Impact of Substation Automation System on 110 kV Protection and Control Schemes

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Abstract: Transmission substations are important parts of the infrastructure of power system networks. These substations have grown extensively over the past few years and become large and complex. The complexity is due to key factors such as the protection and control process, which is connected through hundreds or thousands of copper wires, and reflects considerable increases in project size and maintenance costs. Such systems must be based on an international communication standard supporting the application domain in terms of specific requirements according to the substation lifecycle. For many years, the International Electrotechnical Commission (IEC) has been developing the IEC 61850 standard for substation automation, "Communication Networks and System in Substations." Its impact on control and protection schemes has been considerable, and the need for laying large numbers of copper wires has been minimized, thus bringing large cost reductions. In this paper, we explore substation automation systems (SASs) and compare the costs of SAS-based substations and traditional substations.
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1.Introduction

Power utilities in the developed world face the constant challenge of providing reliable power to end users at competitive prices. Equipment failures, lightning strikes, accidents, and natural catastrophes can all cause power disturbances and outages in substations, and often result in long service interruptions. Thus, substations must be controlled and monitored in order to enable necessary timely precautions. Substation automation is a key method of controlling and monitoring substations. Substation automation involves the creation of a highly reliable power system that responds rapidly to real-time events with appropriate actions, thus maintaining uninterrupted power services to end users.

Substation automation has been in use in the power sector for two decades, but recent developments have opened up a new era in the field of substation automation.

What is a Substation Automation System?

The simplest definition of substation automation is "a system for managing, controlling, and protecting a power system." Substation automation systems (SASs) enable operators to obtain timely information to assist them in making operational decisions. This is accomplished by obtaining real-time information from the system.

IEC 61850 Impact on Function Integration

Interoperability is a main feature of the IEC 61850 standard. Interoperability is the ability of intelligent electronic devices (IEDs) of different manufacturers to exchange information and use this information to perform some task. This feature is included in IEC 61850 because of a strong market demand to curtail vendor monopoly [1]. However, another vital part of IEC 61850 is the free allocation of functions. The standard describes a flexible and abstract model that allows a small part of the functional representation, in the form of logical nodes, to be properly allocated as per each need or possibility, enabled by technology. The IEC 61850 feature of free allocation of functions permits various features to be integrated in a more standardized way. An immediate advantage may be a reduction in the components at bay level, which would reduce costs and simplify panels. However, this concept requires theoretical changes not only in the design phase of the automation system, but also for operation and maintenance, and a different approach would be required to the treatment of procedures for electrical systems.

Figure 1 shows the various concepts that can lead to protection and control solutions depending on functional allocation. Note that all solutions perform the same functionality, but different needs are obtained. Thus, the result will be different costs according to the development of the SAS. However, each solution, described below, can be considered and developed in standardized ways to enable cost-effective engineering [2].

As a consequence, the costs of engineering, manufacturing, testing, maintenance, and quality control may be lowered. For the automation system, the logics, interlockings, data sets, GOOSE messages, and other features can be described and prepared in advance [3][4].

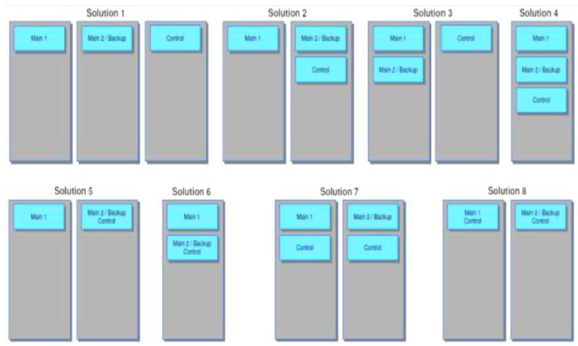

Figure 1. Concepts behind various protection and control solutions according to functional allocation

2.Protection Requirements

In electrical networks, protection carries out a number of roles:

- Avoids considerable damage to primary and secondary equipment.
- Ensures maximum power availability by isolating the faulty part in the network.

This guides the following significant needs:

- Selectivity: The protection must isolate the faulty part in the network.
- Speed: The protection must isolate the faulty part quickly in order to minimize the damage.
- Security: The protection must remain stable under normal conditions and must not cause a false trip.
- Availability: The protection must be available continually in order to react correctly at any time.
- Adaptation: The protection must be adapted to network changes.

Most IEDs have been developed to meet the requirements described above, and the introduction of GOOSE in new technology has made protection requirements secure and more reliable [5][2]. The aim of GOOSE messages is to substitute hardwired signals by clearly naming all data elements and then transferring this data via the Ethernet station bus. Other advantages of GOOSE include expandability of the SAS without additional hardwiring between IEDs. New hardwiring is only required between processing equipment and the implemented IEDs. Similarly, new applications can be installed or modifications made to existing applications without incremental hardwiring, because desired data can be sent via GOOSE.

3.GOOSE Applications

More intelligent schemes may be performed to ascertain the operability of a few logics of protection and control with the help of GOOSE messages. These messages are multicast type and quickly reach all equipment connected to the network. Only those devices configured to collect the messages will absorb the necessary relevant information. Therefore, information is transferred efficiently in short intervals of time. This concept permits the use of conventional (or new) protection functions by utilizing horizontal communication and GOOSE messages. For example, the following functionalities may be implemented via GOOSE messages:

- Breaker failure initiation.
- Reverse blocking (selectivity).
- Status for circuit breakers and disconnectors.
- Transfer tripping.

4.Busbar Protection Schemes

The substation busbar is the most significant node of the power network. Because many supply circuits are used in combination, high current magnitudes are involved. If a fault, occurs, damage may be considerable. The damage may affect a large area by causing a disastrous cascade tripping of generators and lines and ultimately the breakdown of a large portion of the power network.

New decentralized numerical busbar protection schemes are highly dependable and sensitive. Sensitivity of the protection must be combined with its ability to discover the direction of each fault on each line, so as to protect the tripping selectivity. To achieve selectivity, the busbar requires a dynamic picture of the busbar topology, i.e., which switches are currently open or closed and which switches are connected in the single-line topology. All status signals for the switches are received at the busbar main central IED unit through GOOSE messages, which are sent from each bay unit IED. The busbar bay unit is present at bay level and is responsible for receiving data from a particular bay controller through GOOSE messages. These data carry information on

- disconnector status Q1, Q2, and Q9.
- circuit breaker “CB” status.
- current transformer measurements.

All such data are accumulated from each bay unit IED in the busbar central unit IED via GOOSE messages, to apply overall busbar protection and zone selectivity. The trip command is transferred from the main central unit through GOOSE messages to the applicable bay unit IEDs in the fault zone. The new standard IEC 61850 presents a challenge in that there are no trip circuits or highly sensitive trip circuit supervision, and harmful or risky circuits in traditional substations due to DC failure will cause faulty conditions and require highly skilled technicians and engineers for maintenance [6].

The job of breaker failure protection is to determine whether a breaker has been unsuccessful at clearing a fault on the busbar, and similarly check all remaining breakers feeding into the busbar section concerned, in order to isolate the fault. Busbar and breaker failure protection react to busbar faults in the same way, which is why both protection functions are typically combined in one common protection scheme. All initiations in the case of a stand-alone breaker failure scheme (PCBF) will be received in the form of GOOSE messages from other protection IEDs, as shown in Figure 2.

If a breaker that is tripped by some other protection (e.g., line protection) does not open because of interior failure, the fault must be cleared by neighboring breakers, which may include breakers at far-end substations.

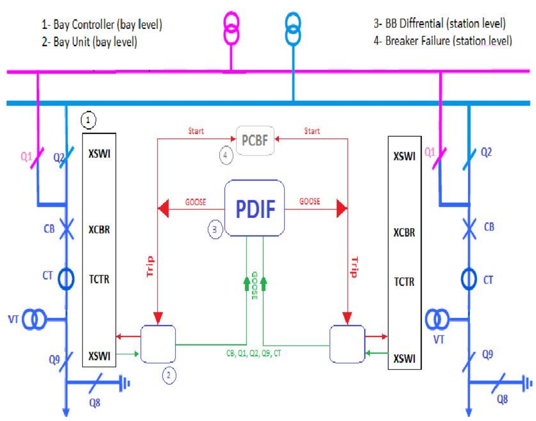

Figure.2 Busbar protection scheme with GOOSE approach

To clear the fault, the protection trip initiates breaker failure protection, then determines whether the current has vanished. If it has not, a trip signal is sent to each contagious breaker after a set time delay.

5.Reverse Blocking

Reverse blocking is a distributed function in the power system that clears a fault quickly, wherever the fault occurs in the radial electric network. Reverse blocking provides complete tripping discrimination and significantly decreases delays in tripping the circuit breaker nearest the source.

The fault current flows between the source and the fault location in the radial network. This means that

- upstream protections are triggered.
- downstream protections are not triggered.
- only the first upstream protection must trip.

One way to achieve reverse blocking is to have larger trip delay times at the upper levels of the radial network. This will result in lengthy delays at the higher levels.

When a protection is triggered by an overcurrent relay,

- it sends a blocking signal to the upstream protections.
- it trips its associated CB if it does not receive a blocking signal sent by a downstream protection.

6.Safety and Reliability Commands

In power networks, it is important that commands are sent safely, because an incorrect command may cause power outages. Safety of commands is ensured by special command procedures in SAS through "select before operate" (SBO), which is a two-step process where two confirmation messages are transferred before the command is operated. A select command is forwarded from the human–machine interface (HMI) to the switch controller logical node CSWI.

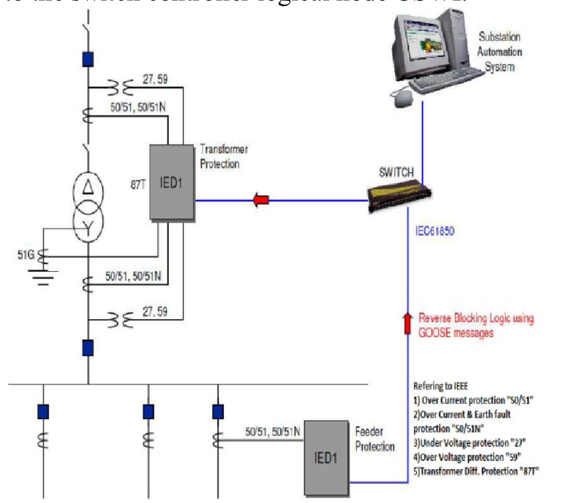

Figure.3 Reverse blocking scheme with GOOSE solution

The CSWI, after determining whether a command is allowed, sends this select request to the switch IED. After selecting the switch successfully, the selected response message is sent back to the operator. Then, the operator at the HMI is permitted to send the operate command, but only for the same individual switch. The reply from the switch controller is delayed until the new position indication signal from the next lower level is reached, and the operation subsequently ends by transferring the termination command from the switch controller to the HMI.

From the time of commencement of successful selection until transference of the termination command, which occurs either when the switch has successfully reached the expected position or after a runtime supervision timeout, the CSWI remains in the selected state. This state can be utilized to block further commands during this time that may influence the interlocking condition for the switch. This principle ensures greater safety by blocking double command operation. Figure 4 shows the SBO feature for the circuit breaker XCBR logical node.

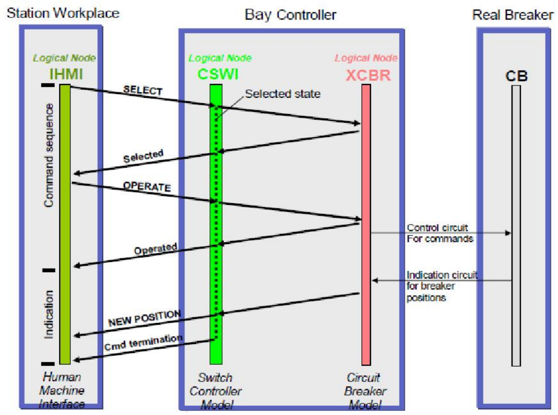

Figure.4 Command sequence

7.Bay Interlocking

The purpose of switchgear interlocking is to prevent switchgear operation that may damage the primary switching equipment or cause it to malfunction. This is achieved by evaluating switch positions in related switches or disconnectors and determining the individual interlocking conditions of switches according to logical rules. Interlocking can either stop or permit switching operation based on the logical rules between switch positions.

Typically, two types of bay interlocking are used. Closure of the earth switch is locked when the disconnector is closed. Another type of interlocking must be used when the earth switch is closed and work is being done in the switchgear. In this case, all line disconnectors capable of feeding power to the line under consideration must be locked in the open position. Thus, closure of the concerned circuit breakers must be locked. The status signals of disconnectors and earth switches that were traditionally hardwired can be sent with the help of GOOSE messages. Figure 5 shows an example of bay interlocking. For simplification, only one disconnector and one earth switch are shown. If the disconnector is closed, Feeder IED1 controlling the earth switch requires the *position closed* and *position OK* signals from Incomer IED0, which are shown in the figure as blue lines. The *position OK* signal means that the disconnector is not between positions, in other words, the information is authentic and valid. If any of the signals is true, closure of the particular earth switch is blocked. Similarly, when the earth switch is closed, Incomer IED0 requires signals indicating that the earth switch position is *closed* and *OK*, as shown in Figure 5 as green lines. These signals are connected virtually with the help of an OR gate to the blocking input of CBXCBR1.

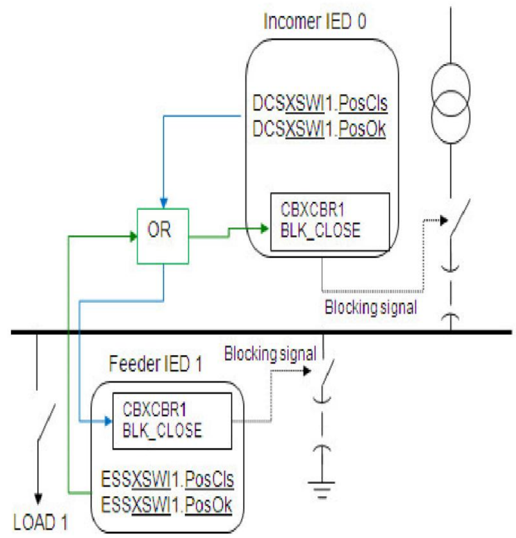

Figure .5 Interlocking with GOOSE approach

One function is used for the earth switch and three functions for the disconnectors. In the example described here, only one disconnector function is implemented; the other two functions are separated by enhancing the number of the logical node, which primarily depends on the substation single-line topology.

8.Synchronizing

Synchronism Check is required when two circuits with differing power sources are connected via impedance. The synchronization check is implemented by comparing the voltages on both sides of the breaker. To maintain stability of the power system and minimize possible internal damage, the difference in magnitude, phase angle, and frequency must be kept within certain limits. The IED that compares the voltages requires the magnitude, phase angle, and time stamp of all phase voltages, as shown in Figure 6.

In this example, the bus has two possible feeders, a generator or a transmission line. When the generator is, for example, under maintenance and the power feed must be transmitted to the transmission line, a synchronism check is required. The Synchronism Check IED subscribes the line voltages from the line protection IED as an analogue GOOSE message. The challenge of analogue GOOSE messages is in the time synchronization of the network. To provide correct data, the time difference in the network should be less than one microsecond. The bus voltages are sent directly from a bus voltage transformer via typical hardwiring. The RSYN function compares the difference in the values and decides whether closing the circuit breakers is sufficiently safe.

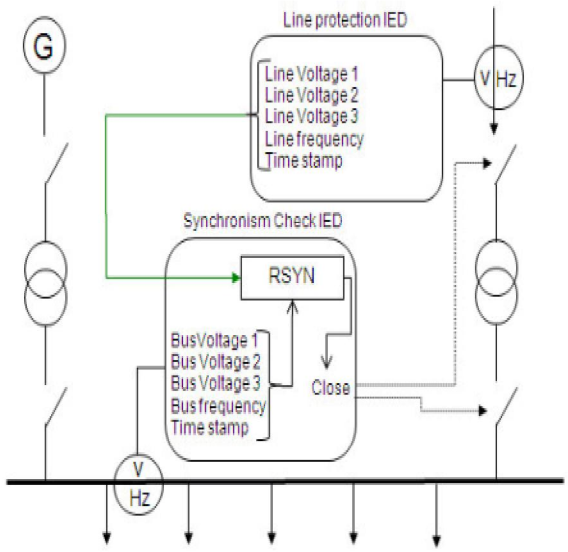

Figure .6 Synchronizing scheme with GOOSE solution

9.Cost Comparison Between Automated and Conventional Substations

It is believed that SAS has the potential to reduce significantly substation costs. If this is true, then the amount thus saved may be used for future projects and for organizational development, which will not only benefit utilities but customers as well. Therefore, it is important to make cost comparisons between projects that use SASs and conventional substations.

To achieve this, we collected data from electric utilities and obtained comparisons by means of MATLAB. A single-line diagram of the case study undertaken is shown in Figure 7.

Cost-based data were collected for two traditional projects and two SAS-based projects. The analysis was done based on the average cost of these projects. The project cost is divided into four main categories, i.e., engineering, materials, installation, and testing commissioning, which are subdivided into further categories. Cost comparisons of every category are beyond the scope of this project, and we therefore present in this paper only those categories that have a considerable impact on the total cost of SAS-based projects.

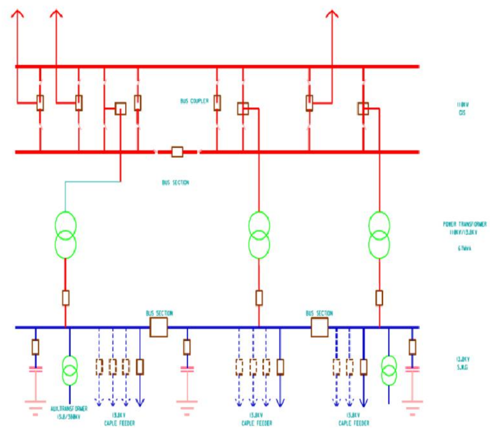

Figure .7 Case study

Because the main impact of substation automation is on control and protection cable requirements, the savings in this area were higher than those of any other category, as shown in Figure 8.

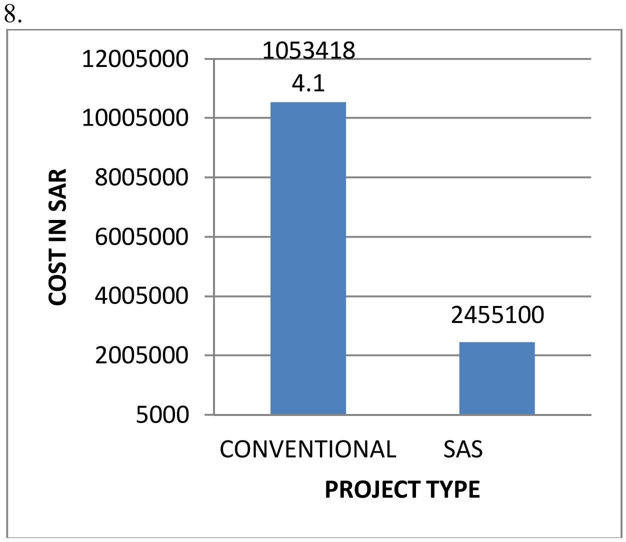

Figure .8 Total control, protection, and auxiliary costs, in Saudi riyals (SAR)

The savings for SAS projects were 76.69%. The resultant reductions in the control and protection cabling are shown in Figure 9.

Such high savings will play an important role in decreasing the total costs of SAS-based projects to less than those of conventional substation projects.

The difference in the costs between SAS-based and conventional projects shows significant savings of approximately 17.86%, which means that millions of Saudi riyals may be saved. Thus, utility providers may adjust their plans accordingly to lower their project budgets.

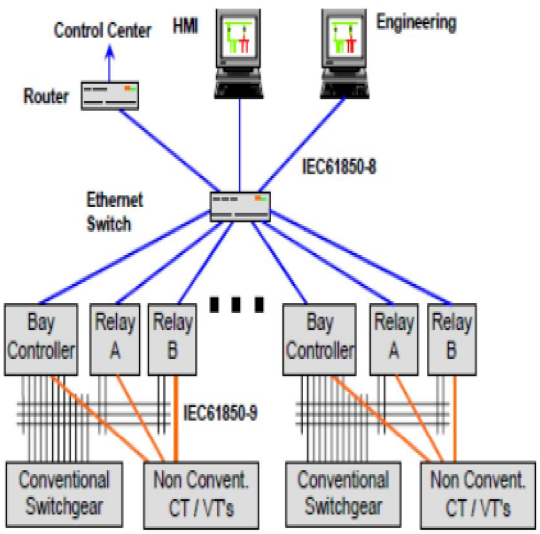

Figure 9. Reduction in the control and protection cabling

The total costs for SAS-based and conventional projects (Figure 10) were obtained after combining the costs of all the categories.

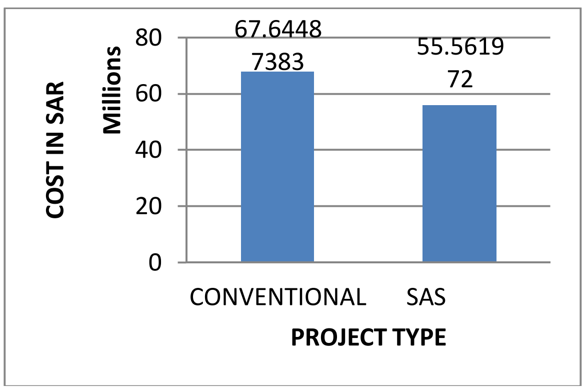

Figure .10 Total project costs, in Saudi riyals (SAR)

10.Conclusion

The concept of IEC 61850 offers a powerful opportunity to utility providers to save costs through the higher integration and interoperability of historically separated and individually hardwired systems. The utilities sector has shown an initial reluctance to use GOOSE-based applications. However, as the IEC 61850 becomes more common in the field of substation automation, it is likely that the standard will become a more prominent solution for electric utilities and process industry customers.

One of the advantages of GOOSE is the costs saved in using less labor-intensive hardwiring. Initially the use of GOOSE may be expensive if the costs related to training and learning are taken into account. In the long run, however, the use of GOOSE is more cost effective as the configuration process becomes part of the engineering process. Further benefits can be achieved via expandability of GOOSE-based applications. New IEDs can be added or replaced without additional hardwiring. Instead, the required signals can be added to the configuration files of each IED.

As technology develops, more IEDs with native IEC 61850 communication will become available on the market. With additional functionality in these IEDs, more applications can be realized with GOOSE communication.

It is widely believed that developments have reached the point at which it is financially advantageous for utility providers to commit to substation designs based on IEC 61850 communications. The case study described in this paper supports this belief. Our overall result obtained from the software developed via MATLAB shows a 17% reduction for SAS-based projects compared with conventional substation projects. It is also important to mention here that the technology is only in the initial phases of introduction. When more tools become available, and as engineering management gains experience and confidence in the technology, it becomes more probable that the costs will decrease further and herald a new era of self-documenting, in which all IED configurations are presented in a simple, integrated environment.

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