Protection, Control, and Automation System for a Multistation Looped Distribution System

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***Abstract*—This paper describes the protection, control, and automation system developed for a distribution system consisting of 2 generators and 14 substations that are on 3 loops. This project updated the protection and control scheme and added Supervisory Control and Data Acquisition (SCADA) to the site. The design is based on installing multifunctional microprocessor relays at all remote sites and on the corresponding loop circuit breakers in the 13.8 kV switchgear at the Power Plant. Protection is accomplished using programmable functions in each relay and multicast Ethernet messages to mirror data from one relay to others at adjacent substations on each loop. SCADA is accomplished by directly accessing the Human Machine Interface (HMI) and software provided with the relays. A diesel generator transfer-switching scheme was installed that utilizes existing circuit elements with the installation of new digital generator controls and a second peer-to-peer communication method. Control and supervision of generation operation is provided through the HMI. The communication system is made up of a fiber-optic backbone that runs throughout the complex.**

The fiber-optic communication system is the backbone that provides the ability to support the first three of four applications performed by the relay:

1. **Distributed Network Protocol (DNP) LAN/WAN to provide SCADA information to HMI's to monitor and operate the facility.**
2. **Telnet, FTP, and SEL protocol to provide remote engineering access to monitor and set protection devices. These protocols also allow access to oscillography data, sequential event records (SER), and maintenance data from these devices.**
3. **IEC 61850 GSSE, also known as UCA2 GOOSE, to provide Permissive Overreach Transfer Trip (POTT) communications.**
4. **A high-speed, secure protocol is used to perform main bus and tie transfer schemes.**

I. Introduction

A large, industrial customer engaged the services of the ESCO Group to upgrade the protection scheme and design a Supervisory Control and Data Acquisition (SCADA) system for their South 13.8 kV Electric Distribution System. This distribution system is similar to those used in many industrial sites as well as large universities. These contracted services included the design, settings, configuration, and commissioning of these systems. The overall project required automating switching and coordination of the loop circuits supplying industrial loads, control and operation of on-site generators supplying power to each loop bus, and control and automation of utility power supply switching, all integrated into one SCADA system with a Human Machine Interface (HMI) for electric department operations. The generator transfer switching for the two 3750 kW generators required installing new electronic engine controls, a new protective relay interface, and integrating the controls into the SCADA network. Communication among devices was designated to be Ethernet using dedicated fibers of the site's backbone system. The HMI operator information is to be available at any location with Ethernet access to the SCADA network.

In a departure from the typical project sequence of hiring a consultant to design the system, hiring a contractor to purchase materials and install the system, and making the system work after the consultant and contractor have given up, the electric department decided this time the proposed system would be designed, programmed, simulated in a lab environment, and thoroughly demonstrated before installation activities commenced. Furthermore, they wanted to work with a firm that had designed, installed, tested, and commissioned SCADA systems to put all the responsibility associated with the project with one entity. After soliciting proposals from several equipment suppliers whom offered engineering services, the customer selected ESCO Group on the basis of not representing any one particular solution. ESCO Group had demonstrated experience in each aspect of the project and they also had the proximity to support the project after start-up.

The customer's directive to ESCO Group was to use the latest technology with a proven history using as few moving parts as possible that could be maintained with the existing facilities resources. Instead of a "Do it Today" mentality, the customer's philosophy was do it right so that it works when installed.

II. Existing Electric System

The customer's electric distribution system is divided into two distinct distribution systems served from two sources by the regional Investor-Owned Utility. A one-line diagram of the south system is shown in Fig. 1. The 13.8 kV switchgear located at the power suppliers Substation U is owned by the customer. As shown in the one-line diagram, the 13.8 kV switchgear is connected in a main-tie-main bus configuration with local back-up generation. Breaker 1 feeds Bus 4 from Utility Source 1 while Breaker 11 feeds Bus 5 from Utility Source 2. The tie breaker (Breaker 6) is normally open.

Should one of the utility sources be lost, the corresponding main will open and the tie breaker will close to pick up the lost bus. If both sources are lost, the generators connected to Breakers 5 and 7 will come online and feed loads. It is also possible to operate the generators in parallel with the utility source if needed for additional load support.

The feeder breakers connected to the 13.8 kV bus feed a looped distribution system with multiple substations that span the customer's site. Each of these distribution substations has a distribution transformer that is connected between two breakers. One of the breakers is fed from 13.8 kV Bus 4 while the other breaker is fed from 13.8 kV Bus 5. While this type of distribution system provides for increased reliability, protection for this looped system requires more care than a typical radial distribution system.

The switchgear was installed during the late 1980s and has been well maintained, but the electromechanical relaying has become outdated. There was no initial provision for remote operation of circuit breakers or data acquisition. Over the years, the residues of various propriety systems installed to collect load flow information have remained. This project provided the opportunity to remove all this legacy equipment. The remote substations serving the various facility buildings have equipment from a hodge-podge of suppliers. Each loop has grown and been reconfigured as buildings were added or equipment replaced. The electric distribution department can only designate what the configuration of the building electrical supply is to look like. The actual design and selection of distribution equipment is a combination of the engineer-architect hired to design the facility, and the general contractor with the lowest bid to construct the building. Although each substation consists of a breaker on either side of the loop supplying a fused disconnect switch for the building transformer, a variety of manufacturers are represented with protective relaying consisting of the flavor-of-the-day or fire-sale bargains. Loop coordination is achieved by sequencing time-overcurrent settings, starting from the inner most loop working out to the bus circuit breaker supplying the loop in accordance with a scheme that now only exists in the Westinghouse Electric Corporation *Applied Protective Relaying* [1]. Coordination has suffered from diminishing time separation of the protective relay settings, failure to apply the coordination philosophy correctly, inconsistent updates of the relay settings to reflect a change, and a multiplicity of relay types and settings. Consequently, outages require the distribution department to first determine where the fault occurred, physically break the system apart, and restore service sequentially until the fault condition is isolated for repair. This often leads to a one- to two-hour outage, which may have been tolerated 20 years ago, but today, arouses the irritation of the management.

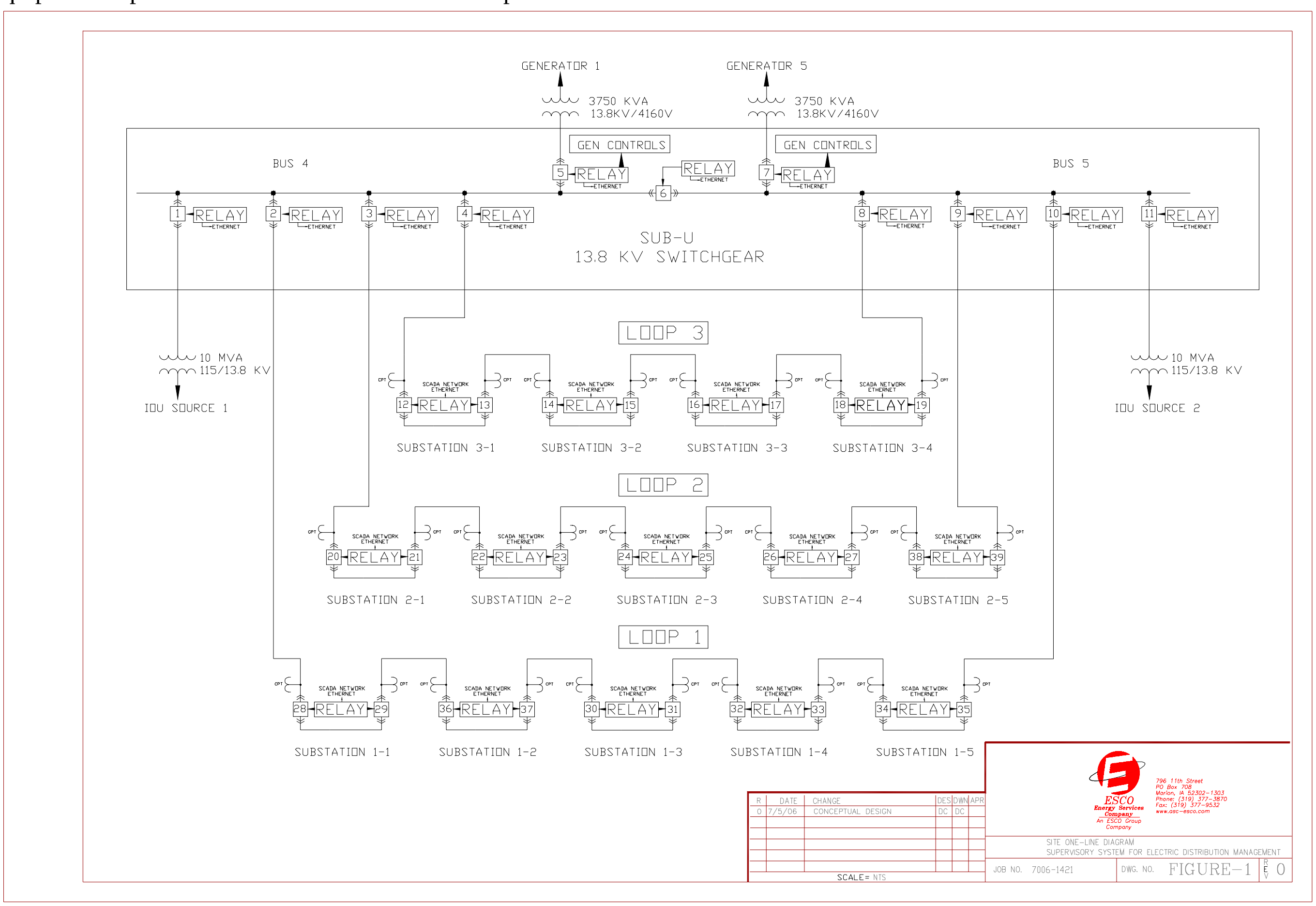


Fig. 1. South Electrical One-Line Diagram

The existing generator controls consist of several refrigerator-sized cubicles covered on the exterior with lights, dials, switches, relays, and meters, and are stuffed full on the inside with relays, transducers, control devices, timers, and more indicating lights, dials, switches, and meters. The modes of operation were intended to support running in parallel with the power source and standby operation for loss of source power. Both generation units do not operate in parallel, even though the same transmission source is supplying both buses, and never seem to operate for a loss of source power.

III. Project Statement

A condensed set of criteria for a new protection and SCADA system are based on the following statements made by the customer:

1. Simplify the protection and control schemes by eliminating a multiplicity of discrete relays and components with one device that can be used to satisfy all required applications. The goal being to reduce training requirements and issues in dealing with different manufacturers. The customer also wanted to reduce the number of protective relay configuration software packages to one.
2. Improve the automatic and manual operations of the system. The existing schemes were either not useful because they were not automatic enough or they were not understood enough by the operators. The requirement of this project was to make these schemes intuitive to eliminate operator mistakes in maintaining the power system.
3. Improve the coordination of the system to eliminate ongoing over-tripping that was being experienced. Thus the requirement was to isolate the fault by dropping the smallest amount of load. They also required that fault location and type data be available without operator intervention from the SCADA HMI to assist them in expediting restoration.
4. Provide the capability to obtain fault event recorder information and sequential event recorder data from anywhere on the SCADA communication network without requiring travel to the relay location.
5. Provide an HMI SCADA system that has two control stations and five view-only stations that can be loaded on a commercial off-the-shelf desktop or laptop computer. This computer should be able to work from any Ethernet connection on the SCADA communication network. They emphasized that this investment in the SCADA system should be able to be supported for a long time so it should not be a proprietary system.
6. All of the communication protocols must run on the customer's fiber system on a dedicated network using Ethernet topology. It will be maintained by the IT department. It was recognized that there would be different speed requirements for different applications. For instance, the pilot scheme requires communication speed in cycles while the SCADA HMI requires update times in seconds. It was required that none of the conversations could degrade the overall performance of its application or of any other application.

IV. System Description (Product Selection)

To properly protect the electric system reliably and be cost effective, a multifunctional relay with flexible logic, multiple current and voltage inputs, and robust communications was needed. The same device should be used, if possible, to protect, control, and automate the following:

- Automatic main-tie-main transfer scheme on the 13.8 kV bus
- Generator breaker synchronizing control and generator protection
- Overcurrent protection for the main and tie breakers on the 13.8 kV bus
- Overcurrent protection for the feeder breakers on the 13.8 kV bus
- Directional overcurrent pilot protection for each of the breakers in the small distribution substations
- Overcurrent protection for the transformer in each of the small distribution stations

The relay selected to protect and automate this system had the following capabilities:

- Configurable operator interface with programmable pushbuttons
- Distributed Network Protocol 3.0 (DNP3) and IEC 61850 GSSE Communications
- Ethernet interface
- Relay-to-relay communication with MIRRORED BITS® communications
- Flexible logic for both protection and automation functions
- Six ac current inputs and six ac voltage inputs to allow protection and control of two breakers
- Up to 23 dc inputs and 38 output contacts available
- Six configurable time-overcurrent elements

The relay features meet the requirements of remote substation control, protection, and automation. Supervisory control and data acquisition are accomplished by directly accessing the devices through a Wonderware® HMI using DNP3 protocol. A software program provided free by the relay manufacturer and loaded on the same computer running the HMI software provides direct access to each relay through the Ethernet SCADA network using FTP, Telnet, and SEL protocols.

Main bus and tie transfer schemes are supported by MIRRORED BITS® communications available on each of three serial ports.

Permissive Overreach Transfer Trip (POTT) communications is supported via an Ethernet multicast message (IEC 61850 GSSE, also known as UCA2 GOOSE). Originally designed as part of the UCA2 protocol suite and given the name GOOSE (Generic Object Oriented Substation Event), the message was merged into the newer IEC 61850 standard and renamed GSSE (Generic Substation Status Event). This was done so that a new message with different capabilities within the 61850 standard could be named GOOSE. Both 61850 GOOSE and GSSE are useful, co-exist on Ethernet networks, and are collectively known as GSE (Generic Substation Events). For the purpose of this specific design, either could have been chosen. Some design selections predated the publication of the IEC 61850 standard and so 61850 GSSE (UCA2 GOOSE) was used. However, if done today, IEC 61850 GOOSE would be recommended. Since both can accomplish this design, further references in this paper use the term GOOSE.

A detailed discussion of each aspect of the project follows.

V. Remote Substations

At each remote substation, there are three zones of protection: two zones of line protection for each incoming source and one zone of transformer protection that feeds the load at each distribution station. While the transformer is fused, it is necessary to protect the bus that the transformer is connected to as well as provide backup transformer protection. Conventionally, three relays would be required to properly protect the station and incoming sources. However, the relay chosen has two sets of current inputs and extensive logic available that, when implemented properly, can protect all three zones with only one relay. Fig. 2 shows the three zones of protection that the single relay will protect at each remote distribution substation.

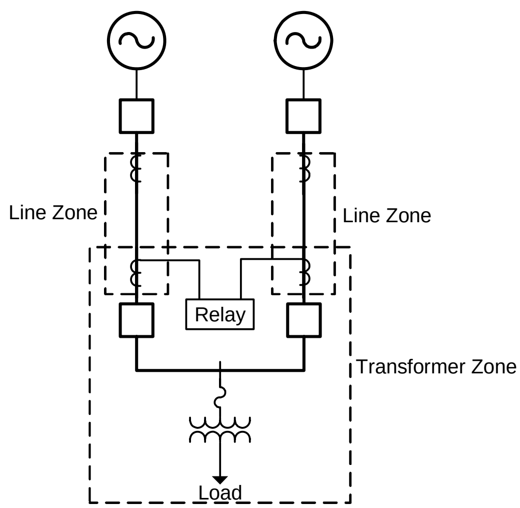
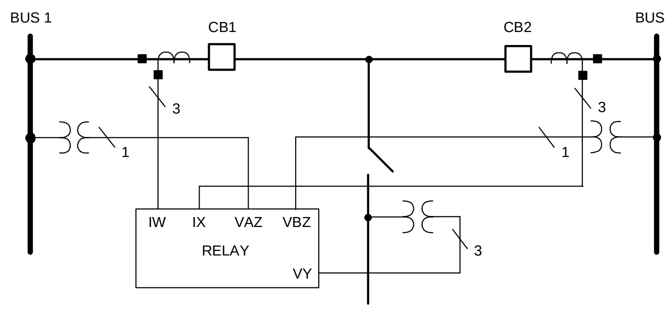


Fig. 2. Relay Protection Zones for Remote Substations

To accomplish the protection needed with one relay, the relay must have the ability to sum currents from each CT to provide transformer protection. Also, each individual CT must be able to protect its respective line as well. Since the line is in a loop scheme, it will be necessary to have a directional comparison scheme on each line to provide the fastest and most secure protection. This will require a directional element for each current input and the ability to communicate with each remote terminal.

The relay selected has settings built in to protect a ring bus or breaker-and-a-half configuration, as shown in Fig. 3. For convention, the manufacturer defines the Breaker 1 current input as IW and the Breaker 2 current input as IX. In this scheme, both current inputs are summed inside the relay to protect the line. However, the internal directional element is also used for this same line protection. So, this configuration allows for protection and metering of the transformer zone using the line protection settings, but it does not offer separate directional overcurrent protection for each line coming into the distribution station.

Fortunately, the relay has flexible logic available that not only includes typical digital logic, but also has the ability to use analog values measured from each voltage and current input. With analog values available for use in the logic, it is possible to create custom protection elements that the user can implement for unique applications. Also, the relay allows the user to select which current quantity the built-in time-overcurrent elements will operate on. There are six available time-overcurrent elements that can be set to operate on the following quantities: line current (IX + IW), Breaker 1 current (IW), or Breaker 2 current (IX). Therefore, an overcurrent element can protect the transformer (IX + IW), another overcurrent element can protect an incoming line (IW), and a third overcurrent element can protect the other incoming line (IX).



Analog Input	Function
IW+IX	Line Protection
IW	Circuit Breaker 1 (CB1) protection
IX	Circuit Breaker 2 (CB2) protection
VY	Line protection
VAZ	Synchronism check Circuit Breaker 1
VBZ	Synchronism check Circuit Breaker 2

Fig. 3. Example of a Relay Configuration Provided by the Manufacturer

An analysis of the direction current flow during a fault in each of the three protection zones is defined below. For convention, forward current flow for each breaker is defined as current into the distribution transformer. In other words, a transformer fault will produce forward current flow in both breakers. A line fault will produce reverse current flow in the breaker that will clear the fault.

Fig. 4 shows a fault on the remote station bus or transformer.

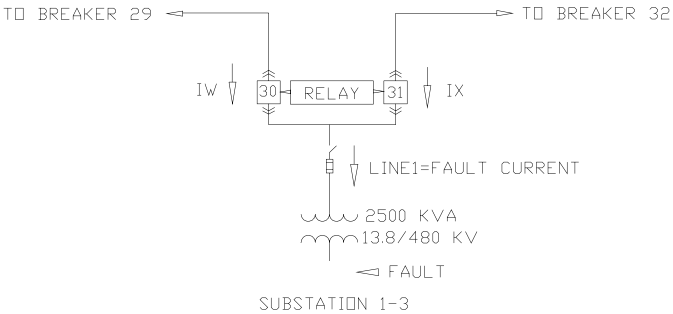


Fig. 4. Fault on Remote Station Bus or Transformer

In this case, the fault current is equal to the relay calculated line current (IW + IX). An overcurrent element (51S1T) will be configured to operate on the line current value and set to coordinate with the fuse for the expected fault current. It will also be set to operate before the feeder breakers on the customer's 13.8 kV bus.

Fig. 5 shows a fault toward Bus 4 in an adjacent line segment.

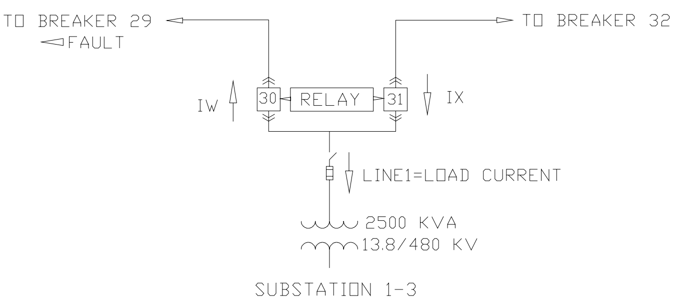


Fig. 5. Fault on Line Protected by Breaker 30

In this case, current will be in the reverse direction for Breaker 30 but current is in the forward direction for Breaker 31. An overcurrent element (51S4) will be set to send permission on reverse IW fault current and also trip Breaker 30 if permission is received from the remote end.

Fig. 6 shows a fault toward Bus 5 in an adjacent line segment.

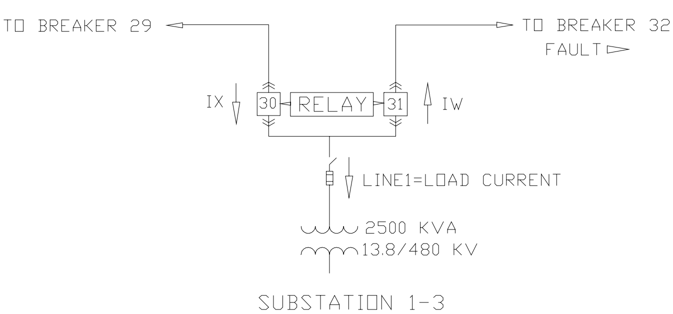


Fig. 6. Fault on Line Protected by Breaker 31

In this case, current will be in the reverse direction for Breaker 31 but current is in the forward direction for Breaker 30. An overcurrent element (51S5) will be set to send permission on reverse IX fault current and will also trip Breaker 31 if permission is received from the remote end.

The overcurrent elements are configured in the standard settings to operate on the appropriate current input value. Overcurrent element 51S4 is set to operate on the maximum phase current IW. Overcurrent element 51S5 is set to operate on the maximum phase current IX. This essentially sets up two non-directional overcurrent elements that look at the line current each breaker sees in the substation. As mentioned above, non-directional elements will not be enough to securely protect this distribution network.

Since the relay is configured such that the internal directional elements can only be used for transformer protection, an alternative must be developed to directionally control time-overcurrent elements 51S4 and 51S5. The analog quantities and math capabilities of the relay allow the application of traditional phase angle calculations to determine the fault direction of IX and IW. Reference [2] shows a 90-degree connected-phase directional element to be implemented and details the polarizing and operating quantities.

Sonnemann describes the popular 90-degree connected-phase directional element [3]. Table I lists the operating and polarizing quantities of these elements.

TABLE I
INPUTS TO THE 90-DEGREE CONNECTED-PHASE DIRECTIONAL ELEMENT

Phase	Operating Quantity (I_{OP})	Polarizing Quantity (V_{POL})
A	I_A	$V_{POLA} = V_{BC}$
B	I_B	$V_{POLB} = V_{CA}$
C	I_C	$V_{POLC} = V_{AB}$

The following equations represent the torque (T_{PHASE}) calculations for each 90-degree connected-phase directional element:

$$T_A = |V_{BC}| \bullet |I_A| \bullet \cos(\angle V_{BC} - \angle I_A) \quad (1)$$

$$T_B = |V_{CA}| \bullet |I_B| \bullet \cos(\angle V_{CA} - \angle I_B) \quad (2)$$

$$T_C = |V_{AB}| \bullet |I_C| \bullet \cos(\angle V_{AB} - \angle I_C) \quad (3)$$

where:

I_A, I_B, I_C = Phase A, B, and C currents, respectively.
V_A, V_B, V_C = Phase A, B, and C voltages, respectively.
V_{AB}, V_{BC}, V_{CA} = voltage differences $V_A - V_B$, $V_B - V_C$, and $V_C - V_A$, respectively.

Each directional element declares a forward fault condition if the torque sign is positive and a reverse fault condition if the torque sign is negative.

As can be seen from (1)–(3), a torque quantity is generated for each phase using the current and voltage from the other two phases. For a Phase A-to-ground fault, this cross polarization scheme will produce a high torque quantity since Phase A current will be high and the phase-to-phase BC voltage should be unaffected.

Under perfectly balanced voltage and a unity power factor condition, the torque developed for Phase A will be zero. The angle between V_{BC} and I_A will be exactly 90 degrees and the cosine of 90 degrees is 0. Therefore, regardless of the magnitude of the V_{BC} voltage or Phase A current, the torque output is zero.

For a forward Phase A-to-ground fault, I_A current lags Va voltage, which makes the angle difference between V_{BC} and I_A less than 90 degrees. Taking the cosine of an angle less than 90 degrees will produce a positive torque value. For a reverse Phase A-to-ground fault, I_A current leads Va voltage, which makes the angle difference between V_{BC} and I_A more than 90 degrees. Taking the cosine of an angle greater than 90 degrees will produce a negative torque value. In summary, a positive torque is current in the forward direction; a negative torque is current in the reverse direction.

The cosine operator determines the directionality or sign of the torque value, but the magnitude of voltage and current multiplied together give the torque its magnitude. It can be seen that for a Phase A-to-ground fault, the torque value for Phase A will be much larger than the torque values for the unfaulted phases. In general, the phases involved in the fault will generate the largest torque values.

In an electromechanical scheme with directional torque control, each phase had a dedicated overcurrent element that was controlled by its directional polarizing quantity. Therefore, if there was a forward Phase A-to-ground fault, only the Phase A relay could operate for the fault because it was the only phase with enough current to spin the induction disc. Even though the induction disc may not have spun on the two unfaulted phase overcurrent relays, the directional torque control may have still determined a direction, and quite possibly, the wrong direction. During a Phase A-to-ground fault, the unfaulted phases, which are still carrying load, are unreliable and cannot be used. Due to this, the torque quantity of the faulted phases must be used in determining the direction of the fault.

In a digital relay, all three phases are available which can sometimes lead to unexpected problems. The overcurrent element being used in the digital relay is a three-phase element, which means it asserts if any phase current becomes greater than the set point. Once that overcurrent element asserts, the faulted phase(s) are not known, therefore, the torque quantity that needs to be used is also not known.

One way to solve the problem is to set up a "fault detector" in the logic. This would require taking the pickup setting of the overcurrent element and putting it into the logic to supervise the torque control. This would operate similar to the electromechanical scheme mentioned earlier where only the torque of the faulted phases is used. The disadvantage of doing this is that the overcurrent pickup setting must now be entered in the logic. It is conceivable that this setting could be forgotten or not updated properly as new settings were issued and lead to undesirable operation of the directional element.

Another option is to compare the torque quantities the relay calculates during the fault and use the largest absolute torque value to determine direction. By using the torque comparison method, no additional fault detectors are needed, and more importantly, the faulted phase(s) will determine the direction of the fault. The logic for winding IW is shown in Fig. 7 (the logic for winding IX is similar).

```
PROTSEL24   #PSV10 INDICATES BUS VOLTAGE IS NOT HEALTHY FOR POLARIZATION
PROTSEL25   PSV10 := VABYM < 1 AND VBCYM < 1 AND VCAYM < 1

PROTSEL26   #TORQUE IS POSITIVE IF FAULT IS FORWARD
PROTSEL27   #TORQUE IS NEGATIVE IF FAULT IS REVERSE

PROTSEL28   PMV01 := VBCYM * IAWM * COS(VBCYA - IAXA) #TORQUE A
PROTSEL29   PMV02 := VCAYM * IBWM * COS(VCAYA - IBXA) #TORQUE B
PROTSEL30   PMV03 := VABYM * ICWM * COS(VABYA - ICXA) #TORQUE C

PROTSEL31   #FIND THE ABSOLUTE VALUE OF EACH TORQUE
PROTSEL32   PMV04 := ABS(PMV01)  #|TORQUE A|
PROTSEL33   PMV05 := ABS(PMV02)  #|TORQUE B|
PROTSEL34   PMV06 := ABS(PMV03)  #|TORQUE C|

PROTSEL35   #FIND THE LARGEST ABSOLUTE TORQUE
PROTSEL36   PSV04 := PMV04 >= PMV05 AND PMV04 >= PMV06 #|TORQUE A| IS LARGEST
PROTSEL37   PSV05 := PMV05 >= PMV04 AND PMV05 >= PMV06 #|TORQUE B| IS LARGEST
PROTSEL38   PSV06 := PMV06 >= PMV04 AND PMV06 >= PMV05 #|TORQUE C| IS LARGEST

PROTSEL39   #DETERMINE IF THE LARGEST |TORQUE| IS NEGATIVE
PROTSEL40   PSV07 := PMV01 < 0 AND PSV04 #TORQUE A IS NEGATIVE AND LARGEST
PROTSEL41   PSV08 := PMV02 < 0 AND PSV05 #TORQUE B IS NEGATIVE AND LARGEST
PROTSEL42   PSV09 := PMV03 < 0 AND PSV06 #TORQUE C IS NEGATIVE AND LARGEST

PROTSEL43   #IF PSV11 ASSERTS, THE LARGEST |TORQUE| IS NEGATIVE
PROTSEL44   PSV11 := (PSV07 OR PSV08 OR PSV09) AND NOT PSV10

PROTSEL45   #ADD A DEFINITE TIME DELAY TO THE OC ELEMENT
PROTSEL46   PCT01IN := 51S4
PROTSEL47   PCT01PU:= 1 #ADD A ONE CYCLE DELAY

PROTSEL45   PSV02 := PCT01Q AND PSV11 #FAULT DETECTED IN THE REVERSE DIRECTION
```

Fig. 7. Directional Element Logic

Notice that lines PROTSEL28–PROTSEL30 match the formulas given for the 90-degree connection in (1)–(3). The manufacturer defines the following analog quantities that are used in this application as follows:

- VBCYM, VCAYM, VABYM: Phase-to-phase filtered instantaneous voltage magnitude in volts secondary
- IAWM, IBWM, ICWM: Terminal W phase-filtered instantaneous current magnitude in amps secondary
- VCBYA, VCAYA, VABYA: Phase-to-phase filtered instantaneous voltage angle in degrees
- IAWA, IBWA, ICWA: Winding (IW) filtered instantaneous current angle in degrees

To add security to the directional element, the operate time of any instantaneous element must be delayed one cycle to allow time for the relay's filtered values to determine the proper fault direction.

This directional element was tested for common type faults in the lab using system impedance values from the customer and operated reliably. However, a close-in three-phase fault can disable the directional element since there is no voltage memory polarization and backup tripping will be needed to clear this type of fault. Roberts and Guzman also detail the possibility of 90-degree directional element misoperation if only a zero-sequence source is located behind the relays [2]. In this distribution system, however, it is highly unlikely that a zero-sequence-only source could become available. Also, for a very high, resistive phase-to-ground fault, the largest torque quantity may not be on the faulted phase. However, this type of fault would be very difficult to detect with traditional overcurrent elements and is not considered a problem in this application since only phase overcurrent elements are being used. Sensitive ground overcurrent elements would require additional design and testing.

As can be seen, the performance of any directional element must be evaluated before applying them to a certain system. In this system and scheme, the shortcomings of the element should not affect the reliability or security of the scheme. However, in another system or another scheme, this element may be deemed unacceptable for use.

VI. Implementation

From the logic in Fig. 7, it can be seen that PSV02 is the reverse fault detected bit. When this bit is combined with a permissive signal supplied by GOOSE messaging from adjacent relays, the breaker will trip. PSV02 is also used to generate GOOSE messages to be sent to the relays in the loop multicast group as a permissive to trip in the POTT scheme. Fig. 8 shows an example of how the whole scheme works.

For the fault in Fig. 8, the objective is to open Breakers 15 and 16 to isolate the fault. When Breaker 4 sees fault current, the backup time-overcurrent setting is picked up and begins timing. Breaker 12 is not sending a GOOSE message to trip Breaker 4 because the fault current is in the forward direction, not the reverse as defined earlier. Through GOOSE messaging, Substation 3-1 is indicating a through fault and Breaker 13 is telling Breaker 14 it's got a reverse fault current and is looking for permission to trip. Substation 3-2 is indicating a through fault, and Breaker 14 is not sending a GOOSE message to Breaker 13 to trip because the current is in the forward direction. Breaker 15 is indicating a reverse direction fault and is sending permission to Breaker 16. Breaker 16 is responding in kind, and both receive the GOOSE permissive to trip and isolate the fault. The entire process takes about 11 cycles with a 1-cycle delay on the definite overcurrent element, less than 5 cycles for GOOSE messaging, and 5 cycles for the breakers to open. Breaker 8 is undergoing the same crisis as Breaker 4, but both backup 51S1T elements drop out before timing out.

That all worked well enough, but what if one breaker is already open? GOOSE messaging also lets Breaker 15 know if Breakers 16 and 17 are open or closed, and an open state is used as a permissive to trip Breaker 15 for a reverse fault condition. Since the loops are relatively small, an added layer of protection is provided by backup definite time-overcurrent settings enabled for a reverse fault condition that persists beyond 30 cycles. These elements are coordinated with the backup time-overcurrent settings in the loop supply breakers to allow a remote breaker to operate before a bus breaker.

The control schematic for breaker control at the remote substations can be seen in Fig. 9.

The trip logic and relay bit assignment within the GOOSE message can be seen in Fig. 10.

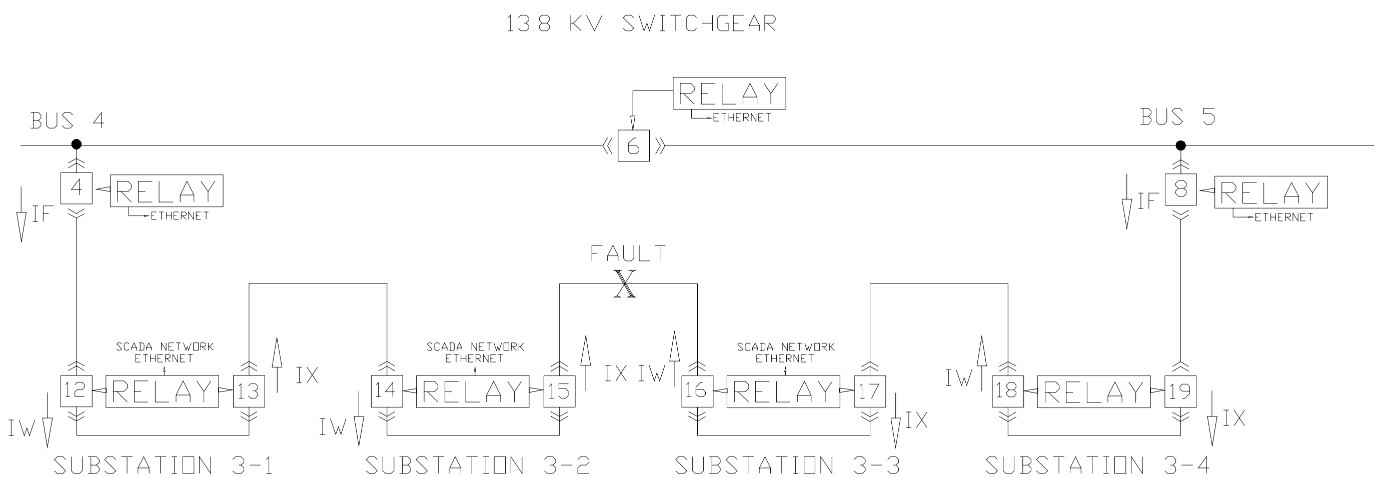


Fig. 8. System Fault

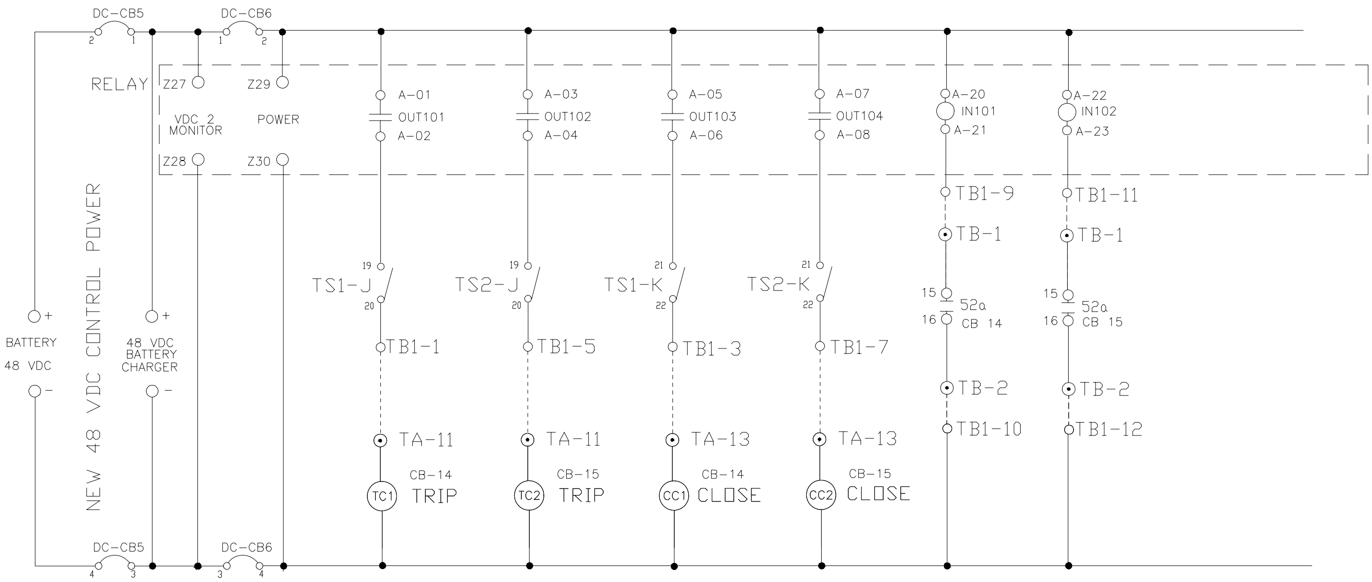


Fig. 9. DC Breaker Control Schematic

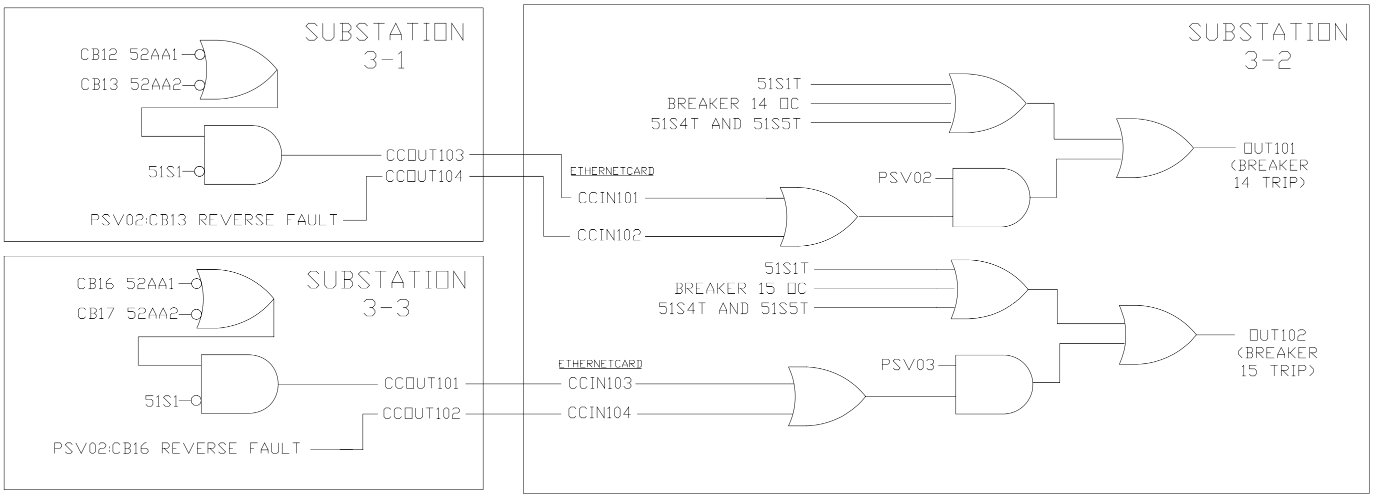


Fig. 10. Breaker Trip Logic

Note that the CCOUT word bits are set with logic statements similar to relay outputs and the CCIN word bits are assigned by addressing. The word bits updated on a change of state only.

Word bits used in Fig. 10:

- 51S1T: Transformer time-overcurrent protection
- OC: Serial port open command issued
- 51S4T and 51S5T: Line protection time-overcurrent backups

The final installation will have an outdoor enclosure with the relay mounted with test switches, shorting blocks for existing instrument current transformer circuits, and fuses for existing potential transformer circuits. Control power will be provided by a sealed battery and charger and utilize the relay alarm function for low dc voltage. An interposing relay will be provided for trip and close circuits for the existing circuit breakers at the remote sites. Synchronism check will be provided by the relay by a contact wired in series with the close output. A local/remote switch function is provided by the programmable operator buttons. Up to 12 programmable pushbuttons are available as well as a trip/close control switch that is independent of the relay power and logic as shown in Fig. 11.

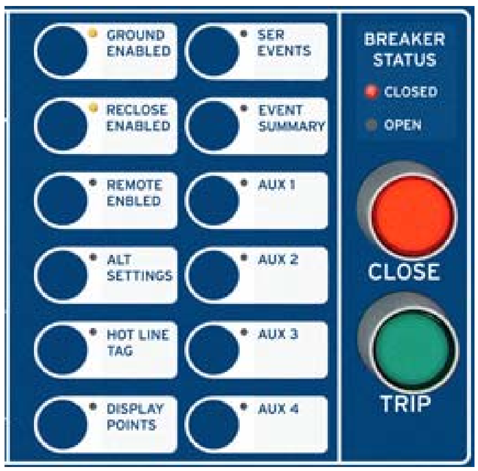


Fig. 11. Local Breaker Control Panel

VII. Substation U Switchgear

The substation 13.8 kV switchgear installation is different than the remote sites since only one circuit breaker is controlled by the relay using a standard one-breaker configuration. However, the main and tie-breaker relays are also used to implement an automatic transfer scheme.

The main breakers have time-overcurrent settings coordinating with the time-overcurrent settings of the loop breakers and an instantaneous setting to detect bus fault conditions. The bus fault condition is used to supervise the autosource transfer of the bus-tie breaker so that the tie is never allowed to close into a bus fault. When the generator breakers are closed, additional settings are enabled in the main relays for under/overvoltage, under/overcurrent, and reverse power.

The automatic transfer scheme is implemented using the logic available in the relay as well as using relay-to-relay communications. The local control of the scheme is accomplished through the programmable pushbuttons on the relay as shown in Fig. 12.

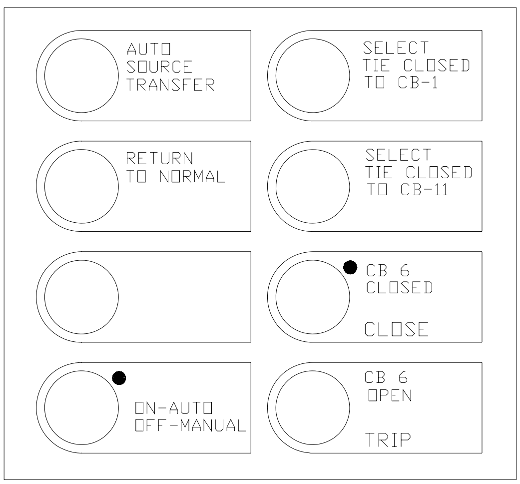


Fig. 12. Automatic Transfer Pushbuttons

The following items describe how the pushbuttons are used in the automatic transfer scheme:

- Auto/Manual Mode
  When the scheme is in Auto mode, closed transition bus-tie operations are enabled and breaker close pushbuttons are disabled. When the scheme is in Manual mode, all automatic and remote operations are blocked, however, manual closing of breakers via pushbuttons are allowed.
- Automatic Operations
  The following operations can only be performed when the scheme is in Automatic mode:
  - Automatic Source Transfer

    An automatic source transfer occurs when one utility source becomes unhealthy for a configurable amount of time while the other utility source is still healthy. Once the source is determined unhealthy, the associated main opens to isolate the facility from the failed source. Once the relay determines the associated bus is dead, the tie will close. All load at the complex will be fed via one utility source in the transferred state.
  - Return to Normal

    For a retransfer to the normal state, the failed source must become healthy for a configurable amount of time. Once the source is healthy, operator action (press the Return to Normal pushbutton) is used to close the main and then open the tie. The relay determines that the source is healthy and in sync before the main is closed.
  - Utility 1 Source Transfer

    This pushbutton allows the user to transfer the entire load at the facility over to Utility Source 1 on CB-1. The tie breaker will close to parallel both sources if they are in sync and then CB-11 opens to remove the Utility 2 source. This operation is blocked if a generator breaker is closed. The scheme can be reconfigured to the normal state by pressing the Return to Normal pushbutton.
  - Utility 2 Source Transfer

    This pushbutton allows the user to transfer the entire load at the facility over to Utility Source 2 on CB-11. The tie breaker will close to parallel both sources if they are in sync and then CB-1 opens to remove the Utility 1 source. This operation is blocked if a generator breaker is closed. The scheme can be reconfigured to the normal state by pressing the Return to Normal pushbutton.

Due to installation constraints, MIRRORED BITS® communications protocol was used for the autotransfer scheme. Fig. 13 shows the MIRRORED BITS® communications scheme that was used to exchange status and control between the 13.8 kV switchgear to implement the autosource transfer. As can be seen from the diagram, all the information needed to perform or block transfers is transmitted so each relay can determine when operation is necessary.

The proposed installation is to have new door panels manufactured with cutouts for the relay, test switch, and generator controller for the generator breaker cubicles. The new door panels will be wired off-site. Installation on-site will require removing the existing doors and wiring back to terminal strips, installing the new door panels on existing hinges, and wiring current, potential, and control circuits. Each loop breaker can be done on one bus while remote sites are powered from the other bus. The bus-tie can be closed, and a source interconnection breaker can be retrofitted. The tie breaker will be done last. All relay settings and control programming have been developed and tested in advance of the installation.

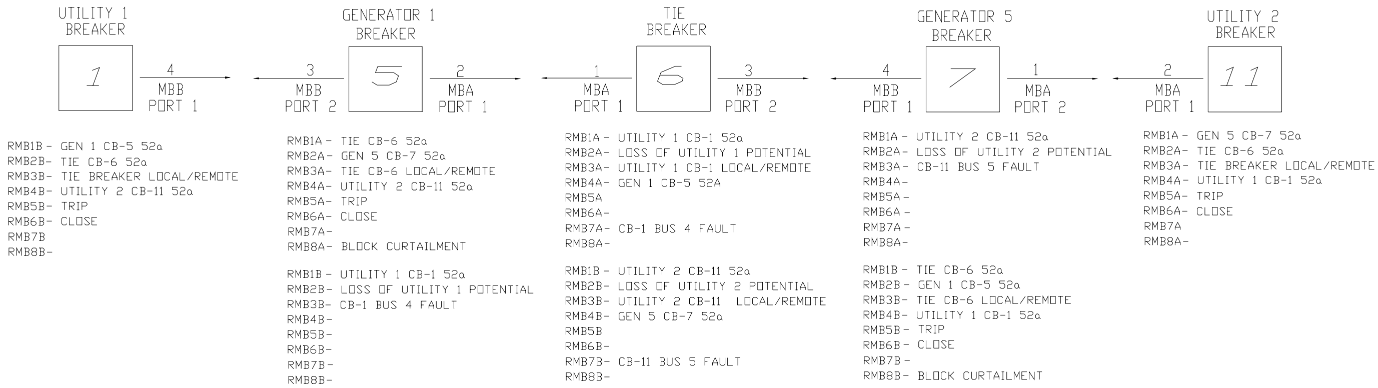


Fig. 13. Automatic Source Transfer Logic

VIII. Generator Controls

The same relay used in the loop scheme and main breaker protection also provides the generator protection and control logic for selecting modes of operation. Because the relay does not have the ability to supply an analog output for driving a governor signal, ESCO initially had thought of using a programmable automation controller with analog outputs. This concept was abandoned in favor of using a generator controller that provided preprogrammed functionality. The generator protection relay provides the operator interface and hardwire interconnects to drive the Woodward GCP, as shown in Fig. 14.

The digital controllers start the engine, parallel the generator to the 13.8 kV bus, and drive the governor for load control. The digital controller loads the engine up to the generator rating as determined by operator input for parallel operations. The digital controller provides generator protective functions, alarming, and monitors currents and potentials. The relay selects the operating mode and operates the utility breakers accordingly. The relay also provides generator protection including a differential circuit (not shown) that wraps the generator, step-up transformer, and circuit breaker.

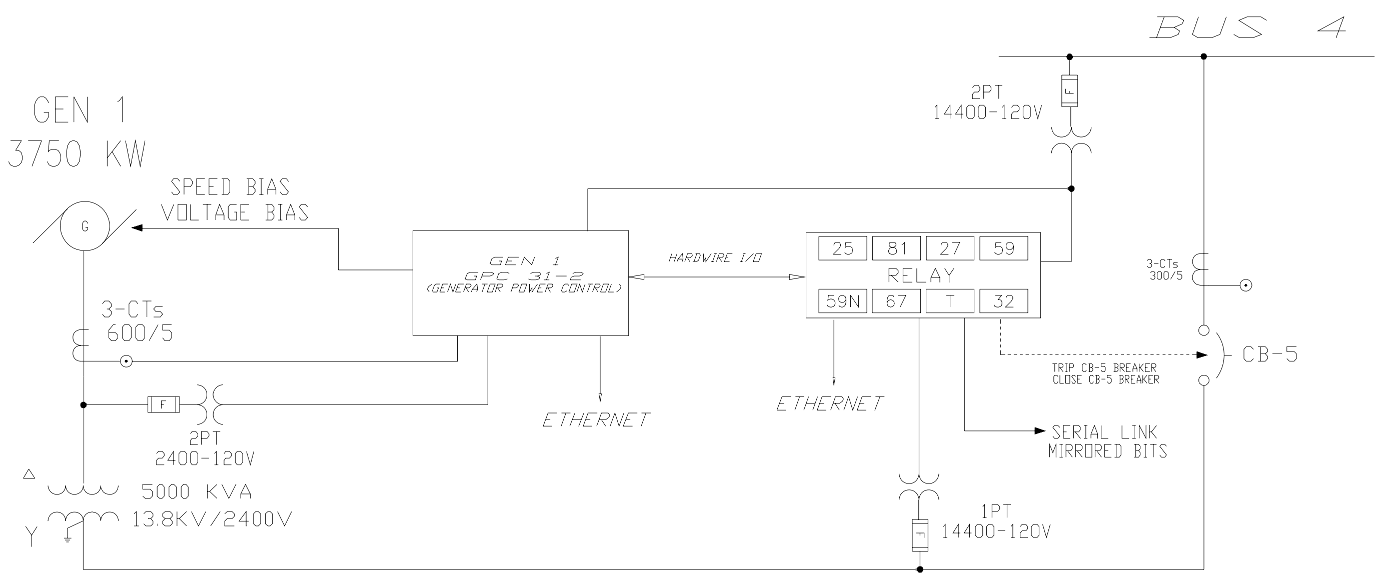


Fig. 14. Hardware Interconnections for Generator Controls

Operating modes for the system are as follows:

- Standby: Normal operating mode where a loss of source potential or condition other than a bus fault causes the main breakers to open—both have to open to instigate a standby condition. The loop breakers open to isolate loads from the bus and the tie breaker closes to form a generator bus so all generation capacity is available for load pickup. The first generator breaker closes to the bus and the second is paralleled to the first. The loop breakers are then closed sequentially. If the load on each main was greater than the generator capacity right before the outage occurred, one loop is not given the permission to reclose after the generators restore bus voltage. The loop that is left last to close is selectable, and the last loop closure also has underfrequency settings enabled for an outage operation that will trip if the generator frequency is pulled down for longer than two seconds. The maximum previous load is stored in the main breaker relays using math variables and an inequality statement in the logic is used to determine if the last loop should be closed. When the source returns, the generators parallel to one utility source and that breaker is closed, then the other utility breaker is closed. The tie breaker is opened and the generators are soft unloaded and the generator breakers open.
- Isolate: Operator-selected mode will start both generators in parallel with the utility sources. The tie breaker is closed and the load is transferred to the generators. When the power flow across the utility is zero, the utility circuit breakers open. When the operation is cancelled, the combined bus is synchronized to one utility source in the same manner as a return from Standby.
- Base Load: Operator-selected mode will start both generators in parallel with the utility sources. Both generators will be loaded to the operator-set value up to the rating of the generator. When the operation is cancelled, both generators will unload and open the generator breakers.
- Curtailment: Operator-selected mode will start both generators in parallel with the utility sources. Both generators will be loaded to reduce the imported power to the set demand level. When the operation is cancelled, both generators will unload and open the generator breakers.

Again, the generator relay has sufficient programming capabilities to implement these operations. The programmable operator pushbuttons are used as the manual interface, with the same control interface available from the HMI.

IX. Communications System

Even though there is only one multifunctional relay that is being used for all these schemes, there are four different communication protocols being utilized within it to accomplish all the necessary functions. These protocols and their functions are:

- DNP3 LAN/WAN is being used to provide data to the SCADA system
- GOOSE is being used for high-speed communications between relays for the pilot protection scheme
- Telnet is being used for providing terminal access to any of the multifunctional relays
- MIRRORED BITS® communications is being used for the automatic transfer scheme

DNP3 LAN/WAN is a SCADA protocol, which was developed for use in telecontrol applications. The protocol has become popular for both local substation data collection and telecontrol. DNP3 is one of the protocols included in the IEEE *Recommended Practice for Data Communication between Remote Terminal Units and Intelligent Electronic Devices in a Substation* [4].

Rather than wiring individual input and output points from a station Remote Terminal Unit (RTU) to the station Intelligent Electronic Devices (IEDs), DNP3 is used to convey this same measurement (binary and analog) and control data directly to the SCADA master via data communications. This reduced the equipment and wiring requirements. In turn, this reduced installation, commissioning, and maintenance costs while increasing remote control and monitoring flexibility.

The multifunctional relay chosen for this project supports both serial and LAN/WAN implementations of DNP3. LAN/WAN was selected because using the Internet protocol suite as a transport mechanism for DNP3 provides seamless integration of the SCADA LAN to the customer's WAN. It permitted use of existing backbone equipment with minimal need to install additional equipment or wiring. Plus it is highly scalable for future growth of the network. One of the big advantages of using Ethernet is the ability to support multiple protocols over the same communication media. Thus, DNP3 LAN/WAN, GOOSE, FTP, and Telnet are all supported using the same communication equipment and wiring. The growth of the Internet has stimulated the large availability of networking equipment and technology, which has proved that the IP protocol suite is capable of transporting tremendous quantities and types of data.

The GOOSE capability of exchanging binary data very quickly between multiple devices in a multicast method made it very attractive for doing the POTT communications in this project.

Telnet is part of the TCP/IP protocol suite. Telnet can establish terminal access to a remote device. A Telnet connection provides access to the user interface of either the host or the Ethernet card. Host user interface access is similar to an ASCII terminal connection to the front port of an IED. Since the relay configuration software supports Telnet connections, this was a big advantage to the customer. This software not only supports settings, it also has a built in HMI that is very useful in commissioning and troubleshooting. It also has tools that allow the user to send commands, display event histories, and retrieve event reports. Using the built-in event waveform view allows engineering to quickly analyze fault records and relay element response. With the facilities' communication network, all of this can be done from anywhere on the complex.

MIRRORED BITS® communications protocol is used for the automatic transfer scheme. With this protocol, protective relays and other devices can directly exchange serial information quickly and securely without the need for any external equipment. This protocol accomplishes the reliable exchange of critical data using a simple and effective method to communicate the state of eight logical bits of information between IEDs. This protocol is also capable of transmitting up to seven analog values between IEDs. This protocol also supports comprehensive diagnostic messages. Thus, when there is a communication issue, that issue is reported to the remote operator almost instantaneously. There are also extensive communication logs available to easily troubleshoot the communication issue.

The multifunctional relay specified in this project has a built-in Ethernet processor that supports many protocols including DNP3, GOOSE, Telnet, and FTP. The Ethernet interface processes incoming GOOSE messages and delivers them to the relay quickly so that word bit state changes are processed in milliseconds. GOOSE messages are published when the contents change or to verify channel integrity to the other peers on the network. Ultimately, each device processes only the messages it is configured to use. Configuration parameters allow configuration of the system to manage GOOSE traffic and processing burden.

The customer's backbone fiber system is a single-mode fiber system consisting of several 24-fiber bundles. The electric department allocated one 24-fiber bundle. Six fibers are assigned to the SCADA network and those are extended to each remote site by installation of six strand, single-mode, direct bury fiber from existing splice points. The proposed arrangement is shown in Fig. 15. At the time this system was developed, the Ethernet interface only supported multimode fiber-optic compatibility, so a media converter was used to connect to the network.

The trial devices were supplied with a network port 10/100BASE-T option using a CAT 5 cable and an RJ-45 connector to the media converter. To simulate the actual SCADA network conditions, the media converter was connected to a single-mode fiber, which was connected to a fiber panel, then to another fiber, which in turn was connected to an Ethernet switch. From the Ethernet switch, fiber was used to connect to another Ethernet switch using a media converter. In lab tests over this network, 30 cycles were shown more than sufficient to exchange all the POTT-required GOOSE messaging with six relays in a multicast group.

X. HUMAN MACHINE INTERFACE (HMI)

The supervisory HMI package selected was from Wonderware. This is the software package that provides capability to develop customized screens to allow the remote personnel to monitor and control the power system. In addition, a DNP3 I/O Server from Imperious Technologies was used to gather the information from the various multifunctional relays using DNP3 LAN/WAN and converting the data to Suitelink. Suitelink, in turn, interfaces to Wonderware. A Dell™ tower computer was selected as the platform of choice, because the client uses the same machine in other HMI applications and feels the computer can be changed as the technology changes without sacrificing much of an investment. The greater cost is in the software license, screen development, and programming, all of which are transportable to some degree or can be upgraded over time. A 3000-tag license was selected to allow for further development beyond the initial installation, which consumed almost 1000 points. Because both master control stations were to be placed in control room environments and because none of the functions in the HMI were deemed critical, no "hardening" was felt to be necessary. The software application can be loaded on another machine in minutes, and with two control stations at different locations, both failing simultaneously is not expected. The HMI is not critical to the operation of the system, and all HMI functions can be performed locally at the relay location.

DNP3 has many features that help it obtain maximum possible message efficiency. These features optimize the use of bandwidth and maximize performance. DNP3 event data collection eliminates the need to use bandwidth to transmit values that have not changed. Event data are records of when observed measurements changed. For binary points, the remote device logs change from logical 1 to logical 0 and from logical 0 to logical 1. For analog data, the remote device logs a change only when that value exceeds a dead-band limit. DNP3 remote devices collect event data in a buffer that the master can either request or the relay can send to the master without a request message. Data sent from the remote to the master without a polling request are called unsolicited data. The multifunctional relay allows the development of custom DNP3 maps, so that the amount of polling is even further reduced by looking at a smaller subset of all the information available. The concern was to keep routine communications traffic at a minimum for coordination messages. The general consensus during development was DNP3 is much faster than Modbus®.

The intent of the HMI is to show, at a glance, the current state of all the breakers and if each line section has voltage. The HMI also allows remote control of circuit breakers and provides metering information. Additional information, such as currents, voltage, kW load, alarms, and fault event data, is available through accessing additional screens. An overview screen of the whole system similar to Fig. 1 is the default HMI display. Clicking on an object drills down to the control elements and data displays. Operating breakers requires two distinct operator actions including entering an employee number assigned by the customer. Present alarms show up at the bottom of any page and are archived in an alarm summary. The operator control screens mimic the front panel of the relays. Trending is a popular application of Wonderware, so additional screens track voltage profile and power usage. The generator controls have a separate screen. Event and waveform analysis software is used to access individual relays one at a time.

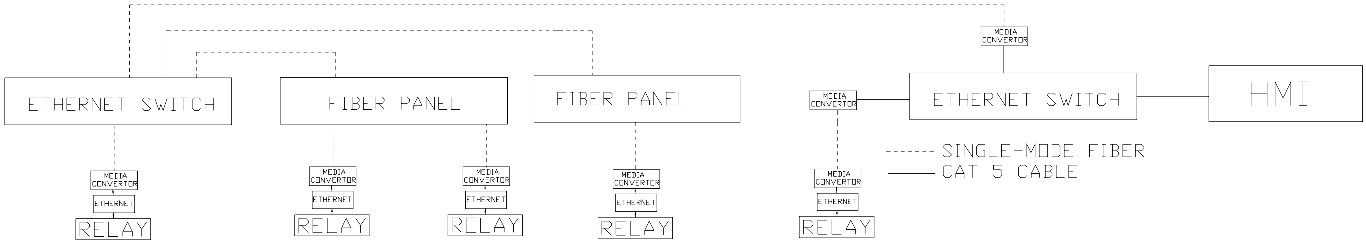


Fig. 15. Ethernet Communication Network

The HMI provides an operator interface for generator mode control and loading control, as well as generator information and operating alarms. Generators may be started and stopped from the HMI, and the mode of operation selected remotely. The standby function may be enabled or blocked remotely. Further development may take advantage of the Ethernet capability of the Woodward devices to set control parameters and obtain alarms.

The view-only licenses offer access from a server connected to the SCADA network that is provided an IP address. The view-only access is limited to five connections and can be password protected to prevent unauthorized use. The view-only access does not allow circuit breaker control. Other control actions allow resetting the meter functions and remote resetting of targets. The system is not manned, but intended for checking system status, responding to system events, fault analysis, and periodic metering functions. The computers running the HMI application are actually used for other applications.

Fig. 16 shows what the HMI screen for a remote substation looks like.

XI. Conclusions

The customer is very happy with the results of this project. The use of a single, multifunctional, microprocessor-based relay resulted in a dramatic reduction in the number of discrete devices. Utilizing this relay, along with the communication scheme, greatly improved the protection of this system and allowed them to install a very powerful SCADA system for very little cost. They believe that the new design will greatly improve the overall reliability of their system because of the significant reduction in individual devices that were converged with one device. They expect a reduction in maintenance requirements as a result of these changes as well. The system is also a lot more flexible because changes can be easily made in logic rather than adding components and wiring.

Due to the flexibility of the relay and analog logic available, one relay was able to protect two lines in a POTT scheme as well as protect a transformer at each distribution station. This type of protection would traditionally require three separate relays. For the 14 distribution installations in this network, using one relay instead of three led to purchasing 28 fewer relays and a significant cost savings.

The SCADA system provides much more measured information about the power system than the customer ever had previously. Not only does the customer now have the capability of remotely monitoring their power system, but they can now reconfigure and restore power remotely resulting in manpower savings and reducing outage time. The customer was not aware of the functionality, the amount of information available, and the simplicity of operations by having the remote operator interface match that of the local operator interface.

Another benefit that is being used is the ability to get engineering access data, for example, fault event reports, from anywhere on their communication network. They are using the information from the multifunctional relays to ensure that their protection and automation schemes and settings are correct.

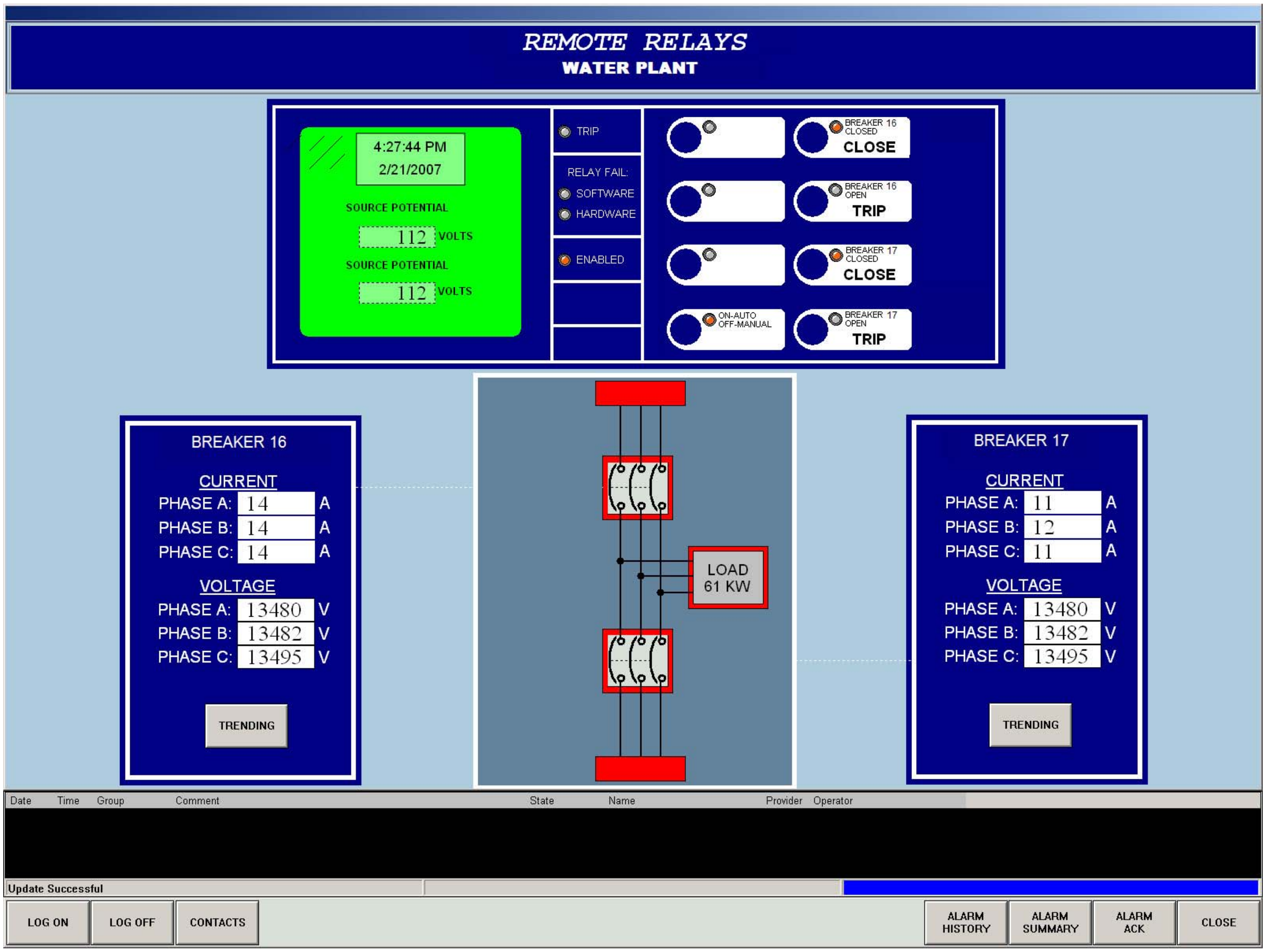


Fig. 16. Example SCADA HMI Screen

XII. References

[1] Westinghouse Electric Corporation, *Applied Protective Relaying*. Florida: Westinghouse Electric Corporation, 1982.

[2] J. Roberts and A. Guzman, "Directional Element Design and Evaluation," in *1994 21st Annual Western Protective Relay Conference Proceedings*.

[3] W.K. Sonnemann, *A Study of Directional Element Connections for Phase Relays*, vol. 69. AIEE Transactions, 1950, pp. 1438–1451.

[4] *Recommended Practice for Data Communications Between Remote Terminal Units and Intelligent Electronic Devices in a Substation*, IEEE 1379, Sep. 2000.

XIII. BIOGRAPHIES

David Charles earned his B.S. in Electrical Engineering from the University of Iowa in 1980. In 1980, he was employed by Stanley Consultants, where he was a Project Manager/Electrical Engineer in the Transmission and Distribution department. At Stanley Consultants, his responsibilities included engineering design of power generation facilities, industrial power plant facilities, electrical substations, switchgear selection, protective device settings and coordination, conductor selection and routing, distribution and transmission line design, SCADA and instrumentation installations, specification and selection of electric power distribution systems and utilization equipment, and load management system specification and installation. In 1996, he took a position at ESCO Energy Services as a Project Manager. His responsibilities include managing projects and services for industrial, municipal, and utility clients and providing complete solutions from conceptualization to installation for all types of energy supply, transmission, distribution, and utilization equipment and facilities. Mr. Charles is a registered professional engineer in the state of Iowa.

Ryan R. McDaniel graduated from Ohio Northern University in 2002 with a B.S. degree in Computer Engineering. Prior to graduation, Ryan began working for American Electric Power in Findlay, OH, as a relay technician. After graduation, Ryan returned to American Electric Power in Columbus, OH, and worked in the Station Projects Engineering group where he focused on substation design work and also worked in the System Protection group focusing on line protection settings. In October, 2005, Ryan was hired at Schweitzer Engineering Laboratories, Inc. in Bellville, IL, as an Associate Field Application Engineer. His responsibilities include providing application support and technical training for protective relay users.

Michael J. Dood earned his B.S. in Electrical Engineering from Michigan Technological University in 1979. In 1979, he was employed by Wisconsin Electric Power Company (WEPCo), where he was a Senior Engineer in the Distribution Automation Group. His responsibilities at Wisconsin Electric included substation automation design and implementation, distribution automation, and SCADA. He also has over 15 years of experience in substation design and project management. In June 1998, he took a position at Schweitzer Engineering Laboratories, Inc. as an Integration Application Engineer. His responsibilities include training and assisting SEL customers in their substation integration and automation efforts. Mr. Dood is a registered professional engineer in the state of Wisconsin. He is a Senior Member of the IEEE and is an active member of the PES Substation Committee.