Lessons Learned Through Commissioning, Livening, and Operating Switchgear: Part 2

Matthew Watkins and Kamran Heshami
Schweitzer Engineering Laboratories, Inc.

Taylor B. Chambers
Chevron

Nilushan K. Mudugamuwa and Anil S. Pandya
Tengizchevroil

Presented at the
2024 PCIC Europe Conference,
Rotterdam, Netherlands
June 2024

LESSONS LEARNED THROUGH COMMISSIONING, LIVENING, AND OPERATING SWITCHGEAR: PART 2

Copyright Material PCIC Europe

Matthew Watkins	Kamran Heshami	Taylor B. Chambers	Nilushan K. Mudugamuwa	Anil S. Pandya
Schweitzer Engineering Laboratories, Inc. 101 E Park Blvd, Ste 1180, Plano, Texas 75074 United States	Schweitzer Engineering Laboratories, Inc. 3760 14th Ave, Ste 200, Markham, Ontario L3R 3T7 Canada	Chevron 1400 Smith St Houston, Texas 77002 United States	Tengizchevroil 9 Stockbridge Rd Fleet Hampshire GU51 1AR United Kingdom	Tengizchevroil Level 2/1 The Esplanade, Perth WA 6000 Australia

Abstract—The 500 MW expansion of a facility's power system, incorporating 12 000 protective relays and modern technologies in a radial scheme and a breaker-and-a-half scheme, requires special attention. Potential errors during the constructing, commissioning, livening, and synchronizing of new facilities with an existing power system can lead to safety incidents and/or a loss-of-production event to the existing facility.

The events presented in this paper cover individual power system elements, such as incorrect delta link placement on a transformer, challenges in the testing and starting up of large direct-on-line motors, a yard modification leading to an arc-flash trip, and a broken overhead optical ground wire leading to a line-to-ground fault. More complex system events included systems used for synchronizing to and decoupling from the electric utility. The paper elaborates on communications-based IEC 61850 protection systems and the dependence on managed Ethernet switches for communications between intelligent electronic devices.

Index Terms—Event Reports, Generator Control, Autosynchronization, Arc Flash, Network Storm, Motor Differential Protection, Optical Ground Wire, Root Cause.

I. INTRODUCTION

This paper highlights six events that occurred during commissioning or just after the system transfer to the client. These ranged from more complex system-level events to events that involved only local equipment, and they included:

- A generator autosynchronization event in which the voltage transformer used for sensing was unknowingly impacted by the tap changer of the buffer transformer (BT). This lowered the synchronizing voltage when the operator expected the system to already be in the voltage-qualified window.
- The impact of Ethernet-based network storms on Ethernet-based protection schemes.
- Incorrect delta links (three single-phase dry-type transformers connected in a three-phase delta configuration) on a transformer, which led to a synchronization error. Properly commissioned and trusted relay protection prompted a design review.
- A failed optical ground wire (OPGW), which not only caused breaker status loss to an electronic control system (ECS) human-machine interface (HMI) screen but, more importantly, impacted the 87L line current differential protection.
- Commissioning challenges with a 10 kV direct-on-line (DOL) motor application with dissimilar current transformers (CTs).
- A manufacturing yard modification to a busbar, which resulted in an arc-flash event.

This paper is a continuation of [1] in which the authors discuss additional challenges revealed in commissioning a new facility's power system. As with the previous paper, in sharing these events, the authors will describe how to use event reports and other tools to determine the root cause and illustrate how to avoid similar issues in the future.

II. AUTOSYNCHRONIZATION AUTOMATIC VOLTAGE REGULATOR (AVR) LIMITS

One system that was commissioned was an autosynchronization control system. This system is intended to automatically resynchronize the facility with the local electric utility after any trip or event that results in the facility being islanded. To achieve this, the system automatically controls the facility's gas turbine generators (GTGs) to bring the facility's frequency and voltage within an appropriate range relative to the utility by sending signals to the governors and AVRs of each GTG. After the facility's frequency and voltage are within range, a sync-check relay waits for the angle difference between the facility and the utility to fall within a closeable range. Fig. 1 shows a simplified view of the system within the central breaker-and-a-half substation that connects to the utility. The central substation connects to the utility via a 110 kV/110 kV BT with a tap changer.

The full system as designed utilizes all GTGs to influence the facility's islanded frequency and voltage. However, for the first stage of the system-level site acceptance test, only a single 120 MW generator was used. The rest of the generators remained in constant-megawatt control via the secondary generator control. At a high level, the test consisted of three major steps:

1. Islanding the facility from the utility by opening Circuit Breakers E11 and E12, as shown in Fig. 1.
2. Intentionally lowering the now-islanded facility's frequency from nominal 50 Hz to 49.9 Hz.

3. Using the autosynchronization system to bring the facility within the closing range and automatically close Circuit Breaker E11.

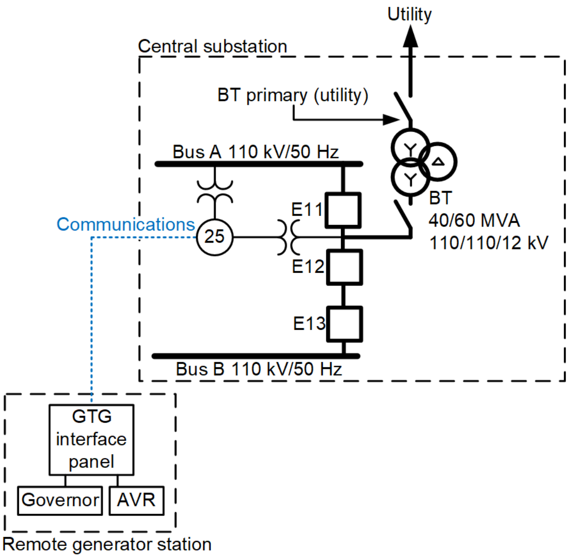

Fig. 1 Simplified system diagram

Since this autosynchronization system was a new addition to the operating plant, the test required coordination between the power system dispatchers, the duty electricians of the central substation, and the commissioning team. The dispatchers were situated at a remote control center, while the commissioning team performed tests from the local synchronization HMI in the substation. To arrange the initial conditions of the test, the dispatchers islanded the plant grid from the utility and temporarily lowered the island frequency to 49.9 Hz.

After the initial conditions were in place, the key power system parameters as displayed on the dispatcher's console were a facility frequency of approximately 49.9 Hz, a facility substation voltage of 111.5 kV, and a utility voltage of approximately 114.5 kV. Therefore, once initiated, it was expected that the autosynchronization system would:

1. Send speed raise commands to the participating GTG to lift the island frequency toward 50 Hz until it was within the slip limit of 0.05 Hz.
2. Send no voltage commands to the GTG, as the voltage difference between the utility and the island was within the defined closing range of ±3 percent.

At approximately 15:40 local time, the autosynchronization test was initiated. As expected, the controller sent speed raise signals to the participating GTG until the island's frequency was within 0.05 Hz of the utility's frequency, as shown in Fig. 2. However, unexpectedly, the controller also sent multiple voltage lower commands to the AVR of the participating GTG. Quickly after autosynchronization began, at 15:41:30, the dispatchers received a low terminal voltage alarm from the participating GTG. The autosynchronization controller continued sending voltage lower commands, eventually lowering the central substation bus voltage from 111.5 kV to approximately 110.6 kV, as well as triggering a low-low alarm for generator terminal voltage at 15:44:52. The team soon realized that the utility voltage shown on the dispatcher console is measured from the primary (utility-side) of the BT, whereas the autosynchronization controller is comparing the substation bus voltage to the secondary (facility-side) of the BT (refer back to Fig. 1). Indeed, the BT's tap, which is manually operated by power operations, was not in the 1:1 transformation ratio position, resulting in a significantly lower secondary voltage, as shown in Fig. 3. As such, the controller correctly tried to lower the island voltage.

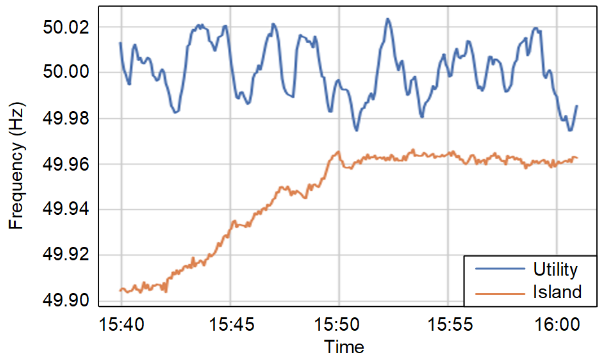

Fig. 2 Autosynchronization initiated

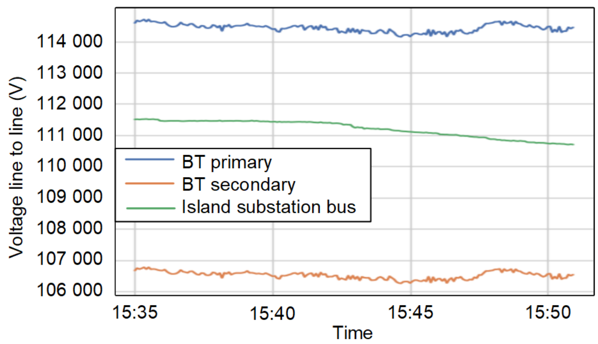

Fig. 3 Secondary voltage much lower due to tap position

After the team realized the problem, the dispatchers adjusted the tap position on the BT until the BT secondary voltage was closer to the substation bus voltage and returned the participating GTG back to a typical terminal voltage. The team reinitiated the autosynchronization, which sent no further GTG signals since the island voltage and frequency were now within the closing range. After waiting for the angle difference to come within the closing range, the system closed the utility breaker, and the facility was resynchronized, as shown in Fig. 4.

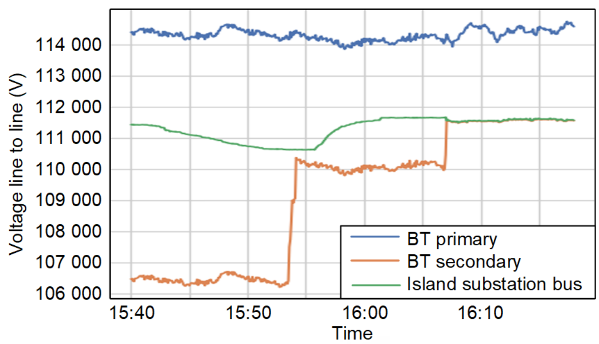

Fig. 4 Successful synchronization

Before continuing with the rest of the site acceptance test, the commissioning team and operators recommended that the following actions be completed:

- Ensure the operating procedure begins with verifying the BT tap changer position, and, if necessary, change the tap position such that the BT secondary voltage is within a synchronizable range.
- Add a communications link to display both the utility-side and facility-side BT voltages on the dispatcher console.
- Add a blocking signal from the generator secondary control system to block autosynchronization raise or lower signals for an individual GTG if terminal voltage limits would be exceeded. (The transmission of a similar blocking signal from the governor had already been configured if speed or real power limits would be exceeded.)

III. IMPACT OF NETWORK STORM ON ARC-FLASH PROTECTION

Arc-flash protection is incorporated in 35 kV, 10 kV, and 6 kV medium-voltage distribution boards (MDBs) as well as 380 V low-voltage (LV) motor control centers (MCCs) to ensure that the energy generated from an arc will be extinguished as soon as possible via isolating the source of energy. Typical switchboards consist of two normally closed incomers with a normally open bus-tie breaker. The arc-flash design includes a transparent fiber loop design to capture light in the busbar chambers and droppers and is used as an input into the intelligent electronic devices (IEDs) of the 10 kV and 380 V LV MCCs while arcs at the breaker compartment and the cable connection points are captured using point sensors [2]. Fig. 5 shows a typical 10 kV MDB arrangement showing transparent fiber loops and a point sensor arrangement.

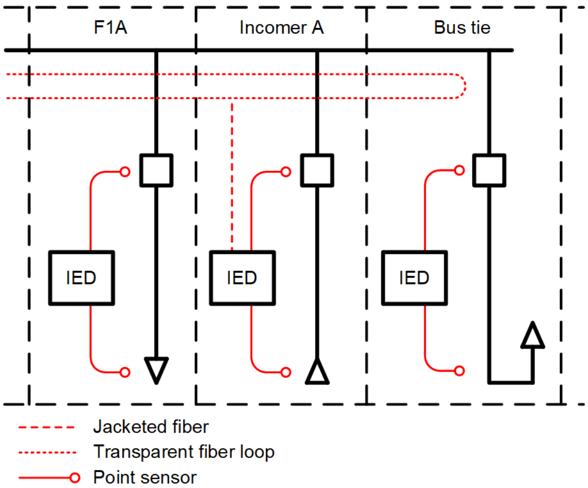

Fig. 5 Typical 10 kV MDB with bare fiber, a point sensor arrangement, and connections to IEDs

Transparent fiber loops or a point sensor will detect the light generated in the arc and transmit it to the relay, which is supervised with current pickup prior to tripping. In addition, due to the overlap between protection zones or location of the fault, the relay must identify the switchboard arrangement to safely isolate the sources while maintaining a continuous supply of electricity to downstream consumers.

Advantages of an Ethernet network in substations have been discussed in detail over the last couple decades and considered as a robust solution to connect a modern IED using an Ethernet interface. This project also utilized an Ethernet-based network for information exchange regarding the protection, control, and status of the apparatus. For protection, the IEC 61850 Generic Object-Oriented Substation Event (GOOSE) protocol via an Ethernet network was applied to communicate between IEDs and the arc-flash controllers, which are connected to the same redundant network switches. Redundant arc-flash controllers are used to process the logic to identify the correct source to isolate.

Fig. 6 shows the redundant arc-flash controllers as well as the other controllers, IEDs, and redundant switches that are used in the MV switchboard and its connection to the external Ethernet network. The number of switches and IEDs is dependent on the number of feeders allocated per switchboard. The LV switchgear also has a similar arrangement, except it has limited connectivity to the main network.

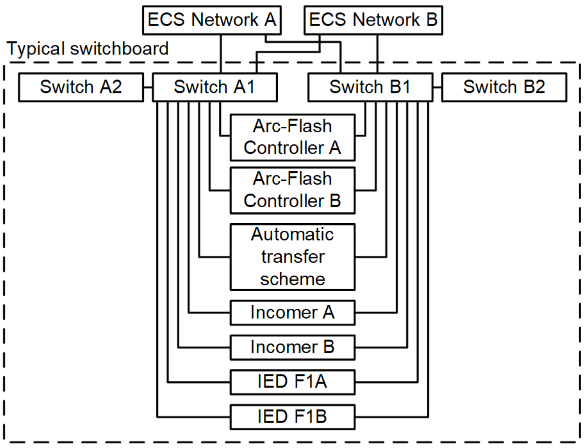

Fig. 6 Typical network architecture of a switchboard

One of the downsides of an Ethernet-based network is the possibility of a network storm. A network storm occurs when a large number of broadcast, multicast, or unicast packets continuously floods the Ethernet network. Although protocols, such as Rapid Spanning Tree Protocol (RSTP) (or enhanced RSTP), are introduced with features to avoid these network storms, the Ethernet networks are still vulnerable to network storms for various reasons, such as incorrect switch configurations, partial connections to IEDs, or the introduction of incompatible third-party devices. Hence, a network storm could disrupt or corrupt the essential communications between IEDs in the same Ethernet network, despite having separate virtual local-area networks.

As discussed previously, the arc-flash controllers communicate to IEDs using the GOOSE protocol, which is a communications model defined by the IEC 61850 standard. The GOOSE protocol is also vulnerable to network storms, which will compromise the arc-flash protection. During the commissioning phase, several network storms compromised the arc-flash protection for MDB and LV MCCs. The transmission leg of the Ethernet cable that was grounded at a sliding contact of an LV compartment led to a network storm; restart of certain switches created a port flapping event, which disabled ports; and the update of a configuration file of a switch created a multicast storm after restarting the switch.

For an MDB, the normal operating condition involves two incomers and an open bus tie. Upon the detection of an arc flash in the feeder breaker compartment, a GOOSE message is published by the feeder relay, which is subscribed by the redundant arc-flash controllers. These controllers process the message and publish a message that will be subscribed by the incomers and bus-tie relays. If the voting logic sees the arc-flash current and the virtual bit from the arc-flash controller, that particular incomer or bus-tie breaker will be tripped to isolate the source from the arc-flash location.

For LV switchgear, the normal operating condition involves two closed incomers and an open bus tie. Upon the detection of arc flashes in the feeder cubicle, a GOOSE message is sent to the arc-flash controller. The arc-flash controller publishes a GOOSE message, which will be subscribed by the incomer and bus-tie relays. If a relay simultaneously measures the arc-flash current as it subscribes to a GOOSE message from the arc-flash controller, that particular incomer or bus tie (if closed) will trip to isolate the section of the bus.

The communications status between the IED and arc-flash controllers is continuously monitored and needs to be healthy to process GOOSE messages. As shown in Fig. 7 during a network storm, the communications between the IEDs and the arc-flash controllers were disrupted. The arc-flash controller communications bad message quality status toggled from healthy to unhealthy every 25 to 50 ms and maintained unhealthy communications status for several seconds. Arc-flash protection logic was disabled in certain switchboards during this network storm due to disrupted communications, as described previously. The project had several types of network storms, which impacted the arc-flash protection and controls. To limit the disruption to functions such as arc-flash protection or control and data acquisition of the electrical system, it was recommended to limit the data traffic in the ports for all modes of communications, i.e., broadcast, multicast, and unicast. This was achieved by setting egress port rate limits to allow normal network traffic.

Feeder A Date: 10/07/2023 Time: 14:10:18.351
xx-xxx-xxxx Time Source: Internal

#	DATE	TIME	ELEMENT	STATE
200	10/07/2023	13:57:59.843	AFC A COMM BAD	1
199	10/07/2023	13:57:59.843	AFC B COMM BAD	1
198	10/07/2023	13:58:01.023	AFC B COMM BAD	0
197	10/07/2023	13:58:11.673	AFC A COMM BAD	0
196	10/07/2023	13:58:11.753	AFC A COMM BAD	1
195	10/07/2023	13:58:20.033	AFC A COMM BAD	0
194	10/07/2023	13:58:20.203	AFC A COMM BAD	1
193	10/07/2023	13:58:23.983	AFC B COMM BAD	1
192	10/07/2023	13:58:25.258	AFC A COMM BAD	0
191	10/07/2023	13:58:25.278	AFC A COMM BAD	1
190	10/07/2023	13:58:26.048	AFC A COMM BAD	0
189	10/07/2023	13:58:26.088	AFC A COMM BAD	1
188	10/07/2023	13:58:39.198	AFC B COMM BAD	0
187	10/07/2023	13:58:39.223	AFC B COMM BAD	1
186	10/07/2023	13:58:39.923	AFC B COMM BAD	0
185	10/07/2023	13:58:39.963	AFC B COMM BAD	1

Fig. 7 LV Feeder IED event history in which the virtual bit received toggle due to a network storm

Although integrating traditional protection functions with modern technologies has improved safety while maintaining an uninterrupted power supply, phenomena like network storms can jeopardize the safety of the electrical system. A detailed review should be performed during the design stage to evaluate the consequences and mitigations of network storms. This review might require a backup or a separate network for arc-flash protection to avoid disturbances from third-party activities in the Ethernet network.

IV. INCORRECT DELTA LINKS WENT UNNOTICED

Two 10 kV delta to 380 Vac wye transformers energize MCC incomers separated by a normally open bus tie. Both transformers were independently commissioned. During precommissioning, the 380 Vac incomer (either Bus A 380 V or Bus B 380 V in Fig. 8) was energized via a temporary generator. This permitted energizing downstream loads off the MCC to aid in commissioning activities. As the electrical commissioning neared completion for both the transformers and MCC, preparations were made for each transformer to be energized by the permanent supply. This is often done a week or two apart from the final activity of verifying the manual transfer scheme, which consists of a closed transition that is achieved by closing the bus tie and then opening the selected incomer. In the process of performing the manual transfer, the normally open bus-tie breaker cannot close. See Fig. 8.

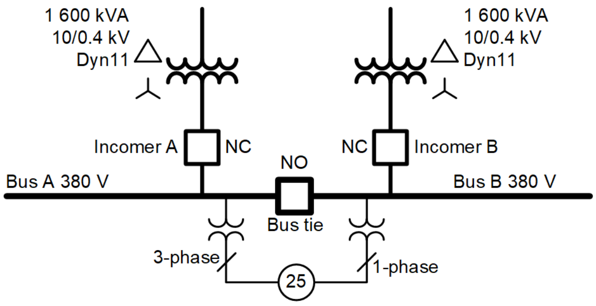

Fig. 8 Two delta-wye transformers energizing an MCC

At this point in the commissioning, the bus-tie relay was already precommissioned. Prior to closing the bus-tie breaker, the relay performed a sync-check function to verify that both incomers were in sync. The bus-tie relay measured three-phase voltage from Bus A and a sync-check voltage from Bus B. In this case, the sync element was not asserted, and fortunately, the commissioning team trusted the relay and did not attempt to override the relay sync supervision. Fig. 9 shows the voltage phasors from the bus-tie relay. In this instance, the synchronizing voltage VS is lagging VA by 30 degrees. But based on relay settings, the VS voltage should be lagging VA by 330 degrees.

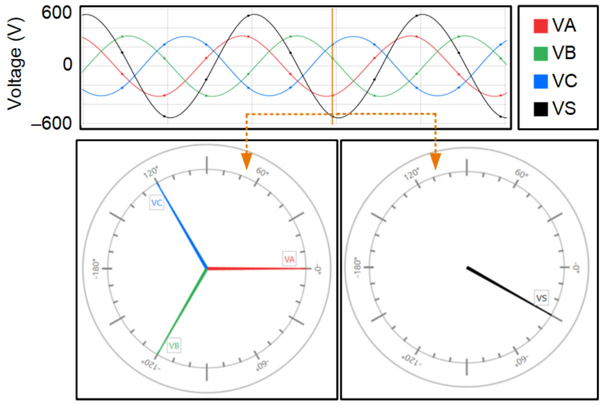

Fig. 9 Bus-tie voltage phasors—bus tie open

To quickly verify the expected phase angle, the comissioning team opened Incomer B and closed the bus-tie breaker. In this state, an event report was captured from the bus-tie relay to confirm the expected synchronizing voltage phasor. See Fig. 10 for expected phasors.

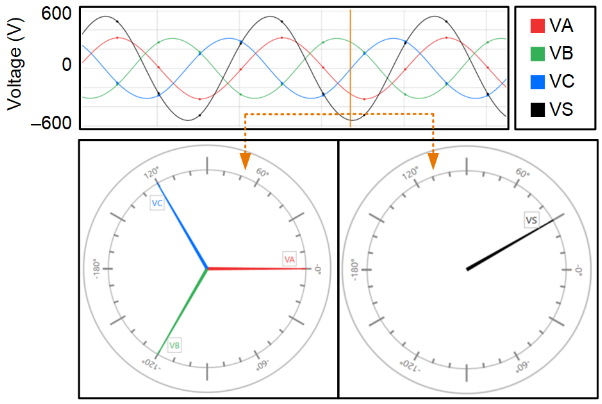

Fig. 10 Bus-tie relay expected phasors

In reviewing the installation in detail, the commissioning team found that the delta links on the 10 kV transformer winding were installed incorrectly on Incomer B. See Fig. 11 for a typical installation showing the delta link placement (photo taken during precommissioning).

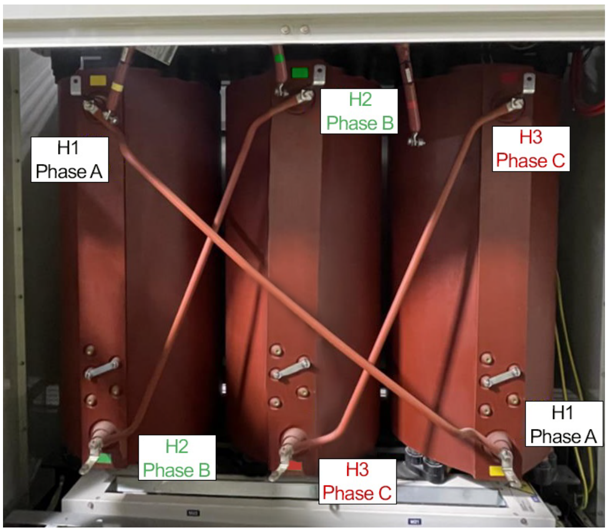

Fig. 11 10 kV delta links

Inconsistent delta link placements result in the Incomer B transformer connected in a Dyn1 transformer connection when the installation or design requires a Dyn11 transformer connection. While a Dyn1 transformer connection results in a 30-degree lead of the high-voltage winding to low-voltage winding, a Dyn11 connection results in a 30-degree lag of the high-voltage winding to low-voltage winding. See [3] for a complete review of the transformer delta connections, including the derivation of the phase shift, and the impact on the phasors measured by the relay. Fig. 12 highlights how transformer secondary side voltages differ based on the transformer's primary delta connection.

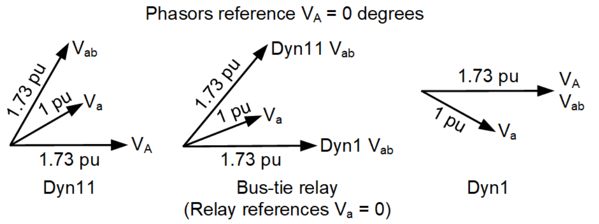

Fig. 12 Secondary side voltage phasors

Due to the transformer size, protection for the transformer did not include differential protection. Instead, the transformer was only protected with 50/51 overcurrent elements, which is another reason the compensation difference between Dyn1 and Dyn11 went unnoticed.

After commissioning over 100 switchboards, the field commissioning team was familiar with the synchronization function in the relay and never had it block closing. This was the only transformer found with incorrect delta link placement. It was important for the field team to trust the information provided and use that information to dig deeper into the root cause. Ultimately, the delta links were reconfigured to achieve the proper desired transformer connection and permit proper synchronization.

With the incorrect delta link configuration, all three-phase voltages were 60 degrees out of phase. With both incomers energized, under normal conditions, the voltage across the open contacts is 0 percent of the phase-to-ground voltage. However, with the incomers 60 degrees out of phase, the voltage across the open contacts was 100 percent of the phase-to-ground voltage. See Equation (1) based on the actual synchronizing phasor in Fig. 9 and the expected synchronizing voltage in Fig. 10. While this voltage difference is no different than having one energized source and one de-energized source, the problem is the short-circuit current interruption. If operators attempt to close a normally open tie circuit breaker with two out-of-phase sources, there will be significant transient current between the two sources, which may exceed the capability of the circuit breaker to interrupt out-of-phase currents [4].

$$\begin{aligned} V_{DIFF} &= VS_{ACTUAL} - VS_{EXPECTED} \\ V_{DIFF} &= (220\angle -30) - (220\angle 30) = 220\angle -90 \end{aligned} \tag{1}$$

V. FAILED OPGW 87L LOSS

This event was initially reported as a utility-side circuit breaker status discrepancy alarm observed in the facility's fast load-shedding system HMI, which still receives good analog values for active and reactive power import. The facility operations team inquired of the utility about this alarm; however, the utility confirmed that the utility-side circuit breaker was closed with no alarms in the system. Since the utility did not find any obvious cause of the alarm, the facility operations team sent the complete alarm log to the fast load-shedding design team for further analysis. The design team suggested that, based on the sequence of alarms, the most likely cause for the alarm was loss of the dedicated redundant line current differential communications between the facility-side and utility-side line protective relays.

The bus configuration at the utility substation is a double-bus single breaker with an additional bypass bus, as shown in Fig. 13 with key breakers and switches labeled. In this configuration, the line can be fed from either Bus 1 or Bus 2 when both the main breaker and main switch are closed, or fed from the bypass bus when both the bypass breaker and bypass switch are closed. The main breaker, bypass breaker, and switch statuses are wired to the line protective relays on the utility side. The breaker and switch positions are then transmitted to the facility-side line protective relays through the line current differential channel and finally transmitted to the fast load-shedding system via a serial communications channel between the facility line protective relay and the fast load-shedding system. No direct communication occurs between the fast load-shedding system and any of the equipment on the utility side. Additionally, due to the limited bandwidth available on the dedicated line current differential, the status of the utility breaker was sent as a combined "both open" and "either closed" signal. The combined "both open" and "either closed" logic generated in the utility line protective relay is shown in Fig. 14.

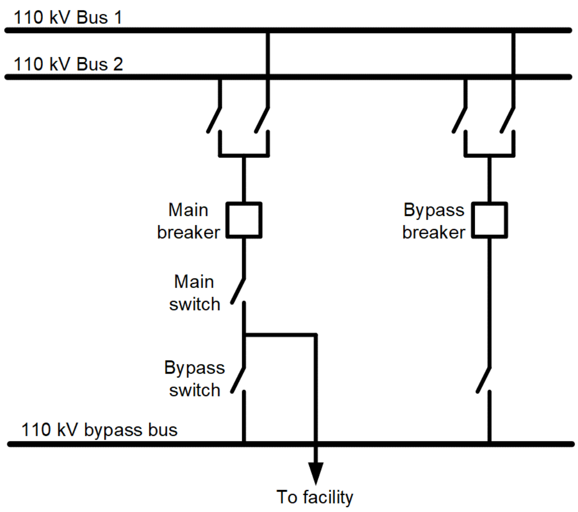

Fig. 13 Simplified utility single-line diagram

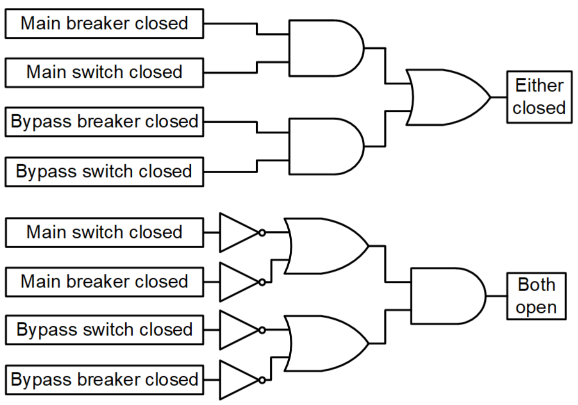

Fig. 14 Utility "both open" and "either closed" logic

As the field team was preparing to examine the line relays for a potential line current differential fiber issue, there was a report of a line trip on the same utility interconnection line.

The field teams from both the facility and utility sides were dispatched to investigate the root cause. When examining the relays, the team found that the facility-side relays had their line current differential protection disabled due to an issue with the line differential fiber channel and the line was tripped by the backup distance protection in the same relay. The team on the utility side also found that the line differential channel was disabled, and the trip was issued by a dedicated backup overcurrent protective relay.

Upon review of the relay event reports confirming presence of a legitimate power system fault, the team conducted a walkdown of the transmission line. The OPGW was found to be broken on one of the transmission poles. This OPGW carried the line current differential fiber for the redundant line differential channels of the line relays. When it broke, it caused failure and disabling of the line current differential channel. This demonstrates the importance of routing each fiber channel in two physically separated paths. Alternately, an existing communications network and multiplexing technologies, such as a synchronous optical network (SONET), can be leveraged to establish a secondary line differential channel to complement a primary dedicated line differential channel [5].

The picture shown in Fig. 15 was taken during the walkdown of the tripped transmission line. The figure shows that the broken OPGW, which was suspended on one of the poles, had contacted one of the phase conductors. This established a sequence of events in which the initial report related to the bad utility circuit breaker was caused by the breakage in the OPGW. Then, a protective trip followed due to the broken OPGW making contact with one of the phase conductors.

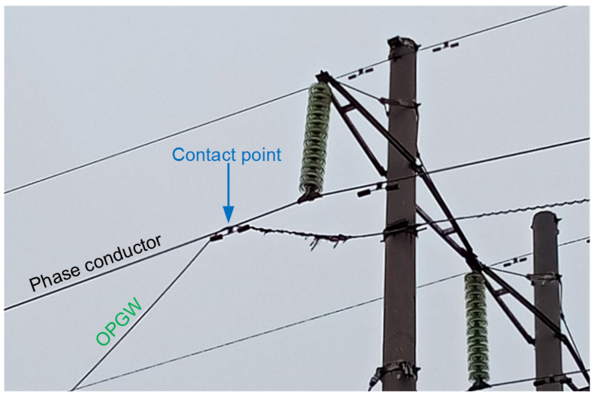

Fig. 15 Broken OPGW contact with C-phase conductor

This event highlights the importance of monitoring the line current differential channels and generating alarms in case of a channel failure. A line current differential channel failure alarm would have asserted in this case and allowed the system operators to address the issue before the broken OPGW caused a line trip. Additionally, [1] describes advanced reporting functionalities that can be implemented in line current differential relays to enhance monitoring of the communications channel.

VI. MOTOR PROTECTION FALSE DIFFERENTIAL CURRENT

During the initial bump start of an uncoupled 2.6 MW air compressor motor from a 10 kV medium-voltage switchboard, the protective relay tripped on the 87 differential element. The commissioning team identified that the motor rotated in the wrong direction. While the root cause of the incorrect rotor rotation was easy to identify, the cause for the differential trip was more complex. Differential CT connections to this relay are shown in Fig. 16. Feeder CTs from the switchboard are used by the relay for motor currents. These CTs are externally summed with the motor neutral-end CTs for the differential current connection. With opposing CT polarity, for a no-fault condition, the differential current into the relay should be zero.

In Fig. 16, the application intent was for the rotor to rotate in the counterclockwise direction. As a result, the motor terminal U connection needs to be the power system C-phase, the motor terminal V needs to be the power system B-phase, and the motor terminal W needs to be the power system A-phase. Instead, the commissioning team found the motor wired to the power system as identified in Fig. 16a and needed to reconnect the motor to the power system as identified in Fig. 16b. When multiple problems are found during commissioning, it is important to treat each one independently and to recognize that the solution may impact the other problem. In this case, when modifying the primary leads to the motor terminals, the commissioning team had to change the CT connections on the neutral end accordingly so that A-phase on the medium-voltage breaker side aligns with Terminal W on the motor's neutral end. Incorrect CT wiring was not the root cause of the differential trip.

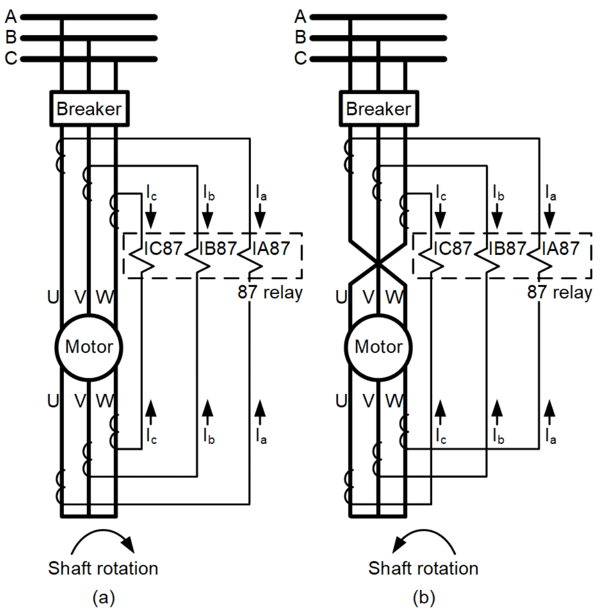

Fig. 16 (a) Clockwise and (b) counterclockwise rotation of the power system connections

To analyze the unexpected differential trip, the commissioning team reviewed the event report generated by the relay. See Fig. 17 for the filtered event of the initial start and Fig. 18 for the raw or unfiltered event report of the same motor start. The event reports show an increase in current on the B-phase differential current, which results in a trip 100 ms later. Based on the voltage waveforms (relay connections also include bus-side voltage inputs), however, there was no B-phase-to-ground fault on the power system. The current magnitude was also decreasing in the differential circuit leading up to the trip. This decaying differential current is a sign of false differential current and led the commissioning team to suspect CT saturation [6]. Raw or unfiltered event reports allowed the commissioning team to confirm CT saturation as the root cause.

For this 10 kV motor application, 87 differential protection consists of source- and neutral-side CTs. In this case, the switchboard supplier was a different manufacturer than the motor manufacturer, and the CTs were not of the same type or manufacturer as normally recommended for 87 differential protection [7]. In addition, the distance between the relay and the switchboard feeder CTs was less than 3 meters, while the distance from the relay to the motor neutral end was over 200 meters. Differences in lead length also compromise differential protection [7].

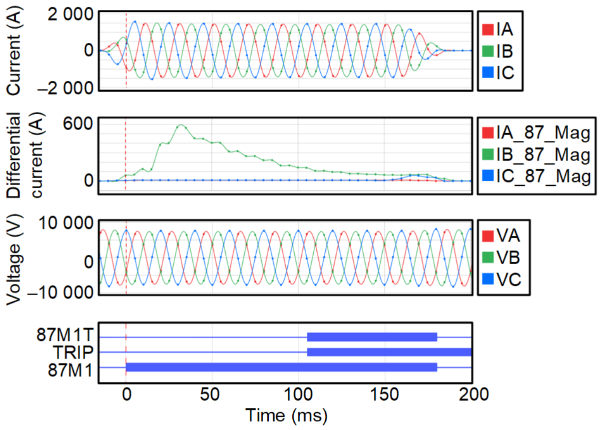

Fig. 17 Initial start filtered event report

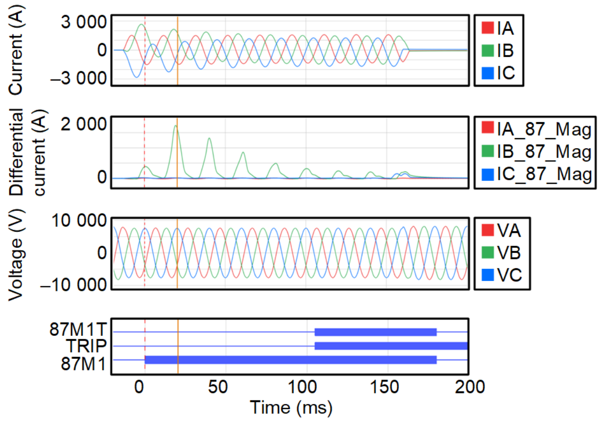

Fig. 18 Initial start unfiltered event report

Based on relay settings, the differential element was configured with two set points. A 50 element torque controls the motor relay's selected differential set point. During the motor start, the differential element pickup was set to 0.2 A secondary (20 percent full-load amperes [FLA]) with a time delay of 100 ms. When the current is greater than 2.5 times FLA, the starting element is active. Once the motor is in the running state, the relay automatically enables a lower-set, more sensitive element at 0.1 A secondary (10 percent FLA) with the same 100 ms trip delay.

The differential current waveforms in Fig. 17 and Fig. 18 are classic signs of dissimilar CT performance. After a discussion with engineers, it was agreed to extend the 87 differential start pickup trip time to 500 ms and maintain the existing set point to permit a start. With the relay set to generate an event report when the 10 kV breaker changed state, the following waveform was captured during the successful start. Fig. 19 shows the filtered event report. In this case, the motor successfully started, but the false 87 differential current lasted for 364 ms. To make the relay secure during start, the starting differential element needs to account for this expected fault differential current. From the relay's sequential event report and motor start report, the motor remained in the starting state for approximately 2.5 s during this uncoupled run. From motor nameplate information, however, a normal coupled load start for the motor is expected to take 9 to 17 s, depending on the voltage (100 to 80 percent nominal voltage, respectively).

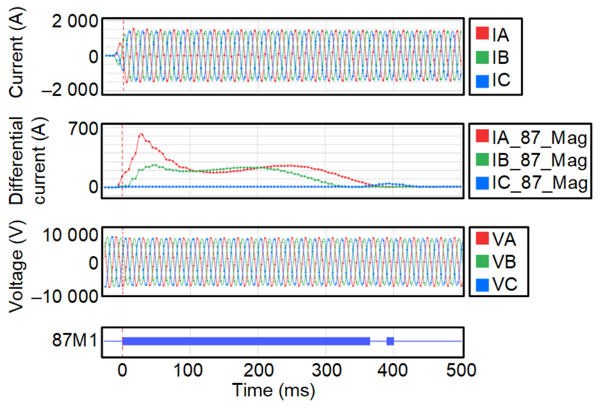

Fig. 19 Successful start filtered event report

Over the course of the next 2 to 3 months, several similarly sized 10 kV DOL motors were started. All motor relays captured similar false differential current. Event reports were captured for all starts and compared. For the worst-case scenario, the starting differential element remained asserted for over 700 ms. Phases involved in the false residual current appear random. However, they are specific to the point on wave when the motor was energized. Engineers reviewed the event reports and observed that the false differential current was approximately 50 to 60 percent of the locked-rotor amperes (LRA) of the machine. As a result, the starting differential pickup and trip delay were changed to 3.35 A secondary with a trip time delay of 0.2 s. While this was much shorter than the observed 700 ms maximum with the original 0.2 A secondary pickup, it was determined appropriate with the increased pickup to 3.35 A secondary. In addition, while sensitivity was reduced during the motor start, it was determined appropriate based on other active motor protection elements.

Even though changing CTs to be made by the same manufacturer and to account for the lead length difference was another potential solution to this problem, it was quickly ruled out as a result of space constraint, cost, project delays, and value.

VII. MCC ARC-FLASH INCIDENT

During the switchover from temporary power to permanent power at a 380 V MCC, the system developed a short circuit at the moment the incomer breaker closed. The fault was picked up and cleared by the arc-flash scheme, which isolated the fault by intertripping the 10 kV transformer feeder breaker located at the upstream substation. This incident caused no injuries to personnel and minor damage to assets.

Fig. 20 depicts the simplified single-line diagram of the system. The incomer protective relay is wired to measure phase currents from a current transformer installed upstream to the incomer circuit breaker. This relay receives three-phase voltage from the line side of the circuit breaker and single-phase (sync-check) voltage from the bus side of the circuit breaker. This figure also depicts the location of the arc-flash event based on the post-fault inspection of the MCC.

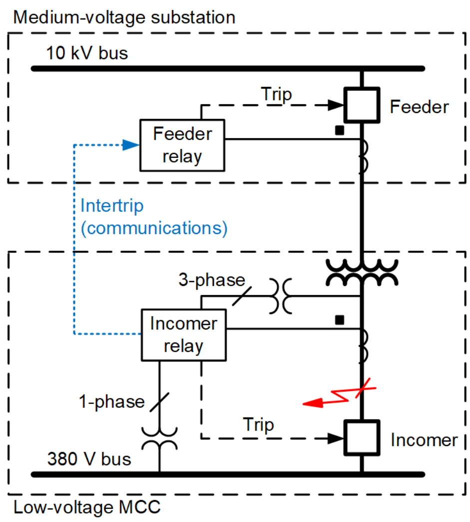

Fig. 20 380 V Incomer/Bus B simplified single-line diagram

During the cutover from temporary power to permanent power, the commissioning team followed all procedures, including an appropriate switching procedure, isolation of the temporary supply, and permit to work. The prechecks completed included a 72-hour soak test of the dry-type 10/0.4 kV transformer. Busbars were previously energized under a temporary 380 V supply from a diesel generator for a much longer time. A pre-energization insulation resistance test had also shown normal insulation levels.

Upon an intrusive post-event inspection of the MCC, copper shavings, which were hardly visible during the general visual inspection, were found at the rear of the circuit breaker busbar connections. The copper shavings were suspected to be left over from a retrofit installation of a voltage transformer on the busbar, which occurred in the fabrication yard where the module was constructed. There were threaded holes drilled on the busbar to accommodate installation of the voltage transformer. Fig. 21 shows the drilling point on the copper buses for the installation of the new voltage transformer. Many copper shavings were found inside the breaker compartment. It is suspected that one of the shavings fell down on the busbar due to breaker jolt while closing and resulted in the arc-flash event.

Fig. 21 Postmanufacturing drilled holes on the 380 V busbar

Fig. 22 is a screenshot from the event report, which was triggered by the incomer relay for the arc-flash trip. The third waveform from the top shows the single-phase voltage input from the busbar. This is the most accurate representation of the time the breaker was closed. For reference, the digital chart at the bottom shows the breaker status feedback (52a) that arrived in the relay about half a cycle after the appearance of the bus voltage. Shortly after the breaker was closed, the phase voltages became distorted and currents jumped to fault levels.

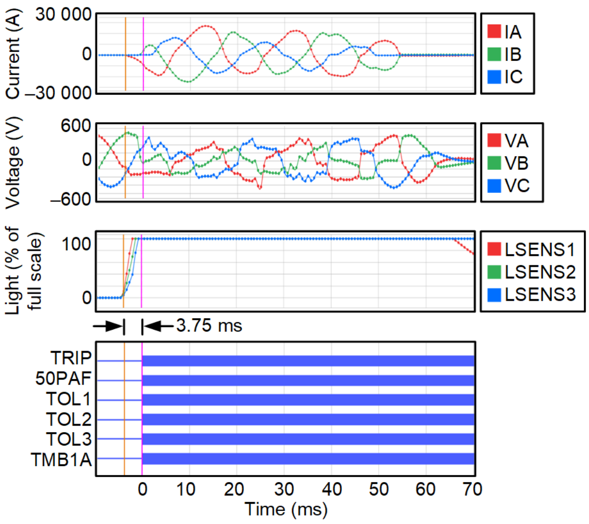

Fig. 22 380 V incomer relay response to an arc flash

The arc-flash protection scheme relies on the presence of both fault current and light to declare an arc-flash fault. Light sensors were installed in various locations within the MCC to cover the entire length of the busbar, circuit breaker, transformer, and most importantly, all the joints connecting to primary equipment. The light sensors are connected directly to the incomer protective relay, where it supervises the over-light condition with a fast, unfiltered overcurrent element for detection of an arc-flash event. In the case of an over-light condition detected in the breaker compartment, the over-light signal is also transmitted to the upstream relay for overcurrent supervision, as the current could be either on the line-side or bus-side stabs of the breaker. In case the fault is on the line-side stabs, the opening of the LV side breaker will not interrupt the current and the medium-voltage side breaker shall be tripped. This condition is depicted in Fig. 20.

As shown in the digital chart at the bottom of Fig. 22, both the over-light and overcurrent conditions were detected about 4 ms after fault inception (appearance of fault current). The TRIP output was issued within the same relay processing cycle to trip the incomer breaker. The upstream breaker tripped 54 ms after the trip command was issued for a total clearing time of 58 ms. Note that for the timing measurements mentioned previously, the fault inception is considered as the first appearance of fault currents and the breaker opening is defined as the time that the currents were reduced to zero.

An arc-flash event can have severe consequences to both human life and company assets. Luckily, this arc-flash event occurred while remotely operating a breaker, and no operator was standing near the breaker. As a result, nobody was injured. The damage caused to the switchgear was limited to minor melting traced back to where the fault occured thanks to the high-speed operation of the protective devices. This event highlights the benefits of leveraging the latest advances in protective relay technology for arc-flash protection to reduce operating speed to only a few milliseconds.

The major lesson learned from this event was to implement a thorough housekeeping plan as part of the prechecks prior to energizing equipment for the first time for cleanup of any debris accumulated during the construction and commissioning phases. As this event proves, a thorough housekeeping of the switchgear would have discovered the copper shavings inside the breaker compartment and prevented this incident from happening.

VIII. CONCLUSIONS

This paper continued teaching the lessons learned from the original paper [1], detailing an additional six events. The lessons learned from each event were described, as well as the solutions that the engineers applied. The review of each event is further expedited and simplified with readily available information, such as event reports and relay settings. To summarize for each event:

- During autosynchronization procedures, operators should be prepared to abort synchronization if the system response does not meet expectations. In this case, the procedure was aborted once the low-low alarm appeared from the generator, and the procedure continued once the issue was identified and resolved. In addition, both engineering and administrative controls were added to prevent recurrence in the future.
- Creating redundant failover Ethernet networks can improve reliability, but network storms can occur and need to be quickly identified and mitigated. Using port-limiting features in managed Ethernet switches is one method to eliminate and reduce overall system impact.
- As seen in the incorrect delta link event, operators should trust the relay sync permissive and determine the root cause before moving forward. It was important to verify that both incomers' transformer secondary sync voltage did not align and pointed toward the Incomer B transformer delta links as the root cause.

- If status signals are lost on an HMI, operators should first verify that protection is enabled and active. Troubleshooting a missing status point is not time-critical, but making sure protection is active certainly is critical. In this event, while troubleshooting the missing breaker status, the problem evolved into a fault that was cleared with backup protective elements. A quicker look into protective differential channel alarms would have elevated the critical nature of this and potentially would have prevented the fault. Alternately, primary protection could have been enabled before the OPGW failed into the primary circuit.
- Finding dissimilar CT performance, which impacts motor differential protection, during commissioning and startup can be challenging. Time is needed to collect data to evaluate and come up with the proper solution to permit secure but sensitive protection.
- The arc-flash event root cause came down to proper housekeeping. It is critical to clean up any debris that accumulates during the construction and commissioning phases.

IX. REFERENCES

[1] M. Watkins, K. Heshami, M. T. Mendiola, and N. K. Mudugamuwa, “Lessons Learned Through Commissioning, Livening, and Operating Switchgear,” *PCIC Europe Conference Record*, 2022.

[2] M. Catto, S. Manson, and M. Watkins, “Techniques for Commissioning Arc-Flash Mitigation Systems,” *IEEE PCIC Conference Record*, 2019.

[3] B. Edwards, D. G. Williams, A. Hargrave, M. Watkins, and V. K. Yedidi, “Beyond the Nameplate – Selecting Transformer Compensation Settings for Secure Differential Protection,” *70th Annual Conference for Protective Relay Engineers Record*, 2017.

[4] Siemens, “Tie Circuit Breakers and Out-Of-Phase Applications,” siemens.com/us/en/products/energy/techtopics/techtopics-95.html.

[5] R. Beck, P. Robertson, T. Ledford, and C. Salo, “Analysis of In-Service Line Current Differential Protection Circuits: Comparing SONET With Packet-Switched Network Performance,” *47th Annual Western Protective Relay Conference Record*, 2020.

[6] D. Costello, “Lessons Learned Through Commissioning and Analyzing Data From Transformer Differential Installations,” *60th Annual Conference for Protective Relay Engineers Record*, 2007.

[7] C. R. Mason, *The Art and Science of Protective Relaying*, New York, NY: John Wiley & Sons, 1956.

X. VITAE

Matthew Watkins, PE, received his BS, summa cum laude, from Michigan Technological University in 1996 and an MBA from Cardinal Stritch University, Wisconsin, in 2003. He worked for five years as a distribution protection engineer responsible for the application of reclosers throughout the distribution system. In 2005, Matthew joined Schweitzer Engineering Laboratories, Inc. (SEL) as a product manager and later served as a field application engineer. He presently holds the title of principal engineer in the SEL Engineering Services division in Plano, Texas. He is a senior member of IEEE and a registered professional engineer in the state of Texas.
matt_watkins@selinc.com

Kamran Heshami, PEng, received his BASc in electrical engineering from the University of Waterloo in 2015. In 2015, he joined Schweitzer Engineering Laboratories, Inc. (SEL) as a project engineer in the SEL Engineering Services division in Toronto, Canada. He is a registered professional engineer in the Canadian provinces of Ontario, British Columbia, Manitoba, Saskatchewan, Newfoundland and Labrador, Nova Scotia, New Brunswick, and Prince Edward Island.
kamran_heshami@selinc.com

Taylor B. Chambers received his BS in electrical engineering, with a minor in computer science, from Texas A&M University in 2014, as well as a Master of Data Science from Rice University in 2023. He has worked at Chevron since 2014 supporting industrial transmission and distribution projects in the United States and Kazakhstan. He has particular experience with relay protection and power system-specific control systems, such as power management and load-shedding systems.
TaylorChambers@chevron.com

Nilushan K. Mudugamuwa received his PhD in renewable energy from the University of Surrey, United Kingdom, in 2009, and BEng (honors) in electrical and electronic engineering at City, University London, in 2004. He joined KBR London in 2010 as an electrical engineer and worked on a variety of projects. In 2015, he went on secondment to Azerbaijan and became responsible for onsite electrical engineering design for two offshore platforms. Since 2018, he has worked for Tengizchevroil (TCO) in Kazakhstan as a lead electrical protection engineer. He is a member of the Institution of Engineering and Technology (MIET) and has been registered as a chartered engineer from the Institution of Engineering and Technology, United Kingdom (IET UK) since 2014.
nmgn@chevron.com

Anil S. Pandya is a professional electrical engineer with over 31 years of experience covering various aspects including design; operation and maintenance; engineering and construction of greenfield and brownfield projects from concept to commissioning; high-, medium-, and low-voltage power system operation and maintenance; power system protection study; and relay coordination of electrical networks, including power generation. He has worked in oil and gas in Australia and Kazakhstan, power generation and water treatment plants in the United Kingdom, and the fertilizer and petrochemical industry in India and Malaysia. Anil has led the design and execution of grassroots projects and plant upgrades and is skilled in analyzing failures, reviewing protection systems, and implementing remedial solutions to achieve power system reliability. Due to his work with industries where highly flammable gases and liquids are used for various process applications, Anil has gained knowledge of selection, installation, and commissioning of the electrical equipment in hazardous areas.
Anil.Pandya@tengizchevroil.com

Previously presented at the 2024 PCIC Europe Conference, Rotterdam, Netherlands, June 2024. © 2024 PCIC Europe All rights reserved.
20240716 • TP7152