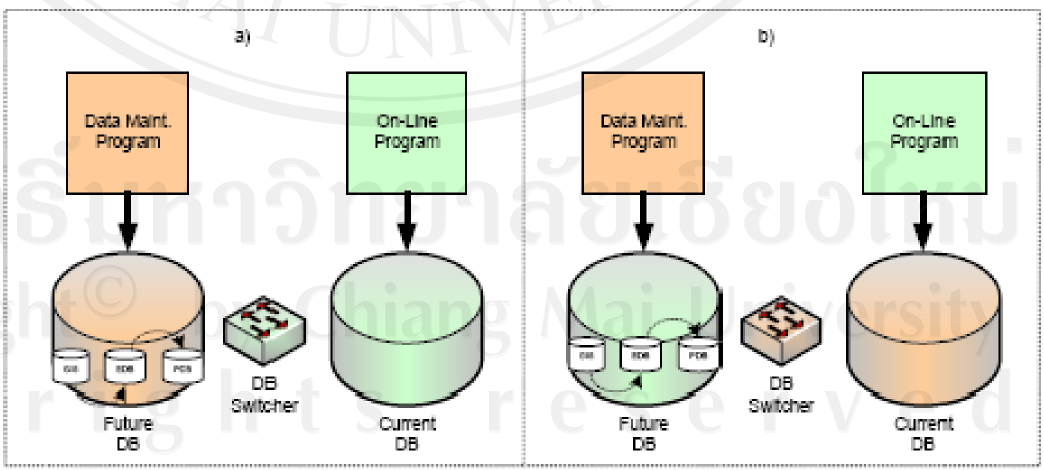

Figure 2.17: Data Management

One off-line mode function that is considered important to operator and service crew is temporary cut and jump in figure 2.18. Normally, it was done in case of emergency. Eventhough, it is not the on-line update, operator need to do this function off-line in operator console for the safety reason. This is identical to the pin point in the map on the board for temporary cut and jump. And this should not be forgotten to remove after restoring the line back into normal service.

2.5 Design, construction, and operation of DMS

In the DMS system product life-cycle (figure 2.19), Utilities learn how to get the optimized system that is adequate to their distribution network and organization. They use DMS system as a tool to monitor and reduce their operation and maintenance cost with the same Quality of Supply. In organizational learning, the utility staffs really need to acquire some new system knowledge and need to develop their skills into action. The DMS system organizational learning process intensively occurs during system planning, designing, installing, commissioning, operation and maintenance procedures.

At the beginning, the planning staffs have to develop the DMS project schedule, transform their requirements into functions defined in the specification as precisely as possible. At the procurement state, bidding evaluation and project execution may be very complex tasks according to many technical deviations and regulations. When the project is awarded, project manager who knows the context, process, background and legal aspects of the contract will be selected to manage the DMS project. He/She must be a DMS domain specialist; moreover he/she should have close contacts to his/her base organization and he/she should be able to lead a team including conflict management. The production of hardware, software, system configuration and integration can not be started before document approval state has been finished. After production, the Factory Acceptance Test (FAT) should be examined at the manufacturer's factory.

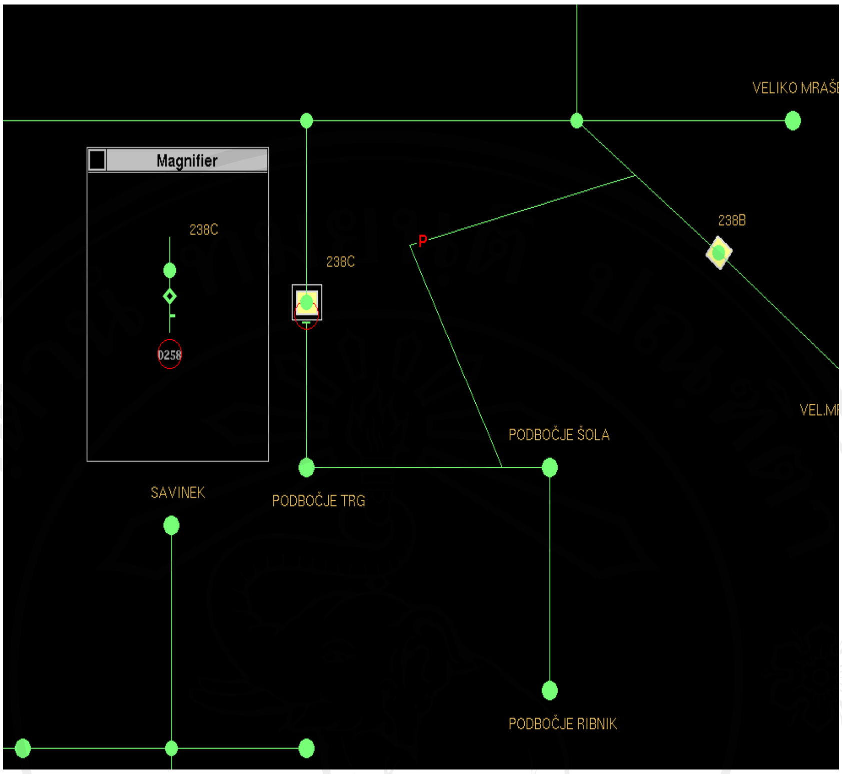

Figure 2.18: Temporary Cut and Jump

Source: PSI-CNI

This process should be performed under the customers' inspection. After that, the systems are installed and commissioned at a site to get Site Acceptance Test (SAT) which is again under customer inspection. At this time, the DMS system is ready to be operated. In addition, the operation and maintenance staffs must be trained how to operate the systems. To encourage the co-operative team which is founded from both side: - the utility and supplier, a relationship agreement may be signed during system life cycle. Diagnosis, replacement and maintenance procedures during the operation influence the availability and safety of the system. The life-cycle maintenance should be included system expansion and upgrading. Lastly, Utilities will be decommissioned and replaced the system with a new one at the end of life time.

The utility problem in designing DMS is lack of expertise within organization. Usually technical assistance by expert is always used for DMS project. However, utility will not have his/her own knowledge to maintain the system. Knowledge management and knowledge engineering theory is then presented in next chapter.

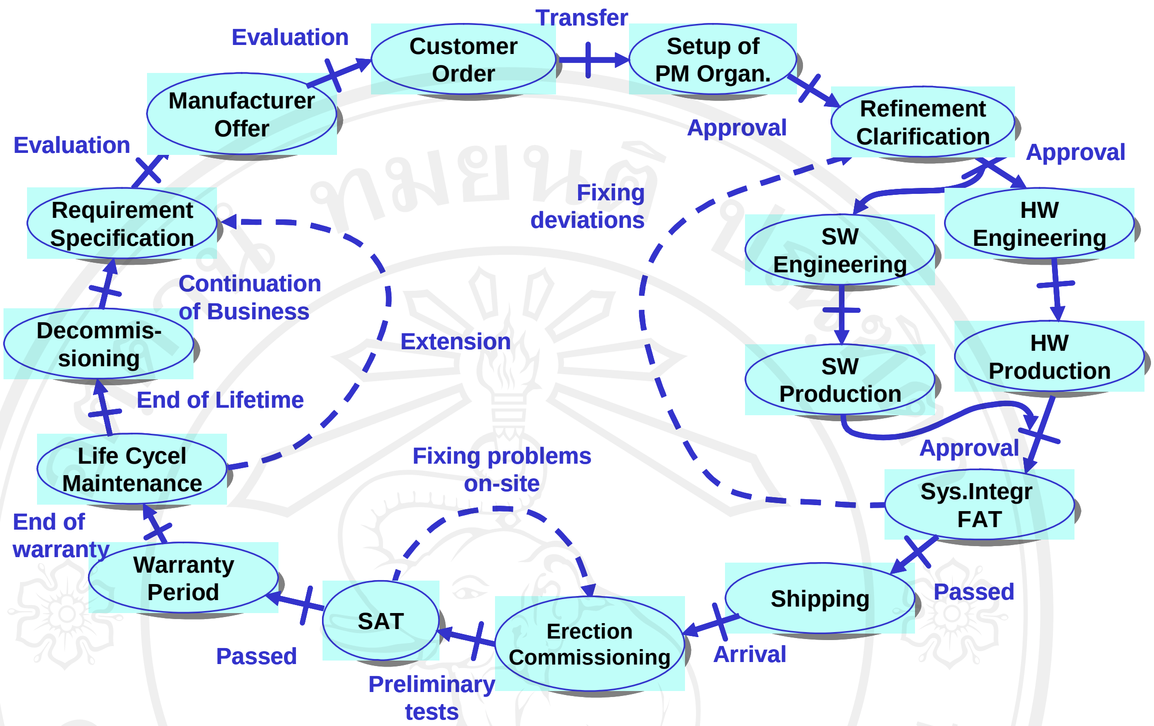

Figure 2.19: Life Cycle Assessment [26]