THE DISTRIBUTION DISPATCHING CENTER PROJECT AT THE PROVINCIAL ELECTRICITY AUTHORITY OF THAILAND

R. Hoffman[1], M. Dubois[1], W. Koykul[2], S. Chiochanchai[2], R. Wasley[3]

[1]SNC-Lavalin Energy Control Systems, [2]Provincial Electricity Authority of Thailand, [3]KEMA Consulting

INTRODUCTION

The Provincial Electricity Authority of Thailand (PEA) is modernizing its power system distribution network by installing distribution automation (DA) facilities in its HV/MV substations and on its MV feeders. A large-scope Distribution Management System (DMS) is also being installed to allow remote operation of the distribution network. This hierarchical system will provide PEA with its first ever computer-based distribution dispatching centers.

The DA and DMS procurement is part of PEA's Distribution Dispatching Center (DDC) Project 1st Stage, which is partially funded by a loan from the World Bank. The project includes a new System Management Center (SMC) and five new Area Distribution Dispatching Centers (ADDCs).

The SMC will manage ADDC power system operations from PEA headquarters in Bangkok, whereas the ADDCs will perform their power system operations from sites within their own service territories. This distribution system automation and management project is believed to be the largest of its kind ever undertaken in the world.

The purpose of this paper is to give a brief over view of PEA's operations and distribution network and then to describe the main DA and DMS facilities that are being installed.

BACKGROUND

PEA Operating Responsibilities

PEA collaborates and shares responsibility for electricity supply in Thailand with two other state enterprises, namely the Electricity Generating Authority of Thailand (EGAT) and the Metropolitan Electricity Authority (MEA). EGAT is responsible for generation and bulk power transmission. On the other hand, MEA distributes power to Bangkok and two adjoining provinces, while PEA distributes power to all other parts of Thailand.

PEA is organized into four administrative regions. Each of these Northern, North-eastern, Central, and Southern regions consists of three service areas, each with its own Administrative Office and ADDC.

Before completion of the DDC Project 1st Stage, power system operations continue to depend not on computer-based facilities, but on manual dispatch procedures aided by hand-dressed mimic boards, paper maps, and voice communications based on telephone and UHF and VHF radio systems. Dispatchers plan and direct daily operations that are performed by personnel located at the substations and electric offices.

The electric offices are responsible for providing local customer services that include meter reading, bill collecting, connecting and disconnecting power, responding to customer telephone calls, and executing power system construction, maintenance, and repair activities.

PEA Power System

The PEA power system serves more than 11.7 million customers. The maximum demand from these customers is more than 10,500 MW and, with annual energy sales in excess of 56,500 GWh, demand continues to grow rapidly at more than 5.9% per year.

The system covers 510,000 square kilometers (approximately 99% of Thailand's total area). It includes more than 298 substations with circuits operating at 115, 69, 33 and 22 kV. The 115 and 69 kV circuits constitute the high-voltage (HV) subtransmission system with a total length of 4,624 km. The 33 and 22 kV circuits constitute the medium-voltage (MV) primary distribution system. Their total length is more than 244,617 km (approximately 19% at 33 kV and 81% at 22 kV).

PEA's low-voltage (LV) secondary distribution system is operated at a voltage of 380/220V.

With few exceptions, the power system is overhead and radial in nature. It is anticipated, however, that the HV circuits will become more meshed in the future. The substations include switchable shunt capacitor banks and transformers with on-load tap changers. More and more substations are being automated through the application of Computer-Based Substation Control Systems (CSCSs). The MV circuits include circuit breakers at substations, reclosers on main lines, and fuse cut-outs on branch lines. Line regulators are used as well as fixed and time-switched capacitor banks. For efficiency and reliability, a system of open loops has been adopted. Feeders can be reconfigured by closing the normally open tie-switches at substation load transfer buses and at various pole-mounted locations outside the substations.

A small number of generators are connected to PEA's power system. They are owned and operated by Small Power Producers (SPPs) under contract with EGAT.

PROJECT OBJECTIVE AND GOALS

The objective of the DDC Project 1st Stage is to apply distribution automation and management facilities to improve service reliability, reduce operating costs, increase profitability, and enhance customer service in five of PEA's most industrialized and heavily loaded service areas. It is anticipated that PEA's other seven service areas will be automated at some future time in a separate second stage project. To meet the objective, the DMS has been designed to achieve the following goals:

- Improve dispatcher ability to monitor and control the power system during normal, abnormal, and emergency conditions by providing more reliable and appropriate real-time data.
- Improve ability of PEA engineering staff to perform power systems analysis and planning by providing increased access to past and current operations data and associated software tools.
- Improve quality of service and customer relations by responding to customer service interruptions more rapidly.
- Improve quality of customer power supplies in regard to voltage sags and swells as well as harmonics.
- Improve power system efficiency by maintaining acceptable power factors and reducing losses.
- Improve power system effectiveness by controlling and limiting peak power demands.
- Improve power system maintenance and safety practices by providing more reliable, meaningful, and timely information on the status of the power system and its field devices.
- Improve PEA's ability to manage its power system assets and system operations by providing increased access to better performance data and other historical records and statistics.
- Improve dispatcher training facilities and hence dispatcher abilities and skills as they relate to modern operating practices.
- Improve efficiency of operations by providing increased automation and the potential for reducing PEA manpower requirements.

The rest of this paper describes the facilities, equipment and software systems that are being procured and installed as part of the DDC 1st Stage Project.

FIELD EQUIPMENT

Remote Terminal Units

A large number of Remote Terminal Units (RTUs) are being installed to enable automation of the distribution network. They are being installed in substations (SRTUs) and on various types of feeder devices outside the substation (FRTUs). In addition, RTUs are being installed as digital communication interfaces to existing CSCSs.

The RTUs are modular in design and can be configured in various sizes ranging, from a single node configuration for pole-top applications, to large multi-node configurations for use in HV/MV substations.

A distributed architecture is used that allows small input/output nodes to be distributed throughout the substation near the equipment being monitored and controlled, thus greatly minimizing the amount of wiring needed. The distributed nodes communicate with a central node via fiber optic communication links. The central node in turn communicates with the DMS master using the DNP3.0 protocol. The ability to use other protocols such as IEC 870-5 is also provided. Unsolicited report-by-exception will be used for status changes while analog values will be reported by exception with polling.

I/O nodes include a Digital Signal Processor (DSP) that permits direct AC input from potential and current transformers. In addition to basic RMS amplitude determination, the DSP enables computation of MW and Mvar power, calculation of harmonic content and other power quality data such as voltage sags and swells, detection and collection of disturbance data including sequence of events, and detection of fault passage, etc.

The RTU also supports definition and execution of programmable logic functions, such as closed loop voltage control of transformer taps.

The following is a summary of the locations and quantities of RTUs being installed under the current phase of the program:

- 50 large substation RTUs
- 100 communication interfaces to CSCSs
- 1600 remotely controlled pole-top SF_6 load break switches
- 422 line reclosers
- 40 line voltage regulators with reclosers.

Multiple Address Radio System

Most of the SRTUs will communicate with the DMS master over existing digital microwave links and/or a time division multiple access radio system. However, all FRTUs as well as a few SRTUs, will communicate via an extensive Multiple Address Radio System (MARS) that will extend digital communications from the microwave facilities to the FRTU locations.

The MARS includes 56 sets of redundant master radios, 42 sets of redundant repeater radios (at 21 sites), and 2,062 individual remote radios. The number of remote radios corresponds to the number of FRTUs. A communication path analysis was performed automatically using digitized topography data from PEA's Geographical Information System (GIS). In some remote or mountainous areas, up to 3 hops are required to get adequate signal strength.

Feeder Capacitor Control

PEA uses both fixed and time-of-day switched capacitors on its distribution feeders. However, to make better and more efficient use of switched capacitors, a total of 139 capacitors are being equipped with interfaces to allow remote control from the DMS via a commercial paging communication facility. The DMS will determine when the capacitor should be switched based on estimated voltages and Var flows at the capacitor locations

DMS MASTER STATIONS

Control Center Buildings

Six new control center buildings have been constructed under the DDC 1st Stage Project to house the five ADDCs and the SMC.

System Hardware and Software

The SMC and each ADDC will be equipped with a modern DMS. The DMS hardware consists of multiple Compaq Alpha processor nodes in an open distributed architecture with dual 100Base-T LANs to connect the various computer nodes.

The Tru64 UNIX operating system is used on each node along with the SNC-Lavalin Distributed Application Environment (DAE) middleware to enable high-performance and high-availability operation of the distributed system. Among its numerous features, the DAE supports replicated real-time databases, which allow virtually instantaneous fail-over of dual-redundant software processes.

Each ADDC control room is furnished with a supervisor console, an HV console, two MV consoles, and two LV consoles, whereas the SMC control room is furnished with a supervisor console and two HV consoles. Except for the LV consoles, which have two dispatcher monitors, the other control room consoles have three. All control rooms include a BARCO large screen (2.25 m x 5 m) rear projection system. Each system also supports a visitor's console, approximately 10 PCs used for a variety of data maintenance and other support functions, and up to 15 PC-based consoles in remote electric offices.

SCADA Software

Each DMS has full, high-performance SCADA functionality. This provides all typical data acquisition, alarming, supervisory control, historical data collection, and other functions expected in a modern day system. The following is a brief summary of some of the features included:

- It has a high-performance full graphics user interface (GUI) that can operate both on UNIX workstations and on MSWindows PCs for displaying electrical networks. The GUI supports panning, zooming and decluttering and has a rich set of rendering and network colouring functions. The system's user interface supports both Thai and English.

- It has a powerful calculated points package that in addition to usual arithmetic operations supports advanced features such as low-pass filtering, best source selection from multiple points, counting of breaker operations, maintaining last non-zero value of current through a breaker before it tripped, and many more.

- It has a user-programmable scripting language that can, for example, with a single command automatically perform multiple switching operations including programmable logic including conditional branching based on values of current telemetered data.

- There is full support of modern industry standard communication protocols such as DNP3.0 and IEC870-5 for RTUs and IEC-870-6 TASE.2 (ICCP) for control centers.

DMS APPLICATION FUNCTIONS

At the heart of the DMS are the application functions that provide network modelling and analysis capability. The main DMS applications are described in the following sections.

Network Model

The DMS includes a full 3-phase unbalanced model of the entire MV distribution network. This model begins with an injection device representing the bulk supply point from the EGAT or PEA HV network.

All conducting devices including HV/MV transformers, overhead lines, underground cables and all circuit breakers, sectionalising switches and fuses down to the MV/LV distribution transformers are modelled. If desired, it is also possible to model the LV network, but generally modelling to this level of detail is not considered cost-effective. The wired connectivity between all of the conducting devices must be modelled explicitly.

The total customer load supplied by each distribution transformer is modelled as a single aggregate load. For the trouble call and outage analysis subsystem, it is also necessary to model which distribution transformer supplies each customer.

The network model will be extracted from whatever adequate data is available from PEA's GIS. In addition, data must be obtained from PEA's customer information system (CIS) and other sources of engineering data not currently included in the GIS. A considerable amount of work is required to capture the initial data needed for the model.

Temporary Changes

The model is capable of correctly representing temporary network changes including allowing dispatchers in the real-time on-line environment to define conductor cuts, jumpers, and temporary grounds such as may be applied during maintenance operations and temporary restoration of power following storms.

Connectivity Analysis

The Connectivity Analysis (CA) application uses the open-closed status of every telemetered and manually up-dated switch device in the network to determine the live/dead and grounded status of every device in the network. In real-time operation, CA automatically updates the network state whenever any switch device changes state or whenever a temporary change is applied or removed.

Power Flow

After CA has determined a new network state the Power Flow (PF) application automatically computes the estimated 3-phase unbalanced voltage and current flow at every point in the distribution network. The results of the power flow are automatically checked against limits and alarms raised. At regular intervals the loads used by PF are scaled by the Demand Estimation application so that the results of the PF application match any available telemetered measurements from the real network.

Var Control

PEA has contractual obligations on power factors at bulk supply points from EGAT. Also keeping power factors on feeders close to 1.0 will minimize losses in the PEA network.

The Var control application uses telemetered measurements of Var flows in substations as well as estimated values of Var flows as determined by the PF application to determine when to automatically switch capacitors. The objective is to keep power factors throughout the distribution network as well as voltages seen by customers within pre-defined limits.

Voltage Control

It is generally recognized that the total MW load in a distribution network can be slightly reduced during times of peak demand by reducing the system voltage slightly. The objective of the Voltage Control application is to achieve temporary small reductions in system load by reducing the voltage at the secondary side of HV/MV transformers. The voltage Control application uses the PF application to ensure that voltage levels received by customers remain within obligatory levels.

Load Shedding and Restoration

The objective of the load shedding and restoration (LSR) application is to enable dispatchers to quickly and efficiently shed load under emergency conditions when EGAT is unable to supply the total PEA demand. The load shedding application will automatically trip breakers on feeders according to predefined lists until the amount of load requested by the dispatcher is shed.

LSR also includes a rotating mode under which loads that have been shed for longer than a defined period of time are automatically restored and replaced by other loads.

Fault Location, Isolation and System Restoration

The objective of the FISR application is to minimize the duration of outages to customers caused by network faults. FISR automatically assists the dispatcher in locating network faults that cause feeder breakers to trip and in quickly determining the switching actions that will isolate faulted sections and restore power to unfaulted feeder sections both upstream and downstream of the faulted sections.

FISR execution is triggered automatically whenever a feeder breaker trips on its own and where reclosing attempts are unsuccessful. It automatically checks which of the FRTUs downstream of the tripped breaker did and did not detect a passage of fault current. The fault is deemed to have occurred in the section downstream of the last FRTU which saw the fault passage and upstream of the first FRTU that did not see the fault.

The most difficult task for the FISR application is to determine switching actions that will restore power to the unfaulted downstream island by finding normally-open tie switches to close without causing system overloads or low voltages to customers. The restoration task is especially difficult when there is a problem in the substation and restoration strategies must be found for multiple feeders.

Trouble Call and Outage Management

The TCOM application is used to assist the dispatcher in identifying and responding to network outages undetected by SCADA telemetry. Generally, customers report these outages via trouble calls to the utility.

TCOM provides computer-based facilities for keeping track of each customer trouble call and automatically grouping multiple calls in the same part of the network into a single suspected outage. This is achieved by mapping customer calls to the electrical network model and tracing them to a common suspected open fuse or other protective device.

TCOM automatically determines the number of customers affected by each outage and assists the dispatcher in prioritising outages according to their size and in dispatching trouble crews to deal with the outage.

TCOM also automatically collects statistics on the number of customers affected and the duration of each outage. These statistics are used to determine industry standard quality-of-service indices.

Switching Order Management

The purpose of the Switching Order Management (SOM) application is to provide computer-aided creation, verification and execution of switching orders. The objective is to reduce dispatcher workload and to ensure higher quality switching plans.

SOM includes facilities to automate to a large extent the creation and verification of switching orders by making use of the network tracing services of the distribution network model. SOM has support for the PEA safety rules that must be followed during switching procedures.

Switching sheets may be automatically executed in study mode to verify the validity of the proposed switching actions prior to actually implementing them.

During actual execution, SOM automatically tracks progress from the field crews, and records the time of completion of each step in the order. As switching actions are completed the real-time network model is automatically updated accordingly. Where switching involves remotely controllable devices, SOM is able to automatically execute such steps when enabled by the dispatcher.

High Voltage Applications

Under the DDC 1st Stage Project, a complete set of EMS-type applications is also being provided for the PEA HV distribution network. This includes Load Forecast, State Estimation, Power Flow and Contingency Analysis as well as Fault Level Calculation. Some of the HV applications will have limited usefulness initially, but will become more important in the future as the HV network becomes more meshed.

Dispatcher Training Simulator

A DTS facility is being provided at one of the ADDCs. It will be used to train new dispatchers how to operate the power system via the actual DMS, and to provide refresher training to more experienced dispatchers.

The objective of the DTS is to make the training environment match the real-time operational environment as closely as possible. Thus, it includes an exact copy of the displays and applications used on the real-time DMS, but in such a way that the DTS supports these facilities by also executing a simulation of the PEA distribution network, RTUs and associated communications system.

The DTS includes instructor facilities to define realistic training scenarios that may include both simulated network faults as well as RTU or communication malfunctions.

PROJECT STATUS AND SCHEDULE

In July 2000, PEA signed a contract with SNC-Lavalin of Montreal, Canada, for the supply of the DMS. This includes the computer systems, the SRTUs, the FRTUs, the MARS radio system, the six new distribution dispatching center buildings, and all necessary field installation and adaptation services.

The 1600 line switches were procured under two separate contracts for 800 switches each and most are already installed by PEA. The installation of the RTUs and the MARS radio system commenced in the first quarter of 2002.

The SCADA component of the DMS systems were delivered during the second quarter of 2002 and are being used along with the communication facilities to perform end-to-end testing of the RTUs as they are being installed.

The systems, including the control centers and all field equipment, will be fully operational and commissioned in 2003.