Lessons Learned Through Commissioning, Livening, and Operating Switchgear: Part 3

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LESSONS LEARNED THROUGH COMMISSIONING, LIVENING, AND OPERATING SWITCHGEAR: PART 3

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Abstract—Industrial and distribution facilities involving modern protection schemes, such as arc-flash detection and automatic transfer schemes in addition to conventional protection, pose inherent challenges during the development, construction, commissioning, testing, and livening of the electrical system. Using an arc-flash protection scheme for secure, fast clearing of an electrical fault resulting in an arc-flash event is common in modern industrial protection systems. Improved reliability, selectivity, and speed is achieved by using a well-designed arc-flash protection system, which saves human lives, mitigates serious mechanical equipment and asset damage, and results in greater reliability and a shorter outage and restoration time. This paper presents lessons learned from the commissioning, testing, and livening of a 500 MW industrial expansion project that involves complex protection and control schemes. It discusses some power system-related events that have occurred during livening, involving arc-flash detection, automatic transfer scheme performance during an external fault, and the importance of electrical and mechanical interlocks for safety when manually operating primary equipment. Event details, root cause analyses, engineering improvements, and administrative actions are discussed in detail.

Index Terms—Reliability, Selectivity, Speed, Arc Flash, Event Reports, Root Cause.

I. INTRODUCTION

Commissioning, testing, and livening of a 500 MW industrial expansion project that involves complex protection and control schemes require more enhanced systematic, controlled, and procedural approaches than traditional methods to mitigate fatalities, injuries, and apparatus damage due to human error, albeit incidents are still recorded.

Design errors, defects introduced during construction, and errors of commissioning, testing, livening, and operation can be considered human errors at any stage of the project. These errors may be found during the same stage or at a different stage of the project. Human error or defects embedded into the system at any stage could compromise the safety, integrity, and reliability of the plant.

The authors have carefully selected events to describe how human errors were committed at each stage (construction and commissioning), which could have resulted in a fatality or loss of production, but were prevented by complex protection schemes and equipment. In addition, the authors discuss a fault in the 110 kV network that uncovered the failed transfer scheme at a downstream 10 kV system. Also, the authors have highlighted the importance of understanding primary and backup relay protection element logic in redundant protection and the control system.

The authors present these events as valuable examples of lessons learned to increase awareness, improve commissioning and startup processes, and increase the reliability of the power system.

II. MOLDED-CASE CIRCUIT BREAKER (MCCB)-INDUCED ARC-FLASH EVENT

As part of commissioning the gas turbine generator (GTG) auxiliary systems, a three-phase, 380 V cooling water heater experienced a phase-to-phase short-circuit fault during the initial energization of the heater. The Phase-A-to-Phase-B short-circuit fault occurred in the heater terminal box when the feeder cubicle contactor was energized and closed onto the fault, as shown in Fig. 1, Fig. 2, and Fig. 3.

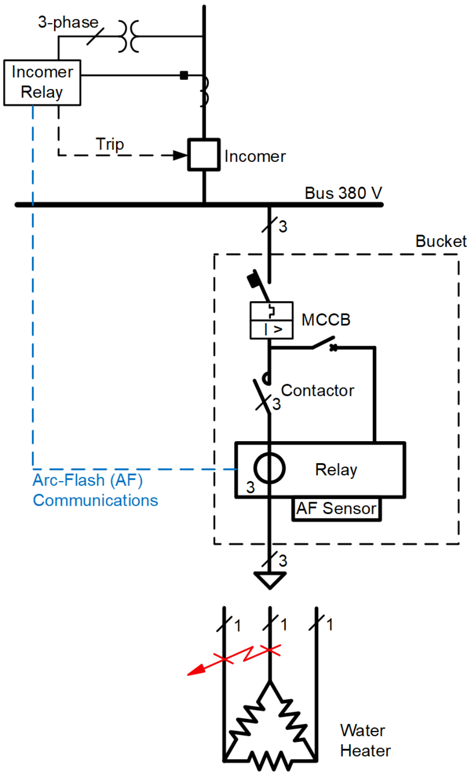

Fig. 1 Single-line diagram of a typical contactor feeder.

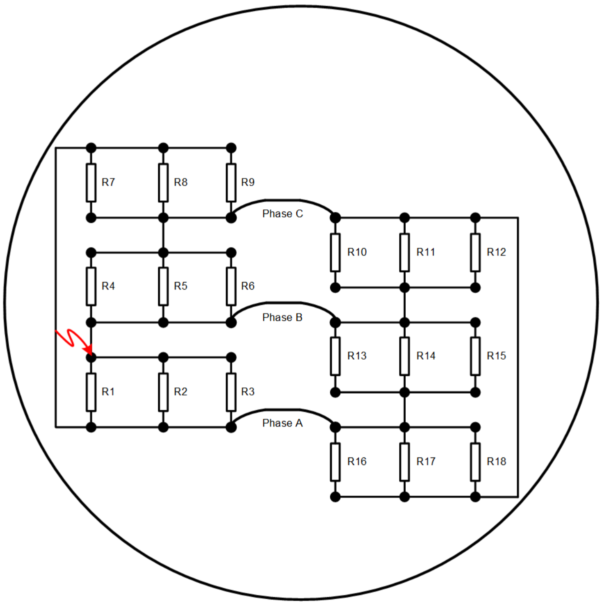

Fig. 2 Typical three-phase delta connection configuration diagram for a cooling water heater.

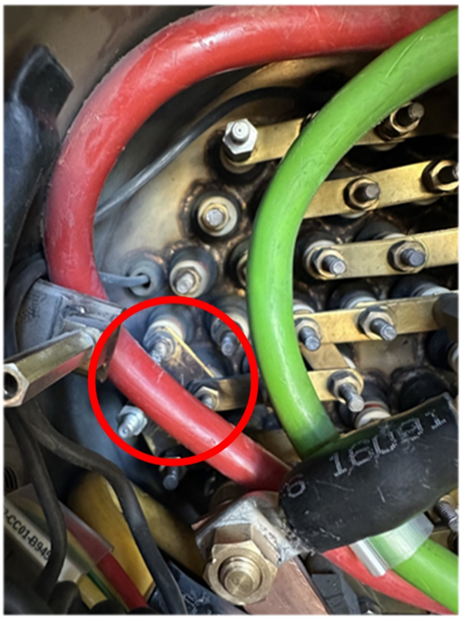

Fig. 3 Fault location at heater terminal box element.

In clearing the fault, the MCCB experienced an arc across its contacts. The resulting intense arc-flash light was quickly detected by the arc-flash detection (AFD) point sensor on the feeder relay and triggered the feeder's cubicle arc-flash protective relay, leading to the motor control center (MCC) incomer tripping, following the low-voltage MCC AFD protection system scheme.

The phase-to-phase fault occurred between the link connecting elements R1 and R13, which was supplied from Phase A, and the second rod conductor of Element R13, which was supplied from Phase B, as shown in Fig. 2. The clearance at this point was approximately 2 mm.

Before energization, precommissioning de-energized electrical checks were conducted, following approved procedures and project electrical check sheets. These included:

- A cable insulation resistance (IR) test, which indicated that normal insulation levels were greater than 550 MΩ. This test was performed with the feeder cable disconnected at the terminal box.
- Individual heating element resistance and element IR measurements, which were taken and confirmed to be correct.
- Thermostat and heater elements, which were configured according to the manufacturer's instruction manual.
- Torque checks on the terminal connectors and wiring inspections, which were conducted in the low-voltage feeder cubicle, heater, and thermostat.

Fig. 4 shows the event recorded by the feeder protective relay during this arc-flash fault. It shows the incident started with a Phase-A-to-Phase-B short-circuit fault when the contactor was energized (52A_CR) and closed on to the fault. It shows the through-fault current that the feeder MCCB interrupted peaked at 9.6 kA on Phase A and 9.3 kA on Phase B, and the fault was cleared in less than half a cycle, 5 ms.

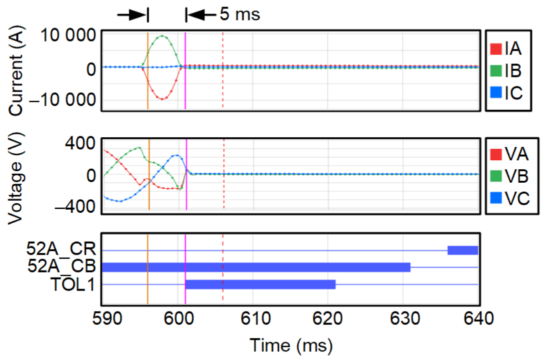

Fig. 4 Event record from feeder protective relay.

Fig. 5 shows the event recorded by the incomer protective relay during this arc-flash incident. The through-fault current that the low-voltage air circuit breaker (ACB) experienced at peak reached 9.4 kA on Phases A and B.

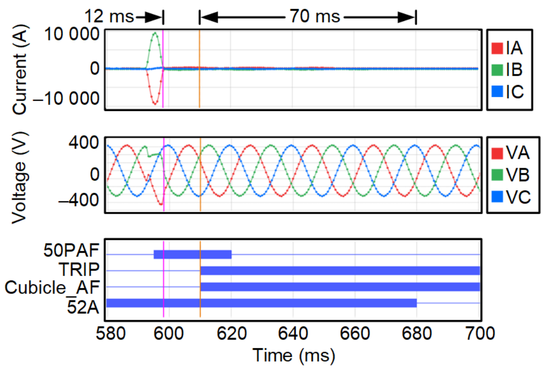

Fig. 5 Event record from incomer protective relay.

It also shows the trace for the digital signal Cubicle_AF from the feeder intelligent electronic device (IED). This digital signal asserts when AF is detected and the current supervision element, 50PAF, was asserted a half cycle before due to the fault current being above its setting threshold. The 50PAF element is a special, fast-acting, overcurrent element that works from individual samples, and not from the digital cosine filter that calculates the fundamental component.

The breaker trip command was issued instantaneously on the same first cycle or at 12 ms. The trace of incomer breaker status, 52A, shows that it tripped open after 70 ms. Fig. 6 shows a simplified incomer IED logic diagram for the current-supervised AF trip.

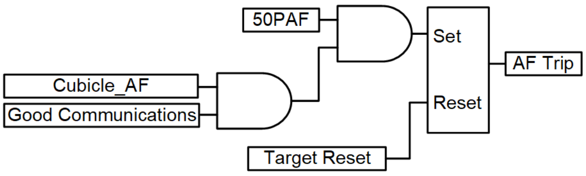

Fig. 6 Incomer protective relay AF trip logic.

During the event, the MCCB could not successfully interrupt the fault current and was severely damaged, as shown in Fig. 7 and Fig. 8. The MCCB, according to the manufacturer's specifications, has a rated capacity of 70 kA. However, it suffered irreparable damage clearing the short-circuit fault.

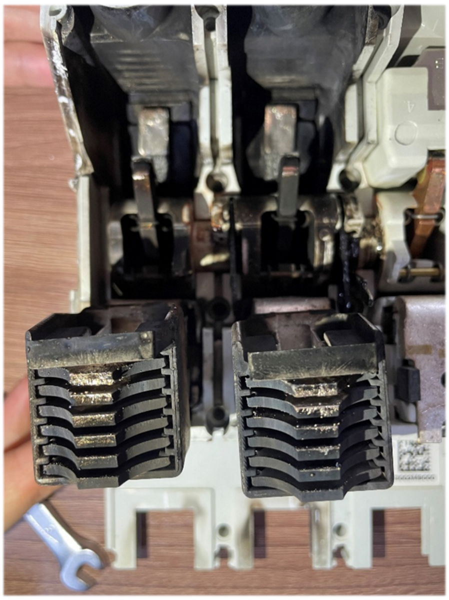

Fig. 7 Failed MCCB.

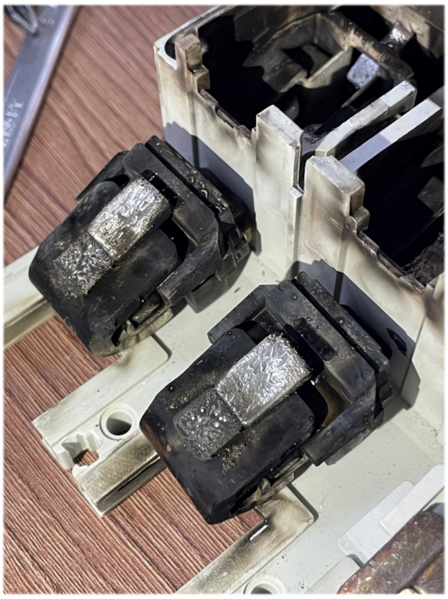

Fig. 8 Failed MCCB contact tips.

The root cause of the protection event and the unselective trip of the MCC incomer ACB was an arc flash within the outgoing feeder bucket at the load side. This occurred when the MCCB was breaking the fault current and was severely damaged during the interruption. The electrical protection scheme operated as designed.

A lesson learned from this event is that after the final connection of the cabling and links, pre-energization final IR tests shall be performed on the complete circuit with the star point disconnected to ensure that there are no phase-to-phase or phase-to-ground short circuits present.

In this particular event, the cabling and elements were tested individually while disconnected and confirmed to be acceptable. After connection and disturbing the cabling and links, the feeder was then energized without a final IR test being performed, which would have identified short circuits on Phases A and B.

This event highlights one of the challenges of an arc-flash protection scheme when distinguishing an arc-flash event versus a downstream protection trip of the MCCB inside the drawer. This is because of the likelihood of the MCCB to produce a flash inside a dark drawer during a close-in fault, as shown in this event. To prevent the entire MCC bus from being cleared for such an event, the drawer MCCB must be sealed (as much as possible) and must coordinate the MCCB with the incomer relay current supervision thresholds below the bus fault duty and above the MCCB fault ability. The engineering team carefully evaluated this event and recommended delaying the arc-flash trip sensed by outgoing feeders by 30 ms on the incomer relay to achieve selectivity.

This event pointed out another prospective challenge posed by the flash that may be generated by the contactor during motor start and stop operations. During motor start, high inrush currents of up to six to ten times of the motor's full-load amperes can create a flash on the contactor and result in a false arc-flash trip. Therefore, carefully calculated overcurrent supervision in the incomer arc-flash scheme is very important for secure and selective arc-flash protection in motor control applications.

III. ROUTINE TEST RESULTED IN ARC FLASH

A commissioning contractor technician was performing an IR test on the primary cable of an outgoing feeder cubicle at the MCC distribution board. The IR test of cables is performed to check the integrity of the insulation of the conductors (refer to Fig. 9).

During the preparation for the IR test, a worker was installing a bare copper wire to verify continuity. The wire was connected to the grounding cable plug, as shown in Fig. 10. During this process, the opposite end of the wire inadvertently passed through a small aperture in the separation plate between the cable and bus compartments, contacting one phase of the live busbars, initiating an arc-flash fault. The arc rapidly propagated to adjacent phases. According to the event record captured by the incomer relay, the arc was extinguished within 50 ms by the incomer relay AFD system per design. There were no injuries to the technician involved but some minor damage to the equipment, involving replacement of a burnt arc-flash fiber loop.

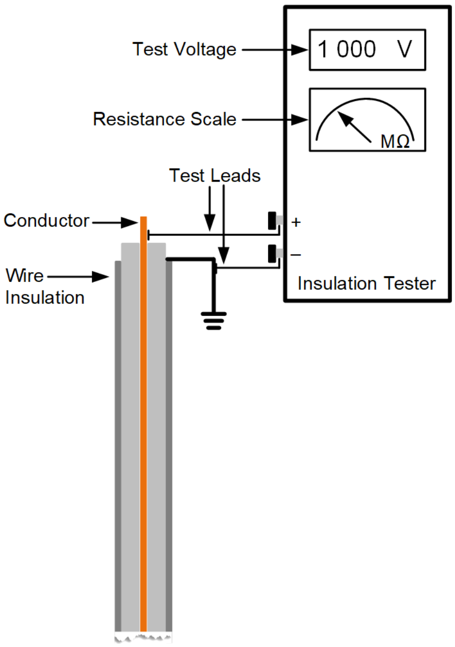

Fig. 9 Typical connections for IR test instrument.

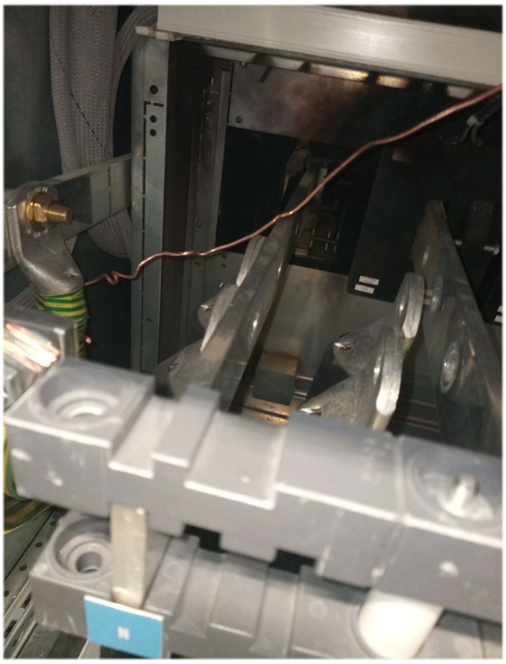

Fig. 10 Fault path created by copper wire for IR test.

Fig. 11 shows the typical AFD scheme for a low-voltage MCC distribution board. The typical arc-flash zone of detection is created using arc-flash fiber loops around the horizontal and vertical busbar section to detect the arc in the busbar protection zone. The current transformers from the incomer breaker connect to the incomer relay, and the relay uses that current along with the light detected by the AFD sensor loop to declare an arc-flash event on the busbar zone and trip the incomer breaker, as shown in the following equation.

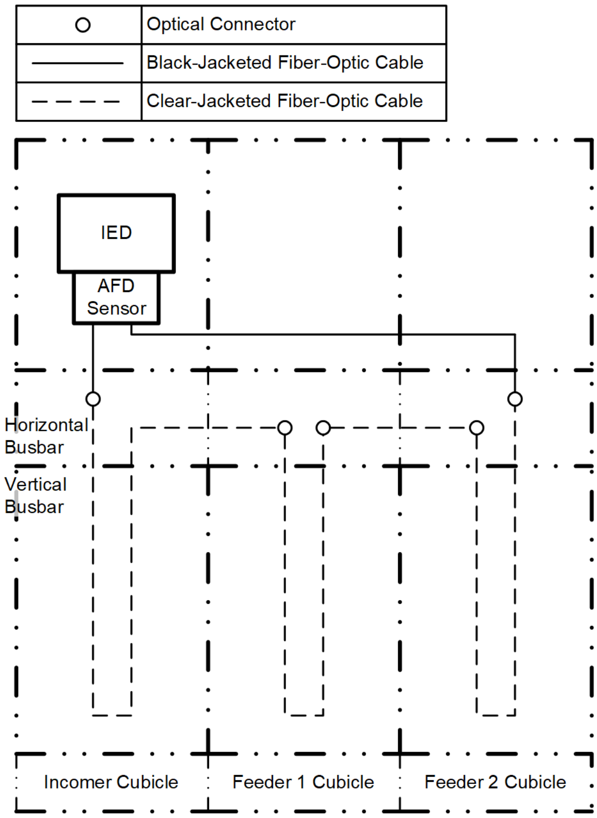

Fig. 11 Typical low-voltage MCC distribution board AFD scheme.

OUT301 := fast overcurrent element AND arc flash detected

Modern IEDs typically detect and send a trip command for an arc-flash event in less than 5 ms and trip the breaker to isolate the fault. To achieve high-speed isolation of the arc-flash fault, modern microprocessor relays are provided with fast high-current interrupting outputs for tripping purposes. These output contacts operate about 8 ms faster than standard output contacts, which is a significant amount time for high arc-flash energy exposure incidents in low-voltage systems [1] [2] [3].

Fig. 12 shows the event recorded by the incomer relay during this arc-flash episode. It shows that the incident started with a Phase-B-to-ground fault, when the technician accidently made contact with the energized bus bar using the ground cable. The fault rapidly propagated to Phases A and C, creating the three-phase-to-ground fault. As shown in Fig. 12, the relay detected the arc flash (TOL3 refers to time-over-light pickup on the relay) and took 4 ms to declare the arc-flash event and issue the TRIP command to clear the fault (OUT301 refers to the high-speed output contact wired from the incomer relay to the incomer breaker). And it took a total of 50 ms to completely isolate the fault by opening the incomer breaker (IN302 refers to the incomer breaker open status). This high-speed clearance of the arc-flash fault by the protective relay saved a life and limited the equipment damage to the very minimal. We can highlight two very important aspects from this incident: first, human error was the cause of the arc-flash incident and second, arc-flash protection schemes are vitally important for personal safety, equipment protection, system reliability, and economical operation.

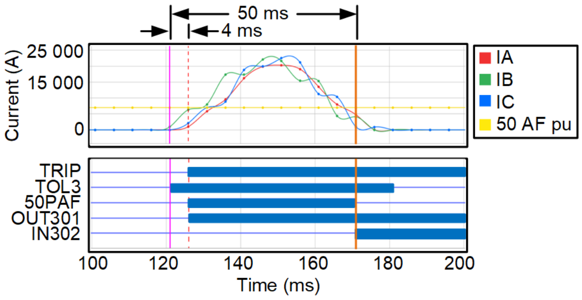

Fig. 12 Incomer relay fault currents, AFD, trip command timing, and total fault clearing time.

Arc-flash incidents can be triggered by several factors. One of the most common causes of arc-flash incidents is human error. The investigation carried out after this arc-flash event at the commissioning site found that poor electrical hazard awareness was the main reason for this incident. It also found that despite all safeguards for the electrical work in place, the team performing the job was not aware of how the risk profile changes from the construction phase to the operation phase. Specifically, in the greenfield site, the electrical workers were accustomed to working in de-energized switchboard conditions. Complacency and a lack of proper training can lead to insufficient risk assessments. As a construction site enters the operation phase, the likelihood of life-threatening critical events increases, due in part or mainly to human error. Workers may overlook established safety procedures, forget to reassess risk and work procedures, or assume that previous assessments are adequate without considering changes in the environment and equipment state. To mitigate human errors, organizations should implement enhanced and continuous employee development programs that provide comprehensive training on electrical safety, hazard recognition, safe work practices, and strict safety protocols.

Arc-flash protection schemes are crucial for many reasons. Arc-flash incidents can cause severe injuries or fatalities due to the intense heat, light, and pressure shock waves generated. Arc flashes can lead to catastrophic equipment failures, resulting in significant property damage and costly repairs. By mitigating arc-flash incidents, industries and utilities can reduce downtimes, which ensures the continuous power supply for critical systems of industries and utilities and ultimately leads to a significant reduction in the cost associated with injuries, equipment damage, and operational downtime. This incident clearly shows that properly designed and commissioned [4] arc-flash protection schemes help to minimize these risks through quick detection and isolation of faults. In addition, this incident highlights the importance of fast detection (in milliseconds) and isolation of arc-flash faults provided by modern arc-flash protection technology.

IV. LOAD BANK INTERLOCKS

As part of the dynamic commissioning of five GTGs of 125 MW each, a temporary load bank facility was installed. Load bank units of 5 MVA each were supplied in standard shipping containers. An additional shipping container unit with a transformer and SF_6-insulated ring main unit (RMU) was provided. A typical single-line diagram of a load bank is shown in Fig. 13, and 16 of these load banks were connected to 8 temporary feeders.

The load banks were connected to the downstream 10 kV distribution system instead of being connected to the 110 kV network to simplify the temporary arrangement. Containerized load banks have their own protection and, although it is a temporary connection, standard protection and unidirectional interlocks were incorporated to the feeder design. It was expected that the operation of the load banks would follow established operating procedures, as load banks operate simultaneously with 10 kV critical startup loads, such as air compressors.

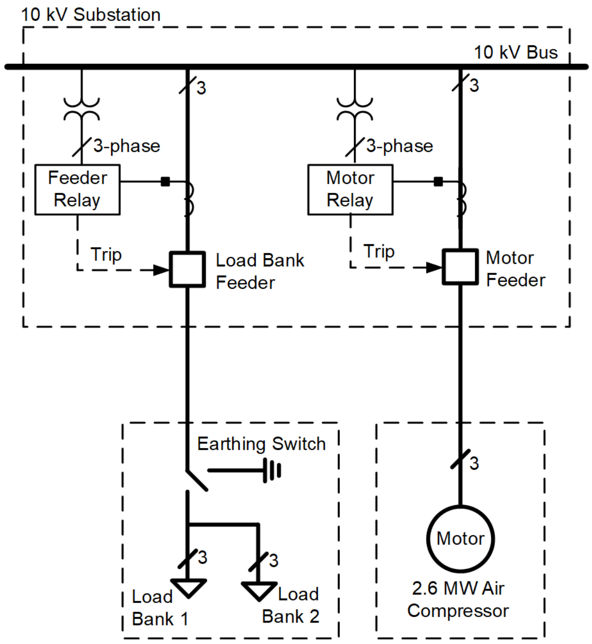

Fig. 13 Connection diagram of load bank and the transformer and RMU to the medium-voltage distribution board (MDB).

A load bank fed from a spare feeder of a 10 kV MDB was scheduled to be commissioned prior to the GTG load tests. The MDB was operational and serving plant loads. Switching on a live switchboard was controlled via operational procedures to avoid unexpected shutdowns when simultaneous operations occur.

Soon after completing a 4-hour load run, unloading and isolation was expected to follow as per the shutdown procedure. Around the same timeline, the operator reported a trip on a 2.6 MW air compressor that was fed from the same 10 kV MDB. The initial investigation by the mechanical team focused on the compressor, as the trip was issued from the safety integrity system (SIS). The operation resulted from vibration levels in the compressor, reaching or going over set trip levels. The investigation could not identify any issue with the compressor, so the electrical protection team continued the investigation on the MDB to identify the root cause of the trip.

IEDs on the load bank feeder recorded an event showing a three-phase fault, albeit the operator never reported it. Further investigation of the Sequential Events Recorder (SER) of the protective relay confirmed that the operator closed the earthing switch (ES) on the load bank side (refer to Fig. 13) while the feeder breaker was closed. Closing the ES created a three-phase-to-ground fault (around 14 kA) and the feeder was tripped immediately on instantaneous (50P) protection. As per Fig. 14, the fault current was cleared within 100 ms. The feeder relay is wired with bus voltage, and it is evident from the event record that the bus

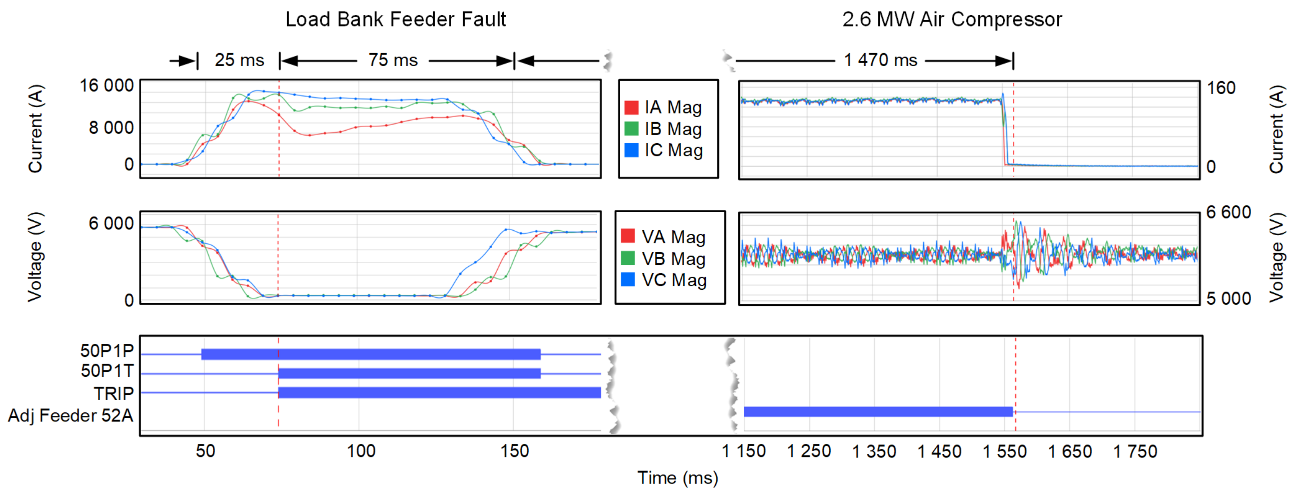

Fig. 14 Impact on the voltage and current during short circuit and the timeline of the events at load bank feeder and compressor feeder.

voltage was impacted significantly as it fell below 1 kV (line to ground) during the fault from its nominal 5.7 kV. Although the voltage was below 1 kV for approximately 55 ms, the bus voltage recovered within 125 ms. The motor feeders are set to trip for undervoltage events (less than 80 percent) with a 200 ms time delay to protect the motor feeder. However, in this instance, the voltage recovered well before the delayed time. This significant voltage dip was not expected. However, further investigation confirmed that the power system was in a weak state due to the ongoing routine maintenance taking place on the brownfield GTGs.

It is well documented that the motor's performance is affected by the power supply, where unbalanced voltages rapidly increase vibration levels that could cause undesirable operational conditions on the motor and driven equipment, in addition to impacting the motor's lifespan [5] [6] [7]. As shown in Fig. 14, the air compressor was tripped around 1.5 seconds after the operation of the load bank feeder breaker. This suggests that the vibrations on the compressor could have been caused by the low-voltage levels reached during the sudden voltage dip, which aligns with the observation made by the mechanical team.

After the investigation, it was evident that the operator did not follow the correct de-energizing procedure and applied the ES on the SF_6-insulated RMU of the load bank prior to switching off the feeder breaker. The impact to the voltage caused the shutdown of the air compressor. There was no physical damage observed on the ES at the SF_6-insulated RMU, as it is rated for higher short-circuit currents (21 kA for 3 s). It was also evident that the operator did not notice the trip on the load bank feeder as the operator was investigating the simultaneous trip of the air compressor. The inadequate communication between the operators at both the substation and the load bank led to the short-circuit event. The operator at the load bank did not experience any shock due to the the integrity of the SF_6-insulated RMU and instant tripping of the upstream breaker, under 100 ms.

Fig. 15 shows the physical movement of the cables caused by the magnetic forces generated due to the three-phase fault. Engineers tested the feeder breaker, cables, and apparatus at the load bank to confirm their integrity and that no damage occurred due to the event. These high magnetic forces that displaced and deformed these cables serve as a good reminder to construction crews of the importance of taking the time to install proper cable cleats and avoiding faster installation approaches, like the use of cable ties. As part of the root cause analysis, the operators were trained. The trainings emphasized good communication, highlighted the key items to be discussed at safety toolbox talks, and stressed the importance of following procedures to avoid complacency. In conclusion, even in temporary electrical arrangements, it is important to include bidirectional interlocks between the source and the feeder, in addition to following procedures meant to create and maintain a safe working environment [8].

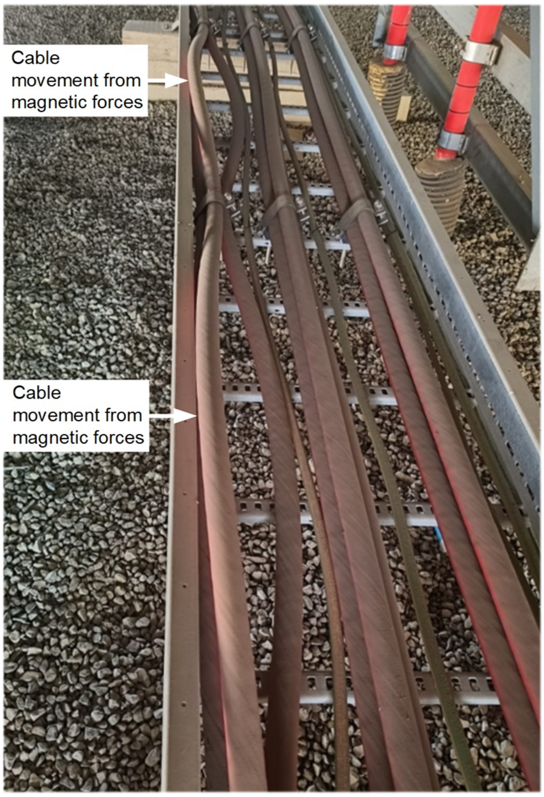

Fig. 15 300 mm^2 temporary feeder cables affected by short circuit.

V. LINE DIFFERENTIAL FAULT IMPACTS AUTOMATIC TRANSFER SCHEME (ATS)

A Phase-C-to-ground fault occurred on a 110 kV transmission line energizing a 110 kV to 10.5 kV step-down transformer. In turn, the low-voltage side of the transformer energizes the 10.5 kV Incomer B into an MDB. Fig. 16 shows a simplified single-line diagram. The root cause analysis on this event provided interesting insight from two perspectives. First, the event highlights the operating difference in primary and backup relay performance in the 10.5 kV distribution substation in lieu of enabled disturbance detection logic. Second, the 10.5 kV switchboard's ATS did not operate. The logic of the ATS can be improved to include operation for an external line fault.

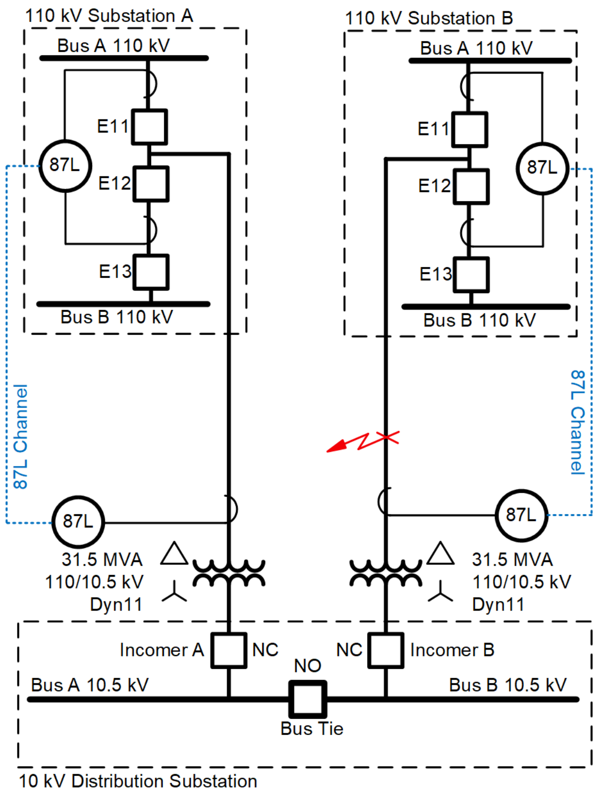

Fig. 16 Internal fault single-line diagram.

A. Disturbance Detection

The line current differential (87L) relays shown in Substation A, Substation B, and the 10.5 kV distribution substation in Fig. 16 consist of a primary and backup relay. The relays are of the same manufacturer. However, they are different models. Prior to the fault, the 10.5 kV distribution substation had both incomers energized with the bus-tie breaker open. The 10.5 kV substation is only energized from these two incoming lines, leading to a weak infeed condition for 110 kV line faults. The event report from the Substation B primary relay is shown in Fig. 17. The performance of the backup relay matched the primary relay, and the trip occurred due to phase (87LP), negative-sequence (87LQ), and ground (87LG) differential elements asserting in both relays in 0.25 cycles.

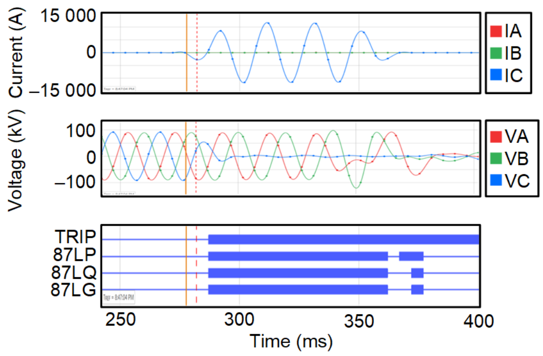

Fig. 17 Substation B primary 87L relay.

The 10.5 kV distribution substation terminal primary and backup relays are shown in Fig. 18 and Fig. 19, respectively. The fault current magnitude is several orders of magnitude less than that of the 110 kV side and appears phase-to-phase because of the delta-wye transformer due to the weak infeed contribution from the 10.5 kV substation.

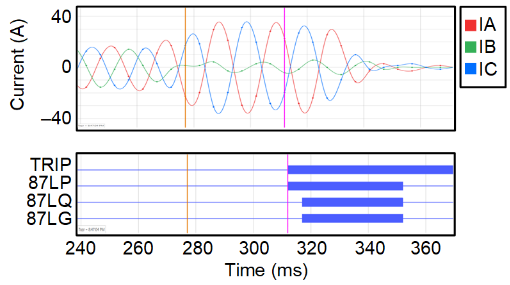

Fig. 18 10.5 kV substation primary 87L relay.

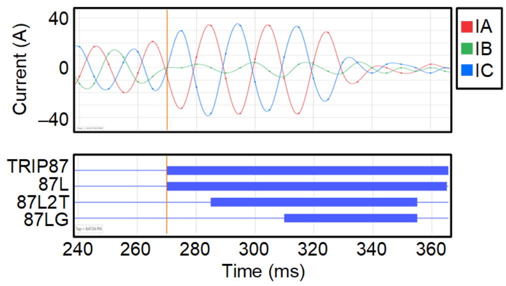

Fig. 19 10 kV substation backup 87L relay.

Both the primary and backup relays contain a disturbance detector designed to qualify 87L communications channel events from actual power system faults. The backup relay has the disturbance detection logic disabled. As shown in Fig. 18, the trip was delayed in the primary relay by 40 ms. Fig. 19 shows that the backup relay did not delay the trip.

In the primary relay, the disturbance detector qualifies 87L differential trip events by asserting digital status 87DD. 87DD asserts when both a local (87DDL) and a remote (87DDR) disturbance is detected. In the local relay, a local disturbance is detected based on changes on either zero- and positive-sequence currents or the line-sequence voltages (zero-, negative-, and positive-sequence). 87DDR asserts on receipt of a disturbance detection bit from the remote end across the differential channel. For weak infeed conditions, the relay can base the local disturbance detection on the voltage. However, voltage inputs were not wired in this 10.5 kV distribution substation application. The trip logic also includes a 2-cycle pickup timer for instances where an 87 differential event is detected without the associated assertion of 87DD. See Fig. 20 for the logic in the primary relay.

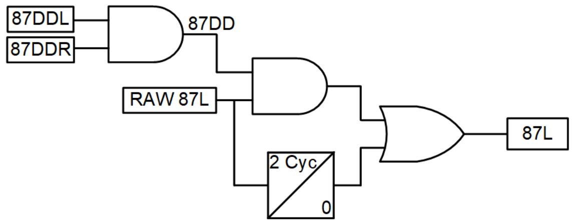

Fig. 20 Primary relay disturbance detection logic.

Fig. 21 highlights the primary relay's performance of the disturbance detection logic. The differential phase currents are shown where Phase C is elevated for the line-to-ground fault. Two cycles later (40 ms) as the differential current went above the pickup, the relay issued a trip. 87L50C is supervising the overcurrent element of the Phase C differential element while 87DTTRX is the 87 direct transfer trip received status from the remote end relay.

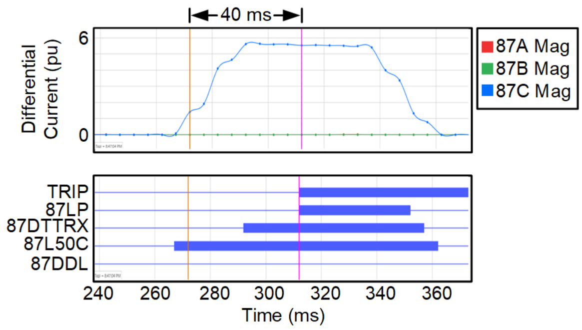

Fig. 21 10.5 kV substation primary differential relay operation.

The backup relay also contains disturbance detection logic that performs a similar delay in tripping when a disturbance is not detected. Whereas the primary relay had this logic enabled, the backup relay did not. After reviewing the event, studying the detailed explanation of each relay's performance, and knowing that the remote end cleared the fault without delay, the engineering team evaluated the benefits to the radially energized substation versus the cost to change across their power system and confirmed the relay settings; no immediate changes were implemented. Instead, aligning this logic between the primary and backup relays would be done at a future date.

B. *ATS Performance*

Following the line fault in Fig. 16, the ATS detected a loss of voltage on Incomer B. However, it did not initiate the expected close command to the bus-tie breaker. In reviewing the ATS controller's autotransfer initiate logic (see Fig. 22) along with the relay's sequential event report (Fig. 23), it was observed that the line-to-ground fault on the 110 kV line that energized Incomer B depressed the C-phase system voltage significantly enough to be seen on the Substation A line to energize Incomer A.

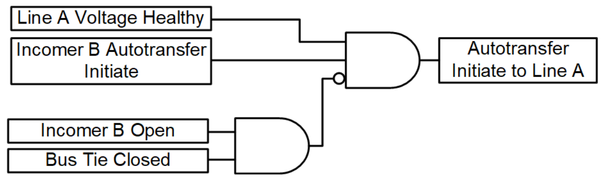

Fig. 22 Simplified ATS initiate logic.

```
ATS Cntrl              Date: 29/12/2023    Time: 07:10:18.351
xx-xxx-xxxx                              Time Source: External

 #     DATE         TIME           ELEMENT             STATE

100   28/12/2023   20:47:04.2864   Line A V Healthy      0
99    28/12/2023   20:47:04.2864   Line B V Healthy      0
97    28/12/2023   20:47:04.3024   Inc B AT Init         1
                         .
                         .
                         .
81    28/12/2023   20:47:06.3024   Inc B AT Init         0
80    28/12/2023   20:47:07.3703   Line A V Healthy      1
```

Fig. 23 Simplified ATS SER.

Fig. 22 highlights the Line A voltage healthy check required prior to initiating the transfer to Line A. In this case, the external fault on Line B resulted in Incomer B initiating a transfer to Line A. However, the autotransfer control also received Line A Voltage Unhealthy status, which blocked the transfer to Line A. The incomer relay declares an unhealthy voltage source if any phase immediately drops below 0.9 pu. Once the voltage is restored above 0.9 pu, the relay checks that this condition is true for 3 seconds before declaring healthy voltage. This is seen in Fig. 23 as Lines 100 and 80 while the Incomer B transfer initiate is shown in Lines 97 and 81.

Fig. 24 is taken from the Bus A power quality meter set to capture an event report anytime bus voltage falls below 0.9 pu. For this power quality meter, voltage measurements are on the 10.5 kV side of the transformer in which a transformer primary side Phase-C-to-ground line fault results in a depressed B- and C-phase voltage on the bus.

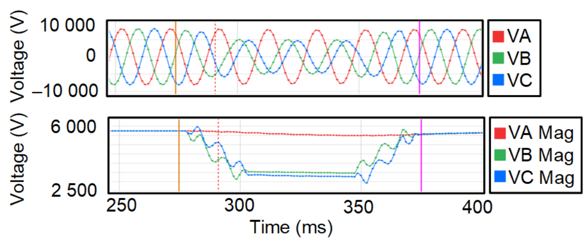

Fig. 24 Bus A voltage.

This event was timely such that the captured events pointed out a shortcoming in the ATS logic. Other relay applications that used a similar voltage healthy status, which immediately declared unhealthy voltage when the voltage fell below 0.9 pu but required 3 seconds of nominal voltage to be declared healthy again, were under review due to the inability to ride through normal voltage dips that resulted from external power system faults. Similar to these applications, the engineering team reviewed event reports and SERs and concluded that a healthy voltage declaration should be able to ride through a 300 ms voltage dip before declaring an unhealthy voltage. For an unhealthy voltage to be declared healthy, it must be above 0.9 pu for 3 seconds. Based on this power system event analysis, subsequent line faults will result in a proper automatic transfer to the healthy adjacent bus.

Several lessons learned can be observed from this event. Reviewing internal relay logic is just as important to the settings engineer as reviewing protection study reports and logic diagrams. Power system faults create voltage disturbances that can impact a declared healthy voltage status. While overlooked in factory acceptance testing and site commissioning, this illustrates the need to test every protection element and custom logic as it would react based on actual power system conditions.

VI. CONCLUSIONS

With this paper, the authors continue sharing and teaching lessons learned as in previous papers [9] [10], which showcased four different events. It documents, analyzes, and presents engineering and administrative solutions for each event presented.

As described in this paper, an arc flash is a dangerous event that occurs when an electrical fault causes a high-voltage arc between conductors or to the ground; the effects of arc-flash events can be extremely severe; and the temperature of an arc flash can reach above 19,000°C and can vaporize metal components, causing severe damage to electrical equipment, fires, or violent explosions. Arc-flash events pose significant risk to personnel, causing electrical burns, injuries and death. Understanding and mitigating the risks associated with arc flashes is essential for maintaining a safe working environment in electrical installations during commissioning and operation. By implementing modern arc-flash protection technology and addressing human errors, industries and utilities can significantly reduce arc-flash incidents and improve overall workplace safety, minimizing equipment damage.

Protection systems must be dependable to clear all in-zone faults and should be secure for any out-of-zone faults. To overcome the challenges of unselective trips posed by the MCCB and contactor flash, this paper underscores the importance of careful manufacturing of a low-voltage drawer with MCCB sealing, selection of MCCB, and precise setting of the incomer relay current supervision thresholds.

For all work in electrical facilities, including commissioning , testing, and normal operations, procedure adherence and good communications are key factors that impact human performance and can impact the safety of personnel and the availability of key equipment. Electrical power distribution equipment shall only be commissioned and operated by trained, qualified, and experienced personnel where electrical safety rules are strictly followed.

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VIII. VITAE

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