APPLICATION OF PLC WITH IEC 61850 AS A STANDARD IN 132KV SUBSTATION

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CHAPTER ONE

INTRODUCTION

Over the last decade, the "digitization" of the electron enterprise has grown at exponential rates. Utility, industrial, commercial, and even residential consumers are transforming all aspects of their lives into the digital domain. Moving forward, it is expected that every piece of equipment, every receptacle, every switch, and even every light bulb will possess some type of setting, monitoring and/or control. In order to be able to manage the large number of devices and to enable the various devices to communicate with one another, a new communication model was needed. That model has been developed and standardized as IEC61850-Communication Networks and Systems in Substations.

The standard IEC61850 - Communication Networks and Systems is the first and only global standard that considers all the communication needs within a substation, it is covering design aspects, defines guidelines for protection, monitoring, control and automation. This standard also raises interoperability and free allocation of functions and devices, support all type of architectures protocol and its practical application for substation automation systems.

Substation automation protocols and architectures typically provided basic functionality for power system automation and were designed to accommodate the technical limitations of the networking technology available for implementation. There has recently been a vast improvement in networking technology that has changed dramatically what is now feasible for power system automation in the substation. Technologies such as switched Ethernet, TCP/IP, high-speed wide area networks, and high performance low-cost computers are providing capabilities that could barely be imagined when most legacy substation automation protocols were designed. IEC61850 is an important new international standard for substation automation that will have a very significant impact on how electric power systems are designed and built for many years to come. IEC61850 is a part of the International Electrotechnical Commission's (IEC) Technical Committee 57 (TC57) architecture for electric power systems. The modeldriven approach of the TC57 standards, including IEC61850, is an innovative approach that requires a new way of thinking about substation automation that will result in very significant Improvements in both costs and performance of electric power systems.

The new communication standard IEC 61850 is introduced in Substation Automation replacing almost all traditional wires by serial communication. Based on mainstream communication means like Ethernet it provides a high flexibility regarding communication architectures. Due to its flexibility utilities are concerned about the process of specifying an IEC 61850 based Substation Automation systems.

Communication has always played a critical role in the real-time operation of the power system. In the beginning, the telephone was used to communicate line loadings back to the control center as well as to dispatch operators to perform switching operations at substations.

Telephone-switching based remote control units were available as early as the 1930's and were able to provide status and control for a few points. As digital communications became a viable option in the 1960's, data acquisition systems (DAS) were installed to automatically collect measurement data from the substations. Since bandwidth was limited, DAS communication protocols were optimized to operate over low- bandwidth communication channels. The "cost" of this optimization was the time it took to configure, map, and document the location of the various data bits received by the protocol.

As we move into the digital age, literally thousands of analog and digital data points are available in a single Intelligent Electronic Device (IED) and communication bandwidth is no longer a limiting factor. Substation to master communication data paths operating at 64,000 bits per second are becoming commonplace with an obvious migration path to much high rates. With this migration in technology, the "cost" component of a data acquisition system has now become the configuration and documentation component. Consequently, a key component of a communication system is the ability to describe themselves from both a data and services (communication functions that an IED performs) perspective. Other "key" requirements include:

- High-speed IED to IED communication
- Networkable throughout the utility enterprise
- High-availability
- Guaranteed delivery times
- Standards based
- Multi-vendor
- Interoperability
- Support for Voltage and Current samples data
- Support for File Transfer
- Auto-configurable / configuration support
- Support for security

Given these requirements, work on a "next generation" communication architecture began with the development of the Utility

Communication Architecture (UCA) in 1988. The result of this work was a profile of "recommended" protocols for the various layers of the International Standards Organization (ISO) Open Systern Interconnect (OSI) communication system model. This architecture resulted in the definition of a "profile" of protocols, data models, and abstract service definitions that became known as UCA. The concepts and fundamental work done in UCA became the foundation for the work done in the IEC TC57 Working Groups 10, 11, and 12 which resulted in the International Standard IEC 61850 Communication Networks and Systems in Substations

Features of IEC 61850 includes:

Interoperability between devices and application functions through standardized data models and information exchange.

Free configuration of communication network and allocation of functions to devices.

Long term stability through decoupling of application and communication.

1.1 Electrical Substation

An electrical substation is a subsidiary station of an electricity generation, transmission and distribution system where voltage is transformed from high to low or the reverse using transformers. Electric power may flow through several substations between generating plant and consumer, and may be changed in voltage in several steps.

A substation that has a step-up transformer increases the voltage while decreasing the current, while a step-down transformer decreases the voltage while increasing the current for domestic and commercial distribution. The word substation comes from the days before the distribution system became a grid. The first substations were connected to only one power station where the generator was housed, and were subsidiaries of that power station.

1.2 Elements of a Substation

Substations generally contain one or more transformers, and have switching, protection and control equipment. In a large substation, circuit breakers are used to interrupt any short-circuits or overload currents that may occur on the network. Smaller distribution stations may use recloser

circuit breakers or fuses for protection of branch circuits. Substations do not (usually) have generators, although a power plant may have a substation nearby. A typical substation will contain line termination structures, high-voltage switchgear, one or more power transformers, low voltage switchgear, surge protection, controls, grounding (earthing) system, and metering. Other devices such as power factor correction capacitors and voltage regulators may also be located at a substation.

Substations may be on the surface in fenced enclosures, underground, or located in special-purpose buildings. High-rise buildings may have indoor substations. Indoor substations are usually found in urban areas to reduce the noise from the transformers, for reasons of appearance, or to protect switchgear from extreme climate or pollution conditions.

Where a substation has a metallic fence, it must be properly grounded (UK: earthed) to protect people from high voltages that may occur during a fault in the transmission system. Earth faults at a substation can cause ground potential rise at the fault location. Currents flowing in the earth's surface during a fault can cause metal objects to have a significantly different voltage than the ground under a person's feet; this touch potential presents a hazard of electrocution.

1.3 Transmission Substation

A transmission substation connects two or more transmission lines.

The simplest case is where all transmission lines have the same voltage. In such cases, the substation contains high-voltage switches that allow lines to be connected or isolated for maintenance. A transmission station may have transformers to convert between two transmission voltages, or equipment such as phase angle regulators to control power flow between two adjacent power systems.

Transmission substations can range from simple to complex. A small "switching station" may be little more than a bus plus some circuit breakers. The largest transmission substations can cover a large area (several acres/hectares) with multiple voltage levels, and a large amount of protection and control equipment (capacitors, relays, switches, breakers, voltage and current transformers).

1.4 Distribution Substation

A distribution substation transfers power from the transmission system to the distribution system of an area. It is uneconomical to directly connect electricity consumers to the high-voltage main transmission > network, unless they use large amounts of energy; so the distribution station reduces voltage to a value suitable for local distribution.

The input for a distribution substation is typically at least two transmission or sub transmission lines. Input voltage may be, for example, 132 kV, or whatever is common in the area. The output is a number of feeders. Distribution voltages are typically medium voltage, between 11kV and 33 kV depending on the size of the area served and the practices of the local utility.

The feeders will then run overhead, along streets (or under streets, in a city) and eventually power the distribution transformers at or near the customer premises.

Besides changing the voltage, the job of the distribution substation is to isolate faults in either the transmission or distribution systems. Distribution substations may also be the points of voltage regulation, although on long distribution circuits (several km/miles), voltage regulation equipment may also be installed along the line.

Complicated distribution substations can be found in the downtown areas of large cities, with high-voltage switching, and switching and backup systems on the low-voltage side. More typical distribution substations have a switch, one transformer, and minimal facilities on the low-voltage side.

1.5 Collector Substation

In distributed generation projects such as a wind farm, a collector substation may be required. It somewhat resembles a distribution substation although power flow is in the opposite direction, from many wind turbines up into the transmission grid. Usually for economy of construction the collector system operates around 35 kV, and the collector substation steps up voltage to a transmission voltage for the grid. The collector substation also provides power factor correction, metering and control of the wind farm.

1.6 Design

The main issues facing a power engineer are reliability and cost. A good design attempts to strike a balance between these two, to achieve sufficient reliability without excessive cost. The design should also allow easy expansion of the station, if required.

Selection of the location of a substation must consider many factors. Sufficient land area is required for installation of equipment with necessary clearances for electrical safety, and for access to maintain large apparatus such as transformers. Where land is costly, such as in urban areas, gas insulated switchgear may save money overall. The site must have room for expansion due to load growth or planned transmission additions. Environmental effects of the substation must be considered, such as drainage, noise and road traffic effects. Grounding (earthing) and ground potential rise must be calculated to protect passers-by during a short-circuit in the transmission system. And of course, the substation site must be reasonably central to the distribution area to be served.

1.7 Layout

The first step in planning a substation layout is the preparation of a one-line diagram which shows in simplified form the switching and protection arrangement required, as well as the incoming supply lines and outgoing feeders or transmission lines. It is a usual practice by many electrical utilities to prepare one-line diagrams with principal elements (lines, switches, circuit breakers, transformers) arranged on the page similarly to the way the apparatus would be laid out in the actual station.

Incoming lines will almost always have a disconnect switch and a circuit breaker. In some cases, the lines will not have both; with either a switch or a circuit breaker being all that is considered necessary. A disconnect switch is used to provide isolation, since it cannot interrupt load current. A circuit breaker is used as a protection device to interrupt fault currents automatically, and may be used to switch loads on and off. Where a large fault current flows through the circuit breaker this may be detected through the use of current transformers. The magnitude of the current transformer outputs may be used to 'trip' the circuit breaker resulting in a disconnection of the load supplied by the circuit break from the feeding point. This seeks to isolate the fault point from the rest of the system, and allow the rest of the system to continue operating with minimal impact. Both switches and circuit breakers may be operated locally (within the substation) or remotely from a supervisory control center.

Once past the switching components, the lines of a given voltage connect to one or more buses. These are sets of bus bars, usually in multiples of three, since three-phase electrical power distribution is largely universal around the world.

The arrangement of switches, circuit breakers and buses used affects the cost and reliability of the substation. For important substations a ring bus, double bus or so-called "breaker and a half setup can be used, so that the failure of any one circuit breaker does not interrupt power to branch circuits for more than a brief time, and so that parts of the substation may be de-energized for maintenance and repairs. Substations feeding only a single industrial load may have minimal switching provisions, especially for small installations.

Once having established buses for the various voltage levels, transformers may be connected between the voltage levels. These will again have a circuit breaker, much like transmission lines, in case a transformer has a fault (commonly called a 'short circuit').

Along with this, a substation always has control circuitry needed to command the various breakers to open in case of the failure of some component.

1.8 Switching Function

An important function performed by a substation is switching, which is the connecting and disconnecting of transmission lines or other components to and from the system. Switching events may be "planned" or "unplanned".

A transmission line or other component may need to be deenergized for maintenance or for new construction; for example, adding or removing a transmission line or a transformer.

To maintain reliability of supply, no company ever brings down its whole system for maintenance. All work to be performed, from routine testing to adding entirely new substations, must be done while keeping the whole system running.

Perhaps more importantly, a fault may develop in a transmission line or any other component. Some examples of this: a line is hit by lightning and develops an arc, or a tower is blown down by a high wind. The function of the substation is to isolate the faulted portion of the system in the shortest possible time.

There are two main reasons: a fault tends to cause equipment damage; and it tends to destabilize the whole system. For example, a transmission line left in a faulted condition will eventually burn down, and similarly, a transformer left in a faulted condition will eventually blow up. While these are happening, the power drain makes the system more unstable. Disconnecting the faulted component, quickly, tends to minimize both of these problems.

CHAPTER TWO

TRADITIONAL CONTROL OF SUBSTATION

2.1 Introduction

After the pneumatic and hydraulic systems, the electrical control took place, since it is easier to lay a wire than laying a pipe, and with small insulation it is possible to cut any leaks.

Control panels are typically used in larger buildings, providing a central platform for switching large numbers of loads. These panels typically contain relays with low-voltage inputs from control devices and line-voltage outputs to the load. The control panels are typically installed in the electrical room near the electrical panel.

Some lighting control panels include controllable breakers and can therefore replace the electrical panel, saving space. Some control panels also provide the capability to mingle switching and dimming modules.

For lighting automation to occur-that is, automatic shut-off of lighting based on a schedule-the control panel must be automated, or intelligent. In other words, it must include an internal time-clock that enables time-based functions.

This control system provides the backbone for the building's lighting control, providing the basic function of scheduled shut-off. Additional layers of devices/strategies can be added to this system, such as photosensors, occupancy sensors, dimmers, etc.

The system is typically centralized, with all local switches and switch-legs (sub-circuits) connected to the control panel via line-voltage wiring, and accessory inputs such as photosensors connected to the panel via low-voltage control wiring. See Figure 1 for an example of a centralized control system.

The control panel polls connected control devices for input that is then filtered through its logic circuit to determine the output (ON or OFF). In a building requiring control of very large zones, this approach can be economical.

If the building requires greater granularity of control with smaller zones, then another approach-distributed control-should be considered,

which in many applications can provide greater capabilities at a lower cost than centralized systems.

2.2 Mechanical and Electrical Control Systems

A control system is a device or set of devices to manage, command, direct or regulate the behavior of other devices or systems.

There are two common classes of control systems, with many variations and combinations: logic or sequential controls, and feedback or linear controls. There is also fuzzy logic, which attempts to combine some of the design simplicity of logic with the utility of linear control. Some devices or systems are inherently not controllable.

The term "control system" may be applied to the essentially manual controls that allow an operator to, for example, close and open a hydraulic press, where the logic requires that it cannot be moved unless safety guards are in place.

An automatic sequential control system may trigger a series of mechanical actuators in the correct sequence to perform a task. For example various electric and pneumatic transducers may fold and glue a

cardboard box, fill it with product and then seal it in an automatic packaging machine.

In the case of linear feedback systems, a control loop, including sensors, control algorithms and actuators, is arranged in such a fashion as to try to regulate a variable at a setpoint or reference value. An example of this may increase the fuel supply to a furnace when a measured temperature drops. PID controllers are common and effective in cases such as this. Control systems that include some sensing of the results they are trying to achieve are making use of feedback and so can, to some extent, adapt to varying circumstances. Open-loop control systems do not directly make use of feedback, but run only in pre-arranged ways.

For example, a thermostat is a simple negative-feedback control: when the temperature (the "measured variable" or MV) goes below a set point (SP), the heater is switched on. Another example could be a pressure switch on an air compressor: when the pressure (MV) drops below the threshold (SP), the pump is powered. Refrigerators and vacuum pumps contain similar mechanisms operating in reverse, but still providing negative feedback to correct errors.

Simple on-off feedback control systems like these are cheap and effective. In some cases, like the simple compressor example, they may represent a good design choice.

In most applications of on-off feedback control, some consideration needs to be given to other costs, such as wear and tear of control valves and maybe other start-up costs when power is reapplied each time the MV drops. Therefore, practical on-off control systems are designed to include hysteresis, usually in the form of a deadband, a region around the setpoint value in which no control action occurs. The width of deadband may be adjustable or programmable.

2.3 Basic Control Concepts

Most basic process control systems consist of a control loop as shown in Fig. 2.2. This has four main components which are:

• A measurement of the state or condition of a process.

• A controller calculating an action based on this measured value against a pre-set or desired value (set point).

• An output signal resulting from the controller calculation which is used to manipulate the process action through some form of actuator.

•The process itself reacting to this signal, and changing its state or condition.

2.4 Electrical Interlock

An interlock switch arrangement is used to disconnect the low voltage connections of electrical components such as transformers and the like in metal-enclosed switchgear. An electrical switch is mounted within a switch housing positioned and mounted adjacent to the access opening o the metal enclosure of the switchgear. A key projection or finger is mounted on a door overlying the access opening to the enclosure and positioned to enter an opening in the switch housing when the door is closed and to actuate the switch so that an electrical circuit is completed for electrical components within the enclosure. When the door is opened the key projection disengages the switch causing the switch to oper thereby electrically disconnecting the components so that a servicemar can perform maintenance with improved security against electrical shock. Typically, the invention is used on metal-enclosed switchgear having double-door arrangement, i.e., an inner screen door and a outer solic door, and the projection is mounted on the inner screen door so that once the screen door is opened, certain of the electrical components ar disconnected. However, when only visual inspection is desired, the outer door only may be opened so that the components can be observe through the inner screen door without the necessity of disconnecting the electrical components.

CHAPTER THREE

COMPUTER CONTROL SYSTEMS

3.1 Introduction

After the electrical age, and with the complication of control circuits, the need appear to have better systems that can be modified easily, since the electrical control systems need to change wires (hardware)or start the control system all over from the beginning. So the idea of using programs (software)to modify any system with limited change in hardware.

A substation IEC-61850 based is an intelligent substation, with an Ethernet local area network (LAN) gathering operational and non- operational data with human-machine interface available over a wide area network (WAN). The network includes sensors, monitors and intelligent electronic devices (IED) with peer-to-peer protocols, allowing automated digital substation buses, high speed operation, environmental monitoring, physical security and information analysis.

According to this standard, optical fibers are used, there by replacing copper wires in the control room. Using a system called Generic Object-Oriented System Event (GOOSE) allows virtual connection over the whole control system. It includes SCADA, protection, control, transformer monitoring, and integrated automatic and power system data collection. It uses GOOSE messaging for protection and client-server model reporting and control with peer-to-peer distributed application. Any fault in a relay, for example, is gathered by a Digital Fault Recorder (DFR) in the relay. Using this technology, thousands of copper cables can be replaced with limited length of optical fiber cables, thus minimizing labor power needed for installation in the control room and in the substation yard, thus making the cost much less, though with much higher technology and much greater facility.

The discussion about IEC61850 and the use of GOOSE messages reminds a little bit of the discussion when the first numerical relays got introduced. That the protection functions got performed by a virtual algorithm rather by electro mechanic interaction was for many protection engineers not comfortable. Over the years numerical relays gained the trust of the protection community because they proved themselves as reliable and offered many advantages to the previous generation.

A similar discussion is taking place today, it gives many protection engineers an uncomfortable feeling that wiring between the relays is replaced by light signals in a fiber optic connection. However the authors belleve that the advantages of GOOSE messages will lead to an acceptance of this technique in the next couple of years. As shown in this paper, GOOSE messages have the following advantages:

-High flexibility

-Cost effective (past and copy)

-Secure, with built in supervision

-Faster than wired solution

3.2 Comparison of IEC61850 GOOSE messages and control wiring between protection relays

Since the new standard IEC61850 was released in 2005, one feature that has gotten the attention of protection engineers is the exchange of information between relays via GOOSE messages. There are many applications known which traditionally require wiring between relays within a substation. When considering control wiring, one must consider the cost and labor involved to install, modify or add additional wiring. Another consideration is the aging of control wires. Because wiring between relays and panels is labor intensive and the fact that it adds significant cost to a project, the idea to replace control wiring by using IEC61850 GOOSE messages is realized immediately, when discussing the advantages of this new standard. However, even though many of the problems that exist with control wiring are eliminated by using IEC61850 GOOSE messages, only a few utilities are using this new architecture presently. The reason for this is that with any new technological development or application techniques, utilities usually are slow to Implement changes compared to other industries and take more precautions because of the customers they serve. An evaluation process is typically undertaken to learn and understand new concepts and pilot

projects are implemented to gain experience. certain requirements. One other feature of the new technique is the ability to monitor an uninterrupted GOOSE connection between relays via extracting and processing the quality information inside a GOOSE message.

3.2.1 Basics

A GOOSE message is used to exchange data between IED's (Intelligent Electronic Devices) and is only one part of the new standard

IEC61850. The reader has to keep in mind that IEC61850 is not only a new communication protocol that describes the communication between IED's and a Scada system, it does also address many tasks inside a substation. Other standards and IEC working groups are now using the concept of the IEC61850 for their own domain; it includes the DER (Distributed Energy Ressources), the WindPower and the Hydro working groups; the standard is therefore gaining influence in many domains of the power utility automation. Figure 1 shows all aspects addressed by the new standard.

The GOOSE part for certain, got the most attention under protection engineers because it would enable him to replace wiring between relays by using the Ethernet communication between the relays. The term GOOSE is the abbreviation for the term Generic Object Oriented Substation Event. The term GOOSE is not new and was also used in the UCA protocol. However the IEC61850 GOOSE is an advanced version of the UCA GOOSE. The major difference is that an IEC61850 GOOSE is not a static number of bits or bit pairs. The IEC61850 version can exchange a wide range of common data which become described by a so called Data- Set. For example an IEC61850 GOOSE message can include bits, bit pairs, measurement values and other data elements. The concept to exchange bits between relays is not really new and was used in private solution by different manufacturers also in the past. The big advantage of IEC61850 implementation is that it is realized as a multicast message what means that several relays can be the receiver (so called subscriber) of a GOOSE message. This let exchange information between all relays connected to the station bus. The fact that IEC61850 is a world wide standard makes it also possible that relays from different manufacturers are able to

exchange information as long as the relays conform to the IEC61850 standard. To guarantee interoperability and enhance the configuration phase, the content of the Data-Set is described in a standardized way, using SCL (Substation Configuration description Language). This description language uses XML as syntax, and is defined in the IEC 61850 part 6. Of course, the SCL does not only makes sense during the configuration, the resulting station's file also provides a solid documentation about the entrire station configuration. This makes the whole concept of using Goose messages versus wires between relays very attractive for protection engineers.

However, before a utility user is going to use this new technology he wants to be sure that this is an established technique and he knows about all the drawbacks. The standard is now more than two years old and a lot of experience has been collected already.

World wide there are already over 1000 substations running by using the IEC61850 standard. In North America several utilities are right now evaluating the capability of the new standard and there are already some substation working with IEC61850. The most valuable project in the United States was the IEC61850 implementation from TVA at there 500 KV Bradley substations. The project used IED's from different

manufacturers (ABB, GE and Siemens) and used also different aspects of the IEC61850 standard, one of them was the GOOSE messages between the IED's.

3.2.2 Process to Program a GOOSE message-Engineering

One may ask the question, how a system which includes IED's from different manufactures can be configured when each manufacturer normally uses his own proprietary tools. The answer is that IEC61850 introduced a common language which can be used to exchange information manufacturer independent. Each proprietary tool must have a function which allows the export of the IED's description into this common, XML-based language. The so called ICD file (IED Capability Description) contains all information about the IED, which allows the user now to configure a GOOSE message. The configuration can be performed by a manufacturer independent tool the so called IEC61850 System Configurator. Some manufacturer advanced there proprietary tools in a way that they can be used as IEC61850 System Configurator, however there are also some third party tools available. All ICD files get imported into the IEC61850 System Configurator and the GOOSE messages can be programmed by specifying the sender (so called publisher) and the receiver(s) (so called subscriber(s)) of a message. On the end the whole description of the system, including the description of the GOOSE messages get stored in the SCD file (Substation Configuration Description). Each proprietary tools must be able to import this SCD file and extract the information needed for the IED.

The information out of the SCD file are typically the list of the GOOSE messages a device signed up and who signed up for the GOOSE messages send out by the device.

3.3 Transducers

A transducer is a device, usually electrical, electronic, electro- mechanical, electromagnetic, photonic, or photovoltaic that converts one type of energy or physical attribute to another for various purposes including measurement or information transfer (for example, pressure sensors).

The term transducer is commonly used in two senses; the sensor, used to detect a parameter in one form and report it in another (usually an electrical or digital signal), and an actuator may be described as opposite to a sensor-it converts electrical signal into generally nonelectrical energy. An example of a transducer is a loudspeaker which converts an electrical signal into a variable magnetic field and, subsequently, into acoustic waves.

Electric motors are another common form of electromechanical transducer, converting electrical energy into kinetic energy to perform a mechanical task. The inverse of an electric motor a generator is also a transducer, turning kinetic energy into electrical energy that can then be used by other devices.

- **Millivolt Output Pressure Transducers**

Transducers with millivolt output are normally the most economical pressure transducers. The output of the millivolt transducer is nominally around 30mV. The actual output is directly proportional to the pressure transducer input power or excitation. If the excitation fluctuates, the output will change also. Because of this dependence on the excitation level, regulated power supplies are suggested for use with millivolt transducers. Because the output signal is so low, the transducer should not be located in an electrically noisy environment. The distances between the transducer and the readout instrument should also be kept relatively short.

4-20 mA Output Pressure Transducers

These types of transducers are also known as pressure transmitters. Since a 4-20mA signal is least affected by electrical noise and resistance in the signal wires, these transducers are best used when the signal must be transmitted long distances. It is not uncommon to use these transducers in applications where the lead wire must be 1000 feet or more.

3.3.1 Sensors

A sensor is a device that measures a physical quantity and converts it into a signal which can be read by an observer or by an instrument. For example, a mercury thermometer converts the measured temperature into expansion and contraction of a liquid which can be read on a calibrated glass tube. A thermocouple converts temperature to an output voltage which can be read by a voltmeter. For accuracy, all sensors need to be calibrated against known standards.

3.3.2 Electromagnetic Relay

An electromagnetic relay is a type of electrical switch controlled by an electromagnet. The electromagnetic relay is used in a variety of applications, including alarms and sensors, signal switching, and the detection and control of faults on electrical distribution lines. The electromagnetic relay was invented in 1835, and its straightforward function has not changed much since. Consumers interact with the electromagnetic relay in a variety of forms daily, from timed office lights to test buttons and other quality control devices.

The core of the electromagnetic relay, naturally, is an electromagnet, formed by winding a coil around an iron core. When the coil is energized by passing current through it, the core in turn becomes magnetized, attracting a pivoting iron armature. As the armature pivots, it operates one or more sets of contacts, thus affecting the circuit. When the magnetic charge is lost, the armature and contacts are released. Demagnetization can cause a leap of voltage across the coil, damaging other components of the device when turned off. Therefore, the electromagnetic relay usually makes use of a diode to restrict the flow of the charge, with the cathode connected at the most positive end of the coil.

Contacts on an electromagnetic relay can take three forms. Normally opened contacts connect the circuit when the device is activated and disconnect it when the device is not active, like a light switch. Normally closed contacts disconnect the circuit when the relay is magnetized, and a change-over incorporates one of each type of contact. The configuration of the contacts is dependant upon the intended application of the device.

The electromagnetic relay is capable of controlling an output of higher power than the input, and it is often used as a buffer to isolate circuits of varying energy potentials as a result. When a low current is applied to the electromagnet, throwing the switch, the device is capable of allowing a higher current to flow through it. This is advantageous in some applications, such as tripping alarms and other safety devices, because a safer low current can be used to activate an application requiring more energy.

CHAPTER FOUR

PROGRAMMABLE LOGIC CONTROLLER (PLC)

4.1 Introduction

Control engineering has evolved over time. In the past humans were the main method for controlling a system. More recently electricity has been used for control and early electrical control was based on relays. These relays allow power to be switched on and off without a mechanical switch. It is common to use relays to make simple logical control decisions. The development of low cost computer has brought the most recent revolution, the Programmable Logic Controller (PLC). The advent of the PLC began in the 1970s, and has become the most common choice for manufacturing controls.

PLCs have been gaining popularity on the factory floor and will probably remain predominant for some time to come. Most of this is because of the advantages they offer.

• Cost effective for controlling complex systems.

• Flexible and can be reapplied to control other systems quickly and easily.

• Computational abilities allow more sophisticated control.

• Trouble shooting aids make programming easier and reduce downtime.

• Reliable components make these likely to operate for years before failure.

4.2 What is a Programmable Logic Controller (PLC)?

A **PROGRAMMABLE LOGIC CONTROLLER (PLC)** is an industrial computer control system that continuously monitors the state of input devices and makes decisions based upon a custom program to control the state of output devices.

Almost any production line, machine function, or process can be greatly enhanced using this type of control system. However, the biggest benefit in using a PLC is the ability to change and replicate the operation or process while collecting and communicating vital information.

Another advantage of a PLC system is that it is modular. That is, you can mix and match the types of Input and Output devices to best suit your application.

4.3 What is inside a PLC?

The Central Processing Unit, the CPU, contains an internal program that tells the PLC how to perform the following functions:

• Execute the Control Instructions contained in the User's Programs. This program is stored in "nonvolatile" memory, meaning that the program will not be lost if power is removed.

• Communicate with other devices, which can include I/O Devices, Programming Devices, Networks, and even other PLCS.

• Perform Housekeeping activities such as Communications, Internal Diagnostics, etc.

4.4 How does a PLC Operate?

There are four basic steps in the operation of all PLCs; Input Scan, Program Scan, Output Scan, and Housekeeping. These steps continually take place in a repeating loop (As shown in Fig 4.1).

Four steps in the PLC operations includes

1.) Input Scan

Detects the state of all input devices that are connected to the PLC

2.) Program Scan

Executes the user created program logic

3.) Output Scan

Energizes or de-energize all output devices that are connected to the PLC.

4.) Housekeeping

This step includes communications with programming terminals, internal diagnostics, etc...

4.5 What programming language is used to program a PLC?

While Ladder Logic is the most commonly used PLC programming language, it is not the only one. The following table lists of some of languages that are used to program a PLC.

Ladder Diagram (LD) Traditional ladder logic is graphical programming language. Initially programmed with simple contacts that simulated the opening and closing of relays, Ladder Logic programming has been expanded to include such functions as counters, timers, shift registers, and math operations.

• **Function Block Diagram (FBD**) A graphical language for depicting signal and data flows through re-usable function blocks. FBD is very useful for expressing the interconnection of control system algorithms and logic.

• **Structured Text (ST)** - A high level text language that encourages structured programming. It has a language structure (syntax) that strongly resembles PASCAL and supports a wide range of standard functions and operators. For example;

```
If Speed1 > 100.0 then
Flow Rate: 50.0+ Offset A1;
 Else
 Flow_Rate: 100.0; Steam: = ON
End If;
```

Instruction List (IL) A low level "assembler like" language that is based on similar instructions list languages found in a wide range of today's PLCS

Sequential Function Chart (SFC) A method of programming

complex control systems at a more highly structured level. A SFC program is an overview of the control system, in which the basic building blocks are entire program files. Each program file is created using one of the other types of programming languages. The SFC approach coordinates large, complicated programming tasks into smaller, more manageable tasks.

4.6 Programming a PLC?

Ladder logic is the main programming method used for PLCs. As mentioned before, ladder logic has been developed to mimic relay logic. The decision to use the relay logic diagrams was a strategic one. By selecting ladder logic as the main programming method, the amount of retraining needed for engineers and tradespeople was greatly reduced.

Modern control systems still include relays, but these are rarely used for logic. A relay is a simple device that uses a magnetic field to control a switch, as pictured in Figure 4.5. When a voltage is applied to the input coil, the resulting current creates a magnetic field. The magnetic field pulls a metal switch (or reed) towards it and the contacts touch,

closing the switch. The contact that closes when the coil is energized is called normally open. The normally closed contacts touch when the input coil is not energized. Relays are normally drawn in schematic form using a circle to represent the input coil. The output contacts are shown with two parallel lines. Normally open contacts are shown as two lines, and will be open (non-conducting) when the input is not energized. Normally closed contacts are shown with two lines with a diagonal line through them. When the input coil is

In actual PLCs inputs are never relays, but outputs are often relays. The ladder logic in the PLC is actually a computer program that the user can enter and change.

The first PLCs were programmed with a technique that was based on relay logic wiring schematics. This eliminated the need to teach the electricians, technicians and engineers how to program a computer - but, this method has stuck and it is the most common technique for programming PLCs today. An example of ladder logic can be seen in Figure 4.6. To interpret this diagram imagine that the power is on the

vertical line on the left hand side, we call this the hot rail. On the right hand side is the neutral rail. In the figure there are two rungs, and on each rung there are combinations of inputs (two vertical lines) and outputs (circles). If the inputs are opened or closed in the right combination the power can flow from the hot rail, through the inputs, to power the outputs, and finally to the neutral rail. An input can come from a sensor, switch, or any other type of sensor. An output will be some device outside the PLC that is switched on or off, such as lights or motors. In the top rung the contacts are normally open and normally closed. Which means if input A is on and input B is off, then power will flow through the output and activate it. Any other combination of input values will result in the output X being off

The second rung of Figure 4.6 is more complex, there are actually multiple combinations of inputs that will result in the output Y turning on. On the left most part of the rung, power could flow through the top if C is off and D is on. Power could also (and simultaneously) flow through the bottom if both E and F are true. This would get power half way across the rung, and then if G or H is true the power will be delivered to output Y.

4.7 PLC Connections

When a process is controlled by a PLC it uses inputs from sensors to make decisions and update outputs to drive actuators, as shown in Figure 4.7. The process is a real process that will change over time. Actuators will drive the system to new states (or modes of operation). This means that the controller is limited by the sensors available, if an input is not available, the controller will have no way to detect a condition.

The control loop is a continuous cycle of the PLC reading inputs, solving the ladder logic, and then changing the outputs. Like any computer this does not happen instantly. Figure 4.8 shows the basic operation cycle of a PLC. When power is turned on initially the PLC does a quick sanity check to ensure that the hardware is working properly. If there is a problem the PLC will halt and indicate there is an error For example, if the PLC backup battery is low and power was lost, the memory will be corrupt and this will result in a fault. If the PLC passes the sanity check it will then scan (read) all the inputs. After the inputs values are stored in memory the ladder logic will be scanned (solved) using the stored values not the current values. This is done to prevent logic problems when inputs change during the ladder logic scan. When the ladder logic scan is complete the outputs will be scanned (the output values will be changed). After this the system goes back to do a sanity check, and the loop continues Indefinitely. Unlike normal computers, the entire program will be run every scan. Typical times for each of the stages is in the order of milliseconds.

4.7 PLC HARDWARE

4.7.1 INTRODUCTION

Many PLC configurations are available, even from a single vendor. But, in each of these there are common components and concepts. The most essential components are:

Power Supply This can be built into the PLC or be an external unit. Common voltage levels required by the PLC (with and without the power supply) are 24Vdc, 120Vac, 220Vac.

CPU (Central Processing Unit) This is a computer where ladder logic is stored and processed. Central Processing Unit (CPU) is the brain of a PLC controller. CPU itself is usually one of the microcontrollers.

1/0 (Input/Output) A number of input/output terminals must be provided so that the PLC can monitor the process and initiate actions.

Indicator lights These indicate the status of the PLC including power on, program running, and a fault. These are essential when diagnosing problems.

The configuration of the PLC refers to the packaging of the components. Typical configurations are listed below from largest to smallest.

Rack A rack is often large (up to 18" by 30" by 10") and can hold multiple cards. When necessary, multiple racks can be connected together. These tend to be the highest cost, but also the most flexible and easy to maintain.

Mini These are similar in function to PLC racks, but about half the size.

Shoebox A compact, all-in-one unit (about the size of a shoebox) that has limited expansion capabilities. Lower cost, and compactness make these ideal for small applications.

Micro These units can be as small as a deck of cards. They tend to have fixed quantities of I/O and limited abilities, but costs will be the lowest.

Software A software based PLC requires a computer with an interface card, but allows the PLC to be connected to sensors and other PLCs across a network.

4.7.2 INPUTS AND OUTPUTS

Inputs to, and outputs from, a PLC are necessary to monitor and control a process. Both inputs and outputs can be categorized into two basic types: logical or continuous. Consider the example of a light bulb. If it can only be turned on or off, it is logical control. If the light can be dimmed to different levels, it is continuous. Continuous values seem more intuitive, but logical values are preferred because they allow more certainty, and simplify control. As a result most controls applications (and PLCS) use logical inputs and outputs for most applications. Hence, we will discuss logical I/O and leave continuous 1/0 for later.

Outputs to actuators allow a PLC to cause something to happen in a process. A short list of popular actuators is given below in order of relative popularity.

Solenoid Valves logical outputs that can switch a hydraulic or pneumatic flow.

Lights logical outputs that can often be powered directly from PLC output boards.

Motor Starters motors often draw a large amount of current when started, so they require motor starters, which are basically large relays.

Servo Motors a continuous output from the PLC can command a variable speed or position.

Outputs from PLCs are often relays, but they can also be solid state electronics such as transistors for DC outputs or Triacs for AC outputs. Continuous outputs require special output cards with digital to analog converters.

Inputs come from sensors that translate physical phenomena into electrical signals. Typical examples of sensors are listed below in relative order of popularity.

Proximity Switches use inductance, capacitance or light to detect an object logically.

Switches mechanical mechanisms will open or close electrical contacts for a logical signal.

Potentiometer resistance. measures angular positions continuously, using

LVDT (linear variable differential transformer) displacement continuously using magnetic coupling. measures linear

Inputs for a PLC come in a few basic varieties, the simplest are AC and DC inputs. Sourcing and sinking inputs are also popular. This output method dictates that a device does not supply any power. Instead, the device only switches current on or off, like a simple switch.

Sinking When active the output allows current to flow to a common ground. This is best selected when different voltages are supplied.

Sourcing When active, current flows from a supply, through the output device and to ground. This method is best used when all devices use a single supply voltage.

This is also referred to as NPN (sinking) and PNP (sourcing). PNP is more popular.

4.8 Some Pictures of Different PLCS

CHAPTER FIVE

APPLICATION OF PLC IN SUBSTATION

5.1 Introduction

As in many other areas, the computer applications in electrical power systems have grown tremendously over the last several decades penetrating apparently all aspects of electrical power systems, including operational planning, energy management, load forecast, power quality, automated generation, transmission and distribution, etc. A system used to monitor and control equipment and processes is called SCADA where the acronym stands for Supervisory Control And Data Acquisition. SCADA consists of a central host (Master Terminal Unit, MTU); field data gathering and control units (Remote Terminal Units, RTUs); communication system, and a software application to monitor and control RTUS. SCADA systems may implement open or closed-loop control in conjunction with long or short distance communications.

Very few industrial plants can be left to run themselves, and most need some form of control system to ensure safe and economical operation. Figure 5.1 is thus a representation of a typical installation, consisting of a plant connected to a control system. This acts to translate the commands of the human operator into the required actions, and to display the plant status back to the operator.

5.2 SCADA System

SCADA (supervisory control and data acquisition system) refers to the combination of telemetry and data acquisition. SCADA encompasses the collecting of the information via a RTU (remote terminal unit), transferring it back to the central site, carrying out any necessary analysis and control and then displaying that information on a number of operator screens or displays. The required control actions are then conveyed back to the process. In the early days of data acquisition relay logic was used to control production and plant systems. With the advent of the CPU (as part of the microprocessor) and other electronic devices, manufacturers Incorporated digital electronics into relay logic equipment, creating the PLC or programmable logic controller, which is still one of the most widely used control systems in industry. As needs grew to monitor and control more devices in the plant, the PLCs were distributed and the systems became more intelligent and smaller in size. PLCs and/or DCS (distributed control systems) are used as shown below. Although initially RTU was often a dedicated device, PLCs are often used as RTUs these days.

As the requirement for smaller and smarter systems grew, sensors were designed with the intelligence of PLCs and DCSs. These devices are known as IEDs (intelligent electronic devices). The IEDs are connected on a fieldbus such as Profibus, DeviceNet or Foundation Fieldbus to the PC. They include enough intelligence to acquire data, communicate to other devices and hold their part of the overall program. Each of these super smart sensors can have more than one sensor on board. Typically an IED could combine an analog input sensor, analog output, PID control, communication system and program memory in the one device.

A SCADA System usually consists of the following subsystems:

• A Human-Machine Interface or HMI is the apparatus which presents process data to a human operator, and through this, the human operator, monitors and controls the process.

• A supervisory (computer) system, gathering (acquiring) data on the process and sending commands (control) to the process.

• Remote Terminal Units (RTUs) connecting to sensors in the process, converting sensor signals to digital data and sending digital data to the supervisory system.

• Programmable Logic Controller (PLCs) used as field devices because they are more economical, versatile, flexible, and configurable than special-purpose RTUS.

• Communication infrastructure connecting the supervisory system to the Remote Terminal Units

There is, in several industries, considerable confusion over the differences between SCADA systems and Distributed control systems (DCS). Generally speaking, a SCADA system usually refers to a system that coordinates, but does not control processes in real time. The discussion on real-time control is muddied somewhat by newer telecommunications technology, enabling reliable, low latency, high speed communications over wide areas. Most differences between SCADA and DCS are culturally determined and can usually be ignored. As communication infrastructures with higher capacity become available, the difference between SCADA and DCS will fade.

The term SCADA usually refers to centralized systems which monitor and control entire sites, or complexes of systems spread out over large areas (anything between an industrial plant and a country). Most control actions are performed automatically by remote terminal units ("RTUs") or by programmable logic controllers ("PLCs"). Host control functions are usually restricted to basic overriding or supervisory level intervention. For

example, a PLC may control the flow of cooling water through part of an Industrial process, but the SCADA system may allow operators to change the set points for the flow, and enable alarm conditions, such as loss of flow and high temperature, to be displayed and recorded. The feedback control loop passes through the RTU or PLC, while the SCADA system monitors the overall performance of the loop.

Data acquisition begins at the RTU or PLC level and includes meter readings and equipment status reports that are communicated to SCADA as required. Data is then compiled and formatted in such a way that a control room operator using the HMI can make supervisory decisions to adjust or override normal RTU (PLC) controls. Data may also be fed to a Historiah, often built on a commodity Database Management System, to allow trending and other analytical auditing.

SCADA systems typically implement a distributed database, commonly referred to as a tag database, which contains data elements called tags or points. A point represents a single input or output value monitored or controlled by the system. Points can be either "hard" or "soft". A hard point represents an actual input or output within the system, while a soft point results from logic and math operations applied

to other points. (Most Implementations conceptually remove the distinction by making every property a "soft" point expression, which may, in the simplest case, equal a single

hard point) Points are normally stored as value-timestamp pairs a value, and the timestamp when it was recorded or calculated. A series of value-timestamp pairs gives the history of that point. It's also common to store additional metadata with tags, such as the path to a field device or PLC register, design time comments, and alarm information.

5.2.1 Human Machine Interface (HMI)

A Human-Machine Interface or HMI is the apparatus which presents process data to a human operator, and through which the human operator controls the process.

An HMI is usually linked to the SCADA system's databases and software programs, to provide trending, diagnostic data, and management information such as scheduled maintenance procedures, logistic information, detailed schematics for a particular sensor or machine, and expert-system troubleshooting guides.

The HMI system usually presents the information to the operating personnel graphically, in the form of a mimic diagram. This means that the operator can see a schematic representation of the plant being controlled. For example, a picture of a pump connected to a pipe can show the operator that the pump is running and how much fluid it is pumping through the pipe at the moment. The operator can then switch the pump off. The HMI software will show the flow rate of the fluid in the pipe decrease in real time. Mimic diagrams may consist of line graphics and schematic symbols to represent process elements, or may consist of digital photographs of the process equipment overlain with animated symbols.

The HMI package for the SCADA system typically includes a drawing program that the operators or system maintenance personnel use to change the way these points are represented in the interface. These representations can be as simple as an on-screen traffic light, which represents the state of an actual traffic light in the field, or as complex as a multi-projector display representing the position of all of the elevators in a skyscraper or all of the trains on a railway.

An important part of most SCADA implementations are alarms. An alarm is a digital status point that has either the value NORMAL or ALARM. Alarms can be created in such a way that when their requirements are

met, they are activated. An example of an alarm is the "fuel tank empty" light in a car. The SCADA operator's attention is drawn to the part of the system requiring attention by the alarm. Emails and text messages are often sent along with an alarm activation alerting managers along with the SCADA operator.

5.2.2 Hardware Solutions

SCADA solutions often have Distributed Control System (DCS) components. Use of "smart" RTUS or PLCS, which are capable of autonomously executing simple logic processes without involving the master computer, is increasing. A functional block programming language, IEC 61131-3 (Ladder Logic), is frequently used to create programs which run on these RTUS and PLCs. Unlike a procedural language such as the C programming language or FORTRAN, IEC 61131-3 has minimal training requirements by virtue of resembling historic physical control arrays. This allows SCADA system engineers to perform both the design and Implementation of a program to be executed on an RTU or PLC. Since about 1998, virtually all major PLC manufacturers have offered integrated HMI/SCADA systems, many of them using open and non-proprietary communications protocols. Numerous specialized third-party HMI/SCADA packages, offering built-in compatibility with most major PLCs, have also entered the market, allowing mechanical engineers, electrical engineers and technicians to configure HMIs themselves, without the need for a custom-made program written by a software developer.

5.2.3 Remote Terminal Unit (RTU)

The RTU connects to physical equipment. Typically, an RTU converts the electrical signals from the equipment to digital values such as the open/closed status from a switch or a valve, or measurements such as pressure, flow, voltage or current. By converting and sending these electrical signals out to equipment the RTU can control equipment, such as opening or closing a switch or a valve, or setting the speed of a pump.

Quality SCADA RTUS have these characteristics

- Supervisory Station

The term "Supervisory Station" refers to the servers and software responsible for communicating with the field equipment (RTUS, PLCs, etc), and then to the HMI software running on workstations in the control room,

or elsewhere. In smaller SCADA systems, the master station may be composed of a single PC. In larger SCADA systems, the master station may include multiple servers, distributed software applications, and disaster recovery sites. To increase the integrity of the system the multiple servers will often be configured in a dual-redundant or hot- standby formation providing continuous control and monitoring in the event of a server failure.

Initially, more "open" platforms such as Linux were not as widely used due to the highly dynamic development environment and because a SCADA customer that was able to afford the field hardware and devices to be controlled could usually also purchase UNIX or OpenVMS licenses. Today, all major operating systems are used for both master station servers and HMI workstations.

Operational philosophy

For some installations, the costs that would result from the control system failing are extremely high. Possibly even lives could be lost. Hardware for some SCADA systems is ruggedized to withstand temperature, vibration, and voltage extremes, but in most critical installations reliability is enhanced by having redundant hardware and communications channels, up to the point of having multiple fully equipped control centres. A failing part can be quickly identified and its functionality automatically taken over by backup hardware. A failed part can often be replaced without interrupting the process. The reliability of such systems can be calculated statistically and is stated as the mean time to failure, which is a variant of mean time between failures. The calculated mean time to failure of such high reliability systems can be on the order of centuries.

Communication infrastructure and methods

SCADA systems have traditionally used combinations of radio and direct serial or modem connections to meet communication requirements, although Ethernet and IP over SONET/SDH is also frequently used at large sites such as railways and power stations. The remote management or monitoring function of a SCADA system is often referred to as telemetry.

This has also come under threat with some customers wanting SCADA data to travel over their pre-established corporate networks or to share the network with other applications. The legacy of the early low- bandwidth protocols remains, though. SCADA protocols are designed to be very compact and many are designed to send information to the master station only when the master station polls the RTU. Typical legacy SCADA

protocols include Modbus RTU, RP-570, Profibus and Conitel. These communication protocols are all SCADA-vendor specific but are widely adopted and used. Standard protocols are IEC 60870-5-101 or 104, IEC 61850 and DNP3. These communication protocols are standardized and recognized by all major SCADA vendors. Many of these protocols now contain extensions to operate over TCP/IP. It is good security engineering practice to avoid connecting SCADA systems to the Internet so the attack surface is reduced.

RTUs and other automatic controller devices were being developed before the advent of industry wide standards for interoperability. The result is that developers and their management created a multitude of control protocols. Among the larger vendors, there was also the incentive to create their own protocol to "lock in" their customer base. A list of automation protocols is being compiled here.

Recently, OLE for Process Control (OPC) has become a widely accepted solution for intercommunicating different hardware and software, allowing communication even between devices originally not intended to be part of an industrial network.

5.3 SCADA Architectures

SCADA systems have evolved through 3 generations as follows:

First Generation: "Monolithic"

In the first generation computing was done by Mainframe systems. Networks didn't exist at the time SCADA was developed. Thus SCADA systems were independent systems with no connectivity to other systems. Wide Area Networks were later designed by RTU vendors to communicate with the RTU. The communication protocols used were often proprietary at that time. The first generation SCADA System was redundant since a back-up mainframe system was connected at the bus level and was used in the event of failure of the main mainframe system.

Second Generation: "Distributed"

The processing was distributed across multiple stations which were connected through LAN and they shared information in real time. Each station was responsible for a particular task thus making the size and cost of each station less than the one used in First Generation. The network protocols used were still mostly proprietary.

Third Generation: "Networked"

These are the current generation SCADA systems which use open system architecture rather than a vendor controlled proprietary environment. The SCADA system utilizes open standard and protocols thus distributing functionality across a WAN rather than a LAN. It is easier to connect third party peripheral devices like printers, disk drives, tape drives due to the use of open architecture. WAN protocols such as Internet Protocol (IP) are used for communication between the master station and communications equipment. This on the other hand has put a question on the security of SCADA system which seems to be vulnerable to cyber-warfare and cyber terrorism attacks.

5.4 SCADA Hardware

A SCADA system consists of a number of remote terminal units (or RTUS) collecting field data and sending that data back to a master station via a communications system. The master station displays the acquired data and also allows the operator to perform remote control tasks. The accurate and timely data allows for optimization of the plant operation and process. A further benefit is more efficient, reliable and most Importantly, safer operations.

This all results in a lower cost of operation compared to earlier non- automated systems. On a more complex SCADA system there are essentially five levels or hierarchies:

• Field level instrumentation and control devices

• Marshalling terminals and RTUS

• Communications system

• The master station(s)

• The commercial information technology (IT) or data processing department computer system.

The RTU provides an interface to the field analog and digital sensors situated at each remote site. The communications system provides the pathway for communications between the master station and the remote sites. This communication system can be wire, fiber optic, radio, telephone line, microwave and possibly even satellite. Specific protocols and error detection philosophies are used for efficient and optimum transfer of data.

The master station (or sub-masters) gather data from the various RTUS and generally provide an operator interface for display of

Information and control of the remote sites. In large telemetry systems, sub-master sites gather information from remote sites and act as a relay back to the control master station.

5.5 SCADA Software

SCADA software can be divided into two types, proprietary or open. Companies develop proprietary software to communicate to their hardware. These systems are sold as 'turn key' solutions. The main problem with these systems is the overwhelming reliance on the supplier of the system. Open software systems have gained popularity because of the interoperability they bring to the system. Interoperability is the ability to mix different manufacturers' equipment on the same system. Citect and WonderWare are just two of the open software packages available on the market for SCADA systems. Some packages are now including asset management integrated within the SCADA system. The typical components of a SCADA system are indicated in the diagram below.

SCADA systems invariably include an alarm system and these usually display alarms which appear as a banner on the screen which must be acknowledged by the operator. It is usual to store these alarm banners in an alarm history file which shows the time at which the alarm occurred and the time the alarm was accepted. These alarm histories, commonly called an Alarm Log, can be very usual for fault finding or subsequent post mortems. They are essential if the alarm system does have a 'first-up' system to filter alarms.

CHAPTER SIX

IEC 61850 AS A STANDARD FOR DESIGN OF ELECTRICAL SUBSTATION AUTOMATION

6.1 INTRODUCTION

A substation IEC 61850 based is an intelligent substation, with an Ethernet local area network (LAN) gathering operational and non operational data with human machine interface available over a wide areas network (WAN) The network includes sensors, monitors and intelligent electronic devices (IED) with peer to peer protocols, allowing automated digital substation buses, high speed operation, environmental monitoring, physical security and information analysis.

The other advantage of this standard is the interoperability of vendor equipments, such that spare parts from any vendor can replace original manufacturer parts. This is really a great advantage

In short, the advantages of IEC61850 are summarized below

• Saves time during implementation.

• Simplifies upgrading and extending the substation

• Reduces wiring and schematics.

• Reduces cost

• Optical fiber with high speed networks provide new opportunities for communication.

• Makes utilities less dependent on suppliers.

• Changes in the profession as complementary skills required of engineers is an advantage for young engineers.

Transformation from static structure to dynamic viewpoint, manual operation to self monitoring, and upstream control to localized automatic response is really the main outline of the benefit.

With this technology, a roomful of electromechanical device panels can be replaced with one digital panel only.

6.2 Principle

Modern electric power systems Include multifunction relays, distributed programmable controllers, phasor measurement units (PMUs), and similar IEDs that are capable of producing and consuming various sorts of data for monitoring, metering, automation and control.

In existing electromechanical schemes when a multitrip lockout switch operates, the following happens:

Unique Lockout Function:

Each protection function that performs lockout has its own lockout state, not combined with others. For example, if a transformer differential relay trips, it sets a lockout state for the breakers that isolate that transformer. If subsequent to the tripping operation, one of the breakers fails, then that breaker failure function sets a separate lockout state for the failed breaker and all the other breakers or TT channels to isolate it. The failed breaker then has two independent lockouts applied to it.

- Local Indication:

An operator must be able to determine which of these individual lockouts are in effect, so he can check on the cause and remedy for each, and sign off on corrections before resetting each one.

Close Inhibit:

A breaker cannot be closed as long as any lockout is still in effect, even if some lockouts applied to it have been reset.

- Immunity to Relay Loss of Power:

The application of the lockout must not be dependent on the life of any particular relay, or on power to the relay. In other words, failure of the controlling relay or its DC supply cannot possibly enable closing of a locked out breaker.

Immunity to System Loss of Power:

The memory of each of the possible lockout must be nonvolatile. In other words, even if the entire power and closing system is de energized and

later re-energized, all the lockouts that were in effect must be remembered.

To remedy the shortcomings indicated above, we should look out for the followings:

- Remote Indication:

The lockout states are reported to SCADA and to maintenance via the LAN and remote communications.

Single Procedure Reset:

The resetting of a particular lockout has a single procedure, all the affected breakers, channels, and other systems are reset as a group with respect to this particular lockout when that resetting procedure is applied. The operator cannot be expected to routinely go around the station finding and resetting the lockout actions at each of many target relays, breakers, or channels.

Backup Indication and Reset:

There must be a clear backup process for identifying and clearing lockouts per above rules if the substation concentrator, computer, or human- machine interface (HMI) are down.

- Lockout Restored by System

Lockout memory system must be robust in the face of relay failures and replacements. The system should have the means to align the picture of lockouts among all the relays and IEDs in the substation. If any is replaced, the system should be able to set its lockout states correctly when it is turned on, even though the replaced device was not there when the problem initially arose.

Removal of lockout can be remotely blocked or overseen to prevent careless resetting by field personnel in a hurry. Back office applications can compile statistics on frequency, causes, time duration and handling of lockout incidents for business process reporting and improvement.

6.2.1 Distributed Lockout

Distributed lockout functions are essential in breaker fail applications and any application where lockout over a large distance or over the span of multiple IEDs is desired. In these applications, it is essential that the lockout state be retained after the loss and regain of power. However, this has operational consequences if this has to happen. All the traditional inter-relay wiring can be replaced by inter-relay

communication, utilizing the IEC61850 standard, with a scheme that can be easily expanded.

This scheme has a better reliability than existing scheme, by utilizing two identical lockout schemes running in parallel and each scheme has redundant communication channels with secure networks.

6.2.2 Philosophy of Distributed Lockout

We shall describe a simplified substation which has one 400 KV line, one 132 KV line and one 400.132 KV transformer [6]. The transformer relays are connected directly to 132 KV circuit breaker trip and close coils and the 400 KV line relays are directly connected to the 400 KV circuit breaker trip and close coils. For complete redundancy, two schemes per device are required, therefore there are six IEDs performing overall scheme protection. All latching functions are of non-volatile type to ensure that the state of the latch will be maintained even during loss of power. The main focus is the logic configuration in the two 400 KV line IEDs, though it should be similar to the 132 KV line IEDs.

The first part of the lockout scheme is the transformer protection operation that has to latch trip lochout all close commands to both 400 KV and 132 KV breakers. The transformer protection operation of scheme 1 set the latch within the transformer IED, that is, within itself, a latch within both schemes 1 and 2 of 400 KV line protection relays and both schemes 1 and 2 of 132 KV line protection relays. The set command from transformer 1 IED can be transported by means of Generic Sub-Station Event GSSE messaging to the line IEDs. Each of these latches then ensures tripping and blocks closing of the local breaker. Each latch set is unique to the originating lockout function, this accomplishes the first critical feature. All applicable latches must be reset before the close inhibit is removed. This addresses the third critical point.

The breaker failure trip function of the 132 KV breaker which is located in the 132 KV line IED scheme 1, sets the latches in both schemes 1 and 2 of 400 KV line IEDs. Breaker failure trip of 132 KV scheme 2 line IED will result in the same latches being set, except for system 1 of 132 KV line IED.

The breaker failure of the 400 KV breaker of scheme 1 and 2 of line 400 KV IEDs should set only a latch in itself respectively and key this information to the remote end of the 400 KV line to ensure the line gets cleared.

Resetting of this logic becomes a challenge and great care should be taken to ensure that when a function is reset in an IED, that it would reset all latches that was set, for example, if transformer IED scheme 1

operated, the local resetting of this function should reset all local and remote latches. This provides the first desired feature. The same principle should apply for the breaker failure. Since there is a risk that some devices can be offline, due to loss of power or communications, a master reset feature hasd to be available that these devices can be reset remotely.

As described, the lockout scheme has the following advantages:

• Compared with traditional lockout schemes, it is less complex as there is no need for auxiliary equipment, except for communication equipment.

• Multiple repetition can be performed expanding the overall lockout scheme without the need to add any additional hardware or wiring.

During implementation the following have to be taken into consideration:

• All lockout latch functions should be of non-volatile type, and maintain their state after power was cycled to the IED.

• Communications to each device should preferably be redundant, reducing the-risk of loss of communication.

• The output contacts associated with each other lockout within each IED should preferably be of lockout type and thus should not change state if the IED was to loose power.

• The lockout function of scheme 1 and 2 should preferably be separated from each other to minimize inter-system communications, and to allow one system or parts of it, to be taken out of service for maintenance and testing.

6.3 Technology and System Architecture

In this type of technology, there is a unit called "Brick" which conforms to the followings:

• The I/O interface to copper world.

• Rugged hardware to meet demanding environment condition.

•Suitable for mounting on outdoor gear.

• All Interfaces connectorized.

•Self-powered via copper pair embedded in fiber cable.

•1/O devices with no settings, firmware or maintenance port.

• No sophisticated processing.

4.2 System Architecture:

•"Bricks" in the switchyard provide complete I/O capabilities for the system.

•Redundant bricks for critical signals.

•Data acquisition and outputs only, no processing (future proof).

•Bricks connected via multi-fiber cables (star topology).

•Fiber cables in trenches, directly buried.

• Bricks powered via copper wires integrated in the fiber cable.

• Single high-density cable connector.

• All switchgear (CB+CT, PTs, free-standing CTs, disconnect and ground switches, sensors) are interfaced via bricks.

• Cables terminate on two redundant patch panels.

• Uniform switchgear to control room layout, with no variability.

6.4 DESIGN OF IEC 61850 BASED SUBSTATION AUTOMATION SYSTEMS ACCORDING TO CUSTOMER REQUIREMENTS

6.4.1 INTRODUCTION

IEC 61850 is the global standard for Substation Automation. It allows for and open and "future proof" design, different architectures and possibilities to combine products from multiple vendors. This new standard has many new possibilities but also challenges. By using the inherent advantages of IEC 61850 it is possible to optimize more reliable and cost effective solutions. The big vendors are speeding up quite fast. In order for users and system integrators to utilize the benefits of IEC 61850 it is necessary for the generation, transmission and distribution companies to start now with the awareness and education program for their most crucial asset people, and start the migration to IEC 61850.

For specification, design and engineering, the most important feature of IEC 61850 is its support to strong formal description of the substation and its automation system.

6.4.2 CUSTOMER SPECIFICATION

6.4.2.1 General

The customer specification has to include three areas of requirements:

A. the functionality needed

B. the performance requested

C. constraints applicable.

The functionality refers mainly to the given single-line diagram of the substation and the protection and control functions of the substation automation system.

The performance includes figures for reliability and availability.

The constraints may include interfaces needed for remote network control centers or remote maintenance systems. Constraints include also the geographical situation on-site, i.e. the distances between components, building space, shielding and grounding facilities, and last not least the existence of prescribed IED types.

6.4.2.2 The single Lline Diagram

The SLD shows all power equipment to be controlled and protected, and defines how this shall be done from the operator's point of view. The topology, how the power equipment is electrically connected, gives further information needed e.g. for interlocking and synchrocheck functionality.

6.4.2.3 Functions (Specification Method)

The functionality as given by the SLD should be specified without reference to any implementation to allow optimizing the solution. IEC 61850 offers the concept of logical nodes (LN) for formally defining functions. The LN is an object, which comprises at least all related mandatory data and attributes and all extensions according to the rules of IEC 61850. LNs allow defining functional requirements in a standardized way used in the SLD (see Figure 2)

We have to know which power equipment and bay within the switchyard refers to what function or reverse. This may be done with help of SCL. The resulting file is called System Specification Description (SSD) file. The SSD file allows however including short text parts or references to files containing additional information into the objects of the SLD as well as into the LN definitions. With these features the degree of understandability is enhanced quite a lot compared to current verbal specification.

The LN class definitions according to IEC 61850 are given:

XCBR: Circuit breaker

XSWI: Isolator or earthing switch

TCTR: Instrument transformer/transducer for current

YLTC: Power transformer

CSWI: Switch control

CILO: Interlocking

MMXU: Measuring unit

PTOC: Time overcurrent protection

ATCC: Automatic tap changer control

ITCI: Telecontrol interface or gateway

IHMI: Human machine interface, operators place.

6.4.2.4 Performance

Performance comprises a wide range of topics such as response time, safety and reliability. These requirements guide the allocation of LNs and their related functions to devices, and strongly influence the structure of the communication system. It is up to the system designer selecting IEDS, communication configurations and function implementations which match these response times and failure modes additionally to the needed availability. Safety and availability are normally specified as probability values, together with some general rules.

6.4.2.5 Constraints

The constraints include some boundary conditions like the geographical extension and topology of the substation, the existence of building structures, switchyard kiosks, shielded rooms for the station HMI, etc. All these conditions influence the SA system architecture regarding possible IED locations and the resulting communication links. The performance requirements together with the given constraints define the final physical architecture.

6.4.3 THE DESIGN PROCESS

6.4.3.1 Design Steps

The general design process from customer specification to final system design is principally independent from any standard but some features of IEC 61850 influence and facilitate this process.

6.4.3.2 Start

The design process can either start with the functional specification, in case of IEC 61850 preferably with an SSD description, or with the boundary conditions (see Figure 3). When starting with the functional specification, the next step is to search for IEDs, which support the required functions. Then it has to be checked if the grouping of functions (LNs) on the found IEDs fulfills the availability and safety criteria. In the next step the boundary conditions and the availability conditions are used to design the connecting communication architecture in a cost optimal way. Now the overall system structure is known, and detail design can start. When starting with the constraints and performance requirements, this determines the minimum number of IEDs needed at the interface locations, and their main functionality. This first design step must already cover the requirements for functional redundancy.

6.4.3.3 Tools and formal specification

To get maximum benefit from tool support the specification has to be translated into the SCL based SSD (System Specification Description). The SSD is an unambiguous input, which enhances the quality of the specification.

6.4.3.4 Grouping LNs to LDs and non-functional requirements

We have to decide the geographical allocation of functions. During this allocation we have to prove that no constraints are violated and the reliability and availability goals are met. If we have a free choice of devices, we may first group functions.

1. The LNs belonging together in Logical Devices (LD).

2. combining all LDs in IEDs in such a way that a minimum number of devices results.

3. We have to find proper devices for implementing this optimized solution.

6.4.4 Example for Selection of IEDs and Allocation of Functions

In case of free selection of IEDs, the availability requirements, at least for transmission substations, end up mostly with two devices per bay. The selection is influenced by the process interface normally given by the switchgear. Figure 4 shows examples for both conventional hardwired interfaces in the bay IEDs and remote interfaces near the switchgear connected to the bay IEDs by the process bus. The IED allocated to the instrument transformers TCTR is called Merging Unit (MU) since it may merge the signals. Switches are active communication nodes connecting Ethernet links.

6.4.5 The requirement of redundant protection

To avoid single point of failures, there have to be two process bus segments, which connect the sensor (Merging Unit IED, i.e. MU) with the protection and breaker (Breaker IED) each (see Figure 5). Each segment may contain an external or embedded switch. If any component of one segment fails, the protection of only this segment is out of order, and at least the other one is operating well. Control may be connected to any of the two switches.

Logically, communication according to IEC 61850 takes place between LNs. In any implementation, physical communication takes place between IEDs. Multiple communication ports may exist. IEC 61850 is based on Ethernet, and Ethernet allows different physical variants. Since the standard and Ethernet is supporting both client-server relations and peer-to-peer communication, any communication topology connecting all related IEDs fulfills the functional requirements. Therefore, the final determination of the communication topology is strongly influenced by constraints, l.e. by non-functional requirements like performance, availability and others.

6.4.7 The Final System

The selected IEDs together with the communication architecture represent the final system. Different solutions are possible. Since all solutions have their functional and non-functional properties and their price tag, a proper trade-off can be made. In case of ordering, the high level data and communication engineering is already made.

Two extreme examples are given in what follows. They include all essential functions from the station level with its station computer and gateway to the network control center down to the process level with conventional and unconventional sensors and actuators, i.e. station bus and process bus features. According to the scope of IEC 61850, details of functions are not discussed but all related communication aspects.

6.4.8 MV system (Example)

Functional requirements are given with no redundant bay protection. The following nonfunctional Requirements apply: Determined hardwired process interface,

switchgear cubicles at one place, prescribed combined protection-control units, average system availability, Indoor switchyard with no separated control room. The result is a SA system with protection independent from any serial communication but with a single

point of failure for the control and information exchange from station level and from remote (see Figure 6). With one switch only and one fiber link per bay, the communication system has a low price tag.

6.4.9 HV system (Example)

Functional requirements are given with redundant bay protection (main 1 and main 2). The following non-functional requirements apply: Determined non- conventional instrument transformers (NCIT) with serial interface via Merging Unit (MU), geographically distributed switchgear (AIS), switchyard kiosks, and high system availability

The communication ring is safe against a single point of failure. With one switch for the operators' place, the NCC gateway and any bay, the communication at station level has a high price tag. As seen in Figure 7, the resulting solution may be applied for GIS also. The LNs allocated to the devices are found in Figure 5.

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