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APPLICATION POLICY FOR COMPUTER-BASED CONTROL SYSTEMS IN SUBSTATIONS: A REVIEW

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Summary

Case studies from seven utilities about their application policy for computer-based control systems in substations are reviewed. The application policy and the relevant experience of the utilities are given under the headings of costs, architecture, EMC, functionality, communication, reliability, flexibility, operation, maintenance and relationship with the vendor. Conclusions are drawn about similarities.

Keywords

Computer-based control systems, policy, experience.

Introduction

In recent years, many utilities have installed computer-based control systems in both new and renovated substations. This does not, however, mean that there is a uniform rationale or application policy underlying the decision to apply this kind of equipment. Experience has shown that a coherent utility-wide policy is necessary to obtain a successful and useful implementation of these systems. The question is whether any similarity in the policies can be identified.

The objective of this paper is to bring together the relevant experience of utilities with over ten years experience in the application of advanced control systems. To this end, the relevant policy developed by these utilities will be reviewed on the basis of a number of case studies.
In addition to the policy, which is currently operative within the utilities, the case studies also address the design approach and the evolution of the policy over time. Issues such as functionality, maintainability, man-machine interfaces, the architecture, the costs and the communication with other power system equipment will be covered. Conclusions will be drawn and similarities and possible universal policy lines identified.

Case studies

Seven utilities provided the case studies. These are : **Case 1** (the Netherlands), **Case 2** (Spain), **Case 3** (Switzerland), **Case 4** (Venezuela), **Case 5** (the Netherlands), **Case 6** (Poland) and **Case 7** (the Netherlands). The results of the case studies are given in the appendix.
All of the participating utilities have at least ten years experience with substation automation (SA); some have experience dating from 1984. This experience with SA covers application for voltage levels from 110 kV up to 400 kV.

Application policy

The policy depends on the user requirements and on the possibilities offered the supplier technology. The utilities that started earlier with SA placed more emphasis on reliability and availability than the utilities that started later. Over time SA has proven its reliability and availability.

<u>Costs</u>

Cost reduction is an important issue. It is expected that the initial purchase cost of a SA system should at least not be higher than that of a conventional system but that the SA system should have a lower lifecycle cost.

Architecture

Most utilities prefer a decentralised architecture with redundancy or other back-up facilities. The system should use recognised standards and be based as far as possible on open systems architecture.

EMC

The EMC requirements are very important for all the utilities. Nowadays the subject is well covered by international standards. The use of fibre optic cables for inter-bay communication is common.

Functionality

The degree of functionality depends on the utility and the length of its experience with SA.
Some utilities focus on the functionality of the conventional system (the basic functionality of Supervision Control And Data Acquisition) with the possibility to extend the functionality in a later stage.
Other utilities (the early bird utilities) initially want a separate and independent interlocking system and an extra hardwired interface (relays) between SA and the primary process.
In later phases there is more integration of secondary functions such as interlocking, RTU function, integration of the secondary protection functions (such as breaker failure protection, synchrocheck, transformer voltage regulator etc.) and serial communication with the protection systems.
The level of functionality is in principle the same as that provided by conventional systems.
Finally there is the provision of new functionality such as monitoring of the primary systems to optimise the maintenance process.

Communication

The system should use protocols based on recognized international standards.

Reliability and availability

Reliability and availability are important issues for all the utilities. The system must be stable and reliable.
The availability and security of the system must at least be equal to or better than the existing and well-proven system based on conventional technology.
Reliability can be increased by continuous self-supervision and by a reduced number of spare parts (less product diversity).

Flexibility

The SA system has to be flexible. Flexibility can be achieved by:

- Simplification of hardware arrangement (less space, less cabling, less marshalling.);
- Interface compatibility and extendibility required;
- Use of the same standards for control and protection;
- Simplified replacement of existing equipment due to compactness of cabling and cubicles allowing new decentralised structures;
- Reducing the number of protection devices.

Operation and maintenance

The first line maintenance is done by the utility itself with maintenance support by the manufacturer.
The engineering tools of the system must be suitable for use by non-specialists.
Local communication via MMI must be simple and appropriate for easy use by substation personnel.

Relationship with vendor

Most utilities work in close co-operation with the vendor, especially in the first project to train the utility’s engineering, operation and maintenance personnel. Maintenance support by the manufacture is a common policy.
Reduced delivery and commissioning time due to factory pre-tested equipment is noted by two utilities.

Experiences

Costs

SA systems are still mostly proprietary systems. Because of this, the costs are still relatively high. The use of standardized software, hardware and interoperable equipment will bring the cost down for vendors and utilities.

Case 5 shows that the average investment for a bay equipped with SA has been approximately halved between 1996 and 2000. This reduction has been achieved by advances in technology and by competition between suppliers.

Case 2 and **Case 7** report considerable savings in the construction and refurbishment of substation, both in primary and secondary equipment due to:

- Integration of auxiliary relays and measurement converters;
- The possibility to minimise the primary equipment e.g. to leave out VT's in feeder bays (2 busbar VT's instead of 6 or 8 VTs in the feeder bays);
- Serial communication with protection equipment;
- Integration of transformer regulator into the SA system;
- Elimination of breaker failure protection;
- Distributed I/O interfaces on the primary equipment. In comparison with the present concept there is a total saving of about 25 % in the cost of the secondary equipment.

Architecture

Most utilities have good experience with decentralised architecture with some kind of redundancy. **Case 4** (400 kV) reports on a redundant architecture with duplicated star-couplers (Master and Hot-Stand-By). The transition from a ring busbar configuration to 1½ breaker system leads to special problems for the interlocking.

Redundant architecture and duplicated fiber optic cables to bay controllers is common.

EMC

Much work has been carried out in the field of EMC. The key points of the EMC philosophy of **Case 1** are:

- The earthing grid is meshed with a mesh width of 5m and is connected to the reinforcement;
- All equipment is connected as directly as possible to the earthing grid;
- Shielded cabling with the shield earthed at each end and very short terminal connections outside the shielding is used;
- The shielded cabling is installed very close to the copper bars of the earthing grid.

Functionality

Initially the functionality of SA systems was focused on functionality of conventional systems. Later many more substation functions are integrated in SA such as:

- Interlocking in software
- Several partial solutions (protection systems, metering, fault recording, automatic voltage regulation, synchrocheck, tap changer control, …)
- Switching sequences (for example: switch one bay to a busbar or change of single bays or all bays from one busbar to an other one)
- Automatic measurement and report of "distance to fault" to control center in case of an earthfault on outgoing overhead lines Case 6

Communication

In the eighties and early nineties standard protocols were not available for SA systems. **Case 4** reports that the lack of standard protocols prevented the use of a serial link between protection equipment and the SA system. The alarm signals were fed into the bay units by parallel connection.

In later installations, when standard protocols (IEC 60870-5-*) are applicable for SA, it is very common to have a serial link between protection systems and the SA system.

Some of the utilities report on the experience of remote reading of disturbance records and downloading of parameters for protection relays.

Reliability and availability

The experience of reliability and availability of all utilities is very good. The higher voltage level substations (**Case 4** and **Case 6** : 400 kV) use redundant power supplies for each bay unit and doubled remote connections to several control centers.

Operation and maintenance

- The transition from hardware engineering to software engineering is complex. Sophisticated software tools were not available in the initial SA installations;
- The rapid change of software is a problem for extensions and the addition of functionality to older systems;
- Maintenance of software by utility staff is complex;
- **Case 2** and **Case 6** report on experience with remote connection to a maintenance centre;
- **Case 6** performs an automatic daily protocol of the energy transfer;
- **Case 7** reports on the use of remote MMI via TCP/IP involving:
  - Transfer of the process mimics to the remote PC;
  - Upload of files (e.g. alarm lists, trend data, fault recordings) from the control system;
  - Reduction in the number of visits to the (unmanned) substations.

Relationship with vendor

Case 2 has communication (via modem) with the software supplier. **Case 4** reports that a close co-operation with vendor during engineering, FAT and commissioning phase was very useful for training the utility personnel.

Review

The experience of the utilities in their first project can be considered positive. Based on this success they have decided to implement SA in both new substations and in substation renovations.
The knowledge required by the utility engineer to work with SA systems is very different to that required for conventional systems. Close co-operation between the utility and the vendor is a good method of achieving a sufficient degree of knowledge. It is important to use an up to date database management system for the application software.
However, in practice, the implementation of SA is slow in spite of the advantages provided by these systems.

- The additional functionality of modern control systems is not usually a driving factor for the responsible managers to install SA;
- It is not easy to integrate SA by partial renovation of a substation. The interface with the conventional system is expensive and the advantages provided by a SA system are reduced.

Costs

SA systems are mainly proprietary systems. Because of this, the costs are still relatively high. Use of standardized software, hardware and interoperability will bring the cost down for vendors and utilities.
One of the main goals for the use of SA, was a reduction of cabling costs. In the present solutions we see that cabling costs are still substantial. A lot of cabling for protection and control systems still exists but should be reduced in the coming years.
Case 2 and **Case 7** report considerable savings in the construction and refurbishment of substation, both in primary and secondary equipment.
Further reduction of costs can be reached by standardisation (engineering, tools, equipment, functions and interfaces). The data acquisition and calculation functions

available in modern digital protection systems will be fed into the numerical control system via serial connections. These are expected to result in a reduction of the total cost of the substation.
A flexible SA system is an important tool to reduce the overall costs of substations (to reduce secondary equipment, cabling, installation costs, primary equipment etc.).

Architecture

The decentralised architecture with some kind of redundancy fulfils the needs of the utilities very well. In the case of lower voltage levels there is no need for separate bay-level control (small distances in a substation).
In future "intelligent" HV equipment will communicate with the SA system via optical links (LAN).

EMC

EMC was a very important issue and the utilities have obtained a lot of experiences in this field. The EMC views from the University of Eindhoven are implemented and field trials have given **Case 1** expertise in shielding and earthing technology to prevent malfunctions.

Functionality

It is common practice that conventional substation functionality, incl. the so-called secondary protection functions, is integrated in SA. At present very few new functions have been introduced (the primary process has not changed).
However powerful new functions have been proposed for the future, such as:

- Monitoring of the primary systems to optimise the maintenance process;
- Possibility to increase the load on the HV equipment, without fear of overload and shortening of service life;
- Connection of "intelligent" HV equipment to a substation LAN;
- archiving of data on station level (optimised archiving and communication capacity requirements);
- Automatic functions (switching sequences, reports, ...) to reduce the daily workload of the local or remote substation operators who will however require additional training;
- Integration of next generation control modules into protection relays.

Communication

Nowadays standard protocols (IEC 60870-5-*) are applicable for the communication with the dispatch centre and the protection relays. There is a need for more standardisation to decrease the costs:

- More standardisation effort (protocols, object modelling etc.);
- remote station control terminal in regional control centre for easy stepwise introduction;
- Data storage at the substation level, which is expected to reduce the communication, load to the dispatch centre.

Reliability and availability

The systems are proving to be very reliable. Any fears of the operating staff about working with an MMI instead of the very robust hardware switches has completely disappeared.
Increased of accuracy, security and ease of operation leads to reduced outages and better electrical transmission system availability.

Operation and maintenance

Substation operation with MMI screens does not cause any difficulties for the operating personnel. The maintenance of HV equipment can be optimised by continuous monitoring of the critical functions of the HV equipment.
The hardware installed in the existing substations is very common and is not difficult to maintain.
Software maintenance, however, is another issue. It is more abstract and is subject to regular upgrades. Some relevant points are:

- Higher knowledge level required for engineering and maintenance staff;
- Data maintenance requirements are of great importance;
- Close co-operation with the vendor in the engineering and project phase is essential for training and transfer of know-how;
- An increase in the number of different systems due to more vendors and more competition, and their need for regular upgrades adds to the workload of the maintenance staff.

Relationship with vendor

- Upgrading of the system software. Software is often changed by the vendor (system bug or the client wants more functionality) and leads to other releases and versions;
- Upgrading of existing systems with a new software release sometimes leads to problems. It is the responsibility of the vendor to guarantee the quality of the new software.

Conclusions

Based on the successful experiences of the utilities with SA, they have decided to implement SA in both new substations and renovated substations. A flexible SA system is an important tool to reduce the overall costs of substations (to reduce secondary equipment, cabling, installation costs, primary equipment etc.). A decentralised architecture with some kind of redundancy fulfils the needs of the utilities very well. EMC was a very important issue and is completely solved.

At present very few new functions have been introduced (the primary process has not changed). However powerful new functions have been proposed for the future, such as monitoring of the primary systems to optimise the maintenance process.

The systems are proving to be very reliable. Any fears of the operating staff about working with an MMI instead of the very robust hardware switches has completely disappeared.

Software maintenance is another issue. It is more abstract and is subject to regular upgrades. A higher knowledge level for engineering and maintenance staff is needed.

It is the responsibility of the vendor to guarantee the quality of the new software used in any system upgrade.

In this paper we report about the experiences of the utilities in the last 10 till 15 years. In the coming years there will be obtained a lot of experiences on other items, such as:

- Prediction and optimising of maintenance;
- More information for the deregulated market;
- Integration of control and protection;
- Advanced monitoring systems to increase the load on HV equipment, without fear of overload and service life;
- Integration of “intelligent” HV equipment;
- More standardisation of IT products and software.

Appendix

- Case study 1: Experiences in HV substation of NUON, A.W.H. Geerling, NUON, the Netherlands.
- Case study 2: Experiences in high voltage automation substation of RED, J.C. Sánchez Martin, RED Electrica, Spain
- Case study 3: Case study Electricity of Laufenburg EGL, B. Sander, EGL, Switzerland.
- Case study 4: Experience on numerical substation protection and control systems in Edelca network, E. Padilla etc. Edelca, Venezuela.

- Case study 5*:* Case study REMU, F. Koers, REMU, the Netherlands.
- Case study 6*:* Case study PSE, P. Molsky, Energoprojekt-Krakow S.A, Poland
- Case study 7*:* Case study Essent, H. Timmerman, Essent Netwerk Noord, the Netherlands

Appendix

1 *Case study 1:* Experiences in HV substation of NUON, the Netherlands

A.W.H. Geerling, NUON, the Netherlands.

NUON's high voltage Power Grids.

The NUON's HV power grids are a mix of HV networks (50; 110; 150 and 220 kV). The 220 kV network is a part of the national backbone grid. All the new substations over the past 15 years have been equipped with Substation Automation (SA).

Substation Automation Drivers

In '84 two utilities wherefore later Nuon is founded, decided to build a new type 150 kV Gas Isolated Switchgear (GIS) substation and updating 110 kV substations, with a number of new technologies including SA.
NUON decided at that time to automate the Protection & Control system of this new build- and renovated Substations with the most advanced technology for SA in the 80's.
During the feasibility study it became clear that some vendors developed their proprietary solutions for Substation Control and Protection and those were conceptual appropriate for NUON's substations.

Substation Automation Pilot.

The GIS pilot was a completely new designed substation, including building, earthing philosophy and protection & control system. The open-air substation was completely overhauled. The GIS pilot and the open-air substation has two different suppliers of SA systems.
In close co-operation with these vendors the SA pilot systems are developed as standard vendor solutions, which could meet at most all the NUON requirements.
NUON's own engineering department defined the functionality of application software and the User Interface.
NUON engineers carried out the application engineering, with their expertise in hardware oriented protection & control functionality.

Substation Automation Functionality.

First of all there is a basic functionality called Supervising And Data Acquisition & Control.
Further on, the standard vendor interlocking philosophy was not applicable for NUON. It has been changed to a so called 'interlocking-block system'. An interlocking-block consists of a feeder, a bay coupler and buss-bar earthing switches. This interlocking philosophy gives more flexibility for the operators. It covers all switching operations within the interlocking. The basic development rule for interlocking is not only safety in switching procedures but also the principle for convenient use. To put it differently: "Interlocking should be a real support and not an obstruction for carrying out switching operations.

EMC Requirements.

Earthing is a very important EMC issue for SA. In the design phase the latest views (which are still valid) about earthing philosophy were implemented.

<u>Key-topics of the EMC philosophy are:</u>

- The earthing-grid is mashed with a mash-width of 15 feet and is connected to the reinforcement.
- Connect all equipment as much as possible to the earthing grid.
- Use shielded Cabling with double sided earthing to the grid and very short terminal connections outside the shielding.
- Install the shielded Cabling very close to the copper bars of the earthing grid.

Typical configuration for SA at one of the first substations.

The chosen Siemens SA solution for the GIS pilot has an independent level for bay control with interlocking facility. It forms a redundant system for the substation- and Control Centre control. The interlocking module is build with special fail-safe software. The software is time redundant and works with direct process values only.

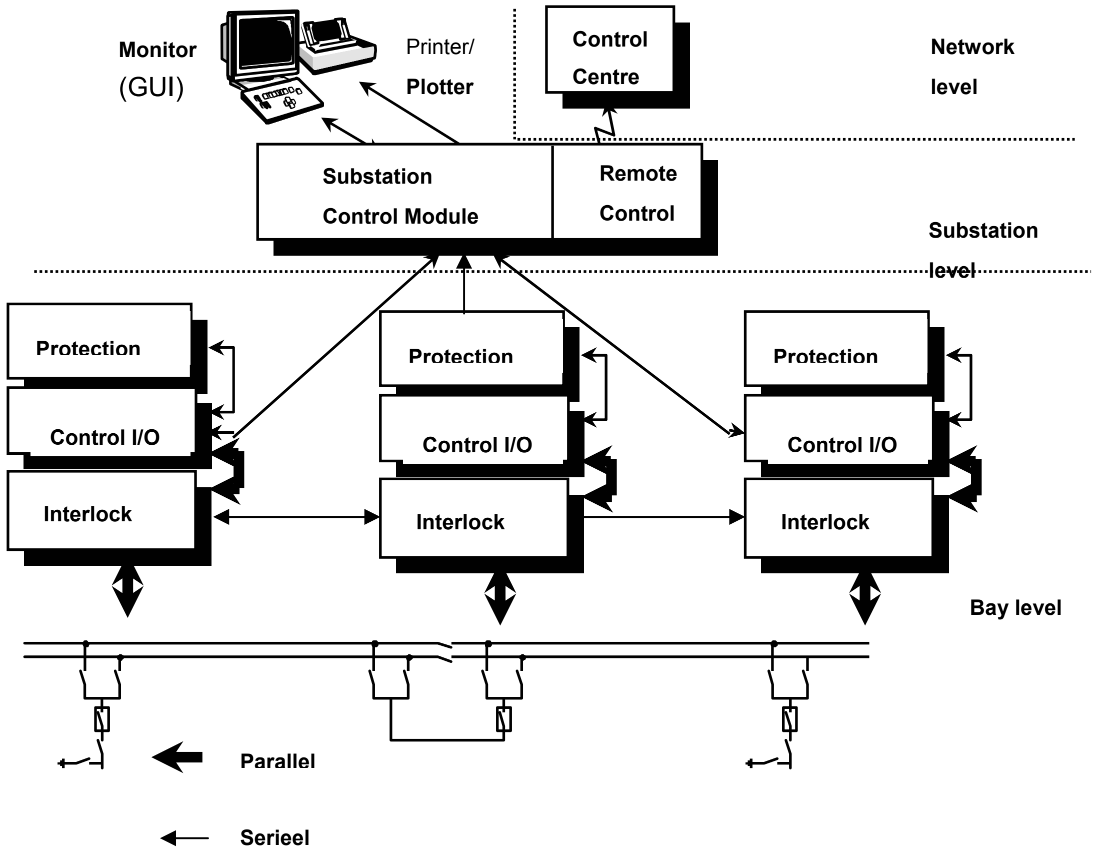

Fig 1 Substation Automation configuration.

In this configuration interlocking modules have there own control panel, this includes an emergency control facility in case of an outage of the processor.
The bay control level with the interlocking acts as a redundant control level for Control Centre and Substation Control.
In the follow up projects, the protection relays are connected to the I/O bay-modules by means of the IEC 870-5 protocol. Those relays can realize disturbance recording on analogue and digital bases. The results can be shown through the SA substation module.

Experience since 1986.

Over the past 15 years NUON has gathered a lot of experience in SA. In the early days, the engineers were inexperienced not used to work with a software orientated Technology. Usually engineering was done by putting a lot of hardware devices in a Technical Design to create a control and protection system for a Substation.
With software design, all the functionality has to be known in advance in a structured form.
This approach was rather new for hardware oriented engineers. Another handicap was the application of simple engineering tools. Engineers carried out software programming and surveyed manually the whole software and looked for right interconnections between all the program modules.
Nowadays there are sophisticated application oriented tools, which produce application software and generates automatically all hard and software engineering documentation.
The systems in service are running very stable and reliable. Only a few computer boards have failed and have been replaced by NUON's maintenance staff.
Software is a new phenomenon in substations, especially for long life-cycle systems. The rapid change in technology is so dramatic, that the pilot- and some other older systems have been become obsolete and they can't be extended or added with new functionality.

Maintenance.

With SA, managing of maintenance is a completely different ball game. Software is a new phenomenon for protection and control in substations.
The installed hardware in the existing substations is very common and the maintenance can be carried out very well. Software maintenance is an other issue. It is more abstract and changes are regularly. Changes from '86 until now of one vendor; the following releases and versions:

- 3 operating system versions
- Firmware migrated from release V1 to V9 and
- Application Program Tools in 3 versions.

For systems with a long lifecycle it becomes a real problem. These issues are unusual in the traditional Substation Control Technology. The maintenance staff has to learn how to deal with this subject.
Specific system knowledge of the installed systems is drifting away at vendor's side. SA systems have a very long live cycle compared to Industrial Process Automation. Therefore loss of maintenance support from vendors side is a problem that must be solved.
There is also a loss of knowledge in maintenance staff because of reorganisations and job switching within or outside the company.

Maintenance Solutions.

Due to the disadvantage of a rapid evolution of automation systems and software, an early replacement is sometimes necessary. NUON has already replaced, after some years of operation, processor cards to improve functionality and either makes extensions or better maintenance possible.

SA is more abstract and has more functionality. Therefore NUON needs a higher knowledge level for engineering and maintenance staff to keep system management and -maintenance at a good level. This knowledge has to be spread over more- and better-qualified people.

Maintenance is now carried out by all-round maintenance staff but they will be in the future become maintenance specialists. These specialists have to maintain their experience lever.

Because of the very reliable SA systems, practical training (there are not enough faults) in maintenance will be a problem. At this time, only the hardware/software engineers have and will keep sufficient skills and experience.

Lessons learned

During the past 15 years NUON has gained a lot of experience in the use of SA technology. The main aspects are:

- The systems are running very reliable and the fear of the operating staff for working with User Interface instead of the very robust hardware switches has completely disappeared.
- The reliability of the SA pilot systems has given NUON much confidence in the technology. Because of this NUON has now decided to build all the new and renovated substations with SA.
- EMC was a very important issue and is completely solved. The EMC views from the University of Eindhoven are implemented and field trials have given NUON expertise in shielding and earthing technology to prevent malfunctioning.
- SA systems are mainly proprietary systems. Because of this, the costs are still relatively high. Use of standardized software, hardware and interoperability will bring the cost down for vendors and utilities.
- One of the main goals for the use of SA was reducing of cabling costs. In the present solutions we see that cabling costs are still substantial. A lot of cabling for protection and control systems is still existing and should be reduced in the coming years.

Future Challenges.

- Because the small distances in a substation it is not necessary to have separate bay-level control. In NUON's view, one central substation User Interface is sufficient. Therefore all I/O bay modules in the bays or feeders do not need a control panel anymore.
- For predicted maintenance there is a need for more information about the condition of HV equipment. Therefore NUON wants to collect more data to combine with static data from a Geographic Information System.
- Mostly for safety reasons, HV systems are mostly not fully loaded. When more accurate process data becomes available, you can move more towards the nominal limits of the HV equipment, without fear of an overload with a corresponding shortening of live span. The open market for electricity requires a reduction of costs for HV systems and SA systems.
- New HV equipment becomes more and more "Intelligent" and has to be connected to a future Substation LAN.
- NUON's goal is to support the standardisation efforts in IEC, CIGRE, IEEE and the EPRI initiatives for Object Modelling of all HV, control and protection equipment in substations.
- In software systems there is always a strong need for standardisation of protocols. Without these protocols it is not possible to interconnect devices of different vendors.
- With SA standardisation, Utilities are more flexible in engineering and become independent from proprietary solutions. SA will be become cheaper by using as much as possible standard IT products and software.
- Next generation control modules can be integrated in the Protection Relays. The protection software has to be separated from the SCADA software. Independent test-, supervision- and configuration possibilities with a dedicated HMI for protection functionality should be available
- More "Monitoring" of the HV system is a must to reduce the maintenance cost.

2 *Case study 2:* Experiences in high voltage automation substation of RED

J.C. Sánchez Martin, Electrica de Espana (REE), Spain

General information about RED ELÉCTRICA de ESPAÑA (REE)

REE is partially owner of HV network in Spain (79% of 400kV substations and 13% of 220kV substations).
Regarding this network, REE is responsible of design, maintenance and operation.
Since 1988, REE employ SA (Substation Automation) technologies in two ways: protection-control integration and maintenance.

Protection-control integration

The numerical technologies used to control and protection devices have allowed the development of new systems. These systems try to save and to improve availability and security.
REE begun the SA implementation in a first stage (1988-1994) where the main objective were to reduce the number of protection devices and substitute the conventional external cabled logic by internal programmed logic (incorporated in the protections), integrating functions that were before in independent relays.
We also implemented new redundant channels to dispatch center transmission and new SCADA.
This integration has to warrant the criteria and the established practices of REE.
The second stage (1994-2000) consisted in a control-protection linking (via serial based in IEC870-5 protocols) and a new equipment reduction. REE developed a pilot project using open architectures and remaining independence between control and protection functionality.
The prototype designed has had a good performance but we had some problems to implement it in real projects due the difficulty to find equipment suppliers that accepted the defined open architecture and the protocol.
The experience in this case has showed us the neediness to elaborate standard protocols and the importance of making it in short time. The delay in these agreements drives to outdate normative because of the rapid development of technologic.
In the third stage, (nowadays) we are incorporating external logic based local control panel into digital devices and we are linking control-protection via serial (with standard protocols). We also continue with function integration.
The aim is to eliminate (as possible) the conventional cabling among secondary equipment (level 1) and among secondary equipment and substation control and dispatch center (level 2 and 3) using fiber optic and standard protocols.
For next future, we are planning challenges to link the primary elements (level 1 to secondary equipment, analogue and digital signals) using optical or digital systems.

Maintenance

The second way taken to incorporate de SA system has been in control and protection maintenance area. Since 1997 we dispose technical office (maintenance dispatch) where we get incidents, disturbance recording, device situation, etc., and we can transmit new settings, real time measures, remote probes, etc.
This technical office has allowed reducing urgent displacement to inform about incidents and helps to preventive maintenance.
In this case, the communication is via modem with the software supplier.

We are now investigating about LAN design in substations (possible fiber optic, ETHERNET, TCP-IP) to communicate the control device, protection device and some high voltage equipment with the technical office.

Results and benefits

The achieved result in our experiences points out that the SA implementation offer many benefits:

- Retrenchment of engineering and montage costs (less equipment, less cabling, less space, etc.). This supposes roughly a 60% reduction of original costs.
- Retrenchment of maintenance costs. The time between preventive probes has increased from 2 to 5 (or more) years. The remote communications allow preventives and correctives actions from office.
- Increasing accuracy, security and operatively reducing outages and allowing more electrical transmission availability.

3 *Case study 3:* Case study Electricity of Laufenburg EGL

B. Sander, EGL, Switzerland.

Policy:

- Industrial approach. Make use of the advantages of the new technology. Make experience in an evolutionary way. Introduction in older less important installations. Combine new young staff with experienced maintenance staff
- Cost reduction (Equal purchasing costs, less life cycle costs)
- Optimisation of architecture of control system (decentralised solution by decentralising functions as synchronising, sequence of events recording, RTU…)
- Simplification of hardware arrangement (less space, less cabling, less marshalling.)
- Increased reliability by continuous self supervision and by a reduced number of space parts (less product diversity)
- Interface compatibility, EMC and extendibility required
- Equal standard for control and protection required
- Possibility of close combination with control systems of hydro power plants
- Increased functionality
- Maintenance support by manufacture
- Simplified replacement of existing equipment due to compactness of cabling and cubicles allowing new decentralised structures
- Reduced delivery and commissioning time (factory pre-tested equipment)
- Increased flexibility, decreased modification costs

Applications:

- 2 complete substations (Sassello, Fionnay)
- several partial solutions (protection systems, metering, fault recording, automatic voltage regulation, tap changer control, …)

Experience:

- concepts, basic requirements and principles, evaluation of possible products: since 1987
- first installation: since 1990

Review, results:

- clear separation of power plants and substation is recommended
- clear separation of control systems of different voltage levels is recommended (different requirements and technology)
- vertical system division into 3 application fields: control and operation, metering and diagnostics/ maintenance
- archiving of data on station level (optimised archiving and communication capacity requirements)
- remote station control terminal in regional control centre for easy stepwise introduction
- data maintenance requirements of great importance
- Further reduction of costs by standardisation (engineering, tools, equipment, functions,)

4 *Case study 4:* Experience on numerical substation protection and control systems in Edelca network

E. Padilla etc. Edelca, Venezuela.

Introduction

The progress made in the Information- and Computer technology in the recent past and the successful application of these technologies in the electrical systems of Europe motivated C.V.G. Electrificacion del Caroni C. A. (EDELCA) to decide to introduce numerical control of substations in its network. Taking advantage of the planned extension of the interconnection to Colombia at the 400 kV substation Cuatricentenario, located in the north west of Venezuela, EDELCA decided to use numerical control for this extension as a pilot project [1].

Basic Considerations

The numerical control was expected to fulfill the following Criteria:

- The control and interlocking functions of the primary equipment must satisfy the established practices of EDELCA operating personnel:
  - Different access levels for control, maintenance and system administration including implementation of extensions and modification are to be defined hierarchically in order to avoid access to non-authorized personnel.
  - Protection systems will continue to remain autonomous and be independent of the numerical control system at 400 kV and above. However, the signals of protection system operation will be fed to the numerical control system for data handling and transmission to the dispatch center.
  - Energy measurement for billing purposes will be done separately as in the past.
  - For this pilot project the fault and event recorders will be separate and not form a part of the control system. Also the logic for automatic voltage regulation and for the control of parallel operation of power transformers will not be integrated into the numerical control. However the information of the transformer tap level and the manual command to the conventional voltage regulation equipment will be routed via the numerical control.
  - The numerical control system should also include the control and supervision of auxiliary services.
  - The system should be user friendly and be capable of being used; maintained and extended by personnel who are neither computer experts nor specifically trained in information technology or programming.
- The availability and security of the system must at least be equal to or better than the existing and well-proven system based on conventional technology.
- The system should use standard, commercially available „off-the-shelf components“ and the design must be based as far as possible, on open systems architecture, so that future expansion of the station can be planned and executed with a minimum of interference to the system in operation and at minimum cost. Ideally, the system should be capable of being connected to different vendors, either by direct connection or through a Gateway.

- For Data transmission within the station, the system should use protocols based on recognized international standards.
- Profiting from the possibilities of digital technology, the numerical control system should include supervision of the operating status of primary equipment, secondary circuits and provides information for initiating preventive maintenance.
- The functions of the conventional RTUs such as time synchronization, Data acquisition, communication between the substation and Dispatch center, etc. are to be integrated into the control system.
- A decentralized architecture and sufficient storage capabilities at the station level should reduce the load on the communication system to the Dispatch Center.
- Visualization and operation possibilities from the station control room including alarm indications, event printing, ...etc. should be provided in conformity with the standard practices of EDELCA
- All the equipment should conform to applicable international standards on EMC
- Preferably fiber optic cables should be used for interbay communication as well as for data transmission within the substation to reduce the cost of parallel connections using conventional copper cables and to reduce the effect of electromagnetic perturbances.
- The pilot project will be used to give sufficient training and technology transfer to engineering, operation and maintenance personnel, so that they will be capable of operating, maintaining and implementing the extensions of the system with minimum help from the vendor.
- The engineering tools of the system will be used to modify the system in terms of signals- and event-definition / lists, updating the Bay-unit software to include new or modify existing interlocking functions, changing station pictures, ...etc. as well as to implement plant extensions. They should be ergonomically attractive and should be such that they can be used easily by power engineers, who are not specialists in computers or programming. Preferably the tools should be provided with macro libraries and are programmed in a higher level language based on internationally recognized standards. The tools must not use programming language proprietary to any particular vendor.

Design Criteria

The design is based on n-1 principle: Failure or degradation of any single component in the whole system should still guarantee the reliability and availability of the system without any degradation of performance. Wherever necessary, essential equipment such as power supplies should be duplicated to ensure maximum availability and fulfill the „n-1“ criterion at optimum total cost.

Architecture

A distributed architecture with intelligent Bay-units was specified. In a 1½-breaker system the central breaker will have inputs from both the feeders. A conventional design principle of providing one Bay-unit for each breaker will increase the complexity of design while at the same time increasing the costs considerably. As a compromise the solution where one intelligent Bay-unit will control one full diameter having two feeders was chosen. In order to meet the availability requirements at 400 kV level and to avoid loosing control of two feeders in case of an outage of the Bay-units either for maintenance or due to failure of any one component, a scheme using redundant Bay-units was specified. Based on the experience in the first years of operation with the new technology the need to provide redundant Bay-units can be reexamined.

Substation Topology

The 400 kV Cuatricentenario substation will be executed in different stages. During the first stage the 400 kV bus will be a ring system with two incoming feeders and one 450 MVA 400/230 kV autotransformer. The system will be expanded over the next few years to a 1½-breaker system with 3 incoming lines and 3 power transformers.

The software for interlocking and operation must be suitable for all stages and the implementation of the extensions must be done without interfering with the operation of the existing system and should allow at all times the maintenance of the equipment without limitations.

SCADA functions

Bay-units:

The alarm and event signals will be collected at the bay level. The analog values (I, U,) should also be collected and the calculated values prepared at the bay level. Depending upon the facilities provided in the protection system, the analog values can be fed to the Bay-units either from the protection system by a serial communication or directly from the associated current transformers. The control of the transformer tapchanger and parallel operation including tap position indications will also be integrated into the bay control units as appropriate. The same also applies to the synchrocheck function where this function is not already a part of the protection system.

Continuous supervision of the secondary circuits for control and operation as well as supervision of operational status of primary equipment such as circuit breakers (for information on maintenance needs) should be included. Self-supervision and auto-diagnostic features including „hot-stand-by“ facilities must be provided. During switch over from one system to the other following a failure of one Bay-unit there should be no loss of information.

The Bay-units should automatically start and initialize when the auxiliary power returns after a failure. Voltage dips and short interruptions up to 5s in the auxiliary power supply should not have any adverse effect on the operation of the system and should not result in any loss of data.

Sufficient buffer memory has to be provided to manage bursts of alarm signals during a system disturbance (up to 500 events / day) without loss of data.

Station level:

The Data acquired by the Bay-units must be permanently stored and kept ready for transmission to the Dispatch Center as and when required. The alarms and event logs must be grouped as per the standard practice of EDELCA and transmitted. Facilities must be provided to extract and analyze the Data as necessary and prepare alarm and event lists as well as the historical data of the analog values in a suitable form. Facilities should also be provided to export the stored data to a permanent storage facility such as tapes, diskettes, etc.

The equipment „status supervision“ data should also be stored at the station level and transmitted to the dispatch center on demand. During the initialization and „General Scanning“ process either from the dispatch center or at the Bay-units level, (for e.g. after loading „new“ software) the corresponding registers must be synchronized at the last value stored.

A local „event printer“ should be provided. The Cuatricentenario substation will be initially operated as a „non-attended“ station. Hence the printer must be capable of being controlled manually as required. In order that the „„event“ information is not lost, the events should be kept stored separately in a „permanent“ (non-volatile) file and the events printed on demand. The capability to manipulate this file should be reserved for specialized personnel with higher hierarchical access.

Time signals for time stamping will be derived from the Satellite GPS signals. Time synchronization of the different equipment such as protection systems, fault and event recorders, etc. should be designed in such a way that the deviation at different equipment within the substation is less than ± 1 ms.

Visualization facilities with suitable MMI should be provided for general supervision of the substation and control of the primary equipment. As standard the 400 kV station will be controlled remotely from the dispatch center. However, to take into the possibility of operation in „attended“ mode, facilities should also be provided for controlling the equipment from the station control room.

Taking into account that the substation will be non-attended, it was decided to install only one station computer and MMI.

Communication:

Communication to the load dispatch center will be assured by two Gateway units connected to the redundant Bay-units and the redundant communication channels within the station.

Since there is only one communication channel available from Cuatricentenario to the dispatch center, the Gateways should operate on a „Master“ principle. One of the two systems will be declared as the „master“ and will normally be connected to the dispatch center. In case of failure the communication will be assured by the second Gateway.

General:

In order to keep the design complexity to a minimum and for security and dependability reasons, the two systems must be kept independent as far as possible and should have minimum interconnection.

Since the 400 kV substation is non attended, facilities should be provided to override and switch the operation mode at the station level to „remote“ from the dispatch center.

Solution Implemented:

EDELCA has implemented a redundant architecture with duplicated star-couplers implemented. One of the two systems will operate as „Master“ with the redundant system in „Hot-Stand-By“ mode. In case of failure of the „Master“ system the redundant system takes over the control functions. When the „Master“ system“ comes back into service, the redundant system is switched back to „Hot-Stand-By“ mode.

It was possible to select a vendor whose standard equipment fulfilled most of the design requirements mentioned above. During the engineering phase it was found necessary to modify some of the above design criteria to avoid complex special development which would have led to implementing proprietary solutions. Some of the important modifications are mentioned below:

To assure maximum availability and reliability without however increasing the total cost unreasonably, the power supply for each Bay-Unit was duplicated. Each power supply is separated from the incoming circuits galvanically and is capable of supplying the Bay-unit with the required auxiliary power.

Since the MVB protocol was not implemented in the digital protections used, the alarm signals were fed into the Bay-units by parallel connection (copper conductors) and the current circuits were looped through and the voltage circuit connected to the Bay-units; the calculations of P, Q, f as well as the active and reactive energy are performed at the Bay-units redundantly.

The design of the interlocking and control software posed some difficulties in meeting the requirement that they must be suitable for different stages of construction and that the extensions should be implemented without undue interference with the existing system. The final solution adopted is as follows:

The software is designed for the final stage of construction with three diameters and six feeders in an 1½ Breaker system. The Bus disconnects are considered as part of the bus and will have to be installed always when constructing a diameter. Also the central breaker together with its disconnects shall be installed as the first component of the diameter. During the intermediate stages (from ring to a full diameter) the missing breakers will be simulated as direct connections in the Bay-Unit hardware. To avoid conflicts within the station control software corresponding interlock for blocking operation of the missing breaker at software level was included. This procedure assures that in the future when a new breaker is installed, the system can be adapted to the new topology simply by changing a few hardware connections and removing the blocking at the station level. The access to change the software blocking is reserved for the higher hierarchical level. The procedure is expected to take less than 30 minutes.

The station computer and MMI are connected to the „Master" system only. The operation can be chosen either for operation at station level or remotely from the dispatch center. Normally, although both the systems are active and receive field information in parallel, only the „Master" system is allowed to perform the control functions of the station. In case of an outage of this system (either the Bay-unit or the communication connection), the redundant Bay-unit takes over the control functions of the affected bay and it is possible to control this bay remotely from the dispatch center via the redundant gateway. The operation of the other bays is not affected.

For „Local" control of the primary equipment from the Bay-units, a mimic was provided at the „Master" Bay-unit only. In case of an outage of the „Master" system the „Local - Remote" switch also controls the operating hierarchy and the „remote" operation via the redundant system is blocked when the switch is in „Local" position. This and the switching of the gateways are the only interconnections between the two independent control systems. This philosophy enables to simplify to a great extent the complexity of implementing duplicate systems on a „Hot-Stand-By" principle without sacrificing flexibility of operation and keeping system outages to an absolute minimum.

Another special problem to be addressed was the maintenance. Since each Bay-unit controls the complete diameter switching the Bay-unit for „Local" control during maintenance of any one breaker will disable the possibility of control of the other breakers in the same diameter either from the station level or from the dispatch center. This is of course not acceptable. After discussions with the operation dept. the following solution was implemented:

During maintenance, the „Local - Remote" selector switch at the primary equipment in the field (Breakers and disconnects) will be placed at „Local". The hardware connections are then automatically modified to interrupt the control voltage circuit coming from the Bay-unit thereby disabling any control signals coming either from the station or from the dispatch center. The selector switch at the Bay-unit will be left at the position „Remote". The control of the rest of the diameter remains unaffected. A signal indicating maintenance of the primary equipment is sent both to the station and to the dispatch center. Local indication of this signal is also provided at the Bay-unit. This way EDELCA will be able to continue with their standard maintenance procedures with minimum modification.

Testing:

The modifications mentioned above as well as the fact that the vendor was using the software for the first time for a 1½ breaker system, EDELCA wanted to make sure that the project software is thoroughly tested and the functionality verified at the factory to prove the maturity of the software used before shipping. The vendor was required to maintain a complete record of all failures (Hard- and Software) from the start of the integration phase until the completion of acceptance tests and make them available to EDELCA.

After integration the equipment was left in service permanently. In addition to standard tests to prove conformity with the requirements of the technical specifications a set of „non-structured" tests were made on the equipment during acceptance tests. These tests consisted mainly in overloading the system, simulating „wrong" and „forbidden" maneuvers, alarm surges, violation of interlocking rules, failure of auxiliary power supplies (transient voltage dips and permanent outages), Operation outside the tolerance limits, break-down of communications between the bay units and the station and „wrong" inputs and key strokes. The stability and the capability of automatic restarting with initialization and „General-Scan" as well as the integrity of the stored values (loss of Data!) were used as criteria to judge the equipment.

To judge the maturity of software the failures were divided into three categories: „severe, moderate and light". As an example, failures affecting control and data acquisition (loss of data) were considered severe and the tests will be stopped until the error is corrected. The moderate failures (e-g. event printing not in chronological order) will have to be corrected before shipping, but the testing will continue. All other failures or deficiencies (e-g. signal names, colors) are a matter of negotiation. From the records of the fault history since the completion of integration, the time interval between detection of two successive failures was used to judge the maturity of software and to decide when to stop the tests with a reasonable assurance that after commissioning and site acceptance tests, the software can be expected to be stable and the number of major software faults during the life time of the equipment will not exceed single digit value.

It may be noted that using the above criteria the total test duration was approx. 7 weeks. Only the gateways had to be tested separately after the formal completion of acceptance tests and these were specially tested again during site acceptance tests.

Thanks to such intensive testing at the factory, the time needed for commissioning and site acceptance tests could be reduced quite considerably and is expected to be well below the planned values.

Training and Know-how transfer:

During the engineering and design phase 6 persons from the engineering and operations were given intensive training at the vendor's premises on the data base generation, preparation of signal lists, station computer and MMI (SCADA), implementing extensions, etc., both on Hard- and Software including trouble shooting based on the signals generated by the self-supervision and diagnostic software. In addition, 5 persons from the engineering, operation and maintenance tested the system during FAT. Such an intensive training helped the EDELCA personnel to familiarize themselves with the new technology and equipment before installation in their system. An active participation in the commissioning as well as site acceptance tests helped to enhance the capability of EDELCA's personnel.

Conclusion:

The experience made by EDELCA in their first project implementing numerical control can be considered positive. Thanks to the good will and co-operation of the vendor, it was possible to meet the goals set at the beginning of the project. Based on this success, EDELCA has decided to implement numerical control in all new substations

In the future projects it is planned to integrate additional protection functions such as synchrocheck- into the numerical control. Also by storing data at the station level, it is expected to reduce the communication load to the dispatch center. The data acquisition and calculation functions available in modern digital protection systems will be fed into the numerical control system via serial connections. These are expected to result in a reduction of the total cost of the substation.

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5 *Case study 5:* Case study REMU

F. Koers, REMU, the Netherlands.

Introduction

In 1987 we began to equip transmission stations with station automation rather than traditional relay technology. In this memo I set out our experiences with systems of this type. 30% of our transmission stations are currently equipped with station automation. The use of station automation has far-reaching consequences from both a technical and an organisational point of view. On the basis of implemented projects I will analyse the trend of the past ten years.

Initial experiences with station automation.

In 1987 two 150 kV transmission stations were simultaneously equipped with station automation. The order was preceded by an extensive preliminary study. Opinions within the company were sharply divided. At the time the advantages and disadvantages were difficult to quantify. Inexperience, uncertainty about reliability and the absence of actual figures made the discussion a complex one. In addition, a number of staff wondered why a relatively static process had to be automated.

A universal automation system from the process industry was selected. The system consists of several PLCs that communicate with each other over a redundant network. Because industrial PLCs were selected, additional EMC measures had to be taken. The protection room was electromagnetically shielded (a Faraday cage was created), the station earthing was extended further and the secondary cables were provided with an earth shield.

The programming took a long time. The programming freedom with systems like this is enormous. Our ideas on how systems and functions ought to be built up were implemented relatively easily. A great deal of energy went into making the entire system robust. To eliminate any risk, switch-error locking devices were created in the software and by means of auxiliary relays ("hard" contacts). The implementation of the initial systems represented a new trend for our company.

Over the years several changes have been made vis-à-vis the initial systems. The main ones are: locks and switch back-up protection were placed only in the software, the automatic clearing of the busbar was further extended, remote I/O was applied and it became possible to read out protective relays. For the most recent projects, a combined protective control unit was used for the 10 kV fields. In the next section I will set out our experience of the past 10 years. For the analysis I have used the following criteria: the average number of I/O points, the development of the number of different functions, the number of systems and the average field price.

Analysis of our experience over the past 10 years.

I will be analysing the trend using the four criteria mentioned above; I would however like to make the comment that the number of transmission stations on which I am basing my analysis is relatively small. The figures presented should not be taken as absolute. To enable different systems to be compared, weighting factors were used for 150, 50 and 10 kV fields. The following graphs show the development of the past years as percentages, with the current method having the value 100%.

Average number of I/O points

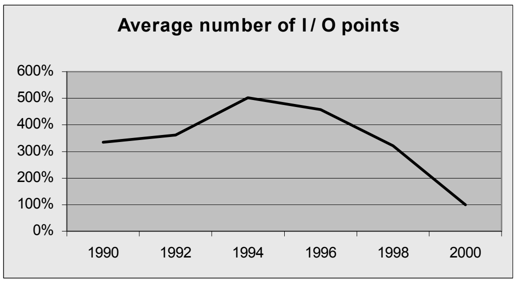

Figure 1 shows the average hardware data points per field. By comparison, after the introduction of station automation the number of reports increased by 60%. The graph shows appreciable growth between 1990 and 1995. This growth is a consequence of increasing confidence in the technology used (an increasing need to report everything develops). After 1995 a sharp drop can be seen. This fall was due to the fact that people started to wonder whether everything really had to be reported. A second cause was that in 1998 an integrated unit for protection and operation was selected for the first time. Within the sector, protection and station automation were two separate worlds. The only form of integration was the exchange of adjustment and switch-off data. For protection specialists in particular, the idea of combining protection with station automation was not a subject for discussion. As a result, suppliers could hardly supply products in which protection and control were combined together. In the recent projects, a combined relay/field unit was used for the 10 kV fields. As a result of this development, the number of hardware connections has decreased by a factor of five.

Average number of functions

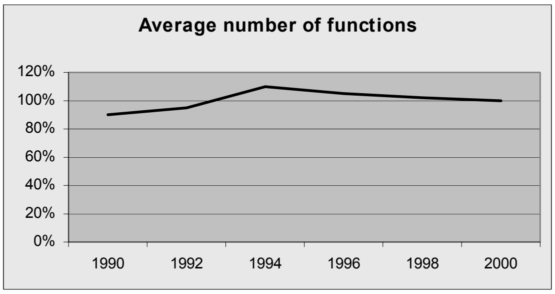

Figure 2 shows the average number of functions. By function I mean switch-error locking, voltage control, protection data read-out, automatic reclosing, etc. The number of functions has barely changed in the past ten years. Over the years a number of functions have been added, but on the other hand others have disappeared. It may be concluded that today's station automation systems perform virtually the same tasks as the initial systems (this is not really surprising, since the primary process has not changed). The effects of the liberalisation of the energy sector cannot be measured at this moment. In the short term I see a trend that the number of functions will decrease slightly: having fewer functions normally results in reduced costs.

Number of different systems

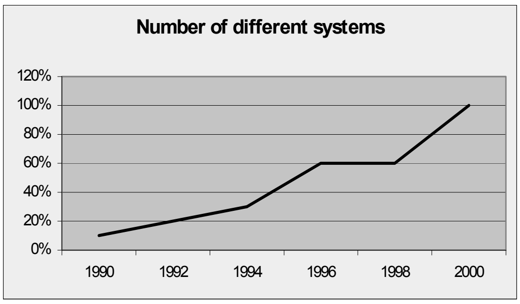

Figure 3 shows the number of different systems. In this overview I define a different system as one in which the hardware or software is substantially different. In the period 1990 to 1996, the number of systems increased constantly. There are currently six different systems operational in our organisation. This increase is caused by developments at the supplier. For a number of reasons, until 1996 we opted for a single supplier. After 1998 the slope of the graph increases slightly. One of the factors contributing to this increase is the introduction of a second supplier. The reason why a new supplier was introduced, apart from considerations of competition, was the fact that 50/10 kV transmission stations became considerably simpler. The functionality (and therefore the required investment) of powerful industrial systems is no longer proportional to the simplified primary installation.

Average costs for station automation.

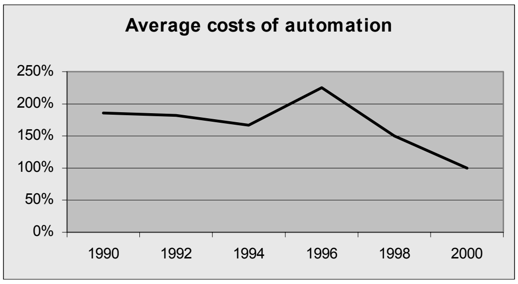

Figure 4 shows the average investment for a field equipped with station automation. Investments from previous years have been adjusted to 2000 prices. The average field price was determined using weighting factors for 150, 50 and 10 kV. In the period 1990 to 1995, the average investment hardly increased. If on the other hand you also take into account an increase in the number of I/O points of over 30% (see Figure 1), the average investment per data point has decreased. The average field price approximately halved between 1996 and 2000. This fall is attributable both to different technology (see number of different systems) and competition between suppliers. It can be stated that the average costs for station automation have approximately halved in the past ten years.

Station automation systems management.

The introduction of station automation has brought about a change in the management of secondary installation. For the management a distinction must be made between preventive and corrective maintenance. As regards corrective maintenance, our experience is that the systems require very little maintenance.

We carry out the following activities periodically:

- making a back-up of the software: after every major change or once a year,
- visually inspecting PCBs and rendering them dust-free: every two years,
- periodically replacing dust filters (after system warning),
- checking analogue inputs and replacing batteries: every five years.

As regards corrective maintenance, we should make a distinction between faults in the remaining secondary installation and faults in the station automation. Because generally speaking much more reporting is done and also the time sequence is fixed, faults in the remaining secondary installations are relatively simple to solve. Solving faults in station automation systems is often a complex process. In conventional stations faults can be traced by means of a multimeter, whereas with automated stations a specialist often has to come with his laptop (signals disappear into a "black box"). Another aspect is that faults often remain unexplained: they come and go spontaneously. The unpredictability is caused by the complexity, the impossibility of testing everything and the high degree of component integration.

Besides having to find solutions to more complex faults, we are increasingly faced with rising hardware costs. Our experience is that hardware stays in production for an average of five years, after which the supplier switches to a different technology. While it is true that suppliers guarantee delivery periods of up to 15 years, replacement system components are expensive. Generally speaking we can say that the maintenance costs of stations with station automation are not much different from those of conventional stations.

Personnel

The introduction of station automation has had not only a technological impact, but also consequences for personnel. A shift has taken place in employees' tasks, procedures and level of knowledge. Instead of designing and drawing circuit diagrams, the engineering department now has to write functional specifications. The supplier often does the detailed engineering and the programming.

The number of assembly hours performed by the implementation/management department has fallen sharply. As the number of hours has declined, however, the training level of the technicians concerned has increased.

As indicated, we made a conscious decision to build up the initial systems with industrial PLCs. The initial systems were programmed in close collaboration with the supplier. At that time the programming tools were less intelligent than today's tools. The great advantage of having extensive co-operation and a relatively low level of intelligence is that this enables our technicians to acquire a great deal of system knowledge. In the ensuing years, the application software has increasingly taken over tasks that used to be done by the technicians. Windows technology more broadly applied, terms like cut and paste, what you see is what you get, are increasingly common in application software. Suppliers are more and more developing universally applicable function blocks. These function blocks are designed in such a way that they can be used in different projects for different customers. The use of these function blocks shortens the time needed to write the application. However, the actual knowledge required by the technician is reduced. A consequence of the more complex software and decreasing system knowledge is that faults are more and more difficult to remedy.

Besides the problem of declining system knowledge as described above, the number of different systems is constantly increasing. Our technicians are therefore increasingly involved with different programming methods. Know-how and experience can be secured by taking out maintenance contracts. Such maintenance contracts are generally very expensive, however. Our policy is to ensure that the first-line maintenance, including correcting faults, can be performed by our own personnel. Whether we can continue to maintain this point of view in the future is a matter that we will have to resolve in the near future.

Conclusion

Our experience is that station automation systems have made a major contribution in the past few years. A shift has taken place, not only in the technology, but also for the employees involved. The number of different functions has not increased in the last few years, the transmission stations still do the same thing, whereas at the same time investment has halved. After a peak in 1995, when everything was reported, nowadays a critical look is taken at whether certain reports are useful and necessary.

One point for attention is the maintenance of the systems. We are faced with an increasing number of different systems. Each system has its own specific programming method. Particularly due to the increasing complexity, our employees are being called on to an ever greater extent. For the time being we will continue the policy that the systems must be able to be maintained by our own employees.

6 *Case study 6:* Case study PSE

P. Molsky, Energoprojekt-Krakow S.A, Poland

Policy:

- System must be stable and reliable (self supervision)
- Decentralized architecture
- Increased functionality and flexibility
- Easy handling for substation personnel
- EMC and extendibility required
- Interlocking of every single bay and interlocking of complete switchyard must be integrated in SA
- Serial integration of protection devices (events and settings) *(only Mikolowa)*
- Reduced delivery and commissioning time
- Maintenance support by manufacturer

Experiences:

- Redundant architecture and duplicated fiber optic cables to bay controllers
- Redundant power supplies for each bay controller *(only Krosno-Iskrzynia)*
- Doubled remote connections to several control centers
- Switching sequences (for example: switch one bay to a busbar or change of single bays or all bays from one busbar to an other one)
- In case of an earthfault at the overhead lines to abroad automatic measurement and report of "distance to fault" to control center *(only Krosno-Iskrzynia)*
- Automatic daily protocol of the energy transfer *(only Krosno-Iskrzynia)*
- Serial connections of SA and protection devices with standard protocol IEC 60870-5-103 *(only Mikolowa)*
- Remote reading and setting of protection parameters (only Mikolowa)
- Remote reading of disturbance records (in COMTRADE format) as well as local display *(only Mikolowa*)
- Remote maintenance via modem

Review:

- Step by step putting into operation is possible
- The reliability and availability of SA is surprising good
- Automatic functions (switching sequences, reports, ...) makes the daily work of the local or remote substation operators more easy but they need to be more educated
- Remote access to protection devices enables a much better survey and a good fault analyses possibility *(only Mikolowa)*
- Remote maintenance enables a much quicker diagnosis and fault removal, but it is more complex

7 *Case study 7:* Case study Essent

H. Timmerman, Essent Netwerk Noord, the Netherlands

Essent Netwerk Noord

Essent Netwerk Noord NV is the Grid Company of Essent in the North East of the Netherlands with 220 kV and 110 kV networks. SAS2000 is the product name of the SA, that is developed by an automation company in the Netherlands and Essent Netwerk Noord.

Starting-point SA

At the end of the eighties Essent has done extensive studies in the field of applicability of SA. The starting-points were:

- reduction of costs
- focus on the functionality of the conventional system. It must be possible to extend the functionality in a later stage
- the reliability and availability have to be satisfied to a high defined level
- the essential protection functions stay independent and are not integrated in SA, the secondary protection functions (such as breaker failure protection, transformer voltage regulator etc.) could be integrated in SA.
- communication with dispatch centre is part of SA.
- local communication via MMI must be simple and appropriate

The results of the study:

- extended functional specification of SA
- requirements in the field of EMC, reliability and availability
- the systems in the market didn't cover the specifications or were to expensive

After that we have developed a pilot system for the 110 kV substation Enschede van Heekstraat (1991) in close co-operation with the supplier of the SA system. The system concept and experiences are described below. Up to now we have installed 13 SA in our substations.

The SAS2000 concept

The co-ordinated control system consists of centralised redundant multi-processor units (user interface, substation processor and bay processing) and bay wise process interface modules. The interface modules (IM) are connected to the central control units (CU) with a number of independent local area networks (LAN's) as redundant glass fibre rings. The concept is shown in Figure 1.

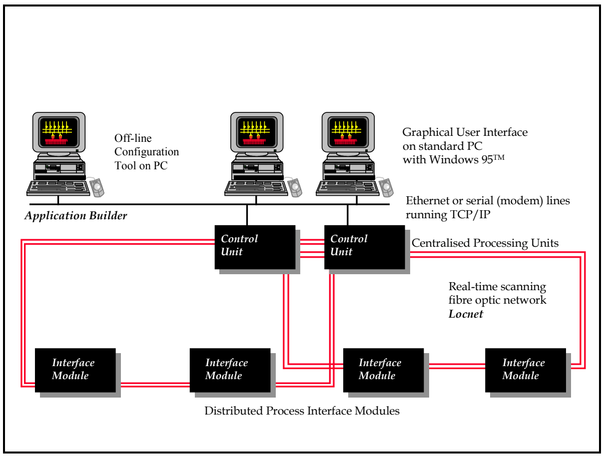

Figure 1: Schematic principle of SA

The communication between the distributed interface modules and the centralised control units is extremely reliable and with a high performance.

The interface modules of the co-ordinated control system, as well as the protection equipment, are bay oriented. They are mounted into cubicles in the central control building or in bay kiosks. The cabling of all primary equipment of a specific bay is connected to a marshalling cabinet in the switchyard (figure 2). From there on connections are made with multi-core cables to the co-ordinated control system and the protection equipment in the central control building. The length of the cabling in the switchyard can add up to many kilometres.

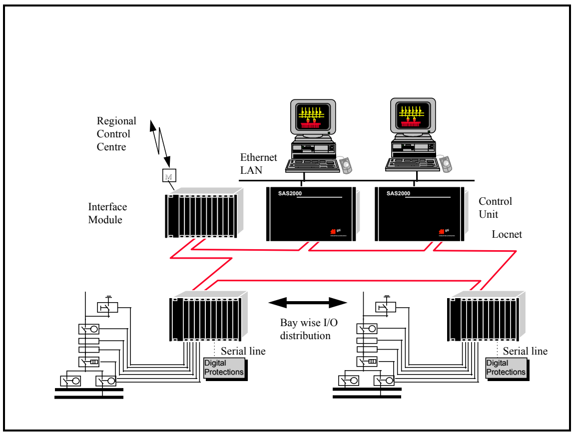

Figure 2: Typical hardware configuration

Experiences

In the past years, we have achieved considerable savings in the construction and refurbishment of substation, both in primary and secondary equipment. The activities we employed are described below.

Integration of auxiliary relays and measurement converters

The digital output channels of the SA are equipped with on-board relays, which can switch the current (up to 5 A) that flows through the switch's coils.

The analogue input channels of SA can be wired directly to the output of voltage and current transformers (110 Vac and 5 or 1 Aac, respectively). This means a reduction of engineering effort, as well as a considerable saving on material costs. The return on investment for the development cost was 2 to 3 substations.

Leave out VT's in feeder bays

Many of ESSENT's substations have 6 feeder bays and a busbar system. The feeders are protected by a distance relay, which requires the current and voltage for that bay. Instead of the line voltage, we measure the busbar voltage, which is wired to all protection relays. In case of a double busbar, we use a simple software function and kipp relays to select the right voltage for a particular protection.

The savings are average 4 VT’s per substation.

Serial communication with protection equipment

Most vendors of digital protection equipment support the IEC 870-5-103 protocol standard. Using this standard, we exchange information with the control system. This not only lead to cost reduction, but also to additional functionality:

- Serial exchange of alarm indications.
- Only trip signals, required by other equipment, are hard-wired. All other signals are exchanged via the serial link.
- Serial exchange of measurement data like voltages, currents, power, reactive power and frequency.
- Mass storage of fault recordings (disturbance data).
- The protection relay has limited storage capabilities, whereas the control unit is capable to store all recordings that may occur during the life cycle of the substation.
- Central accesses to fault recordings.
- The recordings of all protection equipment (if connected via serial link) is stored centrally. You just need to have access to the control system.

Software transformer regulator

In conventional substations, a separate transformer regulator is applied. In substations, equipped with SA, this function is implemented in software, eliminating the cost for the regulator.

Leave out breaker failure protection

Modern circuit breakers have extremely low failure rates; the main remaining failure mechanism is a fault in the control circuit.

This leads to the decision not to implement the breaker failure protection in substations, equipped with modern circuit breakers, if we could eliminate the dominant problem that can still lead to failing breakers. This can be achieved by continuously monitoring the closing coil of the breaker by the SA.

Distributed I/O interfacing on equipment level

The distributed I/O concept on equipment level is shown in figure 3.

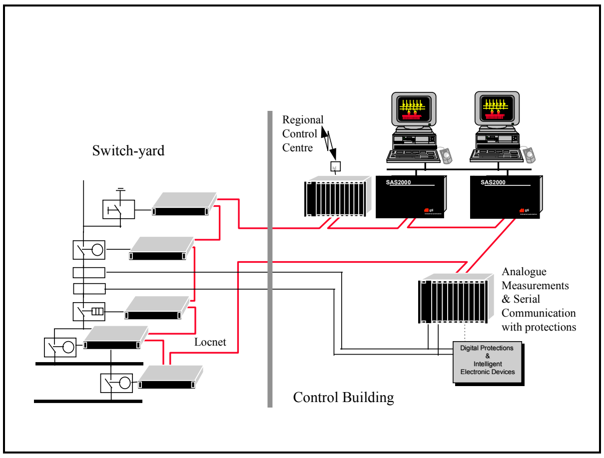

Figure 3: Process interfacing in the switchyard

Most primary equipment (circuit breakers, disconnectors and transformer) has his own interface module (outdoor mini IM), mounted in a water resistant cabinet close to or mounted on the primary equipment. The mini interface module has only a few digital inputs and outputs to control the primary equipment.

The protection equipment is installed in the control building and is serial connected to the interface module in the control building.

The analogue signals of the measurement transformers are directly connected to the interface modules in the control building, as well as the protections.

The outdoor mini interface modules and the central located interface modules are connected to the central control units in the control room via a fibre optical local area network.

In comparison with the present concept the main differences are:

- "bay control" cubicles do not exist any more.
- extra outdoor mini interface modules.
- saving on cubicles in the control building.
- saving on cabling in the switchyard.
- saving on marshalling cabinets in the switchyard.
- a fibre optical local area network in the switchyard.
- saving of personnel costs, especially the mounting of cabinets and cabling and testing.
- saving on cable ducts in the switchyard.

In comparison with the present concept the total savings are about 25 % of the secondary equipment. The most important savings are on engineering, construction and testing costs (84 % of the total savings). The savings on equipment amount to 5%. In comparison with the I/O concept on bay level 4 to 6 field IM's are needed instead of 1 IM (depends on the number of the primary apparatus in a bay field).

Remote MMI via TCP/IP

A major break-through was the implementation of the TCP/IP protocol stack in the control unit. We can now place our MMI anywhere we choose, as long as there is a TCP/IP connection with the control unit.

Apart from bringing the process mimics to the remote PC, we can also download files (e.g. alarm lists, trend data, fault recordings) from the control system. We expect that this will reduce the number of visits to the (unmanned) substations.

Knowledge level of engineers and maintenance staff

Software is a new phenomenon for protection and substation control. The knowledge of the engineer must be of an other and higher level. Software is more abstract than conventional systems. To develop the pilot system in close co-operation with the vendor our engineers have got a high and sufficient degree of knowledge to build the applications of the projects and to maintain the systems.

The knowledge of the local operator isn't principal changed. It is important to use a look and feel MMI.

Conclusions

Application of SA in substations leads to:

- high degree of reliability and availability
- a good EMC concept is necessary
- the knowledge of the engineer is of an other level of the knowledge of the conventional engineer. Close co-operation of the engineers and the vendor is a good opportunity to achieve a sufficient degree of knowledge.
- a flexible SA is an important tool to reduce the overall costs of substations (to reduce secondary equipment, cabling, installing costs, primary equipment etc.).
- to monitor continue the critical functions it is possible to optimise the maintenance and the maintenance costs.
- Upgrading of the system software. Software is often changing by the vendor (system bug or the client wants more functionality) and leads to other releases and versions.
- Upgrading of existing systems with a new software release sometimes leads to problems. It is the responsibility of the vendor to guarantee the quality of the new software.
- It is important to use an up to date database management system of the application software

In spite of the advantages of a modern control system for substations the implementation of these systems in practice is slow. There are two main reasons:

- The extra functionality of modern control systems is not often a driving factor for the responsible managers to install SA
- By part renovation of a substation it is not easy to integrate SA. The interface with the conventional system is expensive and the advantages of a SA are less.