Settings Management With IED-Integrated Reporting Leads to Enhanced System Benefits

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This paper was presented at the 71st Annual IEEE IAS Petroleum and Chemical Industry Technical Conference, Orlando, FL, September 11–14, 2024.

For the complete history of this paper, refer to the next page.

Presented at the
71st Annual IEEE IAS Petroleum and Chemical Industry
Technical Conference (PCIC)
Orlando, Florida
September 11–14, 2024

SETTINGS MANAGEMENT WITH IED-INTEGRATED REPORTING LEADS TO ENHANCED SYSTEM BENEFITS

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Abstract**—**Device settings management, associated with the 500 MW expansion of an existing oil and gas facility's 250 MW power system incorporating approximately 12,000 protective relays and other intelligent electronic devices, requires careful planning, defined commissioning processes, and meticulous change management administration. However, once systems are in place, loss-of-production events due to settings errors or relay manufacturer defects can be minimized in duration or eradicated completely when compared to traditional settings management methods.

This paper presents an overview of the expanded power system, including intelligent electronic device-communications data flow, settings database structure, settings management, including the inventory of firmware and serial numbers, and an automated, facility-wide intelligent electronic device event report collection, as well as several examples in which automated, integrated reports resulted in a faster system restoration than was previously available at the facility. Sample events that resulted in an accelerated system restoration include a greenfield construction-area loss of source, a 60 MVA transformer energization, and the incorrect current transformer polarity leading to a line differential relay trip event.

Index Terms—Settings Management, Event Reports, Sequential Event Report, Sequence of Events, Device Manager, Change Management, Relay Protection, Root Cause.

I. INTRODUCTION

Technologies have been developed toward remote working and monitoring at a steady speed and have made a big leap due to the recent pandemic. System operators are better able to gather large amounts of data and quickly analyze data as a result of the development of machine-learning technologies. This has helped large organizations be environmentally friendly, reduce their carbon footprint, and lessen operational costs significantly [1].

Intelligent electronic devices (IEDs) used in oil and gas facility expansions are also expected to apply novel technologies to improve reliability, minimize loss-of-production (LOP) events, and reduce operational costs. This paper describes how this type of technology is used to gather information about all network-connected IEDs into one device management platform and the associated advantages.

II. OVERVIEW OF THE POWER SYSTEM

The 50 Hz power system, in which the subject IEDs are installed, consists of a 110 kV high-voltage (HV) transmission system, a 10 kV medium-voltage (MV) distribution system, and a 380 Vac low-voltage (LV) system. A recent expansion to this power system consists of adding five gas turbine generators (GTGs), each rated at 150 MW. Six new 110 kV substation facilities, 20 MV substations, and 200 LV motor control centers (MCCs) are also commissioned as part of this project.

Part of the power system expansion for the new facilities includes a 110 kV breaker-and-a-half substation to tie the existing utility connection to both the existing and expanded facility generation and load centers. Figure 1 provides an overview of this new 110 kV tie substation. The remaining new 110 kV substations are spread across various locations in the expanded facility. The five new GTGs are stepped up from 15 kV to 110 kV and connect to the 110 kV expanded network.

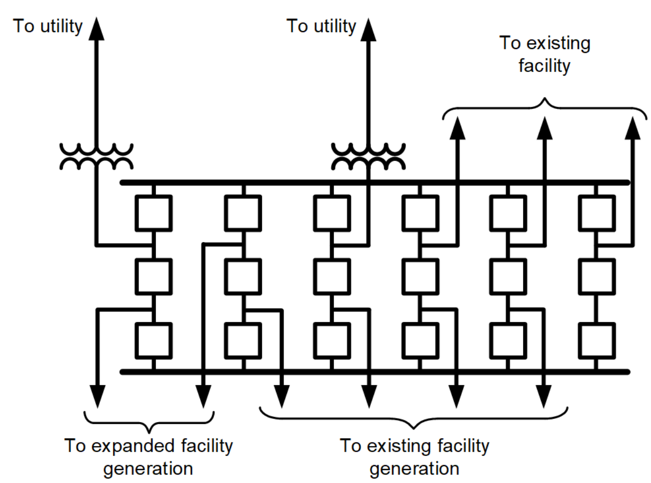

Figure 1. 110 kV Transmission Tie Substation

The 10 kV system consists of dual incomers with an automatic transfer scheme between Bus A and Bus B. Depending on the substation, there are up to 30 feeders on each bus section, each energizing either 10 kV direct-on-line motors or energizing 380 Vac MCCs downstream via dedicated 10 kV/380 V transformers. Figure 2 shows a typical configuration. Two of the MV switchboards also include a standby bus that connects up to eight 10 kV standby diesel generators in the event that the site generation and utility tie are lost.

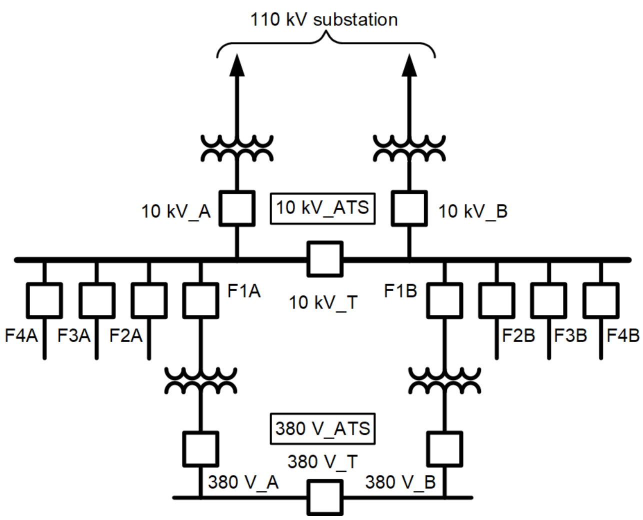

Figure 2. 10 kV/380 Vac MCC Power System Overview

Each primary power system component in the network is protected by microprocessor-based IEDs. Each IED receives data from the power system in various methods, such as current transformers (CTs), potential transformers, discrete contacts, and other sensors. Collecting these data in a consolidated-report format using the methods discussed in this paper provides a valuable tool to monitor the overall health of the power system and enhance the troubleshooting process.

III. SETTINGS MANAGEMENT CHALLENGES

Protection settings development and its verification process at the precommissioning and commissioning stages of over 12,000 IEDs require meticulous review steps to ensure that verified final set points and logic are downloaded into the devices and tested prior to becoming operational. Inadequate verification can result in LOP events valued at millions of dollars.

Achieving verified final set points and logic is a painstaking process due to various reasons, including the following:

1. Continuous design changes
2. Mismatches between manufacturer and design data
3. Settings vs. protection-study mismatches
4. Manufacturer errors
5. Logic issues

Protection settings changes in the postcommissioning or startup stages can lead to schedule delays due to the shutting down of processes, revisiting quality verification documentation, and creating backups at local and global data-gathering stations.

During the operational period, regular maintenance of the apparatus is necessary to avoid production downtime due to failures or nuisance operations. IED maintenance includes the following:

1. Revalidating protection settings and optimizing to meet the process requirements
2. Maintaining an appropriate stock of spare relays to reduce the downtime of the plant
3. Identifying the vulnerability of IEDs to bugs and cybersecurity threats based on their firmware versions and the application of manufacturer-recommended mitigation actions (such as a firmware upgrade)

In addition to periodic activities, analyzing ad hoc protection trips in a timely manner is part of the responsibility of the operational staff to maintain reliable production operations.

A data-gathering hub with a backup that can access devices remotely and locally and maintain a protection settings database with version control, firmware versions, serial numbers, and events can significantly reduce the man-hours associated with this task if it is approached manually. Furthermore, it reduces the risk of data inaccuracies and shortens the troubleshooting cycle of a modern-day oil and gas plant by making settings remotely accessible. Section IV describes how such a database is designed and developed to house all of the IEDs.

IV. DEVICE MANAGEMENT DATABASE

Each local engineering workstation (EWS) uses an Open Database Connectivity (ODBC)-compliant database. The database stores relay settings, time-synchronized event reports, and sequence-of-operation data. Database device configuration is performed via a device manager dialog, in which the user can structure the listing by using common tree folders. Depending on the substation size and the number of downstream electrical-equipment outstations (EEO modules), each local EWS consists of over 250 relays. An EEO can contain one or more 380 Vac MCCs, depending on the process the module is supporting.

Because there are over 12,000 protective relays, standardizing the tree structure across the 19 EWS servers is critical for the end user. This standardization permits filtering on settings, event reports, or Sequence of Events (SOEs) at the substation, bus, or device level. Early in the project, the commissioning team defined the folder levels as follows:

1. Substation and facility
2. Switchboard
3. Bus (for MV and MCC) or diameter (for HV breaker-and-a-half schemes)

Figure 3 shows a typical switchboard folder structure; it demonstrates an HV distribution board and an MV distribution board.

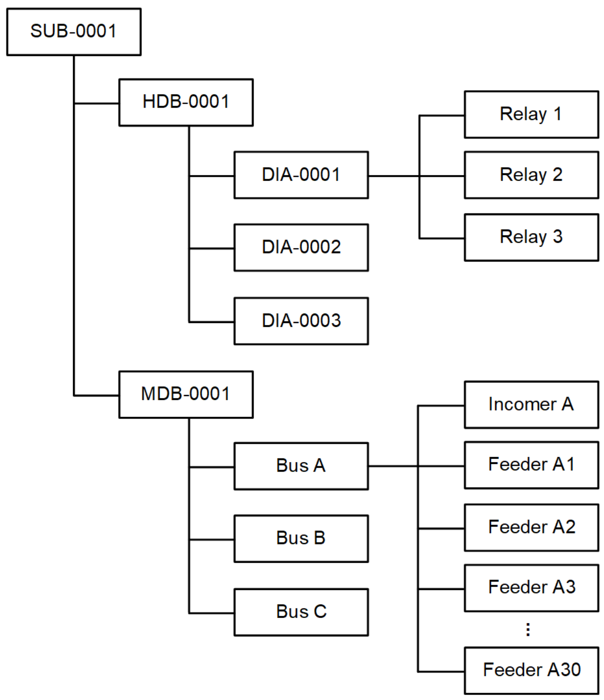

Figure 3. Typical Switchboard Folder Structure

It is as important as the folder structure for the commissioning team to agree on the IED device tags. Due to the project size and different design teams involved, naming conventions are consistent among IEDs within each voltage level but not across different voltage levels. The commissioning team agreed upon the convention example shown in Figure 4.

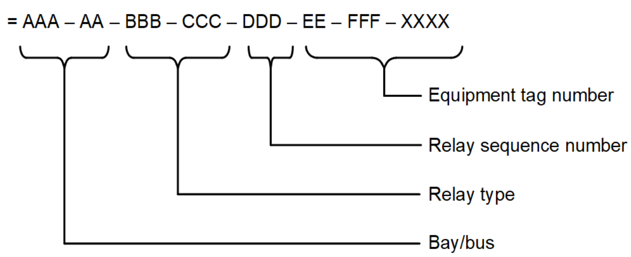

Figure 4. IED Naming Convention

Once the device tree structure is configured, each device needs a device tag and defined connection method (IP address or port). When the connection to the device is first established, device configuration information is populated into the database, including the firmware and serial number. The device information contained in the database includes the following:

1. Device tag
2. Global device tag
3. Firmware
4. Serial number
5. Connection method
6. Settings

Settings are then read from each IED to populate the settings portion of the database. In addition, automated event and SOE gathering is configured in such a way that once every 6 hours, the server polls each IED for any new report information since the previous poll.

The 19 local EWSs are physically located in each 110 kV or 10 kV substation. Within the substations, communications from the EWS server to each switchboard occurs via managed Ethernet switches using multimode fiber-optic communications. Communications to an external 380 Vac EEO module are similar to using managed Ethernet switches; however, they occur through single-mode fiber optics. In general, all communications external to the electrical facility occur over single-mode fiber optics. In addition to communicating to the downstream IEDs, these 19 local EWSs communicate to both primary and backup global engineering workstations located in each main operational area (MOA) facility. Also, the 19 local EWS servers synchronize relay settings, event, and SOE reports to a single database located in the primary MOA. Simplified data flow diagrams are given in Figure 5 and Figure 6.

When data transfer between global and local EWSs, the global device tag is used to match the corresponding devices. Based on the configuration, the global device tag includes the device tag information appended with the facility name. The global device tag is also used to match the events and SOE data between the local EWS and event report / SOE server.

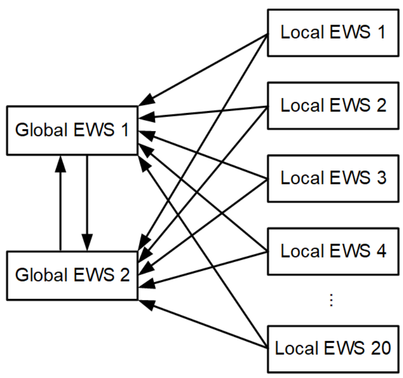

Figure 5. Local-to-Global EWS Setting Synchronization

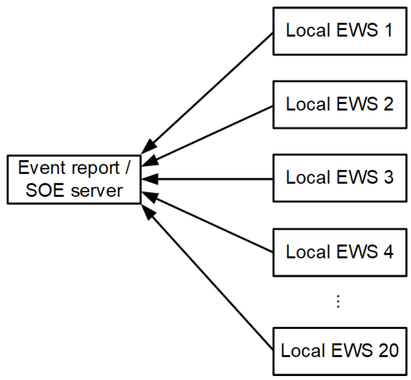

Figure 6. Event Report and SOE Synchronization

V. STREAMING SYNCHRONIZED-PHASOR MEASUREMENTS

The facility also uses streaming synchronized-phasor measurements from 39 line protective relays on the 110 kV transmission system, 5 GTG protective relays at 15 kV, and 8 standby diesel generator protective relays at 10 kV. Each relay is capable of streaming synchronized-phasor measurements at a 20 ms sample rate (50 messages per second). Per the IEEE C37.118, Standard for Synchrophasors for Power Systems, a high-accuracy Inter-Range Instrumentation Group (IRIG) time input into the relay is necessary [2]; it supports 1 µs accuracy and IEEE 37.118 IRIG-B control-bit assignments.

Data flow for the streaming synchronized-phasor measurements originates from the protective relay that functions as a phasor measurement unit (PMU) and streams via Ethernet connection to the phasor data concentrator (PDC) located in the primary MOA facility. Operators can monitor real-time streaming data for system stability, as shown in Figure 7.

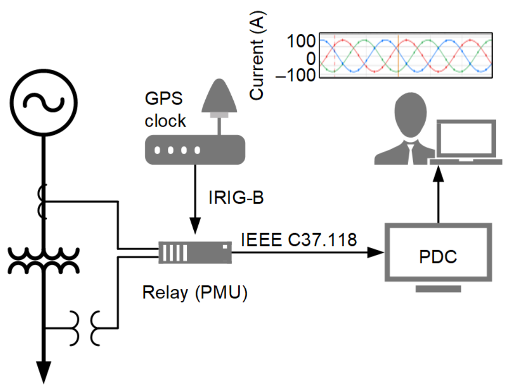

Figure 7. Example of PMU Data Flow Diagram

Beyond viewing streaming data that originate from the protective relays, the PDC can also calculate custom quantities in real time using standard and complex math operators with the streaming data. The following sample calculations show how total power can be calculated from the addition of two parallel-line power quantities. Similar to the streaming data, these calculations are made on 20 ms sample intervals, and the associated value is also stored within the database.

```
# Total Power Calculations
#
# Total Power Import / Export to X Substation (Lines L101
 and L102)
Sub_X_Total.X.Export:ThreePhase.Power.Real :=
(L101_X_E21_L:ThreePhase.Power.Real +
 L102_X_E33_L:ThreePhase.Power.Real)

Sub_X_Total.X.Export:ThreePhase.Power.Reactive :=
(L101_X_E21_L:ThreePhase.Power.Reactive +
 L102_X_E33_L:ThreePhase.Power.Reactive)

Sub_X_Total.X.Export:ThreePhase.Power.Apparent :=
(L101_X_E21_L:ThreePhase.Power.Apparent +
 L102_X_E33_L:ThreePhase.Power.Apparent)
```

Figure 8 shows a 5 min window, in which the oil and gas facility decoupled from the utility due to system instability. The frequency dropped to 49.3 Hz during this event prior to decoupling. The event is shown from the perspective of an adjacent substation to the substation that decoupled.

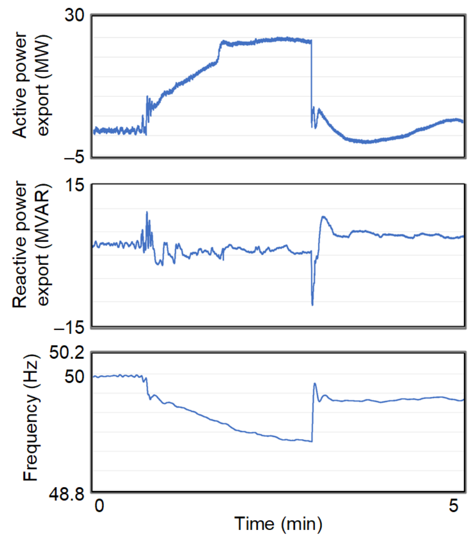

Figure 8. Sample of Decoupling Event

VI. OPERATIONS MAINTENANCE

As described in Section III, there are three key activities performed during a typical relay maintenance period of a plant. The first activity includes revalidating the protection settings and associated changes. With traditional operations maintenance methods, operational personnel must visit individual relays to download or upload settings. A state-of-the-art device manager database allows the operator to remotely log in to individual relays and verify the settings. The operator can do this by reading the setting out of the device and then comparing it to the latest settings file backup. The operator can also change the settings and check the SOE recorder to see any anomalies from the MOA. Table 1 shows a typical revision history, in which the operator can see the history of setting changes and the associated documented reason for the change. In addition, this eliminates the requirement of mobilizing teams to hazardous operational areas, minimizing risk to personnel.

TABLE 1
TYPICAL PROTECTIVE RELAY
SETTING HISTORY AND FEATURES

State	Version	Saved	Saved by	Comment
As Left	2023 0801.0	8/1/2023 8:15:38 a.m.	Engineer 3	20230801 Updated per Scope of Work (SOW No.)
As Left	2023 0301.0	3/1/2023 5:00:14 a.m.	Engineer 1	20230301 Updated per Design Change Notice (DCN No.)
As Left	2022 1001.0	10/1/2022 12:20:38 p.m.	Engineer 2	20221001 Updated per Request for Information (RFI No.)
As Left	2021 0628.0	6/28/2021 7:06:10 a.m.	Engineer 2	20210628 Ready for Operation (RFO No.)
As Left	2021 0331.0	3/31/2021 6:24:12 a.m.	Technician	20210331 Commissioning as Left—Ready for Startup (RFSU No.)

The second function of the database is that it maintains an inventory of the part numbers and the serial numbers of all installed IEDs. This allows the relay maintenance staff the opportunity to maintain a healthy stock of IEDs based on the actual numbers in service. This improves the downtime during a replacement of a faulty device, while reducing the operational costs associated with overstocking.

It is important to maintain the IEDs with project-approved firmware to eliminate cybersecurity vulnerabilities. The database provides the current firmware, the serial number, and the location of the devices. Once the manufacturer issues a service bulletin that requires a firmware upgrade, the operator can check against the database if it is applicable to the plant by filtering with either the serial number or the part number. Manufacturer firmware upgrade releases should be analyzed carefully to determine if the improvements or fixes introduced are applicable to the facility. If the service bulletin is applicable to a device in service, the operator can locate the device quickly from the database and upgrade the device.

Routine maintenance activities can be planned remotely by using the database to minimize the downtime of the plant. However, the operational plant can experience unplanned events, such as protection trips, that can shut down either a section of the plant or the complete plant, regardless of the many redundant options available. The operations team must restore the system safely as soon as possible in order to restart the facility. The advantage of the database is that the operator can download the events from the relays that are impacted via the main operating area and provide all the details necessary to complete root-cause analysis without mobilizing to the fault location. This is seen as a significant improvement compared to a traditional method of onsite analysis in a plant that handles hazardous material. The detailed analysis includes fault location, type of fault, fault current, arc flash section, etc. Section VII provides examples to aid the understanding of some of the features used.

VII. APPLICATION EXAMPLES

The paper explores three real-world application examples that resulted in accelerated system restoration with the aid of settings management and automated reporting tools described in this paper.

A. Greenfield Construction Loss of Source

As discussed previously, the 110 kV transmission tie station connects the existing utility connection to both the existing and expanded facility generation. The existing facility generation is the primary feed for the commissioning load at the expanded facility, with the utility connection available as a reserve supply with a power-import limit.

The existing facility is equipped with a centralized load-shedding scheme to prevent a power system collapse in the event of generation loss. The load-shedding scheme ensures the total plant electrical load is less than the calculated generator capacity after a power system contingency occurs. Contingencies can occur when a tie line or generator breaker opens under load. To achieve the balance between generation and load, a load-shed priority table is defined in the centralized load-shed system. The load-shedding system then selects load to shed based on the priority list and continues shedding load until the required amount of load shed exceeds the available generation.

Ahead of the event, the expanded power system was under commissioning with no production output and, therefore, was given lowest priority in the load-shedding system.

A load-shedding contingency was triggered due to the loss of one of the generators at the existing facility, which was operating at 71.07 MW prior to the event. The facility was importing 0 MW from the utility, and the import limit was set to 66 MW. The utility import reserve margin calculated by subtracting the current import from the import limit is shown as follows:

$$P_{\text{UTILITY-RESERVE}} = P_{\text{MAX}} - P_{\text{CURRENT}} = 66\text{ MW} - 0\text{ MW} = 66\text{ MW}$$

The amount of load to shed can then be calculated as follows:

$$P_{\text{SHED}} = P_{\text{LOST}} - P_{\text{UTILITY-RESERVE}} = 71.07\text{ MW} - 66\text{ MW} = 5.07\text{ MW}$$

The commissioning load at the expanded facility was 10.78 MW at the time, which was correctly selected and shed by the load-shedding system.

In Figure 9, the trending screen captures the commissioning facility's active and reactive power import, along with the frequency at the time of the event. The frequency dips to 49.8 Hz upon the loss of a generator and the commissioning load is shed shortly thereafter, which leads to the recovery of the system frequency.

With the aid of the historical trending data, the operators were able to quickly determine the load profile at the construction facility prior to the load-shed event and bring online the required amount of available generation to support this demand. Power at the greenfield construction facility was restored within 10 minutes.

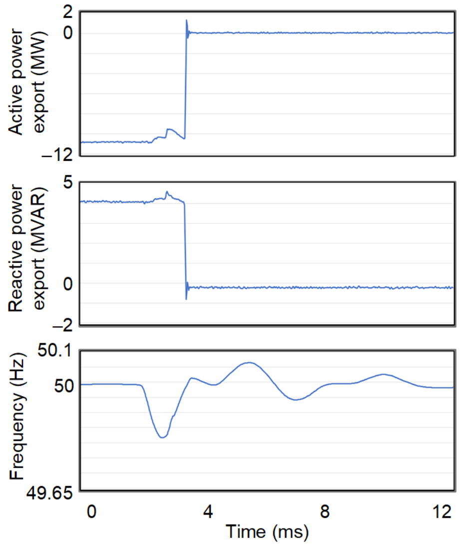

Figure 9. Load-Shedding Trip Event

B. Incorrect Transformer CT Polarity

In this event, a line current differential (87L) relay detected a line fault and tripped the source side breaker shortly after the initial transformer energization. As shown in Figure 10, the 110 kV underground cable and 110/10 kV, 40 MVA transformer were energized by closing the 110 kV breaker 52HV1 with the 10 kV breaker 52MV open. Notably, there are no 110 kV current interrupting devices on the transformer end of the underground cable. The protection scheme consists of:

1. Line differential protection for the 110 kV underground cable using combined current (HVCT-1 + HVCT-2) connected to the relay 87L-1 and the downstream HVCT-3 connected to the relay 87L-2. There is a dedicated and redundant direct fiber-optic connection between 87L-1 and 87L-2 for the exchange of current readings. Primary and secondary line differential protection is used.
2. Transformer differential protection using the transformer HV-side CT (HVCT-4) and MV-side CT (MVCT) wired to a nonredundant transformer protective relay 87T. Along with tripping the local 52MV breaker, the 87T relay also trips the 110 kV breakers via the 87L-1 and 87L-2 relays relying on the line differential channel. Both 87T and 87L-2 are part of the substation Ethernet network and data flow between the two relays in IEC 61850 Generic Object-Oriented Substation Event (GOOSE) high-speed communications protocol.

Figure 10 depicts the simplified single-line diagram for the transformer inrush event. For simplicity, the redundant line differential relays are displayed as a single relay; however, the actual installation consisted of two separate relays with dedicated CTs and redundant fiber-optic cables on both the HV and MV substations.

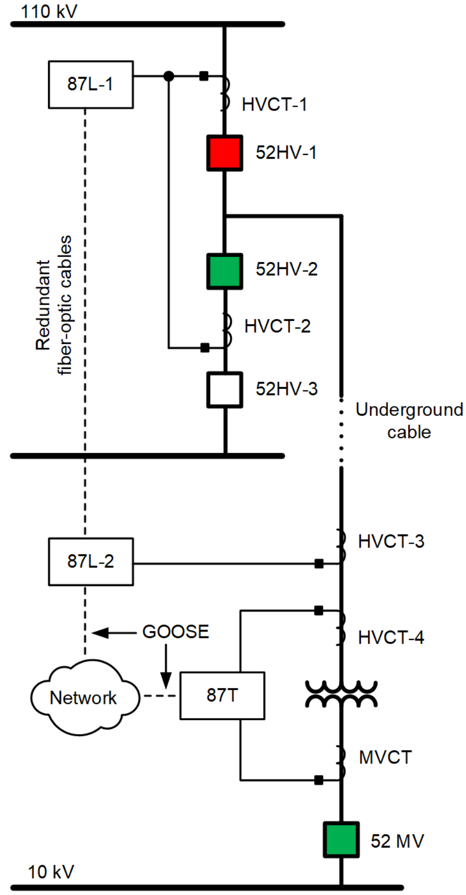

Figure 10. Simplified Single-Line Diagram of Transformer Inrush

During the transformer energization, the 87T relay remained secure as expected and did not trigger any event records. This relay saw a current reading from HVCT-4, and no current reading on MVCT. However, the harmonic-blocking scheme correctly blocked the operation of the transformer differential relay due to the presence of high even-numbered harmonics (2nd and 4th), which is a signature of transformer energization [3] [4].

Both the line differential relays, 87L-1 and 87L-2, produced a trip for this event. This was not an expected outcome if the CT polarity is wired, according to Figure 10. However, as it is evident in the trip event report produced by the relays and shown in Figure 11, the relay clearly saw the remote current reading in phase with its local current reading, which indicates an in-zone fault. Figure 11 is a screen capture from a primary 87L-1 event record; however, similar readings were observed on the backup relay as well.

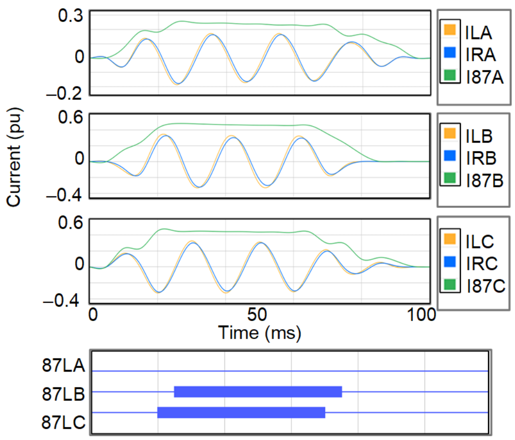

Figure 11. Phase Differential Current During Transformer Inrush

Upon review of the field wiring, the secondary wiring of the HVCT-3, which is a transformer-bushing CT, was found to be incorrectly wired, which resulted in the change of CT polarity. The wiring issue was addressed, and the transformer was successfully energized.

As a common commissioning practice, the line differential relay is temporarily blocked during initial energization of line-end transformers. In this configuration, it is critical to ensure that backup protection elements, such as distance or overcurrent, are in place and remain active in case of energizing onto a fault. This allows the relay technicians to study the relay event report to validate the CT polarities after the first energization event and reenable the line differential element once confirmed. Implementing this practice has proven to be advantageous in this application and allowed for detecting the CT polarity issue without producing a trip. It is also possible that the magnitude of the inrush current does not produce a high enough differential current to produce a trip, so an incorrect CT polarity may go unnoticed until occurrence of an out-of-zone trip event or an in-zone fault in which no trip is produced. As observed from the digital chart at the bottom of Figure 11, the Phase A differential did not produce a trip, while Phases B and C did produce a trip.

Both the primary and backup line differential relays on the HV side are configured to produce event reports for any breaker operation (open or close). This allows the opportunity to verify CT polarities once the transformer is energized via either 52HV-1 or 52HV-2, regardless of whether the differential element produces a trip or not. This troubleshooting experience is further enhanced by implementing an automated reporting system like the one discussed in this paper. An automated reporting system allows timely event notification and automated event report retrieval for an event involving multiple relays. In this application example, there were five unique relays that required interrogation to find the root cause of the problem.

C. A 60 MVA Transformer Energization

During initial transformer energization, common commissioning practice includes triggering an event report to verify that the differential phasors are in the expected location. In Figure 12, a 110 kV to 7.85 kV transformer with an 11 kV harmonic filter bank is shown. Five windings are included in the transformer differential protection.

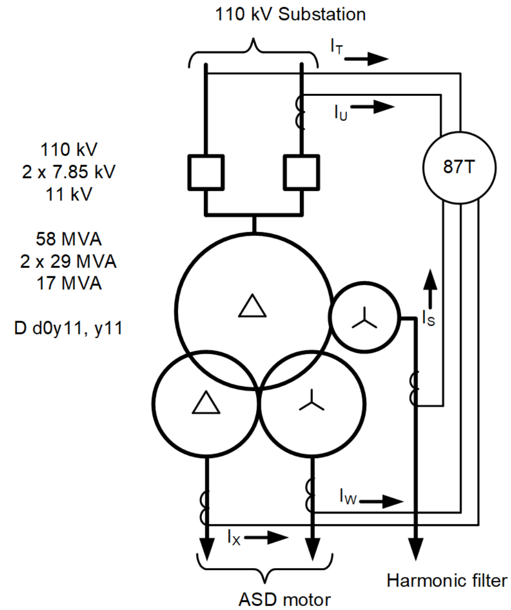

Figure 12. Adjustable Speed Drive (ASD) Transformer Differential Zone

After the initial transformer energization, phasors were captured in an event report during a 60-second no-load acceleration of the connected ASD motor. At the time, the harmonic filter bank was also energized. This brought measurable currents to all transformer windings. Figure 13 shows phasors during this no-load acceleration.

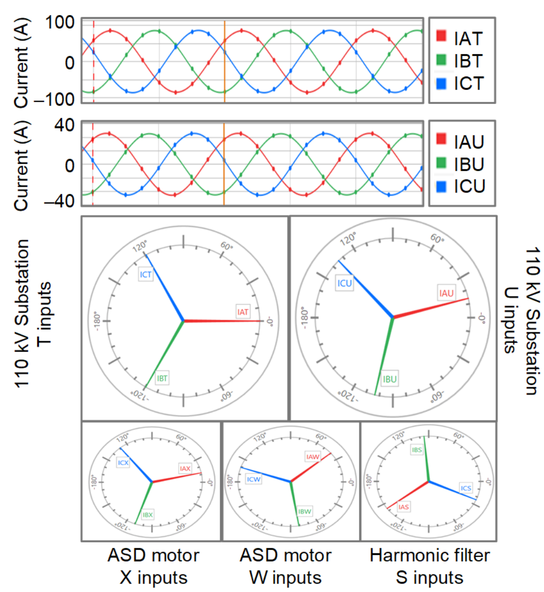

Figure 13. 87T Phasors During No-Load Acceleration

Using standard event reporting tools and analog quantities provided by the protective relay, the relay-calculated differential operate and restraint current can be analyzed. Figure 14 shows the relay-calculated operate and restraint currents.

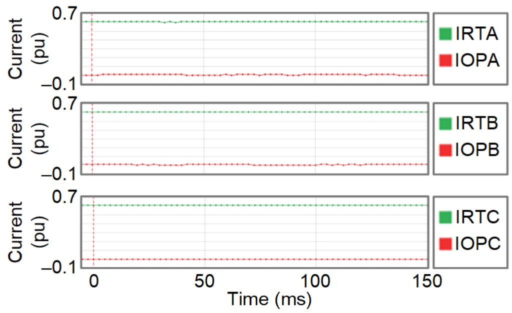

Figure 14. Relay-Calculated Operate and Restraint Currents

Even though the relay-calculated operate currents were all zero, the commissioning engineers questioned why the phasors for Winding X and W were in phase with the transformer source supply. Using calculation techniques from [5], commissioning engineers used the event viewer software to apply an additional 180-degree compensation matrix onto the Winding X and W inputs into the relay. Figure 15 and Figure 16 demonstrate that the compensated currents are now 180 degrees out of phase for Winding X and 150 degrees out of phase for Winding W. The phase-current vectors are not compensated, which explains the 180- and 150-degree respective differences.

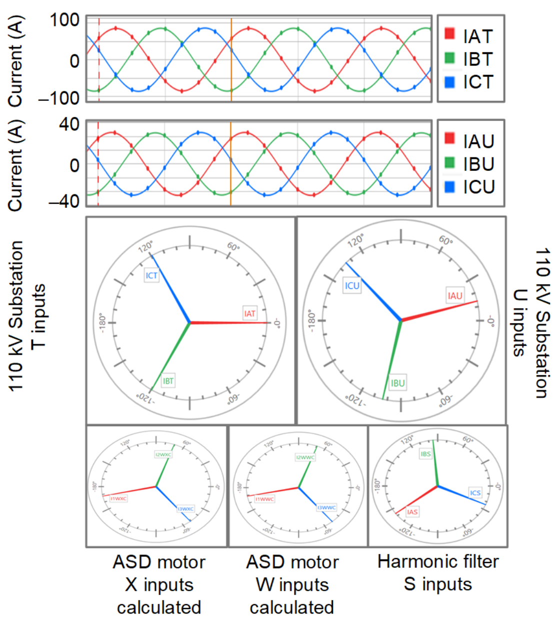

Figure 15. Custom Equation-Modified Compensated Phasors

Using these new compensated quantities, the engineers then plotted the operate and restraint current. Figure 16 shows that they had measurable operate current and confirms the existing installation of the CT wiring is correct, per the drawing in Figure 12.

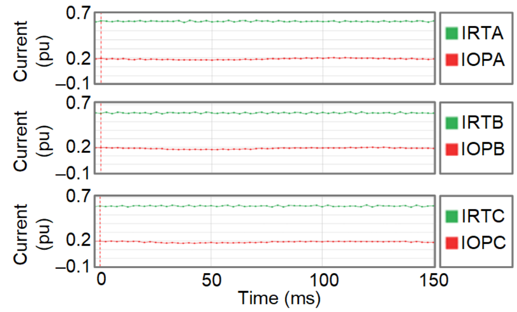

Figure 16. Custom Equation-Modified Operate and Restraint Currents

Suspecting the unexpected phase-current polarity has to do with the interaction of the harmonic filter bank and the firing of the thyristors, the team agreed to perform a 0 to 90 percent, no-load motor-acceleration test to verify that the differential phasors are in the expected location. Figure 17 demonstrates how the faster acceleration confirmed expectations.

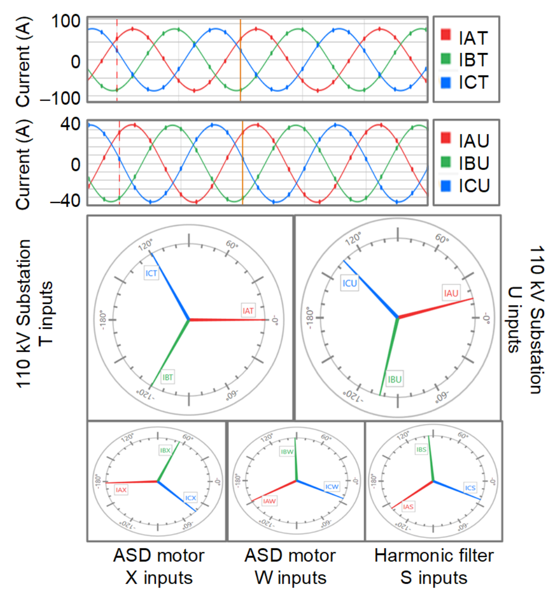

Figure 17. 87T Phasors During Acceleration

Doing a final verification on differential operate and restraint currents confirmed there was only restraint current with no operate current, similar to Figure 14.

This event is an excellent example of instances when commissioning engineers can use readily available reports to perform what-if scenarios that are far simpler than rewiring CTs only to find the system was already properly configured.

VIII. CONCLUSION

The operation and maintenance of a large facility can be enhanced, can be made less susceptible to human error, and can have the restoration time shortened by implementing a settings management and reporting system. This paper discusses the settings management and reporting system implemented at a facility consisting of approximately 12,000 IEDs; the system leveraged the advanced capabilities of modern IEDs to consolidate the instrumentation data into integrated reports and communicate the information to central operator facilities.

This paper also details multiple events that illustrate how each component of the settings management and reporting system was used for quick restoration of power to the greenfield construction facility, to collect data from multiple IEDs at different locations to determine the root cause for a line relay trip during transformer energization, and to confirm CT polarities by observing the differential current phasors of a five-winding transformer.

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X. VITAE

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Previously presented at the 71st Annual Petroleum and Chemical Industry Technical Conference, Orlando, Florida, September 2024.

20240329 • TP7151