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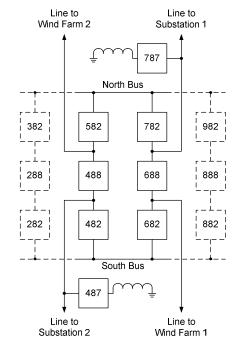
Abstract—A great deal of wind generation development is occurring in the western Great Plains, causing utilities in the area to make major upgrades to the transmission system to integrate wind generation resources to the grid. This has prompted one utility to consider modernizing standards and evaluate new technology for application in their extra-high-voltage (EHV) substations. This paper describes a new protection and control system design that was piloted in a greenfield substation. All or part of the system design developed for this project may be used for future substation designs. The substation consists of a two-rung, breaker-and-a-half substation layout with two bays for grid connections and two bays for wind generation facility connections. The substation design is expandable to additional rungs as necessary. IEC 61850 Generic Object-Oriented Substation Event (GOOSE) messaging is used for all lockout tripping and interlocking to reduce substation wiring and simplify the schematic design. This paper discusses the design philosophies developed and used in designing this substation and the practical impacts of testing and validating the new design.
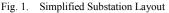
I. INTRODUCTION

A great deal of wind generation development is occurring in the western Great Plains, causing utilities in the area to make major upgrades to the transmission system to integrate wind generation resources to the grid. The substation project that is the subject of this paper is one such addition to the grid. This new substation is located at approximately the midpoint of a 345 kV line connecting a generating station to a major transmission hub substation. The substation includes two line terminals for the existing line that is being cut into the substation and two line terminals for connection of two nearby wind generation facilities. This paper describes a new protection and control system design that was piloted in this greenfield substation. All or part of the system design developed for this project may be used for future substation designs.

As shown in Fig. 1, the substation has a two-rung, breaker-and-a-half configuration with room for expansion to additional rungs. Each line terminal includes shunt reactors for system voltage control. The protection system design includes complete redundancy, including separate station batteries for the dual primary protection systems.

Because this substation is on the western fringes of the Eastern Interconnection, the transmission grid is rather loosely tied together. For this reason, a requirement was to design the substation for future conversion of the line protection to

single-pole trip (SPT) and reclose operation. SPT and reclose helps ensure system stability by tripping only the faulted phase during a single-line-to-ground fault—the most prevalent type of fault on a power system. The other two phases remain energized and carrying power across the line, which helps prevent one terminal from going out of step with the other [1]. The downside of SPT systems is that they almost triple the I/O and wiring for tripping and breaker failure initiate (BFI) circuits.

Fig. 1. Simplified Substation Layout

In order to reduce the hard-wired I/O requirements and associated cabling and construction costs, as well as facilitate isolation of the primary system (System P) from the secondary system (System S), it was decided to use peer-to-peer, Ethernet-based IEC 61850 Generic Object-Oriented Substation Event (GOOSE) messaging for lockout and breaker failure (BF) functions. Compared to traditional I/O required for lockout relaying, GOOSE-based lockout tripping greatly simplifies the wiring, implementation, and documentation of the system.

GOOSE can be thought of as replacing most traditional hard-wired I/O, the way other parts of the IEC 61850 standard

replace other traditional substation functions with Ethernet communications. Manufacturing Message Specification (MMS), for example, replaces traditional supervisory control and data acquisition (SCADA) communications, and Sampled Values (SVs) replace current transformer (CT) and voltage transformer (VT) signaling. Only the GOOSE functionality of the IEC 61850 suite of protocols was used in this application.

This paper focuses on how GOOSE messaging was integrated into the design of the substation. We cover the following:

- The design philosophies that were developed to guide how and for what purpose GOOSE would be used.
- The design of the protection and control system to meet application requirements.
- The design of the Ethernet network architecture to provide a secure, robust, and fault-tolerant communications network that could reliably support protection tripping.
- Testing and validation of the design.
- Documentation of tripping logic in this new environment.

II. GUIDING PRINCIPLES

In the preliminary stage of the system design, it was important to establish guiding principles of how IEC 61850 GOOSE messaging would be used to achieve the design goals. Reference [2] was used for guidance on how to design substation protection, control, and monitoring systems taking advantage of modern multifunction microprocessor-based protective relays and communications technologies.

A. Direct Tripping for Primary Fault Clearing

Rule 1: *For primary fault protection, all relays must be programmed and connected via hard-wired connections to directly perform all signaling and tripping to isolate their zone of protection.*

This rule was adapted from the advice in [2] and was originally intended to eliminate the use of auxiliary relays, such as lockout relays, for contact multiplication and circuit isolation in favor of using the multiple programmable output contacts available in multifunction relays.

For example, a traditional bus protection system design would have the bus differential relay trip a lockout relay and the lockout relay energize the trip circuits of all of the breakers around the bus. A modern system programs and connects output contacts in the multifunction bus relay to directly trip each breaker. Often, the bus differential relay also trips the lockout relay to be a secondary tripping path and to perform the block close function. In this design, the fault is cleared faster by bypassing the delay inherent in the lockout operating time, and the lockout relay is now no longer a single point of failure that can prevent clearing the fault.

1) Zone Protection

When we applied this direct tripping rule to the design, this meant that the zone relays were all wired directly to the trip circuits of the breakers for their zone of protection. GOOSE messaging was not used for the tripping of breakers for primary fault protection.

For example, for the line zones, System P uses directional comparison blocking (DCB) over power line carrier (PLC), supplemented by direct underreaching transfer trip (DUTT). System S uses permissive overreaching transfer trip (POTT) over microwave, supplemented by DUTT. Signaling between the relays and the teleprotection transceivers is done via hard-wired connections.

2) Lockout Functions

For zones that require lockout, such as the bus and reactor zones, the zone protection relays also trip a physical lockout relay on the panel. However, the lockout relay has no tripping contacts. It only asserts an input on both the System P and System S zone relays. The zone relays then broadcast the status of the lockout relay via GOOSE messaging to the designated breaker control relays. The breaker control relays for the breaker that is locked out assert their tripping contacts and block all manual and automatic close commands that operate through that relay.

B. GOOSE Signaling for Backup Functions

Rule 2: *For backup protection, all signaling must be via GOOSE messaging.*

This design rule promoted using GOOSE messaging for the most I/O-intensive functions, where we could get the greatest economy in wiring reduction while not impacting the primary fault protection.

1) Breaker Failure Protection

The primary system for interrupting fault current is the high-voltage circuit breaker. While we use breakers with dual trip circuits for separation of the secondary circuitry, we do not typically use two circuit breakers in series for interrupting the flow of current. BF relaying is the backup system for interrupting fault current in the case of a breaker failure to open or clear [3].

In a breaker-and-a-half substation such as this, the BF system design is extremely complex. Every breaker separates two primary zones. These two zones are different for every breaker in the substation. Thus, each breaker has a unique set of BFI signals and a unique set of backup breakers to trip and lock out.

In addition, the BF protection system is typically on separate panels from the initiating relays, and the backup breakers that must be tripped are also on separate panels from the BF protection system. Further, SPT systems require phase-segregated BFI signals. Using GOOSE messaging for BFI and BF trip greatly simplified the schematic design and greatly reduced the I/O requirements and amount of interpanel wiring for this project.

When this rule was applied to the three channel teleprotection transceivers, we had the seemingly odd arrangement that permissive or block and DUTT transmit (TX) and receive (RX) signals were hard-wired, but BF direct transfer trip (DTT) TX and RX signals used GOOSE messaging.

2) Block Close Lockout Functions

As mentioned previously, GOOSE messaging is used for all lockout functions, including bus and reactor zone lockouts. Every relay directly trips the breakers required to clear faults in its zone of protection, so the lockout relays are mainly used to block the close of breakers associated with a locked out zone.

To satisfy the rule that only backup functions could be done via GOOSE messaging, we defined that the primary system for preventing the close of a locked out breaker is the utility switching order procedures. A breaker should never be closed in a power system without proper switching orders, and a switching order should never be issued to close a breaker on a locked out zone of the power system until the lockout condition has been cleared.

C. Design for Full Redundancy

Rule 3: *For any critical protection or control function, there must be redundancy and no single point of failure.*

1) Protection

When this rule is applied for protection functions, it is often called dual primary. That is, both System P and System S must be functionally equivalent in sensitivity and speed. The application of dual primary protection is well developed in the industry and will not be discussed further here.

2) Manual Control

Manual control is implemented such that remote control signals are sent from SCADA to System P relays and local control is associated with System S. Thus, local control backs up SCADA control and SCADA control backs up local control.

To maintain redundancy, each breaker has a designated control relay in both System P and System S. The design did not include separate breaker intelligent electronic devices (IEDs). Because each breaker separates two zones of the power system, manual control functions can be implemented in a number of relays. So, it was necessary to designate one of the zone protection relays in each system as the control relay for each breaker. The designated control relay for each breaker receives all lockout signals associated with its breaker via GOOSE messaging and provides all close supervisory functions, including synchronism check and voltage supervision.

The relays on the transmission grid connection lines are used for manual control supervision of the bus and midbreakers for their lines. The relays on the wind farm connection lines are used for manual control supervision of the bus breaker for their lines. The reactor relays are used for manual control supervision of the reactor breakers.

3) Automatic Reclosing

Automatic reclosing is typically not redundant. Remote SCADA close control is considered the backup for automatic reclosing. Thus, automatic reclosing is implemented in the System S line relays only.

4) SCADA Data Acquisition Functions

SCADA data acquisition functions are typically not redundant. However, because the System P and System S relays are nearly identical in functionality, the communications processors are programmed to monitor both systems with automatic failover logic to use status and metering information from the System S device if the System P device stops communicating.

D. Isolation of System P and System S

Rule 4: *Provide maximum isolation between System P and System S.*

1) Physical Separation

Physical separation is accomplished by using two rows of simplex protection and control panels with System P protection and control across the aisle from the System S protection and control panels. The two battery systems are located in separate battery rooms.

2) Eliminate Cross-Tripping

In redundant systems, there are two main tripping philosophies: cross-tripping or letting each system trip via only one of the two trip circuits. Traditional systems often used cross-tripping, where the relays of System P and System S both tripped both trip circuits in the breaker. This philosophy was popular because hidden failures were more likely. In modern systems with continuous self-monitoring functions, trip circuits can be greatly simplified and isolation of the separate battery systems can be greatly improved by having System P only connected to Trip Circuit 1 and System S only connected to Trip Circuit 2. This philosophy was used in this design.

A secondary reason for not cross-tripping was to make the number of tripping contacts required manageable. Because this system is wired for SPT, every trip circuit had to have three separate contacts. Cross-tripping would have nearly doubled the contact count.

3) Separate Ethernet Networks

The Ethernet networks for System P and System S are separate, with no crossover between the two networks. See Section IV for more details on the Ethernet network design.

4) Separate Breaker Failure Systems

In an integrated substation design, BF protection can be implemented in many ways. Determining the optimum design depends on many factors [4]. The options that could have been chosen in this application include the following:

- The BF function could be implemented in each individual zone tripping relay. Each relay would directly trip the breaker, monitor the current in the breaker, declare BF, and trip backup breakers via GOOSE messaging.
  - Pro: Eliminates all BFI signaling.
  - Con: Increases the complexity of BF tripping.
  - Con: Requires interpanel wiring to trip the BF lockout relay.

- The BF function could be implemented in dedicated breaker relays. One breaker relay per breaker would contain common functions such as synchronism check, automatic reclosing, and BF.
  - Pro: Makes the design easy to understand because all breaker functions are concentrated in an obvious device.
  - Con: Requires additional relays, additional panel space, and additional wiring.
  - Con: Reduces the separation of System P and System S because there is a single BF scheme that both systems have to initiate.
  - Con: Creates a single point of failure for both local and remote manual control because the close supervision functions are no longer redundant.
  - Con: Complicates the automatic reclosing scheme because we cannot take advantage of the dual breaker recloser per zone scheme available in the line relays.
- The BF function for System P could be implemented in the System P bus relay and BF for System S could be implemented in the System S bus relay.
  - Pro: Improves the separation of System P and System S.
  - Pro: Makes the design easy to understand because the BF functions are concentrated in one location.
  - Pro: Makes the BFI and BF trip signaling more straightforward because all signals travel to and from the same devices.
  - Pro: Minimizes additional wiring, in most cases, because the bus relays are already wired to the CTs and breakers for their respective bus.
  - Con: Creates the possibility for confusion of which bus relay takes care of BF for the midbreakers and reactor breakers because the CTs of these breakers can be wired to either of the bus relays.

This last option was the design chosen for this project.

5) Use of a Physical Lockout

Because the local and remote manual control functions are separated with one on System P and one on System S, it is necessary for both systems to know when a breaker is locked out. If System P tripped and locked out a bus, for example, it would be necessary to prevent closure by the local control handle that is supervised by the System S relay associated with that breaker.

The design team struggled with this problem. We did not want to install a crossover connection between the systems and have each relay subscribe to GOOSE messages from both systems. That would greatly increase the complexity of the network design to prevent any possibility of problems on one network affecting both systems. It would also greatly increase the complexity of the GOOSE programming and testing by doubling the number of subscriptions that any relay would have to have.

We implemented a solution that is elegant in its simplicity. A physical lockout relay with two normally open (NO) tripping contacts that are closed when the lockout is in the tripped state was installed. One NO contact is wired to an input on the System P relay, and the other NO contact is wired to an input on the System S relay. The status of the lockout is broadcast by each tripping relay to the relay on its system that is controlling the locked out breaker. The only crossover between the two systems is the status of the lockout.

E. Conventional Interfaces

Rule 5: *The advanced technology should be behind the scenes.*

1) Operator Interface

The panels are designed such that primary operator control functions are implemented using physical breaker control switches and selector switches. Only secondary control functions such as reclose enable and pilot scheme enable are implemented using pushbuttons on the front of the relays.

The physical lockout relays are another example of using traditional operator indications. The operators find lockout relays on the panel the same as their other substations. Operating instructions for response to lockout conditions are no different for this substation than any other. From the front of the protection and control panels, no one knows that the lockout relays do not have traditional NO and normally closed (NC) contacts and carry out their function over an Ethernet network.

2) Technician Interface

Technicians use physical test switches when they are working on a relay to isolate trips. By opening the trip test switches and interrupting the connection between the trip contact and the trip buses, they can confidently work without worrying about tripping a circuit breaker that is in service. For GOOSE BFI and trip signals, there is no physical contact associated with the signals. To address this difference, we implemented GOOSE test switches to allow relay technicians to isolate these signals in exactly the same way that they isolate a physical trip or BFI contact [5].

Every relay has two poles of the trip isolation test switch wired to inputs. One is designated the GOOSE TX test switch, and the other is the GOOSE RX test switch.

When the TX test switch is open, the input is de-asserted. All relays subscribed to GOOSE messages from the relay under test see the test switch open status and will not activate the function that the GOOSE bit is intended to perform. By sending the test switch status along with the other bits in the message, it is possible to test mapping of bits through the network without actually tripping anything.

Similarly, when the GOOSE RX test switch is open, the input is de-asserted. The relay under test will not activate any function that it is supposed to perform upon assertion of that GOOSE bit.

This arrangement is immediately familiar to any technician testing a relay in this substation. The GOOSE isolation test switches are physically located in the same bank of test switches as all of the other trip isolation test switches. This makes it very easy for the technician to avoid making a mistake.

III. Protection and Control System Architecture

A. Intelligent Electronic Devices

There are two separate multifunction relays for each protection function, and taken together, they constitute two separate, redundant protection systems operating in parallel. In each system (P or S), there is a line protection relay for each bay and a bus protection relay for each bus (north and south). Additionally, there is a P and S reactor protection relay for the reactor breakers on Line 1 and Line 2. Finally, there are two pilot channel modules for sending and receiving transfer trips on Line 1 and Line 2 via either PLC (System P) or microwave (System S). All these IEDs require peer-to-peer signals sent over GOOSE messaging and comprise the GOOSE local-area network (LAN) that is connected together using a managed Ethernet switch. See Table I for a list of IED names and functions.

TABLE I
SUBSTATION PROTECTION DEVICES

System P	Description	System S
87BP-N	North bus protection	87BS-N
87BP-S	South bus protection	87BS-S
21P-SPVL	Line 1 protection	21S-SPVL
21P-HOLC	Line 2 protection	21S-HOLC
87LP-CIM1	Wind Farm 1 line protection	87LS-CIM1
87LP-CIM2	Wind Farm 2 line protection	87LS-CIM2
87RP-SPVL	Reactor 1 protection	67RS-SPVL
87RP-HOLC	Reactor 2 protection	67RS-HOLC
85P-SPVL	Line 1 pilot/DUTT/DTT	85S-SPVL
85P-HOLC	Line 2 pilot/DUTT/DTT	85S-HOLC
16-ESP1	Primary Ethernet switch	16-ESS1
16-ESP2	Failover Ethernet switch	16-ESS2

At the very beginning of the project, every device was given a unique identifier. This identifier was used throughout the project on all diagrams. This is an important step before generating any of the drawings to ensure consistency throughout the design documentation package. The identifier should be as short as possible because it will be used with every contact and input in the schematic package. It also must be unique. It can be extremely confusing when a device is identified differently on various drawings. This can raise questions when trying to follow complex systems through multiple drawings: Is this the device I think it is? Or is it a similar device?

The device code is based on the IEEE C37.2 Standard for Electrical Power System Device Function Numbers, Acronyms, and Contact Designations, except that we did not use Device Code 11 to designate the multifunction relays [6]. The project team determined that Device Code 11 conveys no information at all about the primary purpose of the device in question. Instead, we named each multifunction device based on its primary protection function.

Note the use of Device Code 16 (data communication device) for the Ethernet switches. This code was added in the 2008 update of this standard.

The naming convention used the following structure:
- First two or three digits for primary function (i.e., 87L for line differential).
- Next digit for system (i.e., P for primary).
- Hyphen, followed by a unique identifier.

Thus, device 87BS-N is easily identifiable as the secondary bus differential relay for the north bus.

B. Lockout Relaying

As previously described, the status of the lockout relay is transmitted over GOOSE messaging to the breaker control relays, thereby saving on wiring while keeping the physical lockout relay on the panel. In general then, the GOOSE message for each lockout function has at least two bits: lockout trip command (OUTxxx) and lockout status (INxxx). The receiving relay trips for either bit asserted.

At this substation, there are 16 lockout relays, as follows:
- Eight for BF (86BF).
- Two for buses (86B).
- Two for shunt reactors (86R).
- Four for DTT from each remote line terminal (86TT).

The north and south bus relays control the lockouts for bus protection as expected, but they also provide the decision making (timing and trip commands) for BF protection. The south bus relay makes BF decisions for the south bus breakers (482 and 682) as well as one of the midbreakers (688) and one of the reactor breakers (487). The north bus relay makes BF decisions for the remaining four breakers. Table II and Table III summarize the lockout relaying scheme for these lockouts.

TABLE II
NORTH BUS CONTROLLED LOCKOUT RELAYS

Lockout Relay	BF	Breaker Tripped		DTT TX	
86B-N	NA	582	782		
86BF-582	582	782	488	CIM2	
86BF-782	782	582	688	SPVL	
86BF-488	488	582	482	CIM2	HOLC
86BF-787	787	782	688	SPVL	

TABLE III
SOUTH BUS CONTROLLED LOCKOUT RELAYS

Lockout Relay	BF	Breaker Tripped		DTT TX	
86B-S	NA	482	682		
86BF-682	682	482	688	CIM1	
86BF-482	482	682	488	HOLC	
86BF-688	688	682	782	CIM1	SPVL
86BF-487	487	482	488	HOLC	

Besides the bus relay sending lockout trips and statuses to the breaker control relays, the line and reactor relays must send trip information (BFI) back to the BF relays. These BFI signals come from all tripping relays, including the pilot channel equipment for DUTT trips from remote substations. Immediately upon receiving a BFI signal from the tripping relay, the bus relay issues a retrip over GOOSE messaging. This ensures that if the BFI signal is spurious, only a single breaker erroneously trips rather than all surrounding breakers (disconnecting the entire transmission line), as would be the case if we waited for the BF timer.

If the bus relay still detects fault current after the BF timer expires, it trips the appropriate 86BF lockout relay. When the lockout relay changes state, it sends the lockout status to the breaker control relay to issue the trip and block automatic and manual closing.

There is a quality bit generated by the receiving relays. This bit is a logical 1 when the GOOSE link is okay and goes to logical 0 when the link is down. It does this by checking that the GOOSE message is received within the expected heartbeat period. If no message is received during this period, the relay knows there is a problem with the GOOSE message and de-asserts the quality bit. It is a good idea to supervise all received GOOSE bits with this quality bit in order to prevent making decisions with invalid data.

All of these data (BFI, retrips, lockout trips and statuses, and DTTs) are communicated over GOOSE messaging. Fig. 2 shows an example of the GOOSE data sent and received by the System P north bus relay, which controls all the lockout relays listed in Table II.
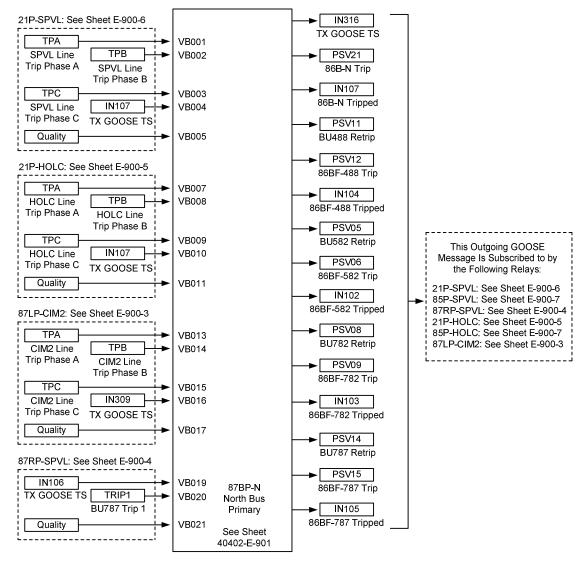

Fig. 2. Sample GOOSE Interdevice Logic Diagram

IV. GOOSE NETWORK ARCHITECTURE

A. The Managed Ethernet Switch

The managed Ethernet switch is the most important part of an IEC 61850 network. Its main function is shared by its less sophisticated counterpart, the unmanaged switch. Both devices inspect the incoming Ethernet frame for a destination address and forward the packet out of the appropriate port to the intended recipient. A managed switch, however, offers many more features. The most important feature exclusive to a managed switch is the ability to partition traffic using virtual LANs (VLANs). This allows different types of network traffic (video, voice, storage, and so on) to be assigned different broadcast domains with different priorities, keeping traffic segregated to avoid network congestion and apply different settings to dissimilar kinds of traffic.

In addition to VLAN configuration and related tools, managed switches support priority tagging, link aggregation, Spanning Tree Protocol (STP), and media access control (MAC) filtering. They usually have a command line interface and graphical web interface for configuration and monitoring the system using Simple Network Management Protocol (SNMP). The managed switch is an IED of equal sophistication and complexity as other protection and control system equipment and should be given due consideration in the design process.

The foremost considerations when choosing a network architecture are availability and security. If the network is unavailable, either entirely through a failed switch or partially through a failed network link, the protection functions that are implemented over GOOSE are lost. Redundancy, in both links and switches, is how we ensure maximum availability.

B. Cybersecurity

To ensure the network is secure from network-borne threats, any connections to outside networks must be protected by a firewall and encrypted. At this substation, we purposely maintained a physical separation between the GOOSE network and all outside networks so that cybersecurity is not an issue for the network. Part of the physical separation entails keeping SCADA functions entirely off of the GOOSE tripping network. The SCADA connections are traditional serial links to a remote terminal unit (RTU), while GOOSE connections are Ethernet links to a pair of switches. GOOSE messages are a data link layer function (in the Open Systems Interconnection [OSI] model) and therefore not routable. However, there is no router nor any other connection between the GOOSE network and communications outside of the substation, ensuring network security from all external threats.

Nevertheless, physical security is still an important consideration, as is proper authorization among utility employees and other substation visitors. Once an attacker has physical access to a machine, settings, connections, and network topology can all be changed, negating any security they might have originally provided.

C. Redundancy

At this substation, there are two redundant protection and control systems (P and S) that operate in parallel. Mirroring the protection, there are two Ethernet networks that are completely isolated and operate in parallel. The redundancy in this substation GOOSE network is of three forms. First, as mentioned previously, there are two separate redundant Ethernet networks (System P and System S). If the System P communications network fails entirely, there is still the System S Ethernet network and its associated protection and control system to carry on the protection and control functions for the substation, and vice versa.

Second, each IED has two redundant Ethernet ports set to failover mode. This mode uses a single link primarily but will transparently activate the secondary link if the primary link fails. This is contrasted with switched mode, which treats the two Ethernet ports as a simple, two-port switch, or fixed mode, which uses the primary port only and disables the secondary port.

Finally, to ensure a clean separation between the System P and System S communications networks, each Ethernet network must have a second switch for the IED standby port to failover to. This offers maximum availability because each network can lose any number of primary links, or an entire switch, without disrupting communications [7].

Each GOOSE network has its own redundant backup (two switches for each network, for a total of four switches), with each relay connected to one primary switch through its primary port and the backup switch through its standby failover port. Fig. 3 is a diagram of this redundant system (P only—the S communications system is identical).
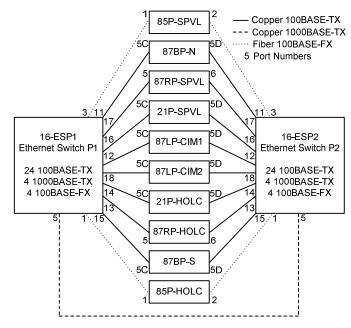

Fig. 3. Network Architecture Diagram

Because each relay is set to fail over to its standby port connected to the backup switch if the primary link stops working, the primary and backup switches in each system are connected together. The traffic from the secondary port has to get to all the other relays, which are still communicating over their primary port through the primary switch. Another failure mode occurs when an entire Ethernet switch fails. In this case, every relay simultaneously fails over to the backup switch after the short failover time-out period required to detect the loss of communications.

D. Implementation

GOOSE messaging is a publish-and-subscribe protocol. Each IED assigns a set of analog or Boolean values to a GOOSE message (in this project, all GOOSE data are Boolean), which it then publishes to the LAN. Other IEDs on the network have access to that message and may subscribe to those data or ignore them as the design requires.

GOOSE messages are sent using an exponential backoff period. When the data in a GOOSE message change, a new message is generated and broadcast immediately, or as fast as the relay hardware permits. This can usually occur within 2 milliseconds. Assuming there are no more changes to the data set, the next message is sent at 4 milliseconds, then 8 milliseconds, 16 milliseconds, and so on, until some maximum time period is reached. Even if no data change, a copy of the GOOSE message is repeated over and over on this heartbeat with a user-settable period, often 1 second, but in the case of this substation, 100 milliseconds. (A shorter heartbeat time uses extra bandwidth but allows the network to recognize broken links more quickly.) When this heartbeat period is reached, the message rate stays constant until such time as the data change again, in which case the exponential backoff starts again.

The software for configuring and subscribing to GOOSE message data varies with the IED manufacturer, but the output format for these settings is enforced by the IEC 61850 standard. Each IED has an IED Capability Description (ICD) file. This is an Extensible Markup Language (XML) document that describes the IED and the data available within it. Using the ICD file, IEC 61850 settings software is used to create a Configured IED Description (CID) file. This is the file that is then uploaded to the device, telling it what to subscribe to and what data to publish. ICD and CID files are part of the Substation Configuration Language (SCL) files. SCL is the IEC 61850 dialect of XML.

Each relay usually has dedicated logic bits for assigning GOOSE data to, called virtual bits, virtual inputs, communications inputs, or something similar. These bits can then be used in the IED internal programmable logic to construct the required functionality, just as we would use the status of hard-wired inputs or a remote control bit.

E. VLANs

VLANs allow us to create virtual cables, preventing any message not intended for a particular IED from using bandwidth on that IED network link or interface. This is how we minimize, as much as possible, the problems caused by the high traffic GOOSE messages can create during a data storm event such as a fault.

When the status of bits is changing, as in a fault or other substation event, GOOSE messages are sent very rapidly. This has the potential to threaten communications integrity because messages can be dropped when the network link becomes congested. This is prevented through the proper choice of hardware (such as high-capacity Ethernet switches), performing bandwidth calculations, and the correct application of tools such as VLANs.

In regular commercial networks, VLANs are often used to separate various kinds of traffic for differential treatment. For example, Voice over Internet Protocol (VoIP) traffic may be on one VLAN and regular network traffic on another. Or research and development traffic could be on one VLAN and human resources traffic on another. There are many examples.

Managed switches with VLAN capability have a setting for each port, which can be either edge or trunk. Trunk ports are usually used for passing data across a dispersed network to another (i.e., remote switch). Trunk ports pass all VLAN traffic. Edge ports pass data for their own VLAN only and block other traffic. This is how VLANs are traditionally used. In this way, VLANs are grouped together logically but may be physically distant. They may also be geographically close but logically separated.

In GOOSE networks, however, we reverse the traditional use of VLANs. Each GOOSE message is assigned its own unique VLAN identification (ID). Each port with a connected GOOSE IED is set to trunk. In this way, all ports can send and receive all VLAN traffic.

Why do we use VLANs if we allow all ports to pass all VLAN traffic? There is another setting for use with VLANs—on some switches it is a forbidden ports list, on others an allowed ports list. Because each GOOSE message is associated with a unique VLAN ID, we allow that VLAN traffic to egress only the ports for which a subscribing IED is connected (or forbid all ports except for those connected to a subscriber). This is what we mean by virtual cabling. GOOSE traffic is forbidden from using up bandwidth on links to relays that do not subscribe to it. GOOSE traffic is confined only to those devices that will use that message, similar to a dedicated copper cable.

It is good practice to have another VLAN with no forbidden ports: the management VLAN. It can be configured in the switch for all traffic that is not already tagged with a VLAN ID (i.e., non-GOOSE traffic) to be automatically assigned to the management VLAN upon ingress into a port. This provides engineering access to all the relays from a single convenient location, the network switch.

V. TESTING

Two inputs from a test switch are used to facilitate testing. The RX GOOSE test switch and the TX GOOSE test switch, respectively, cause the relay to ignore incoming GOOSE messages (the internal tripping logic is supervised with the test switch input status) or tell all subscriber relays to ignore messages from the sending device. This allows, for example, a

technician to manually trip a lockout relay and ensure that the corresponding GOOSE bits correctly assert in the receiving relays without tripping any breakers. Fig. 3 shows the TX GOOSE test switch for all incoming and outgoing GOOSE messages. The RX GOOSE test switch status is used only internally and is not sent to any other devices.

The test procedure verifying the programming for the GOOSE-based lockout tripping consists of opening the appropriate test switches (including the GOOSE test switches) and injecting current to simulate an appropriate fault (differential or BF) in each relay. We then verify the correct relay trips the correct lockout and that the correct GOOSE recipient relays trip the correct breakers according to the appropriate tripping table (e.g., Table II for the case of the north bus relay). Furthermore, we can verify all logic bits assert at the right time and in the right sequence by checking their sequence of events (SOE) records. With all IEDs synchronized to a satellite clock using IRIG-B, we can check sequence and timing across all relays. For each test, we collect the SOE report from each relay and combine it into a single station-wide SOE report. We repeat this procedure for each lockout scenario and for each system, P and S.

Table IV is a sample of a test SOE record generated during functional testing 86BF-487. This is a small portion from a greater than 100-row spreadsheet. It illustrates an SOE report from multiple devices, sorted according to the time of the bit state change. Multiple bits changed at the same time, and these are highlighted in order to show that this portion of the list represents a single instant in time. Spreadsheet tricks such as these can make the job of analyzing each test much easier.

The station-wide SOE report provides us the ability to analyze test results for sequential and timing accuracy from the office rather than during validation tests out in the field. In addition, the station-wide SOE report allows us to easily verify that no GOOSE bit is flying in the wrong direction. If a bit asserts in a relay that is not involved in the test, it means that the bit is mismapped and may cause an adjacent zone or breaker to trip. Negative tests (verifying that the wrong thing does not happen) are as important as positive tests (verifying that the correct thing happens).

Organization here is key. Maintaining a strict SOE point list, with identical point names across all devices, and paring the list down to only the relevant bits improve the ability of engineers to analyze the data. SOE point discipline makes each set of test results look very much like another, highlighting important differences that indicate, for example, a GOOSE bit asserting out of order.

For example, if a retrip signal were mismapped to the lockout trip virtual bit (VB), this would cause a misoperation, tripping surrounding breakers for a BF that has not happened.

A consistent set of virtual bit assignments helps too. If each VB number has a similar role across devices, this makes each test SOE record look very similar, which further highlights the differences that indicate a failed test. After testing the GOOSE-based tripping, we may restore the SOE point list to one more suitable and expansive for everyday use. Temporarily cutting down the list to only the relevant points eases the job of testing GOOSE-related protection functions

Compared to testing the protection scheme, testing the Ethernet network failure modes was quick and easy. We simply pull the primary network cable from each relay and verify that it fails over to the standby link within the failover period and that communication still occurs over the backup switch. After that, we pull fuses in order to power off a single switch and make sure that all connected devices fail over to the backup switch within the failover time period [8].

TABLE IV
SAMPLE OF 86BF-487 TEST SOE RECORD

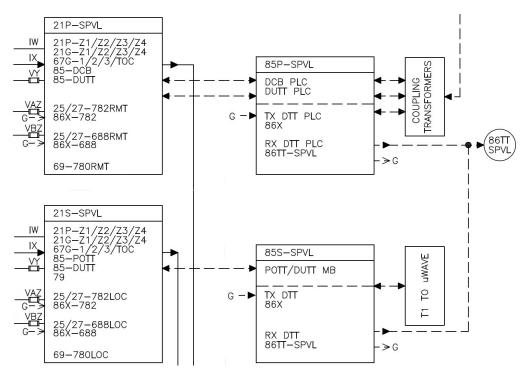| Relay	#	Date	Time	Element	State
87LS-CIM2	2	3/23/2012	14:43:08.048	VB001	0
21S-HOLC	2	3/23/2012	14:43:08.228	VB001	0
21S-SPVL	29	3/23/2012	14:43:09.430	OUT205	1
21S-SPVL	28	3/23/2012	14:43:09.430	OUT305	1
21S-SPVL	27	3/23/2012	14:43:09.430	OUT201	0
21S-SPVL	26	3/23/2012	14:43:09.430	OUT202	0
21S-SPVL	25	3/23/2012	14:43:09.430	OUT203	0
21S-SPVL	24	3/23/2012	14:43:09.430	OUT301	0
21S-SPVL	23	3/23/2012	14:43:09.430	OUT302	0
21S-SPVL	22	3/23/2012	14:43:09.430	OUT303	0
21S-SPVL	21	3/23/2012	14:43:09.430	VB009	0
87LS-CIM2	1	3/23/2012	14:43:11.394	VB001	1
21S-HOLC	1	3/23/2012	14:43:11.574	VB001	1
21S-SPVL	20	3/23/2012	14:43:12.775	OUT201	1
21S-SPVL	19	3/23/2012	14:43:12.775	OUT202	1
21S-SPVL	18	3/23/2012	14:43:12.775	OUT203	1
21S-SPVL	17	3/23/2012	14:43:12.775	OUT301	1
21S-SPVL	16	3/23/2012	14:43:12.775	OUT302	1
21S-SPVL	15	3/23/2012	14:43:12.775	OUT303	1
21S-SPVL	14	3/23/2012	14:43:12.775	OUT205	0
21S-SPVL	13	3/23/2012	14:43:12.775	OUT305	0
21S-SPVL	12	3/23/2012	14:43:12.775	VB009	1

Fig. 4.   List Box Method for Multifunction Relays in a Single-Line Diagram

VI. DOCUMENTATION

Because IEC 61850 is a relatively new technology, there has not yet been time to develop a customary set of documentation best practices. We needed to create a design documentation package that would contain all information required to understand, troubleshoot, and maintain the system. Single-line, communications, and schematic diagrams needed to be improved over traditional design documentation packages to adequately document the system.

A. Single-Line Diagram

A common occurrence today is single-line diagrams that show a relay labeled with Device Code 11, multifunction device, with no indication of what functions are implemented in the device. Traditional single-line diagrams showed all of the single-function devices, and it was easy to see what functionality was included in the substation protection and control system and what devices provided those functions.

In this project, with its high degree of integration, it would not be at all obvious which devices provided local or remote control functions, which devices provided BF functions, which devices provided lockout auxiliary functions, and so on.

To address this deficiency, we used the list box method suggested in [6] for the single-line diagram. Fig. 4 shows just the portion of the diagram dealing with the multifunction IEDs on Line 1.

From this diagram, we can easily see what protection elements are implemented on the line in the System P and System S relays. We can see that synchronism check and dead-line supervision for remote control (RMT) are implemented in the 21P-SPVL relay for Breakers 688 and 782. Similarly, we can see that synchronism check and dead-line supervision for local control (LOC) are implemented

in the 21S-SPVL relay for Breakers 688 and 782 as well as reclosing (79). The lockout auxiliary function (86X) designates that the relay receives lockout statuses and implements their function from the various lockout relays via GOOSE messaging. The interlock function (69) indicates that close supervision is provided for Line Switch 780 (not shown in Fig. 1) to prevent opening or closing the switch unless the line breakers are open. Similar detailed functional information can be discerned for the pilot relaying channel devices (85P-SPVL and 85S-SPVL).

The solid lines designate CT and VT connections. The dashed lines designate logic connections. The G indicates a GOOSE logic connection.

B. Communications Diagrams

Furthermore, there are many more connections possible to a modern relay than just hard-wired I/O and CT and VT connections. A complete drawing package must also incorporate a communications network architecture drawing. The ac and dc schematics detail the instrumentation and I/O connections, but a communications drawing is required to illustrate the serial port connections, Ethernet connections, and IRIG-B, among other possibilities such as radio links, antenna connections, and multiplexers.

The communications drawing for the GOOSE LAN is simple compared to many communications diagrams. It shows Ethernet switches, Ethernet cables, the connected IEDs, and associated information such as port assignments, VLAN IDs, and Internet Protocol (IP) addresses. See Fig. 3 for a portion of the communications diagram, also called a network architecture diagram.

We modeled our GOOSE documents after the requirements of multifunction microprocessor-based relays. In modern

relays, schematics are not enough to fully describe the function of the relay. Internal logic needs to be documented. Built-in functions are described in the instruction manual, but settings and user logic must also be documented [2].

To this end, a set of logic diagrams is used to illustrate the internal functions of each microprocessor-based relay. Starting with external elements (CT and VT modules, hard-wired inputs, and communications-based remote controls), the relay logic diagram details the exact logic used by the relay to determine output contact statuses.

In addition to the relay logic diagrams, which detail the custom relay settings from input to output, we issued another logic drawing called the interdevice logic diagram to cover the gap between relays over GOOSE messaging. This illustrates which specific logic bits from the sending relay make up the GOOSE message and which virtual bits they are assigned to in each subscribing relay. An example is shown Fig. 2.

GOOSE interdevice logic diagrams have the same structure as a relay logic diagram, including text boxes with logic bits and a short description of each bit function underneath. These are treated as either inputs or outputs depending on whether the relay is receiving them or publishing them. There is no actual logic in these diagrams, however; the relay is shown as a black box. The role of these diagrams is to link the bits in one relay—protection variables, input and output statuses, and trips—to the logic bits in another relay, usually with virtual bits (VBxxx) similar to the way that the schematic diagrams link hard-wired inputs and outputs between devices. Interdevice logic diagrams complete the picture that would be hidden if we only documented the internal logic in the relays. Interdevice logic diagrams may be considered analogous to dc schematics in a traditional copper I/O-based scheme. They answer the question, "Where do these statuses come from?"

Each GOOSE interdevice logic diagram shows the received GOOSE messages, along with the virtual bits they are assigned to in the receiving relay. They reference the drawing for the internal logic in that relay so we can follow the GOOSE bits into the relay logic diagram. They also show all outgoing GOOSE bits as collected in one or more GOOSE messages. Finally, the GOOSE interdevice logic diagram lists the subscribing relays and references their respective GOOSE logic diagrams.

C. As-Found Settings

One additional documentation challenge concerns as-found settings. Protection and other relay settings are often downloaded from the device over a serial cable, backing up the known good settings (as found) before making potentially regressive changes. In the case of GOOSE, we usually must download the CID file from every IED in order to obtain all the publish and subscribe relationships between them. GOOSE settings and settings software tend to be substation-oriented rather than device-oriented. This means we must change our perspective from device settings to substation settings when designing, organizing, or making changes to the settings.

VII. COMPARISON TO TRADITIONAL METHODS

See Fig. 5 for an illustration of the relationships between GOOSE messages. Each line represents a logical connection between devices (or virtual cable), and the arrow represents the directionality of the information (some connections require data going both ways, requiring two GOOSE messages). Compare the complexity of the relationships in Fig. 5 with the relatively simple star network in Fig. 3. Now consider that each GOOSE message contains up to 15 statuses (in this project, GOOSE messages in general can contain up to an entire Ethernet frame [1,500 bytes], which works out to over 200 logic bits per message) and each device can transmit up to eight or more separate GOOSE messages. It is evident that the complexity in a hard-wired I/O approach to this application would have been much greater. The more data we want to send, the more complicated an alternative hard-wired system needs to be.
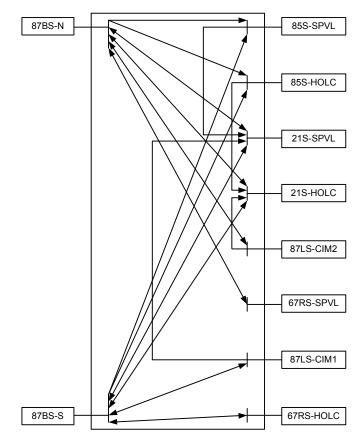

Fig. 5.   GOOSE Message Relationships

In general, communications networks with a point-to-point topology, like copper I/O, are exponentially more complex than star communications networks such as an Ethernet LAN.

In addition to simplicity, GOOSE offers extra redundancy. Using I/O contacts in this scheme would have left a single point of failure for each communicated bit. Having two redundant protection systems keeps the system as a whole from having a single point of failure, but in the GOOSE solution, there are two possible paths for information to travel for each relay in each system, doubling the redundancy. This

extra redundancy costs money (for more switches and Ethernet cabling), impacting the budget. However, the same redundancy is vastly more expensive and often not even possible in most hard-wired I/O alternatives.

Testing this system took a similar level of effort compared to testing a hard-wired system. It required opening appropriate test switches, simulating a fault, and analyzing SOE report and event data from the relays. However, fixing a problem with an incorrect or omitted GOOSE message is quicker and less expensive than rewiring a mistaken input or output contact.

The price differential between this GOOSE solution and a hypothetical traditional hard-wired solution was not studied. However, based on complexity analysis alone, it stands to reason that GOOSE is much more economical to implement and maintain. The redundancy, ease of installation, and ability to quickly adapt to future substation modifications are further advantages.

VIII. Conclusion

Using IEC 61850 GOOSE messaging greatly simplified the implementation and installation of the BF and lockout relaying schemes at this substation. Using GOOSE messaging was simpler; easier to design, install, and maintain; and therefore likely much less expensive than a traditional hard-wired I/O solution.

However, the new system architectures require careful planning. By establishing rules up front on how GOOSE would be used in the substation protection and control design, we were able to ensure consistency in logical application of this new technology.

The new technology also presents challenges for traditional processes in testing and documentation. New methods are required to adequately document the design, build in testability, and develop commissioning test procedures.

The new technology can be implemented without significantly changing operator interfaces with the associated impacts on training and operating instructions. While the operator interface remains familiar, new test procedures and design philosophies were found to be foreign to the relay technicians at the utility. In the future, we suggest training them early and ensuring support for the technology from the technicians as well as the engineers. However, the advanced technology was used mostly behind the scenes in ways that provided the most value and in places where it would have minimal impact on primary functions if it failed to live up to its potential.

For the past 40 years, advances in computer networks, plus the exponential price decreases afforded by Moore's Law, have ushered in an unprecedented era in communications technology. Traditionally, power system operators have not seen a need for the bandwidth and flexibility offered by modern computer networking technology, so point-to-point solutions such as hard-wired I/O and serial communications have been adequate. As innovation continues to disrupt the power transmission and distribution industry, with more and more data that need to be used and therefore communicated between subsystems and IEDs, more connections are applied.

Fortunately, we do not have to invent the systems required for these changes. We can make use of widely used and established technologies such as Ethernet, IP, and fiber optics. The modern microprocessor-based devices controlling the power system today already have the capability to take advantage of these technologies, with IEC 61850 compliance built into the IEDs.

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X. Biographies

Derek Vonada received his BS, cum laude, from Kansas State University in 2010. Since then, he has worked for Sunflower Electric Power Corporation as a transmission engineer and project manager.

Gary Condict received his BS, cum laude, from Wichita State University in 1990. After graduation, he worked as telecommunications supervisor for Centel Electric in Great Bend, Kansas. Centel was sold to Utilicorp in 1991, which later became Aquila, where he held positions in IT, engineering, and operations. He was system operations supervisor for Aquila in Pueblo, Colorado for three years and later headed the SCADA replacement projects for both Missouri and Colorado. He joined Sunflower Electric Power Corporation in 2008 as a system protection engineer.

Jonathan Martin is a managing engineer at UC Synergetic (previously Pike Energy Solutions) in Charlotte, North Carolina. Jonathan received his BS in Electrical Engineering from the University of Alberta, Canada in 1995. Jonathan spent the first 10 years of his career commissioning substations all over North America and has since been involved with all aspects of substation design and engineering, with emphasis in protection and controls. Jonathan is a registered professional engineer in 11 states and one province.

Jason Keeney received his BS, cum laude, from Southern Illinois University Edwardsville in 2005. After graduation, he worked as a system protection engineer at Ameren Illinois Utilities for 4 years. He is presently a protection engineer in the engineering services division at Schweitzer Engineering Laboratories, Inc. and a registered professional engineer.

Michael J. Thompson received his BS, magna cum laude, from Bradley University in 1981 and an MBA from Eastern Illinois University in 1991. He has broad experience in the field of power system operations and protection. Upon graduating, he served nearly 15 years at Central Illinois Public Service (now Ameren), where he worked in distribution and substation field engineering before taking over responsibility for system protection engineering. Prior to joining Schweitzer Engineering Laboratories, Inc. (SEL) in 2001, he was involved in the development of several numerical protective relays while working at Basler Electric. He is presently a principal engineer in the engineering services division at SEL, a senior member of the IEEE, chairman of the Substation Protection Subcommittee of the IEEE PES Power System Relaying Committee, and a registered professional engineer. Michael was a contributor to the reference book *Modern Solutions for the Protection, Control, and Monitoring of Electric Power Systems*, has published numerous technical papers, and has a number of patents associated with power system protection and control.

Josh Bariola received his BS, cum laude, from Southern Illinois University Edwardsville in 2009. Since 2011, he has worked for Schweitzer Engineering Laboratories, Inc. as an automation engineer in the engineering services division.

Dave Pool is a senior automation specialist in engineering services at Schweitzer Engineering Laboratories, Inc. (SEL) in Golden, Colorado. Dave has 37 years of combined utility experience at Sunflower Electric Power Corporation (SEPC), ten of which were in the generation department at Garden City and Holcomb. He later transferred to system operations as a system operator for 10 years and then transferred to the transmission department, where he worked as a relay technician before joining SEL. Dave was responsible for the design, integration, and automation of substation SCADA communications for SEPC.