STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

APPLICATION OF INDIANAPOLIS POWER & LIGHT COMPANY D/B/A AES INDIANA FOR APPROVAL OF A FUEL COST FACTOR FOR ELECTRIC SERVICE DURING THE BILLING MONTHS OF DECEMBER 2021 THROUGH FEBRUARY 2022, IN ACCORDANCE WITH THE PROVISIONS OF I.C. 8-1-2-42, AND CONTINUED USE OF RATEMAKING TREATMENT FOR COSTS OF WIND POWER PURCHASES PURSUANT TO CAUSE NOS. 43485 AND 43740, AND APPROVAL OF A FUEL HEDGING PLAN AND AUTHORITY TO RECOVER COSTS OF THE FUEL HEDGING PLAN PURSUANT TO I.C. 8-1-2-42.	)	**CAUSE NO. 38703 FAC 133**

APPLICANT'S SUBMISSION OF DIRECT TESTIMONY OF
<u>JOHN BIGALBAL</u>

Indianapolis Power & Light Company d/b/a AES Indiana ("AES Indiana", "IPL", "Company", or "Applicant"), by counsel, hereby submits the direct testimony and attachment of John Bigalbal.

Respectfully submitted,

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The undersigned hereby certifies that a copy of the foregoing was served this 17th day of September, 2021, by email transmission, hand delivery or United States Mail, first class, postage prepaid to:

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APPLICANT'S EXHIBIT 3
I.U.R.C. CAUSE NO. 38703-FAC 133

VERIFIED TESTIMONY OF JOHN BIGALBAL
CHIEF OPERATING OFFICER, US CONVENTIONAL GENERATION

Q1. Please state your name, employer, and business address.

A1. My name is John Bigalbal. I am employed by AES US Services, LLC ("the Service Company"), which is the service company that serves Indianapolis Power & Light Company d/b/a AES Indiana ("AES Indiana" or "IPL" or the "Applicant"). The Service Company is located at One Monument Circle, Indianapolis, Indiana 46204.

Q2. What is your position with the Service Company?

A2. I am the Chief Operating Officer, US Conventional Generation.

Q3. Please describe your duties as Chief Operating Officer.

A3. As Chief Operating Officer, I manage the US conventional generation fleet that includes coal and natural gas steam, combined cycle gas turbine and simple cycle generation plants with a combined capacity of approximately 3,600 megawatts.

Q4. Please summarize your educational and professional background.

A4. I graduated from Thames Valley State Technical College with a degree in Electrical Engineering. I have also completed an Executive Leadership Program at Georgetown University's McDonough School of Business.

Q5. Please summarize your prior work experience.

A5. I started my career in 1987 with Connecticut Light and Power and worked in Operations and Engineering. I left the utility in 1991 to perform the startup and commissioning of

Exeter Energy, a 30-megawatt tire-fired generation plant. In 1992, I started working for AES at the AES Thames cogeneration plant. I have been with AES for 29 years. During my time with AES, I have worked in Instrumentation and Controls, Engineering, Environmental, Safety, Business Development, Commercial and Construction. I have been in several leadership roles including the management of a large merchant coal-fired generation plant and a fleet of six merchant coal-fired generation plants, business development, fuel, and logistics as well as this current role.

Q6. Have you previously testified before this Commission?

A6. No.

Q7. Are you sponsoring any attachments?

A7. Yes. I am sponsoring the following attachments, which were prepared or assembled under my direction or supervision:

- Petitioner's Attachment JB-1 – which is a copy of the Root Cause Analysis ("RCA")[1] for the Eagle Valley forced outage discussed below.

Q8. What is the purpose of your testimony in this proceeding?

A8. As explained by AES Indiana Witness David Jackson, AES Indiana follows the purchased power daily benchmark methodology approved in Cause No. 43414. He explains that during the historical period in this FAC (May through July 2021), AES Indiana incurred purchased power costs over the benchmark in the amount of $1,198,183. Witness Jackson identifies the reasons for the purchased power costs, including a forced outage at the Eagle Valley CCGT plant. My testimony discusses 1) the forced outage, 2) the steps taken by

[1] Public and Confidential versions of the Root Cause Analysis

AES Indiana to return the unit to service, 3) the root cause analysis, and 4) the actions taken by AES Indiana in response to the RCA. AES Indiana Witness Jackson discusses the purchased power.

EAGLE VALLEY CCGT FORCED OUTAGE

Q9. Please describe the Eagle Valley CCGT.

A9. The Eagle Valley CCGT plant ("Eagle Valley") is a 671 MW gas-fired facility located in Morgan County, Indiana. The plant consists of two GE 7FA.05 gas turbines, associated Nooter Eriksen heat recovery steam generators, and a Toshiba steam turbine. Eagle Valley commenced commercial operations on April 28, 2018, which is the date AES Indiana took ownership and control of the CCGT. Eagle Valley had more than two years of very solid performance. It has reliably operated as a baseload unit with more energy production and service hours than originally expected. Eagle Valley CCGT had top decile and top quartile annual Equivalent Availability Factors in 2019 and 2020, respectively. Its heat rate is top decile, and it operates as a baseload plant with high capacity factors. It has provided low cost generation to our customers and has contributed to the overall emissions reductions for the AES Indiana generation fleet.

Q10. Is there a simple diagram to aid in your testimony?

A10. Yes.

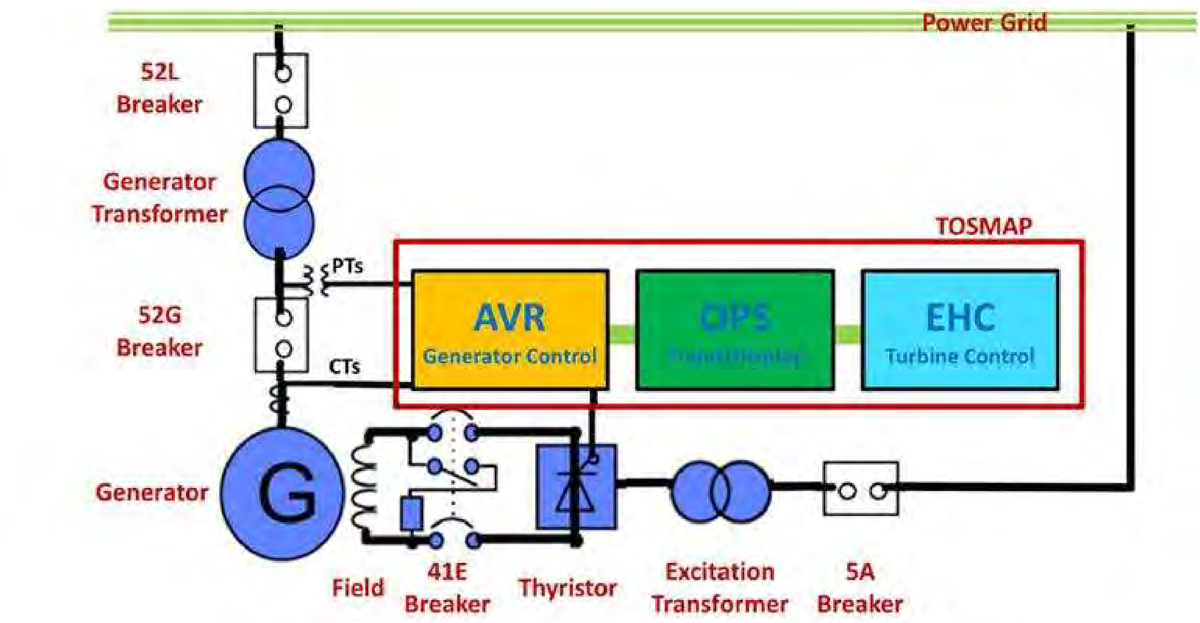

Figure 1, Simplistic diagram of generator protection and control components

Q11. When did the outage at the Eagle Valley CCGT occur and what were the events that led to the outage?

A11. The outage began on April 25, 2021 and the following events led to the outage.

Q12. When restarting after planned maintenance, the unit did not synchronize with the grid because of an issue with the generator breaker.

A12. On April 25, 2021, the unit was returning from its planned maintenance outage and began start up. During start up, the steam turbine unit experienced an issue with the generator breaker (52G Breaker as shown in Figure 1 above) that prohibited it from synchronizing with the grid. The generator breaker (52G Breaker) should have closed to allow the unit to synchronize (or connect) to the grid. The control system (OPS) was showing the generator breaker (52G Breaker) open in one location and closed in another.

Q13. A disconnected wire was identified during troubleshooting with support of Toshiba, but reconnecting the wire according to the schematics did not resolve the generator breaker (52G Breaker) issue.

A13. The team worked with Toshiba, the Original Equipment Manufacturer ("OEM"), to troubleshoot the issue. During troubleshooting, the team found a disconnected wire in the generator breaker (52G Breaker) cabinet and test landed it on the terminal according to the wiring schematic. This did not change the state of the conflicting indications on the generator breaker (52G Breaker). Toshiba recommended a manual trip and restart of the turbine-generator to try to reset the logic. This did not change the state of the mismatched indication. It also did not open the field breaker (41E Breaker).

Q14. Shutdown initiated with a plan to resume troubleshooting the next day.

A14. At this time, the operations leader shut down the plant start up process and planned to resume troubleshooting the next morning when additional resources would be available. A manual trip was initiated, and the turbine-generator coasted down. During coast down, the 86G1 and 86G2 lockout relays activated. The 86G1 and 86G2 lockout relays are generator protective relays that isolate the Generator from several different faults. These relays should open the generator breaker (52G Breaker), open the field breaker (41E Breaker), trip the turbine by closing all steam valves, and shut down the Automatic Voltage Regulator ("AVR"). The generator breaker (52G Breaker) was already opened, the field breaker (41E Breaker) did not open, the steam turbine tripped and all steam valves closed, and the AVR shut down. It is important to note that the field breaker (41E) did not open when the lockout relays activated.

Q15. A reset of generator protective relays (86G) was initiated while the field breaker (41E Breaker) was closed and the excitation transformer relay (86ET) activated.

A15. The turbine completed its coast down and was placed on turning gear. The 86G relays were reset by a technician while the unit was on turning gear and the field breaker (41E) was closed, which put the AVR in service. Fourteen minutes after the 86G relays were reset, the 86ET lockout relay tripped. The 86ET lockout relay protects the Excitation Transformer from a fault by opening the 5A Breaker. The field breaker (41E breaker), which isolates and protects the generator, did not open as expected and remained closed.

Q16. Troubleshooting resumes the next day and the addition of a jumper wire opens the field breaker (41E breaker) and resolves the generator breaker (52G breaker) issue; a short to ground in the field was identified.

A16. The following morning, Monday, April 26th, troubleshooting was restarted, and the team checked several wiring connections between the generator breaker (52G Breaker) cabinet and the TOSMAP controller (the steam turbine-generator control system), generator protective relay cabinet and the field breaker (41E Breaker) cabinet. From these checks it was determined to place a jumper between two terminals in the field breaker (41E Breaker) cabinet which would be equivalent to re-landing the loose wire found in the generator breaker (52G Breaker) cabinet. When this was done, the two generator breaker (52G Breaker) indicators matched, and the field breaker (41E Breaker) opened. During troubleshooting the team determined that the ground protective relays (64F1 and 64F2) had activated indicating a short to ground in the Field. The Field insulation was tested Tuesday, April 27th using a megger, which is an instrument used to test the insulation resistance, and it confirmed that the Field had a short to ground.

Q17. Please describe the actions taken by AES Indiana immediately following the forced outage.

A17. Once the short to ground was determined, a third-party vendor was called in to validate the status of the Field. The ground was verified on Wednesday, April 28th by the vendor. The Generator end bells were removed, and the inspection ports opened to get a visual inspection of the Generator. Upon inspection, copper debris was seen as well as what appeared to be a piece of a copper bar laying in the bottom of the Generator. Toshiba was dispatched on Friday, April 30th to remove the Field and engineering was performed to determine what was needed to remove the Field. Due to the live load capacity of the turbine floor a support structure needed to be engineered and installed before the Field could be removed. Once the support structure was installed the Field was removed and shipped to Milwaukee for Toshiba to disassemble and assess the damage to determine the repair. With the Field removed a visual inspection of the stator was performed as well as several electrical tests, including, DC Leakage, Winding Resistance and DC HiPot, which are performed to check the condition of the insulation and windings. All electrical tests showed everything was normal. Visual inspection showed that metallic material, both ferrous and non-ferrous was contaminating the stator. The stator was cleaned, and later re-wedged based on the OEM and owner's engineer recommendations. Re-wedging the stator allowed for additional cleaning and inspection behind the wedges. The stator was checked after cleaning using an Electromagnetic Core Imperfection Detection ("EL CID") test which showed normal results. The EL CID test checks the condition of the stator core lamination insulation. After the disassembly of the Field in Milwaukee, it was determined that the copper bars and end windings needed to be replaced and the Field rewound. The retaining rings were also damaged, and new retaining rings were ordered. Additionally, the rotor forging at the end slots were damaged (melted from the heat caused by the ground) and would need to be repaired. The rotor was then shipped to Sulzer Turbo Services Houston, Inc. ("Sulzer") in Houston to be weld repaired. An expedited order was immediately placed with Arland Tool and Manufacturing, Inc. ("Arland") for the new copper bars. Once the damage was assessed and a repair process determined, the timeline for the work was put together to get an estimate of the outage duration. This estimate for the repairs to be made and the unit to be returned to service was used to implement a hedging program that Mr. Jackson's testimony describes.

Q18. What steps did AES Indiana take to mitigate the duration of the Eagle Valley CCGT forced outage?

A18. All repairs and procurement of parts that could be expedited have been and are being expedited, including payment of an expediting fee of approximately $195,000 to move the manufacturing of the copper bars up in the queue. Additonally, AES Indiana has several meetings each week with Toshiba to ensure that everthing stays on track. There is also a cross-functional internal team that meets several times each week to manage all issues related to this event. AES Indiana has an owner's engineer that we are are working with and representatives have been sent to both Toshiba's shop in Milwaukee and to the Sulzer shop in Houston.

Q19. What is the expected duration of the Eagle Valley forced outage?

A19. The Eagle Valley CCGT is expected to be in outage until November 7, 2021. There may be additional delays if there are issues with the high-speed balancing of the rotor, shipping, weather, or issues with balancing the turbine-generator (once the Generator is reassembled). The length of the outage is due to the removal of the Field, transporting the Field to Milwaukee for inspection, Field disassembly to determine damage and repair process, transporting the rotor to Houston for repair, repair of the rotor, stress relief of the rotor, machining the rotor to obtain the proper runout (the amount of wobble in a rotating system), transporting the rotor back to Milwaukee for rewind, fabrication and shipping of the copper bars, retaining rings and other parts, rewinding the Field, high-speed balancing of the Field prior to shipping back to Eagle Valley, transporting the Field to Eagle Valley and ultimately the reassembly of the generator and balancing of the turbine-generator. AES Indiana will continue to report on the status of the CCGT in the AES Indiana's next FAC filing, which will be made in December 2021.

ROOT CAUSE ANALYSIS

Q20. What is an RCA?

A20. RCA stands for Root Cause Analysis. RCA is a systematic process to identify all aspects of a system failure or identified problem. Documenting what happened, how it happened and most importantly why it happened, so that actions can be developed for preventing reoccurrences. Information is reviewed and a sequence of events is created, which are then used to lead to the origin or root of the problem being analyzed.

Q21. What is the purpose of an RCA?

A21. The purpose of an RCA is to determine the most probable cause of an event and factors, that if eliminated, would have the highest probability of preventing a reoccurrence. The RCA process allows us to learn through hindsight analysis how to improve our business on a going forward basis so we can better serve our customers. The RCA is an essential component to continuous improvement. Its purpose is distinct from a prudence review, which assesses actions based on what was known or should have been known at the time an action was taken.

Q22. Did AES Indiana conduct a root cause analysis?

A22. Yes. Immediately following the incident, AES Indiana mobilized an RCA team comprised of Holcombe Baird, Senior Reliability Consultant with Reliability Center, Inc., who was the Facilitator, Kevin Cook, Plant Manager, who was the sponsor, Brandon Berlin, Maintenance Leader, who was an Analyst and Jason Hoage, Operations Leader, who was also an Analyst. A copy of the RCA is included with my testimony as Petitioner's Attachment JB-1.

Q23. What did the RCA determine?

A23. The root cause investigation determined that the incident was caused by several different factors including physical, human, and latent. The RCA went down two paths to determine why the generator failed to synchronize with the grid and what caused the Field short to ground. The failure to synchronize with the grid was caused by the disconnected wire in the generator breaker cabinet. Investigation of the disconnected wire using the as-built wiring schematics should have determined that it was the cause of the mismatched indication and failure of the Generator to synchronize. Unfortunately, the as-built wiring schematic was incorrect, therefore, test landing it did not change the state of the incorrect generator breaker (52G Breaker) indication. The Field short was caused because the field breaker (41E Breaker) did not open when the turbine was tripped nor did it open when the 86G protective relays activated. When the protective relays were reset with the field breaker (41E Breaker) closed, the AVR energized the Field and there was not enough hydrogen flow to cool the excited Field on turning gear since the amount of circulation is driven by the rotor speed.

The physical factors were:

- The disconnected wire in the generator breaker (52G Breaker) cabinet that prevented the synchronization of the Generator.
- The AVR that sent excitation voltage and current to the Field while the unit was on turning gear.

The human factors were:

- The 86G relays were reset without a coordinated effort with operations to confirm the reason they tripped, the current state of the turbine-generator, and monitoring of conditions after they were reset.
- Loose wires with exposed conductor ends were not recognized as a questionable situation which should have been reported and corrected
- Wires in the generator breaker (52G Breaker) cabinet were not installed in accordance with OEM standards.

The latent causes were:

- The AVR logic prevented any field breaker (41E Breaker) open signal due to programmed interlocks based on a signal from an indirect contact of an auxiliary relay indicating the generator breaker was closed.
- All signals (logic and hardwired) to open the field breaker (41E Breaker) were blocked by an indirect contact off an auxiliary relay.

- Logic responded as designed to an incorrect generator breaker (52G Breaker) status indicator provided by an indirect contact off an auxiliary relay.
- Logic did not detect the conflicting indication which showed the generator breaker (52G Breaker) open in one area and closed in another.
- Incorrect generator protection control system initialization issue of the generator breaker (52G Breaker) closed while the field breaker (41E Breaker) open was not detected by personnel nor controls.
- Wiring drawing was incorrect as to the terminal that the disconnected wire should have been landed.
- Lack of a written standard operating procedure detailing personnel responsibilities and actions in response to an 86 series lockout relay trip.
- Insufficient communication and coordination amongst all onsite personnel to confirm awareness of the potentially damaging conditions presented when the field breaker (41E Breaker) remained closed as the reason for the Operations Leader’s decision for the work stoppage.

MANAGEMENT IMPLEMENTATION OF RCA RECOMMENDATIONS

Q24. What were the recommended actions of the RCA and what is AES Indiana’s status on implementing those?

A24. The recommended corrective actions are:

- Re-terminate the disconnected wire in the generator breaker (52G Breaker) cabinet using OEM recommended standards including terminal ring lugs - <u>to be completed prior to return to service.</u>

- Clean up wiring in the field breaker (41E Breaker) cabinets to remove wiring with exposed conductors and other identified deficiencies – to be completed prior to return to service.
- Establish 86 series lockout relay reset Standard Operating Procedure ("SOP") in accordance with industry best practices – SOP is being developed and will be completed prior to return to service.
- Establish operational pre-startup step to confirm agreement in status indicators for the generator (52G Breaker) and field (41E Breaker) breakers – startup procedure is in the process of being amended to include this step and will be completed prior to return to service.

In addition, the RCA recommended the following:

- Conducting an engineering review of the field breaker (41E Breaker) open signal circuit hardwired interlocks and control system interlocks for effective redundancy as well as compliance with IEEE and EPRI standards – third party review is being solicited from engineering firms.
- OEM review of the incident details to consider installing provisions in the AVR (Automatic Voltage Regulator) logic to detect and alert operators of a discrepancy in the generator (52G Breaker) and field (41E Breaker) breaker status – Toshiba is reviewing, and we are awaiting a response.
- Perform an audit of all wiring diagrams for accuracy of generator protection systems and document the findings and develop a plan to correct discrepancies – this inspection and a redline markup of the drawings is complete, and a plan to formally update the

drawings has been developed and is in progress All critical items will be completed prior to return to service.

- Implement a training program for operators and technicians specifically on the design and operation of the generator protection system, including processes for operating breakers and resetting lockout relays – training program development has been completed and training is being implemented by Technical Training Professionals, a third party who produces training materials and provides training, and is expected to be completed by plant personnel by the end of September 2021. The training program developed will be used on an on-going basis for new employees.

Q25. What is the estimated repair work cost?

A25. As of the date of this filing, repair costs are estimated to be approximately $3,683,824 in Operation & Maintenance and $3,648,900 in Capital Expenditures. These costs are not recoverable through the FAC process and therefore are not part of this FAC application.

Q26. Do you have any other comments on the event?

A26. AES Indiana strives to provide reliable service. Eagle Valley has operated as a baseload unit and has provided low-cost generation to its customers. As stated above, its historic availability and heat rate indicate solid performance prior to this outage. The RCA summarizes the event after the fact and outside of the plant environment and makes assessments in hindsight.

All plant personnel received training on the entire facility, including, specific training provided by Toshiba on the steam turbine-generator and its systems.

A disconnected wire showing the incorrect status of the generator breaker (52G Breaker) allowed for the field breaker (41E Breaker) to close and excite the Field but would not allow it to reopen after a turbine trip or when the 86G lockout relays activated. The team discovered the disconnected wire in the generator breaker (52G Breaker) cabinet. If this wire had not been disconnected, the event would not have occurred.

The as-built wiring schematic was incorrect. If it was correct, the wire would have been landed on terminal B3 instead of B4 and the issue would have been resolved.

The turbine-generator was allowed to reset with the generator breaker (52G Breaker) showing closed.

The AVR was allowed by the logic to re-eneregize the Field while the turbine-generator was on turning gear.

The RCA indicates the team used a methodical trouble shooting process, including support from external experts like Toshiba and was proceeding down a reasonable path to identify and resolve initial issues.

AES Indiana reasonably recognized the need for additional resources as well as the need for rest and thus correctly called an end to the day, which was the right and safe thing to do.

The event that ultimately caused the extended forced outage was human error in resetting the 86 Lockout Relays before a thorough investigation of why they operated, knowing the current state of the turbine-generator and monitoring conditions after they were reset. The relays should not have been reset because the field breaker (41E) was closed. If conditions were monitored after the reset, it may have been determined that the AVR was put back into service and current was flowing to the Field.

The occurrence of human error, or identification of corrective actions going forward, do not, in and of themselves, mean that AES Indiana has failed to act reasonably in providing service to its customers, given the information available at the time.

Q27. Please summarize your testimony.

A27. This event was caused by a disconnected wire that provided false indication to the control system. There are several control system issues that come into question leading up to the resetting of the 86G relays which include, not recognizing the generator breaker (52G Breaker) indicating closed prior to resetting the turbine-generator and allowing it to be reset, allowing for the field breaker (41E Breaker) to close with the generator breaker (52G Breaker) indicating closed, not allowing the field breaker (41E Breaker) to open after a turbine trip, not allowing the field breaker (41E Breaker) to open after the 86G lockout relays activated. After the 86G relays were reset, the control system should not have allowed the AVR to return to service while the unit was on turning gear.

AES Indiana is proactively implementing the RCA recommendations. While I do not claim AES Indiana acted perfectly, the improvement opportunities suggested in an RCA should not lead to a conclusion that AES Indiana acted imprudently. AES Indiana also took appropriate steps to mitigate the duration and costs of the outage. Therefore, the Commission should not disallow fuel costs incurred due to this incident. AES Indiana will further report on the status of Eagle Valley in the next FAC proceeding.

Q28. Does that conclude your prefiled direct testimony?

A28. Yes.

Verification

I, John Bigalbal, Chief Operating Officer, US Conventional Generation for AES US Services, LLC affirm under penalties for perjury that the foregoing representations are true to the best of my knowledge, information, and belief.

John R. Bigalbal

John R. Bigalbal
Dated September 17, 2021

RCA Report

STG1 Failure on Start-Up

April 25, 2021

For

AES Indiana

Eagle Valley Power Plant

Privileged & Confidential:
Attorney-Client Communication/Attorney Work Product

Analysis Title: STG1 Startup Failure
Principle Analyst: Holcombe Baird
Analysis Sponsor: Kevin Cook
Analysis Dates: May 2, 2021 - July 8, 2021
Report Date: August 20, 2021

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This Report is Issued for Client use.

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Event Summary

NOTE: *A glossary of the technical terminology used throughout this report can be found on Page 6.*

The STG steam turbine generator at AES Indiana Eagle Valley power plant underwent a planned annual maintenance outage from April 10, 2021, through April 25, 2021. On Sunday April 25th, the power plant began the startup process to return the plant back online. Shortly after 1:00pm, the STG was taken off turning gear and went through the startup process of speed increase and heat soaking stages. At 4:00pm the unit was at synchronization speed. The operators switched the control into Auto-Sync mode and Field Circuit Breaker (41E Breaker) closed. Synchronization did not happen. The SYNCHRONIZE screen indicated the Generator Circuit Breaker (52G Breaker) was open on the Turbine Status side bar and closed on the 52G OPEN/CLOSE DEMAND SYNCHRONIZE progress tracking display. Around 6:00pm, the technicians troubleshooting the problem found a disconnected jumper wire in the Generator Circuit Breaker cabinet. The wire was test-landed on terminal B4 as indicated on the wiring schematic. This did not correct the problem and no changes were observed. After phone discussions between the technicians and a Toshiba support engineer, an attempt to realign the indicators was performed with a manual trip of the turbine from the control room. At 9:00pm the manual turbine trip was initiated. When the turbine slowed down to a speed it could be reset, it was restarted. There was no change of the 52G Breaker status indication on the SYNCHRONIZE screen. Throughout the manual turbine trip, the Automatic Voltage Regulator (AVR) continued supplying volts and amps to the field, tracking with the turbine speed, and adjusting volts and amps accordingly. At 10:30pm the Operations Leader made the decision to shut down the turbine and resume the troubleshooting Monday morning, allowing people to get some rest. The manual turbine trip was initiated just before 11:00pm. Shortly after the turbine trip was initiated, the 86G1 and 86G2 Lockout Relays tripped. At that time, the field excitation voltage went to zero. The turbine coasted down and was placed on turning gear. At 11:43pm the 86G1 and 86G2 Lockout Relays were manually reset. The 86ET Lockout Relay tripped 14 minutes afterwards. No further troubleshooting was conducted.

On Monday morning, April 26th, the troubleshooting efforts resumed. Using the Toshiba wiring schematics and the internal to external cable connection diagrams, the team checked the wiring connections and I/O terminations from the Generator Circuit Breaker cabinet to the TOSMAP controller. The wiring connections and I/O terminations from the Generator Circuit Breaker cabinet to the Generator Protection Relay cabinet for the Schweizer Engineering Laboratories protective control devices (300G-SEL) were checked. The wiring connections and I/O terminations from the Generator Circuit Breaker cabinet to the Field Circuit Breaker cabinet were also checked. From these checks it was decided to connect a test wire between terminals 7 and 9 in the Field Circuit Breaker cabinet for the 52GX1 Relay RESET coil, the electrical equivalent of connecting terminals B3 and B10 in the Generator Circuit Breaker cabinet. Upon doing so, the 52G Breaker status indication reset. It was also determined the Ground Protective Relays (64F1 and 64F2 Relays) had activated, indicating a resistance to ground less than 1,000 ohms within the field. Toshiba's technician was consulted and replied this was a normal response for turbine trip shutdown events.

Review of the trend data revealed the AVR had resumed sending excitation voltage to the field when the 86G1 and 86G2 Lockout Relays were reset, even though the turbine was on turning gear. The level of current sent to the field by the AVR was shown to be around 1,760 amps, spiking to 2,700 amps as the excitation voltage dropped off. A 500-volt Meggar resistance reading confirmed the field had a dead short to ground indicating damage to the field, rendering the generator inoperable.

Executive Overview of Findings

The Root Cause Analysis (RCA) investigation studied Toshiba's electrical schematic drawings, Toshiba's Functional Block Logic Diagrams, ABB generator breaker drawings, CB&I interconnection diagrams and historical data trends to determine how the steam turbine-generator (STG) protection and controls system functioned during the STG start-up on April 25, 2021. The analysis was broken into two separate investigative efforts. First, why the STG unit failed to Synchronize to the power grid. And second, what caused the physical damage to the field indicated by the internal short to ground. The RCA Logic Tree's Top Box, or problem definition, reflected these two investigative paths. (Refer to the PROACT® Logic Tree Top Box in the Logic Tree section of this report.)

The investigation into the STG failure to synchronize reviewed the troubleshooting efforts on April 25th and 26th. Using the Toshiba wiring schematics and CB&I connection schedules it was determined the operator display screen receives signals from two different sources. The lower left indication comes from a 52a auxiliary contact mechanically linked to the 52G Breaker mechanism. The OPS SYNCHRONIZE screen display receives its indication signal through software logic in the AVR microprocessor from contacts in the 52GX1 Relay, an auxiliary latching relay located in the Field Circuit Breaker cabinet. The indirect signal provided by the 52GX1 Relay was providing an incorrect indication as it did not receive a signal to the RESET coil based on the real status of the 52G Breaker. The investigation then focused on the disconnected wire found in the Generator Circuit Breaker cabinet. When a temporary wire was test connected between terminals 7 and 9 in the Field Circuit Breaker cabinet during the troubleshooting on Monday April 26th, the 41E Breaker opened and the 52G Breaker status indications matched on the OPS SYNCHRONIZE screen. On May 4, 2021, field confirmation was performed by test connecting the loose yellow jumper wire to terminal B3 in the Generator Circuit Breaker cabinet. The RESET coil of the 52GX1 Relay activated in the same manner as observed during the troubleshooting on April 26, 2021.

The RCA investigative review of the AES technicians' troubleshooting efforts concluded the technicians with the assistance of Toshiba's engineers were on the correct path towards resolving the problem preventing the synchronization to the grid. Their efforts were stymied by the incorrect indication on the wiring interconnection drawings showing the jumper wire to be connected between terminals B10 and B4. The investigation's detailed review of the drawings combined with field testing determined the correct termination of the jumper wire is to be between terminals B10 and B3. How the jumper wire became disconnected remains undetermined. Consideration was given to it being intentionally disconnected, accidentally disconnected, or simply loosened and disconnected over time on its own. (Refer to Hypotheses for jumper wire becoming disconnected in the Logic Tree section) With only a statement from the ABB service technician who observed the wire was disconnected when he began his work to test the 52G Breaker, any explanation for the wire disconnection is inconclusive.

A review of the historical trend data for the manual turbine trip on April 10th in preparation for the annual maintenance outage concluded the 41E Breaker and 52G Breaker functioned normally on shutdown. After the testing of the 52G Breaker, power was restored to the AVR cabinet, restoring the fiber optics communications to the TOSMAP. The trending data for the 52G Breaker status indication signal showed its value was high, indicating a closed status. This indicated the wire disconnection occurred sometime between the manual turbine trip on April 10th and the restoring to the communication on April 22nd. A reenactment to duplicate the 52G Breaker testing operations performed during the outage was performed on June 21st and 22nd. The development and execution of the reenactment utilized subject matter experts from Toshiba and AES as well as the team of onsite technicians and operators. The main objective was to determine if disconnecting the wire was necessary to perform the 52G Breaker testing. The reenactment was also performed to determine if the 41E Breaker could be operated to open when the wire was disconnected. The conclusion of the reenactment was the functionality of the protection controls system, including the correct indication of

52G Breaker status and the opening of the 41E Breaker, required the wire to be terminated between the B3 and B10 terminals. Therefore, the wire had to be connected when the STG was shut down on April 10th.

The disconnected wire was determined to be the reason the STG would not Synchronize to the grid. The controls system software logic was reacting properly as it had closed the 41E Breaker as the first step of the auto-synchronize operation and it had indications the 52G Breaker was closed. There was no need to send a close command to the 52G Breaker, the final step in the Synchronize operation.

The investigation into the short to ground failure of the generator field revealed physical damage to the copper conductors in the generator field. This damage was due to the exposure of the field to excitation current without the benefit of hydrogen flow cooling as the field was not rotating at operational speed.

When the 86G1 and 86G2 Lockouts were manually reset at 11:43pm Sunday evening, the conditions for the AVR to send excitation voltage to the field were met, the 5A Breaker for the Excitation transformer was closed, the 41E Breaker was closed, and there was demand for current based on indication the 52G Breaker was closed, and the exciter controls thought the generator was connected to the power grid. The AVR increased excitation voltage to produce terminal voltage. As the excitation voltage climbed, the insulation between the copper conductors began to breakdown, destabilizing the current through the conductors. This was recorded by the 64F1 and 64F2 Relays as they indicated a fault to ground in the field. As the current increased, the temperature of the copper material increased until melting occurred. Finally, the 86ET Lockout tripped when it detected abnormal conditions in the excitation transformer, sending a signal to open the 5A Breaker which stopped the electrical flow through the 41E Breaker to the field.

Interviews with the operators and technicians revealed it is current practice for the technicians to reset a tripped 86 Series Lockout after a presumed cause has been identified. If the Lockout Relay does not re-trip, the STG is returned into operation. If the reset 86 Series Lockout does re-trip, further investigation is then performed to identify and resolve the source initiating the trip. On April 25th, a coordinated investigative effort between the operators and the technicians into the reason for the 86G1 and 86G2 Lockout trips did not take place. As a result, the potentially damaging conditions presented when the 41E Breaker remained closed was not considered prior to resetting the tripped 86G1 and 86G2 Lockouts. Nor were the system conditions monitored after the protection circuits were re-energized when the 86G1 and 86G2 Lockouts were reset.

Glossary of Report Terminology

The generator control system is an integrated arrangement of electrical devices, microprocessors, wiring interconnections, and logic configured to manage the operation for power generation while providing protection to personnel, the power grid, and asset equipment. The following glossary is provided to aid the reader's understanding of the RCA findings by standardizing the terminology used within the report to describe the investigation finds on the complex functionality of the generator control system. A simplistic diagram of generator protection and control components is provided in the Supporting Figures section. (Refer to Figure 1)

AVR: is the abbreviation for **A**utomatic **V**oltage **R**egulator which controls the voltage of the generator to match the requirement of the power grid.
Breaker: Often referred to as a circuit breaker, is an automatic device for stopping the flow of current in an electric circuit as a safety measure to protect an electrical device.
Contacts: are switches within a Breaker or Relay used to provide or interrupt the flow of electrical current signals based on the status of the Breaker or Relay to which they are mechanically connected.
Direct Contacts: for the purpose of this RCA report, the term is used for contacts which provide live status representation of a breaker status by being mechanically connected to the breaker.
EHC: is the abbreviation for digital **E**lectro-**H**ydraulic **C**ontroller which provides the operational control of the steam turbine, including start-up, shutdown, speed regulation and power generation.
Indirect Contacts: for the purpose of this RCA report, the term is used for contacts of an auxiliary latching relay controlled through Direct Contacts to provide additional status contacts within a Relay Logic schemes.
I/O: **I**nput and **O**utput points of interface connection to the microprocessor where the microprocessor Software Logic receives or transmits signals with the hardwired Relay Logic.
Latching Relay: an electrical device incorporating two electromagnet coils, which is put into a Set condition by a current or signal from a circuit to the first electromagnetic coil. It is held in that state until it is put into a Reset condition by a current or signal from another circuit to the second electromagnetic coil.
Lockout Relay: is an electrically Tripped, commonly referred to as Rolled, hand reset relay device that functions to shut down and hold an equipment out of service, upon the occurrence of abnormal conditions. The Lockout Relay needs to be reset through a mechanical lever attached to the relay by the operator/engineer before they can go ahead and energize the circuit. This is a time-tested way of checking that the operator/engineer has consciously made the decision to energize the circuit after duly investigating the cause of trip.
LOTO: is the abbreviation for **L**ock **O**ut – **T**ag **O**ut, a safety related process for the protection of personnel to ensure the equipment being worked on remains in a zero-energy state through the isolation of electrical, hydraulic, pneumatic, kinetic, and potential energy sources.
N/C: abbreviation for normally closed contact which allows flow of electrical signal when the device is in its non-activated state.
N/O: abbreviation for normally open contact which prevents flow of electrical signal when the device is in its non-activated state.
OPS: is the abbreviation for the **OP**eration **S**ystem which provides the human machine interface for the operators, including the display consoles and data trending functions.
Relay: an electrical device, typically incorporating an electromagnet, which is activated by a current or signal in one circuit to open or close another circuit.
Relay Logic: interlock control with hardwired relays
Reset: returning a Tripped circuit breaker to its operational state, allowing current to flow to the device being protected. The same term also applies to changing a Latching Relay from its Set condition and a Lockout Relay from its Tripped and locked out condition.
Software Logic: interlock controls using microprocessor programming.

SWYD: is the abbreviation for Switchyard, specifically for this RCA, the 52G Breaker and the Generator Circuit Breaker cabinet.

Synchronize: the process of connecting the generator to the power grid. The process requires the parameters of the power produced by the generator match the parameters of the power grid, including voltage, frequency, phase sequence and phase angle.

TOSMAP: is the abbreviation for **TOS**hiba **M**icroprocessor **A**ided **P**ower system control, which is the combination of various sophisticated devices providing the overall control of the steam turbine generator including the EHC, AVR and OPS.

Trip: is when a circuit has detected a fault condition and has shut itself off by activating the associated circuit breaker to prevent damage to electrical component of equipment being protected.
Lock out roll as a rotational aspect of the handle when tripped and to reset.

Function 24: is a control device monitoring the Volts per Hertz (VPFL or V/F Limiter) within the 300G-SEL device. Its function limits over voltage per hertz of the generator and the main step-up generator transformer.

300G-SEL: are the Schweizer Engineering Laboratories control devices which monitors numerous parameters for generator power quality and condition. The two units provide redundancy to trigger protective responses through the Tripping of the 86G1, 86G2, 86ET, 86AE1, 86AE2 and 86BF Lockout Relays.

41E Breaker: also called the FCB, Field Circuit Breaker, is a device that functions to apply or interrupt the field excitation to the generator. (Refer to Photograph 2)

41TP Coil: is the electromagnetic coil to trigger a trip of the 41E Breaker.

5A Breaker: is a 4,160 volt protective device used to shut down power to the excitation transformer provided through the 41E Breaker.

52G Breaker: also called the GCB, Generator Circuit breaker, is device that is used to close and interrupt an a-c power circuit between the power gid and the generator under normal conditions or to interrupt this circuit under fault or emergency conditions. (Refer to Photograph 1)

52GX1 Relay: is an auxiliary Latching Relay to provide indirect status of the 52G Breaker.

64F1 and 64F2 Relays: or the Ground Protective Relays, are relays which actuate on failure of the insulation of the generator field, allowing current to short circuit to ground.

86G1 and 86G2 Lockouts: are 86 Series Lockout Relays which function to shut down and hold the STG equipment out of service upon the occurrence of abnormal generator conditions.

86ET Lockout: is an 86 Series Lockout Relay which functions to shut down and hold turbine and generator equipment out of service upon the occurrence of abnormal excitation transformer conditions.

The following is a listing of the root causes identified in this RCA investigation:

Identified Root Causes

Title	Node Type
Jumper wire became disconnected from terminal	Physical Root
AVR sent excitation voltage and current to field while turbine on turning gear	Physical Root
86G1 and 86G2 Lockouts were reset without a coordinated effort with operations to confirm the reason they tripped and then monitor the conditions after they were reset	Human Root
Loose wires with exposed conductive ends not recognized as a questionable situation which should be reported for resolution	Human Root
Jumper wire in STG Generator Circuit Breaker cabinet not installed in accordance with OEM standards	Human Root
Toshiba AVR logic prevented any 41E Breaker Open signal due to programed interlocks based on signal from 52GX1 Relay indicating 52G Breaker status as Closed	Latent Root
All signals (Logic and Hardwired) to Open 41E Breaker were blocked by the 52GX1 Relay N/C contact, a Toshiba designed hardwired interlock	Latent Root
TOSMAP responded as designed to an incorrect 52G Breaker status indicator as it had no means to verify the accuracy of the indirect 52G Breaker status indication provided through the 52GX1 Relay	Latent Root
TOSMAP logic did not detect different status indications displayed on the OPS for 52G Breaker by the AVR and by the EHC microprocessors	Latent Root
Incorrect Generator Protection Control system initialization issue of 52G Breaker Close indication with 41E Breaker Open not recognized by personnel nor TOSMAP controls	Latent Root
Wiring connection drawing was incorrect, showed jumper wire connecting between terminals B4 and B10	Latent Root
Lack of a written Standard Operating Procedure detailing personnel responsibilities and actions in response to an 86 Series Lockout Relay trip	Latent Root
Insufficient communication and coordination amongst all onsite personnel to confirm awareness of the potentially damaging conditions presented when the 41E Breaker remained closed as the reason for the Operations Leader's decision for the work stoppage	Latent Root

The following is a listing of deficiencies uncovered during this RCA investigation but not a root cause:

Observations from the Analysis Process

Title
The OEM drawings from Toshiba were challenging to follow. Without guidance, or an explanation on the linking references, it was difficult to determine the inter-relationship between wiring schematics and Logic Functional Block diagrams. Understanding the connection between the Toshiba wiring schematics and the ABB wiring schematics required the field wiring cable termination drawings supplied by CB&I. Blank boxes were used on the Toshiba drawings designate connections to devices out of the Toshiba scope of supply. This makes troubleshooting and failure investigations time consuming.

Summary Listing of Actions and Recommendations

Immediate Corrective Actions

A. Action: Re-terminate B3 to B10 jumper wire using OEM recommended standards, including terminal ring lugs. *(Eliminate)*

B. Action: Clean up wiring in Field Breaker Cabinets to remove wiring with exposed conductors. *(Minimize Impact)*

C. Action: Establish 86 series lockout reset Standard Operating Procedure in accordance with industry best practices. *(Eliminate)*

D. Action: Establish operational pre-startup step to confirm agreement in status indicators of 52G and 41E breakers. *(Detect/Prevent)*

RCA Based Recommendations

I. Recommendation: Conduct an independent engineering review of 41E Open Signal Circuit hardwired interlocks and TOSMAP programming interlocks for effective redundancy as well as compliance with IEEE and EPRI standards.

II. Recommendation: Have Toshiba review incident details and consider installing provisions in the AVR logic to detect and alert operators of discrepancy in 52G and 41E Breaker status indications.

III. Recommendation: Perform audit of all wiring diagrams for accuracy of generator protection systems. Document the findings and develop plan to correct discrepancies.

IV. Recommendation: Implement a training program for Operators and Technicians specifically on the design and operation of the Generator Protection System, including processes for operating breakers and resetting of lockout relays.

Detailed Description of Findings

The RCA incident investigation into the generator failure was broken into two failure events, the failure for the STG to synchronize to the grid and the damage to the generator field. The findings of each event are detailed below.

STG Failure to Synchronize with Grid

The RCA investigation into the STG failure to synchronize to the grid began with a review of the historical data trends of signals for 41E Breaker, 52G Breaker, turbine speed, turbine trip, generator parameters and fault signals to understand the sequence of events on April 25th. (Refer to Figure 2)

The trends showed a normal startup of the steam turbine, progressing through pre-programmed heat soak cycles until it reached a speed of 3,600 rpm. At that time, the Auto- Synchronize sequence was initiated. The 41E Breaker changed status from Open to Closed. (Refer to Figure 4) The operator's SYNCHRONIZE display screen indicated the 52G Breaker status as closed while showing 52G Breaker as open on the status menu at the lower left of the screen. (Refer to Figure 3) When the manual Turbine Trip was initiated, the operator display screen indicated a turbine trip on the lower left status menu while 41E Breaker indicated as remaining closed. (Refer to Figure 5) When the second manual Turbine Trip was initiated the same results as previous trip were recorded; however, the 86G1 and 86G2 Lockouts tripped. (Refer to Figure 7) The review of the trend data also noticed the indication signal on the SYNCHRONIZE display screen was indicating the 52G Breaker was Closed when the startup sequence was initiated. Using earlier data trend, it was determined the signal had been showing a 52G Breaker Open status before the 52G Breaker testing during the outage. The signal was lost when the outage LOTO isolated the power to the AVR cabinet. When the power was restored, the signal was indicating the 52G Breaker was Closed. The 52G Breaker status signal remained showing Closed until a test wire was connected between terminals 7 and 9 in the Field Circuit Breaker cabinet for the 52GX1 Relay. (Refer to Figure 9)

The RCA investigation reviewed the findings from the AES onsite technicians' troubleshooting efforts of April 25th. Their efforts involved tracing the source of the Input for the operator display output of the 52G Breaker status through the Toshiba logic, and back to the 52GX1 Relay. The 52GX1 Relay was not activating the RESET Coil to send the 52G Breaker Open status signal. They traced the activation source for the 52GX1 Relay RESET coil to terminal B10 in the Generator Circuit Breaker cabinet. It was then the technicians found a yellow wire hanging loose and attached to terminal B10. (Refer to Photograph 3) The construction wiring connection drawings showed a jumper wire connection between B10 and B4. (Refer to Figure 10) The loose end of the yellow wire was test landed to terminal B4 but there was no change in the display status on the SYNCHRONIZE Operation screen. The troubleshooting effort continued but made no further progress.

When the test wire was connected across terminals 7 and 9 in the Field Circuit Breaker cabinet, the 52GX1 Relay RESET Coil activated and the display showed 52G Breaker as Open status in agreement with the lower left status display. The 41E Breaker also opened at that time. The troubleshooting efforts also determined the source of the 86G1 and 86G2 Lockout trips came from the Function 24 protection device providing a voltage/hertz fault signal to the 300G-SEL protection monitor. The voltage/hertz ratio exceeded the 105% limit when the turbine slowed to a speed where the AVR was unable to maintain a permissible terminal voltage to speed ratio.

Not until the following week, after an in-depth electrical engineering review of the various wiring diagrams, was it determined the correct connections for the loose yellow jumper wire in the Generator Circuit Breaker cabinet should have been between terminal B10 and B3.

The RCA team also examined the Toshiba wiring diagrams, the ABB wiring diagrams, the CB&I wire interconnection drawings and the Toshiba block logic diagrams to understand the control logic and signaling circuitry related to the status indications of the 52G Breaker. They also received technical input from a team of Toshiba controls experts.

The AVR receives its 52G Breaker status indication through contacts on the 52GX1 Relay. (Refer to Figure 12) The TOSMAP I/O input KI0004 receives a signal from the N/O contact of the 52GX1 Relay for an indication the 52G Breaker is Closed. The TOSMAP I/O input KI0005 receives a signal from the N/C contact of the 52GX1 Relay for an indication the 52G Breaker is Opened. (Refer to Figure 13) The 52GX1 Relay is a latching relay. It receives SET and RESET signals from mechanically actuated contacts on the 52G Breaker. (Refer to Figure 11) The SET signal is through N/O contact to indicate the 52G Breaker Closed and the RESET signal is through N/C contact to indicate 52G Breaker is Open. (Refer to Figure 9) The jumper wire between Terminals B10 and B3 is there to provide the positive source connection to the N/C contacts of the 52G Breaker. (Highlighted in Yellow on Figure 9) The yellow jumper wire was incorrectly shown connecting terminals B10 to B4 on the CB&I interconnecting cable drawings. (Refer to Figure 10) The drawing is incorrect as proven through understanding the wiring circuitry as this connection would not complete the circuit from the positive to negative sources.

The RCA team findings confirmed the technicians' findings during the April 26th troubleshooting efforts. The RCA team findings were further confirmed through field verification of the wiring connections and an operation test of the 52GX1 Relay while monitoring the corresponding TOSMAP inputs.

While performing the field verification, the RCA team discovered several discrepancies between the documentation and what was observed physically in place. They also found some incidents where the installation did not adhere to best practices for a reliable electrical protection control system. Two examples of conditions found were insulated ring lugs not used on CT sensor connecting circuits, and incorrect rated wire type was used for jumper connections between terminals. The issues were documented and reported to the site management team.

The RCA investigation also investigated the causes for the 41E Breaker failure to open when the manual Turbine trip was initiated. There are three sources for signals to open the 41E Breaker: 1) The hardwired 86 Series Lockouts, 2) the Turbine Trip from processor logic monitoring process related conditions, including the Manual Trip push button, and 3) a 41E Open Demand signal initiated by the AVR. (Refer to Figure 14) All three of these signals are interlocked through a N/C contact of the 52GX1 Relay. When the 52GX1 Relay is latched in the SET position (52G Breaker closed status) the N/C contact is open, preventing the signals to open the 41E Breaker from reaching the 41TP coil which opens the 41E Breaker. As a result of the 52GX1 Relay not receiving a RESET signal, the AVR did not send a 41E Open Demand signal. In addition, the hardwired signals to open the 41E Breaker from the 86G1, 86G2 and 86ET Lockouts as well as the Turbine Trip were all blocked from activating the 41TP coil. (Refer to Figure 14 and Figure 15) There was no way for the 41E Breaker to receive a signal to open. The RCA investigation determined the 41E Breaker Open signal from the 86 Series Lockouts and the Turbine Trip signals to open the 41E Breaker utilize 52G Breaker status indications using Direct Contacts on the 52G Breaker. The AVR, on the other hand, uses the Indirect Contact signals from the 52GX1 Relay in its logic to initiate the signal to open the 41E Breaker.

The RCA Team findings confirmed the disconnected wire was the reason behind the failure to complete the Synchronization to the grid. The RCA team hypothesized how and why the yellow jumper wire could have become disconnected. (Refer to Hypotheses for jumper wire becoming disconnected in the Logic Tree section of this report) The hypotheses can be grouped into three general categories: an intentional action, an accidental action, or an independent action. In verifying a need to disconnect the jumper to perform the testing operations of the 52G Relay, the ABB technician and the AES technicians stated they did not need to disconnect the yellow jumper wire to perform their respective testing. The ABB technician stated he observed the yellow jumper wire was disconnected when he started his work in the Generator Circuit Breaker cabinet on April 16, 2021. His observation was not reported until he was interviewed as part of the RCA investigation. Inside the Generator Circuit Breaker cabinet on the left wall near the yellow jumper wire, there was another jumper wire with one end disconnected. (Refer to Photograph 5) This jumper had the crimped-on ring lug. Exposed, bare conductors should be called out as a safety hazard from possible electric shock. On the right side of rear panel there were several wires landed without crimp-on ring lugs. (Refer to Photograph 6) The wires may have been left behind from where instrumentation was attached during commissioning. These issues seem to project a message such conditions are not important or even normal. This is supported by the fact the loose end of the yellow jumper wire was not recognized as an issue to be reported and properly addressed.

As for the possibility the wire could have been accidentally touched or knocked loose, the investigation considered any activities requiring access inside the Generator Circuit Breaker cabinet. The Generator Circuit Breaker cabinet is not accessed as part of normal operations. The investigation focused on the outage timeframe when work activities were performed requiring access into the Generator Circuit Breaker cabinet. The LOTO activities for the outage, the ABB 52G Breaker testing and the AES Relay Team testing activities were determined not to have been in the immediate proximity of the jumper wire. As such, it would be extremely unlikely these activities impacted the yellow jumper wire. With no one admitting to disconnecting or altering the jumper wire, the RCA team considered the possibility the jumper wire was never connected or became disconnected prior to the outage beginning April 10, 2021.

To provide the verifications needed, the RCA team conducted a reenactment on the outage activities for the testing of the 52G Breaker. The protocol steps tested the equipment response to trips of the 52G Breaker both with the yellow jumper wire in place, and with it disconnected. The operation of the 52GX1 Relay and the status displayed on the operator's screen were tracked for each iteration of the reenactment protocol. The 41E Breaker was forced closed and the same protocol steps repeated. This was done to confirm there was no other signal path to open the 41E Breaker. With the findings of the reenactment, it was determined the yellow jumper wire needed to be connected to terminals B10 and B3 for the controls to function properly. The yellow jumper wire had to be in place when the STG was shut down on April 10, 2021. Trend data from the Turbine Trip on April 10, 2021, show the 41E Breaker opened when the Turbine Trip was initiated. (Refer to Figure 8) The trend also shows there was no trip of the 86G1 Lockout, indicating the shutdown process worked as designed. This meant the yellow jumper wire became disconnected sometime between the turbine shutdown on April 10, 2021, and April 16, 2021, the date the ABB technician accessed the cabinet and reportedly observed the wire was disconnected. It is extremely unlikely to ever determine how or why the jumper wire became disconnected.

The reenactment also confirmed the AVR uses only the 52G Breaker status signals from the 52GX1 Relay in its software logic. The AVR software logic will not initiate a 41E Breaker open signal when the 52G Breaker is closed. Doing so would be an operational condition which could damage the generator field and possibly the steam turbine. The TOSMAP systems, in this case the AVR, did not send an Open Demand signal, I/O output KO004, to the 41TP coil nor give any indications of an abnormal condition through the activation of the 41E Open Failure, I/O output KO0002, because of the jumper wire being disconnected.

With the 41E Breaker closed, the 52GX1 Relay indicating a 52G Breaker Closed condition, and the 5A Breaker for the excitation transformer closed, there was nothing to prevent the AVR from sending excitation voltage to the field when the 86G1 and 86G2 Lockouts were reset after the shutdown of the STG turbine.

The onsite technicians and the ABB technician reported the Generator Circuit Breaker cabinets for the STG, GT-1 and GT-2 are each wired differently. A visual inspection of GT-1 and GT-2 confirmed the wiring is visually different for the termination positions B1-B10. The jumper wires are installed with short wire runs and terminated with insulated ring style crimped on lugs. (Refer to Photograph 7 and Photograph 8) A review of the wiring schematics revealed both GT-1 and GT-2 use one contact of their corresponding 52G Breaker versus the two contacts used for the STG interface between its 52G Breaker and AVR.

As a plausible explanation for the difference in the jumper wire connection in the STG Generator Circuit Breaker cabinet, the following should be considered. Initially, the STG wiring connections between the Generator Circuit Breaker cabinet and the Field Circuit Breaker cabinet were designed using one set of contacts from the 52G Breaker. A second set of contacts was required for the Toshiba interlock controls design using a latching relay, 52GX1 Relay, requiring separate SET and RESET signals from the 52G Breaker. A drawing revision was made which is identified by the clouded revision #2 on the CB&I wiring connection drawing, where the wires were added. (Refer to Figure 10) An additional wire between the Generator Circuit Breaker cabinet and the Field Circuit Breaker cabinet added to terminal B9 in the Generator Circuit Breaker cabinet, and a jumper was added between Terminal B10 and B4. When the RESET of 52GX1 Relay did not function, the installers realized the jumper wire needed to be connected between terminals B10 and B3 to complete the circuit for the RESET coil of 52GX1 Relay. The originally installed B10 to B4 jumper was too short to make the connection to B3. The installation contractor found a piece of scrap yellow wire in the cabinet and used it to reroute the jumper wire. (Refer to Photograph 4) In the turnover process to the owner, the schematics were not updated to indicate the change and the temporary jumper wire was not replaced to comply with OEM standards. It is also worth considering the jumper wire loosened on its own. The yellow jumper wire was installed without crimped on ring lugs. The use of ring lugs provides a greater assurance for a connection to remain tight. Without the ring lugs, vibrations from the opening and closing of the 52G Breaker could have worked the bare strands of the yellow jumper wire loose from the terminal screw.

Toshiba's use of a latching relay, the52GX1 Relay, for both the hard wired 52GX1 Relay N/C interlock contact to the 41TP Coil and the AVR Software Logic is questionable. Had the AVR used a live indication of the 52G Breaker status, the Software Logic would have sent a signal to open the 41E Breaker. Then when the 41E Breaker failed to open, the 41E Open Failure alarm would have indicated a problem and prevented the opening the 41E Breaker with the N/C contact. (Refer to Figure 14) Plus, during the startup on April 25th, the AVR would have recognized several conditions requiring the 41E Breaker to be opened. There are 25 Location in AVR Software Logic where the 52G Breaker Closed signal from 52GX1 Relay is used in the AVR Software Logic.

The RCA investigation reviewed the operator's display screen used during the STG start up. The desire was to determine if and how the operators could have detected a problem when starting the STG. When the operators started the STG, they used the ST AUTOMATIC START-UP screen. (Refer to Photograph 9) The only status indication is provided on the side status bar at the lower left. They showed normal, Turbine Reset (Green), 86G Reset (Green), 52G Opened (Green), and 41E Opened (Green). When the Synchronize ready indication block turned yellow, the operators opened the SYNCHRONIZE screen to initiate the auto-synchronize sequence. (Refer to Photograph 10) The 41E closed but 52G Breaker did not close. The status indications on the lower left showed Turbine Reset (Green), 86G Reset (Green), 52G Opened (Green), and 41E Closed (Red). (Refer to Figure 3) It was then they noticed the 52G Breaker status discrepancy between the lower left and status indications on synchronize sequence progress display. When the manual Turbine Trip was initiated, the lower left status indications showed Turbine Trip (Red), 86G Reset (Green), 52G Open (Green) and 41E Closed (Red). (Refer to Figure 6) This is an abnormal response to a Turbine Trip. When the second Turbine Trip was initiated to shut down the STG, the status indications on the lower left showed a Turbine Trip (Red), 86G Trip (Red), 52G Open (Green) and 41E Closed (Red). This indicated an even more serious problem as the 86G Lockout relay indicated tripped status. The discrepancy between the 52G Breaker status from the 52GX1 Relay signals and the 52G Breaker direct contacts would have also been observed on the GENERATOR OPERATION screen which is provided to monitor the generator controls. (Refer to Photograph 11)

It is important to mention, the 41E Breaker status indication signal to the AVR software logic also uses a latching relay with SET and RESET coils for the 41EX1 Relay. (Refer to Figure 16) The same indication discrepancy which happened with 52G Breaker is possible for the 41E Beaker. The connections between the 41E Breaker direct contacts and the 41EX1 Relay indirect contacts are in the Field Circuit Breaker cabinet. (Refer to Figure 17) The wiring terminations are all Toshiba OEM design and were factory assembled by Toshiba. The RCA investigation inspected the wiring terminations and found they were installed using insulated ring style crimped on lugs.

Conclusion:

The disconnected yellow jumper wire was determined to be the fundamental reason the STG would not Synchronize to the grid. The controls system software logic was reacting as designed; it had closed the 41E Breaker as the first step of the auto-synchronize sequence and it had indications the 52G Breaker was already closed. As such, the AVR Software Logic would not send a signal to close the 52G Breaker, finalizing the auto-synchronize sequence. The AVR software logic is not designed to detect any discrepancy in the 52G Breaker status indications provided by indirect signals from the 52GX1 Relay contacts versus the indication signal provided by the direct or live signals from the 52G Breaker contacts.

The RCA investigation reviewed the trend data from the time the 86G1 and 86G2 Lockout relays were reset until the 86ET Lockout Relay tripped. (Refer to Figure 18) Once the Lockout relays were reset, the AVR was responding to generate voltage to the grid as the input signals indicated both the 52G Breaker and 41E Breakers were closed. (Refer to Figure 19) When the generator terminal voltage remained low, the AVR continued to increase voltage, thereby increasing the current through the field. The level of current sent to the field by the AVR was shown to be around 1,760 amps, spiking to 2,700 amps as the excitation voltage dropped off. As the excitation current flowed through the field, the resistance of the copper components created heat. The steam turbine was rotating on Turning Gear which is too slow for the rotational induced air flow to provide effective cooling of the field. The buildup of heat increased as the resistance of copper increases with temperature increases. Finally, the insulation broke down and short circuiting began. The voltage dropped as the current went unstable due to short circuiting. As the AVR continued feeding the field excitation voltage, the transformer could no longer maintain voltage as the current to ground increased. The 64F1 and 64F2 fault to ground sent signals. Then the 86ET Relay tripped when the excitation transformer parameters exceeded acceptable levels. The trip of the 86ET Lockout opened the 5A breaker powering the excitation transformer, ending the flow of excitation voltage to the field. (Refer to Figure 20)

Physical examination of the generator internals discovered splattering of molten copper. Further disassembly uncovered melted copper conductors. The damage to the field required its removal for repairs off site.

When the decision was made by the Operations Leader to shut the unit down, he expected a complete work standdown for the STG unit. He requested the technicians to address a valve issue on the CT1 unit. When the technicians went to work on the CT1 unit, their path took them through the STG unit where they reset the tripped 86G1 and 86G2 Lockouts. This action was not coordinated with the operators nor the Operations Leader.

Interviews with Eagle Valley technicians about resetting 86 series Lockouts found it was standard practice for them to take responsibility for investigating and resetting a tripped 86 Lockout. Once reset, if the Lockout did not trip immediately, everything was assumed to be OK as the initiating faults were cleared. If the Lockout immediately tripped again, the technicians would investigate further.

Interviews with the Eagle Valley operators about handling 86 series Lockouts found they were somewhat unclear on what was expected. The 86 Lockout trips are listed on a large display screen with any other alarms for the whole plant. For them, it was basically the duty of the technicians to handle the 86 Lockout trips.

The Toshiba Operator Training Manual provides the following operator instructions when an 86 Series Lockout relay is operated trip:

1) *Check turbine trip operation.*
2) *See that the generator breaker 52G and field breaker 41E are turned OFF. When 52G is not turned OFF, see that the 52L is turned OFF.*
3) *Check that the MSV, MCV, RSV ICV, LPSV, LPCV are fully closed.*

The status of Turbine Trip, 86G Trip, 52G Breaker, 41E Breaker are presented in the lower left corner on all the Toshiba Operator displays screens. When an 86 Series Lockout trips, the display screens provide the operator with information to assess the status of the protective devices in compliance with Toshiba's instructions.

The practice of resetting a tripped Lockout without a coordinated investigative effort amongst the operators and technicians is poor practice. The investigative effort must not be limited to a confirmation any conditions which can create an 86 Series Lockout trip have cleared. The effort must identify a presumed cause for the current trip event and provide monitoring to ensure no further problems happen once the tripped Lockout is reset. The 86 Series Lockouts are physically located in an electrical room some distance away from the operator control center. (Refer to Photograph 12) Positioned in the same cabinet are the two 300G-SEL device panels which provide insight into the control faults that trip the 86 Series Lockouts. (Refer to Photograph 13) The action of resetting a tripped 86 Series Lockout should require not only physical actions but a conscious, informed decision to energize the circuit. This decision must be based on knowledge of the protection controls system and the information provided by the displays to understand the cause for the trip.

Conclusion:

The lack of a coordinated investigative effort between the operators and technicians into the reason for the 86G1 and 86G2 Lockouts trip failed to provide complete situational awareness to both operators and technicians. No actions were taken to monitor potentially damaging conditions when the circuits were energized while the 41E Breaker remained closed after the manual Turbine Trip. When the 86G1 and 86G2 Lockouts were reset, the AVR sent excitation voltage to the field while it was at the slow turning gear speed, thereby damaging the field’s copper conductors.

Detailed Recommendations

I. **Recommendation:** Conduct an independent engineering review of 41E Breaker Open Signal Circuit hardwired interlocks and TOSMAP programming interlocks for effective redundancy as well as compliance with IEEE and EPRI standards.

Latent Root Causes Addressed:

- Toshiba AVR logic prevented any 41E Breaker Open signal due to programed interlocks based on signal from 52GX1 Relay indicating 52G Breaker status as Closed.
- All signals (Logic and Hardwired) to Open 41E Breaker were blocked by the 52GX1 Relay N/C contact, a Toshiba designed hardwired interlock.

Details:

It is recommended for Eagle Valley to undertake an engineering review of the Toshiba design for the relay and software logic utilized for the generator protection controls. The RCA determined when the 52GX1 Relay was unable to receive a RESET signal, it prevented the AVR from activating its generator protection steps. The AVR software logic uses the 52G Breaker Closed signal from the 52GX1 Relay in 25 locations. In addition to the software logic in the AVR, there is hardwired relay logic using a N/C contact of the 52GX1 Relay to prevent the opening of the 41E Breaker, regardless of the signal source, including a Turbine Trip, a 41E Trip Demand from the 86 Series Lockouts or from the AVR. The use of indirect status signals from a remote latching relay in the AVR software logic, versus using direct or live status indication signals should be analyzed for accuracy, reliability, and redundancy.

II. **Recommendation:** Have Toshiba review incident details and consider installing provisions in the AVR logic to detect and alert operators of discrepancy in 52G Breaker and 41E Breaker status indications.

Latent Root Causes Addressed:

- TOSMAP responded as designed to an incorrect 52G Breaker status indicator as it had no means to verify the accuracy of the indirect 52G Breaker status indication provided through the 52GX1 Relay.
- TOSMAP logic did not detect different status indications displayed on the OPS for 52G Breaker by the AVR and by the EHC microprocessors.
- Incorrect Generator Protection Control system initialization issue of 52G Breaker Close indication with 41E Breaker Open not recognized by personnel nor TOSMAP controls.

Details:

Eagle Valley should request Toshiba to perform a review of their generator protection controls and the use of signals from latching relays within the software programming logic. Especially the use of latching relays to provide the status indication signals as they depend on both a SET and REST signals to function to provide a true status of the breaker. The review should justify the need for a latched or holding signal indication for both the N/C interlock preventing the opening of 41E Breaker and the software logic within the AVR program. Toshiba should consider providing a pre-start confirmation of signal agreement of both the direct wired inputs from the breakers (both 52G Breaker and 41E Breaker) and the indirect inputs from remote latching relays (52GX1 Relay and 41EX1 Relay). Failure in the wiring connections, the relay coils or relay contacts could lead to the same problems experienced on April 25th. There were three (3) occasions on April 25, 2021, where the protection control system could have detected a problem but failed: 1) upon initial startup of the Turbine when 41E Breaker was open and 52G Breaker was indicating closed by the AVR OPS display. 2) when the 41E Breaker failed to open when a manual Turbine Trip was initiated. 3) When the 41E Breaker failed to open when the 86G1 and 86G2 Lockouts tripped. Had all the Toshiba protection controls used live or direct signals for the 52G Breaker status, as displayed on the lower left of every control screen, it would have accurately detected a problem.

III. Recommendation: Perform audit of all wiring diagrams for accuracy of generator protection systems. Document the findings and develop plan to correct discrepancies.

Latent Root Causes Addressed:

- Wiring connection drawing was incorrect, showed jumper wire connecting between terminals B4 and B10.

Details:

The error in the wiring connection drawings impacted the troubleshooting effort. An accurate drawing depicting the jumper wire termination points would have allowed the technicians to repair the loose jumper wire and resume the synchronization process. The review should consist of field verification of the wiring connection drawings and OEM wiring schematics to identify any discrepancies and items not meeting codes or best practices. The field verification should also look for loose or improper terminations, exposed electrical conductors presenting a safety hazard, and mis-labeled wires. Considerations should be given to improvement of the verified documentation by identifying missing details which would provide better troubleshooting. Upon completion of the field verification, a listing of the findings should be sorted by criticality. With that list, an action plan is needed to remove the critical deficiencies and follow through with addressing all the items on the list.

IV. Recommendation: Implement a training program for Operators and Technicians specifically on the design and operation of the Generator Protection System, including Standard Operating Procedures for operating breakers and resetting of lockout relays.

Latent Root Causes Addressed:

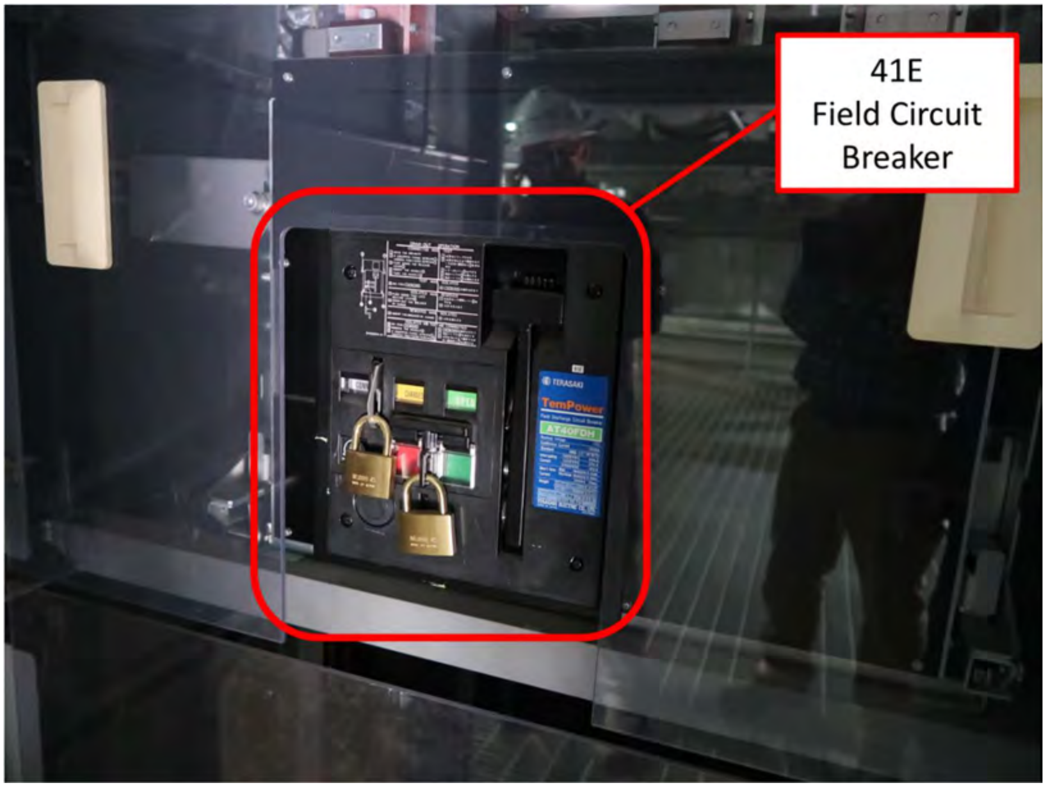
- Lack of a written Standard Operating Procedure detailing personnel responsibilities and actions in response to an 86 Series Lockout Relay trip.
- Incorrect Generator Protection Control system initialization issue of 52G Breaker Close indication with 41E Breaker Open not recognized by personnel nor TOSMAP controls.
- Insufficient communication and coordination amongst all onsite personnel to confirm awareness of the potentially damaging conditions presented when the 41E Breaker remained closed as the reason for the Operations Leader's decision for the work stoppage.

Details:

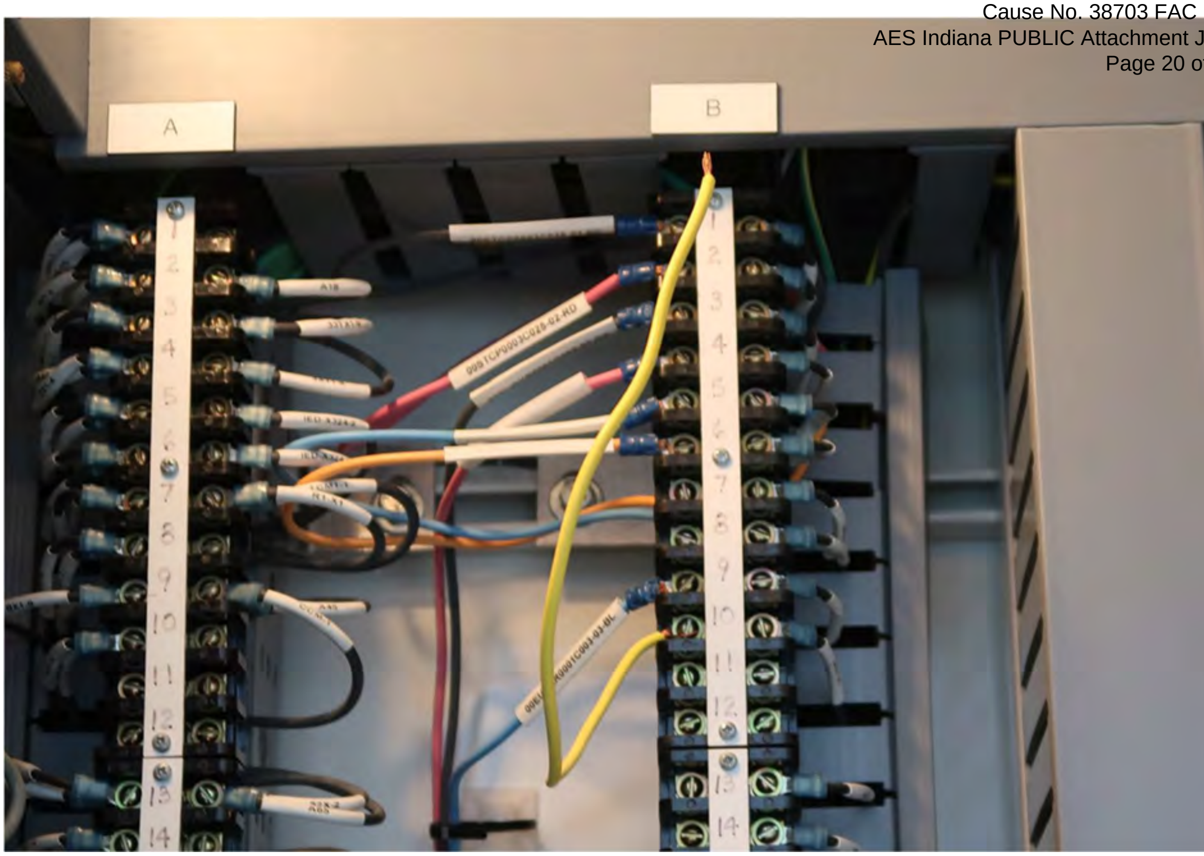
When the 41E Breaker failed to open on the manual Turbine Trips as well as the trips of the 86G1 and 86G2 Lockouts, the operators and technicians could have realized there was a major problem in the generator protection control system. Knowledge of the generator protective controls would have allowed the operators and technicians to appreciate the severity of potential equipment damage based on the resulting status configuration of the protection breakers. The training should also cover the 300G-SEL protective device, specifically on how to retrieve the trip initiating condition. Response to 86 Series Lockout trips must be a coordinated effort between operators and technicians to understand the reason for the protective trip. Only when the source of the trip event is identified and resolved, should resetting the lockouts be authorized for the resumption of operations. The personnel at Eagle Valley should avoid having a dependency on the automated controls to detect problems and prevent dangerous situations. The Toshiba STG equipment has achieved a reputation at Eagle Valley of high reliability. As experienced on April 25th, equipment can fail, and automated controls can become unreliable. Knowledge of the purpose, function, and designed sequence of operation for the generator protection devices is critical to maintaining a safe and reliable plant operations. In addition to the training, AES Indiana Eagle Valley Power Plant must establish written Standard Operating Procedures for addressing protection device trip events, especially 86 Series Lockout trips. The procedures must clearly assign who investigates the cause for the trip, who communicates the findings, who resolves the initiating fault, who can authorize the reset, who physically performs the reset and who monitors the system after the reset is performed.

[redacted]

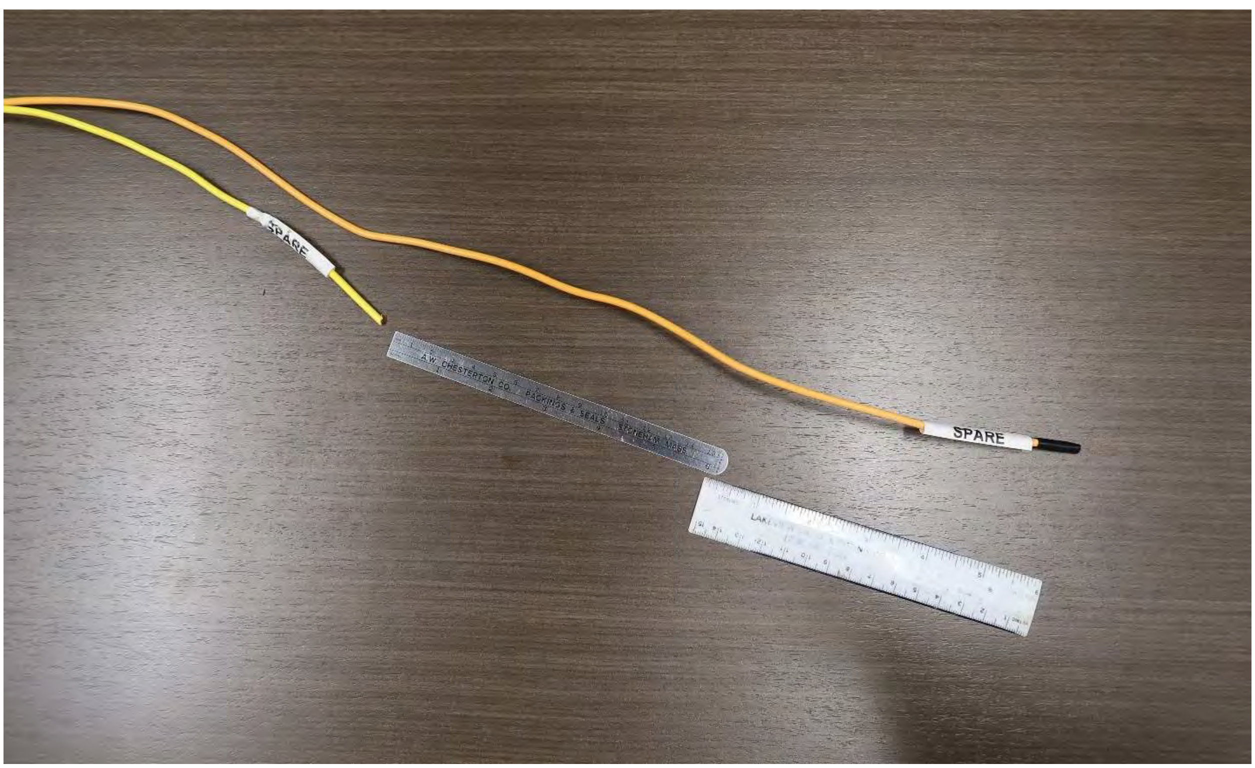
Photograph 1, STG 52G Breaker Cabinet Location



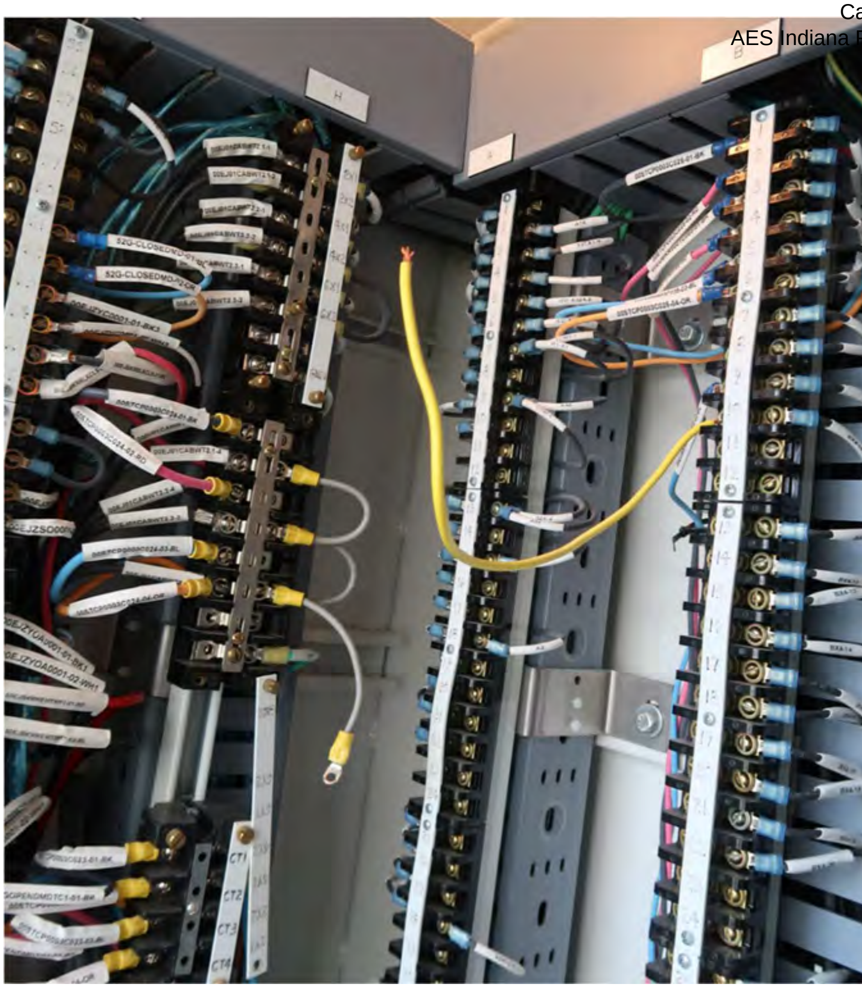
Photograph 2, STG 41E Breaker Location



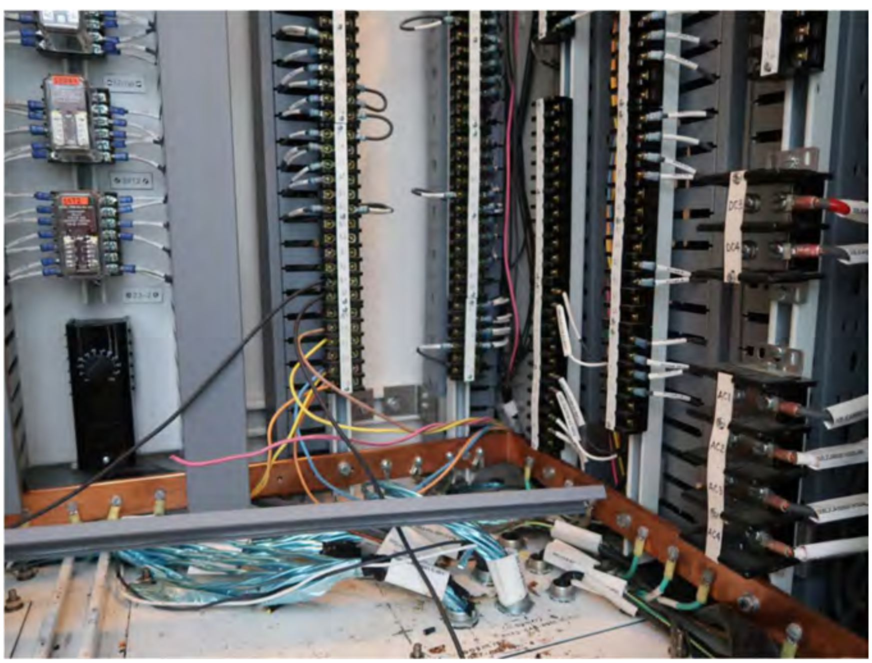
Photograph 3, Loose yellow jumper wire in STG 52G Breaker Cabinet



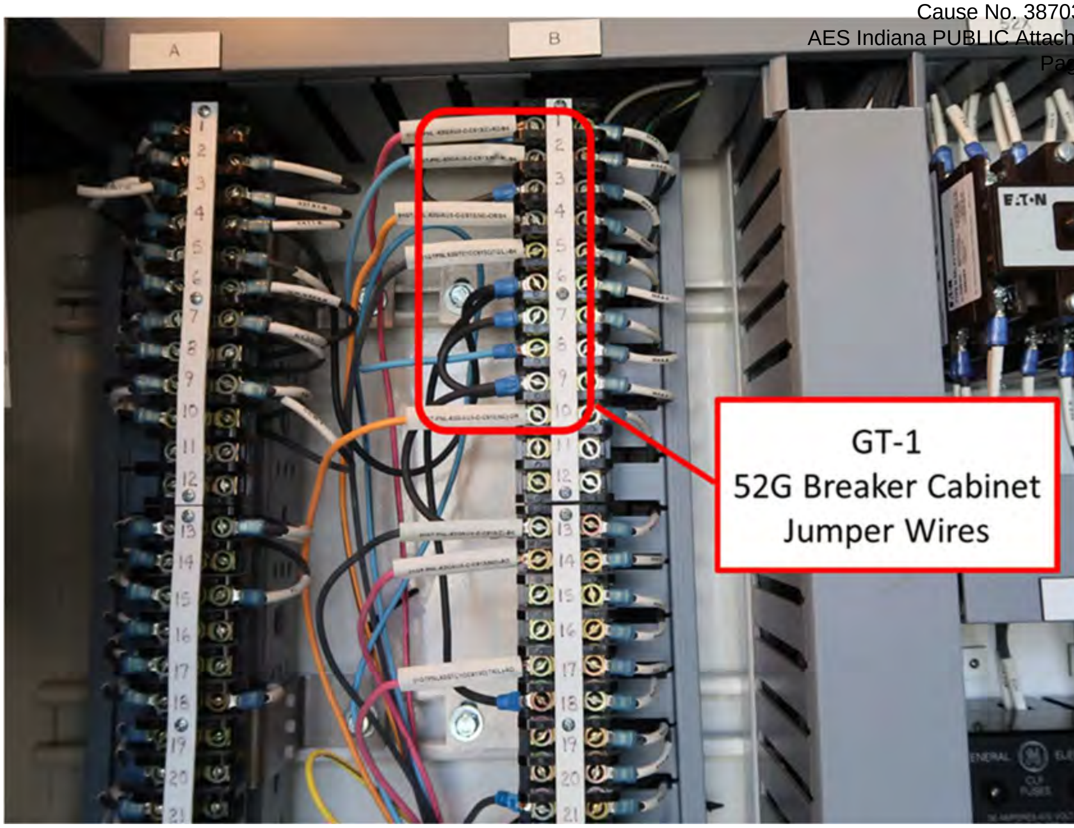
Photograph 4, Source of yellow jumper wire, found in STG 52G Breaker Cabinet.



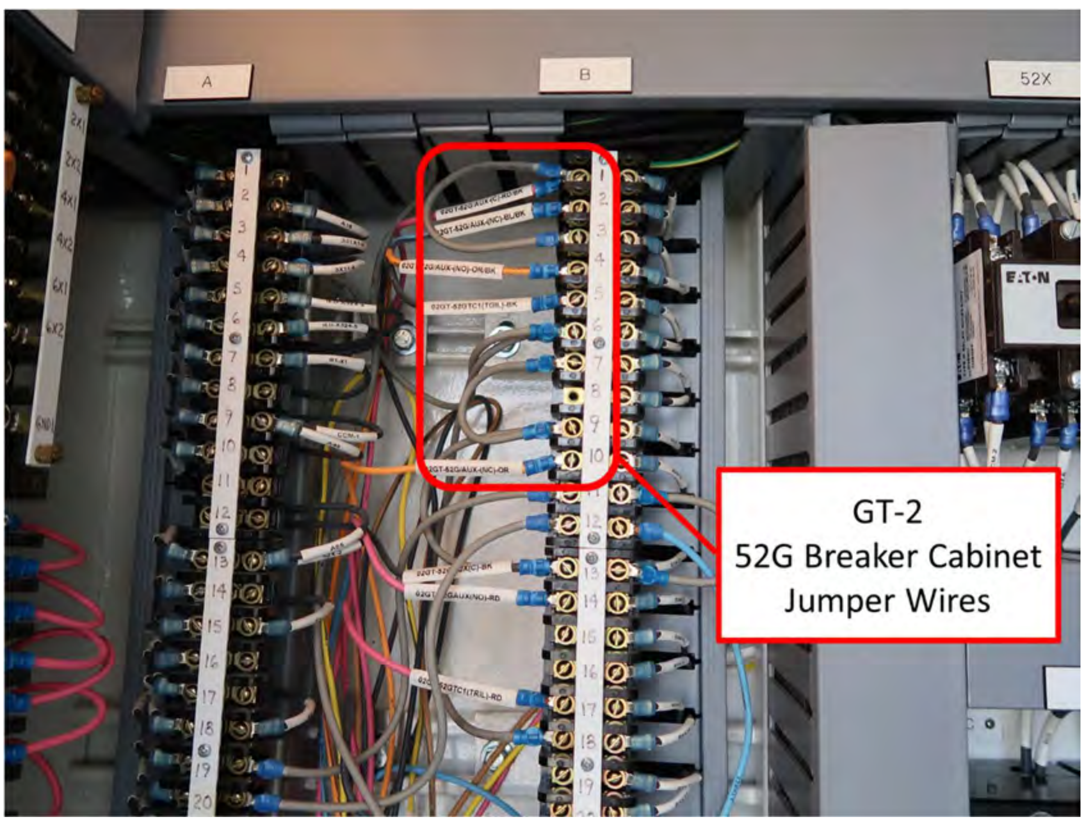
Photograph 5, Bare conductors in STG 52G Breaker cabinet



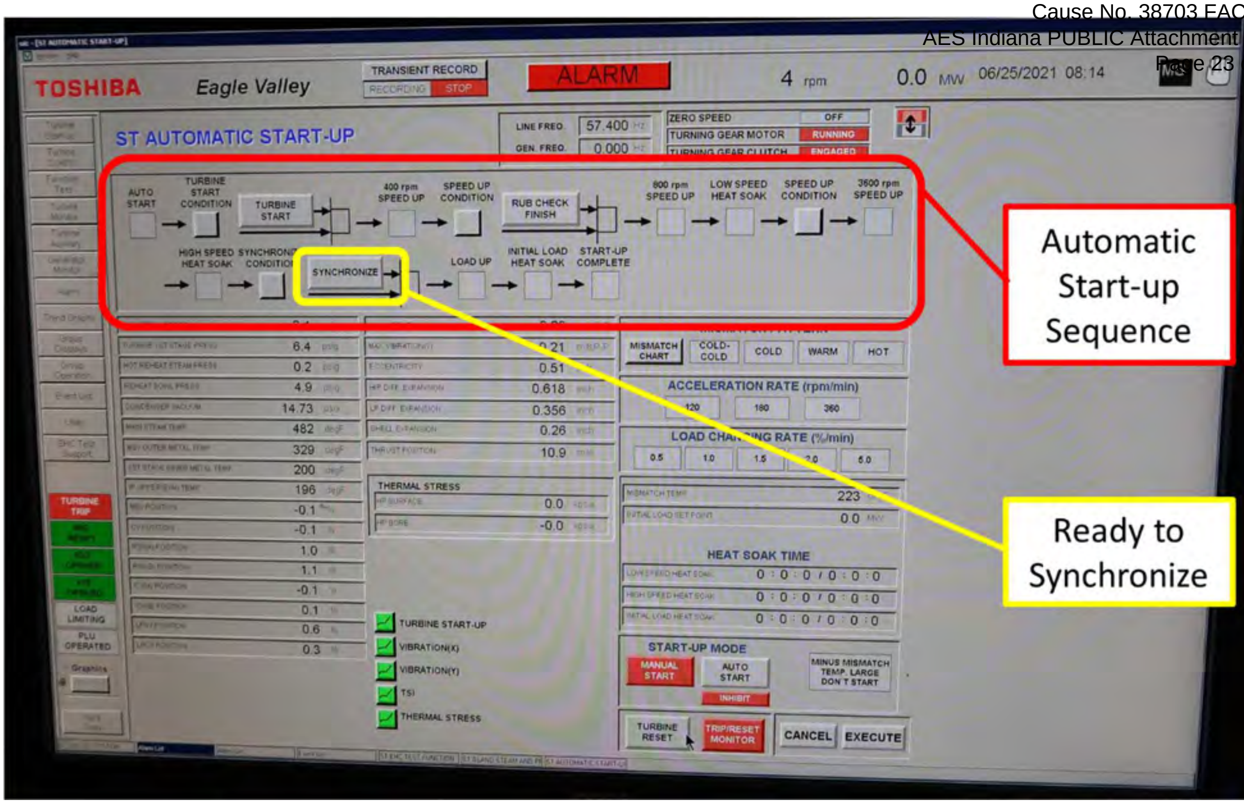
Photograph 6, STG 52G Breaker Cabinet condition



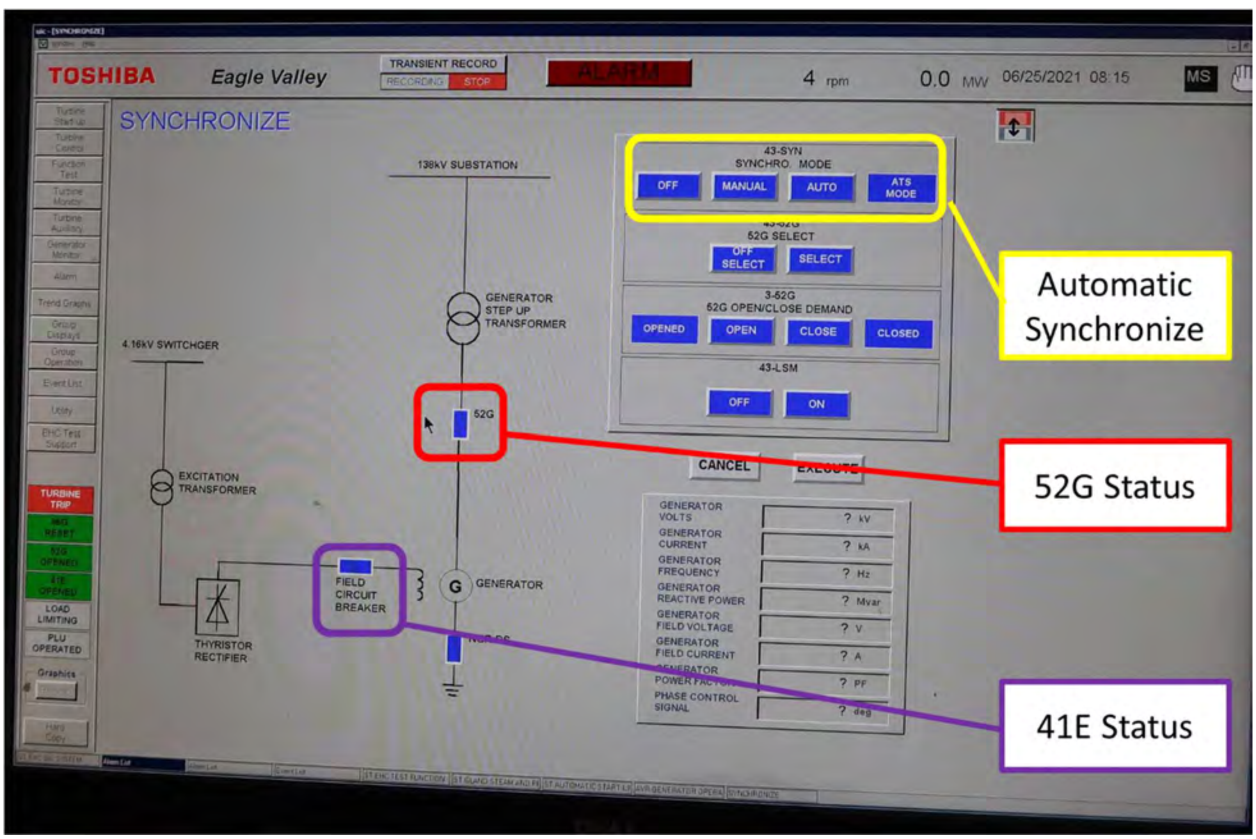
Photograph 7, GT-1 Jumper Wires (black color wire) on B-Terminals



Photograph 8, GT-2 Jumper Wires (grey color wire) on B-Terminals



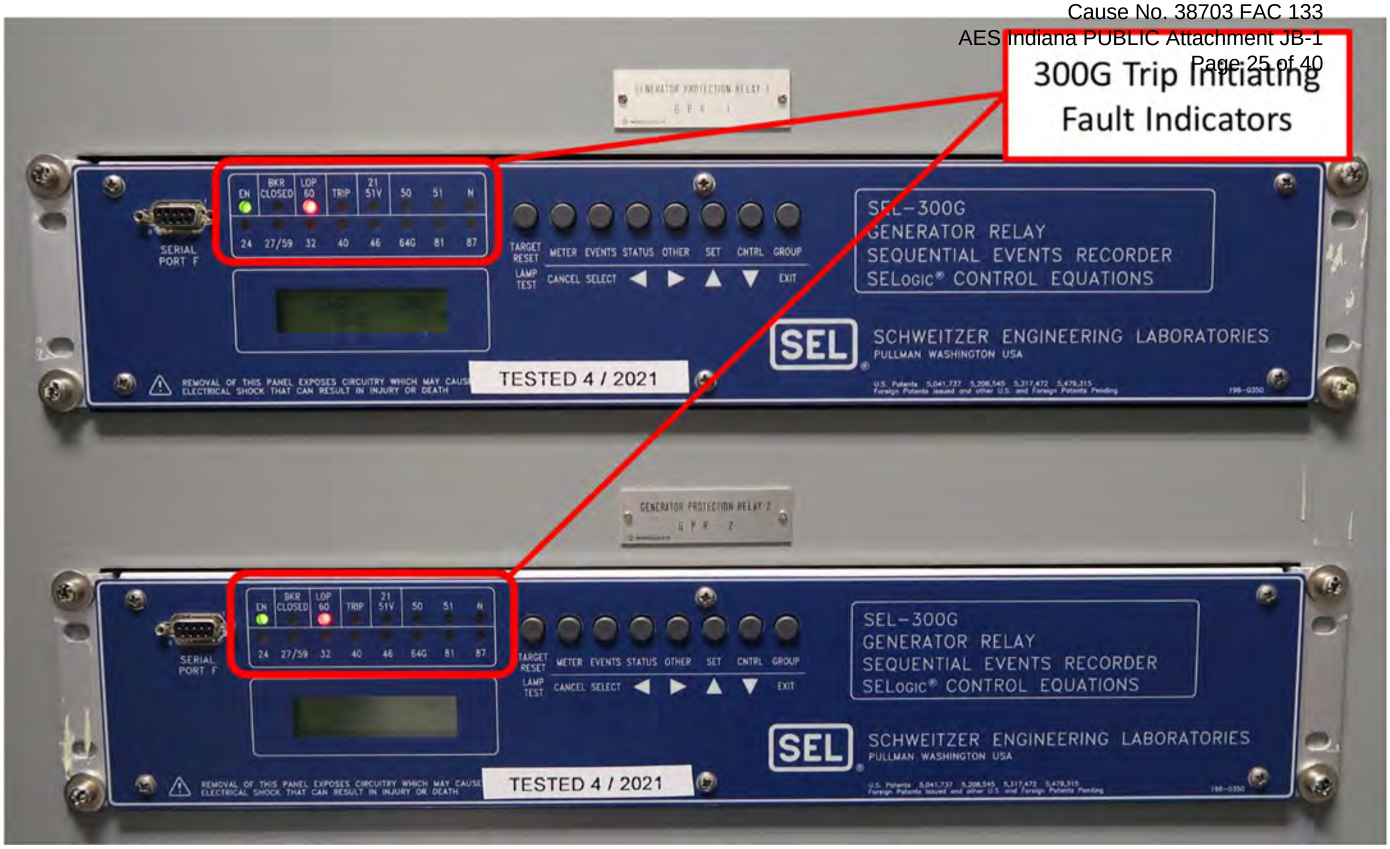
Photograph 9, STG Turbine Automatic Start operator display



Photograph 10, STG Generator Synchronize operator display.

Photograph 11, STG Generator Operation operator display

Photograph 12, STG 86 Series Lockouts Trip/Reset levers



Photograph 13, STG 300G-SEL Monitor displays

Supporting Figures

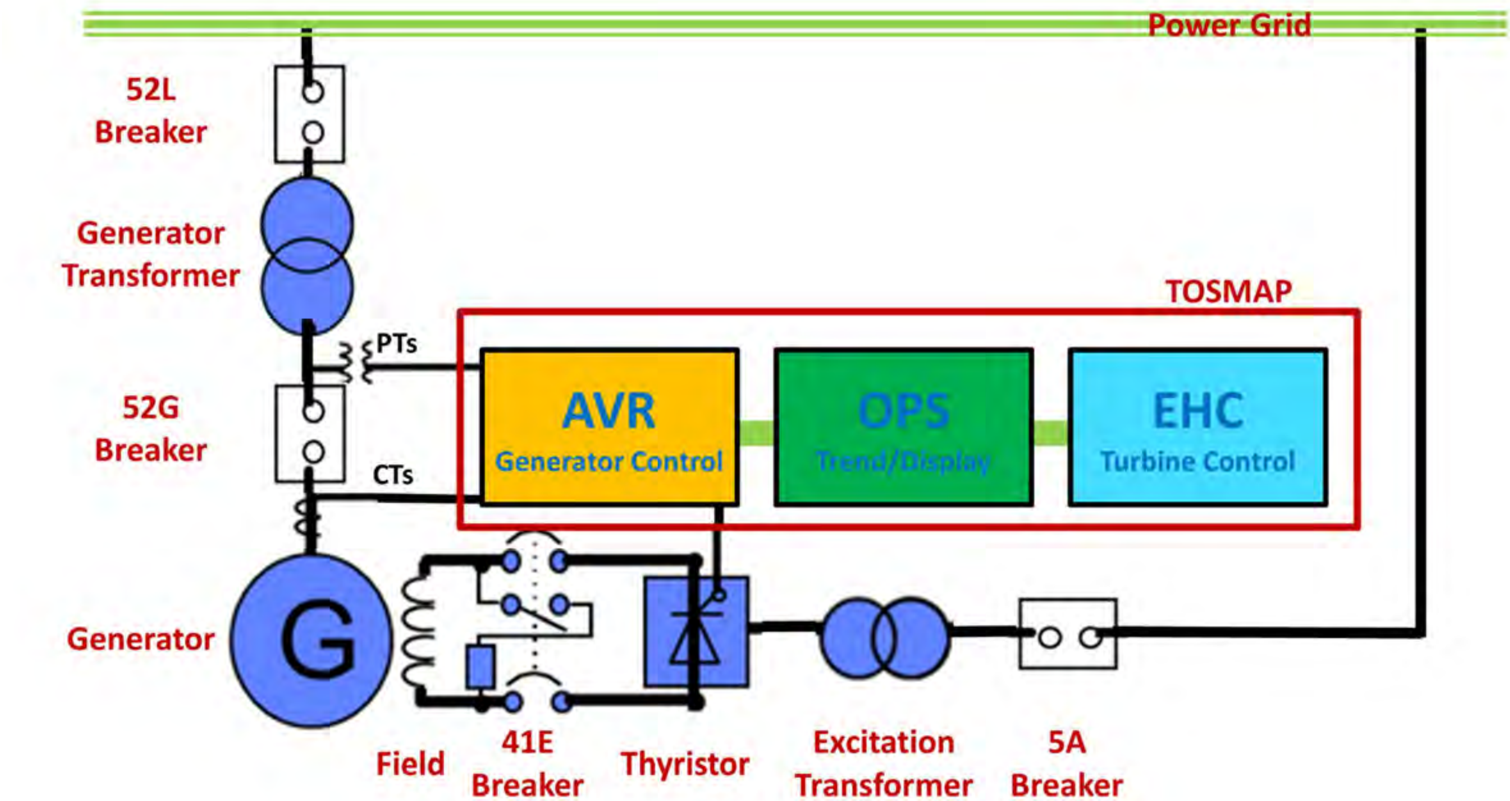


Figure 1, Simplistic diagram of generator protection and control components

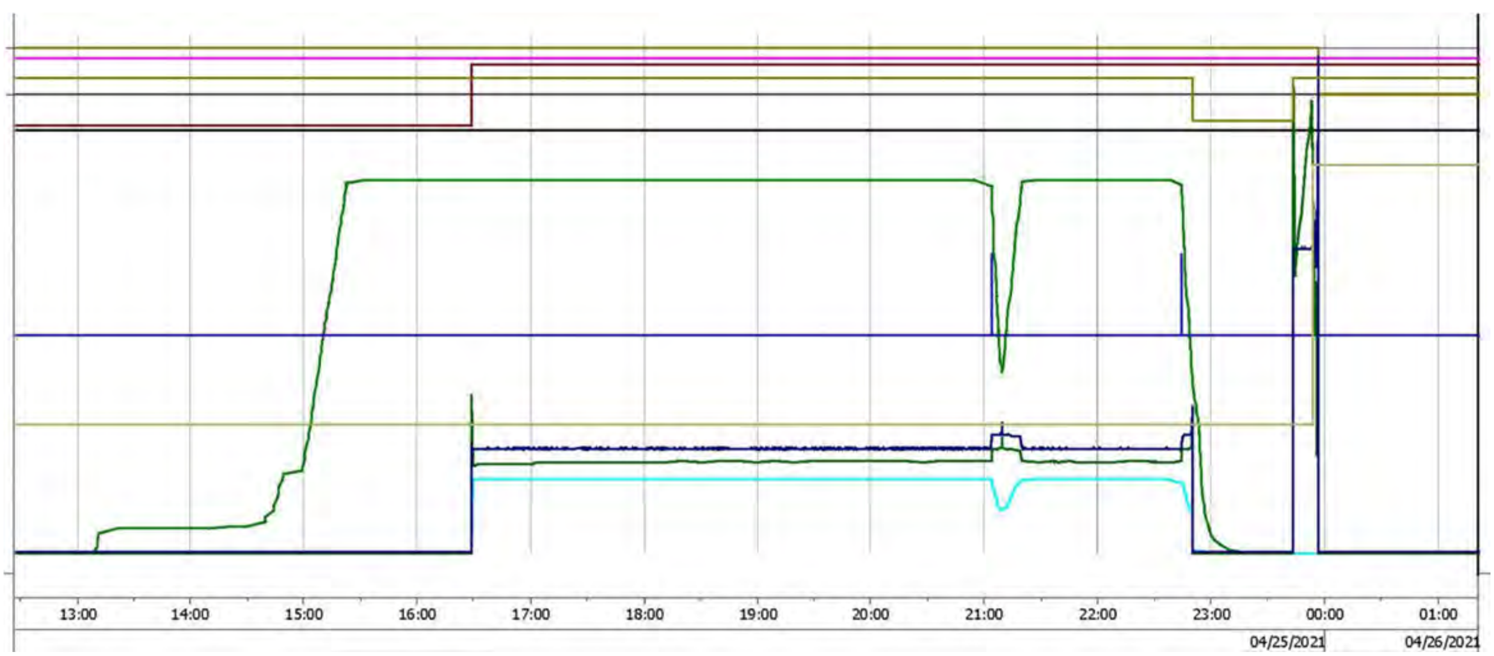


Figure 2, Trend data from April 25, 2021

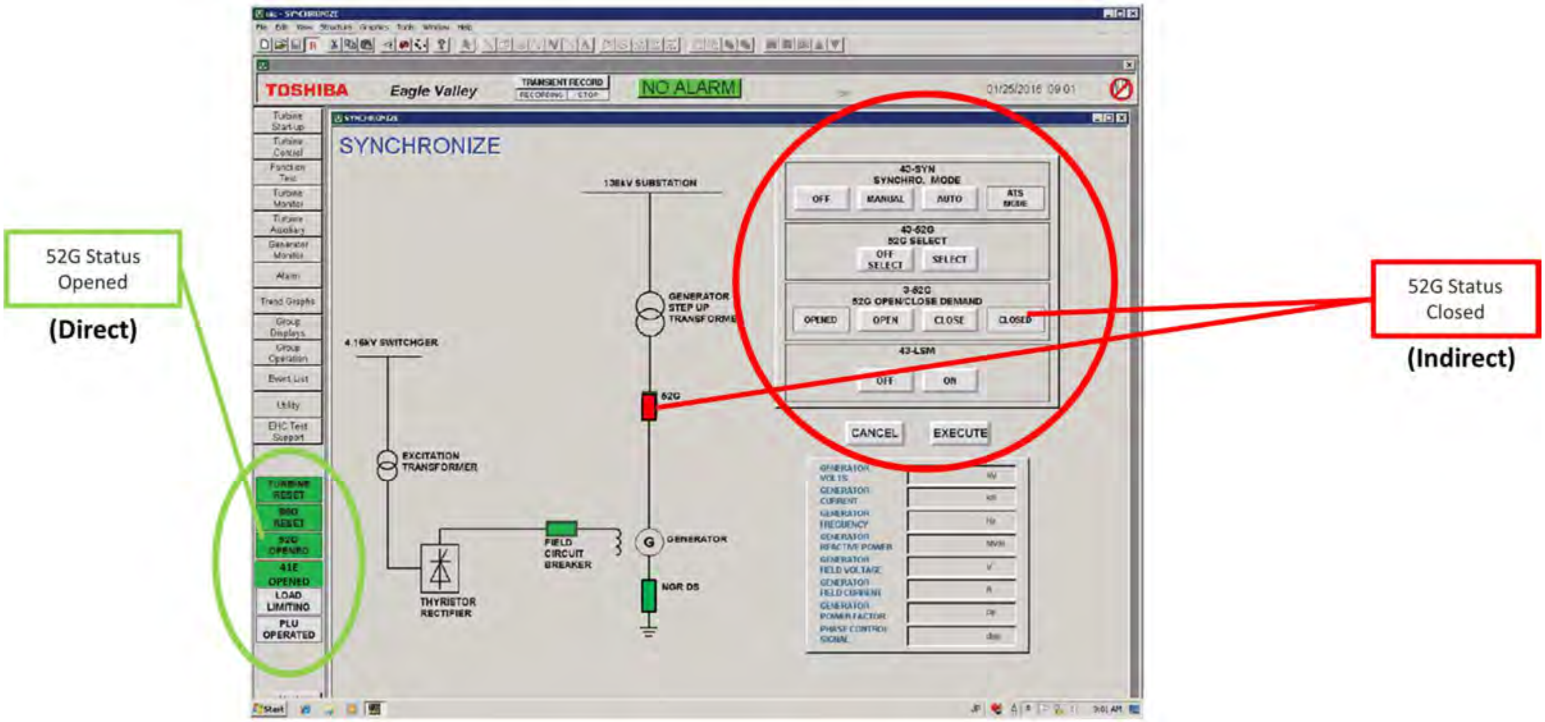


Figure 3, Synchronize screen when STG start-up was initiated (mock-up)

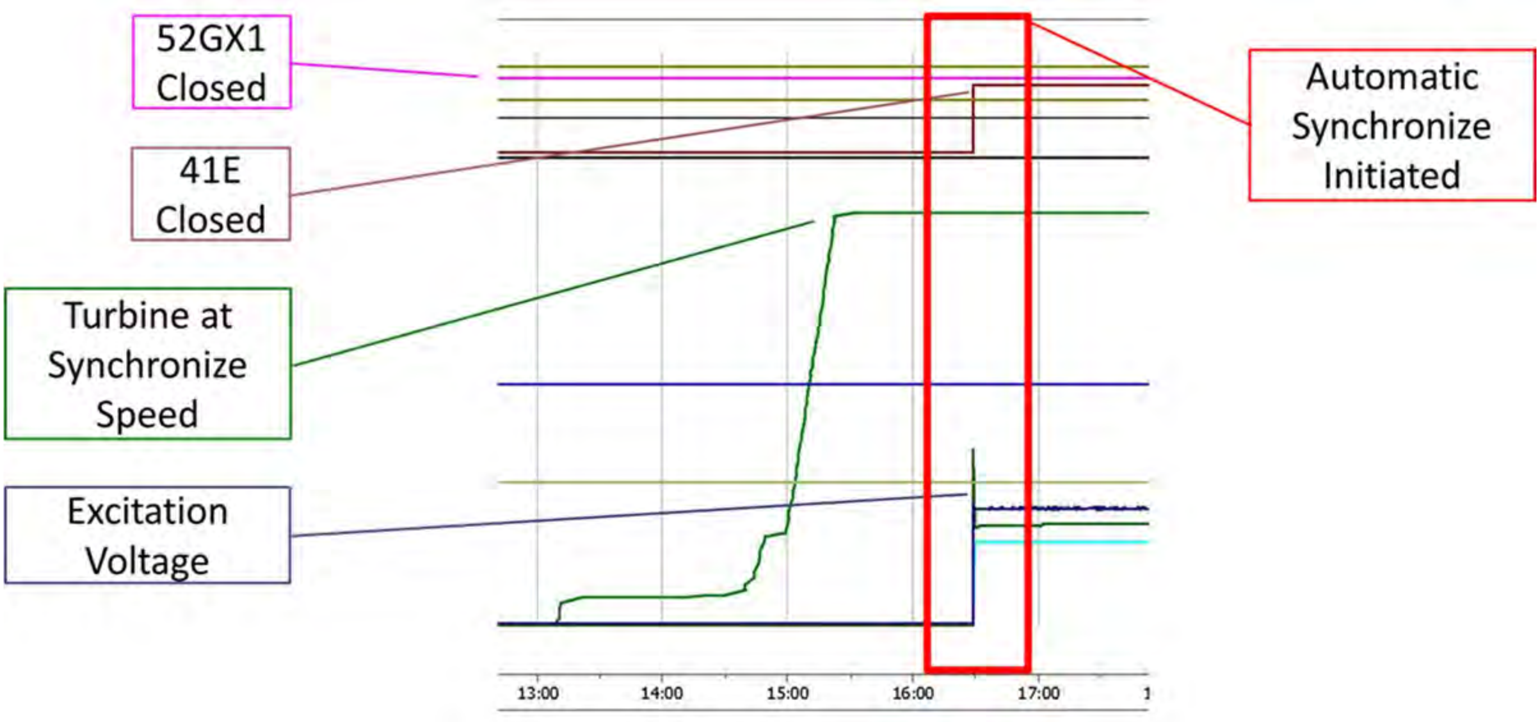


Figure 4, Trend data at Auto Synchronize start

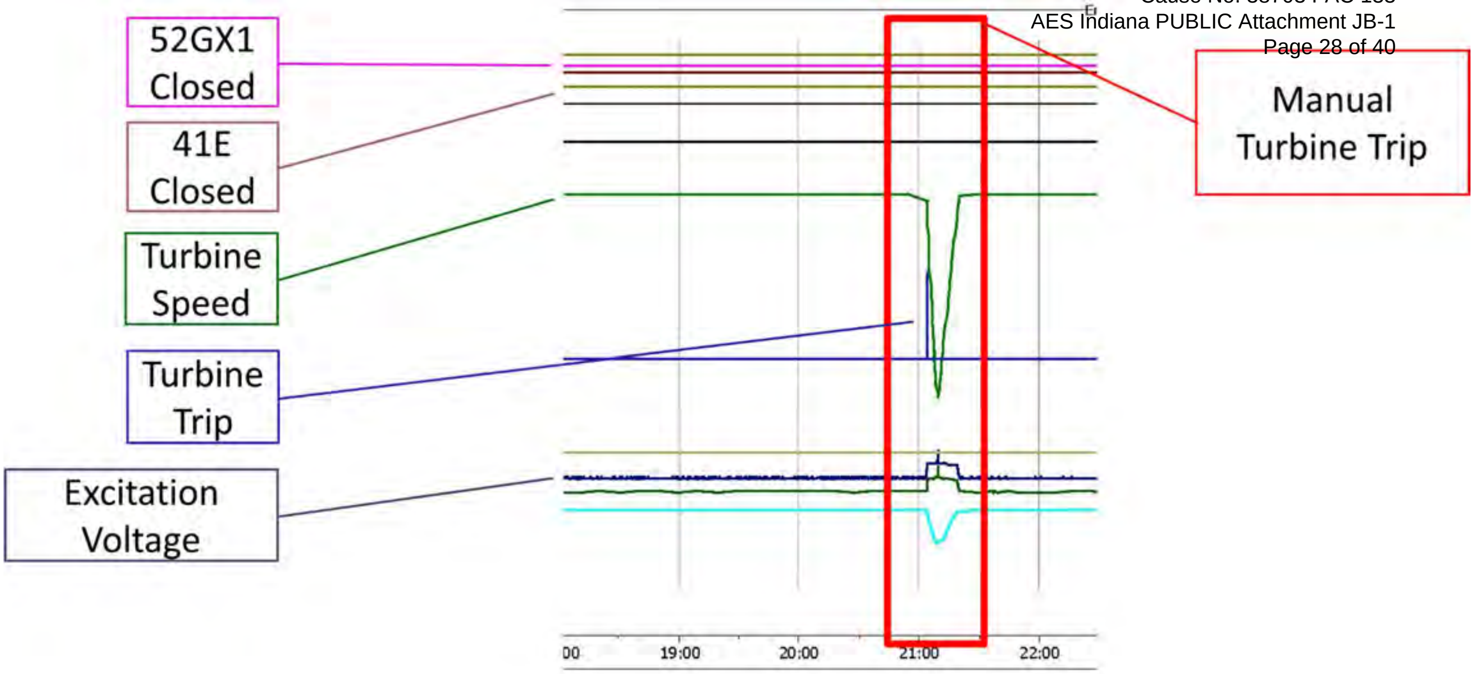


Figure 5, Trend data during 1st manual Turbine Trip

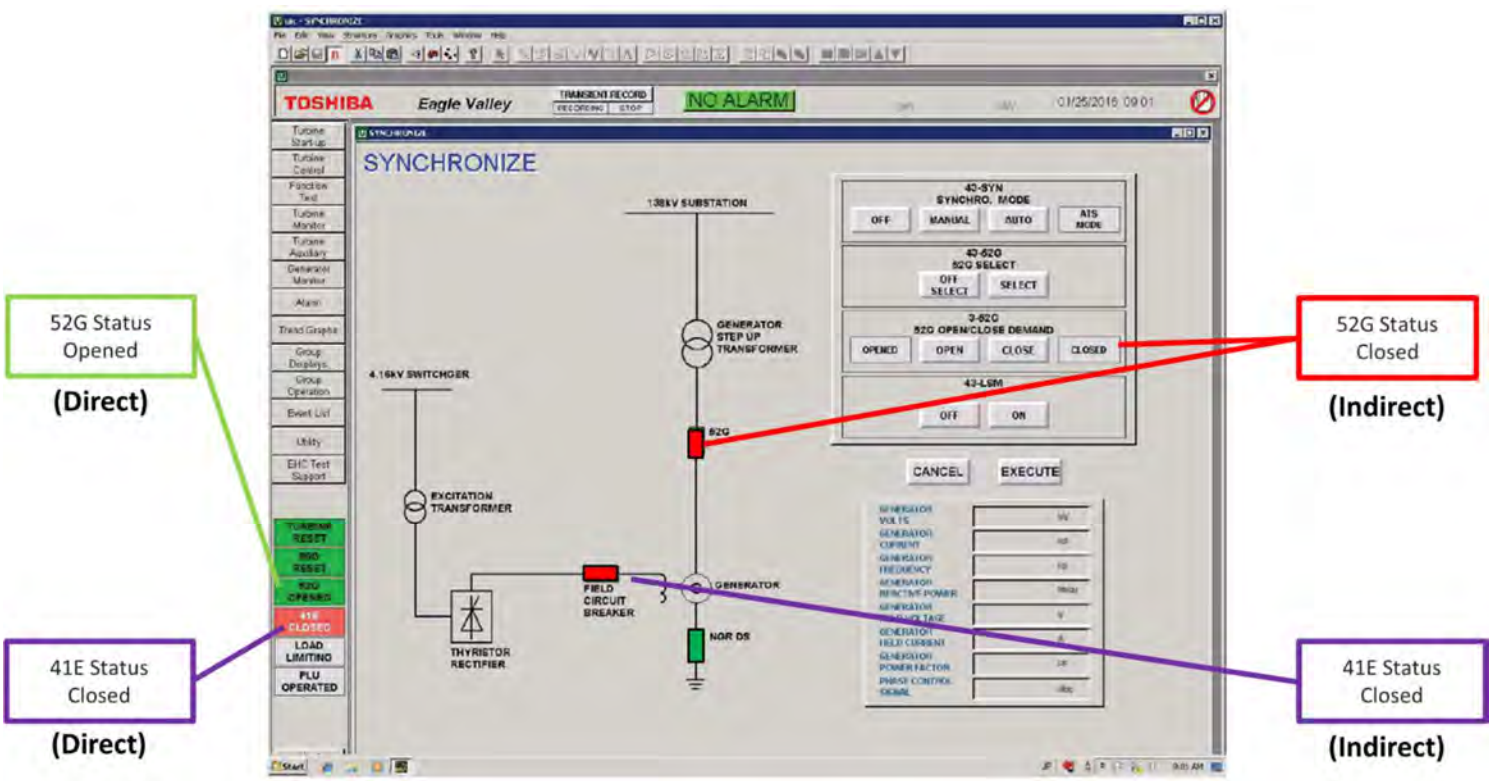


Figure 6, Synchronize screen after manual Turbine Trip (mock-up)

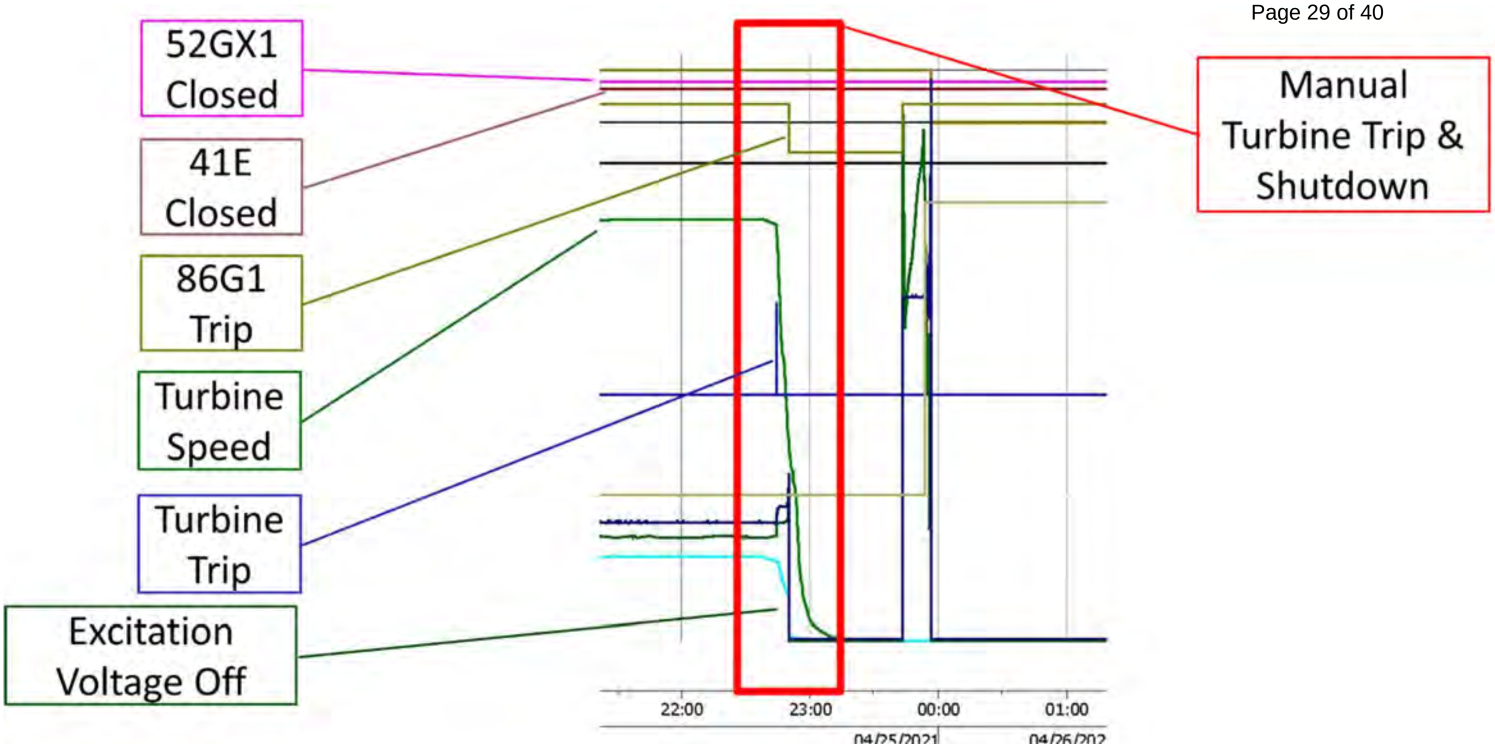


Figure 7, Trend data during 1st manual Turbine Trip and Shutdown

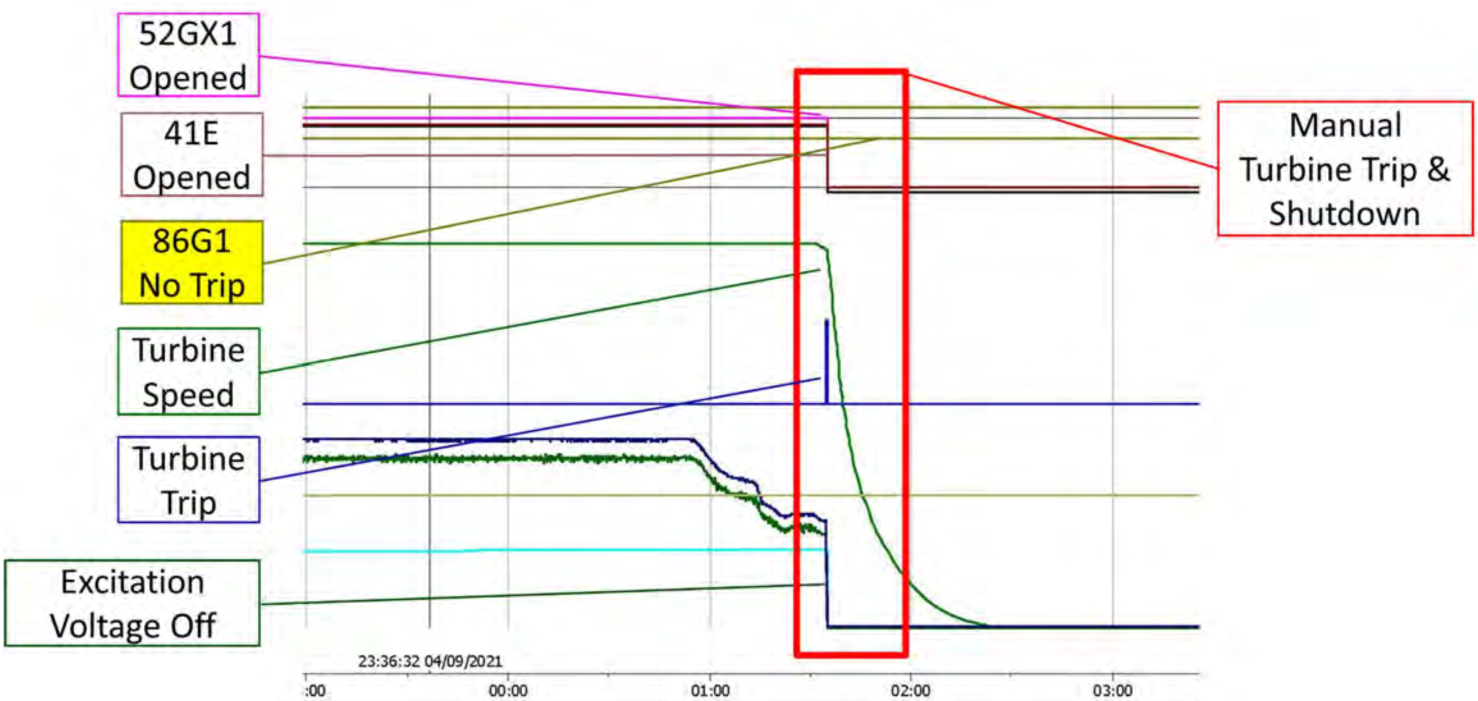


Figure 8, Shutdown on April 10, for Outage

[redacted]

Figure 9, Toshiba Wiring schematic of 52GX1 Relay coils connections to 52G Breaker.

[redacted]

Figure 10, CB&I Wiring connection diagram in 52G Breaker Cabinet.

[redacted]

Figure 11, ABB wiring diagram of Direct 52G contacts for 52GX1 signal source

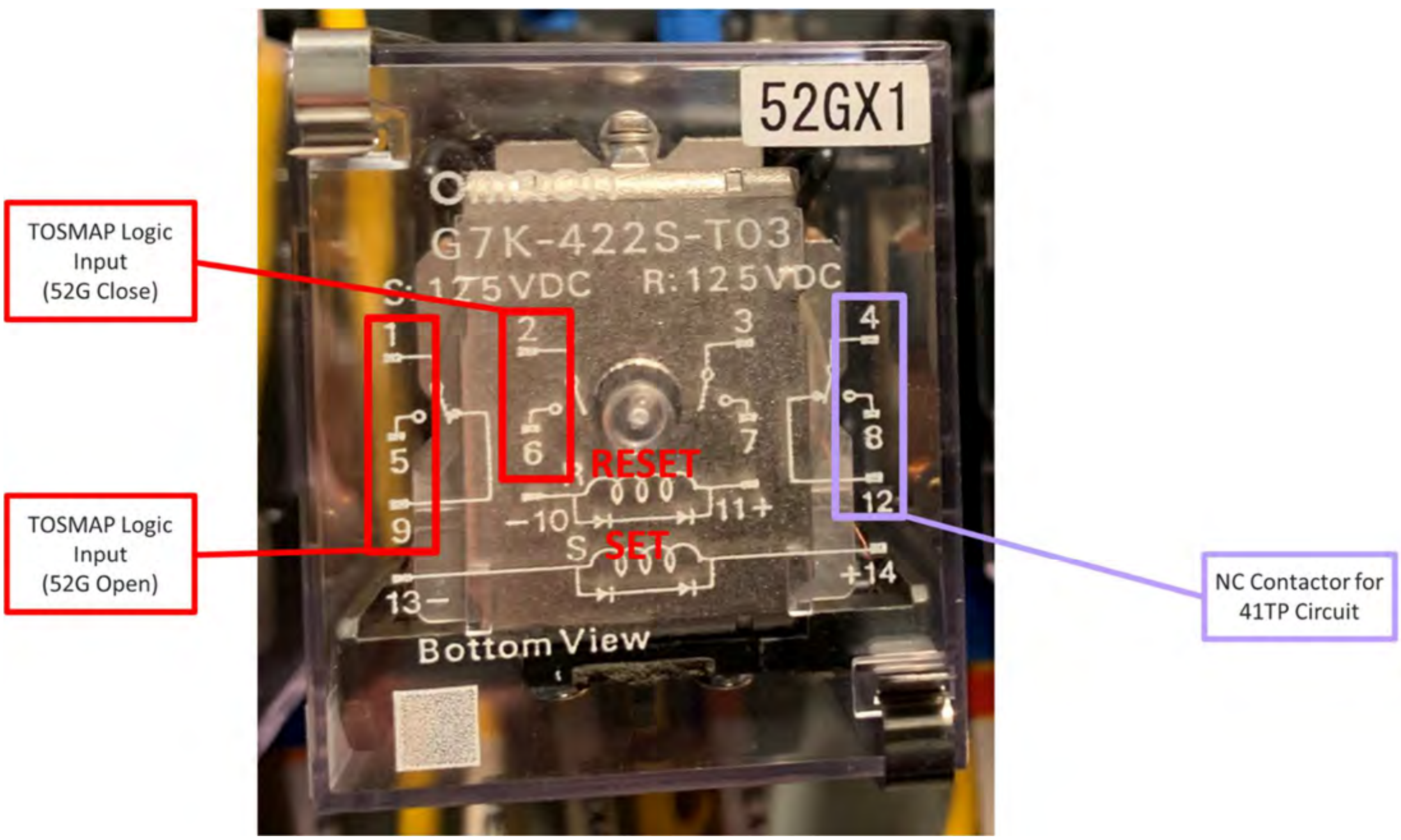


Figure 12, 52GX1 Relay diagram.

[redacted]

Figure 13, TOSMAP I/O Card 52G status inputs from 52GX1 Contacts.

[redacted]

Figure 14, Toshiba wiring schematic of 41E trip circuit

[redacted]

Figure 15, Toshiba wiring schematic of hardwired 41E Trip Demand inputs

[redacted]

Figure 16, Toshiba wiring schematic of 41EX1 and 52GX1 Relay coils

[redacted]

Figure 17, Direct 41E contacts for 41EX1 signal source

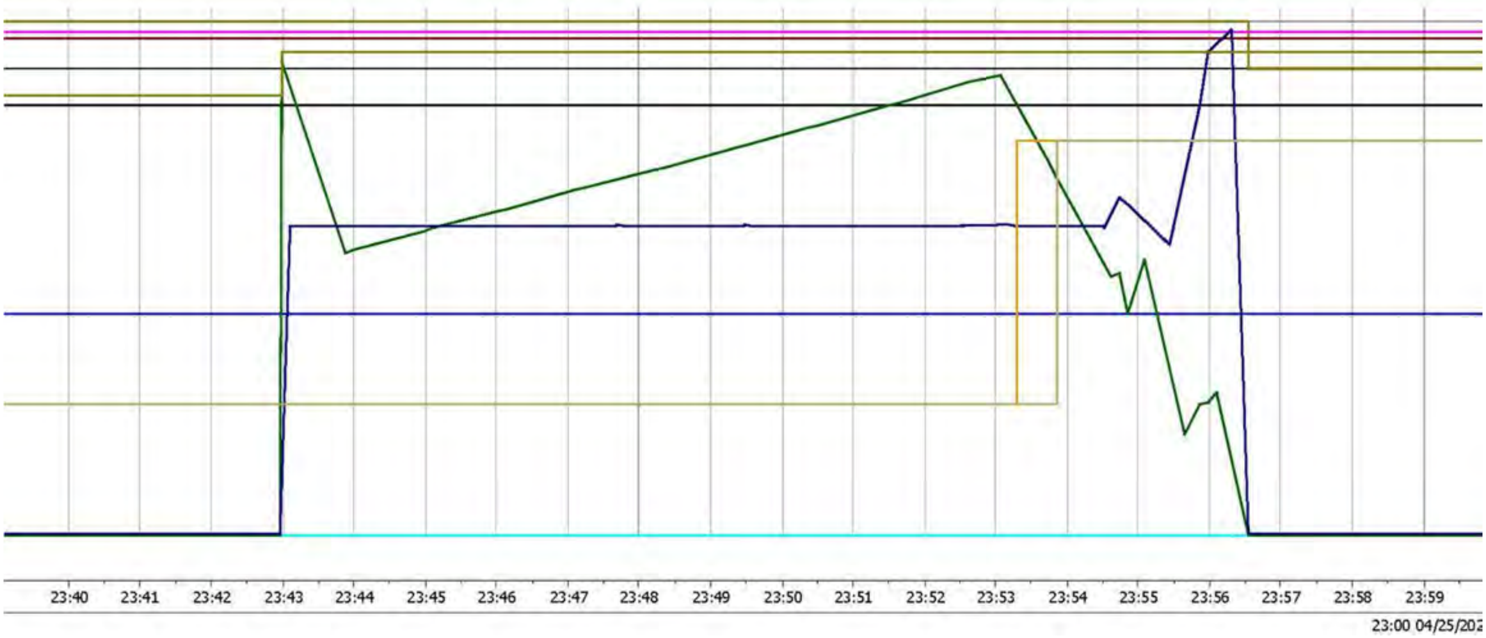


Figure 18, Trend data of Generator Field damage event

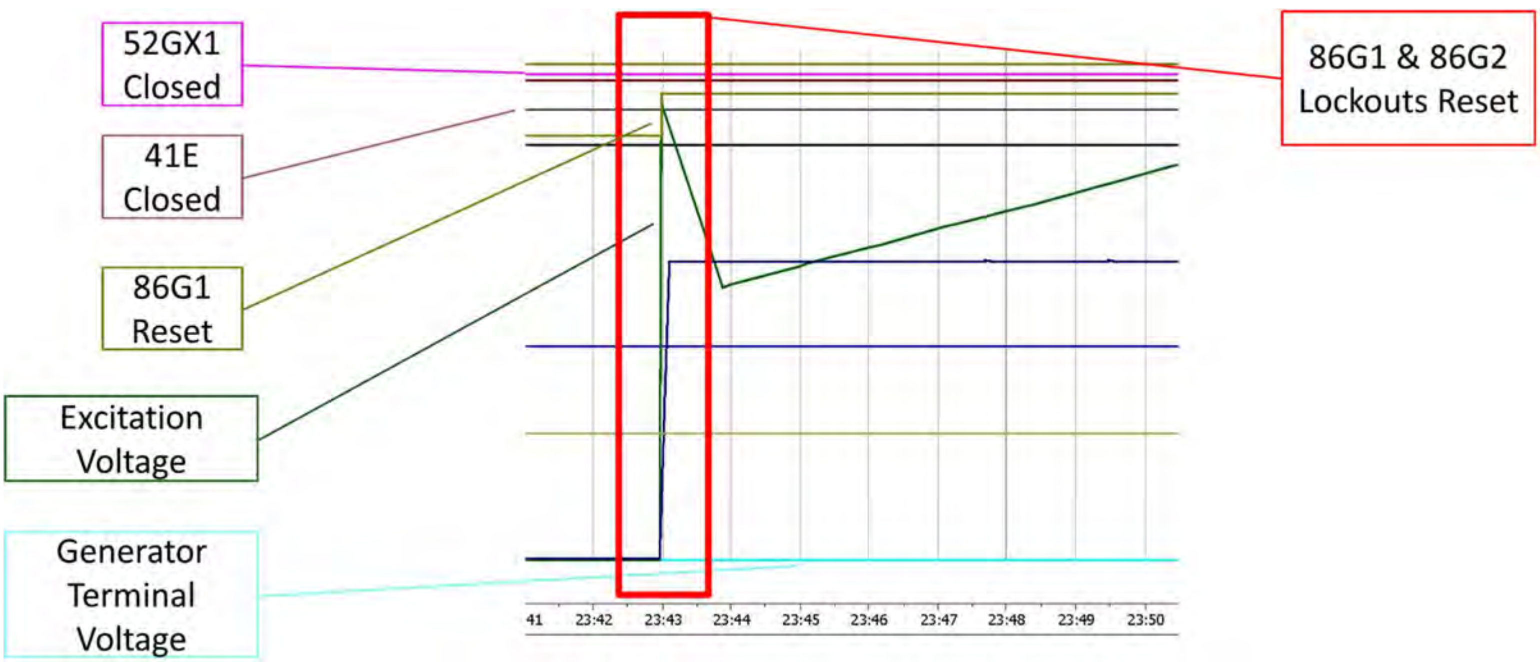


Figure 19, Trend data when 86G1 and 86G2 Lockout Relays were reset.

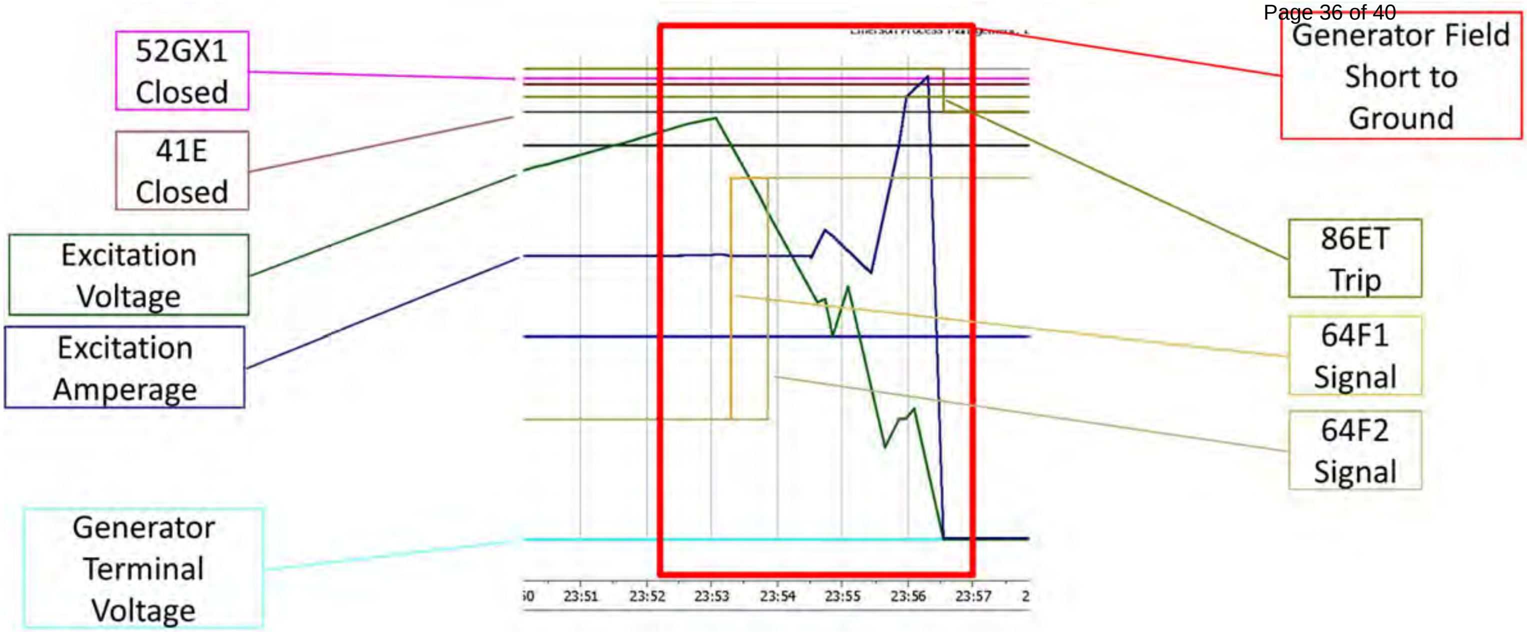
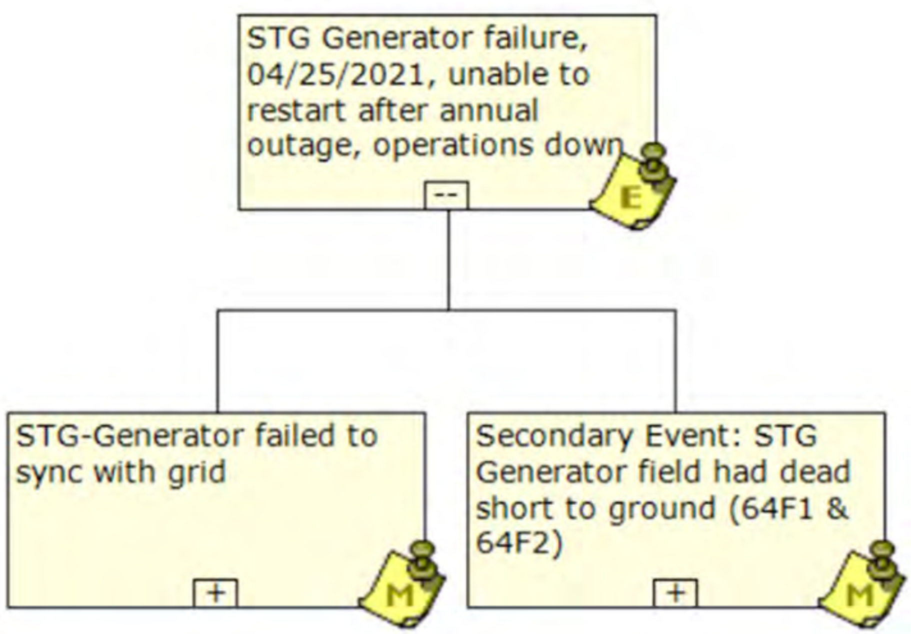


Figure 20, Trend data showing insulation failure, 64F1, 64F2 and 86ET trips.

PROACT® Logic Tree

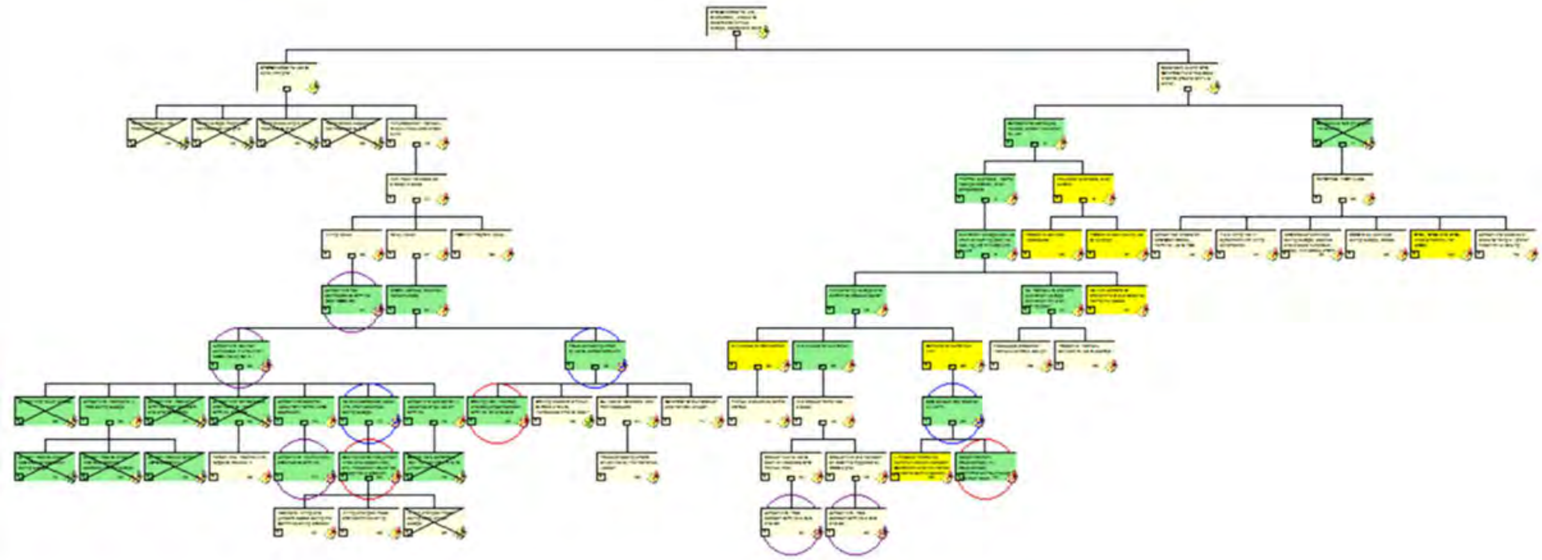
Any undesirable outcome is a result of a series of "cause-and-effect" relationships. The data provided by AES, in-person interviews and on-site visits, serve as proof (evidence) as to what did or what did not occur. A Logic Tree was utilized in the PROACT® application to graphically express the "cause-and-effect" relationships. In this approach, the top two levels of blocks represent the EVENT Level 1 and the MODE Level 2. From-level-to-level the path represents a "cause-and-effect" relationship. These levels specifically represent the "undesirable outcomes" that did occur (facts only). From the MODE Level, the analysts do not know why they have occurred, just that they did occur. From this point the analysis becomes hypothetical and the analysts repeatedly ask the question "How Can?". As hypotheses are developed in this fashion, the evidence collected is used to verify what is true and what is not true. In this fashion, facts lead the analysis not assumptions. This process is reiterated until true root causes are uncovered; the reasons why people make decision errors that lead to undesirable outcome. Root causes originate from vulnerabilities in the organizational systems upon which employees depend to make informed decisions. These are called Latent Root Causes or Organizational Root Causes. Vulnerabilities in organizational systems lead to poor decisions being made by well-intentioned individuals. These decisions are referred to as Human Root Causes. Decision errors lead to the Physical Root Causes, or events or conditions that are visible. When the Latent Roots or Organizational System Roots are identified and addressed, the investigation becomes a true and effective Root Cause Analysis.

Top Box (problem definition)

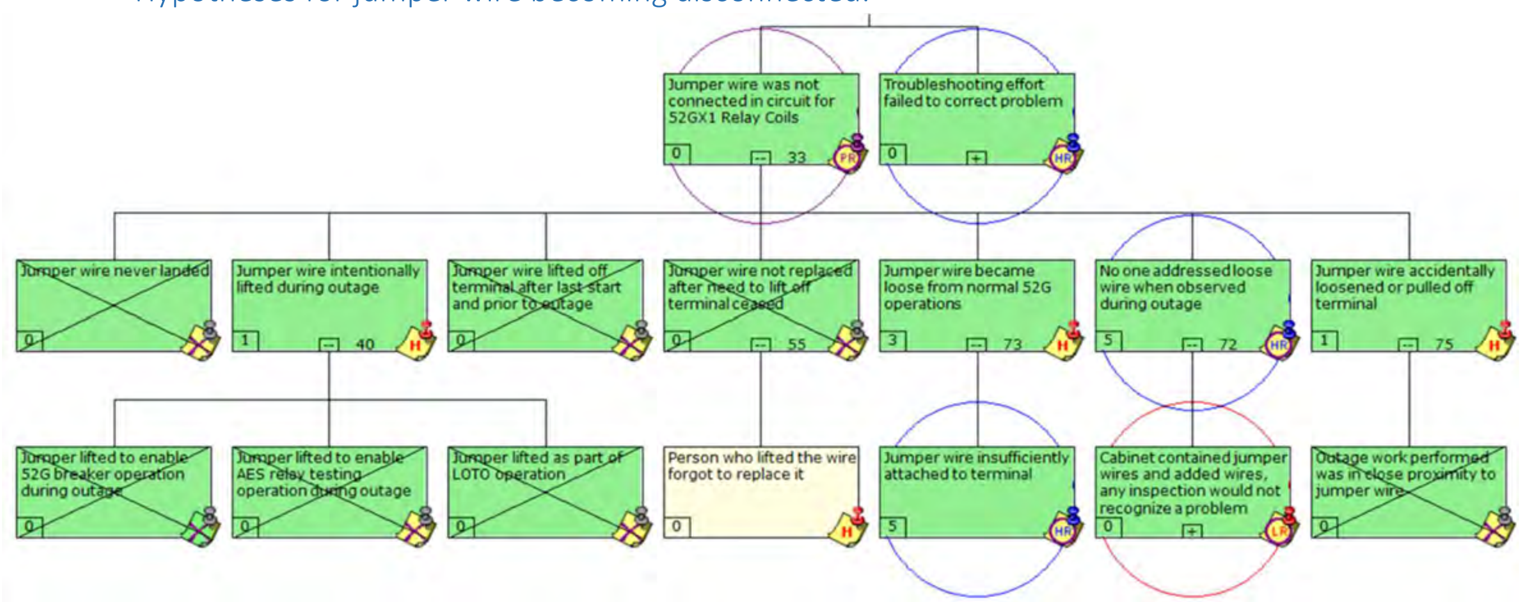


PROACT® Logic Tree Top Box

Entire Logic Tree



Hypotheses for jumper wire becoming disconnected.



Analysis Team Information

RCA Team Charter

To identify the root causes of the STG-1 generator failure to synchronize with grid and the damage to the generator field at the Eagle Valley power plant facility. This includes identifying deficiencies in, or lack of, management systems and oversight. Appropriate recommendations for root causes will be communicated to management for rapid resolution.

Analysis Critical Success Factors

- A cross-functional section of personnel/experts will participate in the analysis.
- All analysis hypotheses will be verified or disproven.
- Management agrees to fairly evaluate the analysis team's findings and recommendations.
- A disciplined RCA approach will be utilized.
- Use of an unbiased team facilitator who is an expert in the PROACT® RCA methodology.

Analysis Team Members

Name	Role	Company	Title
Kevin Cook	Sponsor	AES	Facility Manager
Brandon Berlin	Analyst	AES	Maintenance Leader
Jason Hoage	Analyst	AES	Operations Leader
Holcombe Baird	Facilitator	Reliability Center, Inc.	Senior Reliability Consultant

Analysis Dates

Event Date: 04/25/2021
Analysis Start Date: May 2, 2021
Analysis Team Completion: July 9, 2021

Appendix A: Reference Reports

Excitation Breaker (41E) Control
PowerPoint by Toshiba, June 1, 2021, A report on Toshiba investigative findings and explanation of 41E Breaker operational logic

Appendix B: Contributors to Analysis Effort

John Griffin – IPL DCS Technician
Ron Stiles – IPL DCS Technician
Kirk Daily – IPL CP
Matt Lockwood – IPL CP
Billy Hunt – IPL Operator
Dave Haymond - IPL Operator
Jamin Quin – Electrician
Jonathon Marques – AES Electrical Engineer
David Eads – AES Relay SCADA Technician
Doug Warren – AES Relay/SCADA Technician
Bryan Hang – Toshiba Technician
Mark Magnuson - Toshiba Project Manager
Arron Kreel – Toshiba Project Manager
George Lala – Toshiba Instrumentation and Control System Manager
Jesse Johnson – Toshiba Instrument and Control Systems Engineer
Jacques Potgieter – ABB technician
Ricardo Covarrubias – Generator Engineer