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THE REAL-TIME AND STUDY-MODE DATA ENVIRONMENT IN MODERN SCADA/EMS

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1.1 INTRODUCTION

1.1.1 General Background

Most large industrial control systems need to collect data at a central location, or at distributed sites, from a range of equipment and devices in the field, and to process this data in order to make a decision regarding any action required. Electric power control systems work basically in the same way but impose particularly stringent requirements on remote data acquisition and related processes because:

- Power systems may encompass large geographical areas as almost all electric utilities have strong electrical interconnections with neighboring systems, which are generally owned and operated by different entities. Examples include: the interconnected systems in North America, such as the Western Interconnection, which consists of the power systems in all the western U.S. states plus the provinces British Columbia, Alberta, and Manitoba in Canada; and the large interconnection in mainland Europe, covering all the mainland European Union member countries plus some nonmembers.
- Interconnected power networks are therefore very large, with potentially tens of thousands of nodes and branches and thousands of generating units.

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- Power systems in general must operate synchronously and this requires that all the interconnected systems must operate cooperatively in order to maintain reliability of the entire system.
- Because of these strong interconnections, any disturbance in one part of the large network can affect the rest of the network.
- Power system disturbances can propagate very rapidly (milliseconds to seconds) and this requires high-performance control systems, some of which are local, such as protective relays that operate in milliseconds, and some at central sites such as SCADA/EMS systems, which typically operate on the time frame of seconds (monitoring and control) to several days (scheduling).
- Power system operations typically entail control requirements that can be met only by implementing complex hierarchies of regional and central/national control systems.
- Power system operations in the context of large regional or subcontinental electric markets typically require exchange of information and coordination of control actions among various entities, such as independent system operators, security coordinators, and transmission system operators, thus leading to a higher degree of coordination and control systems.

1.1.2 Anatomy of a SCADA System

The data acquisition systems that are implemented in the utility industry therefore have to be able to support these needs. Furthermore, in order to make sure that the control actions being taken are correct and safe, certain control actions performed centrally require a positive confirmation, that is, they must be supervised. This is the *supervisory control* function and, therefore, the overall system is called supervisory control and data acquisition or SCADA.

The basic elements included in, and the minimum capability of, a typical SCADA system, consist of:

- Interfaces in the field (substations) to equipment and devices located within the substation.
- Ability to scan these interfaces to obtain the values of various quantities such as real and reactive power, current, voltage, and switch and circuit breaker position. The data are either reported by exception or scanned periodically. Typical scan rates are every 1–2 seconds for generation and interchange data and circuit breaker status indications; every 2–15 seconds for line flow and voltage measurements, and every 15 minutes to one hour for energy values.
- Transmission of these data items to a central location known as the SCADA (or SCADA/EMS, as shown in Section 1.4) center.
- Processing and analyzing this information at the SCADA center and displaying it to the operator.

- Determining any control action to be taken either automatically or by operator request. The control actions required can be for controlling real power, reactive power, voltage, circuit breakers, and power flows.
- Transmitting the request for control to the field equipment.
- Monitoring the completion of the control request.
- Building the real-time database and periodically saving real-time information for archival purposes.

1.1.3 Real-Time Versus Study-Mode Processes

Most of the SCADA functions are executed in real-time. By real-time we mean that the:

- Input data reflect the most recent picture of the system conditions. In the field (substation), they come directly from devices that capture analog values and status indications; at the SCADA center they are stored into, and retrieved from, the real-time database.
- Processing is performed within very short delays typically not exceeding a couple of seconds.
- Output is usable almost instantly; again, "instantly" in this context means approximately one to two seconds.

The monitoring of data generated by a real-time process is a typical example of real-time activity. But the information generated in a SCADA system can be used in many other ways that do not qualify as real-time. For example, statistics can be built to record how many times the taps of a tap changing under load (TCUL) transformer have moved during a specified period of time. The tap changes were recorded in the real-time database immediately after they occurred, and then they were exported to some archival system and became historical data. The calculations entailed in building the statistic constitute a "study" performed with "real-time" data and, perhaps, some additional information; thus we will say that this is a "study-mode" calculation.

In the computational environment of a modern power system control center, some functions are performed only in real-time, whereas some others are performed only in study mode. However, as we will see in the next section, there are functions that can be used both in real-time and in study mode.

Let us say in passing that real-time and online are not necessarily interchangeable attributes. On line implies that the calculations are available to the operator in the SCADA/EMS system itself, hence they are online as opposed to being available on some other separate system. However, there is no guarantee that the online computational process will be fast enough to produce results that can be labeled real-time. These considerations should help the reader understand the difference between the real-time stability assessment, stability monitoring, and online stability assessment concepts that are often mentioned throughout this book.

1.1.4 Next Level of Functionality: The EMS

In order to determine the control actions required, it is necessary to simulate the operation of the power system in close to real-time. The software tools needed include what are commonly referred to as energy management system (EMS) applications. A very terse and unstructured summary of these functions is given below:

- Automatic Generation Control (AGC) to determine the real power output of all the generating units in the system to maintain interchange and frequency. In the interconnected system, each member (control area) performs the AGC function by computing the area control generation load mismatch (area control error or ACE) at the nominal frequency (60 Hz or 50 Hz) and adjusts its generation to reduce the mismatch to acceptable limits.
- Economic Dispatch (ECD or EDC) to determine the optimal level of real power output for each generator to minimize the total production cost (this function works in conjunction with the AGC function).
- Reserve Monitoring (RM) to compute the real power capability available in the system to meet changes in demand.

The above functions consider the generating units only and generally tend to ignore the network (transmission lines, transformers, reactors/capacitors) and voltage. Some ECD implementations do include an approximate model for transmission system losses.

In order to obtain a more comprehensive view of the system, the following network analysis functions are required:

- The State Estimator is used for determining the complete state of the system (voltage and phase angle at each node) based on the measurements from the field. These measurements are generally "noisy" and not available for every element. The state estimator determines the best estimate of the state using a set of redundant measurements, taking into account the measurement error characteristics and missing and bad data.
- Static security analysis, or contingency evaluation, determines the effect of possible outages such as loss of branches (transmission lines, transformers), generating units, and combinations thereof.

These two functions run both in real-time, either executed periodically, with a period of a few seconds to a few minutes, or triggered by events or operator requests, and in study-mode, that is, executed if and when needed to assess postulated scenarios closed to, or derived from, the current operating conditions.

In addition, there are other functions that are executed in study-mode, including:

- The load-flow/optimal power flow, which is used to calculate all of the system variables, with the optimal power flow being used to compute these variables based on optimizing certain system quantities (production cost, losses, voltage levels, transformer tap changes). These are initialized using the results of the state estimator, and additional data needed, such as generator data, is retrieved from the database.

- Hourly load forecasting which is used to predict the hourly total load/total demand that the system will have to supply over the next few hours to up to several days. This function enables the operator to schedule facilities for maintenance, for reconnection, and for start-up and shutdown of units
- Unit Commitment/Hydro-Thermal Scheduling is used to schedule the start-up and shutdown of generation units to meet the forecasted demand. This function typically looks ahead for 24–168 hours depending on the characteristics of the generating units being scheduled. This is a nonlinear optimization problem with both integer and continuous variables. Consequently, it is a computationally intensive function for systems with a large number of generating units that have to be scheduled. It should be noted that whereas in vertically integrated utilities the unit commitment/hydro thermal scheduling is part of the EMS/SCADA, in deregulated electricity markets, the software that performs unit commitment/hydro thermal scheduling is part of the market system. However, the functionality is the same; only the responsibility is separated.

When these EMS functions are included, one generally refers to the system as a SCADA/EMS system although historically the EMS acronym implied that the system included both SCADA and EMS functions.

Finally, there are a number of support functions required in SCADA/EMS systems such as:

- Alarm processing,
- Display generation,
- Report formatting and printing,
- Storage of real-time data in a historical information system (HIS) for archival purposes,
- Special-purpose functions for data conversion and interfacing to local devices, such as mapboards, time and frequency standards, and chart recorders, and
- Communication interfaces with the SCADA/EMS systems of other electric utilities.

As one may infer from the above, the infrastructure needed in the current-day SCADA/EMS systems is very extensive and includes:

- A large-scale telecommunication network that interconnects the field equipment to the SCADA/EMS center. The telecommunication technologies include a mix of leased telephone lines, power-line carrier, microwave radio, copper and fiber optic cable, as well as VHF and UHF radio. Most electric utilities are implementing large-scale backbone networks using fiber optic cables and moving from a radial system to a more meshed system using IP.

- Powerful computer systems at a central location or, for hierarchical control systems, at one location on top of the hierarchy and several subordinated computer systems at the other locations.
- Operator interface equipment that can respond to multiple requests for new displays within one second.
- Large data storage and long-term historical data archival capabilities that are easily accessible to operators and engineering personnel.

Last, but not least, the system must have a very high availability. At the SCADA/EMS center, 99.9% availability is required and is achieved by providing redundant computer and local communication systems.

The brief enumeration of functions and capabilities presented in the previous paragraphs suggests that in order to understand the complex data interfaces and software interactions between the SCADA/EMS system, on the one hand, and a sophisticated add-on application such as stability assessment software, on the other hand, we need to step back and follow a systematic approach aimed at identifying the:

- Overall architecture in a simple format, such as a conceptual overview diagram, that depicts the major building blocks and would make it easy to visualize the information flow between them.
- Functional architecture, for the purpose of positioning the stability assessment application in the SCADA/EMS data and functional environment.
- Implementation architecture, which provides clues about the integration, tight or loose, of software that performs real-time and study-mode stability assessment.

This analysis is briefly developed in Section 1.2.

1.1.5 The Impact of Wide-Area Monitoring Systems

Phasor measurements, a technology developed in the late 1970s and early 1980s, mainly due to the visionary work of Arun Phadke [5], are being finally deployed extensively in power system networks. To some extent, this has been facilitated by the availability of relatively inexpensive GPS receivers that enable the synchronization of the phasor measurements over large geographical areas, but it is also due to the better and more powerful electric utility telecommunication networks, largely fiber optic based, and faster low-cost processors. Direct measurement of the voltage and current phasors throughout the entire network essentially eliminates the need for state estimators in an ideal case (complete and error-free measurement set) and gives a complete picture [6] of the system on a milliseconds (2–5 cycles) time frame.

However, due to measurement errors and bad or missing data, state estimation will be necessary but will be simpler since a linear model suffices. Most phasor measurement units calculate phasor values by sampling the analog signal for each phase at sampling rates of 12 times per cycle and higher, and using discrete Fourier transform analysis to compute the positive sequence values. Phasor reporting time is synchronized throughout the power network, and the phasors are estimated from sampled data, which is referenced to the phasor reporting time. Availability of phasor values on a milliseconds time scale thus has very important consequences for power system operation since it allows monitoring of power system dynamic behavior [2].

In the technical literature, these measurements are referred to as wide-area monitoring systems and have been deployed in many countries worldwide, for example, the United States, with more concentration in the western states (California, Oregon, etc.); in Switzerland, especially on the interconnection tie lines; in many generating plants and interconnection points in Southern China; and in Canada (BC Hydro). Phasor measurements are not simply ideal for steady-state analysis; they can be used to detect possible system separation and system oscillations in close to real-time and, in principle, may allow for closed-loop control for maintaining system stability. One of the principal problems with the current EMS state estimation and related functions such as contingency analysis is the need for a model for the "external system," that is, the system outside the internal area. This is still an unsolved problem, even with greater intercontrol center communication. Phasor measurements can help to largely overcome this problem since the availability of synchronized phasor measurements from the external areas can make the modeling of external networks more accurate and simpler, since a reduced-order model can be used. Furthermore, since phasor measurements give information on a millisecond time frame they can assist in the rapid detection of system separation and potential blackouts.

However, it must be noted that phasor measurements are another mechanism for monitoring the system and do not have predictive capability. In other words, one still has to perform some analysis to determine where the system will be at a future time. Furthermore, at the present time, closed-loop control for transient operation has not been realized in practice and remains a subject of active research. However, installation of phasor-measurement units is becoming more common and their use can only increase, especially as the cost of these units continues to fall. In fact, many companies are providing the ability for determining phasors as part of the digital relays, which are being used in substation automation. Thus, if a substation is being upgraded, adding phasor measurement is a low-cost option requiring only a GPS receiver.

Acceptance and deployment of phasor measurements adds exciting new options for power system operation, monitoring, and control. Such measurements have already proved their value in many cases and their use is only likely to flourish in the future. However, phasor measurements at the current time are not fully integrated with the standard SCADA system; instead, a separate phasor data concentrator is used to receive and process phasors. The data is archived and can also be sent to the SCADA database (see [1] and [3] for some recent examples and [10] for an interesting method for including phasors in SCADA/EMS-based state estimation).

1.2 SCADA/EMS ARCHITECTURES

1.2.1 Conceptual Overview

Figure 1-1 depicts the conceptual overview of the SCADA/EMS and market system facilities of a typical organization that performs both system operator and market operator functions.

In this example, the SCADA/EMS and the market system are at the top level of the hierarchy and accommodate the EMS and market applications. The SCADA functions are performed both at this level and at the next level of hierarchy corresponding to the "regional" control centers. Historical and current operational information are made available to the users with appropriate credentials via HIS and, perhaps, a dedicated WebInfo server. Raw system data are scanned from RTUs and ISAS (integrated substation automation systems) by using standard communication protocols. Processed information is exchanged over the Internet and/or over via ICCP (Inter-utility Control Center Communication Protocol), now 60870-6-TASE 2.

Figure 1-1 is simply a conceptual overview that illustrates the key building blocks of the architecture and shows the major paths for information exchange; actual implementations vary widely in detail but not in any fundamental way. For example, the SCADA/EMS block above will in practice consist of a network of computers, display devices, communication processors, local device interfaces, and bulk storage compo-

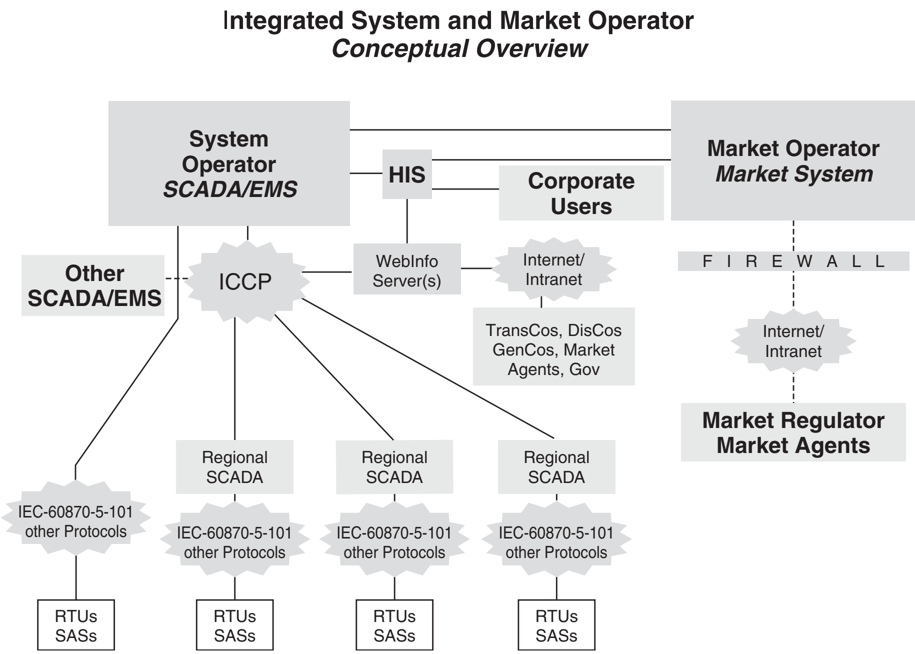

Figure 1-1. Conceptual overview illustrating the SCADA/EMS building blocks.

nents. Actual instances of implementations are given in the subsequent chapters, where specific cases are discussed (LIPA, NOS-BiH, NEMMCO, and others).

1.2.2 Functional Architecture

The basic functionality of a SCADA/EMS system has been illustrated generically in the introductory section. A more rigorous and structured approach is to consider these functions in the context of a layered architecture and, accordingly, to group them into software layers as follows: system software, support software, and application software.

The *system software* encompasses operating systems, compilers, debuggers, utilities, libraries, and so on.

The *support software* consists of communications support, database management, and user-interface software.

The *application software* typically includes the following application subsystems:

- SCADA subsystem—includes the basic data acquisition, control, and display functions that allow the operator to determine the actual status of the power system and to perform remote control actions.
- Generation control subsystem, including AGC, economic dispatch, reserve monitoring, production costing, interchange scheduling, and energy accounting.
- Network analysis subsystem—consists of a suite of programs that work in real-time and study mode, including:

  Network Topology Processor,

  State Estimator,

  Static security analysis (contingency evaluation),

  Dispatcher's Power Flow,

  Optimal Power Flow,

  Service routines such as bus load forecast and transmission losses penalty factor calculation.
- Short-term operations scheduling subsystem—composed by the short-term Load Forecasting and Unit Commitment/Hydro-Thermal Scheduling programs.

All of the above applications are used in actual operation. In addition, especially in the current deregulated environment, systems need to be prepared for auditing, accounting, and post-facto analysis. Therefore, the SCADA/EMS systems include a disturbance recording system, a historical information system (HIS), and reporting and analysis tools that enable the owner as well as outside agencies (regulators, market participants, generator companies, etc.) to view and analyze the operation that occurred.

The execution of the system, support, and application software is distributed among the SCADA/EMS system servers and workstations in order to:

- Minimize the response times of the applications
- Maximize the redundancy and availability of the information

- Allow functions and data to be accessed from any local or remote workstation included in the configuration
- Facilitate the system expansion both horizontally, by adding more processors, and vertically, by replacing existing machines and software with more powerful ones

The functional architecture described above can be considered as "standard" in the sense that it is supported by practically all the major SCADA/EMS vendors today. By contrast, in the current state of the art, real-time stability assessment is not yet a "standard" application in the sense that there is no "standard" way of performing such functionality in a SCADA/EMS context.

In order to understand the place of real-time stability assessment in this functional architecture, we need to briefly identify its input–process–output requirements:

- Input. The key input for real-time stability assessment is the current, or most recent, state of the power system, which, in turn is provided by the most recently solved state estimate; additional inputs include, but are not limited to, off-line information such as generator data and event scenarios for evaluating contingencies.
- Process. Stability applications use proprietary algorithms that are unique and cannot be used to perform other functions in the SCADA/EMS context. In some cases, as shown in Chapters 6 and 7, the stability software suite encompasses more than one application and, in order to provide an acceptable level of performance, requires a multiple computer configuration and a complex distribution of functions among processors.
- Output. Key calculation results produced by true real-time stability assessment software are amenable to real-time monitoring and must be redirected to the real-time database or, as a minimum, to historical storage, for subsequent display on standard SCADA trending charts, but most of the output of stability calculations is usually very specific and not used by other SCADA/EMS applications; also, it may entail graphics and tables not normally supported by the standard SCADA/EMS display facilities.

With this background, and without attempting, for the moment, to determine how the actual implementation is realized, the real-time stability assessment functionality can be considered as a nonstandard capability of the real-time network analysis, as shown in Figure 1-2. In this figure, the stability assessment module is labeled "real-time" but, depending upon the approach, the stability calculations may be quite involved and the time required for such calculations may be one or even several orders of magnitude higher than the completion time of the other network analysis applications. This is why the standard network analysis sequence entails the automatic execution of contingency analysis immediately after the state estimator without waiting for the stability computations to complete.

Let us also note that online or real-time stability assessment are sometimes referred to as dynamic security assessment (DSA) and typically entail evaluating contingency

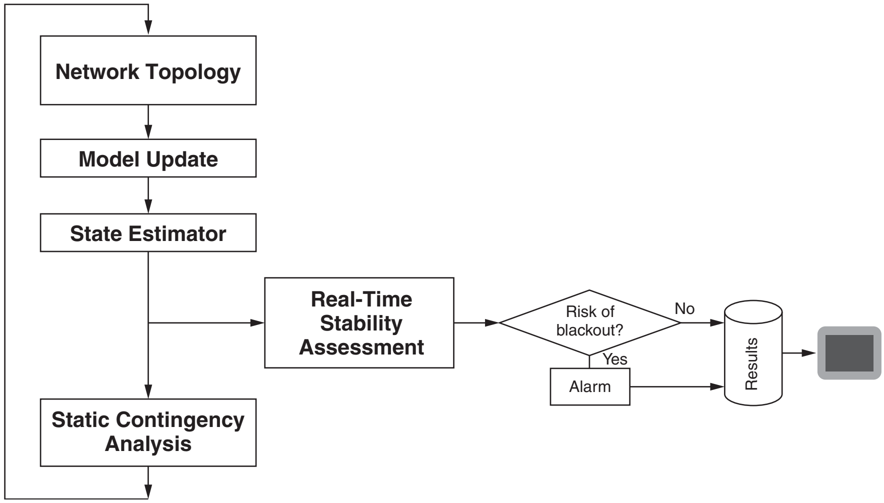

Figure 1-2. Real-time stability assessment in the context of real-time network analysis.

scenarios in addition to base case stability calculations; accordingly, we use the terminology "static contingency analysis" in order to differentiate it from DSA.

The stability calculations can be triggered from within the network analysis subsystem, either periodically, or by events or upon operator request, in which case we talk about "seamless" integration. However, the functional capability depicted in Figure 1-2 can also be implemented by "loosely" integrating the stability assessment software with the SCADA/EMS, that is, by simply executing it periodically or on demand with data produced by the state estimator but independently of the real-time network analysis sequence.

1.2.3 Implementation Architecture

From the early 1970s, when digital computer based SCADA/EMS systems started to become more prevalent, until the early 1990s, SCADA/EMS systems were based on the supplier's proprietary hardware and software. This made it virtually impossible to add third-party software to these systems and even more unfortunately required that the entire system be replaced when it became obsolete, even if the same vendor supplied the new system. Thus, for example, the communication protocols used to communicate with the field devices (remote terminal units or RTUs)—the user-interface system, much of the SCADA software and all of the EMS software—were proprietary. Often, the operating system was modified to meet the real-time control and data acquisition requirements, making it also proprietary. This forced electric utilities to rely on the vendor to support and maintain the system.

Because of the high costs and poor performance of these systems, electric utilities and the research institutes made a concerted effort to evolve toward more open systems, which were far less vendor dependent by developing standards for various interfaces. The growth of the internet has made the technologies of the internet de-facto standards and given additional momentum to the development of open architectures. Furthermore, electric utilities insisted that the vendors supply "integration friendly" systems that the users or their consultants could augment and modify.

Therefore, in order to meet these requirements and to be able to expand the system capabilities as the needs change and the power network evolves, almost all recent systems have a distributed Ethernet-based local area network (LAN) architecture at the central site, with a multiple-loop fiber optic backbone telecommunication system in which the individual sites are connected via a variety of communication media.

This architecture is much more flexible than the "closed" dual, quad, and multiple computer architectures used in the early digital SCADA/EMS systems. Its flexibility enables the user to not only upgrade the existing hardware but also to add third-party hardware and software without excessive effort. Incidentally, a LAN architecture is also increasingly deployed at the larger substations, with intelligent electronic devices (IEDs) replacing the traditional analog interface to field equipment.

In line with the technological developments in the computer industry, alternate architectures are being considered and in some cases deployed. These include service-oriented, remote hosting, and "service bus" architectures, which have been developed to allow access to databases by third parties using standardized models and communication protocols, as well as "cloud computing," in which one simply uses the computational resources in a "cloud" using telecommunication facilities.

The adherence to industry-wide standards such as IEC 61850 and IEC 60870 further facilitates addition of third-party hardware and software. These systems have also begun to use Microsoft operating systems, Internet type browsers and internet protocols, off-the-shelf database systems, and to provide interfaces to commercial packages such as Microsoft Word and EXCEL which contribute to the greater flexibility available for adding new hardware and software without excessive reliance on the original vendor. Figure 1-3 illustrates one of the many potential ways to implement the hypothetical system and market operator conceptual overview depicted in Figure 1-1.

The SCADA/EMS configurations described throughout this book are similar to the conceptual implementation architecture illustrated in Figure 1-3. They may differ in terms of functionality, levels of hierarchies, and so on, but they all adhere to the open architecture paradigm. The deregulation of electric utilities and the unbundling of the main activities of generation, transmission, and distribution have resulted in a clear need for such open architectures because:

1. The systems and software are constantly evolving since market needs and rules tend to change often.
2. The number and qualification of the participants in the market is large, qualifications are not uniform, and interface equipment is diverse.
3. Much more extensive audit and billing mechanisms have to be in place.
4. A single vendor cannot supply all of these capabilities nor can they support cost-effectively the almost continuous changes. This is evident in many large systems

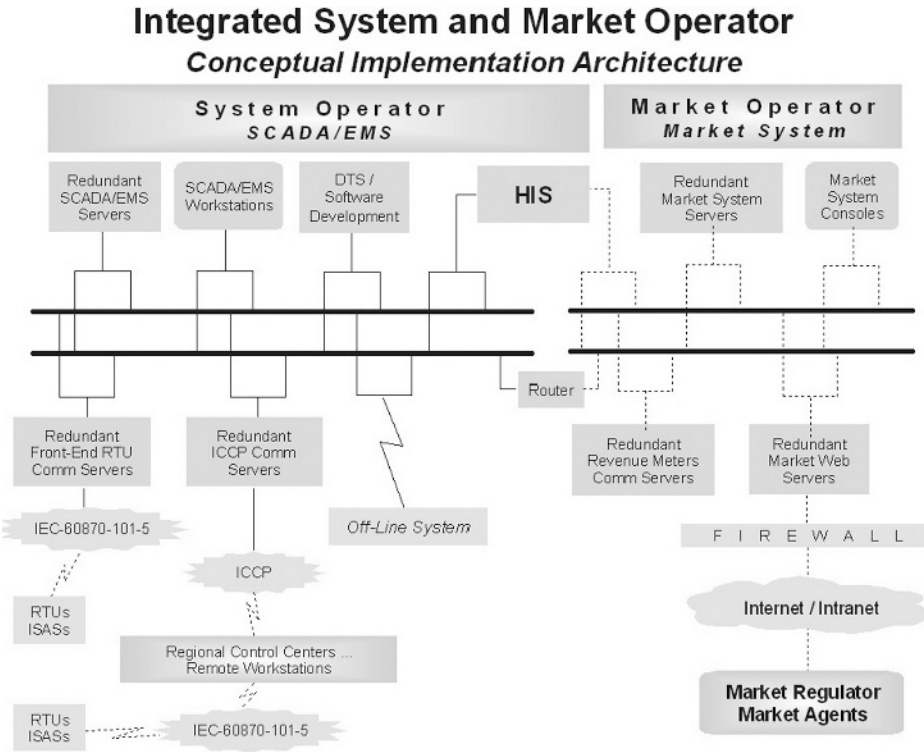

Figure 1-3. Example of SCADA/EMS conceptual implementation architecture.

installed at independent system operators, where one sees quite a mix of capabilities supplied by different vendors.

5. Participants in the generation and transmission market have to be given access to the appropriate systems.
6. A separate revenue-quality metering system of higher accuracy has to be implemented for accounting and billing purposes.

1.3 INTEGRATING STABILITY APPLICATIONS WITH THE SCADA/EMS

1.3.1 Stability Assessment in the SCADA/EMS Context

It is necessary to digress slightly in order to provide a more complete picture of power system operation and to place the rest of this book in perspective. The SCADA/EMS systems implicitly assume that the power system is essentially in a steady-state or quasi-steady-state condition. To illustrate this, when executing network analysis programs, the system is assumed to reach its postoutage operation without considering the trajectory it will follow to get from the initial state (no outage) to the final state (equipment not in service). Thus, the transient behavior is ignored. Even the AGC function, which is actually controlling the MW output of the generating units in real-time, does not take into account the actual path the generator output will follow. This is a serious drawback since, depending on the initial loading levels and the severity of the disturbance, the power system may become unstable (transient instability) and the postdisturbance steady-state condition may not be reachable. There is also a much higher frequency transient (microseconds to a few milliseconds) that occurs due to a switching operation, which is assumed to decay quickly, although it could result in cascading failures.

Unfortunately, the transient stability problem is computationally far too demanding for a true real-time implementation if one uses the conventional time-step simulation method. Not only does the outcome of transient stability calculations depend on the initial state, it is also critically dependent on the location and duration of the fault on the network. Therefore, in order to determine whether a system is stable, one is faced with a huge computational effort for even reasonably sized networks. Although NERC (North American Electric Reliability Council, now ERO—the Electric Reliability Organization) has stated that the computation of indicators such as total transfer capability (TTC) and available transfer capability (ATC) must take into account transient stability, they do not specify how this is to be computed. Most commonly, off-line studies are used to determine a "safe operating region." Although it is possible to provide the operator the ability to run transient stability studies, these are not even close to real-time; they are online only, in the sense discussed in Section 1.3.

Another type of stability is the ability of the power system to remain stable in the presence of slowly varying changes in the total demand. Specifically, one would like to know how much additional load can be carried by the transmission system starting from the current state if the load and, accordingly, generation and imports would be increased gradually. We will refer to this as steady-state stability. Unlike the transient stability problem, we are not looking at large disturbances caused by faults, loss of equipment, and so on. The steady-state stability limit thus corresponds to the maximum loadability, including both the system load and the wheeled power, if any, that the current configuration can carry without a system collapse.

For the system operator, the real-time knowledge and monitoring of the steady-state (voltage) stability limit is extremely valuable. In order to be usable as a simple indicator, this limit should be specified in terms of a "distance" to instability, that is, how far the current system is from the limit. There are a number of rather subtle issues related to the computation of this limit and these are discussed in complete detail in some of the subsequent chapters and appendices as well as the material listed in the bibliography.

In this book, we discuss the stability problem in the context of power system operation and describe all of the techniques, including implementation considerations, that are currently in use. The stability assessment implementations addressed herein are used in actual power system control centers where they are integrated with the SCADA/EMS system but with varying levels of integration. The open SCADA/EMS systems make such integration not too onerous and can be accomplished without excessive effort.

1.3.2 Data Issues

1.3.2.1 Real-Time, Study-Mode, and Planning Models

Prior to attempting to integrate a stability assessment application with a SCADA/EMS system, the software designer has to be fully aware that the power system models deployed in real-time and study mode in the SCADA/EMS, and off-line, in planning, are not identical. In fact, the discrepancies may be so significant that they may preclude the execution of stability programs with mixed models that combine both SCADA/EMS and planning data. The differences between the real-time, study-mode, and off-line models are due essentially to the:

- Bus naming and numbering conventions,
- Level of detail used to represent the power system components,
- Extent to which the internal and external areas of transmission systems are represented, and
- Making sure that the network model and state estimator results are adequate for the reactive power/voltage analysis.

A "bus" in the SCADA/EMS and a "bus" in the planning environment are different concepts. In order to avoid confusion, different names may be used, for example, in Chapter 9, where the transmission planning "buses" are called "nodes," as "nodes" in a theoretical graph.

In operations, dispatchers and system engineers work with substations in which a "bus" may either come into existence or temporarily disappear depending upon the status of breakers and switches that interconnect the various bus bars in the substation. Accordingly, the "bus names" are fixed, whereas the "bus numbers" may change each time the network topology and network model update processors triggered within the real-time network analysis sequence have identified a new system configuration. In some cases, for example, the implementation described in Chapter 5, not even the bus names are fixed; they are recreated at each run of the real-time network analysis sequence based on an algorithm that merges a fixed four-character base designating the substation with another four-character field generated dynamically. Therefore, the stability assessment program should be "smart" enough to associate correctly the off-line information, such as generator data, with the actual bus names and numbers as they appear in the current dataset.

In planning, where the substations are not represented and the one-line diagrams are fully consistent with the topological network model used by the algorithms, the bus names and numbers are fixed. This is the good news. The bad news is that both the bus naming and the bus numbering conventions deployed off-line are usually different from those used in the SCADA/EMS environment, thus making it impossible to add off-line data to cases computed in real-time and vice versa without running cross-referencing algorithms.

The level of detail to which the power system components are represented may be quite different in the SCADA/EMS and in the planning environment. The first example that comes to mind is the representation of generators. State-of-the-art stability applications used today in planning support sophisticated generator models that represent both the synchronous machine and its controls and the turbine governors. Such data are normally not available in the SCADA/EMS database, although they can be implemented specifically for the purpose of integrating the stability software. Another example, which actually goes the other way around, is offered by the so-called P-Q capability curves, which are almost always available in the SCADA/EMS database but are not normally found in the "dynamic" datasets used by off-line stability applications.

The extent to which the internal and external areas of the interconnected transmission system are represented is another modeling issue that may significantly impact the outcome of the calculations. In the planning environment, the tendency is to build large detailed power system models that include a large portion of the "external" system. Although such comprehensive models provide precise load-flow and transient-stability calculations, they place a heavy burden on the computing resources and may require special algorithms, such as the procedure described in Chapter 6, to build and update a reduced-order dynamic-equivalent model for use in online transient-stability assessment. When other types of stability are investigated, for example voltage stability via the $d\Delta Q/dV$ criterion, as shown in Chapters 3, 4, 5, and Appendix A, using a huge external model is not only unnecessary, but may adversely affect the computational results since the phenomena being investigated are local.

The SCADA/EMS databases, on the other hand, represent in detail the so-called "internal area," that is, the power system network directly supervised and controlled by the SCADA/EMS, and add a buffer zone and/or a reduced-order equivalent to model the "external areas." Expanding the internal area with buffers and equivalents for the external area is very important when simulating contingencies because line and/or generator trips within the internal area may have significant impacts on the tie lines that interconnect it with the external world. Modern state estimators are quite good at using the real-time data exported by the neighboring control centers, either directly or via ICCP, to develop state estimates that depict accurately and reliably both the internal area and the tie lines.

When performing stability assessment calculations, another subtle issue arises from the representation of tie line injections in the SCADA/EMS models. At the boundary between the internal network model and the external world, the incoming power flows (imports) are typically shown as injected generated powers. But since these are not actual generators, some mechanism must be found to represent them in the stability calculations. One way is to introduce dynamic equivalents, as described in Chapter 6. Another solution to this otherwise difficult problem is the approach described in Chapters 3, 4, and 5.

1.3.2.2 Formal and De Facto Data Format Standards

The open-system emphasis has led to increased development and deployment of software, communication, and database standards. Although much of the algorithm details are justifiably proprietary, the ability to interoperate, share data, use different hardware, and communicate with devices from multiple vendors is now deemed essential in any implementation. To this end, many organizations such as the IEEE, EPRI, CIGRE, and UCTE have been instrumental in the development of standards that have been accepted by the IEC. These standards include the 60870-5 series for RTU communication, the 60870-6 for interutility control center communication, the 61850 series for communication within substations, and others. Furthermore, increasing reliance on Internet technologies (TCP/IP, XML, browsers) and support for interfaces to Microsoft Office applications further "opens" up EMS/SCADA systems. However, here we are primarily concerned more with the interface and database standards.

In the database area, the basic data are stored in a standard off-the-shelf relational database product that supports the accepted techniques for access (e.g., SQL) and updates. Unfortunately, the "content" of the database may not be standard. For example, a transformer may be modeled differently in each implementation and may be incompatible with other implementations. Therefore, a major effort was made to develop a standard model of power system components that any user could access for his or her own application. This is referred to as the Common Information Model (CIM) and is now an IEC standard. Most systems require that CIM support be included. This does not mean that the operational data has to be in CIM format, merely that it should be possible to read and write CIM compatible data. With this facility, it is possible to share the data with third parties, something that was impossible with proprietary databases and models.

1.3.2.3 Data Interfaces and Quality

In spite of all the benefits of CIM, stability assessment programs, just like any advanced network analysis applications that might be seamlessly or loosely integrated with a SCADA/EMS, do not get their input directly from CIM, nor do they interface directly with the real-time database. One very important reason for this is that stability assessment software cannot handle raw data; rather, it requires on input an actual and accurate picture of the system state, that is, the *correct* values of the complex bus voltages and bus-injected complex powers as computed by the state estimator or, perhaps, by the dispatcher's power flow, which are typically assembled in an industry de facto standard solved load-flow format. The other reason is the simplicity and transparency of the integration process. Theoretically, at least, it is possible to expand the stability applications with CIM compliant front-end modules and/or SQL interfaces that could access directly the SCADA/EMS database, but such an approach would significantly increase the complexity of the integration and, furthermore, would adversely impact the portability of the stability software.

In all the integration examples described in this book, the stability assessment software gets the state estimation results in solved load-flow case format. In all these implementations, the host SCADA/EMS exports the state estimate in one of the various load-flow formats supported by the Siemens PTI/Siemens PSS/E load-flow program. Other solved load-flow formats, such as the IEEE Common Exchange Format [11], are also possible, but are seldom implemented. But the availability of the state estimate in solved load-flow case format is not the end of the road, just the beginning. This is because data must not only be available but also accurate.

The data quality of the state estimate has a direct impact on the data quality of the solved load-flow case, which, in turn, has a great impact on the outcome of the calculations performed by the stability assessment software. In this context, the "data quality of the state estimate" refers to the validity and consistency of the model and parameter data used by the state estimator; by contrast, the "quality of the state estimate" refers to how accurate (or inaccurate) was the estimation process, for example, how small (or how large) was the solution mismatch. In other words, the state estimate quality may be poor even if the data quality was good. The data quality problems that affect the state estimate can be classified as temporary versus permanent.

Temporary data-quality problems may be caused by the state estimator to compensate for analog metering errors or erroneous status-data indications. Persistent data-quality problems may be caused by incorrectly defined items in the database, such as: modeling errors, for example invalid line or transformer reactance values; or incorrect parameters, for example, upper and lower limits, specification of controlled buses, and so on. Incorrect limits may be particularly damaging, such as too high values for the upper MW and MVAr generator limits; the state estimator may be based on a solution technique that does not worry about such values, whereas the stability assessment algorithm may produce erroneous results because it just does not know whether the upper limits of the generators are too high because this is how they are in real life, or they are too high because the data are wrong.

The presence of errors in the load-flow case derived from a state estimate or a dispatcher's power flow solution can be detected by computing the MW and MVAr mismatches, but such checks may be inconclusive or even misleading. For example, extremely large mismatches can be caused by a serious bad data problem but might also be due to the fact that the SCADA/EMS exported a nonconverged load-flow case.

1.3.2.4 User Interface and Interaction

The layout and aesthetics of the displays, the design of messages and user interaction procedures, and the use of charts and diagrams to quickly convey the essence of large amounts of information are all matters of good software design. They apply to stability analysis programs just as they do to any other computer application. But in the case of online and real-time stability assessment, there are a few other issues that also must be addressed.

A key concern is how to convert the inherently complex calculation results to *information* that can be instantly absorbed and digested for quick and reliable decision making. The immediate answer that comes to mind is to use graphics and pictorial images. This is easier said than done, for this question transcends the user interface issue—the calculation results will be simple and easy to understand only if the underlying solution technique provides such simple and easy to use indicators that capture the distance to instability, quantify the risk of blackout, and so on.

Additional difficulties stem from the fact that, in most cases, the stability software used in the control center originates in the offline realm where the user interface hardware and software, the design of the displays, and the procedures deployed to interact with the computer are quite different from those commonly found in a SCADA/EMS.

The first barrier encountered when porting an off-line program to SCADA/EMS is that the user interface hardware and operating system can be quite different from how off-line applications are designed and implemented.

The user interface look and feel is another issue. The SCADA/EMS user typically monitors and controls different processes that run more or less concurrently and share simultaneously the user interface, as opposed to the off-line user who does only one thing at a time and can, and normally does, allow the application to take full control of the screen. Further differences arise from the style of the user computer dialog. Real-time applications are repetitive "tasks" that, once activated (automatically, triggered by events, or started manually), run transparently and require no further user intervention until the next execution cycle; facilities to set and change execution control parameters also exist but are seldom used except for system initialization. By contrast, off-line applications are designed to perform studies, where each software execution may correspond to a different scenario, with different data and different parameters that may have to be edited each time when running the program.

An easy way out of these difficulties is to install the stability software on a separate workstation, import the input data from the SCADA/EMS, and display the calculation results on the application's own user interface. But this would force the operators to navigate between two display environments—one on the SCADA/EMS console and the other one on the workstation where the stability calculation results are presented. Quite obviously, this is neither easy nor comfortable.

The best and perhaps the only acceptable approach is to control the execution of the stability application, display the key stability calculation results, and monitor the distance to instability *directly in the native SCADA/EMS user interface.* This is normally done by the SCADA/EMS vendor and can be relatively easily achieved if the stability assessment application was designed in a truly modular fashion, that is, if the modules that perform computations and the display services that create the output results are totally separated from the user dialog shell, so that they could be invoked from within the SCADA/EMS system if and when needed. Another benefit of this approach is the ability to accommodate local user requirements such as the format and language used to present calculation results and messages.

The user interface and interaction issues that were summarized in general terms in the preceding paragraphs will be addressed in more detail in the subsequent chapters of this book.

1.3.3 Performance Issues

The performance requirements for online and real-time stability assessment should represent a balance between what is truly needed, on the one hand, and what is reasonable to expect, on the other.

In order to assess "what's needed," let us note that, unlike other operating reliability issues, which can be mitigated over a period of time, stability is unique in the sense that if the risk for the system to become unstable is imminent, there is no time to react and the damages caused by the ensuing blackout could reach colossal proportions. But the risk of instability is also a matter of probabilities. Multiple contingency scenarios are by far less probable than single contingencies. So, if it could be ascertained that none of the single contingency events would cause transient instability for a relatively broad range of operating conditions, the response time requirements for online transient stability assessment do not have to be too stringent if the purpose is to assess what would happen if a very unlikely event would take place. But if the purpose of the stability calculations is to track or monitor the distance to instability in real-time regardless of how far from instability is the power system, then the solution time of the stability application has to be much shorter.

When it comes to “what is reasonable to expect” given the current state of the art, some stability computations can be performed truly in real-time, whereas some others require longer times to complete. The elapsed time expected for stability analysis depends upon the choice of methods and algorithms, size of the network model, number of contingencies to be simulated, and the computer configuration deployed to perform the calculations.

If the goal is to perform online transient stability analysis, it is not realistic to expect solution times of the order of a few seconds, and if the power system network size is large, the response time of the transient stability analysis calculations can be quite high. For example, the current performance requirements at NEMMCO, as indicated by Boroczky in the Chapter 9 of this book, are in the range of 2 to 15 minutes for online transient stability runs on computer hardware equipped with multiple 64-bit processors. For extended online simulations that encompass a suite of transient and other types of stability assessment on hardware configurations consisting of multiple computers, Morrison and coworkers (Chapter 6) quote response times of up to 30 minutes for a very large system, whereas Jardim (Chapter 7) mentions response times in the range of a couple of minutes for a medium-sized power system network.

On the other hand, it is possible today to perform real-time stability assessment and monitor the distance to instability by using special steady-state stability algorithms that are both reasonably accurate and extremely fast, with response times much shorter than the state-estimation cycle. Arnold and coworkers (Chapter 3), Vickovic and Eichler (Chapter 4), and Campeanu and coworkers (Chapter 5) describe actual real-time stability assessment and monitoring solutions that have been operational for quite some time, with which a steady-state stability case is solved in less than one second for moderately sized networks by using standard PC hardware.

The subsequent chapters of this book provide further insight into the performance requirements of stability analysis techniques and related hardware and software solutions that have successfully been implemented and are being used on a daily basis to perform online and real-time stability assessment.

What is *not* covered in this book is the possibility to perform two-stage real-time, and online stability assessment more or less like static contingency analysis, which has been implemented for a long time. The current state of the art in static security assessment consists of running a simplified form of contingency evaluation of a very large set of contingency cases as soon as a new state estimation solution has been obtained; should any contingency case result in thermal or voltage violations, it would be further investigated with a detailed load-flow calculation. Similarly for stability analysis, the idea is to execute, immediately after the state estimate becomes available, a quick stability check by using a fast algorithm such as the ones described in [7] and Appendices A and B of this book. If the system is far from the stability limit corresponding to the current operating conditions, that is, if the risk of instability is small or quasinonexistent, that would be it and no further computation would be needed until the next state estimate was computed. Otherwise, a second stage of detailed stability calculations would have to be triggered to determine whether any of the postulated contingencies could cause transient instability.

This approach has already been proposed [7] but as far as we know has not yet been tested in any actual implementation. As a further refinement, the list of contingencies could be periodically updated, say once an hour, to identify what contingencies would be truly relevant for current operating conditions. Enhancements such as these are already feasible and, we believe, it will be just a matter of time until they are implemented.

1.4 REFERENCES

There is a vast literature on SCADA/EMS, telecommunication in electric utilities, standards used in SCADA, advanced applications, and stability analysis. Here, we list a few published works that contain extensive references to the literature.

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