PROTECTION, CONTROL AND AUTOMATION FOR A MULTISTATION LOOPED DISTRIBUTION SYSTEM - PART II

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VI. IMPLEMENTATION

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.

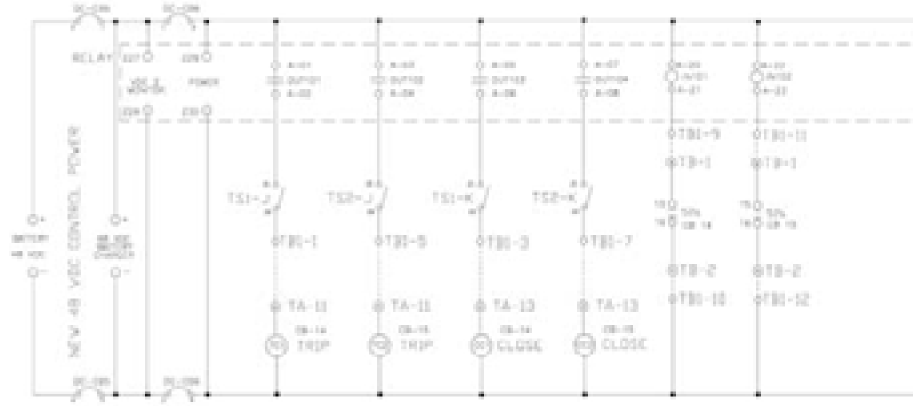

Fig. 9. DC Breaker Control Schematic

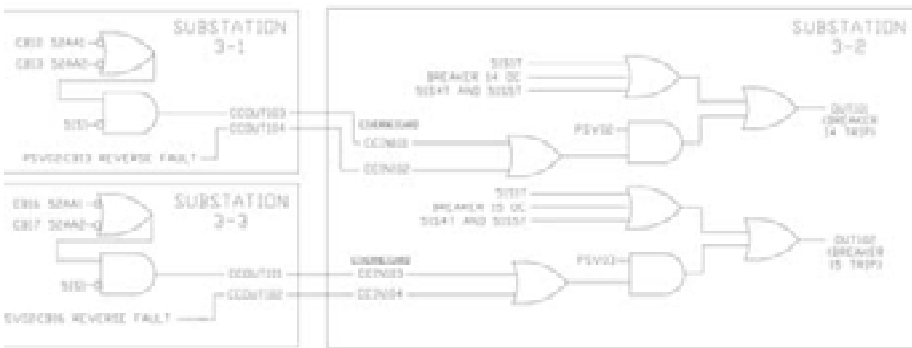

Fig. 10. Breaker Trip Logic

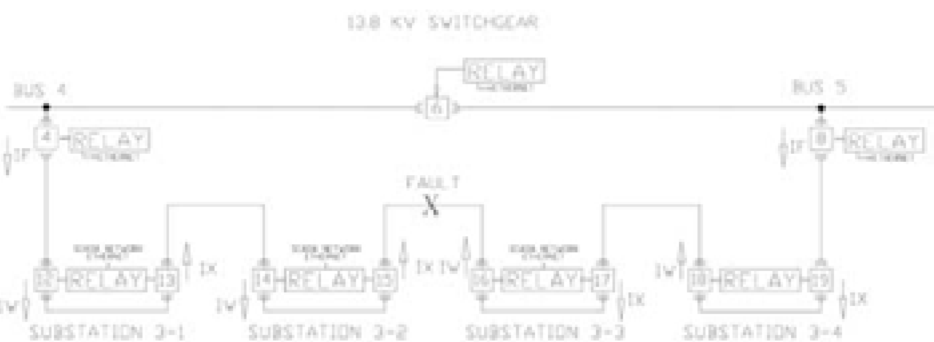

Fig. 8. System Fault

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

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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.

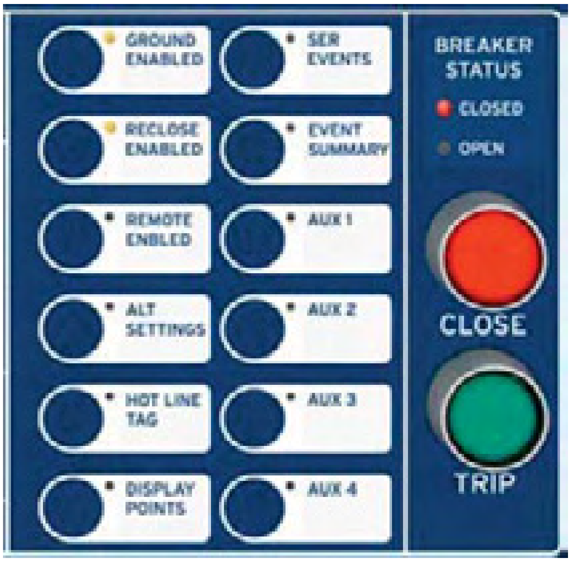

Fig. 11. Local Breaker Control Panel

VII. SUBSTATION U SWITCHGEAR

The substation 13.8 kV switchgear installation is different from 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.

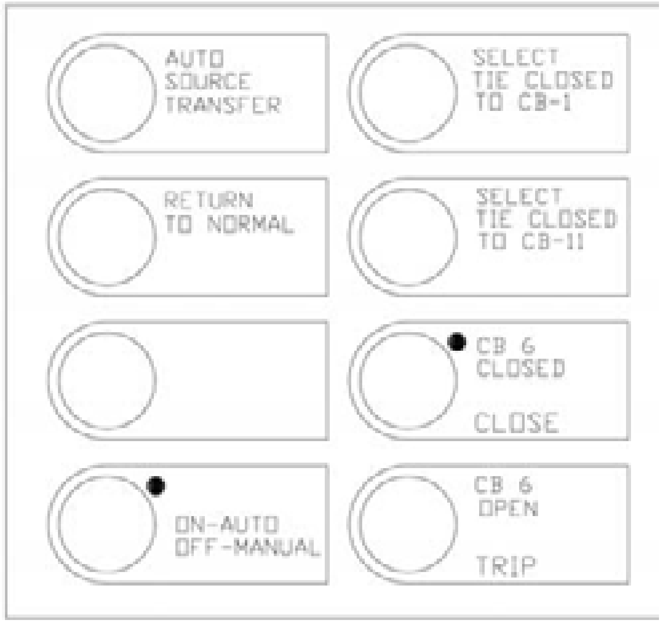

Fig. 12. Automatic Transfer Pushbuttons

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.

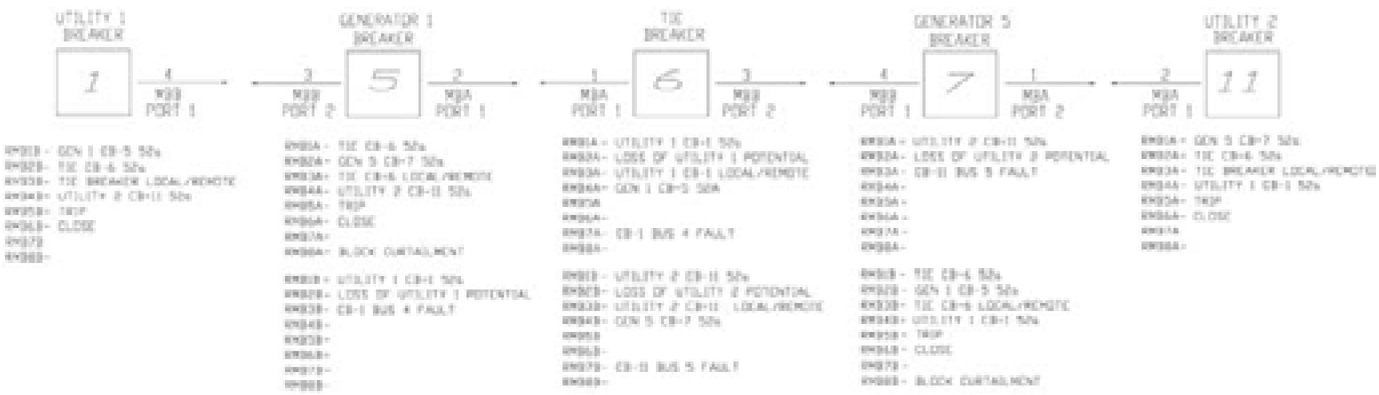

Fig. 13. Automatic Source Transfer Logic

- 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.

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 gen-

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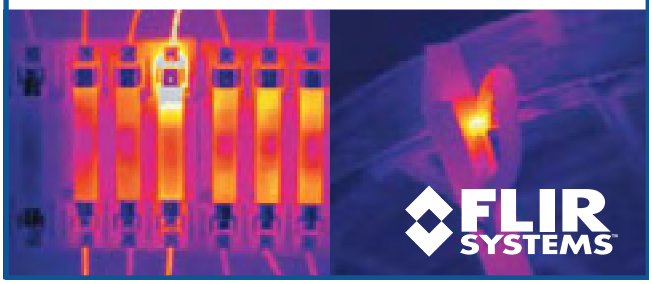

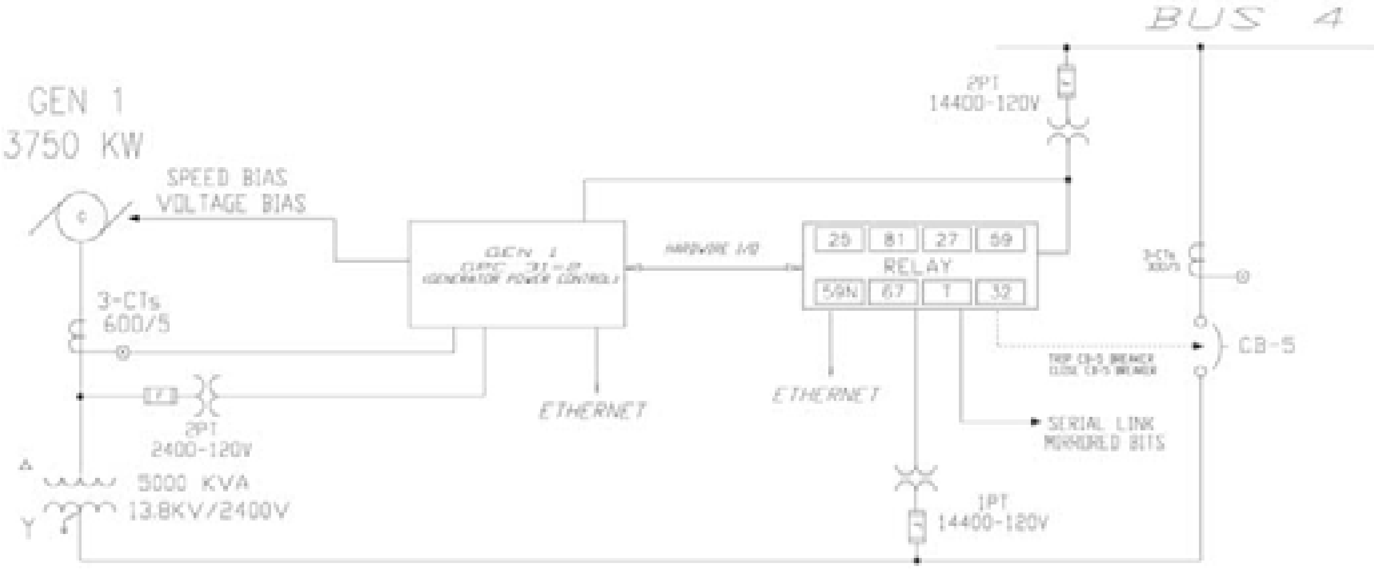

Fig. 14. Hardware Interconnections for Generator Controls

erator, step-up transformer, and circuit breaker.

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

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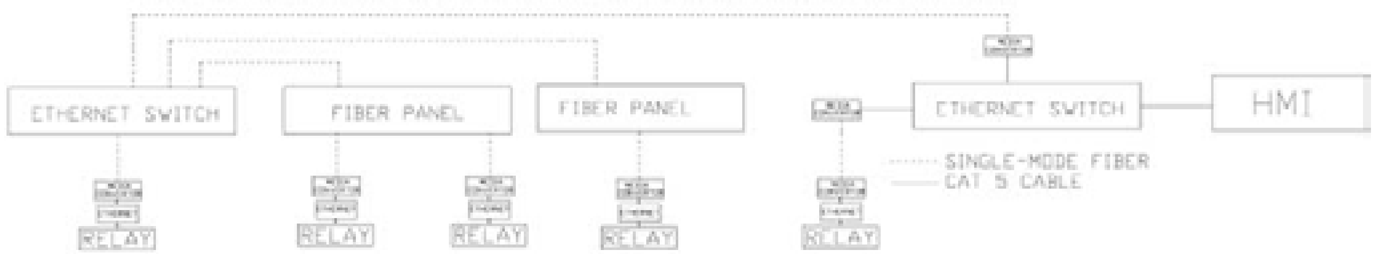


Fig. 15. Ethernet Communication Network

• 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.

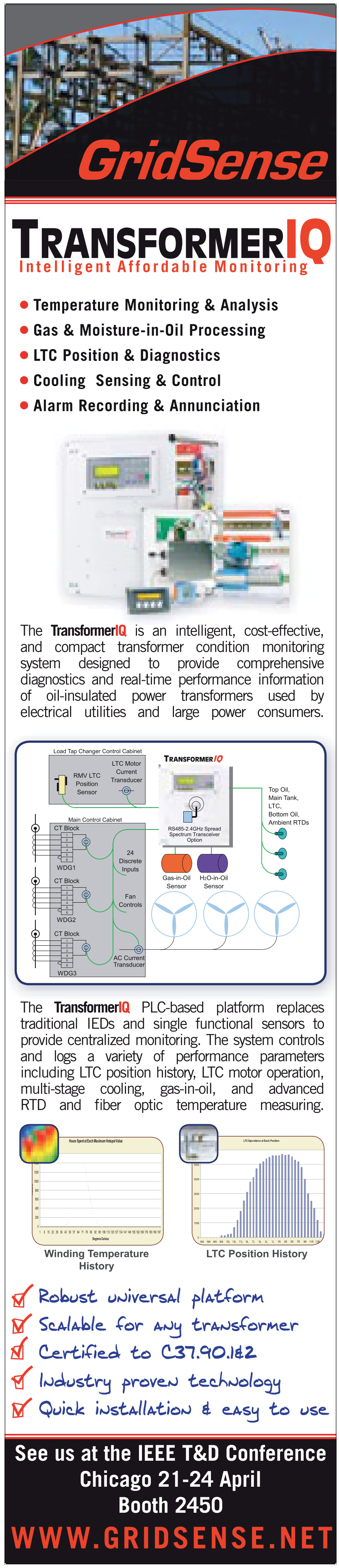
The operator control screens mimic the front panel of the relays. Trending is a popular application of Wonderware, so additional screens track voltage profile and power usage. The generator controls have a separate screen. Event and waveform analysis software is used to access individual relays one at a time.

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 pro-



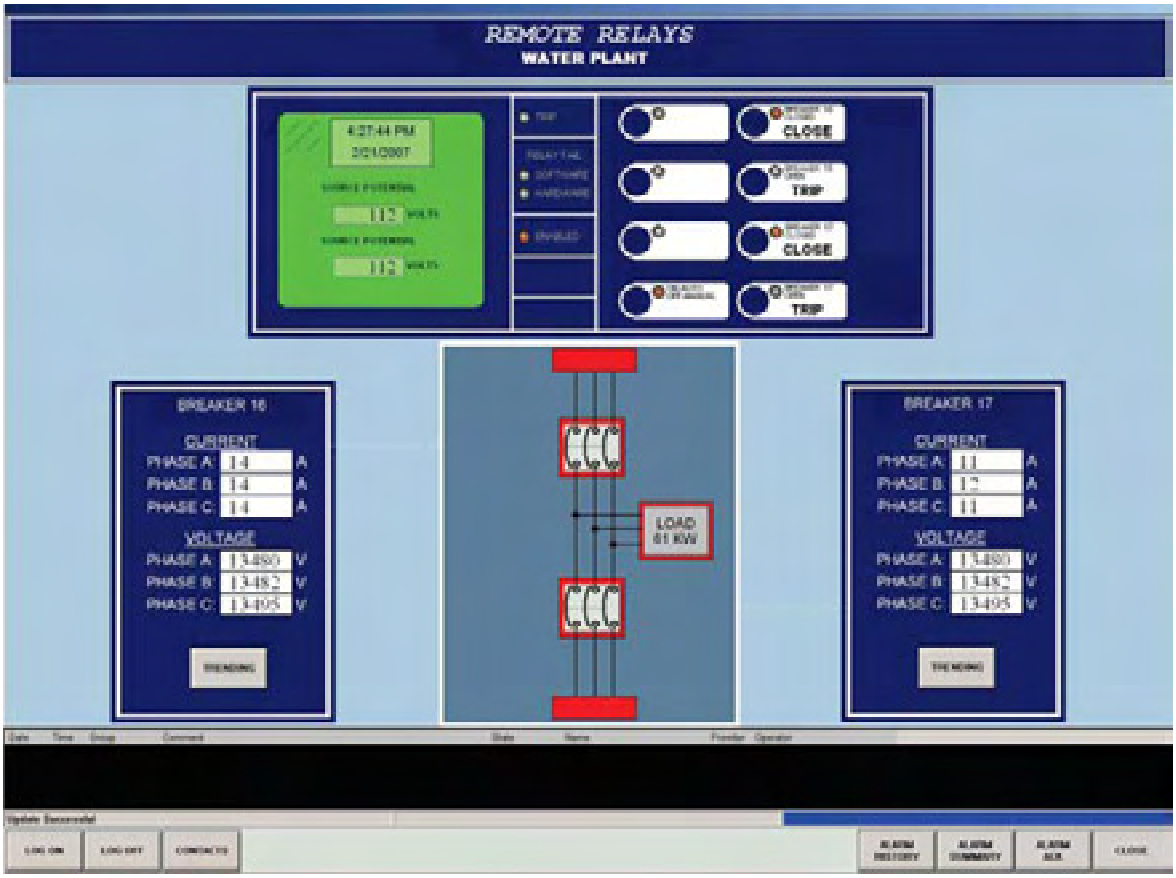


Fig. 16. Example SCADA HMI Screen

tected 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 this/her power system, but he/she 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.

XII. REFERENCES

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