Demonstrating the Flexibility Provided by GOOSE Messaging for Protection and Control Applications in an Industrial Power System

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***Abstract*— IEC 61850 GOOSE messaging provides an incredible amount of flexibility to the design and implementation of protection and control systems. This flexibility was essential to recent projects involving the upgrade of the electrical distribution system at an oil refinery. GOOSE was used for transfer tripping, breaker failure, islanding detection, remote synchronizing, automatic restoration, manual transfer, and load shedding.**

This paper describes the design approach for each scheme, documentation methods, and lessons learned. Data from live event captures is included to demonstrate the operating speed of the schemes.

I. Introduction

An oil refinery in Salt Lake City, UT recently embarked on a series of projects to improve the reliability of the on-site power system. These upgrades included installation of a new utility ring-bus substation, a new utility interconnect substation, separation of two combustion turbine generators (CTGs) onto separate buses, and installation of new 13.8 kV, 4.16 kV, and 2.4 kV distribution equipment. All of the protective relay systems for this new equipment were microprocessor-based devices.

Figure 1 shows a simplified single line diagram for the upgraded plant electrical system. Sources of power for the refinery include a connection to the 46 kV utility system and two 14.9 MVA aero-derivative CTGs. The exhaust heat from the CTGs is used in a heat recovery process to produce process steam. The CTGs are the only source for steam at the refinery, which makes their reliable operation critical for process continuity.

The topology of the new plant electrical distribution system drove the need for several communications-aided protection and control schemes. These schemes initially included transfer tripping, breaker failure tripping, islanding detection and remote synchronizing. Due to the number of devices involved in these schemes, and in order to simplify the logic programming requirements, IEC 61850 GOOSE messaging was selected as the communications protocol for these new schemes. The choice to utilize GOOSE messaging played a key role in the design of a new Ethernet-based refinery electrical SCADA system installed as part of the upgrades.

Load growth at the refinery drove the need for a load shedding scheme. The need for this scheme was not identified until the new plant distribution system infrastructure had been delivered to site and commissioned. GOOSE messaging was utilized as the communications protocol in this load shedding scheme. The only new equipment installed for this scheme consisted of two sets of logic processors that acted as the scheme controllers.

Documentation of the new GOOSE-based protection and control schemes presented a challenge. Several of the schemes previously would have been implemented using hard-wired I/O, which would have been documented on control schematics. Functional specifications, logic diagrams, and GOOSE mapping tables were produced to support the design and also provide an intuitive documentation set for the end-users.

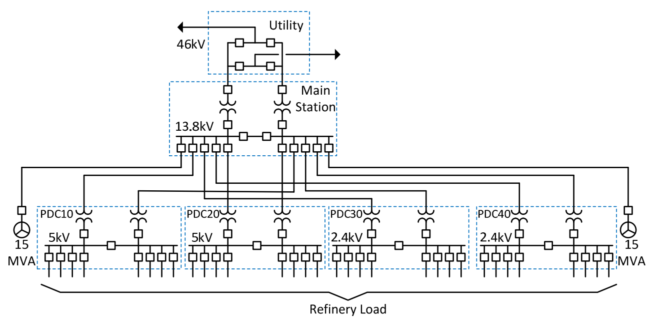

Figure 1. Single line diagram showing new medium voltage infrastructure

II. Need for Communications-Aided Schemes

Preliminary engineering for the upgrade project included the conceptual design of the protection and control systems for the new distribution infrastructure, as well as determination of the control system modifications required for the CoGen units. The following sections describe the communications-aided protection schemes identified during the preliminary design.

A. Transfer Tripping

As shown in Figure 1, the feeder breakers at the main 13.8 kV Power Distribution Center (PDC) serve as the high-side breakers for the downstream transformers. The downstream transformers are between 1500 feet and 2500 feet from the main PDC. The protective relays for the downstream transformers needed to be capable of tripping the upstream feeder breakers during transformer faults. This transfer trip required protection-speed communications. The architecture of this scheme is illustrated in Figure 2.

An additional transfer tripping scheme was identified for the

Cogen units to allow them to remain on-line, islanded with their auxiliary loads in the event of a voltage or frequency collapse during islanding. The generator relays would be configured to send a direct transfer trip to the feeder breaker at the main 13.8 kV station during sustained or severe voltage and frequency excursions. This allowed the machines to stay on-line, which would allow the refinery to be restored in a more timely fashion and reduce the duration of the steam outage.

B. Breaker Failure

Backup protection was desired for all (*n*-1) contingencies. For a fault in, or downstream of, one of the distribution transformers serving PDCs 10, 20, 30, or 40, a failure of the main station feeder breaker would result in the fault being sustained due to the limited sensitivity of the upstream main and tie breaker relays. This drove the need for breaker failure protection for the main station feeder breakers.

The breaker failure logic was implemented in the feeder relays. If a breaker failure trip was declared, the relay would broadcast a GOOSE message to the adjacent breaker control relays, as shown in Figure 3. Upon receipt of this GOOSE message, the breaker control relays would trip and block close of their respective breakers. The breaker failure trip indication is latched in the sending relay, which provides a similar functionality to a breaker failure lockout relay. One advantage of the GOOSE-based breaker failure scheme is that additional relays can be easily added to the scheme if additional feeder breakers are added to the bus in the future. The addition of these breakers to the breaker failure scheme would only require minor relay programming changes and modifications to the GOOSE configuration.

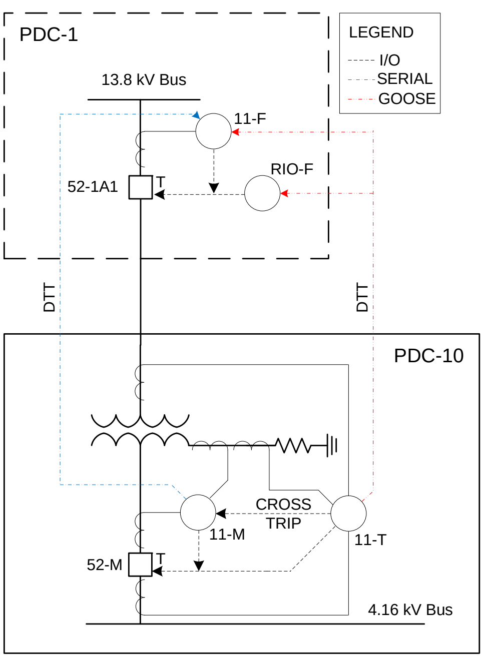

Figure 2. Redundant transfer trip paths employed for transformer protection.

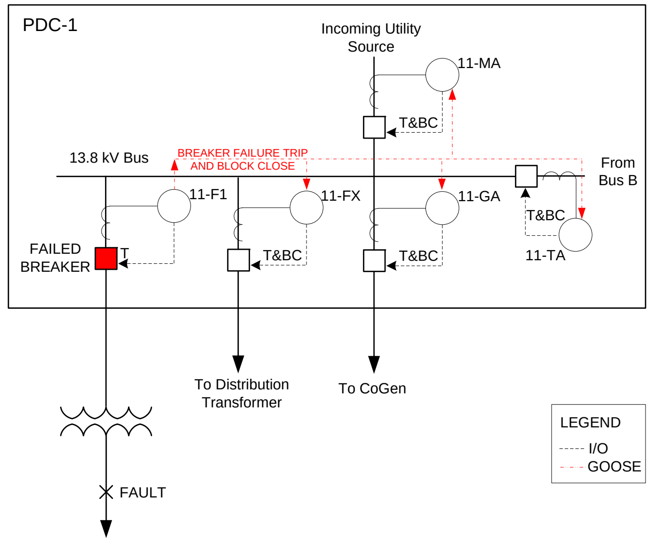

Figure 3. GOOSE eliminated hard-wired breaker failure lockout relays.

C. Remote Synchronizing

The refinery upgrades included separation of the CoGen units onto separate buses. Each CoGen unit was tied to the main substation by a 1500 foot run of overhead cable. These cables terminated at a generator feeder breaker at the main substation. To provide operational flexibility, the plant operators needed the ability to synchronize each CoGen unit across the main, tie and generator feeder breakers at the main substation. This functionality required a communications-aided scheme to send voltage and frequency raise and lower commands to the exciter and governor controls.

D. Islanding Detection

The generators are capable of operating in either droop or isochronous speed control modes. The generators are intended to operate in droop control when operating in parallel with the utility and in isochronous mode when the refinery is islanded. Similarly, the excitation controls operate in power factor control mode during parallel operation and in voltage control mode during islanding. In the existing system, the islanded/parallel determination was made through monitoring of the GSU high-side breaker and a single breaker at the utility interconnect. The topology of the new system made this determination more complicated since the island/parallel determination needed to take into account several breakers at the main PDC, as well as the generator breakers.

The generator controls were capable of accepting contact indications to put the units in either isochronous and voltage control or droop and power factor control. The islanding detection determination needed to take into account the status of the high- and low-side main, tie, and generator feeder breakers at the main station, as well as the status of the generator breakers. Due to the physical layout of the system, a communications-aided control scheme was required to provide the critical breaker states to a central controller located at the CoGen. This controller would determine if the generators were in parallel to the utility and to one another based on the breaker statuses received via GOOSE. The controller would then provide an islanded/paralleled indication to the governor and exciter controls via hard-wired I/O.

E. Protocol Selection

Two protocols were considered for implementing the communications aided schemes at the refinery: A protection-speed serial communications protocol and IEC 61850 GOOSE messaging.

The serial communications protocol has been in wide use for several years and provides reliable high-speed performance. This protocol was much more familiar to the authors than GOOSE messaging at the outset of the refinery upgrade project. For schemes where data must be shared between several devices, a logic processor is required, which can accommodate connections to 15 devices. This application initially required connections to approximately 20 devices, which would have necessitated two logic processors. Additional devices could be added to the schemes only by installing a new serial connection to the logic processor. If the number of devices grew, additional logic processors would need to be implemented to accommodate them. For schemes requiring redundancy, additional logic processors and serial connections would be required. One key attribute of this protocol was its familiarity to the project team as well as the client. This protocol has been used to implement several communications-aided schemes at the client's other facilities.

IEC 61850 GOOSE messaging provides comparable operating speeds to the serial protocol, but utilizes an Ethernet network as the communications medium. The primary advantages of GOOSE messaging are the elimination of the logic processors, which are no longer required for "routing" data, as well as the option of implementing communications-aided schemes in the future (or expanding existing schemes) without the need to install additional equipment or serial cables. The only caveat is that the IEDs must be specified with GOOSE messaging capabilities, and the network must be designed to meet the performance requirements of the protection and control schemes.

We decided to utilize GOOSE messaging as the primary communications protocol for all of the protection and control schemes. The more familiar serial communications protocol was employed in parallel with GOOSE messaging for the transfer tripping application due to the criticality of the application. This also eliminated the Ethernet switches as a single-point-of-failure for the distribution transformer protection. The serial protocol was also used to implement a manual synchronizing scheme. For backup protection schemes, such as the breaker failure scheme, and also for schemes where serial communications were not practical, GOOSE messaging was used as the sole communications protocol.

III. Hardware Selection and Network Design

Once the decision was made to use GOOSE messaging on this project, it was also decided to order every capable device with the IEC 61850 option selected. This applied to devices where an immediate need for GOOSE messaging had not been identified.

This project followed the established best practice of using IRIG-B to distribute time to each relay. Accurate timing is required for event analysis using the SER and Oscillography capabilities of the relays.

The need for an optimized Ethernet network was identified. Optimization included redundancy and latency. Managed Ethernet switches were required throughout the network. These switches included features such as Rapid Spanning Tree Protocol (RSTP), Virtual Local Area Networks (VLANs), and message prioritization.

VLANs and prioritization were used to optimize network latency. The goal was to minimize latency for critical messages. Each GOOSE scheme was assigned to a dedicated VLAN. This served to segregate messages to only the devices needing to receive them. Classes of Service (CoS) were used to give tripping messages the highest priority through the network.

RSTP was used to optimize network redundancy. Two single-mode fiber optic rings were deployed to connect the PDCs to the network. Rings were also used inside of each PDC. However, each relay only had one connection to the network creating a single point of failure for some schemes. Future projects will be designed with the capacity necessary to connect each relay with two different switches. It is important to note that fiber should be used on all gigabit connections because of an inherent 750ms delay in link failure detection for copper ports.

IV. Scheme Design Process

Effectively documenting the design is one of the challenges associated with implementing GOOSE-based protection and control schemes. With GOOSE messaging being a relatively unfamiliar technology in the United States, there is not an established documentation method for GOOSE-based schemes. Traditional hard-wired protection and control logic is typically documented on a control schematic. Engineers and technicians are familiar with these drawings. When these hard-wired schemes are replaced with communications-aided schemes and relay logic, information is removed from the schematic diagrams, but the end-user still needs some form of detailed documentation of the scheme functionality.

To address the need for documentation, the team implemented a tiered approach to the communications-aided scheme documentation including a functional specification, GOOSE mapping spreadsheet, and IED logic diagrams. A document flow diagram is shown in Figure 4. The objective of these documents was two-fold. The documents needed to aid the team in the implementation of the schemes, and the documents also needed to serve as an intuitive set of reference materials for the end-user. After completion of these documents and diagrams, the actual relay programming and GOOSE configuration were executed. The following sections describe the approach taken to each tier of the documentation.

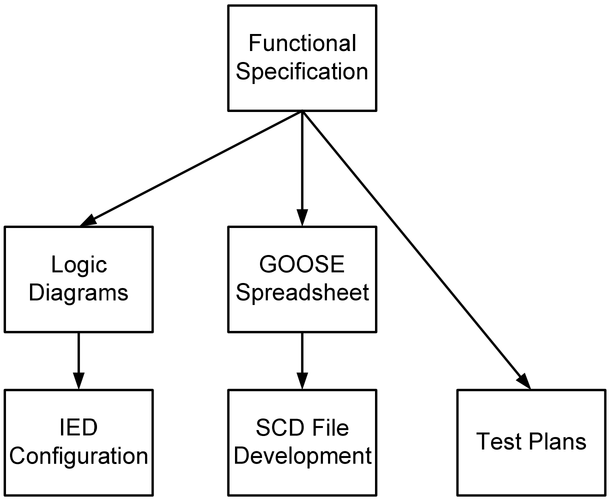

Figure 4. Document Flow Diagram

A. *Functional Specification*

After the required schemes were identified, each of them needed to be defined clearly prior to detailed engineering. A functional specification document was developed for each scheme. These documents included a written description of the purpose and intended modes of operation of the scheme. The hard-wired I/O, relay display points, pushbutton assignments, target LED assignments, event reporting requirements, and transmit/receive GOOSE messages were defined for each IED involved in the scheme.

Secure failure modes are critical in a refining environment. A component failure should not result in an unintended scheme operation or equipment outage. The functional specifications defined the desired scheme failure modes for conditions such as IED failure, power cycles, relay settings changes, and communications failures.

The team also defined “test mode” states for each of the schemes. Each of the transmitting relays could be placed into “test mode” via relay front panel pushbutton, which is similar to the concept of a traditional test switch. When a relay is in “test mode”, the receiving devices will ignore any messages from the device under test.

B. *GOOSE Spreadsheet*

The GOOSE spreadsheet was developed after the team had completed the functional specification. The intention of this document was to more clearly organize and define the GOOSE messages being exchanged between devices, define classes of service, the specific contents of each GOOSE message, and the Virtual Bit assignments for incoming GOOSE messages. This document defined the information required to develop the SCD files for each IED. A simplified version of this GOOSE spreadsheet is shown in Figure 5.

Receiving Relay											11-751-1A1	11-751-1A2
IP Address											10.50.1.145	10.50.1.146
Sending Relay	IP Address	Gateway	Message ID (<64 char)	VLAN (hex)	CoS	AppID (hex)	Multicast Address	Dataset Name (<16 char)	Description	Sending Variable		
11_751_1A1	10.50.1.145	10.50.1.254	11_751_1A1_Dset_BF	14	6	1	01-0C-CD-01-00-14	Dset_BF	Quality	N/A		VB009
									Test Mode	LT05		VB007
									Breaker Failure	LT09		VB008
			11_751_1A1_Dset_TT	1	6		01-0C-CD-01-00-01	Dset_TT	Quality	N/A		
									Test Mode	LT05		
									Transfer Trip	SV11T		
11_751_1A2	10.50.1.146	10.50.1.254	11_751_1A2_Dset_BF	14	6	3	01-0C-CD-01-00-14	Dset_BF	Quality	N/A	VB009	
									Test Mode	LT05	VB007	
									Breaker Failure	LT09	VB008	
			11_751_1A2_Dset_TT	1	6		01-0C-CD-01-00-01	Dset_TT	Quality	N/A		
									Test Mode	LT05		
									Transfer Trip	SV11T		

Figure 5. GOOSE Spreadsheet

C. *Logic Diagrams*

The logic diagrams were intended to replace the information that would typically be represented in a DC control schematic for a hard-wired scheme. The logic diagrams only included the relay logic, target indications, and LCD display messages associated with the GOOSE-based protection and control schemes. The details of logic provided in the firmware of the relays were specifically not provided in detail, but were represented in a simplified form where appropriate. The logic diagrams served two purposes. The first purpose was to aid the design team in the development of the detailed IED logic programming. The second was to provide an intuitive representation of the communications-aided scheme logic for the client’s future reference. The diagrams were organized such that all applicable inputs to the relay (hard-wired, GOOSE and serial) were shown on the left, side of the drawing. The relay internal logic was shown in the center of the drawings. The outputs (hard-wired, GOOSE and serial) were shown on the right-hand side of the drawing. The drawings could be used to trace out the driving logic behind LED indications, front panel LCD messages, etc.

D. *Settings and SCD File Development*

After the GOOSE spreadsheet and Logic diagrams were completed, the device configuration files and SCD files were developed. The IED configuration files were developed based on the functionality outlined on the logic diagrams. The SCD files were developed directly from the information contained in the GOOSE spreadsheet.

E. *Test Plans*

Test plans were developed for site acceptance and, in some cases, factory acceptance or bench tests. These test plans were intended to verify that the schemes performed according to their functional specifications. Great care was taken to develop the test plans based on the functionality outlined in the functional specifications and not based on the logic diagrams or configuration files. The site and factory acceptance tests were intended to be true functional checks for each scheme.

V. Additional Schemes

Following the completion of the Phase I upgrades at the Refinery, the Phase II PDCs were constructed and shipped to the site. The client identified a need for two additional control schemes after the PDCs had been delivered. These schemes included an automatic restoration and manual transfer (ARMT) scheme and a load shedding scheme known as the “Load Preservation Scheme” (LPS). Since all of the relays installed during Phases I and II were specified with IEC 61850 capabilities, and the network was prepared to handle protection and automation messages, GOOSE messaging was available as a communications protocol for use in these schemes.

A. Automatic Restoration and Manual Transfer

After the Phase II PDCs had been assembled and delivered to the site, the client requested that an automatic restoration and manual transfer scheme be implemented at the four new secondary distribution PDCs. The PDCs were to be operated with their tie breakers normally open. The scheme needed to close the tie breaker in the event that either source was lost. Additionally, the client requested that the manual transfer scheme be capable of performing closed-transition transfers and re-transfers to single- or double-end the switchgear lineup.

The design team elected to designate the A-bus partial differential relay (11-AP) at each PDC as the main controller for the restoration and transfer schemes. The 11-AP relay received information such as breaker status, truck status, bus voltages, sync-check, and fault indications from the main breaker and B-Bus partial differential relays via GOOSE messaging, and used this information to determine when automatic restoration was appropriate, and when it needed to be blocked. The 11-AP relay also sequenced the closed-transition transfers by monitoring the system state and issuing trip/close commands to the main breaker relays.

The use of GOOSE messaging to exchange data amongst the main and partial differential relays eliminated the need for all but a few minor control wiring changes, and also allowed the user interface to be condensed to a simple set of pushbutton-based controls on the faceplate of the existing 11-AP relays.

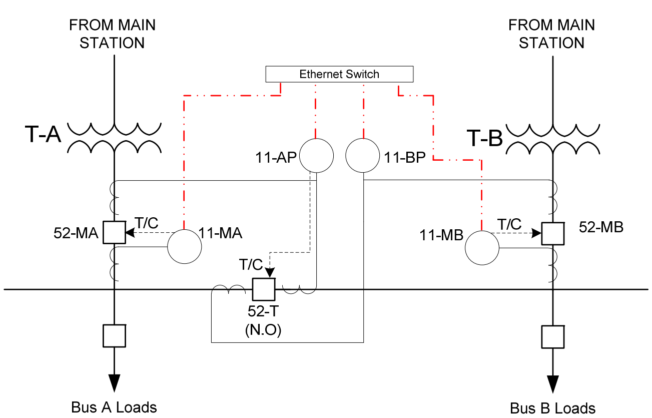

Figure 6. Automatic transfer and manual transfer scheme overview

B. Load Preservation System

Refinery expansion projects coincident to the infrastructure upgrade project caused the refinery load to exceed the capability of the two on-site CTGs. This generation deficit condition created a need for load shedding if the refinery became islanded from the utility. This generation deficit was identified less than one year before the existing refinery loads were cutover to their new feeds out of the secondary distribution PDCs. The load shedding project did not receive a notice to proceed until October 2014, with an expected in-service date in March 2015 during the refinery cutover.

The refinery was an excellent candidate for a modern contingency-based load shedding scheme. Contingency-based load shedding schemes offer improved flexibility, speed, reliability, and security compared to traditional distributed underfrequency-based load shedding schemes. These contingency-based schemes continuously monitor the state of critical system breakers, power import, and load consumption and continuously decide which loads would be shed if a given contingency were to occur (such as a loss of utility source). Loads can be prioritized for tripping by system operators depending on the plant operating conditions. One pre-requisite for a contingency-based scheme is a protection-speed network for collection of system data and transmitting trip signals. Fortunately for the design team, the refinery protection and SCADA network had already been designed with protection-class communications-aided schemes in mind.

The contingency-based scheme needed to monitor the following throughout the system:

- Feeder Breaker Status
- Feeder Loading
- Contingency Breaker Status
- Contingency Breaker Power Metering
- Topology Breaker Status
- System Frequency

The data listed above was collected from breaker control relays at the locations shown in Figure 7. The microprocessor-based relays at each circuit breaker were already monitoring the binary and analog points required by the controller. This information was provided to a central controller via GOOSE messaging. The controller determined the loads to be shed for each contingency, and monitored the system for triggering conditions. If a trigger condition were to occur, the central controller would send trip signals to the pre-selected feeder breakers via GOOSE messaging.

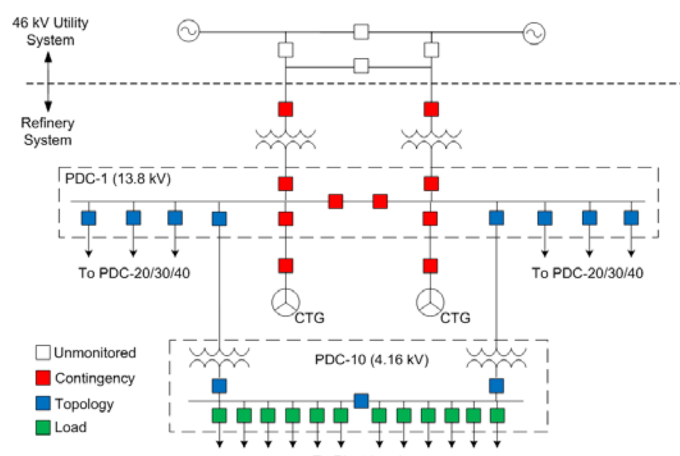

Figure 7. Various breaker types monitored by the load preservation system.

The load preservation scheme involved eighty of the relays at the refinery. The only additional pieces of hardware required for this scheme were the load shed controller logic processors, which occupied a total of two rack-units of space in two of the existing SCADA cabinets at the refinery. The installation of the controllers was completed in less than one day during a refinery turnaround.

A comprehensive factory acceptance test was performed to prove-out the controller logic under a variety of system operating conditions. The factory acceptance testing also verified the failure modes for each unique IED-type employed in the scheme. The combination of factory acceptance testing and minimal hardware and field modification requirements, allowed the site acceptance testing to be expedited. The GOOSE-based scheme and factory acceptance testing approach provided benefit to the client as extensive wiring modifications did not need to be coordinated during an already condensed refinery turnaround schedule. By eliminating the need for extensive field wiring, the outage time was more strictly focused on testing. The team had time to perform communications checks, failure mode testing, HMI commissioning and a limited set of live islanding tests where simulated loads were shed.

VI. Event Data

Phase I of the refinery upgrades included the installation of the new utility substation, the new 13.8 kV main substation, and the separation of the CoGen units. The refinery loads remained on feeds from their existing substations served by a 46 kV overhead line that ran around the perimeter of the plant. The 46 kV line was temporarily tapped off of the high-side of one of the new 46 kV/13.8 kV transformers at the main substation. During the interim between Phase I and Phase II, the existing overhead 46 kV line experienced several faults. These fault events caused the refinery to become islanded in a few cases, and also caused the CoGen units to trip off-line due to problems with their auxiliary systems. The system disturbances associated with these faults were a nuisance to the refinery, but also provided valuable data regarding the operating speeds for the GOOSE-based schemes.

The design team configured the sequence of event recorders (SERs) in the IEDs to record state changes for all received GOOSE messages, and also for bits used in outgoing GOOSE messages. Satellite clocks were used to provide an IRIG-B time source to all of the IEDs at the refinery. This allowed SERs to be compared easily between devices throughout the plant. The SERs of all of the key relays and logic controllers at the refinery were downloaded in December of 2013 after approximately five months of operation. The SER for the CoGen control logic processor provided a valuable snapshot of the performance of the protection network. The CoGen control logic processor monitored the plant topology for the remote synchronizing and islanding detection schemes. This device subscribed to GOOSE messages from eleven IEDs located at the main substation as well as the CoGen PDCs. Thirty GOOSE message state changes were observed by the CoGen logic processor during this time period. The time delay between assertion of the “transmitting” bit in the sending relay, and the “received” bit in the control processor was determined from SER records. The average transmission time was found to be 3.5 ms, with minimum and maximum times of 2 ms and 6 ms, respectively. The processing intervals for all of the IEDs were 4 ms.

VII. Conclusions

GOOSE messaging is well suited for a variety of applications including transfer trip, breaker failure, remote sync, load shedding, and ARMT. Once the network is in place, GOOSE-based schemes can be implemented with little to no hardware modifications. This allows for shorter outages for implementation of GOOSE schemes.

Specifying relays with GOOSE capabilities and utilizing a substation protection and SCADA network is a best practice when a need for communications-aided protection is likely. At a minimum, placing GOOSE-capable IEDs at critical locations throughout a system in the initial design phase can provide significant benefits down the road.

Development of user-friendly documentation, such as logic diagrams, is a best practice when using GOOSE to replace schemes that would have previously been implemented using hard-wired control logic.

VIII. References

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IX. Biographies

Jared Mraz, P.E. received his B.S. degree in electrical engineering from the University of Idaho in 2007. Upon graduation, he joined the SCADA and Analytical Services Business Unit at POWER Engineers, Inc. in Clarkston, WA. He has spent the past 8 years performing a variety of electrical system studies, with an emphasis on protective relaying. His experience includes protective relaying for distribution, transmission, generation and industrial applications, as well as testing of advanced protection and control schemes using Real Time Digital Simulation. Mr. Mraz is a registered professional engineer in Washington, Texas and Louisiana.

Keith Gray, P.E. has diversified experience in SCADA engineering design, networking, and power system protection for high voltage electric power facilities. He has extensive experience with SCADA system design and integration for substations and switchyards and also performs programming and onsite testing and commissioning. He has specific experience with oil refinery SCADA systems. Additionally, Mr. Gray has experience as a system protection engineer, including performing short-circuit and coordination studies to determine protective relay settings and programming relays.

Mr. Gray has experience with IEC 61850 configuration for substation automation projects, including SCADA integration designs and protection and control designs. This experience includes testing of interoperability between systems of different vendors. He has been instrumental in establishing POWER's IEC 61850 testing facility, which provides a laboratory where substation integration engineers can test and validate IEC 61850 design concepts. Additionally, he is involved in developing POWER's internal design guidelines relating to this emerging technology.