DIGITAL SUBSTATION EXPERIENCE WITH THE CITY OF RED DEER

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ABSTRACT

Two substation automation system (SAS) replacement projects operating with redundant IEC61850-8-1 station buses have been successfully commissioned and commenced commercial services. The City of Red Deer, a municipality with a population of about 100,000, collaborated closely with an engineering consultant and SA equipment vendor during various project milestones. This paper reviews and shares the benefits experienced and lessons learned from the design, execution, commissioning and operation perspectives of the two upgrade projects, paying close attention in particular to:

- Implementation of numerical intelligent electronic devices (IED) for versatile protection, automation and control (PAC) applications utilizing IEC61850 Generic Object Oriented Substation Event (GOOSE) and Manufacturing Message Specification (MMS) assisted communication features
- Application of parallel redundancy protocol (PRP) to achieve true network redundancy
- Benefits attained from factory acceptance and resulting expedited commissioning experience
- Lessons learned from the two digital substation experiences

The first substation upgraded had a main-tie-main air insulated bus arrangement, whereas the second one was a double-bus-single-breaker gas insulated switchgear (GIS) system. Each project lends its unique attributes to the discussion of the above listed points and will be referred to and compared with throughout the context of this paper.

I. INTRODUCTION

The City of Red Deer Electric Light and Power (The City), a publicly owned transmission and distribution facility owner serving the municipality of Red Deer, Alberta, Canada, has completed two major refurbishment projects of their 138-25 KV substations, designated SS14 and SS15, by the end of 2013. The two stations, equipped with only hard-wired based centralized RTU systems and protected by outdated electro-mechanical relays, were in need of major overhaul inside the control house not only to improve service reliability but also to prepare for the utility's vision of a smarter distribution grid down the road. The 25 KV switchgear in SS15 was also scheduled to be replaced as part of the project scope with a state-of-the-art modern GIS. The City contracted Phasor Engineering Inc. (The Engineer) for both jobs to design, test and commission the new substation automation systems (SAS) and supervise the swing-over to the new switchgear, in the case of SS15. The City and The Engineer jointly issued technical SAS tenders [1] for the two modernization projects which contained the following general requirements:

- Transformer differential, bus differential, and feeder protection and control functionality in multi-functional IEDs
- The selected communication protocol for the substation LAN is IEC 61850-8-1 MMS for vertical communication and IEC61850-8-1 GOOSE for horizontal signaling. The SAS shall also support remote control and monitoring from/to SCADA centers via gateways over the DNP 3.0 WAN/LAN protocol

- Redundant IEC 61850 station LANs running the Parallel Redundancy Protocol (PRP) with zero fail-over time is required to ensure P&C dependability and security.
- The SAS shall incorporate the control (select-before-operate), monitoring (event list, alarm annunciation, measurement display, disturbance retrieval, trending report), automation (dynamic bus transfer scheme) as well as protection functions.

II. SUBSTATION CONFIGURATIONS

Substation #14 is a live operating station located in the City's north-east quadrant. The substation consists of an air insulated (AI) outdoor bus/breaker assembly in a main-tie-main bus configuration. Two 138–25kV Dy1 connected power transformers supply ten 25kV (MV) feeder circuits, divided evenly by a normally open tie breaker. The transformers are not to be operated in parallel.

The 138kV (HV) section of the station is owned and operated by the transmission facility operator, Altalink, who also employed Phasor Engineering Inc. to replace the 138 KV portion of the PAC system. The new automation system for Altalink is based on the DNP 3.0 technology and hard wired IED signaling. The P&C control building was replaced to accommodate the two different automaton systems in adjacent rooms. The ownership demarcation between the two transmission facility operators is at the HV motor operated disconnect (MOD) switches and HV bus intertie as shown on the single line diagram in figure 1..

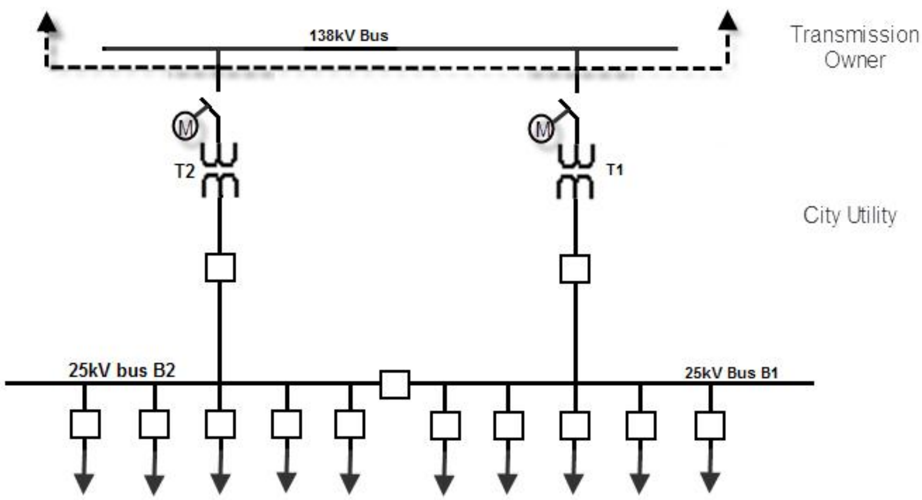

Figure 1: Single Line Diagram of SS14

Substation #15, situated in downtown Red Deer, was the second live station in line for modernization of its PAC system as well as its main 25 kV apparatus. The HV portion of the substation is similar to that of SS14, consisting of an 138KV AI bus section owned and operated by Altalink, but the 25 KV metal clad switchgear in simple bus arrangement, owned and operated by The City, was to be replaced with GIS. The new GIS employs a double-bus, single-breaker design with a tie breaker that allows on-load bus transfers to assist in transformer off-loading and balancing. The compact GIS designed frees up significant space to permit future expansion of the GIS lineup and addition of a third power transformer bay to the system. A sample SLD of SS15 is shown Figure 2 .

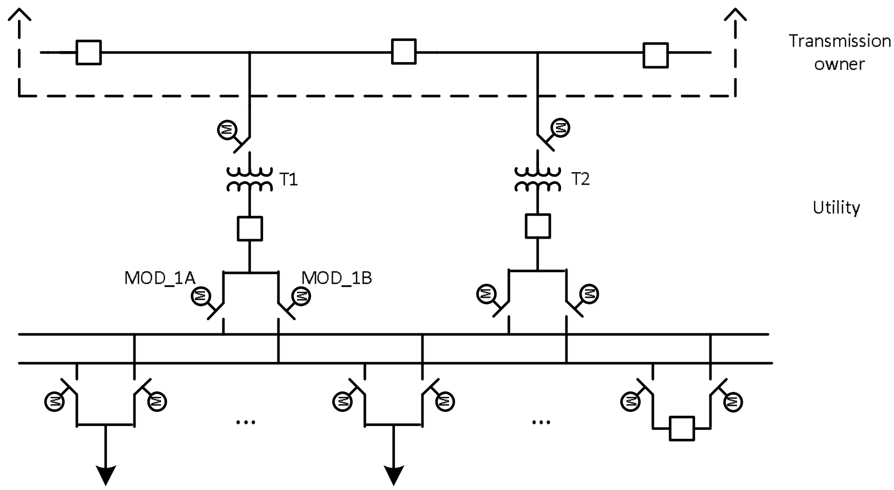

Figure 2: Single Line Diagram of SS15

III. DIGITAL SUBSTATION AUTOMATION DESIGN PHILOSOPHY & IMPLEMENTATION

In MV distribution substations only the HV transformers require full redundant protection units. The City and The Engineer decided to deviate from the typical multi-vendor protection practice in the two projects following the ruling that not only the transformer capacity was small (35 MVA) but also the fact that distinctly different protection philosophies, eg. 87, 50/51, and 63 mechanical protections, had been applied to protect the transformers. The advantages of sourcing PAC devices from a single vendor in pioneering 61850 projects, including reduced learning curve, limited engineering/operating risks and shortened design, engineering and commissioning duration, to just name a few, was considered to have out-weighed the risks of coincidental functional or hardware failure in the same vendor's products.

Visions to experiment multi-vendor interoperability for future substation upgrade projects were set, but time and resources for comprehensive lab testing to acquire products knowledge and learn different configuration procedures and tools have to be invested.

In each project a number of protection panels and one automation panel were designed and built to house all protection, control and networking equipment. In the initial SS14 project mechanical tripping relays located in the bus panel were employed to assist tripping and improve main relay contact breaking duty. They were opted out of design in the subsequent SS15 project when The City and The Engineer could not justify their high expense against the slim likelihood of a breaker failure occurrence in a modern GIS system. Mechanical local/remote selector and apparatus control switches were installed on SS14 panels, as per the request of The City's maintenance and operation team to integrate into the station control design scheme as part of the learning strategy to familiarize and gain confidence with the new digital control technology. Yet they were also removed from the SS15 design owing to the significant saving in material, installation and commissioning associated costs. A comparison of the panels from the two projects is shown in Figure 3.

In the following section the PAC philosophies applied to different protective IEDs were described in details. Emphasis are made to the SS15 due to its revised and more comprehensive automation requirements issued by The City, yet additional notes will be provided on SS14 whenever appropriate.

SS14 SS15

Figure 3: Sample Panel Lineup for SS14 (Left) and SS15 (Right)

III.1. Transformer Bays Protection, Automation and Control

Each transformer bay is protected by a dedicated protection panel that accommodates two identical multifunctional IEDs and external lockout devices. The main PAC features implemented in the transformer IED are summarized below:

- Protection features:

  87T, REF and 50/51 backup protection elements were applied to provide main and backup protection of the transformer and downstream system. All IED protection operations would trip the MV breaker via direct hard-wired relay outputs and initiate breaker failure protection (GOOSE). In SS14 the same signals also operated trip re-enforcement relays, later removed in the SS15 design. Transformer internal fault operations (eg. 87T and REF) would also open the HV MOD and energize a hard-wired relay contact to Altalink's marshalling point to trip and lock-out the HV circuit breakers. A 138 KV bus restoration sequence would then start to re-close the breakers once the faulted transformer's MOD is opened. Breaker failure of the transformer MV breaker (GOOSE) would also transfer trip the HV breakers via the transformer IED.

- Control features

  In SS15 mechanical local/remote selector switches (43) and control switches (52CS) were replaced and superseded by the keypad operated multi-position selection and apparatus control buttons, directly executable via the IED HMI (Figure 4).

  Control operations for MV circuit breaker and MV and HV MODs were executed in a secure "select-before-operate" manner. The breaker and MOD control is supervised by GOOSE assisted interlocking and bus transfer logic for added security. Other control operations implemented through the transformer IEDs include local/remote 86 lock-out reset and on-load tap changer (LTC) control.

  Especially worth noting was the parallel LTC control requirement specified by The City which was not required back in the SS14 project. The Engineer implemented the parallel LTC control using the "master-slave" mode for its simplicity compared to the circulating current reduction method. LTC control commands can be executed directly from the transformer IED, eliminating the need of a dedicated LTC controller and saving extra installation and maintenance overhead. The IED is equipped with parallel LTC control functionality, modelled in standardized IEC61850 voltage control (ATCC) and LTC interfacing (YLTC) abstract data models and services. To accomplish parallel control in the master-salve mode, the LTC controllers involved in a "parallel group" have to communicate with one another to exchange pertinent information. A data set containing predefined analog and binary data such as measured bus voltages, load currents, tap positions, to name a few, is exchanged between the two transformer IEDs (GOOSE).

Remote control commands were issued by the substation gateway using the IEC 61850-MMS protocol.

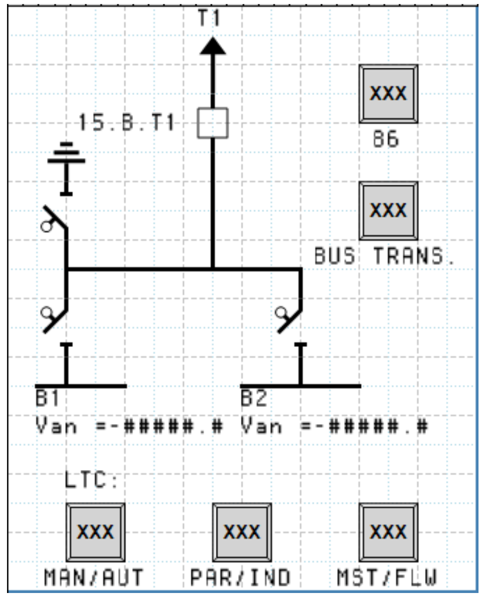

Figure 4: Sample Local HMI control in the Transformer IED

- Automation features:

  Various user customized and vendor provided automation features were implemented and applied in the projects utilizing digital IEC 61850 communication:

  - Process monitoring

    Information reported to the station HMI/gateway to generate alarms, sequence of events and update the SLD included bay apparatus positions, internal protection function operations, external hardwired non-electrical transformer monitors and protective devices operations and alarms, switchgear cell mechanical alarms and other customized logic points

  - Apparatus positions

    The local MOD positions are required by the bus IED to execute its dynamic zone selection algorithm to selectively connect the local bay current measurement to the correct bus differential zone and ensure secure protection operation. In SS15 open and close MOD positions for the 13 feeder bays and 2 transformer incoming bays would indicate a total of:

    $$2\,\frac{MOD}{Bay} \times 15\,Bay \times 2\,\frac{Signal}{MOD} = 60\,Signals,$$

    , not including other required inter-IED signal exchanges.

    IEC61850 GOOSE had been chosen for the obvious reason to handle the signaling requirement. Had the same number of signals been exchanged using the traditional hard wiring method, a minimum of 60 relay digital inputs would have been required, not to mention the cabling, termination and wiring work. Even a modern numerical IED might not have the physical hardware capacity to support that amount of information exchanged. IEC 61850 by far has proven to be the most economical, efficient and elegant solution for this automation task alone.

- Local/remote circuit breaker control Interlock

  In the event of a bus fault, closing circuit breakers back to the bus is conventionally prohibited by electrically hard-wiring normally closed contacts of the lockout relay in the breaker close circuits. Similar to the argument given prior, the varying number of bays that can potentially be connected to a faulted bus makes electrical connection expensive and infeasible. Transmitting the normally closed lockout signal to bay IEDs via GOOSE proved to be a more economical and viable solution for a block close application. Locally the bus lockout status was combined with MOD positions and breaker health alarms to form the close interlock logic.

- Automatic bus transfer scheme

  The City stipulated that an automated bus transfer procedure be implemented by The Engineer in each bay IED to allow for load balancing and equipment maintenance needs. In order to transfer a live feeder from Bus A to B, the tie breaker must be first closed. MOD_B can then be safely closed followed by opening of MOD_A (see Figure 2). IEC61850 GOOSE messages containing transfer command, permissive and supervision signals are exchanged between the bay IEDs and the tie IED to ensure safe operations. In general the following operating sequence was implemented in the bay IEDs:

  - Local bay IED (HMI) or remote SCADA (61850 MMS) can initiate transfer
  - Local MOD and tie breaker positions (GOOSE) are latched in memory. Review conditions to initiate transfer to the open bus
  - Send close command (GOOSE) to tie IED, if required
  - Received updated permissive from the tie IED (GOOSE)
  - Execute transfer, ie. Close MOD_B and open MOD_A
  - Send open command to tie IED to restore the tie breaker to the original position (GOOSE), if required

IEC61850 GOOSE applications implemented in the transformer IEDs are summarized in Table 1

Bus IED	**GOOSE Descriptions**
Published	- Breaker failure protection initiation. This signal generates a re-trip of the local breaker and back-up trips of adjacent breakers - Transformer bay MOD status. These signals are used by the dynamic zone selection and interconnection feature in the bus IED.
Received	- BF of transformer MV breaker, backup tripping signal. The signal is received and passed to Altalink via hardware output contacts to trip and lockout the 138 KV breakers. - Bus protection Lockout. This signal is received to form part of the close interlock logic

Transformer IED	**GOOSE Descriptions**
Published	- Predefined LTC analog and status quantities. These signals are exchanged between transformer IEDs connected to the same bus to facilitate master-slave parallel LTC control

Received	- Predefined LTC analog and status quantities. These signals are exchanged between transformer IEDs connected to the same bus to facilitate master-slave parallel LTC control

Tie IED	GOOSE Descriptions
Published	- Tie close command. Once received, the tie IED closes the tie breaker/MODs to prepare for transfer - Tie open command. Once received, the tie IED opens the tie breaker to end the transfer process
Received	- Tie transfer permissive. This signal consists of tie breaker and MOD group combined positions that indicate whether it's safe to start bus transfer in the local bay

Table 1: GOOSE Applications in Transformer Bay IEDs

III.2. MV Bus Protection, Automation and Control

The bus protection panel consists of three bus differential multifunction IEDs and other auxiliary lockout devices to implement the PAC functions described below.

- Protection features

  Bus differential protection (87B):

  The selected vendor's low impedance bus differential IED can protect up to 24 connected bays in a single-phase variant or 8 connected bays in a three-phase variant, each comprising two independent differential protection zones and one check-zone. In a main-tie-main MV bus configuration with 6 connected bays per bus, as shown in Figure 1, two three-phase variant IEDs were procured to protect each bus using a permanent 87B zone assignment. In SS15, with the requirement of dynamic switching any energized bay to any of the two buses, as shown in Figure 2, three single-phase variant IEDs with dual-zone selection and interconnection algorithm would have to be employed to reliably protect each bus/phase and accommodate the potential number of feeders connected to one bus.

  87B operation trips breakers, initiates breaker failure protections, and operates an auxiliary lockout relay to block all breakers on the bus from closing (GOOSE). Phase-segregated bus differential trips are hardwired to trip all connected circuit breakers and published via GOOSE messages to the other two IEDs to force three-phase operations.

  The selected vendor's IED, featuring flexible and software based dynamic zone selection and interconnection functionality, enabled The Engineer to implement the multi-zone bus protection efficiently and securely while reducing design and engineering efforts.

  The dynamic zone selection function monitors the MOD status of individual bays (GOOSE) to determine which differential protection zone a connected bay should be assigned to. The dynamic zone selection function provides the following added convenience and security to multi-zone bus protection design, engineering and operations:

  - Linking the connected bay seamlessly to the correct differential protection zone without the need of any external switching device
  - Selective operation of bus differential protection to ensure tripping only the circuit breakers connected to the faulty zone
  - Efficient connection of a bay level backup tripping signal (eg. an external BF trip) to trip only the breakers to the connected zone (bus).

The automatic zone interconnection feature merges the two differential zones when two MV buses are interconnected out of operational requirements, such as during bus transfer for load balancing, in order to ensure correct operation of the differential functions. Bay current measurements are automatically routed to both differential protection zones by software algorithms.

A check zone function was also utilized to supervise the operation of each differential protection zone to ensure secure operation in the case of erroneous MOD position indications.

Breaker failure protection:

The bus protective IED features 24 single-phase or 8 three-phase breaker failure protection functions depending on the variant. The benefits of functionally integrating BF protection in the bus IED instead of using separate devices are cost reduction and space saving. The other crucial engineering advantages were the abilities to leverage the automated zone selection feature and share the same tripping output contact per bay for BF backup tripping. In a double-breaker configuration, these engineering benefits have proved invaluable to ensure selective bus clearance for a breaker failure condition and significant wire reduction should dedicated BF relays have been applied.

Phase-segregated BF protection of the feeder/transformer bay is initiated via GOOSE messages published by respective bay IEDs to all three bus IEDs. BF protection operations involve re-tripping without delay the initiating MV breaker and backup tripping, when applicable, the select breakers on the bus through electrical hardwire connections, with the exception of transformer bay. In which case a GOOSE message will be published to the transformer IED to transfer trip the Altalink HV breakers.

- Control

  There are no apparatus control functions configured in the bus IEDs. All apparatus control duties are carried out in the bay units. The only control action performed through the bus is local and remote (IEC61850 MMS) reset of trip lockouts.

- Automation

  There is no customized automation features designed in the bus IEDs. The bus IEDs report to the station HMI/gateway internal information such as protection function operations using IEC61850 MMS protocol. Hard-wired points such as IEDs self-diagnostic alarms and HV breaker positions are also reported via the bus IEDs.

IEC61850 GOOSE applications implemented in the bus IEDs are summarized in

Table 2. The information exchanges with the transformer/feeder bay IEDs are reverse of those in Table 1 and Table 3 so are not duplicated here.

Other 2 bus IEDs	**GOOSE Descriptions**
Published	- Bus differential trip. The signal ensures 3-phase IED operations.
Received	- Bus differential trip. The signal ensures 3-phase IED operations.

Table 2: GOOSE Applications in Bus IEDs

III.3. Feeder Bays and Tie Protection, Automation and Control

The feeder protection panel can accommodate as many as 6 feeder IEDs in SS15, thanks to the space saving resulting from removal of mechanical selector and control switches. The tie IED is designed and engineered for control and automation purposes only. The feeder/tie IED has the following PAC features implemented:

- Protection features

  An instantaneous over-current function is applied to trigger a fuse saving reclose scheme. The high-speed element is set as sensitively as possible to detect faults as far along the main feeder trunk and branches yet secure enough to ride through the worst case inrush conditions. This element is disabled during the auto-reclose cycle to ensure coordination with downstream fuses. The inverse time over-current function is applied to ensure coordination with downstream fuses while protecting against feeder overloads.

  Feeder protection operations would trip and reclose the feeder breaker through electrical hard-wiring. At the same time, the trip signal initiates BF protection and in the case of SS14, operates the trip enforcement relay (GOOSE) as well.

  Under-frequency load shedding protection is enabled in selected feeder IEDs to prevent frequency collapse as directive from the provincial transmission system operator.

- Control features

  Similar to the transformer IEDs, keypad operated selection and control functionality have been fully configured and utilized in the SS15 project. The operator position is normally left in “remote” to allow for substation HMI and SCADA control. The control features implemented in the feeder/tie IEDs includes:

  - Breaker, MODs apparatus control with GOOSE assisted block close and interlocking logic
  - Local/remote on/off control of the auto-reclosing function. Auto-reclosing is automatically disabled during a “hot-line” condition
  - Local/remote on/off control of under-frequency load shedding functions
  - Local/remote on/off control of hot line operation mode. During a “hot line work” condition, protection setting group is dynamically switched to Group 2 with the auto-reclosing function disabled and a very sensitive instantaneous over-current set point to ensure workers’ safety.

  Figure xx shows a sample IED HMI design for the control operations:

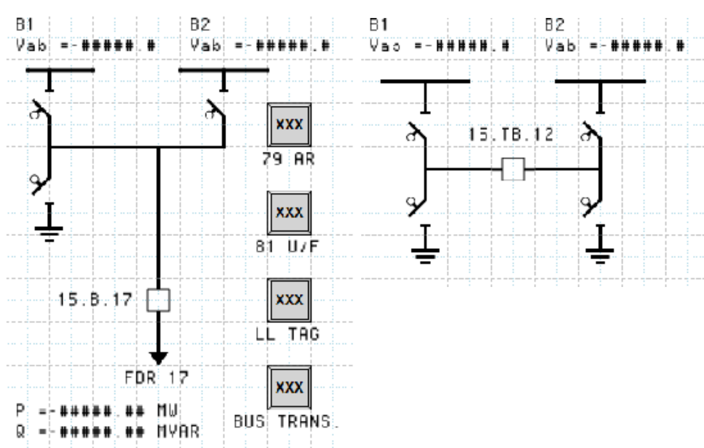

Figure 5: Sample Feeder and Tie IED HMI Design for Control Operations

- Automation features
    - Feeder IEDs report to the station HMI/gateway (IEC61850 MMS) internal information such as main apparatus positions and protection function operations. Other hard-wired information such as switchgear mechanical alarms are also reported.
    - Similar automatic bus transfer logic is implemented in each of the feeder IEDs to allow for load balancing or maintenance purposes. The operating sequence followed by the feeder IEDs is described in the transformer bay section and not repeated here.

      The tie IED communicates with the bay IEDs (GOOSE) to exchange pertinent commands and permissive signals to execute the transfer scheme. During the transfer process the tie IED responds to commands issued by the bay IEDs to adjust the breaker/MOD group positions and confirm by sending the corresponding permissive signals.

IEC61850 GOOSE applications implemented in the feeder/tie IEDs are summarized in Table 3.

Bus IED	**GOOSE Descriptions**
Published	- Breaker failure protection initiation: This signal generates a re-trip of the local breaker and back-up trips of adjacent breakers - Feeder bay MOD status. These signals are used by the dynamic zone selection and interconnection feature in the bus IED.
Received	- Bus protection Lockout. This signal is received to form part of the breaker close interlock logic

Tie IED	**GOOSE Descriptions**
Published	- Tie close command. Once received, the tie IED closes the tie breaker/MODs to prepare for transfer - Tie open command. Once received, the tie IED opens the tie breaker to end the transfer process
Received	- Tie ready to transfer permissive. This signal consists of tie breaker and MOD group combined positions that indicate whether it's safe to start bus transfer in the local bay

Table 3: GOOSE Applications in Feeder/Tie IEDs

IV. Automation System Architecture & SCADA Functionality

Figure 6 illustrates the SAS system architecture implemented in this project. The IEC61850 station bus interconnects the multifunction IEDs and station HMI/gateway unit through two independent LANs in a double star configuration. One 19''panel is dedicated to house the station control, monitoring and communication equipment namely the station HMI/Gateway computer, the GPS clock and the Ethernet switches.

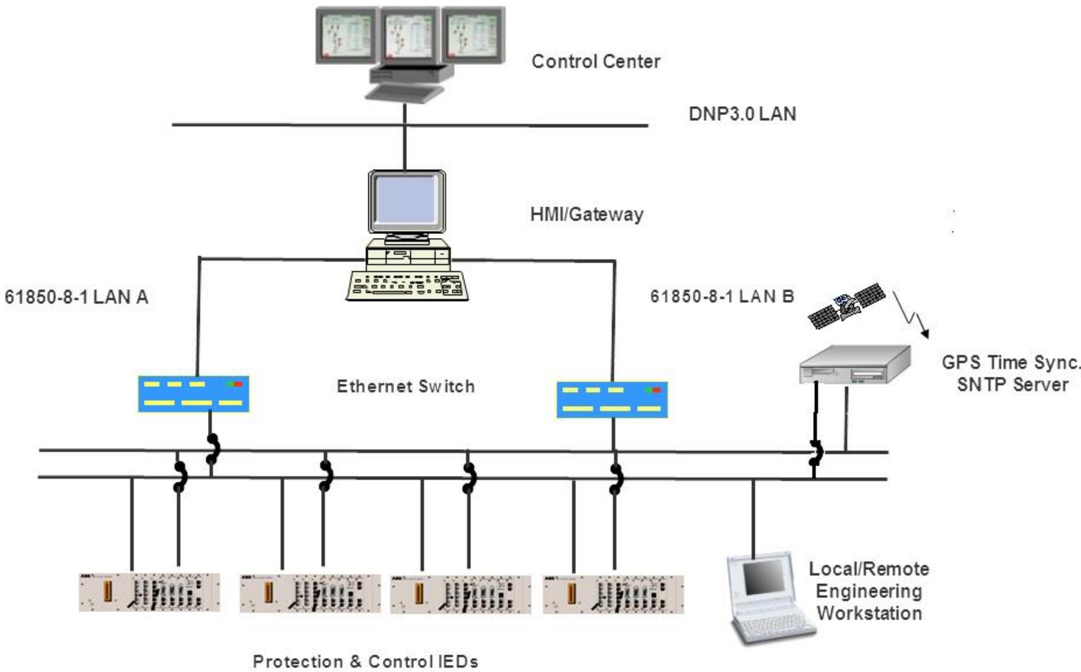

Figure 6: Simplified SA System Architecture

Each protective IED is equipped with two rear 100BaseFX-ST Ethernet modules that support the IEC-61439 Parallel Redundancy Protocol (PRP) [5]. Operating an IEC61850 station with PRP provides complete communication redundancy and network availability upon any single point of network failure. The two Ethernet ports are connected to two separate Ethernet switches forming two independent physical networks. The IED application sends the same Ethernet frames through each of the two ports onto the physically separate networks. The IED receives and processes the first datagram and rejects the second identical datagram that arrives later to achieve the proclaimed redundancy.

The GPS clock broadcasts time synchronizing data frames to the HMI/gateway and IEDs over the LANs in fail-over mode using the Simple Network Time Protocol (SNTP) with accuracy down to 1ms. This accuracy is sufficient for system events and disturbance recording applications.

Local and remote workstations and printers can be connected to either LAN to gain access to the IED configuration, settings, event reports and disturbance recordings. Access to the above information can be guarded with user account management features including multi-level user authorization and password protection.

The HMI and gateway resides in the same industrial hardened PC running Windows XP Professional. This PC has no internal moving components for increased robustness and dependability. The PC is equipped with 4x 100BaseFX LC and 2 copper RJ45 Ethernet modules. Ethernet modules can be paired using a PRP driver and connected to separate LANs to achieve redundancy. A single process database is maintained and shared between the HMI and gateway functionality. The following functions are provided by the HMI/gateway unit:

- Multiple single-line pages can be developed to provide operator interfaces for different monitoring and control requirements. An overall SLD and a communication supervision page were developed for the projects. The station SLD gives visual indication of the positions of all switching devices, the statuses of all hard and soft local/remote and selector switches, metering information and allows for secure select-before-operate control operations. A station remote/local switch allows the substation operator to disable controls from SCADA. The bus bars are color coded depending on their states. The communication supervision page reports the health of all communication links in the SAS. Screenshots of these pages are shown in Figure 7 to 9.

- Sequence of Events are displayed in the event list based on the trigger options set for the data objects stored in the real-time process database. The events are identified by the IEC61850 substation section hierarchy and logical node descriptions defined in the SCL configuration.
- Equipment alarms are collected from various IEDs, triggered from the process database and displayed in two default alarm formats. The first format separates alarms into active and fleeting ones. The second list maintains a record of all new and old alarms during the time the alarm list remains open. Alarms can be acknowledged individually or in groups.
- Disturbance recording in the IED can be automatically retrieved by the HMI client as part of the services defined in IEC 61850 7-2. The stored Comtrade files can be analyzed to verify proper relay operation after system disturbances.
- The gateway functionality of the IEC61850 client handles signal re-routing and protocol conversion to as many as 8 upper level control systems (SCC). The gateway supports a variety of communication protocols for connecting processes to the SCC. This project uses the DNP3.0 via TCP/IP slave protocol to send and receive data responding to SCC polling and control commands. To best utilize bandwidth by reducing the amount of data points being transmitted, the alarm grouping tool in the gateway was used.

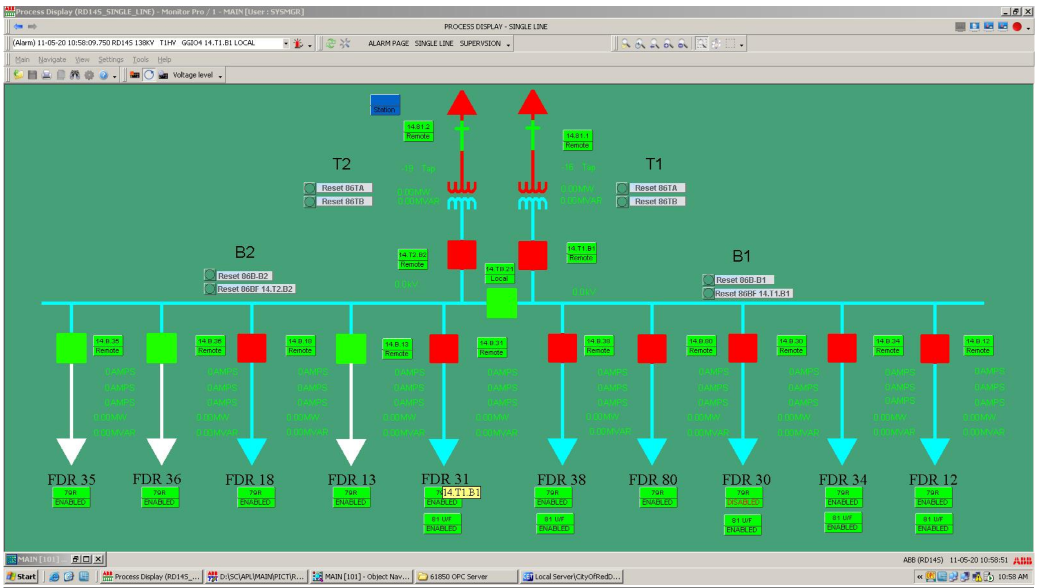

Figure 7 - HMI Station Single Line Diagram for SS14

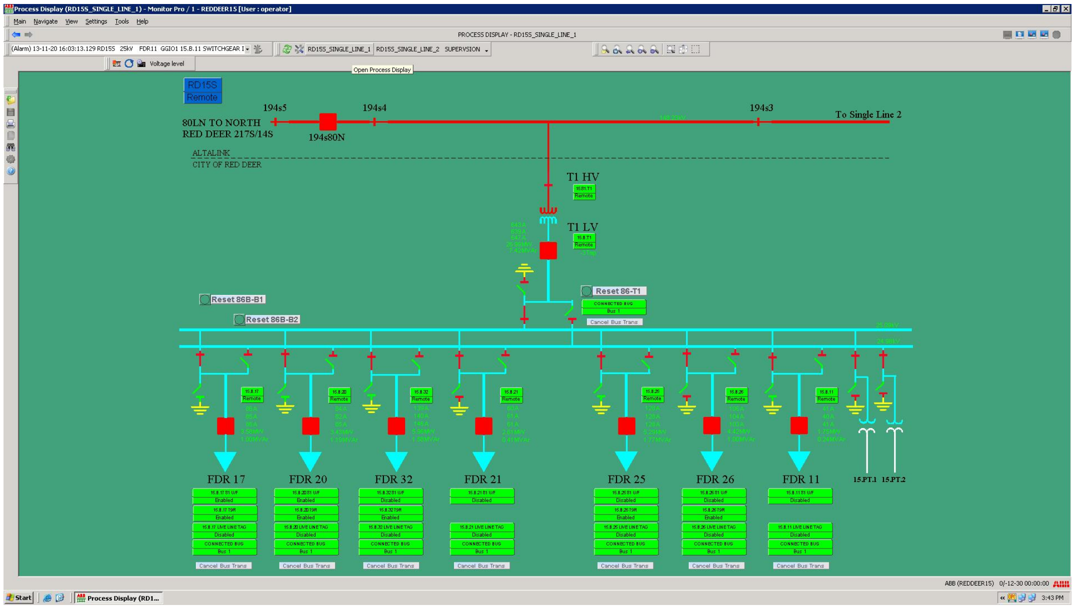

Figure 8 - HMI Station Single Line Diagram for SS15

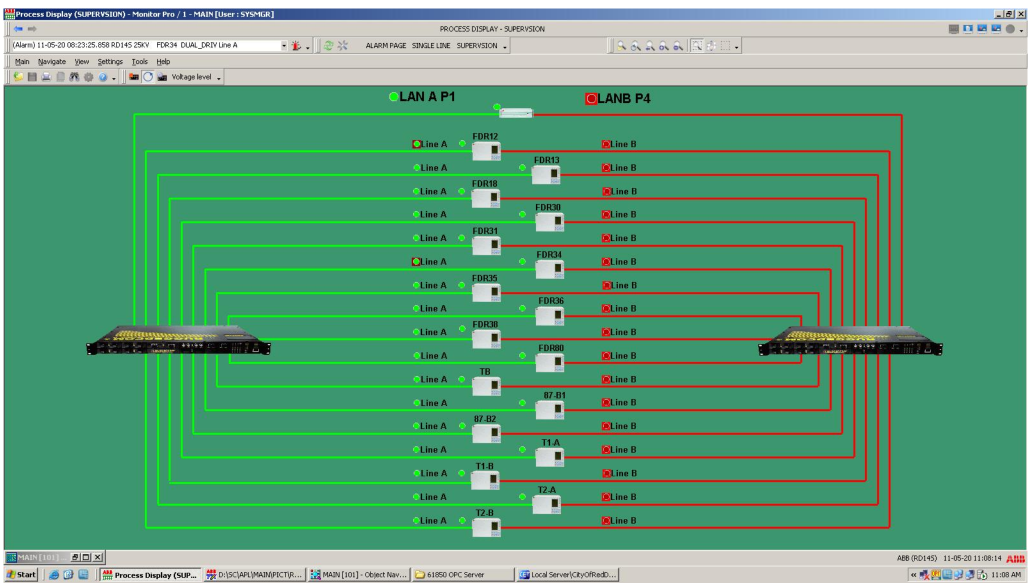

Figure 9 - HMI Communications Supervision Page

V. Parallel Redundancy Protocol (PRP) [4]

System redundancy is critical in high-voltage substations to maximize availability by avoiding any single point of failure. In traditional centralized SA systems redundancy in protection is achieved through duplication of protective devices (eg. main A and main B). Naturally, all hard-wired critical communication links to the remote terminal units can also be duplicated by doubling the wires. Redundancy by this method is reliable but costly. Part of the purpose of IEC-61850's networked communication approach is to reduce wiring and installation costs within a substation control house. An Ethernet network accomplishes redundancy through network reconfiguration protocols residing within the Ethernet switches. The Rapid Spanning Tree Protocol (RSTP), in which the Ethernet switches maintain a list of all possible network path and reconfigure the network path once the original one has failed, is one such example. The disadvantage of RSTP is the reconfiguration delay, typically ranging from tens of milliseconds to multiple seconds depending on the number of Ethernet switches in the network. This time delay in data switching is unacceptable for time-critical power system protection applications such as GOOSE messaging transmitting trip signals or IEC-61850-9-2 process bus transmitting current sample values.

IEC-62439 defines a set of Ethernet-based protocols providing high availability with minimum switch-over time. PRP is one of the network redundancy protocols defined in this standard with a seamless redundancy property. In PRP the redundancy is implemented in the "device" level, as opposed to RSTP where the redundancy protocol is implemented within the Ethernet switch. Each device with double-attached-node (DANP), such as Dual Ethernet ports, is connected to two independent Ethernet networks (see Figure 10) operating in parallel. The source device sends Ethernet fames over each LAN and the receiving device consumes the first frame received and discards the second frame. The two LANs may have different topologies and performance. Since one data frame will be discarded at the MAC layer before reaching the upper layers of the OSI model, from the IED communication management's perspective there is still only one IP address despite the two physical Ethernet ports. Due to the fact the source sends data frames via two separate LANs in parallel, there will be no reconfiguration time for any single-point of failure, making zero reconfiguration delay a reality. The PRP network architecture implemented in this project is shown in Section V.

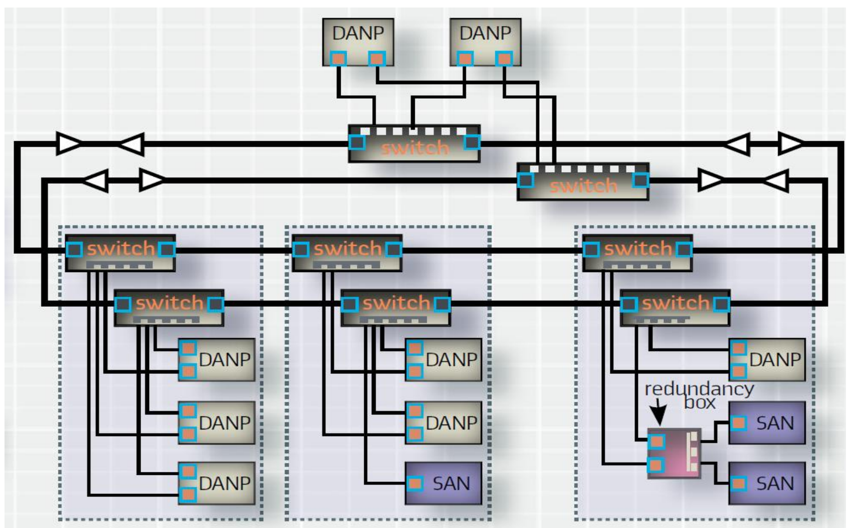

Figure 10 - Example PRP Connections in a Ring Structure

VI. Factory Accetance Testing and Site Commissioning

The factory acceptance testing (FAT) was conducted in The Engineer's integration shop. Once the construction of panels was complete and internal panel wiring was verified the panels were powered up and the IEDs were connected to the LANs. The test system constructed was intended to mimic in functions as closely to the designed SAS as possible. The test system was fully functional except for the connection to the customer's SCADA control center. Any number of operating or faulted conditions can be simulated by injecting analog voltage and current quantities to the IEDs and correct IED responses observed using a modern relay test set. Additionally, all PAC functionality, such as dynamic bus differential, local control, interlocking, auto-transfer logic and SCADA functionality such as remote control, alarms, and metering, can all be verified in advance by monitoring the response of the "test breakers" and station HMI, rather than on site. Some critical test considerations during FAT are presented below:

- Back in SS14 off-the-shelf mini test breakers were used to simulate each circuit breaker positions (14 total) in order to verify the correct IED operations. No motorized disconnect switch existed in the SS14 project that required functional verification. The same test establishment proved to be infeasible for SS15 when it came down to functionally testing every remote controllable apparatus ranging from breakers, disconnect switches and ground switches. At a rough estimate at least 67 test apparatus, corresponding to 134 digital inputs and 134 digital when accounting for the status and control requirements, were needed to completely simulate and verify the PAC functions and logic implemented for the SS15 project. The Engineer decided to take advantage of the vast I/O capacities and flexible programming interface offered by the vendor's IED product line. Two full-size IEDs which became an instrumental part of the FAT process were loaned by the IED vendor to simulate all motorized apparatus.

In the two test IEDs 67 bistable latches were programmed to simulate the controllable apparatus. The set/reset input came from the hard-wired trip/close commands from the protective IEDs via the digital input modules. The set/reset outputs were wired out back to the protective IEDs via digital output modules as indication of apparatus positions. This test system is elegant, scalable and easy to troubleshoot and monitor through the built-in IED monitoring amenity. A sample diagram in Figure 11 indicates such application.

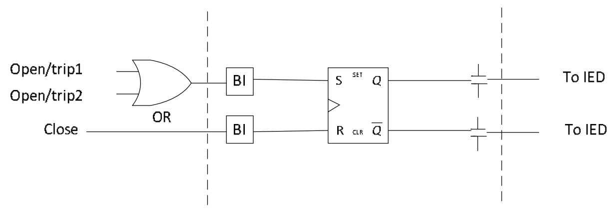

Figure 11: Sample IED Latch to Represent Controllable Apparatus

- Due to the vast amount of GOOSE messages being exchanged on the substation LAN, a modern IEC-61850 capable test set was utilized to simulate and check GOOSE assisted protection schemes. The breaker failure protection test requirements can best explain this decision. Back in the conventional electrical application, a test engineer would have chosen to bench test the BF protection system in portions. First he would functionally verify different functions of the protective relay alone. Then to check the correct timing and operation of the BF logic he would simply force (by electrical shunting) the digital input of the BF relay to simulate the initiation signal. The complete system can be verified once inter-relay wiring has been terminated later on site during commissioning. Following this test procedure, only one relay needs to be operated at any given time on the bench, making the test plan modular and scalable.

  Yet, in the digital realm to simulate a BF initiation signal would entail operating the protective IED in order to generate the GOOSE message. An IEC61850 enabled test set circumvents such inconvenience by allowing a test engineer to simulate any GOOSE message on the network. The test set can imitate the identity of any inter-connecting 61850 IED and at the same time analyze the correct operating sequence of the protection scheme under test. Using a modern 61850 enabled test set to conduct inter-IED functional tests, such as one involving BF protection, allows for fully independent IED testing and prompt test playback during commissioning or audit. Figure 12 illustrates the procedures adopted for the BF inter-IEDs functional test during the FAT. The figure on the left indicates the test plan used to prove the protection functions of the bay IED while assuring correct GOOSE communication with the bus IED. The figure on the right verifies the correct BF logic and timing.

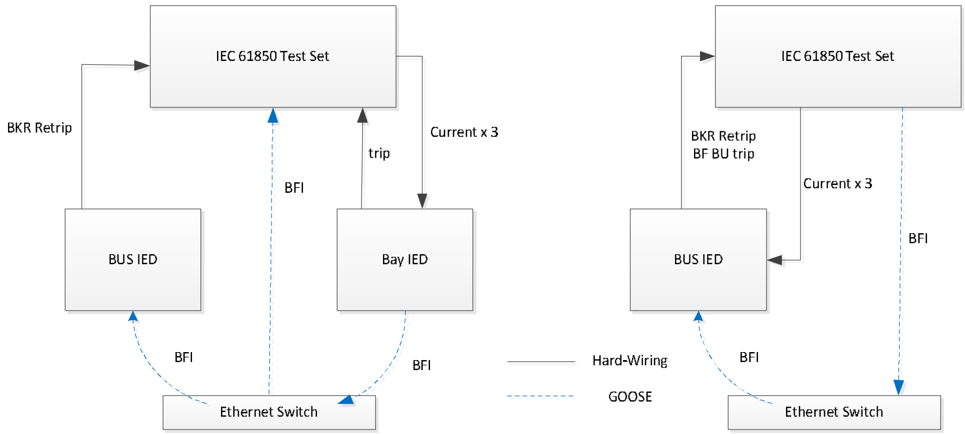

Figure 12: Inter-IED Breaker Failure Test Plan Using a 61850 Enabled Test Set

Both the test set and IED vendor also supplied additional network analyzing tools for monitoring GOOSE traffic on the station bus. The monitoring tools were used to verify, or in some instances, troubleshoot that the correct GOOSE messages were published by the IED under test and that the timing of these messages relative to one another makes sense. Figure 13 demonstrates the monitored GOOSE traffic for the breaker failure application described above. The red line in the top of the figure shows the trip operation of the feeder IED and the bottom half shows the operation of the breaker failure function. The blue line depicts the time delay (270 ms) between the two signals, which matches the BF backup delay set point closely.

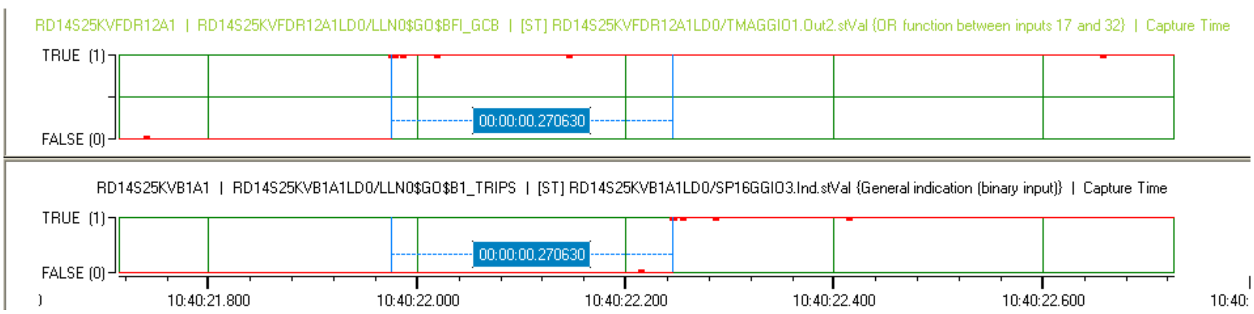

Figure 13 – Screenshot from the vendor's GOOSE traffic monitoring tool

Having all IED protection functions, inter-IED communication and HMI-IED communication completely verified as part of the factory acceptance testing, field commissioning activities were limited to random verification of the previously tested functionality, complete testing of the controls from/indication to the City's control center and the electrical wire terminations between the protection panels and the primary apparatus.

The vast majority of time spent during field commissioning were related to interfacing the new 61850 SA system with the City's SCADA center. Once installed on site and connected to the LAN(s) the SAS functioned exactly as it did in the panel shop during the FAT. Since the entire SAS communicates on fiber optic based LAN, there was very little electrical wiring to be verified on site. Time spent on site was considerably reduced, leading to significant saving in commissioning expenses.

VII. LESSONS LEARNED

The City has to-date successfully completed two SA modernization projects. Lessons learned throughout the design, engineering, commissioning and operation phases of these projects have been recorded and will serve as important guidelines for technical tenders and drive improvements for future similar projects. As a pioneer in the province of Alberta to adopt the digital substation automation philosophy, these lessons would be a valuable source of information to other provincial utilities interested in pursuing the same modernizing path. A few notable lessons from the two projects are summarized below:

- More functional consolidation

  As alluded previously in Section II, mechanical selector/control switches and auxiliary tripping relays then specified by The City for the SS14 project were unanimously eliminated in the service and material tender issued for SS15. This result corroborates the positive feedbacks of convenience and design simplicity The City's personnel appreciated over various switching and control operations using the IEDs soft control toolset. Furthermore, eliminating external devices frees up panel space that permits more equipment to be consolidated into one and contributes to overall cost saving. In SS15 one extra bus differential IED and additional isolating test blocks were added to the same bus panel as part of the engineering/maintenance requirements to protect a much larger switchgear lineup. Up to 6 feeder protective IEDs can be potentially added to each feeder panel subject to availability of wire ways and wiring space.

- Identify functional requirements early

  The engineering steps taken to successfully design and implement an IEC 61850 based SA system requires different considerations from a traditional approach. Since much of the inter-IED communication conventionally handled with hard-wired relay I/Os is now replaced with GOOSE messages, adding a signal from one relay to others becomes a much simpler software based engineering exercise without the needs to identify spare I/Os, pull cables between panels and terminate the wires. However, since updating any 61850 configuration in the selected IEDs requires complete re-writing of the device configuration it is necessary to perform a functional re-test of the IED after making any such change. So although changes can sometimes be unavoidable in a project life cycle and indeed were made late to both projects, the time spent on repeatedly testing the devices demonstrated the importance of developing detailed functional requirements on the outset of the design/engineering stage. The SS15 project has made a significant improvement in this regard.

- Fail-safe or non-fail safe considerations

  Though often considered common senses in PAC practices, this lesson learned reminds and urges practitioners of 61850 to pay extra attention when designing GOOSE communication particularly because it becomes much simpler to exchange binary signals between IEDs. Due diligence should be observed as to the intended application and consequences had a digital signal not been delivered successfully.

  A signal exchanged between two IEDs can be sent in either permissive (fail safe) or blocking (non-fail safe) mode and under the prowess of logic programing capability common in modern numerical IEDs, the physical difference between the two has often been overlooked, if not neglected. After all a Boolean signal can be logically manipulated at will to serve any intended application needs so how a signal is actually being sent warrants extra discretion.

  In a conventional circuit breaker close circuit a number of normally closed (NC) lockout contacts (86b) are electrically connected in series to accomplish close blocking. This age old design generates little thought and in fact a mechanical lockout relay can only be connected this way to fulfill the intended application. On the other hands, when it comes to using an IED to propagate the lockout signal, as exemplified by the SS15 project, the state of the hard-wired contact to the IED and the actual binary signal being transmitted does hold different weight and significance. Wiring a NC contact to an IED digital input and transmitting as permissive to close via GOOSE to the bay IEDs to apply in respective internal block close logic prevents accidental closing onto a faulted bus from a variety of failure modes such as bad contact, faulty IED input module, wiring issues, relay out of service and network communication problems. On the contrary wiring a NO lockout contact and/or sending a block close via GOOSE cannot sufficiently cover all fail safe criteria.

  The Engineer also considered similar tradeoffs in designing the signal exchanges for the auto-transfer scheme. The tie IED was programmed to transmit the non-fail safe "Tie Not Ready" instead of "Tie Ready" signal to all bay IEDs waiting to initiate a bus transfer process. The considerations were two fold. First, electrical interlock between switchgear cells was considered to have been in place, provided by the switchgear manufacturer for safe bus switching. Consequently, The Engineer decided to take the advantage to make the auto-transfer scheme more “available”, that is, allowing transfer when the tie breaker is closed even when the tie IED is out of service.

- Standard 61850 data modelling:

  One of the main enhancements to SA system engineering, troubleshooting and maintenance activities provided by IEC 61850 is the standardized naming conventions of various P&C functions and their abstract data models. By using standardized data attributes in GOOSE messages, the data contained in the dataset is self-descriptive and can be applied in the subscribing IEDs without the need to cross-reference their meaning. Such standardization could improve efficiency during commissioning and save time when troubleshooting the SA system. For signals not defined in the IEC 61850 standard, the generic logic node GGIO is implemented by each vendor to allow for reporting and exchanging of those substation signals, such as for external hard-wired signals, over the substation network. In the IED engineering stage of the SS14 project, GGIO objects were used in many instances where standard IEC 61850 logic nodes could have been applied to take advantage of the benefits mentioned above. As an example, in the feeder IED only over-current operations was designed to initiate the BF protection while control and under-frequency load shedding operations should not. Thorough engineering planning ahead of time could probably have effectively addressed the conflict in many instances, but due to inexperience, realistic time and budget constraints and, in some other cases, direct request from The City specifying certain non-standard data types (eg. single binary position as opposed to double binary), it was decided to use the GGIOs to facilitate those special scenarios. In the subsequent SS15 project similar conflict occurrence had been reduced considerably in large part due to gain in engineering experience.

- Lack of documented maintenance and troubleshooting procedures

  This has been a persistent issue raised by The City’s operating and maintenance personnel ever since the project ownership was turned over by The Engineer back in SS14. The issue can be analyzed in different facades below:

  - Utility’s asset maintenance team has been accustomed to maintaining a set of as-left documents that have been authenticated by the commissioning company as the basis for future maintenance or troubleshooting work. Lacking a similar hard documenting standard to identify GOOSE exchanges in each IED, as electro-mechanical relay I/Os would on a standard schematic, The Engineer appended the GOOSE I/O exchanges and their intended applications in the standard protection logic diagram. In this way the end users can at least assess the potential risks of disrupting the service of an IED on the SA system before planning for any maintenance activity. Detailed logic implementation is not meant to be included in the diagram, but they can be traced using the specific IED configuration software.

  - Proper isolation of tripping and permissive IED output contacts have been a standard work procedure before commencing any IED maintenance or troubleshooting activity. The test blocks traditionally have been used to isolate hardwired electrical I/Os to/from the IED under work. With virtual cyber messages such as GOOSE coming into play, alternative isolating procedures must be in place to ensure secure work on an IED in service. Depending on what functions of the IED and SAS is targeted for maintenance testing, three safe isolation techniques have been previously applied successfully by The Engineer and are recommended here:

    1. Re-verification or troubleshooting of certain protection algorithms can be performed by simply removing the fiber optic cable from the IED LAN ports so that the IED response will not influence other IEDs on the LAN. An IEC 61850 enabled test set can be used to verify GOOSE assisted logic by simulating certain GOOSE signals. Special attention should be paid to the effect of losing the GOOSE signals in blocking applications.

    2. The dual-redundant network architecture (PRP) can be used to the test engineer’s advantage when performing SA functional tests. In one instance The Engineer had to troubleshoot a remote control design in the station HMI. The test engineer isolated the station HMI/gateway and one IED to LAN B and the other SA devices in service to LAN A. By doing so the test

engineer could freely operate the IED without influencing other devices in service. This test procedure can be equally applied to troubleshooting a group of interacting GOOSE IEDs.

3. IEC-61850 Ed.1 stipulates use of the test bit associated with every GOOSE message to flag the status of an IED under test. The subscribing IEDs can thus securely ignore the messages published by the IED under test. This apparently is a sophisticated and elegant solution to perform live maintenance on a 61850 system, but the problem still persisting at the time of writing this paper is that different vendors have put different weight and priority to address safe device isolation hence have implemented this secure mechanisms in their products differently or none at all. The lack of a standard implementation for test bit in different IEDs would completely defeat its usefulness especially in a multi-vendor project. For example, for the selected vendor's product line, a test bit asserts when the IED is entered into "test mode" and can be manually published along with other GOOSE signals to be used as a "handle" to supervise any GOOSE assisted logic. Unfortunately The Engineer was not aware of this security measure at the time of project execution so it was not incorporated into the design of the projects. Edition 2 of the standard reportedly has refined and ascertained the expected behaviors of IEDs under test [14] so that they are less ambiguous. Improvement in this area has yet to be seen until vendors start to embrace Edition 2 in their SA product lines.

- Regardless of the type of isolating procedures adopted to perform live IED work, thorough understanding and appreciation of the SAS design and underlying IEC 61850 technology is instrumental in completing any work safely and securely. Ongoing training on the SAS functionality delivered, SA products, software tools, new test methodology, and Ethernet/61850 technologies in general is crucial to enable technicians who previously have not engaged in network communication line of work to gain experience and confidence in handling modern communication oriented devices and systems.

  Until the 61850 system becomes common and personnel become familiar with it, extra training, warning labels about hidden GOOSE exchanges and customized documentation are required to minimize any operational risk.

- Network bandwidth constraint

  Due to the relative miniscule system in size and non-critical GOOSE applications (no dedicated tripping signal was carried by GOOSE), The Engineer made an educated decision not to invest time and efforts in network management design/engineering such as MAC address filtering and 802.11q virtual LAN to prioritize GOOSE traffic. Assuming a typical GOOSE message of 200 bytes with transmission time of 3 ms in a burst of 5 messages during a change of state, a rough estimate of the bandwidth consumption can be computed as:

$$\frac{200\ byte \times 8\ \frac{bit}{byte} \times 5}{0.003\ sec} = 2.67\ Mbps$$

  A 100 Mbps standard station LAN would provide more than enough data capacity for simultaneous, unmanaged GOOSE and MMS communication.

VIII. CONCLUSION

The first IEC 61850 modernization project, SS14, have commenced commercial services for two years without report of major disruption from the field. A second station, SS15, following suit with a more flexible apparatus design and expanded PAC requirements, was complete by end of 2013. The same engineering consultant was hired to plan, execute and commission both projects. Only single vendor was sourced for the SAS to reduce initial learning curves and gain operational experience of the new technology.

The projects progressed in manners not too different from the traditional substation design, starting from products procurement, schematics design, PAC engineering and FAT, to on-site commissioning. During the course of project execution, additional demands were placed on engineers, field technicians and The

City's operation team to step outside of their previous experience and comfort zone to learn to apply this new technology. Examples may include unfamiliar software tool for IED and communication engineering, modern network based test equipment, virtual "soft" control functionality, and extra precaution required to perform live equipment maintenance.

Wide-ranged applications of GOOSE communication to replace myriad of inter-IED wiring considerably de-cluttered cable trays, saving cabling material and wiring termination labor expenses. Obsolescence of hard, mechanical control and auxiliary tripping devices further reduced the number of P&C panels required otherwise, improving overall utilization per panel.

Adoption of the IEC 61850 enabled test set, network monitoring tools, and the test IEDs ensured a smooth yet comprehensive functional verification of the SAS during FAT prior to shipping panels to site. Overall time and expenses spent on commissioning were thereby reduced considerably.

Once the systems were running, they operated as intended. Messaging via GOOSE and MMS operated reliably and the parallel redundancy protocol ensured redundant communications with no switching time in the event of LAN failure. These projects proved to us that IEC-61850 is ready and provided benefits as claimed. Competent system integrators can successfully plan, engineer and install a system based on IEC-61850.

Utilities considering applying IEC 61850 to their own projects are recommended to carefully evaluate and acknowledge the necessary investment in time and resources for training and learning the technology. If one does decide to implement a system using 61850 devices we expect that he will find the system operate reliably as designed.

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X. BIOGRAPHIES

Jack Chang is a regional technical manager for ABB Inc. in the Substation Automation Products business unit serving customers in western Canada and northern regions. He provides engineering, commissioning and troubleshooting support to customers applying ABB's high voltage protective and automation devices. Prior to joining ABB, Jack worked as a substation P&C project engineer in two specialized consulting firms and also as an engineering consultant to a public owned utility in their transmission expansion and upgrade projects. Jack is a registered professional engineer in the province of Alberta, Canada.

Leo Britos is a planning engineer for The City of Red Deer ('the City') in the Electric Light & Power Dept. primarily serving as a liaison between the City and The Alberta Electric System Operator (AESO). He provides operational, maintenance, planning, smart grid, and engineering support services to the organization on medium to high voltage apparatuses, electrical substations, distribution grid, SCADA systems, wireless systems, fiber optic systems, and protection and control systems. Prior to joining the City, Leo worked as a substation area site engineer in a specialized consulting firm focused on overall design, build, retrofit, testing and commissioning services for medium distribution to high voltage transmission substations in customer facilities across the United States of America. Leo is a registered professional engineer in the province of Alberta, Canada.

Mike Reynen received his Bachelor of Science degree in electrical engineering from Queen's University in Ontario Canada in 2007. He then attended the University of Calgary in Alberta Canada where he completed a thesis advancing an islanding detection method for distributed generators and received his Master of Science degree in electrical engineering in 2009. Since joining Phasor Engineering his primary activities have been the development of protective relay settings as well as relay testing and commissioning.

Hassainan Malik is an practicing Principal SCADA Engineer with Phasor Engineering Inc. with over Six years of experience in an automation power systems consulting industry providing guidance in the areas of designing and implementation of transmission & distribution and the integration of fully automated SCADA systems for Power Substations. Hassainan manages and provides technical guidance to a team of SCADA engineers. He has worked on several different 500kV/240kV/138kV and 25kV projects involving new power substation designs, substation technology upgrades, introducing new automated control systems, and preparing proposals and bid packages. Substation commissioning and experience working with protocols such as IEC 61850, IEC 101/104/103, DNP3 and Modbus, are just few examples of his expertise.