IMPLEMENTATION OF A NEW SCADA/EMS/DMS IN A LARGE UTILITY, INTEGRATED WITH CORPORATE INFORMATION SYSTEMS

J.M. CORERA*, J. MARTÍ*, Z. OJINAGA*, W. LEX†, A KUHLMANN†
*Iberdrola Distribución, SA †Siemens AG
Spain Germany
j.corera@iberdrola.es

INTRODUCTION

This paper reports the control centres renewal project, that Iberdrola Distribution has undertaken with the company Siemens. Three out of six systems are already in operation and the rest are scheduled for 2005. Project highlights are: the concentration of systems carried out, the unified operator's interface, the renewal of the communications in the field, the advance functionality introduced for the first time in Iberdrola such as electrical applications for medium voltage and the connection to the corporate systems, both for static data –network models, graphics- and for dynamic data such as electrical magnitudes and information related to quality of service.

PROJECT CONTEXT

Iberdrola control architecture was common to a vertically integrated utility in a regulated framework: on one side, transmission Energy Management Systems (four in total, one per Region), and on the other side SCADA Distribution Systems with basic functionality, in a large number (around 40), with an average coverage of a province per system (in some cases even just a few substations). Telecontrol had been implemented along many years, and for that reason the systems were from different manufacturers, and in different versions. Some of them were near obsolescence.

Similarly as in other Countries, Deregulation in Spain separated Generation from Distribution activities. The cost reduction pressure in the Distribution business pushed a concentration of Control Centers, both vertically (a control centre would control all the network in his area, from transmission/subtransmission network to medium voltage, blurring the previous separation) and horizontally (from 45 initial locations down to only 6, located in the Region Heads). The existing architecture of control centers was not suitable to this new Operation structure, not only due to the number of different systems the operators had to manage (which have been moved to the definite control centers), but also due to the complexity imposed to field communications to RTUs (RTUs communicated to at least 2 control centers, transmission and distribution, sending the respective information) and to the large number of inter-centre communications (CCR links), coded in proprietary protocols.

Already mentioned, obsolescence was another issue, as some of the systems could not evolve further, in functionality and/or in size.

Functionality limitations was another main reason for renewal, as many of the existing systems were traditional, stand-alone SCADA systems, just supporting telecontrol. Deregulation was bringing new requirements, impossible to implement in the existing platforms, that required some degree of integration with corporate systems. The new functionality should bring improvements in: loss reduction, quality of service management, demand forecast and energy procurement, field crews management, network planning, etc.

Finally, control system maintenance was another important issue. The diversity of systems was making it complex, and it was an obstacle for further evolution. The addition of a new functionality could mean implementing it in at least 6 different systems. Having an homogeneous solution, which would be updated in the future periodically following the state of the art, was also sought (see figure 1).

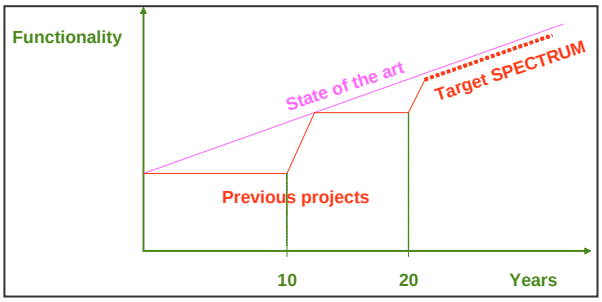

Figure 1: future system evolution

Reference [1], prepared at the time of the start of the project, completes this picture with the detailed targets of the project.

OBJECTIVES

Having these considerations, the project was launched with the following objectives:

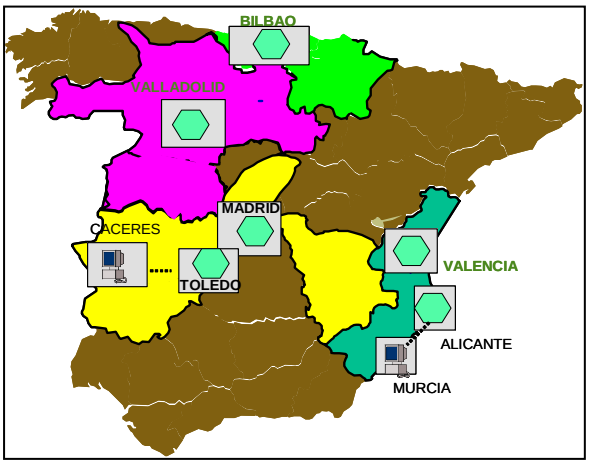

Figure 2: target configuration

- one single system per Region (see locations in figure 2), responsible for all voltage levels, including the management of low voltage trouble calls; as average size, one Region serves 1,5 million customers and has 150 main substations
- only one of the systems includes the EMS functionality, and for that reason receives all the transmission information from the rest of the systems, via ICCP links, and from the TSO (REE); EMS includes contingency analysis and OPF, that before run in an external application
- all systems are from the same manufacturer, all with identical software version

These requirements are completed with other main improvements:

- communications with RTUs are digitalized (elimination of modems) where possible, taking advantage of the large optical fiber network that was reaching many of the main substations
- IEC standard protocols (870-5-101) are placed in the field where it is technically and economically feasible
- Emergency systems are placed for every main system, in a nearby location
- Real-time Distribution Electrical applications are incorporated for the first time in Iberdrola, including operator load flow and network optimization
- Connection to corporate system will be carried out:
  - For incremental download of the GIS network model and graphics
  - To feed corporate systems with operational data, such as electrical magnitudes, quality of service data, etc…

The functionalities which are more innovative, at least for Iberdrola will be described in more detail below, followed by the problems encountered.

DETAILED DESCRIPTION

Unified interface

The system interface allows to operate the whole network with a consistent "look and feel" from substations (transmission and distribution) to non telemetered MV networks. A dual schematic and geographic view is provided for all networks, with efficient navigation and search facilities. Network coloring depending on voltage or feeder is also employed. Trouble calls, faults, crews, are also presented in the same interface.

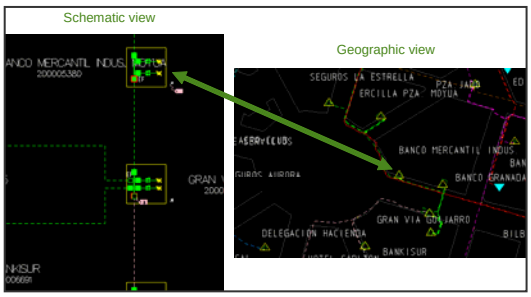

Figure 3: two interrelated views, geographic and schematic

As a result, the operator can identify the network situation much easier than before. As mentioned before, all the GIS graphics are downloaded, and additional diagrams are added when needed.

Distribution electrical applications

They are now being place in operation, after one year of on-line test and improvement. It is for the first time that such functionality exist in Iberdrola, and it is expected to bring significant benefits.

The system performs, every hour or after topology changes as configured, a complete analysis of the distribution network, *estimating* the active and reactive power consumed by every customer that matches the substation telecontrol measurements, and that are proportional to the installed/contracted power of every customer. With this starting point, the system allows:

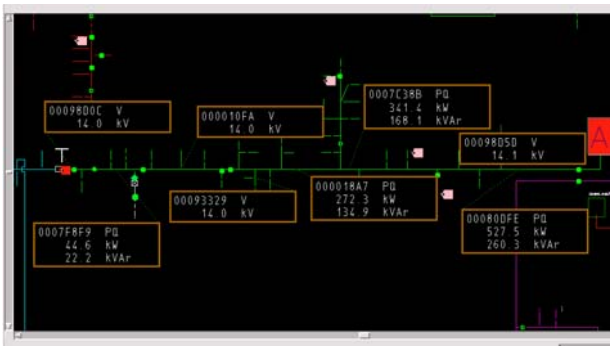

Figure 4: Power flow and voltages along a MV feeder

- case study simulations (useful to prevent voltage violations or power limit violations during network operation)

- network optimization, reducing losses by adjusting tap changers and reconfiguring feeders.

Emergency systems

Nowadays, the electrical service is so critical for society that it is not admissible that a problem in the control centre would leave without telecontrol the network, with negative consequences specially in case of disturbances.

To start, the main systems are redundant, which is *a must* not only to cover a failure of a single server, but to facilitate maintenance issues, system updates, etc. without creating unavailability. However, it does not prevent from large failures, like a blackout of the whole building, the lose of all the communications to the field, or a large scale disaster. For that reason, for every main system an emergency system is placed in a substation with reliable communications and reliable power supply, which is located not far from the main system, so operators can move there easily.

All important substations have two point-to-point links (see figure 5), one connecting to the main system and another to the emergency location. Front ends receiving these links are placed at both sites, which in normal situation are polled by the main system. This system explores alternatively both channels, so the emergency route is permanently checked. The database of the main system is copied daily to the emergency system.

In case the emergency system has to start (lets assume the main location is not operational), it will take over the front ends at its site, end explore the substations from there.

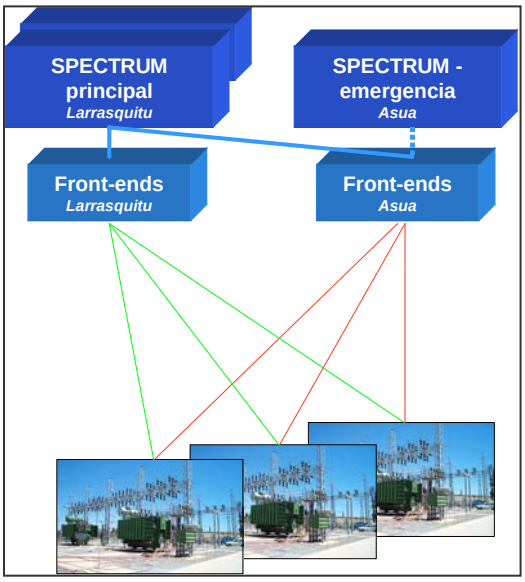

Figure 5 : emergency architecture

Corporate systems integration

As established from the beginning of the project, corporate systems integration was a target. The results achieved so far are explained below (see figure 6). A standardized integration, following IEC 61.968 (Distribution systems interface standard) and IEC 61.970 (CIM model) has not been implemented yet, due to current limitations of some of the systems, and is considered a long-term target.

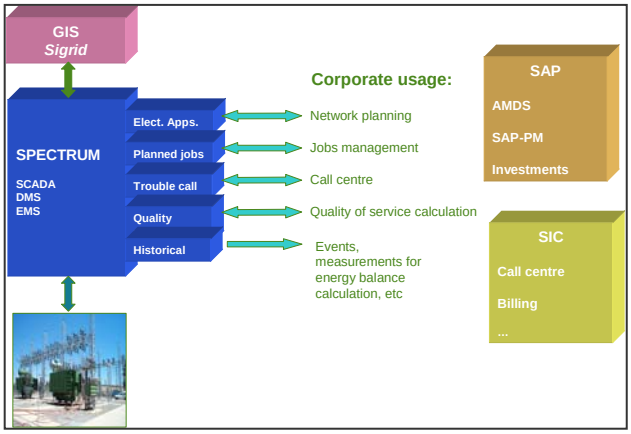

Figure 6 : integration of Spectrum with corporate systems

GIS integration. Iberdrola Distribution GIS, an in-house development based in Intergraph and Frame, is used widely in the company, for network development and maintenance, and it is the network inventory master for the network-related applications running in SAP (maintenance, investment) and in the Customer Information system (CIS). For that reason, it was considered important that both the network data and the graphics used in the control systems should be downloaded from the GIS (except of course telecontrol information, that was considered private to the control systems). This has been achieved: everyday a comparison between the control system database and graphics is performed with the GISs of the Region, and the differences (additions, deletions and/or modifications) are downloaded incrementally to the system. Telecontrol information is referenced to this data so, indirectly, all corporate systems share same data references and can have immediate access to live network data, such as power flows, voltages, outages, etc…

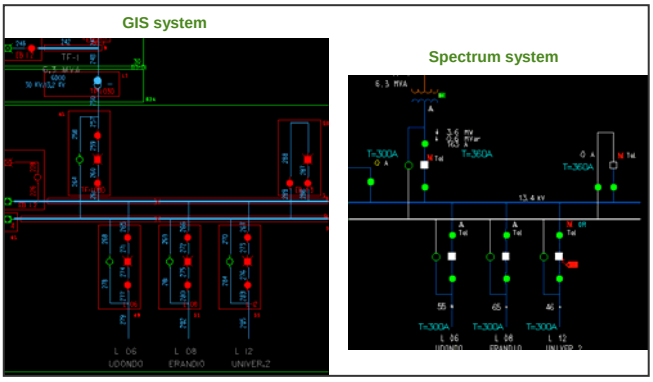

Figure 7: GIS view and control system view of a substation one-line diagram

The sharing of the graphics proved to be useful (see figure 7): before, substation one-line diagrams where different from the GIS and from the SCADA, this creating potential errors when an operator was interacting with a field crew, that typically use GIS diagram.

Quality of service. Spanish Regulations request Distribution Utilities to register quality of service information at individual customer level (discounts are to be applied if outages exceed certain thresholds) and also to calculate different general indexes (similar to SAIDI, etc). All this information has to be elaborated whenever possible in an automatic way by the telecontrol system, to avoid human errors. Trouble calls and planned jobs are also to be taken into consideration in those calculations.

The integrated solution achieved, by which telecontrolled and non-telemetered network are managed jointly, is compliant with the new requirements, and is effective for the operators who are relieved from burdensome registration activities and can concentrate in the restoration process.

A real time connection is established with the CIS: trouble calls are received by the call centre supported by this system, and passed to the control system, which returns the disturbances and quality of service necessary for customer billing.

Reference [2] gives more information on this specific subject.

Network planning, off-line disturbance analysis, energy purchase. These three activities are served by the control systems as follows:
- for network planning, off-line planning tools are being used, which are fed with the network model and live data from the control system
- off-line disturbance analysis for protection evaluation is performed by an in-house developed tool named SINAI, that communicates with protection relays and fault recorders in the field. The control system sends to this application the automatic disturbance report used by the quality of service module, and soon will share the network model downloaded from the control system
- finally, energy purchases by Distribution require real time energy balances to perform corrections in the intra-day market, if deviations from forecasts exist

IT integration security aspects

This is a new aspect that was not relevant in traditional SCADAs, which were basically isolated and only physically accessible in a secured dispatch centre. Now the systems require corporate users access and connections with external applications, as mentioned.

The project has considered these security issues, however it must be said that security is a never-ending subject, as any PC user can recognize. The security is established at several layers:

- the communications channels from the system to the field are configured as point-to-point, or point-to-multipoint private links which are non accessible from the corporate networks.
- Only the front-ends of the system access these links, and are connected to the telecontrol processors through a secondary LAN different from the system LAN
- Finally, the system LAN is connected to the corporate LAN only in one point (redundant) per system, equipped with a high-end firewall.
- Direct access to the system by corporate users is avoided by having replica of the data (alarms, measurements, quality of service information) in additional dedicated servers, placed between the system LAN and the corporate LAN, and protected by the firewall.

RESULTS OBTAINED AND MAIN DIFFICULTIES

At the date of preparing this paper, 3 systems are in full operation: Bilbao, Valencia and Madrid (this last one with partial coverage of the Region, to be completed by Easter 2005).

Figure 8: partial view of North Region Control Centre

A project of this size, which replaces systems in operation, is always complex. Below we are indicating the issues that presented special difficulties.

Telecontrol data standardization. Similarly to other large utilities, substation engineering in Iberdrola was diverse due to history, and the information transmitted via telecontrol was not homogeneous. The *typification* of the systems had to be unique, and it forced an standardization of telecontrol data, which resulted quite complex but paid back by the standardization achieved.

Data porting and GIS incremental interface. Related to the item before, data porting was a complex item, as it involved:
- porting of RTU data from a number of different systems, and different protocols (only once)
- creating an incremental interface from the GIS, for receiving equipment data, plus graphical representation (both schematic and geographic), to be used both for the bulky data loading and for future operation, to keep the GIS and Spectrum synchronized
- cross-referencing GIS data with real-time data

In general, these tasks required a lot of effort, and only a limited part could be contracted outside the company as it required a lot of expertise.

Protocol emulation. Some of the proprietary protocols used in the RTUs could not be replaced by the IEC standard protocols, because they were used by a significant number of RTUs which could not be updated, and the replacement would be too expensive. Therefore these protocols had to be emulated by the control system, which prove to be a difficult task.

Necessity for auxiliary systems. Additionally to the main control system being commissioned, the project required temporarily to replicate a Spectrum system and/or a database for: data porting, functionality testing, point to point test and training. The ease of Spectrum to do this systems replicas, and the availability of hardware (which will be used in the last systems) allowed this to be done whenever needed.

Commissioning of the systems. The replacement of the existing control systems by the new one while the old ones were in satisfactory operation, required careful planning of the activities, as it involved both field activities (e.g. changing an RTU EPROM) and Dispatch activities.

Training. Training is resulting a very effort demanding task, both to the in-house control systems experts, who require enough knowledge for commissioning and future maintenance, and to the operators, with more difficult logistics because the later group works in shifts.

Reliability of the final solution. Concentrating all the telecontrol of the Region in a single system requires a highly dependable solution, far more than before, when smaller, isolated systems existed.

CONCLUSIONS

With the experience of three systems already in full operation, it must be said that the final result is highly satisfactory. One of the aspects more appreciated by the end user is the unified graphical interface, which allows quickly to diagnose the reach of disturbances and to identify the restoration actions. It proved very useful during the snow storms of February 2004, that caused a number of permanent faults in the 13kV, 30kV and 132kV lines in the North of Spain. The appropriate strategy for restoration could be worked out soon.

The project is scheduled to finish end of 2005, when the rest 3 systems (Valladolid, Toledo and Alicante) will be commissioned.

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