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ISA Embraces Open Architecture

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Integration and automation are key factors when upgrading or building new substations.

Fig. 1. Control centers in the Purnio and La Sierra substation control rooms.

Interconexion Electrica S.A. E.S.P. (ISA), Medellin, Colombia, has embarked on a program of installing standardized digital control systems (DCSs) for its high-voltage transmission substations. Although ISA has been installing DCSs in its substations since 1992, these systems have all been of a nonstandardized design. This practice resulted in many problems including the difficulty of providing additions or changes to a system, the lack of interchangeable parts, and the need for specialized knowledge and training for each substation and system. ISA acquired these varied designs from public open bids. The company now has 10 different DCS solutions from 6 different suppli-

Incentives for Standardization

- By developing a standard functional specification, the functionality of an applied substation automation system (SAS) is consistent and independent of the supplier and supplier product line.
- Lower design and engineering costs with the reduction in the number of different SAS solutions.
- A reduction in operation and maintenance costs associated with training of personnel, purchase and tracking of spare parts, and customized upgrades to the SAS.
- Standardization creates a simplified and cost-effective system because the specification restricts the functionality to that only required to satisfy ISA's specific expansion and upgrade objectives at the time of bid.
- The specification of equipment with an open-system architecture that must comply with international standards ensures a low-cost migration path with the possibilities to extend or replace existing parts of a SAS with the most suitable products available.
- A standardized specification will drive competing bidders to provide only the required functionality at the lowest cost. The supplier also will consider the economies of scale in the bid price and the reduction or integration of functions and devices in the system design.

Table 1: Non-Standardized Substation Automation Systems in ISA

Substation	Year	Vendor		System Type			
				Substation Level	Operating System	LAN	Bay Level
San Marcos 230 kV	1995	Schneider	France	ISIS 7000 (v0)	VMS	APRILNet	Telemecanique (APRIL 5000)
Primavera 230 kV	1996	AEG	Colombia	Factory Link	Windows NT	Modbus Plus	Modicon 984
La Sierra 230 kV	1997	AEG	Colombia	Factory Link	Windows NT	Modbus Plus	Modicon 984
Purnio 230 kV	1997	Schneider	Colombia	Factory Link	Windows NT	Ethway	Telemecanique TSX 107
San Marcos 230 kV (extension)	1998	Automatización Avanzada	Colombia	Factory Link	Windows NT	Ethway	Telemecanique TSX 107
Páez 230 kV	1998	Alstom	Colombia	Factory Link	Windows NT	ILSA	IMOS-HV
Sabanalarga 230 kV (extension)	1999	Schneider	France	ISIS 7000 (v8)	Windows 3.11	LAN 7000	BC 7000 (APRIL 5000)
Fundación 230 kV (extension)	1999	Schneider	France	N.A. [1]	N.A. [1]	JBUS	BC 7000 (APRIL 5000)
Cerromatoso 230 kV	1999	Schneider	Colombia	Factory Link	Windows NT	Modbus Plus	SEPAM 2000
Sochagota 230 kV	1999	ABB	Sweden	MicroSCADA	Windows NT	LON	REC 561
Guatiguará 230 kV	1999	ABB	Sweden	MicroSCADA	Windows NT	LON	REC 561
Chinú 500 kV (SVC)	1999	Siemens	Germany	WinCC	Windows NT	SINEC-H1	Simadyn + SU200
La Virginia 230 kV	1999	Cegelec	France	ALSPA P320	UNIX	CONTRONET	CE2000/C370
San Marcos 500 kV	2000	Automatización Avanzada	Colombia	Factory Link	Windows NT	Ethway	Telemecanique TSX 107

[1] Controlled from Sabanalarga.

The SAS provides the framework to enable existing and future intelligent electronic devices (IEDs) from various suppliers to work together to facilitate more efficient and cost-effective monitoring and control.

ers—many of them foreign—in 14 substations. Clearly there was a need for a change to a standardized design.

ISA is the largest electrical energy transmission company in Colombia. It owns and operates more than 75% of the country's power-transmission system. The ISA transmission system consists of: thirty-three 230-kV substations and four 500-kV substations; more than 6058 km (3765 miles) of 230-kV overhead transmission lines (66% of total country) and 1068 km (664 miles) of 500-kV overhead transmission lines (100% of total country); and a total installed transformation capacity of 5294 MVA. ISA supervises and controls the operation of the National Interconnected System (SIN) from its National Dispatch Center. The SIN includes all of Colombia's 230-kV and 500-kV network, as well as 30 hydroelectric and 60 thermal power plants.

ISA began studying the possible introduction of DCSs for its substations in the late 1980s. In 1992, ISA purchased the first DCS for the San Marcos 230-kV substation—located about 300 km (186 miles) southwest of Bogotá—which went into commercial operation in September 1995. After that, ISA continued specifying and acquiring more DCSs for its substations and now has 12 substations equipped with DCSs. Two more DCSs will go into operation in the next 12 months.

To reduce design, specification and operation and maintenance (O&M) costs, ISA initiated a standardization project to coordinate and unify the technical specifications and procurement of future DCSs. In 1997, ISA contracted with a local consulting company (Mejia Villegas S.A.), with external advice from KEMA Consulting, for the preparation of standard technical specifications for DCSs, which was referred to as the substation automation system (SAS). The standards address the application of the SAS in the construction of new substations, as well as in retrofit and extension work in existing substations.

Incentives for Standardization

Table 1 summarizes the various generations of non-standardized SASs (DCSs) currently installed and planned for ISA's substations.

ISA has found that the non-standardized systems, such as the one shown in Fig. 1, provide the required functionality, but extensions or changes impose complications because specific and detailed knowledge of each particular system is required. ISA also has found that it becomes dependent on the manufacturer because it is almost impossible to add and integrate products and functions from other vendors, most of which are foreign suppliers. This dependency has driven up the price of each installed SAS. Some of the other major difficulties with current SAS implementations include:

- The need for specific and intensive training of personnel for each proprietary system and substation.
- The need for a large stock of different, specific spare parts for each system.

The advantages of implementing a standardized SAS include significant savings in investment and life-

Table 2: SAS Logical Architecture

Level 3	**Remote Control & Supervision, and Corporate Users**		
	Level 3 – Level 2 Communications and Interfaces		
Level 2	**Level 2 Processing System**	**Online & Historic Data Repository**	**Application & Substation User Interface**
	Level 2 – Level 1 Communications and Interfaces		
Level 1	**Bay Controller**	**Basic User Interface**	
	Level 1 – Level 0 Communications and Interfaces		
Level 0	**Intelligent Electronic Devices and Individual I/O Points**		
	Power System Equipment		

cycle costs, and the functionality becomes independent of a supplier's product line and O&M costs are reduced.

Selection of local control overrides any control mode higher in the hierarchy.

System Architecture

The SAS is a computer-based system used to bring together independently operating subsystems—such as supervisory control and data acquisition (SCADA), communications, protective relaying, power apparatus control, metering, and alarm annunciation—into a unified data acquisition, monitoring and control system in the substation. The SAS provides the framework to enable existing and future intelligent electronic devices (IEDs) from various suppliers to work together to facilitate more efficient and cost-effective monitoring and control.

The SAS architecture consists of two structured hierarchical levels, the bay level and the substation level (Table 2). Equipment is interconnected through a distributed data network to provide full-operation autonomy at the bay level.

The standardized specification of the SAS architecture required that the SAS satisfy ISA's existing functional requirements with a low-cost migration path to satisfy ISA's future envisioned requirements and expected changes in integration and automation technology.

Functional Criteria

The control modes correspond to the control hierarchical levels as shown in Table 2. Control actions are only possible from one location. Selection of local control overrides any control mode higher in the hierarchy.

Level 1 (Bay Level) Criteria:

■ *Data Acquisition* allows for the acquisition of data from IEDs and the means to acquire inputs that are not available from IEDs.

■ *Processing of Digital Status and Alarms* provides verification and storage of digital input data.

■ *Processing of Measurement Signals* enables the acquisition of measurements from energy-revenue meters and other IEDs, such as multifunction measurement units and protection devices.

■ *Interlocking* provides continuous evaluation of the status of power equipment and operating and protection trip conditions before executing control commands.

■ *Protection Trip Commands and Transfer Trips* are implemented in hardwired schemes separate from the bay controller.

■ *Communications with Local Area Network* handles and monitors communication among all Level 1 devices.

■ *Automatic Monitoring and Control Functions* are based on analog and status inputs acquired at the bay level to consolidate functions currently performed by separate control systems and programmable logic controllers. Time-critical functions, such as fault isolation, are accomplished directly by the protective relays.

Level 2 (Substation Level) Criteria:

■ *System Security.* Each user is assigned one name and code (password) associated with a security level to determine the accessible displays, the data to be consulted or modified, and the functions available in user interface, both for its own operational works and for engineering works.

■ *Historical Data Management* monitors specified substation events, performs calculations on data, and stores the information—including data from digital fault recorders (DFRs) and sequence-of-events recorders (SERs)—in bulk read/write memory.

■ *Device Tagging* blocks the operation of substation devices at all control levels.

■ *Sequence-of-Events, Alarms, Reports and Trending* records, displays and allows analysis of historical and real-time data with a 1 ms time resolution.

■ *Operations Log* allows operators to establish a log of substation operations, equipment failures, equipment maintenance and any other information required for later reference.

■ *Mass Storage Backup* of all information in the processor and controller hard drives.

■ *Automatic Monitoring and Control Functions* is similar to Level 1 functionality, but offers higher levels of monitoring and control for the substation level.

Hardware and Software Criteria

■ *Substation Host Processor.* The substation host processor must be based on industry standards and strong networking ability, such as Ethernet, X/Windows, Motif, TCP/IP, UNIX and Windows NT, as well as an industry accepted relational database with SQL capability and enterprise-wide computing. A full graphics user interface (bit or pixel addressable) must be provided with Windows-type capability. There also must be interfaces to Windows-type applications (Excel, DDE interface and OLE interface). The substation host processor must be flexible and expandable, and transportable to multiple hardware platforms (PCs, Power PC, DEC Alpha, Sun and HP). For a smaller substation, the host processor may be a single processor. For a large substation, redundant processors with failover options may be present. Smaller "slave" or "server" substations will have IEDs, but may not have a SAS. The IED data from these "server" substations will be sent upstream to a larger "master" or "client" substation that contains a SAS.

■ *Substation Local Area Network (LAN).* The substation LAN must meet industry standards to allow interoperability and plug-and-play capabilities.

Open-architecture principles must be followed, such as use of industry standard protocols (TCP/IP, IEEE 802.x [Ethernet], UCA 2.0, IEC 61850). The LAN must interface to bay-level equipment and be hardened for the substation environment. The LAN must have enough bandwidth to support integrated peer-to-peer data acquisition and control requirements.

■ *User Interface.* The user interface in the substation must be an intuitive design to ensure effective use of the system with minimal confusion. An efficient display hierarchy will result in all essential activities being performed from a few displays. The amount of typing must be minimized or eliminated. There must be a common "look and feel" for all displays. A library of standard symbols must be used to represent substation power apparatus on graphical displays. Multiple databases must be avoided. The substation one-line displays may be similar in appearance to the displays on a SCADA/EMS.

■ *Communication Interfaces.* Interfaces to IEDs are required to acquire data, determine the operating status of each IED, support communication protocols used by the IEDs, interface to the SCADA/EMS and to provide data to corporate users over the wide area network. Remote dial-in capabilities may be considered in the future for authorized access to data and alarms, the execution of diagnostic programs and to configure IEDs. An interface to a time reference source, such as a global positioning system, should be available as well.

■ *Corporate Data Repository.* The corporate data repository enables users to access operational and non-operational (load forecasting, engineering studies) substation data while maintaining a firewall to substation control and operation functions. Both operational and non-operational data is needed. The utility must determine the SAS data users, the nature of their application, the type of data needed and the frequency of update required for each user. ISA identified the user groups (operations, planning, engineering, SCADA, protection, metering, maintenance and information technology) of the data from the SAS, and also determined the user requirements for the type, periodicity, accuracy and format of the data.

System support should be provided for comprehensive diagnostic software routines, online software module integration, as well as online modification of database parameters.

Performance Criteria

System performance criteria determine the operation of the SAS, and allow quantitative and qualitative comparison of different vendor proposals. Performance criteria include response times, system utilization, storage capacity, availability and redundancy, failure recovery, maintainability and expandability. Clear criteria must be established to deal with availability, minimal transfer times, fault tolerance and redundancy, which permits the vendor to define the type of redundancy of this equipment to comply with the requirements. No single component failure or detectable communication error should disable or degrade the performance of primary substation monitoring and control functions. For maintainability, self-diagnostics must be performed by all SAS components, and all problems or failures detected must be alarmed. System support should be provided for comprehensive diagnostic software routines, online software module integration, as well as online modification of database parameters.

Supplier Pre-Selection

ISA has established a separate, standardized process for the acquisition of SAS equipment. To ensure that a standardized technical specification results in the procurement of a standardized SAS, ISA has adopted a rigorous procurement strategy.

In the standardized acquisition process, the main suppliers that ISA recognizes will be invited to submit pre-selection proposals for the SAS. The invitation includes a document of pre-selection criteria and questions issued with the standardized specification. The pre-selection proposals will be evaluated by ISA and assigned weighted scores based on the level of compliance to obligatory requirements and desirable requirements.

The resulting scores of compliance to obligatory and desirable requirements will be related to the prices of the proposals to obtain a total technical-economic score. The evaluation of the proposals will result in the selection of two suppliers with the best technical-economical solutions for the SAS. Selection two suppliers minimizes the number of variations of SAS systems installed in ISA and ensures a competitive bid process. Demonstrations of the proposed systems may be evaluated before the final selection.

Contract Negotiation

After the pre-selection process, the objective is to make an alliance with one or both strategic partners, which guarantees their participation in the provision of the required SAS during a five-year period. With this option, ISA guarantees that the most recent and standard hardware and software technology is used in the SAS. This will produce significant time and costs savings in the acquisition, negotiation, contracting, development, implementation, maintenance and training for the SAS. The agreement with the pre-selected suppliers will stipulate that contract terms and prices are valid for the five-year period, and that purchase of the SAS from any one supplier depends on ISA's evaluation of the performance of the suppliers, the standardization of the installed systems and any new technology available.

Organizational Changes

ISA requires organizational changes to ensure a standardized specification and procurement process, and coordinated management of the resources related to the SAS. ISA will create a group of design, construction, operation and maintenance personnel to specialize in the standardized SAS technology. The main functions of the group will be to participate in the planning, design and specification of the SAS; to keep updated on the evolution of the technology of the SAS; and to be involved in all aspects of acquisition and commissioning of the SAS, as well as the maintenance and expansion of SAS installations.

Summary

ISA, as a transmission utility in a recently deregulated and privatized market, is facing several challenges with the use of SASs. In a competitive utility environment, standardization and open-system architectures for integration and automation of substations are key factors in considering substation additions or upgrades to ISA's transmission system. The standardized SAS specification and procurement process ensures that any substation additions or upgrades are at minimal cost by facilitating competitive bids with comparable functionality. ISA's substations interconnect the various parts of the Colombian transmission system, as well as the interconnection to several distribution networks. In a deregulated market, information regarding the status of the network and all of its components is critical. Standardized open systems facilitate the requirement that data must be supplied on an as-needed basis to various users in the enterprise, because the functionality of the SAS can be revised accordingly. Furthermore, the functional requirements of the SAS can follow the migration of the business strategies of ISA, thus providing more cost-effective solutions. For example, ISA is considering a decision regarding the manning of substations versus distributed control. The implementation of this decision will be facilitated by the flexibility of the SAS standardized specification and implementation process.

Vertical disintegration of the industry, unbundling of services, open-transmission access and retail wheeling are requiring the sharing of much more data at the transmission level in real-time. At the same time, a tremendous amount of standardization activity is occurring in substation communications and protocols. Fortunately, the primary groups sponsoring these activities—EPRI, IEEE and IEC—are working together with a high level of input from vendors, utilities and consultants. The great collective purchasing power of major electric utilities in North America has forced the vendors to redesign their products. This amount of industry support and harmonization is proving to be the vehicle for rapid deployment and acceptance of an industry-wide communication standard for field device integration that will support the needs of automation and integration projects being considered at many utilities. ■

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Marco C. Janssen, a consultant with KEMA T&D Power in The Netherlands, has nine years of experience on conventional control and substation automation systems, protective relaying, the use of quality assurance systems and quality surveillance. Janssen is involved in standardization processes related to substation automation and substation design and testing.

John D. McDonald, senior principal consultant and manager of substation automation with KEMA Consulting, has more than 25 years of experience in the electric utility industry. Currently, he is assisting electric utilities in substation automation, distribution SCADA, communications protocols and distribution management systems (DMS). McDonald has the BSEE and MSEE degrees from Purdue University and the MBA in finance from the University of California at Berkeley. He is a member of the Governing Board of the IEEE Power Engineering Society and is vice-chair of the Substations Committee. He has published 15 papers in the areas of SCADA, energy management systems, DMS and communications.

Juan Carlos Olaya, an electronics engineer with data communications specialization in Japan, works with Interconexión Eléctrica S.A. (ISA) in Colombia. He has 16 years of experience in the planning, design and specification of conventional control and substation automation systems (SAS)for HV and EHV substations at ISA. He was the manager of the SAS standardization project at ISA. He has published five papers on substation control systems in Colombian and regional technical publications and seminars.