Application of an IEC 61850 and Synchrophasor Solution for Electricity of Vietnam

***Abstract*—Electricity of Vietnam (EVN) is a state-owned company that operates and maintains the generation, transmission, distribution, and sale of electric power in Vietnam. In 2005, EVN began the modernization of their 500 kV and 220 kV transmission line substations to use an IEC 61850 platform, including their 500 kV backbone system. This line extends 1500 km from Hoa Binh Hydro Power Plant in the Northern Region to Ho Chi Minh City in Southern Vietnam. This project was part of EVN's plan to address an anticipated electricity shortage in 2010 due to the steady annual increase in power load across Vietnam.**

This project included the installation of a new automation system named @STATION. The scope of each @STATION included the following:

- **Redundant substation LANs (local-area networks) using optic fiber.**
- **New redundant HMIs (human-machine interfaces), advanced applications, and SCADA (supervisory control and data acquisition) interface.**
- **Maximum system sizing consisting of more than 60,000 points within the real-time database and historian.**
- **Integration of both IEC 61850-compliant and legacy IEDs (intelligent electronic devices).**
- **Replacement of electromechanical relays and meters.**

To date, EVN has completed new and modernized projects for 35 substations with up to 100 IEDs connected to the IEC 61850 network within each substation. Some of these IEDs did not primarily support IEC 61850, so they were integrated into the substation LAN using legacy device gateways. This involved backward-mapping serial protocols to an IEC 61850 hierarchical data model. Customized tools based on the Substation Configuration Language (SCL) were developed to automate this process and simplify system configuration. All of the bay control units and transformer, directional overcurrent, distance, busbar, and line current differential relays used IEC 61850 GOOSE (Generic Object-Oriented Substation Event) messages and MMS (Manufacturing Message Specification) for communicating protection, control, and automation schemes.

Due to the long line distances and the distribution of power resources among regions, the EVN 500 kV transmission system was prone to angle and voltage instabilities. Therefore, EVN required a supervisory system that would enable them to safely operate their existing transmission infrastructure closer to its stability limit, while meeting the demand growth rate of 15 to 17 percent per year. A customized solution of wide-area measurement was implemented using the synchrophasor functionality within the installed IEDs. This solution allowed EVN to track their current power transfer and compare this against the real-time transmission capability, indicating any stability violations to the operators. This solution involved development of both a desktop and web-based application to satisfy the EVN visualization requirements.

I. Introduction

To support the increasing load rate in conjunction with Vietnam's socioeconomic development and growth, Electricity of Vietnam (EVN) is in the midst of increasing investment in the power network infrastructure by executing more than 2,000 projects annually, with the average invested capital of more than 1 billion U.S. dollars per year for transmission and distribution systems. To ensure safe and stable operation of the power system, an increase in generation capacity of 1,300 to 1,500 MW per annum is required from 2006 to 2010, with even higher expectations until 2025 (see Fig. 1).

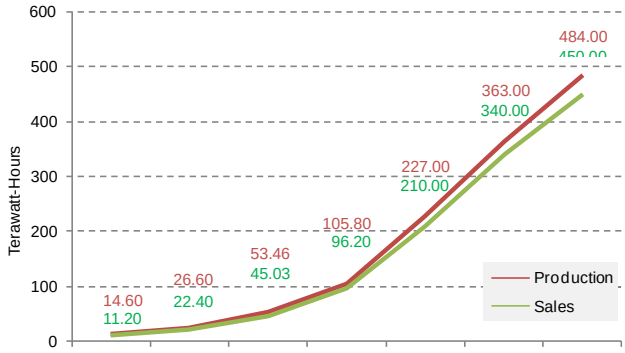

Fig. 1. Electricity Production and Sales Forecast Through 2025 [1]

In an emerging economic country like Vietnam, the demand growth rate has been forecasted up to 17 percent per year in some scenarios; therefore, Vietnam has a very high demand for financing electricity development [1]. Power sector reformation is one of the government's strategies to attract foreign investment capital and improve internal management efficiency. With support from international lending institutions like the World Bank and Asia Development Bank, EVN harmonized their power transmission infrastructures. The first computerized 220 kV substation was installed in Ho Chi Minh City in 1999, followed by several more substations. From 1999 to 2003, EVN faced many problems that were caused by the use of different manufacturers' relays and IEDs (intelligent electronic devices). The lack of international communications standards resulted in poor interoperability between these devices. To address these problems, EVN issued a standard specification for substation protection, control, and automa-

tion in 2003, where UCA2 was introduced for the first time in Vietnam. In October 2005, after the International Electrotechnical Commission (IEC) officially issued Part 10 of the IEC 61850 standard, EVN decided to apply this standard for all new and retrofit substation projects [2]. By 2010, EVN plans to complete IEC 61850 compatibility upgrades on all 500 kV backbone substations. Thus, EVN hopes to derive the benefits of the IEC 61850 substation automation system (SAS) concept, as outlined in a recent study by CIGRE, to make Vietnam one of the world leaders in the power industry [3].

The IEDs selected by EVN, which included protective relays, bay control units (BCUs), and meters, were installed in substations across Vietnam from the far north through the central regions to the south. The critical success factors for these projects were that all the IEDs selected were robust and reliable with a high mean time between failures (MTBF), were compliant with the required standards, and were integrated and serviced by a local system integrator. This integrator provided services ranging from the beginning stages of each project through factory acceptance testing, installation, com- missioning, site acceptance testing, and training. This system integrator is presently the only company able to provide around-the-clock technical services with 24-hour problem solving and repair services.

II. Substation Modernization Using IEC 61850

The 220 kV Thu Duc Substation was an old substation located northeast of Ho Chi Minh City. It was built in the 1960s and encompassed a conventional protection and control system. Due to its strategic location within the transmission system, this substation was being upgraded to improve the transmission capacity of the southern power network. After completing several relatively small, highly successful SAS projects in Vietnam, Applied Technical Systems Co., Ltd. (ATS), a Vietnam-based company, took the challenge to provide a large-scale SAS for one of the largest substations in Vietnam, predicated on new design and approach concepts.

Fig. 2 through Fig. 6 illustrate the differences between the old system and the new SAS. These pictures were taken during the installation and after project completion. Using fiber-optic connections within the substation not only reduced the quantity of hardwire cables to the bare minimum but also resolved the difficulties in maintaining uninterrupted operation during the construction period.

After successfully completing this UCA2 project in 2002, EVN successfully commissioned another 25 IEC 61850-based substations, including the 500 kV backbone substations.

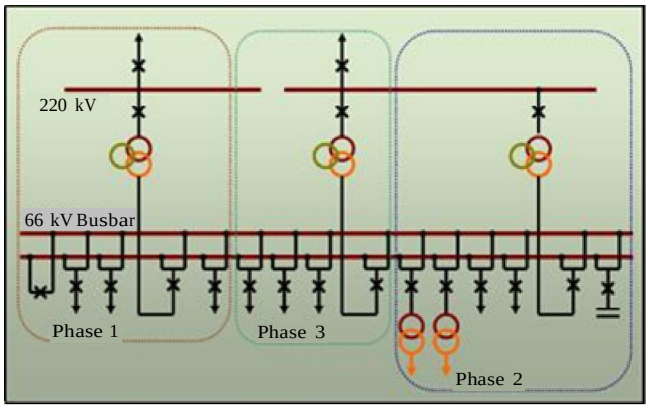

Fig. 2. Old Thu Duc Substation System Architecture

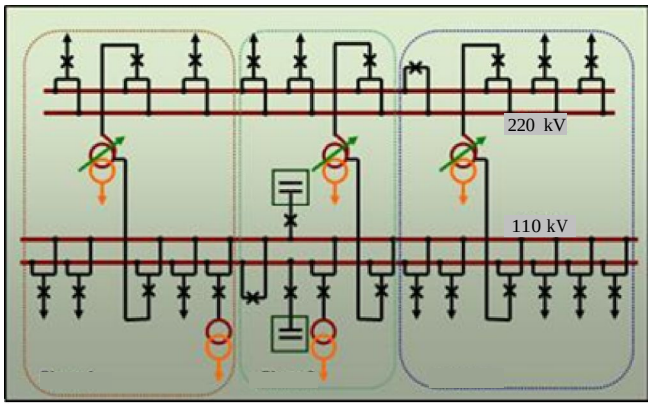

Fig. 3. New Thu Duc Substation System Architecture

Fig. 4. Old and New Relay Panels

Fig. 5. Reduction in Amount of Copper Cabling in New System

Fig. 6. Old and New Control Room Interfaces

A. Project and System Requirements

EVN issued a specification for a complete integrated system requiring the following key features:

1. The operating system applied shall be Windows® NT®, Windows 2000 or the latest version of Linux®.
2. All control and protection equipment shall be linked and interoperated by a dual redundant, 100 Mbps Ethernet LAN (local-area network) using fiber-optic cables to ensure the continuous operation of the system in case of any network failures. The Ethernet LAN shall support TCP/IP (Transmission Control Protocol/Internet Protocol), FTP (File Transfer Protocol), and Telnet.
3. The design of the control system must ensure that any single failure does not affect the system.
4. IEC 61850 and/or UCA2 will be used for substation LAN communications protocols between host computers and IEDs. IEC 60870-5-101 protocol shall be used to move data from substation real-time databases to the existing SCADA (supervisory control and data acquisition) system.
5. Control and monitoring functions shall be performed by the microprocessor-based relays and/or I/O units installed at the substation. The microprocessor-based relays and/or I/O units are responsible for local and remote automatic tripping and closing of the breakers. The relays and/or I/O units send back the status of the breakers along with the operational and maintenance data for the substation apparatus.
6. To reduce the large amount of copper cables, all control and protection cubicles shall be installed outdoors at the bays that they protect and control. The outdoor cubicles shall have appropriate design (e.g., using fans, air conditioners, heating resistors, and conformal coating).
7. Communications processors will be used to perform data concentration and remote terminal functionality. These communications processors will provide the link between the relays and/or I/O units and the substation computer.
8. Analog data from the electrical lines shall be measured by the microprocessor-based relays and/or I/O units, including demand, energy, voltage, current, and instantaneous megawatt and megavar readings.
9. Breaker condition monitoring shall be performed by the microprocessor-based relays. This includes the breaker operational counters, integrated peak and average fault current readings, and percent contact wear.
10. Sequential Events Recorder (SER) functionality shall be performed by the microprocessor-based relays. The sequence of events (SOE) data will automatically stream back to the station computer where they are stored, sorted, and displayed.
11. Analog fault recordings shall be performed automatically through the microprocessor-based relays. Whenever a fault occurs and the relay operates the breaker, an analog fault record will be recorded.
12. Fault location and magnitude shall be calculated by the relay. This information will be mapped back to the station computer for display on the HMI (human- machine interface).
13. The microprocessor-based relay and/or I/O units shall collect all substation alarms. The alarm points shall be mapped back to the station computer for display, and a local historical record will be maintained. The alarm data are also transferred to a database server located in the general office for remote diagnostics.
14. All equipment tagging (red, yellow, purple, and blue) shall be displayed on the microprocessor-based relay LCD and the substation computer. A history of the tags shall be maintained through a database file.
15. The control and monitoring systems will consist of:
    - Main computerized system
    - Backup computerized system
    - Hardwired logic system at the bay level
    - Remote SCADA system

    The control and monitoring of the station will not rely on the station computers; complete control and monitoring will remain available through the communications processors and the microprocessor- based relays and/or I/O units and through traditional hardwired control switches, buttons, and indicators.
16. All protection devices and host computers will be time-synchronized with an IRIG-B time synchronization signal source broadcasted by a GPS clock source.
17. The HMI shall have the design and architecture of a Windows –look and feel‖ and use point-and-click interaction.

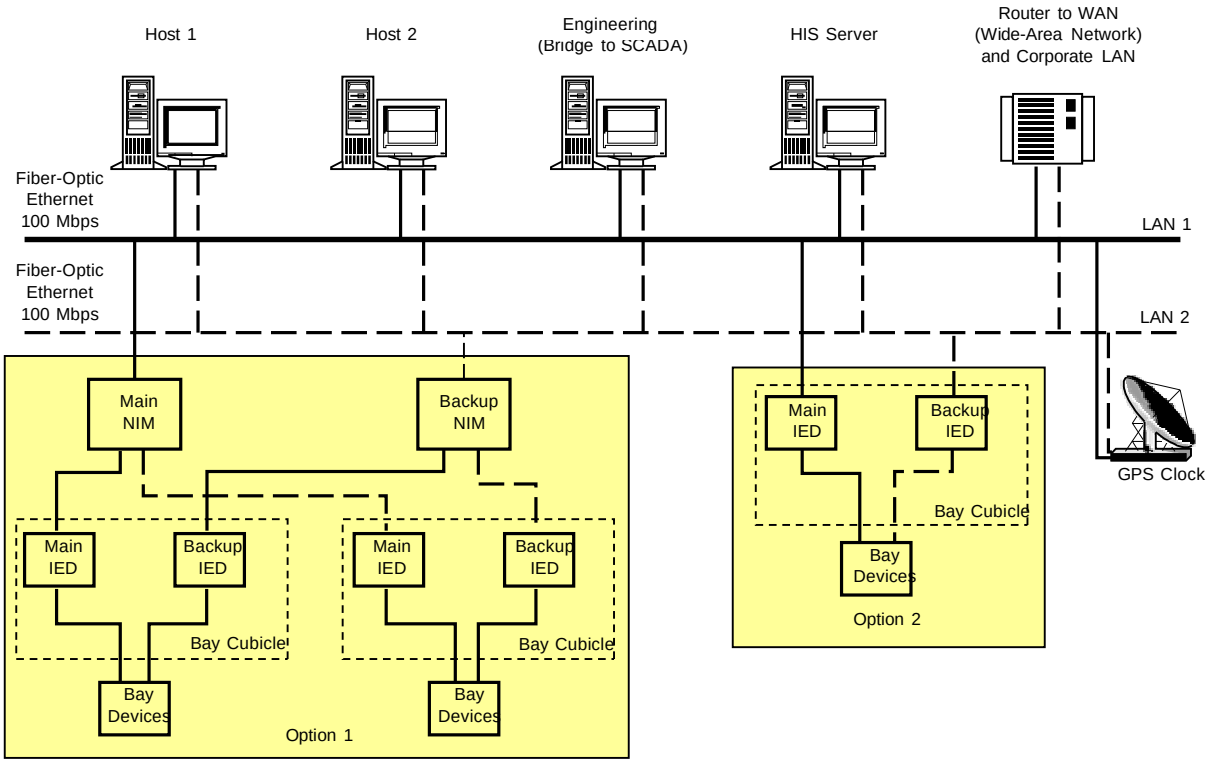

Fig. 7. System Hardware Architecture in EVN Standard

Fig. 7 shows the hardware architecture diagram as designed into the EVN standard.

B. @STATION Network Architecture

Fig. 8 illustrates a typical @STATION system configura- tion overview.

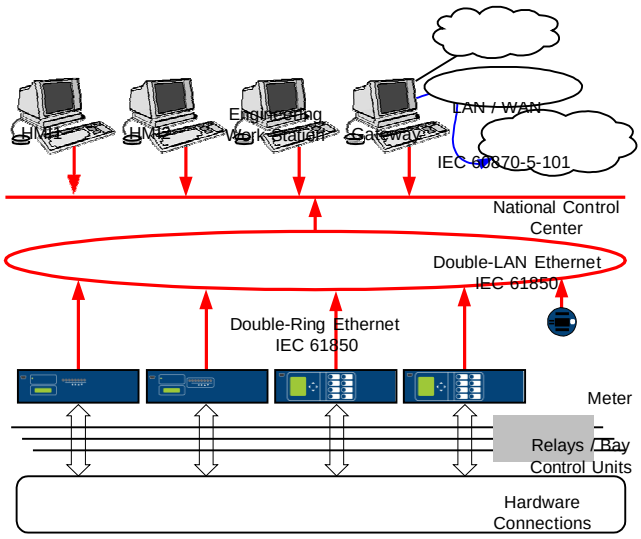

Fig. 8. A Typical @STATION Network Architecture

Due to the importance of the high-voltage and extra-high- voltage substation, the system must ensure the highest levels of reliability and security. To meet this requirement, the sys- tem was designed to encompass two similar structures—one for main protection and control and one for redundancy. Provisions were also included to allow these structures to operate in parallel with the peer-to-peer communications. Both the main and the backup protection and control equipment are linked and interoperated through a double-backbone 100 Mbps Ethernet LAN implemented on multimode fiber- optic cable. The LAN configuration is either in a star or ring architecture, depending on the project. This architecture, which was optimized for performance and economy, ensures the continuous operation of the system in the case of any protection and control component failures.

The main and backup protective relays, revenue meters, and I/O modules are at the lowest level of the architecture. These IEDs, assembled within one cubicle per feeder, collect information and provide system control capability over the LAN using IEC 61850 MMS (Manufacturing Message Specification) messages. The protective relays are connected via serial and fiber-optic Ethernet cables to the second-level communications network, which consists of main and backup network interface modules (NIMs). The NIMs are installed in the master cubicle. The revenue meters and I/O modules are assigned separate IP addresses and connected directly to the

main LAN also by fiber-optic cable. All IEDs are time synchronized by a GPS clock using IRIG-B through a separate coaxial network, as this provides the highest accuracy required for protection applications. Simple Network Time Protocol (SNTP) was determined to be inadequate, as it only provides, at best, one-millisecond accuracy.

The servers are at the highest level of the SAS architecture.

Each server is connected both to main and backup LANs, and

each is directed to execute their own functions. The system includes main and backup servers that support the user interface, the engineering workstation server, and the gateway servers that connect with the SCADA and EMS (energy management system). Details of these functions are provided in the following sections.

To reduce the large number of copper cables used, all of the cubicles are installed outdoors at the bay or feeder. Most of the selected IEDs operate in harsh conditions from −45 to
+80°C. However, other IEDs and ancillary devices may not.
Therefore, appropriate design provisions, such as fans, air conditioners, heating resistors, double-wall special design, moisture- and heat-resistant materials, and conformal coating were adopted to allow the cubicles to resist the extreme weather conditions in Southern Vietnam.

Despite the high reliability of the computerized control
system, the design team decided to install a hard mimic with control switches and indicators at each feeder cubicle. This design approach makes it possible for the operator to manually control the circuit breakers and disconnect switches with full logic and hardwired interlocks in case of a failure of the com- puterized system.

Last but not least, the SAS solution complies with widely accepted industry *de jour* and *de facto* standards for open systems. This enables the integration of equipment from multiple sources. The end user can replace or add new devices and applications when needed. Both the new and existing equipment can interchange and share information from the entire pool of SAS resources.

C. Legacy Device Gateways

During project implementation, the design team needed to find a solution to integrate different types of IEDs from multiple manufacturers, including some that were not com- pliant with IEC 61850. The design team successfully integrated all types of IEDs into the @STATION system using different legacy protocols, such as DNP3, Modbus® TCP/IP, and IEC 60870-5-103, via the IEC 61850 servers, which functioned as legacy device gateways. These gateways converted the data from the IEDs so that they were compatible with IEC 61850 object models, as defined in Parts 7-3 and 7-4 of the standard [4] [5]. This enabled the data to be accessed via IEC 61850 methods over the Ethernet LAN. This mapping was configured using customized tools on both main and backup gateways for redundancy. The hardware selected was based on a rugged computing platform with a high observed MTBF of 70 years.

D. Local HMI and SCADA Interface

The HMI was based on a Wonderware® InTouch solution running on a Windows 2000 platform. This design provided a complete visual control system with a common look and feel, using point-and-click interaction and task-oriented displays. From the HMI servers, the operator can log any piece of information within the integrated system (feeder loading, temperatures, ambient conditions, relay targets, etc.) at a specified period. All alarms issued by the control and

protection system are collected by the HMI servers, where they are grouped by department (operations, communications, maintenance, engineering, etc.), and equipment type (trans- formers, circuit breakers, capacitors, relay trouble/failure, etc.) using customized alarm management software designed and implemented specifically for this project.

The screens were developed with the direct participation of shift engineers, operators, and field service technicians, whose input was critical to gain an intuitive design and provide the best computer interface possible. The colors and symbol defi- nitions used by the HMI followed the EVN standard wherever possible to provide a consistent interface between what the dispatchers and field service technicians see.

The software presents separate windows of information that the service technicians use to operate the station. These windows link to additional views that drill down to show additional detail and information as needed for each station operation. Example HMI screens are illustrated in Fig. 9 and Fig. 10.

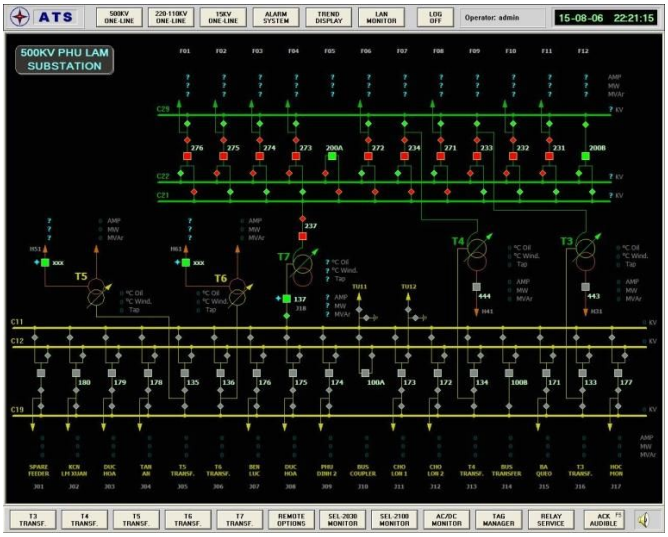

Fig. 9. Single-Line Diagram of 500 kV Substation

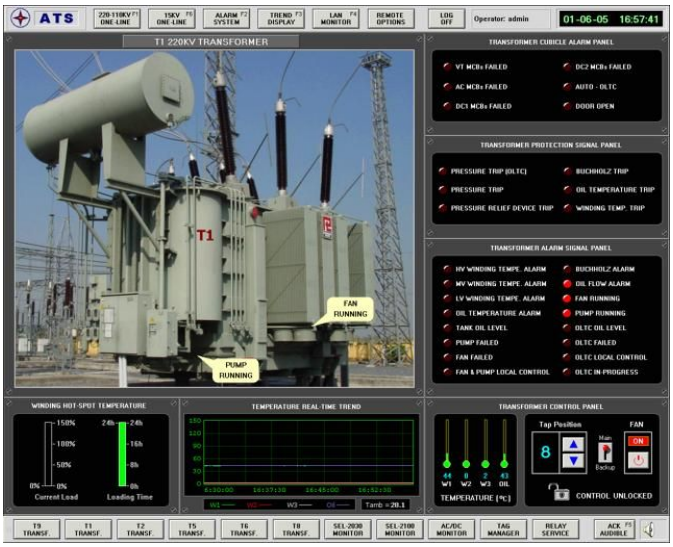

Fig. 10. Detailed Display of 220 kV Transformer

The SAS data environment consists of a real-time database management system (RTDMS). The RTDMS acquires all of the substation data points and builds a robust data repository that enables local and remote applications (historical playback, fault diagnosis, event analysis, SCADA, EMS, etc.) to retrieve the data needed for their own functions. This is a complex system that combines commercially available software with software developed in-house by the system integrator. The SAS RTDMS environment allows the user to custom design substation automation applications by integrating new devices or data mining to optimize the operation and maintenance within the substation. The following are some applications and functions that were developed in-house by the system integrator.

1) Historical Playback

The historical playback system allows the user to move backwards in time to review what happened in the system with data accuracy of just a few seconds. The historical playback user interface is just like any other HMI window and allows adjusting the date and time in a small control window. It can be configured to provide a complete picture of the elec- trical system from the stored data, which include playback of previously recorded monitored data, calculated system para- meters, etc. The historical playback feature is particularly useful when auditing the cause and effect of system events to improve system operations and develop ―what-if‖ and alter-native action scenarios.

2) Web-Based Data Pool

In the context of modern electricity markets, large amounts of data are continuously generated and processed by utility information systems, such as the SCADA or EMS of a network operator and the SCADA systems of various third- party stakeholders. Therefore, the system integrator developed a web-based platform to provide the network operators with timely and accurate information. This user-friendly interface allows operators to run the grid effectively and efficiently. This contemporary application provides access to information regardless of its source and original format. It preserves the integrity and security of the information. The application can also be customized for a variety of needs and is predicated on the use of a standard Internet browser, thus making it easy for use by both experts and nontechnical users, as illustrated by the web parts shown in Fig. 11.

Fig. 11. Web Parts for Interfacing to the Web-Based Data Pool

3) Power Line and Transformer Dynamic Loading Capacity

The online loading capacity calculation program for trans- formers and transmission lines allows the operator to under- stand how to operate each transformer and transmission line under present conditions (e.g., overload and weather condi- tions). Information from this program helps operators know how long the transformer can withstand the present opera- tional state without reducing its life cycle and provides hourly values of transmission line capacity and steady-state, dynamic-state, and transient-state line ratings. The program uses both online data (hot-spot winding temperature, top-oil temperature, ambient temperature, load current, etc.) retrieved from the HMI server and offline information from the transmission line and conductor databases, thus allowing the operator to effectively and economically optimize the capacity of the transformer and transmission line. Fig. 12 illustrates the online loading capacity calculation program interface.

Fig. 12. Dynamic Loading Capacity User Interface

4) SMS Center

The SMS (short message service) Center is an application that allows the user to access the data stored in the archive server through the GMS (global messaging service) by sending SMS messages. The administrator can create and manage user profiles, which include telephone numbers, access levels, and responsibility levels. Afterwards, the user can receive any information in their jurisdiction by sending a message in a predefined format to any telephone number in the world. The program also supports an alarm function that can automatically send SMS alarm messages to specified telephone numbers whenever an event occurs.

For the SCADA gateway, @STATION uses multilevel protocol conversion software. This software first converts data from IEC 61850 MMS to OPC (Object Linking and Embedding for Process Control), then from the OPC environment to the IEC 60870-5-101 and ICCP protocols, which are the protocols that provide interoperability with the existing SCADA and EMS used by the Regional Load Dispatch Center and the National Load Dispatch Center.

Fig. 13 illustrates the different types of software that were used for the SAS configuration. Commercially available off- the-shelf software was used for mapping the substation speci- fication, from drawings and specifications for the physical apparatus to the IED configuration defined within each device's IED capability description (ICD) files. From this mapping, ATS produced a substation configuration descrip- tion (SCD) file that contains information on all IEDs, commu- nications configuration data, and substation descriptions. Vendor-specific tools were used for extracting the configured IED description (CID) information from the SCD file and exporting it to the IEDs. ATS developed their own custom tools for:

Mapping the legacy protocol data from legacy IEDs to IEC 61850 logical nodes and data objects within the IEC 61850 server database.

Developing device configuration descriptions for each legacy device connected to the IEC 61850 servers.

Configuring the SCADA, HMI, and web application databases based on the CID files for each device.

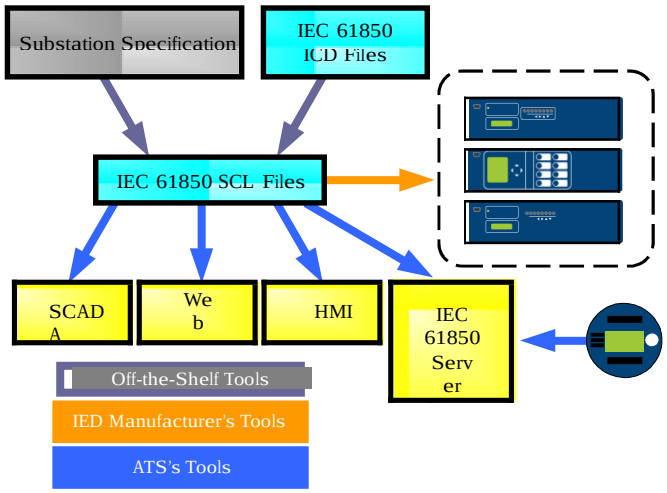

Fig. 13. IEC 61850 Tools for Substation Automation

E. Controls

The design of the fully integrated control system encom- passes a four-level hierarchy with the SCADA and EMS functionality at the top. This design complies with the following requirements:

Level 4: Control and monitoring functions are provided with hardwired interlocking logic at the bay level via a traditional local mimic interface. This level, in combination with interbay-to-substation interlocking signals, enables safe, local operations at the bay cubicles.

Level 3: Control, protection, and monitoring functions are provided with soft interlocking logic at the bay and interbay-to-substation level via relays and BCUs, including interconnection and status exchanges between relays and BCUs. This is accomplished via peer-to-peer communication using IEC 61850 GOOSE (Generic Object-Oriented Substation Event) messages. This level is the most critical for the interlocking

system and for remote and local controls from the operator workstation and SCADA systems. The redundancy ensures that any single failure does not disable control commands, control monitoring, and bay-to-interbay-to-substation interlocking.

Level 2: Control, monitoring, database management, and application functions are provided with soft interlocking logic configured within the substation computers that are used for executing controls from the operator workstation. This logic is configured using a combination of software scripting and relay settings.

Level 1: Control and monitoring functions from SCADA are provided with soft interlocking logic at substation computers and the bay-to-interbay level. The SCADA gateway converts control messages from IEC 60870-5-101 to IEC 61850 MMS.

This design ensures that the substation will continue to be operable even if the @STATION main host fails. There is no single point of failure on the Ethernet LAN or at the IEDs that can cause the substation to become inoperable. The integration system interfaces with the substation equipment through the binary I/O contacts on the relays and BCUs in a redundant configuration that ensures that integration system failures do not disable or degrade the performance of primary station monitoring and control functions.

The protection for lines and transformers includes two sets of protective relays, ensuring that critical functions (protec- tion, primary control functions, metering, etc.) will not be disabled by any single failure.

The meter data are collected from measuring BCU and tariff meters. Backup meters are used in case of main meter source failures. The metering functions within protective relays and BCUs are also available for use as local backup meters.

The design uses two separate dc power sources from two separate battery systems for main and backup elements of the integration system so that no single failure of power source will affect both main and backup elements.

The interfaces of main and backup hosts to other integra- tion elements (communications processors, protective relays, tariff meters, etc.) are electrically isolated by fiber-optic cable, reducing the possibility of electromagnetic field interference or undesired control actions initiated by dc short circuits, such as tripping or closing a circuit breaker.

F. System Functions

The @STATION functions include the following applica- tion subsystems:

Data acquisition and control—includes the basic data acquisition, control, and display functions that allow
the operator to determine the actual status of the substation equipment and perform control actions properly and safely

Historical application—including operational reports and system playback
Analysis

SOE manager
@STATION communications monitoring
Alarm manager
Equipment tagging
Operation report and logbook
Circuit breaker condition monitoring
Online ampacity
Other optional subsystems

The execution of the system, support, and application soft- ware was distributed among the substation computers, relays, BCU servers, and workstations to minimize the response times of the applications, maximize the redundancy and availability of the information, and allow such functionality to be accessed from any local or remote workstation in the configuration. In addition, the @STATION facilities include a historical information system (HIS) and an optional HIS web-based application.

To facilitate these functions, enhance performance, and reduce response times, IEC 61850 GOOSE and IEC 61850 MMS logical node report services were utilized for all communications between the bay or unit level and the substation level.

G. Performance and Functional Testing

The @STATION supports all the functions required by the EVN specifications with the median loading of the system resources not greater than 25 percent under normal loading and 70 percent in high-load scenarios.

As mentioned earlier, the system uses IEC 61850 servers that allow IEDs from different manufacturers to interoperate over an industrial Ethernet LAN. All servers that are directly connected to the LAN are functionally assigned as HMI ser- vers, an engineering server, HIS server, and gateways. The system also provides redundant communications for bay devices. The dual communications include Main 1 and Main 2 communications processors linked to the dual Ethernet LAN. The system ensures automatic recovery for a communications failure in the dual network by automatically reconfiguring the communications ports on the communications processors. On each bay, the main and backup control and protection devices are connected to the main and backup substation LANs by physically separated links.

The factory acceptance testing of the entire IEC 61850 SAS was conducted in ATS's Hanoi factory. A team of ten engineers completed the testing in three weeks. Communications and system performance testing were incorporated into the factory acceptance testing process as part of the EVN system validation requirements. Table I provides a summary of the @STATION performance test results.

TABLE I
@STATION PERFORMANCE TEST RESULTS

Display Response Time	< 1 second	< 1 second
Data Entry Response Time	< 1 second	< 1 second
Display Update Rate	< 2 seconds	< 2 seconds
Update Completion Rate	< 1 second	< 1 second
Alarm/Event Response	< 1 second	< 1 second
Alarm Acknowledge/Delete	< 2 seconds	< 2 seconds
Report and Logbook Response	< 0.5 minute	< 0.5 minute
Display Color Printout	< 0.5 minute	< 0.5 minute
Console Inhibit Time for	< 2 seconds	< 1 second
Analog Data Collection		< 2 seconds
Status Indication Collection		< 1 second
Failover Time Between		0 seconds
GOOSE Exchange Time	< 10	< 8 milliseconds

III. WIDE-AREA SYNCHROPHASOR APPLICATION

Due to the need to increase power transmission across the existing power system infrastructure, coupled with long line distances and large separations between generation and load, EVN required a system that would operate with improved efficiency and service reliability. Using the phasor measure- ment capabilities within the newly installed IEDs, EVN implemented a wide-area synchrophasor monitoring system to provide a real-time display of synchronized values. With this information, operators can improve system performance and stability. EVN identified the following advantages of using protective relays for phasor measurements:

There was minimal incremental cost for equipment (no need to purchase and install separate phasor measurement units).

It reduced the number of required current and voltage connections.

The relays have high reliability and availability. Potential control applications increase the value of the phasor measurements.

The main cause of wide-area disruptions in the present EVN system is due to the relatively long 500 kV transmission line between Hoa Binh and Ho Chi Minh City, which is susceptible to voltage and angle instabilities when there are variances in load and generation sources. Synchrophasor technology provides the state of the power system to operators in real time, allowing calculation of the maximum loading condition for each system bus connected to the transmission network. Preplanned corrective actions can be taken to minimize the risk of wide-area disruptions and increase the system power transfer capability. The availability of a high- speed, high-bandwidth network architecture makes synchrophasors ideal for this application.

A. Real-Time Monitoring on Available Power Transfer Capability

The real power transfer over a transmission line between two network buses is determined by the phase angle difference, the voltage magnitudes at each bus, and the line reactance [6]. Therefore, the real power exchange between Bus A and Bus B is calculated according to the following equation:

$$P \quad \frac{U_A \cdot U_B}{X_L} \sin \qquad (1)$$

where:

P is the real power transfer.

X_L is the transmission line reactance between two buses. is the phase angle difference.

U_A and U_B are the voltage magnitudes at the buses.

From (1), we can derive the maximum power transmission, or the total transmission capability (TTC), as:

$$P_{MAX} \quad \frac{U_A \cdot U_B}{X_L} \qquad (2)$$

Therefore, the reserve margin, or available transmission capacity (ATC), is calculated as:

$$P(\%) \quad \frac{P_{MAX} \quad P}{P_{MAX}} \cdot 100 \qquad (3)$$

Using these two equations, we can compare the TTC with the ATC in real time using the voltage and current synchro- phasor data collected from both ends of the bus.

This application also monitors the change in magnitude and
limits of U and P by:

$$\frac{P}{} \quad 0 \text{ for source nodes}$$

and by:

$$\frac{U}{Q} \quad 0 \text{ for load nodes}$$

and can generate alarms for out-of-tolerance deviations accor- dingly.

B. Synchrophasor Application Architecture

The source of the synchronous phasor measurements comes from the protective relays, which include synchronized measurement and control capabilities in addition to protection functionality. Termed phasor measurement and control units (PMCUs), these IEDs time-align the measured quantities to a common time reference provided by high-quality, high- accuracy GPS clocks. The IEDs stream the synchrophasor messages per the IEEE C37.118 standard over an Ethernet communications channel [7]. These messages are received and filtered through a remote OPC server that is located in Hanoi and functions as a conduit to convert the data packets to OPC format. This enables high-speed integration with a centralized PI (plant information) database server, which is located in the control center. This database functions as a centralized phasor data concentrator (PDC), collecting and time-aligning the data from all data sources. It is the core component of this system. The PI system was chosen because of its capabilities for handling real-time and historical data and its high data retrieval speeds.

The HMI solution consists of several applications that were
developed for specific uses. These include desktop and web- based applications that provide visualization of the synchro- phasor data through a rich graphical user interface, an appli-
cation that interfaces to MATLAB® used for facilitating
complex calculations, and an application that serves as an interface between the PI system and Microsoft® Office appli- cations (e.g., Excel® and Access®). Fig. 14 illustrates the high- level architecture.

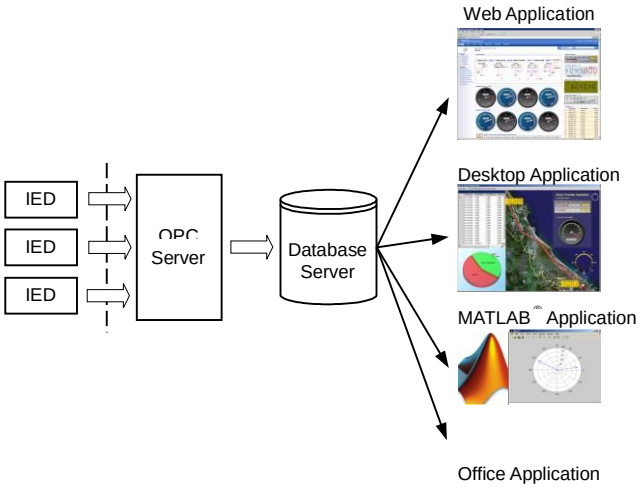

Fig. 14. Synchrophasor Application Architecture

1) Desktop Application

The desktop application was developed primarily to provide visualization of the synchrophasor data for operators. It provides access to both historical and real-time data and is capable of performing sophisticated calculations on the raw
data. The main purpose of this application is to calculate the real-time power transfer capability of the system and

provide alarming on user-settable limits (e.g., high, high-high).

Different data objects can be used to display the data in multiple formats, such as a digital gauge, analog gauge, pie chart, or tabular grid. An example of the interface screen is shown in Fig. 15.

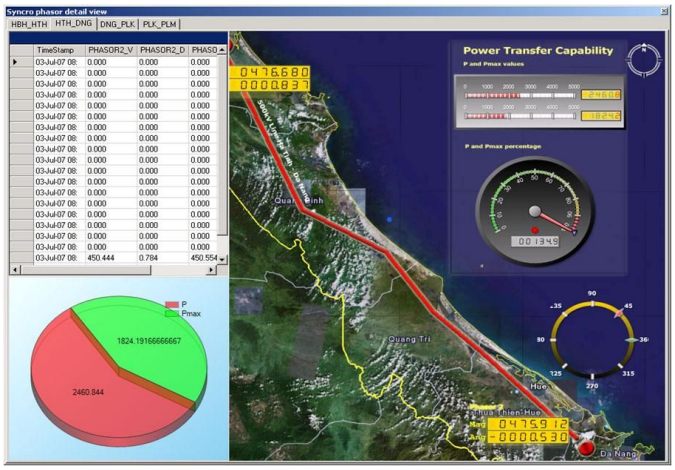

Fig. 15. Synchrophasor Desktop Application Detailed View

Allowing different methods of displaying data facilitates ease of use for each individual operator, which can better inform them of the present situation. For example, the operator can display the current power transfer to compare against the calculated power transfer capability on a pie chart, while simultaneously displaying historical data on the system angle.

2) Web Application

The web application was developed using Microsoft SharePoint® Server, which provides an integrated suite of server capabilities for content management and information sharing across an enterprise portal framework. A web portal site connects operators to the synchrophasor database by logging in through an ordinary web browser. This portal allows users to access the data remotely through a secure Internet connection. The graphical display consists of multiple web parts for visualizing both historical and real-time data. These web parts include circular gauges, trends, archive, and snapshot views. An example of the web application is shown in Fig. 16.

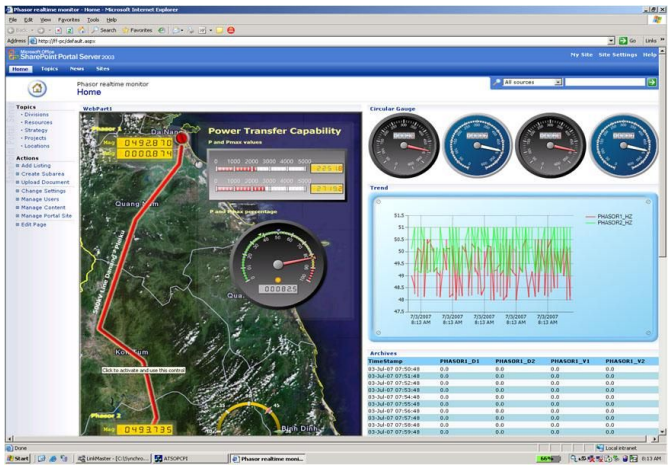

Fig. 16. Web Application Using Microsoft SharePoint Server

The SharePoint portal interface enables each user to confi- gure their own profile and customize the interface to their preferences. This includes modifying the web parts displayed and configuring individual alarm limits.

3) MATLAB Application

The MATLAB application was developed as a simple tool for easy migration of synchrophasor data directly from the OPC server to the MATLAB programming environment using an OPC toolbox extension. This provides a powerful tool for performing very complex calculations. The results of these calculations are then transferred from MATLAB into the PI database, allowing both the desktop and web applications access.

4) Microsoft Office Application

The Microsoft Office application provides a data-link interface to the PI database that enables the user to generate reports based on the historical and real-time synchrophasor data using Microsoft Excel or Access. It is also capable of utilizing modules within the PI system, such as PI Equation and PI Alarm, for utilizing the data within any specific appli- cation that corporate users may need.

IV. Conclusion

Since 1996, EVN has successfully implemented an SAS solution based on IEC 61850. Clear specifications helped them to achieve their goals. The main advantages realized by this system include:

- Interoperability between different manufacturers' IEDs that reduces the need for custom integration labor, enabling lower cost and faster system integration.
- Reduction in the amount of hardwired connections through the implementation of a fiber-optic LAN and GOOSE messages for peer-to-peer data exchange.
- Reduction of copper cables by installing outdoor cubicles adjacent to the bay or feeder.
- Reduction in system malfunctions by nearly 50 percent in the new design compared to the older design.
- Efficient LAN architecture with:
  - Easy system expansion in the future due to fewer complex connections.
  - Integrated system architecture that supports multiple communications streams on the same physical medium.
- Legacy gateways that provide a common network infrastructure for all devices, eliminating application dependency on legacy protocols.

EVN is also using synchrophasors to improve power system performance and reliability through voltage and angle stability monitoring and long-term power system data recording. In the next phase of the project, EVN plans to cooperate with ATS and the Hanoi University of Technology to develop advanced synchrophasor

applications and functions for wide-area, real-time control actions. This includes

undervoltage load shedding of noncritical loads, contingency- based remedial action schemes, automatic generation tripping, switching of shunt capacitors, and system islanding detection.

V. References

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