Designing IEC 61850 Digital Substation Process Bus to Meet Utility Protection and Testing Requirements

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***Abstract*—Pacific Gas and Electric Company (PG&E) is developing a new digital substation design standard for transmission system Protection, Automation, and Control. The design is based on IEC 61850 and IEC 61869-9 and uses Sampled Values (SV), Generic Object-Oriented Substation Event (GOOSE) messaging, Precision Time Protocol (PTP), and Parallel Redundancy Protocol (PRP).**

This paper presents key protection considerations for a digital substation process bus design, with emphasis on protection dependability, security, scalability, and field maintenance practicality. The paper first describes PG&E's protection design basis, including alignment with the company's hardwired protection design standard and protection security during GOOSE and SV failures. It then presents IEC 61850 testing features and PG&E-defined mechanisms such as SV Bypass, Relay Cut Out, and Digital Cut Out.

The paper also discusses merging unit (MU) wiring, MU failure mitigation, backup protection, emergency breaker open functionality, process bus architecture, and time synchronization. Finally, the paper presents brownfield installation and maintenance testing workflows using practical examples. A clear understanding of isolation and testing requirements for process bus-based protection systems can streamline relay testing activities and help prevent misoperations.

This paper illustrates how PG&E applies IEC standards and technologies to digital substation protection systems while maintaining alignment with established protection and operational philosophies. The proposed design has been validated through laboratory prototyping and is being applied at pilot substations prior to broader standardization.

Keywords—IEC 61850, Digital Substation, Process Bus, Sampled Values, GOOSE Publish/Subscribe, Merging Unit, Protection Redundancy, Failure Mitigation, SV Bypass, Relay Cut Out, Digital Cut Out, Brownfield Installation, Test Workflow.

I. Introduction

Digital substations based on IEC 61850 are transforming the way utilities design protection, automation, and control (PAC) systems by replacing extensive hardwired copper circuits with Ethernet-based communications using standardized data models SV, GOOSE, and PTP communications protocols. These technologies offer significant advantages in wiring reduction, control room panel space reduction, engineering flexibility and scalability, and potential test and maintenance cost reduction. However, their adoption introduces new challenges for protection engineers and test technicians. Protection systems operating on the IEC 61850 process bus must maintain the same levels of dependability, security, and maintainability as the traditional hardwired schemes.

PG&E's approach for developing the digital substation standard is driven by utility protection and testing requirements, rather than treating the process bus solely as a communication infrastructure upgrade. Consequently, the design is based on preserving established utility protection practices while adapting them to an IEC 61850 process bus environment. The resulting architecture incorporates process bus redundancy, protection-security measures, equipment isolation mechanisms, and maintenance workflows intended to support practical utility operation throughout the system life cycle.

II. Protection Design for Process Bus

A. Protection Design Based on SMP Standard

PG&E's current transmission protection and control design standard is Sustainable Modular Protection (SMP), which was introduced in 2015. A defining characteristic of SMP is that one standard set of drawings, logics, and panel arrangements applies across all major transmission bus configurations—breaker-and-a-half (BAAH), ring, double bus single breaker, main/aux, looped, and single bus. The standard enforces consistent design practices that have proven reliable in the field and carries PG&E protection philosophy into every transmission PAC project.

Digital substation protection design is grounded in PG&E's existing SMP standard to preserve proven protection philosophies while transitioning to an IEC 61850 process bus. The digital substation standard maintains SMP transmission line, transformer, circuit breaker and bus protection principles and logics, and reuses the SMP modular framework—one universal scheme applicable across different bus configurations. Familiarity with setting, testing, operating, and maintaining SMP protection and control systems can therefore, be carried over to the digital substation environment, helping accelerate the transition from traditional hardwired protection systems to a digital substation process bus.

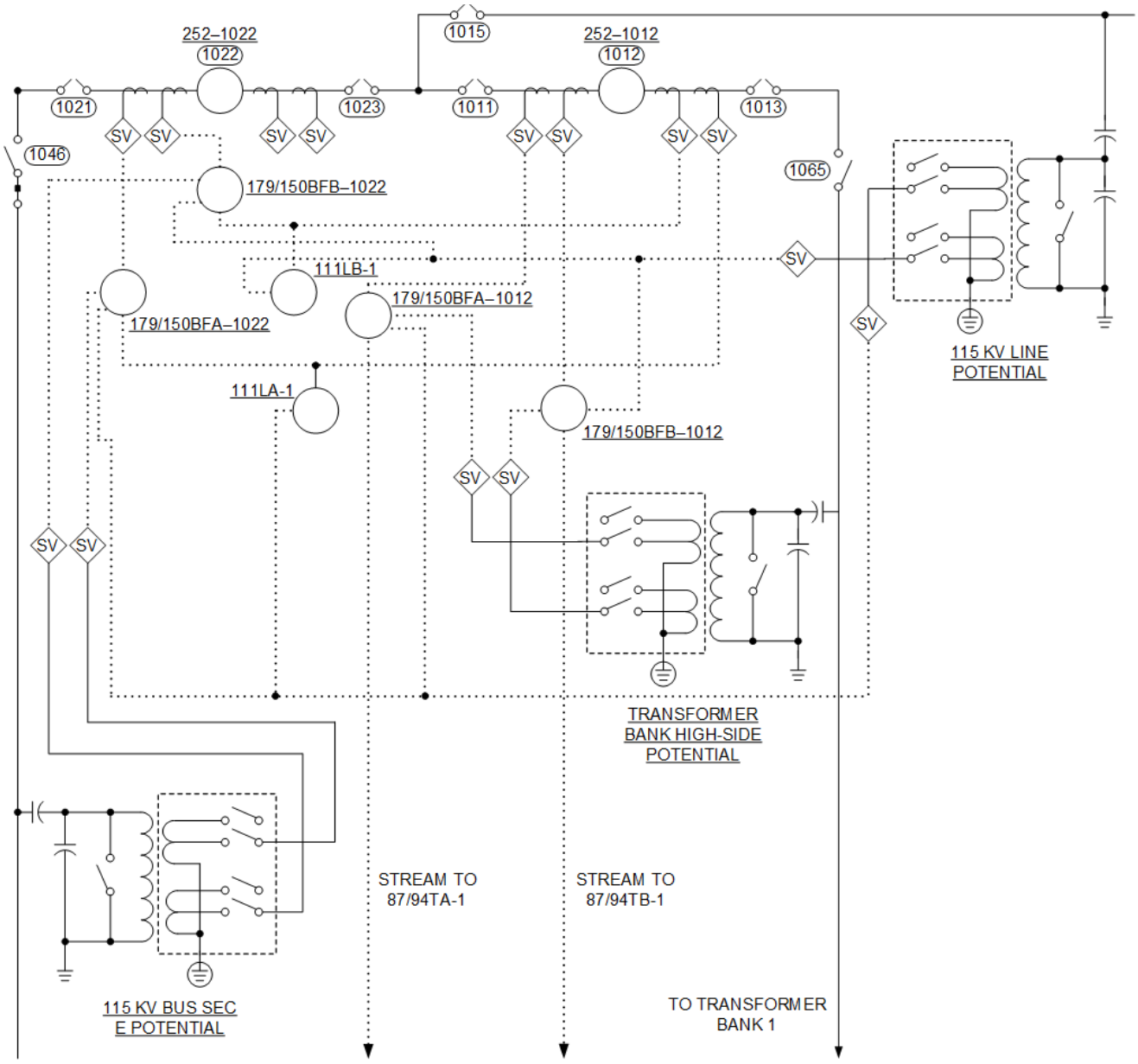


Fig. 1. Example Single-Line Meter and Relay Diagram for the Digital Substation

Fig. 1 shows a portion of the Single-Line Meter and Relay Diagram (SLMR) for PG&E's digital substation laboratory implementation. The SLMR illustrates the conversion of hardwired CT and coupling capacitor voltage transformer (CCVT)/PT signals into SV streams that are subscribed to by the corresponding protection relays. Similar to the SLMR used in the SMP standard, the digital substation SLMR continues to identify each relay's zone of protection. PG&E assigns 'S' and 'T' designations to the two sides of every transmission circuit breaker, and the digital substation design follows this naming convention.

For example, Set A Line Relay 111LA-1 subscribes to the outer CT currents from Breaker 1022 'S' side and Breaker 1012 'T' side, while Set B Relay 111LB-1 subscribes to the corresponding inner CT currents from the same breakers. Similarly, the Set A breaker failure (BF) Relay 179/150BFA-1022 subscribes to the outer CT currents from the Breaker 1022 'S' side, while the Set B Relay 179/150BFB-1022 subscribes to the corresponding inner CT currents from the same breaker.

One major design change introduced by the digital substation standard is the relay package for transmission circuit breakers. PG&E's SMP standard employs two relays per breaker, i.e., a BF and reclosing relay and a SCADA relay. The digital substation design implements redundant BF protection and reclosing relays in Protection System A and B. A dedicated SCADA relay is no longer required because SCADA functions are incorporated into the BF and reclosing relay. The BF relay subscribes to the breaker MU SCADA data set and publishes breaker control commands to the MU in response to either breaker control pushbutton operations from the control room relay panel or SCADA commands. In this paper, MU refers to a Process Interface Unit in the IEC 61850 standard.

The reclosing function is active on only one reclosing relay at any given time to avoid possible discrepancy between Set A and Set B relay reclosing cycles. A three-position control switch, designated as the reclose selector switch, is installed on the BF and reclosing relay panel. The three positions are: Auto A, Manual, and Auto B. The Auto A and Auto B positions determine whether the Set A or Set B relay

has the reclosing function enabled. The Manual position effectively disables reclosing for the breaker. It also logically supervises manual breaker open or close control. The Reclosing Selector switch is wired to both Set A and Set B BF and reclosing relays for SCADA control and status indication.

In the SMP standard, the normally closed (N.C.) block-close contact from each applicable relay or lockout relay is wired in series in the breaker close circuit, as shown in Fig. 2. When the Breaker 'S'- or 'T'-side BF relay is taken out of service, the breaker close circuit requires a temporary jumper to bypass the out-of-service BF relay contacts. With the digital substation BF relay block-close logic and contact wiring, a similar workaround is no longer required.

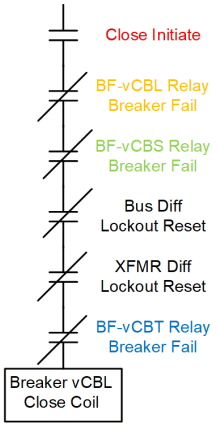


Fig. 2. SMP Breaker Close Circuit Block-Close Supervision

In the digital substation design, the block-close logic, as shown in Fig. 3, is implemented in the BF relay. The BF relay publishes a close command to the breaker MU with block-close logic already applied. Set A and Set B BF relay each has its own block-close logic, and the block-close output is hardwired to the BF relay in the opposite protection system to be included in its block-close logic. This limited hardwired interface allows a block-close condition, detected in either protection system, to prevent breaker closing without creating a process bus dependency between the systems.

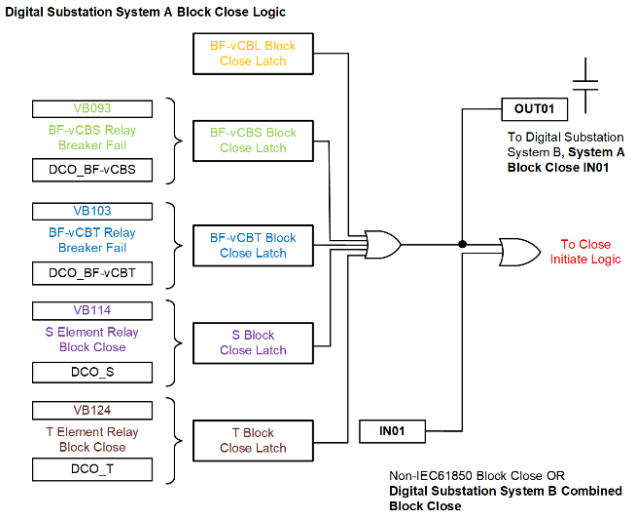


Fig. 3. Simplified Digital Substation Block-Close Logic

The cross-wiring between the Set A and Set B BF relay required by the block-close logic may make implementation of the block-close logic in the breaker MUs appear attractive. However, in some situations, it may be necessary to wire the block-close condition from a relay that does not support IEC 61850 communications. For example, during the cutover period of migrating from a traditional protection system to a digital substation process bus, it may be necessary to interface existing bus protection with the digital substation BF relays. If the block-close logic is implemented in the breaker MU, temporary wiring would be required between the bus differential lockout relay in the control room and the MUs in the switchyard. By implementing the block-close logic in the BF relay, block-close conditions from other relays or lockout relays can instead be wired in parallel with the sibling BF relay block-close contacts.

B. GOOSE Design

Digital substation process bus migrates the underlying signal exchange from hardwired copper circuits to SV and GOOSE messaging. In the SMP design, relay inputs, outputs and their associated test switches have standardized allocations across all applications. Unused relay inputs/outputs (I/O) for each application are not wired to or between the devices. The GOOSE I/O design aligns with established SMP hardware practices, by utilizing standardized GOOSE publishing datasets paired with application-dependent GOOSE subscriptions.

In the digital substation standard, each relay or MU type is assigned a GOOSE publish table and subscribe table with standardized allocations for all applications. Minimizing revisions to GOOSE datasets throughout the life cycle of a relay or MU is important because data set modifications may require corresponding updates to all subscribing relays and MUs. Since publishing unused data within a GOOSE data set is unlikely to cause network traffic concerns when the process bus networks are properly engineered, PG&E implements standardized GOOSE datasets for all relays and MUs.

Each MU publishes two types of GOOSE messages, i.e., one containing protection data and the other containing SCADA data. They are differentiated by GOOSE message name and MAC address. The MU publishes SCADA data using GOOSE rather than Manufacturing Message Specification (MMS), because only the process bus, which uses Open Systems Interconnection Layer 2 non-routable Ethernet traffic, is extended to the MU cabinets in the substation yard for cybersecurity considerations. Engineering access to the MU is available only locally at the MU cabinet in the substation yard and is not provided remotely. Protection relays publish only one type of GOOSE messages containing protection data, while SCADA data is communicated over the station bus using MMS.

The GOOSE subscription table uses standardized allocations for each relay or MU subscription. Typically, 10 or 20 virtual bits are allocated for each subscribed relay or MU, with the first bit assigned to the message quality of that GOOSE subscription. 70 virtual bits are reserved for MU SCADA data. The GOOSE subscriber typically subscribes to most, but not all, of the virtual bits in the allocated range from the publisher. Table 1 shows the GOOSE subscription virtual-bit allocation for a BF relay. The relay cut-out (RCO) relay is discussed in Section III. B.

TABLE I. BF RELAY GOOSE SUBSCRIPTION VIRTUAL BIT ALLOCATION

GOOSE Publisher	GOOSE Subscription Virtual Bits
Breaker MU Protection Data Set	VB001-VB020
Breaker MU SCADA Data Set	VB021-VB090
Breaker 'S'-side BF Relay	VB091-VB100
Breaker 'T'-side BF Relay	VB101-VB110
Breaker 'S'-Side Element Protection	VB111-VB120
Breaker 'T'-Side Element Protection	VB121-VB130
RCO Relay	VB131-VB140

Relays and MUs subscribe only to data required for the specific application. The engineering tool may prevent relays and MUs from subscribing to GOOSE datasets that are not defined within the process bus configuration. With standardized GOOSE subscription allocations, protection logic that references GOOSE subscription bits, where GOOSE messaging replaces hardwired I/O, does not need to be modified for different applications. This approach aligns with the SMP methodology of using common relay protection logic across different applications, with application-specific behavior controlled through software switches that enable or disable an application.

C. Secure Protection Elements from GOOSE or SV Failure

Core protection elements for line, transformer, and BF protection are explicitly designed to remain secure during GOOSE and SV communication failures and time-synchronization failures, so that the security margins built into the SMP standard are not eroded by the transition to digital communications.

PG&E implements digital cut-out supervision for critical GOOSE subscriptions, including trip, close, reclose initiate, reclose block, drive to lock out (DTLO), 86T transformer lockout, 86B bus lockout, BF direct transfer trip, and 94BF BF trip initiated through transformer relays. This approach is functionally equivalent to applying a RCO switch to supervise DC circuits associated with these protection functions in the SMP design. A GOOSE communications channel failure causes the digital cut-out supervision to block the subscribing relay from executing the corresponding protection function. Section III. B describes an additional application of the digital cut-out logics. For GOOSE trip signals that are not supervised by a digital cut-out status, such as transformer mechanical trip signals (e.g., 63T, 63TF and 71QT), the GOOSE message quality bit is used to supervise the trip logic. Digital cut out and GOOSE message-quality supervision help prevent protection system misoperations caused by GOOSE communications failure or interference.

SV subscriber relays can detect when an SV stream becomes unavailable and assert Relay Word bits to indicate a blocking condition for each current and voltage input. Several factors can contribute to SV blocking, including SV stream loss due to communications failure or rejection of SV messages because of a configuration revision mismatch, an invalid or test quality attribute, or an incorrect *smpSynch* value. Section V. C describes *smpSynch* in more detail.

When the SV stream becomes available again, the blocking Relay Word bits remain asserted for an additional 1.5 cycles to ensure that the relay full-cycle cosine filter has sufficient time to stabilize before downstream protection is unblocked [2]. The relays are programmed with an SV block alarm LED to indicate SV blocking conditions that may affect protection. Fig. 4 shows the line relay SV block alarm logic. *IL BLOCK* and *VL BLOCK* indicate blocking condition for line current and voltage inputs. *87 BLOCK* indicates that one or more currents included in the 87L differential calculation are blocked because the corresponding SV stream is unavailable, including conditions caused by communications failure or time-synchronization error.

Upon detection of an SV block condition, the required protection response varies by application.

1) Line and Transformer Protection

Line or transformer relays include built-in security to disable certain protection elements to prevent misoperation when a required SV input becomes unavailable. This includes current differential, distance, directional elements, and loss of potential (LOP). More selective blocking conditions can be applied to protection elements such as overcurrent (50/51/67) elements and restricted earth fault (REF) protection following the standardized settings template. The blocking condition should be driven by the unavailability of the affected current or voltage input, rather than the overall relay SV communications status and should be included in the torque control equation of the affected protection element.

2) Bus Protection

PG&E bus protection consists of a bus differential relay and a bus undervoltage supervision relay. The bus differential element uses zone supervision to apply a blocking condition if any current input within the bus differential zone is affected by an SV block condition. The undervoltage (27) element in the bus undervoltage supervision relay should be applied with the blocking condition in the torque control equation when the voltage inputs are affected by an SV block condition.

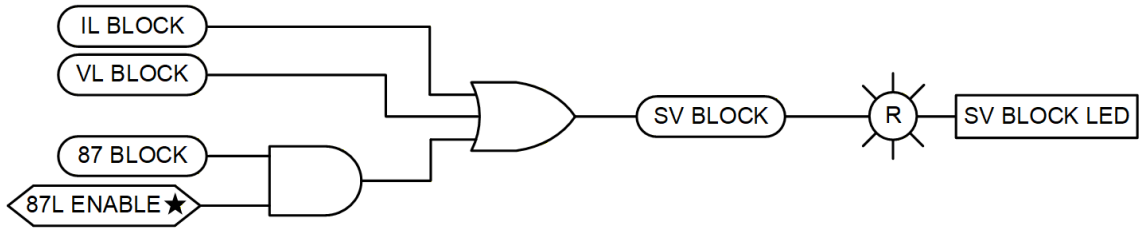


Fig. 4. Line Relay SV Block Logic

3) BF and Reclosing

The BF relay provides an option to "freeze" current inputs when an SV stream becomes temporarily unavailable. The freeze Relay Word bits are inherently applied to relay overcurrent detection, which is subsequently used in BF detection upon receiving BF initiate (BFI) signal. This feature helps prevent the loss of BF protection during temporary SV unavailability. However, it also increases the possibility of an incorrect BF declaration because the relay may continue to declare an overcurrent condition while an SV stream is unavailable, even after the breaker has tripped and cleared the fault. Because PG&E applies redundant BF protection in Protection System A and B, each with independent PRP networks, the BF freeze logic is disabled, allowing BF protection to be blocked when the required SV inputs become unavailable.

Breaker close control requires undervoltage (27), overvoltage (59) element, and synchronism check (25) function. Selective blocking conditions should be applied in the 27 element torque control equation to prevent spurious operation when the associated SV inputs become unavailable.

While GOOSE and SV failures can be mitigated through protection logic design, additional mechanisms are required to support testing, maintenance, and equipment isolation in an IEC 61850 process bus environment. These mechanisms are described in the following section.

III. Features Beyond IEC 61850 Standard

IEC 61850 defines standardized modes and behaviors to support the testing and commissioning of IEC 61850-based systems. The modes include on, blocked, test, test/blocked, and off, with the resulting behavior defined in [3]. In particular, the test mode requires the IEC 61850 quality test flag to be TRUE (*q.test* = TRUE). Devices not placed in test mode ignore test-tagged GOOSE or SV messages, enabling commissioning and maintenance activities while minimizing the risk of impacting in-service equipment when appropriate testing schemes and procedures are implemented.

In addition to these modes, a relay or MU may be placed into simulation through the Sim data object within the LPHD logical node. Published SV or GOOSE messages include a simulation flag that is normally set to FALSE when transmitted by an in-service MU; however, a test set may publish SV streams or GOOSE messages with the simulation flag set to TRUE. When a subscriber is configured to accept simulated messages (*LPHD.Sim.stVal* = TRUE), it will continue to subscribe to SV or GOOSE messages with the simulation flag off until a test set simulated message has been received. Simulation enables testing without affecting the publisher that remains in normal operation. Additional details regarding IEC 61850 modes, behaviors, testing, and simulation are provided in [4].

The PG&E digital substation design employs both test mode and simulation feature; blocked mode is not implemented because the utility conventionally isolates relay outputs using control or test-switch open contacts. IEC 61850 test mode and simulation feature alone can restrict the range of testing that can be performed on energized systems. Additionally, in the case of dual-breaker bus configurations, it is desirable to keep a relay in service when one of the breaker MUs to which it subscribes is taken out of service along with the associated breaker.

To address these concerns, PG&E has implemented the features described in this section, enabling comprehensive digital substation verification while maintaining service continuity and protection redundancy where testing and operational equipment coexist. Implemented through user-defined logic, these features can be applied by other utilities to enhance testing coverage, reduce outage requirements, minimize protection unavailability, and improve maintenance efficiency. As the industry transitions towards digital substations, operational procedures must evolve accordingly to ensure personnel understand these new features and apply them safely and effectively.

A. SV Bypass Feature

In a dual-breaker application, such as BAAH or ring bus configuration, the relay subscribes to two breaker MUs for current inputs. When one MU is taken out of service due to MU failure, process bus failure, or maintenance testing, the relay declares an SV block and blocks the related protection elements. Similarly, when one bus breaker MU is unavailable or in test mode, the bus differential protection zone is blocked even when the associated breaker is opened and cleared.

The SV Bypass feature allows the current contribution from a selected MU to be logically removed from the protection zone when the associated breaker is opened and cleared. The primary equipment can remain in service with unaffected protection and the remaining breaker MU(s) when one MU is taken out of service along with the associated breaker. The feature is activated by opening a N.C. test-switch pole wired to a relay input. Test-switch operation is used rather than relay front-panel pushbutton control so that the SV Bypass feature can only be activated by test technicians. Activating MU SV Bypass is functionally equivalent to shorting breaker CTs in traditional hardwired protection schemes, which, under PG&E practice, requires test technician operation.

Because multiple relays may subscribe to the SV stream published by a breaker MU, removing an MU from service for testing, maintenance, or failure can affect all relays that depend on its data. By incorporating programmable logic based on the status of the SV Bypass inputs, the relay can remain operational following the clearance of a breaker and its MU. The current workflow for activating SV Bypass includes:

1. Cut-out differential protection via relay pushbutton.
2. Activate SV Bypass for a breaker MU by opening the designated test-switch pole.
3. Verify that no differential trip is present.
4. Cut in differential protection.

The CT shorting switches wired around the MU current terminals are operated when breaker maintenance work involves current injection or work on the breaker CTs, while the breaker MU remains in service. The CT shorting switches and SV Bypass feature are applied in different operating scenarios within the digital substation protection systems. Their applications should not be confused with breaker or relay CT shorting switches used in traditional hardwired protection schemes.

The SV Bypass feature is implemented for transmission line protection with dual line breakers, transmission and distribution transformer protection with dual breakers, and bus

protection. Fig. 5 shows a conceptual logic example of the transformer high-side breaker SV Bypass feature.

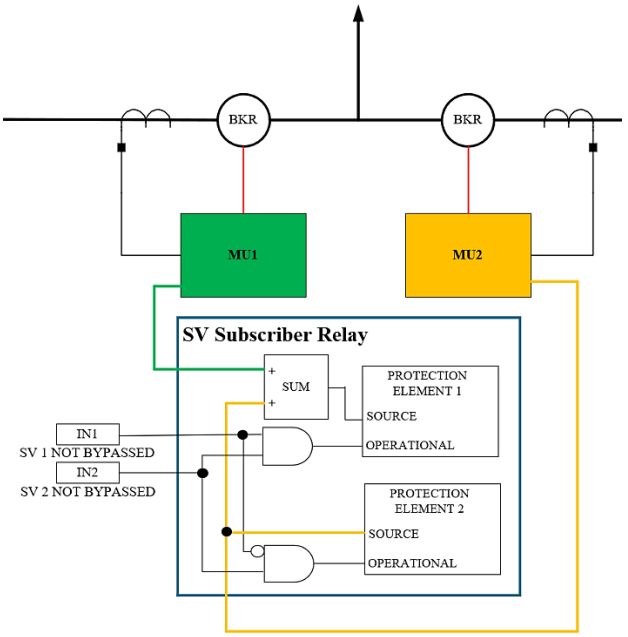


Fig. 5. SV Bypass Conceptual Logic Example

Protection Element 1, which uses MU1 and MU2 currents, is enabled when both MU1 and MU2 are in service. Protection Element 2, which uses MU2 currents, is enabled instead of Protection Element 1 when MU1 is taken out of service and MU2 remains in service.

B. Relay Cut-Out and Digital Cut-Out

Several considerations apply when implementing the RCO/digital cut out (DCO) mechanism in addition to using IEC 61850 test mode for isolation and testing:

- IEC 61850 test mode can be used to isolate a relay or MU under test. However, test mode should not be relied upon as the sole isolation mechanism, because it may not be activated reliably during certain relay failure modes. It cannot be assumed that failure to activate test mode will also result in failure of the SV and GOOSE communication.
- Laboratory testing has shown that if a GOOSE data set contains a data object with a missing quality attribute, an IEC 61850 ON-mode subscriber accepts the data object values when the publisher is operating in test mode. This condition may result in protection misoperation due to a configuration error in the publisher and subscriber.
- When test mode can only be applied at the physical IED level, test mode, once activated, applies to all logical nodes included in the SV and GOOSE datasets. However, it may be necessary to test GOOSE communications between a breaker MU and a relay while the MU remains in service with other relays. In this scenario, the breaker MU cannot be placed in test mode together with the relay under test.

An independent RCO relay capable of IEC 61850 GOOSE messaging is required to publish relay cut-in/cut-out commands. The RCO relay operates in conjunction with the DCO logic implemented within associated relays and MUs to isolate relays on the process bus. This approach is analogous to that described in [5] prior to the adoption of IEC 61850 Edition 2. Functionally, the RCO/DCO mechanism is equivalent to a traditional relay cut-out control switch dedicated to each tripping relay. The combination of IEC 61850 operating modes and the RCO/DCO mechanism enhance protection security while providing flexibility for brownfield installation and maintenance testing.

Protection System A and B each requires one or more RCO relays, because an RCO relay in one protection system cannot publish or subscribe to GOOSE messages in the other protection system. Each RCO relay provides 12 pushbuttons that can be assigned to as many as 12 relays. As shown in Fig. 6, pressing the RLY n pushbutton changes the cut-out status of RLY n and publishes the corresponding cut-in/cut-out command, where n ranges from 1 to 12.

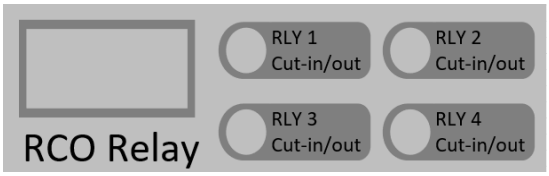


Fig. 6. Pushbuttons for Relay Cut-In/Cut-Out Control on the RCO Relay

All relays and MUs that subscribe to critical protection GOOSE signals from RLY n also subscribe to the corresponding RLY n cut-in/cut-out command published by the RCO relay. This command drives the RLY n DCO status within the subscribing relays and MUs, as illustrated by the DCO logic example in Fig. 7. Under normal operating conditions, the RLY n DCO status in each subscribing relay and MUs should match the status of the RLY n pushbutton on the RCO relay.

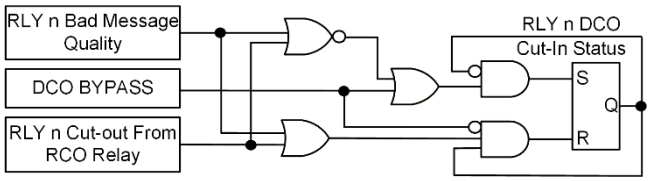


Fig. 7. DCO Logic for RLY n

The DCO logic within the relays and MUs also monitors the GOOSE message quality from RLY n. If the message quality is determined to be bad, the DCO status is forced to cut out, even when the corresponding RCO relay pushbutton remains in the cut-in position. Additionally, assertion of the local control bit, DCO Bypass, forces all DCOs within that relay or MU to the cut-in state regardless of the RCO relay pushbutton status or GOOSE message quality. The DCO Bypass function is intended to support protection logic testing during maintenance when the publisher is cut out. It should only be activated by test technicians during specific maintenance testing after appropriate isolation has been applied to the relay or MU.

Activation of the DCO Bypass function or detection of bad GOOSE message quality from RLY n may result in the DCO status and the corresponding RCO relay pushbutton status being in opposite states. To alert operators to this condition, a DCO disagreement alarm is implemented in the RCO relay for every relay cut-out pushbutton. The RCO relay subscribes to the RLY n DCO status (Fig. 7) from all subscribing relays and MUs and compares it with its local pushbutton status. If any

DCO status disagrees with the RCO pushbutton status, a disagreement alarm is indicated on the front-panel LED. Furthermore, every relay and MU includes a DCO Alarm LED on its front panel to indicate the disagreement between any subscribed RCO status and the corresponding DCO status.

C. Relay Panel Design and Front-Panel Operations

In a digital substation, most hardwired relay I/O is replaced by SV and GOOSE messaging, significantly reducing the number of test switches compared with traditional hardwired protection systems. Test switches are required only for the following functions:

- Interface with control switches, such as the reclose selector switch.
- Provide SV Bypass input to relays.
- Interface with non-IEC 61850 equipment.
- Support relay DC supply and relay failure alarm circuits.

A limited number of conventional control switches and test switches are retained in the digital substation panel design. As a result, operators, test technicians and maintenance personnel continue to use a familiar physical interface similar to that of existing SMP panels, minimizing operational, training, and maintenance impacts during the transition to digital substations.

Because the IEC 61850 test mode, simulation feature, and the DCO Bypass function are intended for use only by test technicians, these functions can only be enabled through relay local bits. Accessing these controls requires navigation through a sequence of front-panel screens or the relay terminal window, helping ensure that activation is deliberate and intentional [1]. All relays and MUs are designed with a common set of front-panel LEDs dedicated to process bus alarm indication. Additional details for each alarm are available through the relay display points:

- Mode Alarm: Test mode or simulation feature is active.
- SV Block: One or more SV subscriptions are blocked.
- DCO Alarm: any DCO status disagreement with corresponding RCO pushbutton status.
- PBUS Comm Alarm: Failure of any SV, GOOSE, PTP or PRP communications channel.

The testing and isolation features described in this section are closely tied to the capabilities and limitations of the MUs that interface process bus communications with primary equipment. The following section discusses MU design requirements and operational considerations in greater detail.

IV. Merging Unit Design and Operational Considerations

Each circuit breaker and transformer will be installed with an MU cabinet in the switchyard that includes a Set A and Set B MU, test switches, and RCO switches. Bus CCVT/PT applications may require a dedicated MU cabinet. Bus voltages may be used for undervoltage supervision as part of bus differential protection. In some applications, a line or transformer connected to the bus may use bus voltages for line or transformer protection. If the bus voltages are wired to the MUs of a nearby bus breaker instead of dedicated bus voltage MUs, the bus undervoltage supervision would be unavailable when that breaker is on clearance and the associated breaker MUs are out of service.

Transformer high-side circuit switchers or motor operated air switches (MOAS) do not require dedicated MUs, such as 289T-1, 289T-2, and 289T-3 in Fig. 8. Transformer 1, Transformer 2, and Transformer 3 each have a Set A and Set B MU that are wired with the transformer high-side switch binary status and control signals. 289-4 and 289-5 require a switchgear interface unit for binary status/control signals.

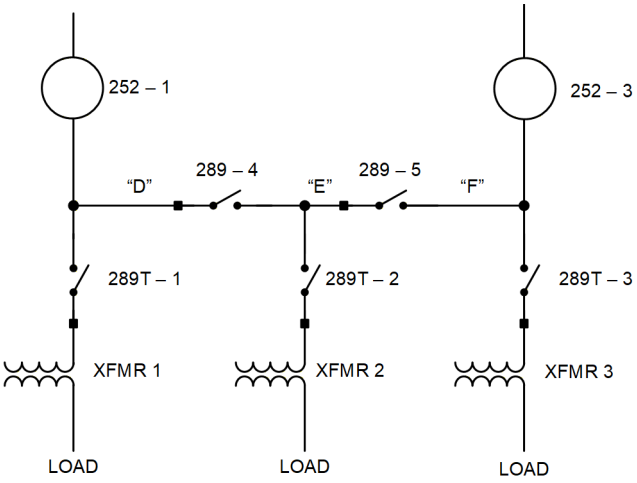


Fig. 8. Typical Looped Station at PG&E

A. MU Wiring

Each breaker MU has separate outputs for 'S' Trip Coil 1, 'T' Trip Coil 1, 'S' Trip Coil 2, and 'T' Trip Coil 2. This is to allow maintenance testing on Breaker 'S'-side protection with the MU 'S' trip outputs isolated while keeping Breaker 'T'-side protection in service, or vice versa. 'S'-side protection trip signals are sent via GOOSE from protection relays to the breaker MU. The MU asserts its outputs and energizes both 'S' Trip Coil 1 and 2 if the breaker is equipped with two trip coils. The same applies for 'T'-side protection trip. If the breaker is equipped with one trip coil, the MU outputs for Trip Coil 1 and 2 should be paralleled in the trip circuits. For manual trip signals, the MU only asserts both 'S' and 'T' Trip Coil 1 outputs regardless of Trip Coil 2 availability.

Each breaker MU is installed with a non-SCADA controlled RCO switch in the breaker MU cabinet. The RCO cut-in position supervises the MU trip/close outputs in the breaker trip/close circuits, as shown in Fig. 9. The RCO switch can be operated without involving test technicians to isolate a failed MU. During an MU failure, the RCO switch contact isolation in the trip circuit is more reliable than applying IEC 61850 block mode to block MU output contact operations.

Transformer MUs are not wired to trip or close breakers. Instead, transformer relays publish trip signals that are subscribed by high-side and low-side breaker MUs, where applicable. For a distribution transformer with a high-side circuit switcher or MOAS, the transformer MU has its trip/close outputs wired to trip/close the circuit switcher or MOAS. Both protection trip and manual trip signals can be sent via GOOSE from protection relays to the transformer MU to trip the high-side circuit switcher. The MOAS is wired for manual or station automatic operation and does not support protection trip.

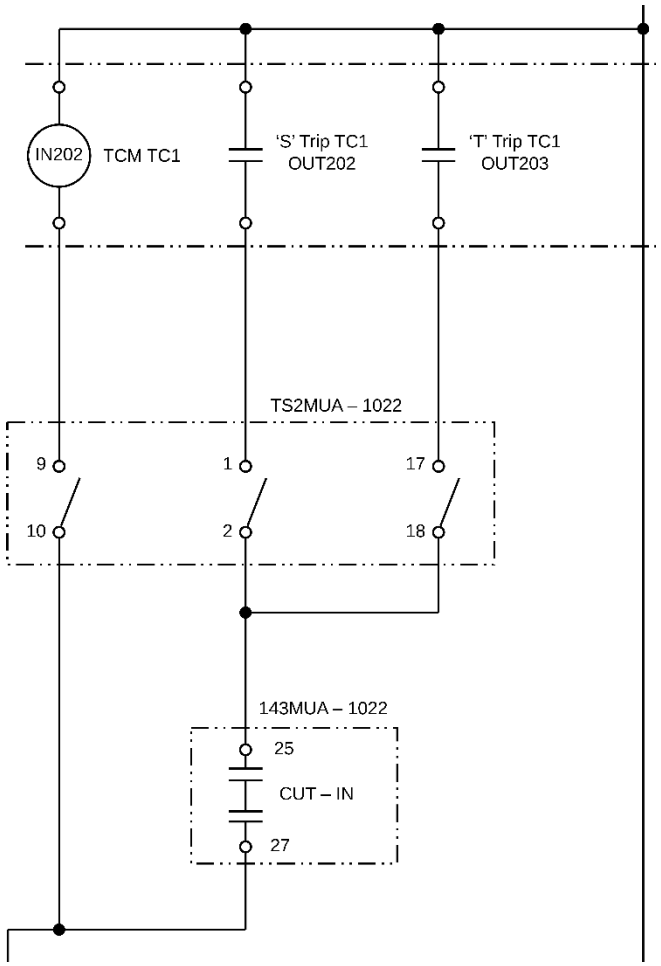


Fig. 9. MU Trip Outputs for Breaker Trip Coil 1 Supervised by RCO Switch

Each breaker MU has six current terminals (IAW, IBW, ICW, IAX, IBX, and ICX) and six voltage terminals (VAY, VBY, VCY, VAZ, VBZ, and VCZ). For design consistency, Breaker 'S'-side CTs should always be wired to the W-current terminals and 'T'-side CTs wired to the X-current terminals. Furthermore, the Breaker 'S'-side CCVT/PT should be wired to the Y-voltage terminals and the 'T'-side CCVT/PT wired to the Z-voltage terminals. All the currents and voltages are included in one SV message using IEC 61869-9 protocol. Line relays protecting a transmission line in a BAAH or ring bus configuration subscribe to the MUs of two breakers. Fig. 10 shows an example transmission line with CB1 and CB2 and their 'S' and 'T' designations.

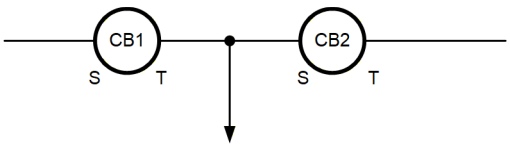


Fig. 10. Example Transmission Line with Two Breakers

Set A and Set B line relays assign CB1 MU W currents to the Relay W currents and assign CB2 MU X currents to the Relay X currents. Line relays internally sum currents from both breakers for line protection. Line voltages are wired to CB1 MU Z voltages, as well as CB2 MU Y voltages. The line relays assign CB1 MU Z voltages as the primary line voltages. When CB1 is cleared and CB1 MUs are out of service, the line relays can automatically switch to CB2 MU Y voltages based on the SV Bypass input status change. The SV Bypass feature makes it possible to keep the line protection in service when either line breaker and associated MUs are taken out of service. Table 2 shows the line relay SV publish/subscribe table.

TABLE II. SET A LINE RELAY SV PUBLISH/SUBSCRIBE TABLE

Subscriber Channel	Publisher Channel
111LA-IAW	MUA-CB1-IAW
111LA-IBW	MUA-CB1-IBW
111LA-ICW	MUA-CB1-ICW
111LA-VAY	MUA-CB1-VAZ
111LA-VBY	MUA-CB1-VBZ
111LA-VCY	MUA-CB1-VCZ
111LA-IAX	MUA-CB2-IAX
111LA-IBX	MUA-CB2-IBX
111LA-ICX	MUA-CB2-ICX
111LA-VAZ	MUA-CB2-VAY
111LA-VBZ	MUA-CB2-VBY
111LA-VCZ	MUA-CB2-VCY

For consistency, the BF relay always subscribes to the Breaker 'S'-side currents, which are wired to the MU W terminals. The BF relay subscribes to both Breaker 'S'- and 'T'-side voltages for the synchronism check function.

The transformer MU can be wired with the transformer high- and low-side winding currents, tertiary circulating current, and high- and low-side neutral currents where applicable. Transformer MUs are also wired with transformer mechanical trip signals, such as fault pressure, conservator oil flow, and transformer low oil trip.

The transmission transformer relay package can have both an outer and inner differential zone. The outer differential zone requires the transformer differential relay to subscribe to the breaker MUs for transformer high- and low-side breaker currents and low-side voltages. The outer differential relay also handles transformer high-side overcurrent, tertiary overcurrent, low-side distance and directional overcurrent, as well as high- and low-side stub bus protection. The inner differential zone requires high- and low-side winding currents from the transformer MU and operates the 86T lockout relay upon differential operation. The inner differential relay subscribes to the transformer MU for transformer mechanical element trip and operates the 86T lockout relay upon receiving mechanical trip signals.

Distribution transformer relays limit the differential zone to the high- and low-side winding currents if bushing CTs are available. The differential zone is extended to low-side breakers for distribution switchgear applications. The differential relay subscribes to high-side breaker currents for high-side overcurrent protection and differential protection when bushing CTs are unavailable. The relay's tertiary overcurrent, mechanical element, and REF protection are applied similarly as transmission transformer protection.

B. MU Failure Scenarios and Mitigation

The protection impact of an MU failure must be understood to properly isolate the failed equipment. In this

section, different MU failure scenarios are evaluated, and corresponding mitigation strategies are proposed.

A failed MU should be isolated by cutting out the MU via the RCO switch. Failure of a breaker MU affects the Breaker ‘S’- and ‘T’-side element protection, ‘S’- and ‘T’-side BF protection, manual breaker operation, and station automatics. If the MU failure causes an SV stream failure, the Breaker ‘S’- and ‘T’-side element protection that subscribe to the SV stream may be blocked. If the MU failure does not involve an SV failure, the Breaker ‘S’- and ‘T’-side element protection may operate for a fault but fail to trip the breaker because of the failed MU or the RCO switch in cut-out position. This may cause the BF relay to incorrectly declare breaker failure if the other protection system does not detect and clear the fault. A similar concern applies to the ‘S’- and ‘T’-side breaker BF relays.

To avoid unnecessary breaker failure operation, the Breaker ‘S’- and ‘T’-side element relays, as well as BF relays, should be cut out when the breaker MU fails. If the Set A breaker MU fails and the Breaker ‘S’-side element is a bus that cannot have its Set A bus protection cut out (for example, during maintenance on the Set B bus protection) one option is to clear the breaker and remove the breaker currents from ‘S’-side bus protection and ‘T’-side element protection using the SV Bypass, where applicable. PG&E’s standard practice is to cut out the BF relay after the breaker is opened and cleared. This helps prevent an incorrect BF declaration when the breaker is cleared and the MU is unavailable.

If both Set A and Set B breaker MUs fail, the breaker should be cleared. The Breaker ‘S’- and ‘T’-side element relays and BF relays may remain in service if SV Bypass can be applied for the breaker with failed MUs. For a breaker that cannot have SV Bypass applied, such as a transformer low-side breaker, the transformer protection elements that subscribe to the failed breaker MUs should be cut out. Protection engineers should evaluate whether the transformer has sufficient protection to remain in service.

If Set A transmission transformer MU fails, the corresponding Set A inner differential relay should be cut out. The Set A outer differential relay can continue to provide differential protection, high-side overcurrent, and low-side distance and directional overcurrent protection. The same applies to a Set B transmission transformer MU failure.

For a distribution transformer with a high-side circuit switcher, the transformer MU has its trip and close outputs wired to trip or close the circuit switcher. A failed transformer MU should be isolated by cutting out the transformer MU via the RCO switch installed in the transformer MU cabinet. For any distribution transformer with a failed transformer MU, the corresponding set of transformer protection should also be cut out to prevent undesirable relay operations.

C. Backup Protection

PG&E implements backup protection on breaker MUs and transformer MUs that are wired to trip transformer high-side circuit switchers. MU backup protection serves as the last line of defense for protecting substation primary equipment during a complete process bus failure. However, MU backup protection should not be considered as sufficient protection to keep primary equipment in service when the process bus is unavailable.

The breaker MU includes backup protection consisting of phase and ground definite-time overcurrent elements. Fig. 11 shows the logic for enabling backup protection in the MU. MU *IN224* is wired with *OUT208* process bus healthy status from the other set of MU, i.e., its sibling MU, and *OUT208* is supervised by the sibling MU RCO cut-in status. The backup protection elements are only enabled when the following occur:

- The MU detects a process bus failure.
- The backup protection is cut in via the front-panel pushbutton.
- The sibling MU is cut out, unavailable or also declaring a process bus failure.

Because the backup protection elements are enabled only during loss of process bus communications, they can be excluded from coordination and loadability requirements. The process bus healthy status is determined by the following conditions, as shown in Fig. 12:

- Either the ‘S’- or ‘T’-side element protection has good GOOSE communications status.
- The MU does not report a hardware alarm.
- The MU is synchronized to a PTP source if its upstream relay subscribes to more than one SV stream, such as a line relay for dual line breakers or a transformer relay.

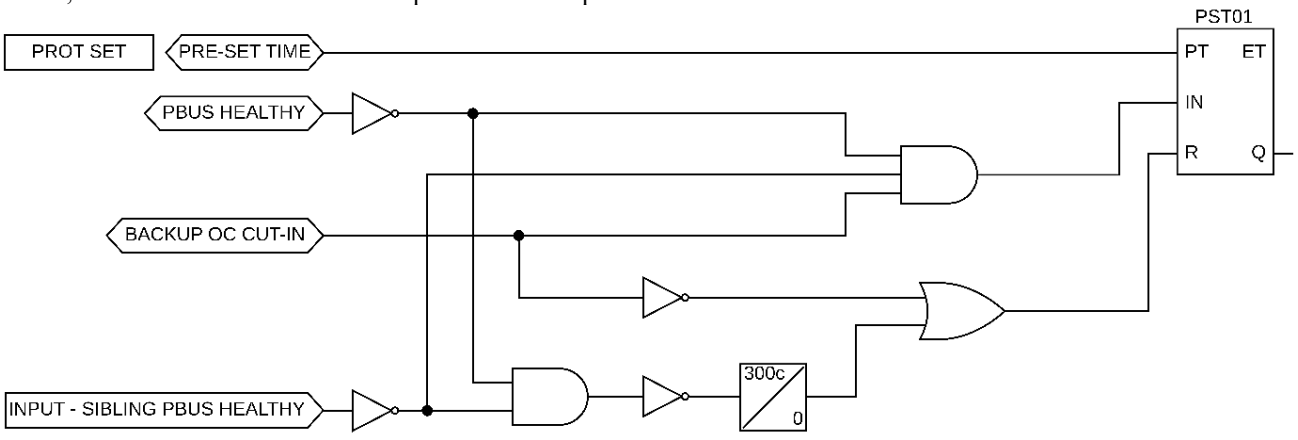


Fig. 11. Breaker MU Backup Protection Enable Conditions

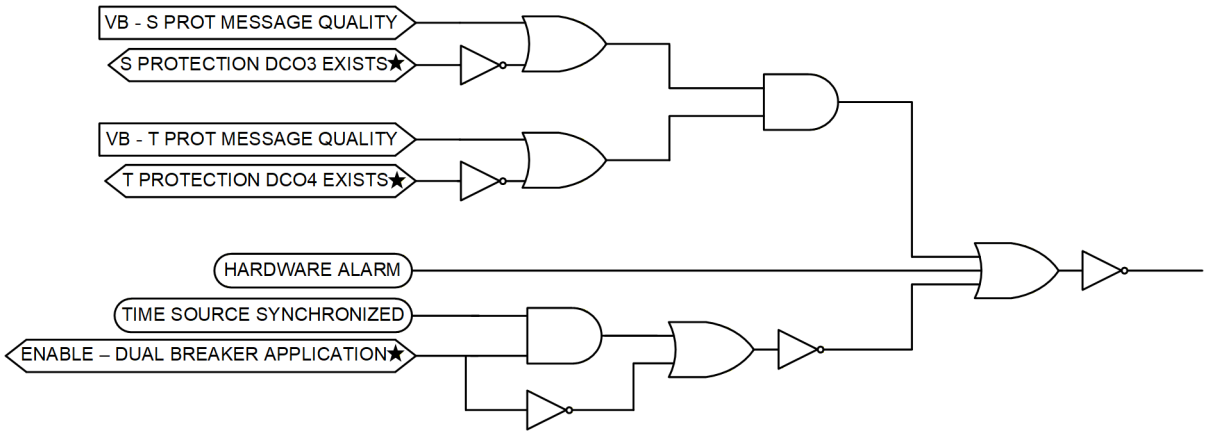


Fig. 12. Breaker MU Process Bus Healthy Conditions for *OUT208*

When the breaker MU experiences PTP time-synchronization failure, the availability of the upstream protection elements depends on the bus configuration and MU instrumentation wiring. The resulting protection availability determines whether the MU backup protection should be enabled.

- For an upstream relay that subscribes to currents from more than one SV stream, the corresponding protection elements are blocked when the MU loses PTP synchronization. In this case, MU backup protection should be enabled.
- For a single breaker application, in which line CTs and CCVTs/PTs are wired to the same MU, the line relay can keep protection elements enabled (except line current differential) during an MU PTP failure. In this case, MU backup protection should not be enabled.
- For a single breaker application, in which line CTs and CCVTs/PTs are wired to different MUs, e.g., when the line relay uses bus voltages wired to a dedicated bus voltage MU, the line relay can keep the 50/51 and line current differential elements enabled during an MU PTP failure. Directional, distance, LOP and out-of-step blocking elements would all be blocked. In this case, protection engineers should evaluate whether MU backup protection should be enabled during an MU PTP failure based on the configured protection elements in the line relays.
- For a looped bus configuration, in which a breaker serves both a transformer and a line as the only line breaker, MU backup protection should be enabled to protect the transformer during an MU PTP failure.

For distribution transformers with a high-side circuit switcher, a transformer MU can provide backup differential protection when transformer high- and low-side winding CTs are wired to it, as well as mechanical element trip protection. The conditions for enabling backup protection in the transformer MU are similar to those for the breaker MUs, shown in Fig. 11. The process bus healthy status is determined by the following:

- There is good GOOSE communications status with the transformer differential relay.
- The MU does not report a hardware alarm.
- The MU is synchronized to a PTP source if the transformer differential relay subscribes to more than one SV stream, such as low-side breaker MUs in distribution switchgear applications.

D. Emergency Open Function

During a process bus failure affecting both breaker MUs, failure of both BF relays, or failure of a Set A breaker MU, together with the corresponding Set B BF relay, or vice versa, the breaker can no longer be opened through the breaker control pushbuttons on the control room relay panel or through SCADA. To address these situations, the breaker MUs provide an emergency open function that allows operators or dispatchers to force the breaker out of service.

The breaker can be manually opened by toggling a local bit on the breaker MU front panel. The emergency open function is programmed with a 30-second walkaway timer to allow sufficient time for the operator or dispatcher to walk away from the breaker for safety purposes. A front-panel LED flashes while the 30-second timer is counting down.

The front-panel local-bit control is used instead of a pushbutton to prevent unintended operations at the MU. Accidental operation of a pushbutton could be mitigated if the pushbutton operation is supervised by other conditions, such as loss of GOOSE communications with both BF relays. However, such supervision may unnecessarily complicate emergency breaker operations by requiring operators or dispatchers to determine whether all supervisory conditions are met. With the front-panel local-bit approach, no supervisory conditions are implemented other than verifying the breaker is closed.

Fig. 13 shows the local-bit screen to activate or cancel the emergency open function. If the emergency open function is activated unintentionally and the 30-second timer LED is flashing, the same local bit can be toggled to cancel the operation.

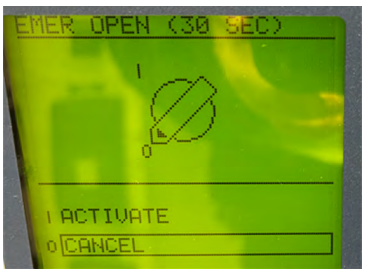


Fig. 13. Breaker MU Front-Panel Emergency Open

V. Process Bus Architecture

By migrating to a digital substation, the process bus architecture becomes a critical part of the protection system and must therefore satisfy the same dependability, security, redundancy, and maintainability requirements applied to the relays and MUs. The design features described in this section provide a resilient process bus architecture that preserves reliable protection performance, even when a component, communications path, clock source, or an entire protection system is out of service. Fig. 14 [6] shows the simplified process bus and station bus communications architecture employed at PG&E. The architecture extends the redundancy principles established in the SMP standard beyond the protection relays and into the communications infrastructure.

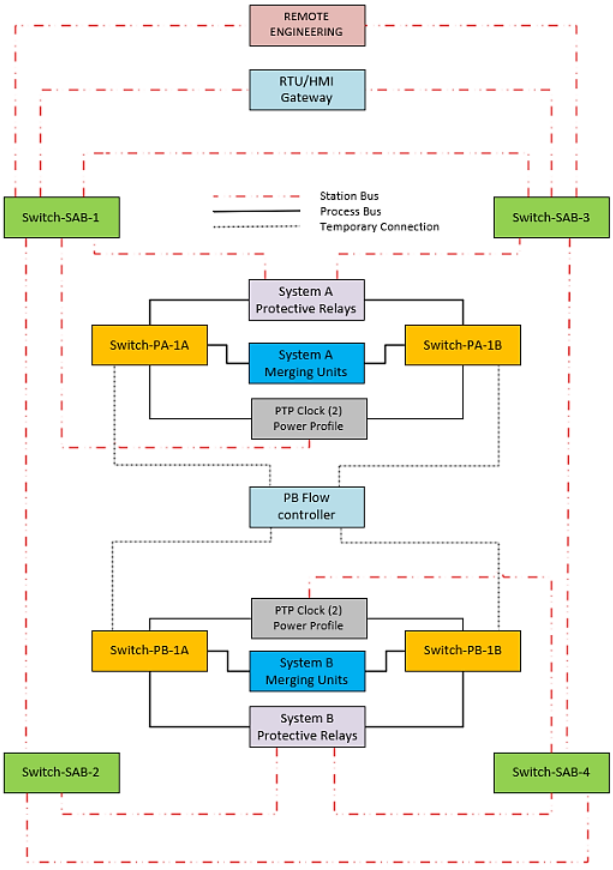


Fig. 14. Simplified Process Bus and Station Bus Communications Architecture

A. *Independent Protection Systems and PRP Network Redundancy*

The digital substation architecture includes two fully independent protection systems, designated Protection System A and Protection System B. Each system includes dedicated relays, MUs, PRP networks, and PTP clocks. Within each protection system, IEC 62439-3 PRP provides seamless communications-path redundancy. The two parallel networks are designated LAN A and LAN B. Each MU and relay operates as a Doubly Attached Node and connects independently to both LANs through fiber-optic Ethernet ports. Each Ethernet frame is transmitted simultaneously over LAN A and LAN B. The receiving device processes the first valid frame and discards the duplicate frame [7].

Failure of either LAN, therefore, does not require communications-path switchover before message delivery can continue. PRP health indications are monitored to alarm the loss or degradation of either network path. These alarms allow the failed path to be identified and restored before a subsequent failure on the remaining communications path affects protection redundancy.

The process bus networks for Protection System A are physically and logically isolated from those for Protection System B. No GOOSE or SV messages are exchanged between the two systems. The only cross-system protection interface is the hardwired block-close connection between the Protection System A and Protection System B BF relays, as described in Section II, and the cross wiring between Protection System A and Protection System B MUs for process bus healthy status. The resulting separation supports maintenance, testing, and configuration activities on one protection system without affecting the process bus communications of the other system.

Complete independence also limits the ability of one protection system to compensate for certain concurrent failures in the other. For example, if the Protection System A BF relay and the corresponding Protection System B element relay are simultaneously unavailable, the Protection System A element relay cannot transfer BFI, high-speed reclosing, or DTLO signals to the Protection System B BF relay. BF protection for the affected breaker may therefore be unavailable. More generally, an N-2 contingency involving the loss of a BF relay in one protection system and the loss of a required element relay or breaker MU in the other system may require the affected breaker to be removed from service.

This operating consequence is balanced against the protection-security benefit of maintaining complete independence between the two process bus systems. Under the existing SMP design, each transmission breaker has one BF relay, and PG&E practice requires the breaker to be removed from service following loss of that relay. The digital substation design improves N-1 availability by providing a BF relay in each protection system, while recognizing that selected cross-system N-2 contingencies may still require removal of the breaker from service.

B. *Software-Defined Networking (SDN)*

PG&E uses SDN and associated flow controllers to define, provision, and manage permitted communications across process bus networks. SDN employs a deny-by-default architecture, in which the flow controller centrally defines authorized communication paths within the control plane and deploys the corresponding flow rules to the SDN switches operating in the data plane. Through deterministic traffic engineering, preconfigured communications paths, and the elimination of unnecessary flooding and learning-based forwarding behaviors, SDN improves network determinism and reduces latency variation (jitter). In addition, SDN can minimize network failover times following link or switch failures [8]. These performance benefits are particularly important for protection applications because excessive network latency or the loss of SV packets may result in

degraded performance or the blocking of protection functions [9].

To limit the potential impact of network reconfiguration activities on protection functions, the process bus flow controller is, by default, not connected. Per PG&E operational procedures, it may only be connected to one process bus LAN at a time. Access to the alternate LANs requires a deliberate physical transfer of the controller connection, reducing the risk that a configuration change could simultaneously affect both redundant communications paths or both protection systems.

C. Time Synchronization

Time synchronization is another critical design consideration in a digital substation because SV communications depend on a common and accurate time reference between MUs and SV subscriber relays. IEC 61869-9 incorporates support for IEEE 1588 PTP, enabling precise synchronization of process bus devices and ensuring consistent alignment of sampled measurements through the sample count (*smpCnt*) attribute, which resets to zero at the top of each second. Loss of synchronization can prevent proper sample alignment, resulting in invalid measurements, degraded protection performance, or protection blocking. Consequently, time-source availability was a key design consideration for PG&E's digital substation implementation. Each independent protection system is supported by two PTP clocks. The clocks participate in the IEEE 1588 Best Master Clock Algorithm, which automatically selects the preferred grandmaster based on configured priority values and clock quality. If the active grandmaster becomes unavailable or its synchronization quality degrades, the alternate clock automatically assumes the grandmaster role, ensuring continued synchronization of process bus devices and minimizing the risk of protection functions becoming unavailable due to loss of time synchronization [10] [11].

In addition to *smpCnt*, the SV message header includes the *smpSynch* field, which indicates the time-synchronization status of the publishing MU. The standard *smpSynch* values are 0 for not synchronized, 1 for synchronization by a local-area clock signal, and 2 for synchronization by a global-area clock signal [12]. Relays use the *smpSynch* indication to validate synchronization consistency among subscribed SV streams. If the *smpSynch* value of a non-reference SV stream is zero or does not match the *smpSynch* value of the reference SV stream, the relay may declare a Sync Mismatch condition, resulting in SV block. If the *smpSynch* value of the reference SV stream becomes zero, the relay may declare SV block for the other subscribed streams. The reference SV stream is determined by the first SV subscription defined in the Substation Configuration Description file and can automatically transfer to the next available SV stream following loss of the reference stream [1].

In addition to implementing a redundant PTP architecture, PG&E selected IEC 61869-9 over IEC 61850-9-2LE because of both its flexibility and its potential impact on protection availability. IEC 61869-9 allows multiple current and voltage measurements from an MU to be included in a single SV stream, reducing network bandwidth requirements and dependence on multiple SV streams from the same MU [13]. For protection functions that subscribe to a single MU SV stream, protection other than line current differential may remain available following the loss of MU time synchronization, provided the relay continues to receive all required measurements within that stream. In contrast, applications that depend on multiple 9-2LE SV streams are more susceptible to protection blocking when loss of synchronization invalidates one or more required streams. Therefore, PG&E's adoption of IEC 61869-9 provides not only communication efficiency and data set flexibility, but also improves protection availability during certain loss-of-synchronization conditions.

VI. Brownfield Installation and Testing

A. Brownfield Cutover Considerations

For brownfield digital substation installations, the transition strategy must be selected based on available clearances and the ability to maintain dependable protection during intermediate construction states.

- Where a full bay or bus clearance is not available, the traditional protection system may need to remain in service until the digital substation protection is fully commissioned. In this arrangement, existing CT secondary circuits can be looped through the new MUs to the traditional relays, while trip and close circuits are transferred to the new breaker DC circuits and paralleled with MU outputs during the transition. Final cutover and load checks are performed one element at a time. After digital substation protection is cut in for the bay or bus, retirement of the traditional protection is then performed one element at a time.
- Where a full bay or terminal clearance is available, digital substation protection can be cut over during the clearance window, and the traditional protection equipment and wiring can be removed as part of the same work sequence. Traditional bus protection remains in service until the entire bus section is converted to the digital substation. A hardwired interface should be provided between the traditional bus protection and the digital substation BF relays to support the transition.

These two approaches show why process bus design must account not only for the final standardized architecture but also for temporary transitional states, parallel protection operation, isolation points, and commissioning checks.

B. Clearance Requirements and Testing Differences

PG&E identified maintainability as a key design requirement early in the development of its IEC 61850-based protection system. In conventional hardwired protection schemes, relay installation and routine maintenance often require transmission equipment clearances, because currents, voltages, and trip circuits may need to be physically isolated or disturbed. Temporary relay settings may be required to protect transmission equipment during reenergization until load and direction checks can verify the relay current and voltage circuits.

In the IEC 61850 process bus design, protection relays subscribe to digitized current and voltage measurements from breaker or transformer MUs. The analog-to-digital conversion

is therefore centralized at the MU and is verified during the MU installation or maintenance cycle. In addition, breaker trip and close circuits are wired only to the breaker MU. Protective relay replacement or maintenance does not require disturbance of the trip and close circuits. Consequently, transmission equipment clearances are generally not required, provided that the breaker MU remains undisturbed and the redundant protection system provides sufficient protection for the equipment.

As a result, activities such as relay replacement, Configured IED Description file updates, and routine maintenance can be performed while the associated transmission equipment remains in service, provided that the required cut out, test, simulation, and verification procedures are correctly applied. This approach is supported by two independent protection systems, System A and System B, each implemented with independent PRP networks.

The main differences between testing a conventional hardwired protection scheme and a digital substation protection system include the following:

1. Isolation:
   Hardwired protection systems use physical RCO switches to isolate relay trip outputs and critical outputs to other relays. Digital substations use a combination of the RCO/DCO mechanism and IEC 61850 test mode. The RCO/DCO mechanism is applied for targeted relay or MU isolation prior to starting any brownfield installation or maintenance work. Test mode is then applied before protection testing to provide complete signal isolation.

2. Protection Testing Setup:
   Secondary-injection testing for hardwired protection schemes is typically performed at the control room relay panel. For a digital substation relay or MU, the relay or MU is first placed in test mode to fully isolate the device and then placed in simulation to accept simulated signals for testing protection elements. Relay testing is performed at the control room relay panel, while MU testing is performed at the MU cabinet in the switchyard.

The following examples describe PG&E's standardized workflows for installation or maintenance work on breaker MUs and line protection relays that require protection testing. Similar principles apply to other IEC 61850 relays and transformer MUs.

C. Test Workflow on Set A Line Relay

During the work, the redundant protection system remains in service and provides protection for the line.

Preparation and Isolation

1. Cut out and remove the Set A line protection from service using the RCO relay and verify that no RCO/DCO disagreement alarms are present.
2. Isolate relay outputs using test switches where required (for example, transformer and BF relay interfaces). Isolation of line relay trip outputs is not required because trip commands are already blocked by the RCO/DCO mechanism.

Testing and Verification

1. Place the Set A line relay in IEC 61850 Test mode. Although trip, close, and reclosing signals are already isolated by the RCO/DCO mechanism, Test mode further suppresses operational GOOSE publications from the relay.
2. Place the relay in Simulation.
3. Use a test set to publish simulated MU SV and GOOSE messages and verify protection elements and relevant GOOSE I/O.
4. Simulate GOOSE messages from the line breaker(s) BF relays and verify the corresponding GOOSE I/O.
5. Simulate RCO relay signals and verify proper operation of the relay DCO logic.
6. Remove the relay from Test mode.
7. Perform trip-path testing and verify that associated MUs and BF relays receive trip and BFI signals as expected. MU trip confirmation may be verified through the MU SCADA GOOSE data set.
8. Remove the relay from Simulation.

Return to Service

1. Perform load and direction checks using the Set B line relay as the reference.
2. Cut in and return the Set A line relay to service using the RCO relay and verify that no RCO/DCO disagreement alarms are present.

D. Test Workflow on Set A Breaker MU

During the work, the redundant protection system remains in service and provides protection for the breaker and its 'S'- and 'T'-side elements.

Preparation and Isolation

1. Cut out and remove the Set A BF relay for the breaker, Set A 'S'- and 'T'-side element and BF relays from service using the RCO relay and verify that no RCO/DCO disagreement alarms are present.
2. Place the MU RCO switch in the cut-out position and open the associated test switches to isolate all breaker trip and close outputs.

Sampled Value Testing

1. Place the MU in IEC 61850 Test mode.
2. Place the Set A elements and BF relays that subscribe to the MU SV stream in Test mode.
3. Perform secondary-injection testing of the MU to verify analog input acquisition and SV publication.
4. Verify SV subscriptions for the associated Set A elements and BF relays.
5. Remove the associated Set A elements and BF relays from Test mode.

GOOSE and Logic Verification

1. Place the MU in Simulation.
2. Use a test set to simulate GOOSE messages from the Set A BF relay for the breaker, Set A 'S'- and 'T'-side element and BF relays. Verify all required GOOSE I/O, including trip checks to the open test switches.

3. Simulate RCO relay signals and verify correct operation of the MU DCO logic.
4. Remove the MU from Simulation.
5. Remove the MU from Test mode.

Return to Service

1. Restore the MU trip and close circuits by closing the test switches.
2. Perform load and direction checks using the corresponding Set B protection as the reference.
3. Return the MU to service by placing the MU RCO switch in the cut-in position.
4. Cut in and return the Set A BF relay for the breaker, Set A 'S'- and 'T'-side element and BF relays to service using the RCO relay and verify that no RCO/DCO disagreement alarms are present.

VII. Conclusion

The work described in this paper demonstrates that IEC 61850 process bus technologies can be applied to utility transmission protection systems when protection performance, maintainability, and operational practicality remain the foundation of the design. The resulting architecture supports digital substation implementation while maintaining alignment with established utility protection philosophies and practices.

PG&E's digital substation laboratory implementation has been used to validate process bus architectures, protection logic, and testing methodologies prior to broader standardization and field deployment. At the time of publication, deployment at two substations is underway, representing the next step toward broader standardization and deployment across PG&E's transmission system.

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