EPIC Final Report

Program	**Electric Program Investment Charge (EPIC)**
Administrator	**San Diego Gas & Electric Company**
Project Number	**EPIC-2, Project 1**
Project Name	**Modernization of Distribution System and Integration of Distributed Generation and Storage**
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Attribution

This comprehensive final report documents the work done in Electric Program Investment Charge (EPIC) 2, Project 1. The project team that contributed to the project definition, execution, and reporting included the following individuals, listed alphabetically by last name:

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EXECUTIVE SUMMARY

This EPIC project was entitled Modernization of Distribution System and Integration of Distributed Generation and Storage and is identified as EPIC-2, Project 1 in SDG&E's EPIC-2 application approved by the California Public Utilities Commission (CPUC). The objective of the project was to demonstrate distribution system infrastructure modernization solutions, including advances in distribution system design to enable use of new technologies, such as power electronic components, new protection systems, and distributed generation and storage technologies.

The chosen priority for focus of this project was to perform a pre-commercial demonstration in a laboratory of the International Electrotechnical Commission (IEC) 61850 standard, with specific emphasis on generic object-oriented substation event (GOOSE) and sampled value (SV) messages. The demonstration work compared the results to current protective relay practice and performance. This project also examined the pros and cons of IEC 61850, investigated vendor interoperability issues, and recommendations on commercial adoption.

Summary of Key Findings and Conclusions

When compared to legacy relay systems, the test system's protective trip times were improved with IEC 61850. No degradation in fault identification performance or signal fidelity was noted with the use of SVs, and all relays were correctly restrained for out-of-zone faults. No failure to trip was noted during fault simulations when the relays properly subscribed to SV signals from the various merging units (MUs). The results demonstrated that an IEC 61850 process bus protection and control (P&C) scheme should be at least as reliable and secure, if not more so, than the existing hardwired P&C scheme. Although the initial costs of this P&C scheme may be higher, it is anticipated that the on-going costs will be reduced over a hardwired implementation, and access to corporate and other enterprise-level data will be improved.

The use of IEC 61850 SV did not impact relay performance, as compared to a direct hardwired solution, as long as the process bus networks were correctly designed and utilized managed switches for media access control (MAC) to address filtering as necessary. All use cases were able to be implemented with the IEC 61850 process bus. The technology is now at a point where it could be applied to utility protection applications, assuming careful attention to equipment selection for compatibility.

The project was focused on interoperability and protection system performance. The interoperability determination was positive. Although interoperability was not achieved with all of the devices, enough interoperability was achieved to allow for performing all of the protection test cases identified. Performance of the protection relays using an IEC 61850 P&C scheme was verified to equal or exceed the performance benchmarks set by the project team.

IEC 61850 process bus technology has progressed to the point where it may be implemented by using equipment from different manufacturers, but the user can initially expect to spend a significant amount of time configuring an application when several different manufacturers' equipment are included, mainly to get them all to communicate (subscribe) correctly. After completion of this task, relay protection settings were straightforward. The design of a fully IEC 61850 compliant substation will differ greatly from the current hardwired state of the art, which will impact design standards that may currently be in place. To ensure success, issues such as maintenance, testing, and training must also be addressed before embarking on commercial adoption and implementation of an IEC 61850 project.

Overall, the results from this project were very promising. Compared to just a couple years ago, implementing GOOSE and manufacturing message specification (MMS) messaging was found to be much easier between relays, and between relays and MUs. SV based P&C was found to be equivalent or better than legacy solutions for the identified use cases. In addition, only a small number of SV interoperability problems were identified. It was anticipated that interoperability will greatly improve in the near term as the IEC 61850 standards, P&C equipment, and software tools mature. Interoperability will be crucial for system maintainability, ensuring that failed components may be replaced with newer equipment without comprising system operation.

Recommendations and Next Steps

The project team recommends that SDG&E continue to explore commercial adoption of IEC 61850 applications within its substations. The project findings and conclusions show that, although care is required in the selection of products, the currently available merging units and relays are sufficiently mature to support interoperability between vendors. In addition, the protection performance of the test system is equivalent to hardwired legacy P&C systems.

The project team further recommends that an SDG&E communications laboratory be developed to support future work and training. This laboratory would include the capability to mock-up future substation communications infrastructure to validate their performance before actual deployment in substations. Although this laboratory would have a focus on IEC 61850, it would also support testing of other communications technologies and standards.

With the completion of the future work items, the project team recommends that pilot projects be initiated to gain experience with IEC 61850. Potential pilot projects could include a GOOSE based 12 kilovolt (kV) capacitor control scheme using existing installed hardware, or a three breaker 69 kV P&C scheme. These pilot projects could be precursors towards development of a larger project to test the technology in an actual substation. A pilot project will serve as the basis for developing new standards for station drawings, relay settings, supervisory control and data acquisition (SCADA) and communication configurations. A substation located in close proximity to a maintenance center would be an ideal candidate for this type of pilot project because of the training opportunities it provides.

An IEC 61850 design implementation will differ greatly from current hardwired state of the art, and issues such as maintenance, testing and training, must be addressed while embarking on the first implementation of this technology.

SDG&E should make the results of this EPIC project available to the various standards bodies associated with IEC 61850 – especially IEC Technical Committee 57, Working Group 10.

The project did not explore networking architecture solutions as they were applied to substations. Network architecture, redundancy and security are essential factors in substation communications which should be considered when designing an IEC 61850 implementation. For an actual substation implementation, considerable thought should be given to network design and optimization.

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1. GLOSSARY

ABBREVIATION	DESCRIPTION
AC	Alternating current
ACSI	Abstract communication service interface
BFI	Breaker failure initiate
BNC	Connector type for coaxial cable
CAT5e	Category 5e Ethernet cable
CDC	Common Data Class
CID	Configured IED description
CIP	Critical infrastructure protection (when referenced with NERC i.e. NERC CIP)
COMTRADE	Common format for transient data exchange for power systems
CPU	Central processing unit
CT	Current transformer
cyc	Cycles (relating to electrical frequency)
DC	Direct current
DER	Distributed energy resource
DNP	Distributed network protocol
DOS	Denial of service (network attack)
DTT	Direct transfer trip (relay protection scheme)
ed	Edition (refers to a specific edition of the IEC 61850 standard)
ER	Event Recorder
EHV	Extra high voltage (refers to an electric system voltage typically exceeding 345,000 volts)
EPIC	Electric Program Investment Charge
FLTn	The fault location number associated with the lab testing
GOOSE	Generic object-oriented substation events (message type defined by IEC 61850)
GPS	Global positioning system
HIZ	High impedance (fault type)
HS	High side (Referring to the high voltage side of a transformer in a substation)
HSR	High-availability seamless redundancy
HV	High voltage (when referring to a substation bus)
HZ	Hertz
I/O	Input / output
ICD	IED capability description
ID	Identifier
IEC	International Electrotechnical Commission
IED	Intelligent electrical device
IEEE	Institute of Electrical and Electronics Engineers
IID	Instantiated IED Description
IP	Internet protocol
IRIG	Inter-range Instrumentation Group; refers to a time code protocol

ABBREVIATION	DESCRIPTION
ITF	Integrated Test Facility (San Diego Gas & Electric)
LAN	Local area network
LC	One of a variety of small form-factor pluggable (SFP) fiber connectors
LS	Low side (Referring to the low voltage side of a transformer in a substation)
LV	Low voltage (when referring to a substation bus)
MAC	Media access control
MM	Multimode Fiber (referencing fiber optic cable type)
MMS	Manufacturing message specification
ms	Milliseconds
MSVCB	Multicast sampled value control block
MU	Merging unit
NERC	North American Electric Reliability Corporation
P&C	Protection and control
PPS	Pulse per second
PRP	Parallel redundancy protocol
PT	Potential transformer
PTP	Precision time protocol
PUTT	Permissive under reaching transfer trip (relay protection scheme)
RJ	Registered jack (network connector as in RJ45)
RSCAD	RTDS simulator software
RTDS	Real time digital simulator for power system simulation
RTU	Remote terminal unit
SAV	Sampled analog value (a common data class in IEC 61850)
SCADA	Supervisory control and data acquisition
SCD	System configuration description
SCL	Substation configuration language
SCSM	Specific communication service mapping
SDG&E	San Diego Gas & Electric
sec	Seconds (for measurement of time)
SER	Sequential events recorder
SFP	Small form-factor pluggable (reference fiber optic transceiver)
SLG	Single line to ground (fault type)
SNTP	Simple network time protocol
SOE	Sequence of Event
ST	Straight Tip (Fiber Optic Connector)
SV	Sampled value (Message type defined by IEC 61850)
SWGR	Switchgear
TC	Technical committee within IEC
TCP	Transmission Control Protocol
UCA	Utility Communications Architecture
UCAIug	Utility Communications Architecture International Users Group

ABBREVIATION	DESCRIPTION
UFLS	Under frequency load shedding
Vac	AC voltage
VAR	Volt-ampere reactive
Vdc	DC voltage
VLAN	Virtual local area network
VxMy	A dual indexed code used to obfuscate the vendor name and model numbers of the IEDs for the project
WAN	Wide area network
Xfer	Transfer (relating to a substation transfer bus)
Xfmr	Transformer
1LG	Single phase line to ground fault
3LG	Three phase line to ground fault
3PH	Three phase (fault type)
9-2LE	IEC 61850 Section 9-2 Light Edition UCAIUG agreement on implementation of IEC 61850-9-2

2. INTRODUCTION

This project was one of three SDG&E Electric Program Investment Charge (EPIC) projects on pre-commercial demonstration of communications architecture standards for power system operations. The three projects were:

- Smart Grid Architecture Demonstrations (EPIC-1, Project 1)
    - Focus: Communications standards for integration of feeder equipment and distributed energy resources (DER) into networked automation
- Monitoring, Communication, and Control Infrastructure for Power System Modernization (EPIC-2, Project 3)
    - Focus: Open Field Message Bus
- Modernization of Distribution System and Integration of Distributed Generation and Storage (EPIC-2, Project 1)
    - Focus: IEC 61850 in Substation Network

The principal standard of interest in these three demonstrations was International Electrotechnical Commission (IEC) 61850, which is an open standard developed by industry stakeholders and promulgated through the IEC. The intent of these EPIC demonstrations was to increase the body of knowledge available to aid users in making decisions regarding their future power system communications architecture. The final reports for all three of these projects were posted on the San Diego Gas & Electric (SDG&E) EPIC website at www.sdge.com/epic. This body of work was limited in scope by funding availability in the SDG&E EPIC program, and it is acknowledged that a much larger body of work in this area is needed.

This report is the comprehensive final report for the third project listed above. The objective of the project, as stated in SDG&E's approved EPIC-2 application, was to demonstrate distribution system infrastructure modernization solutions, including advances in distribution system design to enable use of new technologies, such as power electronic components, new protection systems, distributed generation and storage technologies.

The chosen priority for focus of this project was to perform a pre-commercial demonstration in a laboratory of the International Electrotechnical Commission (IEC) 61850 standard, with specific emphasis on generic object-oriented substation event (GOOSE) and sampled value (SV) messages. The demonstration work compared the results to current protective relay practice and performance. This project also examined the pros and cons of IEC 61850, vendor interoperability issues, and recommendations on commercial adoption.

The test system for the demonstration facilitated the application of IEC 61850 to a predefined set of use cases normally found in distribution substations. Protection system performance and manufacturer interoperability observations were included.

The test system was designed to support a multi-vendor test environment. This enabled the project team to not only evaluate the protection impacts of a GOOSE and SV based P&C system, but also to evaluate the state of the industry in integrating IEC 61850 intelligent electronic devices (IEDs). The primary goals were to demonstrate a multi-vendor IEC 61850 system and determine the impact of IEC 61850 GOOSE and SV P&C messages on the identified protection use cases. Results from the demonstration were used to draw conclusions to support the recommendations.

This report includes documentation of the objective, scope, approach, test case descriptions, concept of operations, specification and design of the test system, laboratory demonstration activities, testing results, analysis, findings, conclusions, and recommendations.

3. IEC 61850 OVERVIEW AND ISSUES

Focus

The project's focus was a pre-commercial demonstration of the IEC 61850 standard as applied to a substation P&C mockup in a laboratory including:

- Specific emphasis on GOOSE and SV messages
- Study of the pros and cons of using this standard with a predefined set of use cases
- Study of vendor interoperability for some of the available IEC 61850 products
- Development of recommendations regarding commercial adoption

This project focused on IEC 61850 implementation, interoperability, control, and protection for specified use cases. Device configuration and manufacturer interpretation of the standard were key challenges in the project. The performance of the protection devices was also evaluated in order to gauge successful implementation of the standard by equipment manufacturers.

IEC 61850

IEC 61850 is an international standard. It is part of the IEC Technical Committee (TC) 57 architecture that provides an open-standard communication architecture for electric power systems. IEC 61850 is more than just a protocol; it contains methods for digitizing information and for its transfer within a substation or within the larger power system. IEC 61850 and the related TC-57 standards currently include other domains such as (but not limited to) wind power, hydroelectric plants, distribution automation, electrical mobility, electrical storage, and distributed energy resources (DER).

IEC 61850 provides a semantic model of the power system in that the model describes the meaning of its instances. This standardized model also provides organizational structure for information exchanges using various types of messaging. The main data exchange methods are MMS, GOOSE, and SV.

IEC 61850 is a large standard that contains ten parts. This standard includes, among other things, a defined set of file structures that describes device and system communications, a list of standard data objects and abstract communications services, standardized object models, a method of mapping messaging to communication methods, and a testing section to aid in verifying conformance with the standard.

Advantages of IEC 61850

A complete and comprehensive description of all of the advantages of an IEC 61850 system is beyond the scope of this section. The bibliography to this report identifies some sources of background reading material. Some of the more significant items are described below:

IEC 61850 provides standard methods of exchanging data between intelligent electronic devices (IEDs). By defining a semantic model, multi-manufacturer interoperability is possible. Not only should this ease configuration effort, but it should greatly reduce the risk that devices from different manufacturers' will not communicate.

By standardizing the communication methods and protocols, manufacturers should be able to reduce development time and costs, thus bringing lower cost products to market sooner. The standardized file transfer method provides a structured method of exchanging configuration data between devices. This can reduce end user engineering development time and costs. It also allows for standardized end user templates that can be reused in each implementation.

One of the big advantages of IEC 61850 P&C schemes is the reduction in control wiring. Control wiring is expensive to design, install, document and modify. IEC 61850 replaces the majority of the control wiring with Ethernet cabling that allows multiple communication sessions to be supported over a single physical media. When fiber optic cabling is employed, additional advantages accrue due to its noise resistance and isolation from ground potential rise (GPR) inherent in high voltage substations.

The communications cabling employed with IEC 61850 is essentially self-monitoring due to the repetitive nature of the messages. Loss of path can be rapidly identified due to message loss. Alarms can then be initiated to resolve failures before a critical failure occurs. This facilitates continuous automatic testing and reduces effort to comply with North American Electric Reliability Corporation (NERC) PRC-005 requirements.

The IEC 61850 semantic model provides for self-descriptive capabilities. Users can browse devices prior to purchase to identify their capabilities. It simplifies design and configuration as the device capabilities are standardized, insuring consistency from manufacturer to manufacturer.

United States Adoption of IEC 61850

Adoption of IEC 61850 in the United States has been slow. There are many proposed explanations for this slow adoption. No single explanation would likely cover all the reasons. The internet provides a multitude of potential explanations for the slow adoption in the United States and the rest of North America. Some examples are:

- There is a major investment in older legacy architectures, and migration to a new architecture will be costly. A business justification is needed.
- The use of some sections of the standard is still new. While MMS and GOOSE are fairly mature, but SV is still evolving and extensive effort is required to ensure interoperability.
- The changes required to implement an IEC 61850 substation are substantial and not every end user is willing to undertake the challenge.
- IEC 61850 provides for a very different P&C scheme, which is unfamiliar to many end users and requires careful change management to succeed.
- Implementing IEC 61850 introduces Ethernet into substations. Potential NERC compliance exposure is a concern with many end users.
- Testing and maintenance will be different with a P&C scheme based on IEC 61850. Development of industry accepted processes and methodologies are still evolving.
- Introduction of the new methods and processes will take time and effort.

From the above, it appears that knowledge and familiarity with the IEC 61850 standard contribute to its limited adoption in the United States. Providing additional information on the application and implementation of the IEC 61850 standard should provide a means to improve the adoption of this technology in the United States. Interest has been growing and adoption in the United States now appears to be accelerating.

Major Thrusts of Project Work

This demonstration project had two major work thrusts. The first was to develop additional information on the interoperability of IEC 61850 GOOSE and SV products between manufacturers. The second was to demonstrate the adequacy of an IEC 61850 P&C scheme when compared to the traditional hardwired scheme.

Knowledge Application

This project demonstrated that the use of IEC 61850 enhances interoperability of multiple manufacturers' products. It also demonstrated that SV and GOOSE could provide protection system performance that was equal to or better than the tradition hardwired solution. This report provides support for these assertions and should aid prospective adopters of IEC 61850 by providing assurance that the IEC 61850 P&C scheme will not degrade protection capabilities of substations.

4. OVERVIEW OF APPROACH

Power system automation and communication technologies are improving and becoming more robust. After studying different options and based on discussion with internal stakeholders, the project team chose pre-commercial demonstration of IEC 61850 for substation protection, control, and automation as the project focus.

The project and pre-commercial demonstration were anticipated to help determine whether the utilization of IEC 61850 based systems could replace existing substation automation and protection functions without compromising characteristics such as selectivity, speed, security and reliability of present substation P&C systems. In this project, existing standards for substation protection, automation and control architecture were used as a starting point. These existing standards were mapped to the new IEC 61850 standard. Bridges between the missing links of the technology were created to provide a transition to an IEC 61850 based protection system. This project implemented test cases in the test system that tested the application of IEC 61850 GOOSE and SV to the identified use cases (breaker failure protection, line protection, bus protection, transformer protection, capacitor/reactor feeder protection, capacitor and reactor protection, and frequency deviation protection).

The use cases were then refined into test cases. Test cases provided additional details so that the performance of the test system could be evaluated for various protection scenarios. These scenarios included in-zone and out-of-zone faults for individual protection elements. In addition, test cases included various control scenarios for capacitor and reactor banks.

The test system equipment was initially installed in racks in the contractor's IEC 61850 lab. All equipment was mounted in 19" racks and connected to power sources. Communication cabling was connected to each device in accordance with Appendix C. IEDs settings were then installed and published data sets were assigned in accordance with the tables in Appendix D. IED subscriptions were also assigned per the tables in Appendix C.

Test scenarios were developed using the Real-Time Digital Simulator (RTDS) and saved as COMTRADE (common format for transient data exchange for power systems) files. These files were then re-played by the relay test sets. The relay test sets injected currents and voltages into the appropriate MUs for processing by the relays. This process enhanced repeatability of the test parameters and reduced testing times. These files were also used as inputs for the RTDS testing that was performed at the end of the project. These tests files utilized actual SDG&E simulations as developed with the RTDS.

For this project, interoperability was considered to have been achieved if the MUs and relays could accurately publish, subscribe, and respond to IEC 61850 messages within the operational time limits of the protection devices.

Pre-Commercial Demonstration

The pre-commercial demonstration was conducted while the test system was located in the contractor's IEC 61850 lab. This provided team members with the opportunity to observe the functional tests performed on each test case and verify results. Additional time was provided to explain each test case and review COMTRADE plots to verify that the team members agreed with the relay operation and timing results.

Additional Demonstration at Integrated Test Facility (ITF)

Additional tests of selected use cases were performed at SDG&E's ITF using direct signals from the RTDS simulations, as described above. This repeat of selected use case tests allowed additional stakeholders to witness testing and have a chance to discuss the results.

Technology Transfer Activities During the Project

This project investigated a multi-vendor IEC 61850 test system that utilized GOOSE, SV, and MMS. It was predominantly a technology demonstration project. Technology transfer activities were performed throughout the project. These included on-site meetings, conference calls, web based presentations, and direct face-to-face meetings. Various workshops and training classes were held as part of the pre-commercial demonstration phase of the project. System architecture, RTDS, test setup, configuring software and relay settings were examples of activities and topics which were covered during the training.

Hands-on training was provided at various times throughout the project for the project team's engineers. This training included IEC 61850 configuration and one-on-one time with relay manufacturers' technical experts while they performed troubleshooting on the test system, when it was located in the contractor's IEC 61850 lab. Additional hands-on training was provided for the project team's members who attended the pre-commercial demonstration held at the contractor's IEC 61850 lab.

Classroom Training

A four day IEC 61850 training class was provided to the project team that covered the basics of IEC 61850 (i.e. operations, theory, standard, hands-on configuration, etc.).

Software Training

All of the manufacturers' configuration software and associated licenses were provided to the project team. Training was held to review each software package and how to configure the associated manufacturer's IEC 61850 IEDs. Additionally, the review of the specific project files was done and delivered to the project team (setting files, configurations, SCL files, etc.) for future reference.

Pre-commercial Demonstration Training

Additional time was devoted to training during the pre-commercial demonstration. This allowed additional stakeholders to obtain background on the design and development of the test system.

During the pre-commercial demonstration, the protection engineers provided additional explanations and background to allow stakeholders to improve their understanding of the test cases.

Hands-On Training with Vendors

Two of the main suppliers were at the lab during the configuration effort. Stakeholders were invited to participate. Stakeholders were on-site for configuration and trouble shooting. This provided an opportunity for the stakeholders to gain additional insight into the configuration of the IEDs in the test system.

5. BASELINE ASSESSMENT

A thorough investigation into SDG&E's current standards and selected existing distribution (138/12 kV or 69/12 kV) substations was conducted to provide a baseline on the SDG&E's philosophies and practices. This provided a reference point to which the conceptual IEC 61850 substation and the IEC 61850 lab demonstrations could be compared. Creating this reference point was important for future identification of the impacts of IEC 61850 substation design and implementation as well as the performance and functionality of the substation.

Several aspects of the existing substations including standard distribution substation electrical drawing package, typical protection system architecture and preferred schemes, protection use cases, communications, time synchronization, and the local operator interfaces were examined. These were included due to the anticipated changes associated with moving toward an IEC 61850 substation.

The baseline was created from a combination of standard drawings, as-built drawings from existing sites, relay settings from existing schemes, as well as discussions with the project team.

A list of anticipated differences for a complete IEC 61850 distribution substation was compiled. Because it was not possible to foresee all potential changes, this list was intended as a starting point and was subject to change as this project progressed. During the project, the list was expanded and can be referenced below:

- **Device Changes**
    - Within the scope of the project, relays and other IEDs will be changed to IEC 61850 compliant devices with SV and GOOSE protocols
    - Merging units will be added in the substation yard with SV and GOOSE protocols
    - Additional network switches will be added to provide for separate process buses and the station bus
    - Substation battery banks may need to be enlarged to accommodate the additional direct current (DC) load associated with the MUs and network switches
    - Panel meters, annunciators, and RTUs can be selected to take advantage of the new substation communications network
- **Wiring Changes**
    - Current transformer (CT) and potential transformer (PT) wiring of substation yard devices will not go back to the control shelter. This wiring will be run to MUs and kept as close to the associated CT and PT as reasonably possible
    - Test switches will be relocated from the control shelter to the substation yard with the MUs
    - When practical, substation yard device status and alarm contacts that were wired back to the control shelter will be wired into MUs for transmission by GOOSE or MMS
    - Wiring to panel meters, annunciators, and RTUS can be reduced when these items communicate over the new substation communications network
- **Fiber Optics Cables**
    - Fiber optic cables will be run from the control shelter to each of the MUs in the substation yard
    - Fiber optic patch panels on both the MU side and the control shelter side will be necessary to facilitate testing and troubleshooting
    - Fiber optic patch cables will be required for connections between patch panels and IEDs

- **Communications Changes**
  - The station will be broken up into independent local area networks (LANs) for each station bus and process bus
  - Protection relays will require multiple Ethernet connections to the station bus and the applicable process bus
- **Documentation Changes**
  - Updates to existing standards and drawings will be required

6. TEST CASES

This project implemented test cases in the test system that tested the application of IEC 61850 GOOSE and SV to the identified use cases. These use cases were defined by the project team at the start of the project. Use cases identified were:

- Breaker failure protection
- Line protection
- Bus protection
- Transformer protection
- Capacitor/reactor feeder protection
- Capacitor and reactor protection
- Frequency deviation protection

Use cases were further refined into test cases as the project proceeded. The test cases were used to compare performance of the test system to the existing protection equipment. Drawings for each test case were included in this report as Appendix A.

- For each test case, these drawings show the general substation equipment arrangement and the applicable bus (process bus #1, process bus #2, or station bus) with the case specific IEDs highlighted
- MUs were connected to simulated instrument transformers (test set/RTDS simulation inputs) with blue solid lines that indicate the location of the simulated instrument transformers. The SV streams were shown with blue dotted lines. From the identified MUs, these lines could be traced to highlighted subscribing relays. The relays' published GOOSE messages were shown with thin black lines, which could be traced to brown "virtual buses" at each highlighted MU. The subscribing MUs' connection to the "virtual buses" was then indicated with a brown arrow
- The MUs breaker control and indication was indicated with a purple arrow. Once the MU received the applicable indication a thin black line could be traced back to another brown "virtual bus", at the subscribing relays. Another brown arrow showed the communication from the relay "virtual bus to the subscribing relay
- Red lines showed the transfer trip connection between the local and remote relays used for line protection.

Each test case is described below:

Test Case #1 – Breaker Failure Protection (50BF)

The breaker failure protection test case was intended to simulate a typical breaker failure relay application for a 69 or 138 kV breaker. The test was run with one relay set consisting of the relay receiving breaker current signals from the instrument transformers via MU and IEC 61850-9-2 process bus SV. The breaker failure relay received breaker-failure initiate (BFI) notification by GOOSE from the line protection relays, and tripped all the bus breakers if the line breaker failed to trip. Trip and indication signals were published via GOOSE messages.

TABLE 1 BREAKER FAILIURE

TEST DESCRIPTION	RELAY	COMTRADE NAME
Breaker Fail – 52A Contact	V1M2[1]	07a_Breaker Fail 52A contact Fail_V1M2_52A_BF
Breaker Fail – Current Loss	V1M2	07b_Breaker Fail No Current Drop out_V1M2_OC_BF

Test Case #2 – Line Differential Protection (87L)

The line differential protection use case was intended to simulate primary line differential protection on a 69 or 138 kV sub-transmission circuit that interconnects a typical 12 kV distribution substation to the grid. The test was run with two relay sets (A & B) each set consisted of one relay that simulated the local relay receiving signals from the instrument transformers via MU and IEC 61850-9-2 process bus SV. The second relay simulated the remote station relay, which used direct injection of secondary test signals. The local relay's trip and indication signals were published via GOOSE messages.

Because modern line differential relaying depends on continuously transmitting line terminal phase current information between relays at each end of a line, this simulation must be performed with a minimum of two relays in each set.

The primary goal of the test was to prove proper relay operation or restraint for a variety of in-zone and out-of-zone balanced and unbalanced faults, and to record the operating times for each in-zone fault for comparison to that expected for conventional relays using directly connected instrument transformers. A secondary goal was to verify that relay element performance was not impacted by the use of SV signals.

TABLE 2 LINE DIFFERENTIAL

TEST DESCRIPTION	RELAY	COMTRADE NAME
3-phase Close In Fault	V2M2	00a_Line Differential, Close In_FLT1_3PH_V2M2_87L2A
3-phase Close In Fault	V1M1	00b_Line Differential, Close In_FLT1_3PH_V1M1_87L2B
SLG Close In Fault	V2M2	00c_Line Differential, Close In_FLT1_SLG_V2M2_87L2A
SLG Close In Fault	V1M1	00d_Line Differential Close In_FLT1_SLG_V1M1_87L2B

Test Case #3 – Line Distance and Directional Overcurrent Protection (21 & 50/51)

The line impedance and directional overcurrent protection test was intended to simulate permissive under-reaching transfer-trip (PUTT) and unsupervised directional element backup protection on a 69 or 138 kV sub-transmission circuit that interconnects a typical 12 kV distribution substation to the grid. The test was run with two relay sets (A & B), with each relay receiving signals from the instrument transformers via MUs and IEC 61850-9-2 process bus SVs. Trip and indication signals were published via GOOSE messages.

Because PUTT direct-transfer-trip (DTT) signals transmitted between each line terminal were unlikely to be IEC 61850 GOOSE, and the test system was not intended to verify built-in relay DTT

[1] See appendix H for explanation of product codes

line protection logic, a remote relay was not required for this test to examine operation of the relay scheme function with IEC 61850 SV signals.

The primary goal of the test was to prove proper relay operation or restraint for a variety of in-zone and out-of-zone balanced and unbalanced faults, and to record the operating times for each in-zone fault for comparison to that expected for conventional relays using directly connected instrument transformers. A secondary goal was to verify that relay element performance was not impacted by the use of SV signals.

TABLE 3 LINE DISTANCE AND DIRECTIONAL OVERCURRENT

TEST DESCRIPTION	RELAY	COMTRADE NAME
3-phase Close In Fault	V3M1	00e_Line Distance & Directional Overcurrent_FLT1_3PH_V3M1_21-1
SLG Close In Fault	V3M1	00f_Line Distance & Directional Overcurrent_FLT1_SLG_V3M1_21-1
3-phase Remote End Fault	V2M2	01a_Line Distance & Directional Overcurrent_FLT3_3PH_V2M2_87L2A
3-phase Remote End Fault	V3M1	01b_Line Distance & Directional Overcurrent_FLT3_3PH_V3M1_21-2
SLG Remote End Fault	V2M2	01c_Line Distance & Directional Overcurrent_FLT3_SLG_V2M2_87L2A
SLG Remote End fault	V3M1	01d_Line Distance & Directional Overcurrent_FLT3_SLG_V3M1_21-2

Test Case #4 – High Voltage (HV) Bus Overcurrent Differential Protection (87B-50/51)

The HV bus overcurrent differential protection test was intended to simulate the operation of the HV bus differential zone bounded by breakers for bus faults. Over-current differential protection was the primary form of protection for 12 kV distribution substation HV buses, so the simulation test for this form of protection was run with two different manufacturers' relay sets (A & B). The test was run with the relays receiving signals from the instrument transformers via MUs publishing IEC 61850-9-2 process bus SVs. Trip and indication signals were published via GOOSE messages.

The primary goal of the test was to prove proper relay operation or restraint for HV bus faults, and to record the operating times for each fault for comparison to that expected for conventional relays using directly connected instrument transformers. A secondary goal was to verify that relay element performance was not impacted by the use of SV signals.

TABLE 4 HV BUS OVERCURRENT DIFFERENTIAL

TEST DESCRIPTION	RELAY	COMTRADE NAME
3-phase HV Bus Fault	V2M1	02a_HV Bus Overcurrent Differential_FLT4_3PH_V2M1_5051EA138
SLG HV Bus Fault	V2M1	02f_HV Bus Overcurrent Differential_FLT4_SLG_V2M1_5051EA138

Test Case #5 – HV Bus Restrained Current Differential Protection (87B)

HV bus restrained current differential protection test was intended to simulate the operation of a high voltage bus differential zone bounded by breakers bus faults using a restrained current differential element. The test was run with the relay receiving signals from the instrument transformers via MUs publishing IEC 61850-9-2 process bus SVs. Trip and indication signals were published via GOOSE messages.

One relay set was assigned to perform both this protection use case and overcurrent differential protection as this use case was not currently applied to typical distribution substations.

The primary goal of the test was to prove proper relay operation or restraint for HV bus faults, and to record the operating times for each fault for comparison to that expected for conventional relays using directly connected instrument transformers. A secondary goal was to verify that relay element performance was not impacted by the use of SV signals.

TABLE 5 HV BUS RESTRAINED

TEST DESCRIPTION	RELAY	COMTRADE NAME
3-phase HV Bus Restrained Current Differential	V1M3	02c_HV Bus Restrained Current Differential_FLT4_3PH_V1M3_5051EB138
SLG HV Bus Restrained Current Differential	V1M3	02d_HV Bus Restrained Current Differential_FLT4_SLG_V1M3_5051EB138

Test case #6 – HV Bus High Impedance (HIZ) Differential Protection (87B-HIZ)

The HV bus high-impedance differential protection test case was intended to simulate the operation of a high voltage bus differential zone bounded by breakers for bus faults. The test was run with the relay receiving signals from a summation of breaker current transformers via a resistor-divider assembly that drives a dedicated MU publishing IEC 61850-9-2 process bus SVs. Trip and indication signals were published via GOOSE messages.

One relay was assigned to perform both this protection use case and overcurrent differential protection as this use case was not currently applied to typical distribution substations.

The primary goal of the test was to prove proper relay operation or restraint for HV bus faults, and to record the operating times for each fault for comparison to that expected for conventional relays using directly connected instrument transformers. A secondary goal was to verify that relay element performance was not impacted by the use of SV signals.

TABLE 6 HV BUS HIGH IMPEDANCE DIFFERENTIAL

TEST DESCRIPTION	RELAY	COMTRADE NAME
3-phase Hi-Z Bus Fault	V2M4	02b_HV Bus Hi-Z Differential_FLT4_3PH_V2M4_5051EA138_HIZ
SLG Hi-Z Bus Fault	V2M4	02e_HV Bus Hi-Z Differential_FLT4_SLG_V2M4_5051EA138_HIZ

Test case #7 – Transformer Restrained Current Differential Protection (87T)

The transformer restrained current differential protection test was intended to simulate the operation of the transformer differential zone bounded by breakers for internal transformer and associated interconnecting bus faults using a restraint overcurrent differential element. The test was run with two different manufacturers' relay sets (A & B) with each relay receiving signals from the instrument transformers via MUs publishing IEC 61850-9-2 process bus SVs. Trip and indication signals were published via GOOSE messages.

The primary goal of the test was to prove proper relay operation or restraint for transformer faults, and to record the operating times for each fault for comparison to that expected for conventional relays using directly connected instrument transformers. A secondary goal was to verify that relay element performance was not impacted by the use of SV signals.

TABLE 7 TRANSFORMER RESTRAINED CURRENT DIFFERENTIAL

TEST DESCRIPTION	RELAY	COMTRADE NAME
3-phase Transformer In-Zone Fault	V2M3	06a_Transformer Restrained Current Differential_FLT8_3PH_V2M3_87T41A
3-phase Transformer In-Zone Fault	V1M3	06b_Transformer Restrained Current Differential_FLT8_3PH_V1M3_87T41B
3-phase Transformer Restrained Current Differential	V2M3	06c_Transformer Restrained Current Differential_FLT8_3PH_V2M1_5051_7A
3-phase Transformer Restrained Current Differential	V1M3	06d_Transformer Restrained Current Differential_FLT8_3PH_V1M3_5051_7B
SLG Transformer In-Zone Fault	V1M3	06e_Transformer Restrained Current Differential_FLT8_SLG_V1M3_87T41B

Test Case #8 – Transformer Overcurrent Protection (50/51T)

The transformer over current protection test was intended to simulate backup overcurrent protection operation for fault in a distribution transformer or interconnected bus. The test was run with two overcurrent relay sets (A & B), and two restrained current differential relay sets (C & D) with backup overcurrent elements, each receiving signals from the instrument transformer via MUs and IEC 61850-9-2 process bus SVs. Trip and indication signals were published via GOOSE messages.

The primary goal of the test was to prove proper overcurrent relay operation for 3LG and 1LG transformer or associated bus faults, and to record the operating times for each fault for comparison to that expected for conventional relays using directly connected instrument transformers. A secondary goal was to verify that relay element performance was not impacted by the use of SV signals.

TABLE 8 TRANSFORMER OVERCURRENT

TEST DESCRIPTION	RELAY	COMTRADE NAME
SLG Transformer Fault	V2M3	06f_Transformer Ovecurrent_FLT8_SLG_V2M3_87T41A
3-phase Transformer Fault	V1M4	06g_Transformer Overcurrent_FLT8_3PH_V1M4_5051_7A
SLG Transformer Fault	V1M4	06h_Transformer Overcurrent_FLT8_SLG_V1M4_5051_7B

Test Case #9 – 12kV Bus Partial Overcurrent Differential Protection (87B-51P/G)

The 12 kV bus overcurrent differential protection test was intended to simulate the operation of the bus differential zone bounded by breakers for bus faults. Overcurrent differential protection was the primary form of protection for distribution substation buses. The test was run with two different manufacturers’ relay sets (A & B), with each relay receiving signals from the instrument transformers via MU publishing IEC 61850-9-2 process bus SVs. Trip and indication signals were published via GOOSE messages.

The primary goal of the test was to prove proper relay operation or restraint for 12 kV bus faults, and to record the operating times for each fault for comparison to that expected for conventional relays using directly connected instrument transformers. A secondary goal was to verify that relay element performance was not impacted by the use of SV signals.

TABLE 9 12 KV BUS PARTIAL OVERCURRENT

TEST DESCRIPTION	RELAY	COMTRADE NAME
3-phase 12kV Bus Fault	V2M1	04a_12kV Partial Bus Overcurrent Differential_FLT6_3PH_V2M1_5051BT_4041A
3-phase 12kV Bus Fault	V1M4	04b_12kV Partial Bus Overcurrent Differential_FLT6_3PH_V1M4_5051BT_4041B
SLG 12kV Bus Fault	V2M1	04c_12kV Partial Bus Overcurrent Differential_FLT6_SLG_V2M1_5051BT_4041A
SLG 12kV Bus Fault	V1M4	04d_12kV Partial Bus Overcurrent Differential_FLT6_SLG_V1M4_5051BT_4041B

Test Case #10 – 12kV Bus Restrained Current Differential Protection (87B)

The 12 kV bus restrained current differential protection test was intended to simulate the operation of the bus differential zone bounded by breakers for bus faults using a restrained current differential element and subscriptions to a maximum of six SV streams. The simulation test was run with the relay receiving signals from the instrument transformers via MUs publishing IEC 61850-9-2 process bus SVs. Trip and indication signals were published via GOOSE messages.

Only one relay set (Mfg. /Model V2M3) was assigned to perform this protection use case as it was the only one capable of subscribing to six SV streams. This 12 kV bus overall wrap has not been applied to distribution substations yet, so the settings will not match those in existing substations.

The primary goal of the test was to prove proper relay operation or restraint for low voltage (LV) bus faults, and to record the operating times for each fault for comparison to that expected for conventional relays using directly connected instrument transformers. A secondary goal was to verify that relay element performance was not impacted by the use of SV signals.

TABLE 10 12 KV BUS RESTRAINED CURRENT DIFFERENTIAL

TEST DESCRIPTION	RELAY	COMTRADE NAME
3-phase 12kV Bus Restrained Current Differential	V2M3	05a_12kV Bus Restrained Current Differential_FLT7_3PH_V2M3_87_1241A
SLG 12kV Bus Restrained Current Differential	V2M3	05b_12kV Bus Restrained Current Differential_FLT7_SLG_V2M3_87_1241A

Test Case #11 – Capacitor and Reactor Feeder Overcurrent Protection (50/51)

The reactive branch over current protection test was intended to simulate a fault on a capacitor/reactor feeder in a typical 12 kV distribution substation. The test was run with two relay sets (A & B), with each relay receiving signals from the instrument transformers via a MU and IEC 61850-9-2 process bus SVs. Trip and indication signals were published via GOOSE messages.

The primary goal of the test was to prove proper relay operation for faults on the feeder connecting the reactive components to the 12 kV bus, and to record the operating times for each fault for comparison to that expected for conventional relays using directly connected instrument transformers. A secondary goal was to verify that relay element performance was not impacted by the use of SV signals.

TABLE 11 CAPACITOR AND REACTOR BANK FEEDER OVERCURRENT

TEST DESCRIPTION	RELAY	COMTRADE NAME
3-phase 12kV Feeder Fault	V2M1	03a_Cap&Reactor Feeder Overcurrent_FLT5_3PH_V2M1_5051_17A
3-phase 12kV Feeder Fault	V1M4	03b_Cap&Reactor Feeder Overcurrent_FLT5_3PH_V1M4_5051_17B
SLG 12kV Feeder Fault	V2M1	03c_Cap&Reactor Feeder Overcurrent_FLT5_SLG_V2M1_5051_17A
SLG 12kV Feeder Fault	V1M4	03d_Cap&Reactor Feeder Overcurrent_FLT5_SLG_V1M4_5051_17B

Test Case #12 – Capacitor Bank Unbalance Protection (59N)

Capacitor bank protection has two specific use cases: feeder fault protection (see test case above) which protects for a flash-over or equipment internal short-circuit, and unbalance protection that was intended to take the bank off line if too many individual capacitor unit fuses blow. This test was intended to simulate the protective relay response to abnormal bank 3V0 voltage due to excessive imbalance. The test was run with only one relay set that matches those currently installed in typical 12 kV distribution substations, but with IEC 61850 GOOSE messaging used to trip all capacitor bank breakers and perform a lockout function to prevent the automatic Volt-Amperes Reactive (VAR) controls from bringing them back on line (the existing cap banks use a hardwired mechanical lockout relay to perform this function).

The primary goal of the test was to prove proper relay GOOSE signaling and logic operation after a trip for imbalance.

TABLE 12 CAPACITOR UNBALANCE

TEST DESCRIPTION	RELAY	COMTRADE NAME
Cap Unbalance	V3M2	Cap 59S Trip and Lockout

Test Case #13 – Reactor Unbalance Protection (51Q)

Reactor bank protection has two specific use cases: feeder fault protection (see “feeder over-current” test case above) which protects for a flash-over or equipment internal short-circuit, and unbalance protection that was intended to take the bank off line if the reactor(s) have significant standing turn-to-turn faults. This test was intended to simulate the protective relay response to abnormal bank negative-sequence current (3I2) due to excessive bank imbalance from one or more turn-to-turn faults. The test was run with only one relay set that matches those currently installed in typical 12 kV distribution substations, but with IEC 61850 GOOSE messaging used to trip all reactor bank breakers and perform a lockout function to prevent the automatic VAR controls from bringing them back on line (the existing reactor banks use a hardwired mechanical lockout relay to perform this function).

The primary goal of the test was to prove proper relay GOOSE signaling and logic operation after a trip for imbalance.

TABLE 13 REACTOR UNBALANCE

TEST DESCRIPTION	RELAY	COMTRADE NAME
Reactor Unbalance	V3M2	Reactor 51Q Trip and Lockout

Test Case #14 – Reactor and Capacitor Bank VAR Control Automation

Reactor and capacitor bank VAR Control Automation use case was intended to simulate the addition and subtraction of capacitor and reactor elements based on VAR flow in and out of the distribution step-down transformer as measured at the transformer high side (HS) connection.

This VAR control demonstration was accomplished by using the 50/51T over-current relay to measure the VAR flow and then transmit this information, in engineering units, via GOOSE analog values to the two automation controllers where the decision making logic was implemented.

All analog and discrete GOOSE messaging was carried over the station bus. Bank unbalance and feeder protection trips to the automation controllers were also handled by GOOSE messaging (see Test cases #12 and 13 above).

The simulation test was run with an automation relay that matched those currently installed in SDG&E substations so as to reuse the existing logic settings, but with IEC 61850 GOOSE messaging and logic changes incorporated as described above. The simulation test was run with one overcurrent transformer overcurrent relay (V3M1) receiving signals from the instrument transformers via a MU and IEC 61850-9-2 process bus SVs. Trip and indication signals were published via GOOSE messages.

The primary goal of the test was to prove proper relay GOOSE signaling and logic operation.

TABLE 14 REACTOR AND CAPACITOR VAR AUTOMATION

TEST DESCRIPTION	RELAY	COMTRADE NAME
Cap and Reactor Bank Automation	V3M2 V3M4	Cap & Reactor Bank Unbalance Protection and VAR Automation Test Records

Test Case #15 – Line Frequency and Voltage (81, 27, and 59)

Line frequency and voltage protection test cases were intended to simulate protective relay response to abnormal voltages (27/59) or frequency (81O/U) on a 69 or 138 kV sub-transmission circuit that interconnects a typical 12 kV distribution substation to the grid. The simulation test was run with two relay sets (A & B), with each relay receiving signals from the instrument transformers via MU and IEC 61850-9-2 process bus SV. Trip and indication signals were published via GOOSE messages.

Current sub-transmission line protection practice does not make use of 27, 59 or 81 tripping elements, but the interconnected distribution substations do use under-frequency (81U) as part of a regional under-frequency load-shed (UFLS) scheme incorporated into dedicated UFLS relays located in each distribution substation. Because IEC 61850 GOOSE messaging across the station bus provides great flexibility in how a UFLS scheme may be implemented, it was reasonable that this scheme could be incorporated into the backup distance line relays, for example, with GOOSE messages transmitted over the station bus network used to trip individual 12 kV feeder breakers; IEC 61850 would also allow a multi-level UFLS scheme to be implemented without much difficulty.

The primary goal of the test was to prove proper relay operation during sustained transmission system voltage or frequency deviations, and verify that relay element performance was not impacted by the use of SV signals.

TABLE 15 LINE FREQUENCY AND VOLTAGE

TEST DESCRIPTION	RELAY	COMTRADE NAME
Under Frequency	V2M2	08a_UnderFreq_V2M2_87L2A
Under Frequency	V3M1	08b_UnderFreq_V3M1_21-2
Under Voltage	V2M2	09a_UnderVolt_V2M2_87L2A
Under Voltage	V3M1	09b_UnderVolt_V3M1_21-2
Over Voltage	V2M2	09c_OverVolt_V2M2_87L2A
Over Voltage	V3M1	09d_OverVolt_V3M1_21-2

7. CONCEPT OF OPERATIONS

The operation of an IEC 61850 substation requires a shift from conventional substation design methods in how the protective relays acquire analog instrument transformer current and voltage signals necessary to detect faults, and the control circuits to breakers, auxiliary relays, alarm annunciators and SCADA. Typically conventional substations performed all this with copper wires that were routed from the substation yard, or within the control shelter, where they connect directly to the various P&C equipment.

The IEC 61850 substation with process bus digitally delivers these digitized current and voltage signals ("Sampled Values" or SV) via digital communications cabling. It delivers these digital signals by wiring the substation yard instrument transformers to MUs located in the high voltage equipment control cabinets in the substation yard. The MUs broadcast the continuous SV signals onto an IEC 61850 communication network called a process bus. The control shelter protection relays subscribe to the appropriate process bus signals and perform their protective functions based on the SV signals. The relays substitute the remotely generated measurements for signals that were previously locally generated analog measurements. These measurements are represented in instrument transformer primary units of volts and amps (engineering units) which facilitate easy use by a multitude of P&C equipment without special programming or decoding.

An IEC 61850 protection system operates much differently than in a conventional substation. Besides the MUs, networking equipment must also be leveraged to create at least one process bus and a station bus. These communication buses allow SV and GOOSE messages to be transmitted to and from the merging units and relays. High accuracy time synchronization also becomes critical so that the devices using these digitized analog signals can verify that the messages are valid, and properly align them with other SV signals before performing protection calculations.

With these changes to the operation of the substation, aspects of the protection system become more flexible and can be re-programmed as needed without the need to modify existing wiring and infrastructure. Lockout relay functions can be implemented in logic within the relays. Transfer trips, breaker fail initiates, and interlocks can be shared between devices over the network without any physical wires, and at far higher speed.

With these advances, substation networking sub-systems become critical to the operation of the protective system. Accurate synchronized time distribution becomes a very crucial consideration. Without it, devices cannot be sure that the data has reached them within an appropriate timeframe.

Thus communication becomes critical because the transmission and reception of messages relies upon the communication cables, Ethernet switches, and time sources. Battery banks likewise may also become larger due to the increased number of IEDs and data switches in the substation.

Protection and Control Architecture

The proposed architecture for a typical 69/12 kV substation with a process bus using SV to transmit ampere and voltage measurements from MUs to relays was examined here. This section also described the use of GOOSE to transmit status, control, and analog values from MUs to relays, from relays to MUs, and from relays to programmable automation controllers.

Process Bus

The process bus was used to transmit SV data from the MUs that digitize the analog signals and publish the data to relays that subscribe to the signals. The process bus also transmitted GOOSE messages containing status, control, and analog data from MUs to relays, from relays to MUs, and from relays to programmable automation controllers.

Multiple process buses were recommended to manage traffic and minimize disruption in the event of a network failure or compromise. The design of this project includes three process bus switches. Due to the required number of ports, process bus #1 had two switches in a single bus and provided message transport on the 138 kV side of the transformer. Process bus #2 had one switch and provided message transport for the 12 kV side of the transformer. They were arranged so that a failure of one process bus will not compromise the overlapping protection of the high side or low-side bus.

Due to vendor implementation variations, several relay models required two connections to the process bus. These manufacturers may change this in future models so that only one connection to the process bus would be needed.

Station Bus

The station bus was the main substation network that provided the information connectivity between substation systems and other remotely located systems. For this test system, the station bus used IEC 61850, GOOSE and various configuration and diagnostic protocols. The station bus also provided engineering access to the various protection equipment and test sets for monitoring, control, and configuration.

Due to the required number of ports, the station bus contained two switches in a single bus. This arrangement minimized network hardware, but did not provide for system redundancy. A thorough review of the redundancy requirements should be made before an actual substation deployment is designed.

Time Synchronization

The design included a global positioning system (GPS) clock. In an actual substation two clocks would be necessary and arranged so that the overlapping protection of the HS or Low Side (LS) bus would not be comprised in the event of a single time source failure.

Engineering and Maintenance Access

The project did not explore remote access for engineering and maintenance. Internal policies and NERC's Critical Infrastructure Protection (CIP) requirements would need to be reviewed in order to determine the level of protection required and the preferred method of achieving this capability.

Information Exchanges

Information exchanges and data flows would be similar to those used in the test system.

Controllable Devices and Functional Specifications

This section covers the controllable devices and algorithms developed to realize the automation logic.

Capacitor and Reactor Bank Automation

Capacitor and reactor bank VAR Control Automation utilized GOOSE analog and digital messaging. This allowed for the addition and subtraction of capacitor and/or reactor elements based on VAR flow in/out of the distribution step-down transformer, as measured on the transformer high side connection. This was accomplished by using the 50/51T relay to measure the VAR flow and then transmit this information via GOOSE to the two automation controllers where the decision-making logic was installed. To prevent adding capacitors when reactors are on line and vice versa, interlocking was performed between the standalone reactor and capacitor bank automation controllers by GOOSE messages. The imbalance relays were used to perform a lockout function when appropriate.

High Side and Low Side Lockout Relays

The lockout relays reproduced the functions of a traditional hardwired lockout relay scheme. To emulate lockout relay functions, a virtual lockout-relaying scheme was developed using latching variables and close blocking logic within the protection relays.

Minimum Local Area Network (LAN) Communication Requirements

The minimum LAN communication requirements for a substation deployment would be dependent upon the size and criticality of the substation. Larger substations would contain many more devices and thus require a higher bandwidth LAN and possibly higher reliability requirements. Network segregation is one way to manage traffic and improve reliability.

Additional requirements for an IEC 61850 process bus substation include:

- At a minimum, substation LANs should support 10/100/1000Base-TX, 100Base-FX multimode fiber (MM), and 1000Base-SX MM. This enabled Ethernet links to end devices at 100Base-FX or 100Base-TX. It also supported 1000Base-SX between Ethernet switches. Providing 10/100/1000Base-TX ports simplified local engineering and technician access to the network. The availability of gigabit switches is especially important for process bus implementation, due to the high bandwidth requirements with SV.
- A high port density on Ethernet switches reduces the number of switches in a substation and lowers costs.
- Managed switches supported virtual local area networks (VLANs) and media access control (MAC) filtering, and provided on-board monitoring of the network.
- Network devices that supported port level VLANs and priority configuration are required. Both GOOSE and SV used VLAN and priority in their message headers. Support for these features increased design flexibility.
- A wide range of media support is required. Typically, most network connections in an IEC 61850 system would use fiber and the connection types will be ether straight tip (ST) or LC. Engineering access or station bus devices required Registered Jack (RJ) 45 copper connections, so the switch needed a number of options available to adapt to project requirements.
- The network must contain devices that are Institute of Electrical and Electronics Engineers (IEEE) 1588 compliant. Devices may need to assume a boundary or transparent clock role to successfully deliver IEEE 1588 Precision Time Protocol (PTP) Power Profile messages to end devices or other switches.
- Network devices should have a wide range of power supply options. This reduces inventory and minimizes confusion with multiple power supply voltages.
    - At a minimum, switches should support DC supply voltages. The network will be part of the P&C scheme; therefore, DC supplies will increase reliability.
    - Network devices with redundant power supplies provide another option for increasing the reliability of the network. Network devices with one alternating current (AC) and one DC supply are available and can provide additional redundancy in the event of an AC outage or DC failure.

Minimum Wide Area Network (WAN) Communication Requirements

The minimum WAN communications requirements for an IEC 61850 substation using GOOSE and SV are unchanged from that of a typical substation. IEC 61850 process bus traffic does not typically extend beyond the substation itself. This allows the existing WAN communication infrastructure to remain in place until other requirements mandate a change.

Cybersecurity Considerations for Switched Networks

The following items apply to Ethernet networks in general and are not specific to IEC 61850 implementations. The following discussion provides recommended practices.

Good design practice includes cybersecurity that starts at the design phase of any communications network. The following elements associated with the Ethernet switch configuration and operation, follow National Institute of Standards and Technology (NIST) SP 800-82r2 guidance for designing a communications network with cybersecurity as a major component of the design and architecture. Compliance with these recommendations should be the bare minimum requirements in a substation deployment.

Network Segmentation and Segregation

Logical segmentation of communication networks provides effective risk management by establishing domains of authority, trust, or function. Managing data flow between domains allows more effective control of overall network traffic and provides points of isolation in the case of an incident. Segregating a substation control network in multiple process bus and station bus segments provides this isolation.

The implementation of IEEE 802.1Q VLANs provides the ability to logically segregate traffic between predefined ports on switches. This reduces the traffic on any segment so only required traffic is present. Although VLANs are an effective method to segregate traffic, they should not be used for security.

Disabling unused ports is a simple way to reduce the attack surface in a network. NERC CIP-007-6 R1 has requirements for high and medium impact bulk electric systems (BES) Cyber Systems that can be deployed on most networks. Once a port is disabled, traffic cannot pass. This is a low cost option to enhance security.

MAC Address Security

In general, Ethernet switches have the option to provide MAC address security, or port security, for each physical Ethernet interface. The MAC address for the connected device is entered into the switch configuration and prevents different devices from using the Ethernet ports on the switch. This option helps maintain a consistent configuration management baseline and reduces the chances of a malicious device being connected to the network. There are ways to “spoof” MAC addresses, so the protection is not assured, but the risk reduction associated with malicious devices and the benefits to configuration management are attractive.

For substation deployment, using port security on those ports dedicated to permanent devices and leaving the laptop ports open from MAC address security, but authenticated using IEEE 802.1X authentication is one way to enhance security.

Device Passwords

All device passwords, including special passwords for field service technicians, are recommended to be changed from the factory default passwords. These default passwords are well known and easily obtained by hackers. Replacement passwords should use a minimum of the criteria as defined in NERC CIP-007-6 R5.5 (listed below) or the maximum supported by the device.

- 5.5.1. Password length that is, at least, the lesser of eight characters or the maximum length supported by the Cyber Asset; and

- 5.5.2. Minimum password complexity that is the lesser of three or more different types of characters (e.g., uppercase alphabetic, lowercase alphabetic, numeric, non-alphanumeric) or the maximum complexity supported by the Cyber Asset.

The passwords are recommended to be changed on a periodic cycle, such as every 15 calendar months.

Devices with multi-level passwords provide increased resistance to password attacks and require sequential access before the configuration level is reached. This provides an additional recommended level of security.

Monitoring and Logging

Monitoring and logging activities are imperative to understanding the current state of the communications network, validating that the system is operating as intended, and ensuring that no policy violations or cybersecurity incidents have hindered the operation of the system. Network security monitoring is valuable to characterize the normal state of the substation communications network and can provide indications of compromised systems when signature-based technologies fail.

For substation deployment, it is recommended to use on-board logging and monitoring for project troubleshooting that can be easily configured to send logs and events to a centralized logging and monitoring server once in production.

Operational Requirements

In conclusion, an IEC 61850 substation will have additional operational requirements compared to current, conventional SDG&E substations. These additional requirements were critical to the proper functionality of the substation protection system, and thus were critical to system safety and reliability. These requirements reach into many areas of the substation and affect all protection use cases. This includes virtual lockouts since the functionality for these virtual devices resides in the protection relays themselves. LAN topology and operation was affected in order to support the protection functions of the system. The communication system was not greatly affected; however, in areas of the WAN and engineering access, the necessary studies will be required.

The changes in how the IEC 61850 substation is expected to operate include:

- Time synchronization
- Communications
- Battery sizing

Time synchronization is critical to protective functions since the validity of data streams is dependent upon the merging units being synchronized to the time source. Without synchronization, the relays will not properly receive the SV streams and GOOSE messages to which they subscribe.

Communication networks are critical and entail many different aspects. Without the proper communication networks, relays cannot receive the data they need to detect faults or to send trip commands. The communication system includes Ethernet cables, fiber optic cables, and networking equipment, all of which must be operational and designed with the specific tasks in mind in order to maintain good communications.

An IEC 61850 substation will likely require a larger battery/DC system than a traditional substation. This is due to the addition of MUs and other IEDs)which must be powered at all times so that they can send and receive SV and GOOSE messages as required for protective functions.

As a final note, this design places potential Cyber Assets in the substation yard and therefore, they may be subject to operational requirements of NERC critical infrastructure protection (CIP) regulations.

8. TEST SYSTEM SPECIFICATION

The system specification summarized each use case and defined the architecture, layout, and interface requirements for the test system. The testing phase of the project was split into two separate phases. For the first phase, the equipment was tested in the contractor's lab using both conventional and IEC 61850 enabled test sets. The first phase also included the pre-commercial demonstration, which was performed while the equipment was in the contractor's lab. After a successful pre-commercial demonstration of each test case, the equipment was shipped to the ITF where it was interfaced with the RTDS. Select test cases were then tested a second time using the RTDS to drive the merging units.

Rack Limitations

Excluding the test sets, all of the project's equipment was to be mounted in equipment racks. The test system was designed to limit the number of equipment racks as much as possible. The test system was initially mounted at the contractor's lab in four-post racks. This mounting arrangement required six racks to hold all of the equipment.

In order to accommodate relocation of the test system to the ITF, the space to be occupied by the equipment had to comply with the available rack space. The ITF's Power Systems/RTDS Lab had only three racks available for project demonstrations. The additional racks would need to be located in the ITF's DER Lab.

With the above limitations in mind, the test system was constructed with three racks of protective devices and networking equipment that would ultimately located in the DER Lab. The remaining three racks would be would be located in the Power Systems/RTDS Lab and contain MUs, test switches, and breaker simulators.

Electrical

Testing was performed in a lab environment so electrical power limits, available bus voltages, and voltage drop constraints were observed. Each rack was equipped with two AC power outlet strips. The AC load for any rack was limited to 10 amperes. The DC load available was limited by the size of the DC power supplies. The DC power supplies were sized to provide a maximum of 1,000 watts to be shared between three racks in the ITF Lab.

Voltages

As much as possible, the test system strived to duplicate the equipment voltages in a typical utility substation. To this end, the DC voltage level was constrained to 125 Vdc (DC Voltage) when practical. 120 Vac (AC Voltage) was available in both the ITF and the contractor's lab. Supplemental sources were available to provide additional voltage levels when needed. Since the test system was installed in adjacent racks, wiring runs were inherently short and line currents were small. For this reason, voltage drop calculations were not performed.

Networking

The equipment and design for the test system network and time synchronization provided a flexible infrastructure to support functions for an IEC 61850 environment. The design provided various network medium connection options and different methods for time synchronization that were referenced in the IEC 61850 standard to support the various equipment used in this test system. The test system infrastructure also demonstrated fiber solutions, which were required between equipment located in a substation yard and in a substation control shelter via the process bus or station bus.

Figure 1 shows a portion of the test system network and time synchronization connection diagram. The intent of this diagram was to show various equipment capabilities and provide a means for documenting the different use case scenario configurations. The full diagram can be viewed in Appendix C.

Fiber

To emulate a substation to the greatest extent possible, multi-mode fiber cables were used. These typically would extend from the control shelter to substation yard equipment.

Copper

The station bus, monitoring and configuration cabling installed for the protection relays, was primarily copper category 5 Ethernet (CAT5e) cable.

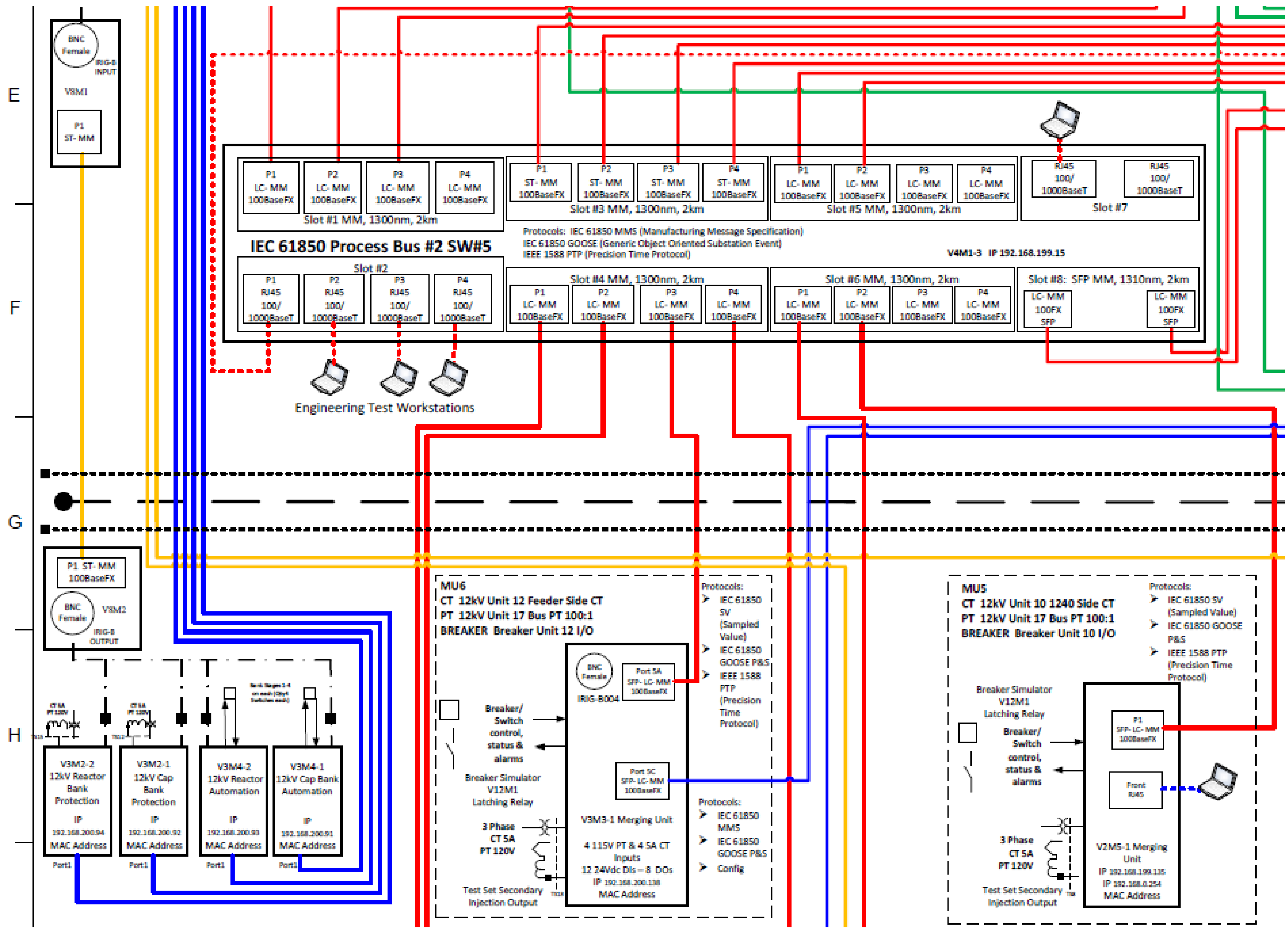


FIGURE 1 DETAIL OF NETWORK DIAGRAM

Network Capabilities

The network was designed to provide 100 megabit fast Ethernet to each end device. Communications between switches supported Ethernet at a speed of one gigabit. Due to the traffic volume associated with an IEC 61850 implementation, the network supported MAC address filtering, priority configuration, and port level VLANs. Each of these items was enabled and configured as required to ensure timely packet delivery.

Network Security

The test system's three networks were isolated, having no remote connectivity to other networks. The network equipment selected for this project was supplied with security features that can be enabled if necessary.

Test Set Interface

Manufacturers' test sets had their Ethernet configuration ports connected to the station bus for engineering programming access. The Ethernet port, on the test set with SV capability, was temporarily connected to one of the two process bus networks depending on the use case test scenario testing with SV messages. The station bus interface was used for configuration and monitoring of the test sets. All test sets were assigned a connection point into the system networks.

Network Tools

The following network tools were used as applicable to monitor the test system environment:

- Freeware network protocol analyzer
- Network monitor using IEC 61850 MMS
- Various manufacturer configuration and event viewing software
- Manufacturer built-in web clients

Station Bus

The station bus was the main substation network that provided the information connectivity between different process buses, substation systems, and other corporate/enterprise-level systems. For this test system, the station bus used IEC 61850, GOOSE, and various configuration and diagnostic protocols. It also provided engineering access to the various protection equipment and test sets for monitoring, control, and configuration. In addition, this network was connected to an IEEE 1588 PTP master clock to provide time synchronization to supporting devices.

Process Bus

The process bus networks were isolated from the station bus. The primary purpose of this network was to transfer information between the equipment MUs and devices requiring the information.

Process Bus #1

Process bus #1 used two managed switches, configured in a star architecture. It supported IEEE 1588 PTP Power Profile, using an isolated connection to the global positioning system (GPS) clock. This process bus integrated all of the equipment required to demonstrate the use cases for the HS of the transformer and transformer protection. The HS test cases were:

- Test Case #1 – Breaker Failure Protection (50BF)
- Test Case #2 – Line Differential Protection (87L)
- Test Case #3 – Line Distance and Directional Overcurrent Protection (21 & 50/51)

- Test Case #4 – High Voltage (HV) Bus Overcurrent Differential Protection (87B-50/51)
- Test Case #5 – HV Bus Restrained Current Differential Protection (87B)
- Test Case #6 – HV Bus High Impedance Differential Protection (87B-HIZ)
- Test Case #7 – Transformer Restrained Current Differential Protection (87T)
- Test Case #8 – Transformer Overcurrent Protection (50/51T)
- Test Case #15 – Line Frequency and Voltage (81, 27, and 59)

Process Bus #2

Process bus #2 uses a single managed switch. It supported IEEE 1588 PTP Power Profile, using an isolated connection to the GPS clock. This process bus integrated all of the equipment required to demonstrate the use cases for the LS of the transformer. The LS test cases were:

- Test Case #9 – 12kV Bus Partial Overcurrent Differential Protection (87B-51P/G)
- Test Case #10 – 12kV Bus Restrained Current Differential Protection (87B)
- Test Case #11 – Capacitor and Reactor Feeder Overcurrent Protection (50/51)
- Test Case #12 – Capacitor Bank Unbalance Protection (59N)
- Test Case #13 – Reactor Unbalance Protection (51Q)
- Test Case #14 – Reactor and Capacitor Bank VAR Control Automation

Test System Time Synchronization

The synchronization of all devices to a single clock was important in determining performance using time stamps and the use of SV. For the MUs and their subscribers, synchronized time was a critical component for publishing and subscribing SV messages. Each end required the same time synchronization in order to interpret the SV within the same time reference. This test system was designed to provide a number of time synchronization options that meet the IEC 61850 requirements.

There were four different methods for time synchronization represented in the IEC 61850 standard that were implemented in this test system: IEEE 1588 PTP; inter-range instrumentation group (IRIG)-B; simple network time protocol (SNTP); and 1 pulse per second (1PPS). The selected PTP GPS clock was anticipated to perform all test system time synchronization. This clock provided four independent network connections that provided PTP and SNTP while leaving the various networks isolated from each other. It also provided eight programmable 1PPS and IRIG-B outputs. These different time source options provided support for the varied manufacturer offerings for time synchronization.

Some devices required fiber optic inputs or it might have been desired that other devices utilize a fiber link from the GPS clock (to better model a substation with fiber connected devices in the yard). This test system used two different manufacturer's solutions to perform this conversion. The first solution covered equipment that had hardwired inputs on both ends, but required a fiber optic interface. This interface was used to time synchronize the reactor and capacitor bank P&C devices. The second interface converted coax to fiber for devices with fiber optic time input from the clock, which has a hardwired BNC connection.

IEEE 1588 Precision Time Protocol (PTP)

The selected clock provided master PTP clock interfaces for all of its network interfaces. The clock also supported an IEEE 1588 PC37.238/D16. *IEEE Draft Standard Profile for Use of IEEE 1588 Precision Time Protocol in Power System Applications* mode of operation. The connections between the clock and the network switches, that support PTP delivery to the end device, were shown in the Test Bed Network and Time Synch Diagram included in Appendix C. This test system used the IEEE

PC37.238 power profile for PTP. The selected switches also needed to be IEEE 1588 compliant. A boundary or transparent clock role was assumed by the switch to successfully deliver IEEE 1588 PTP Power Profile messages to end devices or other switches.

Inter-Range Instrumentation Group (IRIG-B)

Not all devices supported PTP, but they supported IRIG-B. The test system had an IRIG-B un-modulated (DC level shift) bus to provide a time source to these units. The test sets were specified with the IRIG-B input modules to synchronize events and provide time synchronization for SV messages. The test system utilized IRIGB-004, which has the year information encoded in the message.

1 Pulse per Second (1PPS)

Some MUs required 1PPS. The IEC 61850 user group's implementation standard for IEC 61850-9-2 Edition 1, known as IEC 61850-9-2LE, Utility Communications Architecture (UCA) International Users Group *Implementation Guideline for Digital Interface to Instrument Transformers Using IEC 61850-9-2*, specifies using 1PPS for MU time synchronization. The test system included fiber optic transmission equipment for this signal to provide a fiber interface to the MUs. Using this fiber optic interface mimicked field implementation requirements that place MUs in the substation yard.

Simple Network Time Protocol (SNTP)

There would be two uses for the SNTP method of time synchronization. The first was to time synchronize the V2M6 MU. This device only has the option to use SNTP for time synchronization. The second use was for relays V2M1, V2M2, V2M3, and V2M4. These relays required 1PPS inputs for SV messages. In order to maintain a synchronized time, the station bus interface was connected to the clocks SNTP server.

IEC 61850 Information Transfer Protocols

One of the main goals of the project was the reduction in substation P&C wiring. To accomplish this, IEC 61850 protocols were utilized whenever possible.

Manufacturing Message Specification (MMS)

The test system utilized MMS for non-time sensitive communications between individual relays and between relays and other IEDs, such as programmable automation controllers.

Generic Object Oriented Substation Events (GOOSE)

The test system utilized GOOSE messages for time sensitive communications from MUs to relays, between relays. This included messages to operate the breaker simulators and provide status changes to the appropriate relays.

In addition, the test system utilized GOOSE messages to provide volt-ampere reactive (VAR) data from the simulated HS bus to the reactive automation controllers.

Sampled Value (SV)

The test system utilized SV for ampere and voltage measurement communications between merging units and relays.

GOOSE and SV Data Flow Spreadsheet

A spreadsheet was developed to identify the message requirements with publishers and subscribers for both SV and GOOSE messages. Control block parameters were developed during this stage. Both GOOSE and SV messages require the identification of data sets. Each GOOSE message services a specific purpose in the system operation; therefore, the datasets were different from each other. The IEC 61850-9-2LE document was used to fix the SV datasets so all of these datasets looked the same.

Process Bus Data Flow Diagram

For each process bus, data flow diagrams were developed to show the GOOSE and SV data flows. These diagrams document data flows to and from the devices, and the devices' relationship to the substation equipment. A portion of the data flow diagram can be seen in Figure 2. The complete diagrams can be viewed in Figure 12, Figure 13, and Figure 14.

Additional information on the multicast MAC address was included to allow rapid identification of the data flow in a device configuration file or stiffing the network. SV message addresses always start with 01-0C-CD-04 and GOOSE with 01-0C-CD-01, leaving the remaining two octets available for configuration.

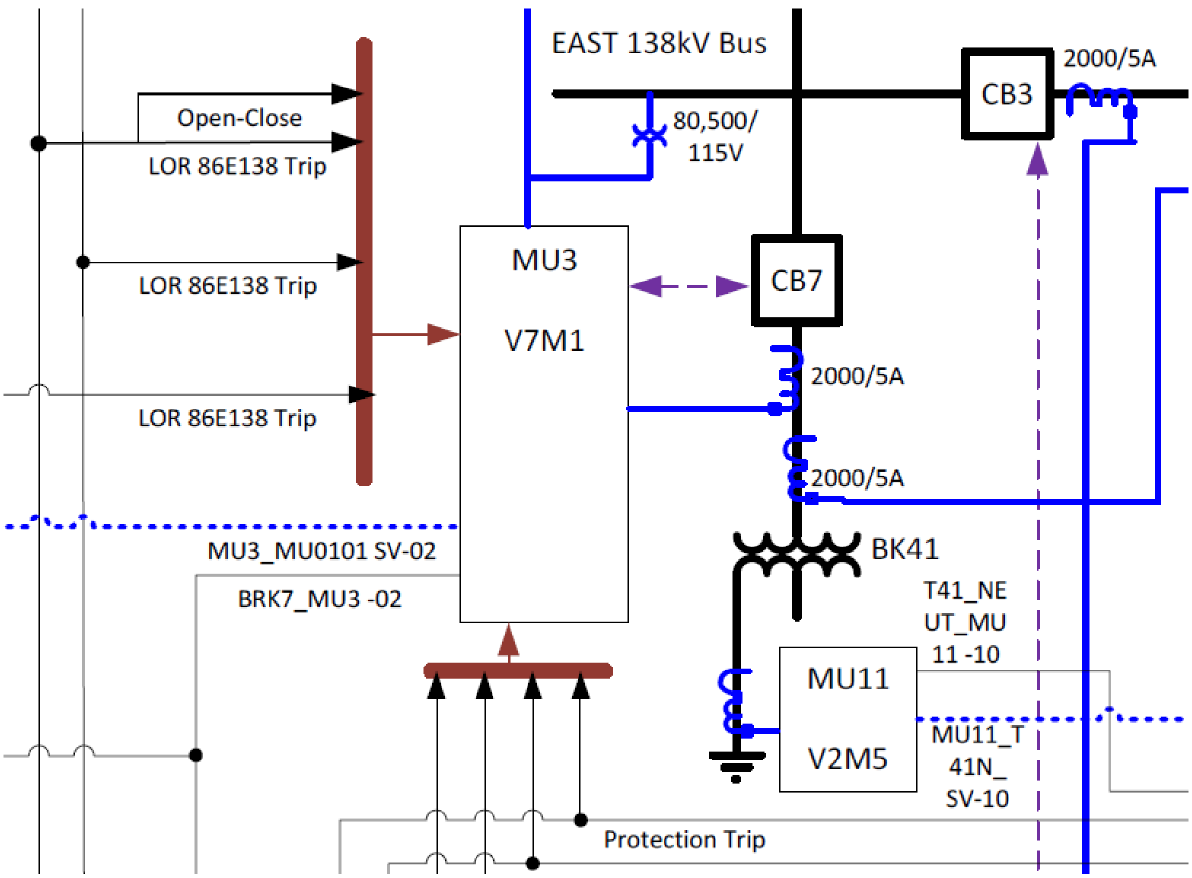


FIGURE 2 DETAIL OF PROCESS BUS DATA FLOW DIAGRAM

Station Bus Data Flow Diagram

For the station bus, a data flow diagram was developed to show the GOOSE and SV data flows. These diagrams documented data flows to and from the devices, and the devices' relationship to the substation equipment.

The only function used for the station bus was reactor and capacitor bank control. With the additional flexibility of GOOSE messaging, the same equipment and control philosophy that was currently used in the typical reactive control systems was used. A HS relay published the required analog measurement data to the controllers using GOOSE messaging. GOOSE messaging was also used to exchange information between the reactive bank protection equipment controllers.

Capacitor and Reactor Bank Automation

Reactor and capacitor bank VAR Control Automation utilized GOOSE analog and digital messaging. This allowed addition and subtraction of capacitor and/or reactor elements based on VAR flow in/out of the distribution step-down transformer as measured on the transformer HS connection. This was accomplished by using the 50/51T relay to measure the VAR flow and then transmit this information via GOOSE to the two automation controllers where the decision-making logic was configured. To prevent adding capacitors when reactors were on line and vice versa, interlocking was performed between the standalone reactor and capacitor bank automation controllers by GOOSE messages. The imbalance relays were then used to perform a lockout function when appropriate.

High Side (HS) and Low Side (LS) Lockout Relays

The lockout relays reproduced the functions of a traditional hardwired lockout relay scheme. To emulate lockout relay functions, a virtual lockout-relaying scheme was be developed using latching variables and close blocking logic within the protection relays. A detailed description of the lockout relay logic can be found in the Test System Design section.

Interfaces

Test Switches

Each MU was provided with a test switch to enable efficient connection from the test set to the MU. Test switches accommodated in-service test plugs to minimize re-wiring of the test set leads. Test switches also limited personnel exposure to energized parts. Test blocks at each MU simulated a real field installation and provide simplified test set connectivity to the MUs secondary current and voltage inputs.

IEDs were supplied with fiber ports whenever possible. When available, IEDs were supplied with at least one copper port. This simplified connection to laptops and other test/monitoring devices.

Device requirements

Relays

The protection equipment had at least one connection to the process bus and at least one connection to the station bus. All information to and from the substation equipment such as a CT, PT, circuit breaker, etc., came through the process bus interface. The station bus interface was used for GOOSE information exchange between process bus bays, SCADA MMS communication, and other uses. The test system used protection relays from three different manufacturers.

Process Bus Merging Units (MUs)

MUs were connected to the process bus and served as the interface to the substation equipment such as a CTs, PTs, circuit breaker, etc. These MUs provided the hardwired connection for the CT, PT, inputs, and output signaling that was digitized over the process bus using IEC 61850 SV and GOOSE. IEDs that subscribed to this information through their process bus connection also had an independent Ethernet connection to the station bus in order to move the required data between bays, substation level systems or corporate/enterprise level systems. These IEDs also published GOOSE messages, which were subscribed to by the MUs to issue trip, close or other control operations to the equipment. The test system used merging units from five different manufacturers.

Software

Each IED was supplied with all of the software needed to configure and trouble shoot its performance.

Ethernet Switch Features

The Ethernet network switches supported the following features:

- Given the expectation for advanced networking features, all switches were managed. Managed switches allowed for other applications such as security features, MAC filtering, monitoring, etc.
- Support for port level VLANs, multi-cast filtering, and priority configuration was required. Both GOOSE and SV uses VLAN and priority in their message headers.
- The switches supported a wide range of media and provide a high port density.
- Most of the network connections used fiber and the connection types were either straight tip (ST) or LC. There were requirements for engineering access or station bus devices that also required RJ45 connections so the switch must have a number of options available to adapt to the project requirements.
- Gigabit switches were important, especially for the process buses, due to the high bandwidth requirements for SV.
- Each switch was IEEE 1588 compliant and was able to assume a boundary or transparent clock role to successfully deliver IEEE 1588 PTP Power Profile messages to end devices or other switches.

Time Clock

There were a wide range of options for receiving time synchronization information. A GPS clock that can provide all four time synchronization methods listed in the IEC 61850 standard; PTP, Inter-range Instrumentation Group, 1PPS and SNTP was required. Due to limitations of the manufacturers' equipment all four methods were ultimately implemented. This clock also maintained network isolation between each of the process buses and the station bus.

Breaker Simulators

The test system had a means of simulating the circuit breaker operation control and feedback interface with the MUs. Dual coil latching relays ("ice cube" relays) fulfilled this requirement. The dual coils allowed for both a trip and close control connection and one of two Form C contacts provided the position feedback to both the MU and RTDS. Another advantage of these relays was that the contact operation and release time was approximately 25 milliseconds, which was fairly close to the operating times for most circuit breakers.

RTDS and COMTRADE

The necessary RTDS model was developed to allow the RTDS to be utilized during testing. An RTDS was used to develop COMTRADE files that could be used for all testing.

RTDS

The RTDS allowed real-time modeling of power system apparatus including generators, transformers, transmission lines and power system controls. The RTDS was a combination of specially designed parallel processing hardware and customized software with detailed, efficient algorithms for representing power system apparatus.

Closed looped testing of protection systems was achieved by interfacing the analog outputs representing real-time currents and voltages from the power system to the analog inputs on the protection system. The outputs from the protection system were connected to the RTDS to provide control, such as circuit breaker tripping and closing, and to monitor the internal elements in the protection system. In addition, digital statuses, such as circuit breaker position were routed back to the protection system digital inputs. Through these connections, the RTDS and the protection system operated as if connected to an actual power system with all of the dynamics and control actions that typically occur.

The power system components were configured in a graphical user interface program. The detailed apparatus models, controls, and input / output (I/O) configuration tools were all included in the interface program. A detailed model was created that included transmission lines, ideal sources, series capacitors, generators, transformers, circuit breakers, and instrument transformers. The apparatus models were very detailed and provide an accurate representation of the power system response. Figure 3 shows a portion of the model.

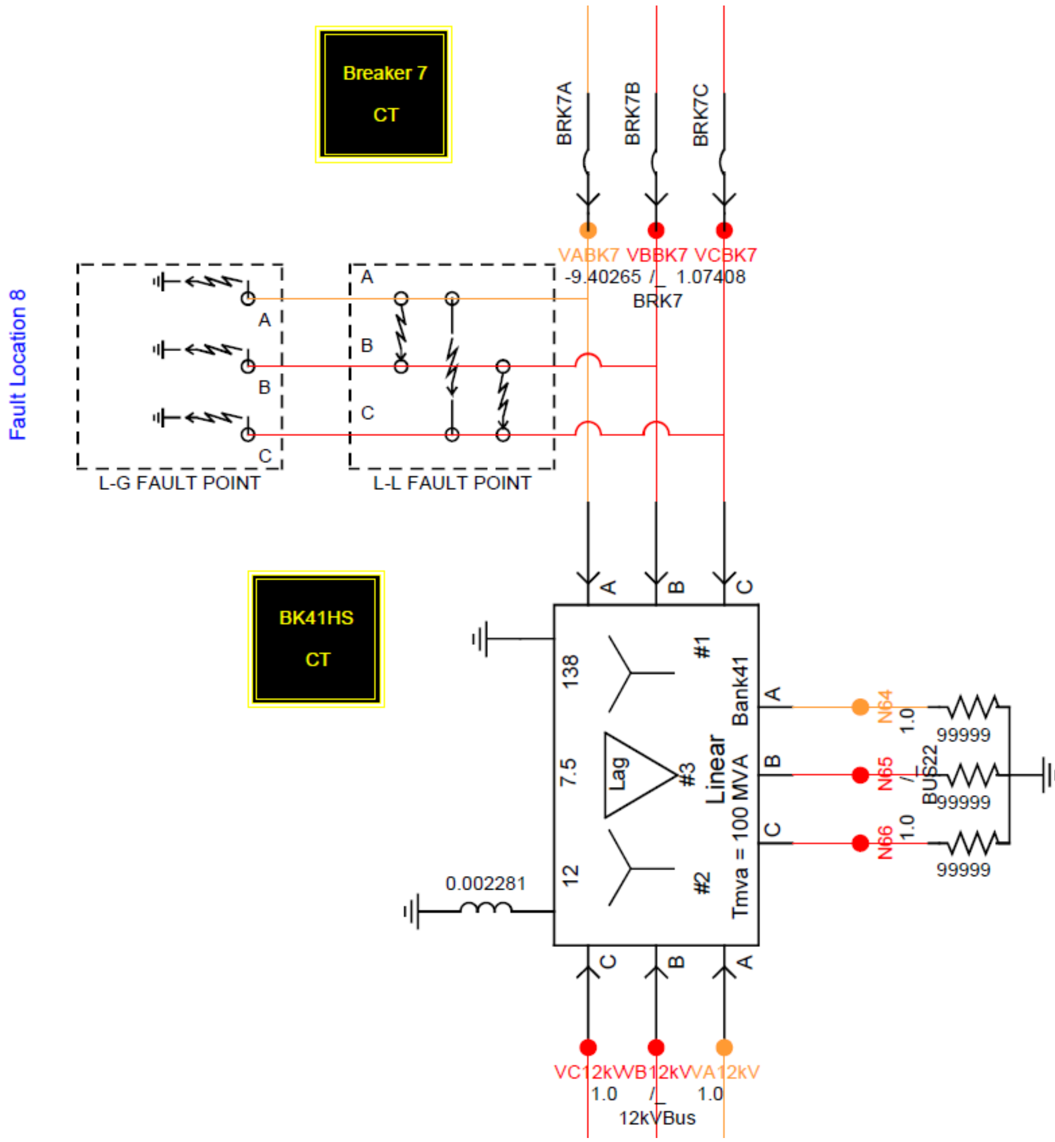


FIGURE 3 DETAIL OF RTDS MODEL SHOWING TRANSFORMER AND FAULTS

The analog waveforms and relay responses that were captured via the RTDS were in a COMTRADE format. The COMTRADE file included all the current and voltages that were being measured by the protection system and the state of the circuit breakers via output contacts from the protection system to the RTDS.

The simulation was run using a 50-microsecond time step (20 kilohertz sample rate). The COMTRADE files were captured at a 2,500 hertz sample rate, which provides 0.4 millisecond resolution of the relay response and changes in the state of the model.

RTDS Model

A power system model was developed using the data supplied. The data included detailed information on the transmission lines, protection, circuit breakers, and transformer characteristics. All transmission lines were modeled using the parameters detailed in the circuit model provided. The system model was loosely based on an existing substation and included one 138 kV bus, one transmission line, one transformer bank, a 12 kV bus, a 12 kV capacitor bank, and a 12 kV reactor bank.

Equivalent source impedances were calculated at each bus using the Network Boundary Equivalent function in the protection database provided. An additional transmission line was included to represent the equivalent transfer impedance between the two substations due to the interconnected nature of the surrounding system. The sources at each bus were modeled as ideal sources. This baseline model allowed modifications, during testing, to accommodate frequency deviation test, voltage deviation tests, and simulation of alternate source impedances.

COMTRADE FILES

The RTDS system produces low-level analog signals that can be output to an external device under test. In order to get true secondary currents and voltages (5 A or 120 V) an amplifier was required. For testing at the contractor's lab, the results of each RTDS simulation was saved in the COMTRADE format and downloaded into a relay test set, then output to the merging units at secondary current and voltage levels.

Balanced and unbalanced faults were simulated at eight different fault locations (FLTn). For each fault location the current through all 138 kV and 12 kV breakers in the simulation, as well as the 138 kV and 12 kV potentials were saved in COMTRADE format. This arrangement allowed the test sets to output any current, voltage, or combination of the two to all merging units that were under test. A detail of the RTDS model showing the transformer and faults can be seen in Figure 4. The full diagram depicting the complete system and the specific location of each fault (FLT1, FLT2, etc.) is in Appendix B.

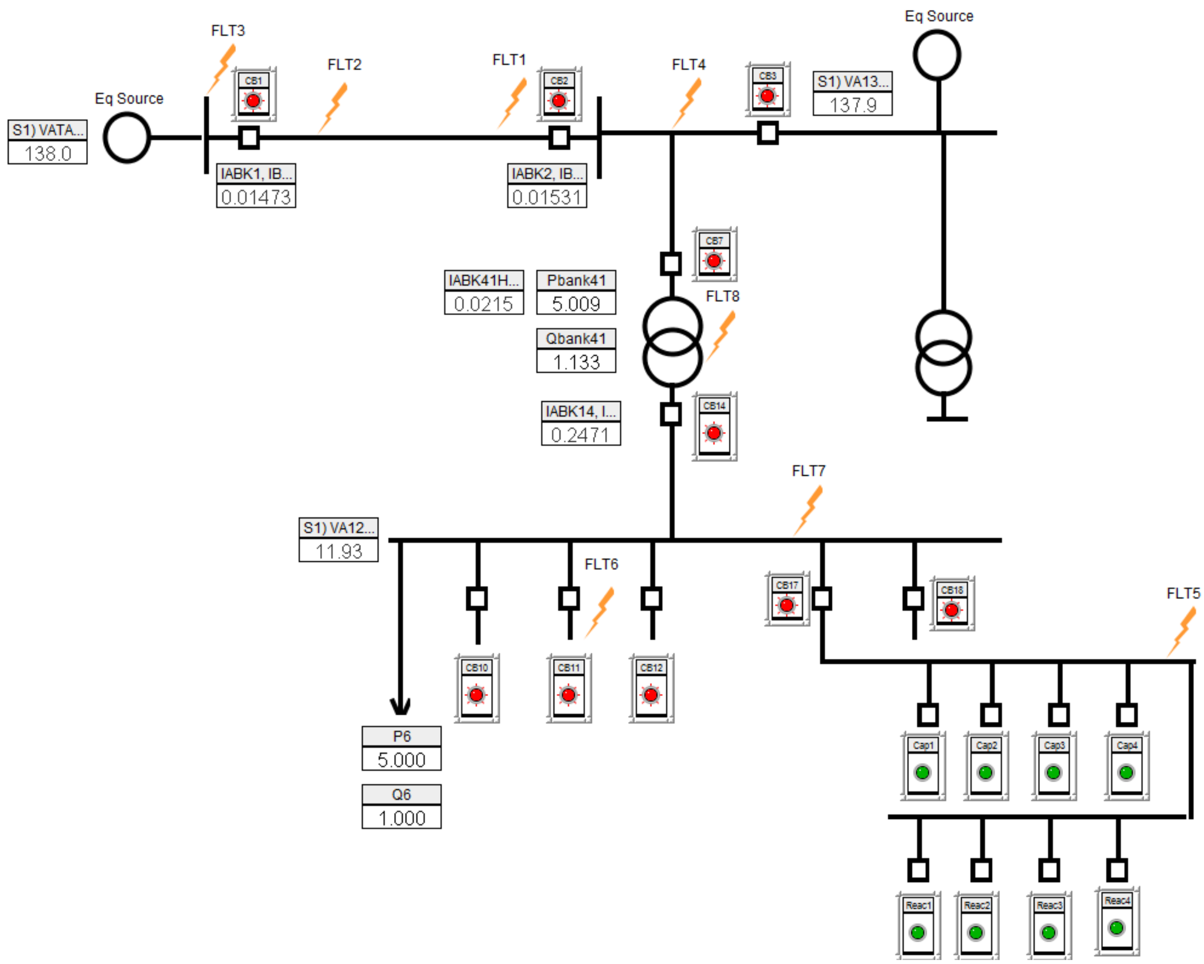


FIGURE 4 SIMPLIFIED ONE-LINE DIAGRAM WITH FAULT LOCATIONS SHOWN

For each protective device under test, analog signals representing in zone and out of zone faults, were injected into the appropriate merging units. The system response was documented to verify that each merging unit was publishing the correct sampled value stream and that the protective devices received and acted on the sampled values as expected.

Wetting voltage

Test system racks were designed so that the breaker simulators could provide the RTDS with simulated breaker position information. The wetting voltage for the RTDS was 5 Vdc (DC Voltage). One set of output contacts from each breaker simulator was available to be connected to an RTDS digital input module. These connections were performed just prior to the demonstration at the ITF.

Integrated Test Facility (ITF) Evaluation

An ITF evaluation was performed as part of this project. The evaluation identified the equipment available at SDG&E's ITF that was necessary to perform the required testing and any material or equipment that would require procurement to perform the testing. The project team acquired the material and equipment to accommodate the test system's racks that were located in the two separate labs.

9. TEST SYSTEM DESIGN

The test system was designed to allow testing of the required study use cases using either relay test sets or RTDS low-level signal amplifiers. Test sets were used at the consultant's lab and the amplifiers were used at ITF with the RTDS. The test system was designed with test switches so that either the test sets or the amplifiers could be used to inject secondary amps and voltage simulation signals into the merging units of the test system. Breaker simulation was provided by latching relays with Form C contacts. The breaker simulator relays provided status indication to the merging units and to the RTDS. Figure 5, below, is a simplified illustration of the test system configuration showing the simulated substation yard and control shelter.

The test system was designed with one station bus and two process buses. One process bus represented the devices on the 138 kV bus and the second represented the equipment on the 12 kV bus. This supported concurrent testing of both buses. Protection relays were connected to both the station bus and the process bus associated with the relay's protective function. Time synchronization was provided by a GPS referenced clock to ensure all the system IEDs were operating from the same time source. This clock provided time synchronization via four protocols: Precision time protocol (PTP, IEEE 1588), IRIG-B, 1PPS, and SNTP. These four time-code options were required to support the varying requirements of the IEDs in the test system.

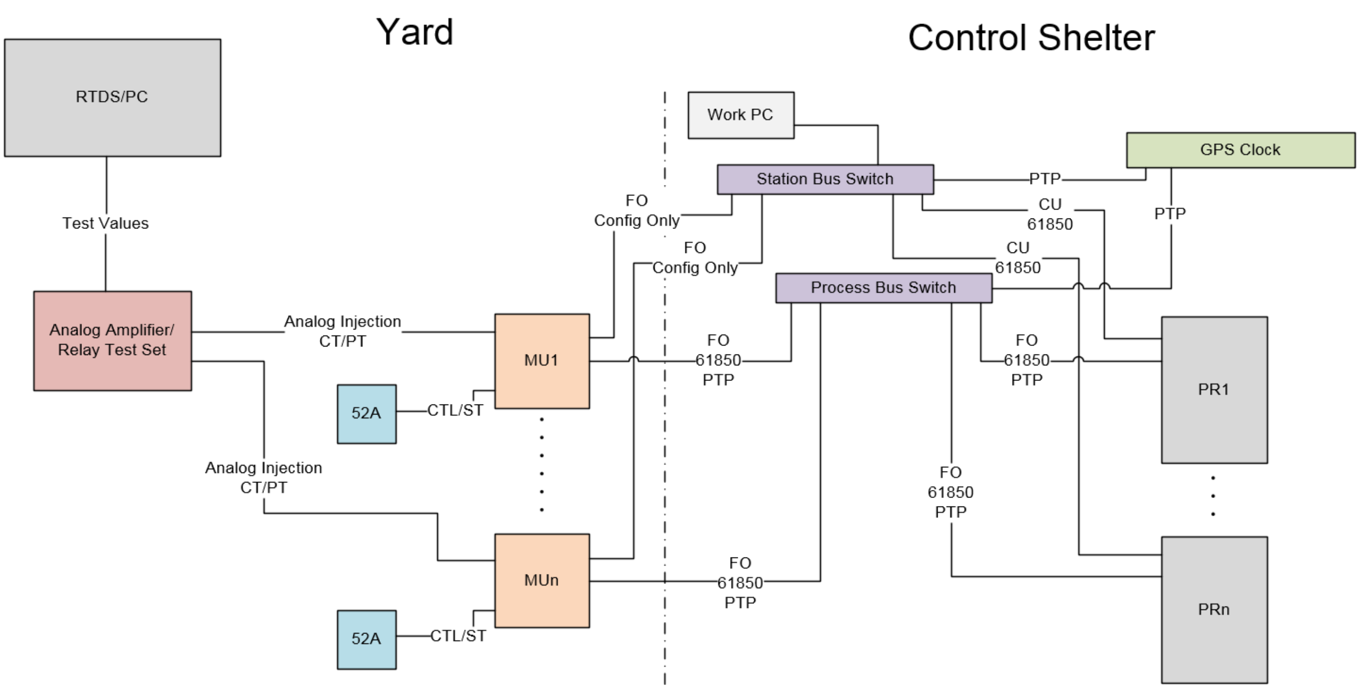


FIGURE 5 SIMPLIFIED TEST SYSTEM DIAGRAM

For the simplest breaker trip scenario, SV traffic from an MU was published to the process bus where a relay subscribes to the SV stream. This relay applies the numerical data to its built-in protection algorithms and when applicable, it publishes a trip message via GOOSE to the process bus. The MU subscribes to this message and when a trip GOOSE message was received, it closes an output contact. A breaker simulator relay coil wired to the MU operates when the output contact closes. When the breaker simulator relay contact, which was wired to an MU digital input, opens a status change (52A) was provided to a digital input on the MU. In response to the 52A status change, the MU publishes a GOOSE message to the process bus. The relay subscribes to this breaker status message and performs any configured response such as lighting LEDs, tagging event reports or recording disturbance reports. Further detailed information was included in the attached appendices.

Design process

The design process is summarized in Figure 6 shown below. From the baseline information, the protection and test environment requirements were determined. Using the single line diagrams, from the identified substation, the CTs, PTs, and breakers required to implement the test cases were determined.

The next step was to determine the functional requirements of the equipment and place them within the single line of the substation. The functional requirements also included breaker simulators, test set injection points, and consideration for space requirements within the two labs.

With the functional requirements identified, the data requirements for each piece of equipment, for both the data source and data destination, were reviewed. This established the general functional equipment and the general data flows for the GOOSE and SV messaging.

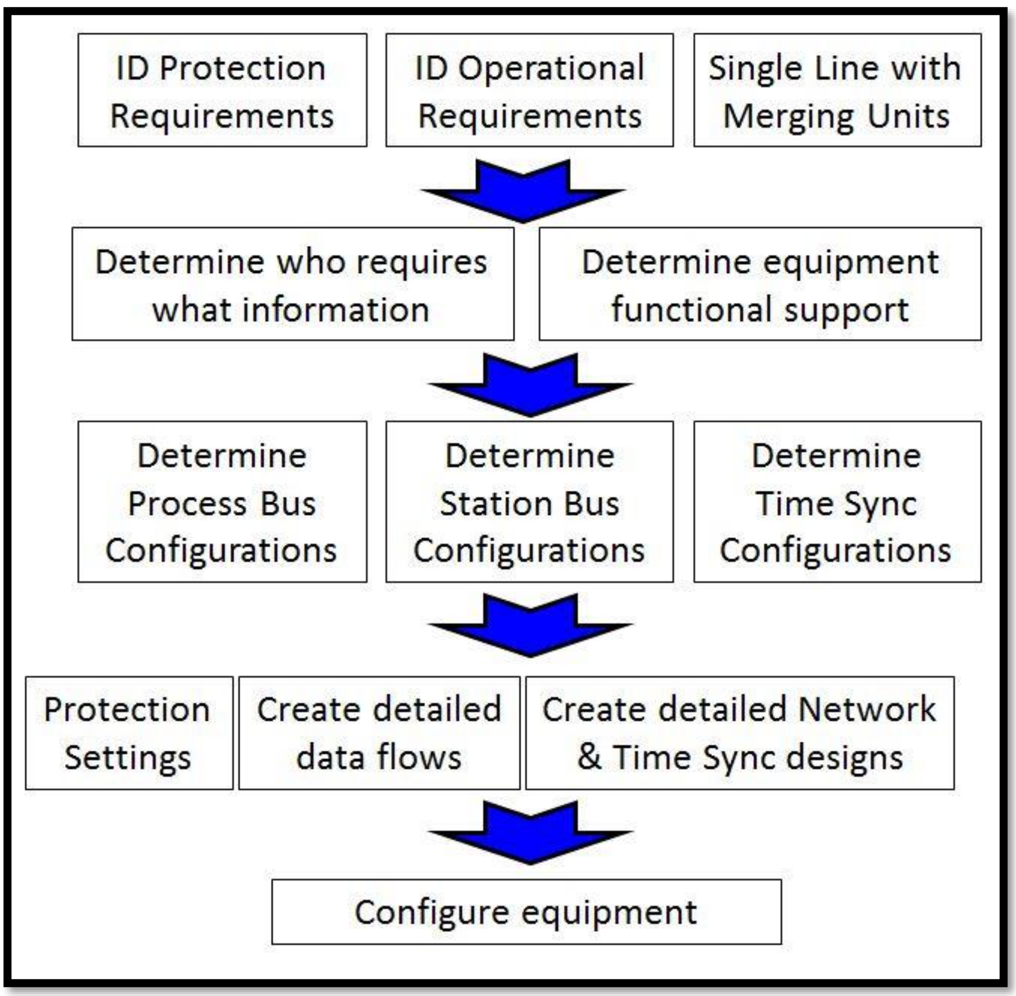


FIGURE 6 DESIGN PROCESS

The next phase was to design the infrastructure to support the IEC 61850 system. Using the information provided by the data flows, it was determined that the test system needed two independent process buses. The independent process buses limited the SV traffic to approximately six SV streams per bus leaving sufficient network bandwidth for GOOSE, PTP, and other configuration and diagnostic software tools. Separate process buses also provided separation of the HS bus test cases from the LS bus test cases, which allowed for concurrent testing of test cases on each process bus.

The single station bus created a communications path between all the protection devices, which left the two process buses isolated from any other networks. The station bus network allowed for GOOSE data exchange between all protection relays and connectivity for device and test set configuration.

The next phase of the design created the protection settings and detailed information for the GOOSE and SV control blocks and data sets. All intelligent components of the system required time synchronization to provide accurate event time stamps and support the time synchronization requirement for SV messages. Knowing that there was a variety of implementation schemes for receiving time synchronization information, a GPS clock that provided the four time synchronization methods listed in the IEC 61850 standard: PTP, IRIG-B, 1PPS and SNTP was specified. The last step was to take all of the design information and configure the equipment. Figure 7 shows a summary of the steps required to complete this phase of the design.

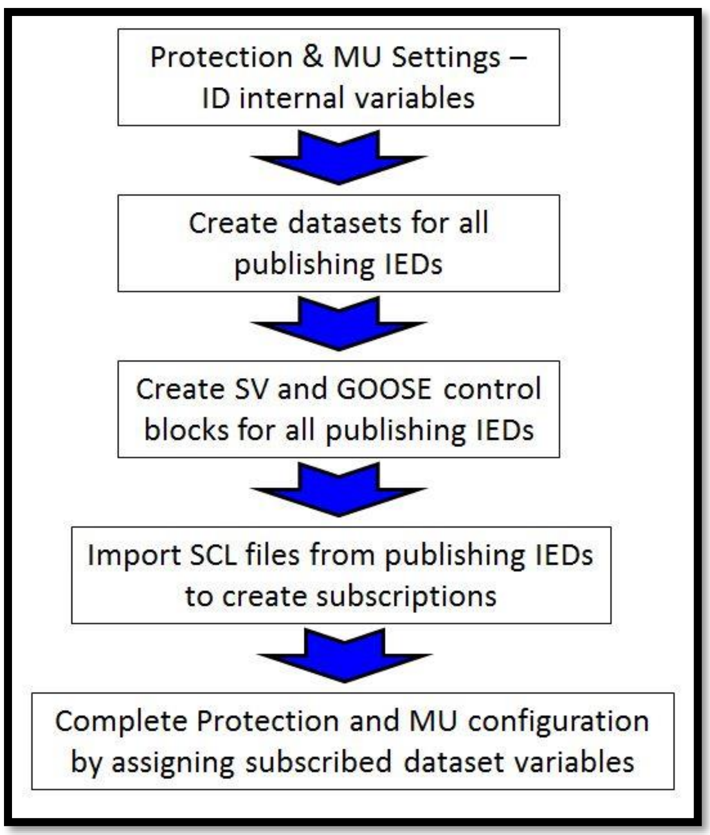


FIGURE 7 DEVICE CONFIGURATION PROCESS

The first step in this process was to determine which internal device data points were used for each functional data exchange. For each of these internal data points, there was an IEC 61850 substation configuration language (SCL), logical node data attribute was assigned for transporting GOOSE messages. For SV messages, all of the manufacturers claimed to support the IEC 61850-9-2LE implementation which, if true, would fix the SV data set. This information was then entered into the detailed data flow tables which were used for configuring the data sets in the test system equipment.

After the data sets were created, the detailed data flow tables were used to create the GOOSE and SV control blocks. Within these control blocks the multicast MAC address, AppID and GOOSE - SV identification (ID) were assigned. At this stage, all published GOOSE and SV messages could be configured.

The next step was to configure all of the required subscriptions. To do this each manufacturer's configuration software tool outputted a device IEC 61850 IED (intelligent electrical device) capability description (ICD), instantiated IED description (IID), configured IED description (CID), or system configuration description (SCD) file. These files contained all the available data set GOOSE and SV information for a device to subscribe to them. The files were then imported into the manufacturer configuration software tool where the subscribing device and specific data points within the message data set were linked to the devices internal points. Once this was done all of the "virtual wires", published messages, and subscription messages, were completed. Information exchanges were then linked from merging units to protection relays and from protection relay to protection relay.

The last step was to configure the devices using this information to fulfill its primary role as defined in the test cases. The following sections explain in greater detail for each of the major phases of the design process.

Material Identification and Procurement

Running in parallel to the design process, and using key information from it, was the equipment vendor selection process. Due to the project's aggressive schedule, manufacturers with significant presence in the United Sates were investigated. In addition, compliance with the following guidelines was required:

- All potential products were required to use a non-proprietary implementation of IEC 61850 MMS, GOOSE, and SV.
- Interoperability, with other manufacturers' products, was a requirement.
- All potential products were required to be commercially available during the project.

The project team identified four relay and merging unit manufacturers. A third party MU manufacturer was also identified. Requests for Information were then developed and in-person interviews with the four identified relay manufacturers were conducted. The interviews included a manufacturer presentation and time for questions and answers. The project team worked with the manufacturers to identify the necessary products and develop the required part numbers.

In order to investigate interoperability, the project required a minimum of two manufacturers for each use case whenever possible. Discussions with the manufacturers were required to identify the necessary relays, merging units, GPS clock, switches and ancillary equipment/materials. The information obtained from these efforts was used to guide the part number development.

Before relay test set procurement could begin, the project team determined the capabilities at the ITF and the available features from the manufacturers. Since the tests would inject currents and voltages from a traditional relay test set and the ITF testing would utilize an RTDS, a single SV test set was determined to be sufficient. At the end of the process, the use of rental test sets was identified to minimize costs. The total number of test sets was determined to allow concurrent testing of several of the use cases described above.

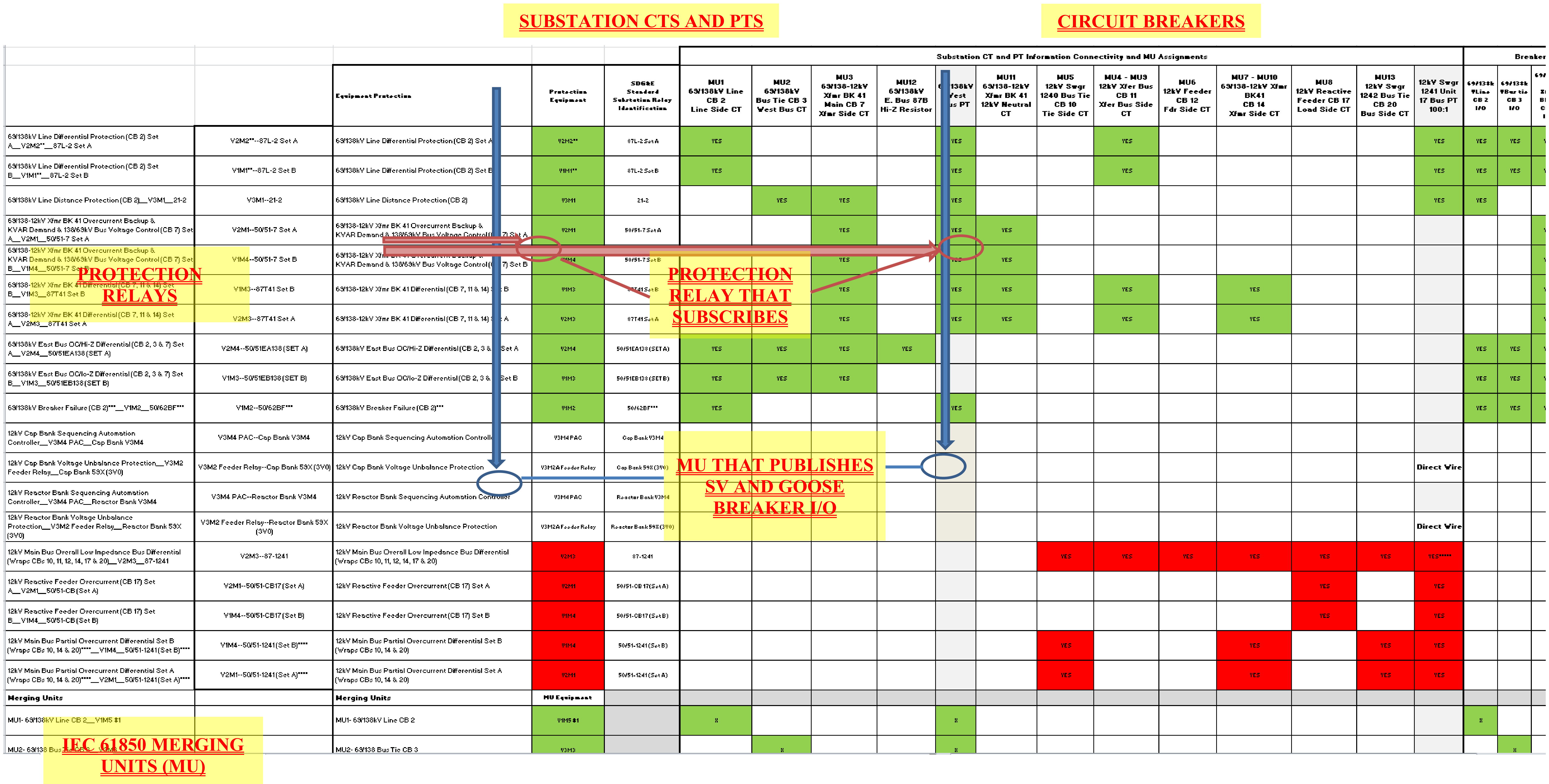
Procurement of the materials and test sets was a joint effort between the project team parties. All purchased materials and equipment were shipped to the contractor's office.

Preliminary Design Process

The preliminary design focused on the requirements to perform the test cases listed in the Test Cases section of this document. Using the single line prints for the identified substation specific protection devices, CTs, PTs and circuits were selected for the tests. The identified substation did not deploy backup protection schemes, but for the purpose of including multiple manufacturers in the testing, backup schemes were deployed. A means of simulating circuit breaker operation control and feedback interface with the MU was also required. Dual coil latching relays ("ice cube" relays) fulfilled this requirement. The dual coils allowed for both a trip and close control connection and the two form C contacts provided position feedback to both the MU and RTDS. The contact operation and release time of 25 milliseconds (ms) was fairly close to the operating times for most circuit breakers. Test blocks at each MU to both simulate a real field installation and provide easy test set connectivity to the MUs secondary current and voltage inputs were included.

From the baseline, methods for implementing the use cases and their protection requirements were known. The goal was to implement test cases using IEC 61850 and some of its supporting standards. To do this every CT and PT required a MU to replace the traditional CT and PT wiring with published IEC 61850 SV messages. Each circuit breaker required supervision from a MU. From the baseline study the data requirements for each of the protection relays and which breakers they would trip during a protection event were known.

In order to provide a clearer picture of all the publication and subscription requirements between devices and MUs the spreadsheet in Appendix D was created. Figure 8 shows the structure of the matrix. The left hand side lists the protection relays at the top followed by the merging units at the bottom. Along the top were the CT and PT equipment followed by the circuit breakers required to provide the protection relays with the information and controls needed to perform their operations. The matrix identified which MU was connected to which CT and PT. It also identified which MU provided the trip/close controls and position feedback for each of the various circuit breakers. Finally for each of the protection relays the matrix identified what CT and PT information they required and which circuit breakers they needed to control.



					Substation CT and PT Information Connectivity and MU Assignments														Breaker		
		Equipment Protection	Protection Equipment	SDG&E Standard Substation Relay Identification	MU1 63/138kV Line CB 2 Line Side CT	MU2 63/138kV Bus Tie CB 3 West Bus CT	MU3 63/138-12kV Xfmr BK 41 Main CB 7 Xfmr Side CT	MU12 63/138kV E. Bus 87B Hi-Z Resistor	138kV West Bus PT	MU11 63/138-12kV Xfmr BK 41 12kV Neutral CT	MU5 12kV Swgr 1240 Bus Tie CB 10 Tie Side CT	MU4 - MU9 12kV Xfer Bus CB 11 Xfer Bus Side CT	MU6 12kV Feeder CB 12 Fdr Side CT	MU7 - MU10 63/138-12kV Xfmr BK41 CB 14 Xfmr Side CT	MU8 12kV Reactive Feeder CB 17 Load Side CT	MU13 12kV Swgr 1242 Bus Tie CB 20 Bus Side CT	12kV Swgr 1241 Unit 17 Bus PT 100:1	69/138k VLine CB 2 I/O	69/138k VBus tie CB 3 I/O	69/
63/138kV Line Differential Protection (CB 2) Set A__V2M2**__87L-2 Set A	V2M2**--87L-2 Set A	63/138kV Line Differential Protection (CB 2) Set A	V2M2**	87L-2 Set A	YES				YES			YES					YES	YES	YES	Y
63/138kV Line Differential Protection (CB 2) Set B__V1M1**__87L-2 Set B	V1M1**--87L-2 Set B	63/138kV Line Differential Protection (CB 2) Set B	V1M1**	87L-2 Set B	YES				YES			YES					YES	YES	YES	Y
63/138kV Line Distance Protection (CB 2)__V3M1__21-2	V3M1--21-2	63/138kV Line Distance Protection (CB 2)	V3M1	21-2		YES	YES		YES								YES	YES		
63/138-12kV Xfmr BK 41 Overcurrent Backup & KVAR Demand & 138/63kV Bus Voltage Control (CB 7) Set A__V2M1__50/51-7 Set A	V2M1--50/51-7 Set A	63/138-12kV Xfmr BK 41 Overcurrent Backup & KVAR Demand & 138/63kV Bus Voltage Control (CB 7) Set A	V2M1	50/51-7 Set A			YES		YES	YES										Y
63/138-12kV Xfmr BK 41 Overcurrent Backup & KVAR Demand & 138/63kV Bus Voltage Control (CB 7) Set B__V1M4__50/51-7 Set B	V1M4--50/51-7 Set B	63/138-12kV Xfmr BK 41 Overcurrent Backup & KVAR Demand & 138/63kV Bus Voltage Control (CB 7) Set B	V1M4	50/51-7 Set B			YES		YES	YES										Y
63/138-12kV Xfmr BK 41 Differential (CB 7, 11 & 14) Set B__V1M3__87T41 Set B	V1M3--87T41 Set B	63/138-12kV Xfmr BK 41 Differential (CB 7, 11 & 14) Set B	V1M3	87T41 Set B			YES		YES	YES		YES		YES						Y
63/138-12kV Xfmr BK 41 Differential (CB 7, 11 & 14) Set A__V2M3__87T41 Set A	V2M3--87T41 Set A	63/138-12kV Xfmr BK 41 Differential (CB 7, 11 & 14) Set A	V2M3	87T41 Set A			YES		YES	YES		YES		YES						Y
63/138kV East Bus OC/Hi-Z Differential (CB 2, 3 & 7) Set A__V2M4__50/51EA138 (SET A)	V2M4--50/51EA138 (SET A)	63/138kV East Bus OC/Hi-Z Differential (CB 2, 3 & 7) Set A	V2M4	50/51EA138 (SET A)	YES	YES	YES	YES										YES	YES	Y
63/138kV East Bus OC/lo-Z Differential (CB 2, 3 & 7) Set B__V1M3__50/51EB138 (SET B)	V1M3--50/51EB138 (SET B)	63/138kV East Bus OC/lo-Z Differential (CB 2, 3 & 7) Set B	V1M3	50/51EB138 (SET B)	YES	YES	YES											YES	YES	Y
63/138kV Breaker Failure (CB 2)***__V1M2__50/62BF***	V1M2--50/62BF***	63/138kV Breaker Failure (CB 2)***	V1M2	50/62BF***	YES				YES									YES	YES	Y
12kV Cap Bank Sequencing Automation Controller__V3M4 PAC__Cap Bank V3M4	V3M4 PAC--Cap Bank V3M4	12kV Cap Bank Sequencing Automation Controller	V3M4 PAC	Cap Bank V3M4																
12kV Cap Bank Voltage Unbalance Protection__V3M2 Feeder Relay__Cap Bank 59X (3V0)	V3M2 Feeder Relay--Cap Bank 59X (3V0)	12kV Cap Bank Voltage Unbalance Protection	V3M2A Feeder Relay	Cap Bank 59X (3V0)													Direct Wire			
12kV Reactor Bank Sequencing Automation Controller__V3M4 PAC__Reactor Bank V3M4	V3M4 PAC--Reactor Bank V3M4	12kV Reactor Bank Sequencing Automation Controller	V3M4 PAC	Reactor Bank V3M4																
12kV Reactor Bank Voltage Unbalance Protection__V3M2 Feeder Relay__Reactor Bank 59X (3V0)	V3M2 Feeder Relay--Reactor Bank 59X (3V0)	12kV Reactor Bank Voltage Unbalance Protection	V3M2A Feeder Relay	Reactor Bank 59X (3V0)													Direct Wire			
12kV Main Bus Overall Low Impedance Bus Differential (Wraps CBs 10, 11, 12, 14, 17 & 20)__V2M3__87-1241	V2M3--87-1241	12kV Main Bus Overall Low Impedance Bus Differential (Wraps CBs 10, 11, 12, 14, 17 & 20)	V2M3	87-1241							YES	YES	YES	YES	YES	YES	YES*****			
12kV Reactive Feeder Overcurrent (CB 17) Set A__V2M1__50/51-CB (Set A)	V2M1--50/51-CB17 (Set A)	12kV Reactive Feeder Overcurrent (CB 17) Set A	V2M1	50/51-CB 17 (Set A)											YES		YES			
12kV Reactive Feeder Overcurrent (CB 17) Set B__V1M4__50/51-CB (Set B)	V1M4--50/51-CB17 (Set B)	12kV Reactive Feeder Overcurrent (CB 17) Set B	V1M4	50/51-CB17 (Set B)											YES		YES			
12kV Main Bus Partial Overcurrent Differential Set B (Wraps CBs 10, 14 & 20)****__V1M4__50/51-1241 (Set B)****	V1M4--50/51-1241 (Set B)****	12kV Main Bus Partial Overcurrent Differential Set B (Wraps CBs 10, 14 & 20)	V1M4	50/51-1241 (Set B)							YES			YES		YES	YES			
12kV Main Bus Partial Overcurrent Differential Set A (Wraps CBs 10, 14 & 20)****__V2M1__50/51-1241 (Set A)****	V2M1--50/51-1241 (Set A)****	12kV Main Bus Partial Overcurrent Differential Set A (Wraps CBs 10, 14 & 20)	V2M1	50/51-1241 (Set A)							YES			YES		YES	YES			
Merging Units		**Merging Units**	**MU Equipment**																	
MU1- 63/138kV Line CB 2__V1M5 #1		MU1- 63/138kV Line CB 2	V1M5 #1		x				x									x		
MU2- 63/138 Bus Tie CB 3__V3M3		MU2- 63/138 Bus Tie CB 3	V3M3			x			x										x	

FIGURE 8 IED 61850 SYSTEM GOOSE AND SV MESSAGE MATRIX

Once the matrix was completed, the subscriptions for each protection relay from each of the MUs for published SV and GOOSE messages were available. These data flows provided the protection relays with the secondary current and voltage samples needed to perform their protection functions and status indication of the circuit breakers' position. Working in reverse this matrix also defined which MUs needed to subscribe to the published GOOSE messages from the protection relays, which execute the trip actions. Additionally the matrix provided a clear overview of the data flow segregation between devices such that the network traffic could be isolated into separate process buses. Two process buses were identified and color coded in the matrix using GREEN for process bus #1 and RED for process bus #2.

One of the testing goals was to digitize the test case implementation including lock out relays. With the matrix completed, identification of which protection relays initiate the lock out and which of the protection relays house the digital lock out logic could be determined. Once the lock out logic within this relay was set, the only means to reset it was through a physical interface with the relay's front panel pushbuttons.

The use cases did not include any SCADA operations, but in order to demonstrate the lock out operation one protection relay, that would be the SCADA control interface for the circuit breakers within a process bus, was selected. This logic required additional data flows (published data and subscriptions) for initiating lock outs and blocking circuit breaker close commands.

Figure 9 shows the lock out and SCADA supervisory device information added to the matrix. Using the base line information, identified substation single line, and the data flows developed from the MU matrix, there was enough information to develop a preliminary design. This design included a network diagram, data flow tables and protection criteria.

PROTECTION RELAY THAT DRIVES THE LOCK OUT

PROTECTION RELAY THAT IS THE LOCK OUT

PROTECTION RELAY THAT SERVES AS THE SCADA INTERFACE

	Equipment Protection	Protection Equipment	SDG&E Standard Substation Relay Identification	Lockouts and SCADA Control IEDs		
V1M3--87T41 Set B	69/138-12kV Xfmr BK 41 Differential (CB 7, 11 & 14) Set B	V1M3	87T41 Set B	LOR 86T41		
V2M3--87T41 Set A	69/138-12kV Xfmr BK 41 Differential (CB 7, 11 & 14) Set A	V2M3	87T41 Set A	LOR 86T41	86T41 Master LOR Relay	
V2M4--50/51EA138 (SET A)	69/138kV East Bus OC/Hi-Z Differential (CB 2, 3 & 7) Set A	V2M4	50/51EA138 (SET A)	LOR 86E138	86E138 Master LOR Relay	SCADA Control 2,3,7
V1M3--50/51EB138 (SET B)	69/138kV East Bus OC/lo-Z Differential (CB 2, 3 & 7) Set B	V1M3	50/51EB138 (SET B)	LOR 86E138		
V1M2--50/62BF***	69/138kV Breaker Failure (CB 2)***	V1M2	50/62BF***	LOR 86E138		
V3M4 PAC--Cap Bank V3M4	12kV Cap Bank Sequencing Automation Controller	V3M4 PAC	Cap Bank V3M4			
V3M2 Feeder Relay--Cap Bank 59X (3V0)	12kV Cap Bank Voltage Unbalance Protection	V3M2A Feeder Relay	Cap Bank 59X (3V0)	LOR 59X CAP	59XCAP Master LOR Relay	
V3M4 PAC--Reactor Bank V3M4	12kV Reactor Bank Sequencing Automation Controller	V3M4 PAC	Reactor Bank V3M4			
V3M2 Feeder Relay--Reactor Bank 59X (3V0)	12kV Reactor Bank Voltage Unbalance Protection	V3M2A Feeder Relay	Reactor Bank 59X (3V0)	LOR 59X REAC	59XREAC Master LOR Relay	
V2M3--87-1241	12kV Main Bus Overall Low Impedance Bus Differential (Wraps CBs 10, 11, 12, 14, 17 & 20)	V2M3	87-1241	LOR 86B1241	86B1241 Master LOR Relay	SCADA Control 10,11,12,14,17,20

FIGURE 9 DEFINED LOCKOUT AND SCADA DEVICES

Test System Network

The equipment and design for the test system network and time synchronization provided a flexible infrastructure to support functions for an IEC 61850 environment. The design provided various network medium connection options and different methods for time synchronization per the IEC 61850 standard to support the various equipment used in this test system. Specifically, the test system infrastructure must demonstrate fiber solutions, which will be required between equipment located in the substation yard and substation control shelter via the process bus.

There were many different manufacturers that could provide equipment and fulfill the requirements for this test system. Manufacturer selection included previous experience with the product, discussion with product manufacturers, providing a multi-vendor test environment, and the products' specifications to meet the requirements for the test system.

The diagram shown in Appendix C was the test system network and time synchronization connection diagram. The intent of this diagram was to show the various equipment capabilities and provide a means for documenting the different use case scenario configurations.

Each network port used in this test system was assigned an IP address that was associated with the network to which it was connected. Some of these ports were required for testing and some were required for point to point connection for access. In some cases the network connection ports did not support transmission control protocol (TCP) /IP. These ports only provided a, non-routable, layer 2 MAC interface for GOOSE and SV messaging.

There were some devices that did not support both GOOSE and SV messages on the same port. These devices had two separate network connections to the process bus.

Station Bus

The station bus was the main substation network that provided the information connectivity between different process buses, substation systems and enterprise systems. For this test system the station bus used IEC 61850, GOOSE and various configuration and diagnostic protocols. It also provided engineering access to the various protection equipment and test sets for monitoring, control and configuration. In addition, this network was connected to an IEEE 1588 PTP master clock to provide time synchronization to supporting devices.

The station bus was the communications conduit for device-to-device GOOSE messages allowing for the transfer of information between isolated process bus networks. IEC 61850 MMS was used to access SCADA, configuration and health information from the various devices. It was also used to test the system supervisory control close blocking by the digital lockouts.

Managed switches made up the station bus. These switches had a mixture of copper RJ45 and multimode fiber connections to accommodate the different manufacturer connectivity options. All network traffic used virtual local area network #1.

Process Bus

Each process bus was designed as a separate network that was isolated from the station bus and the other process bus network. The primary purpose of this network was to transfer information between the equipment MUs and devices requiring the information. MUs typically had only a single process bus interface vs. protection relays that had independent process bus and station bus interfaces. Some manufacturers' protection relays provided independent process bus interfaces, with one only supporting SV messages and the other only supporting GOOSE. Other manufacturers' MUs provided independent station bus interfaces.

The test system used both IEC 61850 SV and IEC 61850 GOOSE protocols. The process buses were also connected to an IEEE 1588 PTP master clock to provide time synchronization to supporting devices. The test system equipment had fiber optic options to emulate real world solutions that would be deployed in the field. The network diagram indicated the demarcation between the substation yard equipment and the substation control shelter equipment with a dashed line. All communications paths crossing this line used fiber optics, which would be the communications medium of choice for process bus connectivity.

There were two independent process bus networks designed into the test system to accommodate different test case scenarios divided between the high side and low side of the transformer. Each process bus had at least four engineering access ports to be used for monitoring and device configuration. The network and its equipment were designed to allow concurrent test case testing on both process bus #1 and #2. All network traffic used virtual local area network #1.

Process Bus #1

Process bus #1 used two managed switches. It was configured in a star design without using high-availability seamless redundancy (HSR) or parallel redundancy protocol (PRP). This process bus integrated all of the equipment required to demonstrate the test cases for the high side of the transformer and transformer protection. It supported IEEE 1588 PTP Power Profile, using an isolated connection to the GPS clock.

Some of the devices connected to the network did not manage all the SV and GOOSE traffic. When some devices dropped packets due to a central processing unit (CPU) overload condition, static MAC filtering on some of the ports was deployed. This solved problems and relieved the affected device of the additional burden on parsing all the messages.

Process Bus #2

Process bus #2 was a single managed switch. It was configured in a star design without using HSR or PRP. It supported IEEE 1588 PTP Power Profile, with an isolated connection to the GPS clock. This process bus integrated all of the equipment required to demonstrate the test cases for the low side of the transformer.

To prevent the same dropped packet problem, seen on process bus #1, static MAC filtering, as used on process bus #1, was deployed.

Test Set Interface

Each test set was connected via Ethernet to the station bus for engineering programming access. The SV capable test set's Ethernet port was temporarily connected to one of the two process bus networks, depending on the SV message needs of the test case scenario. The station bus interface was used for configuration and monitoring of the test sets. All test sets were assigned a connection point into the system networks.

Test System Time Synchronization

All devices were time synchronized to a single clock to allow verification of performance using time stamps and the use of SV. For the MUs and their subscribers, synchronized time was a critical component for publishing and subscribing SV messages. Each end required the same time synchronization in order to interpret the SV within the same time reference. This test system was designed to provide a number of time synchronization options that met the IEC 61850 requirements.

The selected clock supported four independent network connections to provide PTP and SNTP while leaving the various networks isolated from each other. It also provided eight programmable 1PPS and IRIG-B outputs. These different time source options provided support for the varied manufacturer offerings for time synchronization.

In order to maintain the test system's scheme for fiber optic cabling between the MU racks and switch/relay racks, fiber was required. Some devices, however only provided support for copper time signals. When a device required a fiber optic input, or the device required a fiber link directly from the GPS Clock, the test system used two different manufacturer solutions to perform this conversion. The first solution covered equipment on both ends that had hardwired inputs but required fiber optic cabling between the clock and the end device. V8M1 and V8M2 were used to support the copper inputs and provide a fiber channel between the two sets of racks. This interface was used to time synchronize the reactor and capacitor bank P&C devices. The second interface covered devices that required fiber optic time input from the clock's copper output. A V8M1 fiber convertor was used for this interface.

IEEE 1588 PTP

The PTP connections included the connections between the clock and the network switches to support PTP delivery to the end device. This test system used the IEEE PC37.238 power profile for PTP. The following PTP configuration parameters were used:

V3M5 Clock:

- The clock identification was 10
- Power Profile (Layer 2)
- 1 step
- Station bus domain 0, process bus #1 domain 1 and process bus #2 domain 2

Ethernet Switches:

- Power Profile (Layer 2)
- 1 step
- Domain as the network requires
- Transparent Clock
- All ports enabled
- MAC filtering enabled as required per port

The following equipment was configured to use PTP:

- V3M1 and V3M3
- V7M1
- V6M1
- V1M1, V1M2, V1M3, V1M4
- V2M5
- All network Ethernet switches

IRIG-B

For the devices that did not support PTP but supported IRIG-B, the test system used an IRIG-B unmodulated (DC level shift) signal to provide a time source. In addition, the relay test sets were specified with the IRIG-B input modules to synchronize events and provide time synchronization for the V10M1's SV messages. IRIG-B-004 was used to include the year information in the message.

The following equipment was configured to use IRIG-B:

- All test sets
- V1M5 MU
- V2M2 remote station protection relay

1PPS

For relays and MUs that required 1PPS, the test system included fiber optic transmission equipment to provide a fiber interface to the devices in the simulated substation yard.

The following equipment was configured to use fiber optic 1PPS:

- V2M1, V2M2, V2M3

SNTP

There were two uses for this method of time synchronization. The first was to time synchronize the V2M6 MU. This device only supported SNTP for time synchronization. The second use was for the V2M1, V2M2, V2M3, and V2M4 process bus connected protection relays. These relays required 1PPS inputs for SV messages.

The following equipment was configured to use SNTP:

- V2M1, V2M2, V2M3, and V2M4 process bus connected protection relays
- V2M6 MU

Process bus MUs

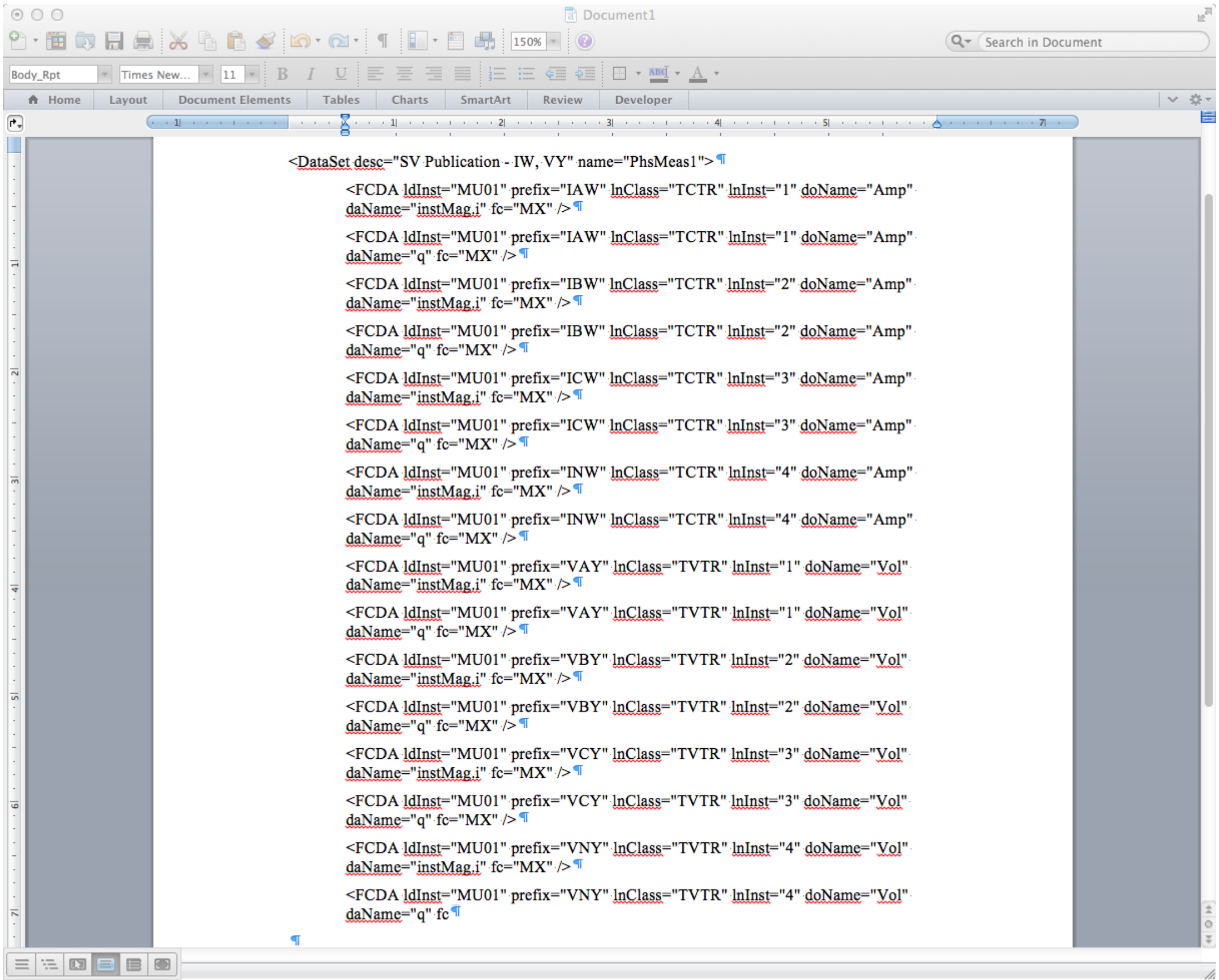
MUs were connected to each process bus and served as the interface to the analog substation equipment such as CTs, PTs, circuit breakers, etc. These MUs provided the hardwired connection for the instrument transformer inputs and output signaling that was digitized over the process bus using IEC 61850 SV and GOOSE. These IEDs also published GOOSE messages which were subscribed to by the MUs to issue trip, close or other control operations to the equipment. The test system used merging units from five different manufactures.

IEC 61850 Editions

With the multi-vendor environment there were varied implementations of the IEC 61850 part editions. A base edition to design the system around and determine if there were any compatibility issues between the manufacturers was required. During testing and despite claims on the device support of IEC 61850-9-2 LE Editions 1 or 2, there were implementation differences from the LE document. In some cases this caused an incompatibility problem between SV publishers and subscribers. The following summarizes some of these differences identified.

The SV dataset in LE was fixed and used the data model from IEC 61850-7-4 ed1. In Figure 10 the dataset name “PhsMeas1” and the order of the logical nodes, data objects and attributes follow the LE document, current ABCN followed by voltage ABCN. The prefix was built using the substation section of the SCL, identifying both the sensor and the phase.

The logical node data objects used the common data class (CDC) SAV. The LE document defined a fixed scaling for the “SVClscaleFactor” and “sVC.offset” attributes.



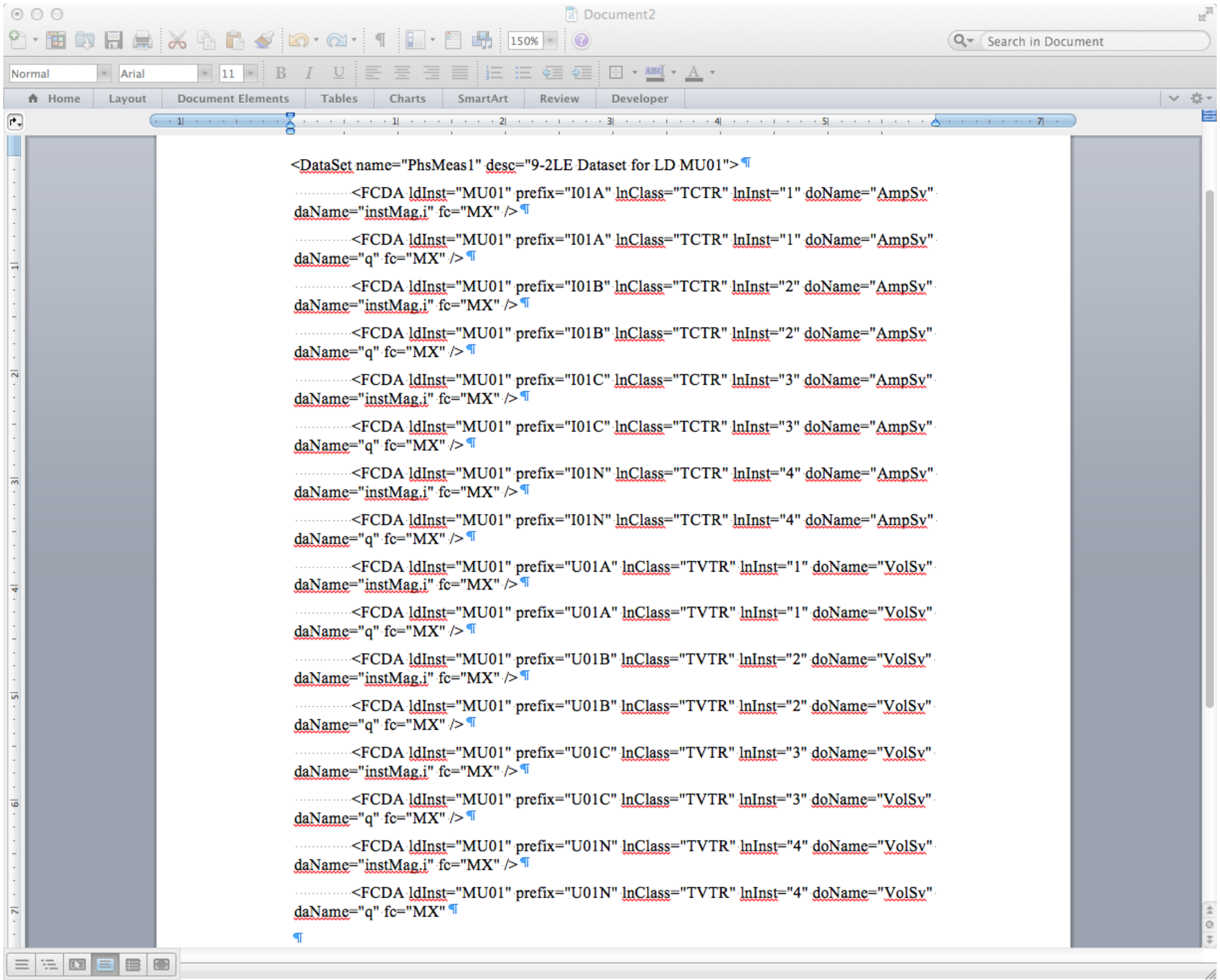
```xml
<DataSet desc="SV Publication - IW, VY" name="PhsMeas1">
    <FCDA ldInst="MU01" prefix="IAW" lnClass="TCTR" lnInst="1" doName="Amp" daName="instMag.i" fc="MX" />
    <FCDA ldInst="MU01" prefix="IAW" lnClass="TCTR" lnInst="1" doName="Amp" daName="q" fc="MX" />
    <FCDA ldInst="MU01" prefix="IBW" lnClass="TCTR" lnInst="2" doName="Amp" daName="instMag.i" fc="MX" />
    <FCDA ldInst="MU01" prefix="IBW" lnClass="TCTR" lnInst="2" doName="Amp" daName="q" fc="MX" />
    <FCDA ldInst="MU01" prefix="ICW" lnClass="TCTR" lnInst="3" doName="Amp" daName="instMag.i" fc="MX" />
    <FCDA ldInst="MU01" prefix="ICW" lnClass="TCTR" lnInst="3" doName="Amp" daName="q" fc="MX" />
    <FCDA ldInst="MU01" prefix="INW" lnClass="TCTR" lnInst="4" doName="Amp" daName="instMag.i" fc="MX" />
    <FCDA ldInst="MU01" prefix="INW" lnClass="TCTR" lnInst="4" doName="Amp" daName="q" fc="MX" />
    <FCDA ldInst="MU01" prefix="VAY" lnClass="TVTR" lnInst="1" doName="Vol" daName="instMag.i" fc="MX" />
    <FCDA ldInst="MU01" prefix="VAY" lnClass="TVTR" lnInst="1" doName="Vol" daName="q" fc="MX" />
    <FCDA ldInst="MU01" prefix="VBY" lnClass="TVTR" lnInst="2" doName="Vol" daName="instMag.i" fc="MX" />
    <FCDA ldInst="MU01" prefix="VBY" lnClass="TVTR" lnInst="2" doName="Vol" daName="q" fc="MX" />
    <FCDA ldInst="MU01" prefix="VCY" lnClass="TVTR" lnInst="3" doName="Vol" daName="instMag.i" fc="MX" />
    <FCDA ldInst="MU01" prefix="VCY" lnClass="TVTR" lnInst="3" doName="Vol" daName="q" fc="MX" />
    <FCDA ldInst="MU01" prefix="VNY" lnClass="TVTR" lnInst="4" doName="Vol" daName="instMag.i" fc="MX" />
    <FCDA ldInst="MU01" prefix="VNY" lnClass="TVTR" lnInst="4" doName="Vol" daName="q" fc
```

FIGURE 10 IEC 61850-9-2LE SV DATASET, EDITION 1

In edition 2, the “doName” was changed for the logical nodes as follows

- “TVTR” was changed to “TCTR”
- ”Amp” was changed to “AmpSv”
- “Vol” was changed to “VolSv”

Figure 11 shows the model for a different LE merging unit, which has the order and dataset naming correct but has implemented the edition 2 changes to the model.



```
<DataSet name="PhsMeas1" desc="9-2LE Dataset for LD MU01">
    <FCDA ldInst="MU01" prefix="I01A" lnClass="TCTR" lnInst="1" doName="AmpSv" daName="instMag.i" fc="MX" />
    <FCDA ldInst="MU01" prefix="I01A" lnClass="TCTR" lnInst="1" doName="AmpSv" daName="q" fc="MX" />
    <FCDA ldInst="MU01" prefix="I01B" lnClass="TCTR" lnInst="2" doName="AmpSv" daName="instMag.i" fc="MX" />
    <FCDA ldInst="MU01" prefix="I01B" lnClass="TCTR" lnInst="2" doName="AmpSv" daName="q" fc="MX" />
    <FCDA ldInst="MU01" prefix="I01C" lnClass="TCTR" lnInst="3" doName="AmpSv" daName="instMag.i" fc="MX" />
    <FCDA ldInst="MU01" prefix="I01C" lnClass="TCTR" lnInst="3" doName="AmpSv" daName="q" fc="MX" />
    <FCDA ldInst="MU01" prefix="I01N" lnClass="TCTR" lnInst="4" doName="AmpSv" daName="instMag.i" fc="MX" />
    <FCDA ldInst="MU01" prefix="I01N" lnClass="TCTR" lnInst="4" doName="AmpSv" daName="q" fc="MX" />
    <FCDA ldInst="MU01" prefix="U01A" lnClass="TVTR" lnInst="1" doName="VolSv" daName="instMag.i" fc="MX" />
    <FCDA ldInst="MU01" prefix="U01A" lnClass="TVTR" lnInst="1" doName="VolSv" daName="q" fc="MX" />
    <FCDA ldInst="MU01" prefix="U01B" lnClass="TVTR" lnInst="2" doName="VolSv" daName="instMag.i" fc="MX" />
    <FCDA ldInst="MU01" prefix="U01B" lnClass="TVTR" lnInst="2" doName="VolSv" daName="q" fc="MX" />
    <FCDA ldInst="MU01" prefix="U01C" lnClass="TVTR" lnInst="3" doName="VolSv" daName="instMag.i" fc="MX" />
    <FCDA ldInst="MU01" prefix="U01C" lnClass="TVTR" lnInst="3" doName="VolSv" daName="q" fc="MX" />
    <FCDA ldInst="MU01" prefix="U01N" lnClass="TVTR" lnInst="4" doName="VolSv" daName="instMag.i" fc="MX" />
    <FCDA ldInst="MU01" prefix="U01N" lnClass="TVTR" lnInst="4" doName="VolSv" daName="q" fc="MX" />
```

FIGURE 11 IEC 61850-9-2 SV DATASET, EDITION 2

Some of the merging units which were set to publish the LE streams sent the edition 2 model vs. the edition 1 model. Examples of this included:

- Clock source in LE was to be 1PPS but most devices did not accept 1PPS taking in its place either or both were IRIG-B or IEEE 1588. There were a number of LE publishers and subscribers which only used IRIG-B or IEEE 1588 for time synchronization.

- The SV control block in all cases matched the edition 1 requirements for LE. Some manufacturers allowed the users to select and de-select control block options to provide additional support for edition 2 SV streams. The multicast sampled value control block (MSVCB) for edition 1 had the following structure (taken from IEC 61850-7-4 Edition 1 2004-04):

    MsvCBNam ObjectName
    MsvCBRef ObjectReference
    SvEna Boolean
    MsvID Visible-string
    DatSet ObjectReference
    ConfRev Integer
    SmpRate Integer
    OptFlds
        refresh-time Boolean
        sample synchronized Boolean
        sample-rate Boolean

The LE document fixed the value for some of these fields. For the protection profile which was used in testing, the SmpRate should be 80; OptFlds: refresh-time could be true or false; sample-synchronized should be true; and sample-rate should be false. The svID and dataset naming conventions were defined.

The SV message buffer was also defined in the LE document but some differences in implementation were identified. The edition 1 message buffer format, minus the header format, was structured as follows (taken from IEC 61850-7-4 Edition 1 2004-04):

- MsvID or UsvID - Should be a system-wide unique identification.
- DatSet- ObjectReference datset OPTIONAL. The value was from the MSVCB.
- SmpCnt- Will be incremented each time a new sampling value was taken. The counter shall be set to zero if the sampling was synchronized by clock signal (SmpSynch = TRUE) and the synchronizing signal occurs. When sync pulses were used to synchronize merging units, the counter shall be set to zero with every sync pulse. The value 0 shall be given to the data set where the sampling of the primary current coincides with the sync pulse.
- ConfRev- The value was from the MSVCB.
- RefrTm contains the refresh time of the SV buffer. OPTIONAL
- SmpSynch- BOOLEAN value, TRUE = SV are synchronized by a clock signal. FALSE = SV are not synchronized.
- SmpRate- The value was from the MSVCB.
- Sample [1..n] Type depends on the common data class defined in IEC 61850-7-3.

The LE document also defined the message buffer format as having the svID, smpCnt, confRev, smpSynch and the data (samples). The OPTIONAL DatSet and RefrTm were not included. The LE stated that as long as the merging unit was time synchronized the "SmpSynch" should be set to TRUE (Boolean). The SmpCnt should behave as specified in IEC 61850-7-2 Edition 1.

In edition 2, there were a few changes to both the MSVCB format and attribute definitions. The following lists these changes:

The "OptFlds" changed as follows:

OptFlds

"refresh-time" was the same

"sample" synchronized was now ignored and kept to ensure backwards compatibility

"sample-rate" was the same

"data-set" was added

"security" was added

"SmpMod" was added in order to identify the method of sampling.

There were a few changes in edition 2 to both the SV message buffer format and attribute definitions. The following lists these changes:

The "SmpSynch" has changed from Boolean to INT8U and the definitions of the values changed as follows:

0= SV are not synchronized by an external clock signal.
1 = SV are synchronized by a clock signal from an unspecified local area clock.
2 = SV are synchronized by a global area clock signal (time traceable).
5 to 254 = SV are synchronized by a clock signal from a local area clock identified by this value
3; 4; 255 = Reserved values – Do not use.

The "SmpMod" data object was added to communicate the method of synchronization taken from the MSVCB.

The biggest impact identified was that most venders claiming to have an LE edition of the SV stream went ahead and implemented the edition 2 definition for the "SmpSynch." This meant that a merging unit that was time synchronized and following the LE document would set this value to TRUE. A SV subscriber using the edition 2 definition would interpret the value of TRUE to a numerical 1 meaning that it was not synchronized. This was identified on one of the test system's merging units.

- The use of GOOSE messaging between editions did not presented a problem. The only changes made in edition 2 were to change the test field to a simulation field. Since this was not used in testing, the edition 1 and 2 devices functioned with both messages. Half of the merging units only implemented edition 2 GOOSE along with some of the protection relays. The exception was the V3M4 which only supported edition 1. No problems were identified in implementing GOOSE solutions for the test system but due to every device except the V3M4 supporting edition 2 we chose to create our projects based on edition 2.
- SCL file schemes and structures changed in edition 2. Some manufacturer's configuration tools accepted both edition 1 and 2 files while others required the user to declare the edition at the start of a project and only accept that edition's files. From the matrix the team determined that all of the software tools would accept edition 2 files verses edition 1 files. This was also a factor in the decision to create the project as an edition 2 project.

TABLE 16 and Table 17 show a summary of the project's edition 1 LE and edition 2 support for SV, GOOSE and configuration system SCL files between the various manufacturer equipment and software tools. These matrices summarized the manufacturer support for each edition based on the option codes selected at the time of purchase. Options may be available to revise the assessments, in these figures, but the listed results were specific to the products selected for this project. In many cases the manufacturers support exceeded the requirements of the specific edition even when strict compliance was not identified.

TABLE 16 PROTECTION DEVICE IEC 61850 EDITION MATRIX

			IEC 61850 Edition 2			IEC 61850 Edition 1			Configuration Tool		
Protection Description	**Protection Equipment**	**Standard Substation Relay Identification**	**61850-8-1: GOOSE**	**61850-9-2: SV**	**SCL Files**	**61850-8-1: GOOSE**	**61850-9-2 LE: SV**	**SCL Files**	**Accepts both editions (1 & 2) within the same project?**	**Will use 9-2 LE using both editions?**	**Input file types**
69/138kV Line Differential Protection (CB 2) Set B	V1M1**	87L-2 Set B	YES	NO	YES: .SCD, .ICD, .IID	YES	YES	YES: .SCD, .ICD, .IID	NO	YES	.SCD, .ICD, .IID
69/138kV Line Distance Protection (CB 2)	V3M1	21-2	YES	NO	YES: .CID	NO	YES	YES: .CID	YES	YES	.ICD, .CID
69/138-12kV Xfmr BK 41 Overcurrent Backup &	V2M1	50/51-7 Set A	YES	NO	YES: .CID, .ICD, .IID	NO	YES	YES: .CID, .ICD	NO	YES	.SCD, .ICD, .IID, .CID
69/138-12kV Xfmr BK 41 Overcurrent Backup & KVAR Demand & 138/69kV Bus Voltage Control (CB 7) Set B	V1M4	50/51-7 Set B	YES	NO	YES: .SCD, .ICD, .IID	YES	YES	YES: .SCD, .ICD, .IID	NO	YES	.SCD, .ICD, .IID
69/138-12kV Xfmr BK 41 Differential (CB 7, 11 & 14) Set B	V1M3	87T41 Set B	YES	NO	YES: .SCD, .ICD, .IID	YES	YES	YES: .SCD, .ICD, .IID	NO	YES	.SCD, .ICD, .IID
69/138-12kV Xfmr BK 41 Differential (CB 7, 11 & 14) Set A	V2M3	87T41 Set A	YES	NO	YES: .CID, .ICD, .IID	NO	YES	YES: .CID, .ICD	NO	YES	.SCD, .ICD, .IID, .CID
69/138kV East Bus OC/Hi-Z Differential (CB 2, 3 & 7) Set A	V2M4	50/51EA138 (SET A)	YES	NO	YES: .CID, .ICD, .IID	NO	YES	YES: .CID, .ICD	NO	YES	.SCD, .ICD, .IID, .CID
69/138kV East Bus OC/lo-Z Differential (CB 2, 3 & 7) Set B	V1M6	50/51EB138 (SET B)	YES	NO	YES: .SCD, .ICD, .IID	YES	YES	YES: .SCD, .ICD, .IID	NO	YES	.SCD, .ICD, .IID
69/138kV Breaker Failure (CB 2)***	V1M2	50/62BF***	YES	NO	YES: .SCD, .ICD, .IID	YES	YES	YES: .SCD, .ICD, .IID	NO	YES	.SCD, .ICD, .IID
12kV Cap Bank Sequencing Automation Controller	V3M4	Cap Bank V3M4	NO	N/A	NO	YES	N/A	YES: .CID - MANUAL CHANGE TO .ICD	YES	N/A	.ICD, .CID
12kV Cap Bank Voltage Unbalance Protection	V3M2	Cap Bank 59X (3V0)	YES	N/A	YES: .CID - MANUAL CHANGE TO .ICD	YES	N/A	YES: .CID - MANUAL CHANGE TO .ICD	YES	N/A	.ICD, .CID
12kV Reactor Bank Sequencing Automation Controller	V3M4	Reactor Bank V3M4	NO	N/A	NO	YES	N/A	YES: .CID - MANUAL CHANGE TO .ICD	YES	N/A	.ICD, .CID
12kV Reactor Bank Voltage Unbalance Protection	V3M2	Reactor Bank 59X (3V0)	YES	N/A	YES: .CID	YES	N/A	YES: .CID	YES	N/A	.ICD, .CID
12kV Main Bus Overall Low Impedance Bus Differential (Wraps CBs 10, 11, 12, 14, 17 & 20)	V2M3	87-1241	YES	NO	YES: .CID, .ICD, .IID	NO	YES	YES: .CID, .ICD	NO	YES	.SCD, .ICD, .IID, .CID
12kV Reactive Feeder Overcurrent (CB 17) Set A	V2M1	50/51-CB (Set A)	YES	NO	YES: .CID, .ICD, .IID	NO	YES	YES: .CID, .ICD	NO	YES	.SCD, .ICD, .IID, .CID
12kV Reactive Feeder Overcurrent (CB 17) Set B	V1M4	50/51-CB (Set B)	YES	NO	YES: .SCD, .ICD, .IID	YES	YES	YES: .SCD, .ICD, .IID	NO	YES	.SCD, .ICD, .IID
12kV Main Bus Partial Overcurrent Differential Set B (Wraps CBs 10, 14 & 20)****	V1M4	50/51-1241 (Set B)****	YES	NO	YES: .SCD, .ICD, .IID	YES	YES	YES: .SCD, .ICD, .IID	NO	YES	.SCD, .ICD, .IID
12kV Main Bus Partial Overcurrent Differential Set A (Wraps CBs 10, 14 & 20)****	V2M1	50/51-1241 (Set A)****	YES	NO	YES: .CID, .ICD, .IID	NO	YES	YES: .CID, .ICD	NO	YES	.SCD, .ICD, .IID, .CID

TABLE 17 MERGING UNIT IEC 61850 EDITION MATRIX

			IEC 61850 Edition 2			IEC 61850 Edition 1			Configuration Tool		
Merging Units	MU Equipment	Standard Substation Relay Identification	61850-8-1: GOOSE	61850-9-2: SV	SCL Files	61850-8-1: GOOSE	61850-9-2 LE: SV	SCL Files	Will accept both editions (1 & 2) within the same project?	Will use 9-2 LE using both editions?	Input file types
MU1- 69/138kV Line CB 2	V1M5 #1		YES	NO	YES: .SCD, .ICD, .IID	YES	YES	YES: .SCD, .ICD, .IID	NO	YES	.SCD, .ICD, .IID
MU2- 69/138 Bus Tie CB 3	V3M3		YES	NO	YES: .CID - MANUAL CHANGE TO .ICD	NO	YES	YES: .CID	YES	YES	.ICD, .CID
MU3- 69/138-12kV Xfmr BK 41 CB 7	V7M1 #1 CKT 1		YES	YES	YES: .CID	NO	YES	YES: .CID	YES	YES	.ICD, .CID
MU4- 12kV Xfer Bus CB 11	V7M1 #1 CKT 2		YES	YES	YES: .CID	NO	YES	YES: .CID	YES	YES	.ICD, .CID
MU5- 12kV Swgr 1240 Bus Tie CB 10	V2M5		YES	NO	YES: .CID, .ICD, .IID	YES	YES	YES: .CID, .ICD	NO	YES	.SCD, .ICD, .IID, .CID
MU6- 12kV Feeder CB 12	V3M3		YES	NO	YES: .CID - MANUAL CHANGE TO .ICD	NO	YES	YES: .CID	YES	YES	.ICD, .CID
MU7- 69/138-12kV Xfmr BK41 CB 14	V2M5		YES	NO	YES: .CID, .ICD, .IID	YES	YES	YES: .CID, .ICD	NO	YES	.SCD, .ICD, .IID, .CID
MU8a- 12kV Reactive Feeder CB 17	V2M6		YES	N/A	YES: .CID, .ICD, .IID	YES	N/A	YES: .CID, .ICD	NO	YES	.SCD, .ICD, .IID, .CID
MU8b- 12kV Reactive Feeder CB 17	V6M1		YES	YES		NO	YES		N/A	YES	.icd
MU9- 12kV Xfer Bus CB 11	V7M1 #2 CKT 1		YES	YES	YES: .CID	NO	YES	YES: .CID	YES	YES	.ICD, .CID
MU10- 69/138-12kV Xfmr BK41 CB 14	V7M1 #2 CKT 2		YES	YES	YES: .CID	NO	YES	YES: .CID	YES	YES	.ICD, .CID
MU11- 69/138-12kV Xfmr BK 41 12kV Neutral CT	V2M5		YES	NO	YES: .CID, .ICD, .IID	YES	YES	YES: .CID, .ICD	NO	YES	.SCD, .ICD, .IID, .CID
MU12- 69/138kV E. Bus 87B Hi-Z Resistor	V3M3		YES	NO	YES: .CID - MANUAL CHANGE TO .ICD	NO	YES	YES: .CID	YES	YES	.ICD, .CID
MU13- 12kV Swgr 1242 Bus Tie CB 20	V1M5 #2		YES	NO	YES: .SCD, .ICD, .IID	YES	YES	YES: .SCD, .ICD, .IID	NO	YES	.SCD, .ICD, .IID

These tables indicated that the manufacturers mostly supported edition 2 along with SV LE. Based on this the project planned to use the edition 2 project files. As the project proceeded and more details on the manufacturers' SV LE implementations were identified, it was determined that none of the manufacturers strictly followed the LE implementation guide. This led to some potential interoperability concerns. In order to determine the IEC 61850 edition for the project to use, a comparison was performed for each manufacturer's IEDs using a strict interpretation of the requirements from the LE implementation guide. With the "No-Any" entry, the items so identified could be configured to become compliant. and Table 19 show the LE agreement implementation items on the left and to the right the tables show how the manufacturers implemented them.

Most of the manufacturers had moved to implement edition 2 features while attempting to maintain the LE compliance which was based on edition 1. Some manufacturers strictly enforced some of the items and made changes in others in order to accommodate both edition 1 and 2. The use of the SmpSynch field in the SV message buffering and the AppID were the two most noticeable items. As stated above, the SmpSynch definition and data type were changed in edition 2 and one merging unit that strictly used the LE implementation for this field would not communicate with a protection device that strictly used the IEC 61850 edition 2 implementation.

In many cases the manufacturers have added support for features in excess of the LE implementation guide. For this case, the table showed a response such as "NO-any." In these cases, the manufacturers were not strictly compliant with the LE implementation guide. However, the manufacturers' products could support the requirement due to enhanced configurability that was added to their products. The "No-Any" entry, indicates that items so identified could be configured to become compliant.

TABLE 18 MERGING UNIT SV – COMPLIANCE WITH 9-2LE

UCA IEC 61850-9-2 Implementation Guideline Document		**SV Publishers**				
Mandatory Item	**Mandatory Value / Format**	**V7M1**	**V2M5**	**V3M3**	**V1M5**	**V6M1**
LDName	xxxxMUnn	YES- missing IED name	YES- missing IED name	YES- missing IED name	YES- missing IED name	YES- missing IED name
Logical Nodes	LLNO	YES	YES	YES	YES	YES
	LPHD	YES	YES	YES	YES	YES
	InnATCTR1	YES	YES	YES	YES	YES
	InnBTCTR2	YES	YES	YES	YES	YES
	InnCTCTR3	YES	YES	YES	YES	YES
	InnNTCTR4	YES	YES	YES	YES	YES
	UnnATVTR1	YES	YES	YES	YES	YES
	UnnBTVTR2	YES	YES	YES	YES	YES
	UnnCTVTR3	YES	YES	YES	YES	YES
	UnnNTVTR4	YES	YES	YES	YES	YES
Logical Nodes data	As defined in IEC 61850-7-4 & 7-3 ed1	NO- Uses ed2	YES	NO	NO- Uses ed1	NO- Uses ed2
DataSet	xxxxMUnn/LLN0$PhsMeas1	NO- ed2	YES	YES	NO- ed2	NO- ed2
DS MemberRef	InnATCTR1.Amp	NO- ed2	YES	YES	NO- ed2	NO- ed2
	InnBTCTR2.Amp	NO- ed2	YES	YES	NO- ed2	NO- ed2
	InnCTCTR3.Amp	NO- ed2	YES	YES	NO- ed2	NO- ed2
	InnNTCTR4.Amp	NO- ed2	YES	YES	NO- ed2	NO- ed2
	UnnATVTR1.Vol	NO- ed2	YES	YES	NO- ed2	NO- ed2
	UnnBTVTR2.Vol	NO- ed2	YES	YES	NO- ed2	NO- ed2
	UnnCTVTR3.Vol	NO- ed2	YES	YES	NO- ed2	NO- ed2
	UnnNTVTR4.Vol	NO- ed2	YES	YES	NO- ed2	NO- ed2
DS MemberRef Data Order	Ordered as shown above	YES	YES	YES	YES	YES
SAV Common data Class	instMag.i: INT32	YES	YES	YES	YES	YES
	sVC.scaleFactor: FLOAT32- .001 for current and .01 for voltage	YES	YES	YES	YES	YES
	sVC.offset: FLOAT33- Always 0	YES	NO- any	YES	YES	YES
Multicast Sampled Value Control Block (MSVCB) Name	xxxxMUnn/LLN0$MSVCB01	NO- any	YES	NO- any	YES	YES
-NoASDU	1	YES	YES	YES	YES	YES
- OptFlds- security	FALSE	YES	YES	YES	YES	YES
- OptFlds- data-set	FALSE	YES	YES	YES	YES	YES
MsvID	xxxxMUnn01	NO- any	YES	NO- any	NO- any	NO- any
SmpRate	80	YES	YES	YES	YES	YES
OptFlds- refresh-time	TRUE/FALSE	YES	YES	YES	YES	YES
- sample-synchronized	TRUE	YES	YES	YES	YES	YES
- sample-rate	FALSE	YES	YES	YES	YES	YES
Clock Source	1PPS +/-1µsec accuracy optical input	YES	NO IEEE 1588	NO IEEE 1588 & IRIG-B	NO IRIG-B	YES
Nominal frequency	50 or 60 Hz	YES	YES	YES	YES	YES
Physical Layer	100BaseFX ST or MT-RJ or 100BaseTX RJ-45	NO LC	NO LC	NO LC	NO LC	NO LC
AppID	Shall always be 0x4000	NO- any	NO- any	NO- any	NO- any	NO- any
Quality IEC 61850-7-3 extended	attribute "derived" BOOLEAN	YES	NO	YES	YES	NO
Message Buffer- SmpSynch	Shall behave as specified in IEC 61850-7-2 ed1	NO- Strict ed2, must be =2 (global)	YES	NO- Strict ed2, must be =2 (global)	Both ed1 and ed2 mods	NO- Strict ed2, must be =2 (global)
Message Buffer- SmpCnt	Shall behave as specified in IEC 61850-7-2 ed1	YES	YES	YES	YES	YES
Calculation	Neutral current and / or voltage	YES	YES	YES	YES	YES

TABLE 19 PROTECTION DEVICE SV – COMPLIANCE WITH 9-2 LE

UCA IEC 61850-9-2 Implementation Guideline Document		SV Subscribers		
Mandatory Item	**Mandatory Value / Format**	**V2M1 V2M2 V2M3 V2M4**	**V3M1**	**V1M1 V1M2 V1M3 V1M4**
LDName	xxxxMUnn	N/A	N/A	N/A
Logical Nodes	LLNO	N/A	N/A	N/A
	LPHD	N/A	N/A	N/A
	InnATCTR1	N/A	N/A	N/A
	InnBTCTR2	N/A	N/A	N/A
	InnCTCTR3	N/A	N/A	N/A
	InnNTCTR4	N/A	N/A	N/A
	UnnATVTR1	N/A	N/A	N/A
	UnnBTVTR2	N/A	N/A	N/A
	UnnCTVTR3	N/A	N/A	N/A
	UnnNTVTR4	N/A	N/A	N/A
Logical Nodes data	As defined in IEC 61850-7-4 & 7-3 ed1	N/A	N/A	N/A
DataSet	xxxxMUnn/LLN0$PhsMeas1	N/A	N/A	N/A
DS MemberRef	InnATCTR1.Amp	N/A	N/A	N/A
	InnBTCTR2.Amp	N/A	N/A	N/A
	InnCTCTR3.Amp	N/A	N/A	N/A
	InnNTCTR4.Amp	N/A	N/A	N/A
	UnnATVTR1.Vol	N/A	N/A	N/A
	UnnBTVTR2.Vol	N/A	N/A	N/A
	UnnCTVTR3.Vol	N/A	N/A	N/A
	UnnNTVTR4.Vol	N/A	N/A	N/A
DS MemberRef Data Order	Ordered as shown above			
SAV Common data Class	instMag.i: INT32	N/A	N/A	N/A
	sVC.scaleFactor: FLOAT32- .001 for current and .01 for voltage	N/A	N/A	N/A
	sVC.offset: FLOAT33- Always 0	N/A	N/A	N/A
Multicast Sampled Value Control Block (MSVCB) Name	xxxxMUnn/LLN0$MSVCB01	N/A	N/A	N/A
-NoASDU	1	N/A	N/A	N/A
- OptFlds- security	FALSE	N/A	N/A	N/A
- OptFlds- data-set	FALSE	N/A	N/A	N/A
MsvID	xxxxMUnn01	N/A	N/A	N/A
SmpRate	80	N/A	N/A	N/A
OptFlds- refresh-time	TRUE/FALSE	N/A	N/A	N/A
- sample-synchronized	TRUE	N/A	N/A	N/A
- sample-rate	FALSE	N/A	N/A	N/A
Clock Source	1PPS +/-1µsec accuracy optical input	YES (Strict)	NO IEEE 1588 & IRIG-B	NO (IEEE 1588)
Nominal frequency	50 or 60 Hz	YES	YES	YES
Physical Layer	100BaseFX ST or MT-RJ or 100BaseTX RJ-45	YES	NO LC	NO LC
AppID	Shall always be 0x4000	YES- must be 0x4000	NO- Does not matter	NO- Does not matter
Quality IEC 61850-7-3 extended	attribute "derived" BOOLEAN	N/A	N/A	N/A
Message Buffer- SmpSynch	Shall behave as specified in IEC 61850-7-2 ed1	NO- Any value greater than 0 is OK	NO- Strict ed2, must be =2 (global)	NO- Any value greater than 0 is OK
Message Buffer- SmpCnt	Shall behave as specified in IEC 61850-7-2 ed1	N/A	N/A	N/A
Calculation	Neutral current and / or voltage	N/A	N/A	N/A

Data Flows

GOOSE and Sampled Value Data Flow Spreadsheet

The documents shown in Appendix E contain the data flow information for process bus #1, process bus #2, and the station bus. Each SV and GOOSE message required a multicast MAC addresses, AppIDs, and message IDs. This spreadsheet was created to identify the message requirements and to establish the publishers and subscribers.

The following figures (Table 20, Table 21, Table 22, Table 23, Table 24, and Table 25) provide a sample of the information contained in this appendix. The purpose of these figures was to orientate the reader on their use and structure. The reader should reference the attached appendices for up to date information on the data flows.

TABLE 20 DATA FLOW TABLE - SV CONTROL BLOCK

	Process Bus #1 Sampled Value (SV) Messages											
IEDname	**Publishing IED**	**Measurement and Control points**	**Voltage**	**Current**	**MAC Address**	**VLAN ID**	**VLAN-PRIORITY**	**App ID (hex)**	**SmpRate (sample/ cycle)**	**MsvID**	**Dataset Name**	**Dataset index 1**
MU1_CB2	MU1- 69/138kV Line CB 2_V1M5 #1	69/138kV Line CB 2 Line Side CT, west bud PT and CB2 I/O	115V - 700 ratio	5A - 400 ratio	01-0C-CD-04-00-00	1	4	0x4000	80	MU1_CB2_V1M5	PhsMeas1	PhA_Amps. instMag.i
MU2_CB3_V3M3	MU2- 69/138 Bus Tie CB 3_V3M3	69/138kV Bus Tie CB 3 West Bus CT, west bus PT and CB3 I/O	115V - 700 ratio	5A - 400 ratio	01-0C-CD-04-00-01	1	4	0x4000	80	MU2_CB3_V3	PhsMeas1	PhA_Amps. instMag.i
MU3_4_CB7_11_V7M1	MU3- 69/138-12kV Xfmr BK 41 CB 7 _V7M1 #1 CKT 1	69/138-12kV Xfmr BK 41 Main CB 7 Xfmr Side CT, 12kV Swgr 1241 Unit 17 Bus PT 100:1and CB7 I/O	115V - 700 ratio	5A - 400 ratio	01-0C-CD-04-00-02	1	4	0x4000	80	MU3_MU0101	PhsMeas1	PhA_Amps. instMag.i
MU3_4_CB7_11_V7M1	MU4- 12kV Xfer Bus CB 11_V7M1 #1 CKT 2	12kV Xfer Bus CB 11, 12kV Swgr 1241 Unit 17 Bus PT 100:1, CB Unit 11 I/O	120V - 100 ratio	5A - 400 ratio	01-0C-CD-04-00-03	1	4	0x4000	80	MU4_MU0201	PhsMeas1	PhA_Amps. instMag.i
MU7_CB14_V2M5	MU7- 69/138-12kV Xfmr BK41 CB 14_V2M5	69/138-12kV Xfmr BK41 CB 14 Xfmr Side CT, 2kV Swgr 1241 Unit 17 Bus PT 100:1, CB Unit 14 I/O	115V - 700 ratio	5A - 400 ratio	01-0C-CD-04-00-06	1	4	0x4000	80	MU7_CB14_V2	PhsMeas1	PhA_Amps. instMag.i
MU11_T41NEU_V2M5	MU11- 69/138-12kV Xfmr BK 41 12kV Neutral CT_V2M5	69/138-12kV Xfmr BK 41 12kV Neutral CT, no I/O	120V - 100 ratio	5A - 400 ratio	01-0C-CD-04-00-10	1	4	0x4000	80	MU11_T41N_V2	PhsMeas1	PhA_Amps. instMag.i
MU12_HIZ_V3M3	MU12- 69/138kV E. Bus 87B Hi-Z Resistor_V3M3	69/138kV E. Bus 87B Hi-Z Resistor, no I/O	115V - 700 ratio	5A - 400 ratio	01-0C-CD-04-00-11	1	4	0x4000	80	MU12_HIZ_V3	PhsMeas1	PhA_Amps. instMag.i

Table 20 shows the information required to program the SV control block parameter in the merging units. This table documents the first section of the data flow document for SV messages.

One would determine the required SV settings for a particular device by starting in Table 20 (in the leftmost column of any row) and reading across the table through Table 21 and Table 22. This information would be input into the IEDs as required. The large format version of the full table in Appendix E would normally be used to identify the SV data for entry into the devices. GOOSE data would be similarly identified in Table 23, Table 24, and Table 25.

TABLE 21 DATA FLOW TABLE- SV DATASET

					SV Control Block and referenced dataset information								
SmpRate (sample/ cycle)	MsvID	Dataset Name	Dataset index 1	Dataset index 2	Dataset index 3	Dataset index 4	Dataset index 5	Dataset index 6	Dataset index 7	Dataset index 8	Dataset index 9	Dataset index 10	D
80	MU1_CB2_V1M5	PhsMeas1	PhA_Amps. instMag.i	PhA_Amps.q	PhB_Amps. instMag.i	PhB_Amps.q	PhC_Amps. instMag.i	PhC_Amps.q	NEUT Amps. instMag.i	NEUT Amps. q	PhA Volts-Vol.instMag.i	PhA Volts-Vol.q	V
80	MU2_CB3_V3	PhsMeas1	PhA_Amps. instMag.i	PhA_Amps.q	PhB_Amps. instMag.i	PhB_Amps.q	PhC_Amps. instMag.i	PhC_Amps.q	NEUT Amps. instMag.i	NEUT Amps. q	PhA Volts-Vol.instMag.i	PhA Volts-Vol.q	V
80	MU3_MU0101	PhsMeas1	PhA_Amps. instMag.i	PhA_Amps.q	PhB_Amps. instMag.i	PhB_Amps.q	PhC_Amps. instMag.i	PhC_Amps.q	NEUT Amps. instMag.i	NEUT Amps. q	PhA Volts-Vol.instMag.i	PhA Volts-Vol.q	V
80	MU4_MU0201	PhsMeas1	PhA_Amps. instMag.i	PhA_Amps.q	PhB_Amps. instMag.i	PhB_Amps.q	PhC_Amps. instMag.i	PhC_Amps.q	NEUT Amps. instMag.i	NEUT Amps. q	PhA Volts-Vol.instMag.i	PhA Volts-Vol.q	V
80	MU7_CB14_V2	PhsMeas1	PhA_Amps. instMag.i	PhA_Amps.q	PhB_Amps. instMag.i	PhB_Amps.q	PhC_Amps. instMag.i	PhC_Amps.q	NEUT Amps. instMag.i	NEUT Amps. q	PhA Volts-Vol.instMag.i	PhA Volts-Vol.q	V
80	MU11_T41N_V2	PhsMeas1	PhA_Amps. instMag.i	PhA_Amps.q	PhB_Amps. instMag.i	PhB_Amps.q	PhC_Amps. instMag.i	PhC_Amps.q	NEUT Amps. instMag.i	NEUT Amps. q	PhA Volts-Vol.instMag.i	PhA Volts-Vol.q	V
80	MU12_HIZ_V3	PhsMeas1	PhA_Amps. instMag.i	PhA_Amps.q	PhB_Amps. instMag.i	PhB_Amps.q	PhC_Amps. instMag.i	PhC_Amps.q	NEUT Amps. instMag.i	NEUT Amps. q	PhA Volts-Vol.instMag.i	PhA Volts-Vol.q	V

Table 21 shows the dataset contents and is located to the right of the columns shown in Table 20. The IEC 61850-9-2LE document fixed the SV dataset so all of these datasets were identical.

TABLE 22 DATA FLOW TABLE- SV SUBSCRIBING DEVICES

	Subscribing IEDs									
ıdex 16	V2M2**--87L-2 Set A	V1M1**--87L-2 Set B	V3M1--21-2	V2M1--50/51-7 Set A	V1M4--50/51-7 Set B	V1M3--87T41 Set B	V2M3--87T41 Set A	V2M4-50/51EA138 (SET A)	V1M3--50/51EB138 (SET B)	V1M2--50/62BF
:s-Vol.q	YES	YES						YES	YES	YES
:s-Vol.q			YES (IW & VY)					YES	YES	
:s-Vol.q			YES (IX & VZ)	YES	YES	YES	YES	YES	YES	
:s-Vol.q	YES	YES				YES	YES			
:s-Vol.q						YES	YES			
:s-Vol.q				YES	YES	YES	YES			
:s-Vol.q								YES		

Further to the right, in Table 21one encounters the last section, which was shown in Table 22. This section indicated which devices subscribed to the various SV messages.

TABLE 23 DATA FLOW TABLE - GOOSE CONTROL BLOCK

Summary Use	IEDname	Publishing IED	Measurement and Control points, etc.	MAC Address	VLAN ID	VLAN-PRIORITY	App ID (hex)	Min Trime (ms)	Heatbeat Rate, Max time (ms)	Control Block Name and GoID	Dataset Name	Datase
Breaker Position	MU1_CB2	MU1- 69/138kV Line CB 2_V1M5 #1	CT TL138XX Breaker 2 Line Side CT; PT 138kV West Bus PT; Breaker 2 I/O	01-0C-CD-01-00-00	1	4	0x0000	4	500	BRK2_MU1	CB2_52A	GGIO1. stVal (5:
Breaker Position	MU2_CB3_V3M3	MU2- 69/138 Bus Tie CB 3_V3M3	CT Bus Tie Breaker 3 West Bus CT PT 138kV West Bus PT BREAKER 3 I/O	01-0C-CD-01-00-01	1	4	0x0001	4	1000	BRK3_MU2	CB3_52A	ANN.II 14,Ind (Input
Breaker Position	MU3_MU4 CB7_11_V7M1	MU3- 69/138-12kV Xfmr BK 41 CB 7 _V7M1 #1 CKT 1	CT Breaker 7 BK 41 Transformer Side CT PT 12kV Unit 17 Bus PT 100:1 BREAKER 7 I/O	01-0C-CD-01-00-02	1	4	0x0002	20	1000	BRK7_MU3	MU3_STATUS	CTRL/E IO1.Inc (CB7
Breaker Position	MU3_MU4 CB7_11_V7M1	MU4- 12kV Xfer Bus CB 11_V7M1 #1 CKT 2	CT 12kV Unit 11 Trans Bus Side CT PT 12kV Unit 17 Bus PT 100:1 BREAKER Unit 11 I/O	01-0C-CD-01-00-03	1	4	0x0003	20	500	BRK11_MU4	MU4_STATUS	CTRL/E IO1.Inc (CB1
Breaker Position	MU3_MU4 CB7_11_V7M1	MU3 & MU4 CB7 & CB 11-1_V7M1 #1&2	ALL STATUS INPUTS	01-0C-CD-01-00-39	1	4	0x0027	1	1000	MU3_MU4_FASTGOOSE_FIXED	DigInput	CTRL/E IO1.Inc (CB7

Table 23 showed the GOOSE messages which were arranged similarly to the SV messages. This first section contained all the GOOSE control block parameters required to program the devices.

TABLE 24 DATA FLOW TABLE - GOOSE DATASET

GOOSE Control Block and referenced dataset information														
Control Block Name and GoID	Dataset Name	Dataset index 1	Dataset index 2	Dataset index 3	Dataset index 4	Dataset index 5	Dataset index 6	Dataset index 7	Dataset index 8	Dataset index 9	Dataset index 10	Dataset index 11	Dataset index 12	Da
BRK2_MU1	CB2_52A	GGIO1.SPCS01.stVal (Input 1-52a)	GGIO1.SPCS01.q (Input 1-52a)	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	
BRK3_MU2	CB3_52A	ANN.IN2GGIO14,Ind01.stVal (Input 1- 52a)	ANN.IN2GGIO14,Ind01.q (Input 1- 52a)	ANN.IN2GGIO14,Ind02.stVal (VT Fuse Fail A)	ANN.IN2GGIO14,Ind02.q (VT Fuse Fail A)	ANN.IN2GGIO14,Ind03.stVal (VT Fuse Fail B)	ANN.IN2GGIO14,Ind03.q (VT Fuse Fail B)	ANN.IN2GGIO14,Ind04.stVal (VT Fuse Fail C)	ANN.IN2GGIO14,Ind04.q (VT Fuse Fail C)	-----	-----	-----	-----	
BRK7_MU3	MU3_STATUS	CTRL/BININGGIO1.Ind1.stVal (CB7 52A)	CTRL/BININGGIO1.Ind1.q (CB7 52A)	CTRL/BININGGIO1.Ind2.stVal	CTRL/BININGGIO1.Ind2.q	CTRL/BININGGIO1.Ind3.stVal (CB7 1241 UNIT 17 PT PHA FUSE)	CTRL/BININGGIO1.Ind3.q (CB7 1241 UNIT 17 PT PHA FUSE)	CTRL/BININGGIO1.Ind4.stVal (CB7 1241 UNIT 17 PT PHB FUSE)	CTRL/BININGGIO1.Ind4.q (CB7 1241 UNIT 17 PT PHB FUSE)	CTRL/BININGGIO1.Ind5.stVal (CB7 1241 UNIT 17 PT PHC FUSE)	CTRL/BININGGIO1.Ind5.q (CB7 1241 UNIT 17 PT PHC FUSE)	CTRL/BININGGIO1.Ind6stVal (CB7 1241 UNIT 17 PT NEU FUSE)	CTRL/BININGGIO1.Ind6.q (CB7 1241 UNIT 17 PT NEU FUSE)	
BRK11_MU4	MU4_STATUS	CTRL/BININGGIO1.Ind7.stVal (CB11 52A)	CTRL/BININGGIO1.Ind7.q (CB11 52A)	CTRL/BININGGIO1.Ind8.stVal	CTRL/BININGGIO1.Ind8.q	CTRL/BININGGIO1.Ind9stVal (CB11 1241 UNIT 17 PT PHA FUSE)	CTRL/BININGGIO1.Ind9.q (CB11 1241 UNIT 11 PT PHA FUSE)	CTRL/BININGGIO1.Ind10.stVal (CB11 1241 UNIT 11 PT PHB FUSE)	CTRL/BININGGIO1.Ind10.q (CB11 1241 UNIT 11 PT PHB FUSE)	CTRL/BININGGIO1.Ind11.stVal (CB11 1241 UNIT 11 PT PHC FUSE)	CTRL/BININGGIO1.Ind11.q (CB11 1241 UNIT 11 PT PHC FUSE)	CTRL/BININGGIO1.Ind12stVal (CB11 1241 UNIT 11 PT NEU FUSE)	CTRL/BININGGIO1.Ind12.q (CB11 1241 UNIT 11 PT PNEU FUSE)	
MU3_MU4_FASTGOOSE_FIXED	DigInput	CTRL/BININGGIO1.Ind1.stVal (CB7 52A)	CTRL/BININGGIO1.Ind2.stVal	CTRL/BININGGIO1.Ind3.stVal (CB7 1241 UNIT 17 PT PHA FUSE)	CTRL/BININGGIO1.Ind4.stVal (CB7 1241 UNIT 17 PT PHB FUSE)	CTRL/BININGGIO1.Ind5.stVal (CB7 1241 UNIT 17 PT PHC FUSE)	CTRL/BININGGIO1.Ind6stVal (CB7 1241 UNIT 17 PT NEU FUSE)	CTRL/BININGGIO1.Ind7.stVal (CB11 52A)	CTRL/BININGGIO1.Ind8.stVal	CTRL/BININGGIO1.Ind9stVal (CB11 1241 UNIT 17 PT PHA FUSE)	CTRL/BININGGIO1.Ind10.stVal (CB11 1241 UNIT 11 PT PHB FUSE)	CTRL/BININGGIO1.Ind11.stVal (CB11 1241 UNIT 11 PT PHC FUSE)	CTRL/BININGGIO1.Ind12stVal (CB11 1241 UNIT 11 PT NEU FUSE)	

Table 24 shows the dataset contents that were located to the right of the columns shown in Table 23. Each GOOSE message served a specific purpose in the system operation and therefore the datasets were different from each other.

TABLE 25 DATA FLOW TABLE - GOOSE SUBSCRIBING DEVICES

	Subscribing IEDs										Subscribing Merging Units						
ndex	V2M2**--87L-2 Set A	V1M1**--87L-2 Set B	V3M1--21-2	V2M1--50/51-7 Set A	V1M4--50/51-7 Set B	V1M3--87T41 Set B	V2M3--87T41 Set A	V2M4-50/51EA138 (SET A)	V1M3--50/51EB138 (SET B)	V1M2--50/62BF	MU1- 69/138kV Line CB 2_V1M5 #1	MU2- 69/138 Bus Tie CB 3_V3M3	MU3- 69/138-12kV Xfmr BK 41 CB 7 _V7M1 #1 CKT 1	MU4- 12kV Xfer Bus CB 11_V7M1 #1 CKT 2	MU7- 69/138-12kV Xfmr BK41 CB 14_V2M5	MU11- 69/138-12kV Xfmr BK 41 12kV Neutral CT_V2M5	MU12- 69/138kV E. Bus 87B Hi-Z Resistor_V3M3
	YES	YES	YES					YES	YES	YES							
								YES	YES	YES							
				YES	YES		YES	YES	YES	YES							
				YES	YES		YES										
				YES	YES		YES										
				YES	YES		YES										

Further to the right in Table 24, one encounters the last section, which was shown in Table 25. This section indicated which devices subscribe to the various GOOSE messages.

Process Bus Data Flow Diagram

Figure 12 and Figure 13 show the data flow diagrams for process bus #1 and process bus #2, respectively. The data flow diagrams provide a graphic representation of the data flow tables presented in the previous section. The diagrams show all the GOOSE and SV data flows for each process bus to and from each device connected to the process bus and the device's relationship to the substation equipment. The diagram was intended to provide an understanding of the purpose of the data flow and provides information to link it to the data flow spreadsheet.

Additional information on the multicast MAC address was useful for quickly identifying the data flow in a device configuration file or to analyze captured traffic on the network. SV message addresses always start with 01-0C-CD-04 and GOOSE with 01-0C-CD-01 leaving the remaining two octets available for configuration. For this project, the fifth octet was not used and set to 00, so, for simplicity; the diagram only displays the value for the last octet. The octets used hex numbers but in order to make the messages easier to identify, the MAC address were sequentially increased so as to appear to be using base 10 numbers. As an example, the addresses jumped from 01-0C-CD-01-09 to 01-0C-CD-01-10 without using A, B, C, D, E or F in the last hex space.

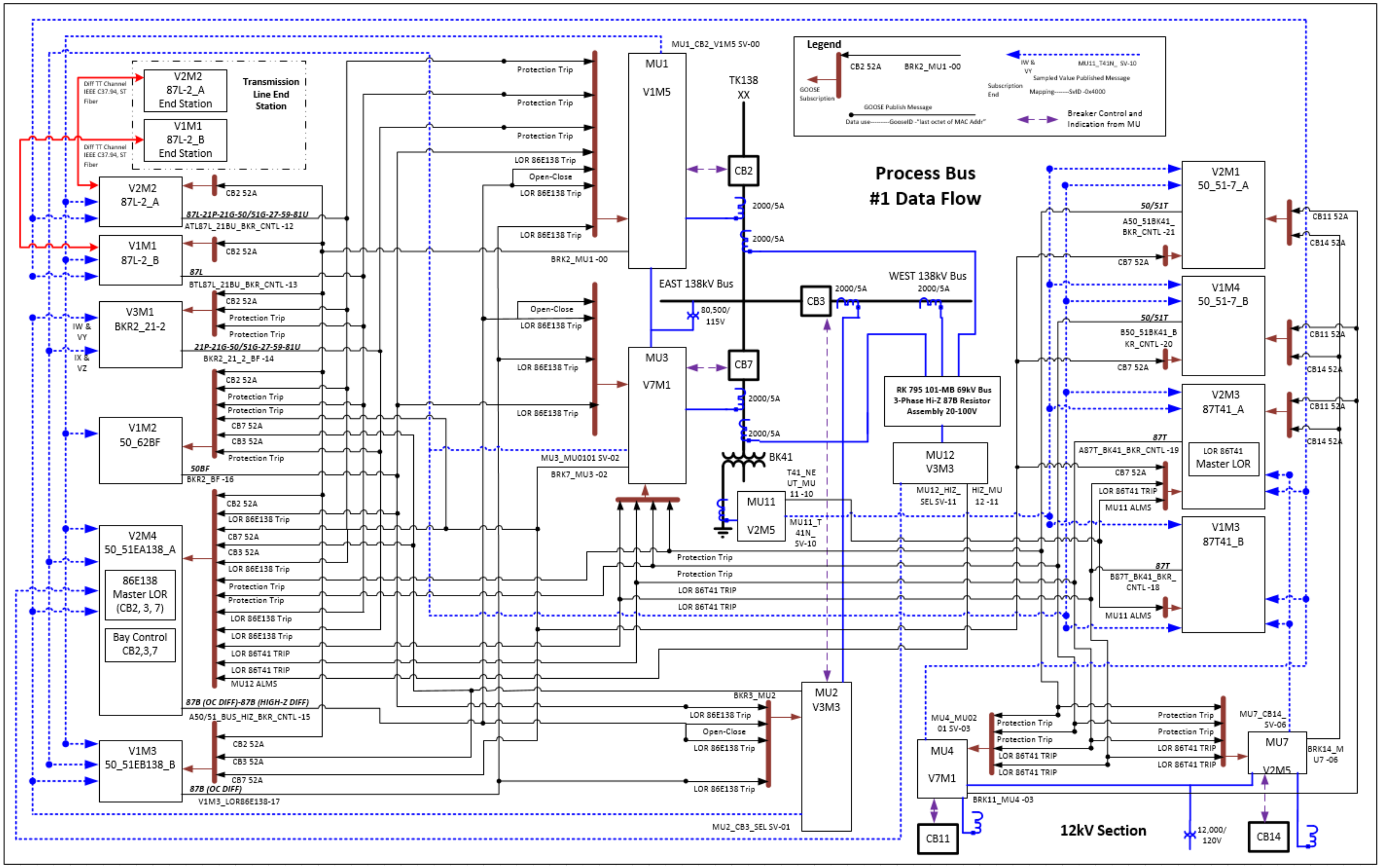


FIGURE 12 PROCESS BUS #1 DATAFLOW DIAGRAM

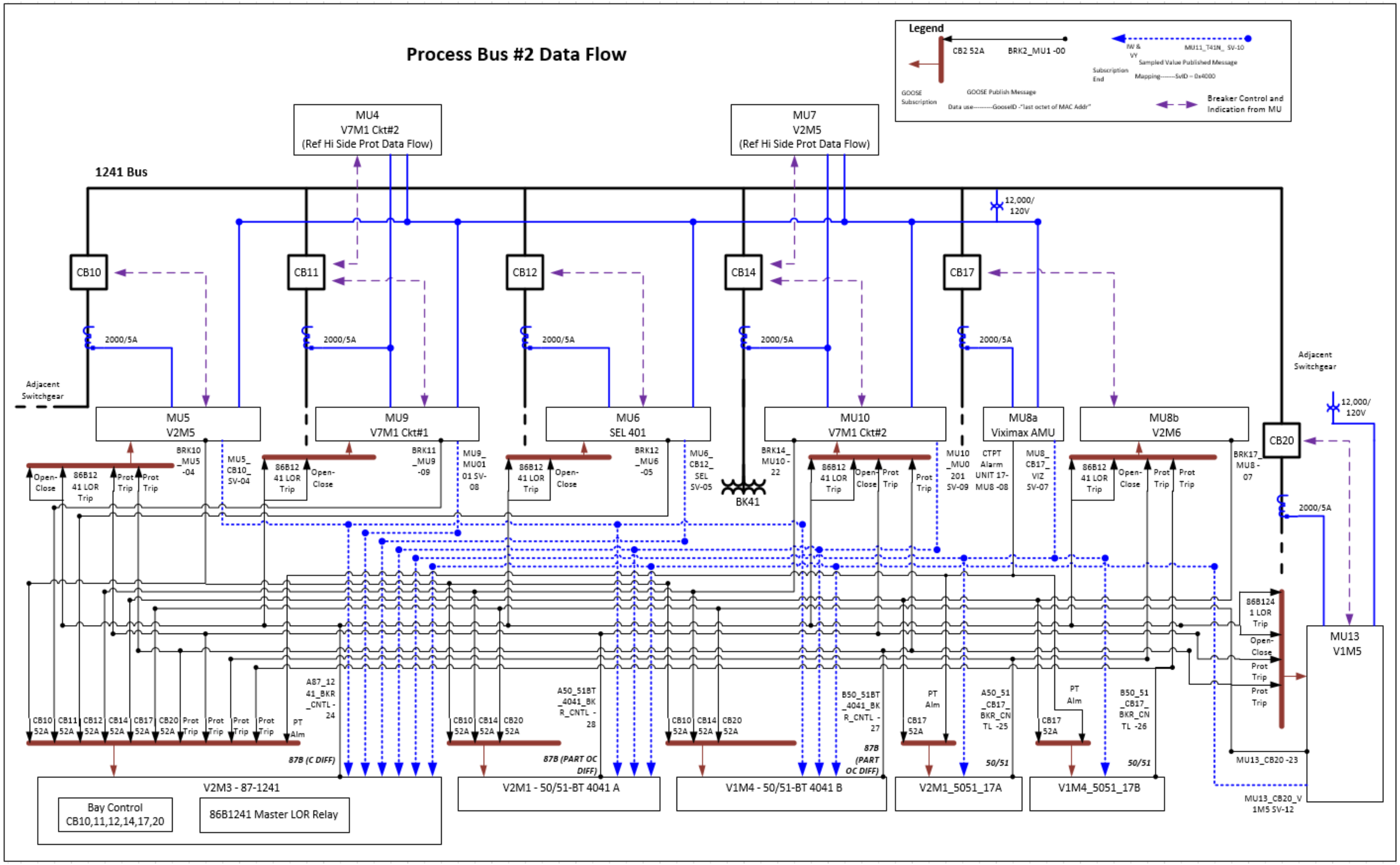


FIGURE 13 PROCESS BUS #2 DATAFLOW DIAGRAM

Station Bus Data Flow Diagram

Figure 14 shows the data flow diagram for the station bus. This data flow diagram provided a graphic representation of the data flow tables presented in the previous section. The diagram showed all the GOOSE data flows for the station bus to and from the devices and the device's relationship to the substation equipment. The diagram was intended to provide an understanding of the purpose of the data flow and provided information to link it to the data flow spreadsheet.

The only function using the station bus was the reactor and capacitor bank control. This was the same equipment and control philosophy as was currently used in the project team's systems with the added flexibility of GOOSE messaging. The V3M1 published the required analog measurement data to the V3M4 controllers using GOOSE messaging. GOOSE messaging was also used to exchange information for the bank protection equipment which included the V3M2 protection relays and the V3M4 controllers.

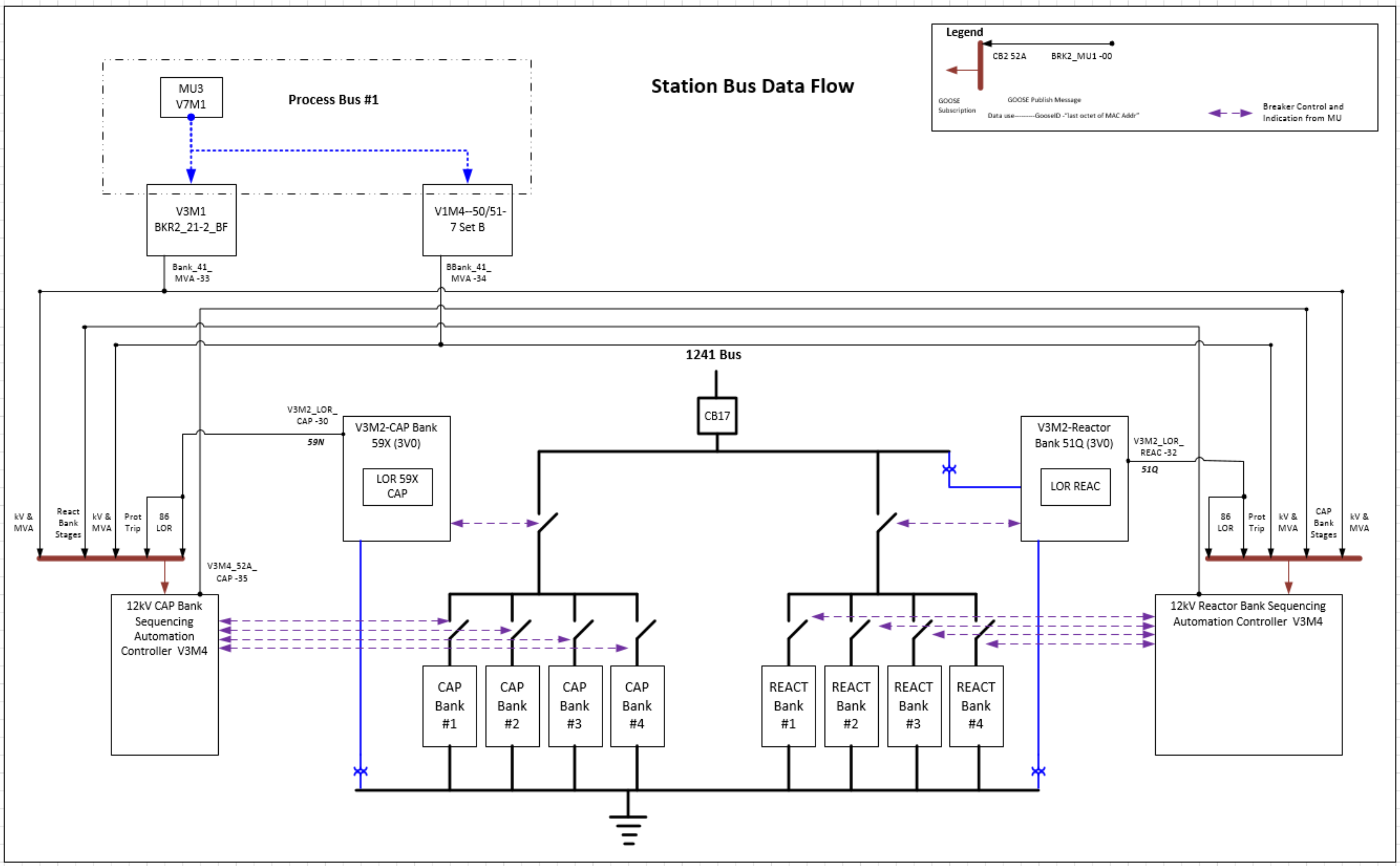


FIGURE 14 STATION BUS DATAFLOW DIAGRAM

Phase One Initial System Integration and Configuration

Throughout this project, a product code was assigned to each product. These codes were used to obfuscate the manufacturer identity and model numbers of the products utilized in the test system. This code was described in Appendix H.

This section covers the integration of the test system components. At this point in the process, Vendor V1's equipment had just arrived and was not included in the initial system check out. The goal of the first phase of the testing was to determine if the equipment would support the critical GOOSE and SV operations.

Vendor V2 Equipment

Vendor V2 sent two engineers to provide support during the three day testing exercise. In summary, the vendor's representatives were not able to get their protection relays to subscribe to any of the four vendor merging units: Vendors V1, V3, V6, or V7. The following summarizes the integration and results with the V2M1 relay:

- This protection relay successfully published and subscribed to the V2M6 I/O merging unit MU8B_CB17_V2M6. The breaker simulator was successfully tripped and closed.
- This protection relay successfully published and subscribed to the V2M5 merging unit MU5_CB10_V2M5. The breaker simulator was successfully tripped and closed.
    - This manufacturer's equipment attempted to subscribe to a SV stream using their V2M1 protection relay from their V2M5 merging unit's SV stream, but was not successful. Many different configuration changes and system reconfigurations were done in order to attempt to solve the problem. The following summarizes these attempts:
    - Validate that the V2M5 was synchronized to the PTP GPS Clock, which was confirmed. Change the IRIG-B time input into the V2M1 protection relay from IEEE 1588 PTP to a direct 1PPS signal and validate it was time synchronized. This did not make a difference.
    - The vendor used their SV sniffing tool to determine that the V2M5 was publishing a validate stream. No problems were detected.
    - The vendor suggested that the AB and CD network connections could not be on the same subnet IP address. Both were required to be connected to the process bus because this vendor only supports SV from one port and GOOSE from the other. This configuration was changed without resolution.
    - The network sniffing tool was using to determine that the correct SV control block parameters were being transmitted. The correct control block was being sent but the time sync indication from the V2M5 indicated it was in local time, not using an external source.
    - This vendor made many configuration changes to include multicast MAC addresses, AppIDs, datasets, etc. This did not make a difference.
    - This vendor checked to verify that the license on the device supported the IEC 61850 functions. They found the licenses were correct.

- This vendor requested a direct fiber point to point connection with their V2M5 merging unit to eliminate the existing process bus network. This was done with no change noted.

- The V3M1 could not subscribe to the V2M5 merging unit either. The error on the V3M1 was a time sync error. All other merging units presented a value of 2, meaning global time traceable synchronization in the “smpSynch” field but the V2M5 had a value of 1, meaning local time. A subscriber will not use the stream if it has lost global time but it was confirmed that the V2M5 was synchronized to the PTP clock. The problem may be in IEC 61850 edition implementation. IEC 61850-9-2 Edition 1 specified the “smpSynch” as a Boolean value with “0” meaning no time sync and “1” meaning good time sync. IEC 61850-9-2 Edition 2 specified the “smpSynch” as:
    - 0= SV are not synchronized by an external clock signal.
    - 1= SV are synchronized by a clock signal from an unspecified local area clock.
    - 2= SV are synchronized by a global area clock signal (time traceable).
    - 5 to 254= SV are synchronized by a clock signal from a local area clock identified by this value.
    - 3;4;255= Reserved values – Do not use.
- The IEC 61850-9-2LE document was based on edition 1 but most vendors have mixed edition implementations focusing only on the dataset, sample rate, and naming conventions from the LE document. The network sniffing tool SV decoder was using the edition 2 definitions of the “smpSynch” but it was postulated that the V2M5 may be using the edition 1 definition. This was thought to be why the V3M1 would not use the V2M5 SV stream, if it used the edition 2 definition (that the time synchronization was bad when in reality it was good).
    - The vendor attempted to subscribe using their V2M1 protection relay to the other vendor merging unit streams but each failed like the V2M5.
- The V6M1 CID file would import into the this vendor’s configuration software but when the IEC 61850 component of the software was opened and then closed, it wrote over the MAC address, AppIDs for both the GOOSE and SV control blocks. The software reset the values to the first allowable values. This vendor agreed to investigate this behavior.
- This vendor’s merging units MU5 and MU11 were configured and tested for proper SV publishing. Both had the local time sync indication in the stream.

This vendor had a system working at their corporate office, which they were using to compare settings and system configuration to the project’s test system setup. It was based on this working system that this vendor requested the various changes to the project’s test system in an attempt to get their equipment to work with the V2M5 SV stream. None of the changes worked, nor did the vendor’s equipment work on the other vendor’s merging units that were working in the system.

The plan was to ship the V2M5 and V2M1 IEDs back to the factory so that the vendor could work on them at their factory. Their current working system was being used for another customer and could not be shipped at the time. This vendor’s field engineers planned to return to implement their findings.

Vendor V3 Equipment

The team tested the V3M3 merging units and the V3M1 protection relay. The following summarizes the results of the integration.

- The team configured the V3M3 MU12_HIZ_V3M3 merging unit and determined that it was publishing the proper GOOSE and SV messages.
- This relay was able to successfully subscribe to the SV stream using the V3M1 relay's WY metering points. Preliminary checks using the test set software, V3M3 and V3M1 metering functions showed that the streams were being transmitted and received correctly with no errors.
- These devices controlled and received feedback using GOOSE to and from the V3M3 MU12_HIZ_V3M3 merging unit and V3M3 with a test bit. (The MU12_HIZ_V3M3 merging unit did not have a connected breaker simulator in the test system).
- A second SV stream in the V3M3 using the XZ metering points from the V2M5 MU5 merging unit was configured. This first produced a configuration revision mismatch error which was corrected and then produced a time sync error which was covered in the Vendor V2 section.
- Configuration of the MU8A_CB17_V6M1 merging unit was attempted, but a CID file schema error in the V3M6 software appeared when attempts to load the new CID file, into the relay, were made. The V6M1 file loaded correctly in the V3M6 software and allowed the data object to map into the V3M3 but the file would not load into the device. The investigation was covered in the Vendor V6 section, and a successful download was achieved.
- Configuration of the V7M1 MU9_10_CB11_14_V7M1 merging unit SV stream into the XZ metering points was attempted but it was unsuccessful.
- The V3M3 MU12_HIZ_V3M3 merging unit stream was then removed from the WY metering points and mapped only the V7M1 MU9_10_CB11_14_V7M1 merging unit SV stream. This worked with no problems.
- The V7M1 MU9_10_CB11_14_V7M1 merging unit stream was then removed from the WY metering points and mapped only the MU8A_CB17_V7M1 merging unit SV stream. This change worked with no problems and avoided the V7M1 CID file problem with the V3M6 software by using the V3M7 software. The V3M7 SV setting overrode the V3M6 settings and did not require the import of an IEC 61850 information exchange file.
- An attempt to add a second stream using the V3M3 MU12_HIZ_V3M3 merging unit to the XZ metering points was made but this did not work.
- Vendor V3 merging units MU12, MU6 and MU2 were configured and tested for proper SV and GOOSE publishing.

This problem was reported to the vendor.

Vendor V6 Equipment

There was only one V6M1 merging unit in the test system. The V6M1 did not have any control and was only used as a SV merging unit. The following observations were from the integration of the V6M1:

- The V6M1 was configured and it was determined that the correct GOOSE and SV published messages were being sent out onto the process bus.
- The V6M2 configuration software did not export an IEC 61850 ICD or CID file. The manufacturer provided a XML template, which required manual input of the proper information from the configuration files into a XML file. Problems arose with both the V2M8 and V3M6 software when using this file. These problems prevented testing of the GOOSE and SV message subscriptions. After a number of attempts to correct the file it was determined that the template provided had too many problems to fix. The V7M1's working CID file was then modified to match the V6M1. This effort succeeded and the file was successful with other third party device configuration tools.
- The V3M1 successfully subscribed to the 8A_CB17_V6M1 merging unit by using the V3M7 vs. the V3M6 software which removed the CID file problem.
- The V6M1 time source was changed to PTP from the IRIG-B connection. This change freed up the fiber connected IRIG-B that provided time to the V3M2 capacitor and reactor bank relays. The fiber converter was determined to be unable to drive all five units.
- After the time source change MU8A_CB_V6M1 was once again subscribed to the V3M3 relay to make sure there was still good time sync for the stream. Everything worked fine.

Vendor V7 Equipment

The V7M1 merging units were received just as the testing started but they were still installed and prepared in time for this integration effort. The following were observations from the effort:

- The first unit that was powered-up would not publish any GOOSE or SV messages. It was then configured as the MU3_4_CB7_11_V7M1 merging unit. The equipment successfully took the configuration and all diagnostics and logs showed no errors but the unit was still not publishing any messages. It was determined that the unit did have the latest firmware. The manufacturer was contacted, they sent the same firmware, and suggested that the unit be re-flashed. The manufacturer's suggestions were deployed but the results were unchanged, leaving the equipment in the same state.
- The second unit was then powered-up. This unit did publish GOOSE and SV streams. It was then reconfigured to match the MU9_10_CB11_14_V7M1 settings in steps, checking after each download that the unit was still publishing. Eventually the unit was fully configured with the exception of the Ethernet ports IP addresses. These addresses were left at the default values.
- It was determined that the SV stream was correct and the V3M1 protection relay was able to subscribe to it.
- Given that the MU9_10_CB11_14_V7M1 unit worked using the default IP addresses the configuration of the MU3_4_CB7_11_V7M1 merging unit was changed back to the default IP addresses. The unit then successfully published GOOSE and SV messages.
- If the SVid name was put in as per the project documents, but the stream could not be read without errors. Once the name was shorten by four characters, the streams worked properly with the subscribers. All four V7M1 unit SVid names were changed.
- All four of Vendor V7 merging units MU3, MU4, MU9 and MU10 were configured and tested successfully for proper SV publishing.

Test Equipment

The team was able to configure the relay test sets to use the IRIG-B interface in order to run time synchronized tests. The team was able to run a COMTRADE file play back through the relay test sets and capture the secondary injection results. When compared, these results matched the expected results and it was determined that the test system was working properly.

Network Equipment

The test system network equipment and configuration performance exceeded the requirements for this test system. During the initial testing, up to nine SV streams ran over a single process bus along with IEEE-1588 PTP, 10 active GOOSE messages, and configuration access. There were no performance issues noted and no delay in configuration and monitoring access over the network.

Phase Two System Integration and Testing Results

This section covered the second phase integration and initial testing. The phase one testing identified problems with V2M1, V2M2, V3M3, and V2M4 relays when subscribing to any merging unit including the V2M5. It was also determined that the V2M5 SV stream could not be subscribed to by the V3M1 even though it could subscribe to the remaining three models of merging units. In order to perform this testing a number of devices were removed from their specified network interface. For this testing these devices were returned back to their assigned networks.

There was also a problem with the V3M3 not subscribing to a second SV stream.

Vendor V3 Equipment

The following observations on this vendor's equipment:

- Concerning the problem with the second V3M1 stream not working, all the files and configurations were gathered and sent to the manufacturer. The manufacturer followed-up by telephone and the situation was discussed. The manufacturer did not see any reason for the lack of errors and the relay still indicated that it was subscribed to the stream. The following was determined:
    - The V3M1 was configured for both PTP and IRIG-B to allow for consideration of redundancy options. It was assumed that the PTP would be the dominant source over IRIG-B but what the V3M1 always defaults to the IRIG-B source. The manufacturer suggested that the IRIG-B was disconnected and the relay was reconfigured to use PTP. Upon completion, the second SV stream started working. The manufacturer later informed the team that there was an additional IRIG-B setting to configure. Under the global settings, time and date management, there was an IRIG-B setting. When this was set to “none” the V3M1, for the purposes of the SV timing, considered itself to be under “local” time even though it had an IRIG-B input. Setting this to the “C37.118” setting changed its use of the IRIG-B signal to global time (C37.118 is the standard for Synchro phasor Measurements for Power Systems). The manufacturer used this to tie into the SV subscriptions for time synchronization. Verification showed that the V3M1 time source switched to IRIG-B. The status of the metering values for the first and second SV streams was then confirmed. Once changed to “C37.118” and re-connected to the IRIG-B signal, both SV subscriptions performed successfully with two streams using both PTP and IRIG-B.
    - It was identified that V3M1 did not have error indication when a stream was dropped. Only the “COM SV” command showed the status of the streams, but it required manual checking.

- This unit had a time differential field which was unused if locally synced but if global sync was in place it indicated a time value. Global sync was required when using more than one SV stream.

- The V3M1 sent both 3-phase voltage and MVA metering values to both V3M4s. It required both the voltage from MU1 and the current from MU3 in order to calculate these metering values. Since MU1 was not operating yet, to test this GOOSE interface MU3's voltage was temporarily directed to VY and it's current to IX. MU3 would normally be mapped to VZ and IX.
- Using the test set injection into MU3 and the metering calculation in the V3M1 it was determined that the M3V4s were receiving the correct voltage and MVA values via GOOSE.
- Because of Vendor V2's strict requirement to have the AppID set to 4000 for all SV messages, V3M1 subscriptions were re-tested and no problems were identified.

Vendor V7 Equipment

The following changes were made to the V7M1 units:

- MU9_MU10 was temporarily placed on process bus #1 for testing. This relocation required a change to the PTP domain to one from two. The PTP setting was then changed back to two and the fiber connection moved to process bus #2. Checks were then performed to make sure the PTP was synced up properly.

Vendor V6 Equipment

The following changes were made to the V6M1:

- V6M1 was temporarily placed on process bus #1 for testing, which required a change to the PTP domain to one from two. The PTP setting was then changed back to two and the fiber connection moved to process bus #2. Checks were then performed to make sure the PTP was synced up properly.

Capacitor and Reactor Bank Control System

The capacitor and reactor bank control system were each consisted of a V3M2 protection relay and a V3M4 automation controller. The concept was for the V3M2 to provide protection and the V3M4 to provide the logic that controls the insertion and removal of the capacitor or reactor bank stages. The V3M4 received the bus voltage and MVA metering data from both the V3M1-21-2 and V1M4-50/51-7 Set B protection relays. During this phase of the testing Vendor V1 relays were not available but V3M1 was running with two streams. The V3M3 units were fully configured and tested in the lab using one of the data streams from the V3M1. The test used both the secondary injection test sets to inject current and voltage into the merging units subscribed to by the V3M1. These values, through logic calculations, were then passed to the V3M4 using GOOSE messaging.

The team found and corrected a number of problems with the logic, and in the end was able to demonstrate that changes made at the test set correctly controlled the proper number of capacitor and reactor banks.

Vendor V1 Equipment

The remaining Vendor V1 equipment arrived and the team worked on assembly and installation into the racks. This work was in preparation for Vendor V1's scheduled site visit.

- The installation for the V1M5s was completed. While working on the Vendor V2 solution it was identified that V1M5 was also streaming on process bus #1. Its AppID was 4000 and MAC address was 00 which was the proper configuration for MU1. A fifth stream was added to the V2M3 87T41 but it would not subscribe to the stream. Using the manufacturer's SV browser it was determined that the stream was set for 50 hertz which caused the stream to be dropped.
- The SymSync field indicated a value of 1 "local" with an IRIG-B signal on the time signal fiber input. The unit would not accept a 1PPS signal without the unit configuration tools on-site. This would be accomplished with Vendor V1's engineers.

Vendor V2 Equipment

This manufacturer found a working solution and returned the shipped equipment back to the lab. The manufacturer also sent an engineering team to report on the problems found from their team's investigation and what needed to be changed in order to get their equipment running in the test system. The following summarizes the meeting and re-test results:

- The manufacturer found two problems, the first was that the V2M1, V2M2, V2M3, and V2M4 protection relays strictly adhered to the LE document stating that only an AppID of 4000 could be used. The device rejected any SV stream that did not have an AppID of 4000. This was the only setting that was not changed during the manufacturer's first three day on-site testing.
- The V2M1, V2M2, V2M3, and V2M4 relays will accept both IRIG-B (hardwired input) and 1PPS (fiber input). The device however, required 1PPS when SV stream synchronization was required per the LE document. This was attempted during the manufacturer's first visit but since the AppID was not set to 4000, the SV subscriptions did not work.
- Once the AppID for the V2M5 MU11 merging units and both of the V7M1 MU3 and MU4 were changed to 4000, SV subscriptions were successful. To confirm a different relay, V2M3 87T41 Set A, was used to perform the tests. This relay successfully subscribed to all three streams with no errors. Injection of currents and voltages into all three merging units and showed that the metering functions on the V2M3 87T41 Set A were accurately indicating the correct metering values.

Phase three system integration and testing results

The primary purpose for this testing session was to work with the Vendor V1 engineer to get the Vendor V1 equipment and software working within the test system. The following summarized the findings:

- MU1 V1M5 was configured per the data flow diagram. The following items were identified:
  - The V1M5 did not support 1PPS on the time source fiber input, only IRIG-B. It did not support IEEE 1588 either, so the IRIG-B fiber signal was used.
  - No configuration parameter was available to tell the MU to calculate the In and Vn values when there was no connection available. The LE document states this and adds a "derived" bit to the quality for the value. This parameter existed on all the other merging units and they all reported "derived" on the In and Vn. The V1M5 did not.
  - With the unit's web page interface, it was seen that the unit was successfully time syncing to the IRIG-B signal.

- o These next two points indicate that the unit had fully switched from publishing an SV LE message to an edition 2 SV message.
  - ▪ The network sniffer could not parse out the SV message using the LE decoder. It was suspected that when the unit was configured for edition 2, it used an edition 2 message buffer not an edition 1 based LE message buffer. This put additional fields in the message that the network sniffer could not decode.
  - ▪ The "SymSync" field was no longer BOOLEAN as the fault published message indicated. It published an edition 2 value of "2" global.
- o Attempts to subscribe to the MU1 stream from the V3M1 relay were unsuccessful. The PDU length error indicated by the V3M1 was the same error type shown in the network traffic capture, which indicated that the SV message had the addition edition 2 fields. The additional edition 2 fields could not be processed by the V3M1 relay.

- The V2M2 87L set A relay was then subscribed to the MU1 stream and had no problems. The SV stream values and synchronization were successful.

The V1M5 merging unit, unlike all the others, completely changed its mode of operation when the unit was configured as edition 1 or edition 2. For full SV LE compatibility one must configure the unit as edition 1. As configured in edition 2 the MU published edition 2 message buffer with the additional fields that were non-LE. It also changed how it published the SymSync field from the BOOLEAN edition 1 definition to the INT edition 2 definitions. The current overwhelming system support was for edition 2 having vendors offer edition 2 GOOSE and files while still using SV LE based on edition 1. Having the V1M5 being one or the other presented a problem when integrating it into the system. The following captures some of the high level problems:

- If one left the V1M5 at edition 2:
  - o The V3M1 would not subscribe to the V1M5 SV stream. This was due to the way that V3M1 examined the SV message and finding an additional field that it cannot understand. The V3M1 dropped the stream at this point.
  - o The V2M1, V2M2, V2M3, and V2M4 relays would subscribe to the V1M5 SV stream. They reacted differently by not analyzing the entire message and accepting it even though it had an additional field.
  - o The Vendor V1 relays would subscribe to the V1M5.
  - o All IEC 61850 files were in edition 2 format and transferred between the various vendor tools. Both V2M8 and V1M9 tools only accepted the edition files for eth project edition in use at the time, which was edition 2.
- If one changed the V1M5 MU back to edition 1:
  - o The IEC 61850 file format for the V1M5 MU would need to be modified to look like an edition 2 file in order to use it in both the V2M8 and V1M9 configuration tools.
  - o The V3M1 would still not be able to subscribe to the SV stream. By changing the MU configuration to edition 1 the SymSync field would change to BOOLEAN which would publish a true "1" value for good time synchronization per the edition 1 and LE documents. The V3M1 only interpreted this field as edition 2, which meant that the V3M1 thought that the MU was only locally time synchronized with no global synchronization. With this indication it would not synchronize with multiple SV

streams. This situation would be similar to the V2M5 which published a SymSync in edition 1. The V3M1 would not be able to subscribe to either of these merging units.

With both cases still resulting in no communications with the V3M3 and both allowing for good SV communications with both the Vendor V1 and Vendor V2 relays, the best course of action was to keep the project in edition 2. A solution must be found to test the V3M1 without using the V1M5 or V2M5 merging units.

V1M5 PDU Length Problem

Out of the box, V1M5 published SV messages which could be subscribed to by the V2M1, V2M2, V2M3, V2M4, and V3M1 relays. The SV messages were found to be configured as 50 Hz and would not work in the relays but a good SV subscription was established. The default factory settings were IEC 61850-9-2 edition 1, 50 Hz. It was also noted that the "SymSync" field in the SV message buffer followed the ed1 BOOLEAN definition.

Figure 15 shows a network capture of the SV message from the V1M5 without any configuration changes. The team was able to successfully subscribe to this SV stream less the 50 Hz problem.

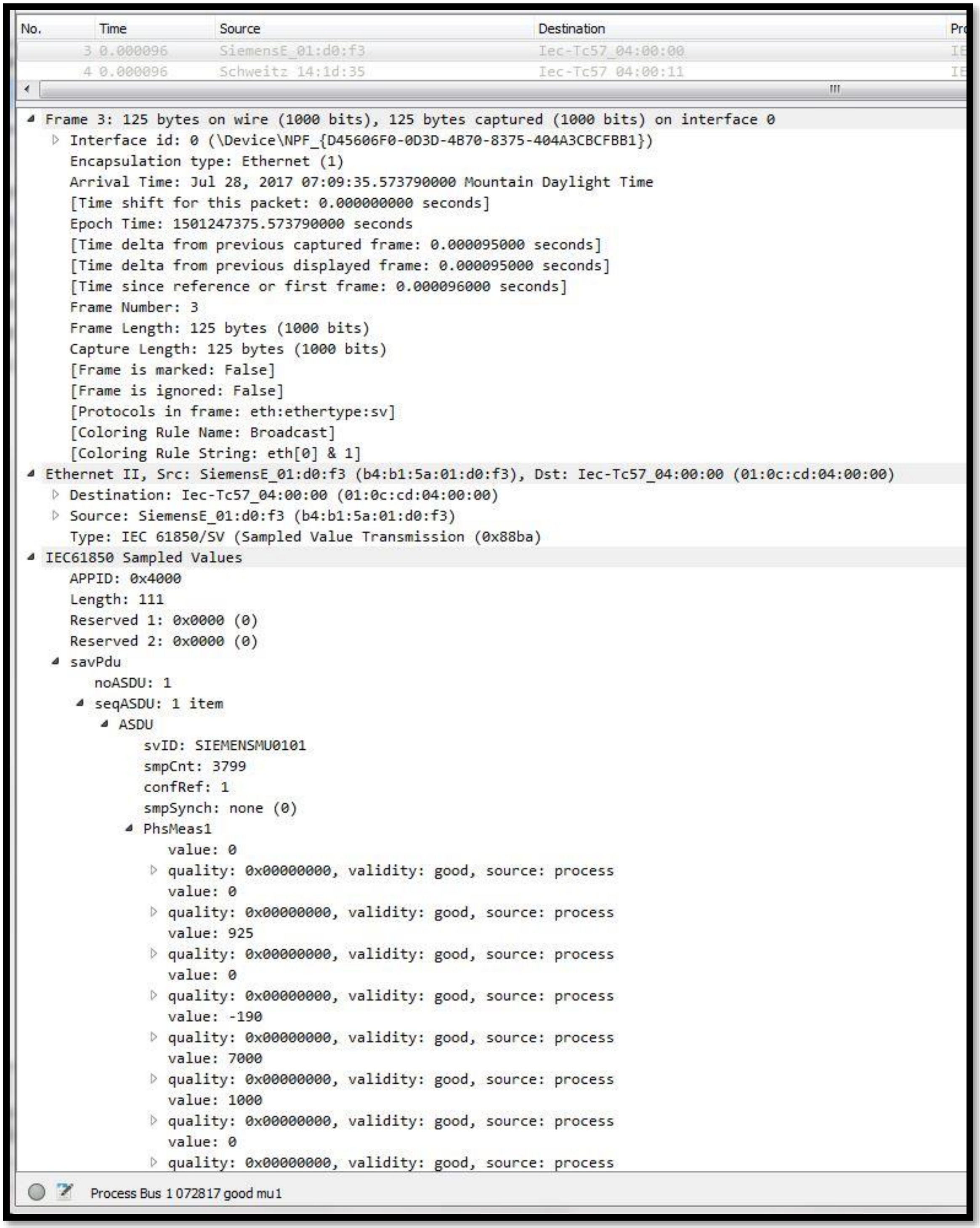


FIGURE 15 V1M5 OUT OF THE BOX SV MESSAGE

After the V1M5 was configured and set for IEC 61850 Edition 2, the behavior changed. The network analyzer picked up an error on the PDU length and the "SymSync" field started behaving like the edition 2 definitions which was expected (see Figure 16).

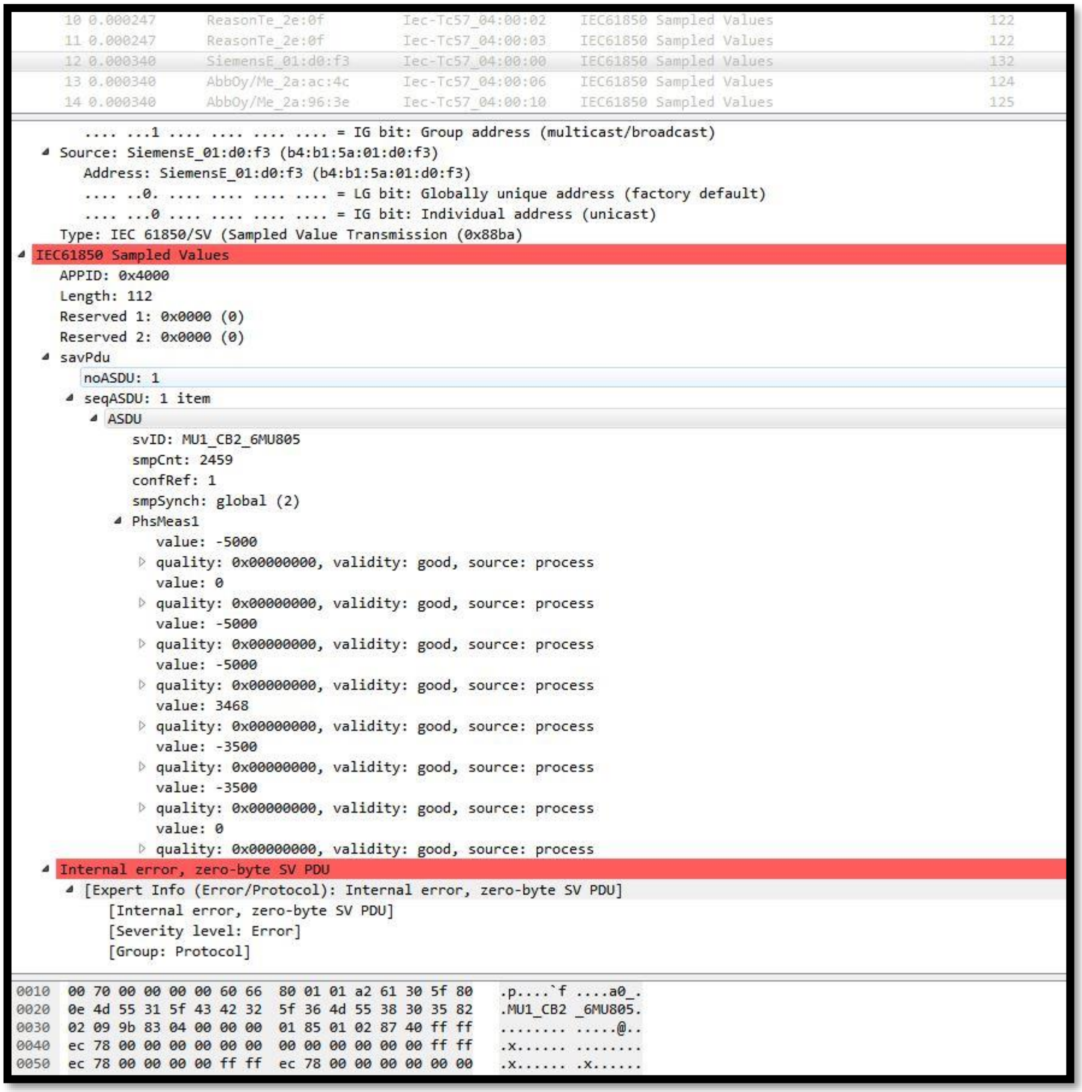


FIGURE 16 V1M5 SV MESSAGE AFTER CONFIGURATION

The PDU length error was unexpected. The V3M1 relay also detected this problem and would no longer subscribe to the SV stream. Figure 17 showed that it too found a PDU length problem.

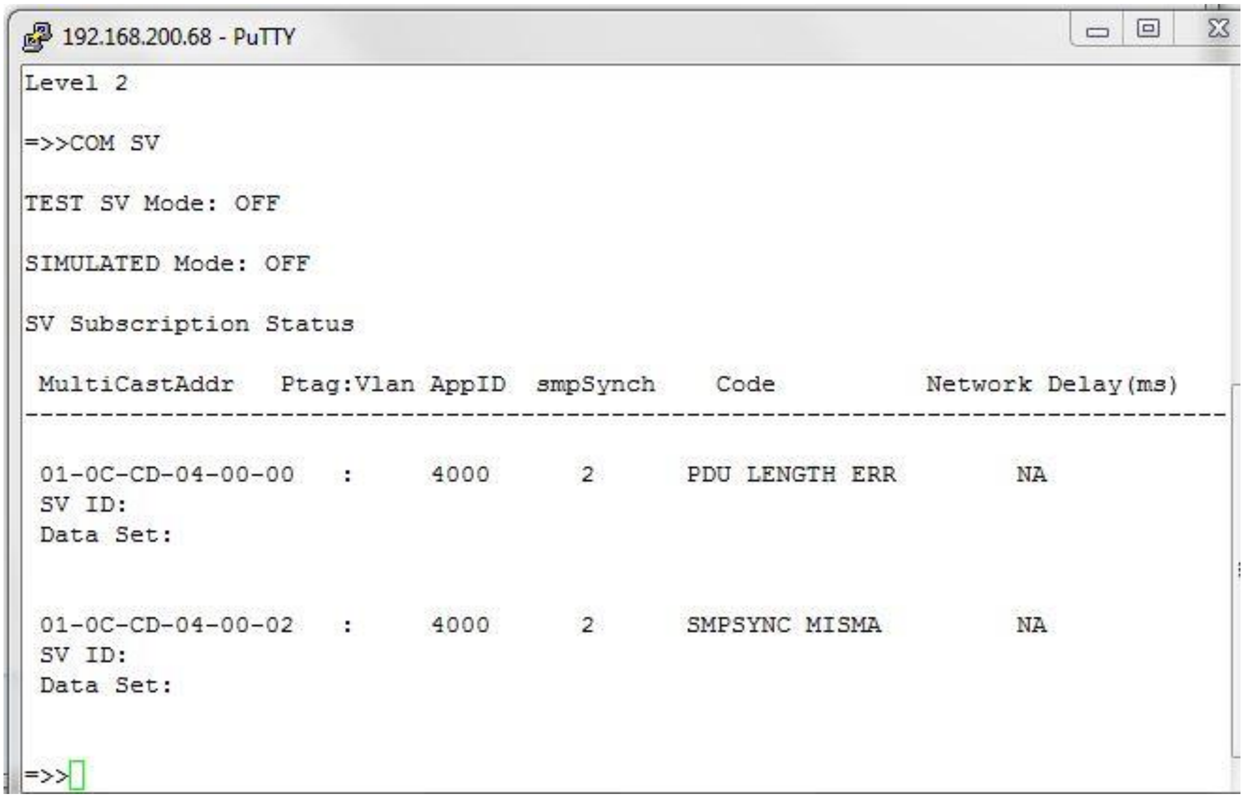


FIGURE 17 V3M1 RELAY ERROR ON THE V1M5 SV STREAM

Explanations were needed for why the V1M5 SV message and behavior differed between setting the unit up as an edition 1 device vs. an edition 2 device. An explanation on why there was a PDU Length error after configuring the merging unit to edition 2 vs. the default configuration SV message was requested.

File Import Problem into V1M8 Tool

The next set of testing was to have Vendor V1 relays subscribe to the other vendor merging units. The following documented the results:

- The V7M1 merging unit was configured into the V1M8 configuration tool. The IEC 61850 CID file generated by the V7M1 tool imported correctly into the V1M8 tool. The V7M1 SV streams were successfully subscribed from both MU3 and MU4 to a Vendor V1 relay.
- The team attempted to import the CID file for the V2M5 MU but ran into an import error showing some missing information. The V1M9 software wanted to see the attributes for "SmpRate," "RigVal" and "ClipVal" from the CID file. If these fields were not in the file, the V1M8 software filled in a zero value and created an error. Once this missing setting error was created, the V1M8 file could not be saved and there was no way to manually enter the require data fields.

The same problem was found when attempting to add the V3M3 and V6M1 merging unit CID files. Vendor V1relays must be able to subscribe to SV and GOOSE messages from the V2M5, V3M3, and V6M1 merging units to complete our planned protection testing schemes. Currently Vendor V1 relays can only subscribe to the V7M1 and V1M5 merging units.

Figure 18 is a view of the V1M8 software used to program the Vendor V2 SVs. The SMV-ID showed MU13 was a V1M5 merging unit and the MU5 was a V2M5 merging unit. When importing, MU5 errors were received with the zeroed data fields.

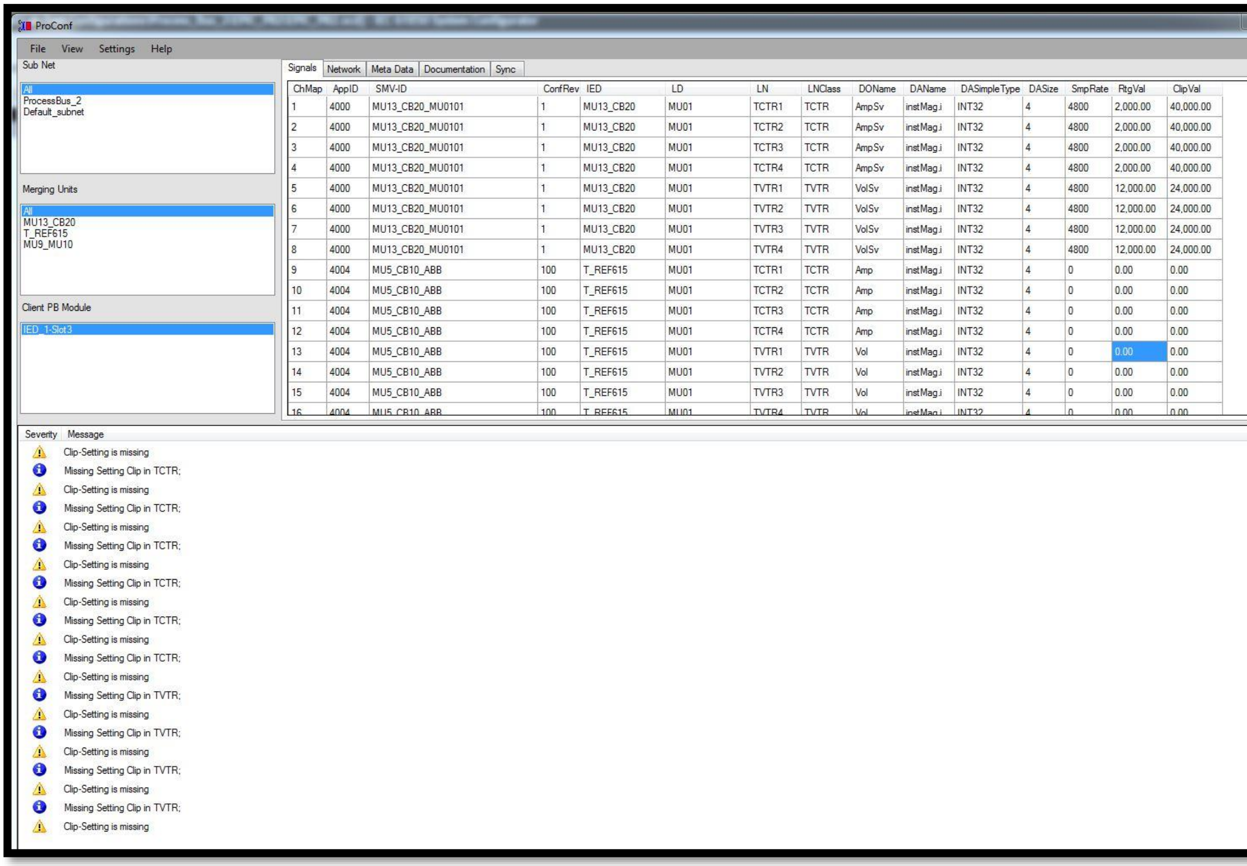


FIGURE 18 V1M8 FILE IMPORT ERROR

The data attribute “smpRate” found in the Measured Value (MV) common data class was an optional field in the standard. The standard also defined the value of the “smpRate” as the number of samples per nominal period. Only in the case of direct current systems was the value represented as the number of samples per second. The V1M8 software required this optional field and converted the value to a sample per second value. The software was also looking for the system frequency value, “HzRtg” within the TVTR and TCTR logical nodes which was also an optional field in the CID file.

The “RtgVal” could not be directly found in the standard but could only be associated with the “VRtg” data object found in the TVTR Voltage transformer logical node. This data object provided the rated voltage and was also an optional settings data object in the standard. The program looked at “VRtg” Data object found in the TCTR voltage transformer logical node. This data object provided the rated current and was also an optional settings data object in the standard.

The “ClipVal” could not be directly found in the standard but could only be associated with “maxVal” data attribute found in the ASG analogue setting common data case which was assigned to the “ARtg” data object in both the TVTR and TCTR logical nodes. This field, too, was optional. Figure 19 showed the error generated after importing V2M5 to a working file using both V1M5 and V7M1.

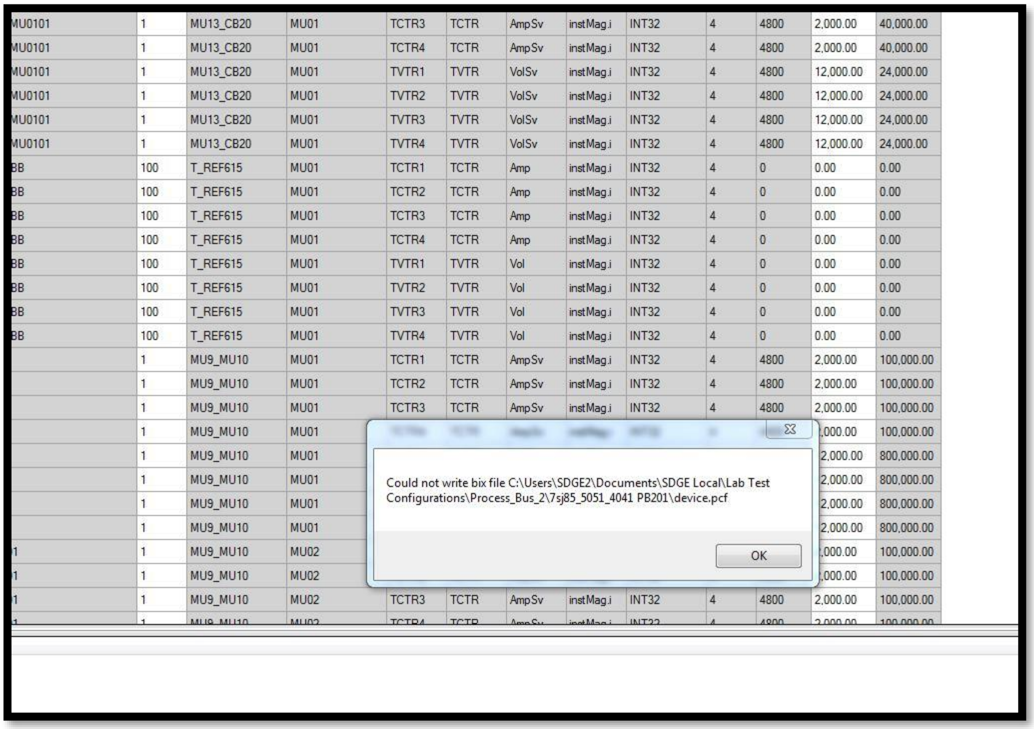


FIGURE 19 V1M8 SAVE ERROR

Figure 20 showed that the V7M1 merging unit provided these optional IEC 61850 data fields.

MU3_MU4 • Data Model • MU01 • U01ATVTR1

LN U01ATVTR1 Voltage transformer

Name		Description	Value
DO Beh		Behaviour	
DO VolSv		Voltage (sampled value)	
DO VRtg		Rated voltage	12000 V
DA setMag	[SP]	The value of an analogue setting or set point	12000 V
DA units	[CF]	Units of the attribute(s) representing the value of the data	V
DA minVal	[CF]	Defines together with maxVal the setting range for ctlVal (CDC INC, BSC, ISC), setVal (CDC IN...	1 V
DA maxVal	[CF]	Defines together with minVal the setting range for ctlVal (CDC INC, BSC, ISC), setVal (CDC IN...	1000000 V
DA stepSize	[CF]	Defines the step between individual values that ctlVal (CDC INC, APC, BAC), setVal (CDC ING)...	1 V
DO HzRtg		Rated frequency	60 Hz
DA setMag	[SP]	The value of an analogue setting or set point	60 Hz
DA units	[CF]	Units of the attribute(s) representing the value of the data	Hz
DA minVal	[CF]	Defines together with maxVal the setting range for ctlVal (CDC INC, BSC, ISC), setVal (CDC IN...	50 Hz
DA maxVal	[CF]	Defines together with minVal the setting range for ctlVal (CDC INC, BSC, ISC), setVal (CDC IN...	60 Hz
DA stepSize	[CF]	Defines the step between individual values that ctlVal (CDC INC, APC, BAC), setVal (CDC ING)...	10 Hz
DO Rat		Winding ratio of an instrument transformer/transducer	100
DA setMag	[SP]	The value of an analogue setting or set point	100
DA f	[SP]	Floating point value	100
DA minVal	[CF]	Defines together with maxVal the setting range for ctlVal (CDC INC, BSC, ISC), setVal (CDC IN...	1
DA maxVal	[CF]	Defines together with minVal the setting range for ctlVal (CDC INC, BSC, ISC), setVal (CDC IN...	10000
DA stepSize	[CF]	Defines the step between individual values that ctlVal (CDC INC, APC, BAC), setVal (CDC ING)...	0.1
DO FuFail		TVTR fuse failure	
DA stVal	[ST]	Status value of the data	

FIGURE 20 V7M1 DATA MODEL

Figure 21 showed the V2M5 data model for the TCTR logical node having no optional data fields. The V3M3 and V6M2 merging units also only had the mandatory data fields required by the standard.

REF615_MU7 • Data Model • MU01 • I01ATCTR1

LN I01ATCTR1 Current transformer

Name		Description	Value
DO Mod		Mode	on
DO Beh		Behaviour	on
DO NamPlt		Name plate	
DO Amp		Current of a non-three-phase circuit	
DA instMag	[MX]	Magnitude of the instantaneous value of a measured value	
DA i	[MX]	Integer value	
DA q	[MX]	Quality of the attribute(s) representing the value of the data	
DA sVC	[CF]	Scaled value configuration	
DA scaleFactor	[CF]		0.001
DA offset	[CF]		

FIGURE 21 V2M5 MERGING UNIT DATA MODEL

The V1M8 software tool, which was required to program the Vendor V2 SVs, required that the vendor implement optional IEC 61850 data fields within their merging units. A solution must be found by the vendor to fix this problem.

Time Synchronization to the V1M5

The V1M5 documentation and configuration tools used the terms PPS and IRIG-B interchangeably. The time synchronization configuration only listed IRIG-B but did reference PPS in other locations. It was determined that the unit will only synchronize if IRIG-B was connected to the unit's fiber time source input. The unit would not time synchronize if the output from the GPS clock was 1PPS.

Neutral Current and Voltage Calculation Problem

The Utility Communications Architecture's Implementation Guideline for Digital Interface to Instrument Transformers using IEC 61850-9-2, known as IEC 61850-9-2LE, stated that if the neutral current and/or voltage were not measured the merging unit must calculate these values as a sum of the phase values. The document then required an additional indication in the quality field to show that the values were "derived." This was resolved in Phase Five below.

Phase Four System Integration and Testing Results

The primary purpose for this testing session was to work with the Vendor V2 engineer to get the manufacturer's equipment and software working within the test system. The findings follow.

Denial of Service to V2M1, V2M2, V2M3, V2M4

Discovered issue with intermittent receipt of GOOSE messages by Vendor V2 relays, particularly the V2M3 (87T41A) relay. The team contacted the factory representative with relay front panel screenshots (Figure 22), a network traffic capture, and exported the device settings files in order to troubleshoot the problem.

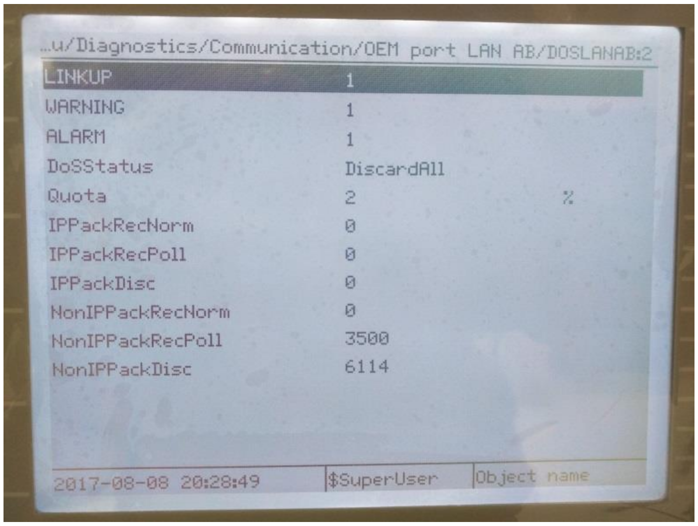


FIGURE 22 V2M3 FRONT PANEL DISPLAY MESSAGE

After contact and discussions with the factory, the intermittent GOOSE message receipt issue was traced to the denial of service (DOS) logic built-in to the relay Ethernet ports. A denial of service situation typically exists when the network traffic exceeds the CPU's ability to process it. The large amount of GOOSE and SV traffic was causing the built-in DOS protection to activate, blocking the receipt of GOOSE messages by the relays.

The DOS issue was corrected by setting up MAC address filtering on the process bus #1 and process bus #2. No further intermittent receipt of GOOSE messages was detected.

V7M2 Analog Data Set Error

Identified V7M2 MU configuration software bug, where one could not import CID file from V3M3 relay. The bug caused all of the available GOOSE datasets to “disappear” from the V7M2 software, rendering them inaccessible.

After contact with the manufacturer, it was determined that the bug was due to the analog GOOSE dataset present in the V3M3 CID. V7M1 MUs could not process CID files which contain analog GOOSE datasets.

```
</DataSet>
<DataSet desc="Transformer Bank 41 MVA data" name="Bank_41_MVA">
  <FCDA ldInst="MET" prefix="MET" lnClass="MMXU" lnInst="1" doName="PhV" daName="phsA.instCVal.mag.f" fc="MX" />
  <FCDA ldInst="MET" prefix="MET" lnClass="MMXU" lnInst="1" doName="PhV" daName="phsA.q" fc="MX" />
  <FCDA ldInst="MET" prefix="MET" lnClass="MMXU" lnInst="1" doName="PhV" daName="phsB.instCVal.mag.f" fc="MX" />
  <FCDA ldInst="MET" prefix="MET" lnClass="MMXU" lnInst="1" doName="PhV" daName="phsB.q" fc="MX" />
  <FCDA ldInst="MET" prefix="MET" lnClass="MMXU" lnInst="1" doName="PhV" daName="phsC.instCVal.mag.f" fc="MX" />
  <FCDA ldInst="MET" prefix="MET" lnClass="MMXU" lnInst="1" doName="PhV" daName="phsC.q" fc="MX" />
  <FCDA ldInst="ANN" prefix="PMV" lnClass="GGIO" lnInst="3" doName="AnIn01" daName="instMag.f" fc="MX" />
  <FCDA ldInst="ANN" prefix="PMV" lnClass="GGIO" lnInst="3" doName="AnIn01" daName="q" fc="MX" />
  <FCDA ldInst="ANN" prefix="PMV" lnClass="GGIO" lnInst="3" doName="AnIn02" daName="instMag.f" fc="MX" />
  <FCDA ldInst="ANN" prefix="PMV" lnClass="GGIO" lnInst="3" doName="AnIn02" daName="q" fc="MX" />
  <FCDA ldInst="ANN" prefix="PMV" lnClass="GGIO" lnInst="3" doName="AnIn03" daName="instMag.f" fc="MX" />
  <FCDA ldInst="ANN" prefix="PMV" lnClass="GGIO" lnInst="3" doName="AnIn03" daName="q" fc="MX" />
```

FIGURE 23 ANALOG DATASET EXAMPLE

Figure 23 is the analog dataset from the V3M3 CID file which the V7M2 software could not import. This was not a “problem” with the CID (this was a valid GOOSE analog dataset) the problem was that the V7M2 software could not import analog GOOSE datasets.

V2M1, V2M2, V2M3, and V2M4 “Fast GOOSE” and Unsubscribing

V2M1, V2M2, V2M3, and V2M4 relay issue with V7M1 MU and its “Fast GOOSE” dataset subscription, which caused issues with the V2M1, V2M2, V2M3, and V2M4 ability to subscribe to other datasets from V7M1.

Removing the “Fast GOOSE” subscription from the V2M1, V2M2, V2M3, and V2M4 relays corrected the issue (see Figure 24).

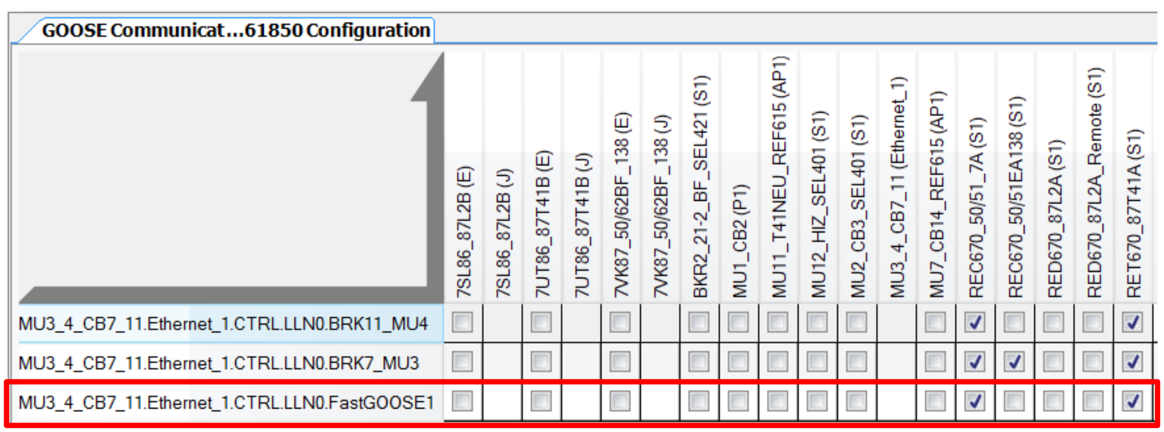


FIGURE 24 V7M1 MU “FAST GOOSE” DATASET

A software bug was identified V2M8 that prevented publishers unsubscribing from some V7M1 MU datasets. After unsubscribing, saving the V2M8 file, and reopening it, all V7M1 datasets were automatically re-subscribed.

The issue was resolved by deleting the V7M1 MU device from the V2M8 software, re-importing the device CID file, and subscribing to only the desired V7M1 GOOSE datasets.

V2M1 Internal Blocking

When a simulated three phase 12 kV bus fault was injected into the V2M1 87-1241A relay, the relay did not respond correctly. While troubleshooting the Vendor V2 relay, it was discovered that all protective functions were receiving an internal blocking signal.

The issue was resolved when one of the MUs affiliated with the V2M1 87-1241A was found to have an incorrect SV AppId value (x4005 instead of x4000). After changing the AppId to x4000, all internal protection blocks were removed.

Miscellaneous Items

- Corrected an issue with duplicate GOOSE dataset MAC addresses for the "MU2_CB3_V3M3" device on the process bus #1 network.
- Found an issue in the GOOSE control block for the V2M1 (5051_EA138) HIZ 138 kV bus differential relay. V2M8 software would overwrite the GOOSE control block information (App ID, MAC address, etc.) with default values, which caused problems with the GOOSE messaging.
    - Issue was deemed to be the result of the internal dataset processing by the software. Corrected issue by deleting and re-creating the GOOSE control block from scratch.
- MU3_CB7: no status/control being displayed on the front of the V2M1 EA138 relay
    - Issue was solved by updating the MU3_CB7 programming to verify that the published GOOSE dataset contained the correct attributes, then re-importing the MU3_CB7 "CID" file into the V2M7 software.
- MU1_CB2: no status received on the V2M1, V2M2, V2M3, and V2M4 relays. Control to MU was active from V2M2 87L2A, but not from V2M1 EA138.
    - Issue was solved during Vendor V1's second site visit as described in Phase Five below.
    - MU13_CB20: receiving breaker status indications, but unable to send controls to MU from V2M1, V2M2, V2M3, and V2M4 relays.
        - Issue was solved by using the same process as described above.

Distance Protection Trips

- At fault location 1, line differential and zone distance trips were issued by Vendor V1 relays, but the distance element protection did not pick-up in V2M1, V2M2, V2M3, and V2M4 relays.
- At fault location 2, Both Vendor V2 and Vendor V1 relays tripped on line differential for a remote three phase fault.
- Vendor V2 and Vendor V1 relays did not trip for a remote SLG fault. The COMTRADE fault waveforms did not look correct upon inspection.

- Both Vendor V2 and Vendor V1 relays tripped on line differential for remote line-line fault.
- V2M2 87L protection for fault locations 1 through 3. Noted that V2M2 distance protection would pick-up for close-in faults, but not remote faults.
    - Distance elements were having issues detecting both phase and ground faults using the simulated COMTRADE files.
    - Issue partially resolved by increasing the local source strength in the RTDS model.
    - Issue with phase distance elements was resolved by adjusting the pickups to values of secondary ohms (the manufacturer had previously indicated that the values should be in primary ohms).
    - Issue with ground distance elements was resolved by disconnecting the neutral current "IN" portion SV DataStream, received from the MU1_CB2_V1M5, from the internal programming in the V2M1, V2M2, V2M3, and V2M4 relays. The V1M5 MU was not transmitting a neutral/residual current value to the V2M1, V2M2, V2M3, and V2M4 relays, hence the neutral/residual current channel was being continuously written to a value of "0." Disconnecting the neutral current "IN" data stream, in the project file and reapplying it to the relays, allowed the V2M1, V2M2, V2M3, and V2M4 relays to internally calculate residual ground currents from the measured phase currents, resulting in correct distance element operation.
- V1M5 MUs were still unable to receive single point controls issued by the various Vendor V2 relays. Contacted both manufacturers, but still waiting on feedback. V1M5 MUs appear to only be controllable by the "SMPPTRC" tripping block (present in the V2M1 87L2A relay, which was the only device configured to control the V1M5 MU).

Phase Five System Integration and Testing Results

The primary purpose for this testing session was to work with the Vendor V1 engineer to resolve the outstanding configuration issues and get this manufacturer's equipment and software working within the test system. The following summarized the findings:

- Single-point TRIP/CLOSE commands sent to V1M5 MUs from the V2M1, V2M2, V3M3, and V2M4 relays were non-functional. Vendor V1 began by troubleshooting the issue with V1M5 MUs not receiving single-point commands correctly. The factory representative spent several hours troubleshooting the V1M5 MUs using a network traffic analyzer and the MUs online diagnostic tools. No errors were found in the relay or MU configurations, the V1M5 MUs simply could not interpret the published datasets
    - Final resolution: issue was related to problems in the headers of the ".ICD" files exported from the V2M8 software. Corrected the issue by manually modifying the ".CID" files exported from the V2M8 software into ".ICD" files, which were imported into the V1M9 software. Previously, ".ICD" files created directly from the V2M8 software had been used to attempt to set up the GOOSE subscriptions.
- The 138 kV breaker failure protection (V1M2 relay) was non-functional.

  Troubleshooting the 138 kV breaker failure protection (V1M2) involved verification that the breaker failure initiated and the breaker status were being received correctly via GOOSE. No issues were found in the existing programming.
    - Final resolution: The factory representative adjusted some of the breaker failure set points and the breaker failure protection was tested and found to work correctly.

Developed Algorithms

Two algorithms were developed during the test design phase. They were the reactive bank automation and the bus lockout function. These algorithms did not previously exist and were developed specifically for this project. These functions were essential to certain protection schemes and while legacy devices may have these functions included, they were easily configured in the test devices due to the versatile nature of IEC 61850 GOOSE messaging.

Capacitor and Reactor Bank

Capacitor and reactor bank VAR control automation was a specific use case that demonstrated the power of GOOSE analog and digital messaging and can eliminate the point-to-point digital signaling currently used in existing distribution substation applications.

This use case included two VAR automation controllers, a transformer overcurrent relay (50/51T), and two reactive bank imbalance protection relays. It was important to note that the automation controllers' options were anticipated to be the same as the current standard part number with the addition of the IEC 61850 GOOSE option. This similarity allowed the majority of the existing logic settings to be reused.

The 50/51T relay provided both of the automation controllers with analog GOOSE messages representing the transformer VAR demand measured at the high side of the terminal. This facilitated addition and subtraction of capacitor/reactor elements to minimize transformer VAR demand, and in turn regulate bus voltage. This scheme was designed to allow up to two 50/51T relays to transmit the GOOSE analog VAR values to the automation controllers. Automatic throw-over logic was included to switch between the sources to prevent relay failure or maintenance from disturbing the automatic reactance control scheme.

One automation controller was dedicated to controlling the capacitor bank stages, while the second was dedicated to the reactor bank. The logic to evaluate VARs outside the threshold was located in the automation controllers.

To maintain the interlock functionality, both automation controllers exchanged their respective stage statuses with each other using station bus GOOSE messages. Thus the capacitor bank automation controller possessed information on the transformer high side VARs as well as the reactor stage statuses. Likewise, the reactor bank automation controller possessed information on the transformer HS VARs as well as the capacitor stage statuses. Both automation controllers utilized this information to decide when to open and close stages while ensuring that the two banks would not "fight each other". This simple scheme inhibited the capacitor bank logic until all of the reactor bank "step" switches were open, and did the same for the reactor bank logic.

Remote monitoring and control of the banks by SCADA could be done utilizing the same station bus connection, eliminating the existing discrete status and control wiring to the SCADA RTU. GOOSE messaging also provided bank unbalance and feeder protection trips to the automation controllers so as to trip all step-switches open and lockout operation for maintenance troubleshooting.

A numerical relay, with GOOSE messaging, was included which replaced the existing capacitor bank electromechanical voltage unbalance relay. This relay implemented a software lockout scheme as opposed to the electromechanical lockout in the standard design. A second numerical relay performed the equivalent unbalance protection function for the reactor bank using a negative sequence overcurrent element. When either relay detected an imbalance condition, it latched a lockout in the relay. This condition was continuously sent by GOOSE to the associated bank automation controller until the lockout was reset. Upon receipt of a GOOSE status that the lockout asserted, the associated automation controller tripped all four stages and the main breaker and blocked closing of until the lockout condition was cleared. A programmed “Lockout Reset” pushbutton on each bank imbalance protection relay cleared the lockout condition.

Bus and Transformer “Virtual” Lockout Relays

These lockout relays programmed in the test system were designed to reproduce the functions of a traditional hardwired bus lockout relay scheme. In a traditional hardwired lockout relay scheme, copper wiring was used to transmit trip and block close signals from a centralized electromechanical lockout to the breakers associated with a particular zone of protection. Commercially available lockout relays provided the flexibility to trip and block close multiple breaker units, initiated by one or several protective relay trips. To emulate lockout relay functions in the test system, a virtual lockout-relaying scheme was implemented using latching variables, close blocking logic and GOOSE messaging in the test system protection relays. Other than the reactive bank lockout functions described above, three virtual lockout relays were simulated in the test system:

- 138 kV bus differential lockout (86-EA138)
- 138/12 kV transformer differential lockout (86-T41A)
- 12 kV bus differential lockout (86-1241A)

The development of the virtual lockout relays for the test system involved three main steps: selecting protective devices to house each virtual lockout relay, programming the virtual lockout relay schemes, and establishing GOOSE subscriptions to implement trip and block close functionality.

- **Protective device selection**
  Three protective devices were selected, one to house each of the virtual lockout relays described above. All virtual lockout logic was implemented using V2M3 and V2M4 relays. These relays were selected to house the virtual lockout relay schemes because these devices were the earliest available for test system development. To simplify the scheme, pushbutton close commands were programmed only in the relays designed to house the virtual lockout relay schemes.

    - The V2M4 50/51 EA138 relay was selected to house the 138 kV bus differential virtual lockout relay 86-EA138. This relay provided close pushbutton functionality for all 138 kV circuit breakers, as well as a virtual lockout relay reset pushbutton.

    - The V2M3 87T41A relay was selected to house the 138/12 kV transformer differential virtual lockout relay 86-T41A. This relay provided close pushbutton functionality only for its 12 kV low-side main breaker, as well as a virtual lockout relay reset pushbutton.

    - The V2M3-1241A relay was selected to house the 12 kV bus differential virtual lockout relay 86-1241A. This relay provided close pushbutton functionality for all 12 kV circuit breakers, as well as a virtual lockout relay reset pushbutton.

Virtual Lockout Relay Programming

Each virtual lockout followed a similar programming approach. A set of trip initiate conditions for each virtual lockout were used to control a latch variable within the relays. An example of the lockout logic for the V2M1 50/51 EA138 relay was included in Figure 25 below. For this example, the lockout trip conditions resulted from the following:

- Assertion of any high-impedance bus differential protection condition
- Assertion of a phase low-impedance bus differential protection condition
- Assertion of a ground low-impedance bus differential protection condition

These protection trips controlled a lockout latch variable, resettable only by front panel pushbutton.

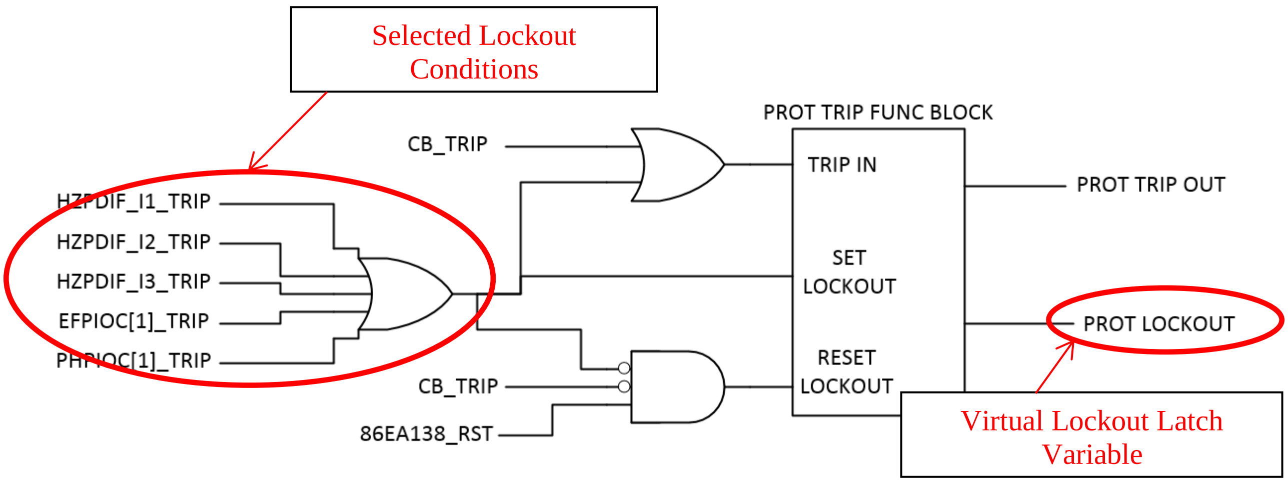


FIGURE 25 V2M4 50/51 EA138 RELAY LOCKOUT PROGRAMMING

GOOSE Implementation of Virtual Lockout Trip and Block Close Functionality

The virtual lockout latch variables tripped and blocked close for all associated breakers participating in the lockout scheme. Virtual lockout latch variables were converted to GOOSE messages by the protective relay and transmitted over the process bus as part of the GOOSE dataset. Block close conditions were compiled for each breaker as required for the application. These block close conditions included:

- The virtual lockout latch variables
- All local protection relay trips
- Any adjacent protection relay trips

Examples of the virtual lockout trip and block close functionality routed via GOOSE messages were provided in Figure 26 below for the V2M1 50/51 EA138 relay. In the example, the 138 kV bus differential virtual lockout latch variable was used to block close for all associated breakers.

An external virtual lockout latch variable was transmitted via GOOSE from the V2M3 87T41A relay to the V2M3 50/51 EA138 relay to block close conditions for only the transformer primary breaker. Front panel pushbutton close commands from the V2M1 50/51 EA138 relay were blocked until all of the associated block close conditions were eliminated.

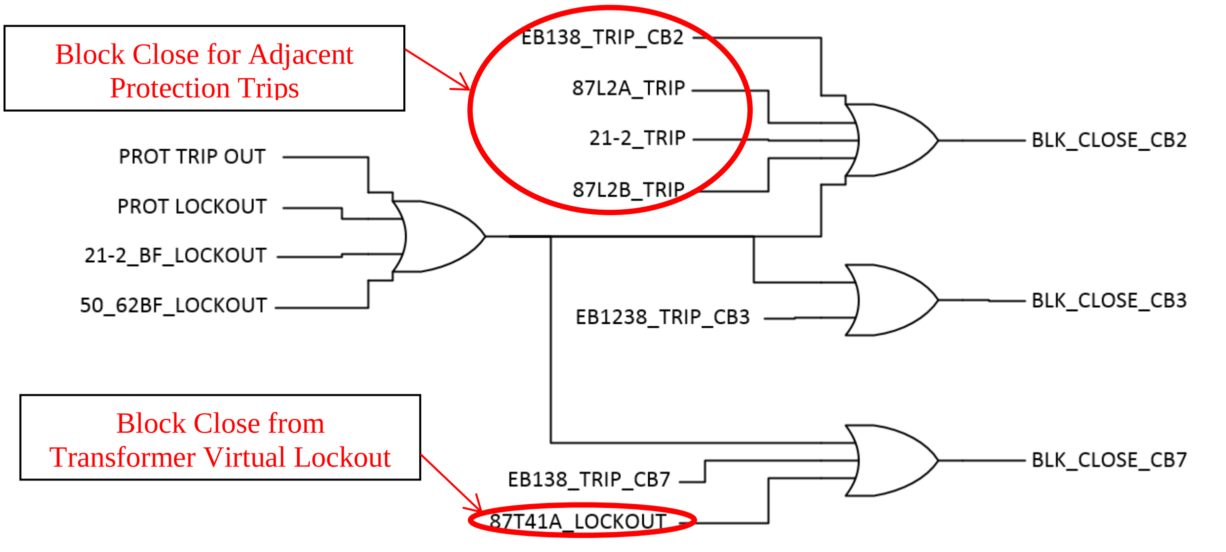


FIGURE 26 V2M4 50/51 EA138 RELAY BLOCK CLOSE PROGRAMMING

Interoperability

Investigation into interoperability was the most challenging experience when designing the test system. Although the Utility Communications Architecture International Users Group (UCAIug) issued an implementation guide in 2006, the recent advent of edition 2 created interoperability issues as the manufacturers migrated to the revised standard.

It was noted that even though manufacturers claimed support for IEC 61850-9-2LE (Light Edition) in both edition 1 or 2, there were differences from the LE document. It appeared that manufacturers picked what they determined were the important aspects of the LE document and only implemented those in their edition 2 products. In some cases this caused an incompatibility problem between SV publishers and subscribers.

Most of the manufacturers moved to implement edition 2 features while attempting to maintain the LE compliance with edition 1. Some manufacturers strictly enforced some of the items and made changes in others in order to accommodate both edition 1 and 2. The use of the SmpSynch field in the SV message buffering and the SV AppID were the two most noticeable items. The SmpSynch definition and data type was changed in edition 2. One merging unit strictly used the LE implementation for this field and it did not work with a protection device that strictly used the IEC 61850 Edition 2 implementation.

The use of GOOSE messaging between editions did not present a problem, and the ease in setting up relay logic for these signals with the current manufacturer software was greatly improved over experiences from just a few years ago. Configuration software included function blocks, directly tied to the IEC 61850 configurations, which could be re-used to quickly build relay logic functions. The only modification made in edition 2 was to change the “test field” to a “simulation field”. This field was not utilized in the test system. For the test system, edition 1 and 2 devices could function with both message types. It was determined that half the merging units had only implemented edition 2 GOOSE along with some of the protection relays. The exception was the capacitor and reactor automation controllers which only supported edition 1 GOOSE. There were no problems in implementing GOOSE solutions for the test system but since every other device supported edition 2, the projects was based on edition 2.

SCL file schemes and structures changed in edition 2. Some manufacturers' configuration tools accepted both edition 1 and 2 files while others required that the edition be declared at the start of a project and would then only accepts files from the declared edition. From the matrices, in TABLE 16 and Table 17, it was determined that all of the software tools would accept edition 2 files versus edition 1 files, which greatly impacted the decision to create the project as an edition 2 project.

10. TEST PROCEDURES

The demonstration plan was developed to ensure that each test case and its associated tests were performed and documented. Test case plan development was based on traditional relay testing plans. For each test case, a description of the case was included to describe the test configuration and success criteria. Test set-up conditions described the relays under test and the protection functions to be evaluated.

The source of the relay settings is then described and the relevant portion of the RTDS model is indicated. This section 10 also describes how the trip and close signals were transmitted. Finally, the test case performance tests are described with individual actions for each step. Captured wave forms, digital point statuses and contact operations are illustrated using COMTRADE plots and a graphical event analyzer. These files illustrate the raw data that was used to populate the results within the plan. Also included is a summary of all the operating times for each fault simulation.

Each test case was carefully designed to emulate real world scenarios. Here the configuration and setup of individual test cases were examined in detail. Relay protection settings and system voltage and current characteristics were explained. Finally, the raw performance data resulting from the simulation by the test set, which was extracted from the protection relays, was analyzed. These files were included in Appendix F.

Performance tests demonstrate proper operation of the test bed setup and relay settings, and record performance result data for the test cases. Tripping of circuit breakers was simulated by latching relays connected to MU digital outputs. Critical timing and observed element operation was recorded and included in Appendix G.

Test Case #1 – Breaker Failure Protection (50BF)

Relay Test Setup Conditions and Requirements

1. The test was performed on one manufacturer's high-performance breaker-failure numerical relay.
    a. The selected relay evaluated was:
        i. Mfg./Model V1M2 breaker failure/control relay
2. Backup line distance (21) and directional overcurrent protection (50/51) element performance was evaluated in a separate test case test from breaker failure so as to produce distinct results for the protection test case analysis.
3. Distance and directional overcurrent element settings matched those installed in the identified substation relays as much as possible.
4. For pre-commercial demonstration, an RTDS model of the identified substation, using equivalents to represent the system beyond the remote substation buses, was used to generate COMTRADE data files for each line node for playback by relay test sets. The secondary current and voltage playback signals were connected to the appropriate MUs and relay analog inputs. COMTRADE results for this test are included in Appendix F with the file names described in Section 6.
5. Trip and close signals to the breakers were via GOOSE messages to the appropriate MUs, and the breakers were simulated by latching relays. Programmable pushbuttons on the protective relays were configured to simulate manual trip and close logic to represent panel mounted control switches.

Test Case Voltage and Current Injection from Relay Test Sets

1. MU1 (69/138 kV line CB 2)
    a. Mfg./Model V1M5
    b. CTR= 400T
    c. PTR= 700T (W. bus)

50BF Performance Tests (Mfg./Model V1M2)

1. Simulate a 3LG fault close-in to the breaker by COMTRADE playback injection with CB 2 breaker current not dropping out and record the following:
    a. Download event record from each relay
    b. Fault Initiation Time: 6:10:7.110 PM**
    c. 50BF Relay Fault Recorder Initiation Time: 6:10:7.116 PM
    d. 50BF GOOSE BFI Received Time: 6:10:7.116 PM (50BF element pickup)
    e. Relay 50BF Trip Time: 6:10:7.496 PM
    f. CB 2 52a Open Detected Time: 6:10:7.561 PM
    g. CB 7 52a Open Detected Time: 6:10:7.550 PM
    h. CB 3 52a Open Detected Time: 6:10:7.547 PM
    i. Comments: 62BF set @ 0.417s (25 cycles)

2. Simulate a 3LG fault close-in to the breaker by COMTRADE playback injection with CB 2 breaker 52a status contact not dropping out and record the following:
    a. Download event record from each relay
    b. Fault Initiation Time: 6:19:01.110 PM
    c. 50BF Relay Fault Initiation Time: 6:19:01.116 PM
    d. 50BF GOOSE BFI Received Time: 6:19:01.116 PM (50BF element pickup)
    e. Relay 50BF Trip Initiation Time: 6:19:01.496 PM
    f. CB 2 52a Open Detected Time: 6:19:01.561 PM
    g. CB 7 52a Open Detected Time: 6:19:01.550 PM
    h. CB 3 52a Open Detected Time: 6:19:01.547 PM
    i. Comments: 62BF set @ 0.417s (25 cycles)

**Note: All times listed in the report were in GMT, which was the master simulations test-system setting.

Test Case #2 – Line Differential Protection (87L)

Relay Test Setup Conditions and Requirements

1. The tests were performed on two different manufacturers' high-performance numerical line differential relays that also incorporated backup impedance and directional overcurrent tripping elements. The selected relays to be evaluated were:
    a. Set A – Mfg./Model V2M2
    b. Set B – Mfg./Model V1M1

2. Backup line distance (21) and directional overcurrent protection (50/51) element performance was evaluated in a separate test case test from line differential (87L) so as to produce distinct results for protection test case analysis.

3. Differential protection communications was via an industry standard IEEE C37.94, 64 kB channel that connected the local and remote simulation relays via a multi-mode (MM) fiber-optic jumper. As the communications channel effect on relaying performance was not under

study, a direct fiber-optic connection without multiplex or transmission delay was assumed for the test.

4. Differential element settings matched those installed in the identified substation relays as much as possible.
5. For pre-commercial demonstration, an RTDS model of the identified substation, using equivalents to represent the system beyond the remote substation buses, was used to generate COMTRADE data files for each line node for playback by relay test sets. The secondary current and voltage playback signals were connected to the appropriate MUs and relay analog inputs. COMTRADE results for this test are included in Appendix F with the file names described in Section 6.
6. Trip and close signals to the breakers were via GOOSE messages to the appropriate MUs, and the breakers were simulated by latching relays. Programmable pushbuttons on the protective relays were configured to simulate manual trip and close logic to represent panel mounted control switches.

Test case voltage and current injection from relay test sets

1. MU1 69/138 kV Line CB 2) for local relays
    a. Mfg./Model V1M5
    b. CTR= 400T
    c. PTR= 700T (W. bus)

2. Direct connection to Set A and B remote relays

Set A 87L Performance Tests (Mfg./Model V2M2)

1. Simulate a 3LG fault behind the local 87L Set A by COMTRADE playback injection and record the following:
    a. Local Relay 87L Element Restrained? (Yes/No): Yes
    b. Local Relay 87L Element Restrained? (Yes/No): Yes
    c. Comments: None – proper operation, no event records triggered in local relay

2. Simulate a 1LG fault behind the local 87L Set A by COMTRADE playback injection and record the following:
    a. Local Relay 87L Element Restrained? (Yes/No): Yes
    b. Local Relay 87L Element Restrained? (Yes/No): Yes
    c. Comments: None – proper operation, no event records triggered in local relay

3. Simulate a 3LG fault close-in to the local 87L Set A by COMTRADE playback injection and record the following:
    a. Download event records from the relays at each line end
    b. Fault Initiation Time: 9:52:00.532 PM
    c. Local Relay 87L Trip Initiation Time: 9:52:00.543 PM
    d. Remote Relay 87L Trip Initiation Time: 9:52:00.543 PM
    e. Local Relay 52a Open Detected Time: 9:52:00.565 PM
    f. Comments: True sub-cycle relay operation

4. Simulate a 1LG fault close-in to the local 87L Set A by COMTRADE playback injection and record the following:
    a. Download event records from the relays at each line end

b. Fault Initiation Time: 10:14:30.534 PM
c. Local Relay 87L Trip Initiation Time: 10:14:30.549 PM
d. Remote Relay 87L Trip Initiation Time: 10:14:30.545 PM
e. Local Relay 52a Open Detected Time: 10:14:30.565 PM
f. Comments: True sub-cycle relay operation

5. Simulate a 3LG fault behind the remote 87L Set A by COMTRADE playback injection and record the following:
   a. Local Relay 87L Element Restrained? (Yes/No): Yes
   b. Local Relay 87L Element Restrained? (Yes/No): Yes
   c. Comments: None – proper operation, event triggered by overreaching distance protection

6. Simulate a 1LG fault behind the remote 87L Set A by COMTRADE playback injection and record the following:
   a. Local Relay 87L Element Restrained? (Yes/No): Yes
   b. Local Relay 87L Element Restrained? (Yes/No): Yes
   c. Comments: None – proper operation, event triggered by overreaching distance protection

Set B 87L Performance Tests (Mfg./Model V1M1)

1. Simulate a 3LG fault behind the local 87L Set A by COMTRADE playback injection and record the following:
   a. Local Relay 87L Element Restrained? (Yes/No): Yes
   b. Local Relay 87L Element Restrained? (Yes/No): Yes
   c. Comments: None – proper operation, no event records triggered in local relay

2. Simulate a 1LG fault behind the local 87L Set A by COMTRADE playback injection and record the following:
   a. Local Relay 87L Element Restrained? (Yes/No): Yes
   b. Local Relay 87L Element Restrained? (Yes/No): Yes
   c. Comments: None – proper operation, no event records triggered in local relay

3. Simulate a 3LG fault close-in to the local 87L Set A by COMTRADE playback injection and record the following:
   a. Download event records from the relays at each line end
   b. Fault Initiation Time: 7:05:00.492 PM
   c. Local Relay 87L Trip Initiation Time: 7:05:00.517 PM
   d. Remote Relay 87L Trip Initiation Time: 7:05:00.519 PM
   e. Local Relay 52a Open Detected Time: 7:05:00.567 PM
   f. Comments: 1.4 cycle relay operation – this was slow for a high-end 87L relay

4. Simulate a 1LG fault close-in to the local 87L Set A by COMTRADE playback injection and record the following:
   a. Download event records from the relays at each line end
   b. Fault Initiation Time: 6:55:30.492 PM
   c. Local Relay 87L Trip Initiation Time: 6:55:30.515 PM
   d. Remote Relay 87L Trip Initiation Time: 6:55:30.523 PM
   e. Local Relay 52a Open Detected Time: 6:55:30.569 PM

f. Comments: 1.4 cycle relay operation - this was slow for a high-end 87L relay

5. Simulate a 3LG fault behind the remote 87L Set A by COMTRADE playback injection and record the following:
   a. Local Relay 87L Element Restrained? (Yes/No): Yes
   b. Local Relay 87L Element Restrained? (Yes/No): Yes
   c. Comments: None – proper operation, no event records triggered in local relay

6. Simulate a 1LG fault behind the remote 87L Set A by COMTRADE playback injection and record the following:
   a. Local Relay 87L Element Restrained? (Yes/No): Yes
   b. Local Relay 87L Element Restrained? (Yes/No): Yes
   c. Comments: None – proper operation, no event records triggered in local relay

Test Case #3 – Line Distance and Directional Overcurrent Protection (21 and 50/51)

Relay Test Setup Conditions and Requirements

1. The tests were performed on two different manufacturers' high-performance numerical line differential relays that also incorporate backup impedance and directional overcurrent tripping elements. The selected relays to be evaluated were:
   a. Set A - Mfg./Model V2M2
   b. Set B – Mfg./Model V3M1
2. Line distance (21) and directional overcurrent protection (50/51) element performance was evaluated in a separate test case test from line differential (87L) so as to produce distinct results for protection test case analysis.
3. Distance and directional overcurrent element settings matched those installed in the identified substation relays as much as possible.
4. For pre-commercial demonstration, an RTDS model of the identified substation, using equivalents to represent the electric system beyond the remote substation buses was used to generate COMTRADE data files for each line node for playback by relay test sets. The secondary current and voltage playback signals were connected to the appropriate MU analog inputs. COMTRADE results for this test are included in Appendix F with the file names described in Section 6.
5. Trip and close signals to the breakers were via GOOSE messages to the appropriate MUs, and the breakers were simulated by latching relays. Programmable pushbuttons on the protective relays were configured to simulate manual trip and close logic to represent panel mounted control switches.

Test Case Voltage and Current Injection from Relay Test Sets

1. MU1 (69/138 kV Line CB 2) for Set A
   a. Mfg./Model V1M5
   b. CTR= 400T
   c. PTR= 700T (W. bus)
2. MU2 (69/138 kV Tie CB 3) for Set B
   a. Mfg./Model V3M3

b. CTR= 400T
c. PTR= 700T (W. bus)

3. MU3 (69/138 kV BK41 CB 7) for Set B
    a. Mfg./Model V7M1
    b. CTR= 400T
    c. PTR= 700T (W. bus)

Set A (21, 50, 51) Performance Tests (Mfg./Model V2M2)

1. Simulate a 3LG fault behind the breaker by COMTRADE playback injection and record the following:
    a. Relay Zone 1, 2, and 3 Forward 21P Elements Restrained? (Yes/No): Yes
    b. Comments: None – proper operation, no event records triggered in relay

2. Simulate a 1LG fault behind the breaker by COMTRADE playback injection and record the following:
    a. Relay Zone 1 and 2 Forward 21G Elements Restrained? (Yes/No): Yes
    b. Relay Zone 1 Forward 50G and 51G Elements Restrained? (Yes/No): Yes
    c. Comments: None – proper operation, no event records triggered in relay

3. Simulate a 3LG fault close-in to the breaker by COMTRADE playback injection and record the following:
    a. Download event record from the relay (the previous 87L test may be re-used)
    b. Fault Initiation Time: 9:52:00.532 PM
    c. Relay Fault Initiation Time: 9:52:00.532 PM
    d. Relay Zone 1 Forward 21P Trip Initiation Time: 9:52:00.542 PM
    e. Relay Zone 2 and 3 Forward 21P Element Pickup? (Yes/No) : Yes
    f. Local Relay 52a Open Detected Time: 9:52:00.576 PM
    g. Comments: True sub-cycle relay operation

4. Simulate a 1LG fault close-in to the breaker by COMTRADE playback injection and record the following:
    a. Download event record from the relay (the previous 87L test may be re-used)
    b. Fault Initiation Time: 10:14:30.534 PM
    c. Relay Fault Initiation Time: 10:14:30.534 PM
    d. Relay Zone 1 Forward 21G Element Trip Initiation Time: 10:14:30.542 PM
    e. Relay Zone 2 Forward 21G Element Pickup? (Yes/No): Yes
    f. Relay Zone 1 Forward 50G Element Trip Initiation Time: 10:14:30.549 PM
    g. Relay Forward 51G Element Pickup? (Yes/No): Yes
    h. Relay 52a Open Detected Time: 10:14:30.562 PM
    i. Comments: True sub-cycle relay operation

5. Simulate a 3LG fault at the remote bus by COMTRADE playback injection and record the following:
    a. Download event record from the relay (the previous 87L test may be re-used)
    b. Fault Initiation Time: 8:05:30.495 PM
    c. Relay Zone 2 and 3 21P Pickup Time: 8:05:30.563 PM
    d. Relay Zone 1 Forward 21P Element Restrained? (Yes/No): Yes
    e. Relay Zone 2 Forward 21P Trip Initiation Time: 8:05:30.766 PM
    f. Relay Zone 3 Forward 21P Trip Initiation Time: 8:05:31.063 PM

g. Relay 52a Open Detected Time: 8:05:30.787 PM
h. Comments: Relay detected high SIR and switched in automatic SIR filtering – this filtering added about 55ms of extra delay to the 21P-2 element operation as compared to the Set B performance for the same fault. The actual network in this location has this actual condition as confirmed with the provided circuit model, so the relay acted appropriately to improve security. 21P-2 delay was 200ms and 21P-3 delay was 500ms.

6. Simulate a 1LG fault at the remote bus by COMTRADE playback injection and record the following:
   a. Download event record from the relay (the previous 87L test may be re-used)
   b. Fault Initiation Time: 11:59:40.500 PM
   c. Relay Zone 2 and 3 21G Pickup Time: 11:59:40.518 PM
   d. Relay Zone 1 Forward 21G Element Restrained? (Yes/No): Yes
   e. Relay Zone 2 Forward 21G Trip Initiation Time: 11:59:40.721 PM
   f. Relay Zone 3 Forward 21G Trip Initiation Time: 11:59:41.021 PM
   g. Relay Zone 1 Forward 50G Element Restrained (Yes/No): Yes
   h. Relay Forward 51G Element Trip Initiation Time: No Operation
   i. Relay 52a Open Detected Time: 11:59:40.744 PM
   j. Comments: Relay's ground directional overcurrent element was not able to detect the 1LG fault due to marginal ground source behind relay, and almost equal magnitude currents in the un-faulted phases at almost the same phase angle (-89°) as the faulted phase due to nearby isolated ground sources which probably lowered the negative-sequence polarizing voltage – this behavior was not a process bus issue but a simulation corner case. The actual network in this location has this actual condition as confirmed with the provided circuit model, and demonstrates that numerical relay settings should always incorporate alternate fault detecting elements.

Set B 21, 50 and 51 Performance Tests (Mfg./Model V3M1):

1. Simulate a 3LG fault behind the breaker by COMTRADE playback injection and record the following:
   a. Download event record from the relay
   b. Relay Zone 1, 2, and 3 Forward 21P Elements Restrained? (Yes/No): Yes
   c. Comments: None – proper operation, no event records triggered in relay.

2. Simulate a 1LG fault behind the breaker by COMTRADE playback injection and record the following:
   a. Download event record from the relay
   b. Relay Zone 1 and 2 Forward 21G Elements Restrained? (Yes/No): Yes
   c. Relay Zone 1 Forward 50G and 51G Elements Restrained? (Yes/No): Yes
   d. Comments: None – proper operation, no event records triggered in relay.

3. Simulate a 3LG fault close-in to the breaker by COMTRADE playback injection and record the following:
   a. Download event record from the relay
   b. Fault Initiation Time: 14:43:08.470***
   c. Relay Fault Initiation Time: 14:43:08.470
   d. Relay Zone 1 Forward 21P Trip Initiation Time: 14:43:08.473
   e. Relay Zone 2 and 3 Forward 21P Element Pickup? (Yes/No) : Yes

f. Local Relay 52a Open Detected Time: 14:43:08.496
g. Comments: Timing from SER report.

***Note: Some relays reported time using a 24 hour format. To simplify comparison between this section and the files in Appendix F, the 24 hour time format was utilized here to match the files in Appendix F.

4. Simulate a 1LG fault close-in to the breaker by COMTRADE playback injection and record the following:
   a. Download event record from the relay
   b. Fault Initiation Time: 16:58:19.511
   c. Relay Fault Initiation Time: 16:58:19.511
   d. Relay Zone 1 Forward 21G Element Trip Initiation Time: 16:58:19.515
   e. Relay Zone 2 Forward 21G Element Pickup? (Yes/No): Yes
   f. Relay Zone 1 Forward 67G1 Element Trip Initiation Time: 16:58:19.518
   g. Relay Forward 51G Element Pickup? (Yes/No): Yes
   h. Relay 52a Open Detected Time: 16:58:19.543
   i. Comments: 67G1 pickup slower than Z1G due to unique phasor situation described above.

5. Simulate a 3LG fault at the remote bus by COMTRADE playback injection and record the following:
   a. Download event record from the relay
   b. Fault Initiation Time: 3:28:13.466 PM
   c. Relay Zone 2 21P Pickup Time: 3:28:13.478 PM
   d. Relay Zone 1 Forward 21P Element Restrained? (Yes/No): Yes
   e. Relay Zone 2 Forward 21P Trip Initiation Time: 3:28:13.680 PM
   f. Relay 52a Open Detected Time: 3:28:13.703 PM
   g. Comments: Sub-cycle relay 21P operation; Zone 2 timer set for 200 ms delay. This relay's performance was very impressive.

6. Simulate a 1LG fault at the remote bus by COMTRADE playback injection and record the following:
   a. Download event record from the relay
   b. Fault Initiation Time: 5:25:09.503 PM
   c. Relay Zone 2 21G Pickup Time: 5:25:09.515 PM
   d. Relay Zone 1 Forward 21G Element Restrained? (Yes/No): Yes
   e. Relay Zone 2 Forward 21G Trip Initiation Time: 5:25:09.714 PM
   f. Relay Zone 1 Forward 50G Element Restrained (Yes/No): Yes
   g. Relay Forward 51G Element Trip Initiation Time: 5:25:09.626 PM
   h. Relay 52a Open Detected Time: 5:25:09.651 PM
   i. Comments: This relay's ground directional overcurrent element had no difficulty detecting the remote bus ground fault unlike Set A. Sub-cycle relay 21G operation; Zone 2 timer set for 200 ms delay. This relay's performance was very impressive.

Test Case #4 – High Voltage (HV) Bus Overcurrent Differential Protection (87B-50/51)

Relay Test Setup Conditions and Requirements

1. The selected relays to be evaluated were:

a. Set A - Mfg./Model V2M1
b. Set B - Mfg./Model V1M3

2. Overcurrent differential element settings matched those installed in the identified substation relays as much as possible.
3. For pre-commercial demonstration, an RTDS model of the identified substation, using equivalents to represent the electric system beyond the remote substation buses was used to generate COMTRADE data files for each line node for playback by relay test sets. The secondary current and voltage playback signals were connected to the appropriate MU analog inputs. COMTRADE results for this test are included in Appendix F with the file names described in Section 6.
4. Trip and close signals to the breakers were via GOOSE messages to the appropriate MUs, and the breakers were simulated by latching relays. Programmable pushbuttons on the protective relays were configured to simulate manual trip and close logic to represent panel mounted control switches.

Test Case Voltage and Current Injection from Relay Test Sets

1. MU1 (69/138 kV Line CB 2)
   a. Mfg./Model V1M5
   b. CTR= 400T
   c. PTR= 700T (W. bus)
2. MU2 (69/138 kV Tie CB 3)
   a. Mfg./Model V3M3
   b. CTR= 400T
   c. PTR= 700T (W. bus)
3. MU3 (69/138 kV BK41 CB 7)
   a. Mfg./Model V7M1
   b. CTR= 400T
   c. PTR= 700T (W. bus)

Set A 87B-50/51 Overcurrent Differential Performance Tests (Mfg./Model V2M1)

1. Simulate a close-in 3LG fault on the transmission line by COMTRADE playback injection and record the following:
   a. Relay 87B-50/51 Restrained? (Yes/No): Yes
   b. Comments: None – proper relay operation
2. Simulate a close-in 1LG fault on the transmission line by COMTRADE playback injection and record the following:
   a. Relay 87B-50/51 Restrained? (Yes/No): Yes
   b. Comments: None – proper relay operation
3. Simulate a 3LG fault on the HV bus by COMTRADE playback injection and record the following:
   a. Download event record from the relay
   b. Fault Initiation Time: 2:55:00.495 PM
   c. Relay Fault Initiation Time: 2:55:00.500 PM

d. Relay 87B-50P Trip Initiation Time: 2:55:00.500 PM
e. Relay Longest 52a Open Detected Time: 2:55:00.528 PM
f. Comments: Excellent sub-cycle operation.

4. Simulate a 1LG fault on the HV bus by COMTRADE playback injection and record the following:
   a. Download event record from the relay
   b. Fault Initiation Time: 3:34:11.504 PM
   c. Relay Fault Initiation Time: 3:34:11.509 PM
   d. Relay 87B-50/51Trip Initiation Time: 3:34:11.509 PM
   e. Relay Longest 52a Open Detected Time: 3:34:11.535 PM
   f. Comments: Excellent sub-cycle operation.

Set B 87B-50/51 Overcurrent Differential Performance Tests (Mfg./Model V1M3)

1. Simulate a 3LG fault on the transmission line by COMTRADE playback injection and record the following:
   a. Relay 87B-50/51 Restrained? (Yes/No): Yes
   b. Comments: None – proper relay operation.

2. Simulate an SLG fault on the transmission line by COMTRADE playback injection and record the following:
   a. Relay Differential Overcurrent Restrained? (Yes/No): Yes
   b. Comments: None – proper relay operation.

3. Simulate a 3LG fault on the HV bus by COMTRADE playback injection and record the following:
   a. Download event record from the relay
   b. Fault Initiation Time: 3:55:00.500 PM
   c. Relay Fault Initiation Time: 3:55:00.504 PM
   d. Relay 87B-50P Trip Initiation Time: 3:55:00.504 PM
   e. Relay 52a Open Detected Time: 3:55:00.534 PM
   f. Comments: Excellent sub-cycle operation.

4. Simulate an SLG fault on the HV bus by COMTRADE playback injection and record the following:
   a. Download event record from the relay
   b. Fault Initiation Time: 4:10:00.495 PM
   c. Relay Fault Initiation Time: 4:10:00.503 PM
   d. Relay 87B-50G Trip Initiation Time: 4:10:00.503 PM
   e. Relay 52a Open Detected Time: 4:10:00.533 PM
   f. Comments: Excellent sub-cycle operation.

Test Case #5 – HV Bus Restrained Current Differential Protection (87B)

Relay Test Setup Conditions and Requirements

1. The selected relay to be evaluated were:
   a. Mfg./Model V1M3

2. Existing distribution substations and standards did not use overcurrent differential protection for this application, so settings did not match those installed in the identified substation relays; typical industry standard settings were applied.
3. For pre-commercial demonstration, an RTDS model of the identified substation using, equivalents to represent the electric system beyond the remote substation buses was used to generate COMTRADE data files for each line node for playback by relay test sets. The secondary current and voltage playback signals were connected to the appropriate MU analog inputs. COMTRADE results for this test are included in Appendix F with the file names described in Section 6.
4. Trip and close signals to the breakers were via GOOSE messages to the appropriate MUs, and the breakers were simulated by latching relays. Programmable pushbuttons on the protective relays were configured to simulate manual trip and close logic to represent panel mounted control switches.

Test Case Voltage and Current Injection from Relay Test Sets

1. MU1 (69/138 kV Line CB 2)
    a. Mfg./Model V1M5
    b. CTR= 400T
    c. PTR= 700T (W. bus)

2. MU2 (69/138 kV Tie CB 3)
    a. Mfg./Model V3M3
    b. CTR= 400T
    c. PTR= 700T (W. bus)

3. MU3 (69/138 kV BK41 CB 7)
    a. Mfg./Model V7M1
    b. CTR= 400T
    c. PTR= 700T (W. bus)

87B Restrained Current Differential Performance Tests (Mfg./Model V1M3)

1. Simulate a close-in 3LG fault on the transmission line by COMTRADE playback injection and record the following:
    a. Relay Differential Overcurrent Restrained? (Yes/No): Yes
    b. Comments: None – proper relay operation.

2. Simulate a close-in 1LG fault on the transmission line by COMTRADE playback injection and record the following:
    a. Relay Differential Overcurrent Restrained? (Yes/No): Yes
    b. Comments: None – proper relay operation.

3. Simulate a 3LG fault on the HV bus by COMTRADE playback injection and record the following:
    a. Download event record from the relay
    b. Fault Initiation Time: 3:55:00.500 PM
    c. Relay Fault Initiation Time: 3:55:00.504 PM
    d. Relay 87B Trip Initiation Time: 3:55:00.504 PM

e. Relay 52a Open Detected Time: 3:55:00.534 PM
f. Comments: Excellent sub-cycle operation.

4. Simulate a 1LG fault on the HV bus by COMTRADE playback injection and record the following:
    a. Download event record from the relay
    b. Fault Initiation Time: 4:10:00.495 PM
    c. Relay Fault Initiation Time: 4:10:00.503 PM
    d. Relay Trip Initiation Time: 4:10:00.503 PM
    e. Relay 52a Open Detected Time: 4:10:00.533 PM
    f. Comments: Excellent sub-cycle operation.

Test Case #6 – HV Bus High Impedance Differential Protection (87B-HIZ)

Relay Test Setup Conditions and Requirements

1. The selected relay to be evaluated was:
    a. Mfg./Model V2M4
2. Existing distribution substations and standards did not use high-impedance differential protection for this application, so settings do not match those installed in the identified substation relays; typical industry standard settings were applied.
3. For pre-commercial demonstration, an RTDS model of the identified substation, using equivalents to represent the system beyond the remote substation buses was used to generate COMTRADE data files for each line node for playback by relay test sets. The secondary current signals from the breakers bounding the differential zone were summed together in the model and the output of this summation was connected to the MU analog input. COMTRADE results for this test are included in Appendix F with the file names described in Section 6.
4. Trip and close signals to the breakers were via GOOSE messages to the appropriate MUs, and the breakers were simulated by latching relays. Programmable pushbuttons on the protective relays were configured to simulate manual trip and close logic to represent panel mounted control switches.

Test Case Voltage and Current Injection from Relay Test Sets

1. MU12 (69/138 kV Line CB 2, CB3, CB7 summed externally in a High Impedance (HIZ) resistor assembly made by Mfg. V2)
    a. Mfg./Model V3M3
    b. CTR= Special Setting based on chosen resistor setting – see relay settings documentation
    c. PTR= 700T (W. bus)

87B-HIZ High Impedance Bus Differential Performance Tests (Mfg./Model V2M4)

1. Simulate a 3LG fault on the transmission line by COMTRADE playback injection and record the following:
    a. Relay 87B-HIZ Restrained? (Yes/No): Yes
    b. Comments: Test simulated by direct MU current injection from F6150e as resistor assembly was not available.

2. Simulate a 1LG fault on the transmission line by COMTRADE playback injection and record the following:
    a. Relay 87B-HIZ Restrained? (Yes/No): Yes
    b. Comments: Test simulated by direct MU current injection from F6150e as resistor assembly was not available.

3. Simulate a 3LG fault on the HV bus by COMTRADE playback injection and record the following:
    a. Download event record from the relay
    b. Fault Initiation Time: 3:35:24.653 PM
    c. Relay Fault Initiation Time: 3:35:24.656 PM
    d. Relay 87B-HIZ Trip Initiation Time: 3:35:24.656 PM
    e. Relay 52a Open Detected Time: 3:35:24.680 PM
    f. Comments: Test simulated by direct MU current injection from F6150e as resistor assembly was not available; relay sub-cycle performance.

4. Simulate a 1LG fault on the HV bus by COMTRADE playback injection and record the following:
    a. Download event record from the relay
    b. Fault Initiation Time: 3:36:42.554 PM
    c. Relay Fault Initiation Time: 3:36:42.557 PM
    d. Relay 87B-HIZ Trip Initiation Time: 3:36:42.557 PM
    e. Relay 52a Open Detected Time: 3:36:42.581 PM
    f. Comments: Test simulated by direct MU current injection from F6150e as resistor assembly was not available; relay sub-cycle performance.

Test Case #7 – Transformer Restrained Current Differential Protection (87T)

Relay Test Setup Conditions and Requirements

1. The selected relays to be evaluated were:
    a. Set A – Mfg./Model V2M3
    b. Set B – Mfg./Model V1M3

2. Transformer restrained differential current element settings matched those installed in the identified substation relays as much as possible.
3. For pre-commercial demonstration, an RTDS model of the identified substation, using equivalents to represent the electric system beyond the remote substation buses was used to generate COMTRADE data files for each line node for playback by relay test sets. The secondary current and voltage playback signals were connected to the appropriate MU analog inputs. COMTRADE results for this test are included in Appendix F with the file names described in Section 6.
4. Trip and close signals to the breakers were via GOOSE messages to the appropriate MUs, and the breakers were simulated by latching relays. Programmable pushbuttons on the protective relays were configured to simulate manual trip and close logic to represent panel mounted control switches.

Test Case Voltage and Current Injection from Relay Test Sets

1. MU3 (69/138 kV BK41 CB 7)

a. Mfg./Model V7M1
b. CTR= 400T
c. PTR= 700T (W. bus)

2. MU4 (12 kV BK41 CB 11)
   a. Mfg./Model V7M1
   b. CTR= 400T
   c. PTR= 100T (12 kV bus)

3. MU7 (12 kV BK41 CB 14)
   a. Mfg./Model V2M5
   b. CTR= 400T
   c. PTR= 100T (12 kV bus)

Set A 87T Transformer Restrained Overcurrent Diff. Performance Tests (Mfg./Model V2M3)

1. Simulate a 3LG fault on the high voltage bus by COMTRADE playback injection and record the following:
   a. Relay Differential Overcurrent Restrained? (Yes/No): Yes
   b. Comments: No operation for out of zone fault.

2. Simulate a 1LG fault on the high voltage bus by COMTRADE playback injection and record the following:
   a. Relay Differential Overcurrent Restrained? (Yes/No): Yes
   b. Comments: No operation for out of zone fault.

3. Simulate a 3LG fault in the transformer zone by COMTRADE playback injection and record the following:
   a. Download event record from the relay
   b. Fault Initiation Time: 8:23:30.488 PM
   c. Relay Fault Pickup Time: 8:23:30.488 PM
   d. Relay 50P Trip Initiation Time: 8:23:30.496 PM
   e. Relay 87U Trip Initiation Time: 8:23:30.505 PM
   f. Relay 87R Trip Initiation Time: 8:23:30.515 PM
   g. Relay Longest 52a Open Detected Time: 8:23:30.516 PM
   h. Comments: Excellent operation.

4. Simulate a 1LG fault in the transformer zone by COMTRADE playback injection and record the following:
   a. Download event record from the relay
   b. Fault Initiation Time: 9:00:30.494 PM
   c. Relay Fault Pickup Time: 9:00:30.494 PM
   d. Relay 50G Trip Initiation Time: 9:00:30.503 PM
   e. Relay 87R Trip Initiation Time: 9:00:30.519 PM
   f. Relay Longest 52a Open Detected Time: 9:00:30.523 PM
   g. Comments: Excellent operation.

Set B 87T Transformer Restrained Overcurrent Diff. Performance Tests (Mfg./Model V1M3)

1. Simulate a 3LG fault on the high voltage bus by COMTRADE playback injection and record the following:
    a. Relay Differential Overcurrent Restrained? (Yes/No): Yes
    b. Comments: No operation for out of zone fault.

2. Simulate a 1LG fault on the high voltage bus by COMTRADE playback injection and record the following:
    a. Relay Differential Overcurrent Restrained? (Yes/No): Yes
    b. Comments: No operation for out of zone fault.

3. Simulate a 3LG fault in the transformer zone by COMTRADE playback injection and record the following:
    a. Download event record from the relay
    b. Fault Initiation Time: 9:23:30.468 PM
    c. Relay Fault Pickup Time: 9:23:30.518 PM
    h. Relay 50P Trip Initiation Time: **No Operation
    i. Relay 87U Trip Initiation Time: **No Operation
    d. Relay 87R Trip Initiation Time: **No Operation
    e. Relay Longest 52a Open Detected Time: N/A
    f. Comments: **Relay restrained due to "Bad Quality" data target for the MU7 Data Stream. This was a possible ICD/CID configuration issue with the process bus communications module.

4. Simulate a 1LG fault in the transformer zone by COMTRADE playback injection and record the following:
    a. Download event record from the relay
    b. Fault Initiation Time: 10:00:30.470 PM
    c. Relay Fault Pickup Time: 10:00:30.520 PM
    j. Relay 50G Trip Initiation Time: **No Operation
    d. Relay 87R Trip Initiation Time: **No Operation
    e. Relay Longest 52a Open Detected Time N/A
    f. Comments: **Relay restrained due to "Bad Quality" data target for the MU7 Data Stream. This was a possible CID/ICD configuration issue with the process bus communications module.

Test Case #8 – Transformer Overcurrent Protection (50/51T)

Relay Test Setup Conditions and Requirements

1. The tests were performed on four relays from two different manufacturers of high-performance numerical overcurrent relays. The selected relays to be evaluated were:
    a. Set A – Mfg./Model V2M4
    b. Set B – Mfg./Model V1M4
    c. Set C – Mfg./Model V2M3
    d. Set D – Mfg./Model V1M3

2. Overcurrent element settings matched those installed in the identified substation relays as much as possible.

3. For pre-commercial demonstration, an RTDS model of the identified substation, using equivalents to represent the electric system beyond the remote substation buses was used to generate COMTRADE data files for each line node for playback by relay test sets. The secondary current playback signals were connected to the appropriate MU analog inputs. COMTRADE results for this test are included in Appendix F with the file names described in Section 6.
4. Trip and close signals to the breakers were via GOOSE messages to the appropriate MUs, and the breakers were simulated by latching relays. Programmable pushbuttons on the protective relays were configured to simulate manual trip and close logic to represent panel mounted control switches.

Test Case Voltage and Current Injection from Relay Test Sets

1. MU3 (69/138 kV BK41 CB 7)
    a. Mfg./Model V7M1
    b. CTR= 400T
    c. PTR= 700T (W. bus)

2. MU11 (BK41 Neutral)
    a. Mfg./Model V2M5
    b. CTR= 600T
    c. PTR= Not Used

Set A (50/51) Performance Tests (Mfg./Model V2M4)

1. Simulate a transformer 3LG fault by COMTRADE playback injection and record the following:
    a. Download event record from the relay
    b. Event Initiation Time: 8:23:30.488 PM
    c. Relay 50P Trip Initiation Time: 8:23:30.498 PM
    d. Relay 52a Open Detected Time: 8:23:30.508 PM
    e. Comments: Excellent sub-cycle operation.

2. Simulate a transformer 1LG fault by COMTRADE playback injection and record the following:
    a. Download event record from the relay
    b. Event Initiation Time: 9:00:30.494 PM
    c. Relay 50N Trip Initiation Time: 9:00:30.504 PM
    d. Relay Open Detected Time: 9:00:30.514 PM
    e. Comments: Excellent sub-cycle operation.

Set B (50/51) Performance Tests (Mfg./Model V1M4)

1. Simulate a transformer 3LG fault by COMTRADE playback injection and record the following:
    a. Download event record from the relay
    b. Event Initiation Time: 9:23:30.492 PM
    c. Relay 50P Trip Initiation Time: 9:23:30.502 PM
    d. Relay Longest 52a Open Detected Time: 9:23:30.512 PM

e. Comments: Excellent sub-cycle operation.

2. Simulate a transformer 1LG fault by COMTRADE playback injection and record the following:
    a. Download event record from the relay
    b. Event Initiation Time: 10:00:30.505 PM
    c. Relay 50N Trip Initiation Time: 10:00:30.516 PM
    d. Relay Longest 52a Open Detected Time: 10:00:30.528 PM
    e. Comments: Excellent sub-cycle operation.

Set C (50/51) Performance Tests (Mfg./Model V2M3)

1. Simulate a transformer 3LG fault by COMTRADE playback injection and record the following:
    a. Download event record from the relay
    b. Event Initiation Time: 8:23:30.488 PM
    c. Relay 50P Trip Initiation Time: 8:23:30.496 PM
    d. Relay 52a Open Detected Time: 8:23:30.516 PM
    e. Comments: Excellent Operation.

2. Simulate a transformer 1LG fault by COMTRADE playback injection and record the following:
    a. Download event record from the relay
    b. Event Initiation Time: 9:00:30.494 PM
    c. Relay 50N Trip Initiation Time: 9:00:30.503 PM
    d. Relay 52a Open Detected Time: 9:00:30.519 PM
    e. Comments: Excellent Operation.

Set D (50/51) Performance Tests (Mfg./Model V1M3)

1. Simulate a transformer 3LG fault by COMTRADE playback injection and record the following:
    a. Download event record from the relay
    b. Event Initiation Time: 9:23:30.488 PM
    c. Relay 50P Trip Initiation Time: **No Operation
    d. Relay Longest 52a Open Detected Time: N/A
    e. Comments: **Relay restrained due to "Bad Quality" data target for the MU7 Data Stream. This was a possible ICD/CID configuration issue with the process bus communications module.

2. Simulate a transformer 1LG fault by COMTRADE playback injection and record the following:
    a. Download event record from the relay
    b. Event Initiation Time: 10:00:30.470 PM
    c. Relay 50N Trip Initiation Time: **No Operation
    d. Relay Longest 52a Open Detected Time: N/A
    e. Comments: **Relay restrained due to "Bad Quality" data target for the MU7 Data Stream. This was a possible CID/ICD configuration issue with the process bus communications module.

Test Case #9 – 12 kV Bus Partial Overcurrent Differential Protection (87B-51P/G)

Relay Test Setup Conditions and Requirements

1. The selected relays to be evaluated were:
    a. Set A – Mfg./Model V2M4
    b. Set B – Mfg./Model V1M4
2. Differential overcurrent element settings matched those installed in the identified substation relays as much as possible.
3. For pre-commercial demonstration, an RTDS model of the identified substation, using equivalents to represent the system beyond the remote substation) buses, was used to generate COMTRADE data files for each line node for playback by relay test sets. The secondary current and voltage playback signals were connected to the appropriate MU analog inputs. COMTRADE results for this test are included in Appendix F with the file names described in Section 6.
4. Trip and close signals to the breakers were via GOOSE messages to the appropriate MUs, and the breakers were simulated by latching relays. Programmable pushbuttons on the protective relays were configured to simulate manual trip and close logic to represent panel mounted control switches.

Test Case Voltage and Current Injection from Relay Test Sets

1. MU5 (12 kV Tie CB 10)
    a. Mfg./Model V2M5
    b. CTR= 400T
    c. PTR= 100T (12 kV bus)
2. MU10 (12 kV BK41 CB 14)
    a. Mfg./Model V7M1
    b. CTR= 400T
    c. PTR= 100T (12 kV bus)
3. MU13 (12 kV Tie CB 20)
    a. Mfg./Model V1M5
    b. CTR= 400T
    c. PTR= 100T (12 kV bus)

Set A 87B-50/51 Overcurrent Differential Performance Tests (Mfg./Model V2M4)

1. Simulate 3LG fault in the transformer by COMTRADE playback injection and record the following:
    a. Relay 87B-51 Restrained? (Yes/No): Yes
    b. Comments: No operation for out of zone fault, no event reports generated.
2. Simulate an SLG fault in the transformer by COMTRADE playback injection and record the following:
    a. Relay 87B-51 Restrained? (Yes/No): Yes
    b. Comments: No operation for out of zone fault, no event reports generated.

3. Simulate a 3LG fault on the 12 kV bus by COMTRADE playback injection and record the following:
    a. Download event record from the relay
    b. Fault Initiation Time: 2:51:00.203 PM
    c. Relay Fault Pickup Time: 2:51:00.207 PM
    d. Relay 87B-51P Trip Initiation Time: 2:51:01.541 PM
    e. Relay Longest 52a Open Detected Time: 2:51:01.569 PM
    f. Relay 51 element operated with the expected time delay? (Yes/No): Yes
    g. Comments: 87B-51P Element has inverse-time delay.

4. Simulate an SLG fault on the 12 kV bus by COMTRADE playback injection and record the following:
    a. Download event record from the relay
    b. Fault Initiation Time: 3:14:09.501 PM
    c. Relay Fault Pickup Time: 3:14:09.506 PM
    d. Relay 87B-51P/G Trip Initiation Time: 3:14:11.206 PM
    e. Relay Longest 52a Open Detected Time: 3:14:11.229 PM
    f. Relay 51 element operated with the expected time delay? (Yes/No): Yes
    g. Comments: 87B-51P/G Elements have inverse-time delay.

Set B 87B-50/51 Overcurrent Differential Performance Tests (Mfg./Model V1M4)

1. Simulate 3LG fault in the transformer by COMTRADE playback injection and record the following:
    a. Relay 87B-51 Restrained? (Yes/No): Yes
    b. Comments: No operation for out of zone fault, no event reports generated.

2. Simulate an SLG fault in the transformer by COMTRADE playback injection and record the following:
    a. Relay 87B-51 Restrained? (Yes/No): Yes
    b. Comments: No operation for out of zone fault, no event reports generated.

3. Simulate a 3LG fault on the 12 kV bus by COMTRADE playback injection and record the following:
    a. Download event record from the relay
    b. Fault Initiation Time: 7:52:30.536 PM
    c. Relay Fault Pickup Time: 7:52:30.541 PM
    d. Relay 87B-51P Trip Initiation Time: 7:52:31.893 PM
    e. Relay Longest 52a Open Detected Time: 7:52:31.906 PM
    f. Relay 51 element operated with the expected time delay? (Yes/No): Yes
    g. Comments: 87B-51P Element has inverse-time delay.

4. Simulate an SLG fault on the 12 kV bus by COMTRADE playback injection and record the following:
    a. Download event record from the relay
    b. Fault Initiation Time: 4:14:09.502 PM
    c. Relay Fault Pickup Time: 4:14:09.508 PM
    d. Relay 87B-51P/G Trip Initiation Time: 4:14:11.218 PM
    e. Relay Longest 52a Open Detected Time: 4:14:11.236 PM
    f. Relay 51 element operated with the expected time delay? (Yes/No): Yes

g. Comments: 87B-51P/G Elements have inverse-time delay.

Test Case #10 – 12 kV Bus Restrained Current Differential Protection (87B)

Relay Test Setup Conditions and Requirements

1. The selected relay to be evaluated was:
    a. Mfg./Model V2M3
2. The typical existing distribution substations do not currently use restrained overcurrent differential protection for this application, although it was shown on the standard drawings, so settings did not match those installed in the identified substation relays.
3. For pre-commercial demonstration, an RTDS model of the identified substation, using equivalents to represent the system beyond the remote substation buses, was used to generate COMTRADE data files for each line node for playback by relay test sets. The secondary current and voltage playback signals were connected to the appropriate MU analog inputs. COMTRADE results for this test are included in Appendix F with the file names described in Section 6.
4. Trip and close signals to the breakers were via GOOSE messages to the appropriate MUs, and the breakers were simulated by latching relays. Programmable pushbuttons on the protective relays were configured to simulate manual trip and close logic to represent panel mounted control switches.

Test Case Voltage and Current Injection from Relay Test Sets

1. MU5 (12 kV Tie CB 10)
    a. Mfg./Model V2M5
    b. CTR= 400T
    c. PTR= 100T (12 kV bus)

2. MU6 (12 kV Feeder CB 12)
    a. Mfg./Model V3M3
    b. CTR= 240T
    c. PTR= 100T (12 kV bus)

3. MU8 (12 kV Cap Feeder CB 17)
    a. Mfg./Model V6M1 and Mfg./Model V2M6
    b. CTR= 240T
    c. PTR= 100T (12 kV bus)

4. MU9 (12 kV Transfer Bus CB 11)
    a. Mfg./Model V7M1
    b. CTR= 400T
    c. PTR= 100T (12 kV bus)

5. MU10 (12 kV BK41 CB 14)
    a. Mfg./Model V7M1
    b. CTR= 400T
    c. PTR= 100T (12 kV bus)

6. MU13 (12 kV Tie CB 20)
    a. Mfg./Model V1M5
    b. CTR= 400T
    c. PTR= 100T (12 kV bus)

87B Restrained Current Differential Performance Tests (V2M3)

1. Simulate a 3LG fault on the Cap/Reactor feeder by COMTRADE playback injection and record the following:
    a. Relay 87B Trip Restrained? (Yes/No): Yes
    b. Comments: No operation for out of zone fault, no event reports generated.

2. Simulate a close-in SLG fault on the Cap/Reactor feeder by COMTRADE playback injection and record the following:
    a. Relay 87B Trip Restrained? (Yes/No): Yes
    b. Comments: No operation for out of zone fault, no event reports generated.

3. Simulate a 3LG fault on the LV bus by COMTRADE playback injection and record the following:
    a. Download event record from the relay
    b. Fault Initiation Time: 9:41:39.080 PM
    c. Relay Fault Pickup Time: 9:41:39.093 PM
    d. Relay 87B Trip Initiation Time: 9:41:39.101 PM
    e. Relay Longest 52a Open Detected Time: 9:41:39.136 PM
    f. Comments: Excellent Hi-Speed Operation – 3.4 cycles fault application to clear.

4. Simulate an SLG fault on the LV bus by COMTRADE playback injection and record the following:
    a. Download event record from the relay
    b. Fault Initiation Time: 10:03:34.081 PM
    c. Relay Fault Initiation Time: 10:03:34.100 PM
    d. Relay 87B Trip Initiation Time: 10:03:34.094 PM
    e. Relay Longest 52a Open Detected Time: 10:03:34.132 PM
    f. Comments: Excellent Hi-Speed Operation– 3.1 cycles fault application to clear.

Test Case #11 – Capacitor and Reactor Feeder Overcurrent Protection (50/51)

Relay Test Setup Conditions and Requirements

1. The tests were performed on two different manufacturers' high-performance numerical feeder relays that incorporated non-directional overcurrent tripping elements. The selected relays to be evaluated were:
    a. Set A – Mfg./Model V2M4
    b. Set B – Mfg./Model V1M4

2. Overcurrent element settings matched those installed in the identified substation relays as much as possible.

3. For pre-commercial demonstration, an RTDS model of the identified substation, using equivalents to represent the system beyond the remote substation buses, was used to generate COMTRADE data files for each line node for playback by relay test sets. The secondary current playback signals were connected to the appropriate MU analog inputs. Results for this test are included in Appendix F with the file names described in Section 6.

4. Trip and close signals to the breakers were via GOOSE messages to the appropriate MUs, and the breakers were simulated by latching relays. Programmable pushbuttons on the protective relays were configured to simulate manual trip and close logic to represent panel mounted control switches.

Test Case Voltage and Current Injection from Relay Test Sets

1. MU8 (12 kV CB17)
    a. Mfg./Model V6M1 and Mfg./Model V2M6
    b. CTR= 240T
    c. PTR= 100T (12 kV bus)

Set A (50/51) Performance Tests (Mfg./Model V2M4)

1. Simulate a 12 kV feeder 3LG fault downstream of Breaker 17 by COMTRADE playback injection and record the following:
    a. Download event record from the relay
    b. Fault Initiation Time: 3:34:11.454 PM
    c. Relay Fault Pickup Time: 3:34:11.504 PM
    d. Relay Trip Initiation Time: 3:34:11.508 PM
    e. Relay 52a Open Detected Time: 3:34:11.528 PM
    f. Relay Element Tripped: 50P
    g. Comments: Feeder too short for 51P operation.

2. Simulate a 12 kV feeder 1LG fault downstream of Breaker 17 by COMTRADE playback injection and record the following:
    a. Download event record from the relay
    b. Fault Initiation Time: 8:10:00.488 PM
    c. Relay Fault Pickup Time: 8:10:00.538 PM
    d. Relay Trip Initiation Time: 8:10:00.543 PM
    e. Relay 52a Open Detected Time: 8:10:00.572 PM
    f. Relay Element Tripped: 50P and 50G
    g. Comments: Feeder too short for 51P/G operation.

Set B (50/51) Performance Tests (Mfg./Model V1M4)

1. Simulate a 12 kV feeder 3LG fault downstream of Breaker 17 by COMTRADE playback injection and record the following:
    a. Download event record from the relay
    b. Fault Initiation Time: 4:34:11.498 PM
    c. Relay Fault Pickup Time: 4:34:11.506 PM
    d. Relay Trip Initiation Time: 4:34:11.515 PM
    e. Relay 52a Open Detected Time: 4:34:11.545 PM
    f. Relay Element Tripped: 50P
    g. Comments: Feeder too short for 51P operation.

2. Simulate a 12 kV feeder 1LG fault downstream of Breaker 17 by COMTRADE playback injection and record the following:
    a. Download event record from the relay
    b. Fault Initiation Time: 4:39:41.080 PM

c. Relay Fault Pickup Time: 4:39:41.088 PM
d. Relay Trip Initiation Time: 4:39:41.089 PM
e. Relay 52a Open Detected Time: 4:39:41.112 PM
f. Relay Element Tripped: 50P and 50G
g. Comments: Feeder too short for 51P/G operation.

Test Case #12 – Capacitor Bank Unbalance Protection (59N)

Relay Test Setup Conditions and Requirements

1. The test was performed on one manufacturer's high-performance numerical feeder relay that incorporated zero-sequence over-voltage elements (59N). The selected relay to be evaluated was:
   a. Mfg./Model V3M2
2. $3V_0$ overvoltage element settings matched those installed in the identified substation relays as much as possible.
3. For pre-commercial demonstration testing, a static test plan was developed for the relay test set. The secondary voltage signal was directly connected to the relays analog inputs. COMTRADE results for this test are included in Appendix F with the file names described in Section 6.
4. Trip and close signals to the breakers were via GOOSE messages to the capacitor bank automation controller, and the breakers were simulated by latching relays. Programmable pushbuttons on the protective relays were configured to simulate manual trip and close logic to represent panel mounted control switches.

Test Case Voltage and Current Injection from Relay Test Sets

Merging units were not used for this simulation test as it was unlikely that the factory-built capacitor bank would ever use merging units and compatible relays since the wiring was all factory installed and the assembly shipped as one pre-assembled unit to the job site.

59N Performance Tests (Mfg./Model V3M2)

Simulate a capacitor bank $3V_0$ over-voltage condition by relay voltage injection and record the following:

1. Download sequential events recorder (SER) and event recorder (ER) from the protective relay and associated reactor and capacitor bank automation controllers for the tests
2. Event Initiation Time: 16:08:46.024
3. Relay Trip Time: 16.08.46.528
4. Relay 59N element operated with the expected time delay? (Yes/No): Yes
5. Relay 59N element tripped and locked out all capacitor breakers? (Yes/No): Yes
6. Capacitor automation controller cannot operate locked-out breakers? (Yes/No): Yes
7. Comments: 0.5 Sec 59N element definite-time delay.

Test Case #13 – Reactor Unbalance Protection (51Q)

Relay Test Setup Conditions and Requirements

1. The test was performed on one manufacturer's high-performance numerical feeder relay that incorporated negative-sequence ($3I_2$) overcurrent elements (59Q). The selected relay to be evaluated was:
    a. Mfg./Model V3M2
2. $3I_2$ overcurrent element settings matched those installed in the identified substation relays as much as possible.
3. For pre-commercial demonstration testing, a static test plan was developed for the relay test set. The secondary current signals were directly connected to the relays analog inputs. COMTRADE results for this test are included in Appendix F with the file names described in Section 6.
4. Trip and close signals to the breakers were via GOOSE messages to the reactor bank automation controller, and the breakers were simulated by latching relays. Programmable pushbuttons on the protective relays were configured to simulate manual trip and close logic to represent panel mounted control switches.

Test Case Voltage and Current Injection from Relay Test Sets

Merging units were not used for this simulation test as it was unlikely that the factory-built reactor bank would ever use merging units and compatible relays since the wiring was all factory installed and the assembly shipped as one pre-assembled unit to the job site.

Test Case Performance Tests

Test case performance tests were intended to demonstrate proper operation of the test bed setup and relay settings, and to record performance result data for the study test cases. Tripping of circuit breakers was simulated by latching relays connected to MU digital outputs. Critical timing and observed element operation was recorded.

51Q Performance Tests (Mfg./Model V3M2)

Simulate a reactor bank $3I_2$ overcurrent condition by relay current injection and record the following:

1. Download SER and ER from the protective relay and associated reactor and capacitor bank automation controllers for the tests
2. Event Initiation Time: 15:36:35.014
3. Relay Trip Time: 15:36:35.735
4. Relay 51Q element operated with the expected time delay? (Yes/No): Yes
5. Relay 51Q element tripped and locked out all reactor breakers? (Yes/No): Yes
6. Reactor automation controller cannot operate locked-out breakers? (Yes/No): Yes
7. Comments: 51Q Element has inverse-time delay.

Test Case #14 – Reactor and Capacitor Bank VAR Control Automation

Relay Test Setup Conditions and Requirements

1. The test was performed with two automation controllers that match the existing installations, and incorporate both GOOSE digital and analog signaling. The selected automation relay to be evaluated was:

a. Mfg./Model V3M4

2. The test was performed using one manufacturer's high-performance numerical overcurrent relay to measure and signal VAR flow data via GOOSE analogs. This relay was used to line impedance and overcurrent protection (see Line Distance and Directional Overcurrent Test Case above), but was mapped to MU3 which was transformer primary breaker CB7. The selected relay to be used was:

    a. Mfg./Model V3M1

3. Automation controller logic settings matched those installed in the most recent capacitor and reactor bank installations as much as possible.
4. For pre-commercial demonstration testing, a static test plan was developed for the relay test set because RTDS simulation files would be too large for the relay test sets for what was a slow operating control function (switching in/out reactors and capacitors would never be performed quickly in regulatory control applications to avoid voltage instability and excess wear on the breakers). The secondary current and voltage simulation signals from the test set were connected to the appropriate MU analog inputs. SER results for this test are included in Appendix F with the file names described in Section 6.
5. Trip and close signals to the breakers were via GOOSE messages to the reactor bank automation controller, and the breakers were simulated by latching relays. Programmable pushbuttons and targets on the protective relays and automation controllers were configured to simulate manual trip and close logic to represent panel mounted control switches and panel status lamps for the breakers.

Test Case Voltage and Current Injection from Relay Test Sets

1. MU3 (69/138 kV BK41 CB 7)
    a. Mfg./Model V7M1
    b. CTR= 400T
    c. PTR= 700T (W. bus)

Capacitor and Reactor Bank Automation Performance Tests (Mfg./Model V3M1 and V3M4)

1. Starting from a reset position with the 51Q and 51N relay lockouts reset, and no capacitor or reactor bank simulated breakers closed, apply a VAR flow into the transformer above the threshold switching point (+1.8 MVAR):
    a. Did capacitor bank controller add a cap within the expected time delay? (Yes/No): Yes
    b. Did reactor bank controller add operate? (Yes/No): No
    c. Did proper breaker status indicators indicate? (Yes/No): Yes
    d. Can additional cap steps be added if VAR flow was maintained above threshold for programmed delay time? (Yes/No): Yes
    e. Comments: Delays set faster than actual installations to speed lab demonstration.

2. Starting from the last capacitor step added state, apply a VAR flow out the transformer above the threshold switching point (-1.8 MVAR):
    a. Did capacitor bank controller remove a cap within the expected time delay? (Yes/No):Yes
    b. Did reactor bank controller add operate? (Yes/No): No
    c. Did proper breaker status indicators indicate? (Yes/No): Yes
    d. Can additional cap steps be removed if VAR flow was maintained above threshold for programmed delay time? (Yes/No): Yes
    e. Comments: Delays set faster than actual installations to speed lab demonstration.

3. Continuing with the capacitor step removal action keep applying a VAR flow out the transformer above the threshold switching point (-1.8 MVAR):
    a. Did capacitor bank controller remove all caps within the expected time delay? (Yes/No):Yes
    b. Did reactor bank controller start adding reactor steps after the capacitor breakers were all opened and with the expected delay time? (Yes/No): Yes
    c. Did proper breaker status indicators indicate? (Yes/No): Yes
    d. Can additional reactor steps be added if VAR flow was maintained above threshold for programmed delay time? (Yes/No): Yes
    e. Can the reactor bank controller add all the reactance steps in the specified time delay period, one at a time? (Yes/No): Yes
    f. Comments: Delays set faster than actual installations to speed lab demonstration.

4. Apply a VAR flow into the transformer above the threshold switching point (+1.8 MVAR):
    a. Will the reactor bank controller remove all reactance steps within the expected time delay until the capacitor and reactor were back at the original starting point of no reactance correction applied? (Yes/No): Yes
    b. Comments: Delays set faster than actual installations to speed lab demonstration.

5. Demonstrate manual cap and reactor bank operation:
    a. Will each controller manually add and subtract reactance steps under pushbutton command? (Yes/No): Yes
    b. Will the reactor bank controller block adding capacitor steps while any reactor step breakers were closed? (Yes/No): Yes
    c. Will the capacitor bank controller block adding reactor steps while any capacitor step breakers were closed? (Yes/No): Yes
    d. Comments: Delays set faster than actual installations to speed lab demonstration.

6. Download SER from each bank controller that records the actions above for the project test record.

Test Case #15 – Line Frequency and Voltage (81, 27, and 59)

Relay Test Setup Conditions and Requirements

1. The tests were performed on two different manufacturers' high-performance numerical line relays that incorporated under/over voltage and frequency elements. The selected relays to be evaluated were:
    a. Set A - Mfg./Model V2M2
    b. Set B – Mfg./Model V3M1
2. Voltage (27/59) and frequency (81) protection element performance were evaluated in a separate test case test from line differential (87L), distance (21), and overcurrent (50/51) test cases due to the typical time delay used with these protective elements
3. For pre-commercial demonstration testing, simulation of 27, 59 and 81U events were performed by use of a relay test set with pre-programmed static test plan. Because relay elements used for tripping on voltage or frequency were delayed far longer than fault protection elements, an RTDS simulation generated COMTRADE file was too large to use for playback testing. COMTRADE results for this test are included in Appendix F with the file names described in Section 6.
4. Trip and close signals to the breakers were via GOOSE messages to the appropriate MUs, and the breakers were simulated by latching relays. Programmable pushbuttons on the protective relays were configured to simulate manual trip and close logic to represent panel mounted control switches.

Test Case Voltage and Current Injection from Relay Test Sets

1. MU1 (69/138 kV Line CB 2) for Set A
    a. Mfg./Model V1M5
    b. CTR= 400T
    c. PTR= 700T (W. bus)

2. MU2 (69/138 kV Tie CB 3) for Set B
    a. Mfg./Model V3M3
    b. CTR= 400T
    c. PTR= 700T (W. bus)

3. MU3 (69/138 kV BK41 CB 7) for Set B
    a. Mfg./Model V7M1
    b. CTR= 400T
    c. PTR= 700T (W. bus)

Set A (27, 59, 81U) Performance Tests (Mfg./Model V2M2)

1. Simulate a 138 kV under-voltage condition by COMTRADE playback injection and record the following:
    a. Download event record from the relay
    b. Event Initiation Time: 4:33:20.002
    c. Relay Pickup Time: 4:33:20.014
    d. Relay 27 Trip Initiation Time: 4:33:21.017

e. Relay 27 Elements operated with the expected time delay? (Yes/No): Yes
f. Relay recorded the correct voltage magnitude? (Yes/No): Yes
g. Comments: 1.0 sec. programmed element delay.

2. Simulate a 138 kV over-voltage condition by COMTRADE playback injection and record the following:
   a. Download event record from the relay
   b. Event Initiation Time: 4:30:50.994
   c. Relay Pickup Time: 4:30:50.014
   d. Relay 59 Trip Initiation Time: 4:30:51.017
   e. Relay 59 Elements operated with the expected time delay? (Yes/No): Yes
   f. Relay recorded the correct voltage magnitude? (Yes/No): Yes
   g. Comments: 1.0 sec. programmed element delay.

3. Simulate a 138 kV under-frequency condition by COMTRADE playback injection and record the following:
   a. Download event record from the relay
   b. Event Initiation Time: 8:33:35.944
   c. Relay Pickup Time: 8:33:36.144
   d. Relay 81U Trip Initiation Time: 8:33:36.644
   e. Relay 81U Elements operated with the expected time delay? (Yes/No): Yes
   f. Relay recorded the correct system frequency? (Yes/No): Yes
   g. Comments: 0.5 sec. programmed element delay.

Set B (27, 59, 81U) Performance Tests (Mfg./Model V3M1)

1. Simulate a 138 kV under-voltage condition by COMTRADE playback injection and record the following:
   a. Download event record from the relay
   b. Event Initiation Time: 10:27:26.981 AM
   c. Element Pickup Time: 10:27:27.017 AM
   d. Relay 27 Trip Initiation Time: 10:27:27.184 AM
   e. Relay 27 Elements operated with the expected time delay? (Yes/No): Yes
   f. Relay recorded the correct voltage magnitude? (Yes/No): Yes
   g. Comments: 10 cycle (166.7ms) programmed element delay.

2. Simulate a 138 kV over-voltage condition by COMTRADE playback injection and record the following:
   a. Download event record from the relay
   b. Event Initiation Time: 10:04:30.980 AM
   c. Element Pickup Time: 10:04:31.016 AM
   d. Relay 59 Trip Initiation Time: 10:04:31.183 AM
   e. Relay 59 Elements operated with the expected time delay? (Yes/No): Yes
   f. Relay recorded the correct voltage magnitude? (Yes/No): Yes
   g. Comments: 10 cycle (166.7ms) programmed element delay.

3. Simulate a 138 kV under-frequency condition by COMTRADE playback injection and record the following:
   a. Download event record from the relay
   b. Event Initiation Time: 10:57:35.542 AM

c. Element Pickup Time: 10:57:35.559 AM
d. Relay 81U Trip Initiation Time: 10:57:36.059 AM
e. Relay 81U Elements operated with the expected time delay? (Yes/No): Yes
f. Relay recorded the correct system frequency? (Yes/No): Yes
g. Comments: 0.5 sec. programmed element delay.

11. TEST RESULTS AND DATA ANALYSIS

The analysis of test results and data and the methodology for the development of findings are discussed below. After the testing was completed, each of the items identified in the test plan were reviewed and assigned to an engineer for analysis.

Measurement and Verification

The project team provided metrics for the performance of their traditional hardwired protective relay system. The primary measurement of interest was the protection system operation time. This time was measured from the initiation of the fault condition until the relay received status that the breaker simulator had operated. These values were used to compare the performance of the IEC 61850 protection and control schemes, identified in the use cases, to the traditional P&C schemes. This information was readily obtained from the relay event recorders and COMTRADE waveform capture capabilities in the relays. See Appendix F for COMTRADE graphical analysis.

Interoperability was more subjective. In general, the interoperability requirements were met if any two devices could communicate via GOOSE and SV. The fact that the test system was able to simulate all the use cases was evidence that interoperability was achieved.

Impacts on Existing Substation and Transmission Protection

The main protection concerns that were identified in this project were speed and reliability. The following items address these concerns.

Reliability – Protection

Protection with IEC 61850 SV performs no differently than a hardwired instrument transformer application of protection relays. The real differences were in how the instrument transformer signals reached the relays and were mapped to the protective elements within the relays themselves.

As far as performance under faulted conditions, simulations performed as part of the study showed that there was little if any impact by going to fully digital CT and PT analog data streams supplied by MUs. Modern numerical relay manufacturers already perform analog to digital conversion at sampling rates equal to those used in MUs. Whether the relay operates with locally produced digitized analog data, or from a remote MU, makes little difference to the protection performance. The potential for a slight additional delay in transmission and reception of remote SV signals does exist, but it could be minimized with good process bus design methodology to avoid any possibility of excessive data latency due to packet collisions.

In this study, relay performance observed during testing far exceeded any requirements that would be expected for application in a distribution substation interconnected to a sub-transmission system. This finding was in line with expectations of replacing existing devices with new devices that have the same or better functionality.

Reliability – Communications

This section considers the reliability of the baseline system vs. the SV and GOOSE implementation for the transportation of CT/PT measurements and binary interlock signals. Reviewing how analog CT/PT and binary signals currently get to the protection relays using the base case system design, one finds the following major components:

- Substation equipment providing the signal source:
    - CT and PT measurement apparatus
    - Breaker and disconnect switch auxiliary (AUX) position contacts

    - Breaker and disconnect switch trip and close coils inputs
- Signal transport:
    - Hardwired point-to-point signal cables
    - Terminal blocks at various locations in the signal path
    - At least one test switch for test signal injection and trip circuit blocking at each protective relay
- Protection relays:
    - CT and PT inputs and signal conditioning circuits
    - Binary inputs and signal conditioning circuits

Using IEC 61850 changes some of the major components and adds additional ones as follows:

- Substation equipment providing the signal source:
    - CT and PT measurement apparatus
    - Breaker and disconnect switch AUX position contacts
    - Breaker and disconnect switch trip and close coils inputs
    - IEC 61850 source merging unit with:
        - CT and PT inputs and signal conditioning circuits
        - Binary inputs and signal conditioning circuits
        - Network Interface Controller
        - At least one test switch for test signal injection and trip circuit blocking
- Signal transport:
    - Fiber optic cable
    - Process bus Ethernet network switch(es)
        - NOTE: Using a process bus HSR network eliminates the network switch(es)
- Protection relays:
    - Network Interface Controller

- IEC 61850 adds an additional IED at the signal source while moving the inputs and signal conditioning circuits from the protection relay to the field installed merging unit. Given that fully tested hardwired installations are generally very reliable, reliability might be reduced by having a single merging unit provide the information to multiple protection relays. However, IEC 61850 does not eliminate the standard practice for overlapping zones of protection for backup failure, and with its additional features, it provides continuous on-line monitoring and alarming for signal failures that a typical hardwired P&C system does not. The IEC 61850 method may add a single point of failure with the merging unit, but with proper design, the potential loss of reliability could be mitigated.

- The multiple copper wires handling individual signals were replaced by a single fiber optic cable, which interfaced at the merging unit, process bus Ethernet network switch, and the protection relay with a single network interface controller on each end of the fiber optic cables that comprise this path. However, including signal path redundancy to an IEC 61850 system was very easy and fairly cost effective, and all equipment used in this study all had this capability.

- The base system did not depend on an accurate GPS sourced time synchronization that an IEC 61850 solution requires.

- Having a test switch at each merging unit could have an increased possibility of test contacts being left open or placed in the wrong position due to its location in the field equipment. This problem also existed with the base system, but the base system did not have the capability to monitor and alarm failure of these signals continuously like an IEC 61850 system.

The IEC 61850 method can be just as reliable, if not more reliable, than a hardwired protection system, but it does introduce additional single points of failure, which need to be mitigated. The IEC 61850 solution provides many built-in redundancy options such as dual merging units, network redundancy using PRP and/or HSR and the flexibility of adding additional protection relays to improve reliability.

Speed of Operations

One interesting finding of protection performance identified during this study, which was not caused by the application of IEC 61850 SV, was a 1-5 ms penalty in protection element operating times that were observed when test results from application specific and software-defined relays were compared. Software defined or "universal" relays were marginally slower to operate when presented with the same fault simulation as the application specific relays and when the same protection elements were compared. Because software defined relays could be configured in a multitude of ways with a large set of potential protection elements to choose from, the task of optimizing protection operating times was made more difficult for the relay design engineer.

For most protection applications, other than at extra high voltage (EHV) or where grid stability would be a concern, the observed difference in operating times would make little if any practical difference and the flexibility of a software defined relay may be of great advantage. Software defined relays do impose a greater time requirement upon the protection engineer to configure and set them, which should be considered before deciding to apply them; better configuration software tools going forward will alleviate this issue.

Impacts on Existing Substation Systems and Equipment

The main substation and equipment impacts associated with an IEC 61850 implementation were the need for IEC 61850 capable protective relays, requirements for additional equipment to be installed in the field, and impacts to control building equipment.

The protective relays that SDG&E currently uses do not have IEC 61850 capabilities or if they do, the capabilities are limited to GOOSE and MMS. Based on currently available IEC 61850 compatible devices, SDG&E would need to adopt different manufacturers and relay types into their substation standards to implement IEC 61850 with process bus functionality.

Additional equipment would need to be installed in the substation yard for an IEC 61850 application that utilizes sampled values. Merging units need to be installed in the yard equipment cabinets which will also require CT/PT test switches, a fiber optic patch panel, DC power, and an AC source for test equipment. Additionally, breaker control switches, local/remote switches, and other types of control switches may need to be moved from the control shelter to the equipment cabinets or duplicated in the equipment control cabinets for use when testing. Either the yard equipment control enclosures need to be sized to accommodate this additional equipment or separate stand-alone enclosures would be required to house the new equipment.

For the control shelter, additional communication equipment such as Ethernet switches must be installed for the IEC 61850 system. Depending on how equipment was located within the racks, this may require additional rack space. Typically additional rack space could be made available when moving from a hardwired solution to an IEC 61850 solution, so this available space would be utilized for the additional Ethernet switches. A larger battery system in the control shelter was also anticipated due to the additional DC load from Ethernet switches and merging units.

Impacts on System Operations

If the IEC 61850 system was limited to within the substation and if properly integrated with the SCADA equipment, there should be little apparent change from a system operations perspective. The main impact to system operations would be any changes made to the location of control switches within the substation. Operational procedures may need to be updated if control switches were moved from the control shelter to the equipment cabinets. Even with an IEC 61850 implementation, there should still be breaker control capability in the control shelter whether it is physical control switches or programmable push buttons on the protective relays.

Maintenance Impacts

The biggest impact from a maintenance perspective will be protective relay testing. If merging units were installed in the substation yard, relay technicians would need to set up test equipment at that location. Test switches for these MUs would be in the equipment cabinets as well.

If additional test switches were desired in the control shelter, for isolation of protective relays from trip circuits and close circuits, they would need to be added. During testing relay technicians would need to put the protective relays in a “test mode” which will communicate to other protective relays to not take action based on received GOOSE messages for trip and close commands.

Costs

The project team performed a cost comparison between the traditional P&C scheme and one using IEC 61850 GOOSE and SV. This estimate calculated the installed costs of the items that would no longer be required with the process bus design and compared that to the costs for the additional equipment with one possible process bus design.

Estimate Assumptions

- This estimate only included the installation costs for the difference between the legacy design and the process bus design
- The estimate assumed that MUs were located in the substation yard high-voltage equipment control enclosures, with relays in the control shelter
- The estimate assumed that 12 kV relays and MUs were located in factory constructed metal-clad breaker assemblies
- Wiring between MUs/relays and equipment terminal blocks remains so these costs were excluded from the estimate
- Test switches will be required in the field equipment but these were already a part of the legacy design so there was no additional material included for these
- Each field wiring run was assumed to start at the field equipment and was run to the Control Shelter and terminated. An additional run of cable was required to connect from the marshalling cabinets/incoming terminal blocks to the panels in the control shelter
- Labor and control cable costs were obtained from the project team
- Current quotes were obtained for legacy IEDs
- Prices on other miscellaneous items were obtained from previous projects

- Impacts to ancillary systems were not studied (Arc Flash, DC bus short circuit interrupting capability, etc.)
- Costs of the process bus IEDs were those obtained during the material acquisition phase for the test system
- Improvements in Engineering efficiency were not tabulated since they were anticipated to be highly dependent on each utility's level of IEC 61850 experience and how each utility allocates its workforce
- These costs were based on one possible design. This design could be optimized to reduce these costs

The costs for the items that would no longer be required for the legacy design were calculated. They were shown in Table 26. These costs would reduce the substation overall cost.

TABLE 26 COSTS FOR TIMES NO LONGER REQUIRED FOR LEGACY DESIGN

QUANTITY	DEVICE TYPE	DESCRIPTION/ DETAILS	COST EACH DELIVERED TO SDG&E	EXTENDED PRICE
7	Meter		1,725.00	12,075.00
6	Ethernet Switch		2,623.00	15,738.00
2	GPS Clock		1,700.00	3,400.00
2	Relay		5,418.00	10,836.00
2	Relay		13,530.00	27,060.00
10	Relay		4,193.00	41,930.00
2	Relay		6,685.00	13,370.00
1	Relay		6,115.00	6,115.00
1	Relay		5,800.00	5,800.00
8	Relay		3,917.00	31,336.00
2	Relay		8,435.00	16,870.00
2	Automation Controller		2,700.00	5,400.00
2	Serial Cable	40 feet	41.92	83.84
1	Serial Cable	7 feet	32.00	32.00
1	Serial Cable	3 feet	21.00	21.00
1	Serial Cable	10 feet	12.06	12.06
1	Serial Cable	7 feet	11.00	11.00
1	Serial Cable	15 feet	14.71	14.71
1	Serial Cable	30 feet	22.66	22.66
1	Serial Cable	5 feet	28.00	28.00
37	Control Cable	1,305 feet	0.74	965.70
14	Control Cable	480 feet	1.42	681.60
7	Control Cable	320 feet	2.77	886.40
11	Control Cable	1,090 feet	1.10	352.00
17	Control Cable	1,910 feet	1.80	576.00
5	Control Cable	550 feet	3.27	1,046.40

QUANTITY	DEVICE TYPE	DESCRIPTION/ DETAILS	COST EACH DELIVERED TO SDG&E	EXTENDED PRICE
20	Control Cable	4,000 feet	2.00	640.00
7	Control Cable	1,400 feet	3.69	1,180.80
89	Terminal Blocks	12 position	31.01	2,759.89
32	Shorting blocks	12 position	44.20	1,414.40
4,048	Terminal Lugs	Ring tongue	0.61	2,469.28
4,048	Labels	Package of 200	29.65	600.12
60	Battery	Cells, 365AH	490.35	29,421.00
1	Charger	Charger	4,431.00	4,431.00
1	Battery Rack	High seismic rated 2 tier	3,003.00	3,003.00
659	Labor	Install labor	83.68 $/hr.	55,145.12
			Total	**237,579.86**

The costs for the additional items that would be required with the process bus design were then calculated. They were shown in Table 27. These costs add to the cost of the overall substation.

TABLE 27 COSTS FOR ADDITIONAL ITEMS REQUIRED FOR PROCESS BUS DESIGN

QUANTITY	DEVICE TYPE	VENDOR CODE	COST EACH DELIVERED TO SDG&E	EXTENDED PRICE
7	Panel meter	N/A	350.00	2,450.00
2	GPS Clock	V3M5	4,970.00	9,940.00
8	Ethernet Switch	V4M1	9,388.00	75,104.00
21	MU	V3M3	5,695.00	119,595.00
11	Relay	V3M1	9,170.00	100,870.00
2	Automation Controller	V3M4	2,700.00	5,400.00
2	Relay	V3M2	2,835.00	5,670.00
13	Relay	V2M1	11,825.00	153,725.00
2	Relay	V2M2	11,488.00	22,976.00
3	Relay	V2M3	12,970.00	38,910.00
4	Fiber Plant	N/A	389.60	1,558.40
60	Battery	N/A	832.65	49,959.00
1	Charger	N/A	6,704.25	6,704.25
2	Battery Rack	N/A	3,093.30	6,186.60
			Total	**599,048.25**

The reader can see that the process bus initial installation costs are significantly greater than the costs estimated for the legacy design. Initial material costs are a primary driver for this cost increase. Some of the reasons for this cost increase are listed below:

- All SV relay and merging units are early generation equipment. The manufacturers are currently charging a premium for these relays as the technology is implemented in their most capable numerical relays
- The addition of IEC 61850 protocols to relays currently increases cost
- SV requires MUs to be installed in all the equipment, in the substation yard, that is associated with the process bus
- Process bus adds a significant amount of DC load to the amount allocated for P&C. This is due to the additional Ethernet equipment and MUs. In this estimate the P&C load increased by approximately 170%. This increase in load required a larger DC plant to supply the load.

Despite the increase in initial material costs, it was anticipated that process bus material costs will reduce as adoption rates increase and the equipment becomes more common. But even with a significant decrease in material costs, IEC 61850 requires additional P&C infrastructure to support the equipment for a process bus implementation. This will likely remain a cost increase when compared to the legacy design.

The labor costs associated with the process bus implementation were reduced significantly. This was primarily due to the reduction in wiring. However, this cost reduction was not as significant as the increase in material costs.

Future savings were anticipated to offset these costs as the engineering effort was reduced by leveraging utility specific standards and templates which were less complex. Substation apparatus could be specified to include factory installation of MUs, further driving down costs. Current industry estimates suggest that IEC 61850 with process bus can reduce engineering time by as much as 75%. In addition, future substation additions and changes will require significantly less effort and cost as much of the new work would be implemented in software.

Finally, IEC 61850 prepares the utility for a digital future that will support features and applications that are only starting to become available. These could include additional diagnostic features and self-test capabilities.

Taking the long view, it would be conceivable that relays will only be available from manufacturers with IEC 61850 features and no hardwired connections in the next 15-20 years, much like what has occurred with the transition to numerical relays from electromechanical and static models. This technology transition was driven not only by improved features and capabilities, but the semiconductor manufacturing industry's tendency to continue to shorten the production lifespan of critical components.

Pros and Cons

Like any new endeavor, migrating to an IEC 61850 process bus P&C scheme includes benefits and drawbacks. This section identifies some of these items.

Pros

Wiring

A very significant advantage to IEC 61850 was reduction in hard wired control circuits and its attendant complexity. All of this complexity gets moved to configuring the protective relays and IEC 61850 communications between devices. Obviously, this saves on wiring, terminating, labeling, and reduces the chances of wiring errors. It also reduces fabrication time and expense for protection panels and reduces construction and testing time at the substation. With the reduction in field wiring, the required time in the field for installation and testing of protection panels could be reduced from weeks to days.

CT Performance

One big advantage with SV protection was that current and potential signals were transmitted across the process bus network in primary engineering units, allowing maximum CT and PT ratios to be used without compromising accuracy or impacting signal fidelity and internal protective relay setting limitations. This has an obvious advantage with impedance relaying, where protection settings developed in secondary units were dependent on the instrument transformer connected ratios, where CTs were frequently tapped down to bring the maximum secondary impedance within the relay's fixed setting range. Because of a multi-ratio CT's poorer electromagnetic performance (saturation) at lower ratios, avoiding reduced taps was a great advantage. With the move towards SV, future relays could be set in primary units, eliminating a major issue in existing protection methodology.

Semantic Model

IEC 61850 provides a semantic model for standardized structured data exchanges between devices. This allows for standard object model names. Thus the data becomes visible without configuration, which enables self-description of the IEDs. An IEC 61850 protocol browser can be used to view the capabilities of an IEC 61850 device even before the device was placed in service at the substation. The schema also allows the configuration files to be standardized into IEC 61850 file types. These file types can be used to support configuration and engineering efforts.

GOOSE

By its nature high speed GOOSE messages were ideal for relay to relay and relay to MU message transfer. It allowed for supervision of the link due to its periodic retransmission properties. Studies of GOOSE timing have identified that it typically performs far faster than hardwired I/O, which was limited by the time to close electromechanical contacts. Within the industry, GOOSE was currently fairly mature and a GOOSE application would be an ideal candidate for an early implementations. Currently, the IEC 61850 standard development teams were working on an implementation of GOOSE for substation to substation control communication.

Sampled Values

SV messages separate the sampling of analog values from their calculation and metering. They allow analog values to be measured one time and shared among applications. Not only does this reduce wiring effort and time, it also allows for consistent high quality data with a minimum of infrastructure and the time to verify calibration during routine maintenance.

Engineering Effort

Engineers will be able to test protective system development in a basic lab environment while developing settings before they were deployed in an actual substation. This will reduce schedule pressure and errors. It will also allow P&C schemes to be developed as standard templates which will significantly reduce future deployment time and improve quality.

Interoperability

One of the most significant goals of the IEC 61850 Standard was interoperability. If consistently implemented, it would allow IEDs from different manufacturers to communicate, exchange data, and make use of the information. It would simplify the design, construction, implementation, commissioning, testing, and maintenance of P&C systems in substations. Allowing users to select any manufacturer's device, apply it with any other manufacturer's device, and be assured that the devices would interoperate would be an enormous benefit to the industry and all users.

Lockout relays

At the request of the project team, lockout relay functionality was implemented within certain relays. This allowed the project team to better visualize the way that a "digital" lockout scheme would perform. While this was not a unique benefit associated with an IEC 61850 P&C scheme, it does demonstrate the capability of advanced numerical relays. The adoption of this type of lockout relaying would eliminate traditional hardwired lockout relays, cumbersome wiring and simplify the NERC PRC-005 testing.

Cons

Limited Interoperability at this Time

The drawbacks to IEC 61850 for the project team included limitations of the current industry technology across manufacturers, the need for modifications to current standards and practices, and the required training of personnel for the large technology shift. The results of this study showed that not all relay manufacturers support sampled values in a completely interoperable manner. Some manufacturers' relays were also much easier to learn and configure than others – an important consideration during the selectin process. Furthermore, interoperability across relay manufacturers was inconsistent. This study found that IEC 61850 SV technologies were still developing in the industry and further development was needed for consistent interoperability between relay manufacturers.

Migration Process

This EPIC-2, Project 1 served as a technology demonstration and feasibility study. In this case, adopting IEC 61850 process bus appears feasible. The next step in the process would be to determine a precise list of the exact functions and features of IEC 61850 that SDG&E would like to adopt. This list should include those functions and features that were beyond the scope of this project.

SDG&E now has the opportunity to evaluate their current standards and determine how they can be modified to accommodate future technologies like IEC 61850. This could include:

- Provisioning future rack/panel space to accommodate the additional communication equipment that will be required in the control shelter
- Increasing the size of control cabinets in transformer, breakers, and other equipment so that the addition of merging units and associated equipment may be easily installed
- Verification that a standard control shelter size can accommodate the larger battery system required for an IEC 61850 application
- Development of a training program around IEC 61850 to cover the technology itself, testing, and operations
- Identification and implementation of small pilot applications, to develop experience with IEC 61850. Implementation of the capacitor/reactor automation logic would be a very achievable project that would allow SDG&E to gain valuable experience in a low risk manner
- Development of a larger pilot project to test the technology in full substation implementation. This pilot project should serve as the basis for developing new standards for station drawings, relay settings, SCADA, and communication configurations. A small substation located in close proximity to a maintenance center would be an ideal candidate for this type of pilot project

- The relays in SDG&E's standards do not currently have IEC 61850 process bus capabilities. This means that new standard drawing packages, relay configurations, and define new equipment standards for IEC 61850 applications will need to be created. The project team may even have to switch to different protection philosophies and suppliers when implementing IEC 61850. An example was the high-impedance bus differential relay applied on some transmission buses. This application would still require a significant amount of CT wiring, in the field to a central summing point, for conversion of the analog signals into an MU readable signal
- Currently IEC 61850 is not used extensively in SDG&E's substations. Adoption of IEC 61850 will mean new technology for the protection and substation design engineers to learn and develop expertise around. Furthermore, field support personnel, such as operators and relay technicians, will also experience the technology change. For operations, testing, procedures will have to be modified to fit the new technology. As an example, when MUs were installed in field devices for SV and GOOSE, some testing will need to be performed at the breakers and transformers located in the substation yard, instead of in the air-conditioned control shelter.

12. KEY FINDINGS

Based on a review of the pre-commercial demonstration test results and execution of the test system design and relay settings/IEC 61850 configurations, the following key findings were developed:

- Multi-vendor interoperability is not universal for the products tested in this project. Because these initial integration efforts were significant, future implementations should benefit from these experiences.
- Use of IEC 61850 SV did not impact relay performance, as compared to a direct hardwired solution, as long as the process bus network was correctly designed and utilizes managed switches for MAC address filtering as necessary.
    - Other than the obvious wiring and data communications advantages that IEC 61850 GOOSE and SV have over conventional hardwired relay installations, protection settings and schemes did not change with an IEC 61850 process bus installation, as basic protection concepts did not change.
- All SV based test cases evaluated were able to be implemented with IEC 61850 process bus. The technology evaluated was at a point where it could be applied to utility protection applications, assuming careful attention to equipment selection for compatibility.
- GOOSE messages successfully replaced traditional hard wire status and control wiring in the project. Analog values that were embedded within GOOSE data sets, successfully controlled a reactive automation application.
- IEC 61850 process bus compatible relays and merging units were still so new that the manufacturers' technical sales representatives were only generally familiar with application and configuration. One should expect to initially spend a considerable amount of engineering time on resolving IEC 61850 process bus configuration issues and locating manufacturer staff that will be able to provide the required engineering support.
- Manufacturers have not coalesced around fully interoperable SV options; IEC 61850-9LE still has a large potential for differences that allows manufacturers' equipment to meet the standard, yet not work with each other without a large amount of end-user effort.
- IEC 61850 GOOSE/MMS messaging was stable with good interoperability between different manufacturers' equipment. Configuration tools were fairly easy to learn and use.
- Relay manufacturers' documentation, as far as implementing an SV application, was lacking and many critical items can be expected to be discovered only by extensive communication with the manufacturers to learn unpublished information and facts.
- SV compatible relays require the capability to subscribe to at least six SV channels, with the ability to internally map the various voltage and amperage signals to the proper protection elements without limitations, if the technology was to maximize its potential to replace hardwired equipment. The overcurrent bus differential use case proved this fact.
- MUs should support, at a minimum, a built-in SER for GOOSE I/O troubleshooting. Built-in capability to implement basic Boolean logic and an ER would be very desirable features too. Some of the test system MUs supported Boolean logic, an ER, and a time stamped SER.
- MUs should integrate analog inputs with digital inputs and outputs into a small panel mounted enclosure for easy field installation in yard apparatus such as transformers and circuit breakers. Only two manufacturers' MUs evaluated in this study were close to meeting this requirement.

- Only one manufacturer's MU used in the study was easily interfaced with all three manufacturers relays evaluated in the study. MUs generally worked very well with relays built by the same manufacturer.
- Manufacturers' relay and MU configuration software packages were still a "work in progress." One major relay manufacture's software evaluated was found to be very difficult to work with, with multiple non-integrated applications, which required direct assistance by the manufacturer's staff to complete the configuration tasks. This level of complexity would not be acceptable in an implementation environment. Other relay manufacturers' software packages were fairly user friendly and intuitive. The majority of the issues encountered during configuration were eventually resolved with assistance from the manufacturers' support staff.
- Ethernet switches necessary to integrate all the parts of an IEC 61850 SV substation have a power demand significantly higher than the relays and MUs themselves, which could impact station battery sizing and should not be ignored.
- The network and time synchronization system proposed for the test system provided a broad range of support to cover the various vendors' networking and time synchronization interfaces. It also provided the quantities and types of equipment to simulate the required process bus architectures and fiber implementation that would occur in a real substation installation.
- The initial material costs of a substation designed with IEC 61850 GOOSE and SV P&C was calculated to be greater than the initial material costs of a traditional P&C substation.
- Some manufacturers' relays require different ports for SV and GOOSE signals intended for the same process bus connection. This was a disadvantage that must be rectified in future models because it impacts the ability to connect the relays to both the station and process buses, provide a port for dedicated maintenance access.
- The results support this project's EPIC value proposition in that the P&C scheme evaluated was anticipated to be at least as reliable, if not more so, than the existing legacy P&C scheme. Although the initial costs of a P&C scheme as described in this project may be higher, it was anticipated that the on-going costs will be reduced.
- The project's goals to investigate interoperability and determine protection system performance were achieved:
  - The interoperability determination was successful. Although interoperability was not universally achieved for all of the devices, enough interoperability was achieved to allow for testing of all of the protection use cases identified in the project scope.
  - Performance of the protection relays using an IEC 61850 P&C scheme were verified to equal or exceed the performance requirements set by the project team.

IEC 61850 Implementation Challenges

Transitioning protection design philosophy from using direct CT/PT and I/O connections to each protection relay to using IEC 61850 GOOSE and SV still presents many challenges.

The first challenge would be to design the infrastructure that would serve as the signal transport medium, replacing the hardwired copper cable. Process bus design and equipment assignment was an important first step which drove parts of the network equipment specification. The manufacturers had different limitations on how the equipment could interface with the process bus which introduced network complexity and interoperability issues. Another important component required by IEC

61850 SV was time synchronization. A mix of time synchronization requirements was identified from the various manufacturers included in this project, which covered the entire list of methods called out in the standard. The test system design team found a GPS clock source that could support all of these time source types and provide network isolation between the various networks.

With the release of edition 2, for many of the IEC 61850 parts, new challenges arose in determining which edition to use for the project. In a single manufacturer solution this would generally not be a problem but with a multi-manufacturer project, it was vital that all of the manufacturers function together under the same SCL model, SV and GOOSE edition. A further challenge in choosing the edition was that most manufacturers were still only providing SV using the UCA International Users Group (UCAIug), "IMPLEMENTATION GUIDELINE FOR DIGITAL INTERFACE TO INSTRUMENT TRANSFORMERS USING IEC 61850-9-2" (LE) which is based on IEC 61850-9-2 Edition 1. A mix of implementations with both edition 1 and edition 2 functions were identified and that added an additional degree of difficulty for the test system implementation.

Another challenge was providing the correct SCL file type and edition necessary to import into other manufacturers' configuration tools. The manufacturers had limitations in their configuration tools for exporting the SCL file type, edition, and providing optional information that was required by other manufacturer configuration tools. In some cases, manual modifications to the SCL files, to allow proper information exchanges, was required. There were numerous character length limitations for the various GOOSE and SV parameter settings which, when exceeded did not produce any errors within the configuration tool. These problems could only be found with the identification of an unrelated problem and working backwards to determine the cause, including application of a network analysis tool. The lack of built-in error checking in the configuration tools required significant additional testing to determine the root cause of problems. Some confusion was identified with one manufacturer's tools, where separate software packages were used for each type of configuration task. In some cases it was not clear how to link the information between the software packages. Appendix H contains a list of observations identified during configuration and testing. This list was anticipated to provide assistance to the engineers responsible for device configuration in future projects.

Protection and merging unit electrical and protection settings were very similar to what was required for the base systems. Some of the protection relays still had some setting requirements around CT and PT ratios, which seemed redundant given that the merging units provided primary values for the samples. This and other settings such as the reference SV stream were different from what the protection engineers were used to but once done, the settings were the same as they have done before.

Testing was another challenge. The development of new procedures to ensure the infrastructure was working correctly was followed by the execution of the protection scheme testing. Good documentation was the key to success and much effort was expended to develop proper dataflow tables and diagrams to communicate all the virtual wiring, GOOSE, and SV used in the system between the various members of the system configuration team. These documents along with the networking and time synchronization diagrams provided the base information to create the testing procedures, and will be crucial when performing actual implementations.

All IEC 61850 implementations challenges were easily solved during the initial equipment selection process and design. Like the traditional design methods, determine the equipment to use, identify which IEC 61850 functions to implement, and determine how the user can work out solutions. Once complete the challenges associated with the first project will be minimized.

13. CONCLUSIONS

Upon review of the demonstration findings, the following conclusions are made:

- The results of this project were very encouraging. SV based P&C were found to be equivalent or better than the legacy hardwired solutions for the use cases identified. IEC 61850 did not degrade and in some cases improved protection, control and automation schemes.
- SV messages were more flexible than the existing traditional hardwired P&C system.
- GOOSE messages were more flexible and faster than the existing traditional hardwired P&C system.
- IEC 61850 SV and GOOSE increased P&C system flexibility and provided opportunities for new P&C schemes due to digitization of the system.
- Although not yet universal, substantial SV interoperability was identified. It was anticipated that interoperability will only improve with time.
- The interoperability results of this project should be of interest to all potential users of SV. The project findings should assist manufacturers with their SV implementations so as to improve interoperability. These results should also assist adopters of IEC 61850 with the selection and evaluation of future manufacturer product offerings.
- Once the team was sufficiently experienced with the products' configuration details configuration time decreased. Configuration templates would be especially valuable in this regard.
- The project provided opportunities to learn more about IEC 61850's limitations, capabilities and vendors' interoperability.

14. RECOMMENDATIONS

The project team recommends that SDG&E continue to explore commercial adoption of IEC 61850 applications within its substations. The project findings and conclusions show that, although care is required in the selection of products, the currently available merging units and relays are sufficiently mature to support interoperability between vendors. In addition, the protection performance of the test system is equivalent to hardwired legacy P&C systems.

The project team further recommends that an SDG&E communications laboratory be developed to support future work and training. This laboratory would include a capability to mock-up future substation communications infrastructure to validate their performance before actual deployment in substations. Although this laboratory would have a focus on IEC 61850, it would also support testing of other communications technologies and standards.

With the completion of the future work items, discussed in the next section, the project team recommends that pilot projects be initiated to gain experience with IEC 61850. Potential pilot projects could include a GOOSE based 12 kilovolt (kV) capacitor control scheme using existing installed hardware, or a three breaker 69 kV P&C scheme. These pilot projects could be precursors towards development of a larger project to test the technology in an actual substation. A pilot project will serve as the basis for developing new standards for station drawings, relay settings, SCADA and communication configurations. A substation located in close proximity to a maintenance center would be an ideal candidate for this type of pilot project because of the training opportunities it provides.

An IEC 61850 design implementation will differ greatly from current hardwired state of the art, and issues such as maintenance, testing and training, must be addressed while embarking on the first implementation of this technology.

SDG&E should make the results of this EPIC project available to the various standards bodies associated with IEC 61850 – especially IEC Technical Committee 57, Working Group 10.

Future work

The following future work items represent valuable next-step options in the adoption of a full IEC 61850 substation. These items would allow the user to gain valuable experience with the IEC 61850 standard. Each item was sized such that a small team of two to three subject matter experts could be identified and assembled to research and develop the necessary components in a relatively short period of time.

Network Optimization

In accordance with the project team's direction, the test system network design was the minimal necessary to complete the testing. Although basic multi-cast filtering was configured, configuration items did not include advanced networking features or optimization. For an actual substation implementation consideration should be given to additional network design and optimization. Suggested items of particular interest may include VLANs, priorities, and multi-cast filtering.

Remote Access

In accordance with the project team's direction, remote access was not explored. It was understood that the project team was investigating this capability as part of a separate project. Internal policies and NERC CIP requirements would need to be investigated in order to determine the level of protection required and the preferred method of achieving this capability.

Redundancy

Redundancy was a broad topic that covers many disciplines. It can include protection design, local network design, and WAN design. Currently the project team has a protection philosophy that provides a degree of redundancy. This philosophy could be combined with local networking to achieve the degree of redundancy necessary to meet the project team's requirements. Combining the protection redundancy requirements with network redundancy could yield synergies and provide significant benefits.

SCADA

The project's scope did not include exploration of metering, data acquisition, or local annunciation. Each of these items presents an opportunity to combine with the IEC 61850 P&C developed in this project to enhance the current design and lower costs.

- Individual panel meters were a standard of the current substation design. The relays included in this project included large LCD screens, which could be used to display local metering. Another option could include stand-alone displays that were connected to serial ports on the relays. Other options could be explored to balance features and costs.
- A station data concentrator, RTU, or gateway that supports GOOSE messages and/or MMS would enable the project team to further reduce station wiring. Multiple products were currently available that support this solution. An engineering study and lab test of these products would enable the project team to identify an acceptable product.
- Similarly, the current use of panel annunciators could be modified to eliminate the serial communications driven annunciators. GOOSE messaging was a potential opportunity to further reduce wiring within the substation.

SV Implementations

This project utilized IEC 61850-9-2, Edition 2 for SV. Many interoperability issues arose from inconsistent design choices between manufacturers concerning the edition 2 implementations. IEC published standard 61869-9 in 2016. This standard provides guidance on the digital interface for instrument transformers. It would be worthwhile to investigate products that have implemented this standard to determine if interoperability would be improved.

15. POST-PROJECT TECHNOLOGY TRANSFER

The project team will submit presentations and papers to major conferences and/or journals. These submissions include, but are not limited to, the annual EPIC Symposium.

The availability of this report on the SDG&E EPIC website https://www.sdge.com/epic will be widely announced.

A PowerPoint presentation will be developed and used to aid in engaging the stakeholder groups within SDG&E. This presentation will also aid in coordination with external stakeholders in IEC 61850.

16.METRICS AND VALUE PROPOSITION:

Metrics:

The following metrics were identified for this project. Given the proof of concept nature of this EPIC project, these metrics are forward looking to prospective adoption of IEC 61850 standards.

The main protection concerns that were identified in this project were speed and reliability. The following items address these concerns.

Potential energy and cost savings

Due to saving on the engineering efforts of the design process using IEC 61850 equipment, which can be reflected to the price of energy for ratepayer.

The main saving comes from the integrated engineering tools that makes it easier to design the substation and test the equipment before deployment, which is hard to achieve now and its is time consuming using the current legacy systems.

Economic benefits

Maintain/Reduce operations and maintenance costs

IEC 61850 digital equipment allows easier maintenance and debugging of the equipment using advanced embedded software tools.

The labor costs associated with the process bus implementation were reduced significantly. This was primarily due to the reduction in wiring.

Improvements in system operation efficiencies and adding automation features

Operation efficiency can be improved using IEC 61850 equipment especially with the new peer-to-peer communication feature, which allows major improvements of operations, and more equipment can be monitored and operated to reduce the cause of outages and improve the efficiency. This also allow more automation in the substation and things like triggering CAP banks and Voltage regulators can be improved.

Value proposition:

The purpose of EPIC funding is to support investments in R&D projects that benefit the electricity customers of SDG&E, PG&E, and SCE. The primary principles of EPIC are to invest in technologies and approaches that provide benefits to electric ratepayers by promoting greater reliability, lower costs, and increased safety. As discussed and summarized below, this project met all three of the EPIC primary principles: reliability, lower cost, and safety, and two of the EPIC secondary principles were applied.

Primary principles

- **Reliability:**
  The new equipment performed all the protection schemes in current substations with a faster initiation time and more operation capabilities.

The new digital system allows easy add and integration of a new equipment without a need of running new wires every time a new IED is added to the network

- **Lower cost:**
  Although the current equipment cost for the new merging units is higher nevertheless, the long run cost is lower due to saving on engineering efforts and design time and reducing the labor cost for wiring in addition to the added operating features.

- **Safety:**
  Reducing the number of wiring reduces the cause of fire due to a short in wires or a failure since the substation racks uses fiber optic.

  Due to peer-to-peer communication feature now you can disconnect lines in case of a failure automatically which avoid the human delay that can cause damage to the network and the grid.

Secondary principles

- **Safe, Reliable & Affordable Energy Sources:**
  As mentioned earlier with peer-to-peer communication, utility networks can perform new safety features that is not available in the current substations which makes it safter and more reliable.

- **Efficient Use of Ratepayers Monies:**
  Saving money in distribution due to the new technologies and features would result in lower distribution and maintenance cost and that can be reflected to the ratepayers energy cost. This can be accomplished using the new engineering tools that comes with IEC 61850 new equipment and the new peer to peer communication without a need to run many cables between equipment in the substation.

Primary Principals			Secondary Principals				
Reliability	Lower Costs	Safety	Loading Order	Low-Emission Vehicles / Transportation	Safe, Reliable & Affordable Energy Sources	Economic Development	Efficient Use of Ratepayers Monies
✓	✓	✓			✓		✓

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APPENDIX A - TEST CASE DATA FLOW DIAGRAMS

The test case data flow diagrams contained in this appendix illustrate the flow of information and which relays and merging units are associated with the case. Use cases that deal with particular conditions, such as the phases of a fault, are not illustrated. Even though the diagram shows all merging units and relays, only the merging units and protection relays which were included in the test are shaded with a blue background and gray cross-hatches. IEC 61850 SV messages are indicated with dotted blue lines. GOOSE messages are indicated with solid black lines. SV and GOOSE message names are indicated near the transmitting device. Arrows on SV and GOOSE messages indicate a device was subscribing to that message.

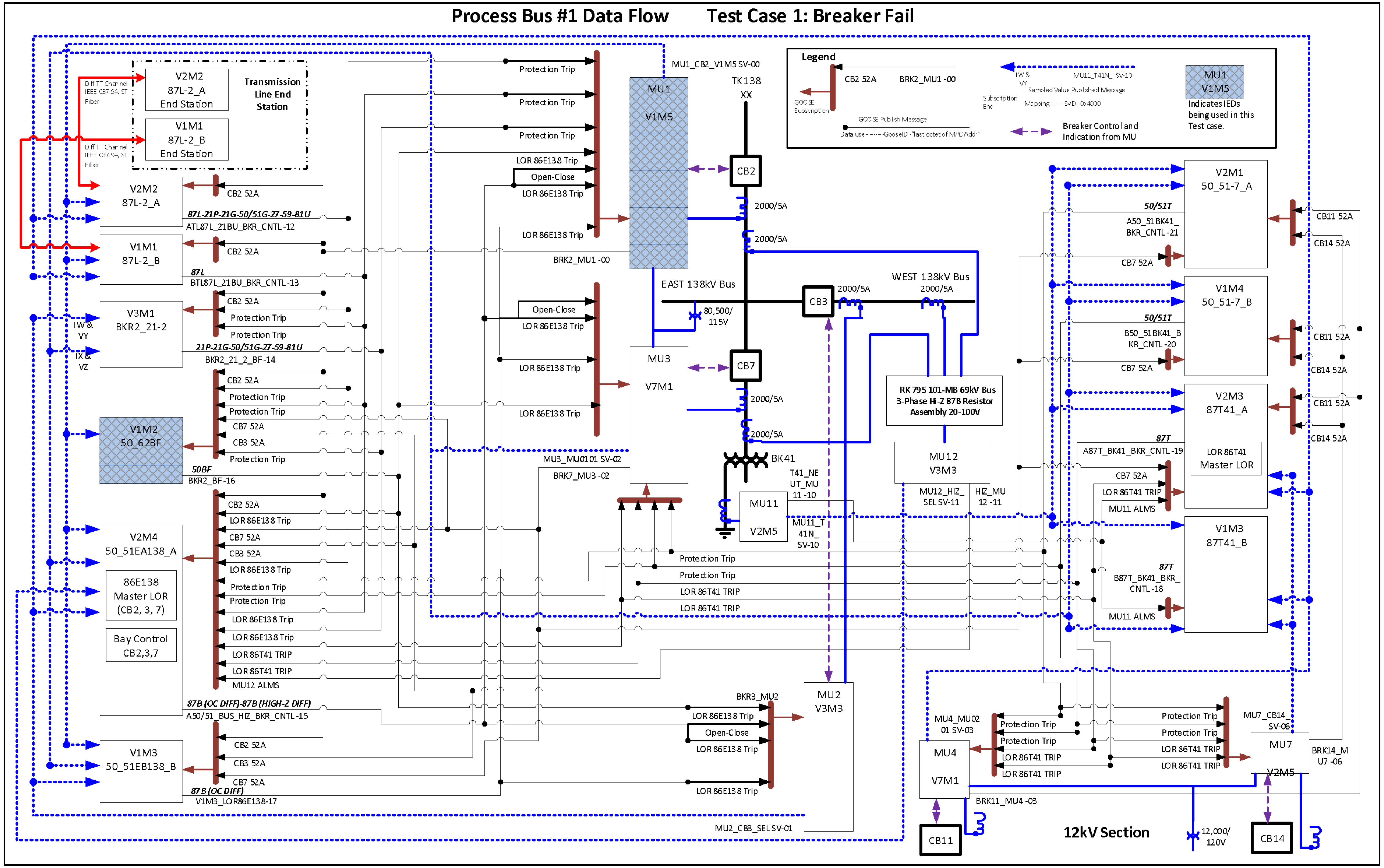

FIGURE 27 BREAKER FAIL DATA FLOW

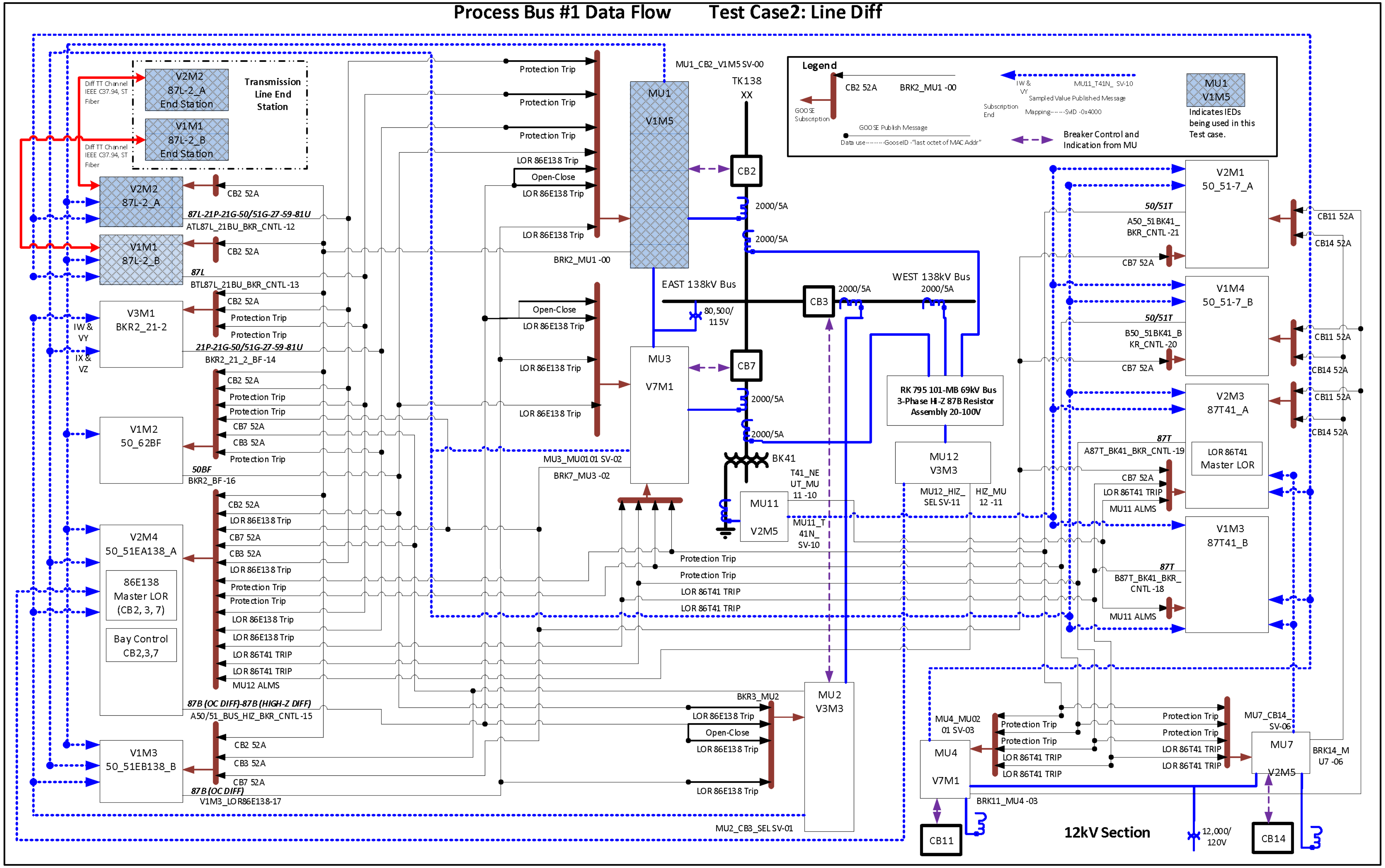

FIGURE 28 LINE DIFFERENTIAL DATA FLOW

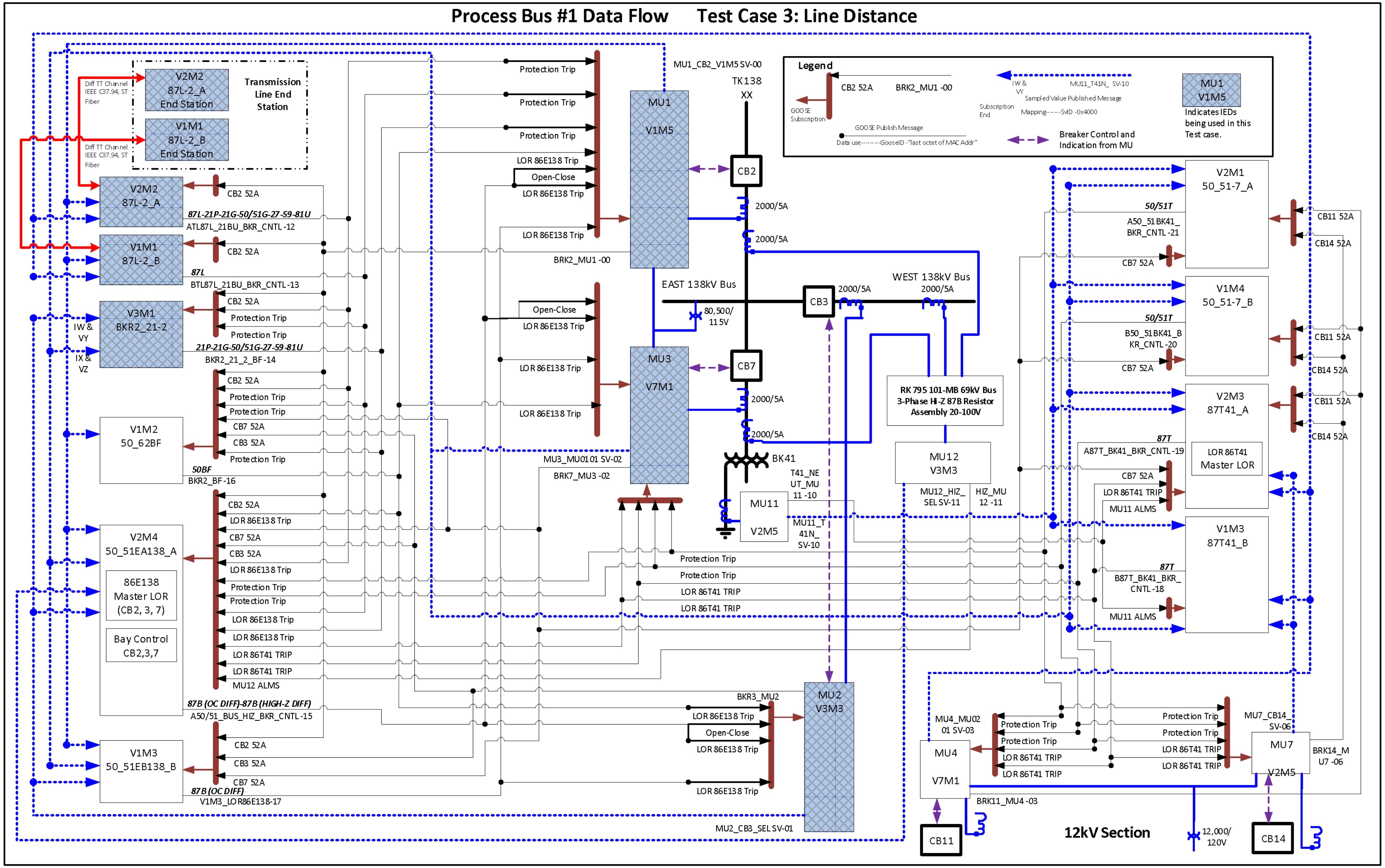

FIGURE 29 LINE DISTANCE DATA FLOW

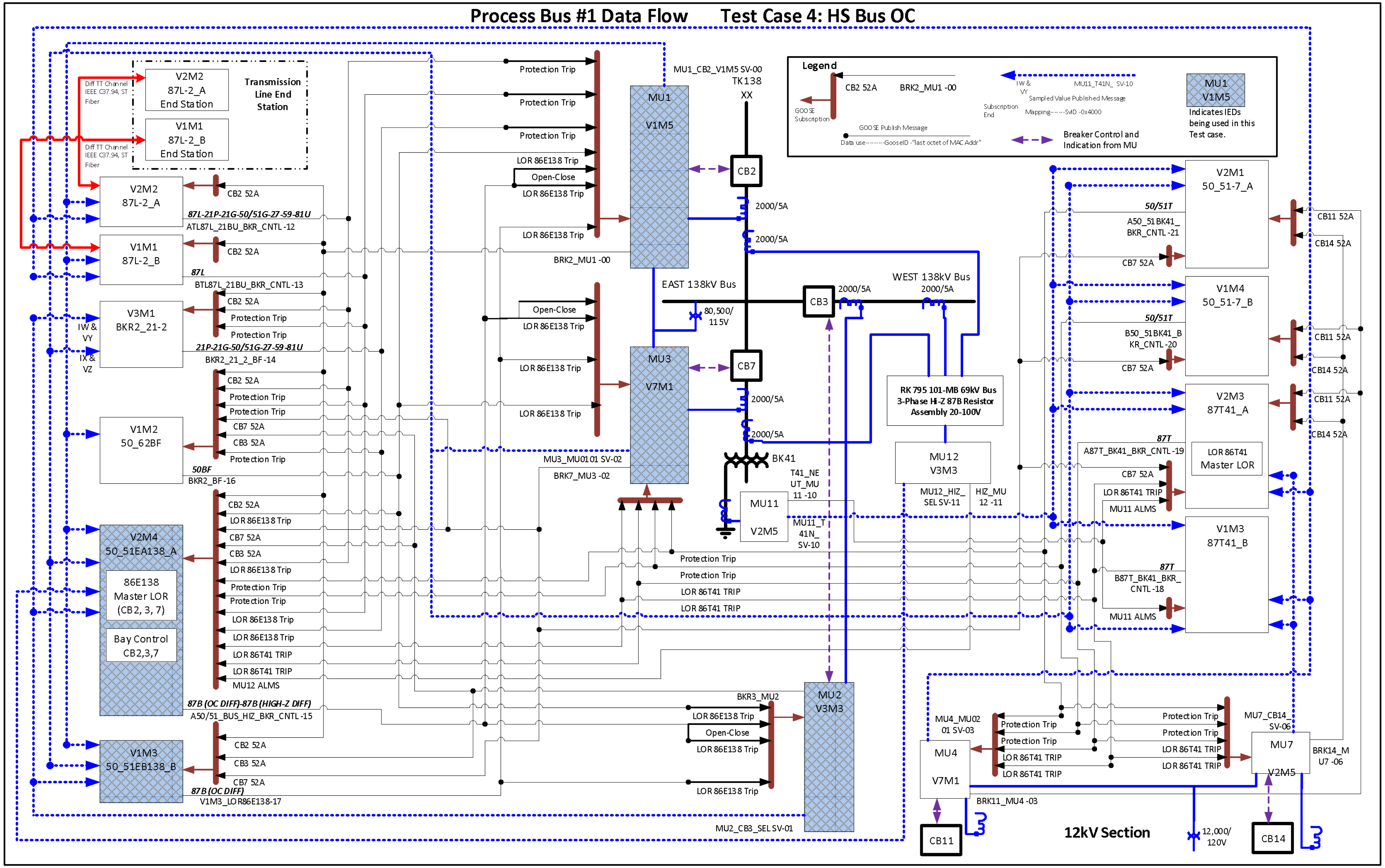

FIGURE 30 HIGH SIDE BUS OVERCURRENT DATA FLOW

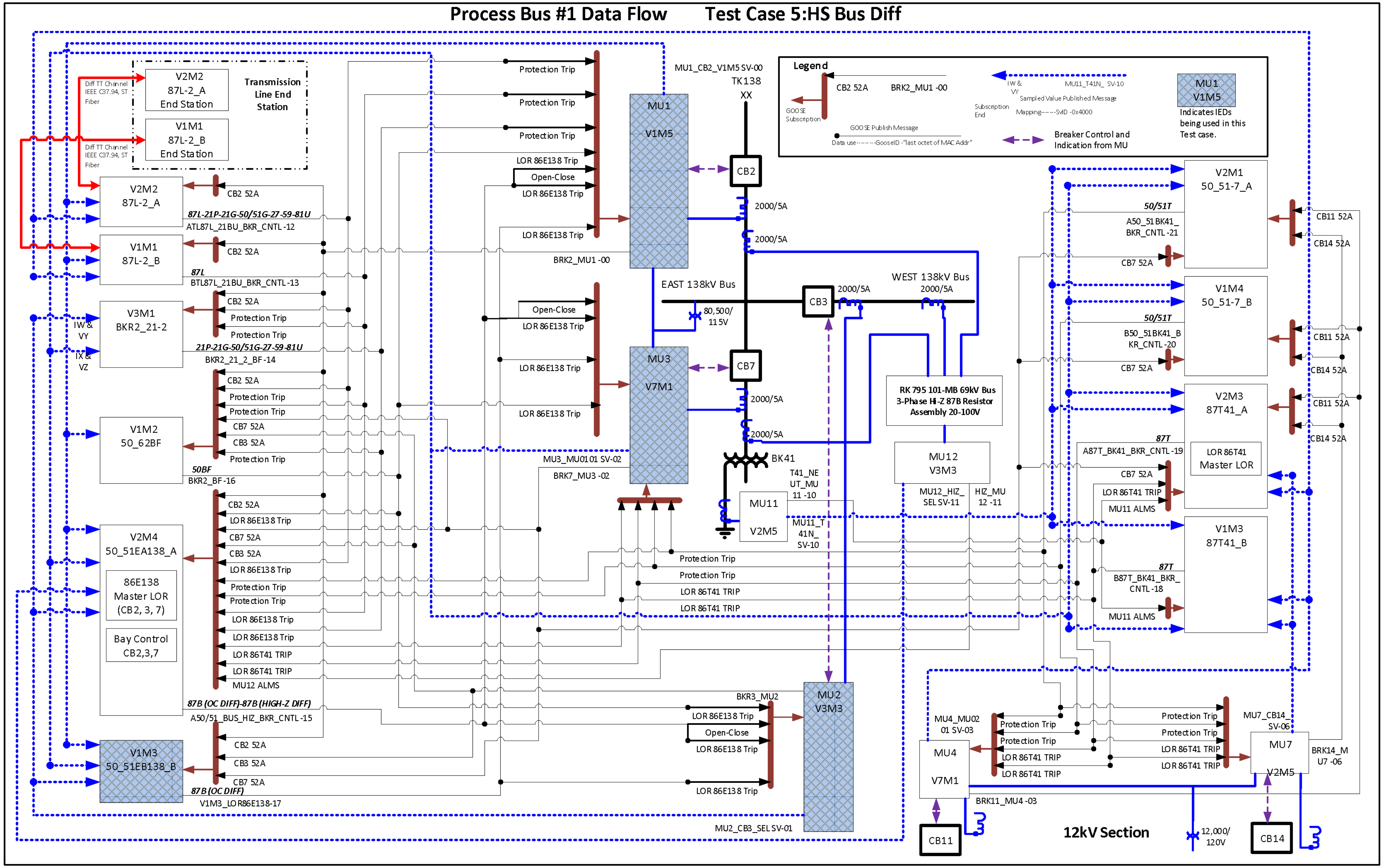

FIGURE 31 HIGH SIDE BUS DIFFERENTIAL DATA FLOW

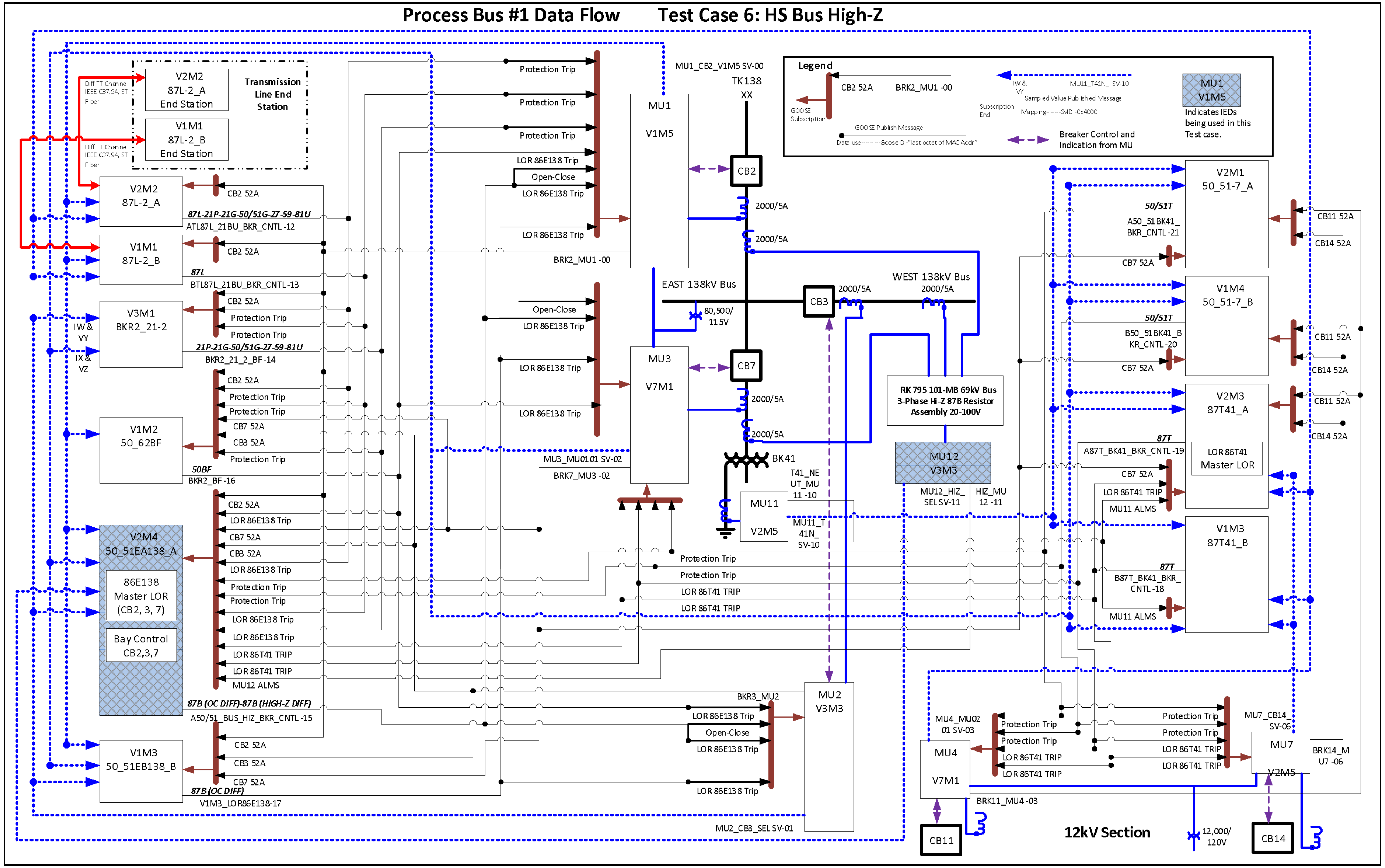

FIGURE 32 HIGH SIDE BUS HIGH-Z DATA FLOW

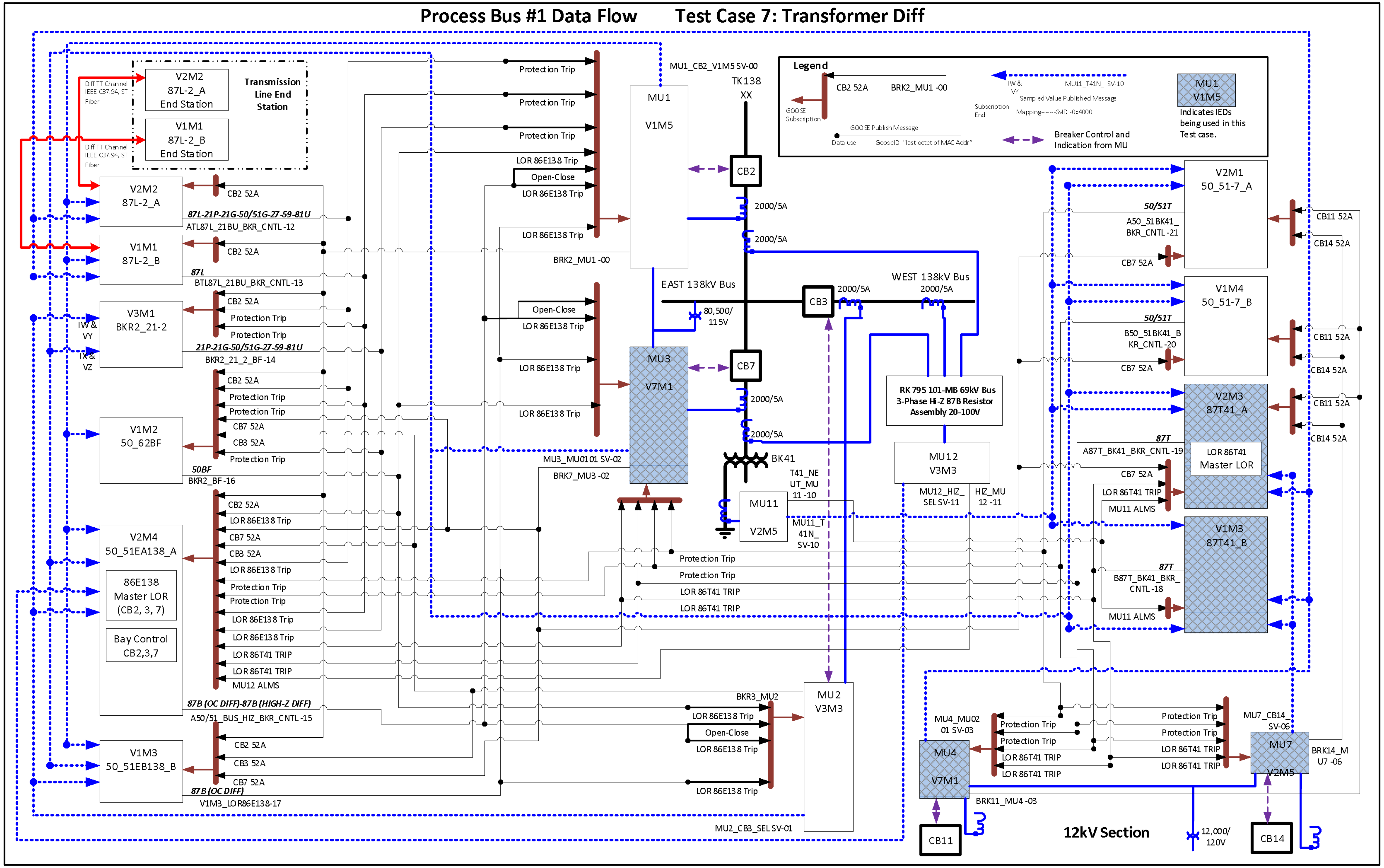

FIGURE 33 TRANSFORMER DIFFERENTIAL DATA FLOW

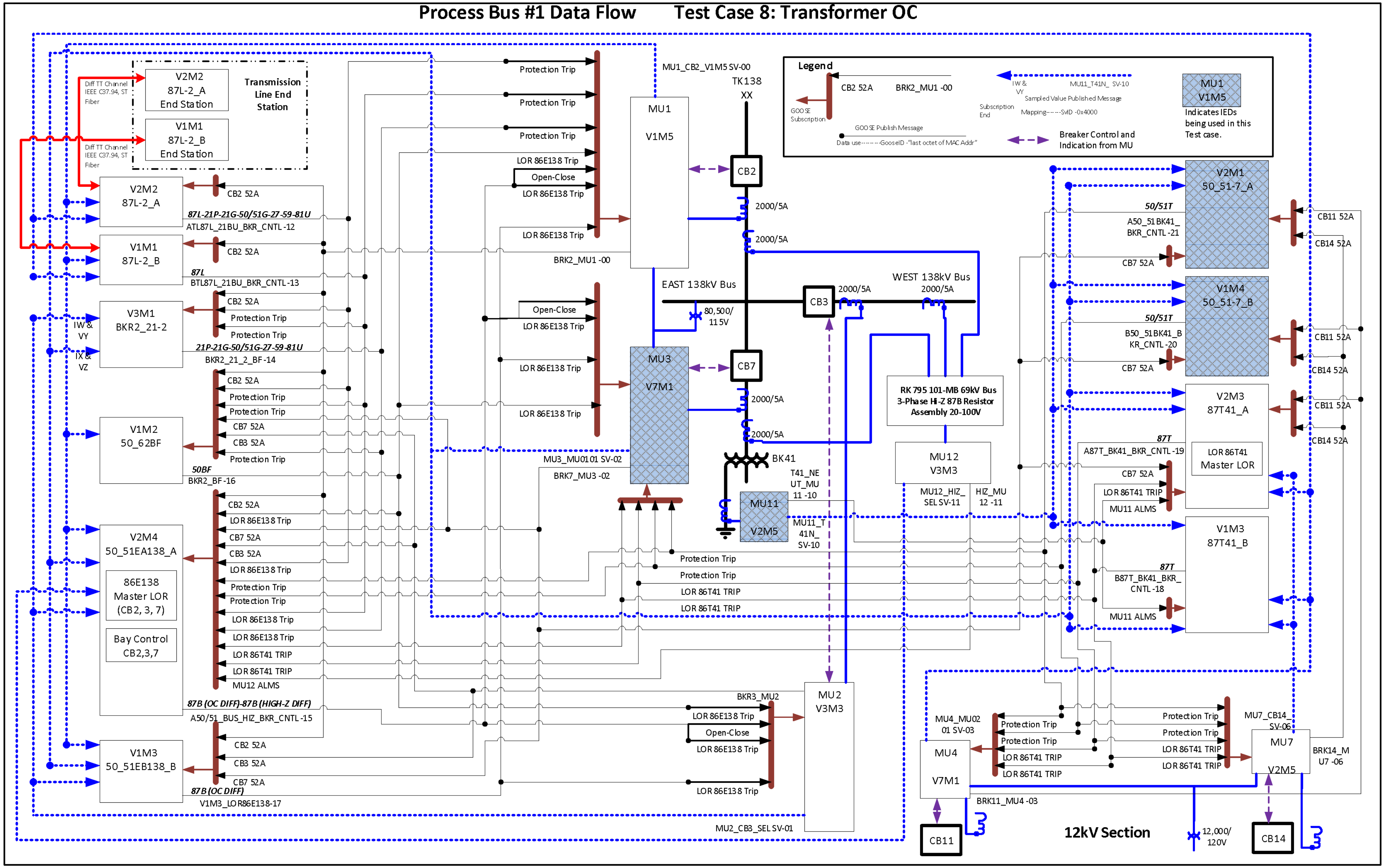

FIGURE 34 TRANSFORMER OVERCURRENT DATA FLOW

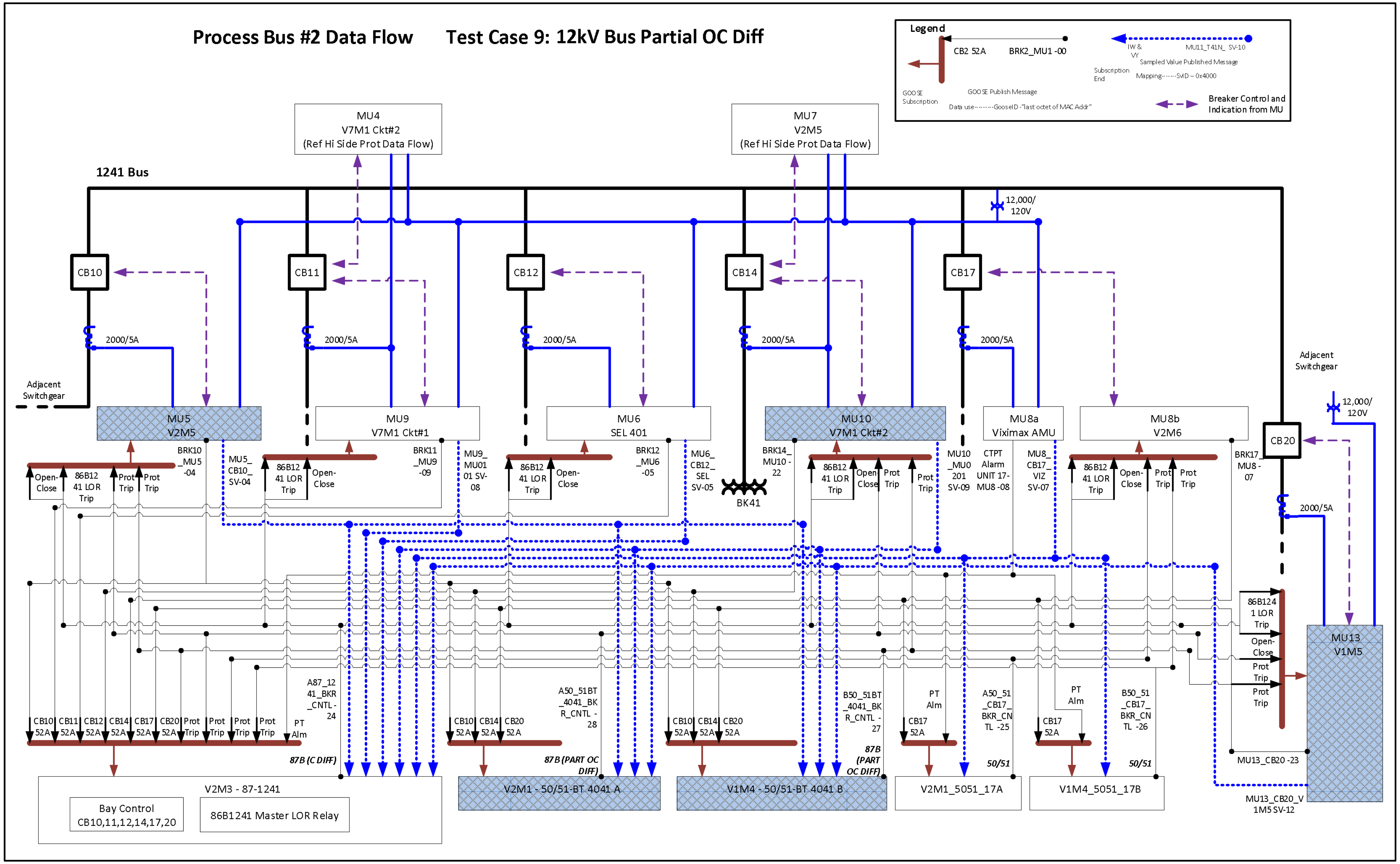

FIGURE 35 12KV BUS PARTIAL OVERCURRENT DATA FLOW

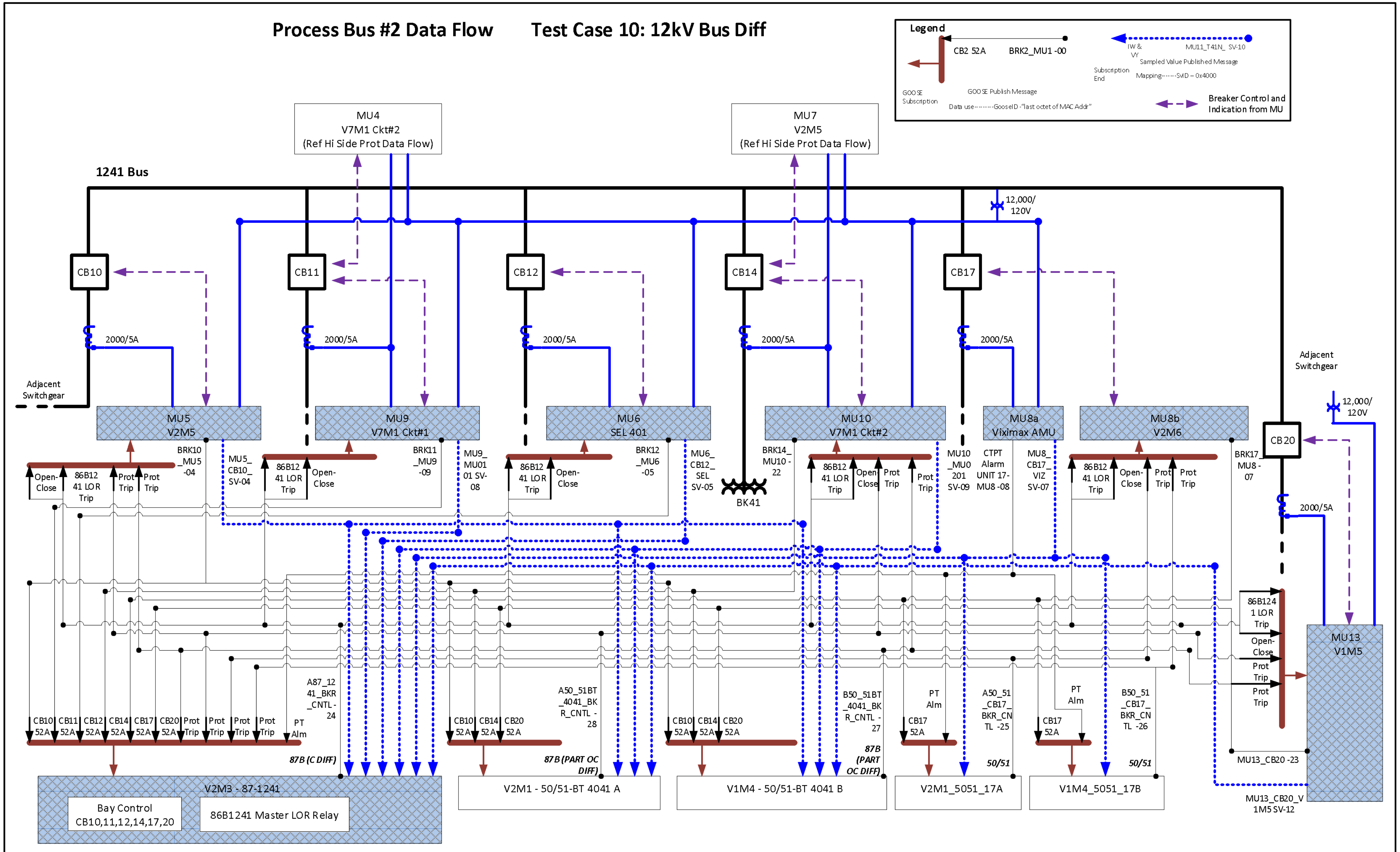

FIGURE 36 12KV BUS DIFFERENTIAL DATA FLOW

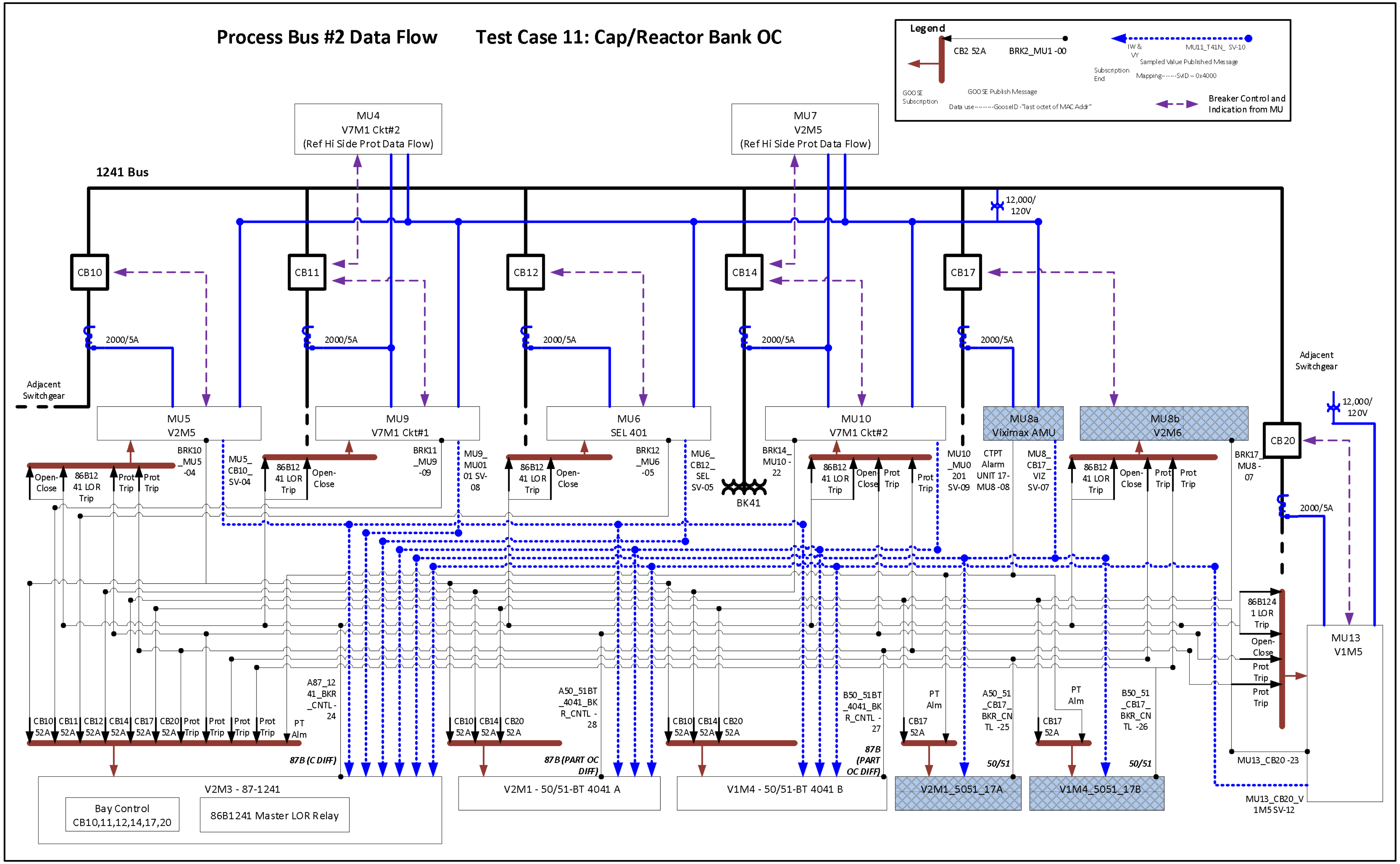

FIGURE 37 CAP/REACTOR BANK OVERCURRENT DATA FLOW

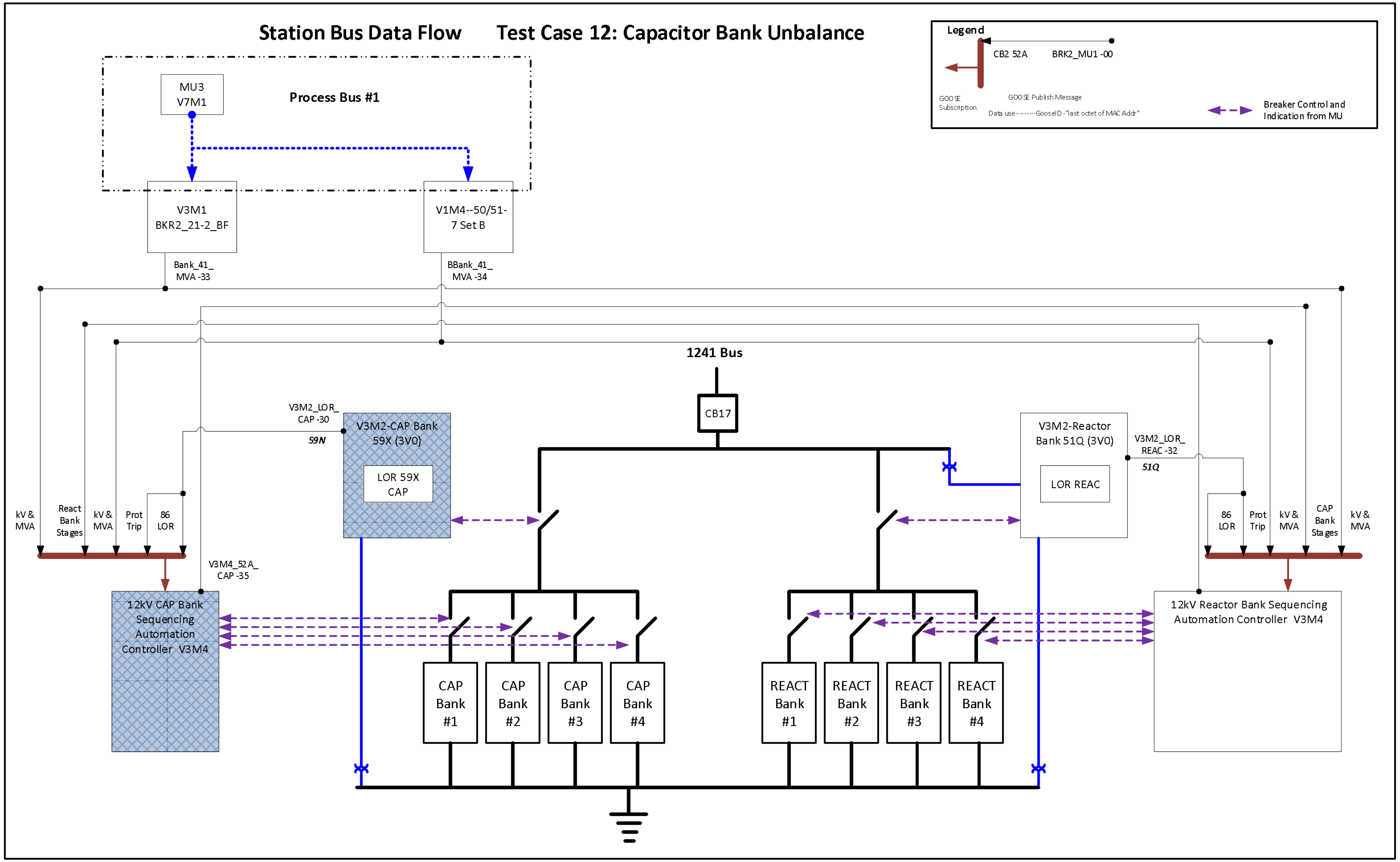

FIGURE 38 CAPACITOR BANK UNBALANCE DATA FLOW

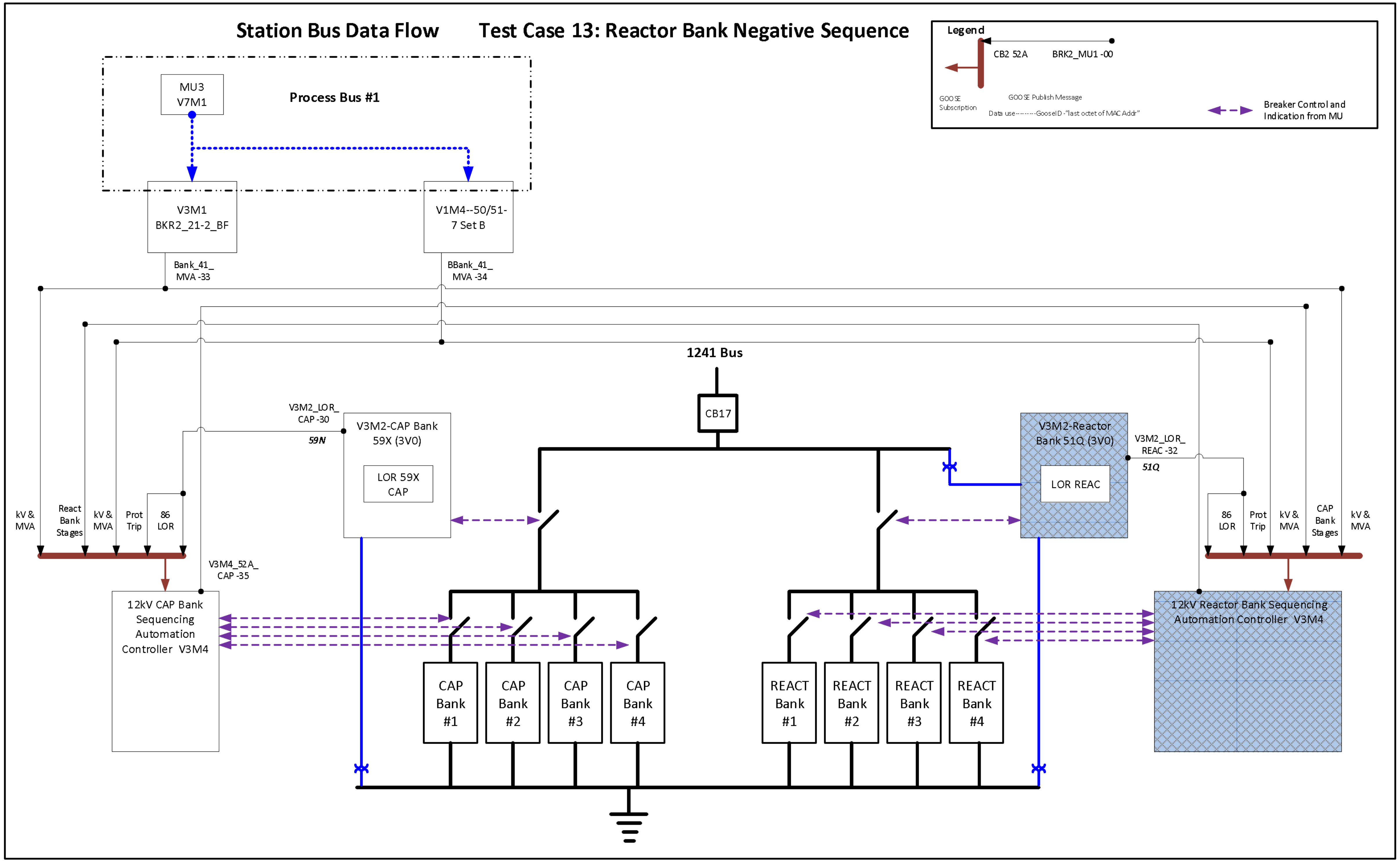

FIGURE 39 REACTOR BANK NEGATIVE SEQUENCE DATA FLOW

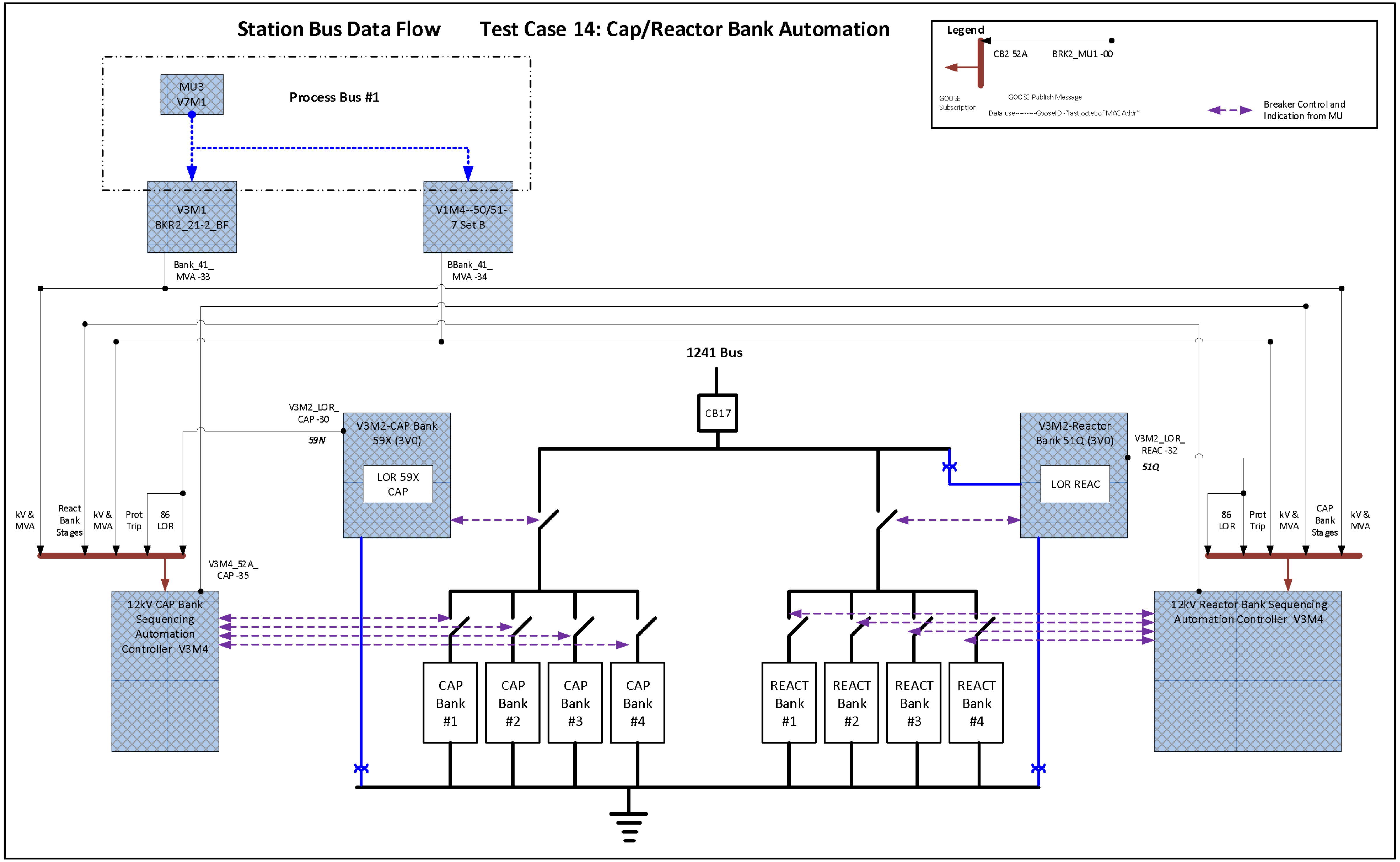

FIGURE 40 CAP/REACTOR BANK AUTOMATION DATA FLOW

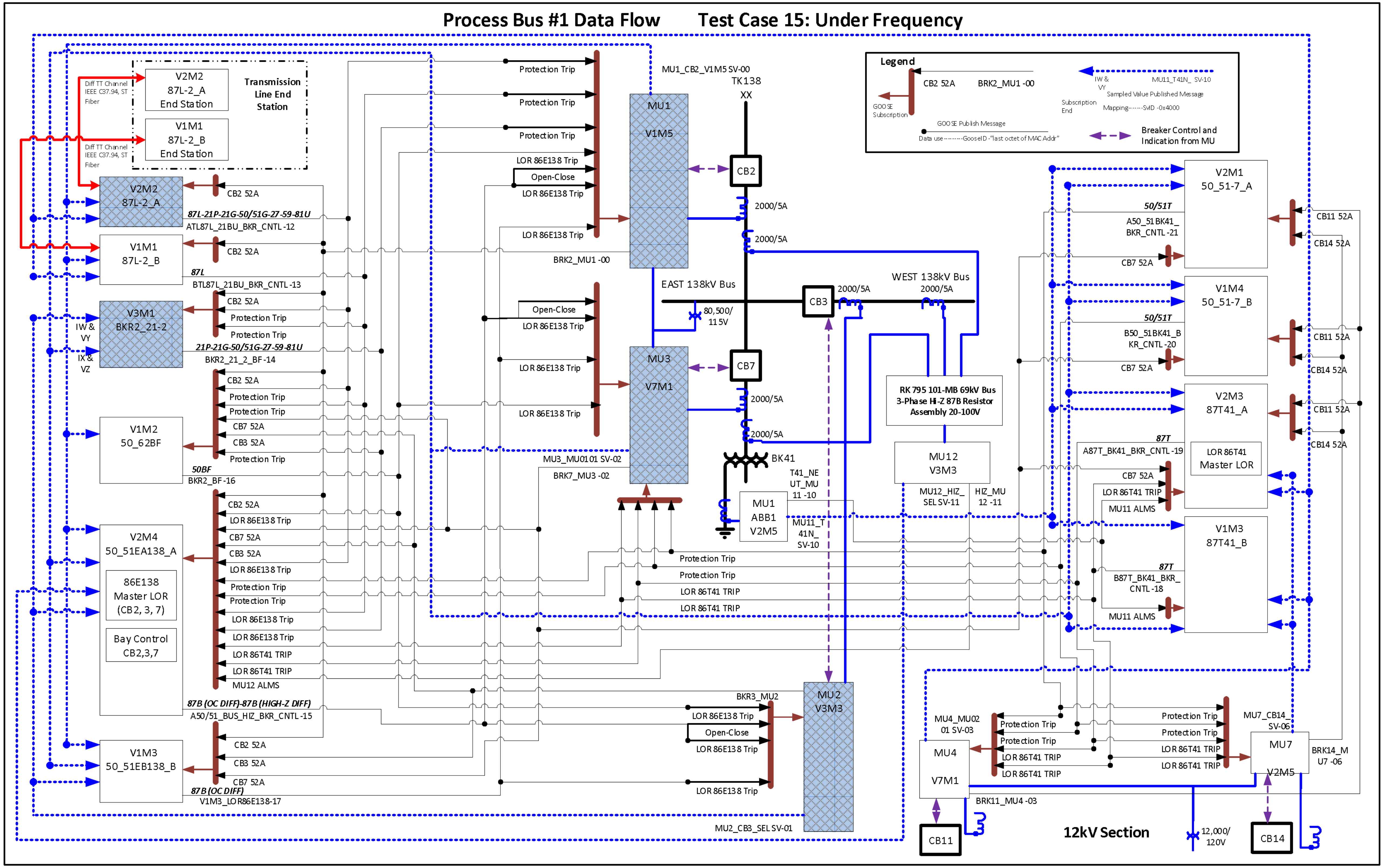

FIGURE 41 UNDER FREQUENCY DATA FLOW

APPENDIX B - RTDS MODEL DIAGRAM

This Appendix B shows the full system model which was used in the RTDS to develop the test parameters and characteristics for each use case. The model in Figure 42 includes all the breakers, capacitors, reactors, transformers and transmission lines in the test system. This diagram also shows the locations of each fault.

Figure 43 shows the RTDS interface. It allowed the display of the controls for each fault as well as breaker status and test results.

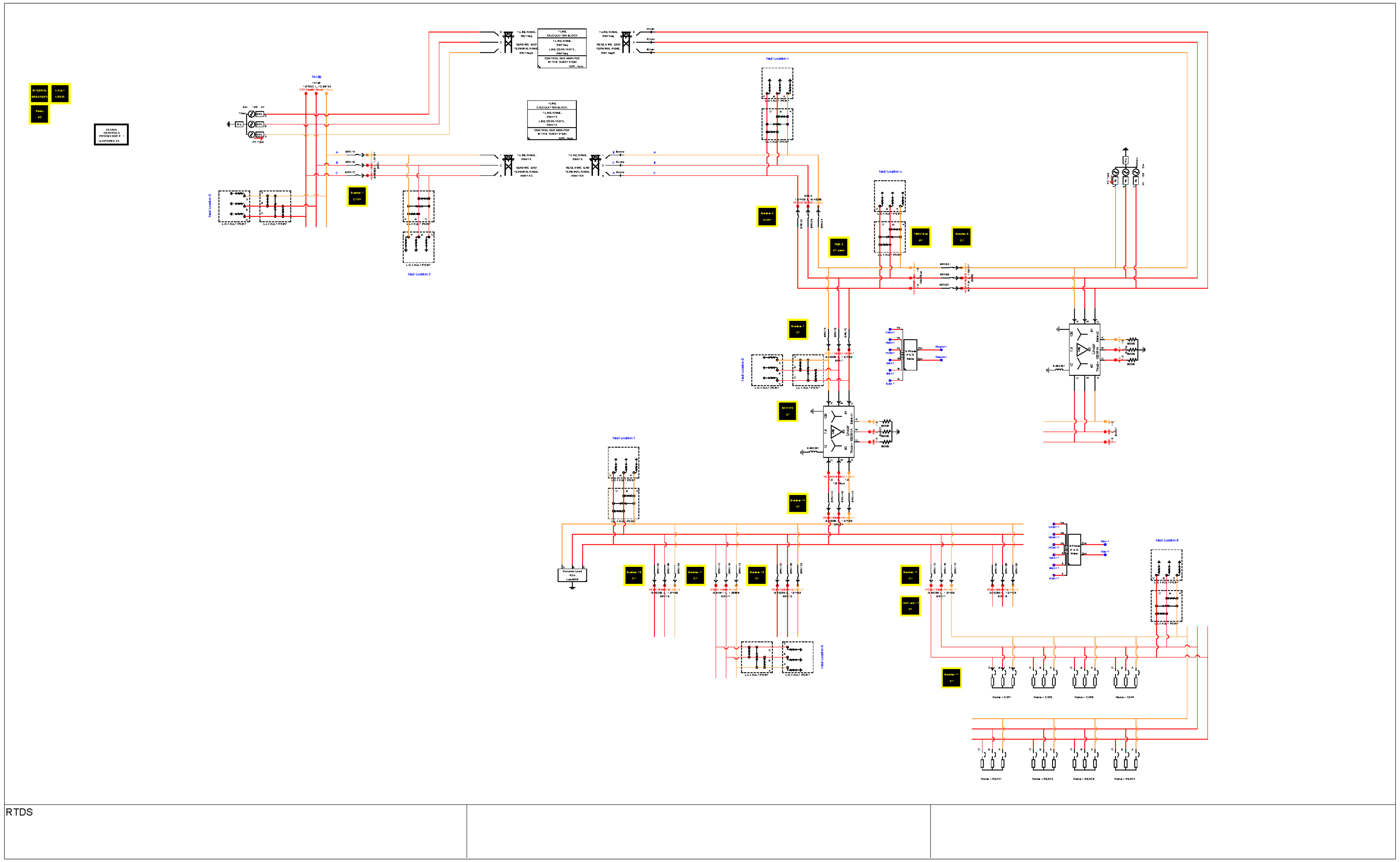

FIGURE 42 RTDS MODEL

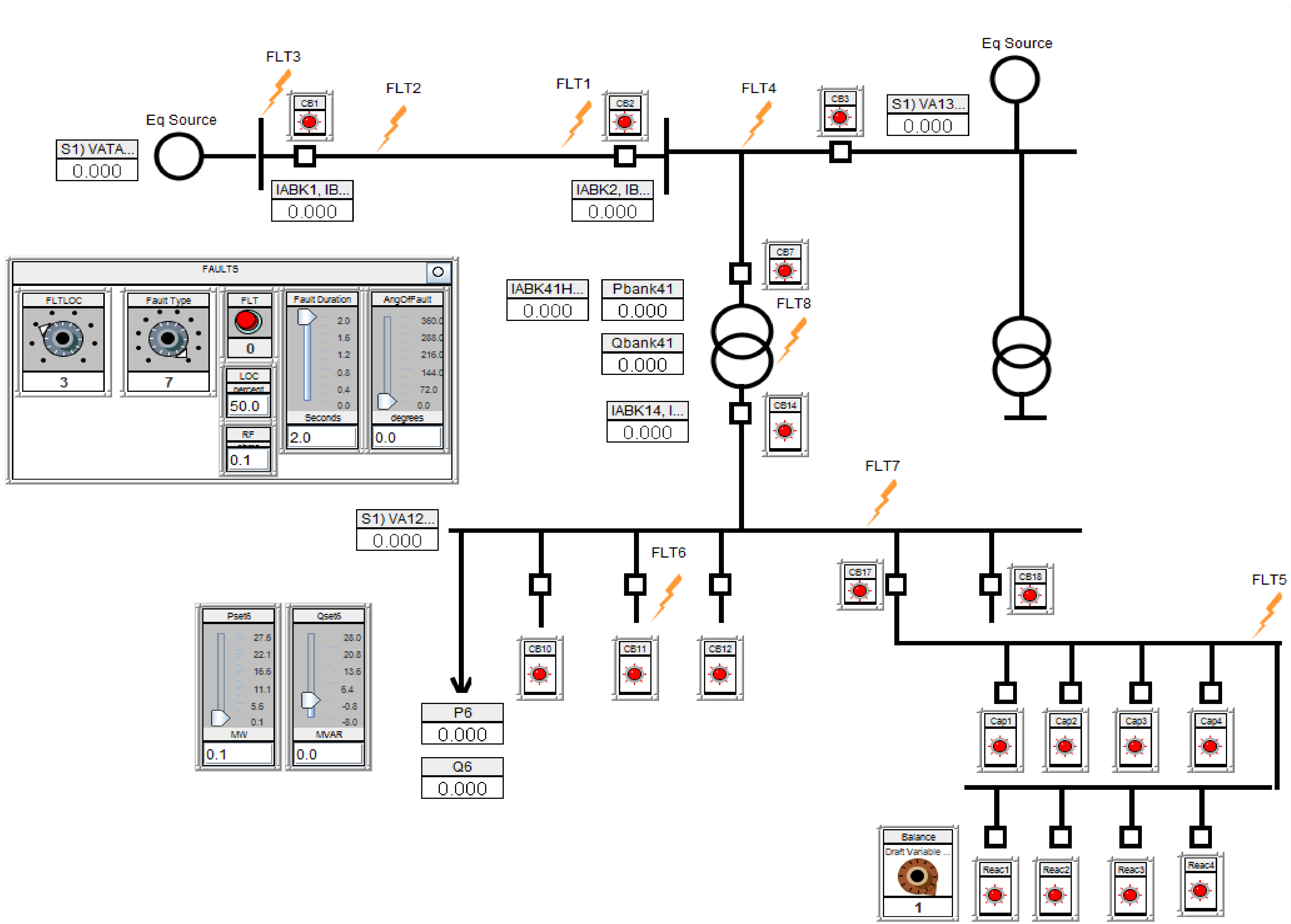

FIGURE 43 RTDS MODEL HMI

APPENDIX C - NETWORK LAYOUT DIAGRAM

The network layout diagram identifies the network connections for each device included in the test system. The diagram includes protection relays, merging units, Ethernet switches and the GPS time clock. In this diagram, the isolated process bus and station bus connections are laid out. These connections are indicated with colored lines to easily and quickly distinguish the networks. Blue lines indicate station bus connections, green lines are bus #1 and red is for process bus #2. The diagram indicates GPS time signals with yellow lines. Also shown in this diagram are the CT/PT sensors and breakers associated with particular merging units. The diagram indicates the physical separation of the substation control shelter and the substation yard with a thick dashed line near the middle of the image.

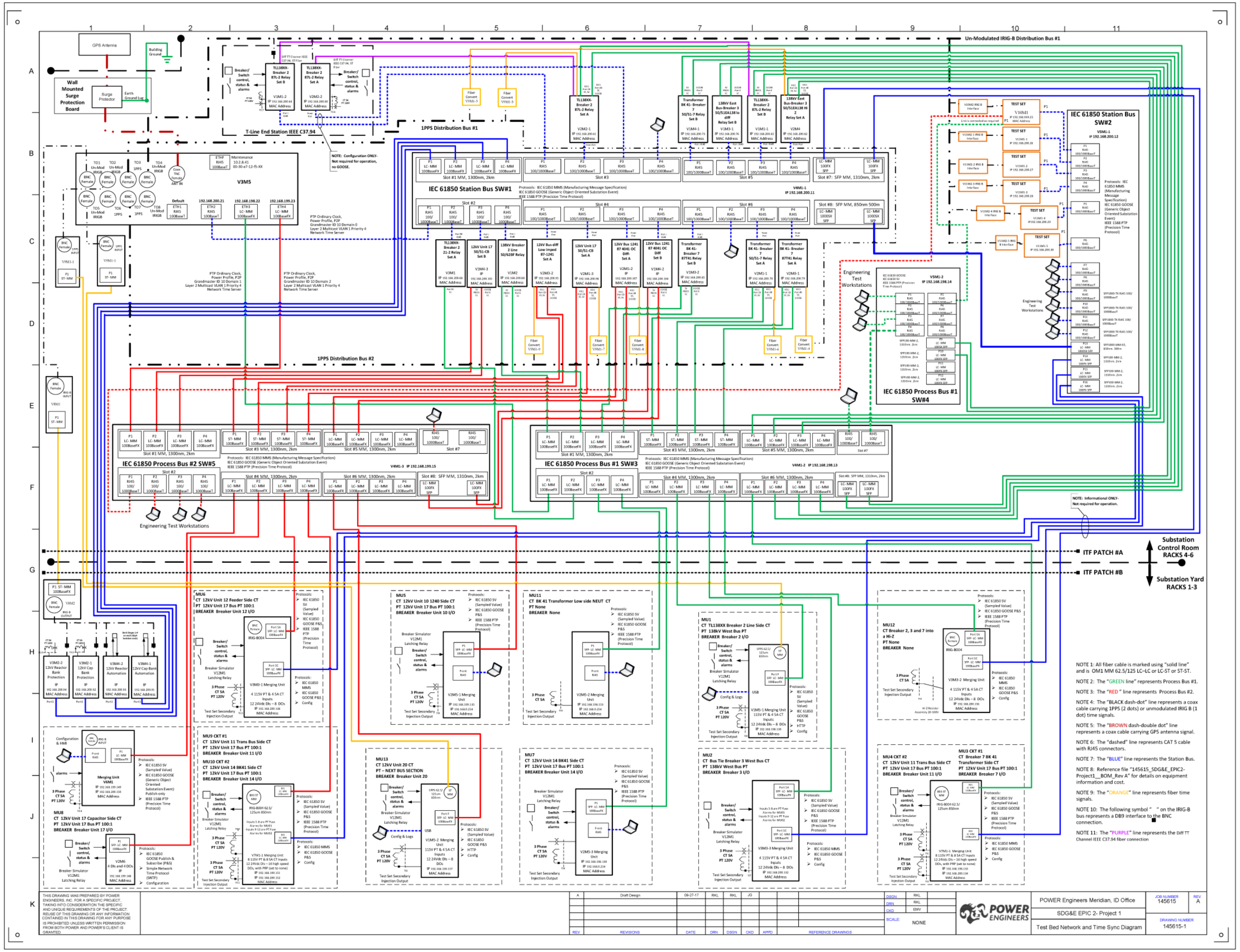

FIGURE 44 NETWORK LAYOUT DIAGRAM

APPENDIX D - IEC61850 MATRIX

This appendix contains the IEC 61850 matrices. The matrix in Table 28 describes the IEDs which were used in the HS and LS use cases. HS cases are indicated with red shading and LS with green shading. This matrix was also used to explain the protection function nomenclature for each protection relay and shows the relay identifiers. In any given row, the control and lock out functions are associated with the relays in that row.

In Table 29, merging units are described with their functional position in the test system. HS cases are indicated with red shading and LS with green shading.

TABLE 28 IEC61850 MATRIX FOR PROTECTIVE DEVICES

Description	Relay Identifier	Equipment Protection	Protective Equipment	Substation Relay Identifier	Lockouts and SCADA Control IEDs		
69/138-12kV Xfmr BK 41 Differential (CB 7, 11 & 14) Set B_V1M3_87T41 Set B	V1M3-87T41 Set B	69/138-12kV Xfmr BK 41 Differential (CB 7, 11 & 14) Set B	V1M3	87T41 Set B	LOR 86T41		
69/138-12kV Xfmr BK 41 Differential (CB 7, 11 & 14) Set A_V2M3_87T41 Set A	V2M3-87T41 Set A	69/138-12kV Xfmr BK 41 Differential (CB 7, 11 & 14) Set A	V2M3	87T41 Set A	LOR 86T41	86T41 Master LOR Relay	
69/138kV East Bus OC/Hi-Z Differential (CB 2, 3 & 7) Set A_V2M4_50/51EA138 (SET A)	V2M4-50/51EA138 (SET A)	69/138kV East Bus OC/Hi-Z Differential (CB 2, 3 & 7) Set A	V2M4	50/51EA138 (SET A)	LOR 86E138	86E138 Master LOR Relay	SCADA Control 2,3,7
69/138kV East Bus OC/lo-Z Differential (CB 2, 3 & 7) Set B_V1M3_50/51EB138 (SET B)	V1M3-50/51EB138 (SET B)	69/138kV East Bus OC/lo-Z Differential (CB 2, 3 & 7) Set B	V1M3	50/51EB138 (SET B)	LOR 86E138	---	---
69/138kV Breaker Failure (CB 2)***_V1M2_50/62BF***	V1M2-50/62BF***	69/138kV Breaker Failure (CB 2)***	V1M2	50/62BF***	LOR 86E138	---	---
12kV Cap Bank Sequencing Automation Controller_V3M4 PAC_Cap Bank V3M4	V3M4 PAC-Cap Bank V3M4	12kV Cap Bank Sequencing Automation Controller	V3M4 PAC	Cap Bank V3M4	---	---	---
12kV Cap Bank Voltage Unbalance Protection_V3M2 Feeder Relay_Cap Bank 59X (3V0)	V3M2 Feeder Relay-Cap Bank 59X (3V0)	12kV Cap Bank Voltage Unbalance Protection	V3M2A Feeder Relay	Cap Bank 59X (3V0)	LOR 59X CAP	59XCAP Master LOR Relay	---
12kV Reactor Bank Sequencing Automation Controller_V3M4 PAC_Reactor Bank V3M4	V3M4 PAC-Reactor Bank V3M4	12kV Reactor Bank Sequencing Automation Controller	V3M4 PAC	Reactor Bank V3M4	---	---	---
12kV Reactor Bank Voltage Unbalance Protection_V3M2 Feeder Relay_Reactor Bank 59X (3V0)	V3M2 Feeder Relay-Reactor Bank 59X (3V0)	12kV Reactor Bank Voltage Unbalance Protection	V3M2A Feeder Relay	Reactor Bank 59X (3V0)	LOR 59X REAC	59XREAC Master LOR Relay	---
12kV Main Bus Overall Low Impedance Bus Differential (Wraps CBs 10, 11, 12, 14, 17 & 20)_V2M3_87-1241	V2M3-87-1241	12kV Main Bus Overall Low Impedance Bus Differential (Wraps CBs 10, 11, 12, 14, 17 & 20)	V2M3	87-1241	LOR 86B1241	86B1241 Master LOR Relay	SCADA Control 10,11,12,14,17,20
12kV Reactive Feeder Overcurrent (CB 17) Set A_V2M1_50/51-CB (Set A)	V2M1-50/51-CB17 (Set A)	12kV Reactive Feeder Overcurrent (CB 17) Set A	V2M1	50/51-CB 17(Set A)	---	---	---
12kV Reactive Feeder Overcurrent (CB 17) Set B_V1M4_50/51-CB (Set B)	V1M4-50/51-CB17 (Set B)	12kV Reactive Feeder Overcurrent (CB 17) Set B	V1M4	50/51-CB17 (Set B)	---	---	---
12kV Main Bus Partial Overcurrent Differential Set B (Wraps CBs 10, 14 & 20)****_V1M4_50/51-1241 (Set B)****	V1M4-50/51-1241 (Set B)****	12kV Main Bus Partial Overcurrent Differential Set B (Wraps CBs 10, 14 & 20)	V1M4	50/51-1241 (Set B)	---	---	---
12kV Main Bus Partial Overcurrent Differential Set A (Wraps CBs 10, 14 & 20)****_V2M1_50/51-1241 (Set A)****	V2M1-50/51-1241 (Set A)****	12kV Main Bus Partial Overcurrent Differential Set A (Wraps CBs 10, 14 & 20)	V2M1	50/51-1241 (Set A)	---	---	---

Process Bus 1 High Side Use Cases

Process Bus 2 Low Side Use Cases

TABLE 29 IEC61850 MATRIX FOR MERGING UNITS

Merging Units	Merging Units	MU Equipment
MU1- 69/138kV Line CB 2_V1M5 #1	MU1- 69/138kV Line CB 2	V1M5 #1
MU2- 69/138 Bus Tie CB 3_V3M3	MU2- 69/138 Bus Tie CB 3	V3M3
MU3- 69/138-12kV Xfmr BK 41 CB 7 _V7M1 #1 CKT 1	MU3- 69/138-12kV Xfmr BK 41 CB 7	V7M1 #1 CKT 1
MU4- 12kV Xfer Bus CB 11_V7M1 #1 CKT 2	MU4- 12kV Xfer Bus CB 11	V7M1 #1 CKT 2
MU5- 12kV Swgr 1240 Bus Tie CB 10_V2M5	MU5- 12kV Swgr 1240 Bus Tie CB 10	V2M5
MU6- 12kV Feeder CB 12_V3M3	MU6- 12kV Feeder CB 12	V3M3
MU7- 69/138-12kV Xfmr BK41 CB 14_V2M5	MU7- 69/138-12kV Xfmr BK41 CB 14	V2M5
MU8a- 12kV Reactive Feeder CB 17_V2M6	MU8a- 12kV Reactive Feeder CB 17	V2M6
MU8b- 12kV Reactive Feeder CB 17_V6M1	MU8b- 12kV Reactive Feeder CB 17	V6M1
MU9- 12kV Xfer Bus CB 11 _V7M1 #2 CKT 1	MU9- 12kV Xfer Bus CB 11	V7M1 #2 CKT 1
MU10- 69/138-12kV Xfmr BK41 CB 14_V7M1 #2 CKT 2	MU10- 69/138-12kV Xfmr BK41 CB 14	V7M1 #2 CKT 2
MU11- 69/138-12kV Xfmr BK 41 12kV Neutral CT_V2M5	MU11- 69/138-12kV Xfmr BK 41 12kV Neutral CT	V2M5
MU12- 69/138kV E. Bus 87B Hi-Z Resistor_V3M3	MU12- 69/138kV E. Bus 87B Hi-Z Resistor	V3M3
MU13- 12kV Swgr 1242 Bus Tie CB 20_V1M5 #2	MU13- 12kV Swgr 1242 Bus Tie CB 20	V1M5 #2
	Process Bus 1 High Side Use Cases	
	Process Bus 2 Low Side Use Cases	

APPENDIX E - IEC61850 DATA FLOW SPREADSHEETS

Appendix E contains the IEC61850 dataflow spreadsheets. Analogous to a wiring schematic, this spreadsheet details each message being used in the test system. Because the messages could become numerous and unwieldy, the spreadsheet is necessarily large. For each network bus, the spreadsheet is divided into two sections; one for SV messages and one for GOOSE messages. Publishing IEDs are listed along the far left column, and subscribing IEDs are listed along the top. Details of each message are listed in the middle.

This spreadsheet provides details about each IED, such as system functional position, CT/PT ratios, measurement and control points. SV and GOOSE control blocks are detailed with the broadcast MAC address, VLAN ID, VLAN priority, Application ID (APP ID) and message ID. Each index of the message is then detailed moving across the spreadsheet from left to right. The IEC 61850 standard defines sampled values message structure, and as such, these messages were identical. GOOSE messages were configured specifically for their individual purpose. Logic nodes, logical devices, data objects and data attributes are all defined in this spreadsheet. In the subscribing IEDs section of the spreadsheet, to the far right, subscribers to certain messages are indicated by a 'Yes' in the cell. If a device is not subscribing to a message, that cell was grayed out. The data flow tables are further described in Section 9.

TABLE 30 PROCESS BUS #1 DATA FLOW SPREADSHEET

Process Bus #1 Sampled Value (SV) Messages

SV Control Block and referenced dataset information / Subscribing IEDs

IEDname	Publishing IED	Measurement and Control points	Voltage	Current	MAC Address	VLAN ID	VLAN-PRIORITY	App ID (hex)	SmpRate (sample/cycle)	MsvID	Dataset Name	Dataset index 1	Dataset index 2	Dataset index 3	Dataset index 4	Dataset index 5	Dataset index 6	Dataset index 7	Dataset index 8	Dataset index 9	Dataset index 10	Dataset index 11	Dataset index 12	Dataset index 13	Dataset index 14	Dataset index 15	Dataset index 16	Dataset index 14	Dataset index 15	Dataset index 16	Dataset index 16	V2M2**--87L-2 Set A	V1M1**--87L-2 Set B	V3M1--21-2	V2M1--50/51-7 Set A	V1M4--50/51-7 Set B	V1M3--87T41 Set B	V2M3--87T41 Set A	V2M4-50/51EA138 (SET A)	V1M3--50/51EB138 (SET B)	V1M2--50/62BF
MU1_CB2	MU1- 69/138kV Line CB 2_V1M5 #1	69/138kV Line CB 2 Line Side CT, west bud PT and CB2 I/O	115V - 700 ratio	5A - 400 ratio	01-0C-CD-04-00-00	1	4	0x4000	80	MU1_CB2_V1M5	PhsMeas1	PhA_Amps.instMag.i	PhA_Amps.q	PhB_Amps.instMag.i	PhB_Amps.q	PhC_Amps.instMag.i	PhC_Amps.q	NEUT Amps.instMag.i	NEUT Amps.q	PhA Volts-Vol.instMag.i	PhA Volts-Vol.q	PhB Volts-Vol.instMag.i	PhB Volts-Vol.q	PhC Volts-Vol.instMag.i	PhC Volts-Vol.q	NEUT Volts-Vol.instMag.i	NEUT Volts-Vol.q	PhC Volts-Vol.q	NEUT Volts-Vol.instMag.i	NEUT Volts-Vol.q	NEUT Volts-Vol.q	YES	YES						YES	YES	YES
MU2_CB3_V3M3	MU2- 69/138 Bus Tie CB 3_V3M3	69/138kV Bus Tie CB 3 West Bus CT, west bus PT and CB3 I/O	115V - 700 ratio	5A - 400 ratio	01-0C-CD-04-00-01	1	4	0x4000	80	MU2_CB3_V3	PhsMeas1	PhA_Amps.instMag.i	PhA_Amps.q	PhB_Amps.instMag.i	PhB_Amps.q	PhC_Amps.instMag.i	PhC_Amps.q	NEUT Amps.instMag.i	NEUT Amps.q	PhA Volts-Vol.instMag.i	PhA Volts-Vol.q	PhB Volts-Vol.instMag.i	PhB Volts-Vol.q	PhC Volts-Vol.instMag.i	PhC Volts-Vol.q	NEUT Volts-Vol.instMag.i	NEUT Volts-Vol.q	PhC Volts-Vol.q	NEUT Volts-Vol.instMag.i	NEUT Volts-Vol.q	NEUT Volts-Vol.q			YES (IW & VY)					YES	YES	
MU3_4_CB7_11_V7M1	MU3- 69/138-12kV Xfmr BK 41 CB 7_V7M1 #1 CKT 1	69/138-12kV Xfmr BK 41 Main CB 7 Xfmr Side CT, 12kV Swgr 1241 Unit 17 Bus PT 100:1and CB7 I/O	115V - 700 ratio	5A - 400 ratio	01-0C-CD-04-00-02	1	4	0x4000	80	MU3_MU0101	PhsMeas1	PhA_Amps.instMag.i	PhA_Amps.q	PhB_Amps.instMag.i	PhB_Amps.q	PhC_Amps.instMag.i	PhC_Amps.q	NEUT Amps.instMag.i	NEUT Amps.q	PhA Volts-Vol.instMag.i	PhA Volts-Vol.q	PhB Volts-Vol.instMag.i	PhB Volts-Vol.q	PhC Volts-Vol.instMag.i	PhC Volts-Vol.q	NEUT Volts-Vol.instMag.i	NEUT Volts-Vol.q	PhC Volts-Vol.q	NEUT Volts-Vol.instMag.i	NEUT Volts-Vol.q	NEUT Volts-Vol.q			YES (IX & VZ)	YES	YES	YES	YES	YES	YES	
MU3_4_CB7_11_V7M1	MU4- 12kV Xfer Bus CB 11_V7M1 #1 CKT 2	12kV Xfer Bus CB 11, 12kV Swgr 1241 Unit 17 Bus PT 100:1, CB Unit 11 I/O	120V - 100 ratio	5A - 400 ratio	01-0C-CD-04-00-03	1	4	0x4000	80	MU4_MU0201	PhsMeas1	PhA_Amps.instMag.i	PhA_Amps.q	PhB_Amps.instMag.i	PhB_Amps.q	PhC_Amps.instMag.i	PhC_Amps.q	NEUT Amps.instMag.i	NEUT Amps.q	PhA Volts-Vol.instMag.i	PhA Volts-Vol.q	PhB Volts-Vol.instMag.i	PhB Volts-Vol.q	PhC Volts-Vol.instMag.i	PhC Volts-Vol.q	NEUT Volts-Vol.instMag.i	NEUT Volts-Vol.q	PhC Volts-Vol.q	NEUT Volts-Vol.instMag.i	NEUT Volts-Vol.q	NEUT Volts-Vol.q	YES	YES				YES	YES			
MU7_CB14_V2M5	MU7- 69/138-12kV Xfmr BK41 CB 14_V2M5	69/138-12kV Xfmr BK41 CB 14 Xfmr Side CT, 2kV Swgr 1241 Unit 17 Bus PT 100:1, CB Unit 14 I/O	115V - 700 ratio	5A - 400 ratio	01-0C-CD-04-00-06	1	4	0x4000	80	MU7_CB14_V2	PhsMeas1	PhA_Amps.instMag.i	PhA_Amps.q	PhB_Amps.instMag.i	PhB_Amps.q	PhC_Amps.instMag.i	PhC_Amps.q	NEUT Amps.instMag.i	NEUT Amps.q	PhA Volts-Vol.instMag.i	PhA Volts-Vol.q	PhB Volts-Vol.instMag.i	PhB Volts-Vol.q	PhC Volts-Vol.instMag.i	PhC Volts-Vol.q	NEUT Volts-Vol.instMag.i	NEUT Volts-Vol.q	PhC Volts-Vol.q	NEUT Volts-Vol.instMag.i	NEUT Volts-Vol.q	NEUT Volts-Vol.q						YES	YES			
MU11_T41NEU_V2M5	MU11- 69/138-12kV Xfmr BK 41 12kV Neutral CT_V2M5	69/138-12kV Xfmr BK 41 12kV Neutral CT, no I/O	120V - 100 ratio	5A - 400 ratio	01-0C-CD-04-00-10	1	4	0x4000	80	MU11_T41N_V2	PhsMeas1	PhA_Amps.instMag.i	PhA_Amps.q	PhB_Amps.instMag.i	PhB_Amps.q	PhC_Amps.instMag.i	PhC_Amps.q	NEUT Amps.instMag.i	NEUT Amps.q	PhA Volts-Vol.instMag.i	PhA Volts-Vol.q	PhB Volts-Vol.instMag.i	PhB Volts-Vol.q	PhC Volts-Vol.instMag.i	PhC Volts-Vol.q	NEUT Volts-Vol.instMag.i	NEUT Volts-Vol.q	PhC Volts-Vol.q	NEUT Volts-Vol.instMag.i	NEUT Volts-Vol.q	NEUT Volts-Vol.q				YES	YES	YES	YES			
MU12_HIZ_V3M3	MU12- 69/138kV E. Bus 87B Hi-Z Resistor_V3M3	69/138kV E. Bus 87B Hi-Z Resistor, no I/O	115V - 700 ratio	5A - 400 ratio	01-0C-CD-04-00-11	1	4	0x4000	80	MU12_HIZ_V3	PhsMeas1	PhA_Amps.instMag.i	PhA_Amps.q	PhB_Amps.instMag.i	PhB_Amps.q	PhC_Amps.instMag.i	PhC_Amps.q	NEUT Amps.instMag.i	NEUT Amps.q	PhA Volts-Vol.instMag.i	PhA Volts-Vol.q	PhB Volts-Vol.instMag.i	PhB Volts-Vol.q	PhC Volts-Vol.instMag.i	PhC Volts-Vol.q	NEUT Volts-Vol.instMag.i	NEUT Volts-Vol.q	PhC Volts-Vol.q	NEUT Volts-Vol.instMag.i	NEUT Volts-Vol.q	NEUT Volts-Vol.q								YES		

Process Bus #1 GOOSE Messages

GOOSE Control Block and referenced dataset information

Summary Use	IEDname	Publishing IED	Measurement and Control points, etc.	MAC Address	VLAN ID	VLAN-PRIORITY	App ID (hex)	Min Trime (ms)	Heatbeat Rate, Max time (ms)	Control Block Name and GoID	Dataset Name
Breaker Position	MU1_CB2	MU1- 69/138kV Line CB 2_V1M5 #1	CT TL138XX Breaker 2 Line Side CT; PT 138kV West Bus PT; Breaker 2 I/O	01-0C-CD-01-00-00	1	4	0x0000	4	500	BRK2_MU1	CB2_52A
Breaker Position	MU2_CB3_V3M3	MU2- 69/138 Bus Tie CB 3_V3M3	CT Bus Tie Breaker 3 West Bus CT PT 138kV West Bus PT BREAKER 3 I/O	01-0C-CD-01-00-01	1	4	0x0001	4	1000	BRK3_MU2	CB3_52A
Breaker Position	MU3_MU4 CB7_11_V7M1	MU3- 69/138-12kV Xfmr BK 41 CB 7_V7M1 #1 CKT 1	CT Breaker 7 BK 41 Transformer Side CT PT 12kV Unit 17 Bus PT 100:1 BREAKER 7 I/O	01-0C-CD-01-00-02	1	4	0x0002	20	1000	BRK7_MU3	MU3_STATUS
Breaker Position	MU3_MU4 CB7_11_V7M1	MU4- 12kV Xfer Bus CB 11_V7M1 #1 CKT 2	CT 12kV Unit 11 Trans Bus Side CT PT 12kV Unit 17 Bus PT 100:1 BREAKER Unit 11 I/O	01-0C-CD-01-00-03	1	4	0x0003	20	500	BRK11_MU4	MU4_STATUS
Breaker Position	MU3_MU4 CB7_11_V7M1	MU3 & MU4 CB7 & CB 11-1_V7M1 #1&2	ALL STATUS INPUTS	01-0C-CD-01-00-39	1	4	0x0027	1	1000	MU3_MU4_FASTGOOSE_FIXED	DigInput
Breaker Position	V2M5_MU7	MU7- 69/138-12kV Xfmr BK41 CB 14_V2M5	BREAKER Unit 14 I/O	01-0C-CD-01-00-06	1	4	0x0006	4	500	BRK14_MU7	CB14_52A
MU Alarms	V2M5_MU11	MU11- 69/138-12kV Xfmr 41 12kV Neutral CT_V2M5	CT BK 41 Transformer Low side NEUT CT BREAKER None	01-0C-CD-01-00-10	1	4	0x000A	4	10000	T41_NEUT_MU11	ALARM
MU Alarms	MU12_HIZ_V3M3	MU12- 69/138kV E. Bus 87B Hi-Z Resistor_V3M3	CT Breaker 2, 3 and 7 into a Hi-Z PT None BREAKER None	01-0C-CD-01-00-11	1	4	0x000B	4	500	HIZ_MU12	HIZ_AL
Breaker Trip	V2M1_87L2A	V2M2-87L-2 Set A	TL138XX- Breaker 2 (2 each with line end IEDs)	01-0C-CD-01-00-12	1	4	0x000C	4	500	ATL87L_21BU_BKR_CNTL	TRIP
Breaker Trip	87L2B	V1M1-87L-2 Set B	TL138XX- Breaker 2 (2 each with line end IEDs)	01-0C-CD-01-00-13	1	4	0x000D	4	500	BTL87L_21BU_BKR_CNTL	DataSet
Breaker Trip	BKR2_21-2_BF	V3M1--21-2 &BF CB2	TL138XX- Breaker 2	01-0C-CD-01-00-14	1	4	0x000E	4	500	BKR2_21_2_BF	TRIP_BF
Breaker Trip	50_51-7_A	V2M1-50/51-7 Set A	Transformer BK 41- Breaker 7	01-0C-CD-01-00-21	1	4	0x0015	4	500	A50_51BK41_BKR_CNTL	TRIP
Breaker Trip	50_51-7_B	V1M4-50/51-7 Set B	Transformer BK 41- Breaker 7	01-0C-CD-01-00-20	1	4	0x0014	4	500	B50_51BK41_BKR_CNTL	DataSet
Breaker Trip	87T41_B	V1M3-87T41 Set B	Transformer BK 41- Breaker 7	01-0C-CD-01-00-18	1	4	0x0012	4	500	B87T_BK41_BKR_CNTL	DataSet
Breaker Trip	V2M3_87T41A	V2M3-87T41 Set A	Transformer BK 41- Breaker 7	01-0C-CD-01-00-19	1	4	0x0013	4	500	A87T_BK41_BKR_CNTL	TRIP
Breaker Trip - Close	V2M4_5051EA138	V2M4-50/51EA138 (SET A)	138/69 Bus OC/Hi-Z Diff	01-0C-CD-01-00-15	1	4	0x000F	4	500	A50/51_BUS_HIZ_BKR_CNTL	TRIP_CLS
Breaker Trip	50_51EB138_B	V1M3--50/51EB138 (SET B)	138/69 Bus OC/lo-Z Diff	01-0C-CD-01-00-17	1	4	0x0011	4	500	V1M3_LOR86E138	DataSet
Breaker Trip	50_62BF	V1M2-50/62BF	TL138XX- Breaker 2	01-0C-CD-01-00-16	1	4	0x0010	4	500	BKR2__BF	DataSet

IEDname	Dataset index 1	Dataset index 2	Dataset index 3	Dataset index 4	Dataset index 5	Dataset index 6	Dataset index 7	Dataset index 8	Dataset index 9	Dataset index 10	Dataset index 11	Dataset index 12	Dataset index 13	Dataset index 14	Dataset index 15	Dataset index 16	Dataset index 17
MU1_CB2	GGIO1.SPCSO1.stVal (input 1-52a)	GGIO1.SPCSO1.q (input 1-52a)	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----
MU2_CB3_V3M3	ANN.IN2GGIO14,Ind01.stVal (Input 1- 52a)	ANN.IN2GGIO14,Ind01.q (Input 1- 52a)	ANN.IN2GGIO14,Ind02.stVal (VT Fuse Fail A)	ANN.IN2GGIO14,Ind02.q (VT Fuse Fail A)	ANN.IN2GGIO14,Ind03.stVal (VT Fuse Fail B)	ANN.IN2GGIO14,Ind03.q (VT Fuse Fail B)	ANN.IN2GGIO14,Ind04.stVal (VT Fuse Fail C)	ANN.IN2GGIO14,Ind04.q (VT Fuse Fail C)	-----	-----	-----	-----	-----	-----	-----	-----	-----
MU3_MU4 CB7_11_V7M1	CTRL/BININGGIO1.Ind1.stVal (CB7 52A)	CTRL/BININGGIO1.Ind1.q (CB7 52A)	CTRL/BININGGIO1.Ind2.stVal	CTRL/BININGGIO1.Ind2.q	CTRL/BININGGIO1.Ind3.stVal (CB7 1241 UNIT 17 PT PHA FUSE)	CTRL/BININGGIO1.Ind3.q (CB7 1241 UNIT 17 PT PHA FUSE)	CTRL/BININGGIO1.Ind4.stVal (CB7 1241 UNIT 17 PT PHB FUSE)	CTRL/BININGGIO1.Ind4.q (CB7 1241 UNIT 17 PT PHB FUSE)	CTRL/BININGGIO1.Ind5.stVal (CB7 1241 UNIT 17 PT PHC FUSE)	CTRL/BININGGIO1.Ind5.q (CB7 1241 UNIT 17 PT PHC FUSE)	CTRL/BININGGIO1.Ind6stVal (CB7 1241 UNIT 17 PT NEU FUSE)	CTRL/BININGGIO1.Ind6.q (CB7 1241 UNIT 17 PT NEU FUSE)	-----	-----	-----	-----	-----
MU3_MU4 CB7_11_V7M1	CTRL/BININGGIO1.Ind7.stVal (CB11 52A)	CTRL/BININGGIO1.Ind7.q (CB11 52A)	CTRL/BININGGIO1.Ind8.stVal	CTRL/BININGGIO1.Ind8.q	CTRL/BININGGIO1.Ind9stVal (CB11 1241 UNIT 17 PT PHA FUSE)	CTRL/BININGGIO1.Ind9.q (CB11 1241 UNIT 11 PT PHA FUSE)	CTRL/BININGGIO1.Ind10.stVal (CB11 1241 UNIT 11 PT PHB FUSE)	CTRL/BININGGIO1.Ind10.q (CB11 1241 UNIT 11 PT PHB FUSE)	CTRL/BININGGIO1.Ind11.stVal (CB11 1241 UNIT 11 PT PHC FUSE)	CTRL/BININGGIO1.Ind11.q (CB11 1241 UNIT 11 PT PHC FUSE)	CTRL/BININGGIO1.Ind12stVal (CB11 1241 UNIT 11 PT NEU FUSE)	CTRL/BININGGIO1.Ind12.q (CB11 1241 UNIT 11 PT PNEU FUSE)	-----	-----	-----	-----	-----
MU3_MU4 CB7_11_V7M1	CTRL/BININGGIO1.Ind1.stVal (CB7 52A)	CTRL/BININGGIO1.Ind2.stVal	CTRL/BININGGIO1.Ind3.stVal (CB7 1241 UNIT 17 PT PHA FUSE)	CTRL/BININGGIO1.Ind4.stVal (CB7 1241 UNIT 17 PT PHB FUSE)	CTRL/BININGGIO1.Ind5.stVal (CB7 1241 UNIT 17 PT PHC FUSE)	CTRL/BININGGIO1.Ind6stVal (CB7 1241 UNIT 17 PT NEU FUSE)	CTRL/BININGGIO1.Ind7.stVal (CB11 52A)	CTRL/BININGGIO1.Ind8.stVal	CTRL/BININGGIO1.Ind9stVal (CB11 1241 UNIT 17 PT PHA FUSE)	CTRL/BININGGIO1.Ind10.stVal (CB11 1241 UNIT 11 PT PHB FUSE)	CTRL/BININGGIO1.Ind11.stVal (CB11 1241 UNIT 11 PT PHC FUSE)	CTRL/BININGGIO1.Ind12stVal (CB11 1241 UNIT 11 PT NEU FUSE)	-----	-----	-----	-----	-----
V2M5_MU7	MVGAPC1.Ind1.stVal (CB 14 52A)	MVGAPC1.Ind1.q (CB 14 52A)	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----
V2M5_MU11	LLN0.Health.stVal (internal alarm)	LLN0.Health.q (internal alarm)	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----
MU12_HIZ_V3M3	ANN.PLTGGIO2.Ind01.stVal (alarm point, PB1 toggles)	ANN.PLTGGIO2.Ind01.q (Alarm point, PB1 toggles)	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----
V2M1_87L2A	CTRL/SMPPTRC1.Op.general (Trip CB 2)	CTRL/SMPPTRC1.Op.q (Trip CB 2)	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----
87L2B	LPHD0.SPS1.stVal (Trip CB 2)	LPHD0.SPS1.q (Trip CB 2)	LPHD0.SPS2.stVal (FUTURE)	LPHD0.SPS2.q (FUTURE)	LPHD0.SPS.stVal (FUTURE)	LPHD0.SPS.q (FUTURE)	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----
BKR2_21-2_BF	PRO.TRIPPTRC1.Tr.general (21 Trip CB 2)	PRO.TRIPPTRC1.Tr.q (21 Trip CB 2)	PRO.BFR1RBRF1.OpIn.q (FUTURE)	PRO.BFR1RBRF1.OpIn.t (FUTURE)	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----
50_51-7_A	MON/SP16GAPC1.Ind1.stVal (Trip CB 7)	MON/SP16GAPC1.Ind1.q (Trip CB 7)	MON/SP16GAPC1.Ind2.stVal (Trip CB Unit 11)	MON/SP16GAPC1.Ind2.q (Trip CB Unit 11)	MON/SP16GAPC1.Ind3.stVal (Trip CB Unit 14)	MON/SP16GAPC1.Ind3.q (Trip CB Unit 14)	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----
50_51-7_B	.stVal (Trip CB 7)	.q (Trip CB 7)	.stVal (Trip CB Unit 11)	.q (Trip CB Unit 11)	.stVal (Trip CB Unit 14)	.q (Trip CB Unit 14)	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----
87T41_B	.stVal (Trip CB 7)	.q (Trip CB 7)	.stVal (Trip CB Unit 11)	.q (Trip CB Unit 11)	.stVal (Trip CB Unit 14)	.q (Trip CB Unit 14)	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----
V2M3_87T41A	MON/SP16GAPC1.Ind1.stVal (Trip CB 7)	MON/SP16GAPC1.Ind1.q (Trip CB 7)	MON/SP16GAPC1.Ind2.stVal (Trip CB Unit 11)	MON/SP16GAPC1.Ind2.q (Trip CB Unit 11)	MON/SP16GAPC1.Ind3.stVal (Trip CB Unit 14)	MON/SP16GAPC1.Ind3.q (Trip CB Unit 14)	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----
V2M4_5051EA138	MON/SP16GAPC1.Ind1.stVal (Open CB 2)	MON/SP16GAPC1.Ind1.q (Open CB 2)	MON/SP16GAPC1.Ind2.stVal (Close CB 2)	MON/SP16GAPC1.Ind2.q (Close CB 2)	MON/SP16GAPC1.Ind3.stVal (Open CB Unit 7)	MON/SP16GAPC1.Ind3.q (Open CB Unit 7)	MON/SP16GAPC1.Ind4.stVal (Close CB Unit 7)	MON/SP16GAPC1.Ind4.q (Close CB Unit 7)	MON/SP16GAPC1.Ind5.stVal (Open CB Unit 3)	MON/SP16GAPC1.Ind5.q (Open CB Unit 3)	MON/SP16GAPC1.Ind6.stVal (Close CB Unit 3)	MON/SP16GAPC1.Ind6.q (Close CB Unit 3)	MON/SP16GAPC1.Ind7.stVal (LOR86E138 Trip 2,3,7)	MON/SP16GAPC1.Ind7.q (LOR86E138 Trip 2,3,7)	MON/SP16GAPC1.Ind8.stVal (LOR86E138 Trip 2,3,7)#2	MON/SP16GAPC1.Ind8.q (LOR86E138 Trip 2,3,7) #2	-----
50_51EB138_B	.stVal (CB3 Pro Trip)	.q ((CB3 Pro Trip)	.stVal (LOR86E138 Trip 2,3,7)	.q (LOR86E138 Trip 2,3,7)	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----
50_62BF	RBRF1.OpEx.general (LOR86E138 BF Trip 2,3,7)	RBRF1.OpEx.q (LOR86E138 BF Trip 2,3,7)	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----

Subscribing IEDs / Subscribing Merging Units

IEDname	V2M2**--87L-2 Set A	V1M1**--87L-2 Set B	V3M1--21-2	V2M1--50/51-7 Set A	V1M4--50/51-7 Set B	V1M3--87T41 Set B	V2M3--87T41 Set A	V2M4-50/51EA138 (SET A)	V1M3--50/51EB138 (SET B)	V1M2--50/62BF	MU1- 69/138kV Line CB 2_V1M5 #1	MU2- 69/138 Bus Tie CB 3_V3M3	MU3- 69/138-12kV Xfmr BK 41 CB 7_V7M1 #1 CKT 1	MU4- 12kV Xfer Bus CB 11_V7M1 #1 CKT 2	MU7- 69/138-12kV Xfmr BK41 CB 14_V2M5	MU11- 69/138-12kV Xfmr BK 41 12kV Neutral CT_V2M5	MU12- 69/138kV E. Bus 87B Hi-Z Resistor_V3M3
MU1_CB2	YES	YES	YES					YES	YES	YES							
MU2_CB3_V3M3								YES	YES	YES							
MU3_MU4 CB7_11_V7M1				YES	YES		YES	YES	YES	YES							
MU3_MU4 CB7_11_V7M1				YES	YES		YES										
MU3_MU4 CB7_11_V7M1				YES	YES		YES										
V2M5_MU7				YES	YES		YES										
V2M5_MU11						YES	YES										
MU12_HIZ_V3M3								YES									
V2M1_87L2A			YES					YES		YES	YES (TRIP Output #1)						
87L2B			YES					YES		YES	YES (TRIP Output #1)						
BKR2_21-2_BF								YES		YES	YES (TRIP Output #1)						
50_51-7_A								YES					YES (TRIP Output #1)	YES (TRIP Output #1)	YES (TRIP Output #1)		
50_51-7_B								YES					YES (TRIP Output #1)	YES (TRIP Output #1)	YES (TRIP Output #1)		
87T41_B							YES	YES (Block CB7 Close)					YES (TRIP Output #1)	YES (TRIP Output #1)	YES (TRIP Output #1)		
V2M3_87T41A								YES (Block CB7 Close)					YES (TRIP Output #1)	YES (TRIP Output #1)	YES (TRIP Output #1)		
V2M4_5051EA138											YES (TRIP Output #1, Close Output #2)	YES (TRIP Output #1, Close Output #2)	YES (TRIP Output #1, Close Output #2)				
50_51EB138_B								YES			YES (TRIP Output #1)	YES (TRIP Output #1)	YES (TRIP Output #1)				
50_62BF								YES			YES (TRIP Output #1)	YES (TRIP Output #1)	YES (TRIP Output #1)				

TABLE 31 PROCESS BUS #2 DATA FLOW SPREADSHEET

Process Bus #2 Sampled Value (SV) Messages

SV Control Block and referenced dataset information

IEDname	Publishing IED	Measurement and Control points	Voltage	Current	MAC Address	VLAN ID	VLAN-PRIORITY	App ID (hex)	SmpRate	MsvID (Note 1) xxxxMUnn01	Dataset Name	Dataset index 1	Dataset index 2	Dataset index 3	Dataset index 4	Dataset index 5	Dataset index 6	Dataset index 7	Dataset index 8	Dataset index 9	Dataset index 10	Dataset index 11	Dataset index 12	Dataset index 13	Dataset index 14	Dataset index 15	Dataset index 16
MU5_CB10_V2M5	MU5- 12kV Swgr 1240 Bus Tie CB 10_V2M5	CB10 CT AND 12KV PT	120V - 100 ratio	5A - 400 ratio	01-0C-CD-04-00-04	1	4	0x4000	80	MU5_CB10_V2	PhsMeas1	PhA_Amps. instMag.i	PhA_Amps.q	PhB_Amps. instMag.i	PhB_Amps.q	PhC_Amps. instMag.i	PhC_Amps.q	NEUT Amps. instMag.i	NEUT Amps. q	PhA Volts-Vol.instMag.i	PhA Volts-Vol.q	PhB Volts-Vol.instMag.i	PhB Volts-Vol.q	PhC Volts-Vol.instMag.i	PhC Volts-Vol.q	NEUT Volts-Vol.instMag.i	NEUT Volts-Vol.q
MU6_CB12_V3M3	MU6- 12kV Feeder CB 12_V3M3	CB12 CT AND 12KV PT	120V - 100 ratio	5A - 400 ratio	01-0C-CD-04-00-05	1	4	0x4000	80	MU6_CB12_V3	PhsMeas1	PhA_Amps. instMag.i	PhA_Amps.q	PhB_Amps. instMag.i	PhB_Amps.q	PhC_Amps. instMag.i	PhC_Amps.q	NEUT Amps. instMag.i	NEUT Amps. q	PhA Volts-Vol.instMag.i	PhA Volts-Vol.q	PhB Volts-Vol.instMag.i	PhB Volts-Vol.q	PhC Volts-Vol.instMag.i	PhC Volts-Vol.q	NEUT Volts-Vol.instMag.i	NEUT Volts-Vol.q
MU8A_CB17_VIZ	MU8a- 12kV Reactive Feeder CB 17_V6M1	CB17 CT AND 12KV PT	120V - 100 ratio	5A - 400 ratio	01-0C-CD-04-00-07	1	4	0x4000	80	MU8_CB17_V6	PhsMeas1	PhA_Amps. instMag.i	PhA_Amps.q	PhB_Amps. instMag.i	PhB_Amps.q	PhC_Amps. instMag.i	PhC_Amps.q	NEUT Amps. instMag.i	NEUT Amps. q	PhA Volts-Vol.instMag.i	PhA Volts-Vol.q	PhB Volts-Vol.instMag.i	PhB Volts-Vol.q	PhC Volts-Vol.instMag.i	PhC Volts-Vol.q	NEUT Volts-Vol.instMag.i	NEUT Volts-Vol.q
MU9_10_CB11_14_V7M1	MU9- 12kV Xfer Bus CB 11 _V7M1 #2 CKT 1	CB11 CT AND 12KV PT	120V - 100 ratio	5A - 400 ratio	01-0C-CD-04-00-08	1	4	0x4000	80	MU9_MU0101	PhsMeas1	PhA_Amps. instMag.i	PhA_Amps.q	PhB_Amps. instMag.i	PhB_Amps.q	PhC_Amps. instMag.i	PhC_Amps.q	NEUT Amps. instMag.i	NEUT Amps. q	PhA Volts-Vol.instMag.i	PhA Volts-Vol.q	PhB Volts-Vol.instMag.i	PhB Volts-Vol.q	PhC Volts-Vol.instMag.i	PhC Volts-Vol.q	NEUT Volts-Vol.instMag.i	NEUT Volts-Vol.q
MU9_10_CB11_14_V7M1	MU10- 69/138-12kV Xfmr BK41 CB 14_V7M1 #2 CKT 2	CB14 CT AND 12KV PT	120V - 100 ratio	5A - 400 ratio	01-0C-CD-04-00-09	1	4	0x4000	80	MU10_MU0201	PhsMeas1	PhA_Amps. instMag.i	PhA_Amps.q	PhB_Amps. instMag.i	PhB_Amps.q	PhC_Amps. instMag.i	PhC_Amps.q	NEUT Amps. instMag.i	NEUT Amps. q	PhA Volts-Vol.instMag.i	PhA Volts-Vol.q	PhB Volts-Vol.instMag.i	PhB Volts-Vol.q	PhC Volts-Vol.instMag.i	PhC Volts-Vol.q	NEUT Volts-Vol.instMag.i	NEUT Volts-Vol.q
MU13_CB20	MU13- 12kV Swgr 1242 Bus Tie CB 20_V1M5 #2	CB20 CT AND 12KV PT	120V - 100 ratio	5A - 400 ratio	01-0C-CD-04-00-12	1	4	0x4000	80	MU13_CB20_V1M5	PhsMeas1	PhA_Amps. instMag.i	PhA_Amps.q	PhB_Amps. instMag.i	PhB_Amps.q	PhC_Amps. instMag.i	PhC_Amps.q	NEUT Amps. instMag.i	NEUT Amps. q	PhA Volts-Vol.instMag.i	PhA Volts-Vol.q	PhB Volts-Vol.instMag.i	PhB Volts-Vol.q	PhC Volts-Vol.instMag.i	PhC Volts-Vol.q	NEUT Volts-Vol.instMag.i	NEUT Volts-Vol.q

Subscribing IEDs

IEDname	V2M3 - 87-1241 A	V2M1 - 50/51-CB17 (CAPS) A	V1M4 - 50/51-CB17 (CAPS) B	V1M4 - 50/51-BT 4041 B	V2M1 - 50/51-BT 4041 A
MU5_CB10_V2M5	YES			YES	YES
MU6_CB12_V3M3	YES				
MU8A_CB17_VIZ	YES	YES	YES		
MU9_10_CB11_14_V7M1	YES				
MU9_10_CB11_14_V7M1	YES			YES	YES
MU13_CB20	YES			YES	YES

Process Bus #2 GOOSE Messages

GOOSE Control Block and referenced dataset information

Summary Use	IEDname	Publishing IED	Measurement and Control points, etc.	MAC Address	VLAN ID	VLAN-PRIORITY	App ID (hex)	Min Trime (ms)	Heatbeat Rate, Max time (ms)	Control Block Name and GoID	Dataset Name	Dataset index 1	Dataset index 2	Dataset index 3	Dataset index 4	Dataset index 5	Dataset index 6	Dataset index 7	Dataset index 8
Breaker Position	V2M5_MU5	MU5- 12kV Swgr 1240 Bus Tie CB 10_V2M5	12kV Unit 10 1240 Side CT & 12kV Unit 17 Bus PT 100:1 & Unit 10 Breaker I/O	01-0C-CD-01-00-04	1	4	0x0004	4	500	BRK10_MU5	CB10_52A	MVGAPC1.SPCSO1.stVal (Input 1- CB 10 52a)	MVGAPC1.SPCSO1.q (Input 1- CB 10 52a)	----	----	----	----	----	----
Breaker Position	MU6_CB12_V3M3	MU6- 12kV Feeder CB 12_V3M3	12kV Unit 12 Feeder Side CT & 12kV Unit 17 Bus PT 100:1 & Unit 12 Breaker I/O	01-0C-CD-01-00-05	1	4	0x0005	4	500	BRK12_MU6	BKR12_MU6	ANN.IN2GGIO14,Ind01.stVal (Input 1- 52a)	ANN.IN2GGIO14,Ind01.q (Input 1- 52a)	ANN.IN2GGIO14,Ind02.stVal (VT Fuse Fail A)	ANN.IN2GGIO14,Ind02.q (VT Fuse Fail A)	ANN.IN2GGIO14,Ind03.stVal (VT Fuse Fail B)	ANN.IN2GGIO14,Ind03.q (VT Fuse Fail B)	ANN.IN2GGIO14,Ind04.stVal (VT Fuse Fail C)	ANN.IN2GGIO14,Ind04.q (VT Fuse Fail C)
Breaker Position	V2M6 (MU8B)	MU8b- 12kV Reactive Feeder CB 17_V2M6	Breaker Unit 17 I/O	01-0C-CD-01-00-07	1	4	0x0007	4	500	BRK17_MU8	CB17_52A	SCMLGGIO1.Ind1.stVal (Input 1- CB17 52a)	SCMLGGIO1.Ind1.q (Input 1- CB17 52a)	----	----	----	----	----	----
MU Alarms	MU8A_VIZ	MU8a- 12kV Reactive Feeder CB 17_V6M1	12kV Unit 17 Capacitor Side CT & 12kV Unit 17 Bus PT 100:1	01-0C-CD-01-00-08	1	4	0x0008	10	500	CTPT Alarm UNIT 17-MU8	gcb01	GGIO1.Ind1.stVal (internal alarm)	GGIO1.Ind1.q (internal alarm)	----	----	----	----	----	----
Breaker Position	MU9_MU10	MU9- 12kV Xfer Bus CB 11 _V7M1 #2 CKT 1	12kV Unit 11 Trans Bus Side CT & 12kV Unit 17 Bus PT 100:2 & Unit 11 Breaker I/O	01-0C-CD-01-00-09	1	4	0x0009	20	500	BRK11_MU9	BKR11_MU9	CTRL/BININGGIO1.Ind1.stVal (CB11 52A)	CTRL/BININGGIO1.Ind1.q (CB11 52A)	CTRL/BININGGIO1.Ind2.stVal	CTRL/BININGGIO1.Ind2.q	CTRL/BININGGIO1.Ind3.stVal (CB11 1241 UNIT 17 PT PHA FUSE)	CTRL/BININGGIO1.Ind3.q (CB11 1241 UNIT 17 PT PHA FUSE)	CTRL/BININGGIO1.Ind4.stVal (CB11 1241 UNIT 17 PT PHB FUSE)	CTRL/BININGGIO1.Ind4.q (CB11 1241 UNIT 17 PT PHB FUSE)
Breaker Position	MU9_MU10	MU10- 69/138-12kV Xfmr BK41 CB 14_V7M1 #2 CKT 2	12kV Unit 14 BK41 Side CT & 12kV Unit 17 Bus PT 100:3 & Unit 14 Breaker I/O	01-0C-CD-01-00-22	1	4	0x0016	20	500	BRK14_MU10	BKR14_MU10	CTRL/BININGGIO1.Ind7.stVal (CB14 52A)	CTRL/BININGGIO1.Ind7.q (CB14 52A)	CTRL/BININGGIO1.Ind8.stVal	CTRL/BININGGIO1.Ind8.q	CTRL/BININGGIO1.Ind9stVal (CB14 1241 UNIT 17 PT PHA FUSE)	CTRL/BININGGIO1.Ind9.q (CB14 1241 UNIT 11 PT PHA FUSE)	CTRL/BININGGIO1.Ind10.stVal (CB14 1241 UNIT 11 PT PHB FUSE)	CTRL/BININGGIO1.Ind10.q (CB14 1241 UNIT 11 PT PHB FUSE)
Breaker Position	MU9_MU10	MU9 & MU10- 1_V7M1 #1&2	ALL STATUS INPUTS	01-0C-CD-01-00-40	1	4	0x0028	1	500	gooseID	DigInput	CTRL/BININGGIO1.Ind1.stVal (CB11 52A)	CTRL/BININGGIO1.Ind2.stVal	CTRL/BININGGIO1.Ind3.stVal (CB11 1241 UNIT 17 PT PHA FUSE)	CTRL/BININGGIO1.Ind4.stVal (CB11 1241 UNIT 17 PT PHB FUSE)	CTRL/BININGGIO1.Ind5.stVal (CB11 1241 UNIT 17 PT PHC FUSE)	CTRL/BININGGIO1.Ind6stVal (CB11 1241 UNIT 17 PT NEU FUSE)	CTRL/BININGGIO1.Ind7.stVal (CB14 52A)	CTRL/BININGGIO1.Ind8.stVal
Breaker Position	MU13_CB20	MU13- 12kV Swgr 1242 Bus Tie CB 20_V1M5 #2	12kV Unit 20 CT & Unit 20 Breaker I/O	01-0C-CD-01-00-23	1	4	0x0017	4	500	Control_DataSet / MU13_CB20	DataSet	GGIO.SPCSO1.stVal (Input 1- CB20 52a)	GGIO.SPCSO1.q (Input 1- CB20 52a)	-----	-----	-----	-----	-----	-----
Breaker Trip-Close	87-1241	12kV Main Bus Overall Low Impedance Bus Differential (Wraps CBs 10, 11, 12, 14, 17 & 20)_V2M3_87-1241	V2M3 - 87-1241 A	01-0C-CD-04-00-24	1	4	0x0018	4	500	A87_1241_BKR_CNTL	TRIP_CLS	MON/SP16GAPC1.Ind1.stVal (Trip BRK Unit 10)	MON/SP16GAPC1.Ind1.q (Trip BRK Unit 10)	MON/SP16GAPC1.Ind2.stVal (Close BRK Unit 10)	MON/SP16GAPC1.Ind2.q (Close BRK Unit 10)	MON/SP16GAPC1.Ind3.stVal (Trip BRK Unit 12)	MON/SP16GAPC1.Ind3.q (Trip BRK Unit 12)	MON/SP16GAPC1.Ind4.stVal (Close BRK Unit 12)	MON/SP16GAPC1.Ind4.q (Close BRK Unit 12)
Breaker Trip	V2M1_5051_17A	12kV Reactive Feeder Overcurrent (CB 17) Set A_V2M1_50/51-CB (Set A)	V2M1 - 50/51-CB (CAPS) A	01-0C-CD-01-00-25	1	4	0x0019	4	500	A50_51_CB17_BKR_CNTL	TRIP	CTRL/SMPPTRC1.Op.general (Trip BRK Unit 17)	CTRL/SMPPTRC1.Op.q (Trip BRK Unit 17)	-----	-----	-----	-----	-----	-----
Breaker Trip	50_51-CB17_B	12kV Reactive Feeder Overcurrent (CB 17) Set B_V1M4_50/51-CB (Set B)	V1M4 - 50/51-CB (CAPS) B	01-0C-CD-01-00-26	1	4	0x001A	4	500	B50_51_CB17_BKR_CNTL	DataSet	.stVal (Trip BRK Unit 17)	.q (Trip BRK Unit 17)	-----	-----	-----	-----	-----	-----
Breaker Trip	50_51-1241_B	12kV Main Bus Partial Overcurrent Differential Set B (Wraps CBs 10, 14 & 20)_V1M4_50/51-1241 (Set B)	V1M4 - 50/51-BT 4041 B	01-0C-CD-01-00-27	1	4	0x001B	4	500	B50_51BT_4041_BKR_CNTL	DataSet	.stVal (Trip BRK Unit 10)	.q (Trip BRK Unit 10)	.stVal (Trip BRK Unit 14)	.q (Trip BRK Unit 14)	.stVal (Trip BRK Unit 20)	.q (Trip BRK Unit 20)	-----	-----
Breaker Trip	V2M1_5051BT_4041A	12kV Main Bus Partial Overcurrent Differential Set A (Wraps CBs 10, 14 & 20)_V2M1_50/51-1241 (Set A)	V2M1 - 50/51-BT 4041 A	01-0C-CD-0-00-28	1	4	0x001C	4	500	A50_51BT_4041_BKR_CNTL	TRIP	MON/SP16GAPC1.Ind1.stVal (Trip BRK Unit 10)	MON/SP16GAPC1.Ind1.q (Trip BRK Unit 10)	MON/SP16GAPC1.Ind2.stVal (Trip BRK Unit 14)	MON/SP16GAPC1.Ind2.q (Trip BRK Unit 14)	MON/SP16GAPC1.Ind3.stVal (Trip BRK Unit 20)	MON/SP16GAPC1.Ind3.q (Trip BRK Unit 20)	-----	-----

IEDname	Dataset index 9	Dataset index 10	Dataset index 11	Dataset index 12	Dataset index 13	Dataset index 14	Dataset index 15	Dataset index 16	Dataset index 17	Dataset index 18	Dataset index 19	Dataset index 20	Dataset index 21	Dataset index 22	Dataset index 23	Dataset index 24	Dataset index 25
V2M5_MU5	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----
MU6_CB12_V3M3	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----
V2M6 (MU8B)	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----
MU8A_VIZ	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----
MU9_MU10	CTRL/BININGGIO1.Ind5.stVal (CB11 1241 UNIT 17 PT PHC FUSE)	CTRL/BININGGIO1.Ind5.q (CB11 1241 UNIT 17 PT PHC FUSE)	CTRL/BININGGIO1.Ind6stVal (CB11 1241 UNIT 17 PT NEU FUSE)	CTRL/BININGGIO1.Ind6.q (CB7 1241 UNIT 17 PT NEU FUSE)	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----
MU9_MU10	CTRL/BININGGIO1.Ind11.stVal (CB14 1241 UNIT 11 PT PHC FUSE)	CTRL/BININGGIO1.Ind11.q (CB14 1241 UNIT 11 PT PHC FUSE)	CTRL/BININGGIO1.Ind12stVal (CB141241 UNIT 11 PT NEU FUSE)	CTRL/BININGGIO1.Ind12.q (CB14 1241 UNIT 11 PT PNEU FUSE)	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----
MU9_MU10	CTRL/BININGGIO1.Ind9stVal (CB14 1241 UNIT 17 PT PHA FUSE)	CTRL/BININGGIO1.Ind10.stVal (CB14 1241 UNIT 11 PT PHB FUSE)	CTRL/BININGGIO1.Ind11.stVal (CB14 1241 UNIT 11 PT PHC FUSE)	CTRL/BININGGIO1.Ind12stVal (CB141241 UNIT 11 PT NEU FUSE)	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----
MU13_CB20	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----
87-1241	MON/SP16GAPC1.Ind5.stVal (Trip BRK Unit 17)	MON/SP16GAPC1.Ind5.q (Trip BRK Unit 17)	MON/SP16GAPC1.Ind6.stVal (Close BRK Unit 17)	MON/SP16GAPC1.Ind6.q (Close BRK Unit 17)	MON/SP16GAPC1.Ind7.stVal (Trip BRK Unit 11)	MON/SP16GAPC1.Ind7.q (Trip BRK Unit 11)	MON/SP16GAPC1.Ind8.stVal (Close BRK Unit 11)	MON/SP16GAPC1.Ind8.q (Close BRK Unit 11)	MON/SP16GAPC1.Ind9.stVal (Trip BRK Unit 14)	MON/SP16GAPC1.Ind9.q (Trip BRK Unit 14)	MON/SP16GAPC1.Ind10.stVal (Close BRK Unit 14)	MON/SP16GAPC1.Ind10.q (Close BRK Unit 14)	MON/SP16GAPC1.Ind11.stVal (Trip BRK Unit 20)	MON/SP16GAPC1.Ind11.q (Trip BRK Unit 20)	MON/SP16GAPC1.Ind12.stVal (Close BRK Unit 20)	MON/SP16GAPC1.Ind12.q (Close BRK Unit 20)	-----
V2M1_5051_17A	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----
50_51-CB17_B	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----
50_51-1241_B	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----
V2M1_5051BT_4041A	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----

IEDname	Subscribing IEDs: V2M3 - 87-1241 A	V2M1 - 50/51-CB (CAPS) A	V1M4 - 50/51-CB (CAPS) B	V1M4 - 50/51-BT 4041 B	V2M1 - 50/51-BT 4041 A	Subscribing Merging Units: MU5- 12kV Swgr 1240 Bus Tie CB 10_V2M5	MU6- 12kV Feeder CB 12_V3M3	MU8b- 12kV Reactive Feeder CB 17_V2M6	MU8a- 12kV Reactive Feeder CB 17_V6M1	MU9- 12kV Xfer Bus CB 11 _V7M1 #2 CKT 1	MU10- 69/138-12kV Xfmr BK41 CB 14_V7M1 #2 CKT 2	MU13- 12kV Swgr 1242 Bus Tie CB 20_V1M5 #2
V2M5_MU5	YES			YES	YES							
MU6_CB12_V3M3	YES											
V2M6 (MU8B)	YES	YES	YES									
MU8A_VIZ	YES	YES	YES									
MU9_MU10	YES											
MU9_MU10	YES			YES	YES							
MU9_MU10	YES			YES	YES							
MU13_CB20	YES			YES	YES							
87-1241						YES (TRIP Output #1, Close Output #2)	YES (TRIP Output #1, Close Output #2)	YES (TRIP Output #1, Close Output #2)		YES (TRIP Output #1, Close Output #2)	YES (TRIP Output #1, Close Output #2)	YES (TRIP Output #1, Close Output #2)
V2M1_5051_17A	YES							YES (TRIP Output #1)				
50_51-CB17_B	YES							YES (TRIP Output #1)				
50_51-1241_B	YES					YES (TRIP Output #1)					YES (TRIP Output #1)	YES (TRIP Output #1)
V2M1_5051BT_4041A	YES					YES (TRIP Output #1)					YES (TRIP Output #1)	YES (TRIP Output #1)

TABLE 32 STATION BUS DATA FLOW SPREADSHEET

GOOSE Control Block and referenced dataset information																								Subscribing IEDs			
MAC Address	**VLAN ID**	**VLAN-PRIORITY**	**App ID (hex)**	**Min Trime (ms)**	**Heatbeat Rate, Max time (ms)**	**Control Block Name and GoID**	**Dataset Name**	**Dataset index 1**	**Dataset index 2**	**Dataset index 3**	**Dataset index 4**	**Dataset index 5**	**Dataset index 6**	**Dataset index 7**	**Dataset index 8**	**Dataset index 9**	**Dataset index 10**	**Dataset index 11**	**Dataset index 12**	**Dataset index 13**	**Dataset index 14**	**Dataset index 15**	**Dataset index 16**	**12kV Cap Bank Sequencing Automation Controller__V3M4 PAC__Cap Bank V3M4**	**12kV Cap Bank Voltage Unbalance Protection__V3M2 Feeder Relay__Cap Bank 59X (3V0)**	**12kV Reactor Bank Sequencing Automation Controller__V3M4 PAC__Reactor Bank V3M4**	**12kV Reactor Bank Voltage Unbalance Protection__V3M2 Feeder Relay__Reactor Bank 59X (3V0)**
01-0C-CD-04-00-30	1	4	1E	100	500	V3M2_LOR_CAP	Cap_LOR_Trip	ANN.LTGGIO5.Ind13.stVal (Trip CAP BANK- used for blocking)	ANN.LTGGIO5.Ind13.q (Trip CAP BANK used for blocking)	ANN.SVGGIO4.Ind06.stVal (MASTER STAGES 1-4 OPEN CMD TO V3M4)	ANN.SVGGIO4.Ind06.q (MASTER STAGES 1-4 OPEN CMD TO V3M4)	ANN.SVGGIO4.Ind07.stVal (MASTER STAGES 1-4 CLOSE CMD TO V3M4)	ANN.SVGGIO4.Ind07.q (MASTER STAGES 1-4 CLOSE CMD TO V3M4)	PRO.QTPTOC7.Op.general (51QT Trip CAP BANK)	PRO.QTPTOC7.Op.q (51QT Trip CAP BANK)	----	----	----	----	----	----	----	----	YES			
01-0C-CD-04-00-32	1	4	20	100	500	V3M2_LOR_REAC	Reac_LOR_Trip	ANN.LTGGIO5.Ind13.stVal (Trip REAC BANK- used for blocking)	ANN.LTGGIO5.Ind13.q (Trip REAC BANK- used for blocking)	ANN.SVGGIO3.Ind06.stVal (MASTER STAGES 1-4 OPEN CMD TO V3M4)	ANN.SVGGIO3.Ind06.q (MASTER STAGES 1-4 OPEN CMD TO V3M4)	ANN.SVGGIO3.Ind07.stVal (MASTER STAGES 1-4 CLOSE CMD TO V3M4)	ANN.SVGGIO3.Ind07.q (MASTER STAGES 1-4 CLOSE CMD TO V3M4)	PRO.QTPTOC7.Op.general (51QT Trip CAP BANK)	PRO.QTPTOC7.Op.q (51QT Trip CAP BANK)	----	----	----	----	----	----	----	----			YES	
01-0C-CD-04-00-35	1	4	23	100	500	V3M4_52A_CAP	Cap_Stage_Stat	ANN/INCGGIO13.Ind1.stVal (Stage 1 open/close)	ANN/INCGGIO13.Ind1.q (Stage 1 open/close)	ANN/INCGGIO13.Ind2.stVal (Stage 2 open/close)	ANN/INCGGIO13.Ind2.q (Stage 2 open/close)	ANN/INCGGIO13.Ind3.stVal (Stage 3 open/close)	ANN/INCGGIO13.Ind3.q (Stage 3 open/close)	ANN/INCGGIO13.Ind4.stVal (Stage 4 open/close)	ANN/INCGGIO13.Ind4.q (Stage 4 open/close)	----	----	----	----	----	----	----	----			YES	
01-0C-CD-04-00-36	1	4	20	100	500	V3M4_52A_REAC	ReacT_Stage_Stat	ANN/INCGGIO13.Ind1.stVal (Stage 1 open/close)	ANN/INCGGIO13.Ind1.q (Stage 1 open/close)	ANN/INCGGIO13.Ind2.stVal (Stage 2 open/close)	ANN/INCGGIO13.Ind2.q (Stage 2 open/close)	ANN/INCGGIO13.Ind3.stVal (Stage 3 open/close)	ANN/INCGGIO13.Ind3.q (Stage 3 open/close)	ANN/INCGGIO13.Ind4.stVal (Stage 4 open/close)	ANN/INCGGIO13.Ind4.q (Stage 4 open/close)	----	----	----	----	----	----	----	----	YES			
01-0C-CD-04-00-33	1	4	21	100	500	A_Cap_Reac_Met	Bank_41_MVA	MET.METMMXU1.PhV.phsA.instCVal.mag.f (69kV bus voltage Phase A)	MET.METMMXU1.PhV.phsA.q (69kV bus voltage Phase A)	MET.METMMXU1.PhV.phsB.instCVal.mag.f (69kV bus voltage Phase B)	MET.METMMXU1.PhV.phsB.q (69kV bus voltage Phase B)	MET.METMMXU1.PhV.phsC.instCVal.mag.f (69kV bus voltage Phase C)	MET.METMMXU1.PhV.phsC.q (69kV bus voltage Phase C)	ANN.PMVGGIO3.AnIn01.mag.f (Bank 41 A phs MVA)	ANN.PMVGGIO3.AnIn01.q (Bank 41 A phs MVA)	ANN.PMVGGIO3.AnIn02.mag.f (Bank 41 B phs MVA)	ANN.PMVGGIO3.AnIn02.q (Bank 41 B phs MVA)	ANN.PMVGGIO3.AnIn03.mag.f (Bank 41 C phs MVA)	ANN.PMVGGIO3.AnIn03.q (Bank 41 C phs MVA)	----	----	----	----	YES		YES	
01-0C-CD-04-00-34	1	4	22	100	500	B_Cap_Reactor_Metering		.f (69kV bus voltage Phase A)	.q (69kV bus voltage Phase A)	.f (69kV bus voltage Phase B)	.q (69kV bus voltage Phase B)	.f (69kV bus voltage Phase C)	.q (69kV bus voltage Phase C)	.f (KVAR Phase A)	.q (KVAR Phase A)	.f (KVAR Phase B)	.q (KVAR Phase B)	.f (KVAR Phase C)	.q (KVAR Phase C)	----	----	----	----	YES		YES	

APPENDIX F - COMTRADE GRAPHICAL ANALYSIS

Appendix F contains the raw COMTRADE file data for each of the fault cases analyzed. Information is divided into analog signals (voltage, current, frequency, etc.) and digital signals (protection element pickup/operate, 52A breaker statuses, etc.) for each relay. Analog signals utilized custom naming where appropriate to identify the channels, whereas digital signals utilized the naming assigned by a given protective relay.

For each case, the fault inception point is marked with a vertical orange line. A vertical blue line denotes the operate time of a protection element or a corresponding 52A dropout time, as appropriate for the fault analyzed. Appendix G contains timing data and additional analysis of the COMTRADE data presented.

Note: some relays produce more digital signals than in use for the given application, or reported no activity on particular digital signal channels. Blank digital element plots were left in the dataset to demonstrate non-operation of protective elements for a given fault scenario.

Note to Reader: Due to its size and format of the graphics, the content of Appendix F is provided in a separate PDF file and is not included in this MS Word document.

APPENDIX G - OPERATING TIMES SPREADSHEET

Appendix G contains the timing information extracted from the raw COMTRADE file data presented in Appendix F. The tables list each fault location analyzed, the fault type, and operate times related to the protective elements under investigation (pickup, trip, and 52A dropout). All timings reported were based on normalizing the fault initiation to a time of zero milli-seconds. Total operate times and the round-trip 52A dropout time conveyed through the network are presented in milli-seconds and cycles (cyc). Relays associated with several circuit breakers (e.g., the 12 kV bus differential relay) have multiple 52A dropout times listed, with corresponding notes that indicate which simulated circuit breaker corresponds to the 52A dropout time reported.

For each fault location, notes are included to discuss the test performed and results obtained. These notes correlate to the faults listed in the table, as well as documented in the raw COMTRADE plots in Appendix F.

Note: results related to the capacitor/reactor automation testing were reported in Appendix F.

TABLE 33 RELAY OPERATING TIMES

Fault Location	Fault Type	Relay	Fault Time (ms)	Pickup (ms)	Trip (ms)	52A Dropout (ms)	52A Dropout (ms)	52A Dropout (ms)	52A Dropout (ms)	52A Dropout (ms)	52A Dropout (ms)	Pickup Time (ms)	Pickup Time (cyc)	Trip Time (ms)	Trip Time (cyc)	52A Dropout Time (ms)	52A Dropout Time (ms)	52A Dropout Time (ms)	52A Dropout Time (ms)	52A Dropout Time (ms)	52A Dropout Time (ms)	Notes
FLT1	3PH	V1M1 Lcl (87L B Set Local)	0	23	23	50.7	-	-	-	-	-	23	1.38	23	1.38	27.7	-	-	-	-	-	
FLT1	3PH	V1M1 Rem (87L B Set Remote)	0	25	25	-	-	-	-	-	-	25	1.5	25	1.5	-	-	-	-	-	-	
FLT1	3PH	V2M2 Lcl (87L A Set Local)	0	10.8	13.3	33.3	-	-	-	-	-	10.8	0.648	13.3	0.798	20	-	-	-	-	-	
FLT1	3PH	V2M2 Rem (87L A Set Remote)	0	10.8	14.2	-	-	-	-	-	-	10.8	0.648	14.2	0.852	-	-	-	-	-	-	
FLT1	3PH	V2M2 Lcl (21P)	0	10	10	33.3	-	-	-	-	-	10	0.6	10	0.6	23.3	-	-	-	-	-	
FLT1	SLG	V1M1 Lcl (87L B Set Local)	0	23	23	54	-	-	-	-	-	23	1.38	23	1.38	31	-	-	-	-	-	
FLT1	SLG	V1M1 Rem (87L B Set Remote)	0	25.8	30.8	53.8	-	-	-	-	-	25.8	1.548	30.8	1.848	23	-	-	-	-	-	
FLT1	SLG	V2M2 Lcl (87L A Set Local)	0	15	25	30.8	-	-	-	-	-	15	0.9	25	1.5	5.8	-	-	-	-	-	
FLT1	SLG	V2M2 Rem (87L A Set Remote)	0	10.8	20.8	30.8	-	-	-	-	-	10.8	0.648	20.8	1.248	10	-	-	-	-	-	
FLT1	SLG	V2M2 Lcl (GTOC 87L A Set)	0	15.8	523.3	30.8	-	-	-	-	-	15.8	0.948	523.3	31.398	-492.5	-	-	-	-	-	
FLT1	SLG	V2M2 Rem (87L A Set Remote)	0	10.8	15.8	-	-	-	-	-	-	10.8	0.648	15.8	0.948	-	-	-	-	-	-	
FLT1	SLG	V2M2 Lcl (21G)	0	9.1	9.1	29.1	-	-	-	-	-	9.1	0.546	9.1	0.546	20	-	-	-	-	-	
FLT1	SLG	V3M1 (21G)	0	4.2	4.2	29.2	-	-	-	-	-	4.2	0.252	4.2	0.252	25	-	-	-	-	-	
FLT1	SLG	V3M1 (GTOC)	0	8.4	108.4	29.2	-	-	-	-	-	8.4	0.504	108.4	6.504	-79.2	-	-	-	-	-	
FLT3	3PH	V2M2 Lcl (21P - Backup)	0	68.3	271.7	291.7	-	-	-	-	-	68.3	4.098	271.7	16.302	20	-	-	-	-	-	
FLT3	3PH	V3M1 (21P - Backup)	0	12.5	212.5	237.5	-	-	-	-	-	12.5	0.75	212.5	12.75	25	-	-	-	-	-	
FLT3	SLG	V2M2 Lcl (21G - Backup)	0	17.5	220.8	244.2	-	-	-	-	-	17.5	1.05	220.8	13.248	23.4	-	-	-	-	-	
FLT3	SLG	V3M1 (21G - Backup)	0	12.5	212.5	150	-	-	-	-	-	12.5	0.75	212.5	12.75	-62.5	-	-	-	-	-	
FLT3	SLG	V3M1 (GTOC)	0	12.5	125	150	-	-	-	-	-	12.5	0.75	125	7.5	25	-	-	-	-	-	
FLT4	3PH	V1M3 (87B)	0	2.2	9	-	-	-	-	-	-	2.2	0.132	9	0.54	-	-	-	-	-	-	
FLT4	3PH	V2M1 (87B - OC)	0	5	5	32.5	21.7	19.2	-	-	-	5	0.3	5	0.3	27.5	16.7	14.2	-	-	-	52A CBs: 2,3,7
FLT4	SLG	V1M3 (87B)	0	0	7.5	-	-	-	-	-	-	0	0	7.5	0.45	-	-	-	-	-	-	
FLT4	SLG	V2M1 (87B - OC)	0	4.2	4.2	30.8	20.8	17.5	-	-	-	4.2	0.252	4.2	0.252	26.6	16.6	13.3	-	-	-	52A CBs: 2,3,7
FLT4	HIZ (3PH)	V2M4 (87B - HIZ)	0	3.3	3.3	26.7	20	17.5	-	-	-	3.3	0.198	3.3	0.198	23.4	16.7	14.2	-	-	-	52A CBs: 2,3,7
FLT4	HIZ (SLG)	V2M4 (87B - HIZ)	0	3.3	3.3	27.2	20.5	17.2	-	-	-	3.3	0.198	3.3	0.198	23.9	17.2	13.9	-	-	-	52A CBs: 2,3,7
FLT5	3PH	V1M4 (PH IOC)	0	0.8	9.5	-	-	-	-	-	-	0.8	0.048	9.5	0.57	-	-	-	-	-	-	
FLT5	3PH	V2M1 (PH IOC)	0	5	8.3	28.3	-	-	-	-	-	5	0.3	8.3	0.498	20	-	-	-	-	-	
FLT5	SLG	V1M4 (GND IOC)	0	9.5	9.5	-	-	-	-	-	-	9.5	0.57	9.5	0.57	-	-	-	-	-	-	
FLT5	SLG	V2M1 (GND IOC)	0	15.9	15.9	39.2	-	-	-	-	-	15.9	0.954	15.9	0.954	23.3	-	-	-	-	-	
FLT6	3PH	V1M4 (PH TOC, Partial Diff)	0	5	1352	-	-	-	-	-	-	5	0.3	1352	81.12	-	-	-	-	-	-	
FLT6	3PH	V2M1 (PH TOC, Partial Diff)	0	3.4	1338.4	1358.4	1351.7	1365	-	-	-	3.4	0.204	1338.4	80.304	20	13.3	26.6	-	-	-	52A CBs: 10,14,20
FLT6	SLG	V1M4 (GND TOC, Partial Diff)	0	5.7	1714.7	-	-	-	-	-	-	5.7	0.342	1714.7	102.882	-	-	-	-	-	-	
FLT6	SLG	V2M1 (GND TOC, Partial Diff)	0	5	1700.9	1720.9	1714.2	1727.5	-	-	-	5	0.3	1700.9	102.054	20	13.3	26.6	-	-	-	52A CBs: 10,14,20
FLT7	3PH	V2M4 (87B - 12 kV)	0	13	13.9	33.9	30.5	30.5	30.5	53.9	50.5	13	0.78	13.9	0.834	20	16.6	16.6	16.6	40	36.6	52A CBs: 10,11,12,14,17,20
FLT7	SLG	V2M4 (87B - 12 kV)	0	14.1	14.9	34.9	31.6	31.6	31.6	51.6	44.9	14.1	0.846	14.9	0.894	20	16.7	16.7	16.7	36.7	30	52A CBs: 10,11,12,14,17,20
FLT8	3PH	V2M4 (87T A Set, PH IOC)	0	7.5	7.5	18.3	18.3	27.5	-	-	-	7.5	0.45	7.5	0.45	10.8	10.8	20	-	-	-	52A CBs:7,11,14
FLT8	3PH	V2M4 (87T A Set, 87U)	0	16.7	16.7	18.3	18.3	27.5	-	-	-	16.7	1.002	16.7	1.002	1.6	1.6	10.8	-	-	-	52A CBs:7,11,14
FLT8	3PH	V2M4 (87T A Set, 87R)	0	27.5	27.5	18.3	18.3	27.5	-	-	-	27.5	1.65	27.5	1.65	-9.2	-9.2	0	-	-	-	52A CBs:7,11,14
FLT8	3PH	V1M3 (87T B Set)*	0	27.8	105.8	-	-	-	-	-	-	27.8	1.668	105.8	6.348	-	-	-	-	-	-	*OC Op Time
FLT8	3PH	V2M1 (5051 7A, PH OC)	0	10	10	20	-	-	-	-	-	10	0.6	10	0.6	10	-	-	-	-	-	
FLT8	3PH	V1M4 (5051 7B, PH OC)	0	4.3	6.5	-	-	-	-	-	-	4.3	0.258	6.5	0.39	-	-	-	-	-	-	
FLT8	SLG	V2M4 (87T A Set, GND IOC)	0	9.2	9.2	19.2	19.2	29.2	-	-	-	9.2	0.552	9.2	0.552	10	10	20	-	-	-	52A CBs:7,11,14
FLT8	SLG	V2M4 (87T A Set, 87R)	0	25.8	25.8	19.2	19.2	29.2	-	-	-	25.8	1.548	25.8	1.548	-6.6	-6.6	3.4	-	-	-	52A CBs:7,11,14
FLT8	SLG	V1M3 (87T B Set)*	0	1063.7	1063.7	-	-	-	-	-	-	1063.7	63.822	1063.7	63.822	-	-	-	-	-	-	*OC Op Time
FLT8	SLG	V2M1 (5051 7A, GND IOC)	0	10	10	20	-	-	-	-	-	10	0.6	10	0.6	10	-	-	-	-	-	
FLT8	SLG	V1M4 (5051 7B, GND IOC)	0	11	13	-	-	-	-	-	-	11	0.66	13	0.78	-	-	-	-	-	-	
OV	OV	V2M2 Lcl (87L A Set Local)	0	11.7	1023.3	1030	-	-	-	-	-	11.7	0.702	1023.3	61.398	6.7	-	-	-	-	-	
OV	OV	V3M1	0	25	191.7	220.9	-	-	-	-	-	25	1.5	191.7	11.502	29.2	-	-	-	-	-	
UV	UV	V2M2 Lcl (87L A Set Local)	0	14.2	1016.7	1040.8	-	-	-	-	-	14.2	0.852	1016.7	61.002	24.1	-	-	-	-	-	
UV	UV	V3M1	0	12.5	179.2	204.2	-	-	-	-	-	12.5	0.75	179.2	10.752	25	-	-	-	-	-	
UF	UF	V2M2 Lcl (87L A Set Local)	0	146.5	654.8	674.8	-	-	-	-	-	146.5	8.79	654.8	39.288	20	-	-	-	-	-	
UF	UF	V3M1	0	500	670.8	-	-	-	-	-	-	500	30	670.8	40.248	-	-	-	-	-	-	
BF	Position	V1M2	0	37.1	417.1	-	-	-	-	-	-	37.1	2.226	417.1	25.026	-	-	-	-	-	-	
BF	Current	V1M2	0	37.1	417	-	-	-	-	-	-	37.1	2.226	417	25.02	-	-	-	-	-	-	

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TABLE 34 RELAY OPERATING TIMES NOTES

Fault Location	Fault Type	Relay Element Tested	Test Results	Testing Notes
FLT1	3PH	87L	Success	87L protection tripped for close-in, in-zone 3PH fault.
FLT1	3PH	87L	Success	87L protection tripped for close-in, in-zone 3PH fault.
FLT1	3PH	87L	Success	87L protection tripped for close-in, in-zone 3PH fault.
FLT1	3PH	87L	Success	87L protection tripped for close-in, in-zone 3PH fault.
FLT1	3PH	21P	Success	21P protection tripped for close-in 3PH fault in the forward direction.
FLT1	SLG	87L	Success	87L protection tripped for close-in, in-zone SLG fault.
FLT1	SLG	87L	Success	87L protection tripped for close-in, in-zone SLG fault.
FLT1	SLG	87L	Success	87L protection tripped for close-in, in-zone SLG fault.
FLT1	SLG	87L	Success	87L protection tripped for close-in, in-zone SLG fault.
FLT1	SLG	87L	Success	87L protection tripped for close-in, in-zone SLG fault. Inverse time delayed element: Pickup = 180 A primary, Curve Type = ANSI Very Inverse, Time Dial = 1.0
FLT1	SLG	87L	Success	87L protection tripped for close-in, in-zone SLG fault.
FLT1	SLG	21G	Success	21G protection tripped for close-in SLG fault in the forward direction.
FLT1	SLG	21G	Success	21G protection tripped for close-in SLG fault in the forward direction.
FLT1	SLG	51G	Success	51G protection timed-out and tripped for a close-in SLG fault in the forward direction. Inverse time delayed element: Pickup = 180 A primary, Curve Type = ANSI Very Inverse, Time Dial = 1.0
FLT3	3PH	87L / 21P	Success	87L protection properly restrained for out-of-zone fault. Overreaching 21P protection tripped for remote 3PH fault in the forward direction. Definite Time Delay = 200 ms. Pickup time delayed by ~60 ms activation of the relay SIR detection filte
FLT3	3PH	87L / 21P	Success	87L protection properly restrained for out-of-zone fault. Overreaching 21P protection tripped for remote 3PH fault in the forward direction. Definite Time Delay = 200 ms.
FLT3	SLG	87L / 21G	Success	87L protection properly restrained for out-of-zone fault. Overreaching 21G protection tripped for remote SLG fault in the forward direction. Definite Time Delay = 200 ms.
FLT3	SLG	87L / 21G	Success	87L protection properly restrained for out-of-zone fault. Overreaching 21G protection tripped for remote SLG fault in the forward direction. Definite Time Delay = 200 ms.
FLT3	SLG	51G	Success	51G protection timed-out and tripped for a remote SLG fault in the forward direction. Inverse time delayed element: Pickup = 180 A primary, Curve Type = ANSI Very Inverse, Time Dial = 1.0
FLT4	3PH	87B (138 kV)	Success	87B protection tripped for in-zone 138 kV 3PH fault.
FLT4	3PH	87B (138 kV)	Success	87B protection tripped for in-zone 138 kV 3PH fault.
FLT4	SLG	87B (138 kV)	Success	87B protection tripped for in-zone 138 kV SLG fault.
FLT4	SLG	87B (138 kV)	Success	87B protection tripped for in-zone 138 kV SLG fault.
FLT4	HIZ (3PH)	HIZ 87 (138 kV)	Success	87B HIZ protection tripped for in-zone 138 kV 3PH fault.
FLT4	HIZ (SLG)	HIZ 87 (138 kV)	Success	87B HIZ protection tripped for in-zone 138 kV SLG fault.
FLT5	3PH	50P (12 kV feeder)	Success	50P protection tripped for a downstream 12 kV feeder 3PH fault.
FLT5	3PH	50P (12 kV feeder)	Success	50P protection tripped for a downstream 12 kV feeder 3PH fault.
FLT5	SLG	50G (12 kV feeder)	Success	50G protection tripped for a downstream 12 kV feeder SLG fault.
FLT5	SLG	50G (12 kV feeder)	Success	50G protection tripped for a downstream 12 kV feeder SLG fault.
FLT6	3PH	51P (12 kV partial diff)	Success	51P protection pickup, time-out, and trip for a downstream 12 kV transfer bus 3PH fault. Inverse time delayed element: Pickup = 2400 A primary, Curve Type = ANSI Very Inverse, Time Dial = 1.0
FLT6	3PH	51P (12 kV partial diff)	Success	51P protection pickup, time-out, and trip for a downstream 12 kV transfer bus 3PH fault. Inverse time delayed element: Pickup = 2400 A primary, Curve Type = ANSI Very Inverse, Time Dial = 1.0
FLT6	SLG	51G (12 kV partial diff)	Success	51G protection pickup, time-out, and trip for a downstream 12 kV transfer bus SLG fault. Inverse time delayed element: Pickup = 500 A primary, Curve Type = ANSI Very Inverse, Time Dial = 6.5
FLT6	SLG	51G (12 kV partial diff)	Success	51G protection pickup, time-out, and trip for a downstream 12 kV transfer bus SLG fault. Inverse time delayed element: Pickup = 500 A primary, Curve Type = ANSI Very Inverse, Time Dial = 6.5
FLT7	3PH	87B (12 kV)	Success	87B protection tripped for in-zone 12 kV 3PH fault.
FLT7	SLG	87B (12 kV)	Success	87B protection tripped for in-zone 12 kV SLG fault.
FLT8	3PH	50P (138 kV XFMR OC)	Success	50P transformer 138 kV overcurrent protection tripped for a transformer internal 3PH fault.
FLT8	3PH	87T, U (Unrestrained XFMR diff)	Success	87U (unrestrained) transformer differential protection tripped for a transformer internal 3PH fault.
FLT8	3PH	87T, R (Restrained XFMR diff)	Success	87R (restrained) transformer differential detected and tripped for a transformer internal 3PH fault.
FLT8	3PH	87T (XFMR diff)	Partial Success	Transformer differential detected internal 3PH fault on all phases but did not trip. Sampled Values received from MU were reported by the relay as "bad quality," which blocks differential operation. Issue with relay Process Bus Module config
FLT8	3PH	50P (138 kV XFMR OC)	Success	50P transformer 138 kV overcurrent protection tripped for a transformer internal 3PH fault.
FLT8	3PH	50P (138 kV XFMR OC)	Success	50P transformer 138 kV overcurrent protection tripped for a transformer internal 3PH fault.
FLT8	SLG	50G (138 kV XFMR OC)	Success	50G transformer 138 kV overcurrent protection tripped for a transformer internal SLG fault.
FLT8	SLG	87T, R (Restrained XFMR diff)	Success	87R (restrained) transformer differential detected and tripped for a transformer internal SLG fault.
FLT8	SLG	87T (XFMR diff)	Partial Success	Transformer differential detected internal SLG fault on the correct phase but did not trip. Sampled Values received from MU were reported by the relay as "bad quality," which blocks differential operation. Issue with relay Process Bus Module
FLT8	SLG	50G (138 kV XFMR OC)	Success	50G transformer 138 kV overcurrent protection tripped for a transformer internal SLG fault.
FLT8	SLG	50G (138 kV XFMR OC)	Success	50G transformer 138 kV overcurrent protection tripped for a transformer internal SLG fault.
OV	OV	59 (138 kV OV)	Success	59 protection pickup, time-out, and trip for a 138 kV overvoltage condition. Definite Time Delay = 1000 ms.
OV	OV	59 (138 kV OV)	Success	59 protection pickup, time-out, and trip for a 138 kV overvoltage condition. Definite Time Delay = 167 ms.
UV	UV	27 (138 kV UV)	Success	27 protection pickup, time-out, and trip for a 138 kV overvoltage condition. Definite Time Delay = 1000 ms.
UV	UV	27 (138 kV UV)	Success	27 protection pickup, time-out, and trip for a 138 kV overvoltage condition. Definite Time Delay = 167 ms.
UF	UF	81U (138 kV UF)	Success	81 underfrequency protection pickup, time-out, and trip for a 138 kV overvoltage condition. Definite Time Delay = 500 ms.
UF	UF	81U (138 kV UF)	Success	81 underfrequency pickup, time-out, and trip for a 138 kV overvoltage condition. Definite Time Delay = 500 ms.
BF	Position	BF 52A (Bkr Fail - Position)	Success	Breaker failure test with breaker position blocked in the close position to test the position-based breaker failure scheme. Breaker failure successfully declared and adjacent breakers tripped. Re-trip Time = 250 ms, Total BF Time = 380 ms.
BF	Current	BF 50L (Bkr Fail - Current)	Success	Breaker failure test with breaker position included but continuous current to test the current-based breaker failure scheme. Breaker failure successfully declared and adjacent breakers tripped. Re-trip Time = 250 ms, Total BF Time = 380 ms.

APPENDIX H – OBSERVATION LOG

Appendix H contains a log of observations regarding specific equipment which were gathered during the process of the project. These observations recorded issues encountered by the project team that required resolution during the course of the project. Observations included physical limitations such time sync connections as well as software and firmware issues that had to be addressed for proper operation. The figures show the date that each observation was made and a detailed description of the observation. Due to the number of entries, the data was divided into three tables.

To remain impartial, it was necessary to avoid disclosing vendor and model information. A product code was developed to obfuscate the vendor name and model numbers of the IEDs for the project. The first character was the letter “V”, which indicated that the next character would reference a vendor. The second character was a numerical index that represented a specific vendor. The third character was the letter “M”, which indicated that the next character would reference a product model. The fourth character was another numerical index that represented a specific vendor’s product model.

TABLE 35 OBSERVATION LOG 1

Epic-2 Project 1

Date	Product Code	Description
8/29/2017	V2M1 V2M2 V2M3 V2M4	Event list and disturbance list must be cleared individually
4/27/2017	V2M1 V2M2 V2M3	Relays selected port for SV protocol will not support any other protocol. This requires an additional process bus connection for GOOSE communications.
4/27/2017	V2M1 V2M2 V2M3	Relays will only support a single port for GOOSE messages. This means that the station bus connection cannot use GOOSE messages
8/28/2017	V2M1 V2M2 V2M3 V2M4	Relays will block all relay actions if any SV stream fails
7/26/2017	V2M1 V2M2 V2M3 V2M4	Relays require optical 1PPS time signal to subscribe to SVs. The IRIGB connection will not work for SV. This requires a SNTP connection in addition to the 1PPS connection to provide real time to the relay.
7/26/2017	V2M1 V2M2 V2M3 V2M4	Relays require SV App ID = 0x4000 for all SV subscriptions. The relay will reject any SV message that does not have this App ID.
7/22/2017	V2M1 V2M2 V2M3 V2M4	Software would overwrite RCB values to first available good value if invalid data was input. No other configuration tool error was indicated. The user must notices that the value had not changed.
8/4/2017	V2	When the user creates the project in the configuration tool the IEC 61850 edition must be declared. The tool will only accept SCL files created using that edition schema, you can not mix editions.
4/27/2017	V2M1 V2M2 V2M3 V2M4	Front port supports MMS and Config when using GOOSE for the process bus port.
7/21/2017	V2M5	Relay uses the SV "smpSynch" from edition 1 only. This is a problem when other subscribers products use the edition 2 definition for the "smpSynch". When this occurs the subscriber interrpets the SV message as not being globally time synced and will not use the stream.
7/11/2017	V2M6	Adjacent module connector pins interfer with din rail bracket end clamp
4/27/2017	V2M7	Only available with 24 Vdc power supply
4/27/2017	V2M1 V2M2 V2M3 V2M4	Relays have thermal limts that prevent side by side mounting on 19" rack
8/31/2017	V2M1 V2M2 V2M3 V2M4	6 Pushbuttons require 2 pushes. One to "wake" the relay & a second to activate function.
6/6/2017	V2	Software, v2.8 - SSL error upon loading for some PCs
9/7/2017	V2	Software will overwrite calculated neutral values with a zero even if MU does not have neutral value inputs, if link is connected in software
8/10/2017	V7M1	MU Configuraion software does not display CIDs from V3 or V1, so import cannot be performed when GOOSE message has analog values in data set
8/30/2017	V7M1	MU does not support event records
7/3/2017	V7M1	MU does not have hardware for high speed tripping yet, but provided catalog number for it during procurement stage.
7/17/2017	V7M1	MU has a 10 character limit on the SVid field. The configuation tool does not provide an error check allowing you to exceed this limit. When exceeded the SV message publishes but is corrupted.
7/17/2017	V7M1	We experienced some problems in changing the default IP address. In some cases the unit would stop publishing, only after a firmware refesh did the unit start working again. This occurred in one of the two units.

TABLE 36 OBSERVATION LOG 2

Epic-2 Project 1

Date	Product Code	Description
7/18/2017	V8M1 V8M2	IRIG media converter could only supply IRIG to a maximum of 4 devices. A different converter would be required if more devices required the signal.
7/12/2017	V4M1	Switches run warm and may need additioanl spacing between adjacent units on a single rack. Manual recommends 1RU above each one.
3/14/2017	V4M1	Switches with 4.3.2x firmware, use strong ciphers and responsiveness was slow. They are shipped using 2048 bit key slowing down the web configurtion interface to a 20 to 30 second response. This was changed to 128bit key via the console port interface which created a fast but still secure web interface.
7/28/2017	V3M4	Unit only supports IEC 61850 edition 1. All SCL files are in editon 1 format and cannot be imported into the V1 or V2 configuration tools.
8/4/2017	V3M1	Relay can not subscribe to V1 or V2 MUs due to the SV "smpSynch" definition missmatch.
7/28/2017	V3M1	Relay defaults to IRIG when given a choice of time protocols. So if IEEE1588 PTP is configured the IRIGB must be dis-connected from the relay. When using PTP the "IRIG B configuration parameter" must be set to "C37.118" for the SV to sync to the PTP source.
7/28/2017	V3M1	Relay does not have an error indication for loss of SV stream
7/18/2017	V3M1	Relay must use PTP in order to subscribe to multiple SV streams
7/18/2017	V3M1	Relay can subscribe to a max of 6 SV streams but relay only provides internal variables to map 2 SV streams.
7/18/2017	V3M1	Relay can only provide metering data for one SV stream.
7/18/2017	V3M1	Relay would only subscribe to SV from the V6 when V3M6 was used because the manual SCL file would not properly import into the configuration tool.
4/11/2017	V3M3	MUs are 19" wide only and have a very large foot print.
9/1/2017	V3M5 V3M6	V3M7 and V3m6 can both be used to configure the V3 relays SV subscriptions. The V3M7 settings will always override the V3M6 settings which leads to confusion during the configuration process.
9/1/2017	V3M1 V3M3	Recommends PTP for SV
9/7/2017	V3M1	Relay displays primary values on display independent of PTR values in relay
9/1/2017	V3M1 V3M3	Time domain of relays must match MU.
9/1/2017	V3M1 V3M3	Relay will reset time source if time domain is changed
7/11/2017	V1M3	Relay has limited clearance to IRIG DB9 connector
8/4/2017		When the user creates the project in the configuration tool the IEC 61850 edition must be declared. The tool will only accept SCL files created using that edition schema, you can not
7/19/2017	V1	IEDs requires 3 different software packages to configure. V1M6, V1M7, & V1M8)
7/11/2017	V1	Invoices are printed on paper that approximates 8x12 instead of 8.5x11
8/4/2017	V1M5	MU can either be strictly Edition 1 or strictly Edition 2. LE is not supported in Edition 2.
8/4/2017	V1M5	MU cannot derive In and Vn from phase quantities per the LE document
8/4/2017	V1M5	MU in Edition 1 requires manual change to CID file so that the file can be used in an edition 2 project.
8/4/2017	V1M1 V1M2 V1M3 V1M4	Relays only support IRIGB fiber input, not 1PPS
8/4/2017	V1M5	MU publishes SV streams with a PRP header even when PRP is not configured. We had to change a separate non-PRP related NIC configuration parameter to stop the the unit from adding the PRP header. The V3M1 would not accept streams with the PRP header.
8/4/2017	V1M5	MU SV message would not parse in Wireshark.

TABLE 37 OBSERVATION LOG 3

Epic-2 Project 1

Date	Product Code	Description
8/4/2017	V1M5	MU SV SymSynch field is strictly Edition 2
8/10/2017	V1M5	MU would not process control messages when sent single point status from V2M1, V2M2, V2M3, V2M4.
4/10/2017	V1M1 V1M2 V1M3 V1M4	Process bus module is limited to 3 SV stream subscriptions
4/10/2017	V1M1 V1M2 V1M3 V1M4	Process bus requires a "add-on" expansion module
7/11/2017	V1M1 V1M2 V1M3 V1M4	Relay mounting brackets are not plates. Instead they are custom drilled rails. Filler plates are available to close off open space in a 19" rack
9/7/2017	V1M1	Remote 7SL86 did not time synch via IRIGB. PTP was required.
9/6/2017	V1M1	7SL86 requires PTP="on" and PPS="off"
8/7/2017	V1M1 V1M2 V1M3 V1M4	Relays do not come with transceiver in service ports of process bus module
7/11/2017	V1M1 V1M2	Relays do not ship with process bus module assembled. User must assemble relay to its process bus module prior to installation
	V6M1	Does not support GOOSE subscriptions.
	V6M1	IEC 61850 template was manually edited using SEL CID as a model. The configuration tool does not export an SCL file.
	V6M1	MU does not support event records
	V6M1	Only supports Modbus for control of output contacts
	V6M1	Provided IEC 61850 CID template that was missing necessary blocks to allow for import into other devices. We had to use another vendors file as a go by.
7/18/2017	V6M1	The configuration tool does not export an SCL file; ICD, CID, or IID files.
9/3/2017	V6M1	"Color identidfier for selected phase" is in hexadecimal
6/16/2017	All	Every vendor had some mixed variation of edition 1 and 2 implementation.
8/9/2017	V2M1 V2M2 V2M3 V2M4	ZZZ MAC filtering of GOOSE is required in switches due to network traffic volume. V2M1, V2M2, V2M3, & V2M4 identified network traffic as a "DOS" condition
8/30/2017	All	ZZZ MUs with differential relaying when set up to reference voltage vector require voltage input
9/5/2017	V2M2	Relay picks up slowly for remote faults when SIR is high. High SIR filter needs additional investigatation.
9/5/2017	V2M1 V2M2 V2M3 V2M4	Relay logic requires multiple logic gates to achieve desired function and this causes 2-3 ms delays in tripping. Delay is dependant on number and type of logic gates. This is most noticable with high speed tripping applications.
9/6/2017	V1M1	Relay interpreted valid data stream with bad quality even though other relays using the same stream operated succsessfully.