NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

BES Protection System Misoperation Reduction Workshop

October 1-2, 2024

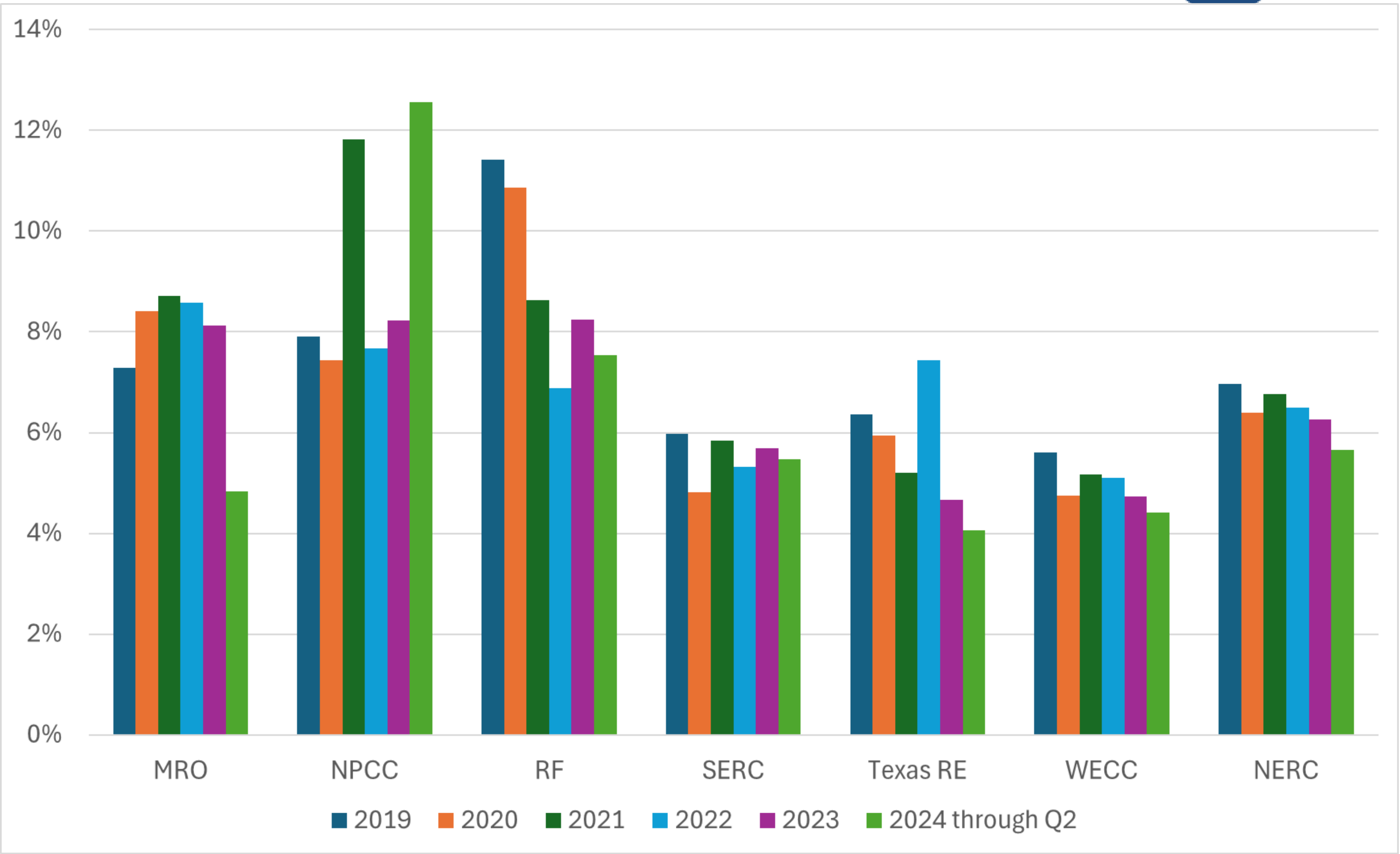
RELIABILITY | RESILIENCE | SECURITY

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

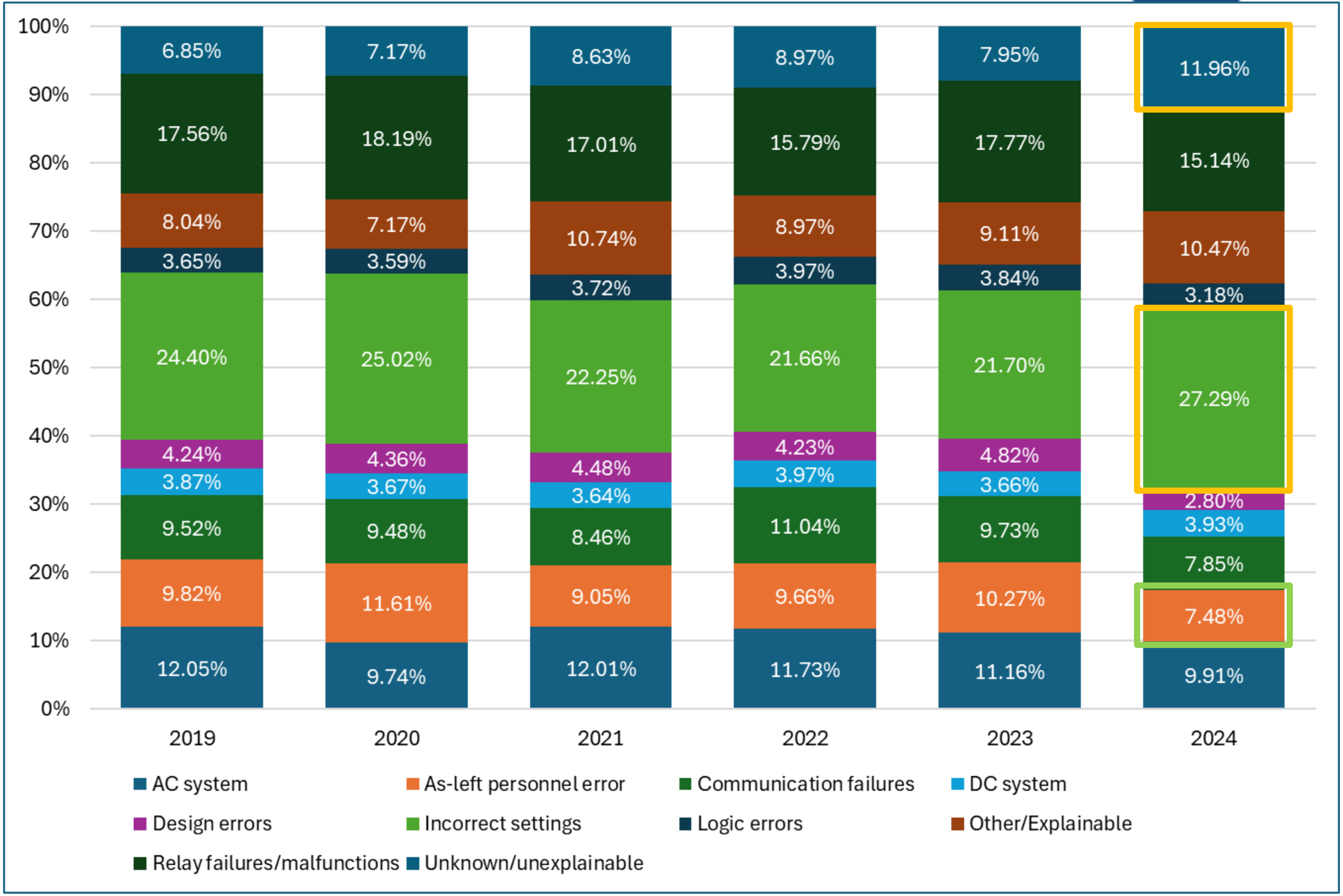
MIDAS Misoperations Breakdown

Jack Norris, Engineer II
Misoperation Reduction Workshop
October 1, 2024

Annual Regional Misoperation Rate

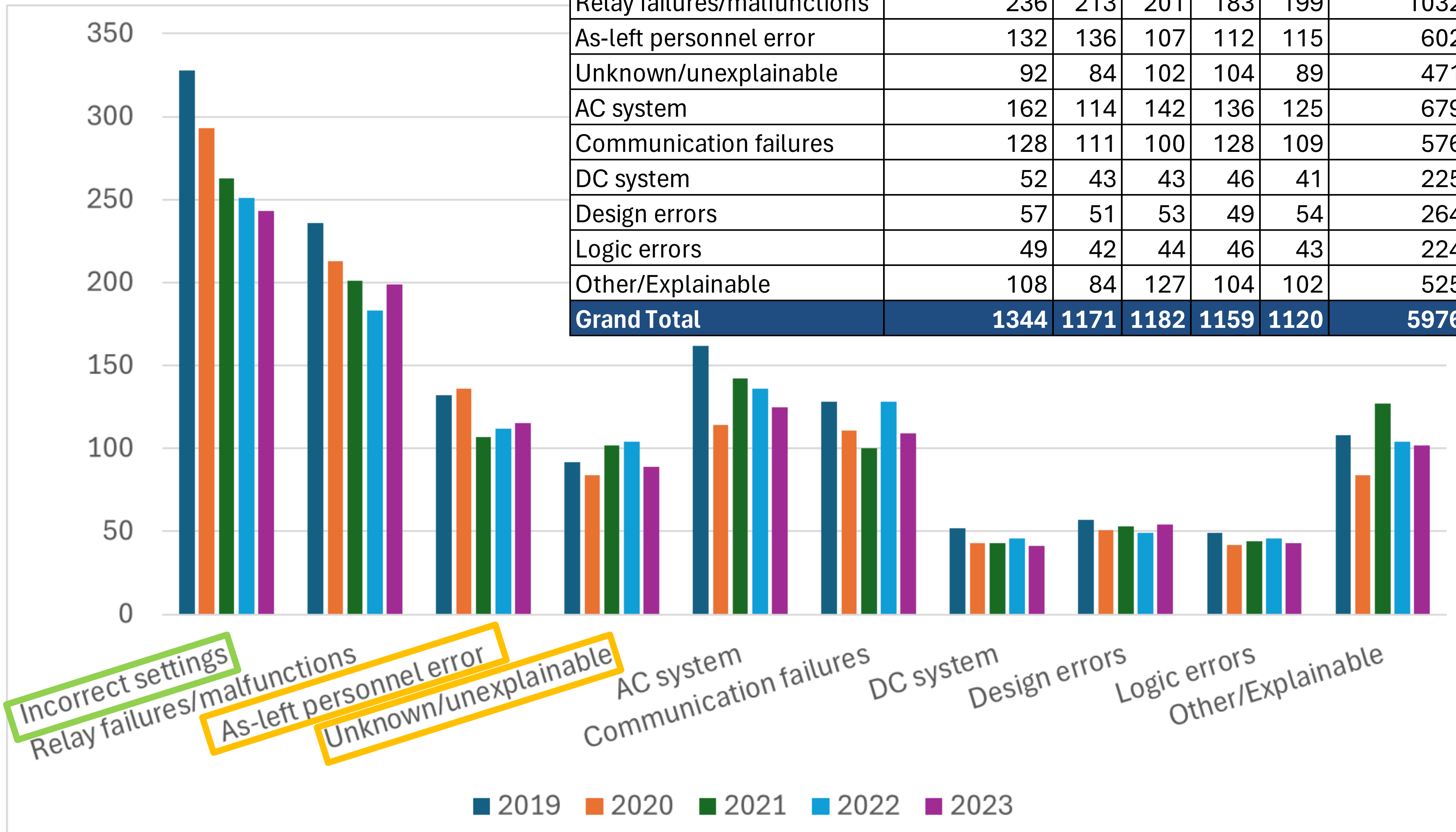


Misoperation Causes Breakdown

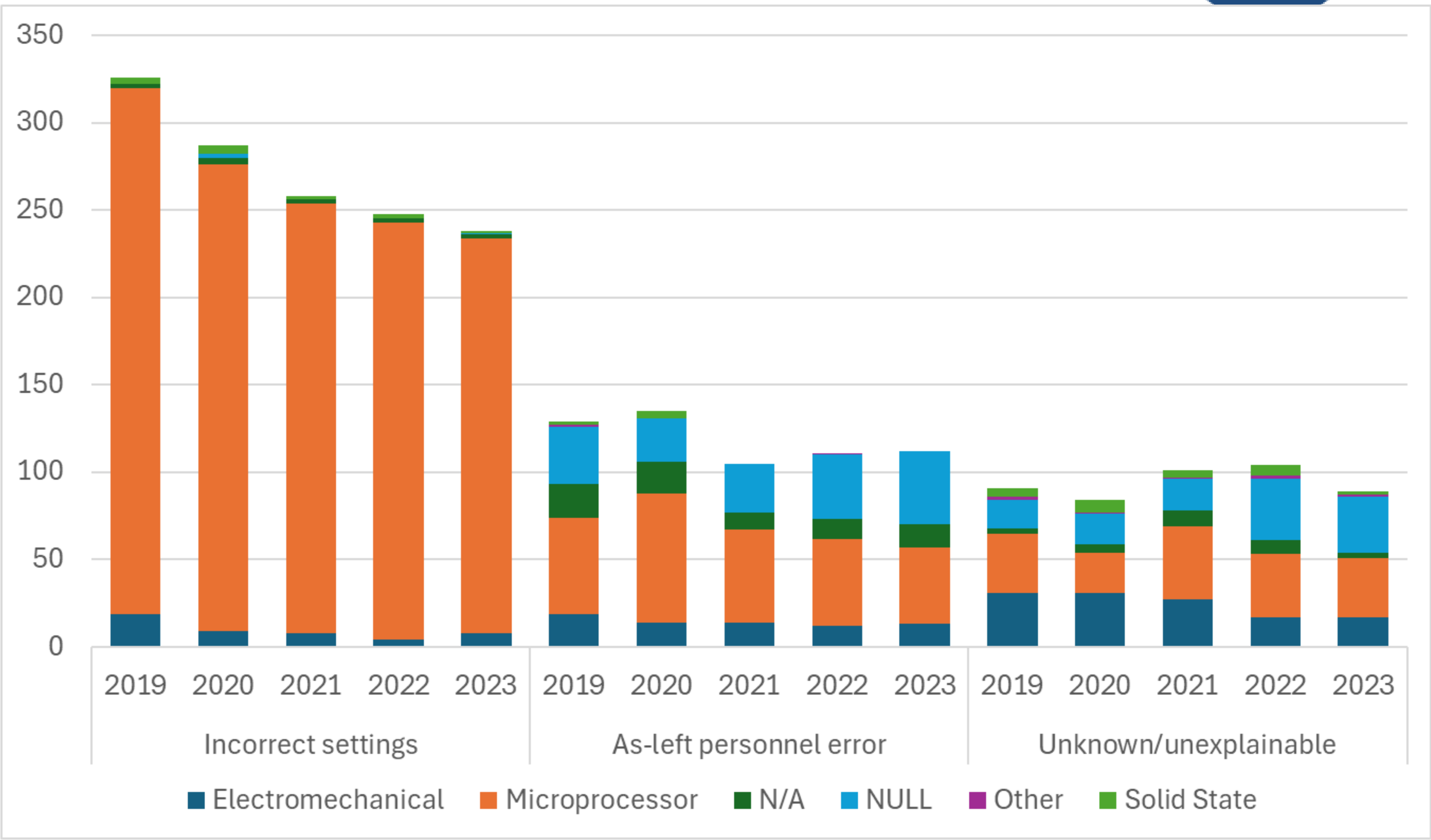


Misoperation Causes Counts

Cause Code	2019	2020	2021	2022	2023	Grand Total
Incorrect settings	328	293	263	251	243	1378
Relay failures/malfunctions	236	213	201	183	199	1032
As-left personnel error	132	136	107	112	115	602
Unknown/unexplainable	92	84	102	104	89	471
AC system	162	114	142	136	125	679
Communication failures	128	111	100	128	109	576
DC system	52	43	43	46	41	225
Design errors	57	51	53	49	54	264
Logic errors	49	42	44	46	43	224
Other/Explainable	108	84	127	104	102	525
Grand Total	**1344**	**1171**	**1182**	**1159**	**1120**	**5976**



Breakdown by Technology



Note: without inventory quantitative comparison between different technologies should be limited

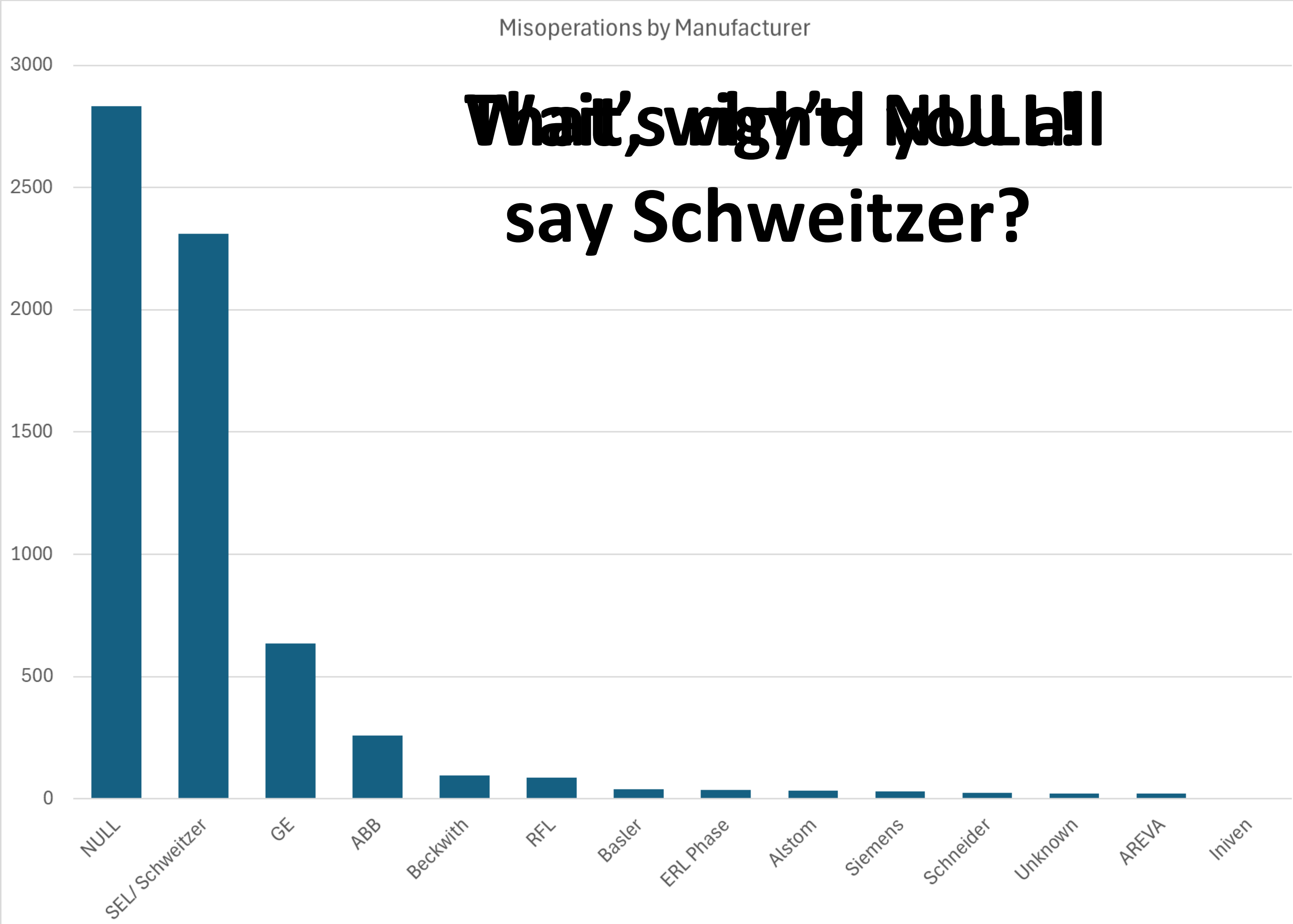
Based on MIDAS data, which manufacturer do you think has had the most Misoperations since 2018?

All together now!

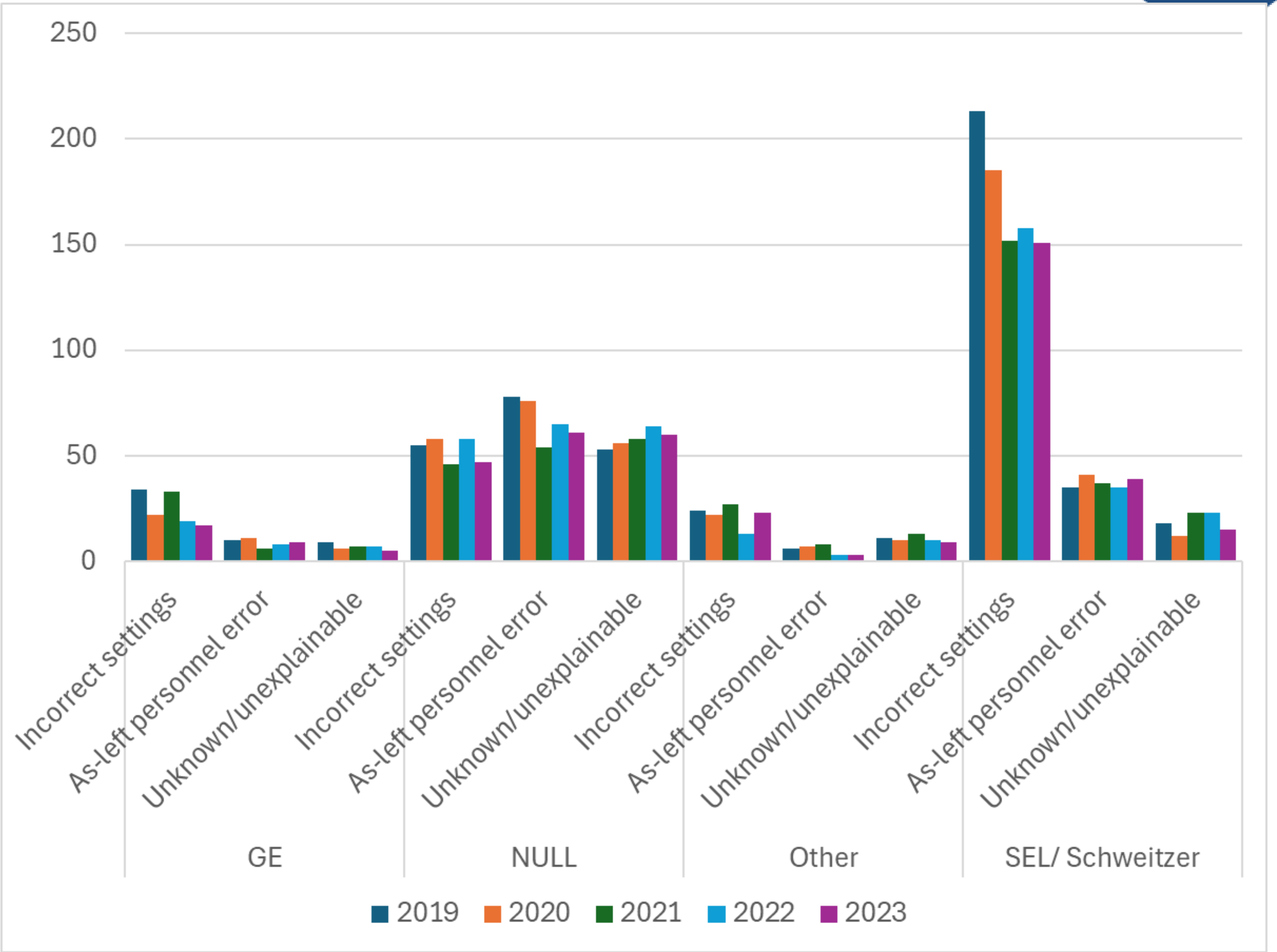
Trivia

That's right, NULL!

Wait, why'd you all say Schweitzer?



Breakdown by Manufacturer



Note: without inventory quantitative comparison between different manufacturers should be limited

Questions and Answers

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Event Analysis Reporting

Protection System Misoperation Snapshot

Wei Qiu, Lead Engineer of Event Analysis, NERC

BES Protection System Misoperation Reduction Workshop

October 01, 2024

RELIABILITY | RESILIENCE | SECURITY

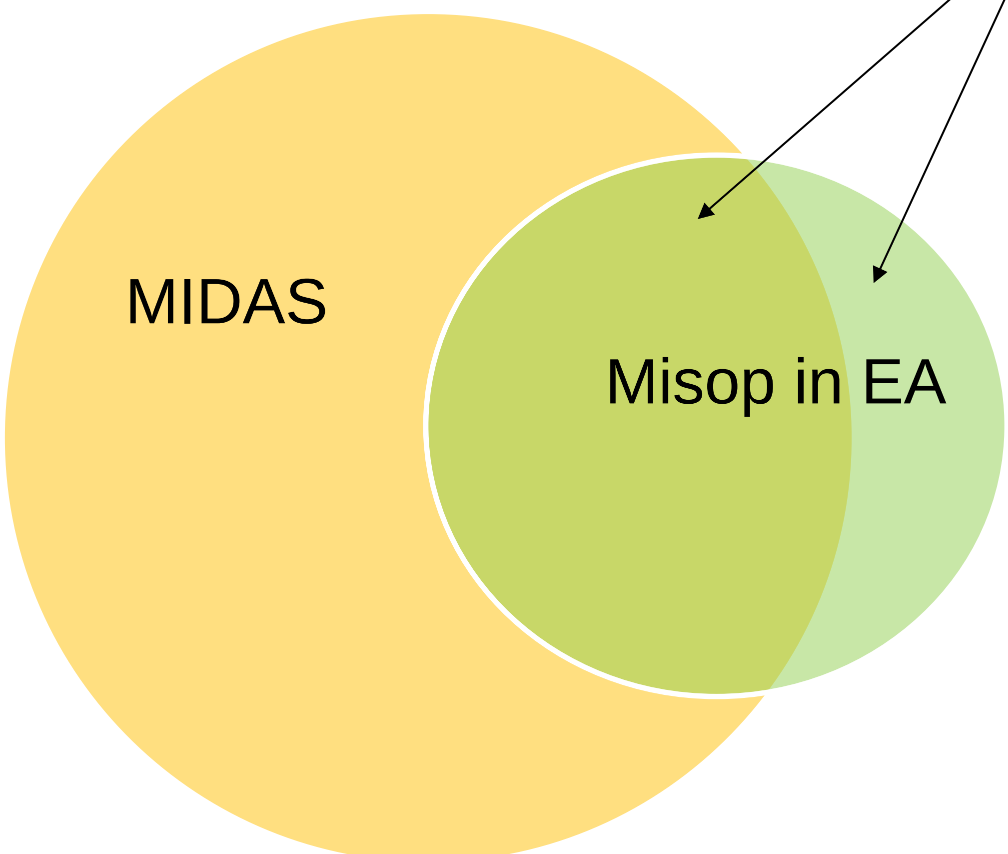



Agenda

- Difference between MIDAS and Misop-related Events in EA
- Trend and Analysis
  - Event Analysis Process (EAP)
  - Cause Code Assignment Process (CCAP)
- Conclusion

MIDAS vs. Misop in Event Analysis

- Qualified events
- Maintenance or testing



Statutory Performance Monitoring

NERC Rules of Procedure (Section 800 and Appendix 8)

- Flexible discretionary risk and/or impact analysis authorities
- Major event response

ERO Event Analysis Process (EAP)

- System operating criterion-based risk and/or impact monitoring
- Off-normal to major system event spectrum

ERO Cause Code Assignment Process (CCAP)

- System risk and/or impact trending

Trending Risk through Off-Normal Events

EAP

- Loss of monitoring and control
- Loss of 3 or more BES Facilities
- BES RAS Misoperation
- Loss of IBR
- Islanding
- …

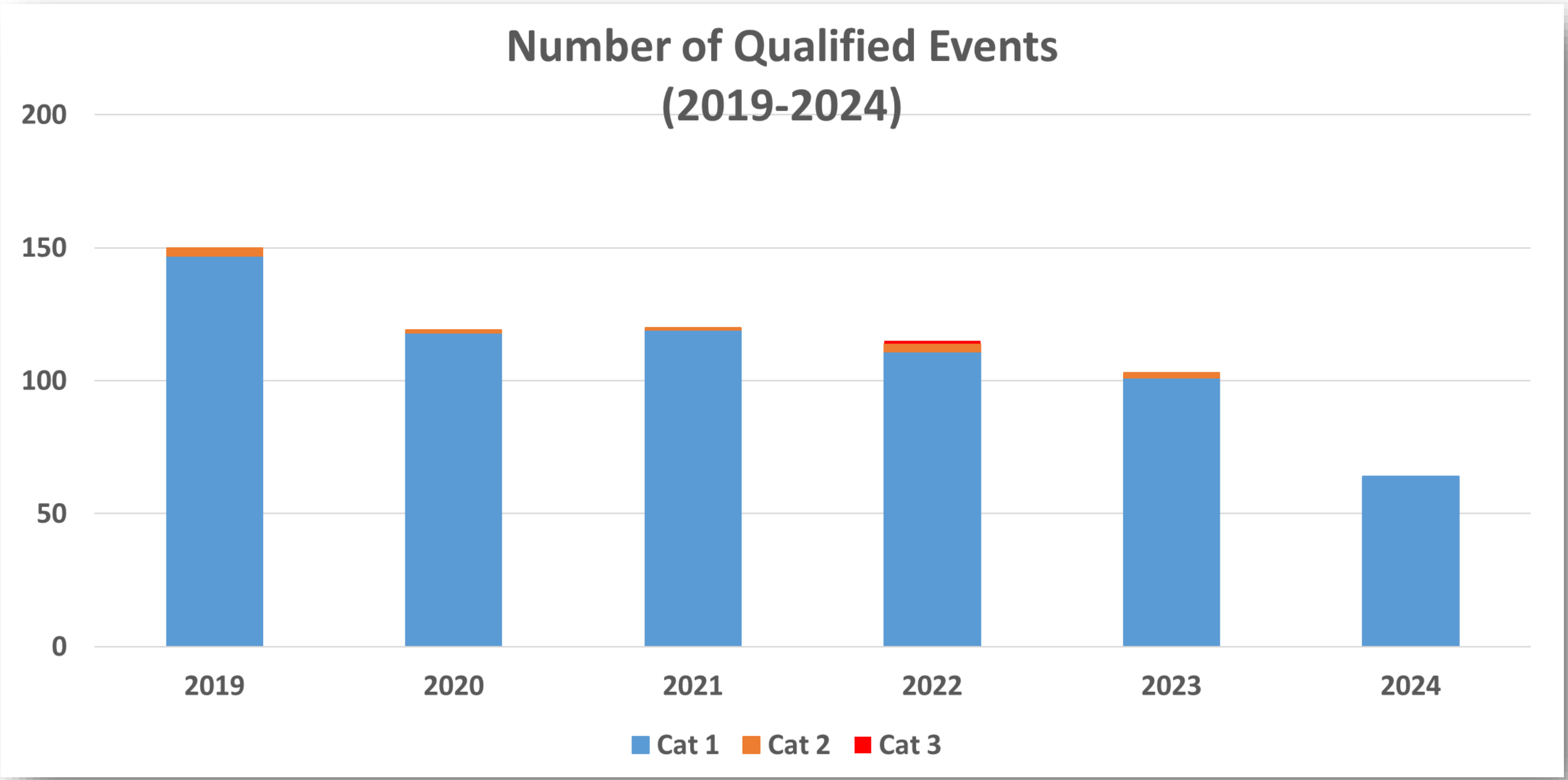
Monitoring System Operating Risk (Criterion-based)

CCAP

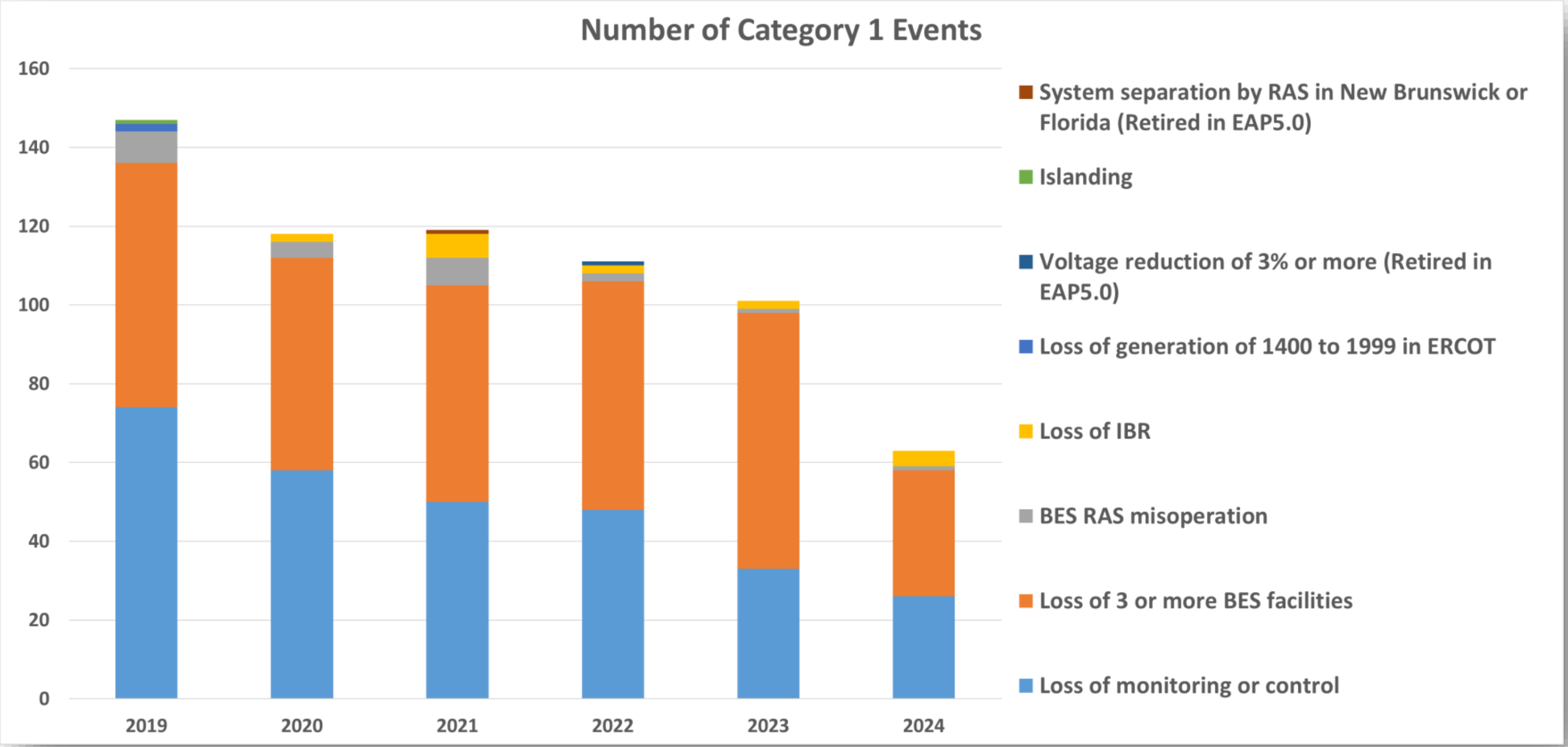
- Management/organization
- Design/Engineering
- Vendors/neighboring entities
- Individual human performance
- Damaged, defective or failed part
- …

Risk Contributors – Entity Performance. Mitigation reflective of corrective action

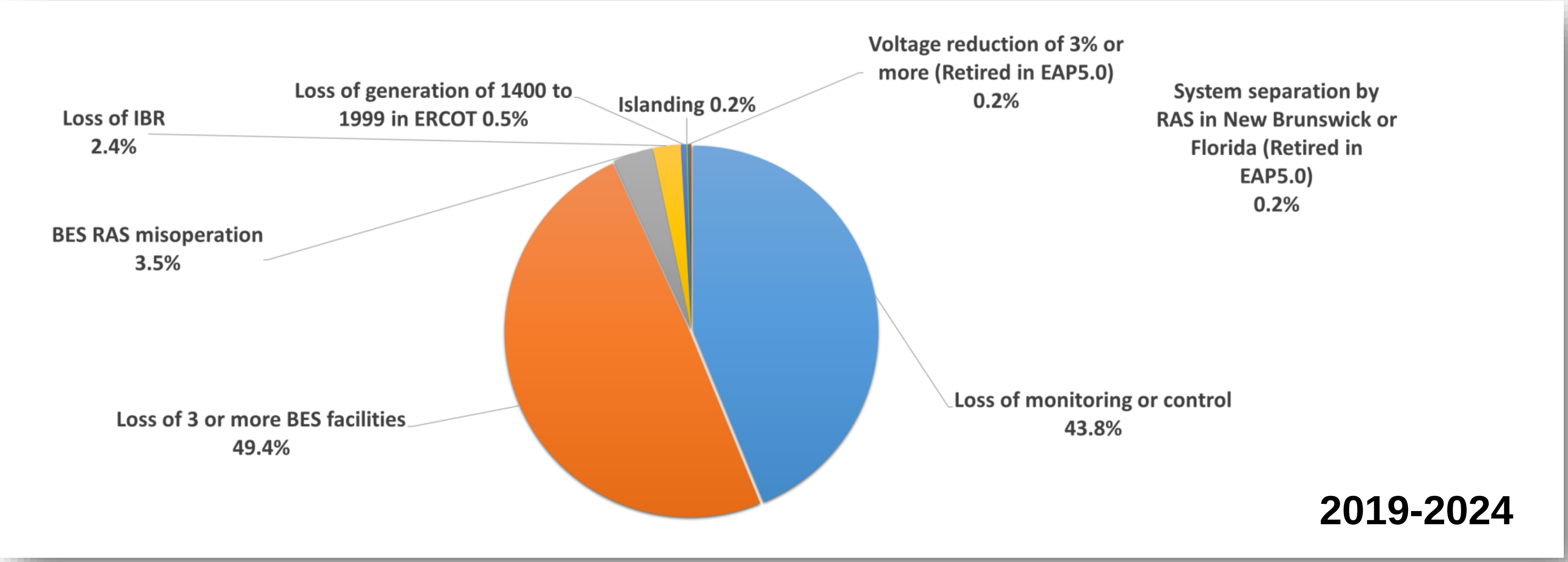
Trending of Qualified Events



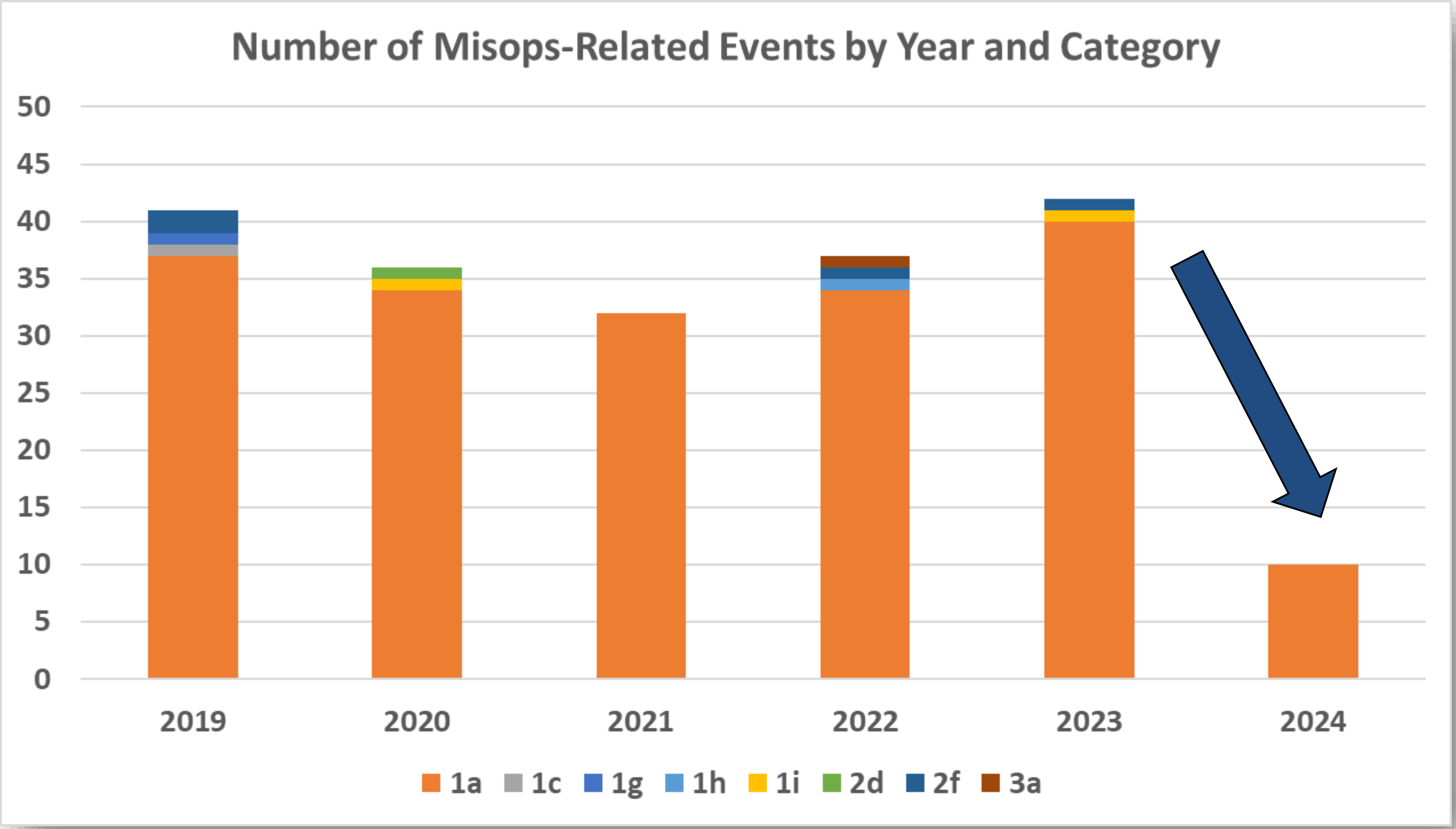
Trending of Category 1 Events



Trending of Category 1 Events (Cont'd)

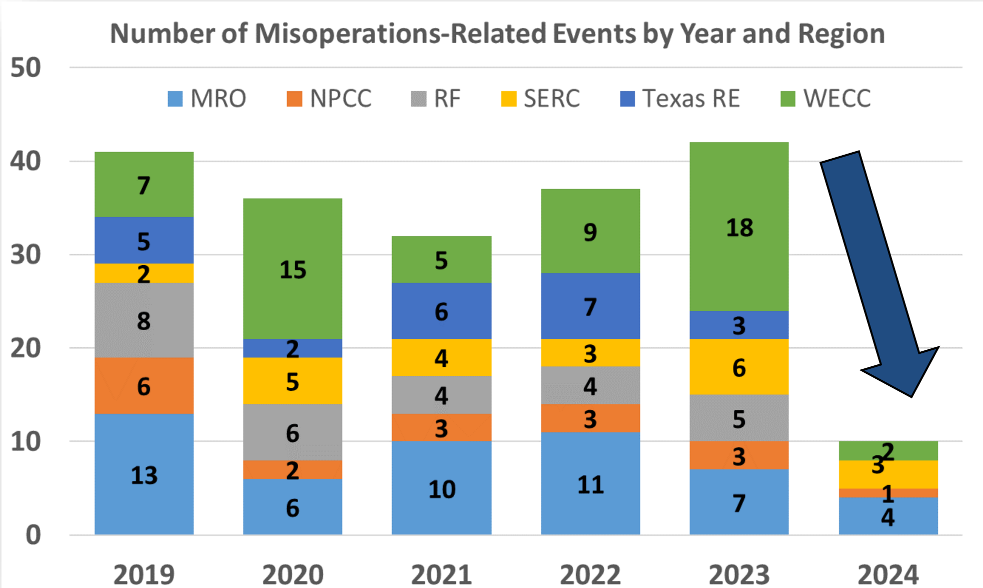


Misoperation Event Type by Year



Category 1a: An unexpected outage, that is contrary to design, of three or more BES facilities caused by a common disturbance...

Misoperation Snapshot



- Gold: incorrect settings
- Silver: relay failures
- Seeking better understanding of mitigation impacts

Total Events (2019-present)	672	Percentage of Total Events (2019-present)
Misops-related Events (2019-present)	198	29%
Reasons		Percentage of Misops-related Events
Incorrect Settings	78	39.4%
Relay Failure	26	13.1%
Other	94	47.5%

Trending Risk through Off-Normal Events

EAP

- Loss of monitoring and control
- Loss of 3 or more BES Facilities
- BES RAS Misoperation
- Loss of IBR
- Islanding
- …

Monitoring System Operating Risk (Criterion-based)

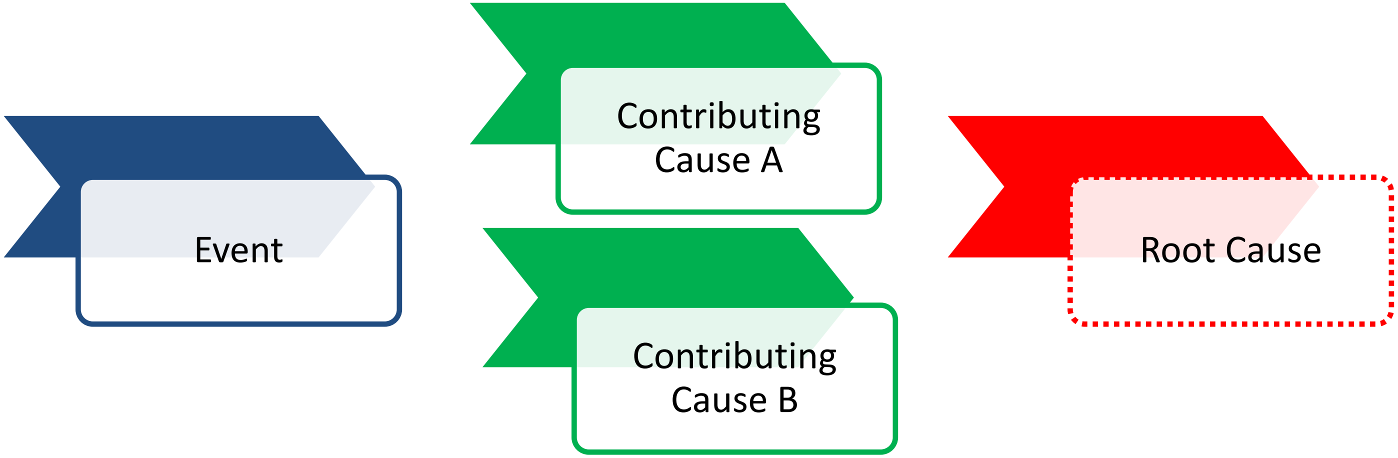
CCAP

- Management/organization
- Design/Engineering
- Vendors/neighboring entities
- Individual human performance
- Damaged, defective or failed part
- …

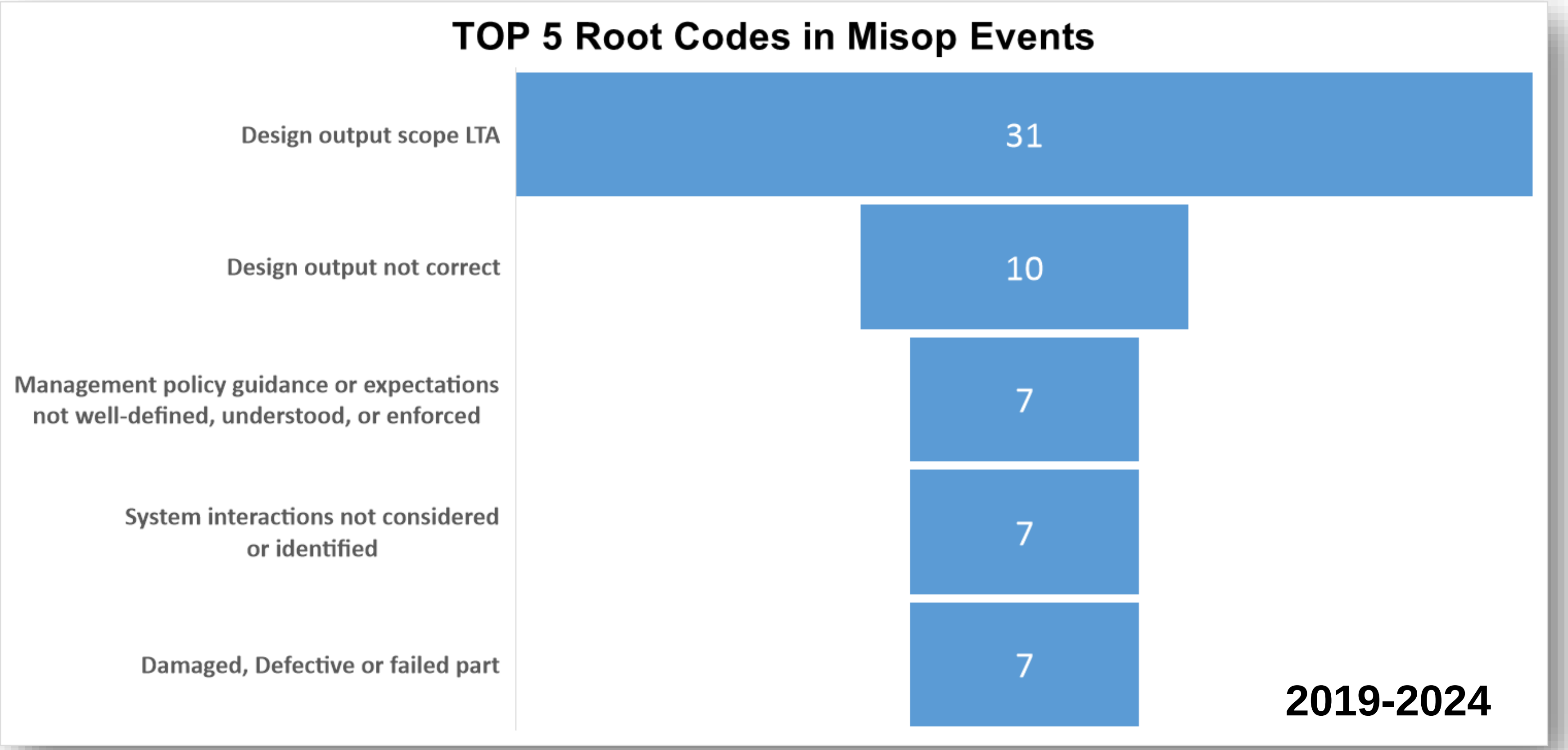
Risk Contributors – Entity Performance. Mitigation reflective of corrective action

Cause Code

- A **root cause** is the fundamental reason for the occurrence of a problem or event - remove the root and no event. A root cause is not always identifiable.
- A **contributing cause** is not a single factor, but one of many that can influence an event.

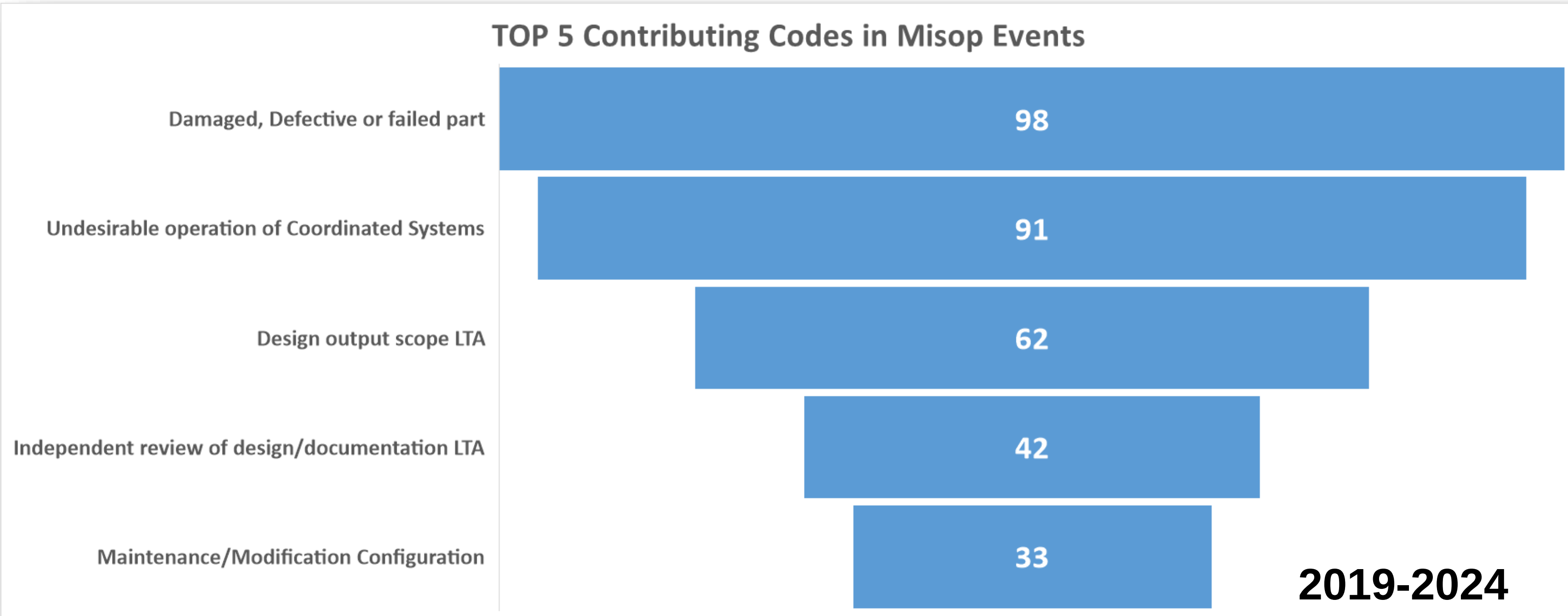


TOP 5 Root Codes in Misop Events



* LTA: Less than Adequate. LTA does not imply any negligence or fault for the entity; it is solely intended to say that the situation to which the “LTA” is assigned was not sufficient to prevent the undesired situation from occurring.

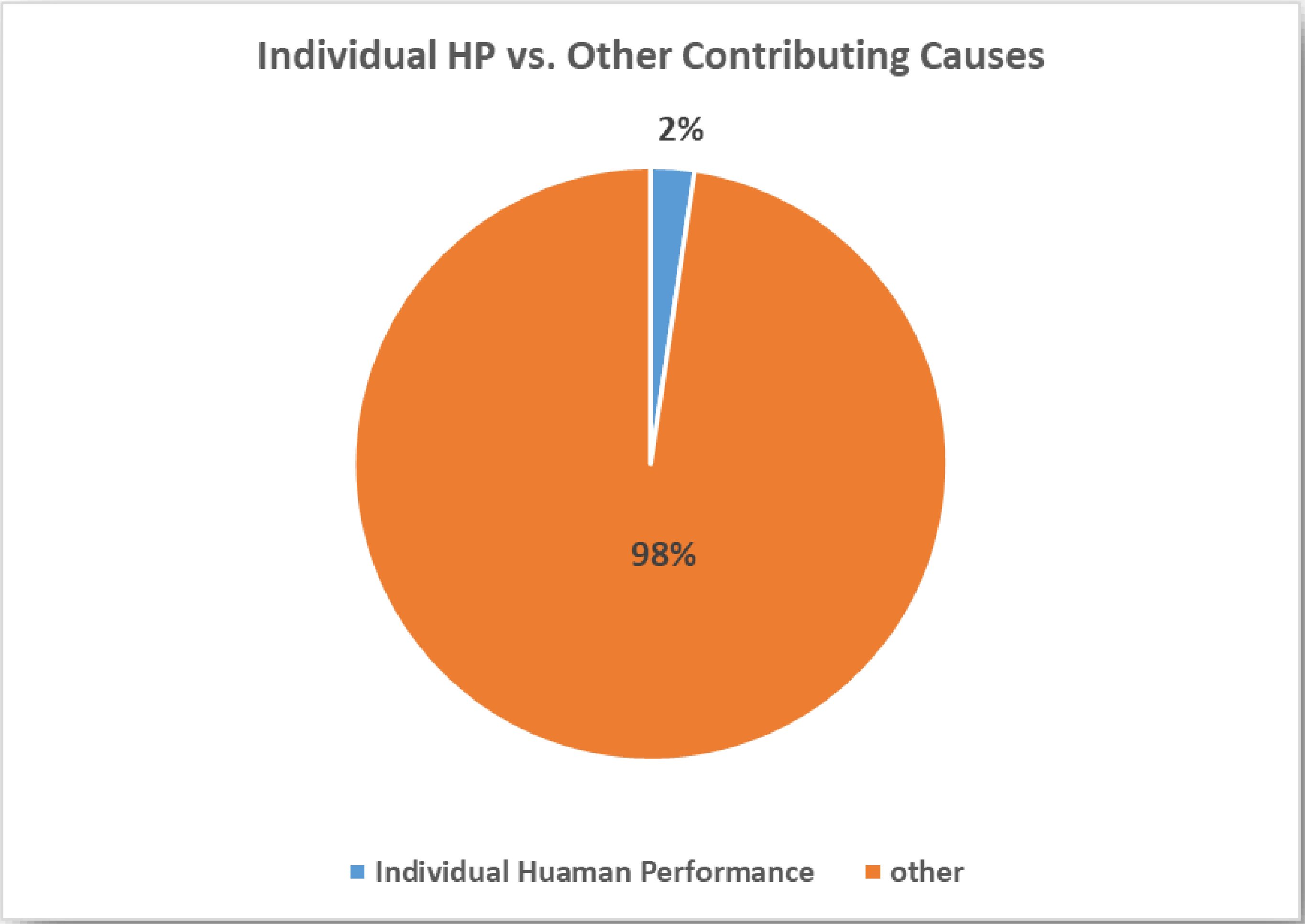
TOP 5 Contributing Codes in Misop Events



Performance Monitoring Insight

System Operating Risk	Risk Contributors	Corrective Actions
Loss of 3 or more BES Facilities - Misoperation	Incorrect Setting	• Start-up testing • Communication between groups • Coordination with neighbors • Peer review • Training - Individual human error
	Relay Failure	• Maintenance • Inspection • Asset management – aging • Vendor support

Individual Human Performance ???



Conclusions

- The number of Misop-Related Events is decreasing in 2024
- Top 2 Reasons – EAP
  - Gold: incorrect settings
  - Silver: relay failures
- Top 2 Root Causes – CCAP
  - Gold: Design output scope LTA
  - Silver: Desing output not correct
- Individual Human Performance is not a main risk contributor.

Questions and Answers

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Reference

- Event Analysis Program
- ERO Event Analysis Process Document - Version 5.0
- Cause Code Quick Reference Guide
- Cause Code Assignment Process
- Event Reports
- Lessons Learned

EAP Category 5.0

Category 1: An Event that Results in One or More of the Following:

a. An outage, contrary to design, of three or more BES Facilities caused by an event:

   i. The outage of a combination of three or more BES Facilities (excluding successful automatic reclosing)

   ii. The outage of an entire generation station of three or more generators (aggregate generation of 500 MW to 1,999 MW)[4]; each combined-cycle unit is counted as one generator.

b. ~~Intended and controlled system separation by the proper operation of a remedial action scheme (RAS) in New Brunswick or Florida from the Eastern Interconnection~~ Retired on January 1, 2024

c. Failure or misoperation of a BES Remedial Action Scheme (RAS)

d. ~~System-wide voltage reduction of 3% or more that lasts more than 15 continuous minutes due to a BES Emergency~~ Retired on January 1, 2024

e. BES system separation contrary to design results in an island of 100 MW to 999 MW. This excludes BES radial connections and non-BES (distribution) level islanding.

f. ~~Unplanned evacuation from a control center facility with BPS SCADA functionality for 30 minutes or more.~~ Retired on January 1, 2016

g. In ERCOT, loss of generation of 1,400 MW to 1,999 MW

[3] ERO Enterprise Guide for the Multi-Region Registered Entity Coordinated Oversight Program, March 2018, Section IX: System Events

[4] Gross MW output of the generators at the time of the outage.

EAP Category 5.0 (cont'd)

h. Loss of monitoring[5] and/or control[6] at a Control Center such that it degrades[7] the entity's ability to make Real-time operating decisions that are necessary to maintain reliability of the BES in the entity's footprint for 30 continuous minutes or more.

Some examples that should be considered for EA reporting include but are not limited to the following. Additional cases are provided in the Addendum for Category 1h Events found under reference materials for event analysis on the EA Program website.[8]

i. Loss of operator ability to remotely monitor or control BES elements
ii. Loss of communications from SCADA remote terminal units (RTU)
iii. Unavailability of ICCP links, which reduces BES visibility
iv. Loss of the ability to remotely monitor and control generating units via automatic generation control (AGC)
v. Unacceptable state estimator or real time contingency analysis solutions

i. A non-consequential interruption[9] of inverter type resources[10] aggregated to 500MW or more not caused by a fault on its inverters, or its ac terminal equipment.

j. A non-consequential interruption[11] of a DC tie(s), between two separate asynchronous systems, loaded at 500 MW or more, when the outage is not caused by a fault on the dc tie, its inverters, or its ac terminal equipment.

Category 2: An Event that Results in One or More of the Following:

a. Complete loss of interpersonal communication and alternative interpersonal communication capability affecting its staffed BES control center for 30 continuous minutes or more.

b. Complete loss of SCADA, control or monitoring functionality for 30 minutes or more. Retired on January 01, 2016 refer to Category 1h

c. BES Emergency resulting in a voltage deviation of ≥ 10% difference of nominal voltage sustained for ≥ 15 continuous minutes.

d. Complete loss of off-site power (LOOP) to a nuclear generating station per the Nuclear Plant Interface Requirement

e. System separation contrary to design, that results in an island of 1,000 MW to 4,999 MW

f. Simultaneous loss of 300 MW or more of firm load due to a BES event, contrary to design, for more than 15 minutes

[5] The ability to accurately receive relevant information about the BES in Real Time and evaluate system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions to maintain reliability of the BES.
[6] The ability to take and/or direct actions to maintain the reliability of the BES in Real Time via entity actions or by issuing Operating Instructions.
[7] For purposes of 1h categorization "degrades" means less-than required functioning of any monitoring/control component, process, or capability.
[8] https://www.nerc.com/pa/rrm/ea/Pages/EA-Program.aspx
[9] Interruption of resources caused by action of control systems on the resources in response to perturbations in voltage and/or frequency on the Interconnection, not including the control actions of a RAS.
[10] In most cases, inverter-based generating resources refer to Type 3 and Type 4 wind power plants, and solar photovoltaic (PV) resources. Battery energy storage is also considered an inverter-based resource. Many transmission-connected reactive devices such as STATCOMs and SVCs are also inverter-based. Similarly, HVDC circuits also interface with the AC network though converters.
[11] Interruption of resources caused by action of control systems on the resources in response to perturbations in voltage and/or frequency on the Interconnection, not including the control actions of a RAS.

g. Interconnection Reliability Operating Limit (IROL) exceedance for greater than 30 minutes

Category 3: An Event That Results in One or More of the Following:

a. Loss of firm load, contrary to design, of 2,000 MW or more.

b. System separation contrary to design, that results in an island of 5,000 MW or more

c. System separation (without load loss) contrary to design, that islands Florida from the Eastern Interconnection

d. Loss of 2,000 MW or more provided by DC tie(s) connected to asynchronous resources

e. Loss of generation (including inverter-based resources) of 2,000 MW or more. This excludes RAS action that performed as designed.

Cause Code Reference

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Start Here

NERC CCAP
Cause Code Quick Reference

nerc.lessonslearned@nerc.net www.nerc.com

A1 Design/Engineering

B1 DESIGN INPUT LTA
- C01 Design input cannot be met
- C02 Design input obsolete
- C03 Design input not correct
- C04 Necessary design input not available

B2 DESIGN OUTPUT LTA
- C01 Design output scope LTA
- C02 Design output not clear
- C03 Design output not correct
- C04 Inconsistent design output
- C05 Design input not addressed in design output
- C06 Drawing, specification, or data error
- C07 Error in equipment or material selection
- C08 Errors not detectable
- C09 Errors not recoverable

B3 DESIGN/DOCUMENTATION LTA
- C01 Design / documentation not complete
- C02 Design /documentation not up-to-date
- C03 Design/documentation not controlled

B4 DESIGN/INSTALLATION VERIFICATION LTA
- C01 Independent review of design / documentation LTA
- C02 Testing of design / installation LTA
- C03 Independent inspection of design / installation LTA
- C04 Acceptance of design / installation LTA

B5 OPERABILITY OF DESIGN/ ENVIRONMENT LTA
- C01 Ergonomics LTA
- C02 Physical environment LTA
- C03 Natural environment LTA

AN – No causes found

AZ – Information to determine cause LTA

B1 UNABLE TO IDENTIFY SPECIFIC ROOT CAUSE
- C01 Multiple, parallel causal sequences exist
- C02 Context out-of-scope of analysis
- C03 No cause uncovered after exhaustive testing

B2 REPORT STOPS AT FAILURE/ERROR MODE
- C01 Apparent Cause Analysis only
- C02 No causal sequence established or identified
- C03 Attributed to weather beyond initiating cause

B3 (OPEN)

B4 CROSS-REFERENCE REQUIRED FOR OTHER SOURCES OF INFORMATION
- C01 Requires secondary review once appropriate reports are received
- C02 Requires secondary review once additional outside investigative report is received

A2 Equipment/Material

B1 CALIBRATION FOR INSTRUMENTS LTA
- C01 Calibration LTA
- C02 Equipment found outside acceptance criteria
- C03 Coordinated tuning or adjustment of instrumentation LTA

B2 PERIODIC/ CORRECTIVE MAINTENANCE LTA
- C01 Preventive maintenance for equipment LTA
- C02 Predictive maintenance LTA
- C03 Corrective maintenance LTA
- C04 Equipment history LTA

B3 INSPECTION/ TESTING LTA
- C01 Start-up testing LTA
- C02 Inspection / testing LTA
- C03 Post-maintenance / Post-modification testing LTA

B4 MATERIAL CONTROL LTA
- C01 Material handling LTA
- C02 Material storage LTA
- C03 Material packaging LTA
- C04 Material shipping LTA
- C05 Shelf life exceeded
- C06 Unauthorized material substitution
- C07 Marking / labeling LTA

B5 PROCUREMENT CONTROL LTA
- C01 Control of changes to procurement specification / purchase order LTA
- C02 Fabricated item did not meet requirements
- C03 Incorrect item received
- C04 Product acceptance requirements LTA

B6 DEFECTIVE, FAILED, OR CONTAMINATED
- C01 Damaged, defective or failed part
- C02 Defective or failed material
- C03 Defective weld, braze, solder joint, crimp, hinge, or other connection
- C04 End-of-life failure
- C05 Electrical or instrument noise
- C06 Contaminant
- C07 Software failure

B7 EQUIPMENT INTERACTIONS LTA
- C01 Communications path LTA
- C02 Data quality LTA
- C03 Supporting power system LTA
- C04 Undesirable operation of Coordinated Systems

A3 Individual Human Performance

B1 SKILL BASED ERROR
- C01 Check of work LTA
- C02 Step was omitted due to distraction
- C03 Incorrect performance due to mental lapse
- C04 Infrequently performed steps were performed incorrectly
- C05 Delay in time caused LTA actions
- C06 Wrong action selected based on similarity with other actions
- C07 Omission / repeating of steps due to assumptions for completion

B2 RULE BASED ERROR
- C01 Strong rule incorrectly chosen over other rules
- C02 Signs to stop were ignored and steps performed incorrectly
- C03 Too much activity was occurring and error made in problem solving
- C04 Previous success in use of rule reinforced continued use of rule
- C05 Situation incorrectly identified or represented resulting in wrong rule used

B3 KNOWLEDGE BASED ERROR
- C01 Attention was given to wrong issues
- C02 LTA conclusion based on sequencing of facts
- C03 Individual justified action by focusing on biased evidence
- C04 LTA review based on assumption that process will not change
- C05 Incorrect assumption that a correlation existed between two or more facts
- C06 Individual underestimated the problem by using past events as basis

B4 WORK PRACTICES LTA
- C01 Individual's capability to perform work LTA [Examples include: Sensory /perceptual capabilities LTA; Motor / physical capabilities LTA; and Attitude / psychological profile LTA]
- C02 Deliberate violation

A4 Management / Organization

B1 MANAGEMENT METHODS LTA
- C01 Management policy guidance or expectations are not well-defined, understood, or enforced
- C02 Job performance standards not adequately defined
- C03 Management direction created insufficient awareness of impact of actions on safety / reliability
- C04 Management follow-up or monitoring of activities did not identify problems
- C05 Management assessment did not determine causes of previous event or known problem
- C06 Previous industry or in-house experience was not effectively used to prevent recurrence
- C07 Responsibility of personnel not well-defined or personnel not held accountable
- C08 Corrective action responses to a known or repetitive problem was untimely
- C09 Corrective action for previously identified problem or event was not adequate to prevent recurrence

B2 RESOURCE MANAGEMENT LTA
- C01 Too many administrative duties assigned to immediate supervisor
- C02 Insufficient supervisory resources to provide necessary supervision
- C03 Insufficient manpower to support identified goal/ objective
- C04 Resources not provided to assure adequate training was provided / maintained
- C05 Needed resource changes not approved / funded
- C06 Means not provided to assure procedures / documents / records were of adequate quality and up-to-date
- C07 Means not provided for assuring adequate availability of appropriate materials / tools
- C08 Means not provided for assuring adequate equipment quality, reliability, or operability
- C09 Personnel selection did not assure match of worker motivations and job descriptions
- C10 Means/method not provided for assuring adequate quality of contract services

B3 WORK ORGANIZATION & PLANNING LTA
- C01 Insufficient time for worker to prepare task
- C02 Insufficient time allotted for task
- C03 Duties not well-distributed among personnel
- C04 Too few workers assigned to task
- C05 Insufficient number of trained or experienced workers assigned to task
- C06 Planning not coordinated with inputs from Walk downs/Task analysis
- C07 Job scoping did not identify potential task interruptions &/or environmental stress
- C08 Job scoping did not identify special circumstances &/or conditions
- C09 Work planning not coordinated with all departments involved in task
- C10 Problem performing repetitive tasks &/or sub-tasks
- C11 Inadequate work package preparation

B4 SUPERVISORY METHODS LTA
- C01 Tasks and individual accountability not made clear to worker
- C02 Progress / status of task not adequately tracked
- C03 Appropriate level of in-task supervision not determined prior to task
- C04 Direct supervisory involvement in task interfered with overview role
- C05 Emphasis on schedule exceeded emphasis on methods / doing a good job
- C06 Job performance and self-checking standards not properly communicated
- C07 Too many concurrent tasks assigned to worker
- C08 Frequent job or task "shuffling"
- C09 Assignment did not consider worker's need to use higher-order skills
- C10 Assignment did not consider worker's previous task
- C11 Assignment did not consider worker's ingrained work patterns
- C12 Contact with personnel too infrequent to detect work habit / attitude changes
- C13 Provided feedback on negative performance but not on positive performance

B5 CHANGE MANAGEMENT LTA
- C01 Problem identification did not identify need for change
- C02 Change not implemented in timely manner
- C03 Inadequate vendor support of change
- C04 Risks / consequences associated with change not adequately reviewed / assessed
- C05 System interactions not considered or identified
- C06 Personnel / department interactions not considered
- C07 Effects of change on schedules not adequately addressed
- C08 Change-related training / retraining not performed or not adequate
- C09 Change-related documents not developed or revised
- C10 Change-related equipment not provided or not revised
- C11 Changes not adequately communicated
- C12 Change not identifiable during task
- C13 Accuracy / effectiveness of change not verified or not validated

A5 Communication

B1 WRITTEN COMMUNICATIONS METHOD OF PRESENTATION LTA
- C01 Format deficiencies
- C02 Improper referencing or branching
- C03 Checklist LTA
- C04 Deficiencies in user aids (charts, etc.)
- C05 Recent changes not made apparent to user
- C06 Instruction step / information in wrong sequence
- C07 Unclear / complex wording or grammar

B2 WRITTEN COMMUNICATION CONTENT LTA
- C01 Limit inaccuracies
- C02 Difficult to implement
- C03 Data / computations wrong / incomplete
- C04 Equipment identification LTA
- C05 Ambiguous instructions / requirements
- C06 Typographical error
- C07 Facts wrong / requirements not correct
- C08 Incomplete / situation not covered
- C09 Wrong revision used

B3 WRITTEN COMMUNICATION NOT USED
- C01 Lack of written communication
- C02 Not available or inconvenient for use

B4 VERBAL COMMUNICATION LTA
- C01 Communication between work groups LTA
- C02 Shift communications LTA
- C03 Correct terminology not used
- C04 Verification / repeat back not used
- C05 Information sent but not understood
- C06 Suspected problems not communicated to supervision
- C07 No communication method available

A6 Training

B1 NO TRAINING PROVIDED
- C01 Decision not to train
- C02 Training requirements not identified
- C03 Work incorrectly considered "skill of the craft"

B2 TRAINING METHODS LTA
- C01 Practice or hands-on experience LTA
- C02 Testing LTA
- C03 Refresher training LTA
- C04 Inadequate presentation

B3 TRAINING MATERIAL LTA
- C01 Training objectives LTA
- C02 Inadequate content
- C03 Training on new work methods LTA
- C04 Performance standards LTA

A7 Other

B1 EXTERNAL PHENOMENA
- C01 Weather or ambient conditions LTA
- C02 Power failure or transient
- C03 External fire or explosion
- C04 Other natural phenomena LTA
- C05 Copper Theft
- C06 Vandalism

B2 RADIOLOGICAL/HAZARDOUS MATERIAL PROBLEM
- C01 Legacy contamination
- C02 Source unknown

B3 VENDOR OR SUPPLIER PROBLEM
- C01 Follow-up LTA
- C02 Vendor corrective actions LTA
- C03 Extent-of-Condition communications LTA

B4 OTHER PARTIES INVOLVED IN EVENT
- C01 Other NERC-Registered entity cited as involved in event
- C02 Vendor or contractor cited as involved in event
- C03 Non NERC-Registered entity cited as involved in event

A8 (Open)

AX Overall Configuration

B1 INSTALLATION/DESIGN CONFIGURATION LTA

B2 MAINTENANCE/MODIFICATION CONFIGURATION LTA

CC_Quick_Reference_2024

Level A nodes are underlined	Level C nodes are in "sentence case"
Level B nodes are in ALL CAPS	LTA = Less Than Adequate

TCIPI

(Transmission Continuous Improvement Program Implementation)

Human Initiated Reliability Event Reporting

TCIPI – Table of Content

- Program Creation & Organization
- The Policy
  - Reportable Events
- Program Execution
- Risk Based Evaluation Process
- Metrics
  - Inadvertent Dashboard
  - Other Utilities Dashboard
  - Data Driven Decisions
  - Corrective Action Dashboard
  - Lessons Learned / Corrective Action Program
  - Example - SEL BFR Actions taken
- Summary

Kammy's Bio

- Current Role
  - Supervisor in Organization Performance & Delivery – System Operations
  - TCIPI Program, Operational Reporting, Reliability Compliance, Project Management
- BPA History:
  - Started at BPA in 1990 in the Safety Office
  - First Federal job was in Power
  - Worked in Power Services, Finance, Corporate, and Transmission
  - Have been with System Operations for 8 years

Brian's Bio

- Current Role
  - Lead Management and Program Analyst in the Transmission Continuous Improvement Program Implementation (TCIPI)
- BPA History:
  - Started at BPA in 2019 in TCIPI
- Prior to BPA:
  - Project Manager for Aerospace Manufacturing Co
  - Retired Air Force 30 years, Air Traffic Controller,
  - Experience in Human Organizational Performance, Human Factors in Aviation Safety, Adjunct College Educator
  - More…

TCIPI – Origins and Background - 2017

Problem Statement: BPA (Transmission) does not currently have a comprehensive program to track, analyze, and provide systemic fixes to Reliability incidents including Inadvertents, mis-operations and equipment on the BPA grid.

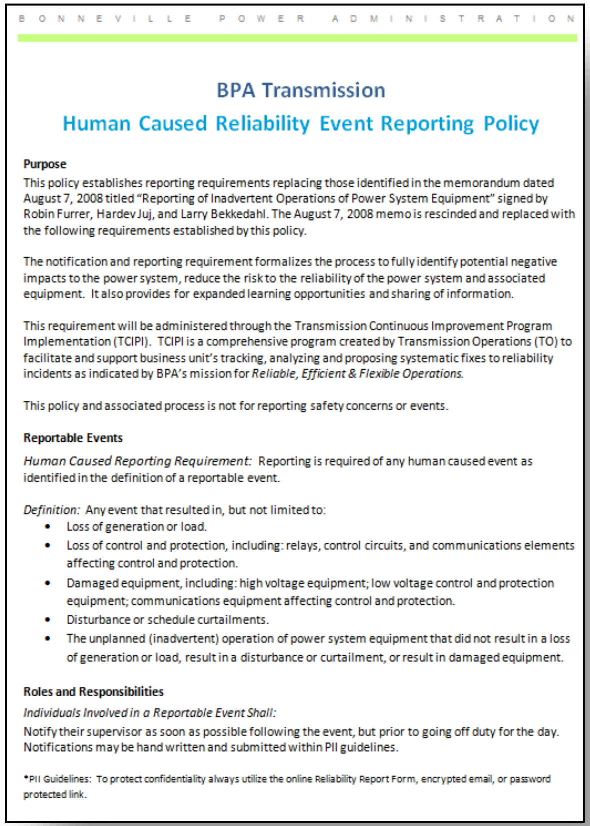
Strategic Alignment:
Strategic Objective 2b: "*Modernize federal power and transmission system operations and supporting technology.*" This effort is also a subcomponent of the Transmission Business Model (TBM) section relating to Continuous Improvement.

Scope:
Develop for implementation an operational continuous-improvement program that identifies a centralized process for Reliability event-analysis, lessons learned, and corrective-action plans across Transmission. This program will promote transmission excellence by incorporating human performance evaluation into the analysis of incidents or events and sharing operating experience.

TCIPI – The Policy

BPA Transmission Senior Vice President and TCIPI Leadership announced a new ***Human Initiated Reliability Event Reporting Policy** in 2019.*

- Policy replaced the 2008 Memorandum entitled, "***Reportable Event Notification & Reporting Process.***"
- Developed by a cross functional group of Tier 3 and 4 managers from Engineering, Field Services, System Operations, and Planning.
- Transferred responsibility for collecting inadvertent and misoperations from System Operations to the Transmission Continuous Improvement Program Implementation (TCIPI).



B O N N E V I L L E P O W E R A D M I N I S T R A T I O N

BPA Transmission

Human Caused Reliability Event Reporting Policy

Purpose

This policy establishes reporting requirements replacing those identified in the memorandum dated August 7, 2008 titled "Reporting of Inadvertent Operations of Power System Equipment" signed by Robin Furrer, Hardev Juj, and Larry Bekkedahl. The August 7, 2008 memo is rescinded and replaced with the following requirements established by this policy.

The notification and reporting requirement formalizes the process to fully identify potential negative impacts to the power system, reduce the risk to the reliability of the power system and associated equipment. It also provides for expanded learning opportunities and sharing of information.

This requirement will be administered through the Transmission Continuous Improvement Program Implementation (TCIPI). TCIPI is a comprehensive program created by Transmission Operations (TO) to facilitate and support business unit's tracking, analyzing and proposing systematic fixes to reliability incidents as indicated by BPA's mission for *Reliable, Efficient & Flexible Operations*.

This policy and associated process is not for reporting safety concerns or events.

Reportable Events

Human Caused Reporting Requirement: Reporting is required of any human caused event as identified in the definition of a reportable event.

Definition: Any event that resulted in, but not limited to:

- Loss of generation or load.
- Loss of control and protection, including: relays, control circuits, and communications elements affecting control and protection.
- Damaged equipment, including: high voltage equipment; low voltage control and protection equipment; communications equipment affecting control and protection.
- Disturbance or schedule curtailments.
- The unplanned (inadvertent) operation of power system equipment that did not result in a loss of generation or load, result in a disturbance or curtailment, or result in damaged equipment.

Roles and Responsibilities

Individuals Involved in a Reportable Event Shall:

Notify their supervisor as soon as possible following the event, but prior to going off duty for the day. Notifications may be hand written and submitted within PII guidelines.

*PII Guidelines: To protect confidentiality always utilize the online Reliability Report Form, encrypted email, or password protected link.

TCIPI - Reportable Events

Human Initiated Reporting Requirement: Reporting is required for any human Initiated event as identified in the definition below.

Definition of Reportable Event: Any event that resulted in, but not limited to:

- Loss of generation or load
- Loss of control and protection, including relays, control circuits, and communications elements affecting control and protection
- Damaged equipment, including high voltage equipment; low voltage control and protection equipment; communications equipment affecting control and protection
- **Disturbance*** or schedule curtailments
- The unplanned (inadvertent) operation of power system equipment that did not result in a loss of generation or load, result in a disturbance or curtailment, or result in damaged equipment

*** NERC Disturbance definition**:

1. An unplanned event that produces an abnormal system condition.
2. Any perturbation to the electric system.
3. The unexpected change in ACE that is caused by the sudden failure of generation or interruption of load.

TCIPI - Program Execution

TCIPI Program functions on 3 key levels, leading into the support, development, and execution of actions to mitigate current and future risk:

1. TIRT (Transmission Incident Review Team)
2. TCIPI Steering Team
3. TCIPI Executive Management Team

Outcomes:

- Three key decision points are used to assess “value”. They are centered upon risk-based prioritization and impact (actual and projected) to the system, based upon the event.
- Quality analysis leading into management decisions to act. Defining the BEST Decision.
- S.M.A.R.T. outcomes defined in individual Corrective Actions
- Management support/authorization to enact changes (i.e., completing the Corrective Actions) with clarity /understanding of “value” based upon risk and impact (actual and projected) to the system

SMART: Specific-Measurable-Achievable-Relevant-Timely

Benefits:

- 360-degree view of event - “Balcony view”
- Predictive analysis component / trending
- Risk-based recommendations derived from analysis
- Shared collaboration and development of corrective measures
- Distribution of a Supervisor View for shared learning opportunities for Transmission personnel

Metrics

- Inadvertent Dashboard
- Other Utilities Dashboard
- Data Driven Decisions
- Corrective Action Dashboard
- Lessons Learned / Corrective Action Program
- Example - SEL BFR Actions taken

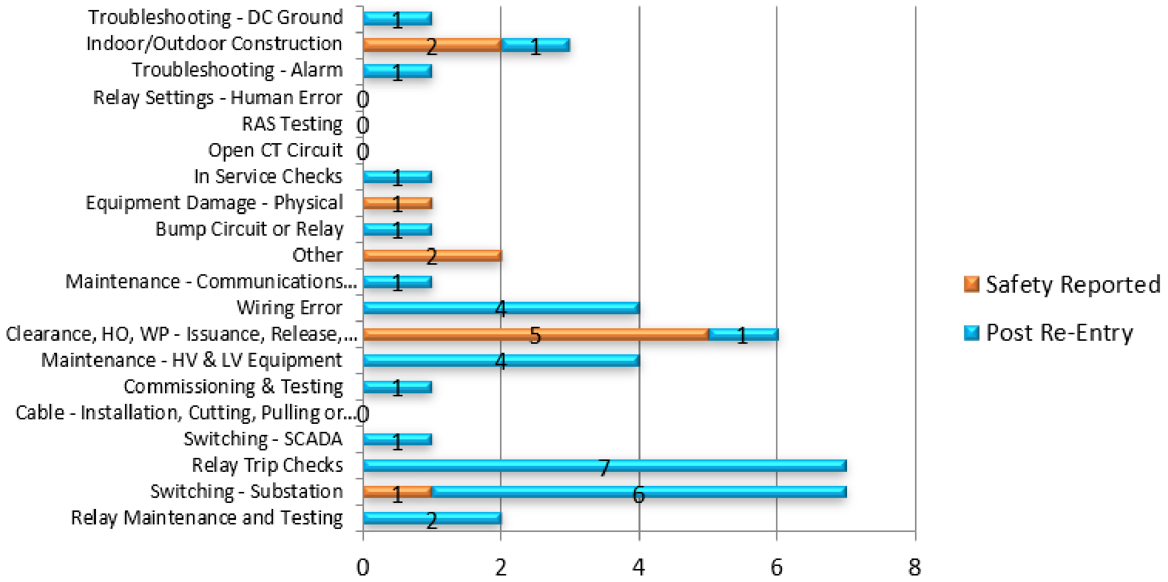
Human Initiated Reliability Event Reporting: FY2024

TCIPI Dashboard

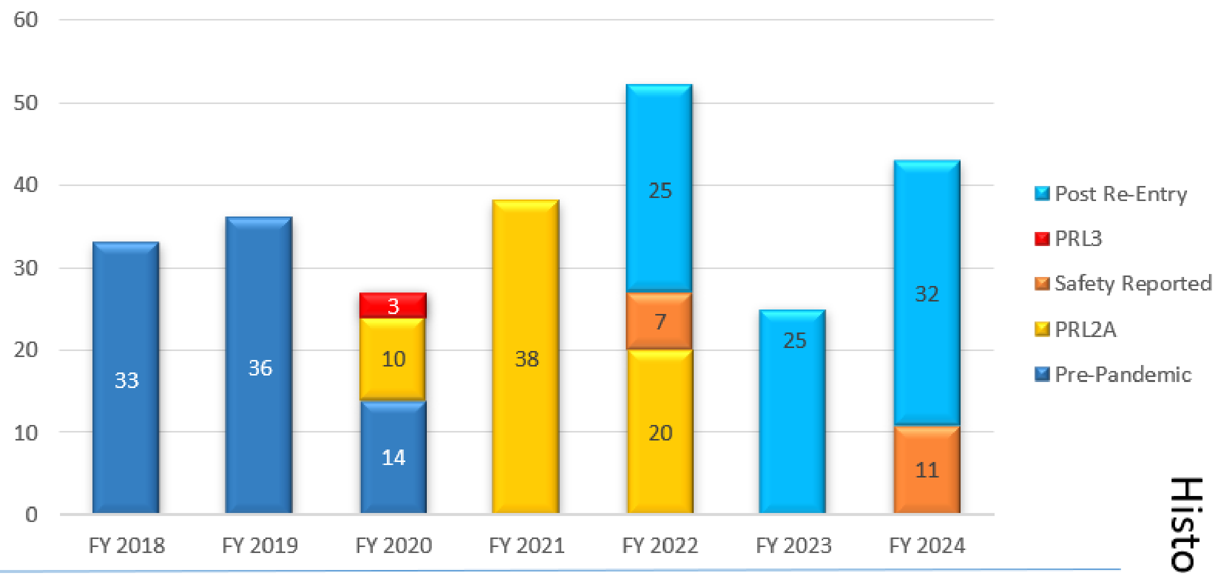
PRL = Pandemic Response Level

2024

Total Reported Events by Activity: FY 2024

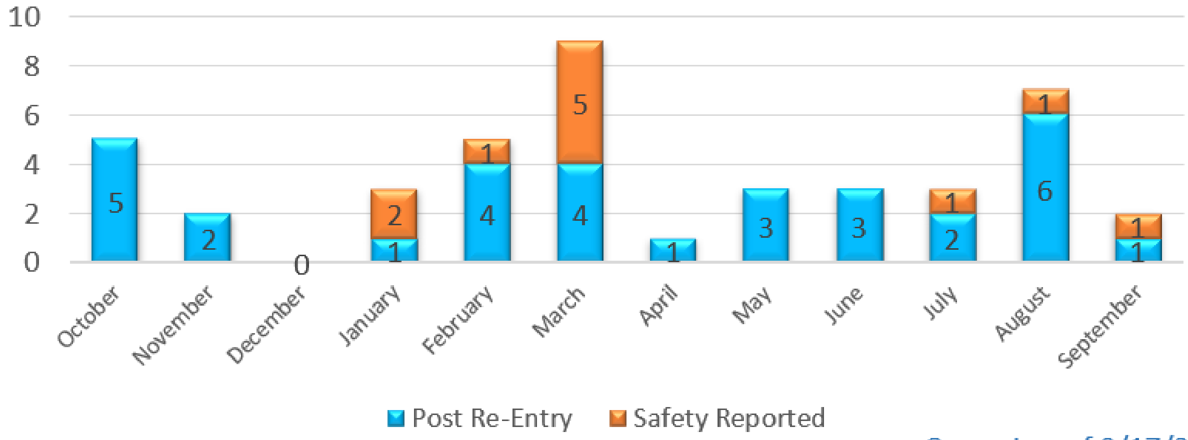


Number of Reported Events by Fiscal Year (FY)



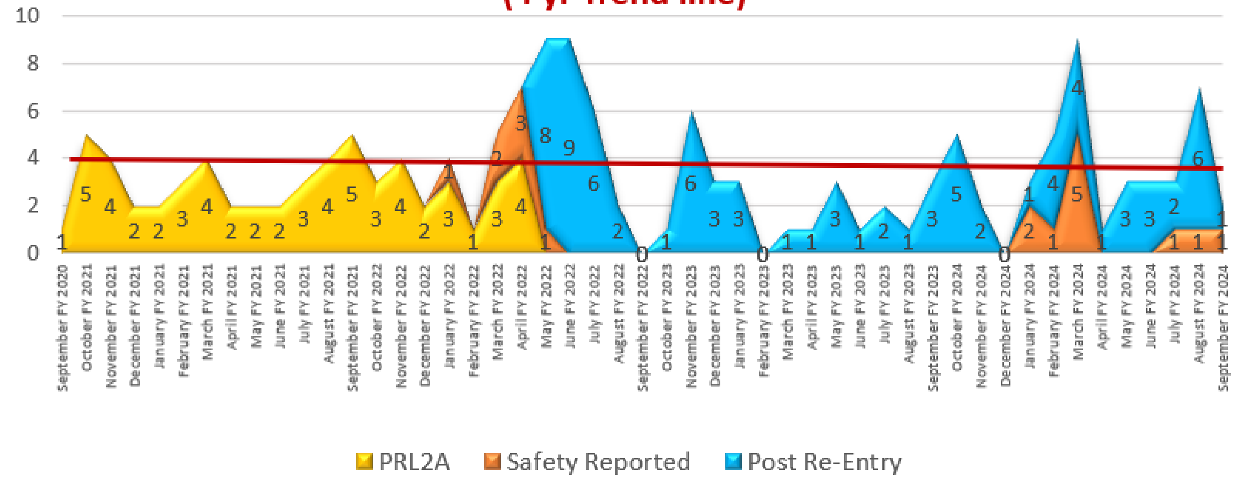
Historical

Number of Reported Incidents by Month in FY 2024



Number of Reported Events

(4 yr Trend line)

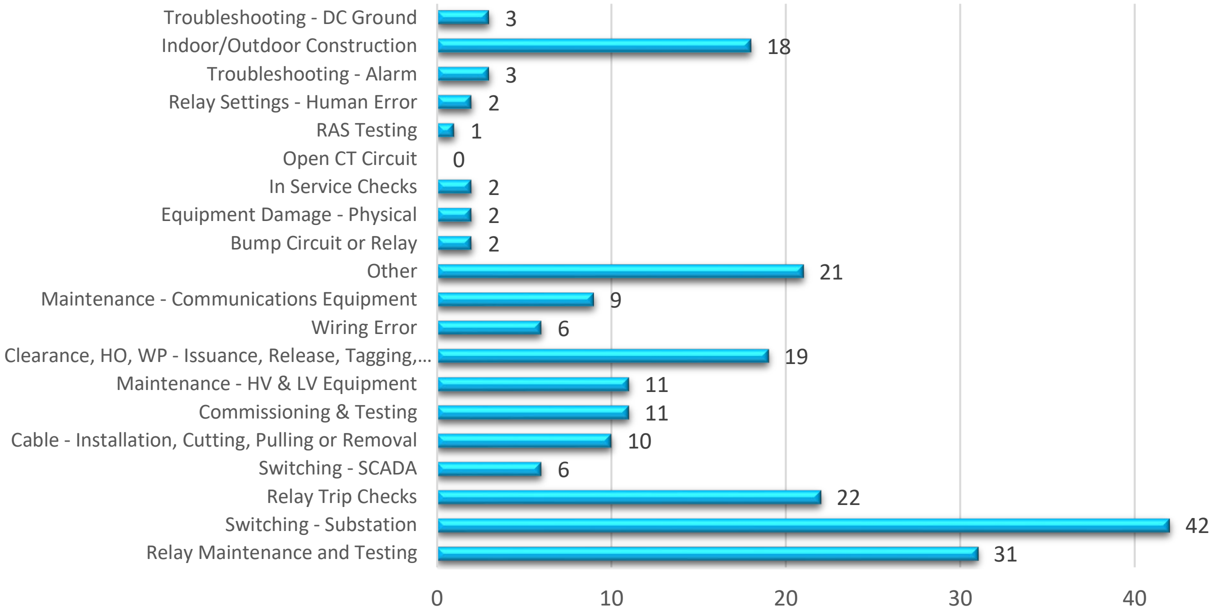


Current as of 9/17/2024 3:15 PM

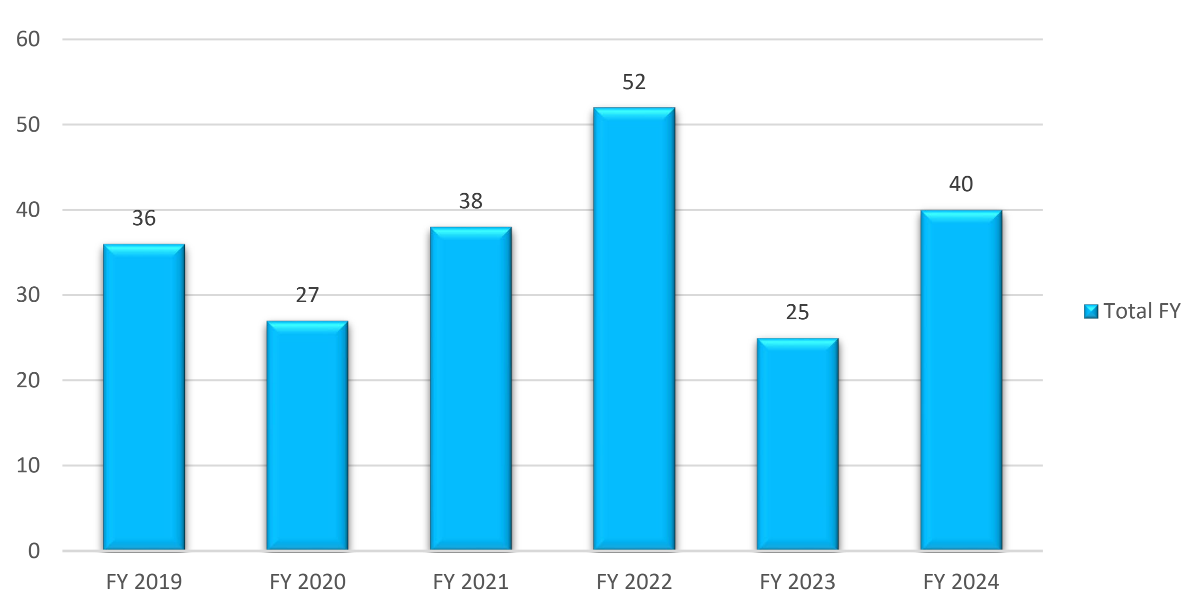
TCIPI Metrics – Inadvertent Summary Dashboard

All Fiscal Years (FY)

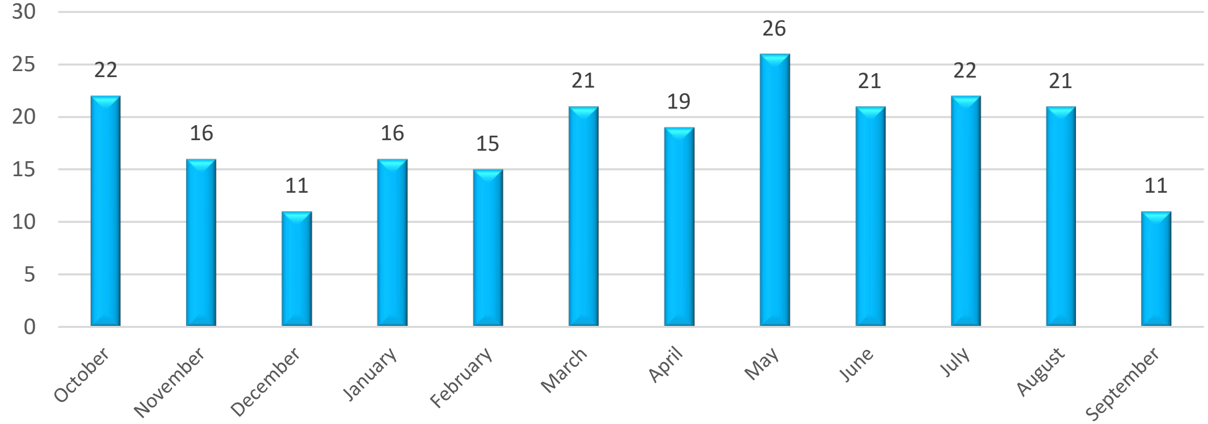
Total Reported Events by Activity: all FY



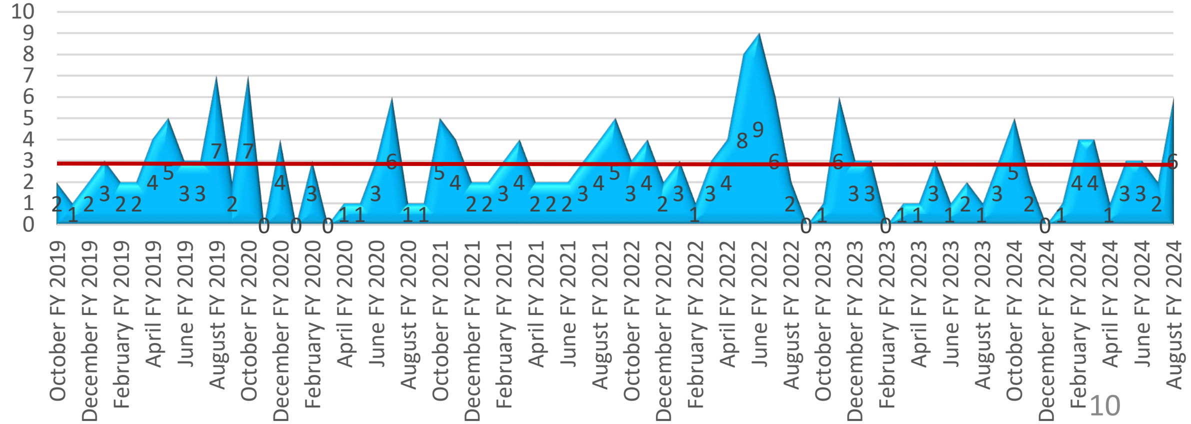
Number of Reported Events by Fiscal Year (FY)



Number of Reported Incidents by Month in all FY



Number of Reported Events (All Years w/ Trend line)

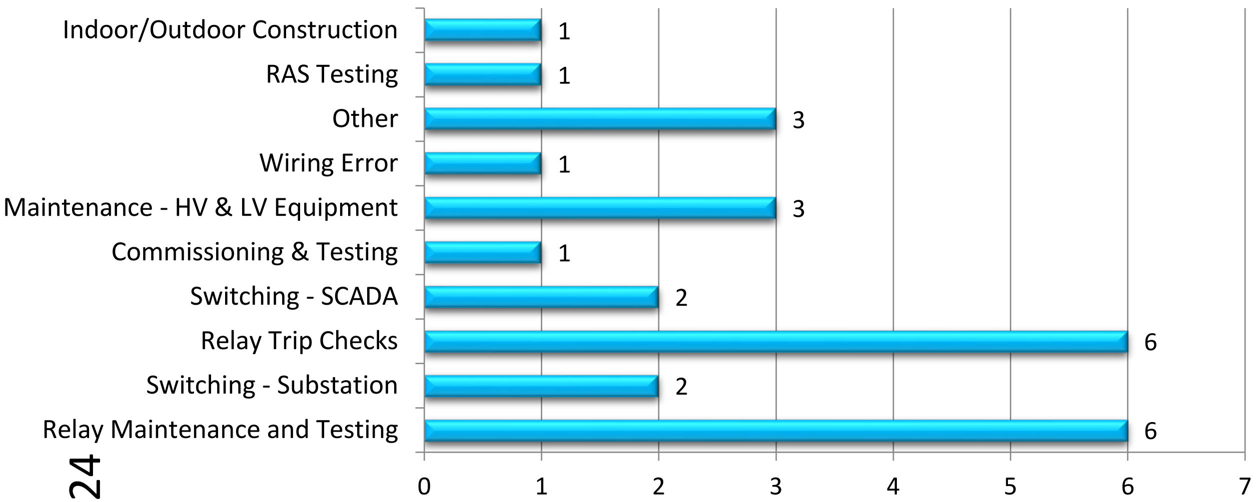


B O N N E V I L L E P O W E R A D M I N I S T R A T I O N

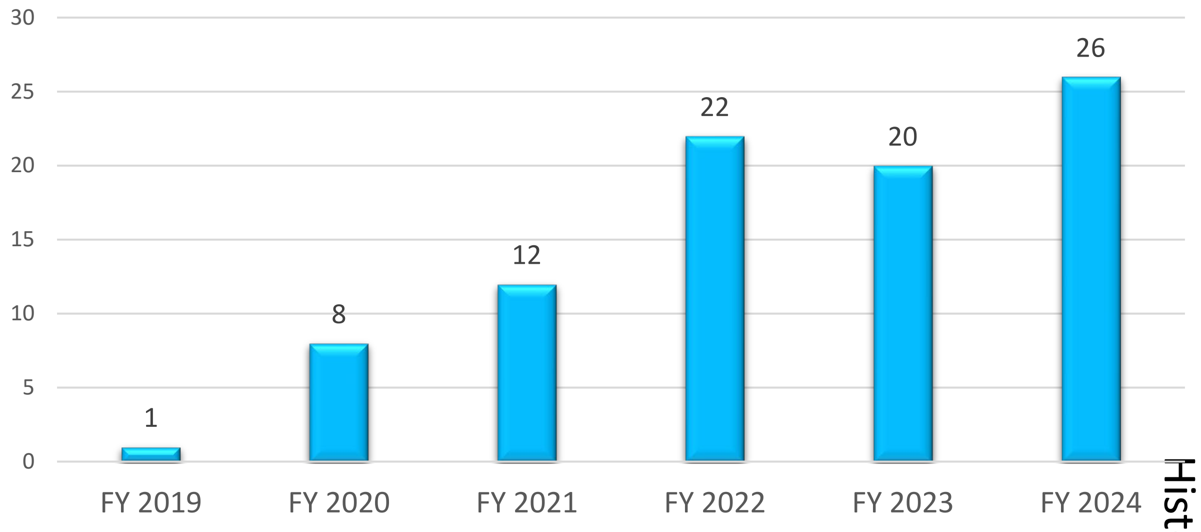
Other Utilities - Human Initiated Disturbance Event Reporting: FY2024

FY2024

Total Reported Events by Activity: FY 2024

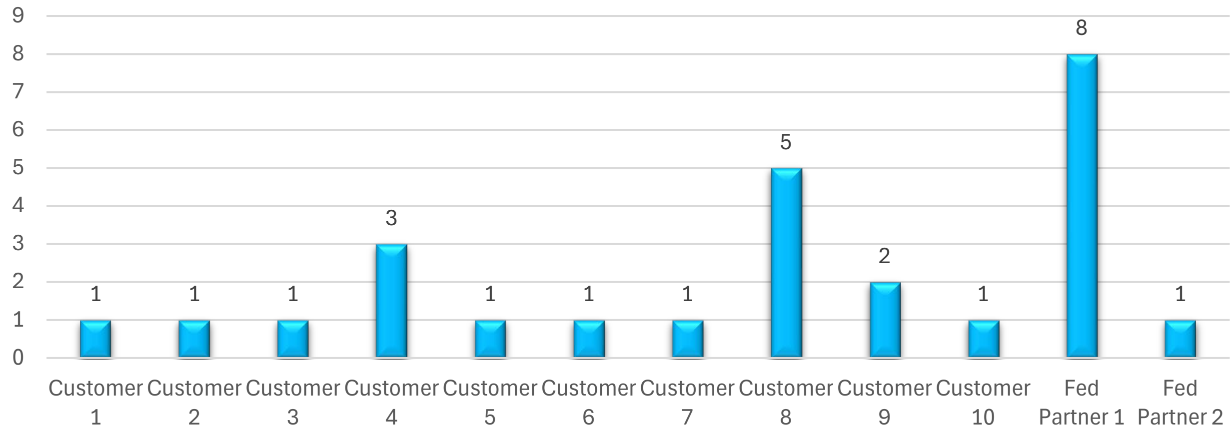


Number of Reported Events by Fiscal Year (FY)

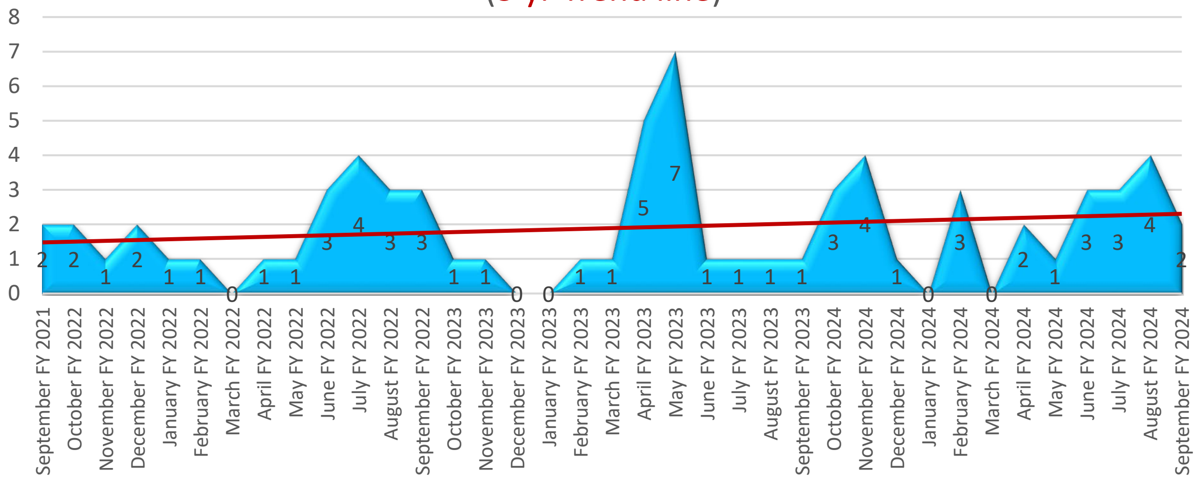


Historical

Number of Reported Human Initiated Incidents Impacting BPA by Other Utilities in FY 2024



Number of Reported Events
(3 yr Trend line)



9/23/2024

Data provided by TOOC Disturbance Event Tracking

Data Driven Decisions

Using Data to Make Decisions

- After Action Review (AAR) Team Recommendation
- Learning Team (LT) Recommendation
- Facilitated Learning Team (LT) Recommendation
- Management Specials

Human Initiated Reliability Event
Learning Team Candidate

9/17/2024

TCIPI Report Summary

Name	20230505 BFR Location
Type of Event	Installation Activities
System/Customer Impact	Equipment unavailable or protective scheme compromised
Customer Affected Y/N	No
Event Summary	While in an outage to replace the line relays, the main trip bus feed was landed in the rack that the crew was removing before it went to the overhead aux bus. A meeting was held about potential dangers. Crew was pushing a cable down the rack to demo it out when the trip bus cable slid out of the terminal block. This powered down the trip bus to the entire station. The cable was barely tightened down causing it to slide out easily. Workers checked the close cable (feeding entire station) and it was also landed in the rack, very loose, so they tightened it. In the process, the SEL-121B's on two lines at substation would not turn back on. Currently working on plan to do emergency relay replacement.
Reporter's Primary Craft/Function	T&E - Commissioning & Testing
Other Crafts Involved	System Protection & Control (SPC)

Trended Summary

Activity Type	Cable - Installation, Cutting, Pulling or Removal
TIRT Disposition	Reliability Management Review
Trending Type	Relay Maintenance
Trending Specifics	SEL-100/BFR Failures
NCC - Level A	A3: Individual Human Performance LTA
NCC - Level B	
NCC - Level C	
Number of times TIRT Trended	0
Number of times Type of Event, Activity Type and Primary Craft are same	2
Number of times Type of event, Activity Type and Trending Type were the same	0

Recommendation

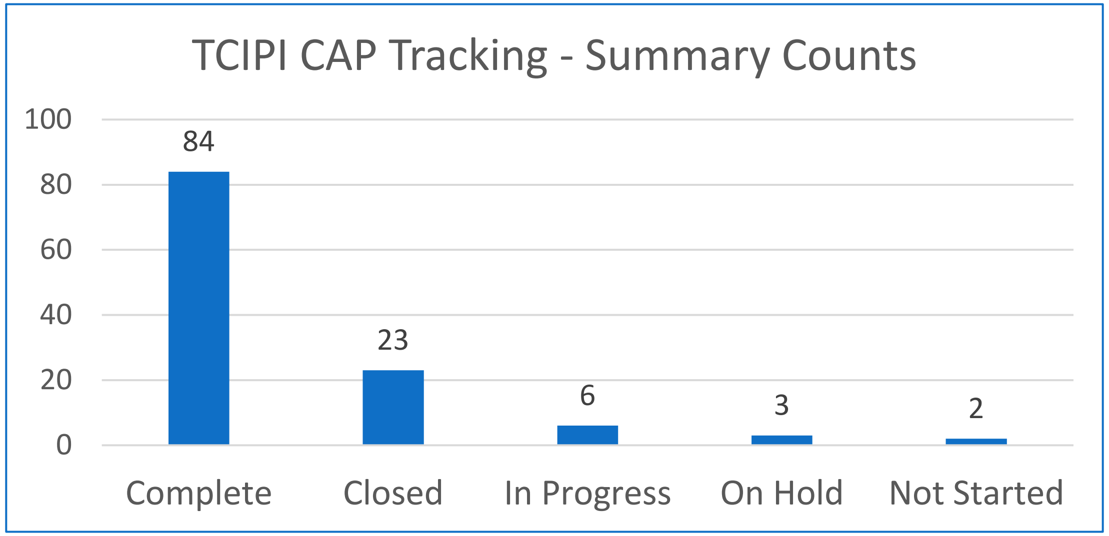
Number of times TIRT Trended	0	> 3 Take Some Action
TCIPI Report Data Score	35	> 65 Normally means AAR

Recommend TIRT Evaluation

TCIPI - Lessons Learned / Corrective Action Program

- Learning Teams
- Sponsor Engagement
- Corrective Action Details / Summary
- Status / Disposition

Learning Team Names	# Corrective Actions
20170929 Learning Team 1	4
20180124 Learning Team 2	5
20180313 Learning Team 3	6
20180805 Learning Team 4	9
20181107 Learning Team 5	12
20190422 Learning Team 6	5
20190805 After Action Review (AAR) 1	9
20191210 After Action Review (AAR) 2	2
20200814 After Action Review (AAR) 3	12
20201004 Learning Team 7	12
03252021 After Action Review (AAR) 4	7
20220521 After Action Review (AAR) 5	7
20211115 After Action Review (AAR) 6	2
FY22 Increased Inadvertents - Management Special 1	4
20220621 After Action Review (AAR) 7	3
20230531 After Action Review (AAR) 8	11
20240124 After Action Review (AAR) 9	8
Grand Total	118



- **Not Started** - CA has been approved for action but has not formally started work on corrective measures.
- **Complete** – CA has completed implementation and has been reviewed and accepted as done by responsible manager/process owner
- **In Progress** – CA has started and is being tracked based upon agreed upon schedule or delivery due date
- **On Hold** – CA has been deferred/delayed to a future date based upon priority or dependency or other action to complete first.
- **Closed** – CA has been halted before defined/scheduled completion due to management decision.

New Effectiveness Table

Hierarchy of Control		**Elimination -** Physically remove the hazard	**Substitution -** Replace the hazard; **Engineering Controls -** Isolate people from the hazard	**Administrative Controls -** Change the way people work	**Administrative Controls**	**Administrative Controls**	**Administrative Controls**	**PPE -** Protect the worker with Personal Protective Equipment
		Most Effective ←						→ Least Effective
Effectiveness Table		**Elimination**	**Engineered / Physical Barriers**	**Administrative Barriers - Design Features**	**Administrative Barriers - Written Communications**	**Administrative Barriers - Tool and Equipment**	**Administrative Barriers - Training and Coaching**	**Individual Control Barriers**
	10	Permanent elimination of the activity / function /hazard that introduced risk during the incident (e.g., cease using hazardous chemicals)						
Most Effective	**9**		**Passive** design features that reduce incident **probability,** with no human action required (e.g., pipe replaced with one made from corrosion-resistant alloys)					
	8		**Active** design features that automatically actuate to reduce incident **probability,** with no human action required (e.g., preventative interlocks)					
	7		**Passive** design features that reduce incident **consequences,** with no human action required (e.g., guard rails)					
	6		**Active** design features that automatically actuate to reduce incident **consequences,** with no human action required (e.g., fire suppression system)					
	5			**Passive** design features that, if manually enabled, reduce incident risk (e.g., reinforced cockpit door)				
	4			**Active** design features that, if manually enabled, reduce incident risk (e.g., front passenger seat air bag)	Procedures or controlled work instructions that are used "in-hand" during task performance (e.g., checklists)	Tools / equipment that reduce incident **probability** (e.g., temporary lock or block that prevents component operation)		Use of proven human error-reduction tools by front-line workers during task performance
	3			Design feature that **automatically** warn workers that a problem requiring action exists (e.g., low oil pressure alarm)	Procedures or controlled work instructions that are not used "in-hand" during task performance	Tools / equipment that reduce incident **consequences** (e.g., Personal Protective Equipment)	Training or coaching that is recurring, and validates learning has occurred	Over checks by individuals using proven error-reduction tools, of tasks completed by front-line workers
Least Effective	**2**			Design feature that, if **manually** actuated, warn workers that a problem requiring action exists (e.g., fire alarm pull station)	Written policies; posted warning signs		Training or coaching that validates learning has occurred, but isn't recurring and/or mandatory	Over checks by individuals who are not using proven error-reduction tools, of tasks completed by front-line workers
	1				Information written communications (e.g., emails, safety alerts)		Training or coaching that does not validate learning has occurred (e.g., lessons learned meetings)	Increased awareness / diligence by front-line workers during task performance

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Corrective Action Effectiveness

Presenting all 118 Corrective Actions to Date

Hierarchy of Control		Elimination - Physically remove the hazard	Substitution - Replace the hazard / Engineering Controls - Isolate people from the hazard	Administrative Controls - Change the way people work	Administrative Controls	Administrative Controls	Administrative Controls	PPE - Protect the worker with Personal Protective Equipment
		Most Effective					Least Effective	
Effectiveness Table		**Elimination**	**Engineered / Physical Barriers**	**Administrative Barriers - Design Features**	**Administrative Barriers - Written Communications**	**Administrative Barriers - Tool and Equipment**	**Administrative Barriers - Training and Coaching**	**Individual Control Barriers**
Most Effective	10							
	9		1					
	8		6					
	7							
	6							
	5			2				
	4			3	6	4		1
	3			3	44	2	3	2
Least Effective	2			2	6		3	
	1				23		6	

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Example: SEL - BFR

Problem

- Over the last several months and years, we've noticed an uptick of mis-operations with SEL-100 series relays and SEL-BFRs on our system. Most recent we had an event in May 2023, again at a different site in July 2023, then looking back historically to July 2021 at another location. As these mis-operations were trending upward, we had SMEs from various organizations to review the data.

Analysis

- From the data, we believed the SEL-BFRs to be the highest risk of the two and would require the most work to replace due to configuration changes necessary to fit a replacement.
- TCIPI represented these BPA SME's who had asked that Engineering / Program Management consider making these replacements a priority on our system.
- The substation list was narrowed down to 8 due to their risk level based on our Agency's 5-level Risk Assessment Scale (Reliability) and asked for all to be prioritized by our Asset Management Team.

Actions Taken

- As a result of this analysis, risk assessments, corrective measure development and more; BPA is now able to get these BFR replacements completed under an emergency capital work order for each identified site. Work has already begun.

BPA Agency-Level Consequence Scales*

Consequence Type Score	Financial -BPA Impact- (PV)[1]	Environmental Stewardship[4] -Societal Impact- (Air, Land, Water, F&W Resources)	Safety -Societal Impact-	Legal/Regulatory[4]	Regional Accountability - Societal Impact - (Reputation; customer & constituent satisfaction)	Reliability -MWs- (TBL)	Reliability -MWHs- (PBL)
5 = Extreme	>$100 M	Substantial, extensive and lasting damage or impact to ecosystems, environmental resources, natural resources and/or valued species. Widespread and long-term corrective action, e.g. remediation or mitigation required.	Fatality or multiple severe irreversible disabilities	Violation or non-compliance with a fundamental statute, regulatory principle or standard leads to severe observable impacts and orders for substantial corrective action, including major mandatory changes in BPA operations or administration.	Extreme negative national and ongoing media, Fed, customer and constituent attention and criticism; extreme damage control.	Violations resulting from multiple contingencies even after load shedding over 300 MW has been applied	Cumulative loss of over 3 million MWHs net generation deliveries or conservation resource acquisition
4 = Major	$10M - $100M	Major damage or impact to ecosystems, environmental resources, natural resources and/or valued species. Major corrective action, e.g. remediation or mitigation required.	Severe disability	Violation or non-compliance leads to observable impacts and orders for corrective action, including some mandatory changes in BPA operations or administration.	National spike or ongoing regional media, Federal, customer or constituent attention; Major damage control	Violations resulting from multiple contingencies even after load shedding of 100 MW to 300 MW have been applied	Cumulative loss of 1 million to 3 million MWHs net generation deliveries or conservation resource acquisition
3 = Moderate	$1M - $10M	Some observable damage or impact to specific localized environmental or natural resources. Impact on wildlife uncertain. Some localized corrective action, e.g. remediation or mitigation required.	Serious injury, immediate medical treatment needed	Violation or non-compliance causes BPA to adopt modest changes in BPA operations, policies or procedures.	Regional spike or ongoing local local media, Federal, customer or constituent attention and criticism; moderate damage control	Load loss of 50 to 100 MW	Failure of critical generation equipment, leading to serious workarounds; zero up to 1 million MWHs cumulative loss of generation deliveries or conservation resource acquisition.
2 = Minor	$100K - $1M	Minor observable effects. No mortality. Corrective or mitigative action uncertain.	Injury requiring first aid, delayed medical treatment OK	Minor change in operations or administrative flexibility	Spike of local media attention and/or internal complaints only (e.g. AEs or other)	Load loss of up to 50 MW	Reduced operating margins elevate risk, but no externally observable impact on service.
1 = Insignificant	<$100K	No or small transitory effects, no corrective or mitigative action required.	No or minor injury, first aid only	No or Insignificant effect on operations or administrative flexibility	No impact or Isolated internal complaints	Momentary interruption with automatic restoration; no customer loss of load	Failure of non-critical assets but minimal risk or observable impact on service

*Consequences are not comparable across columns and shall not be used to infer comparability between categories of impact.

1 - PV Costs for map of risks incurred from doing project; PV Avoided Risks (or Benefits) for map of risks avoided from doing project; Scale will depend on CAB-Approved thresholds.

2 - MWHs can mean one event or multiple aggregated events.

Financial is a "natural scale," Legal/Regulatory is a "constructed" scale and Regional Accountability is a "proxy" scale.

For question about Risk Chart Contact: BPA Enterprise Risk Manager via email jcshea@bpa.gov

TCIPI – Other Achievements

Overall Achievements since 2018

- 275 events evaluated by the Disturbance Team to date.
- 221 Human Initiated Reliability Events (TCIPI reports) submitted / analyzed across Transmission to date
- Completion of 17 “Lessons Learned – Root Cause Analysis”
- 118 Corrective Actions approved for implementation by Management

Ongoing cooperation with Safety:

- Integration with Safety to form a unified front for our personnel, showing a tangible sign of partnership.
- Occasionally when a Safety Event occurs there is also a Human Initiated Reliability Event associated. We assess these events against our reportable criteria and evaluate them for reliability continuous improvement.
- TCIPI resource engagement on Safety Incident Assessment Teams (IAT). Supporting team facilitation, documentation of findings, management of Corrective Action reviews and approvals.
- Leading development of Agency Decision Framework effort resulting from recently completed Safety IAT
- Development of process to collaboratively review Safety and TCIPI “Near Hits” in a secured environment

TCIPI – Summary

We are

- Learning-driven
- Cross-Transmission in nature and intent
- Transparent in execution to build trust
- We focus on the "What" and not the "Who"
- Collaborative by design
- Forward looking to apply predictive value to business decisions
- Adaptive to the changing environment

Questions

Thank you for your interest in TCIPI

Human Performance Improvement & Substation Operations

Gary Riibe Jr.

Substation Operations Manager-West

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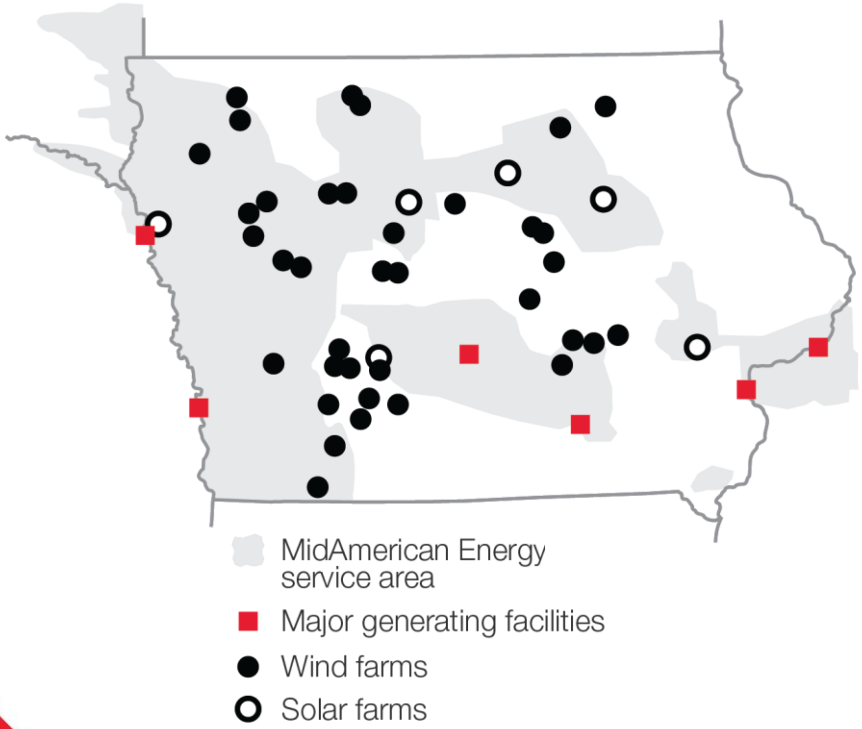


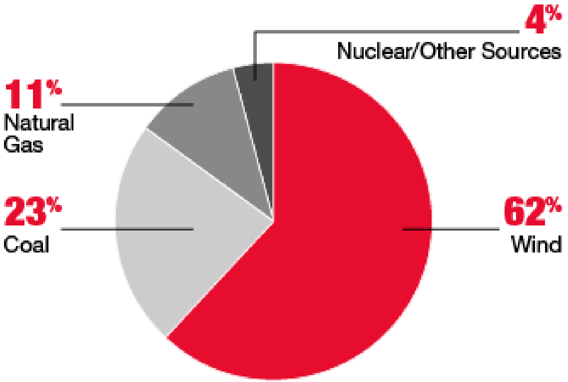
797,000
Natural Gas Customers

820,000
Electric Customers

3,100
MidAmerican Employees

423
Communities Served

GENERATION
CAPACITY 2023



About Me

- Electrical Engineer (PE)
- 21+ Years Substation
- Married 20+ Years
- Father of 4 Active Kiddos
- Red Sox Fan (married into it)
- Volunteer Youth Sports Coach
- Lover of BBQ and Ice Cream
- Green Thumb
- Enjoys the Great Outdoors

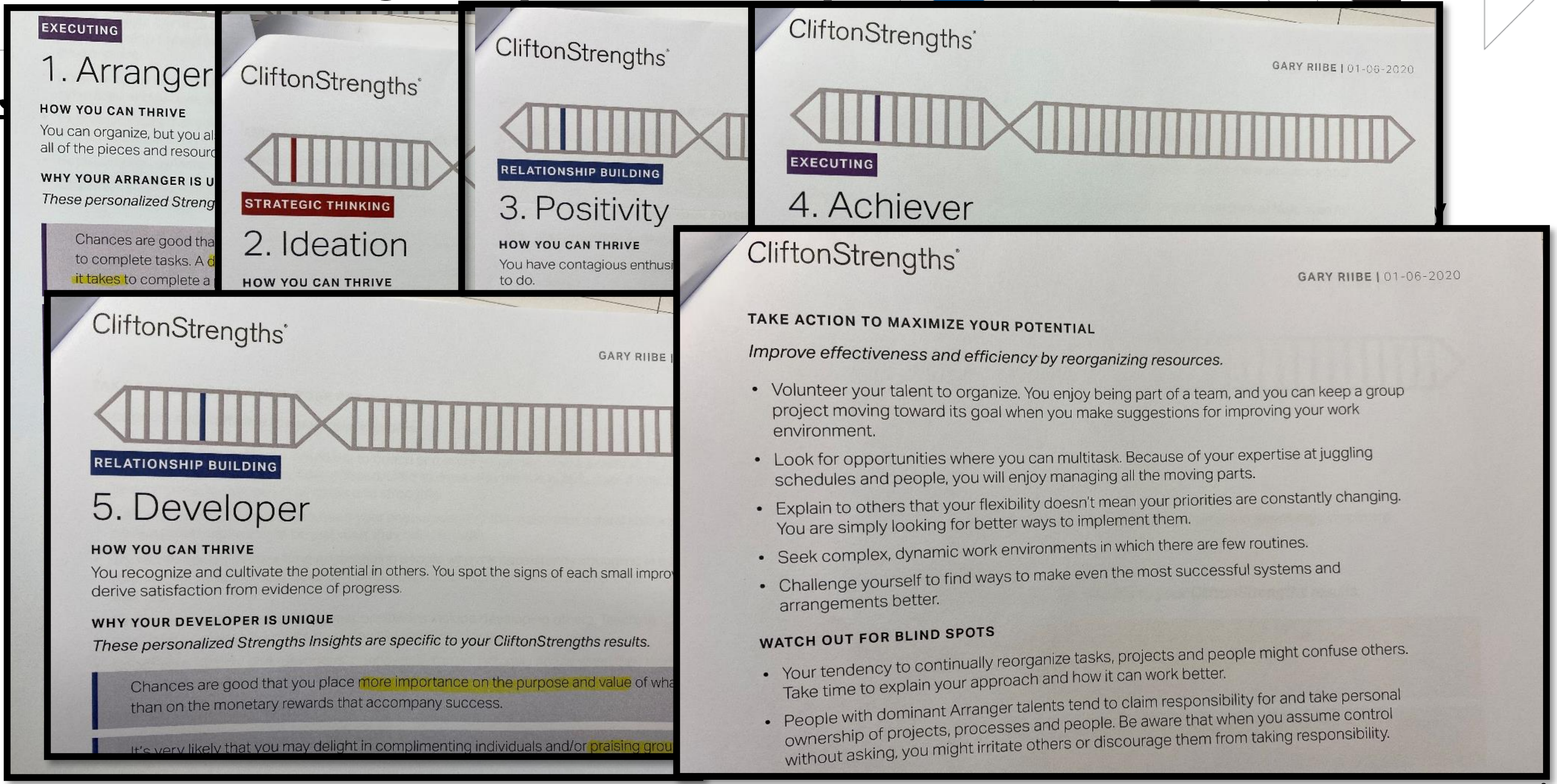
My Background

- From Sioux City, Intern with MEC (Sub Ops, Thermal Gen)
- Graduated U of Neb-Lincoln in Electrical Engineering, Dec 2002
- Started w/ MEC at Davenport in Substation Engineering, Jan 03'
  - Played <u>fantasy</u> football 2003-2005 and met many MEC employees
- Transferred to Substation Operations 2006 at Council Bluffs
  - Supervisor of a <u>real</u> team of substation electricians and techs to complete compliance tasks, projects and job packages in SW Iowa
    - (like a fantasy roster, who are the "sleepers", "must starts" and PUPs each week)
- Transferred to Sioux City, Sub Ops in 2011
  - Back to engineer for a bit, 2014 the manager of NW an SW Iowa
  - Met a new team in SC, they were somewhat the same but different than the team in Council Bluffs

Understanding People and Their Differences

- Around this time of moving around, I thought that **<u>parts</u>** of people are the same
  - These **parts** come together to make up who they are, their personality
  - Different parts, make a different person…and different <u>personalities</u>
    - Part of Person A + part of Person B + part of Person C = Person Z
    - Could be a totally different person than any of persons A or B or C

Clifton Strengths (34 of them)



EXECUTING

1. Arranger

HOW YOU CAN THRIVE

You can organize, but you al
all of the pieces and resour

WHY YOUR ARRANGER IS U

These personalized Streng

Chances are good tha
to complete tasks. A d
it takes to complete a

CliftonStrengths

STRATEGIC THINKING

2. Ideation

HOW YOU CAN THRIVE

CliftonStrengths

RELATIONSHIP BUILDING

3. Positivity

HOW YOU CAN THRIVE

You have contagious enthusi
to do.

CliftonStrengths

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EXECUTING

4. Achiever

CliftonStrengths

GARY RIIBE |

RELATIONSHIP BUILDING

5. Developer

HOW YOU CAN THRIVE

You recognize and cultivate the potential in others. You spot the signs of each small impro
derive satisfaction from evidence of progress.

WHY YOUR DEVELOPER IS UNIQUE

These personalized Strengths Insights are specific to your CliftonStrengths results.

Chances are good that you place more importance on the purpose and value of wha
than on the monetary rewards that accompany success.

It's very likely that you may delight in complimenting individuals and/or praising grou

CliftonStrengths

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TAKE ACTION TO MAXIMIZE YOUR POTENTIAL

Improve effectiveness and efficiency by reorganizing resources.

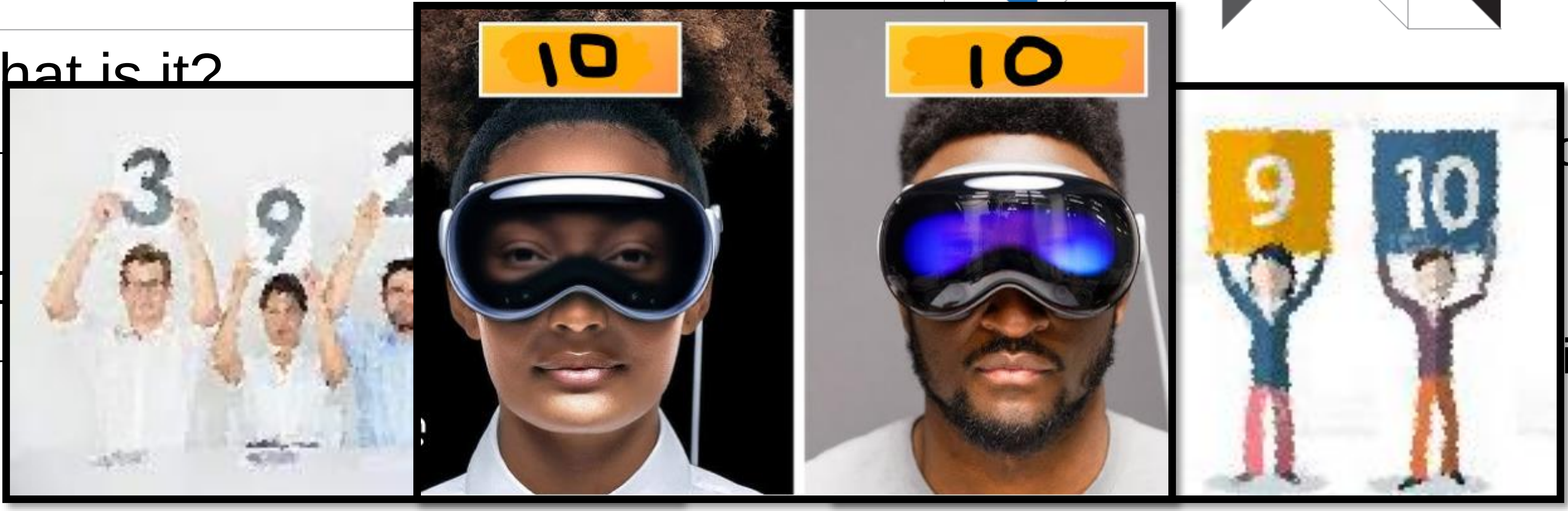
- Volunteer your talent to organize. You enjoy being part of a team, and you can keep a group project moving toward its goal when you make suggestions for improving your work environment.
- Look for opportunities where you can multitask. Because of your expertise at juggling schedules and people, you will enjoy managing all the moving parts.
- Explain to others that your flexibility doesn't mean your priorities are constantly changing. You are simply looking for better ways to implement them.
- Seek complex, dynamic work environments in which there are few routines.
- Challenge yourself to find ways to make even the most successful systems and arrangements better.

WATCH OUT FOR BLIND SPOTS

- Your tendency to continually reorganize tasks, projects and people might confuse others. Take time to explain your approach and how it can work better.
- People with dominant Arranger talents tend to claim responsibility for and take personal ownership of projects, processes and people. Be aware that when you assume control without asking, you might irritate others or discourage them from taking responsibility.

Personal Importance Level

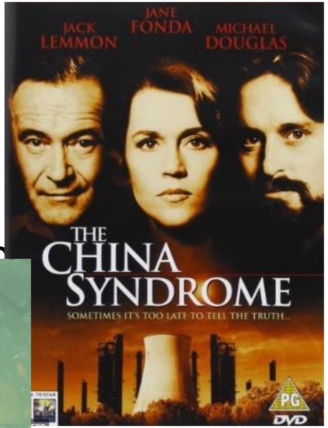
- What is it?
  - …ding
- Ho…
  - …ing

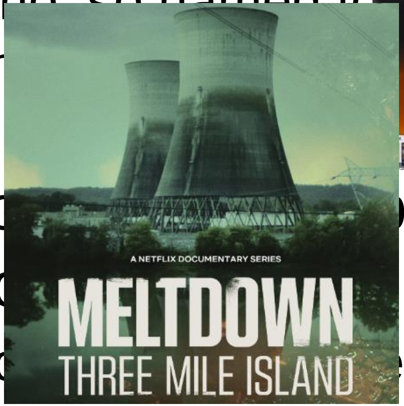


  - If the number is <u>low</u>, give more details or be more interesting…if possible
  - If the number is <u>high</u>, they understand or care
  - If the <u>listener</u> sees that the <u>speaker's</u> number is high, they'd know when to listen *or pretend to care about what the speaker is saying*

Evolution of Human Performance

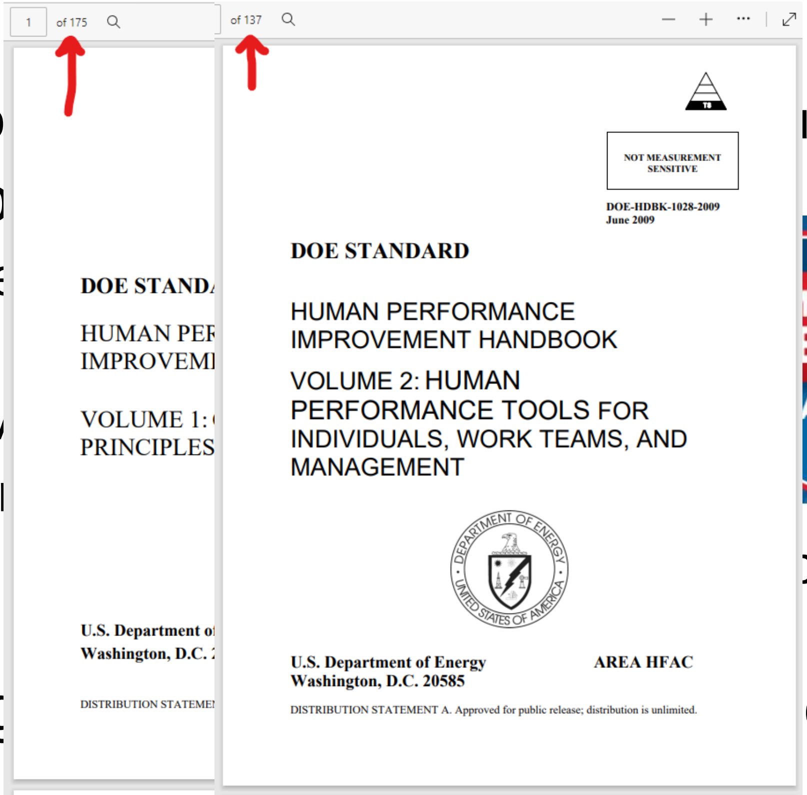
- 3/3/1979, I was born on my dad's birthday and named after him
  - Identity theft was created that same day (needs verified)
- 3/16/1979, **movie** about a core meltdown “The China Syndrome” that occurs at a power plant in California
  - China Syndrome: a nuclear meltdown scenario, so named fo idea that there would be nothing to stop the r the other side of the world (China)
- 3/28/1979, **Three Mile Island** in Middleto artial meltdown of Unit 2 (TMI-2) reactor due to
  - The most significant accident in US commerc r history
  - By 12/1979, Institute of Nuclear Power Operations (INPO) was formed





Evolution of Human Performance

- DOE Human Performance Improvement Handbook June 2009
- It's 300+ Pages, 2 Vol
  – DOE was created in 1977, po ... ıadrupled)
- 5 Principles of Human Perfo
  1. Error is normal. Even the be
  2. Blame fixes nothing.
  3. Learning and Improving is v
  4. Context influences behavio
  5. How you respond to failure ... ɔond counts.
- 2016 no PD Logs, 2017 sing ... ce


1 of 175

DOE STAND

HUMAN PER
IMPROVEM

VOLUME 1:
PRINCIPLES

U.S. Department o
Washington, D.C.

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NOT MEASUREMENT SENSITIVE

DOE-HDBK-1028-2009
June 2009

DOE STANDARD

HUMAN PERFORMANCE
IMPROVEMENT HANDBOOK

VOLUME 2: HUMAN PERFORMANCE TOOLS FOR INDIVIDUALS, WORK TEAMS, AND MANAGEMENT

DEPARTMENT OF ENERGY · UNITED STATES OF AMERICA

U.S. Department of Energy
Washington, D.C. 20585

AREA HFAC

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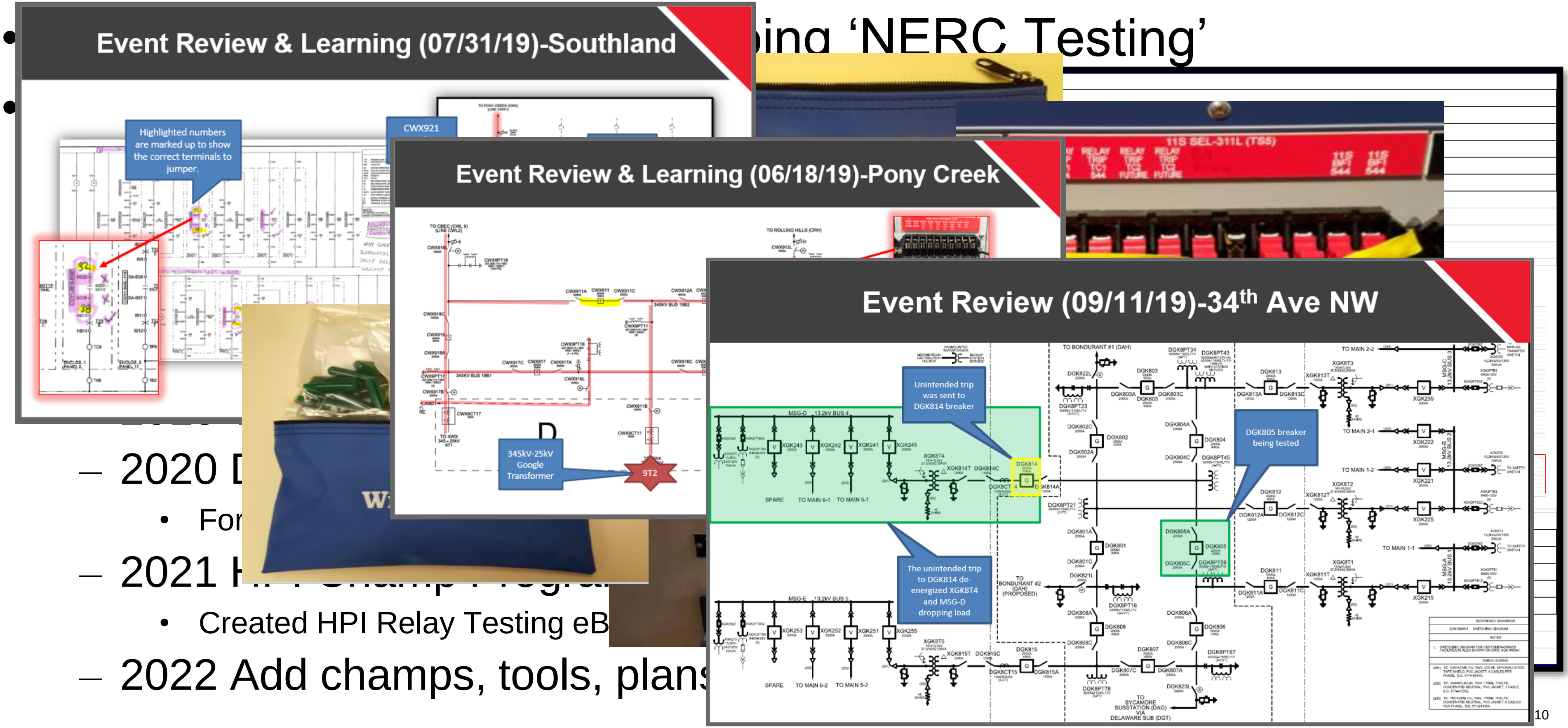
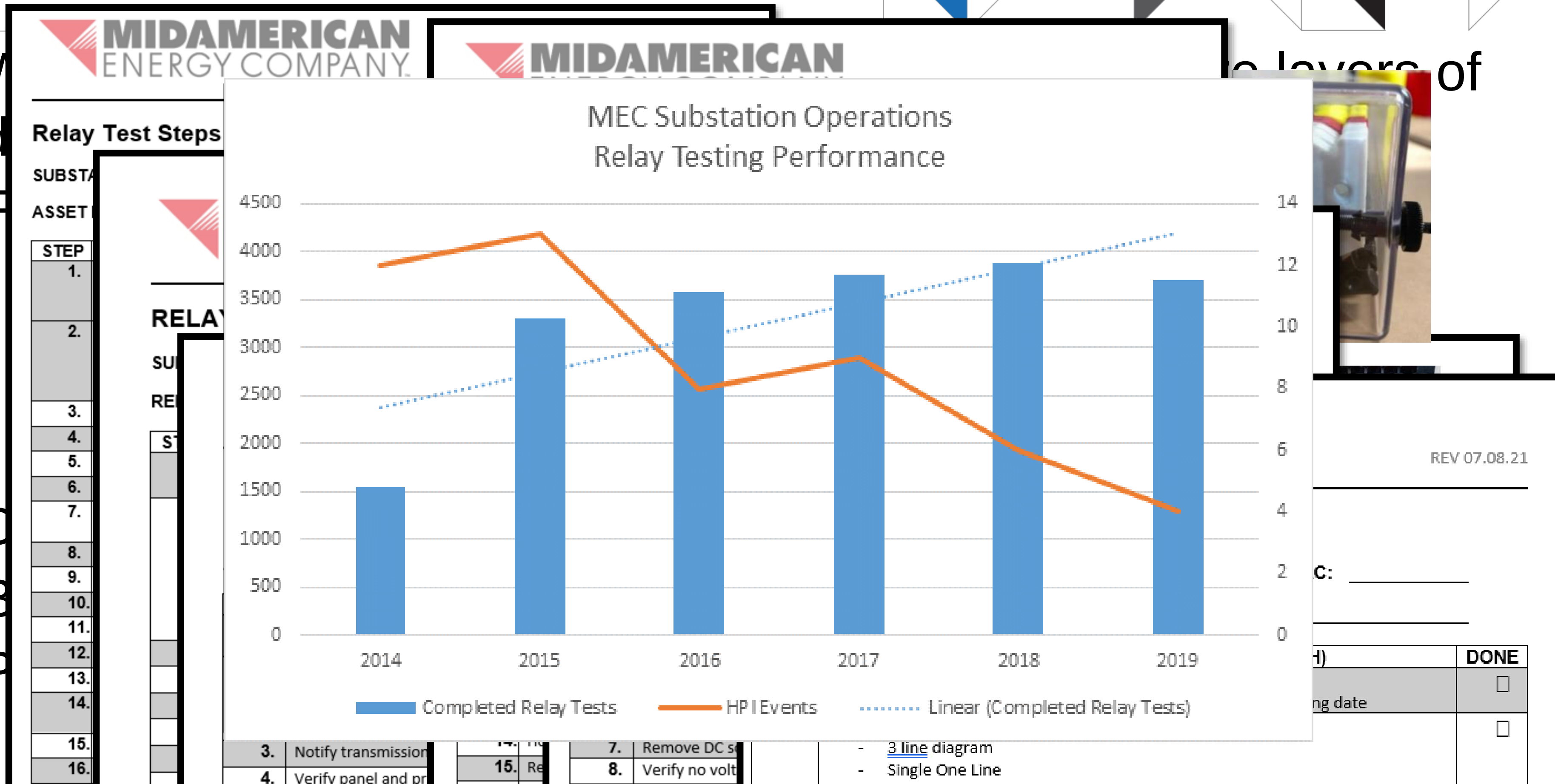
Evolution of Human Performance at MidAmerican

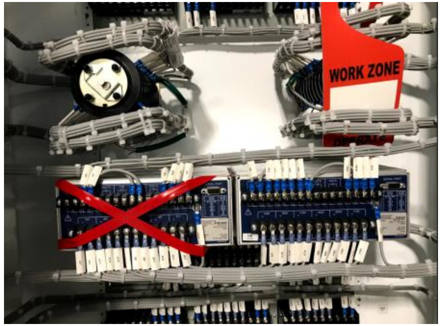
- …ping 'NERC Testing'
- …
  - 2020 D…
    - For…
  - 2021 H… Champ Progra…
    - Created HPI Relay Testing eB…
  - 2022 Add champs, tools, plans…

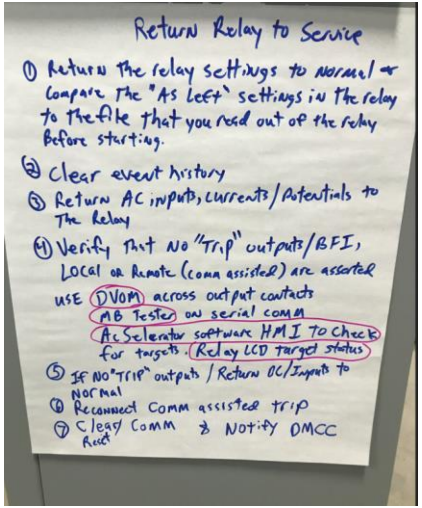


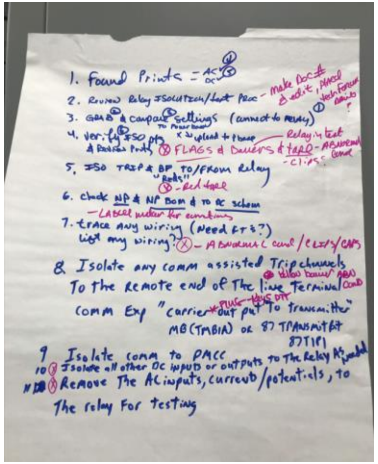
2019-2020 Workshop Pays Off



Workshop Photos







Work Smarter Not Harder

- Developed MEC HP Playbook, Work Zone, and Culture!

Learn From Others-NATF

- Participate in Practice Groups and Forums

North America
FOR

Mission
The NATF's mission is to pr
excellence in the safe, relia
resilient operation of the el
transmission system.

Vision
The NATF envisions contin
improving electric transmis
reliability and resiliency, wh
the safety of utility personn

Approach
We aggressively pursue rel
resiliency, security, and per
excellence by fostering con
challenge to improve and b
sharing timely, detailed, an
information, including lesso
and superior practices.

NATF Members
- Investor-Owned
- State/Municipal
- Cooperative
- Federal/Provincial
- ISO/RTO

North American Transmission
FORUM TransPort

About | Executive Center | Collaboration | Tools & Product

Metrics & Analytics | Practices Groups

- Risk, Controls and Compliance
- EPM Asset Management
- EPM Lines Equipment
- EPM Substations Equipment
- EPM Trans-NPP
- Human Performance Improvement
  - HP Core Team
  - HP Roadmap
  - 2022 HPI Workshop

Collaboration / Practices Groups / Human Performance Improveme

2022 HPI Workshop

NATF Human Performance Improv

08/23/2022 - 08/25/2022

Event Time: All Day

Location: Westminster, CO

Hosted by: TSGT

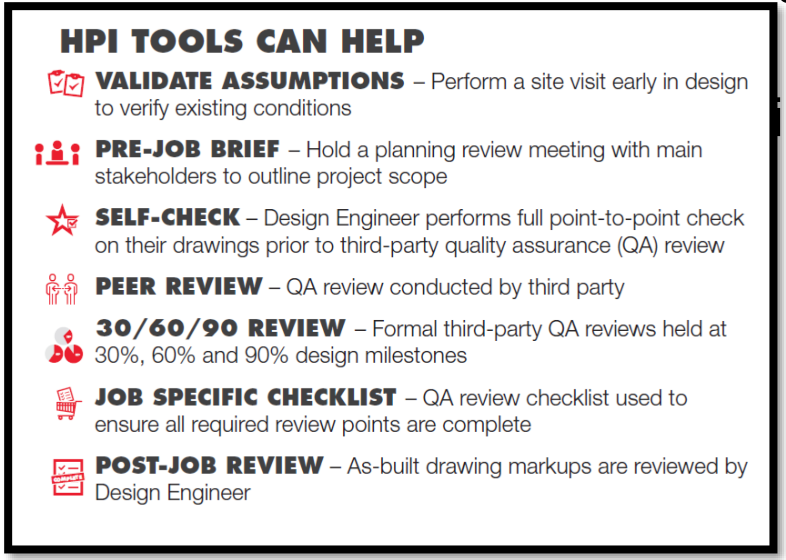
Workshop Location:
Tri-State Generation and Transmission Association Headq
1100 West 116th Avenue
Westminster, CO 80234

Workshop Dates:
August 23: 1:00 p.m. -- 5:00 p.m.
August 24: 8:00 a.m. -- 5:00 p.m.
August 25: 8:00 a.m. -- 12:00 noon

Congratulations to the new Certified Human Performance Professionals!
Kent Peterson, Eric DiLandro, Holly Copeland, John Baumert, Vincent Vincek, Dave Gaul, Timm Maynard, Stacey Pasztor, Sam Reno, LaRhonda Julien and Adeel Laeeq.

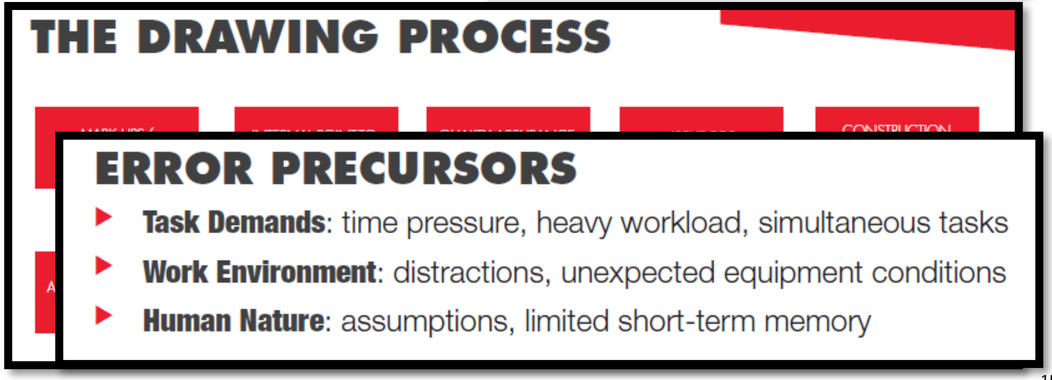
Substation Engineering

- Substation Engineering Presented on use of HPI Tools in NATF HPI Workshop.
- Presentation was over
  - the HPI involved in the design
  - ing and schematics



HPI TOOLS CAN HELP

- **VALIDATE ASSUMPTIONS** – Perform a site visit early in design to verify existing conditions
- **PRE-JOB BRIEF** – Hold a planning review meeting with main stakeholders to outline project scope
- **SELF-CHECK** – Design Engineer performs full point-to-point check on their drawings prior to third-party quality assurance (QA) review
- **PEER REVIEW** – QA review conducted by third party
- **30/60/90 REVIEW** – Formal third-party QA reviews held at 30%, 60% and 90% design milestones
- **JOB SPECIFIC CHECKLIST** – QA review checklist used to ensure all required review points are complete
- **POST-JOB REVIEW** – As-built drawing markups are reviewed by Design Engineer



THE DRAWING PROCESS

ERROR PRECURSORS

- **Task Demands**: time pressure, heavy workload, simultaneous tasks
- **Work Environment**: distractions, unexpected equipment conditions
- **Human Nature**: assumptions, limited short-term memory

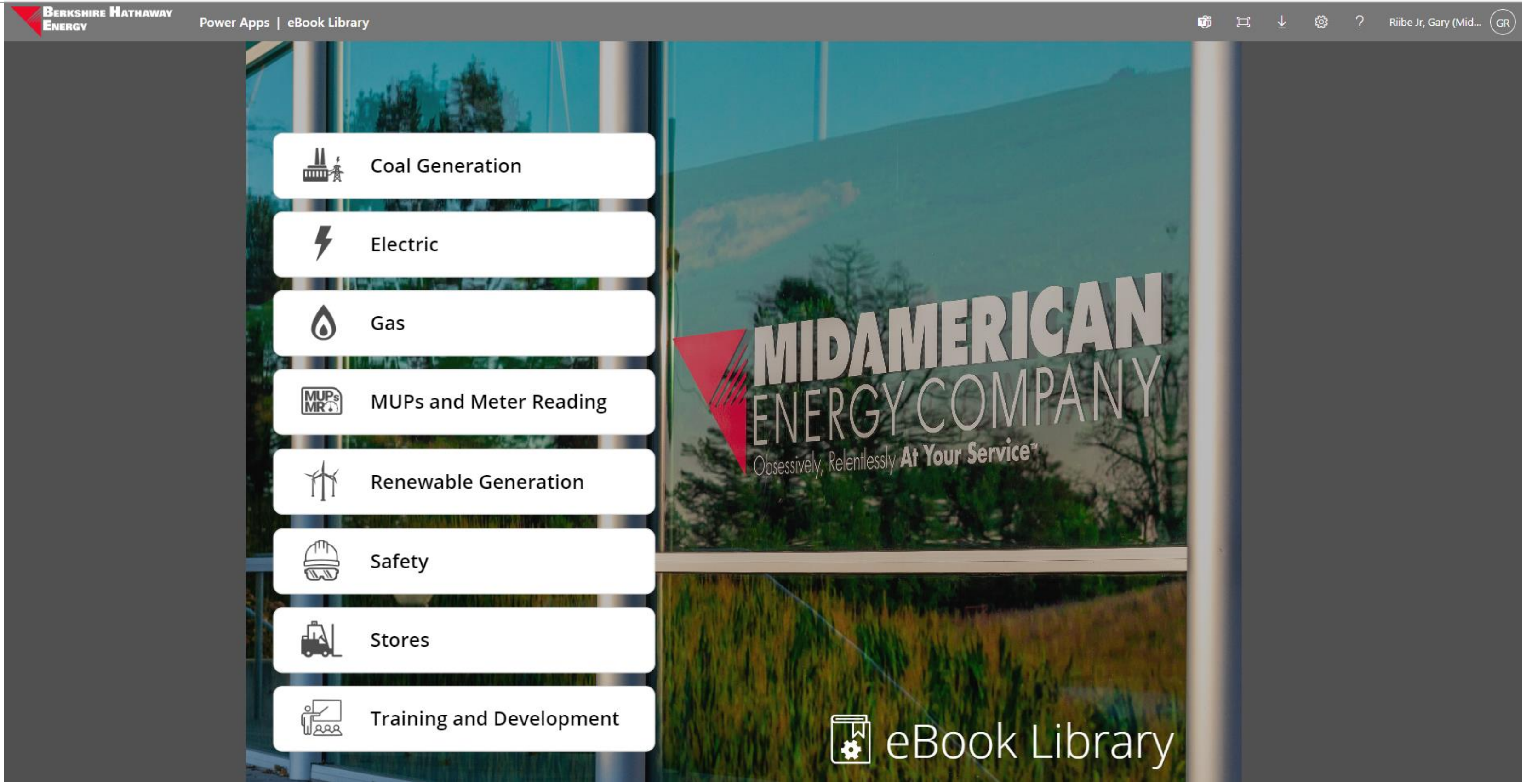
Substation Operations

- Sub Ops followed up the presentation by Sub Eng
- Showed our HPI eBook and (AR) Augmented Reality Apps
  - Used to aid in training apprentices, engineers
  - Supervisors, journeymen, and even contractors
- Talked about how we work with Sub Eng
  - Take their design package to successful outcomes
  - Could have errors (noted on previous presentation)
  - Apply our HPI tools, different 30/60/90 milestones
- Sub Ops follow T/C contractors
  - They must do the same HPI tasks as MEC

Augmented Reality

- Forget about hover boards, we need “Free Guy” glasses
  - Overlay important details “virtually” to the real world (Augmented Reality)
  - Would allow us to “see” error precursors, increasing human performance
  - We’d have “AI” awareness, brought to our human attention in real-time
  - “Personal Importance Levels” are displayed in conversations!

eBook Demo



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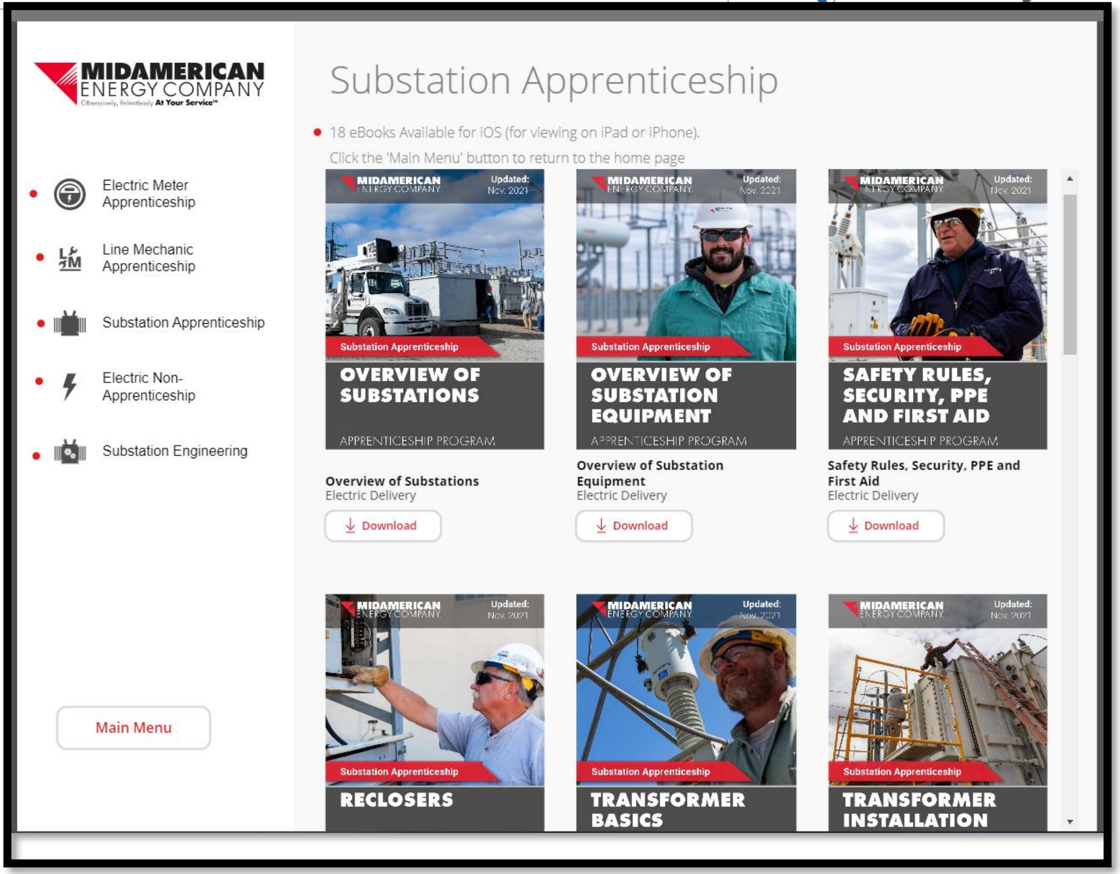


eBooks for Office

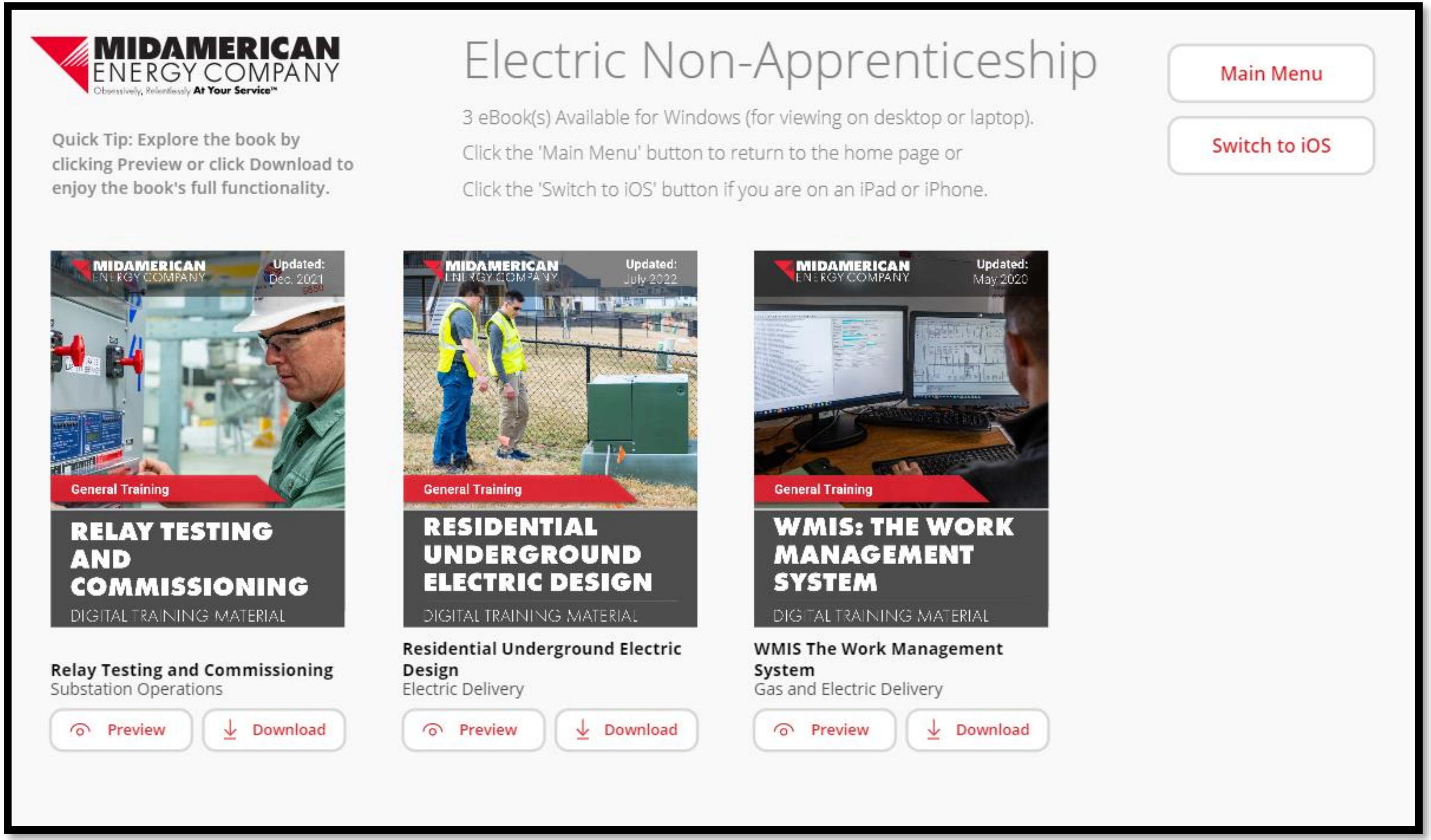
ACCOUNTS PAYABLE

TABLE OF CONTENTS

Click the chapter or section header to navigate to that page.

Accounts Payable - Table of Contents - Updated: Apr. 2021 | i

eBooks for Specific Procedures



Human Performance Resources

- HPI is available to and used by all the groups at MEC (2015->2024)
- New HPI Champions are made each year (2 sessions per year)
- You start to hear "HPI speak" on meetings (that was awesome!)
- Part of the onboarding and overall culture, share best practices/expectations/etc. (no hard knocks)

Accounting
Corporate Communications
Corporate Insurance
Corporate Security and Business Continuity
Customer Service Portal
Electric Delivery
Environmental Services
Facilities
Generation
Gas Delivery
Human Resources
ISO 27001
Information Technology (IT)
Legal and Regulatory Compliance
Office Services
Renewable Development and Generation
Safety, HPI and Training
Supply Chain

Document Library

To help you be successful in using the HPI resources available to you, instructional videos are available as guidance. Find these videos through Microsoft Stream.

eBook

- HPI eBook

Podcasts

- Electric Operations - Dallas County
- Service Dispatch and Safety
- Louisa Generating Station
- Business and Community Development

Templates

- Error Precursor Template
- HP Project Preview Template
- 30/60/90 Check and Review Template
- HPI Tool Plans
- Layers of Defense Analysis Template

HPI Resources

- Overview
- HPI Tools
- Documents Library
- HPI Event Reviews
- Human Performance Champions

HPI References

- HP Metrics
- HP Tool Flipbook
- HP Tool Playbook

Journey to Excellence
Find the latest news from Berkshire Hathaway Energy businesses, as well as information about cybersecurity, sustainability and more on the Journey to Excellence home page.
Learn more

JOURNEY TO EXCELLENCE

Final Thoughts

- 5 Principles of Human Performance

1. Even Superman has a bad day

   Create HP Champions, Understand what it is to be human, Clifton Strengths

2. Blame fixes nothing

   Commitment to Excellence

   Senior Management need to support the effort

3. Learning and Improving is vital. Learning is deliberate.

   eBooks, build your library of knowledge and preserve it, share it

4. Context influences behavior. Systems drive outcomes.

   Build that culture! Fix the procedure. Find those error likely situations. It all influences us.

5. How you and leaders respond to failure matters.

   People achieve high levels of performance because of the encouragement and reinforcement received from their leaders and peers.

Questions?

HP Certification Instructional Guides

HP Project Preview or Learning Team

This activity involves participating or attending an HP Project Preview or Learning Team.

This activity is worth 2 points.

For information on how to complete this activity, refer to Chapter 9, Section 3, which contains a complete list of instructional guides for HP Champion certification.

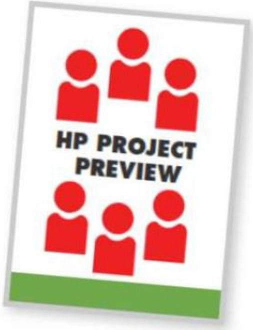
An HP Champion showing the HP Project Preview tool from the HPI Flipbook.

Learning Team Activity

This activity involves facilitating or attending an Event Learning Team.

This activity is worth 4 points.

For information on how to complete this activity, refer to Chapter 9, Section 3.



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NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Human and Organizational Performance

An Event Causal Assignment Analysis

Ed Ruck, Senior Engineer of Event Analysis, NERC
BES Protection System Misoperation Reduction Workshop
October 1, 2024

RELIABILITY | RESILIENCE | SECURITY




Data Source

- Electric Reliability Organization Event Analysis Program
  - A program that includes reviewing off-normal events occurring on the bulk power system.
  - Requires industry participation and support to be effective.
  - Used to identify and publish lessons learned (NERC website) and support system reliability.
  - Event reporting supports identifying trends, identifying themes of occurrence, studying impact-risk relationships, and improving operating culture.

Data Source

- Trends are identified by cause codes that include the following:

Engineering and Design	Equipment and Material
Human Performance	Management and Organization
Communication	Training
Other	Overall Configuration
No cause found	Information to determine cause LTA

Event Numbers

NUMBER OF UNIQUE QUALIFIED EVENTS

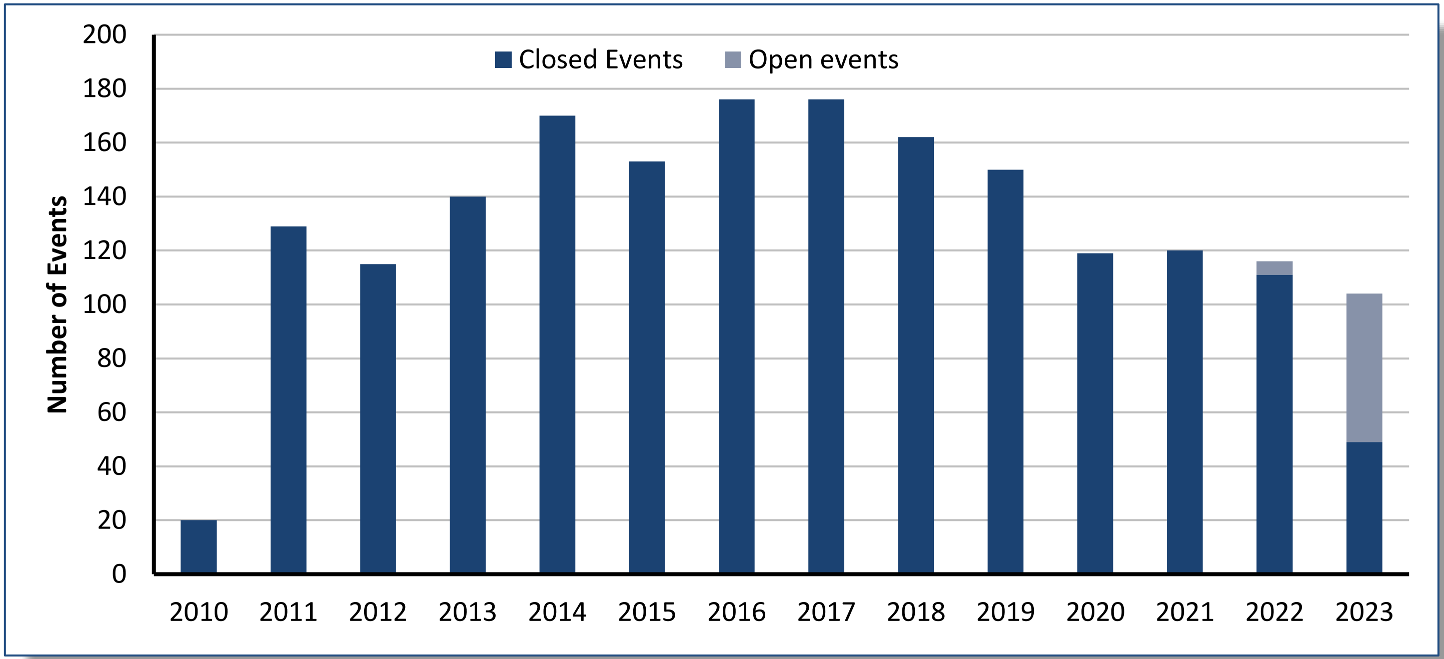
1,855

NUMBER OF EVENTS CAUSE CODED

1,790

NUMBER OF EVENTS IDENTIFIED ROOT CAUSE

1,007

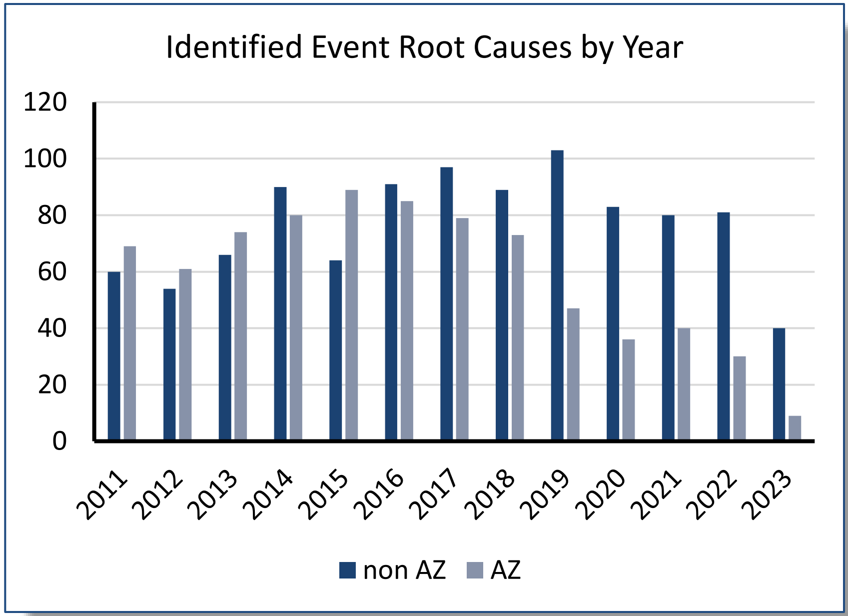


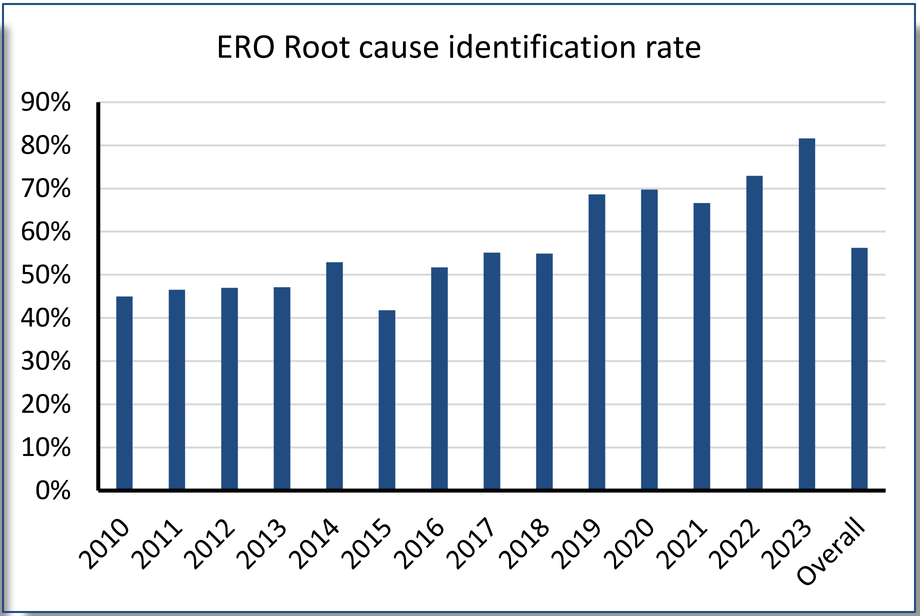
2.1

Per Week

Root Cause Identification Rate

- Root cause identification continues to improve
- Overall average is 55.4%
- 2018–2022 (rolling average of last 5 completed years) is 65.9%





**AZ Codes represent when a specific correctable/actionable root cause cannot be determined for an event*

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Human Performance & Organizational Performance

- Human Performance refers to individual human performance
  - Refers to when a person makes a decision as an individual, not as part of a team
  - A substitution test would show different results, excluding the operating environment from influencing individual action
- Organizational Performance refers to practices, policies, procedures, management decisions, etc.
  - This would include work that is done as part of a team effort
  - Substitution test would show similar result indicting the operating environment leading the individual to action

Types of Human Error*

- Skill-Based Mode
- Rule-Based Mode
- Knowledge-Based mode
- Work Practices Error** (This is when a person can't perform the task or deliberately causes an error.)

* Based on Rasmussen's model

** Not Based on Rasmussen's model

Skill Based Mode

- Skill-Based Mode–associated with highly practiced actions in a familiar situation

- Main error driver–Distraction
- Error Rate 1:10,000

Rule Based Mode

- Rule Based Mode – based on the selection of stored rules derived from one's recognition of the situation

- Main error driver – Incorrectly identified the problem
- Error Rate 1:1,000

Knowledge Based Mode

- Knowledge-Based Mode–Behavior based on unfamiliarity, so individuals must rely on experience, perceptions, and perspectives

- Main Error Driver–Lack of a good mental model
- Error Rate 1:2

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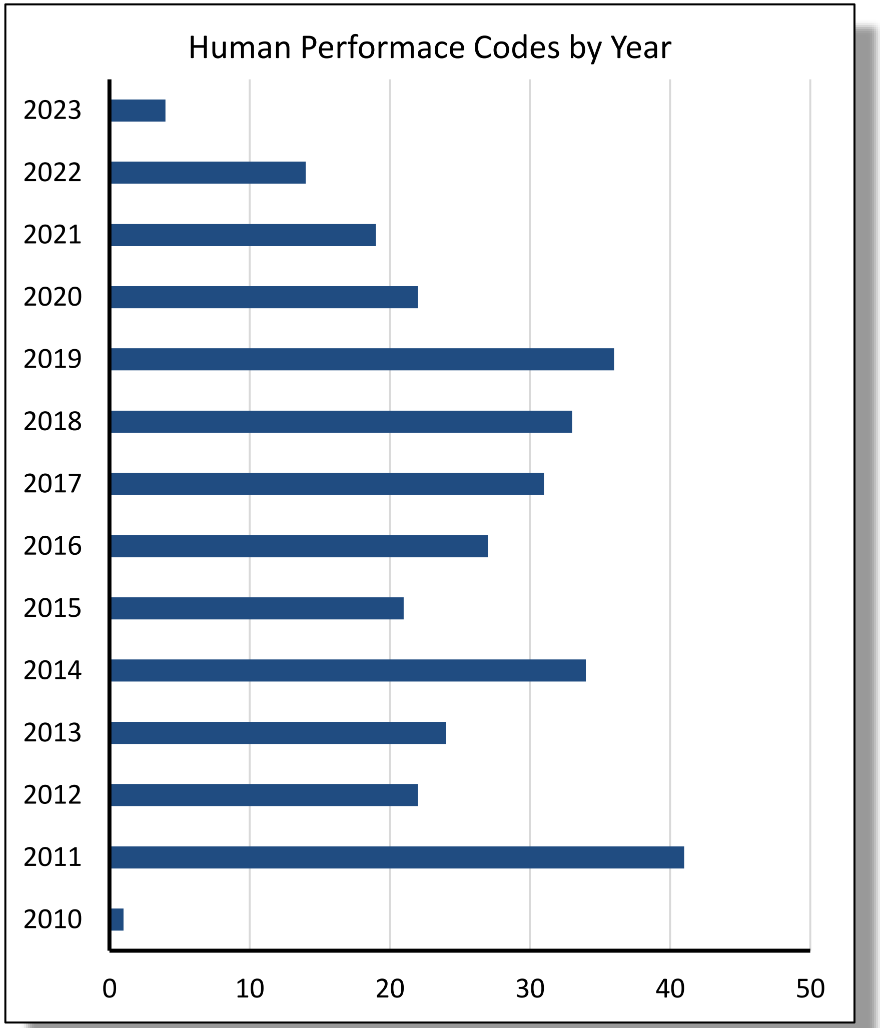
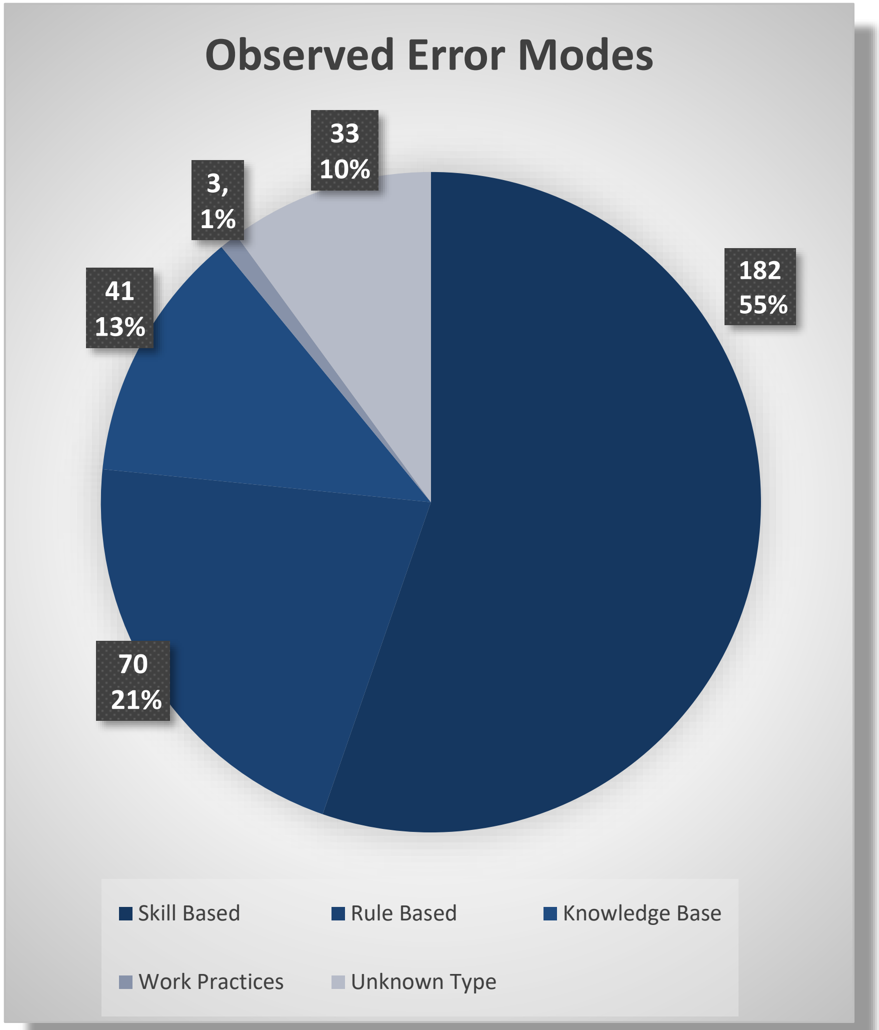
Human Performance Issues

- Human Performance has been identified as either a root cause or a contributing factor 329 times since 2010
- Average of ~26.2 events per year
- So more than once every other week, someone is making a mistake with consequences for the grid



Where are the problems

- Skill-Based Error (182 times)
- Rule-Based Error (70 times)
- Knowledge-Based Error (41 times)
- Unknown mode (33 times)
- Work Practices Error (3 times)



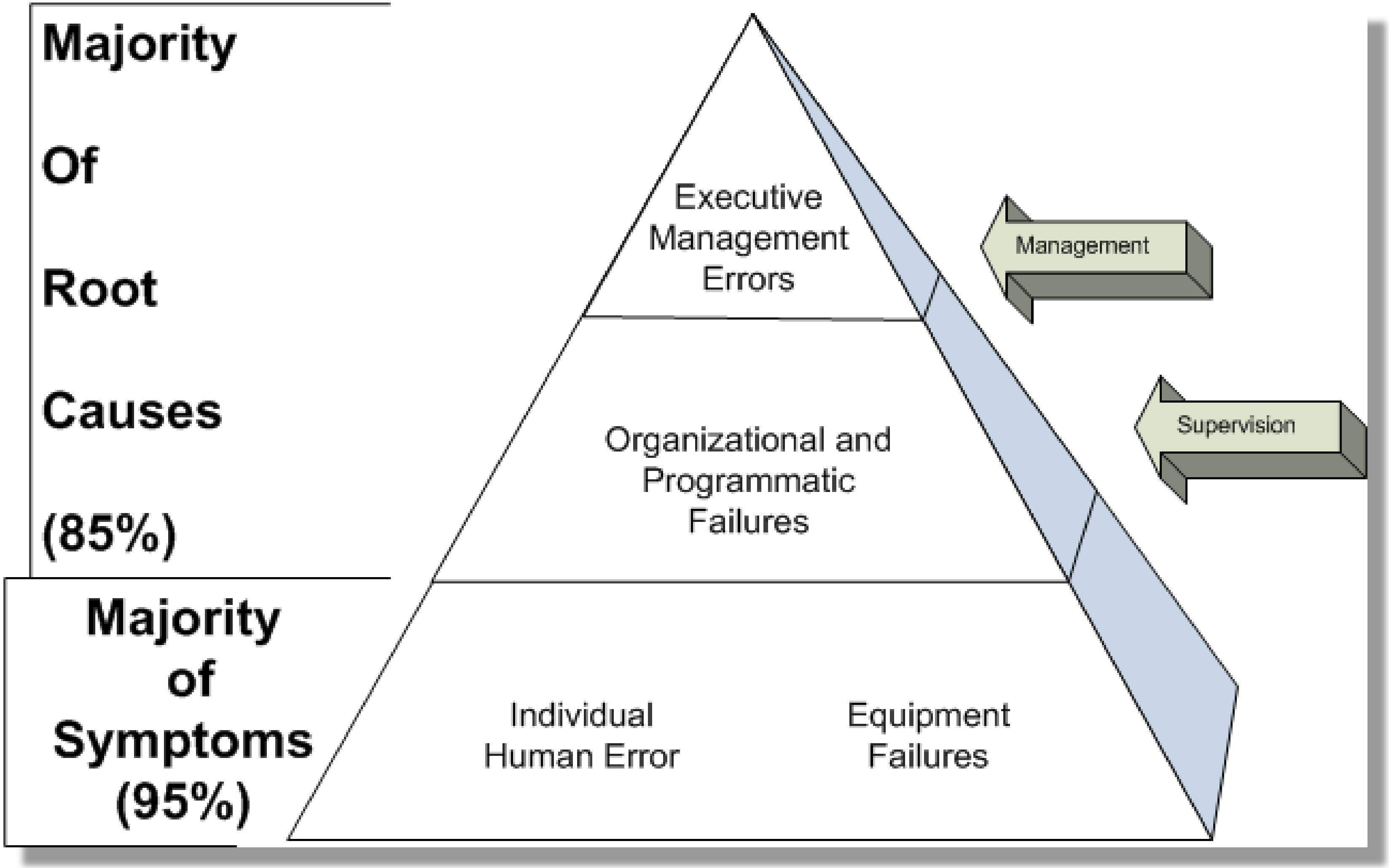
HP codes – Top 5

Out of 329 times a human performance code was identified, the top five codes were:

- Check of work Less than Adequate (LTA) (71 times, skill based)
- Individual Human Performance (33 times, unknown mode)
- Incorrect performance due to mental lapse (27 times, skill based)
- Situation incorrectly identified or represented resulting in wrong rule used (27 times, Rule based)
- General Skill Based Error (25 times)

So is it just the Human?

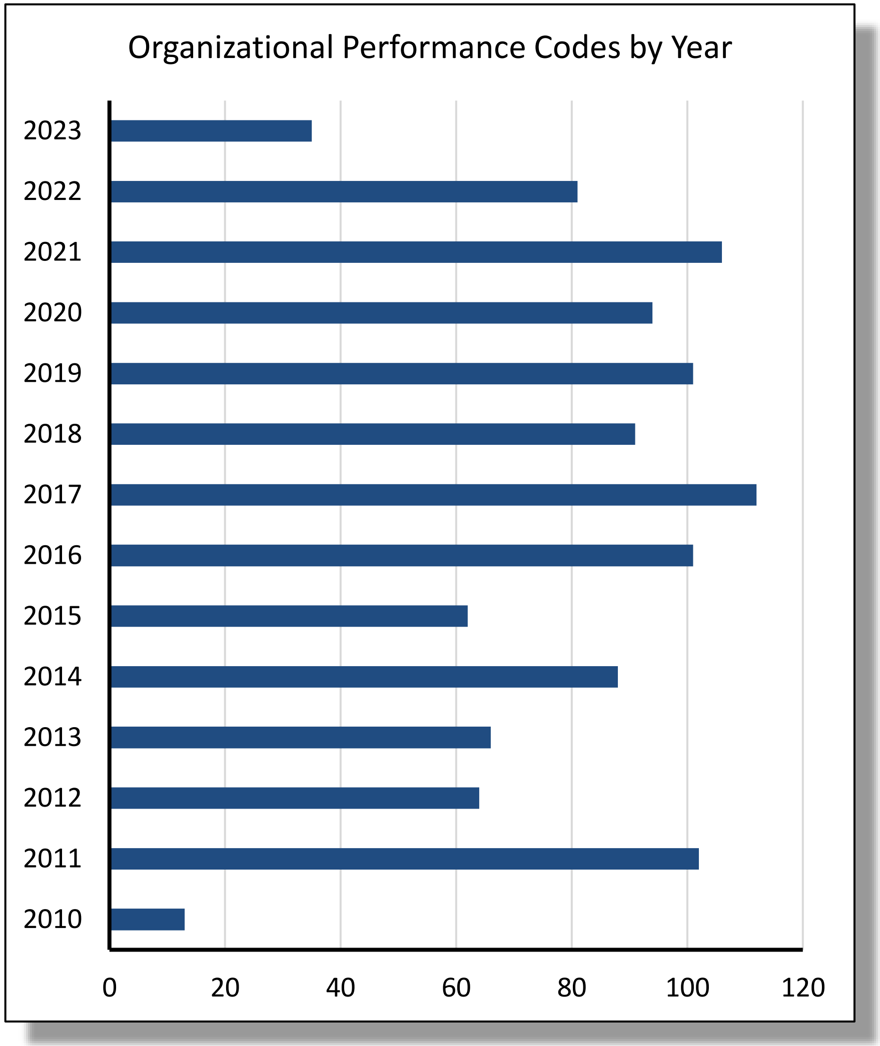
What do others see?



The PII Performance Pyramid TM

Organizational Performance Issues

- Organizational Performance has been identified as a root or contributing factor 1,116 times
- Average of ~89 events per year
- This is over 3x the rate of Individual Human Performance issues



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Organizational Performance Issues – Top 5

Out of the 1,116 times organization performance has been indicated as factor, the top five are the following:

- Job scoping did not identify special circumstances and/or conditions (135 times)
- Corrective action responses to a known or repetitive problem was untimely (99 times)
- System interactions not considered or identified (97 times)
- Risks/consequences associated with change not adequately reviewed/assessed (74 times)
- Previous industry or in-house experience was not effectively used to prevent recurrence (62 times)

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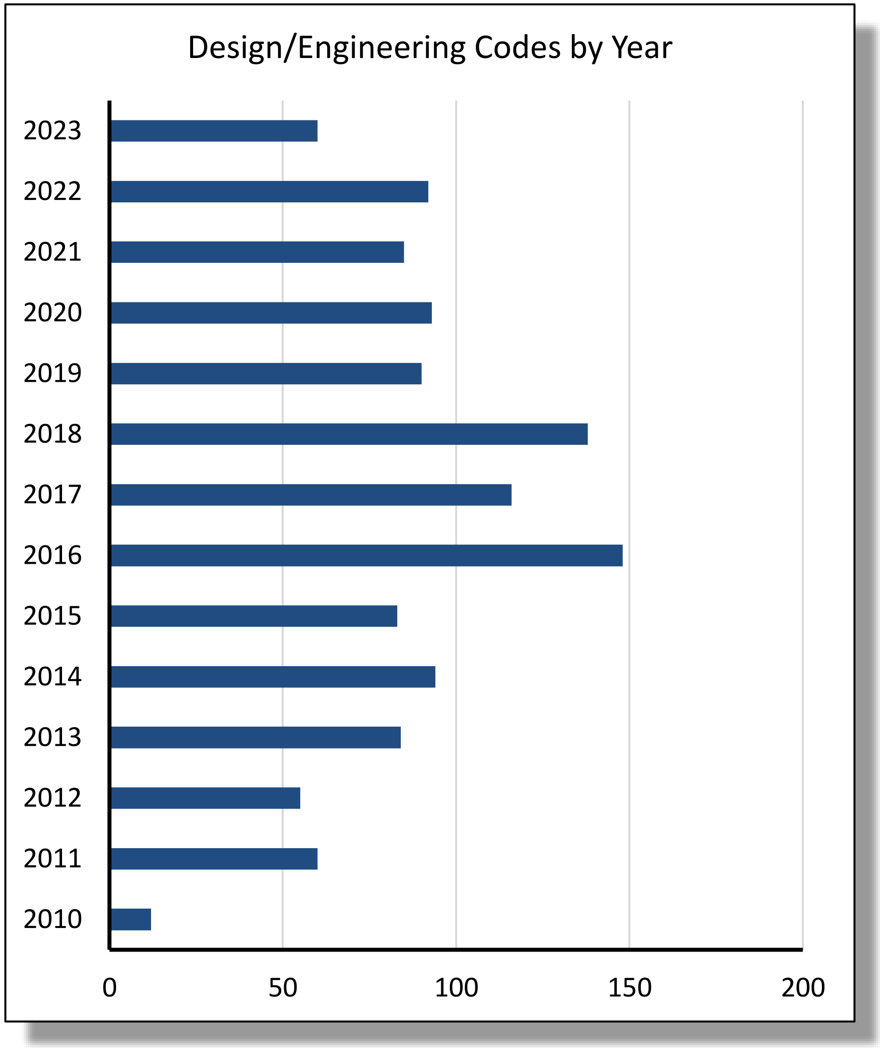
Design/Engineering Issues

- Design/Engineering has been identified as a root or contributing factor 1,210 times
- Average of ~95 events per year
- This is over 3x the rate of Individual Human Performance issues



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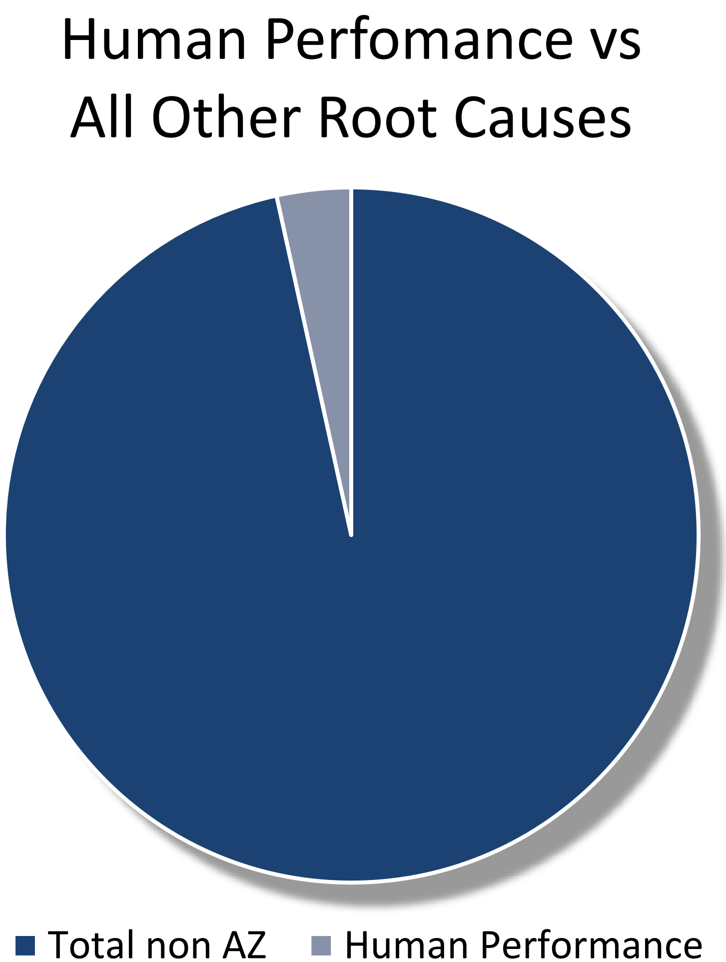
Design/Engineering Issues – Top 5

Out of the 1,210 times Design and Engineering has been indicated as factor, the top five are the following:

- Design output scope LTA (528 times)
- Errors not detectable (134 times)
- Independent review of design/documentation LTA aka, peer checking (126 times)
- Design output not correct (111 times)
- Testing of design/installation LTA (70 times)

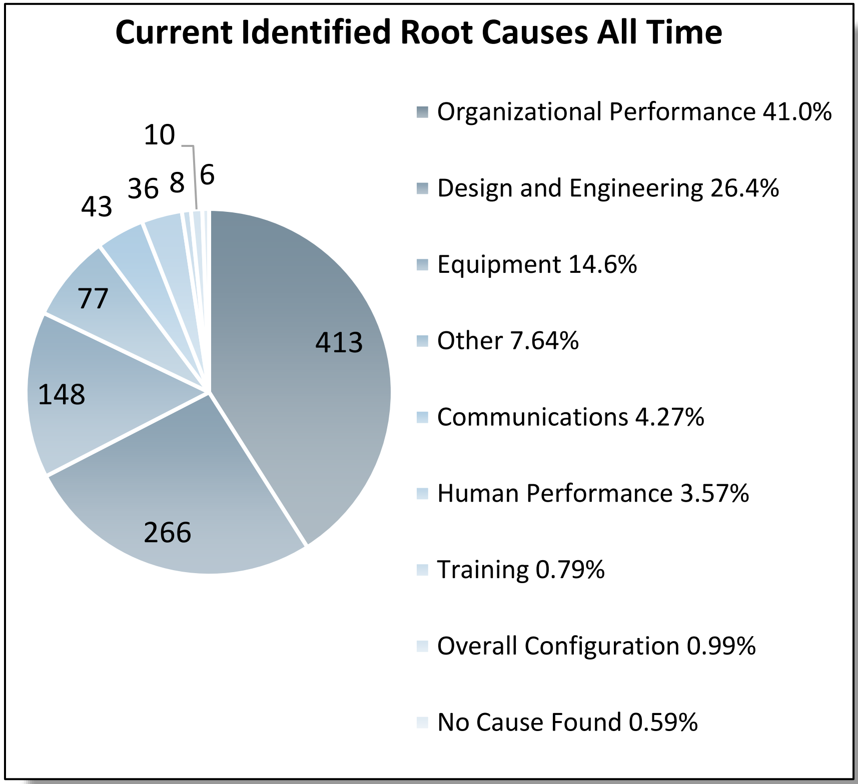
So is it the Human?

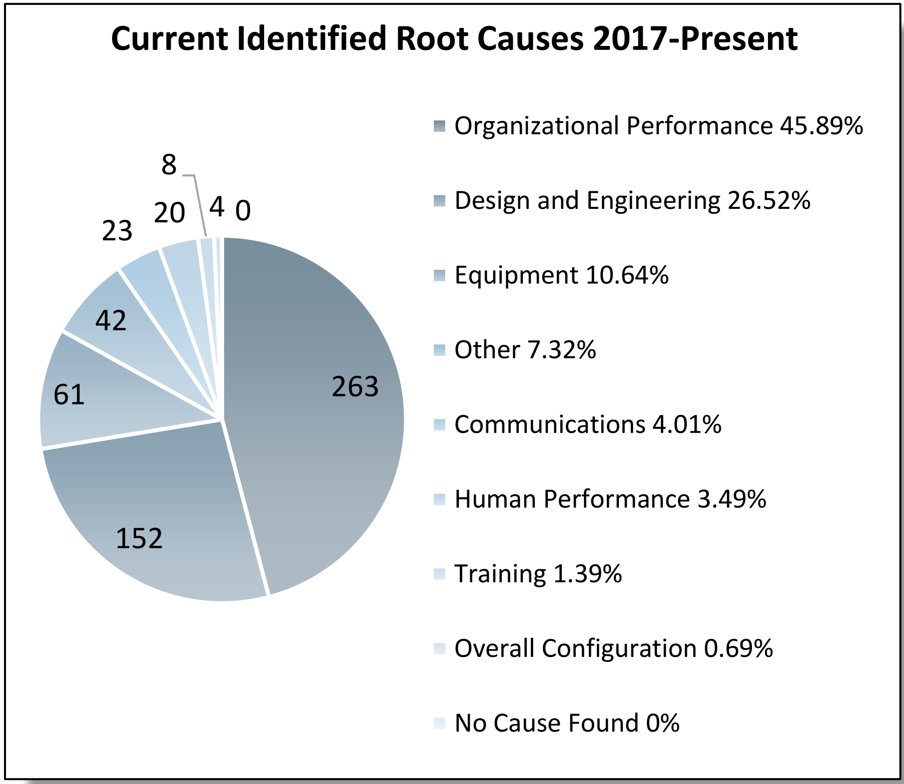


- Only 3.6% of identified event root causes indicate that the event is due to an Individual Human Performance issue

Where are our issues?

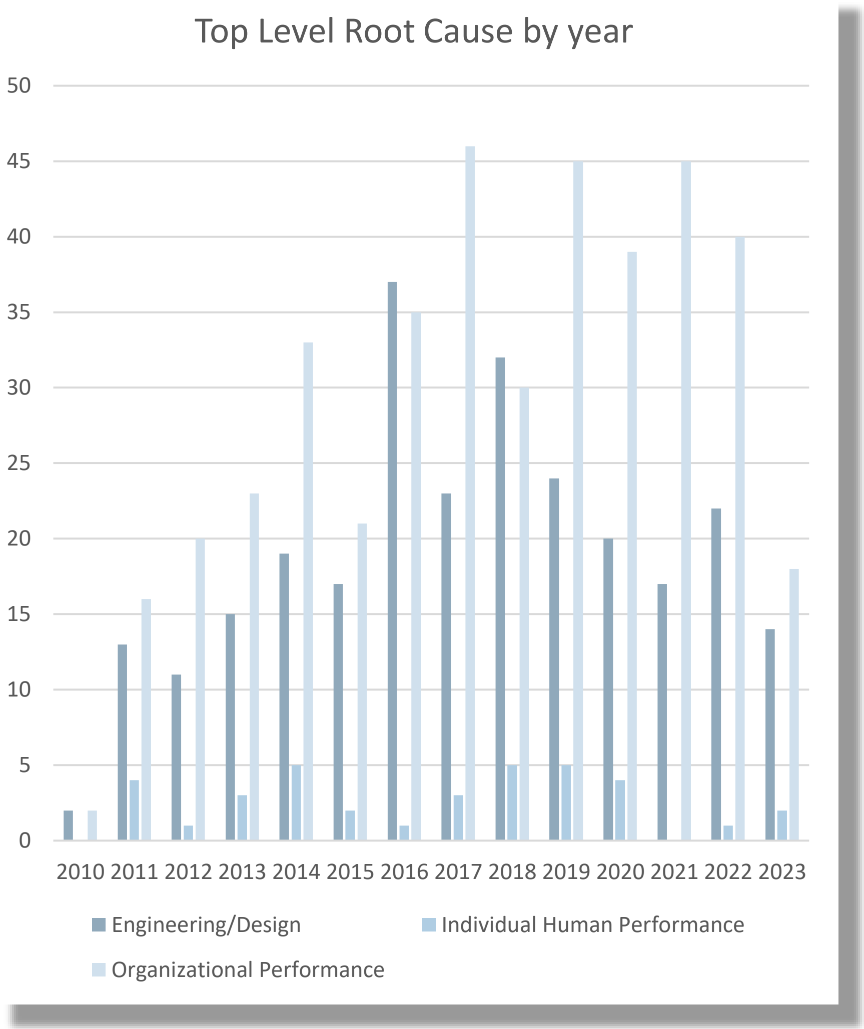
- 41.0% Organizational Performance (45.9% past 5 years)
- 26.4% Design and Engineering (26.5% past 5 years)
- 3.6% Human Performance (3.5% past 5 years)





Human Performance vs. Organization Performance

- Human performance remains fairly constant at a very low level
- Engineering has decreased over the past few years
- Organizational Performance issues remain a major driver of Categorized events



Top HP/OP Event Root Causes

Eng. Design Output Scope LTA (184 times)

Org. Performance – Job scoping did not identify special circumstances and/or conditions (67 times)

Org. Performance – System interactions not considered or identified (40 times)

Org. Performance – Risks / consequences associated with change not adequately reviewed / assessed (31 times)

Org. Performance – Management policy guidance or expectations not well-defined, understood, or enforced (29 times)

Conclusions

Conclusions (Cont’d)

- “Human Performance issues” are usually a symptom of larger challenges within a company.
- Best ways to reduce events are by performing the following:
  - Working to improve engineering, especially improving the understanding of all the ways a design could fail and ensure you have a robust peer review process
  - Working with supervisors and crews to improve job scoping and understanding of how systems interact with each other
  - Ensuring that all potential impacts or dependencies are identified, reviewed, and (if needed) modified to accommodate changes when they are made
  - Ensure that policies and expectations are well defined and understood by your employees and contractors

Conclusions (cont'd)

- Doing what is easy vs doing what is hard
  - It is easy to blame the individual human, a failed component, or weather
  - It is harder to admit our processes, procedures, and policies need improvement
- Yet, It is by identifying and doing what is hard that results in significant improvement for a more Reliable, Resilient, and Secure industry.

"We choose to go to the Moon in this decade and do the other things, not because they are easy, but because they are hard." – President John F. Kennedy

Image Credit: NASA

References

- ERO Event Analysis Program Website
- ERO Event Analysis Process Document
- ERO Cause Code Assignment Process
- Lessons Learned Website

Questions and Answers

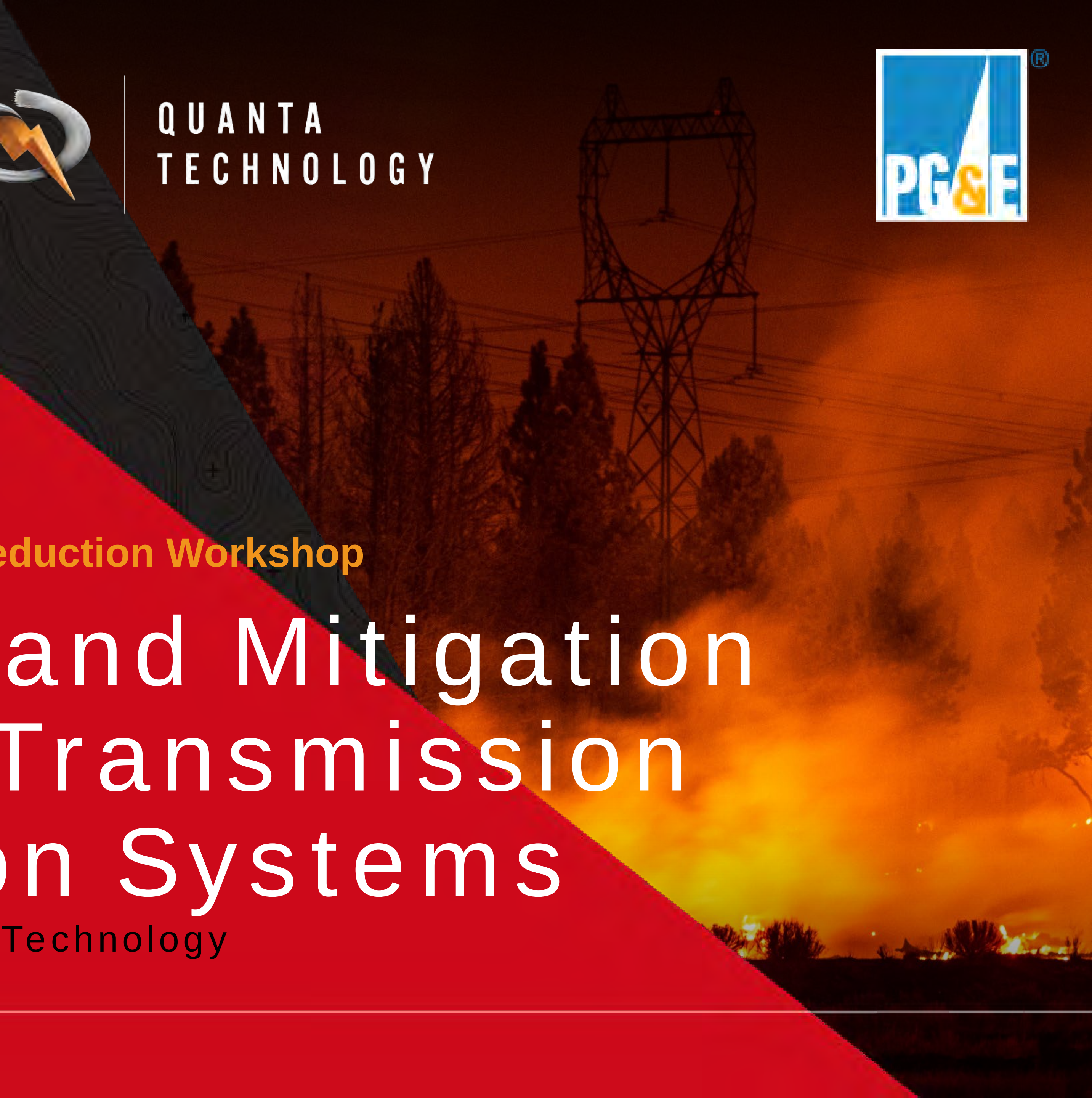
Contact:
Ed Ruck
Senior Engineer of Event Analysis
ed.ruck@nerc.net

OCTOBER 2024

BES Protection System Misoperation Reduction Workshop

Wildfire Risks and Mitigation Strategies on Transmission and Distribution Systems

Jonathan Sykes, Ali Arabnya – Quanta Technology
Scott Hayes – PG&E



Agenda

1. Introduction
2. Economics of Protection Methods for Wildfire Risk Management in T&D Systems
3. IEEE D45 Technical Report
4. Discussion about Regulatory Environment in Australia and U.S.
5. Questions and Answers

Introduction

1 Wildfires (bush fires or forest fires) have become more frequent and more damaging in recent years.

2 The impact of fires is made worse by the increased development in Wildland Urban Interface areas.

3 Electrical equipment is not the largest cause of wildfires but the fires that they cause tend to become larger and more damaging due to their relationship to the environmental conditions at the time of ignition
(i.e., high temperatures, dry fuel, and high wind conditions).

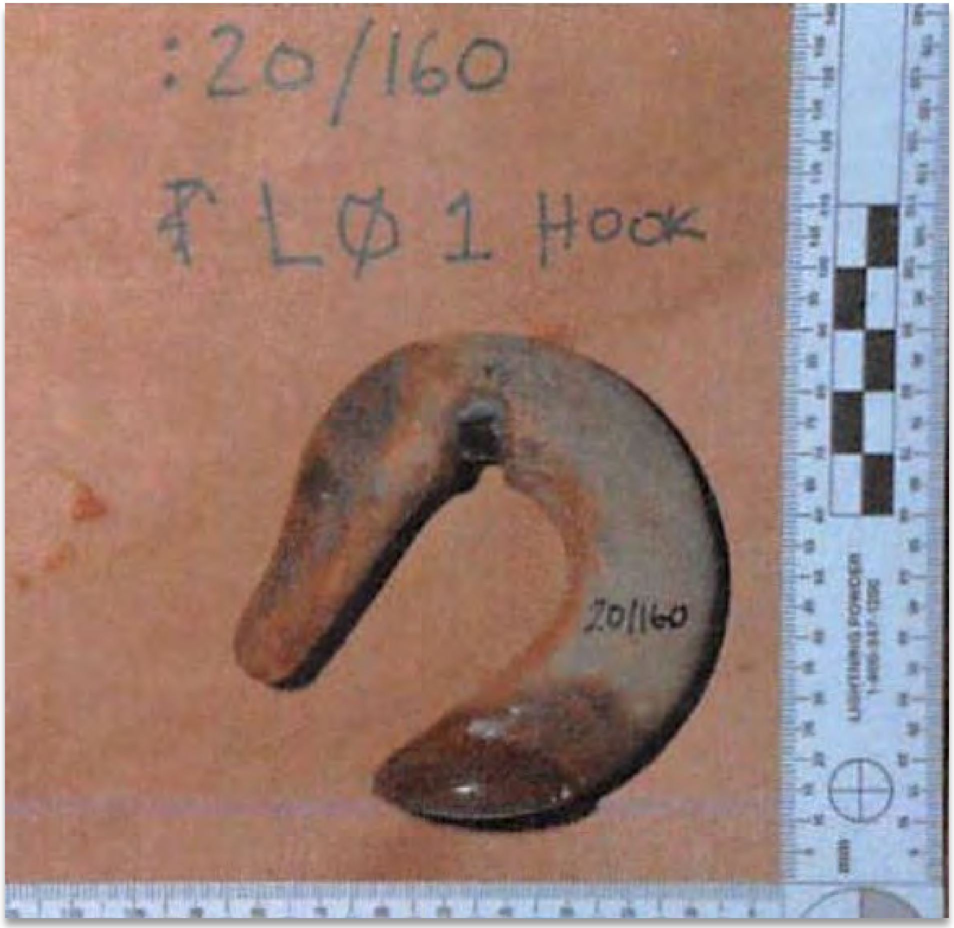
Introduction

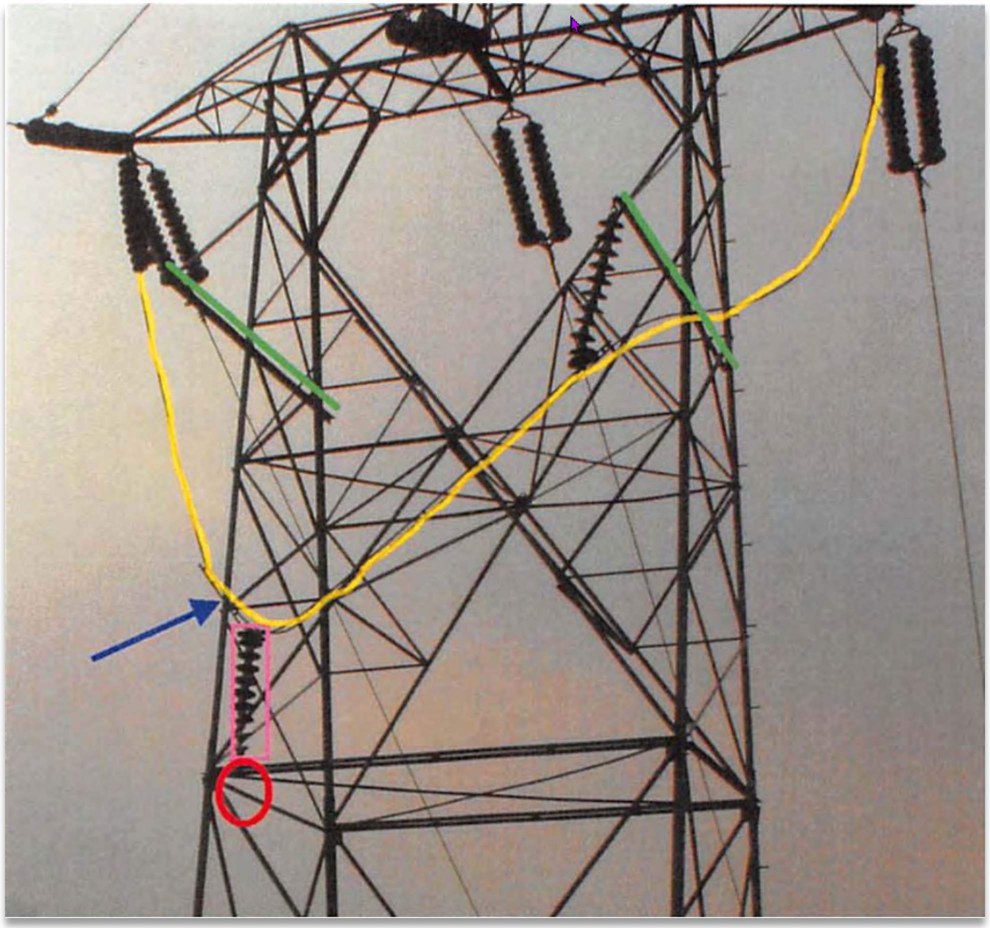
Location	Victoria, Australia
Statistics	
Date(s)	7 February – 14 March 2009 Multiple Fires
Burned area	450,000 hectares (1,100,000 acres)[1]
Cause	Various confirmed sources including: • Power lines[2] • Arson[3] • Lightning[4] • Machinery[5]
Land use	Urban/rural fringe areas, farmland, and forest reserves/national parks
Buildings destroyed	3,500+ (2,029 houses)
Deaths	173[6][7][8]
Non-fatal injuries	414[9]

With costs approaching $100 billion, the fires are Australia's costliest natural disaster. January 16, 2020

Introduction – Distribution Risk vs. Transmission Risk

Camp Fire 115 kV Phase-to-Tower Fault





Introduction – Wildfires and Their Impacts are Increasing


The New York Times

Pleads Guilty to 84 Counts of
ughter in Camp Fire Case

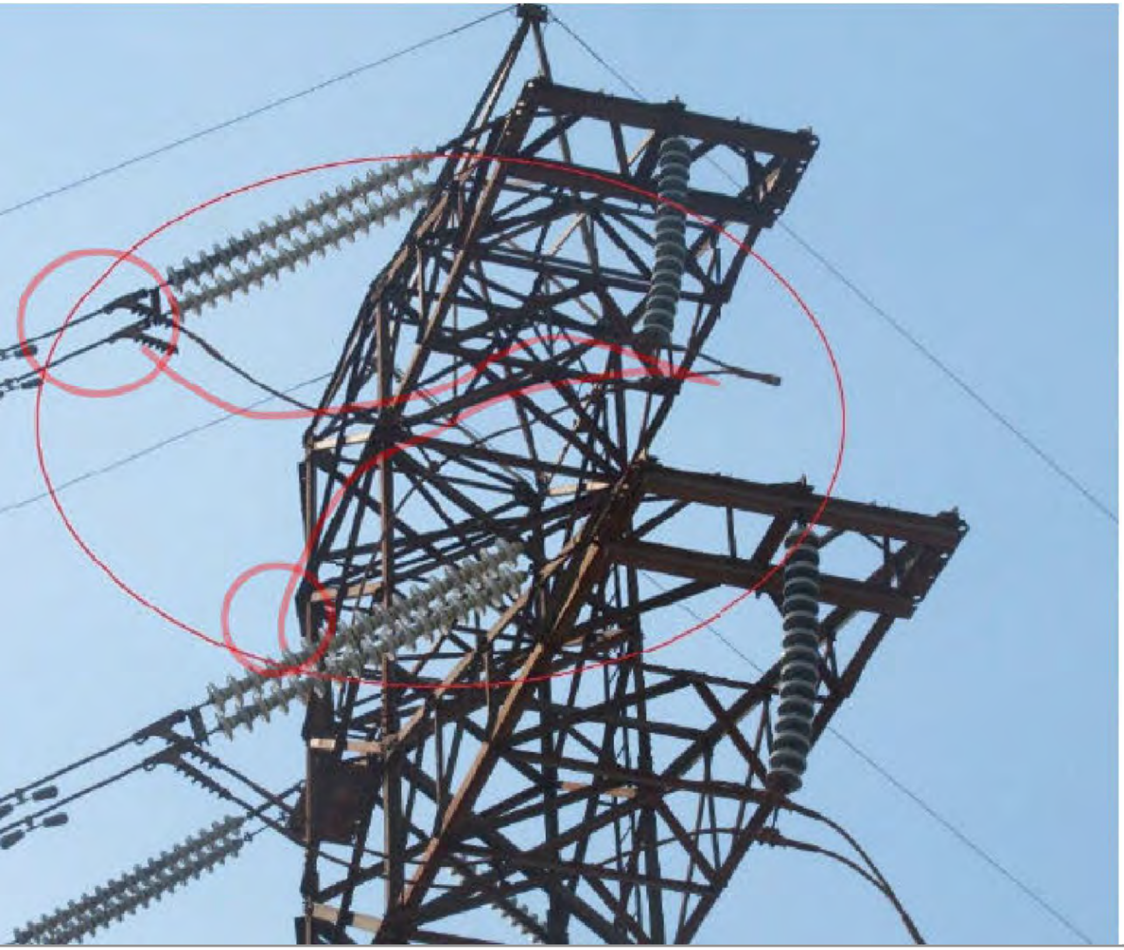
ia utility's transmission line started the 2018 fire tha
s and destroyed the town of Paradise.

Judge approves [Utility's] bankruptcy exit

- A federal judge has approved [Utility's] plan to exit bankruptcy, to compensate victims of a series of wildfires in the state that left more than 100 people dead in 2017 and 2018.
- The action authorized $13.5 billion in compensation for more than 70,000 businesses and homeowners for losses sustained during the fires, which officials said were started by [Utility's] equipment. The company will emerge from bankruptcy with about $40 billion in debt, after agreeing to settle claims from people, insurers, and local government agencies for $25.5 billion.

Introduction – Distribution Risk vs. Transmission Risk

Kincade Fire 230kV Phase-to-Tower Fault



- **374** structures destroyed.
- **185,000+** people evacuated
- **$385 Million** estimated property damage.

Introduction – WECC Weekly (Wildfire) Update

Weekly Update

https://www.wecc.org/wecc-document/14941

Weekly Wildfire Update (PDF)

Western Interconnection Wildfire Assessment_Sept18_Final.pdf (wecc.org)

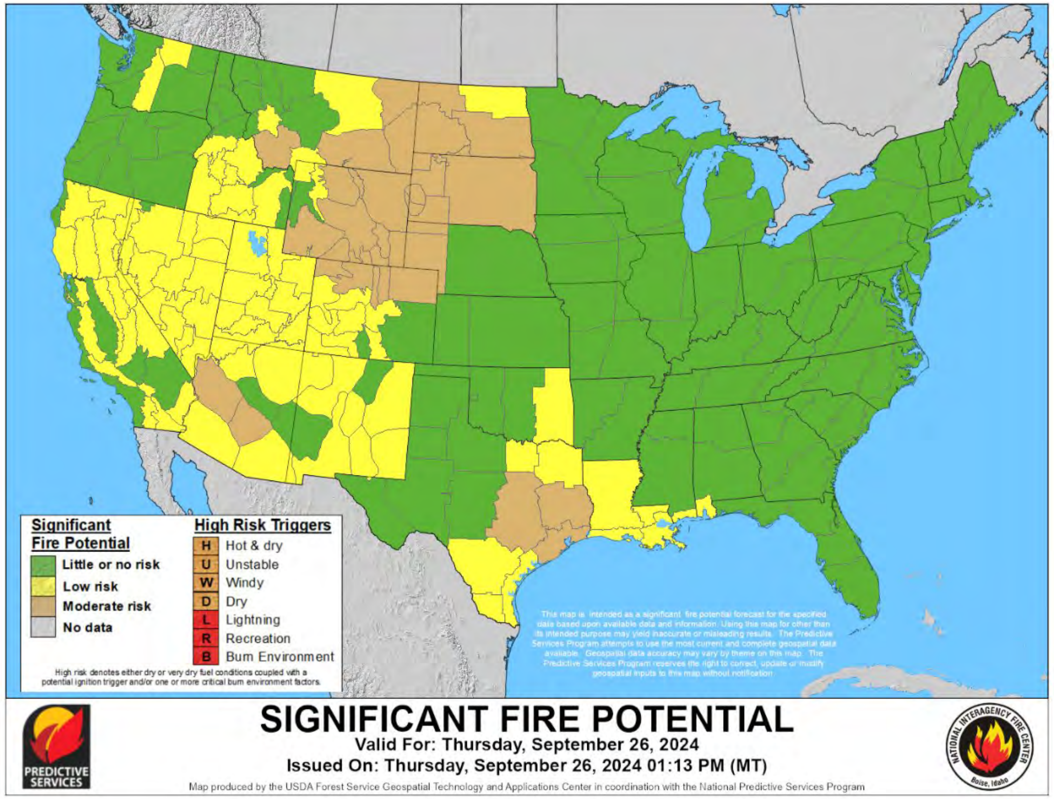
Introduction – WECC Weekly (Wildfire) Update

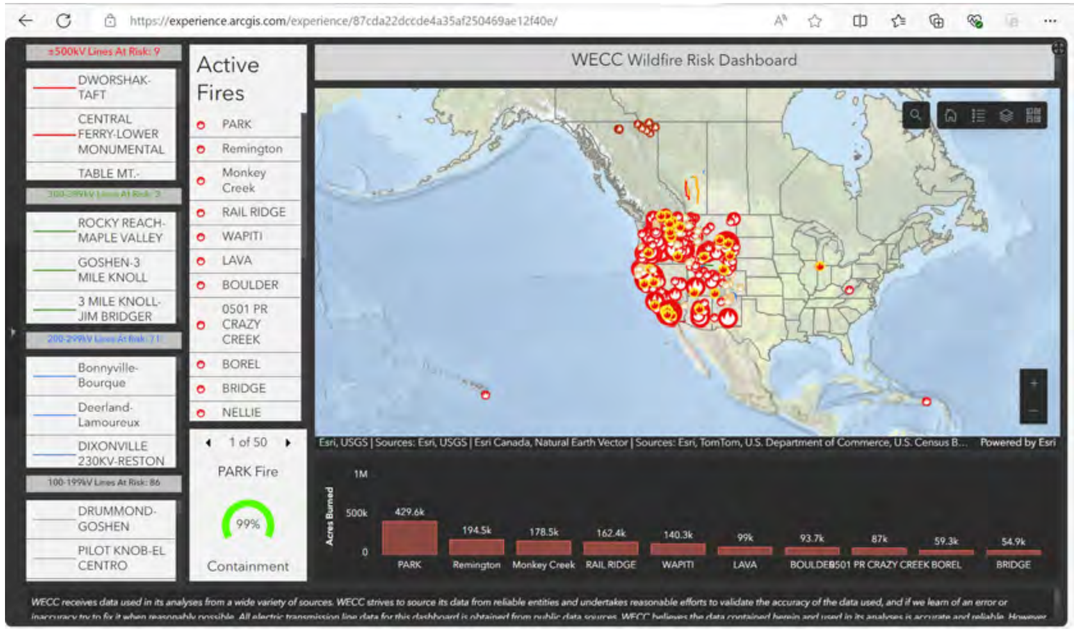
Latest Wildland Fire Outlook (NWS)

https://www.weather.gov/fire/

WECC Wildfire Dashboard

https://experience.arcgis.com/experience/87cda22dccde4a35af250469ae12f40e/





The Economics of Protection Methods for Wildfire Risk Management in Transmission and Distribution Systems

Ali Arabnya – Quanta Technology

Wildfire Risk Management Strategy: Deep Defense

Picture Credit: *Mike Eliason, Santa Barbara County Fire Department, AP / IEEE Spectrum*

The deep defense (or defense-in-depth) approach in risk management is a paradigm that has its origins in ancient military strategy, which relies on multiple lines of defense rather than a single frontline.

An effective wildfire risk management should achieve following objectives:

- **Operational resilience**
- **Financial resilience.**

Three Lines of Defense for Wildfire Risk Management

A three-lines-of-defense (3LD) framework for end-to-end wildfire risk management can facilitate an optimal resource allocation for wildfire resilience building by utilities.

1st Line of Defense

Wildfire prevention

Wildfire prediction
Situational awareness
Limiting fire-inducing faults
System hardening
Grid asset management
Vegetation management

2nd Line of Defense

Wildfire risk mitigation and proactive response

Deployment of wildfire trackers
Preemptive de-energization
Effective suppression tactics
Real-time wildfire monitoring
Emergency grid operations
Technologies to minimize impact

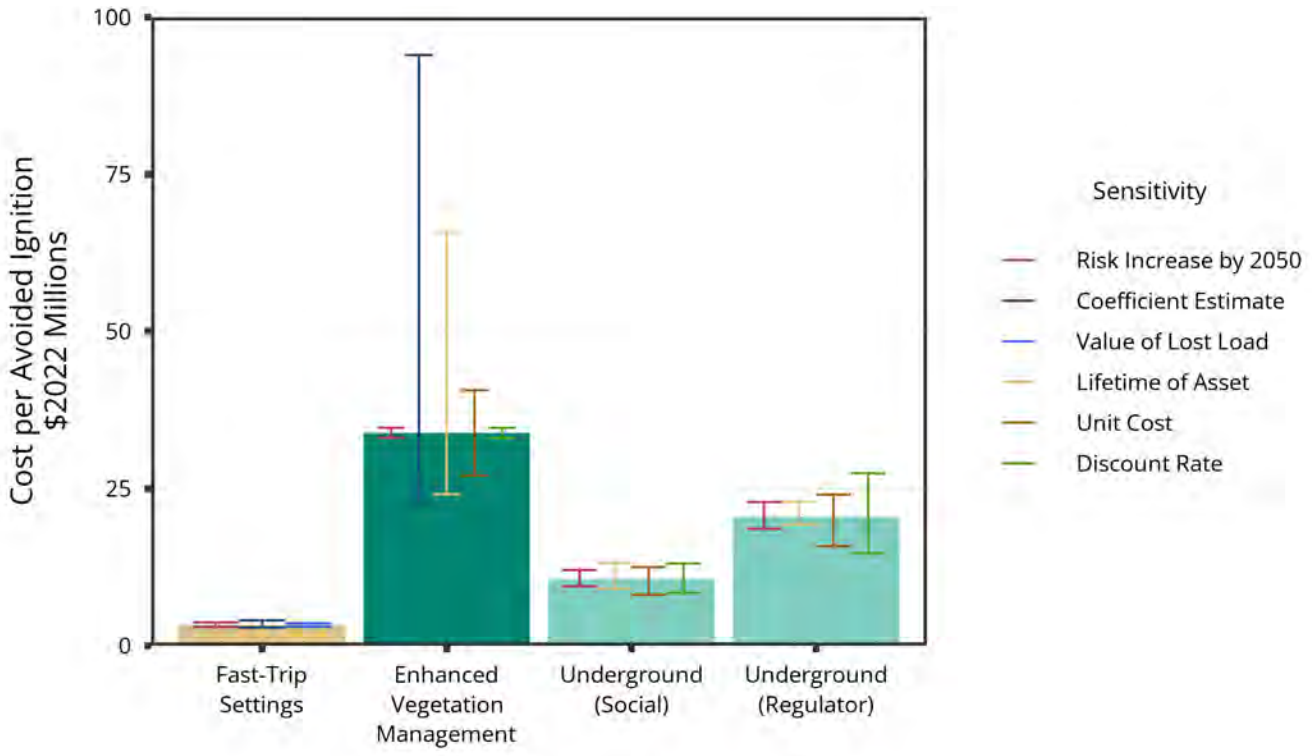
3rd Line of Defense

Recovery preparedness

Recovery logistics
Energy contingency plans
Disaster risk financing
Community engagement

Source: Ali Arabnya et al., Three lines of defense for wildfire risk management in electric power grids: A review. IEEE Access. 2021.

Counterfactual Risk Analysis



A data-driven counterfactual risk analysis can provide crucial input to measuring the success metrics of protection methods used for wildfire risk reduction.

Incremental (marginal) cost analysis of wildfire mitigation strategies (including protection methods) can determine the true cost difference between various alternatives.

Picture credit: Cody Warner et al., Risk-Cost Tradeoffs in Power Sector Wildfire Prevention. The Energy Institute at Haas, 2024.

The Economics of Protection Methods – Fast-Trip Settings

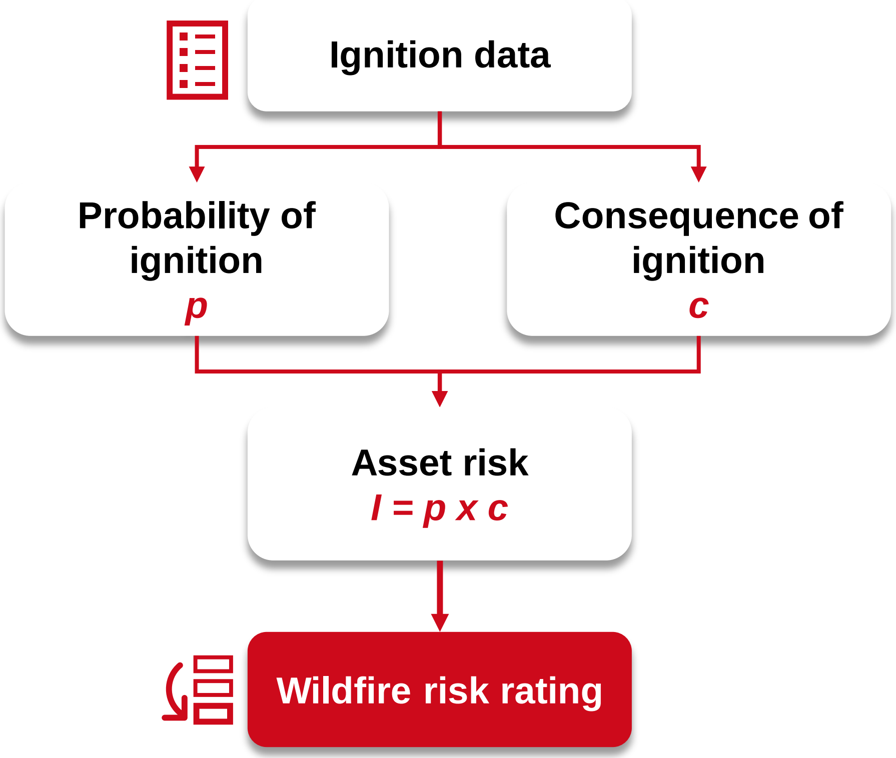
Fast-trip settings should be co-optimized with other mitigation strategies using a risk-based approach:

Minimize:

$$\sum_{i}^{n} Pr\,(ignition)_i\; x\;(consequence)_i$$

Subject to:

- Undergrounding cost ≤ C_{UG}
- Vegetation management cost ≤ C_{VM}
- (Hours of fast trip outages) x (value of lost load) ≤ C_{FT}



Industry Perspective – Emerging Trends

Some of the recent challenges and wildfire risk management objectives set by utility executives are, as follows:

How to reduce the financial exposure from wildfire events by 90%, asked an electric utility CFO? What's the price tag to achieve that goal?

How can Probabilistic Risk Assessment (PRA) methods from nuclear safety codes be leveraged to reduce wildfire ignition risk in an electric utility by x percent?

How a utility can reach its wildfire risk reduction goals using PSPS without compromising SAIDI and SAIFI reliability metrics?

Achieving these multi-objective goals require protection methods to work in sync with other risk reduction methods considering their microeconomic dynamics in utility businesses.

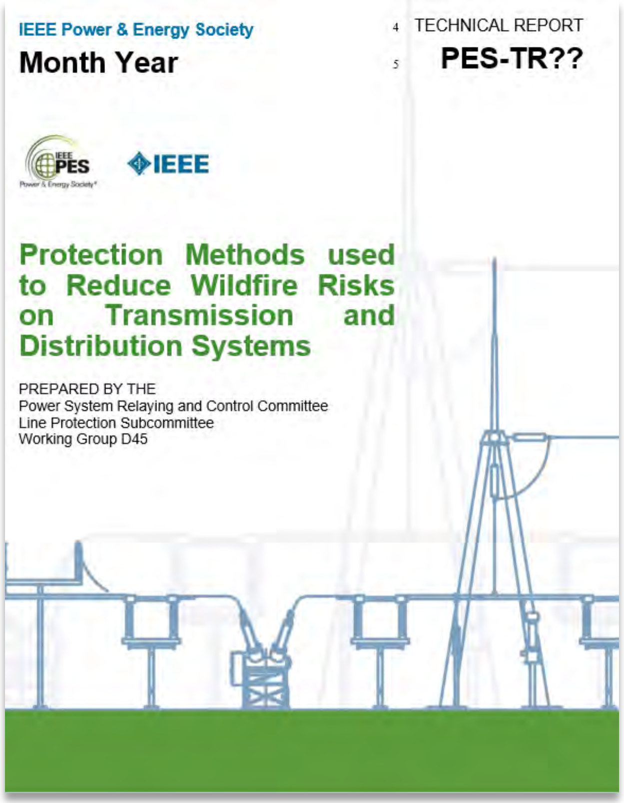
IEEE PRSC D45 WG, Technical Report Document Protection Methods Used to Reduce Wildfire Risks Due to Transmission and Distribution Lines

Jonathan Sykes, PE, IEEE Fellow, Quanta Technology
Scott Hayes, PE, Principal Engineer, PG&E

October 01, 2024
NERC Salt Lake City, Utah

IEEE PES PSRC Working Group D45

Overview



D45: Prepare a technical report to the line protection subcommittee to "document protection methods used to reduce wildfire risks due to transmission and distribution lines."

Chair: Jonathan Sykes
Vice Chair: Scott Hayes
Output: Technical paper approximately January 2025
Team: Utilities, Consultants, Academia, and Manufactures

IEEE PES PSRC Working Group D45

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- Hugh Borland
- Ritwik Chowdhury
- Normann Fischer
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Table of Contents (Abbreviated)

- Fault Behavior and Ignition Risks
- Fault Responsive Relay Applications
- High Impedance Fault Detection
- Incipient Fault Detection
- Impact of Fuses on Fire Risk
- Neutral Grounding Practices
- Compensated Neutral Schemes

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Fault Behavior and Ignition Risk

- The capacity of electricity to start wildfire is as old as lightning, and the fire ignition risks associated with modern electrical equipment led to the creation of the National Electrical Code (NEC), produced by the National Fire Protection Association (NFPA) beginning in 1897.
- At a fundamental level, fire ignition risk increases with an increase in fault energy.
- **Fault energy is a function of the magnitude of fault current and the duration of the fault,** but the variety of fault conditions that occur on the power system factored in with fuel bed and climate conditions make for a much more complicated picture.

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Fault Behavior and Ignition Risk

- There are to many variables to determine the exact risk.
- The electrical grid extends thousands of miles throughout the forest and has millions of arc possibilities.
- Each point of the arc can present very different risk characteristics.
- For over 100 years the grid has used overcurrent and impedance-based detection methods to detect and isolate the fault on the line.
- The protection of the electrical grid focused on the isolation of the fault with as little interruption to the rest of grid as possible.
- Relays were coordinated with intentional time delays to allow coordination between zones of protection.
- Some faults were cleared with an intentional time delay.

The longer the fault or arc lasts the more heat energy is present and the greater risk of a wildfire.

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Fault Responsive Relay Applications

- Distributed Energy Resources (DER) on the distribution system
- Relay setting change methods:
    - **Increase fault detection, selectivity, sensitivity, and lower relay operation time**
    - Automatic and Dynamic Reclosing
- Communication-aided protection methods:
    - Step distance-based communication systems
    - Transmission Line-Current Differential (LCD)
    - Time-domain and traveling wave protection
    - Distribution Line Differential (DLD)
    - Sensor-based methods.

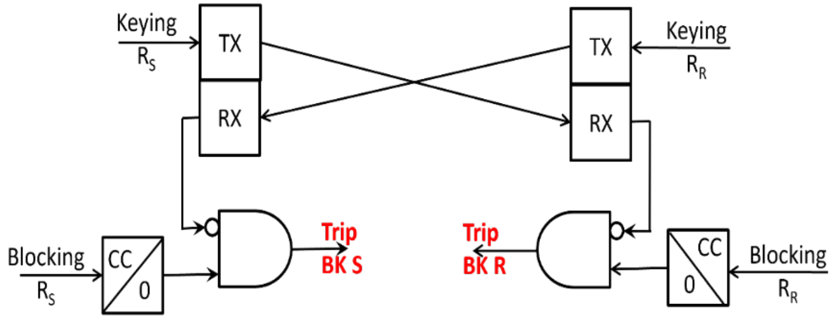

Figure 4.3.1 Simplified Step Distance Communication Scheme

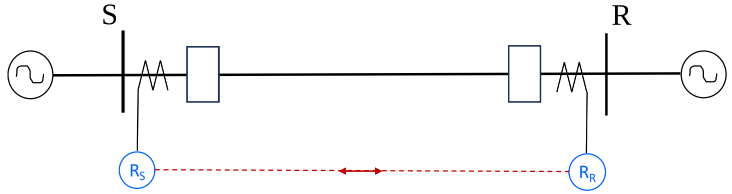

Figure 4.3.2 . Line Current Differential.

Risk-Cost Tradeoffs in Power Sector Wildfire Prevention, Energy Institute at HAAS, WP 347, Cody Warner, Duncan Callaway, and Meredith Fowlie February 2024; https://haas.berkeley.edu/wp-content/uploads/WP347.pdf

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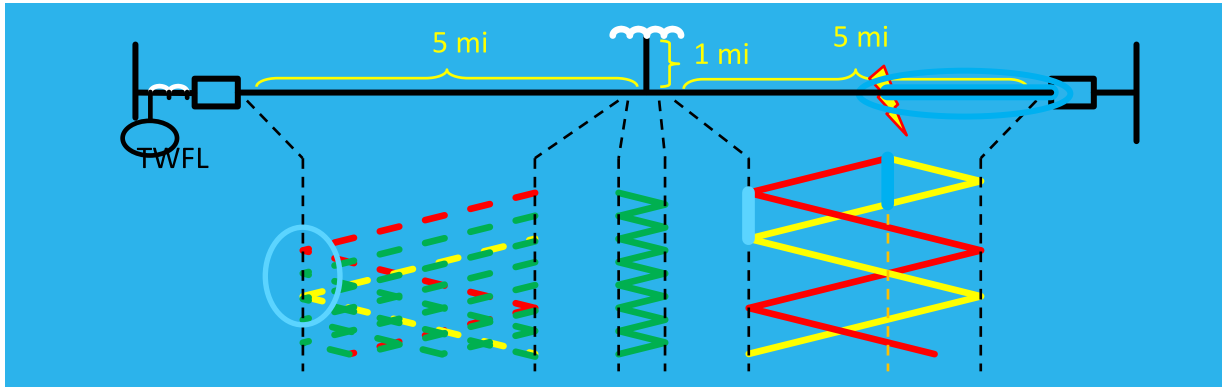
Fault Responsive Relay Applications

Time-domain and travelling wave protection:

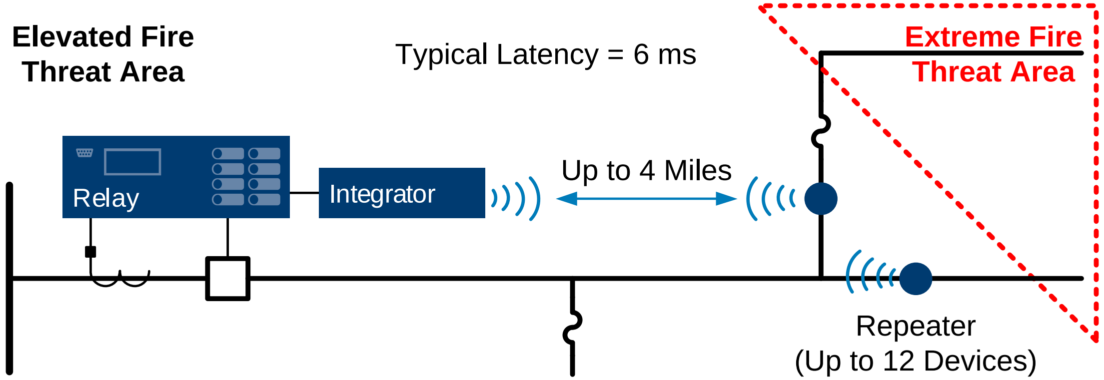
- Transmission application is simpler.

Sensor-based methods:

- Positive detection and location of downed conductors.



TW for Complex Line Topologies



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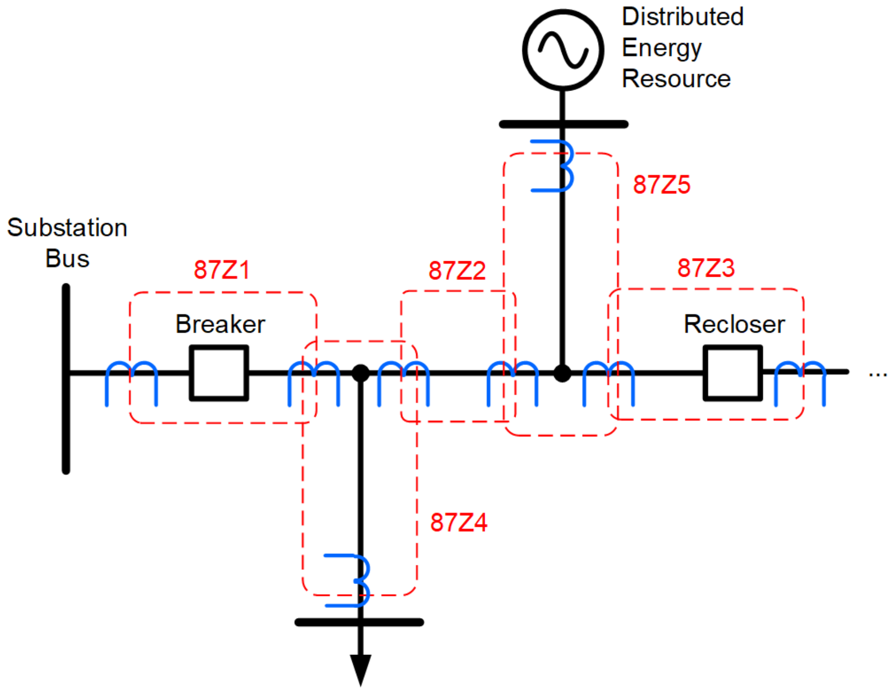
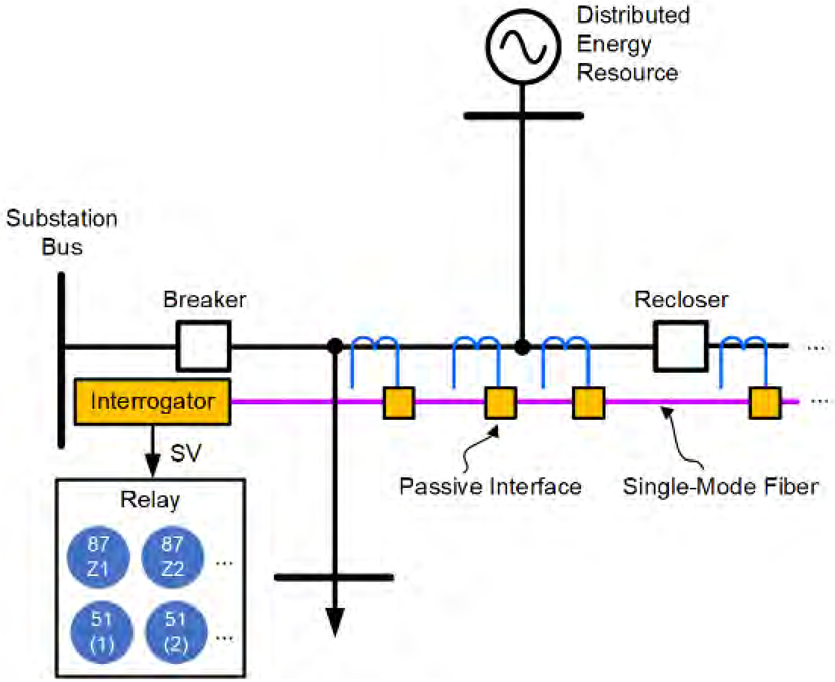
Fault Responsive Relay Applications

Distribution Line Differential and Passive Distributed Measurements





M. Mohemmed, P. Orr, S. Blair, N. Gordon, I. Mckeeman, A. Mohamed, and A. Bonetti, "Differential Protection of Multi-Ended Transmission Circuits Using Passive, Time-Synchronised Distributed Sensors," proceedings of the PAC World Conference, Prague, Czech Republic, 2022.

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High-Impedance Fault Detection and Pulse Counting

Arcing produces a wide spectrum of even-, odd-, and inter-harmonic energy along the power line that extend into the megahertz range.

Detection Strategies:

- Derive the high-frequency signal component including even and odd harmonics in the range of sub-harmonic to 1 MHz.
- Tune the response of the detection algorithms.
- Logic to differentiate an HIF condition from switching operations and noisy loads.
- Detect intermittent arcing (i.e. Pulse Counting)

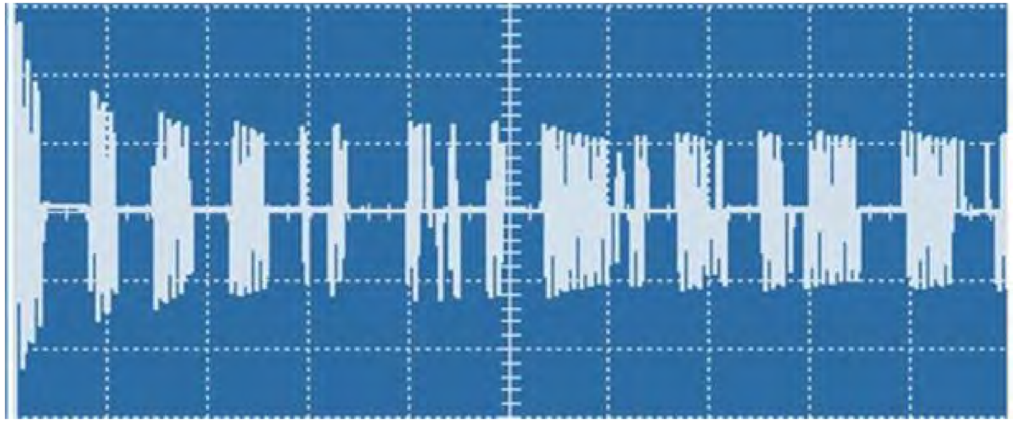

Diagram 5.1 Example of time-varying, intermittent, and harmonic-rich HIF current waveform

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Incipient Fault Detection

- Technologies, trials, and solutions being developed or applied for incipient or “emergent” fault detection that are potential pre-cursors to fire ignition risks.
- The gold standard sought by the industry are methods to detect incipient faults with enough time to take action before high-current faults occur.
- Principles used for the technologies and solutions for incipient fault detection can be classified under the following categories:
  - Pattern recognition
  - Corona discharge detection / partial discharge analysis
  - Remote sensing and LiDAR-based
  - Video monitoring based
  - Fiber-based line monitoring methods.

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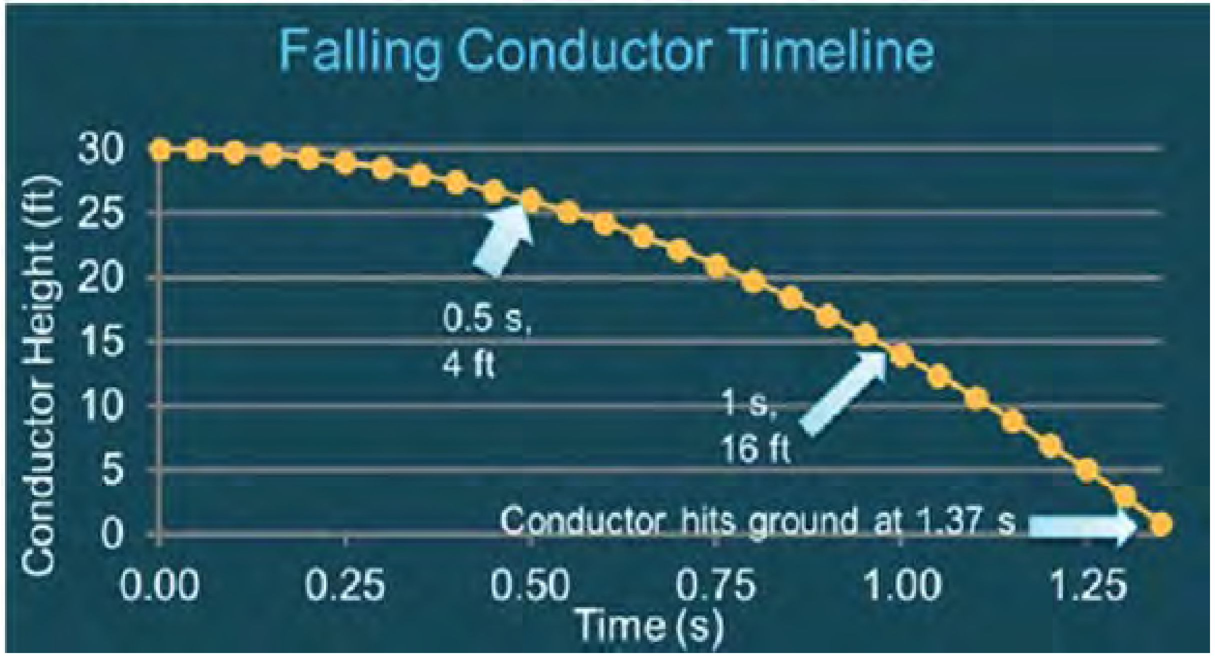
Incipient Fault Detection – Falling Conductor Detection (FCP), Broken Conductor, Open Phase Methods

1 Distribution falling conductor operational timing



- Falling Conductor Protection (FCP) systems, developed around 2014, detects the electrical signature of circuit voltage and/or current changes
- There is adequate time to deenergize the circuit well before the conductors reach the ground
  - A distribution conductor 33 feet in the air takes about 1.4 seconds to reach the ground.
- Voltage sensing is commonly used for distribution and current sensing for transmission.

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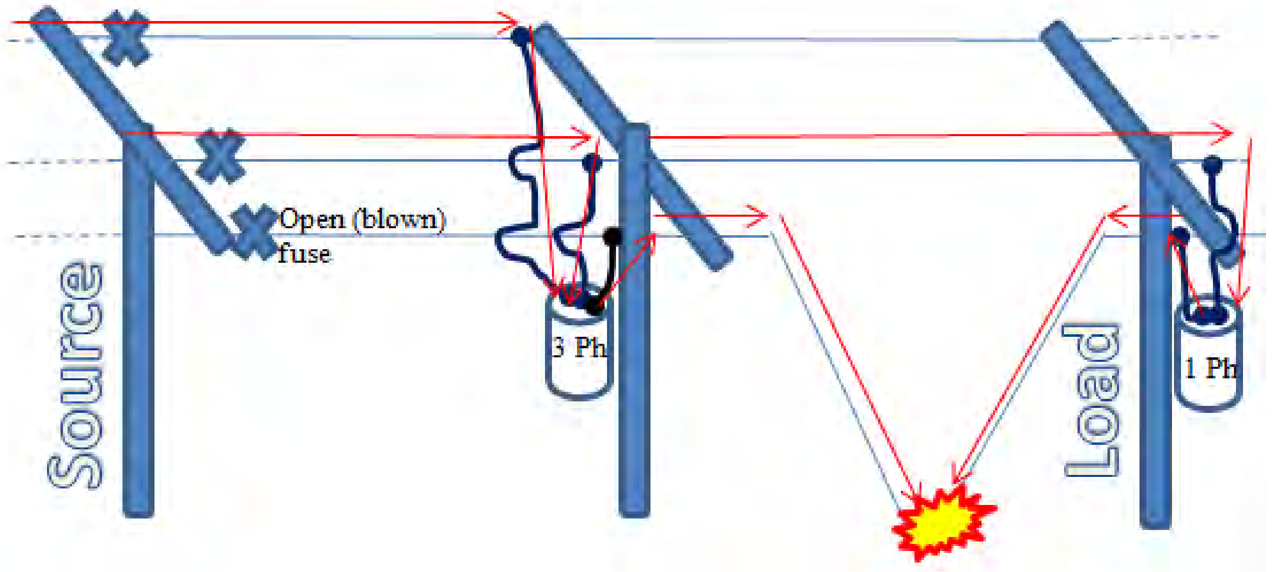
Impact of Fuses on Fire Risk

Fuses are typically the most common protective device installed in overhead distribution systems.

Various types include:
- Single-phase devices
- Expulsion fuses
- Non-expulsion fuses
- Current-limiting fuses
- Electronic interrupters.

Back Feed Issue: If three-phase or phase-to-phase transformers are connected on the load side of the blown fuse, it can result in low-level currents flowing that have been known to ignite fires. This is sometimes called a back fed fault.



Single-Phase Fuse Operation

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Neutral Grounding Practices

- Neutral grounding methods can significantly reduce ground fault-current levels and fire ignition risk.
- Neutral grounding methods can result in ground fault currents ranging from tens of thousands of amps to milliamps.
- When applying delta or high impedance grounding methods the effects of temporary overvoltages on equipment and the impact on detecting ground faults must be considered.

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Neutral Grounding Practices

Multipoint Grounded Wye

- Multipoint grounded Wye or 4-wire systems are prevalent for medium-voltage circuits in North America.
- Supports phase-to-phase and phase-to-ground connected loads. This can reduce equipment costs but typically results in high levels of ground fault current.
- High-impedance grounding is usually not applied. Load unbalance is often high, requiring ground relays with high minimum trip.
- This results in less sensitivity for high-impedance ground faults .

Uni Grounded Wye

- Uni-grounded Wye or 3-wire systems are common at medium- voltage installations internationally.
- This method supports phase-to-phase connected loads without an insulated neutral conductor being brought to the load.
- These systems can accommodate different grounding methods to reduce ground fault-current levels by applying neutral grounding resistors, reactors, or compensated neutral schemes.
- Unbalanced loads do not flow in ground relays allowing sensitive ground time-overcurrent settings.

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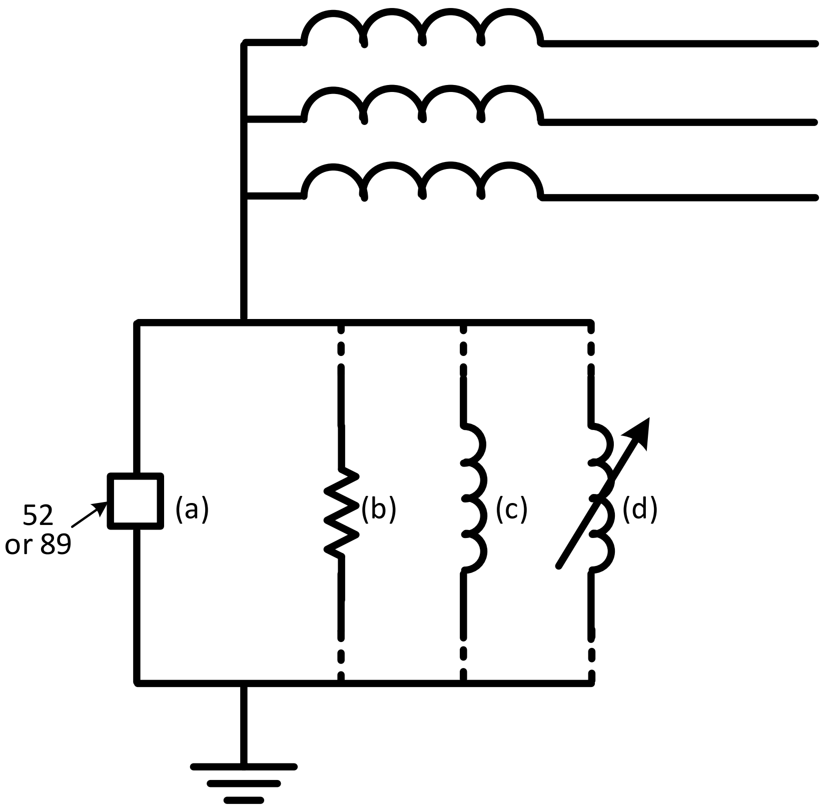
Neutral Grounding Methods

- Multipoint grounded Wye
- **Uni-grounded Wye**
- Delta/ungrounded
- Delta/grounded
- High-impedance grounding for Wye grounded systems.



High-resistance/reactance/compensated ground

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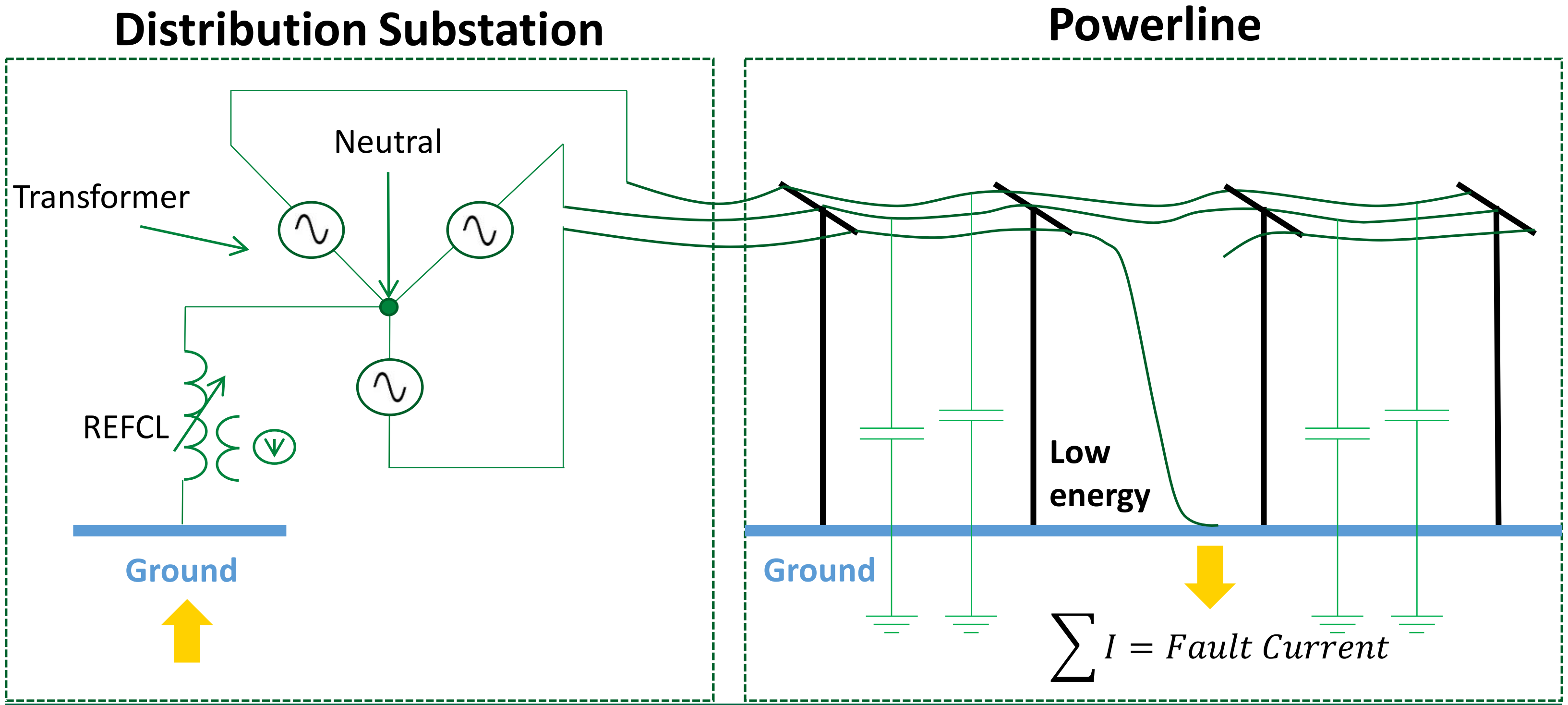
Compensated Neutral Schemes



Future with REFCL: Less than 0.5 Ampere

Source: PowerCore Australia's Control and Ops REFCL Guidebook

Note: Compensated neutral schemes also referred to as Petersen Coils were first developed in Germany by Waldemar Petersen in the early 1900's and appear in AIEE papers beginning in 1922.

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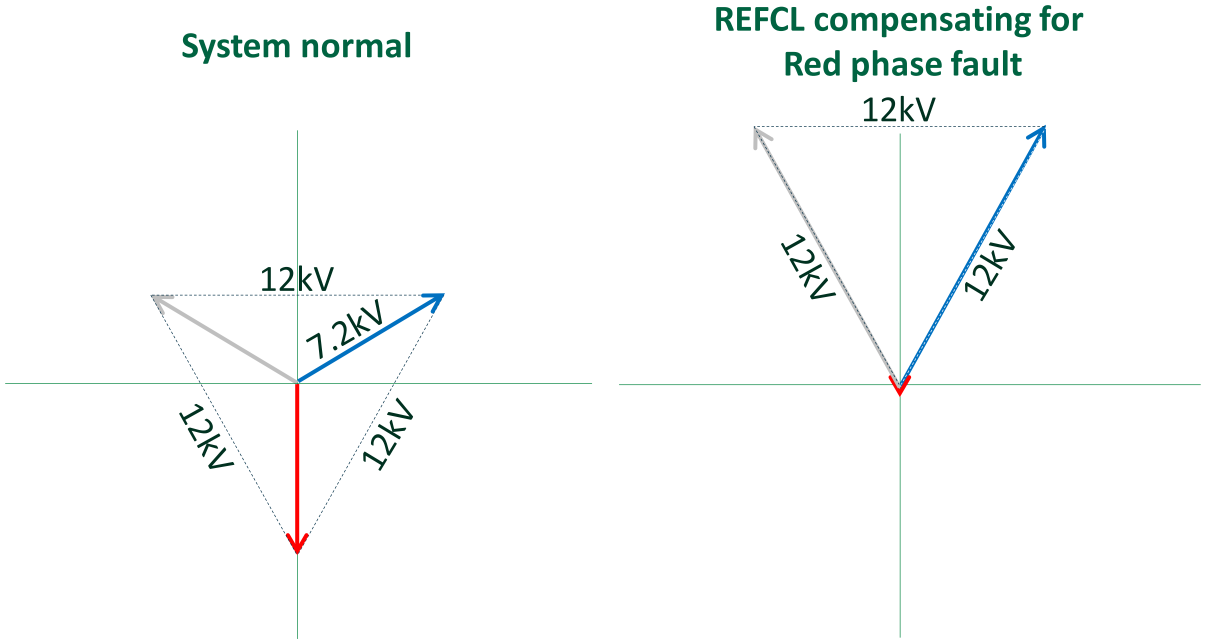
Compensated Neutral Schemes

Resonant Grounding – How Does GFN Work?

- The ASC across the neutral, that is tuned to the network capacitance, will neutralize the unbalanced capacitive current resulted from phase-to-ground voltage on the two healthy phases.
- A residual current due to resistive (residual) losses still exists of between 10-20 amperes typically. This current is then reduced to almost zero by the RCC.

- 12 kV phase-to-ground on the two un-faulted phases
- 0 kV phase-to-ground on the faulted phase,
  7.2 kV neutral-to-ground



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Compensated Neutral Schemes

Rapid Earth Fault Current Limiter (REFCL)

REFCLs come in two main types:

1) Arc Suppression Coils with no power electronic components
2) Ground fault neutralizers with active residual current compensation using power electronics

Other Methods (Outside North America)

- Isolated Neutral
- Directional Residual Overcurrent Methods
- Fault Inception Transient Methods
- qu (Charge Voltage) Method
- Transient Reactive Power Method
- Admittance Methods
- Multi-frequency Admittance Method
- Change in Admittance Method
- Change in Negative-Sequence Current (Δ3* I2) Methods
- Harmonics
- Concurrent Algorithm
- Network protection
- System Wide Ground Fault Protection

Regulatory Environment in Australia and U.S.

Scott Hayes – PG&E

Australian Regulation

- In 2016, the State of Victoria, Australia passed regulation 32/2016 to reduce bushfire risk.
- The regulations are prescriptive and includes 45 substations – listed by name and latitude/longitude.
- Performance requirements are part of the regulation
- **In 2016, only one vendor could meet the performance requirement.**

Australian Regulation

Performance requirement must be validated by testing every year.

In the event of a phase-to-ground fault on a polyphase electric line, the ability:

- (a) to reduce the voltage on the faulted conductor in relation to the station earth when measured at the corresponding zone substation for high impedance faults to 250 volts within 2 seconds; and
- (b) to reduce the voltage on the faulted conductor in relation to the station earth when measured at the corresponding zone substation for low impedance faults to
    - (i) 1900 volts within 85 milliseconds; and
    - (ii) 750 volts within 500 milliseconds; and
    - (iii) 250 volts within 2 seconds; and
- (c) during diagnostic tests for high impedance faults, to limit
    - (i) fault current to 0·5 amps or less; and
    - (ii) the thermal energy on the electric line to a maximum I2t value of 0·10;

Regulatory Framework in the U.S.

Vegetation management laws
Vary by state.

California Utilities:
- Are not allowed to cut healthy trees outside of right of way.
- Some right of ways are 30 feet wide with 100- to 300-foot-tall trees.

Vegetation management laws
Vary by state.

California:
- Has GO 95, which applies to hardware failures and vegetation contacts.
- Faults are generally considered a violation due to Utility “Failing to Maintain its Facilities Safely…”

Ignition Risk Formulas

- Scott Hayes, PE, Principal Engineer, PG&E
- Jonathan Sykes, PE, IEEE Fellow, Quanta Technology

Ignition Risk Formulas

Basic research to develop risk equations

- There are no standard industry equations for ignition risk vs fault current or clearing times. Initial assumptions that fault energy predicted by I^2T have been found overly simplistic and not a good model of ignition risk. The lack of industry wide ignition risk formulas are a result of the chaotic nature of electrical arcs, many construction and hardware variables, and large numbers of environmental variables.
- Australian testing and PG&E testing have developed some formulas that are not consistent or adequate
- Suggest pursuing collaborative funding/testing through an industry group.

Ignition Risk Formulas

Proposed Fault Types to test

- Wire on Ground Low Z/High Z
- Vegetation on wire(s)
- Overhead arcing fault (Phase to Phase or Phase to Ground)
- Fault height above ground.
- Conductor types and configurations
- Vary fault current and clearing time

Ignore environmental variables (wind speed, temperature, humidity)

Ignition Risk Formulas

Fire Ignition Risk ~ Fault Energy

Fault Energy = f(Fault Current and Clearing Time)

THERE ARE NO EXACT FORMULAS

I^2 T R
Where R is resistance at fault point

$$P_I = \frac{1}{1 + e^{-(-7.85+0.129t)}}$$

PG&E Testing: Constants vary with fault current and environmental factors

$$P_{397Al}(I, f, t) = (0.006842\, I)^4 f^2\, exp\big((0.79\, f\; -\; 3.845)t\big)$$

Ignition Risk Formulas

Fault Behavior and Ignition Risk

Ignition Probability

Australian Tests – Arc on dry fuel

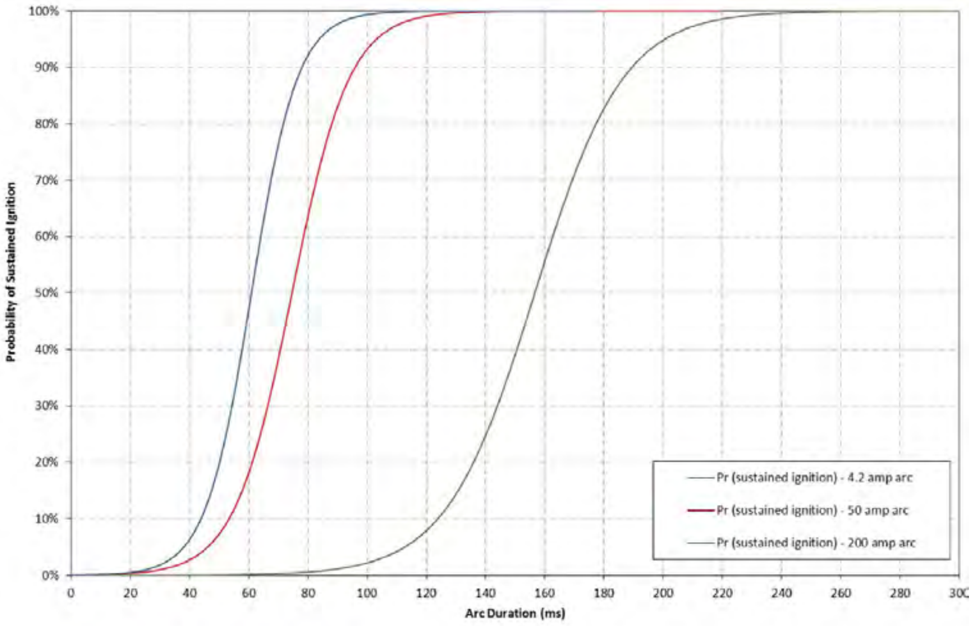

Figure 1. Ignition probability against arc duration for 4.2, 50 and 200 amp arcs at 45°C and 10 kph wind speed for hay/straw at 5% moisture

https://www.researchgate.net/publication/283486798_Probability_of_Bushfire_Ignition_from_Electric_Arc_Faults

Particle Counts

PG&E tests – Overhead arcing faults

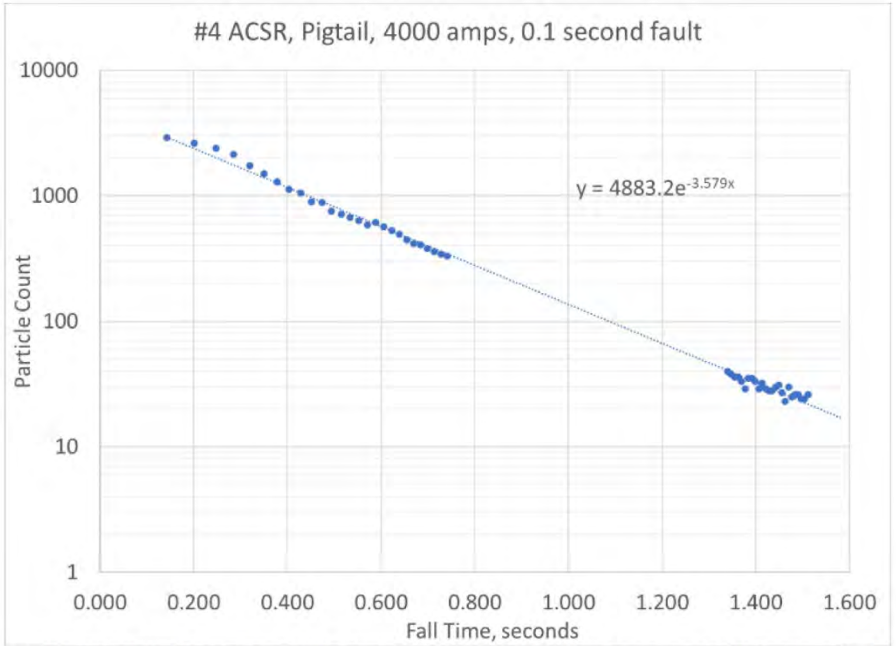

Figure 11. Particle Count vs. Fall Time (seconds) for the Cage and Lift tests combined, 0.1 second fault time, for #4 ACSR, Pigtail Configuration.

Assessment of Hot and Flaming Particles and Fire Risk from High Current Faults, Western Protective Relaying Conference 2022

Questions or Comments?

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Automated Solutions and Remote Settings Changes - AEP's Approach to Implementing PRC-027-1

Jeff Iler, Nelson Doe, and Manish Thakur

American Electric Power

Automated Solutions and Remote Settings Changes - AEP's Approach to Implementing PRC-027-1

2024 ERO Misoperation Reduction Workshop

Agenda:

- AEP Background
- PRC-027-1 Requirement 2
- What is a Protection System Coordination Study
- AEP's Initial 765kV Area Study
- Lessons Learned
- Coordination Study Progress

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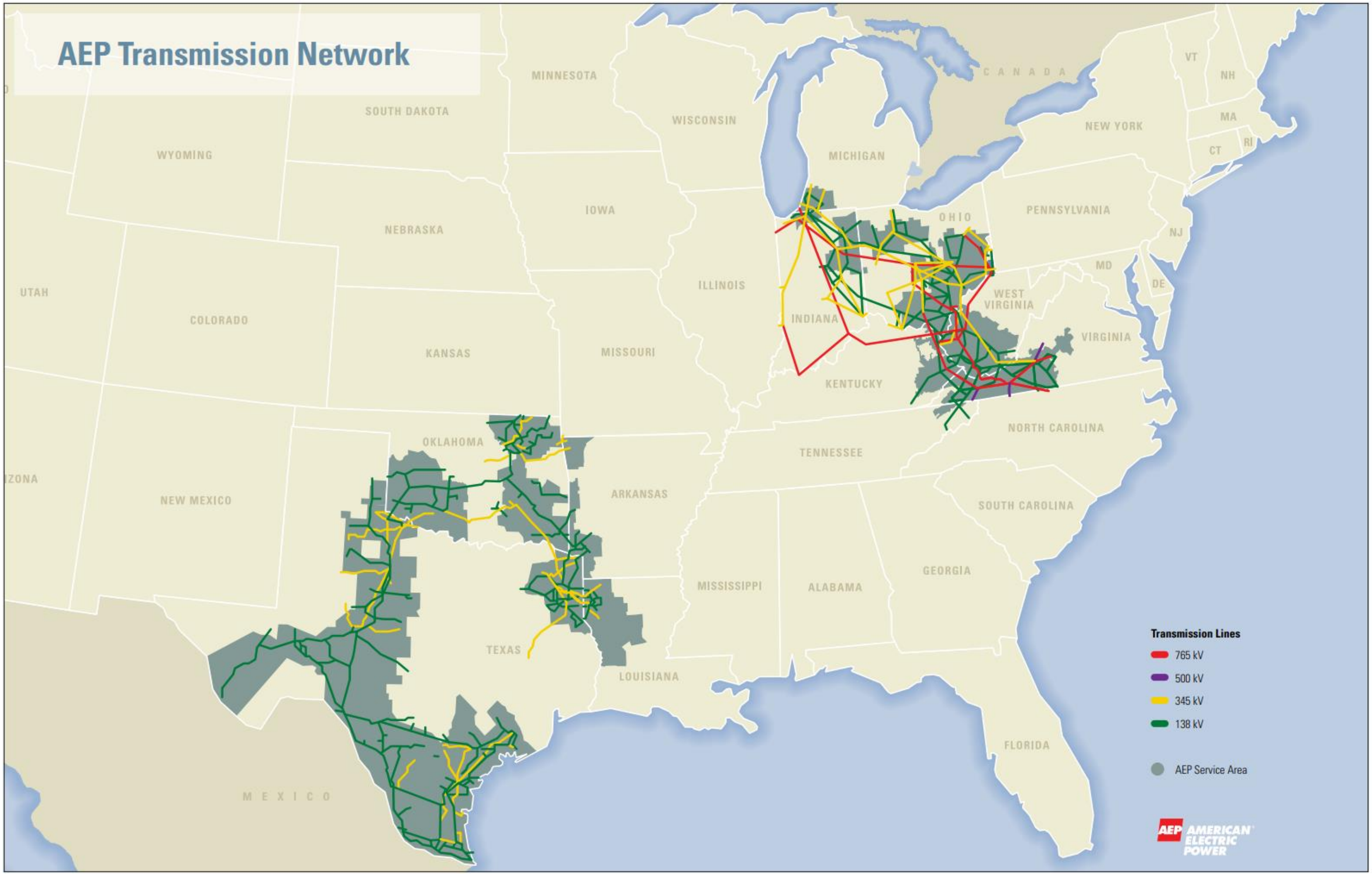


AEP's PRC-027 Applicable Lines

Voltage (kV)	Transmission Lines	Total Line Terminals	Interconnected Terminals
765	36	68	6
500	8	8	8
345	336	506	177
230	9	11	7
161	41	68	20
138	1601	2952	346
115	5	8	2
Totals	2036	3621	566

NERC Standard PRC-027-1

Purpose: To maintain the coordination of Protection Systems installed to detect and isolate Faults on Bulk Electric System (BES) Elements, such that those Protection Systems operate in the intended sequence during Faults.

Requirement R2 Each Transmission Owner, Generator Owner, and Distribution Provider shall, for each BES Element with Protection System function identified in Attachment A:

- **Option 1**: Perform a Protection System Coordination Study in a time interval not to exceed six-calendar years (4/1/2027) ; or
- **Option 2**: Compare present Fault current values to an established Fault current baseline and perform a Protection System Coordination Study when the comparison identifies a 15 percent or greater deviation in Fault current values (either three phase or phase to ground) at a bus to which the BES Element is connected, all in a time interval not to exceed six-calendar years; or,
- **Option 3**: Use a combination of the above.

PRC-027 Attachment A

Attachment A

The following Protection System functions are applicable to Requirement R2 if: (1) available Fault current levels are used to develop the settings for those Protection System functions; and (2) those Protection System functions require coordination with other Protection Systems.

21 – Distance if:

- infeed is used in determining reach (phase and ground distance), or
- zero-sequence mutual coupling is used in determining reach (ground distance).

50 – Instantaneous overcurrent

51 – AC inverse time overcurrent

67 – AC directional overcurrent if used in a non-communication-aided protection scheme

Option 1 or Option 2?

Option 1:

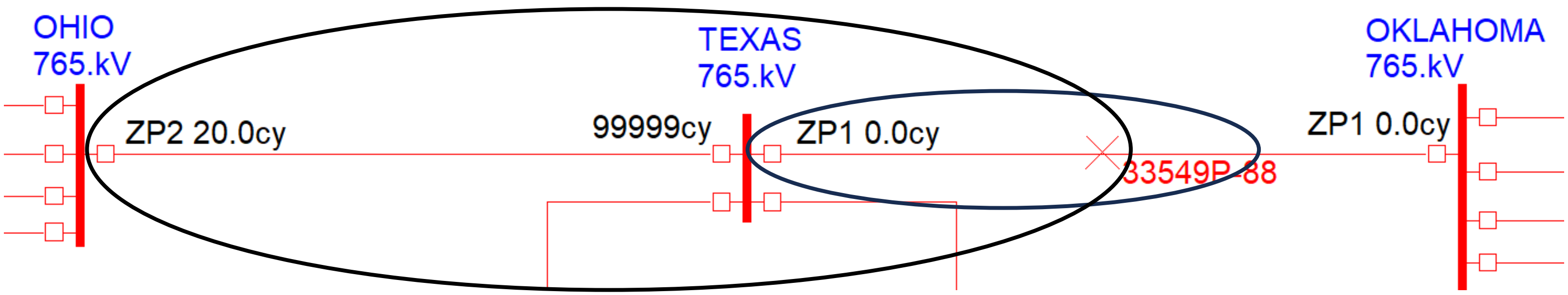
- Ensures that Protection Systems are coordinated
- Potentially reduces misoperations caused by incorrect relay settings
- May be more costly and time consuming than Option 2

Option 2:

- Protection Systems must be coordinated before setting a baseline
- May be less resource intensive than Option 1

What is a Protection System Coordination Study?

An analysis to determine whether Protection Systems operate in the intended sequence during Faults.



The standard does not prescribe reach margins, pickup margins, or coordination time intervals; it allows Transmission Owners to define coordination criteria based on their own philosophy

AEP's Coordination Study

<u>21 – Distance</u>

- Zone 1 reach < maximum value
- Zone 2 reach > minimum value
- Zone 2 reach coordinates with Zone 1 relays on downstream lines
- Zone 3 reach coordinates with Zone 2 relays on downstream lines

<u>50 – Instantaneous overcurrent</u>

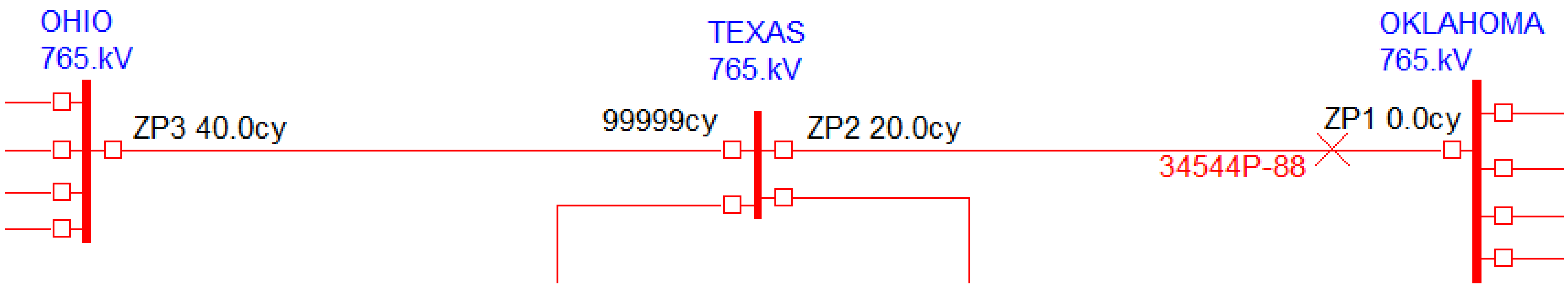
- Instantaneous Elements have adequate margin for remote bus fault

<u>51/67 –AC overcurrent</u>

- Minimum pickup for line end fault
- Minimum pickup for line end fault with single contingency source outage

AEP's Coordination Study

- Coordination checked at the end of the instantaneous zone to determine coordination time interval (CTI)
- Distance and overcurrent checked together – CTI is based on fastest relay function
- Additional check using Aspen OneLiner - Relay Operations Using Stepped Events



Initial 765kV Area Study

In 2019 AEP Studied our 765 KV System

- 34 lines, 66 line terminals studied
- ASPEN OneLiner coordination Checking Tools were used

Coordination Errors Identified:

- 9 issues that could result in a misoperation (Instantaneous Overcurrent)
- 32 other issues – outside AEP's setting criteria

Initial 765kV Area Study

- Reviewed and updated all 765kV line settings (not just attachment A)
- Opportunity taken to update settings up to AEP's latest guidance
  - Directional elements
  - Add a time delay to the DCB ground overcurrent function
  - Disabling phase instantaneous overcurrent elements
- Setting revised for 56 line terminals (112 digital relays)

Why AEP Selected Option 1?

Based on 765kV study results Option 1 was selected

- Achieve reliable system protection by ensuring all relays are properly coordinated
- Significantly reduce, and potentially eliminate, misoperations caused by outdated and incorrect settings
- Provides opportunity to go above PRC-027 R2 requirements and review and update all protective functions

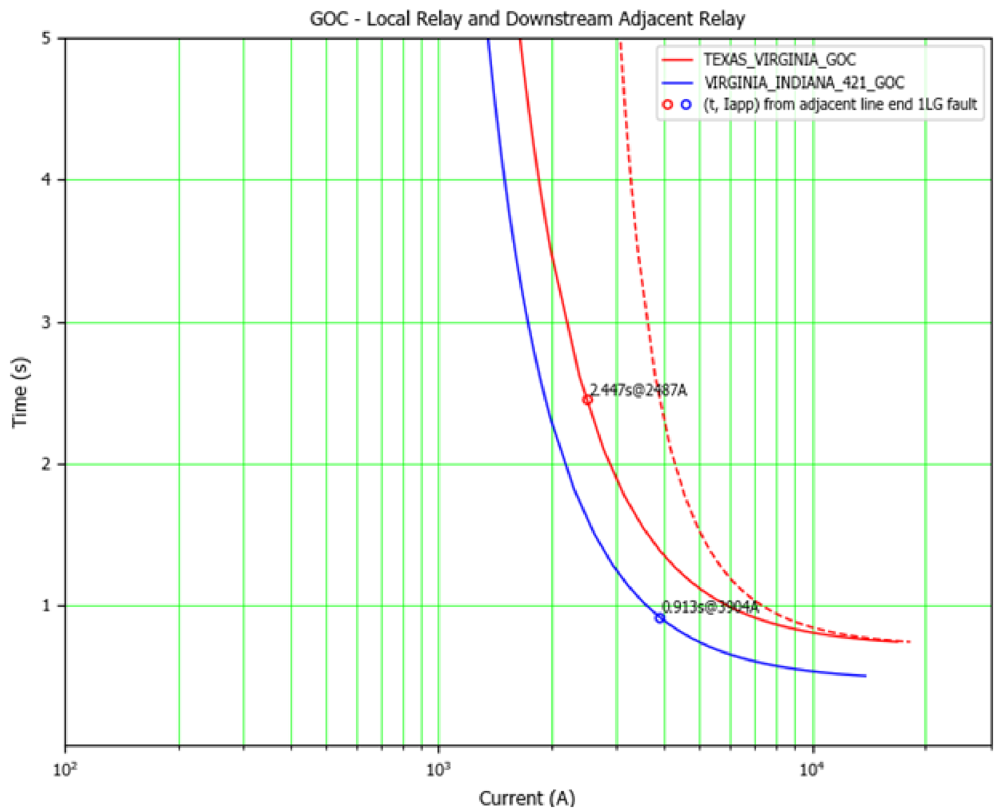
Lessons Learned from Initial 765KV Study

1. Updated the philosophy for setting ground overcurrent backup protection
2. Automated the development of relay settings
3. Adjusted criteria for Protection System Coordination Studies
4. Automated the execution of Area Protection System Coordination Studies
5. Began remotely applying relay settings

Updated the Philosophy for Setting Ground Overcurrent Backup Protection

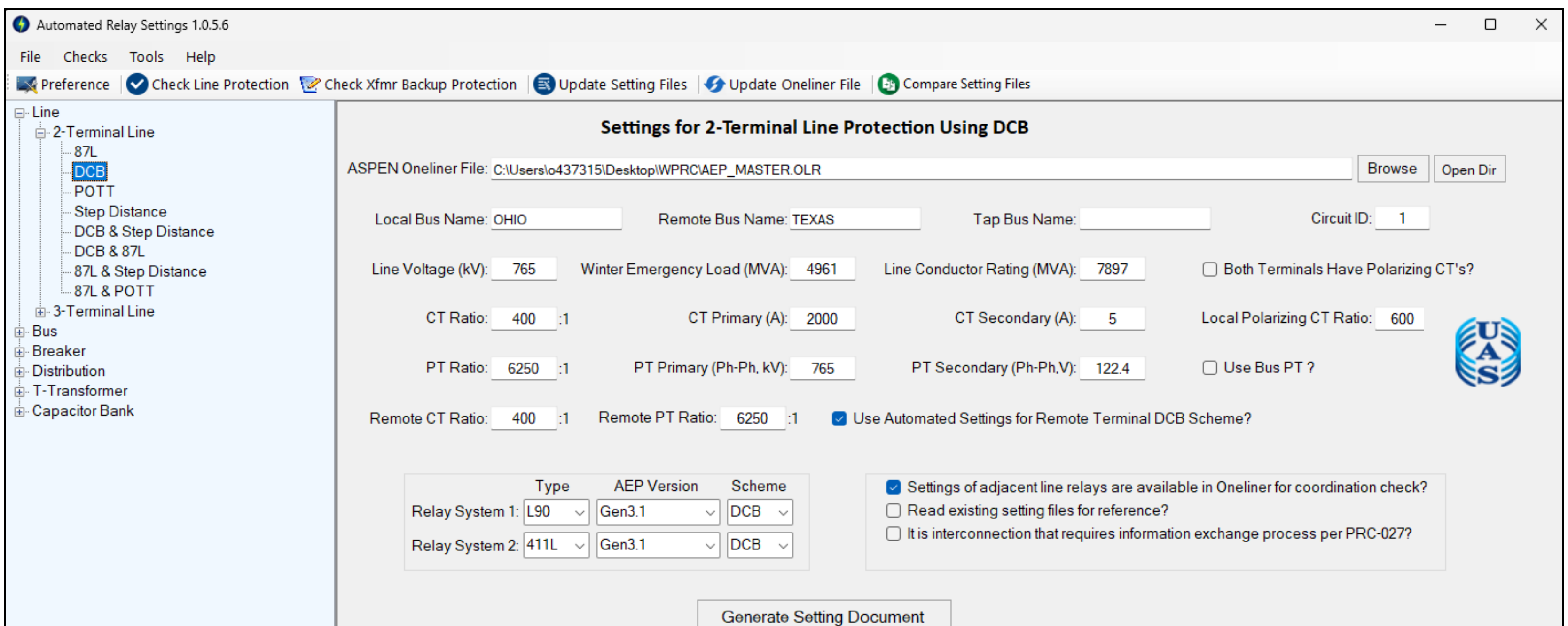
Initial study identified GOC settings as leading cause of coordination errors

- Disable ground instantaneous function
- Slow down time overcurrent function
- Allow ground distance to operate first
- GTOC expected to operate for high impedance faults when pilot system it out of service



Automated Relay Setting Development

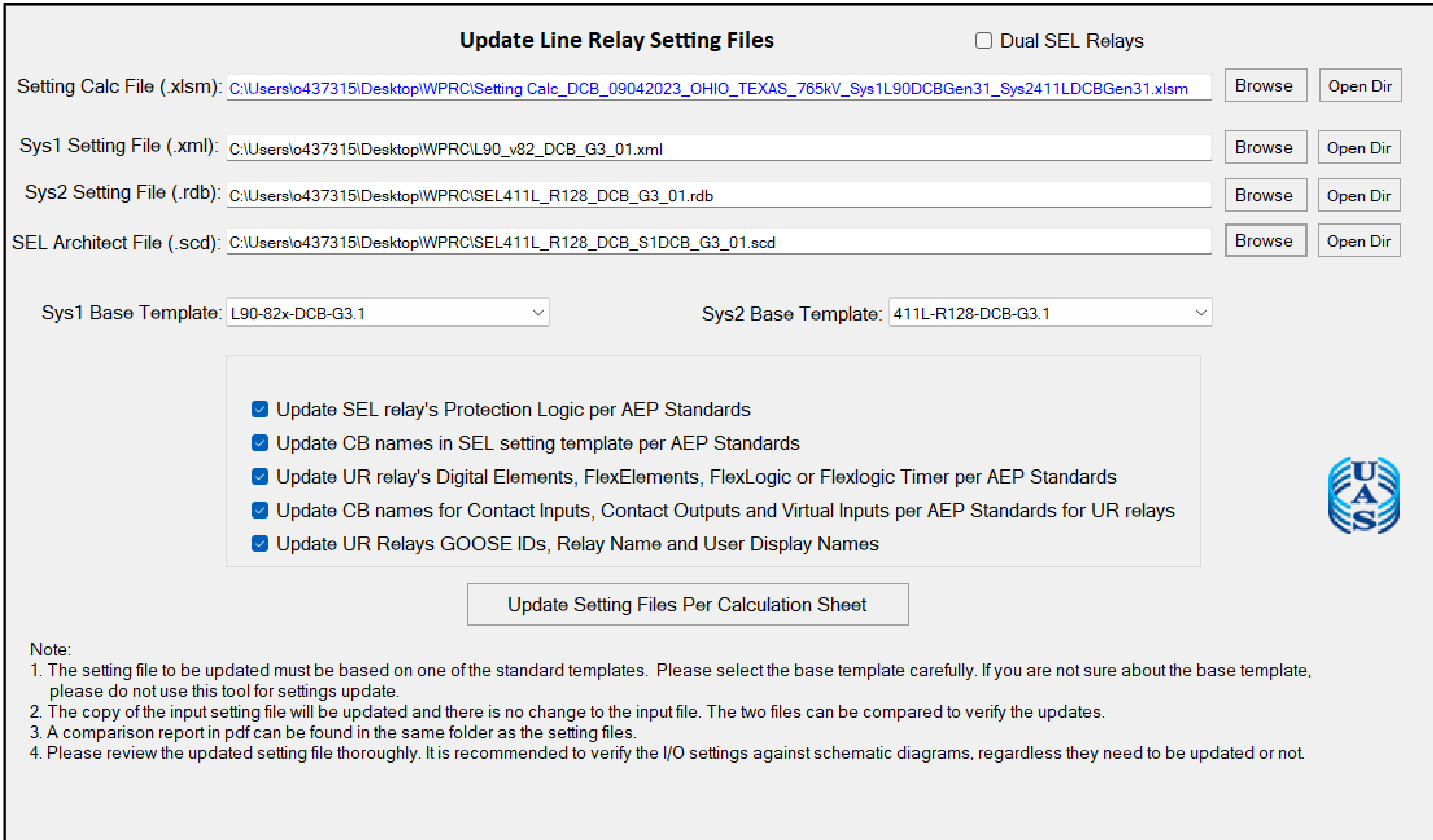
- Automated Relay Settings (ARS) developed by Utility Automation Solutions (UAS)
- ARS was initially used for the 765kV PRC-027 settings – 56 line terminals



ARS Calculation Sheet

3.4 Phase Distance Zone 2							
Phase Distance Zone 2 (Z2P) Function is					Enabled		
125%Z1L=	1.91 Ω	secondary	150%Z1L=	2.29 Ω	secondary		
The Z2P reach is set at					2.29 Ω	secondary	1.92 Ω
Expressed in primary ohms, the Z2P reach setting is					35.78 Ω	primary	
The Z2P reach in percentage of the line positive sequence impedance (Z1L) is					150%		
The Z2P time delay is typically 0.33s - 0.4s, or longer for coordination					0.333 s		
The Current Supervision of Z2P is set at					0.100 pu		
The adjacent line selected for Z2P checking has the following information:							
The line is "242513 TEXAS 765.kV - 242508 OKLAHOMA 765.kV 1 L". The check relay is "TEXAS_OKLAHOMA_D60_PDS", of which the Z1P reach is 0.42 ohms (6.6 primary ohms, 79.5% line impedance).							
The apparent impedance from the 3LG fault (LEO) at the check point is					38.98 Ω	primary	
Based on this and using 0.8 as margin factor, the Z2P check impedance is					2.00 Ω	secondary	
The result of the Z2P coordination check is					Invalid		
Comment:	CHANGED REACH TO 150% ARS CALCULATED Was 1.92 2.00 OHMS IS THE MAXIMUM REACH BEFORE TIME COORDINATION IS REQUIRED						

ARS UI for Updating Setting Files



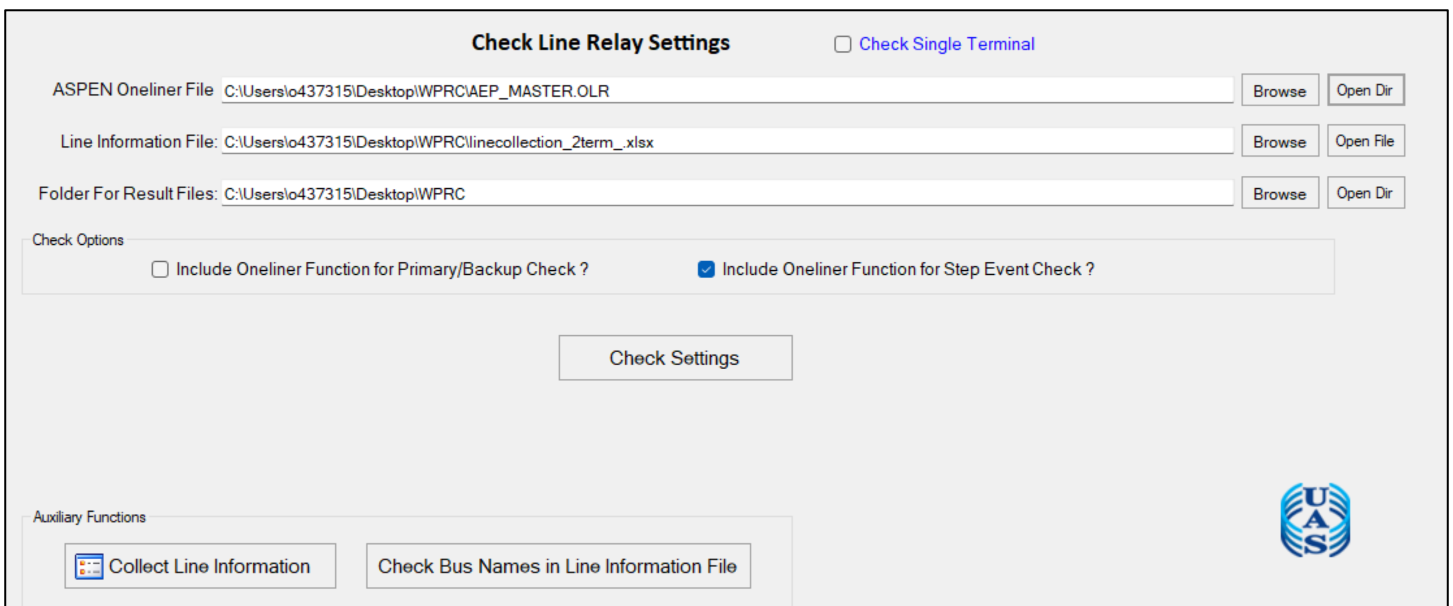
Adjusted Criteria for Protection System Coordination Studies

	Element	AEP Setting Criteria	PRC-027 Criteria
345-765kV	Zone 1 Phase Distance maximum reach	85%	86%
	Zone 2 Phase Distance minimum reach	125%	120%
	Zone 1 Ground Distance maximum reach	80%	85%
	Zone 2 Ground Distance minimum reach	120%	110%
	Zone 2 Distance Z2/Zapp threshold	80%	85%
	Instantaneous overcurrent minimum margin	125%	120%
	Ground time overcurrent pickup margin	3.0x	2.5x
	Minimum Coordination Time Interval (CTI)	20 cycles	18 cycles
115 - 230kV	Zone 1 Phase Distance maximum reach	85%	86%
	Zone 2 Phase Distance minimum reach	125%	120%
	Zone 1 Ground Distance maximum reach	80%	85%
	Zone 2 Ground Distance minimum reach	120%	110%
	Zone 2 Distance Z2/Zapp threshold	80%	85%
	Instantaneous overcurrent minimum margin	120%	115%
	Ground time overcurrent pickup margin	3.0x	2.5x
	Minimum Coordination Time Interval (CTI)	24 cycles	20 cycles

Automated the Execution of Area Studies

ARS has a module that will:

1. Automatically perform all coordination checks
2. Study multiple lines at one time
3. Output easily identifies where errors exists



ARS - Check Line Protection

- List of lines to be studied is needed
- AEP system divided into 87 groups
- Each groups contains about 20-25 lines

2-Terminal Lines			Check From Seq. #	1	To Seq. #	8	
Seq.#	Line KV	Local Bus Name	Remote Bus Name	Tap Bus Name	Relay Modelled for Both Terminals? (Y/N)	Interconnection (Y/N) ?	Circuit ID
1	765	OHIO	TEXAS		Y		1
2	765	TEXAS	OHIO		Y		1
3	765	TEXAS	VIRGINIA		Y		1
4	765	VIRGINIA	TEXAS		Y		1
5	765	KENTUCKY	TEXAS		Y		1
6	765	TEXAS	KENTUCKY		Y		1
7	765	OKLAHOMA	TEXAS		Y		1
8	765	TEXAS	OKLAHOMA		Y		1

ARS - Check Line Protection

- A summary sheet is produced showing each terminal that was checked
- The results of each element checked is shown
- This make is easy to determine which terminals have issues

Summary of Settings Check For Multiple Line Terminals

Oneliner File:	C:\Users\o437315\Desktop\WPRC\AEP_MASTER.OLR				
Folder for Check Files:	C:\Users\o437315\Desktop\WPRC				
Local Terminal	OHIO	**Remote Terminal**	TEXAS		
Number of terminals	2	**Line Voltage**	765 kV	**Seq.#**	1
Check File	OHIO_TEXAS__765kV_SettingsCheck_1_09042023.xlsm				

Type	**Relay ID**	**Elements**	**Check Results**
21P	OHIO_TEXAS_421_PDS	Z1P;Z4P;Z2P	Issue Found
21P	OHIO_TEXAS_D60_PDS	Z1P;Z3P;Z2P	OK
21G	OHIO_TEXAS_421_GDS	Z1G;Z4G	OK
21G	OHIO_TEXAS_D60_GDS	Z1G;Z3G	OK
51G	OHIO_TEXAS_421_GOC	51G	OK, but issue with adjacent relay
51G	OHIO_TEXAS_D60_GOC	51G	OK, but issue with adjacent relay
Coordination With Downstream Relays For Adjacent Line End 1LG Fault			OK
Coordination With Upstream Relays For Adjacent Line End 1LG Fault			Issue Found
Coordination With Downstream Relays For Adjacent Line End 3LG Fault			OK
Coordination With Upstream Relays For Adjacent Line End 3LG Fault			OK
Relay Operations Check Using Step Events			Issue Found

Local Terminal	TEXAS	**Remote Terminal**	OHIO		
Number of terminals	2	**Line Voltage**	765 kV	**Seq.#**	2
Check File	TEXAS_OHIO__765kV_SettingsCheck_1_09042023.xlsm				

Type	**Relay ID**	**Elements**	**Check Results**
21P	TEXAS_OHIO_D60_PDS	Z1P;Z3P;Z2P	OK
21P	TEXAS_OHIO_421_PDS	Z1P;Z4P;Z2P	OK
21G	TEXAS_OHIO_D60_GDS	Z1G;Z3G	OK
21G	TEXAS_OHIO_421_GDS	Z1G;Z4G	OK
51G	TEXAS_OHIO_D60_GOC	51G	OK
51G	TEXAS_OHIO_421_GOC	51G	OK
Coordination With Downstream Relays For Adjacent Line End 1LG Fault			OK
Coordination With Upstream Relays For Adjacent Line End 1LG Fault			OK
Coordination With Downstream Relays For Adjacent Line End 3LG Fault			OK
Coordination With Upstream Relays For Adjacent Line End 3LG Fault			OK
Relay Operations Check Using Step Events			Issue Found

ARS - Check Line Protection

- Individual check sheet is created for each terminal
- Provides details for each check

4.2 Phase Distance Zone 2

21P Plots

From Oneliner, the main settings of Phase Distance Zone 2 (Z2P) relays are:

Relay ID	CTR / PTR	Reach	Primary Ω	% Z1L	Delay	I_sup	Check
OHIO_TEXAS_421_PDS(Z4P)	400 / 6250	2.29 Ω	35.78 Ω	150%	0.333 s	-	ERR
OHIO_TEXAS_D60_PDS(Z3P)	400 / 6250	1.92 Ω	30.00 Ω	126%	0.333 s	0.50 A	OK

Notes on Check Result

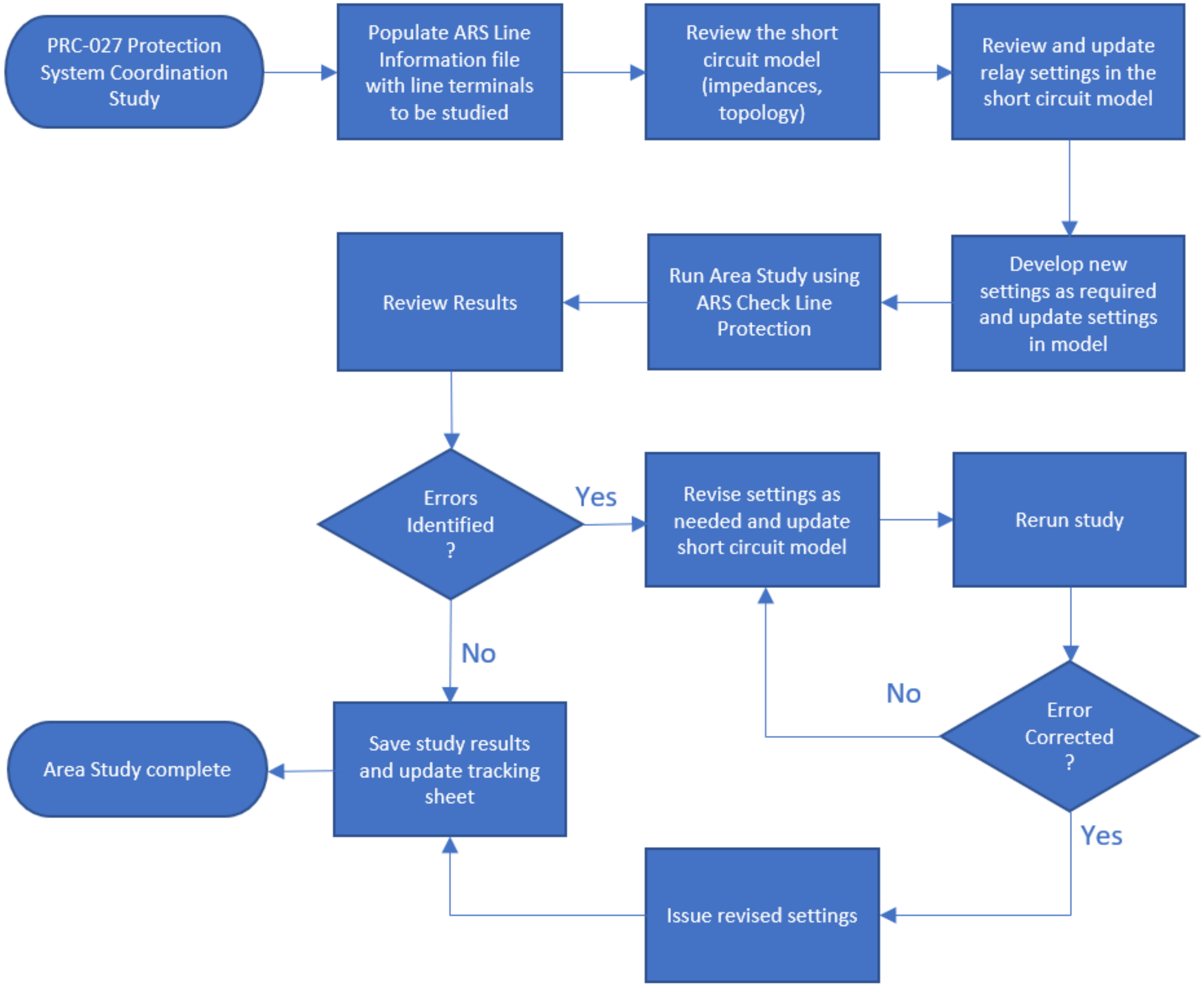
Downstream adjacent Relay ID	Op Time (s)	Local Relay ID	Op Time (s)	Z2P/Zapp	Check	
TEXAS_KENTUCKY_D60_PDS	0.333	OHIO_TEXAS_421_PDS	9999.000	50%	OK	Plot
TEXAS_KENTUCKY_D60_PDS	0.333	OHIO_TEXAS_D60_PDS	9999.000	42%	OK	Plot
TEXAS_KENTUCKY_421_PDS	0.333	OHIO_TEXAS_421_PDS	9999.000	50%	OK	Plot
TEXAS_KENTUCKY_421_PDS	0.333	OHIO_TEXAS_D60_PDS	9999.000	42%	OK	Plot
TEXAS_VIRGINIA_D60_PDS	0.333	OHIO_TEXAS_421_PDS	9999.000	31%	OK	Plot
TEXAS_VIRGINIA_D60_PDS	0.333	OHIO_TEXAS_D60_PDS	9999.000	26%	OK	Plot
TEXAS_VIRGINIA_421_PDS	0.333	OHIO_TEXAS_421_PDS	9999.000	31%	OK	Plot
TEXAS_VIRGINIA_421_PDS	0.333	OHIO_TEXAS_D60_PDS	9999.000	26%	OK	Plot
TEXAS_OKLAHOMA_D60_PDS	0.333	OHIO_TEXAS_421_PDS	0.670	92%	ERR	Plot
TEXAS_OKLAHOMA_D60_PDS	0.333	OHIO_TEXAS_D60_PDS	0.670	77%	OK	Plot
TEXAS_OKLAHOMA_421_PDS	0.333	OHIO_TEXAS_421_PDS	0.670	92%	ERR	Plot
TEXAS_OKLAHOMA_421_PDS	0.333	OHIO_TEXAS_D60_PDS	0.670	77%	OK	Plot

Remote Application of Relay Settings

PRC-027 required a new approach to implement settings

- Procedure developed for remote application of settings
- Criteria created for settings than can be applied remotely
- Setting changes excluded are:
  - Critical interconnects; CT ratio, I/O, firmware, trip logic
- Procedure piloted on AEP's initial 765kV area study
- 55 settings were applied remotely without incident

Study Process



345kV Studies

Lines	Terminals	Interconnections
336	506	177

- 16 groups studied late 2021 thru 2022
- 399 revised settings, 107 did not need reset

Lessons Learned from 345kV Studies

- Interconnects – defer if possible
- Complete PRC-027 Settings as part of capital projects

161kV and 138kV Studies

Lines	Terminals	Interconnections
1642	3020	366

- 70 groups, planned to complete 1/3 each year 2023-2025 (15 months margin)
- Estimated 45% of these will be or have been completed on capital (20% for 345kV)

Line Terminals Studied (7/31/2024)	PRC-027 Specific Setting	Capital Project	% O&M Expense
967	512	455	53

- Plan revised based on 2023 progress
- Completion Q2 2026 (9 months margin)

Remote Application of Relay Settings

- 31% of settings meeting criteria have been applied remotely
- Percentage should increase as personnel become comfortable with process
- Estimated time saving – 4 hours per relay, 8 hours per terminal

Settings Meet Criteria for Remote Application?	Settings Applied at Station	Settings Applied Remotely
No – 454	454	
Yes – 512	353	159
Total – 966	**807**	**159**

Challenges

- System is continually changing
  - List of line terminals must be kept up to date
  - Short circuit models must be kept up to date
  - Budgets and projects schedules constantly changing
- Process must be reviewed and adjusted

Conclusion

- The initial round of studies is costly and time consuming
- End-result:
  - Assures all line protection is coordinated
  - All line protection updated to latest guidance
  - Settings more resilient as system change
  - Misoperation caused by relay settings significantly reduced
- Process ensures system will remain coordinated in the future
- Future studies will be performed more frequently then 6 years
- Automated tools are essential to using Option 1!

Questions ?

Los Angeles Department of Water & Power

Test & Technical Services

Back-to-Back Relay Testing:

Step-by-Step Commissioning Process

Presented by:

Cleofas Rojas, P.E.

Sanjay Mehta, P.E.

October 2, 2024

Introduction

This presentation highlights LADWP's typical commissioning methods to ensure the successful and smooth installation of protection systems on the Bulk Electric System (BES).

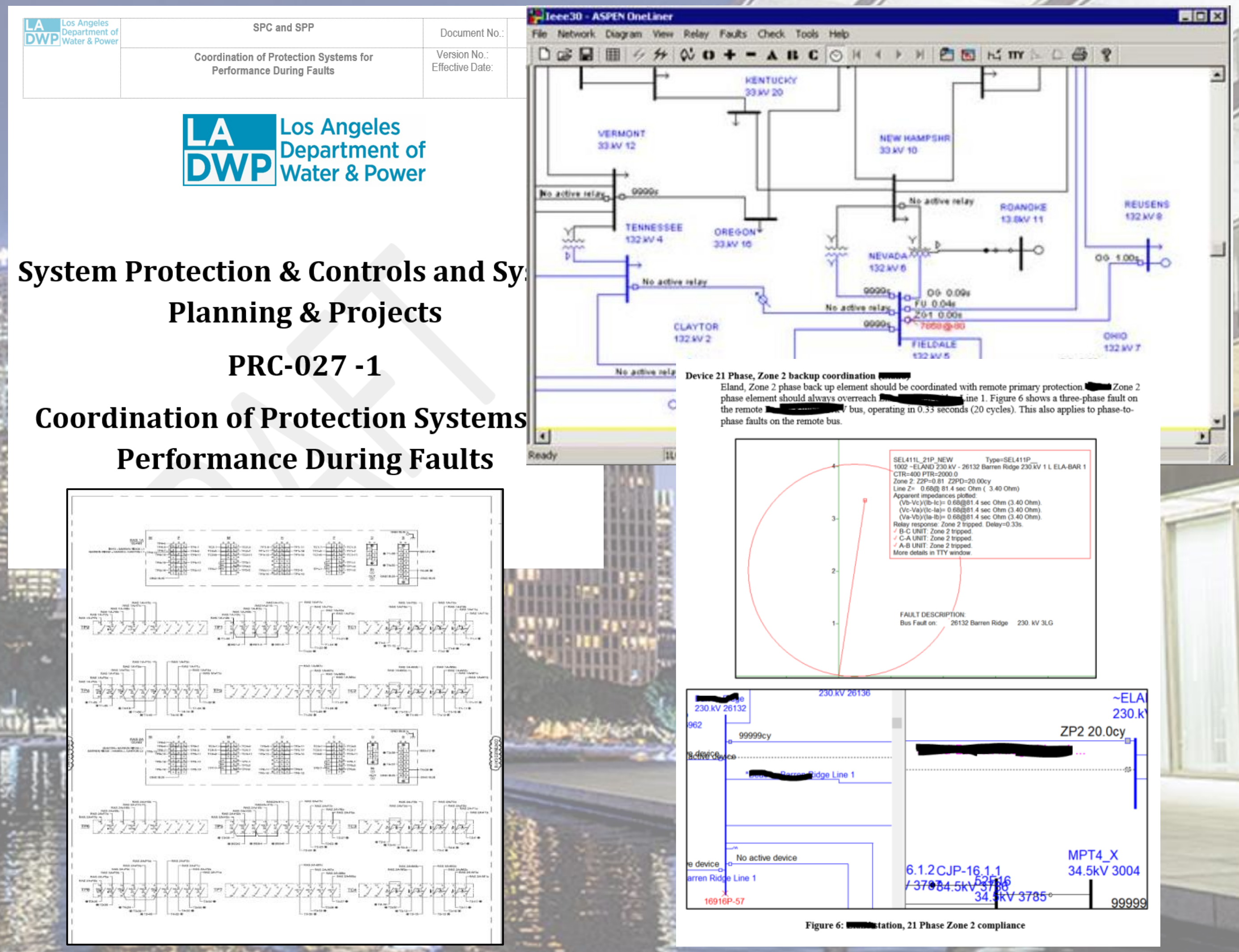
- Protection system design review process and coordination (PRC-027), installation coordination and commissioning tests.

- Back-to-Back relay testing.

- End-to-End relay testing.

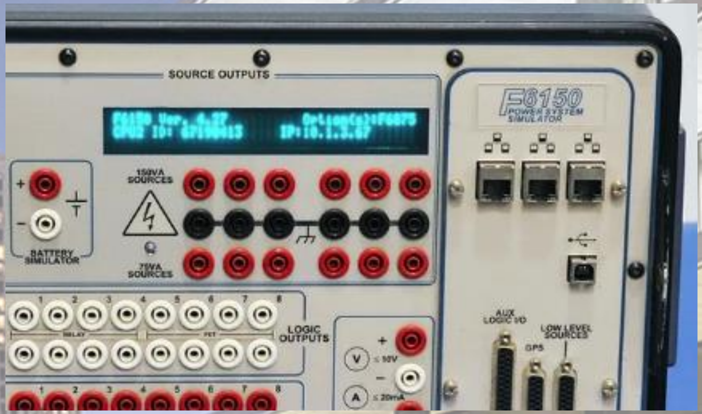
LADWP PRC-027 Program Overview

- Review preliminary and final electrical design prints, relay schematic and wiring prints, etc.
- Exchange short-circuit model data, i.e., impedance parameters & fault data.
- Develop, exchange and review preliminary and final relay settings.
- Perform protection coordination study and notify entity about results.



LADWP PRC-027 Program Overview Cont'd…

- Coordinate the back-to-back relay test plan and schedule.
- Arrange for the relay panels to be shipped to the lab facility.
- Communicate and verify test equipment model & firmware to be used for back-to-back testing.
- Agree on the relay test routines to be used for testing.



Construction & Commissioning Groups

- Electrical Construction (EC)- Installs relay panels, secondary wiring and other electrical equipment as per the construction work package (CWP).

- Station Test (ST) Group– Leads the commissioning activities and provide support to back-to-back and end-to-end testing.

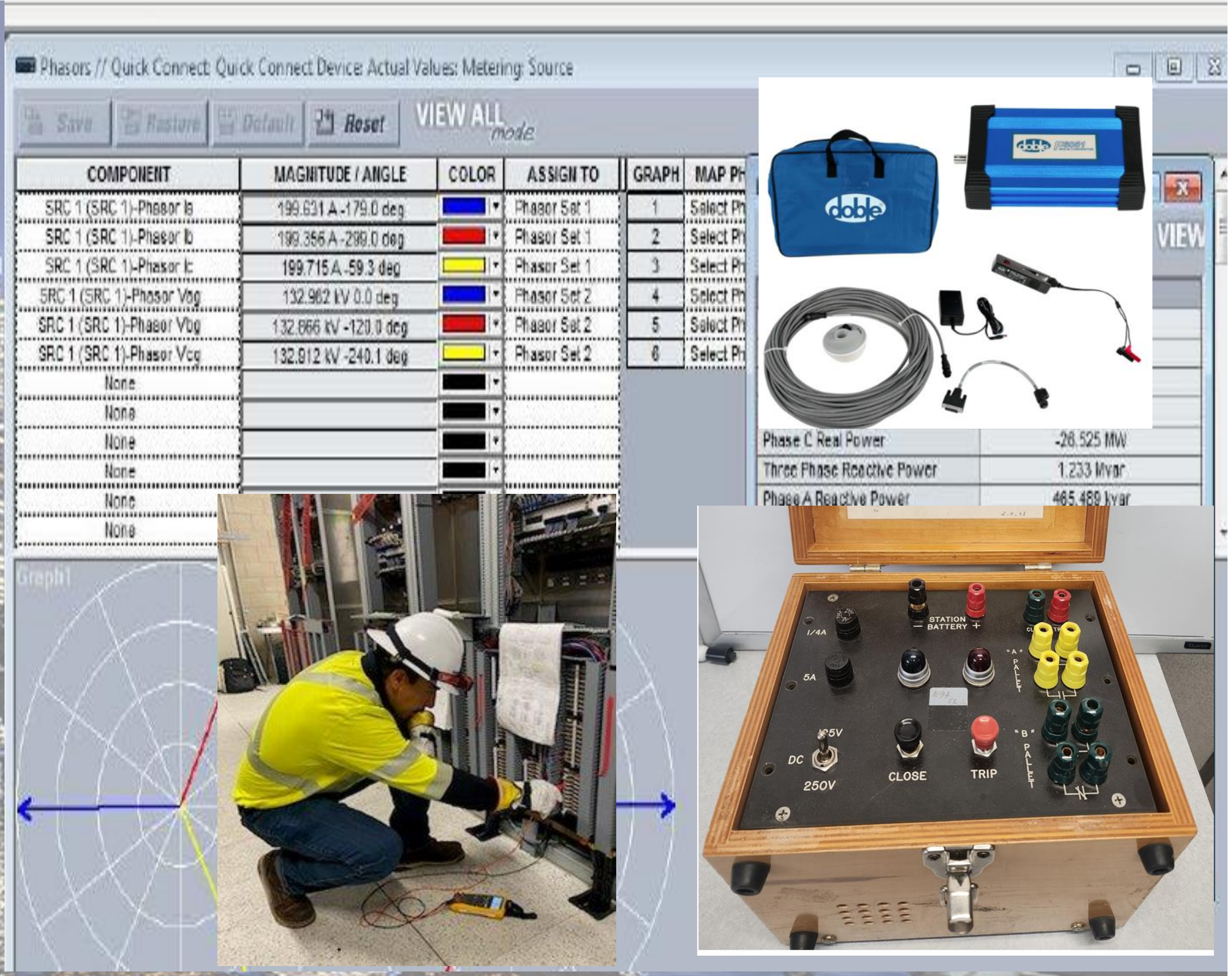
- System Protection & Controls (SP&C) Group– Leads back-to-back testing, end-to-end testing, SCADA/RTU commissioning and PRC-005 baseline testing.

Prepare Relay Panel for Back-to-Back Testing

- Relay panel point-to-point wiring verification “ring-out”, “buzzing” (CWP wiring prints).
- Verify relay panel labels match design.
- Relay cut-off blades, test switches and lock out relays function properly.
- Any wiring issues found need to be resolved.
- Power up the relays.
- Relay firmware version verification & provide info & default settings file to settings engineer.
- Verify test equipment model and firmware version compatibility.
- Verify final relay settings match the approved relay settings write up and upload.

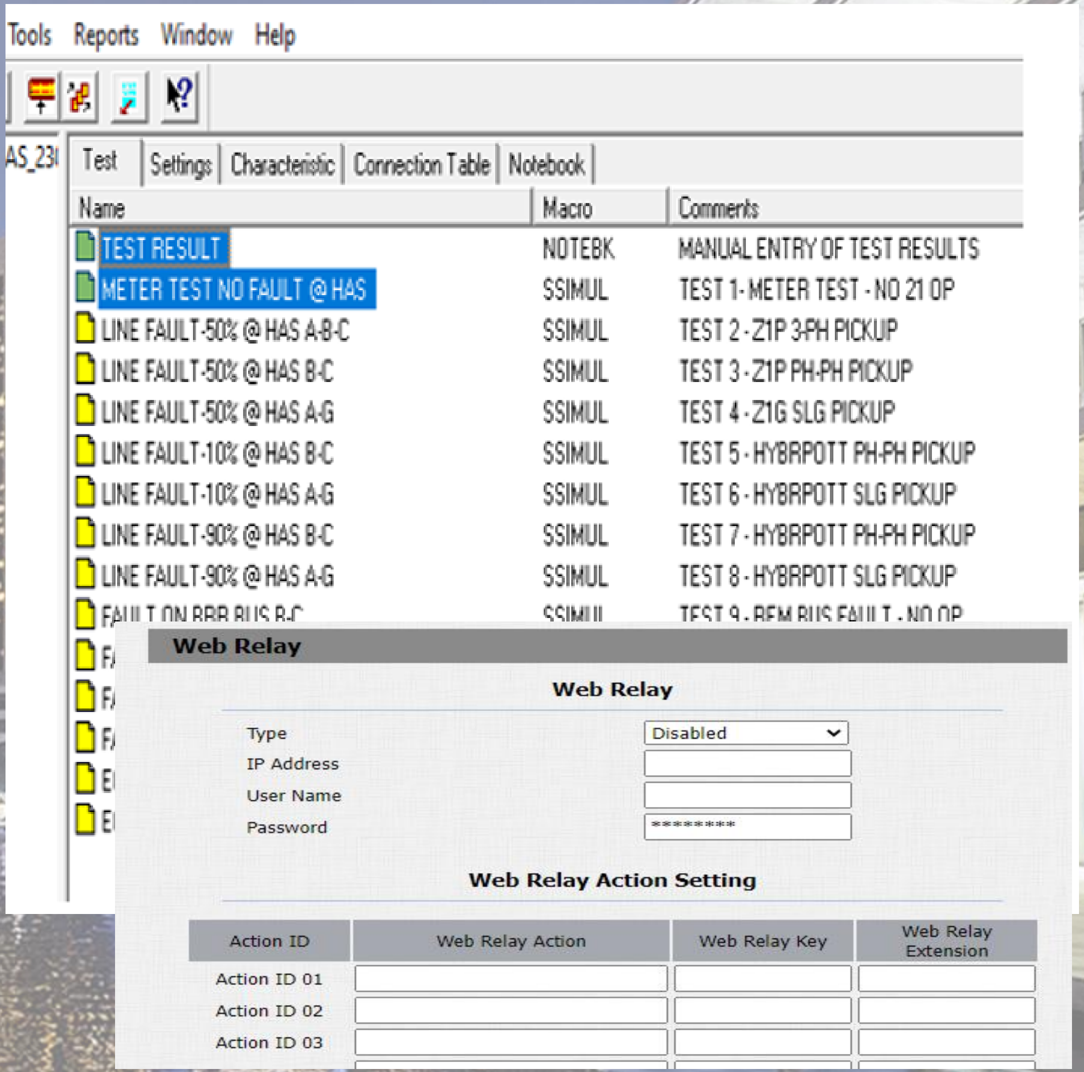
Prepare Relay Panel for Testing – Cont'd...

- Set-up antennas to time synchronize the test equipment (Fault Simulator) to the GPS clock.
- Relay metering test verification i.e., single phase and three phase voltage and current injection to verify CT & PT ratios and test the set-up connections.
- Perform "stand alone panel" schematic functional test down to the termination blocks and perform "Trip Test" using "dummy" breaker(s).



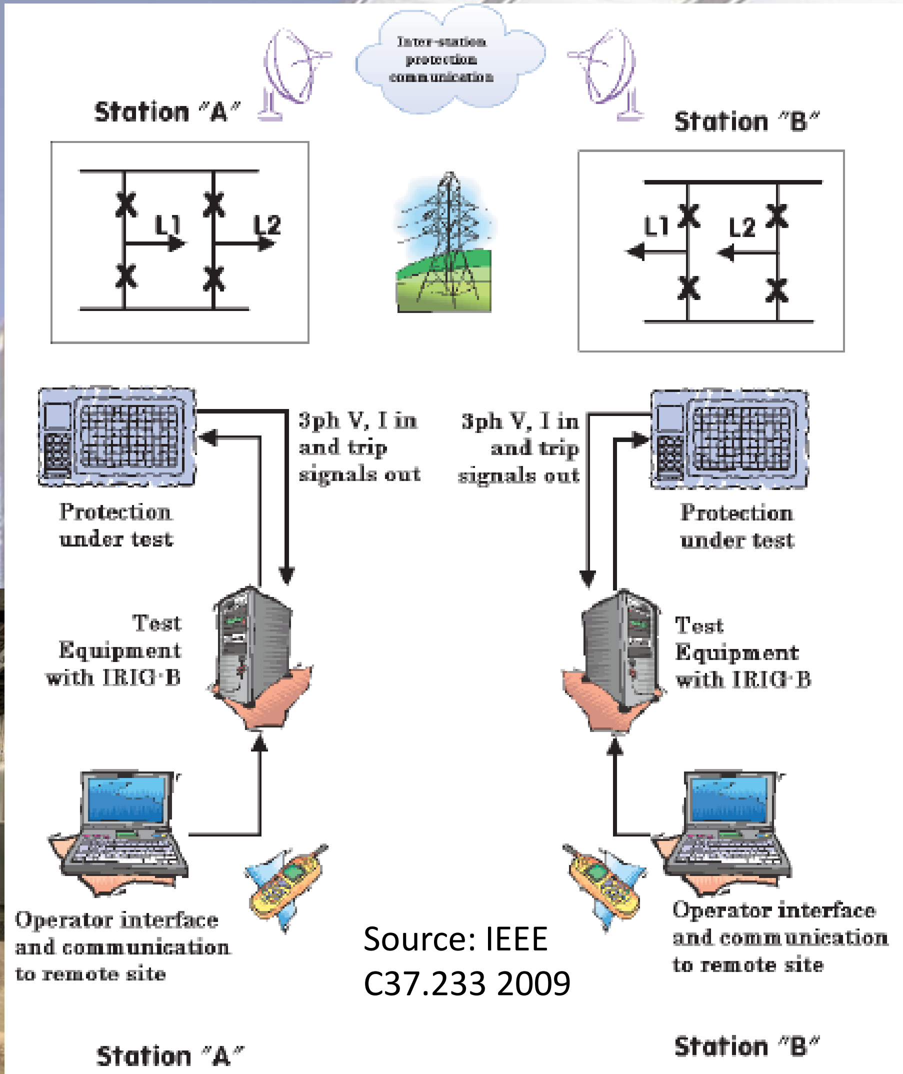
Back-to-Back Test Activities

- Run fault simulation routines to verify protection schemes and logic function as designed, i.e., trips for all internal faults and time delay backups, and restraints for external faults.
- Resolve any settings test discrepancies with protection engineer(s).
- Secure the relay settings by setting relay passwords.
- Generate and review back-to-back relay test reports
- As-Left relay setting files are exchanged, reviewed, and approved
- Ship relay panels to the field for commissioning.



Prepare Equipment for End-to-End Testing

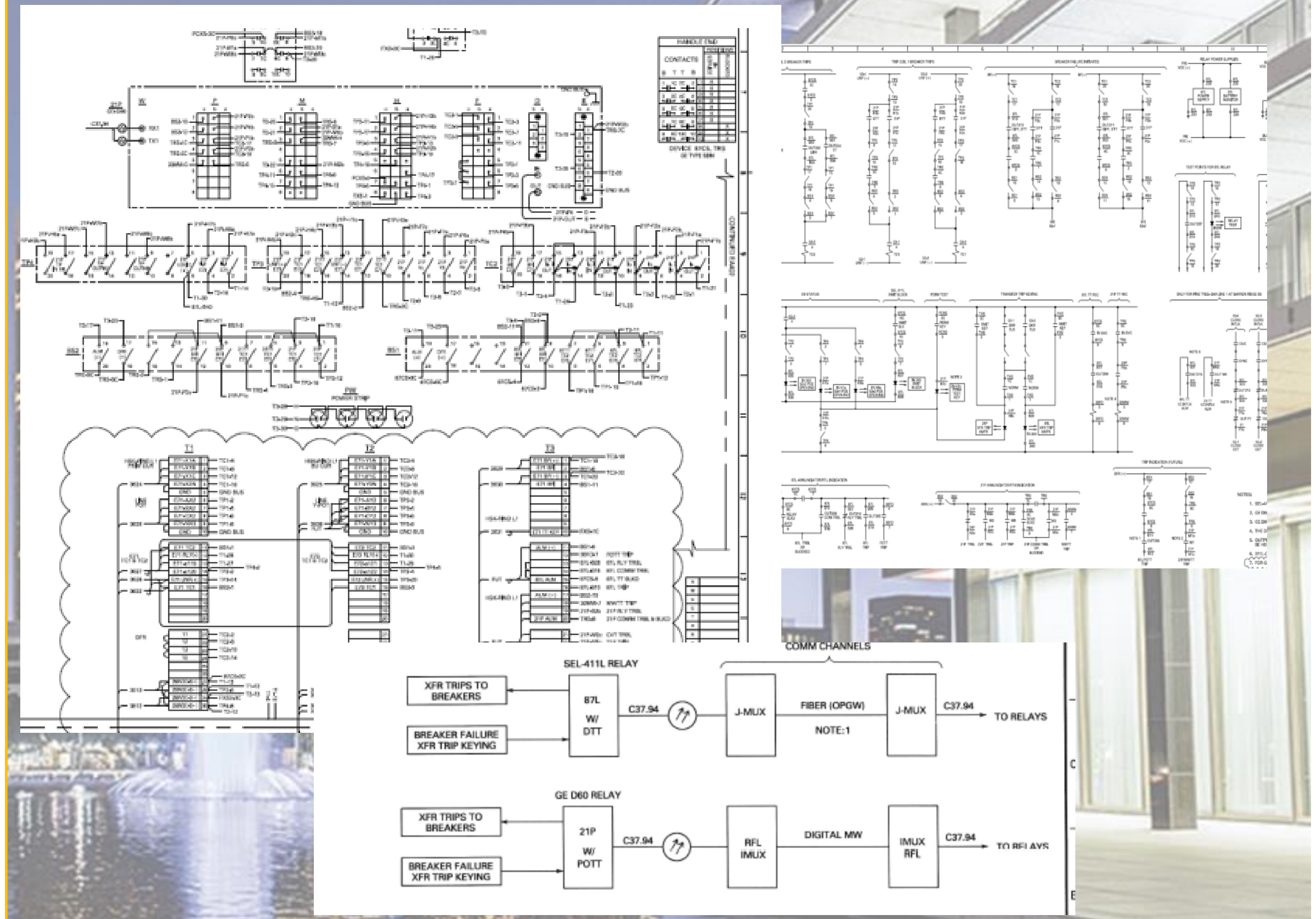
- Communicate and coordinate with Electrical Substation Construction (EC) personnel for the demolition of existing equipment and wiring, as applicable.
- Communicate and coordinate with EC personnel for the installation and testing of new power system equipment (i.e., circuit breakers (CBs), transformers, voltage transformers (VTs), secondary wiring, etc.)
- Coordinate with EC for the installation of the relay panels
- Verify field point-to-point wiring "ring-out", "buzzing" (i.e. CTs, VTs, CBs, etc.).



Source: IEEE C37.233 2009

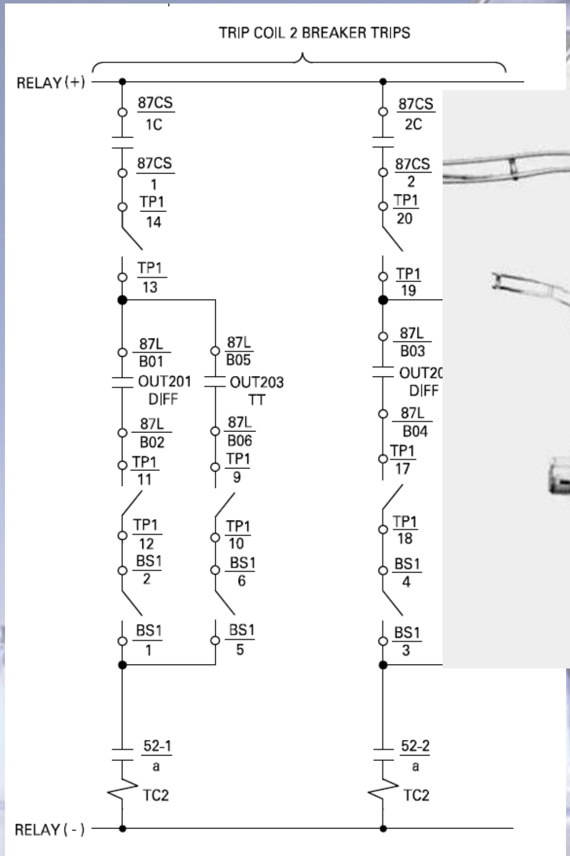
Prepare Equipment for End-to-End Testing Cont'd…

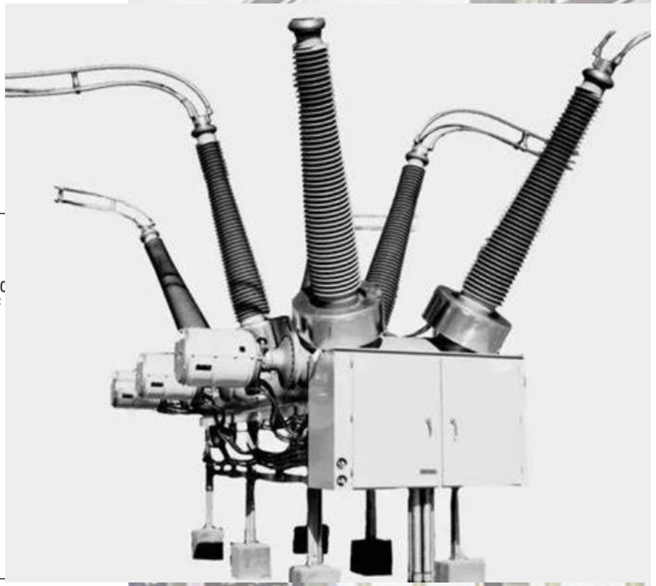
- Verify CT taps ratio & polarity, i.e. non-polarity common or polarity common?
- Verify CT circuit grounding & wire insulation, check for "shorts and ground".
- Verify field-to-panel terminal blocks wiring, all links open, "ring-out" and conductor insulation test "Megger", i.e., 500 V - 1000 V dc.
- Verify field wiring diagram matches the relay schematic diagram (URELs), "field wiring vs schematic".
- Secondary current and voltage injection from furthest point i.e., CB terminal panel to verify wiring and metering values in the relay.



Prepare Equipment for End-to-End Testing Cont'd…

- Verify communication channels are working (i.e. Fiber Optic, Microwave, etc.), i.e. DIFF protection, POTT, etc.
- Perform schematic wiring functional test (i.e. DC control circuits, Trip CBs "Trip Test", etc.).
- Verify relay display and LEDs match the programmed settings.
- Perform Pre-Site Acceptance Testing (Pre-SAT) of RTU/SCADA mapped points to HMI (Human Machine Interface computer). (Local test first)
- Perform Site Acceptance Testing (SAT) of RTU/SCADA mapped points to the Energy Control Center (ECC).





End-to-End Testing

- Prepare the PRC-005 Baseline commissioning test document to record the test data
- Verify relay settings: As-Found vs Final Approved Settings File.
- Verify relay communication is normal.
- Agree with the remote end team at what time to start with the first test and so on, “going at…hh:mm:ss”
- Run fault simulation routines to verify protection schemes and logic function as programmed & designed, i.e., trips for all internal faults and time delay backups, and restraints for external faults.

PRC-005 TESTING

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within **Tables 1-1** through **1-5**, **Table 2**, **Table 3**, **Table 4-1** through 4-3, and **Table 5**.

	TEST REPORT	DATE COMPLETED	INITIAL
1	PROTECTIVE RELAYS Table 1-1	04-09-2019	RU
2	COMMUNICATION SYSTEMS Table 1-2	04-09-2019	RU
3	VOLTAGE AND CURRENT SENSING DEVICES Table 1-3 (PENDING 87CS & TRS Block Contacts, CT Clear GND)	04-09-2019	RU
4	CONTROL CIRCUITRY Table 1-5	04-09-2019	RU
5	ALARMING PATHS AND MONITORING (PENDING) Table 2		
6	SUDDEN PRESSURE RELAY (NOT AVAILABLE) Table 5	N/A	N/A
7	DISTRIBUTED UFLS & UVLS SYS (NOT AVAILABLE) Table 3	N/A	N/A
8	BREAKER FAILURE (PENDING)		

PRC-005-6 Table 1-1 Protective Relay & Table 2 Alarming Paths

PROTECTIVE RELAY – SEL411L and GE-L90

☑ Verify relay settings – Attach a copy of the comparison

- For non-microprocessor relays, verify settings through testing (minimum pickup) (N/A)

Relay	Relay Setting	Test Value	Relay Trip
SEL-411L	87LPP Diff	9.9A	Yes
SEL-411L	87LQP Diff	6.0A	Yes
SEL-411L	Phase TOC	15.4A, 125-cyc	Yes
SEL-411L	Neutral TOC	6.1A, 69-cyc	Yes
SEL-411L	SOTF	9.9A, 42V	Yes
GE-L90	Phase Diff	9.9A	Yes
GE-L90	GND Diff	6.0A	Yes
GE-L90	Phase TOC	15.4A, 125-cyc	Yes
GE-L90	Neutral TOC	6.1A, 69-cyc	Yes
GE-L90	SOTF	9.9A, 42V	Yes

☑ Attach screen shot of relay metering test compared to Doble F6000 (attached at end of report)

☑ Verify relay inputs and outputs that are part of trip testing ONLY – LIST I/O

(PENDING 87CS and TRS Block Contacts)

87L1 (VAY, VBY, VCY)	A, B, C Voltage Inputs (metering screenshot)
87L1 (IAW, IBW, ICW)	A, B, C Current Inputs (metering screenshot)
87L2 (F5a, F5c, F6a, F6c, F7a, F7c)	A, B, C Voltage Inputs (metering screenshot)
87L2 (F1a, F1b, F2a, F2b, F3a, F3b)	A, B, C Current Inputs (metering screenshot)
87L1 DIFF E51, E52 TC2 (OUT201 & OUT202)	Observed TRIP, INST, 87L LEDs, SER Report and CB Open Status LED
87L1 TT E51, E52 TC2 (OUT203 & OUT204)	Observed TRIP, INST, 87L LEDs, SER Report, CB Open Status LED
87L2 DIFF E51, E52 TC1 (H1, H2)	Observed 87L TRIP LEDs, SER Report and CB Open Status LED

End-to-End Testing Cont'd…

- Resolve any end-to-end test discrepancies with protection engineer(s).
- Generate and review end-to-end relay test reports i.e., sequence of event record for each test.
- Develop PRC-005 Baseline Commissioning Test report for review and filing.

Current List Tests

Macro	Eval	Last Tested	Comments
SSIMUL	Pass	6/5/2019 9:50:06AM	TEST 1
SSIMUL	Pass	6/5/2019 9:54:05AM	TEST 2
SSIMUL	Pass	6/5/2019 9:57:05AM	TEST 3
SSIMUL	Pass	6/5/2019 10:02:05AM	TEST 4
SSIMUL	Pass	6/5/2019 10:05:05AM	TEST 5
SSIMUL	Op	6/5/2019 10:08:06AM	TEST 6
SSIMUL	Pass	6/5/2019 10:11:05AM	TEST 7
SSIMUL	Pass	6/5/2019 10:16:06AM	TEST 8
SSIMUL	Pass	6/5/2019 10:20:05AM	TEST 9
SSIMUL	Pass	6/5/2019 10:29:06AM	TEST 10

20120002-D20170518

	ELEMENT	STATE
00.0537	HOT LINE	Asserted
05.0452	TRIPLED	Asserted
05.0452	TRIP OUTPUT	Asserted
05.0452	B-Phase Diff.	Asserted
05.0452	C-Phase Diff.	Asserted
05.0452	Neg. Seq. Diff.	Asserted
05.0452	F-31 DIFF TRIP	Asserted
05.0452	F-32 DIFF TRIP	Asserted
05.0452	F-31 BFI	Asserted
05.0452	F-32 BFI	Asserted
05.0472	DIFF TRIP	Asserted

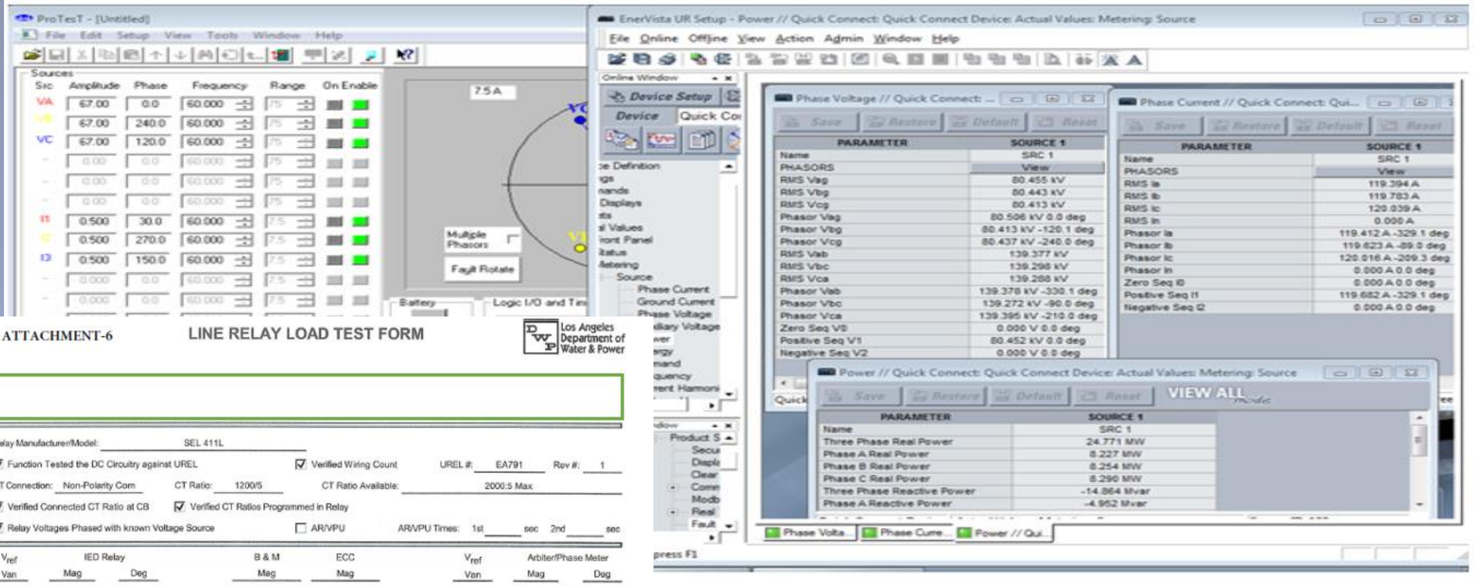
	TEST REPORT	DATE COMPLETED	INITIAL
1	PROTECTIVE RELAYS (Part of Commissioning) Table 1-1	05-29-2019	SM
2	COMMUNICATION SYSTEMS (Part of Commissioning) Table 1-2	05-29-2019	SM
3	VOLTAGE AND CURRENT SENSING DEVICES Table 1-3 (Part of PRC-005)	05-29-2019	SM
4	CONTROL CIRCUITRY (Part of PRC-005) Table 1-5	06-03-2019	KV, BP
5	ALARMING PATHS AND MONITORING (Part of Commissioning) Table 2	06-03-2019	KV BP
6	SUDDEN PRESSURE RELAY (Not Applicable) Table 5	N/A	N/A
7	DISTRIBUTED UFLS & UVLS SYS (Not Applicable) Table 3	N/A	N/A
8	BREAKER FAILURE (Existing BF Relays-Verified only the BFIs to Breaker Failure Relays from Line Protection Relays.) (Part of PRC-005)	06-03-2019	SM, KV, BP

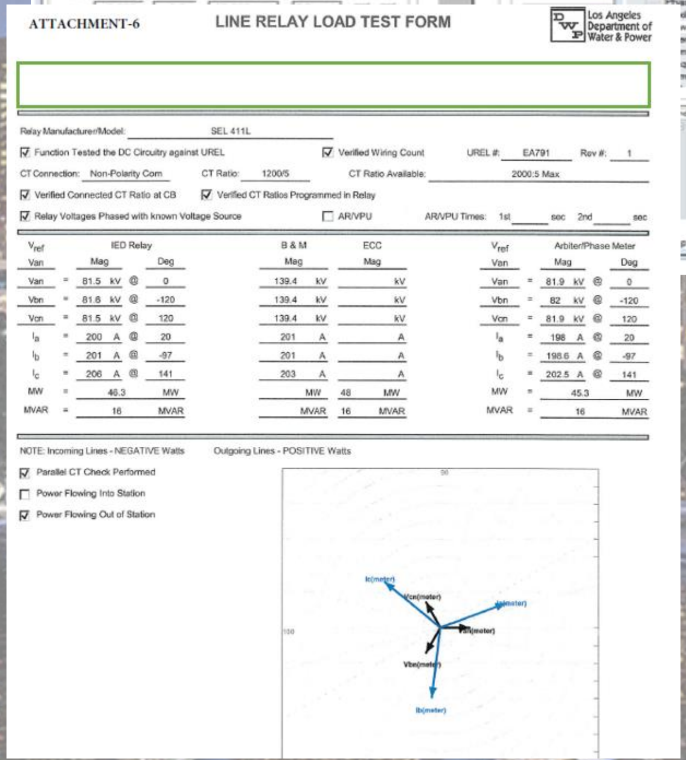
Declarations (Ok for Service) To ECC

- Ensures the NERC critical infrastructure protection (CIP) requirements for new cyber asset compliance documentation is completed.
- Upon successful completion of all tests, communicate with Electrical Construction to declare equipment, i.e. CBs, etc. “OK for Service” to the Energy Control Center (ECC) Load Dispatcher (LD)
- Commissioning Team declares protective relays “OK for Service” to ECC LD.

In-Service Test “Load Checks”

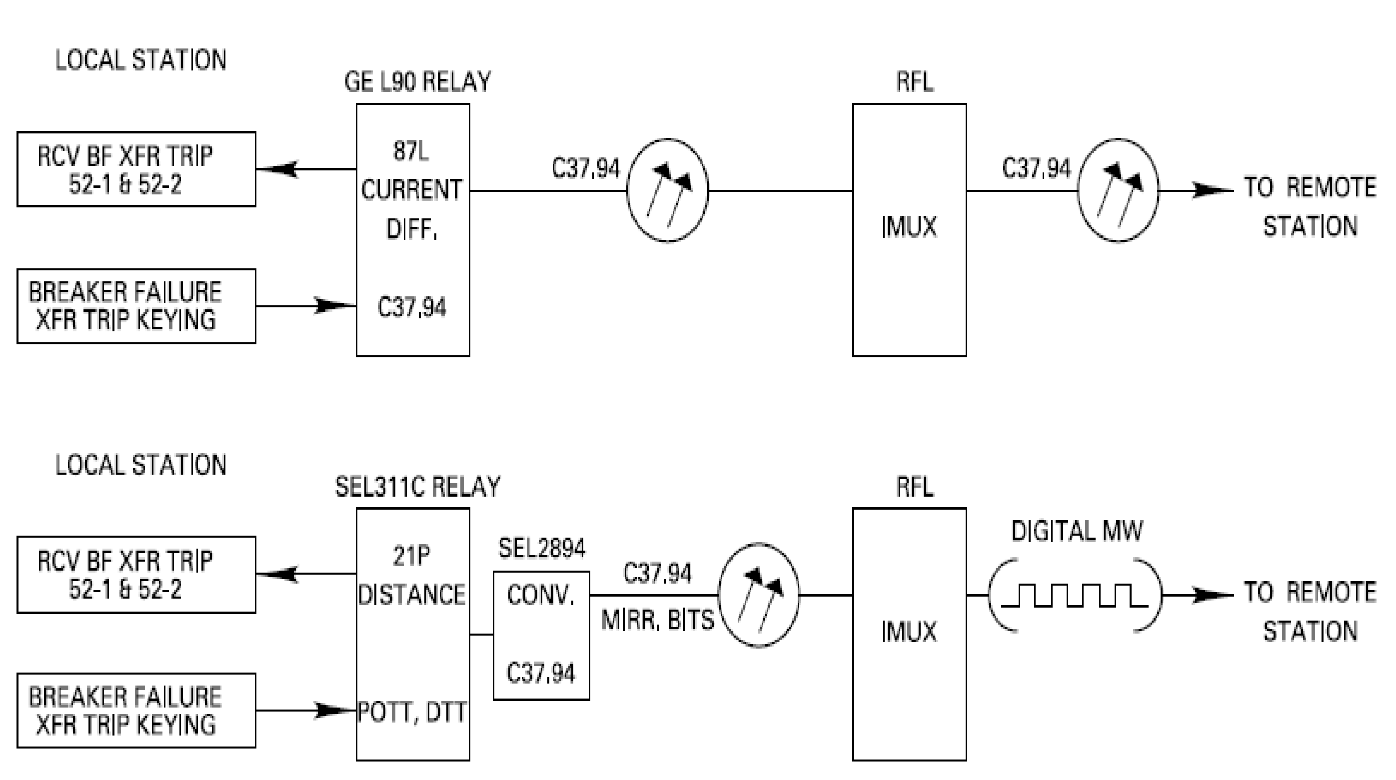
- Line charging current & voltage reads
- Verify phasing, rotation, load checks and meters are correct.
- Exchange load check data with the remote commissioning team
- Prepare & send load data report to setting engineers.
- File As-Built drawings and supporting documents.





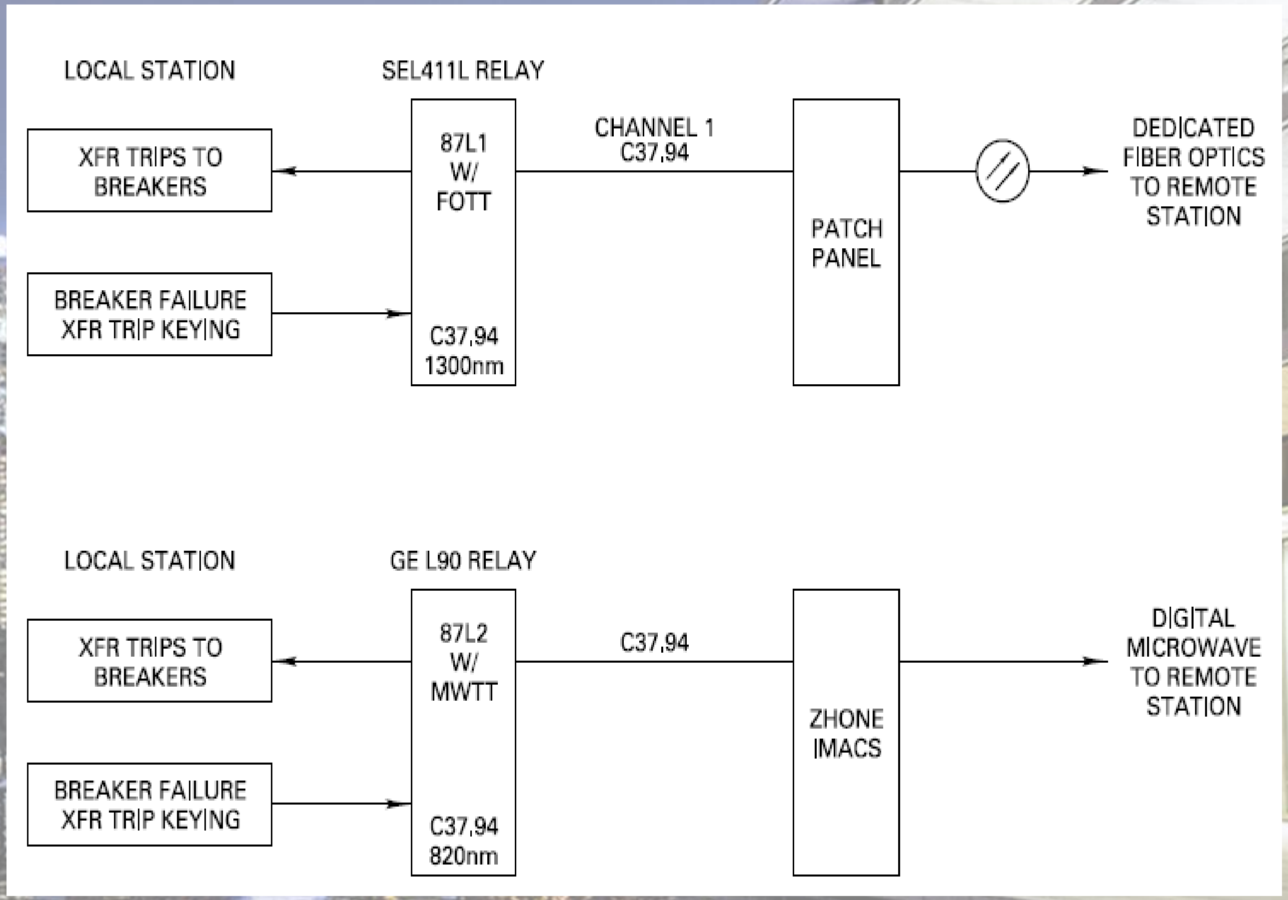
Commissioning Story 1

- Inter-Tie 230kV Transmission line
- Dual Protection – SEL-311C(Dev.21) & GE-L90(Dev.87L)
- Communication Channels: Digital MW & Fiber Optics
- Followed above commissioning methods & steps
- Results: No commissioning discrepancy found
- Transmission line commissioned successfully



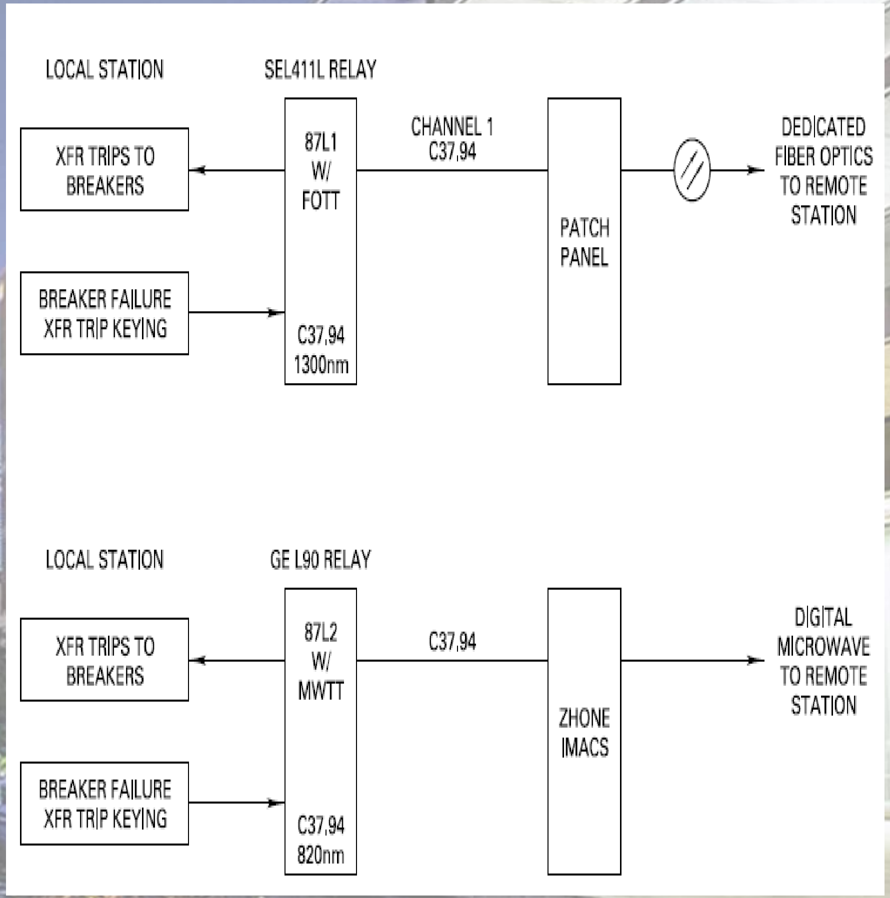
Commissioning Story 2

- Inter-Tie 230kV short transmission line (approx. 6 miles)
- Dual Differential Protection –
  SEL-411L(Dev.87L1+21 BU) &
  GE L90(Dev.87L2 + 21 BU)
- Communication Channels: Digital MW & Fiber Optics
- Followed above commissioning methods & steps
- Results: Commissioning discrepancy found during end-to-end testing



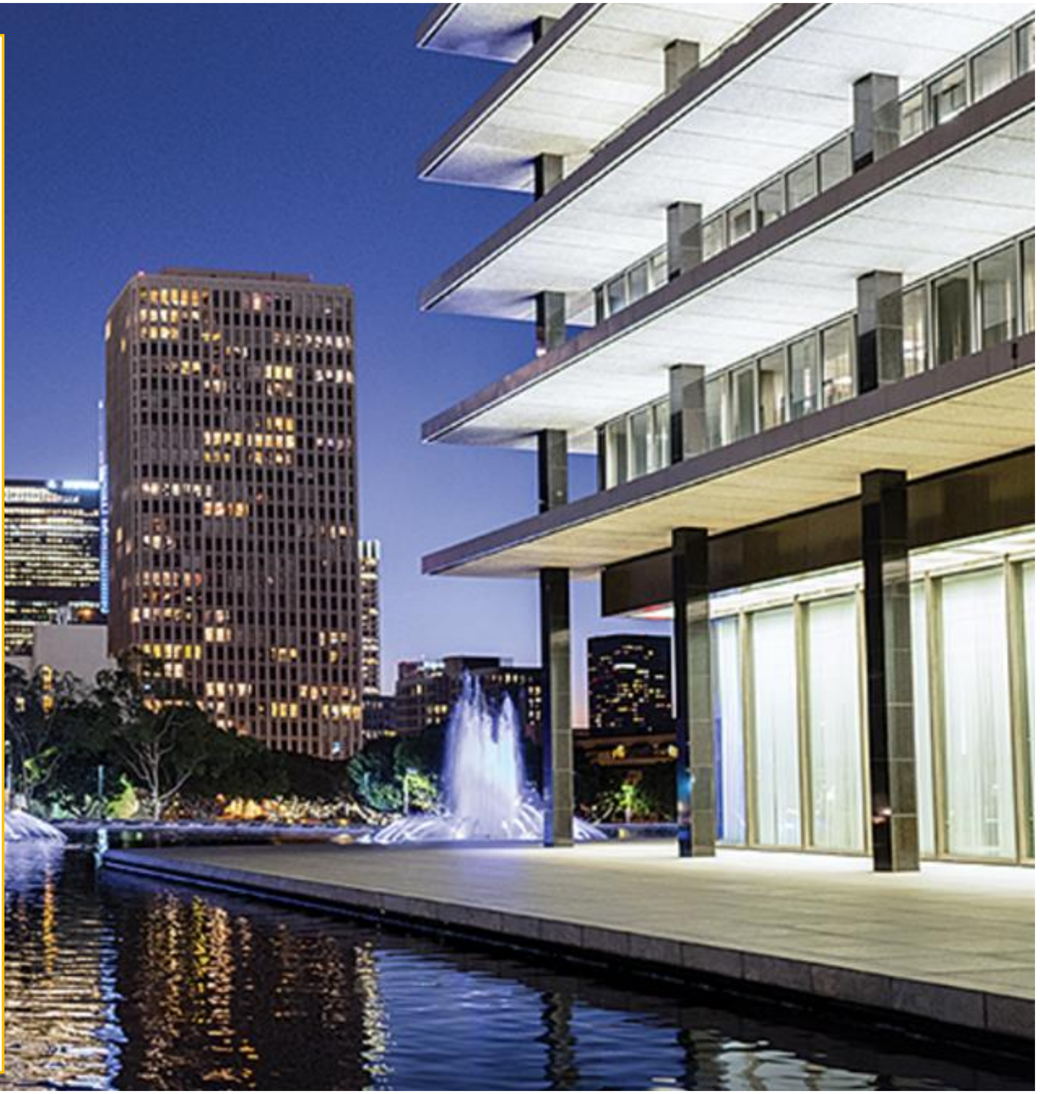
Commissioning Story 2 Cont'd…

- Zone 2 BU test FAILED during end-to-end testing.
- However, Zone 2 BU test PASSED during back-to-back testing.
- Findings: Settings changed at remote terminal prior to the start of end-to-end testing.
- Mitigation: Meeting with relay setting engineers to discuss the findings and a resolution was agreed upon.
- All end-to-end test passed after the resolution was implemented.
- Lesson Learned: Prior to the start of the end-to-end testing exchange final relay settings once again.



Conclusion

- In conclusion, LADWP approach to commissioning of the protection systems installation ensures new equipment to the power system is of the highest quality and meets FERC/NERC regulatory compliance.
- As can be seen in this presentation, the commissioning methods involve several steps, such as, preliminary design review, preliminary and final settings review, coordination of test plans, back-to-back test, end-to-end test, etc.
- The two commissioning stories presented here highlight the successes and lessons learned from each project.
- Thank you for the invitation to participate in this effort to promote best commissioning practices.



End of Presentation

Thank You!

Presented by: Los Angeles Department of Water and Power

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UFLS PROGRAM CHALLENGES AND SOLUTIONS IN LOW INERTIA SYSTEMS

Kevin W. Jones, Consulting Engineer, System Protection Engineering

Presented to NERC Mis-Op Reduction Workshop

October 2, 2024

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OUTLINE OF PRESENTATION

- UFLS Challenges in Predominately Renewable GEN World Recap
- Need to Rethink Underfrequency Mitigation Strategies
- Solution #1: Replace Inertia with Synchronous Condensers
- Solution #2: Arrest Frequency Pre-UFLS with BESS
- Solution #3: Implement Patent Pending RoCoF UFLS Program
- Conclusions

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What is Automatic UFLS? What is its Purpose?

- Automatic UFLS is a ***last-ditch***, first line of defense to prevent blackouts and generator steam turbine damage

Prevent Generator Turbine Damage

Frequency at Full Load (Hz)	Minimum Time to Damage (Min.)
59.4	-----
58.8	90
58.2	10
57.6	1

Time is CUMULATIVE over the life of the machine!!

Blackout Avoidance

	PRC-024-2 Allowable Low Frequency Tripping Time Delay (Sec.)		
Frequency (Hz)	Eastern Interconnection *	Western Interconnection	ERCOT Interconnection
> 59.5 Hz	Continuous	Continuous	Continuous
≤ 59.5 Hz	1792	Continuous	Continuous
> 59.4 Hz	1201	Continuous	Continuous
≤ 59.4 Hz	1201	180	540
≤ 59.0 Hz	242	180	540
≤ 58.4 Hz	22	30	30
≤ 58.0 Hz	4.44	30	2
≤ 57.8 Hz	0	7.5	2
≤ 57.5 Hz	0	7.5	0
≤ 57.3 Hz	0	0.75	0
≤ 57.0 Hz	0	0	0

* EI tripping times follow the formula $10^{(1.7373*f - 100.116)}$ for frequency values > 57.8 Hz and ≤ 59.5 Hz. This formula was applied to fill in EI values in table at frequency shown.

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Brief History of UFLS

- **1965 Northeast Blackout**
- **2003 Northeast Blackout**
- **2011 Arizona-Southern California Blackout**
- **2016 South Australia Blackout**

Blackout	Load Lost (MW)	People Affected (Millions)	Interesting Facts
1965 NE	20,000	30	Min. UFLS; NERC[1] formed 3 years later
2003 NE	62,000	50	26,000 MW UFLS; NERC[2] Standards
2011 Arizona-SoCo	7,835	2.7	ALL UFLS tripped; –3 Hz/s ROCOF
2016 S. Australia	1,826	0.85	ALL UFLS tripped; –6 Hz/s ROCOF

[1] National Electric Reliability Council
[2] North American Electric Reliability Corporation

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UFLS Technical Basics

- **Frequency rise/decay equations:**

System Frequency (60 Hz)

Final Frequency

Time (s)

System Inertia in $\mathrm{MW} \cdot s\ /MVA$

$$f = f_{sys} - \Delta L \cdot \left(1 - e^{-\frac{D \cdot t}{2 \cdot H}}\right) \cdot \frac{1}{D} \cdot 60 \qquad D = \frac{Load_{sys} \cdot 1.5}{100}$$

Change in Load (–) or Generation (+) in pu

Load Damping Constant in pu

$$\frac{df}{dt} = \frac{-30 \cdot \Delta L}{H} \cdot e^{-\frac{D \cdot t}{2 \cdot H}}$$

Solve at t = 0

$$\frac{df}{dt} = \frac{-30 \cdot \Delta L}{H}$$

$$t = -\frac{2 \bullet H}{D} \bullet \ln\left[1 + \frac{D \bullet \left(f - f_{sys}\right)}{60 \bullet \Delta L}\right]$$

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UFLS Regional Practices

SPP/Eastern Interconnect (EI) *

UFLS Step	Frequency (Hz)	Minimum Accumulated Load Relief as Percentage of Forecasted Peak Load (%)	Maximum Accumulated Load Relief as Percentage of Forecasted Peak Load (%)
1	**59.3**	10	25
2	**59.0**	20	35
3	**58.7**	30	45

* **Table is SPP specific, but Eastern Interconnect general with regional variations.**

$$EI\ MAX\ Design\ RoCoF = \frac{59.3\ Hz\ - 59.0\ Hz}{(6\ cyc.TD + 4\ cyc.CB)\Big/60\,\frac{cyc.}{sec.}} = \frac{0.3\ Hz}{0.1667\ sec.} = 1.8\frac{Hz}{sec.}$$

$$ERCOT\ MAX\ Design\ RoCoF = \frac{59.3\ Hz\ - 58.9\ Hz}{(6\ cyc.TD + 4\ cyc.CB)\Big/60\,\frac{cyc.}{sec.}} = \frac{0.4\ Hz}{0.1667\ sec.} = 2.4\frac{Hz}{sec.}$$

$$WECC\ MAX\ Design\ RoCoF = \frac{59.1\ Hz\ - 58.9\ Hz}{(6\ cyc.TD + 4\ cyc.CB)\Big/60\,\frac{cyc.}{sec.}} = \frac{0.2\ Hz}{0.1667\ sec.} = 1.2\frac{Hz}{sec.}$$

ERCOT

UFLS Level	Frequency (Hz)	Load Relief
1	**59.3**	5% of the ERCOT System Load (Total 5%)
2	**58.9**	An additional 10% of the ERCOT System Load (Total 15%)
3	**58.5**	An additional 10% of the ERCOT System Load (Total 25%)

WECC

Load Shedding Block	Percent of Balancing Authority Area Load Dropped	Frequency Set-Point (Hz)	Tripping Time*
1	5.3	59.1	no more than 14 cycles
2	5.9	58.9	no more than 14 cycles
3	6.5	58.7	no more than 14 cycles
4	6.7	58.5	no more than 14 cycles
5	6.7	58.3	no more than 14 cycles
Additional automatic load shedding to correct underfrequency stalling			
	2.3	59.3	15 sec
	1.7	59.5	30 sec
	2.0	59.5	1 min
Load automatically restored from 59.1 Hz block to correct frequency overshoot			
	1.1	60.5	30 sec
	1.7	60.7	5 sec
	2.3	60.9	0.25 sec

Need to Rethink Existing UFLS Program

- High penetrations of renewable resources are depleting system inertia
- Lower system inertia results in higher Rate-of-Change-of-Frequency (RoCoF)

IEEE Power & Energy Society

July 2018

TECHNICAL REPORT

PES-TR68

IEEE PES Power & Energy Society®   IEEE

Impact of Inverter Based Generation on Bulk Power System Dynamics and Short-Circuit Performance

PREPARED BY THE
IEEE/NERC Task Force on Short-Circuit and System Performance
Impact of Inverter Based Generation

3.2.9 UFLS Frequency Time Delay Settings

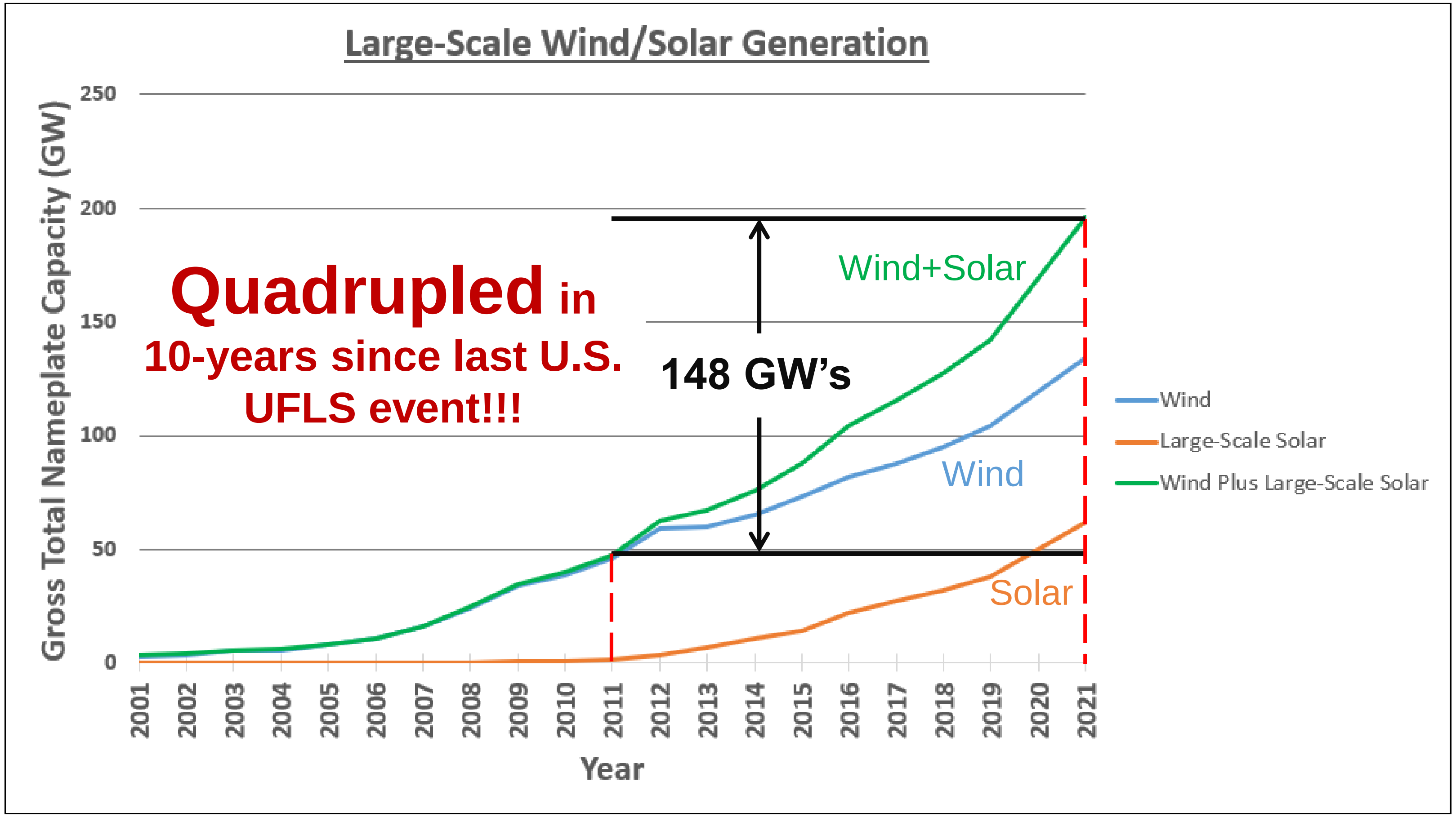
Under Frequency Load Shed (UFLS) is necessary to keep load and generation in an electrical island balanced and as close to the nominal system frequency (60 Hz for North America) as possible after the loss of significant amounts of generation or after the loss of significant power imports following a system separation event. The rapid influx of IBR has both offset and replaced conventional fossil generation resources. Because of this, lower levels of system inertia are available at any given time, which results in more rapid frequency decay following a loss of generation or power imports.

K. Jones, P. Pourbeik, Et. Al., "Impact of Inverter Based Generation on Bulk Power System Dynamics and Short Circuit Performance", July, 2018. Available: Impact of Inverter Based Generation on Bulk Power System Dynamics and Short-Circuit Performance (TR68) (ieee-pes.org)

Need to Rethink Existing UFLS Program

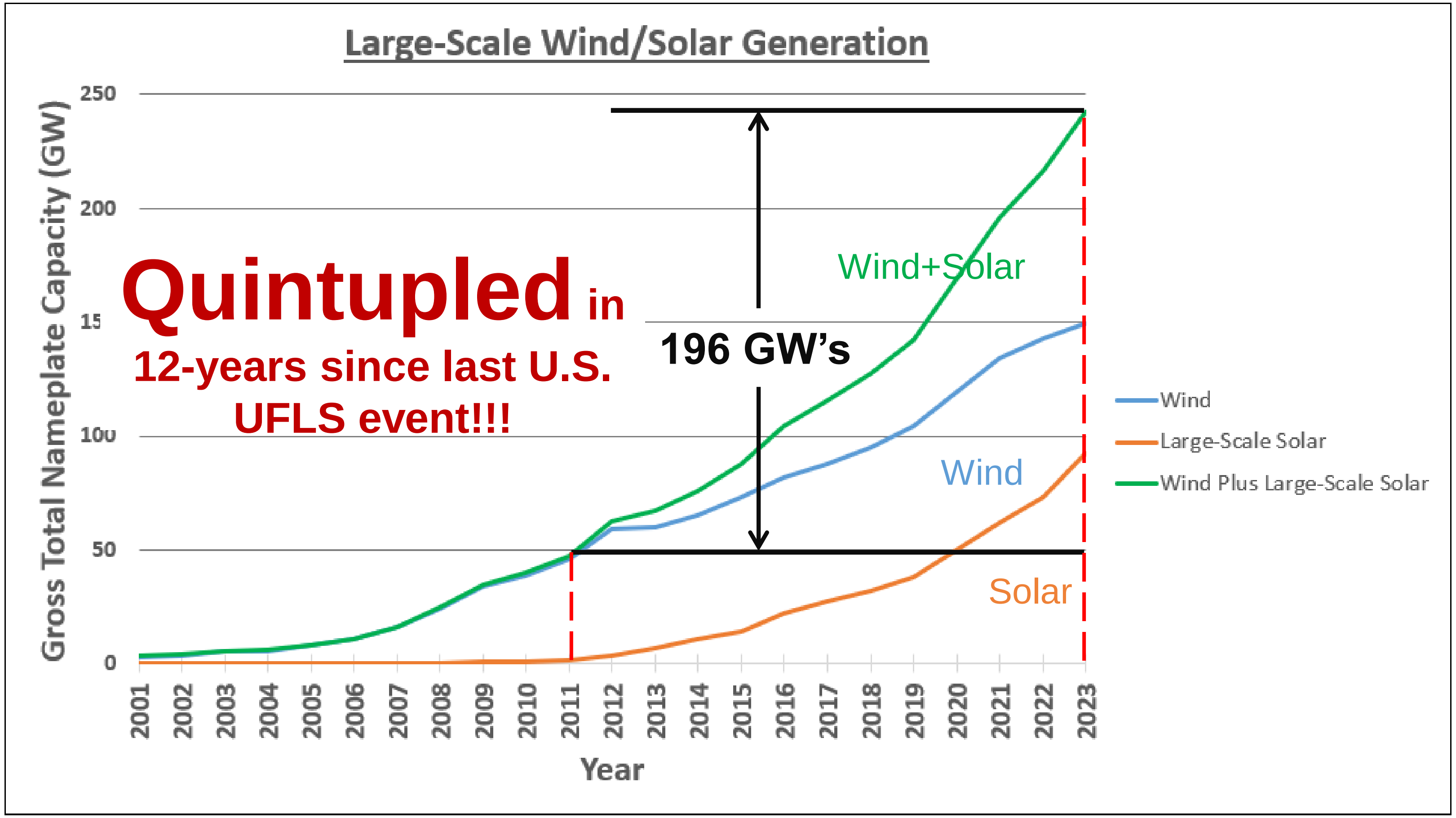
- Significant amounts of UFLS with extended time delays
- Higher ROCOF caused by increasing penetrations of renewable resources

UFLS Level	Frequency (Hz)	Percentage of Underfrequency Relays with Intentional Time Delay = 6-cycles	Percentage of Underfrequency Relays with Intentional Time Delay = 30-cycles
1	59.3	57%	43%
2	59.0	70%	30%
3	58.7	62%	38%
OVERALL		64%	36%



Need to Rethink Existing UFLS Program

- Significant amounts of UFLS with extended time delays
- Higher ROCOF caused by increasing penetrations of renewable resources



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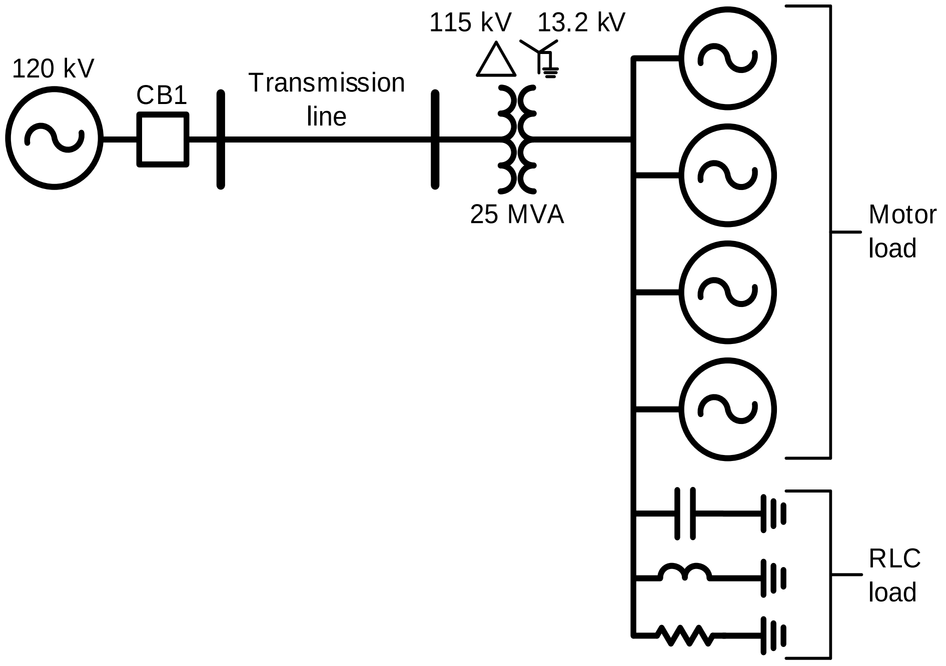
UFLS Challenges Due to Motor Spin-Down

- **Electromagnetic Transient Software (EMTS) program model is used to test for UFLS relay mis-trip under transient or lost source conditions**
- **Two commercially available EMTS programs were used and results were compared**



Four 3-MVA induction motors

RLC loads (R=1.74 MW; L=C=1 MVAR)

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UFLS Challenges Due to Motor Spin-Down

- **Comparison of Time Delays – 6 cyc. vs. 30 cyc. (UV block = 67%):**

Test#	RLC load connected	# of Motors connected	UFLS Levels 1, 2, 3 6 cycle delay	UFLS Levels 1, 2, 3 30 cycle delay
1	Resistor	4	Trip	No Op
2	Resistor	3	Trip	No Op
3	Resistor	2	Trip	No Op
4	Resistor	1	Trip	No Op
5	Capacitor	4	Trip	No Op
6	Capacitor	3	Trip	No Op
7	Capacitor	2	Trip	No Op
8	Capacitor	1	Trip	Trip
9	Inductor	4	Trip	No Op
10	Inductor	3	Trip	No Op
11	Inductor	2	Trip	No Op
12	Inductor	1	Trip	No Op
13	None	4	Trip	No Op
14	None	3	Trip	No Op
15	None	2	Trip	No Op
16	None	1	Trip	No Op

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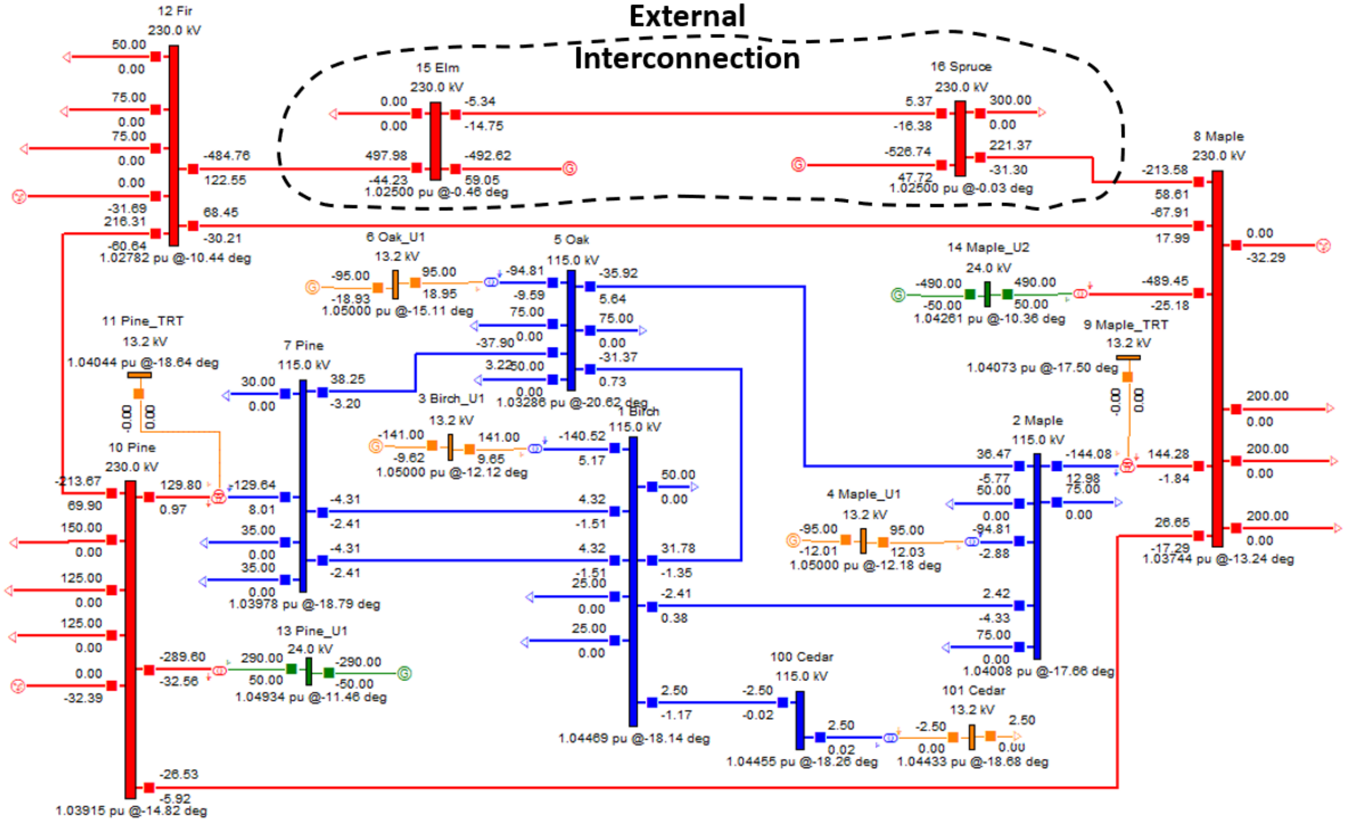
UFLS Challenges Due to Motor Spin-Down

- **Test system details:**

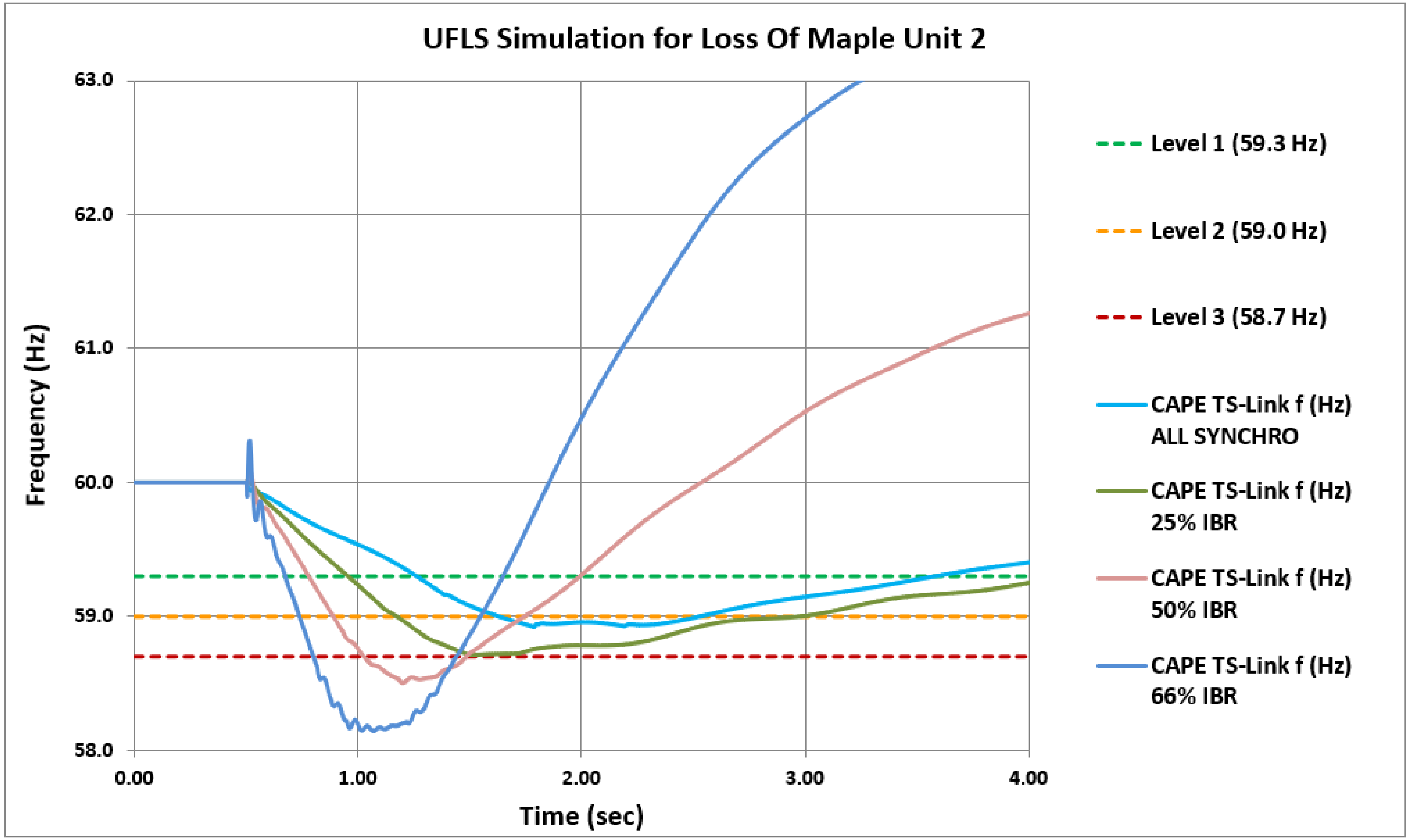
UFLS Level	Freq. (Hz)	Percent of Peak Load Shed (%)	Load Shed with 6-Cycle Delay (MW)	Load Shed with 30-Cycle Delay (MW)	Total Load Shed (MW)
1	59.3	12.5	150	100	250
2	59.0	12.5	150	100	250
3	58.7	12.5	150	100	250

Case	Total Synchronous Generation (MVA)	Total Wind Generation (MVA)	% Wind Penetration
1	3150	0	0%
2	2350	800	25%
3	1550	1600	50%
4	1050	2100	66%



UFLS Challenges Due to Motor Spin-Down

- **ALL Test Cases:**



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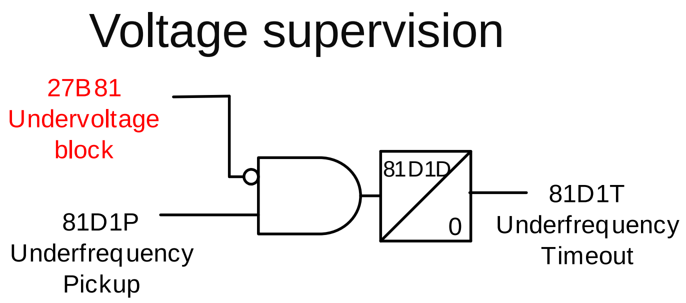
UFLS Solution for Motor Spin-Down

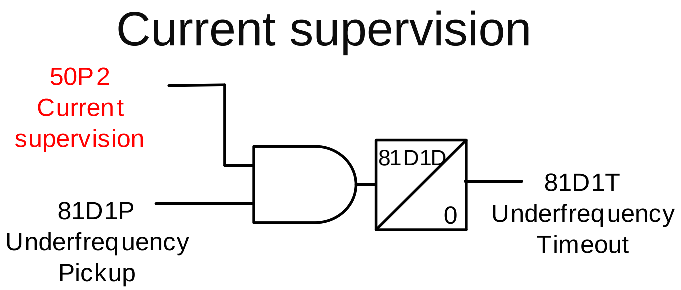
- **Use Supervision of Underfrequency Elements from IEEE C37.117**

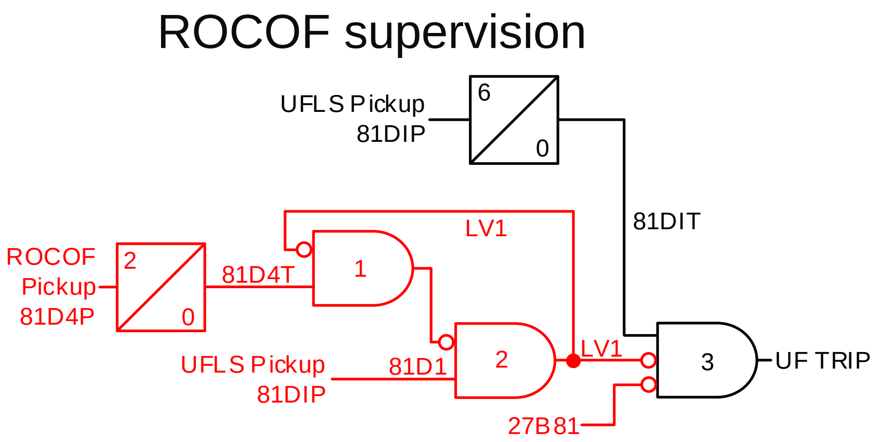
C37.117-2007 - IEEE Guide for the Application of Protective Relays Used for Abnormal Frequency Load Shedding and Restoration

Publisher: IEEE   Cite This   PDF

Status: Inactive - Reserved

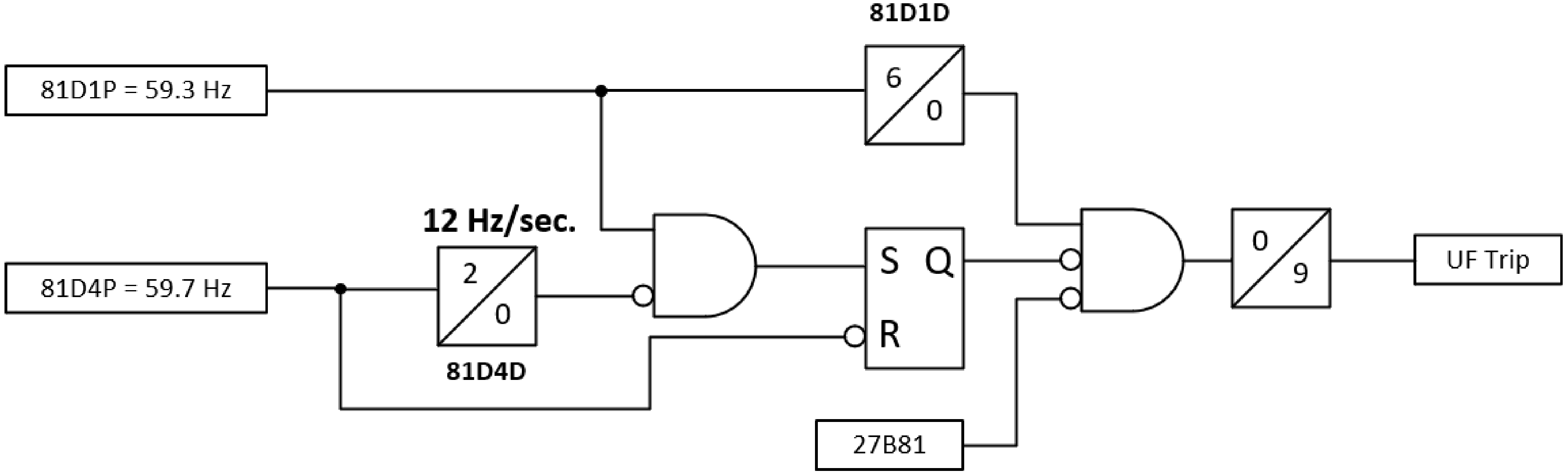






UFLS Solution for Motor Spin-Down

- **ROCOF Supervision:**



$$\text{ROCOF supervision} = \frac{81\text{D4P} - 81\text{D1P}}{81\text{D4D} / 60} = \frac{59.7 - 59.3 \text{ Hz}}{2/60 \text{ s}} = 12 \text{ Hz/s}$$

- The worst-case (lowest) ROCOF for motor bus de-energization was 34 Hz/s
- Frequency decay experienced in South Australia during the 2016 blackout was 6 Hz/s

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UFLS Solution for Motor Spin-Down

- **Summary of Supervision Methods:**

Test	RLC Load Connection	Number of Motors Connected	UFLS With Undervoltage Block = 67%	UFLS With Undervoltage Block = 80%	UFLS With Current Supervision	UFLS With ROCOF Supervision
1	Resistor	4	Trip	No Op	No Op	No Op
2	Resistor	3	Trip	No Op	No Op	No Op
3	Resistor	2	Trip	No Op	No Op	No Op
4	Resistor	1	Trip	No Op	No Op	No Op
5	Capacitor	4	Trip	No Op	No Op	No Op
6	Capacitor	3	Trip	Trip	No Op	No Op
7	Capacitor	2	Trip	Trip	Trip	No Op
8	Capacitor	1	Trip	Trip	Trip	No Op
9	Inductor	4	Trip	No Op	No Op	No Op
10	Inductor	3	Trip	No Op	No Op	No Op
11	Inductor	2	Trip	No Op	No Op	No Op
12	Inductor	1	Trip	No Op	No Op	No Op
13	None	4	Trip	No Op	No Op	No Op
14	None	3	Trip	No Op	No Op	No Op
15	None	2	Trip	Trip	No Op	No Op
16	None	1	Trip	Trip	Trip	No Op

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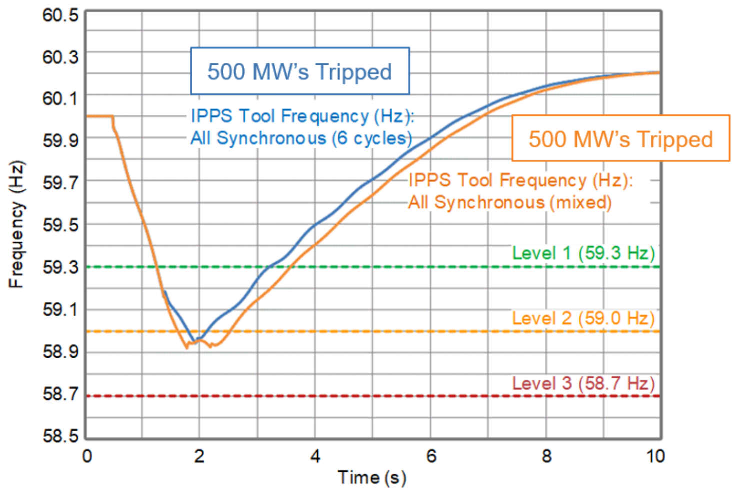
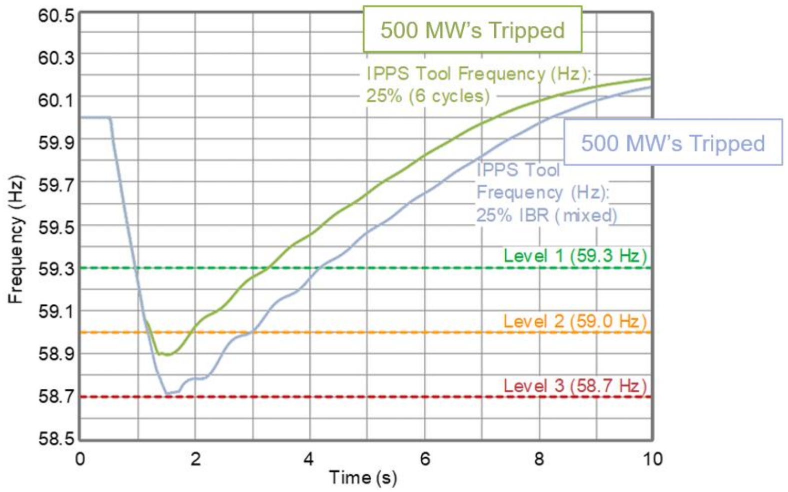
UFLS Solution Test for Motor Spin-Down – ALL delays 6-cyc.

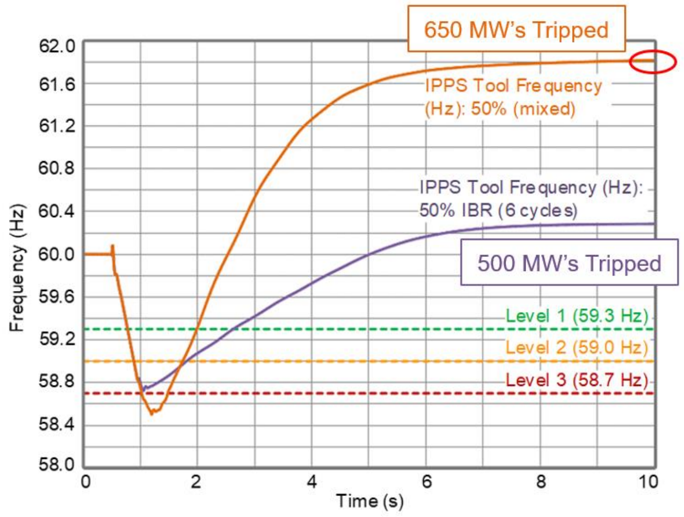
All Synchronous Generation Test



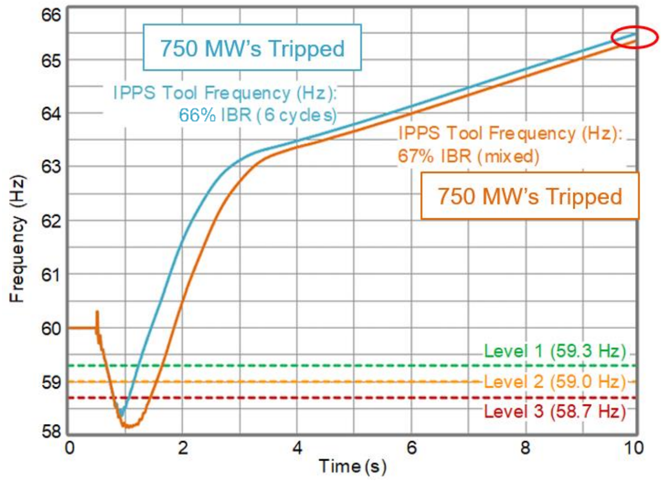
25% Wind Generation Test



50% Wind Generation Test



66% Wind Generation Test



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UFLS Solution Test for Motor Spin-Down Conclusions

- Verified that the 6-cycle UFLS time delay is too short to avoid UFLS relay mis-trips when source transmission line outages feeders with significant motor load
- Verified that the 30-cycle UFLS time delay prevents most UFLS misoperations due to motor spin-down
- Proved that the ROCOF supervisory scheme is the most secure of the three supervisory methods tested in preventing UFLS misoperations due to motor spin-down
- Verified that implementation of ROCOF supervision of UFLS relays allowing use of 6-cycle time delays results in higher frequency nadir, faster recovery to nominal frequency, and less load shed in some cases

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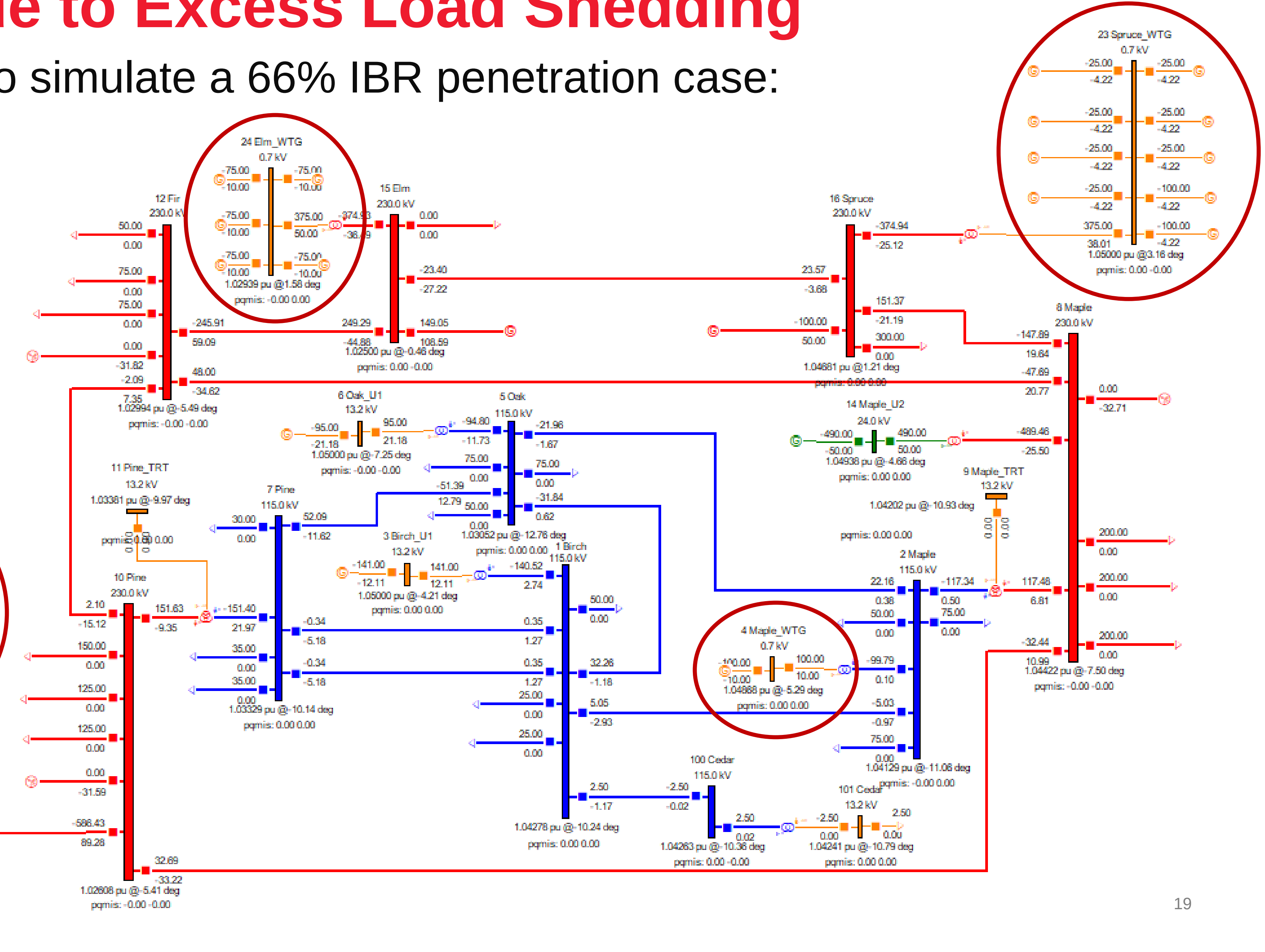
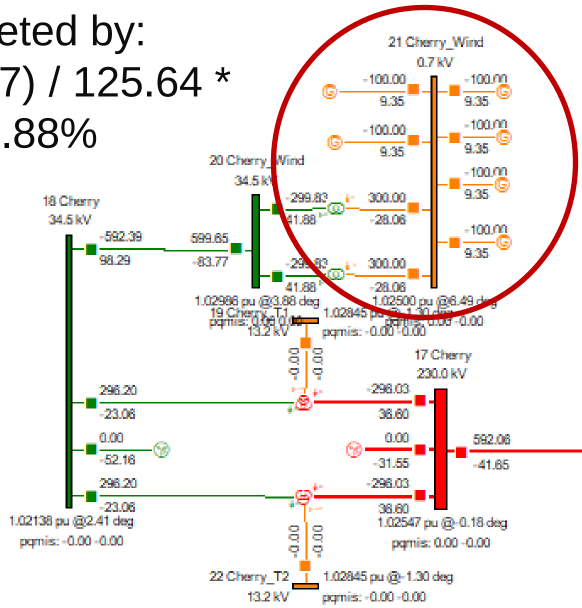
UFLS Challenges Due to Excess Load Shedding

- ❑ The system was modified to simulate a 66% IBR penetration case:
- ❑ Type IV wind farms

Generator Name	Nameplate MVA	Generator Inertia Constant (H)	ALL Synchro H@100 MVA Base	66% Wind H@100 MVA Base
Birch U1	150	6.22	9.33	9.33
Oak U1	100	5.48	5.48	5.48
Pine U1	300	3.33	9.99	0
Maple U1	100	5.48	5.48	0
Maple U2	500	3.236	16.18	16.18
Elm	1000	3.959	39.59	7.918
Spruce	1000	3.959	39.59	3.959
TOTAL	**3150**		**125.64**	**42.867**

Inertia depleted by:
(125.64 – 42.867) / 125.64 * 100 = 65.88%





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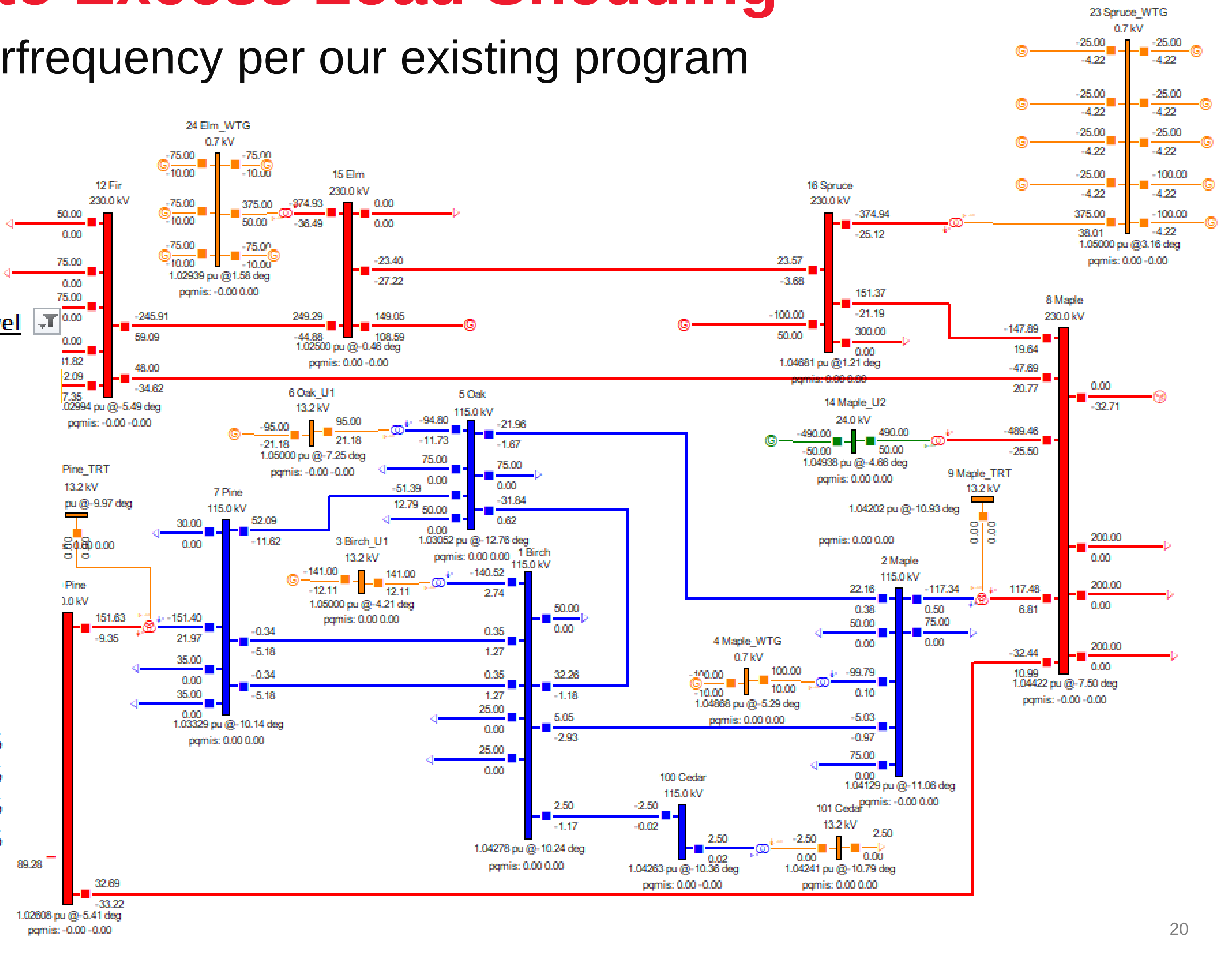
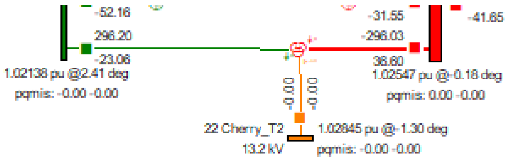
UFLS Challenges Due to Excess Load Shedding

- Loads were set to trip on underfrequency per our existing program
- 10% in each level
- 6-cycle time delay

Substation	Load Label	Load (MW's)	UFLS Level
Birch	1-1	50	3
Fir	12-2	75	2
Fir	12-3	50	1
Maple	2-1	75	3
Maple	2-2	75	3
Maple	2-3	50	2
Oak	5-2	75	2
Pine	10-1	150	1
TOTAL		1800	

Level 1 Total	200	MW's	10.00%
Level 2 Total	200	MW's	10.00%
Level 3 Total	200	MW's	10.00%
Not Used Total	1200	MW's	60.00%





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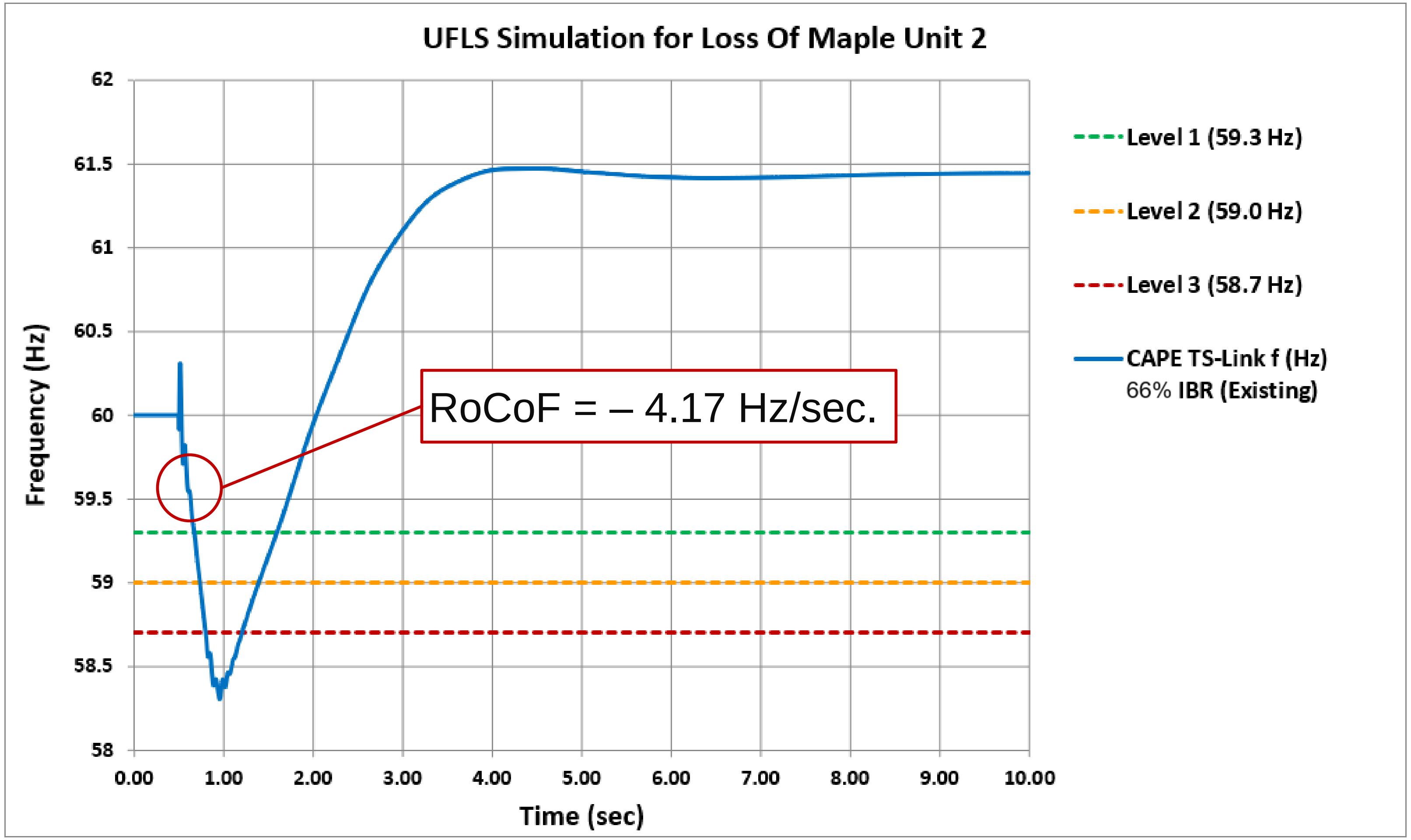
UFLS Challenges Due to Excess Load Shedding

- ❑ CAPE TS-Link example for trip of 490 MW Maple Unit 2
- ❑ All three levels of UFLS operate tripping 600 MW of load



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UFLS Challenges Due to Excess Load Shedding

- 10/13 (77%) cases studied would result in potential uncontrolled generator tripping due to over/under frequency per NERC PRC-024 Standard
- 5/13 (38%) cases studied would lead to uncontrolled, instantaneous tripping of generation, leading to a blackout

Eastern Interconnection

High Frequency Duration	
Frequency (Hz)	**Time (Sec)**
≥61.8	Instantaneous trip
≥60.5	$10^{(90.935-1.45713*f)}$
<60.5	Continuous operation

Low Frequency Duration	
Frequency (Hz)	**Time (sec)**
≤57.8	Instantaneous trip
≤59.5	$10^{(1.7373*f-100.116)}$
> 59.5	Continuous operation

		Existing UFLS				
Generation Tripped (MW's)	RoCoF (Hz/Sec.)	Total Load Shed (MW's)	Excess Amount of Load Shed (MW's)	Frequency Nadir (Hz)	Overshoot Freq. (Hz)	Final Freq. (Hz)
95	-0.54	200	105	59.23	61.23	60.92
140	-1.01	200	60	59.14	60.84	60.60
190	-1.24	200	10	59.10	60.21	60.13
235	-1.71	400	165	58.96	62.15	61.54
330	-2.53	400	70	58.71	61.74	61.18
375	-2.23	400	25	58.79	60.33	60.23
435	-3.35	600	165	58.46	64.04	62.52
490	-4.17	600	110	58.31	61.47	61.44
540	-4.54	600	60	58.17	60.86	60.85
600	-3.58	600	0	58.30	60.04	59.99
640	-5.44	600	-40	57.79	N/A	57.79
700	-4.05	600	-100	56.95	N/A	56.95
750	-4.27	600	-150	54.93	N/A	54.93
		TOTAL	770			
		Ave. Difference	77.00			

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Solution #1: Replace Inertia with Synchronous Condensers

Generator Name	Nameplate MVA	Generator Inertia Constant (H)	ALL Synchro H@100 MVA Base
Birch U1	150	6.22	9.33
Oak U1	100	5.48	5.48
Pine U1	300	3.33	9.99
Maple U1	100	5.48	5.48
Maple U2	500	3.236	16.18
Elm	1000	3.959	39.59
Spruce	1000	3.959	39.59
TOTAL	3150		125.64

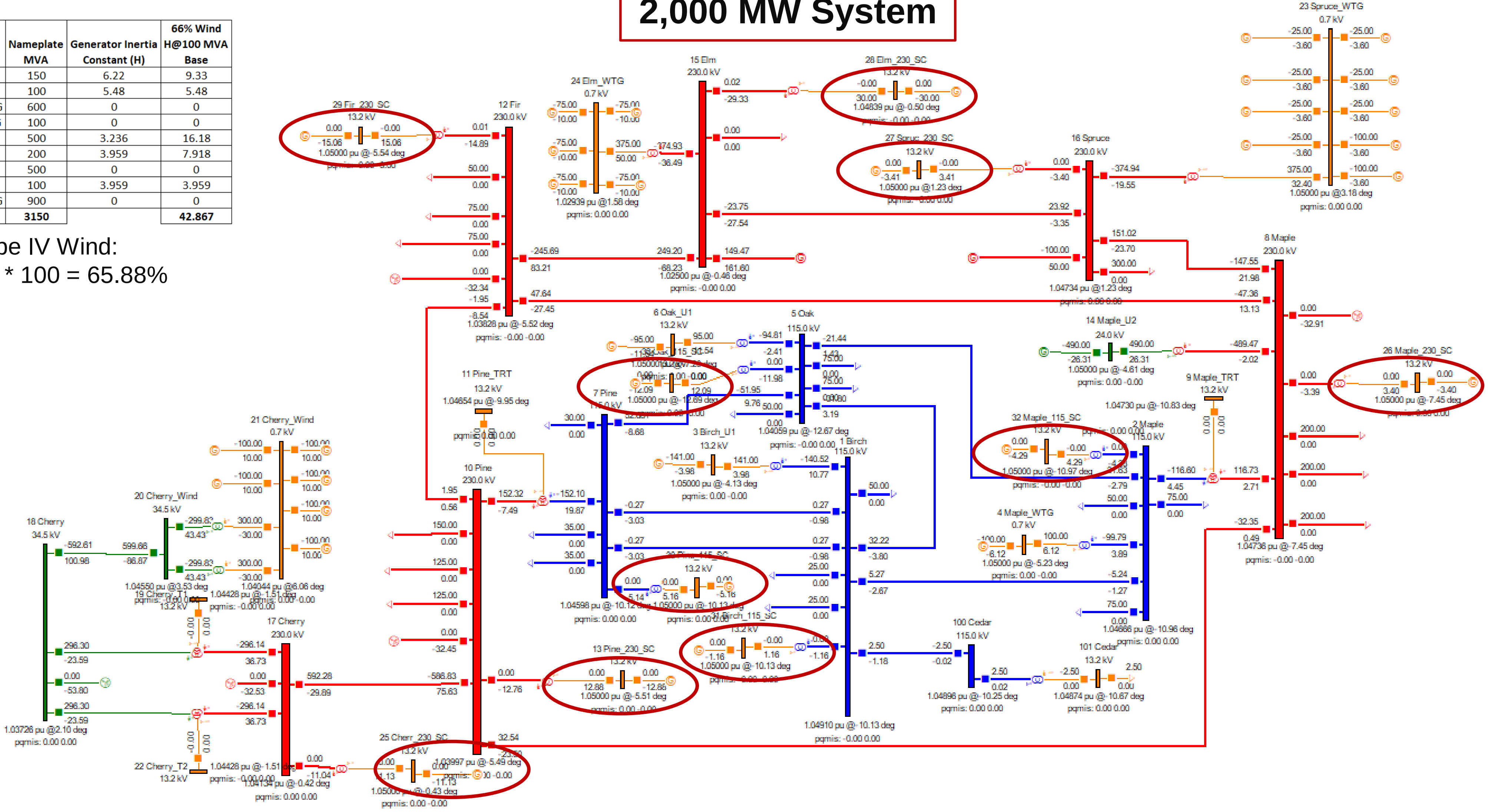
Generator Name	Nameplate MVA	Generator Inertia Constant (H)	66% Wind H@100 MVA Base
Birch U1	150	6.22	9.33
Oak U1	100	5.48	5.48
Cherry WTG	600	0	0
Maple WTG	100	0	0
Maple U2	500	3.236	16.18
Elm	200	3.959	7.918
Elm WTG	500	0	0
Spruce	100	3.959	3.959
Spruce WTG	900	0	0
TOTAL	3150		42.867

Inertia depleted by Type IV Wind:
(125.64 – 42.867) / 125.64 * 100 = 65.88%

SYNC CON Name	Nameplate MVA	SYNC CON Inertia Constant (H)	66% Wind H@100 MVA Base
Birch 115 SC	150	6.00	9.00
Cherry 230 SC	150	6.00	9.00
Elm 230 SC	150	6.00	9.00
Fir 230 SC	150	6.00	9.00
Maple 230 SC	150	6.00	9.00
Maple 115 SC	150	6.00	9.00
Oak 115 SC	150	6.00	9.00
Pine 230 SC	150	6.00	9.00
Pine 115 SC	150	6.00	9.00
Spruce 230 SC	150	6.00	9.00
TOTAL	1500		90.00

Inertia added back by SYNC CON:
(42.867 + 90.00) / 125.64 * 100 = 105.75%

2,000 MW System



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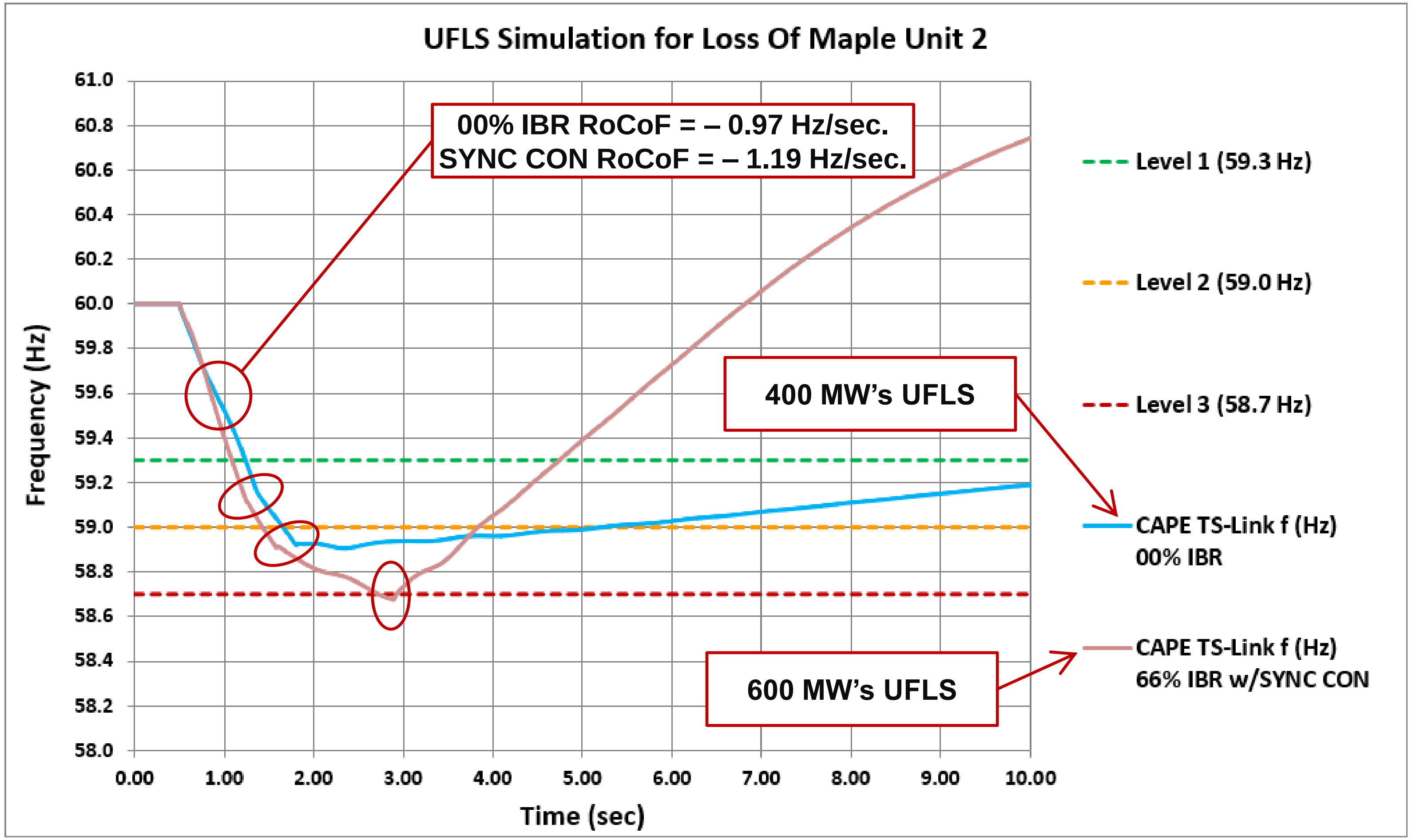
Solution #1: Replace Inertia with Synchronous Condensers

First 10 Case Study Stats	00% IBR Case	66% IBR w/SYNC CON Case
Total Load Shed (MW's)	3400	3800
HIGH RoCoF (Hz/sec.)	1.08	1.33
AVE. RoCoF (Hz/sec.)	0.63	0.79
LOW RoCoF (Hz/sec.)	0.16	0.17
AVE Freq. Nadir (Hz)	59.03	58.98
AVE Freq. Overshoot (Hz)	60.16	60.43
AVE Final Freq. (Hz)	60.07	60.35



Solution #1: Replace Inertia with SYNC CON Conclusions

- **Replacing inertia with synchronous condensers can achieve similar, but not quite as good response as 00% IBR case.**
- **Synchronous condensers add inertia to the system, but can’t provide MW injection like synchronous generation can.**
- **Synchronous condensers are not cheap (~$25 million per 100 MVAR) and are maintenance intensive.**

$$Test\ System\ SYNC\ CON\ Cost = 10\ \text{units}\ \cdot 1.5\ \cdot \$25\ million\ (per\ 100\ MVAR) = \$375\ million$$

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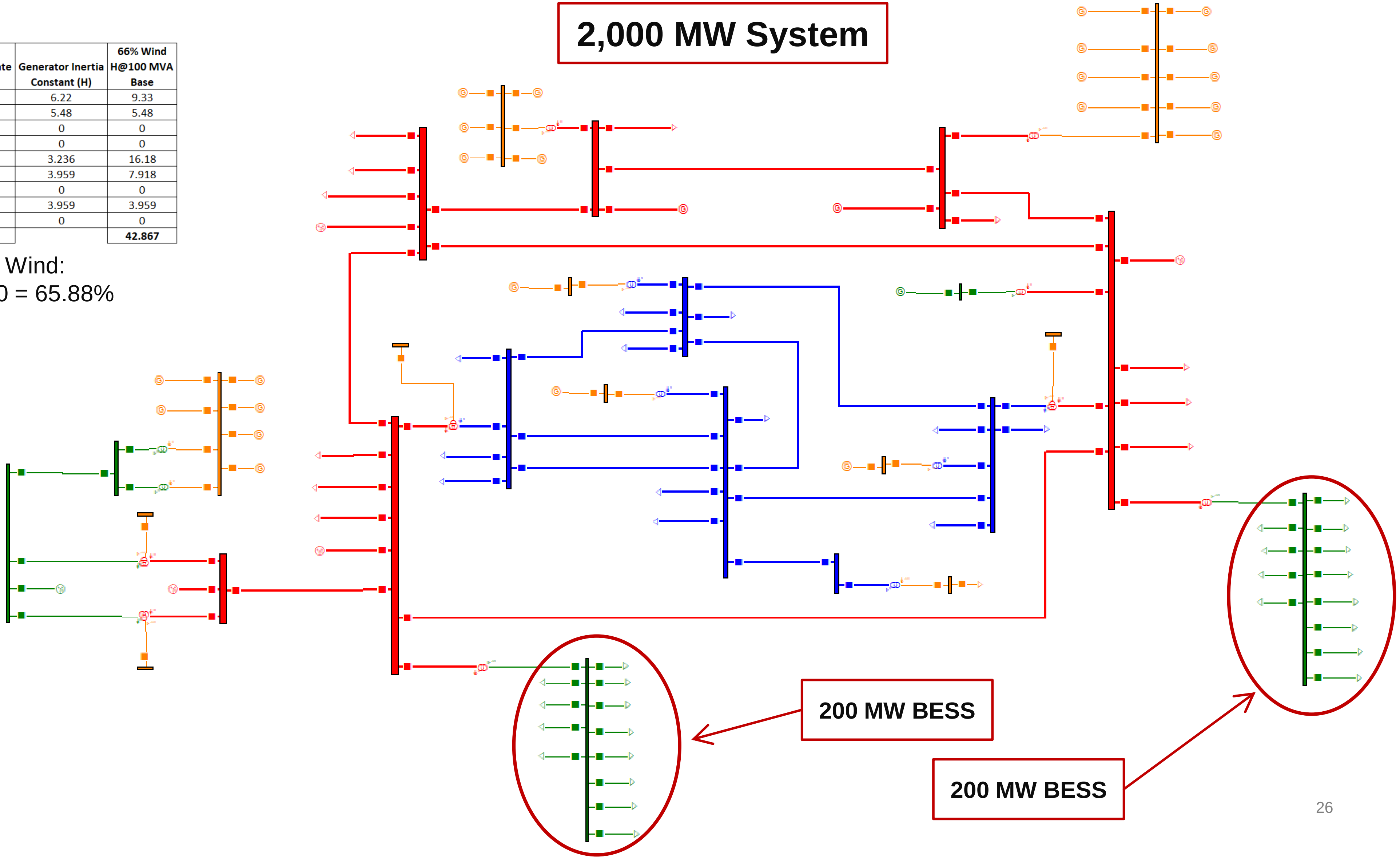
Solution #2: Arrest Frequency Pre-UFLS with BESS

Generator Name	Nameplate MVA	Generator Inertia Constant (H)	ALL Synchro H@100 MVA Base
Birch U1	150	6.22	9.33
Oak U1	100	5.48	5.48
Pine U1	300	3.33	9.99
Maple U1	100	5.48	5.48
Maple U2	500	3.236	16.18
Elm	1000	3.959	39.59
Spruce	1000	3.959	39.59
TOTAL	**3150**		**125.64**

Generator Name	Nameplate MVA	Generator Inertia Constant (H)	66% Wind H@100 MVA Base
Birch U1	150	6.22	9.33
Oak U1	100	5.48	5.48
Cherry WTG	600	0	0
Maple WTG	100	0	0
Maple U2	500	3.236	16.18
Elm	200	3.959	7.918
Elm WTG	500	0	0
Spruce	100	3.959	3.959
Spruce WTG	900	0	0
TOTAL	**3150**		**42.867**

Inertia depleted by Type IV Wind:
(125.64 – 42.867) / 125.64 * 100 = 65.88%



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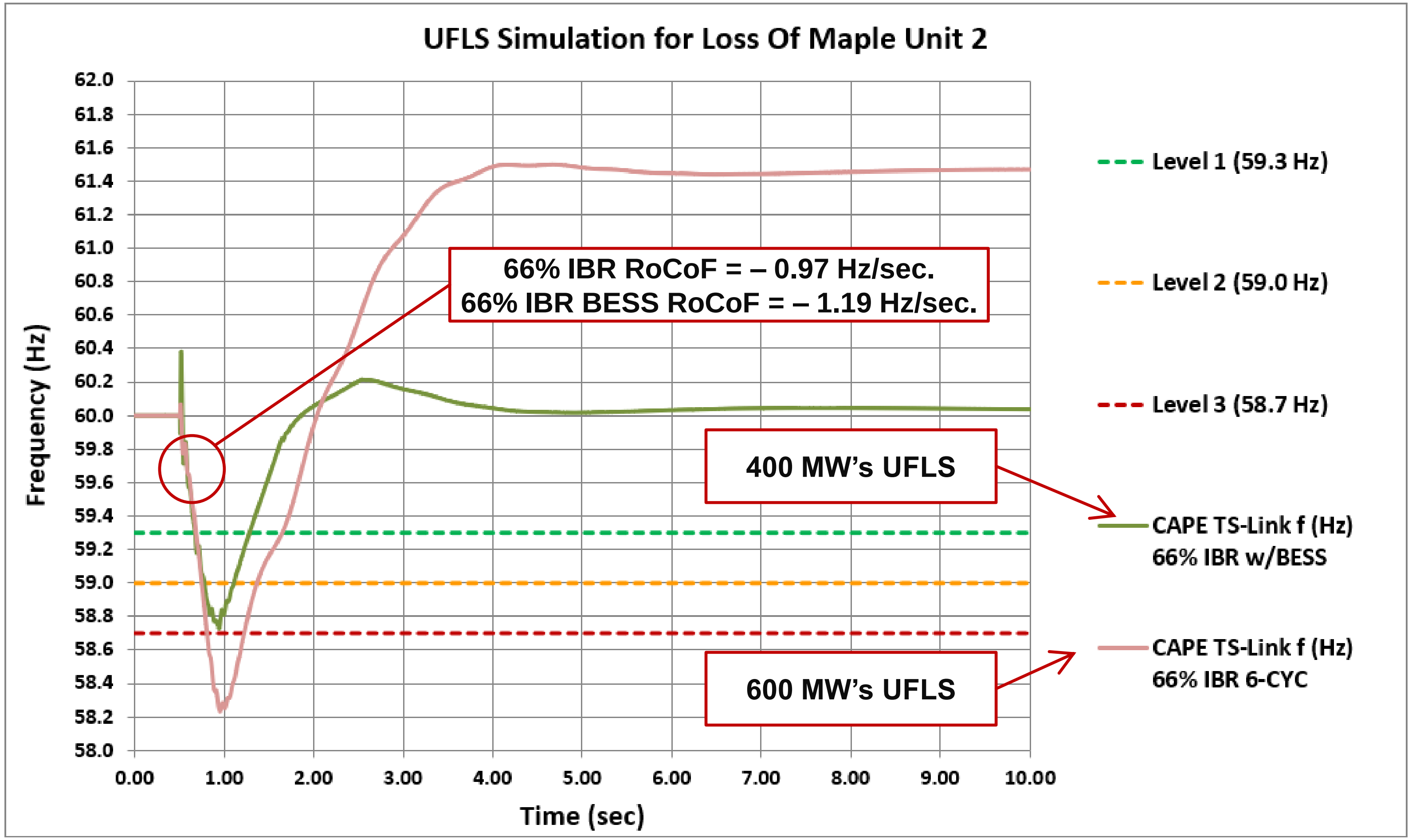
Solution #2: Arrest Frequency Pre-UFLS with BESS

First 10 Case Study Stats	66% IBR Case 6-Cyc. Delay	66% IBR w/BESS Case
Total Load Shed (MW's)	4200	2000 ✓
HIGH RoCoF (Hz/sec.)	4.82	4.42 ✓
AVE. RoCoF (Hz/sec.)	2.59	2.38 ✓
LOW RoCoF (Hz/sec.)	0.54 ✓	0.57
AVE Freq. Nadir (Hz)	58.71	59.10 ✓
AVE Freq. Overshoot (Hz)	61.33	60.11 ✓
AVE Final Freq. (Hz)	60.79	59.98 ✓



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Solution #2: Arrest Frequency with BESS Conclusions

- **BESS fast frequency response MW injection/absorption using only 10% of system peak load (2,000 MW system) can provide significant improvement in conventional UFLS program performance.**
- **BESS fast frequency response can reduce overall load shed by 50% or more.**
- **BESS's are not cheap (~$115 million per 100 MW 4-Hr. duration).**

$$Test\ System\ BESS\ Cost = 2\ Units(100\ MW each) \cdot \$115\ million\ (per\ 100\ MW) = \$230\ million$$

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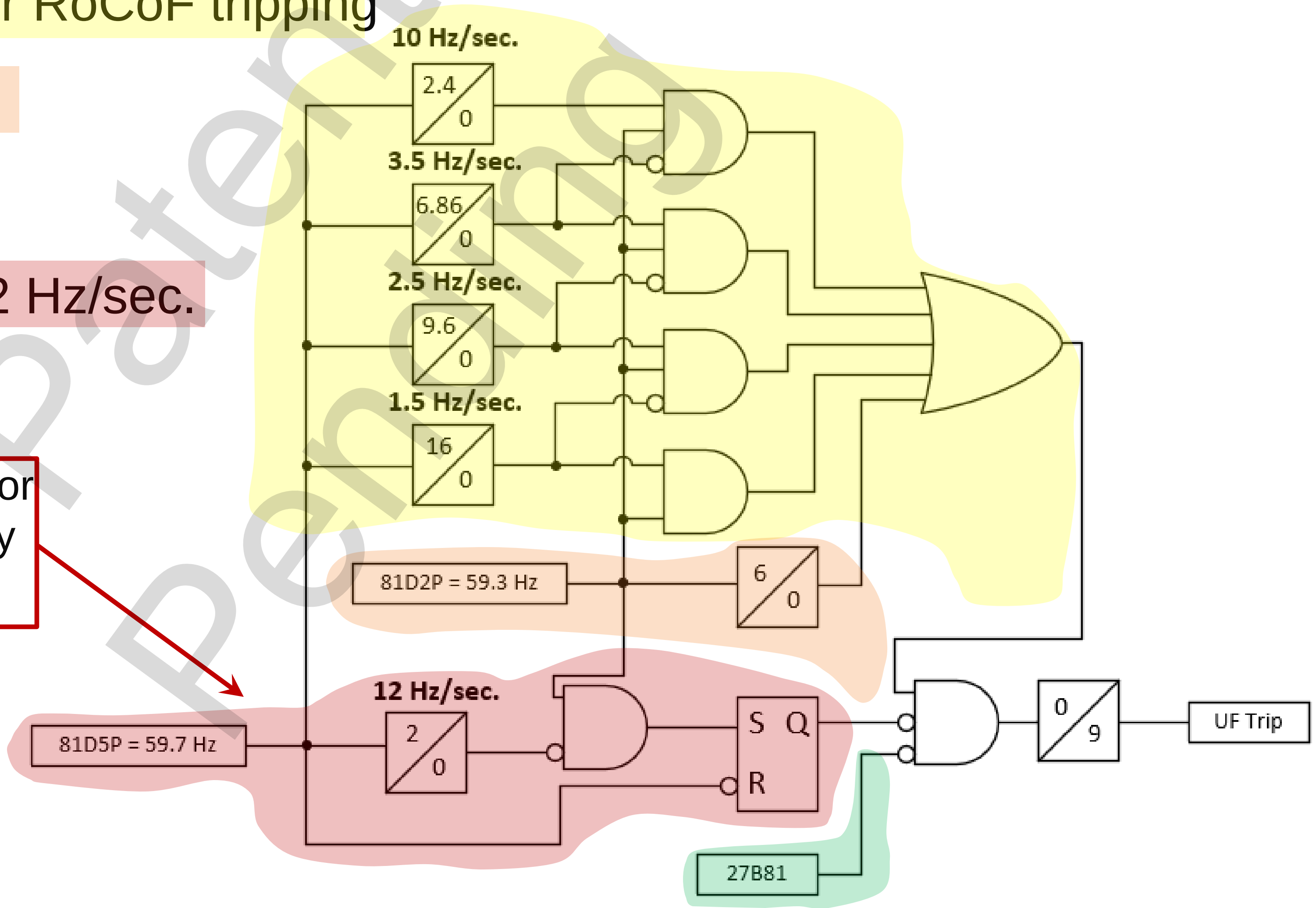
Solution #3: Implement Patent Pending RoCoF UFLS Program

- Trip ***AT*** the UF set point ***IF*** the RoCoF is greater than zero and less than 10 Hz/sec.
- NO intentional time delay for RoCoF tripping
- Maintain normal UF tripping
- Maintain UV inhibit at 67%
- Block tripping if RoCoF > 12 Hz/sec.

Block tripping for motor spin-down caused by loss of source



The Need for Faster UFLS

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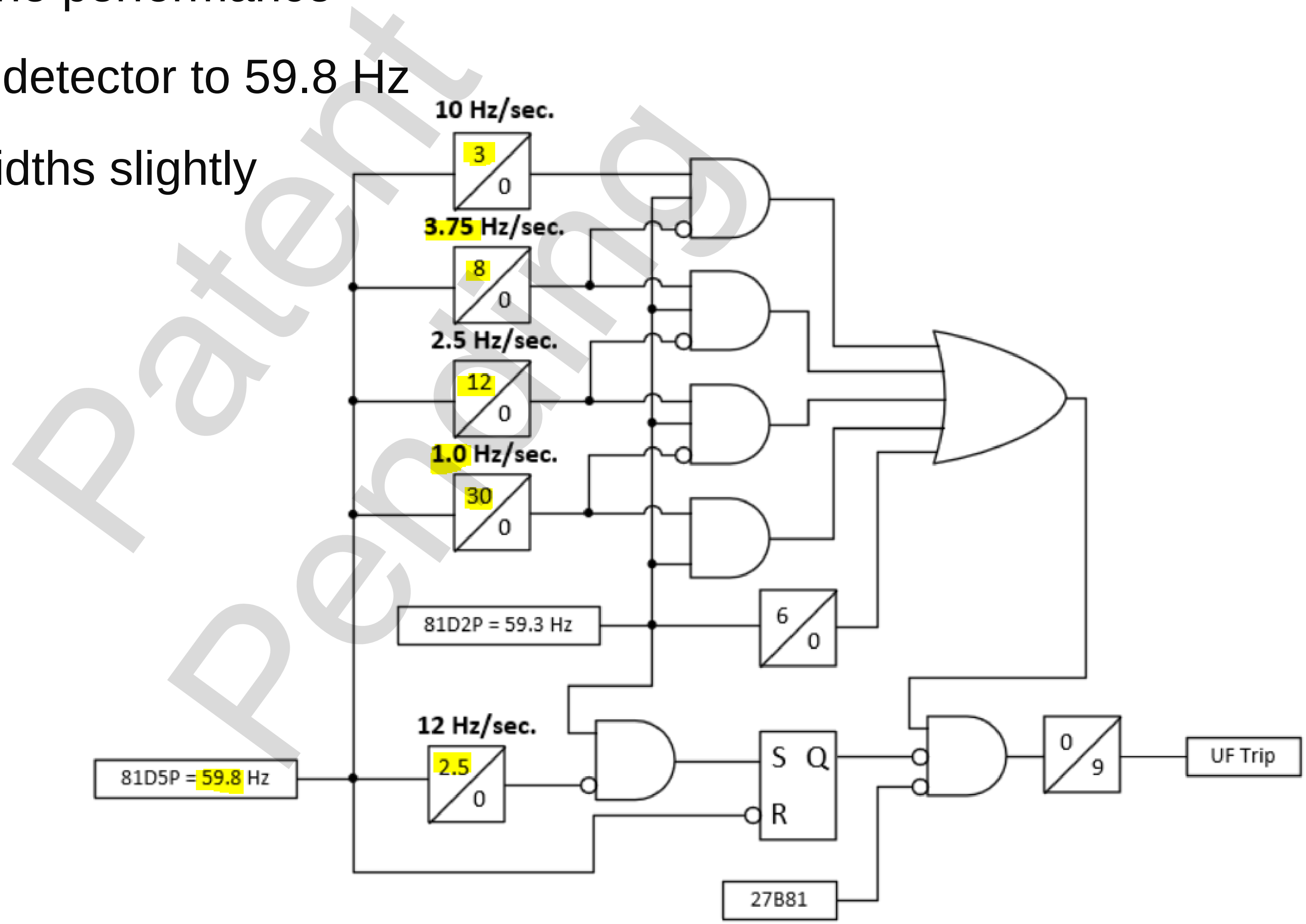
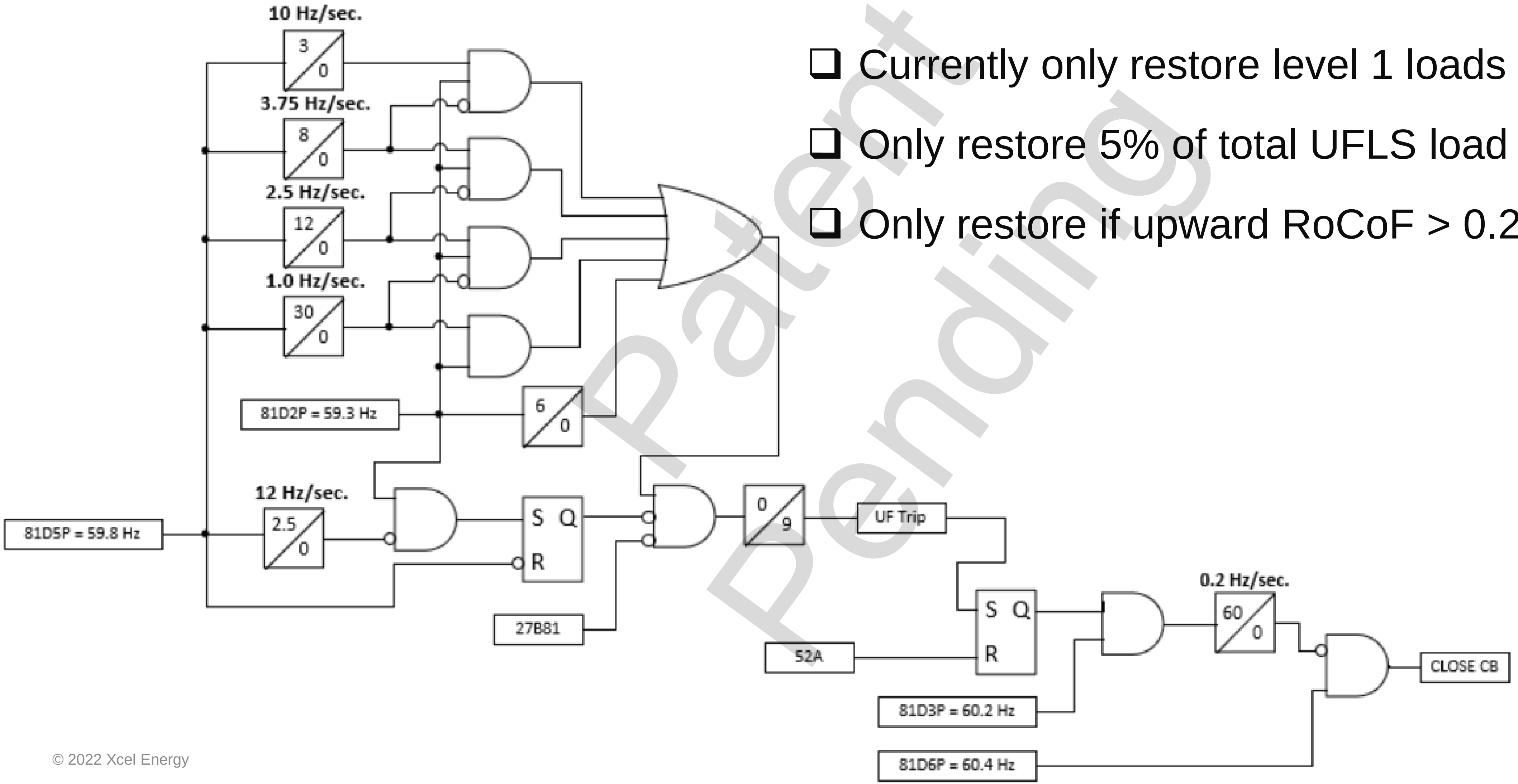
Solution #3: Implement Patent Pending RoCoF UFLS Program

- Minor "tweaks" to fine-tune performance
- Raised under frequency detector to 59.8 Hz
- Changed RoCoF bandwidths slightly



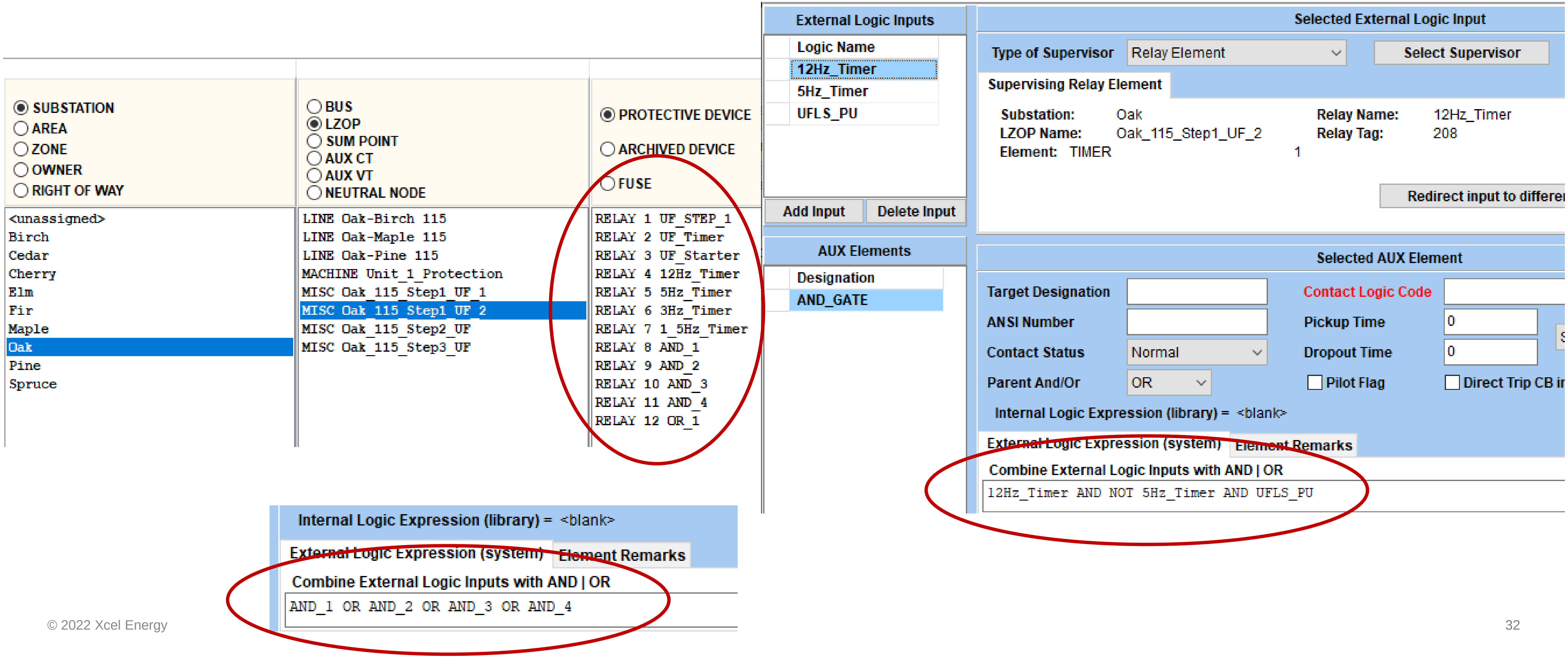
Solution #3: Implement Patent Pending RoCoF UFLS Program



- ❑ Some locations will have auto load restoration
- ❑ Currently only restore level 1 loads tripped
- ❑ Only restore 5% of total UFLS load available
- ❑ Only restore if upward RoCoF > 0.2 Hz/sec.

Solution #3: Implement Patent Pending RoCoF UFLS Program

- CAPE allows building custom logic, which was done for every logic element of this RoCoF UFLS scheme



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Solution #3: Implement Patent Pending RoCoF UFLS Program

- Trip more load in level 1, up to 25%, but minimum of 10%
- Trip 10% in level 2 and level 3

Patent Pending

				460	410	260	205						
				23.00%	20.50%	13.00%	10.25%						
				3 cyc.	8 cyc.	12 cyc.	30 cyc.						
				AND_1	AND_2	AND_3	AND_4		Load	Load Restore			
Substation	Load Label	Load (MW's)	UFLS Level	RoCoF 3.75-10 Hz?	RoCoF 2.5-3.75 Hz?	RoCoF 1.00-2.5 Hz?	RoCoF 0-1.00 Hz?	Time Delay	Restore	RoCoF		f start	f restore
Birch	1-1	50	3	Y	Y	Y	Y	6	N				
Birch	1-2	25	1	Y	Y	Y	Y	6	1	>0.15 Hz/Sec.	80 cyc	60.1	60.3
Birch	1-3	25	1	Y	Y	Y	N	12	1	>0.25 Hz/Sec.	48 cyc	60.1	60.3
Fir	12-2	75	2	N	N	N	N	6	N				
Fir	12-3	50	1	Y	N	Y	N	30	N				
Maple	2-1	75	3	N	N	N	N	20	N				
Maple	2-2	75	3	N	N	N	N	20	N				
Maple	2-3	50	2	Y	Y	N	N	30	N				
Oak	5-1	75	1	Y	Y	Y	Y	6	N				
Oak	5-2	75	2	N	N	N	N	20	N	Was 15 cyc.			
Oak	5-3	50	1	Y	N	N	N	599940	N				
Oak	5-3	50	3	N	N	N	N	10	N				
Pine	7-1	35	1	Y	Y	Y	N	599940	N				
Pine	7-1	35	3	N	N	N	N	20	N				
Pine	7-2	20	1	Y	Y	Y	N	599940	1	>0.5 Hz/Sec.	24 cyc	60.1	60.3
Pine	7-2	20	3	N	N	N	N	20	1				
Pine	7-3	30	1	Y	Y	Y	N	20	1	>0.10 Hz/Sec.	120 cyc	60.3	60.5
Pine	10-1	150	1	Y	Y	N	N	599940	N				
Pine	10-1	150	3	N	N	N	N	30	N				
TOTAL		2055											
Level 1 Total	460	MW's	23.00%	%									
Level 2 Total	200	MW's	10.00%	%									
Level 3 Total	200	MW's	10.00%	%									
Not Used Total	940	MW's	47.00%	%									

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Solution #3: Implement Patent Pending RoCoF UFLS Program

- ❑ Trip 205 MW's (10.25%) of level 1 load when RoCoF is less than 1.0 Hz/sec.

				460	410	260	205						
				23.00%	20.50%	13.00%	10.25%						
				3 cyc.	8 cyc.	12 cyc.	30 cyc.						
				AND_1	AND_2	AND_3	AND_4		Load	Load Restore			
Substation	Load Label	Load (MW's)	UFLS Level	RoCoF 3.75-10 Hz?	RoCoF 2.5-3.75 Hz?	RoCoF 1.00-2.5 Hz?	RoCoF 0-1.00 Hz?	Time Delay	Restore	RoCoF		f start	f restore
Birch	1-1	50	3	Y	Y	Y	Y	6	N				
Birch	1-2	25	1	Y	Y	Y	Y	6	1	>0.15 Hz/Sec.	80 cyc	60.1	60.3
Birch	1-3	25	1	Y	Y	Y	N	12	1	>0.25 Hz/Sec.	48 cyc	60.1	60.3
Fir	12-2	75	2	N	N	N	N	6	N				
Fir	12-3	50	1	Y	N	Y	N	30	N				
Maple	2-1	75	3	N	N	N	N	20	N				
Maple	2-2	75	3	N	N	N	N	20	N				
Maple	2-3	50	2	Y	Y	N	N	30	N				
Oak	5-1	75	1	Y	Y	Y	Y	6	N				
Oak	5-2	75	2	N	N	N	N	20	N	Was 15 cyc.			
Oak	5-3	50	1	Y	N	N	N	599940	N				
Oak	5-3	50	3	N	N	N	N	10	N				
Pine	7-1	35	1	Y	Y	Y	N	599940	N				
Pine	7-1	35	3	N	N	N	N	20	N				
Pine	7-2	20	1	Y	Y	Y	N	599940	1	>0.5 Hz/Sec.	24 cyc	60.1	60.3
Pine	7-2	20	3	N	N	N	N	20	1				
Pine	7-3	30	1	Y	Y	Y	N	20	1	>0.10 Hz/Sec.	120 cyc	60.3	60.5
Pine	10-1	150	1	Y	Y	N	N	599940	N				
Pine	10-1	150	3	N	N	N	N	30	N				
TOTAL		2055											
Level 1 Total	460	MW's	23.00%	%									
Level 2 Total	200	MW's	10.00%	%									
Level 3 Total	200	MW's	10.00%	%									
Not Used Total	940	MW's	47.00%	%									

Patent Pending

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Solution #3: Implement Patent Pending RoCoF UFLS Program

- ❑ Trip 260 MW's (13.00%) of level 1 load when RoCoF is between 1.0 Hz/sec. and 2.5 Hz/sec.

				460	410	260	205						
				23.00%	20.50%	13.00%	10.25%						
				3 cyc.	8 cyc.	12 cyc.	30 cyc.						
				AND_1	AND_2	AND_3	AND_4		Load	Load Restore			
Substation	Load Label	Load (MW's)	UFLS Level	RoCoF 3.75-10 Hz?	RoCoF 2.5-3.75 Hz?	RoCoF 1.00-2.5 Hz?	RoCoF 0-1.00 Hz?	Time Delay	Restore	RoCoF		f start	f restore
Birch	1-1	50	3	Y	Y	Y	Y	6	N				
Birch	1-2	25	1	Y	Y	Y	Y	6	1	>0.15 Hz/Sec.	80 cyc	60.1	60.3
Birch	1-3	25	1	Y	Y	Y	N	12	1	>0.25 Hz/Sec.	48 cyc	60.1	60.3
Fir	12-2	75	2	N	N	N	N	6	N				
Fir	12-3	50	1	Y	N	Y	N	30	N				
Maple	2-1	75	3	N	N	N	N	20	N				
Maple	2-2	75	3	N	N	N	N	20	N				
Maple	2-3	50	2	Y	Y	N	N	30	N				
Oak	5-1	75	1	Y	Y	Y	Y	6	N				
Oak	5-2	75	2	N	N	N	N	20	N	Was 15 cyc.			
Oak	5-3	50	1	Y	N	N	N	599940	N				
Oak	5-3	50	3	N	N	N	N	10	N				
Pine	7-1	35	1	Y	Y	Y	N	599940	N				
Pine	7-1	35	3	N	N	N	N	20	N				
Pine	7-2	20	1	Y	Y	Y	N	599940	1	>0.5 Hz/Sec.	24 cyc	60.1	60.3
Pine	7-2	20	3	N	N	N	N	20	1				
Pine	7-3	30	1	Y	Y	Y	N	20	1	>0.10 Hz/Sec.	120 cyc	60.3	60.5
Pine	10-1	150	1	Y	Y	N	N	599940	N				
Pine	10-1	150	3	N	N	N	N	30	N				
TOTAL		2055											
Level 1 Total	460	MW's	23.00%	%									
Level 2 Total	200	MW's	10.00%	%									
Level 3 Total	200	MW's	10.00%	%									
Not Used Total	940	MW's	47.00%	%									

Patent Pending

Solution #3: Implement Patent Pending RoCoF UFLS Program

- ❑ Trip 410 MW's (20.50%) of level 1 load when RoCoF is between 2.5 Hz/sec. and 3.75 Hz/sec.

				460	410	260	205						
				23.00%	20.50%	13.00%	10.25%						
				3 cyc.	8 cyc.	12 cyc.	30 cyc.						
				AND_1	AND_2	AND_3	AND_4		Load	Load Restore			
Substation	Load Label	Load (MW's)	UFLS Level	RoCoF 3.75-10 Hz?	RoCoF 2.5-3.75 Hz?	RoCoF 1.00-2.5 Hz?	RoCoF 0-1.00 Hz?	Time Delay	Restore	RoCoF		f start	f restore
Birch	1-1	50	3	Y	Y	Y	Y	6	N				
Birch	1-2	25	1	Y	Y	Y	Y	6	1	> 0.15 Hz/Sec.	80 cyc	60.1	60.3
Birch	1-3	25	1	Y	Y	Y	N	12	1	> 0.25 Hz/Sec.	48 cyc	60.1	60.3
Fir	12-2	75	2	N	N	N	N	6	N				
Fir	12-3	50	1	Y	N	Y	N	30	N				
Maple	2-1	75	3	N	N	N	N	20	N				
Maple	2-2	75	3	N	N	N	N	20	N				
Maple	2-3	50	2	Y	Y	N	N	30	N				
Oak	5-1	75	1	Y	Y	Y	Y	6	N				
Oak	5-2	75	2	N	N	N	N	20	N	Was 15 cyc.			
Oak	5-3	50	1	Y	N	N	N	599940	N				
Oak	5-3	50	3	N	N	N	N	10	N				
Pine	7-1	35	1	Y	Y	Y	N	599940	N				
Pine	7-1	35	3	N	N	N	N	20	N				
Pine	7-2	20	1	Y	Y	Y	N	599940	1	> 0.5 Hz/Sec.	24 cyc	60.1	60.3
Pine	7-2	20	3	N	N	N	N	20	1				
Pine	7-3	30	1	Y	Y	Y	N	20	1	> 0.10 Hz/Sec.	120 cyc	60.3	60.5
Pine	10-1	150	1	Y	Y	N	N	599940	N				
Pine	10-1	150	3	N	N	N	N	30	N				
TOTAL		2055											
Level 1 Total	460	MW's	23.00%	%									
Level 2 Total	200	MW's	10.00%	%									
Level 3 Total	200	MW's	10.00%	%									
Not Used Total	940	MW's	47.00%	%									

Patent Pending

Solution #3: Implement Patent Pending RoCoF UFLS Program

- ❑ Trip 460 MW's (23.00%) of level 1 load when RoCoF is between 3.75 Hz/sec. and 10 Hz/sec.

				460	410	260	205						
				23.00%	20.50%	13.00%	10.25%						
				3 cyc.	8 cyc.	12 cyc.	30 cyc.						
				AND_1	AND_2	AND_3	AND_4		Load	Load Restore			
Substation	Load Label	Load (MW's)	UFLS Level	RoCoF 3.75-10 Hz?	RoCoF 2.5-3.75 Hz?	RoCoF 1.00-2.5 Hz?	RoCoF 0-1.00 Hz?	Time Delay	Restore	RoCoF		f start	f restore
Birch	1-1	50	3	Y	Y	Y	Y	6	N				
Birch	1-2	25	1	Y	Y	Y	Y	6	1	> 0.15 Hz/Sec.	80 cyc	60.1	60.3
Birch	1-3	25	1	Y	Y	Y	N	12	1	> 0.25 Hz/Sec.	48 cyc	60.1	60.3
Fir	12-2	75	2	N	N	N	N	6	N				
Fir	12-3	50	1	Y	N	Y	N	30	N				
Maple	2-1	75	3	N	N	N	N	20	N				
Maple	2-2	75	3	N	N	N	N	20	N				
Maple	2-3	50	2	Y	Y	N	N	30	N				
Oak	5-1	75	1	Y	Y	Y	Y	6	N				
Oak	5-2	75	2	N	N	N	N	20	N	Was 15 cyc.			
Oak	5-3	50	1	Y	N	N	N	599940	N				
Oak	5-3	50	3	N	N	N	N	10	N				
Pine	7-1	35	1	Y	Y	Y	N	599940	N				
Pine	7-1	35	3	N	N	N	N	20	N				
Pine	7-2	20	1	Y	Y	Y	N	599940	1	> 0.5 Hz/Sec.	24 cyc	60.1	60.3
Pine	7-2	20	3	N	N	N	N	20	1				
Pine	7-3	30	1	Y	Y	Y	N	20	1	> 0.10 Hz/Sec.	120 cyc	60.3	60.5
Pine	10-1	150	1	Y	Y	N	N	599940	N				
Pine	10-1	150	3	N	N	N	N	30	N				
TOTAL		2055											
Level 1 Total	460	MW's	23.00%	%									
Level 2 Total	200	MW's	10.00%	%									
Level 3 Total	200	MW's	10.00%	%									
Not Used Total	940	MW's	47.00%	%									

Patent Pending

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Solution #3: Implement Patent Pending RoCoF UFLS Program

- ❑ Trip up to 255 MW's of level 1 RoCoF only at level 3 with time delay
- ❑ Allows extra load shed at level 3 (22.75%) for high inertia, low RoCoF situations

				460	410	260	205						
				23.00%	20.50%	13.00%	10.25%						
				3 cyc.	8 cyc.	12 cyc.	30 cyc.						
				AND_1	AND_2	AND_3	AND_4		Load	Load Restore			
Substation	Load Label	Load (MW's)	UFLS Level	RoCoF 3.75-10 Hz?	RoCoF 2.5-3.75 Hz?	RoCoF 1.00-2.5 Hz?	RoCoF 0-1.00 Hz?	Time Delay	Restore	RoCoF		f start	f restore
Birch	1-1	50	3	Y	Y	Y	Y	6	N				
Birch	1-2	25	1	Y	Y	Y	Y	6	1	>0.15 Hz/Sec.	80 cyc	60.1	60.3
Birch	1-3	25	1	Y	Y	Y	N	12	1	>0.25 Hz/Sec.	48 cyc	60.1	60.3
Fir	12-2	75	2	N	N	N	N	6	N				
Fir	12-3	50	1	Y	N	Y	N	30	N				
Maple	2-1	75	3	N	N	N	N	20	N				
Maple	2-2	75	3	N	N	N	N	20	N				
Maple	2-3	50	2	Y	Y	N	N	30	N				
Oak	5-1	75	1	Y	Y	Y	Y	6	N				
Oak	5-2	75	2	N	N	N	N	20	N	Was 15 cyc.			
Oak	5-3	50	1	Y	N	N	N	599940	N				
Oak	5-3	50	3	N	N	N	N	10	N				
Pine	7-1	35	1	Y	Y	Y	N	599940	N				
Pine	7-1	35	3	N	N	N	N	20	N				
Pine	7-2	20	1	Y	Y	Y	N	599940	1	>0.5 Hz/Sec.	24 cyc	60.1	60.3
Pine	7-2	20	3	N	N	N	N	20	1				
Pine	7-3	30	1	Y	Y	Y	N	20	1	>0.10 Hz/Sec.	120 cyc	60.3	60.5
Pine	10-1	150	1	Y	Y	N	N	599940	N				
Pine	10-1	150	3	N	N	N	N	30	N				
TOTAL		2055											
Level 1 Total	460	MW's	23.00%	%									
Level 2 Total	200	MW's	10.00%	%									
Level 3 Total	200	MW's	10.00%	%									
Not Used Total	940	MW's	47.00%	%									

Patent Pending

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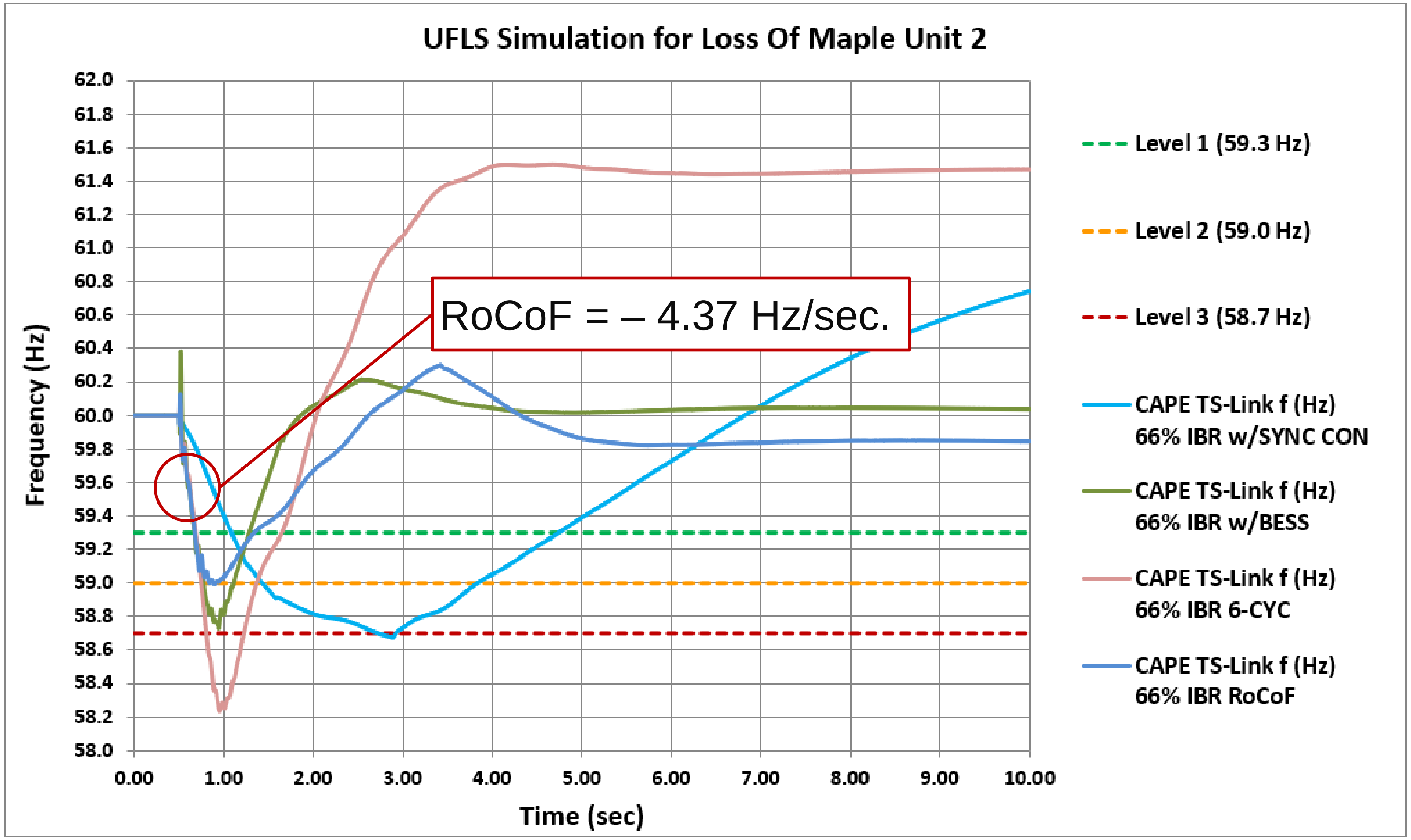
Solution #3: Implement Patent Pending RoCoF UFLS Program

- ❑ CAPE TS-Link example for trip of 490 MW Maple Unit 2
- ❑ ONLY level 1 UFLS operates tripping 460 MW of load



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Solution #3: Implement Patent Pending RoCoF UFLS Program

- NONE of the cases studied would result in potential uncontrolled generator tripping due to over/under frequency per NERC PRC-024 Standard
- ALL final frequencies were within +/- 0.3 Hz of nominal

Eastern Interconnection

High Frequency Duration	
Frequency (Hz)	**Time (Sec)**
≥61.8	Instantaneous trip
≥60.5	$10^{(90.935-1.45713*f)}$
<60.5	Continuous operation

Low Frequency Duration	
Frequency (Hz)	**Time (sec)**
≤57.8	Instantaneous trip
≤59.5	$10^{(1.7373*f-100.116)}$
> 59.5	Continuous operation

		RoCoF UFLS				
Generation Tripped (MW's)	RoCoF (Hz/Sec.)	Total Load Shed (MW's) *	Excess Amount of Load Shed (MW's)	Frequency Nadir (Hz)	Overshoot Freq. (Hz)	Final Freq. (Hz)
95	-0.54	100	5	59.27	60.16	60.06
140	-1.02	160	20	59.23	60.53	60.17
190	-1.25	190	0	59.22	60.31	59.99
235	-1.73	235	0	59.18	60.30	59.97
330	-2.60	310	-20	59.03	60.51	59.88
375	-2.33	390	15	58.91	60.37	60.12
435	-3.47	410	-25	58.96	60.32	59.83
490	-4.37	460	-30	59.00	60.30	59.84
540	-4.82	505	-35	58.85	60.31	59.90
600	-3.72	610	10	58.69	60.31	60.00
640	-5.72	630	-10	58.67	60.34	60.16
700	-4.26	760	60	58.58	60.62	60.30
750	-4.51	790	40	58.44	60.45	60.19
		TOTAL	**-60**			
		Ave. Difference	**16.00**			

* Includes Auto Load Restoration

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Solution #3: Implement Patent Pending RoCoF UFLS Program

- ALL RoCoF UFLS Test System Study Results:

00% Existing UFLS vs. RoCoF UFLS

First 10 Case Study Stats	00% IBR Case 6-Cyc. Delay	66% IBR w/RoCoF Case
Total Load Shed (MW's)	3400	3160 ✓
HIGH RoCoF (Hz/sec.)	1.08	1.08
AVE. RoCoF (Hz/sec.)	0.63	0.63
LOW RoCoF (Hz/sec.)	0.16	0.16
AVE Freq. Nadir (Hz)	59.03 ✓	59.00
AVE Freq. Overshoot (Hz)	60.16	60.02 ✓
AVE Final Freq. (Hz)	60.07	59.95 ✓

25% Existing UFLS vs. RoCoF UFLS

First 10 Case Study Stats	25% IBR Case 6-Cyc. Delay	66% IBR w/RoCoF Case
Total Load Shed (MW's)	3800	3490 ✓
HIGH RoCoF (Hz/sec.)	1.75	1.75
AVE. RoCoF (Hz/sec.)	1.01	1.01
LOW RoCoF (Hz/sec.)	0.19	0.19
AVE Freq. Nadir (Hz)	58.97	58.97
AVE Freq. Overshoot (Hz)	60.47	60.15 ✓
AVE Final Freq. (Hz)	60.38	60.09 ✓

50% Existing UFLS vs. RoCoF UFLS

First 10 Case Study Stats	50% IBR Case 6-Cyc. Delay	66% IBR w/RoCoF Case
Total Load Shed (MW's)	3800	3540 ✓
HIGH RoCoF (Hz/sec.)	2.91	2.91
AVE. RoCoF (Hz/sec.)	1.64	1.64
LOW RoCoF (Hz/sec.)	0.32	0.32
AVE Freq. Nadir (Hz)	58.90	58.98 ✓
AVE Freq. Overshoot (Hz)	60.53	60.25 ✓
AVE Final Freq. (Hz)	60.38	60.10 ✓

66% Existing UFLS vs. RoCoF UFLS

First 10 Case Study Stats	66% IBR Case 6-Cyc. Delay	66% IBR w/RoCoF Case
Total Load Shed (MW's)	4200	3370 ✓
HIGH RoCoF (Hz/sec.)	5.72	5.72
AVE. RoCoF (Hz/sec.)	3.10	3.10
LOW RoCoF (Hz/sec.)	0.54	0.54
AVE Freq. Nadir (Hz)	58.71	59.03 ✓
AVE Freq. Overshoot (Hz)	61.33	60.34 ✓
AVE Final Freq. (Hz)	60.79	59.98 ✓

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Solution #3: Implement Patent Pending RoCoF UFLS Program

- ❑ RoCoF UFLS vs. Synchronous Condenser and BESS:

First 10 Case Study Stats	66% IBR w/SYNC CON Case	66% IBR w/BESS Case	66% IBR w/RoCoF Case
Total Load Shed (MW's)	3800	2000 ✓	3370
HIGH RoCoF (Hz/sec.)	1.33 ✓	4.42	5.72
AVE. RoCoF (Hz/sec.)	0.79 ✓	2.38	3.10
LOW RoCoF (Hz/sec.)	0.17 ✓	0.57	0.54
AVE Freq. Nadir (Hz)	58.98	59.10 ✓	59.03
AVE Freq. Overshoot (Hz)	60.43	60.11 ✓	60.34
AVE Final Freq. (Hz)	60.35	59.98 ✓	59.98 ✓

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Solution #3: Implement RoCoF UFLS Program Conclusions

- **RoCoF UFLS program works well for inertia reductions up to 80%, resulting in final frequencies within +/- 0.5 Hz of nominal.**
- **RoCoF UFLS program is easy/cost effective to implement.**
- **RoCoF UFLS program can be implemented at a fraction of the cost of synchronous condensers or BESS.**

$$Xcel\ Energy\ NM/TX\ RoCoF\ Cost = \sim 135\ Relays \cdot \$150k\ (per\ Relay) = \$20.25\ million$$

$$Xcel\ Energy\ NM/TX\ SYNC\ CON\ Cost = 10\ \text{units} \cdot 1.5 \cdot \$25\ million\ (per\ 100\ MVAR) \cdot 3 = \$1{,}125\ million$$

$$Xcel\ Energy\ NM/TX\ BESS\ Cost = 2\ Units(100\ MW's) \cdot \$115\ million \cdot 3 = \$690\ million$$

Next Steps to Implement New Program

- ❑ Continue testing various IBR penetration levels on actual Xcel Energy New Mexico-Texas region (2025)
- ❑ Develop relay settings and test using COMTRADE file play-back in test lab
- ❑ Perform studies on actual system to determine optimum amount of BESS to provide inertial fast frequency response working in conjunction with RoCoF UFLS program to reduce amount of load shed when compared to existing UFLS program
- ❑ Write paper about RoCoF UFLS program with three co-authors and present at conferences
- ❑ Convince Xcel Energy Protection and Planning Departments that this is a necessary program to implement
- ❑ Convince Southwest Power Pool that this solution fits their PRC-006 mold and is worthy of implementation at SPS
- ❑ Implement program in the SPS region

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Conclusions

- ❑ Underfrequency load shed programs across the industry are outdated and need to be modernized to operate successfully with systems that have high IBR penetrations and low system inertia that leads to high RoCoF
- ❑ If UFLS programs are left as-is, blackouts will become more common
- ❑ Implementing this new RoCoF UFLS scheme will better guarantee adequate load shed and blackout avoidance
- ❑ Implementing this new RoCoF UFLS scheme can potentially save millions of dollars in avoided costs of investment in synchronous condensers to replace depleted inertia and BESS to provide MW injection during UF events

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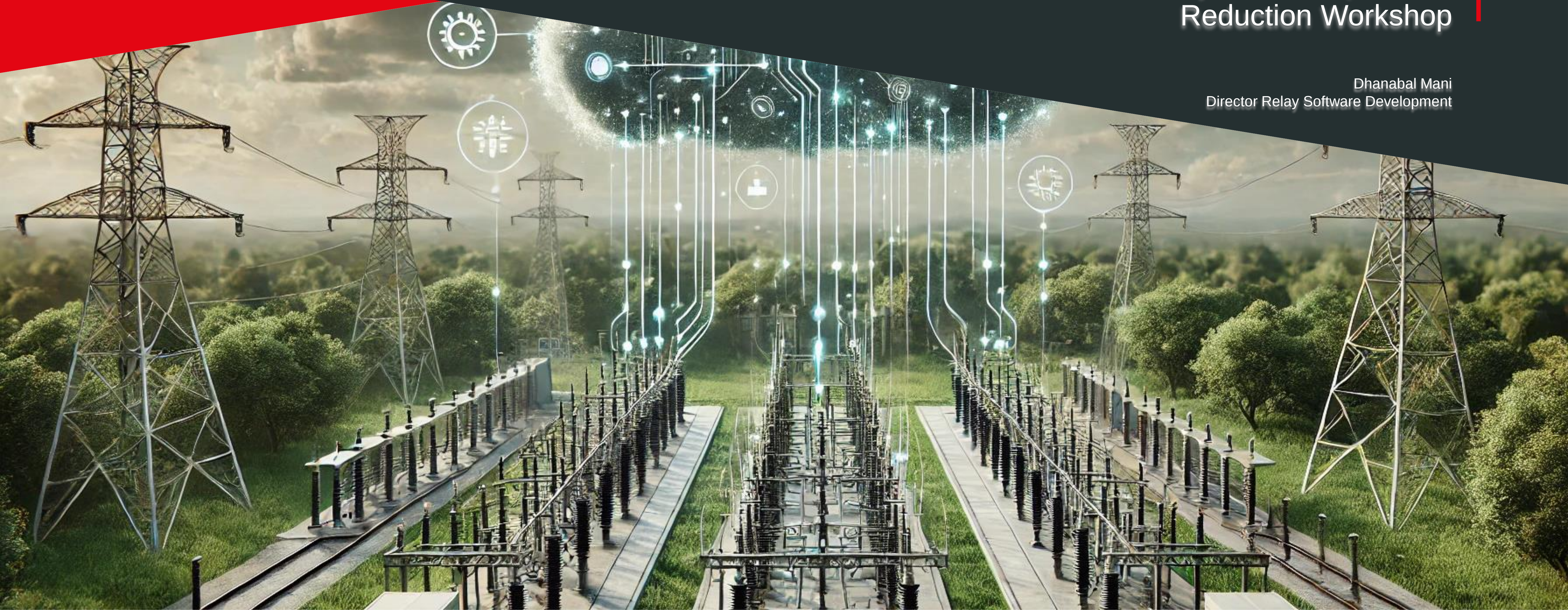
Megger®

Cloud-Based End-to-End Testing

BES Protection System Misoperation Reduction Workshop

Dhanabal Mani
Director Relay Software Development

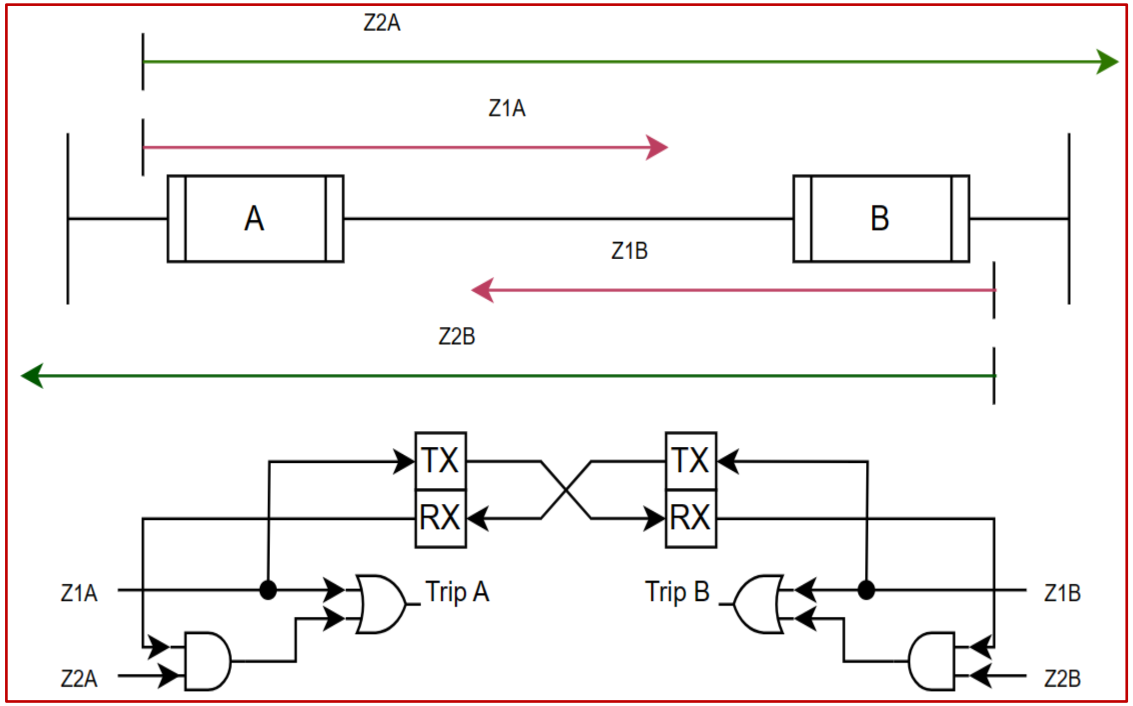


Agenda

- Pilot Schemes
- Line Differential Schemes
- End-to-End Testing Concepts
- Cloud-Based End-to-End Technology and Testing
  - Why, How and What
- Test Scenarios and Results
  - Traditional and Cloud-Based End-to-End
- Summary
- Conclusion

Pilot Schemes - PUTT

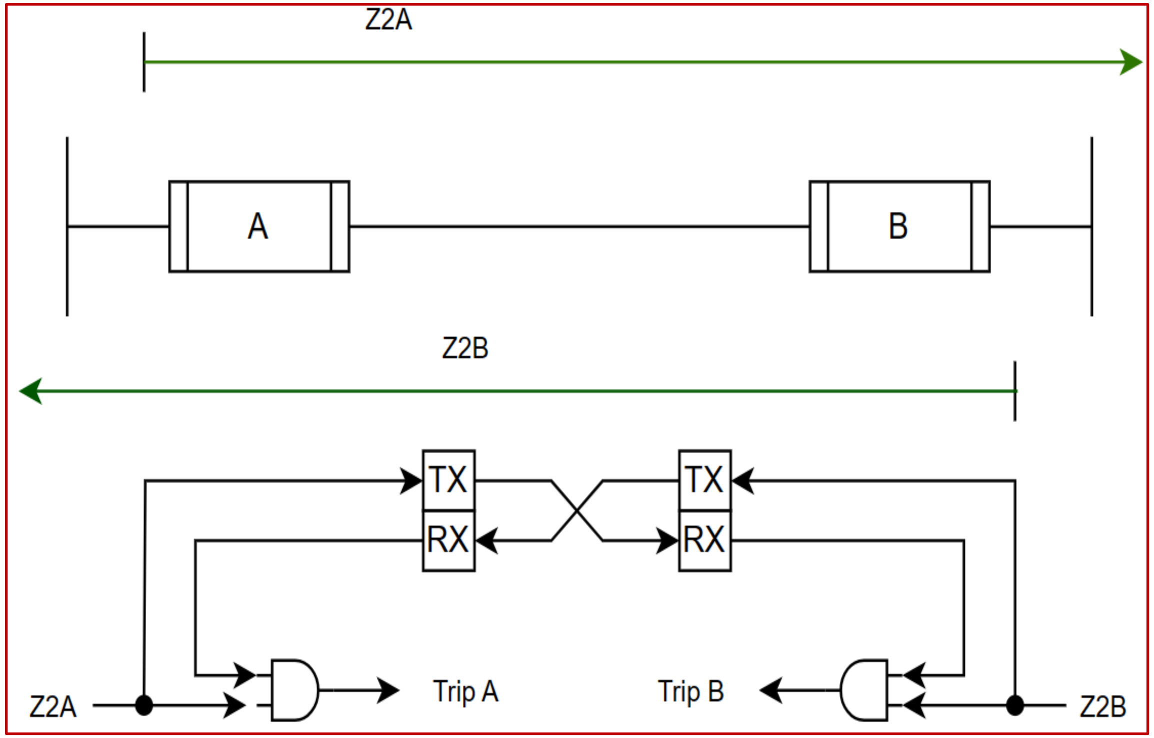
- PUTT schemes use both underreaching (Z1A and Z1B) and overreaching (Z2A and Z2B) elements.
- Each terminal will trip directly for its underreaching element. Accelerate tripping at the remote end by sending a permissive trip signal for faults detected in Zone 1.
- Suitable for shorter transmission lines, focusing on faults near the relay terminals.



Permissive Under-Reach Transfer Trip

Pilot Schemes - POTT

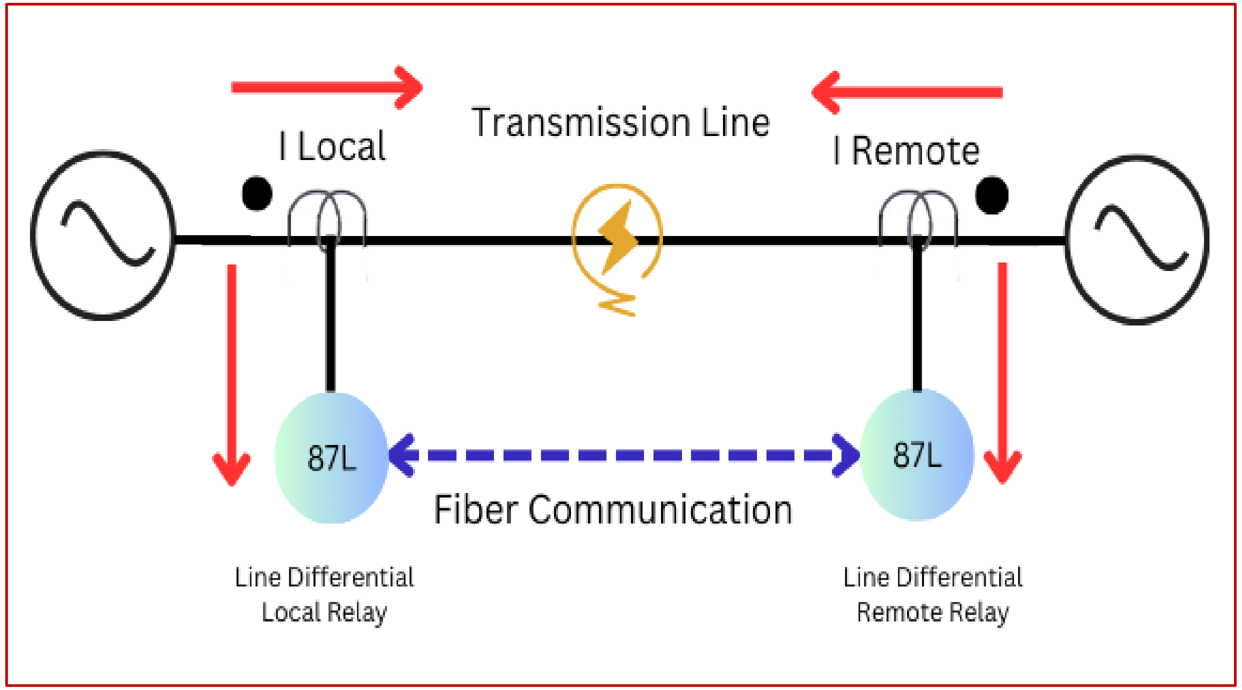
- POTT uses overreaching (Zone 2) elements to detect faults.
- Sends a permissive trip signal from the local to the remote relay when a fault is detected.
- Allows fast tripping for faults in the overreaching zone by communicating with the relay at the other end.
- Ideal for longer transmission lines, where overreaching protection is required to cover a larger area.



Permissive Over-Reach Transfer Trip

Line Differential Schemes

- Line differential protection is based on Kirchhoff's Current Law (KCL), which compares the current entering and leaving of a transmission line.
- Line Differential Relays (LDR) at both ends of the line communicate in real-time to detect and isolate faults.
- The system detects in-zone faults and isolates them quickly to ensure stable power transmission.

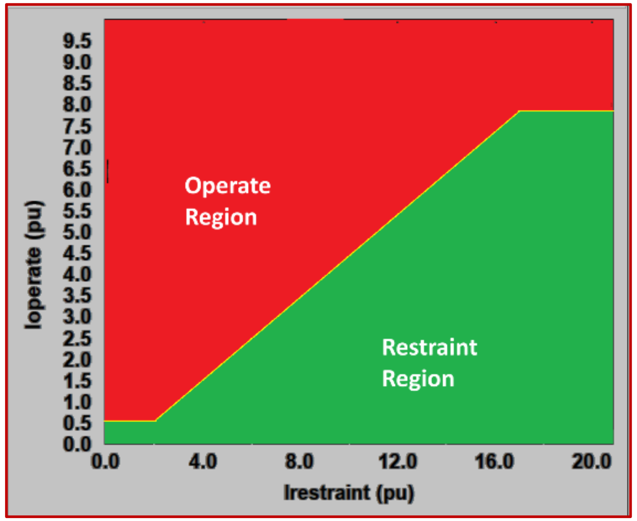


Line Differential Protection

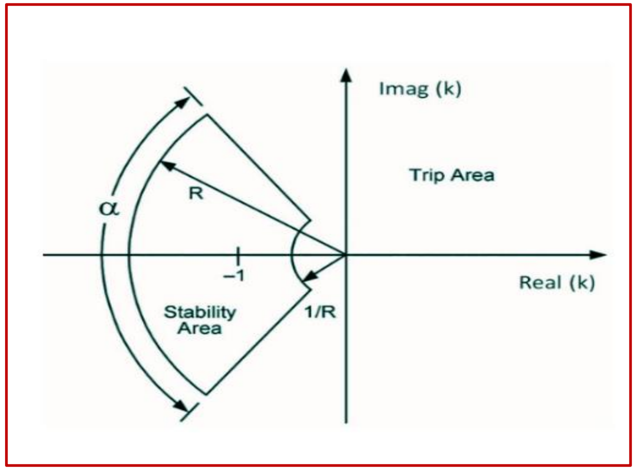
Line Differential Schemes

Types of Line Differential Protection:

- Percent Differential Protection.
  - Uses a differential current (Idiff) and a restraining signal (Ibias) to determine if a fault exists.
  - The protection operates when Idiff exceeds a defined threshold relative to Ibias.
  - Ideal for providing security against false trips caused by CT saturation.
- Alpha Plane Differential Protection
  - Graphically represents phase current ratios on a complex plane
  - Allows for more flexible and adaptable fault detection based on the relationship between phase currents.
  - Defines operational zones with parameters like radii and sweep angles to determine stability and trip regions.



Differential Slope Characteristics



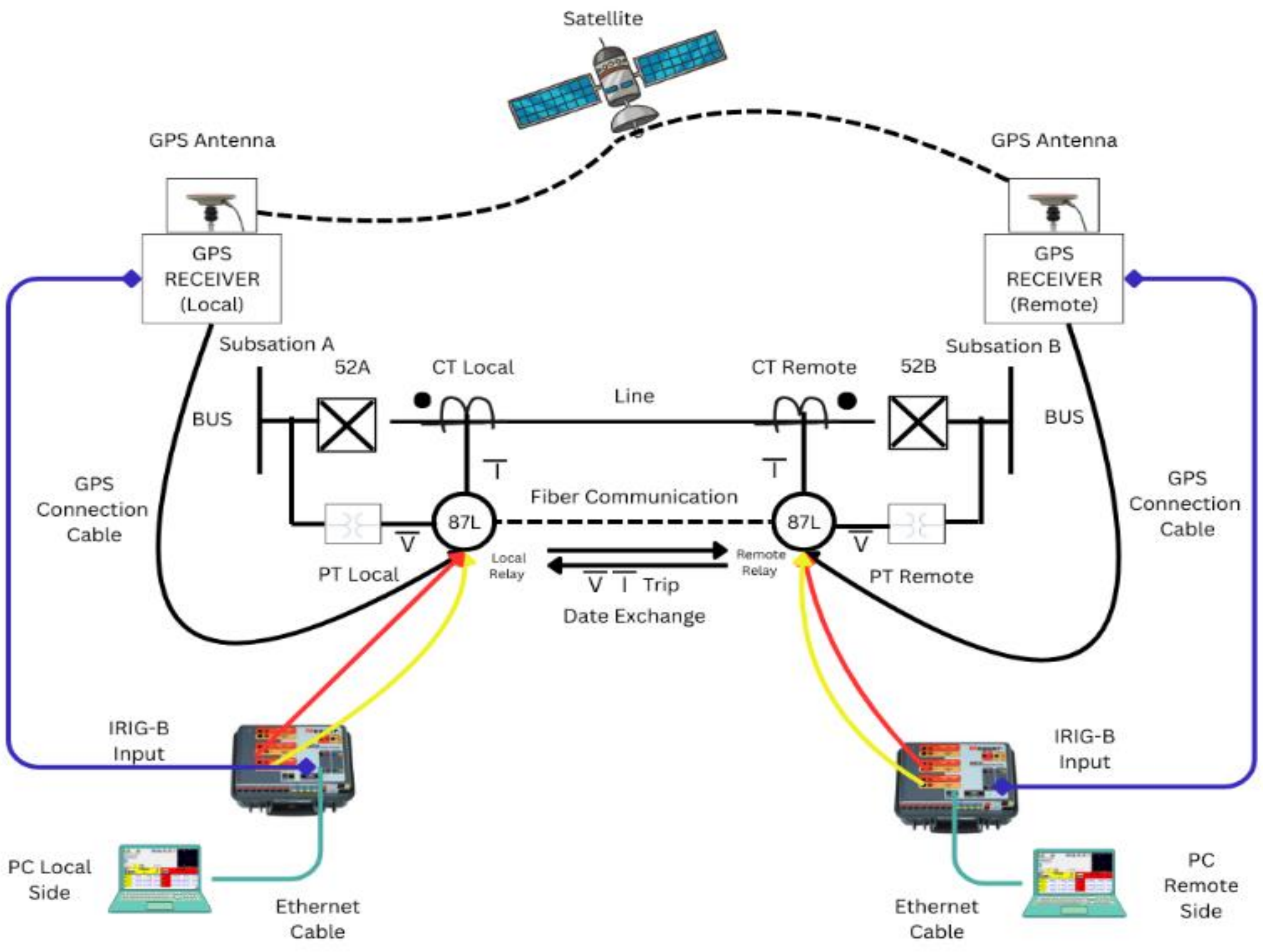
Alpha Plane Characteristics

https://selinc.com/api/download/3192

Megger

End-To-End Testing Concepts

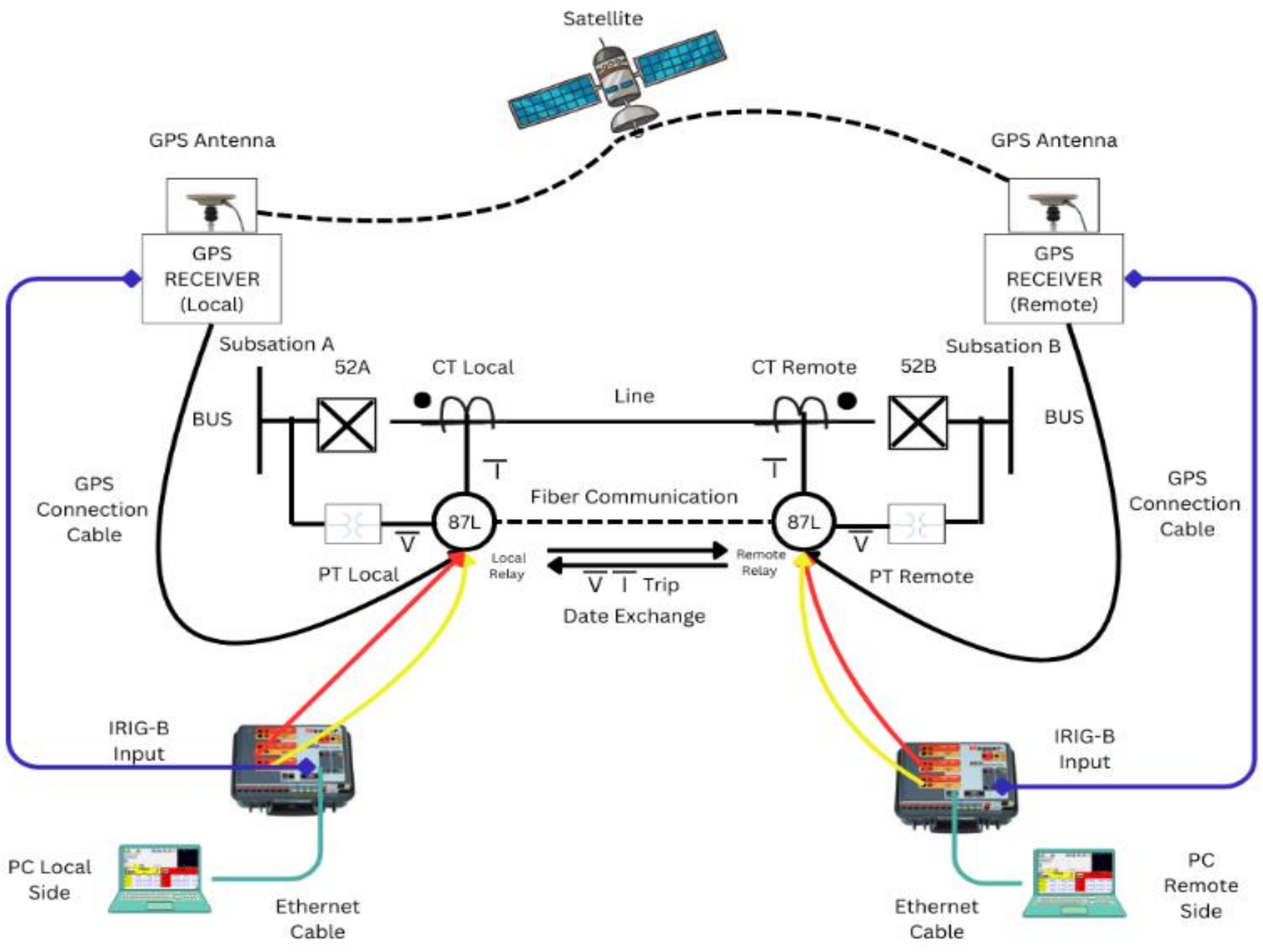
- Traditional testing relies heavily on GPS-based synchronization (IRIG-B signals) to ensure accurate fault simulation and timing coordination between local and remote ends.
- Two test sets are required: one at each end of the power line or transmission line, necessitating coordination between two operators. This makes the process complex and resource-intensive.
- Faults are injected at both ends of the line with pre-fault, fault, and post-fault states.



Traditional End-to-End Testing Setup

End-To-End Testing Concepts

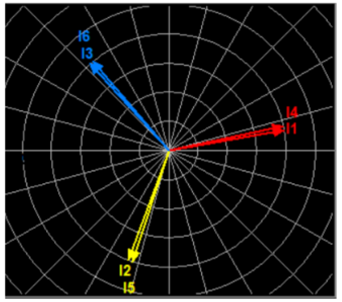
- Traditional end-to-end testing is typically static, focusing on one point at a time, which limits the ability to test dynamic behavior or complex protection schemes.
- Requires fiber-optic communication links between protective relays and test sets for fast signal transmission.
- Fault conditions are simulated to verify relay response and ensure system reliability.

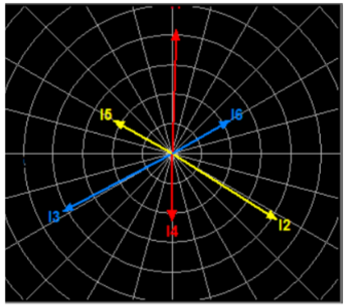


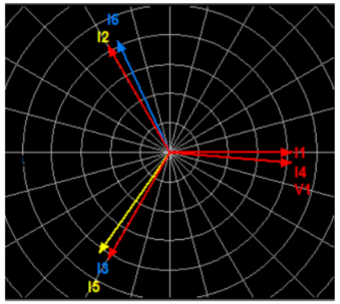
Traditional End-to-End Testing Setup

End-To-End Testing Concepts

Line Protection Relays End-End Testing: Steady State Method







Pre-Fault → **Fault** → **Post-Fault**

Local

Test Set A

Pre-Fault:

	CURRENT I (A)	φ (°)	f (Hz)		VOLTAGE V (V)	φ (°)	f (Hz)
I1	0.800	-10.00	50.000	V1	66.40	0.00	50.000
I2	0.800	110.00	50.000	V2	66.40	240.00	50.000
I3	0.800	230.00	50.000	V3	66.40	120.00	50.000

Fault:

	CURRENT I (A)	φ (°)	f (Hz)		VOLTAGE V (V)	φ (°)	f (Hz)
I1	7.400	-88.00	50.000	V1	44.00	0.00	50.000
I2	7.400	32.00	50.000	V2	44.00	240.00	50.000
I3	7.400	152.00	50.000	V3	44.00	120.00	50.000

Post-Fault:

	CURRENT I (A)	φ (°)	f (Hz)		VOLTAGE V (V)	φ (°)	f (Hz)
I1	1.000	0.00	50.000	V1	66.40	0.00	50.000
I2	1.000	240.00	50.000	V2	66.40	240.00	50.000
I3	1.000	120.00	50.000	V3	66.40	120.00	50.000

Remote

Test Set B

Pre-Fault:

	CURRENT I (A)	φ (°)	f (Hz)		VOLTAGE V (V)	φ (°)	f (Hz)
I1	0.800	-12.00	50.000	V1	66.40	0.00	50.000
I2	0.800	108.00	50.000	V2	66.40	240.00	50.000
I3	0.800	228.00	50.000	V3	66.40	120.00	50.000

Fault:

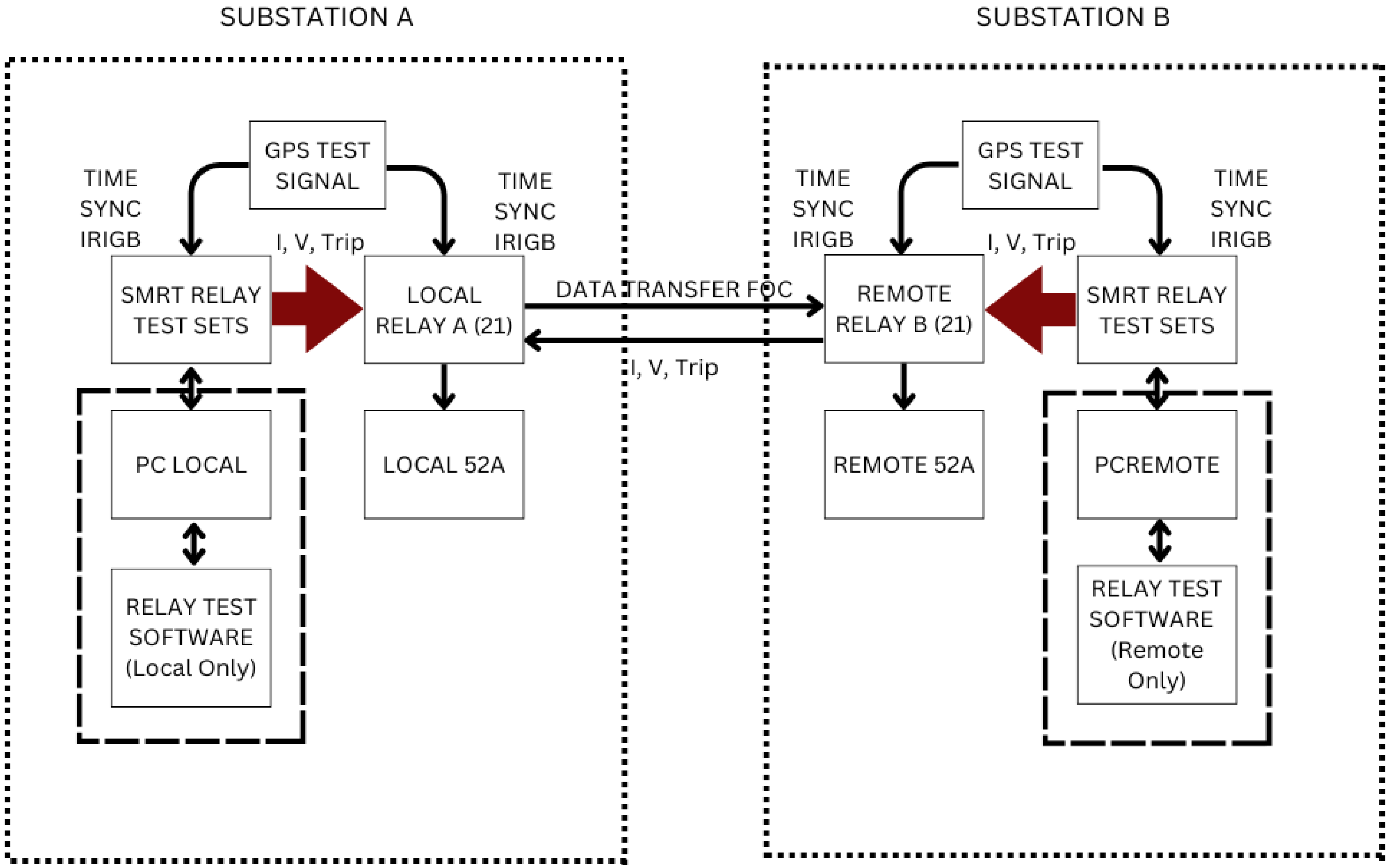
	CURRENT I (A)	φ (°)	f (Hz)		VOLTAGE V (V)	φ (°)	f (Hz)
I1	4.000	90.00	50.000	V1	46.00	0.00	50.000
I2	4.000	210.00	50.000	V2	46.00	240.00	50.000
I3	4.000	330.00	50.000	V3	46.00	120.00	50.000

Post-Fault:

	CURRENT I (A)	φ (°)	f (Hz)		VOLTAGE V (V)	φ (°)	f (Hz)
I1	1.000	5.00	50.000	V1	66.40	0.00	50.000
I2	1.000	125.00	50.000	V2	66.40	240.00	50.000
I3	1.000	245.00	50.000	V3	66.40	120.00	50.000

Cloud-Based End-to-End Technology and Testing – Why?

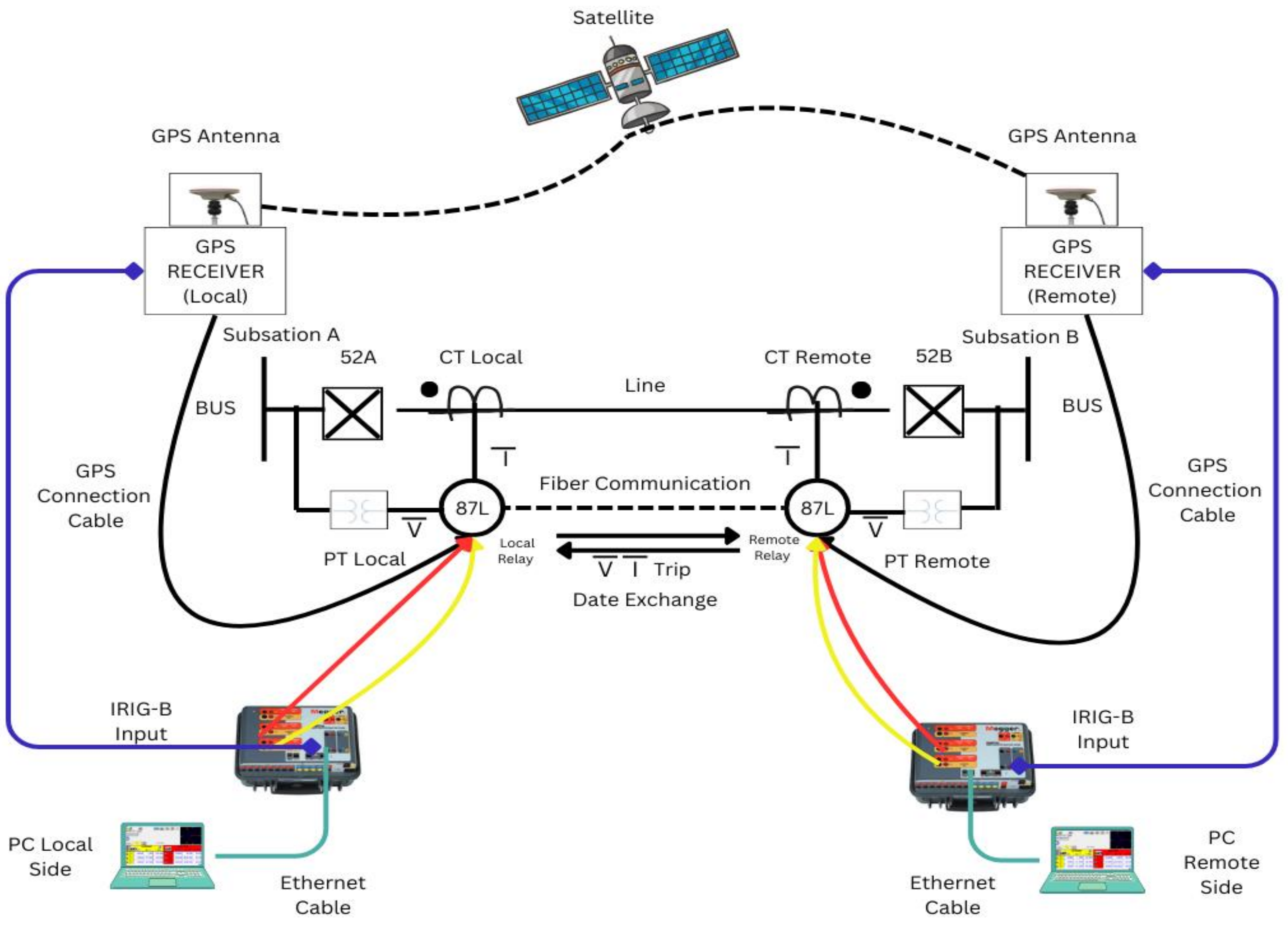
Line Protection Environment Service Condition: Steady State Testing



- Local and Remote 87L Relay trips in up normal fault conditions.
- Data handshake between Local and Remote Relays via FOC.

Cloud-Based End-to-End Technology and Testing – Why?

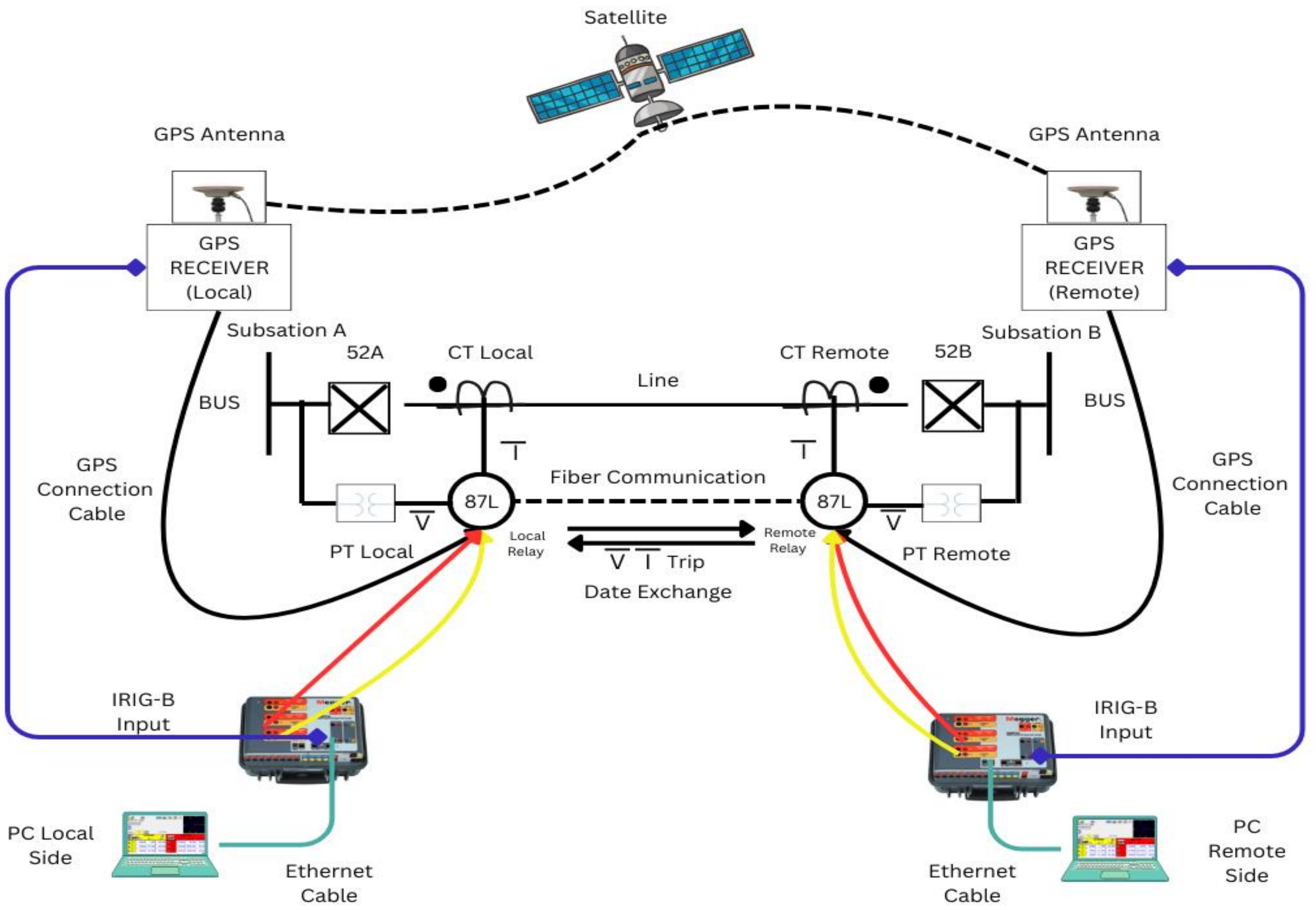
Line Protection Relays End-End Testing: Steady State Method Limitations



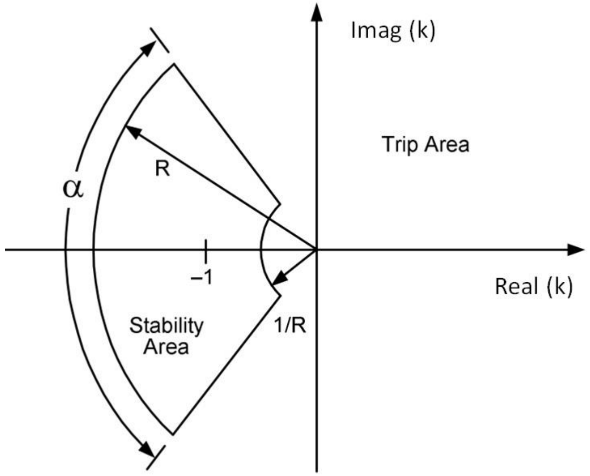
- Always need Multiple operators.
- Limited flexibility and Efficiency
- Difficulty in Simulating Complex Networking Conditions.
- Lake of Real-time Sharing and Analysis.

Cloud-Based End-to-End Technology and Testing – Why?

Line Protection Relays End-End Testing (conventional) : Steady State



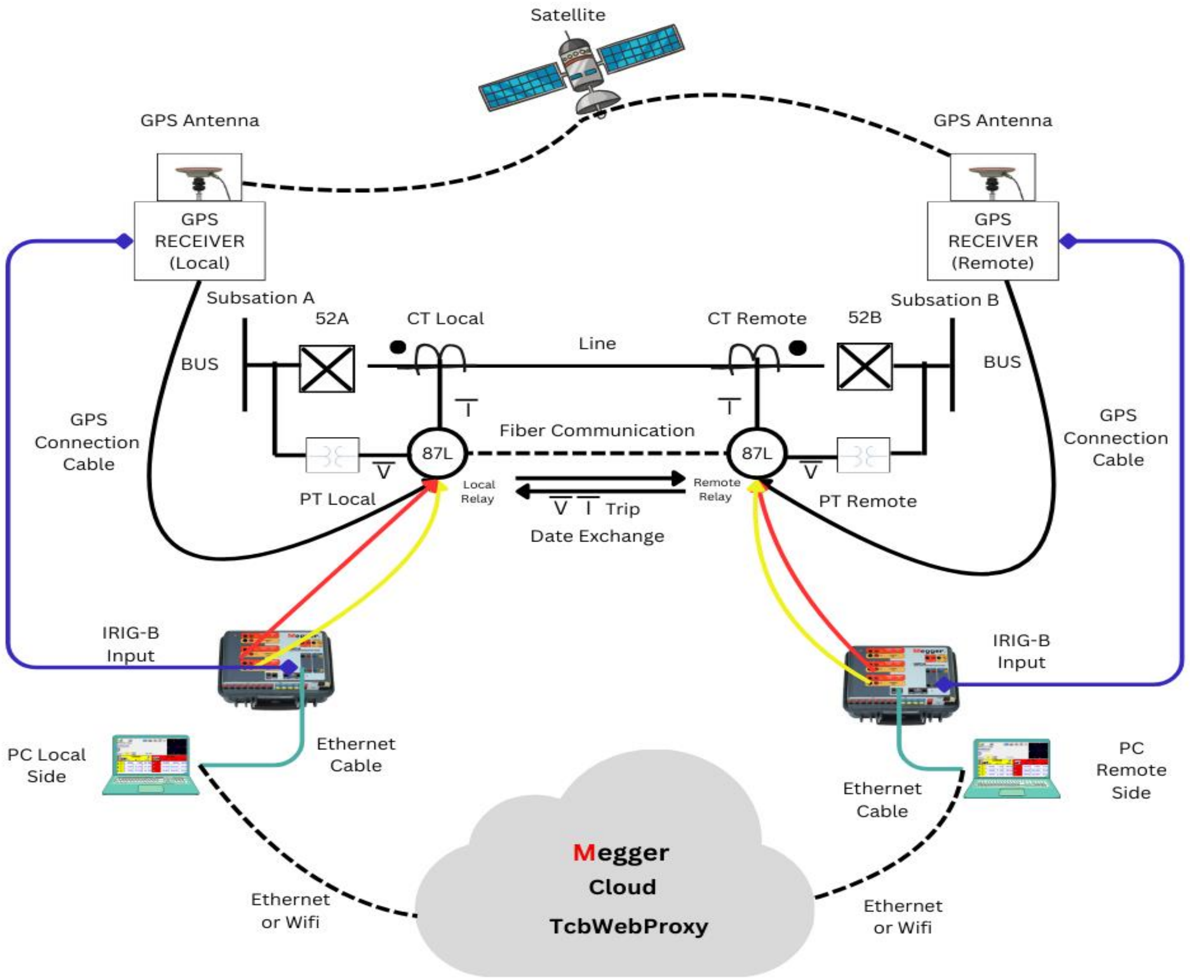
- Limitations on modern Line Differential Relays Algorithms validation.



- Alpha Plane

Cloud-Based End-to-End Technology and Testing – How?

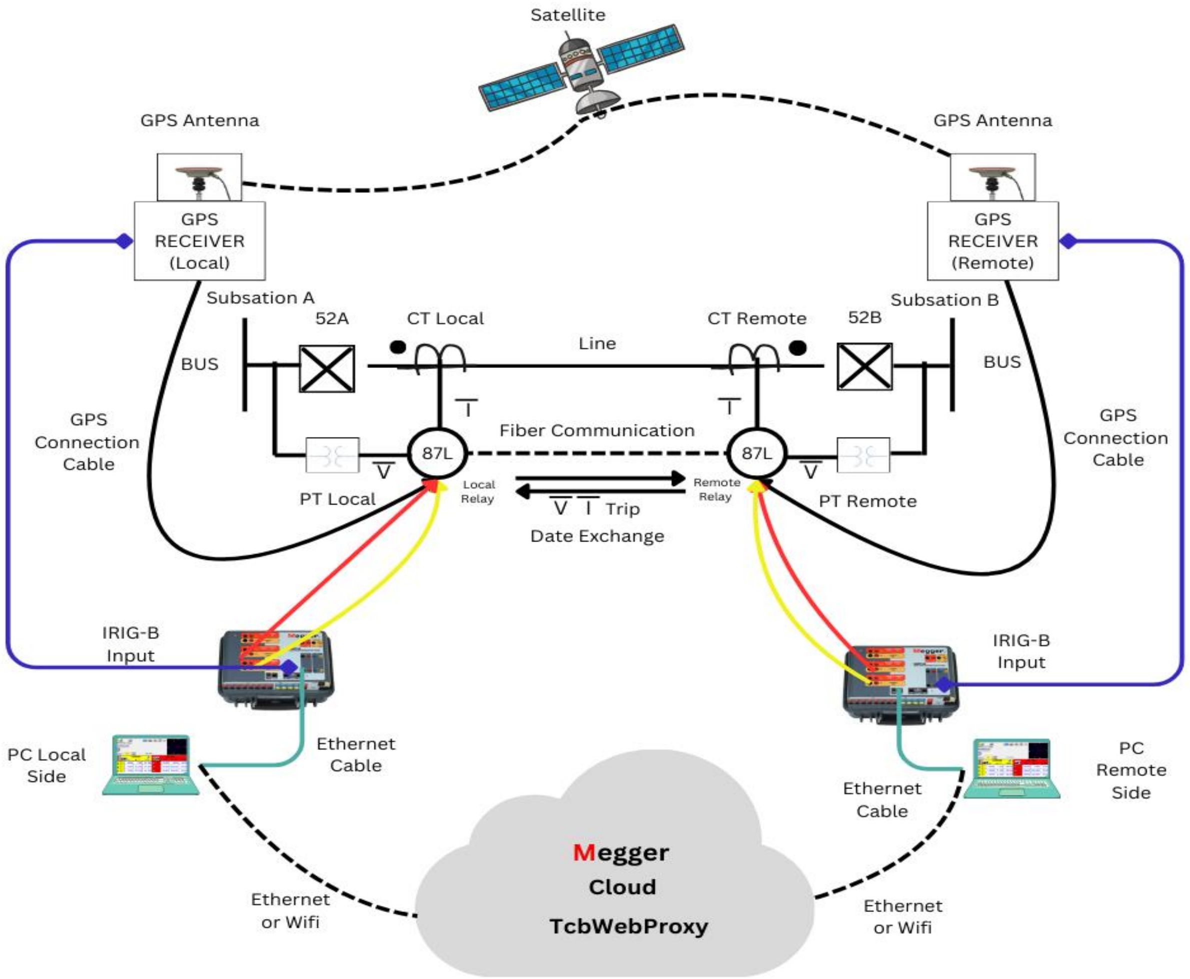
Line Protection Relays End-End Testing: Cloud-Based Approach



- Centralized Control and Flexibility.
- Reduced Operational Errors.
- Synchronization and Real-Time Data Sharing.

Cloud-Based End-to-End Technology and Testing – How?

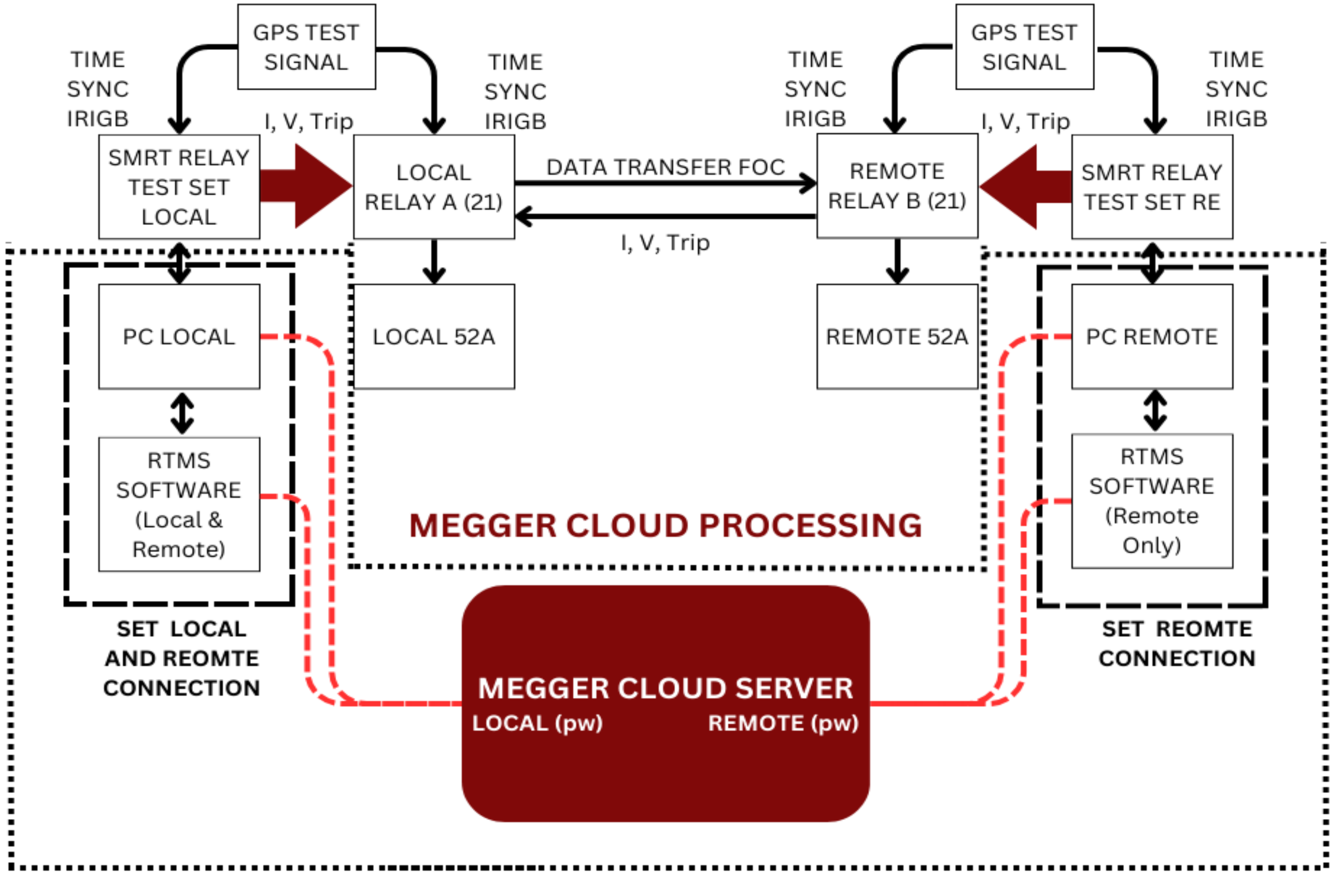
Line Protection Relays End-End Testing: Cloud-Based Approach



- Efficiency and Resource Optimization.
- Enhanced Testing capabilities.
- End-to-end application testing extends beyond just line differential to include Line Distance Schemes as well!

Cloud-Based End-to-End Technology and Testing – How?

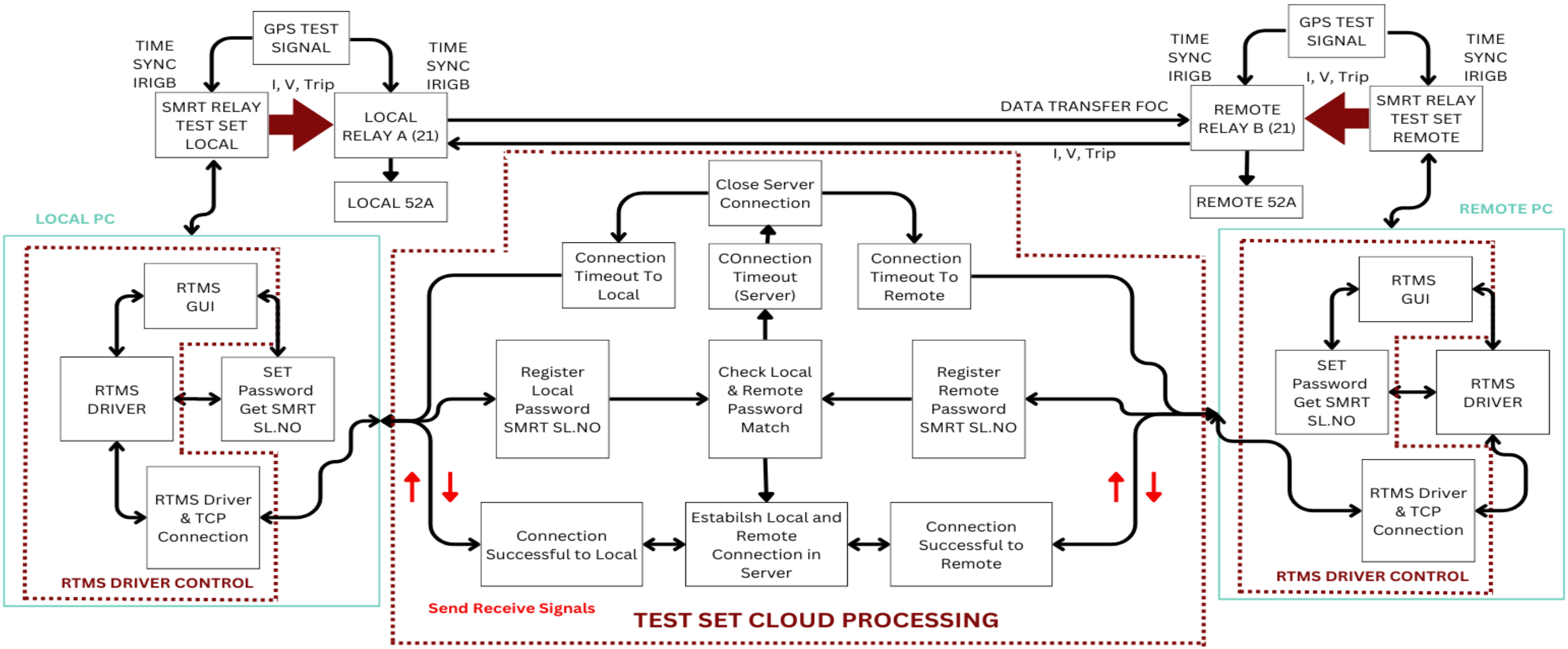
Line Protection Relays End-End Testing: Control From One End



- State-of-the-art method: Integrating two test sets through cloud-level daisy chaining.
- Synchronized Testing.
- Integrated Software and Hardware.
- Cloud-Based Data Management.
- Internet is Mandatory

Cloud-Based End-to-End Technology and Testing – How?

Line Protection Relays End-End Testing: Control From One End



Cloud-Based End-to-End Technology and Testing – What?

Line Protection Relays End-End Testing: Control From One End - Manual

GUI

Test Set A

Relay A

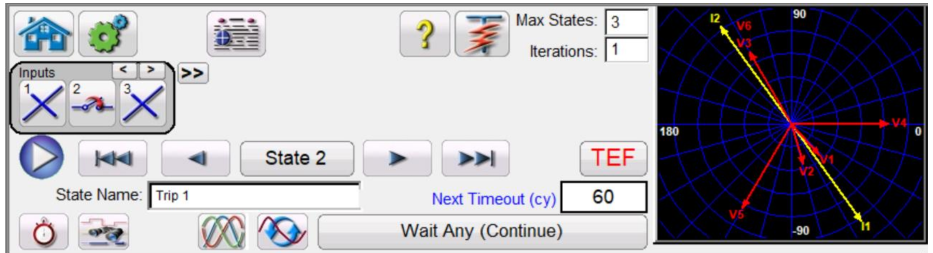
Relay B

Test Set B

Prefault

	CURRENT I (A)	φ (°)	f (Hz)		VOLTAGE V (V)	φ (°)	f (Hz)
I1	5.0000	0.000	60.000	V1	69.000	0.000	60.000
I2	5.0000	-120.000	60.000	V2	69.000	-120.000	60.000
I3	5.0000	120.000	60.000	V3	69.000	120.000	60.000
I4	5.0000	0.000	60.000	V4	69.000	0.000	60.000
I5	5.0000	-120.000	60.000	V5	69.000	-120.000	60.000
I6	5.0000	120.000	60.000	V6	69.000	120.000	60.000

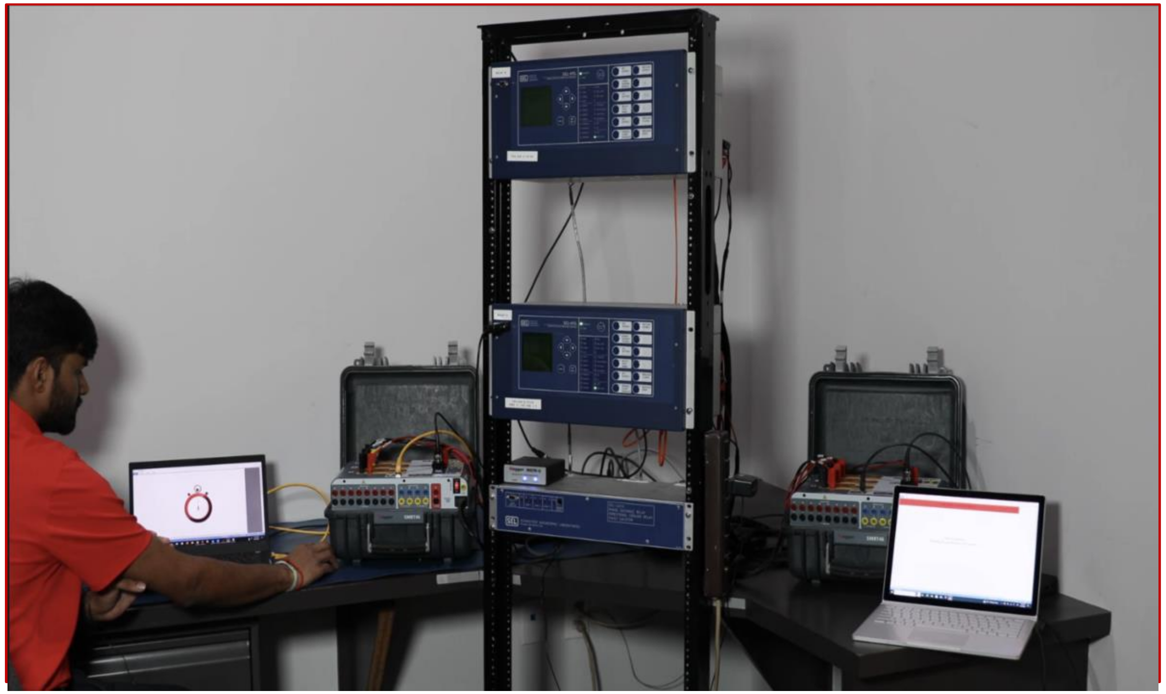
Fault



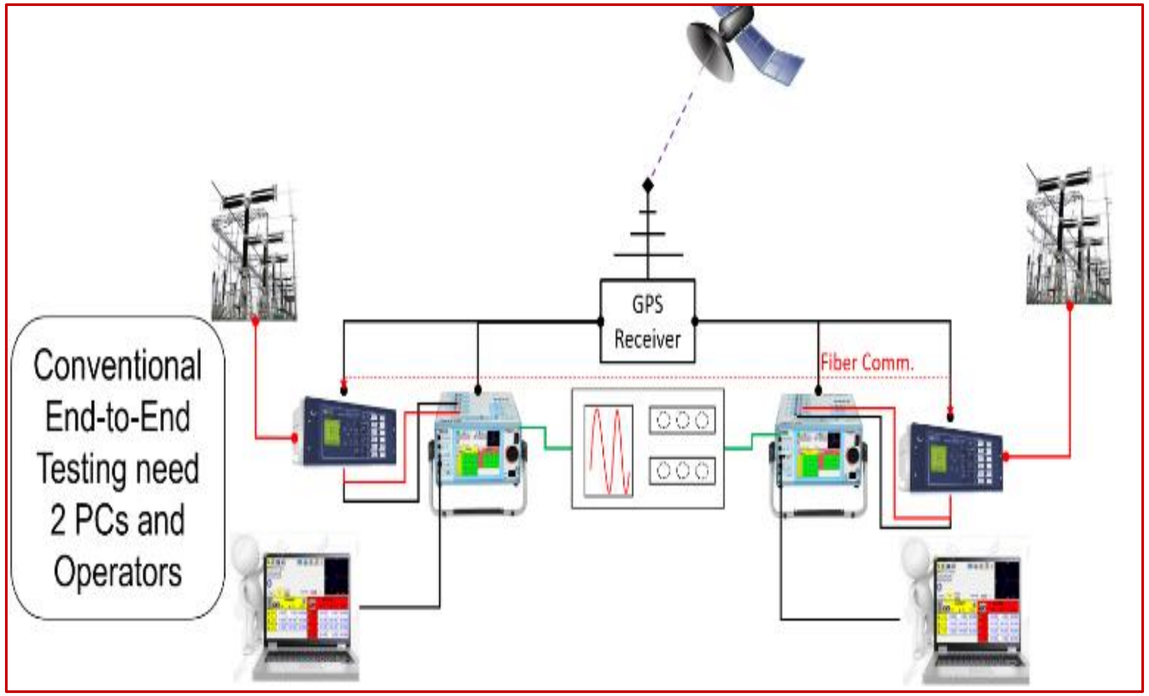
	CURRENT I (A)	φ (°)	f (Hz)		VOLTAGE V (V)	φ (°)	f (Hz)
I1	10.000	-54.000	60.000	V1	35.371	-47.260	60.000
I2	10.000	126.000	60.000	V2	35.371	-72.740	60.000
I3	0.0000	0.000	60.000	V3	69.000	120.000	60.000
I4	10.000	-54.000	60.000	V4	81.060	0.000	60.000
I5	10.000	126.000	60.000	V5	81.060	-120.000	60.000
I6	0.0000	0.000	60.000	V6	69.000	120.000	60.000

Test Scenarios and Results – Traditional and Cloud-Based End-to-End

- Every case was tested using both a conventional setup and a cloud-based setup



Cloud-based Test Setup



Traditional Test Setup

Test Scenarios and Results – Traditional End-to-End

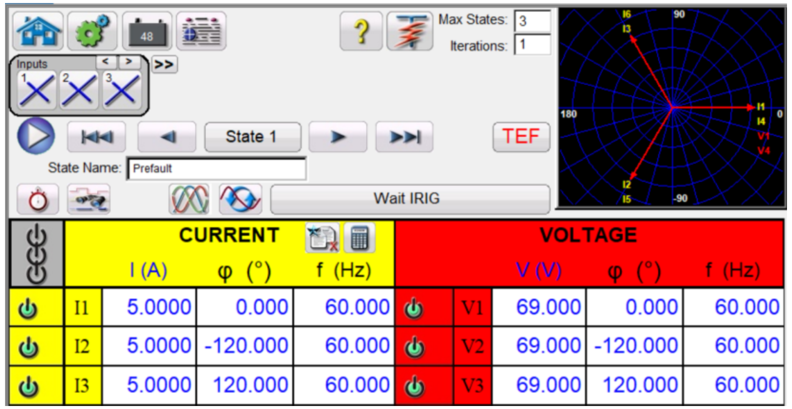
Test Case 1: Traditional Test POTT

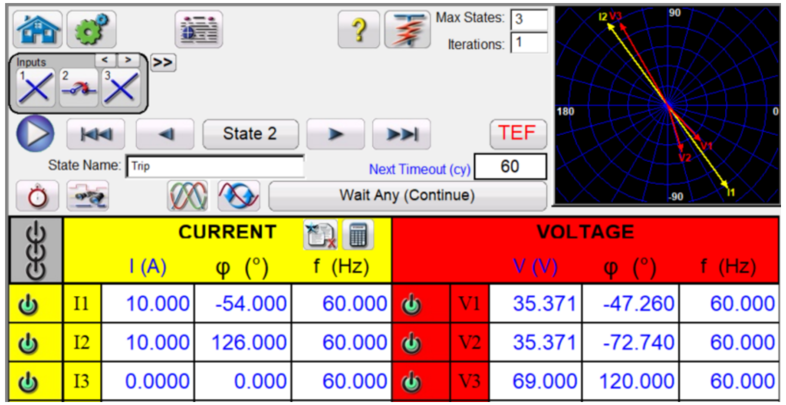
Prefault

Fault

Relay A

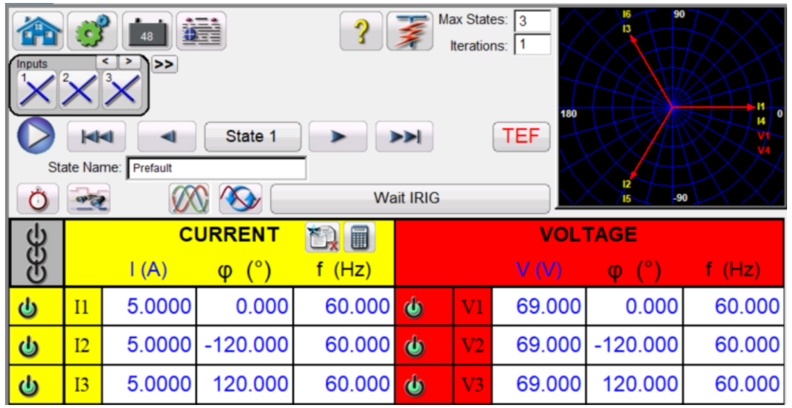
Test Set A

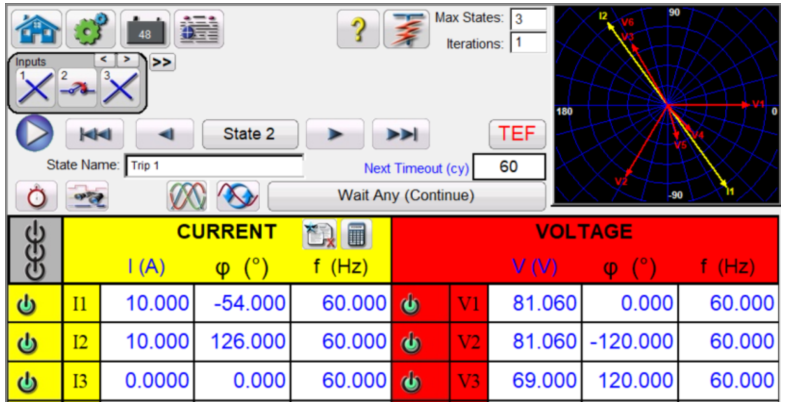




Relay B

Test Set B



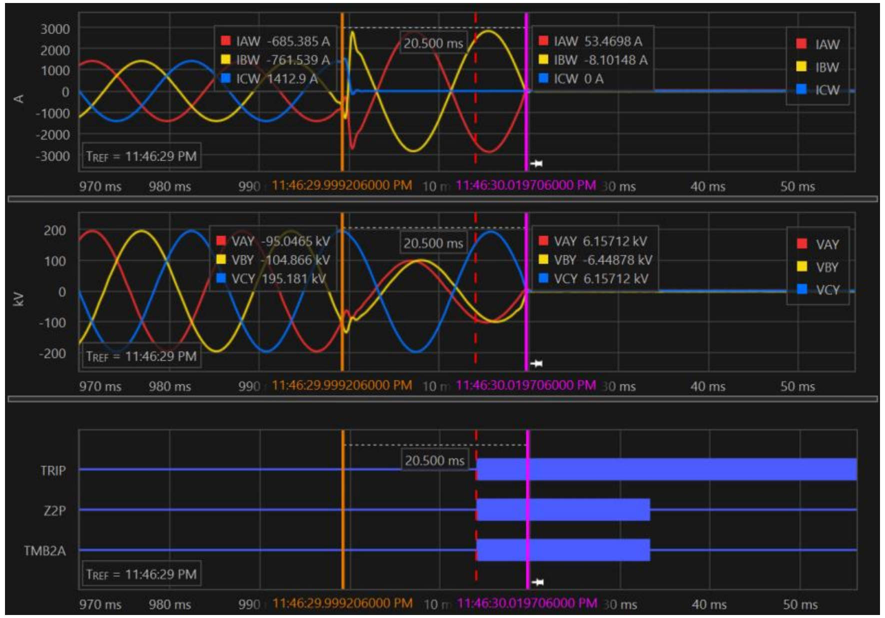


Megger.

Test Scenarios and Results – Traditional End-to-End

Test Case 1: Traditional Test POTT

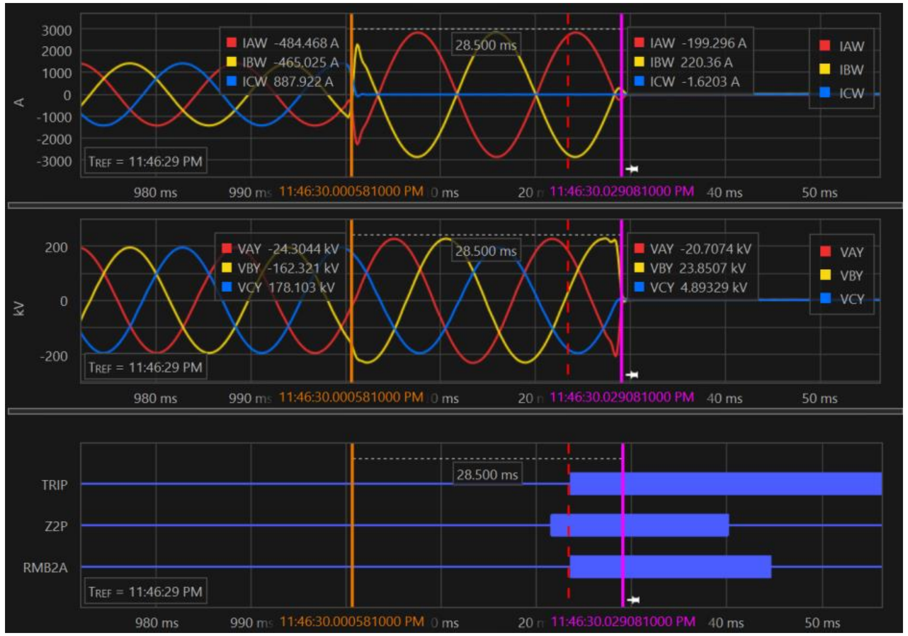
Relay A




```
=>ser

Relay 1                                   Date: 03/08/2024  Time: 23:46:47.174
Station A                                 Serial Number: 1170370041

FID=SEL-411L-1-R124-V2-Z015003-D20201009

#     DATE        TIME           ELEMENT                STATE
6    03/08/2024  23:46:30.0135   Z2P                   ASSERTED
5    03/08/2024  23:46:30.0135   TRIP                  ASSERTED
4    03/08/2024  23:46:30.0135   TMB2A                 ASSERTED
3    03/08/2024  23:46:30.0320   Z2P                   DEASSERTED
2    03/08/2024  23:46:30.0320   TMB2A                 DEASSERTED
1    03/08/2024  23:46:30.2135   TRIP                  DEASSERTED

=>
```

AB fault at 10%. POTT.

Relay B




```
=>ser

Relay 1                                   Date: 03/08/2024  Time: 23:47:50.968
Station A                                 Serial Number: 1170370042

FID=SEL-411L-1-R124-V2-Z015003-D20201009

#     DATE        TIME           ELEMENT                STATE
6    03/08/2024  23:46:30.0208   Z2P                   ASSERTED
5    03/08/2024  23:46:30.0228   TRIP                  ASSERTED
4    03/08/2024  23:46:30.0228   RMB2A                 ASSERTED
3    03/08/2024  23:46:30.0393   Z2P                   DEASSERTED
2    03/08/2024  23:46:30.0433   RMB2A                 DEASSERTED
1    03/08/2024  23:46:30.2228   TRIP                  DEASSERTED

=>
```

AB fault at 90%. POTT.

Test Scenarios and Results – Cloud-Based End-to-End

Test Case 2: Cloud-Based Test POTT

Prefault

	CURRENT I (A)	φ (°)	f (Hz)		VOLTAGE V (V)	φ (°)	f (Hz)
I1	5.0000	0.000	60.000	V1	69.000	0.000	60.000
I2	5.0000	-120.000	60.000	V2	69.000	-120.000	60.000
I3	5.0000	120.000	60.000	V3	69.000	120.000	60.000
I4	5.0000	0.000	60.000	V4	69.000	0.000	60.000
I5	5.0000	-120.000	60.000	V5	69.000	-120.000	60.000
I6	5.0000	120.000	60.000	V6	69.000	120.000	60.000

Fault

	CURRENT I (A)	φ (°)	f (Hz)		VOLTAGE V (V)	φ (°)	f (Hz)
I1	10.000	-54.000	60.000	V1	35.371	-47.260	60.000
I2	10.000	126.000	60.000	V2	35.371	-72.740	60.000
I3	0.0000	0.000	60.000	V3	69.000	120.000	60.000
I4	10.000	-54.000	60.000	V4	81.060	0.000	60.000
I5	10.000	126.000	60.000	V5	81.060	-120.000	60.000
I6	0.0000	0.000	60.000	V6	69.000	120.000	60.000

Test Set A

Relay A

Relay B

Test Set B

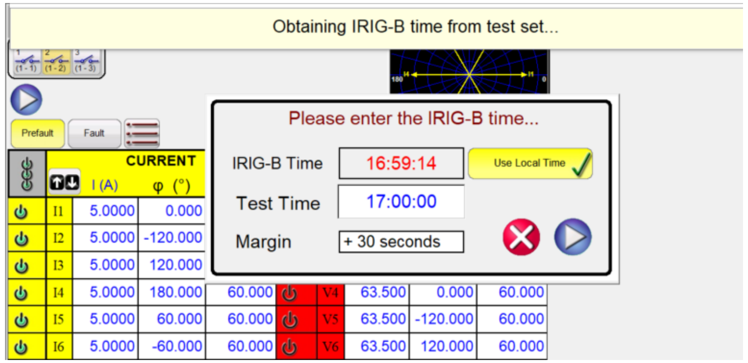
Megger

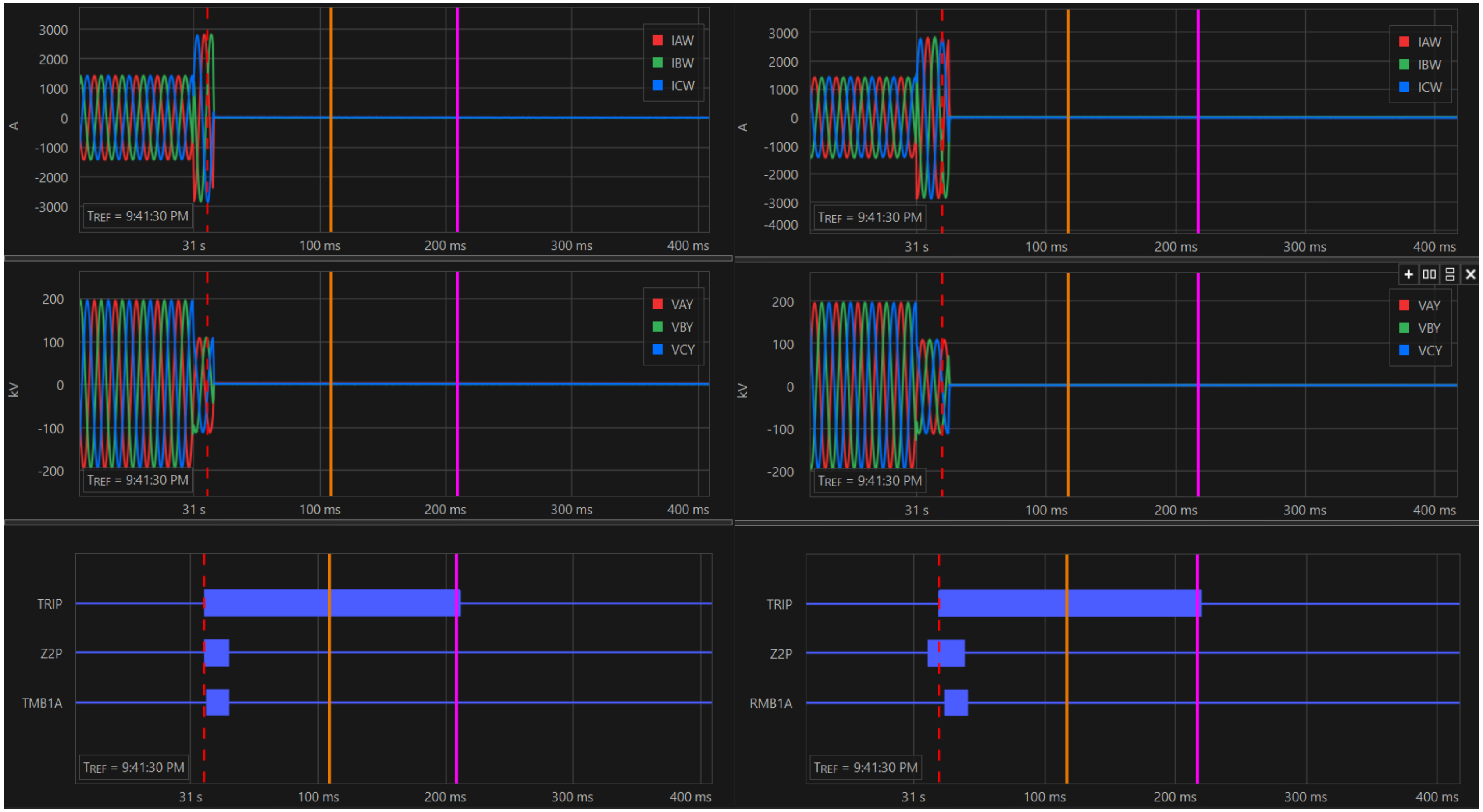
Test Scenarios and Results – Cloud-Based End-to-End

Test Case 2: Cloud-Based Test POTT

Relay A

Relay B






```
=>ser

Relay 1                                          Date: 03/08/2024  Time: 23:46:47.174
Station A                                        Serial Number: 1170370041

FID=SEL-411L-1-R124-V2-Z015003-D20201009

#      DATE        TIME           ELEMENT                STATE
6    03/08/2024  23:46:30.0135   Z2P                    ASSERTED
5    03/08/2024  23:46:30.0135   TRIP                   ASSERTED
4    03/08/2024  23:46:30.0135   TMB2A                  ASSERTED
3    03/08/2024  23:46:30.0320   Z2P                    DEASSERTED
2    03/08/2024  23:46:30.0320   TMB2A                  DEASSERTED
1    03/08/2024  23:46:30.2135   TRIP                   DEASSERTED

=>
```

Megger.

Test Scenarios and Results – Traditional End-to-End

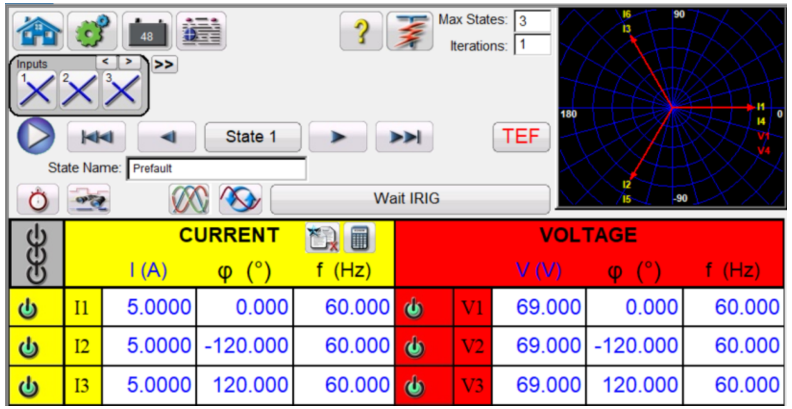
Test Case 3: Traditional Test PUTT

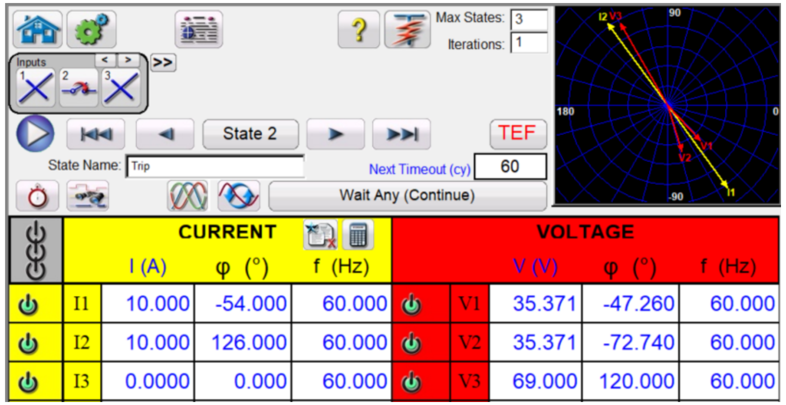
Prefault

Fault

Relay A

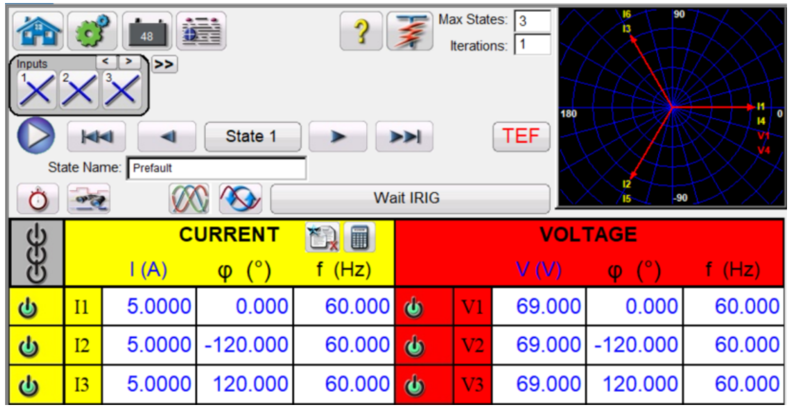
Test Set A

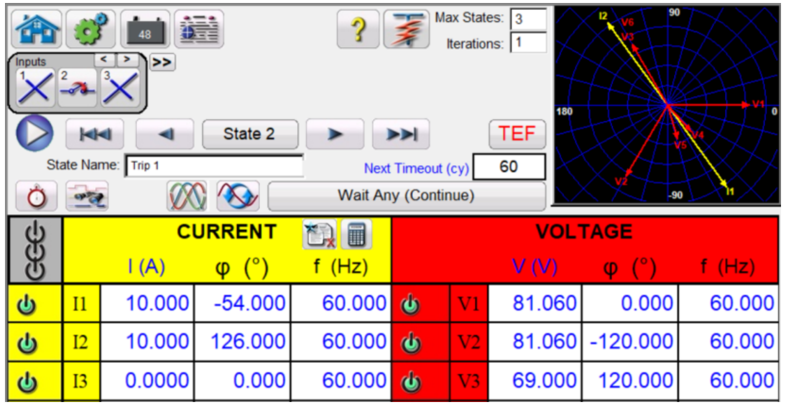




Relay B

Test Set B

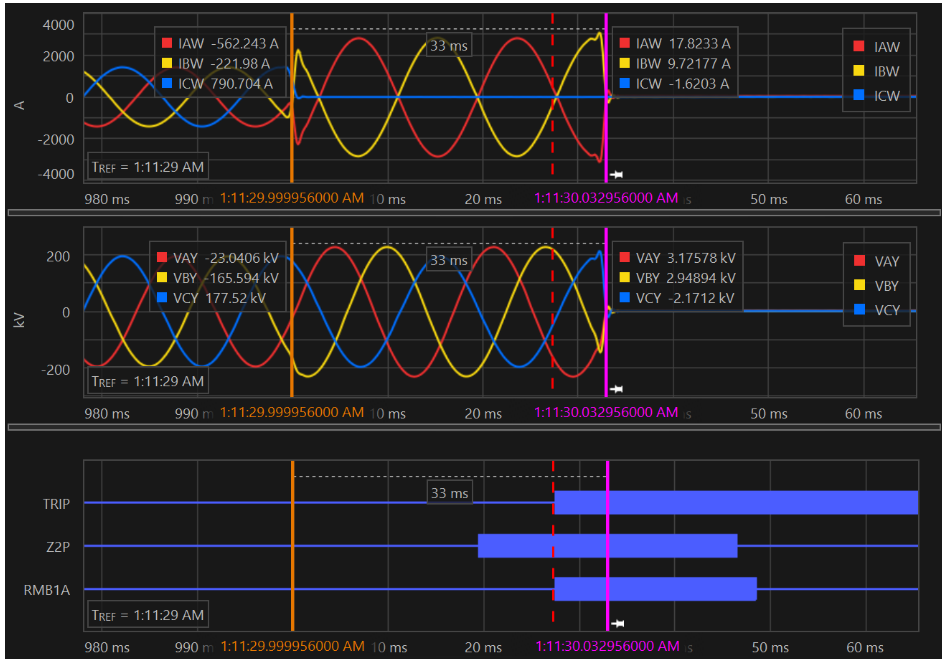




Test Scenarios and Results – Traditional End-to-End

Test Case 3: Traditional Test PUTT

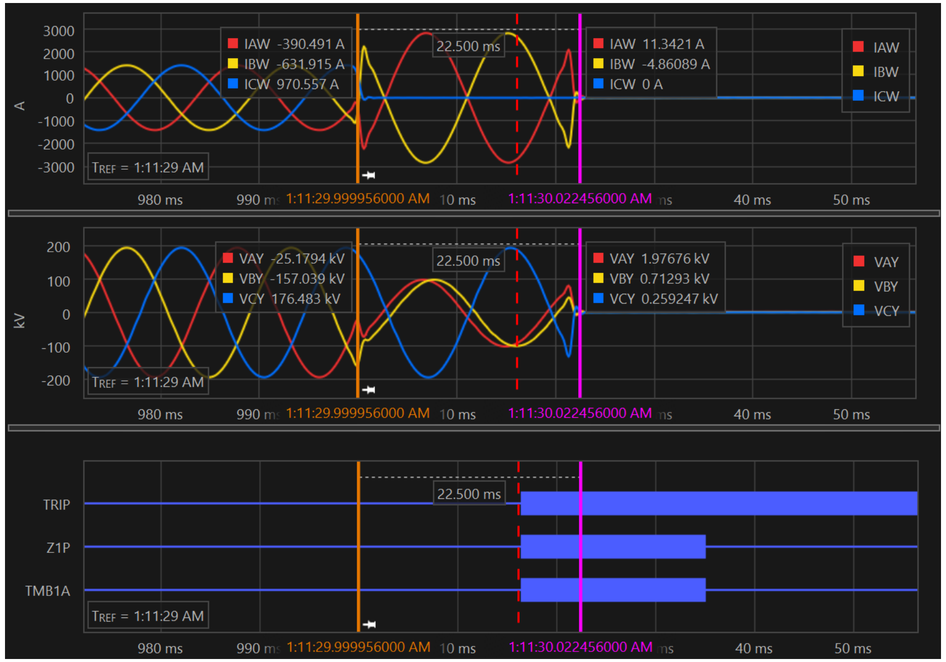
Relay A




```
=>ser

Relay 1                                   Date: 02/25/2024  Time: 01:24:33.563
Station A                                 Serial Number: 1170370041

FID=SEL-411L-1-R124-V2-Z015003-D20201009

#     DATE        TIME          ELEMENT             STATE
6    02/25/2024  01:11:30.0182  Z2P                 ASSERTED
5    02/25/2024  01:11:30.0267  TRIP                Asserted
4    02/25/2024  01:11:30.0267  RMB1A               Asserted
3    02/25/2024  01:11:30.0452  Z2P                 DEASSERTED
2    02/25/2024  01:11:30.0472  RMB1A               Deasserted
1    02/25/2024  01:11:30.2267  TRIP                Deasserted
```

AB fault at 90%. PUTT.

Relay B




```
=>ser

Relay 1                                   Date: 02/25/2001  Time: 01:13:16.071
Station A                                 Serial Number: 1170370042

FID=SEL-411L-1-R124-V2-Z015003-D20201009

#     DATE        TIME          ELEMENT             STATE
8    02/25/2001  01:11:30.0132  Z2P                 ASSERTED
7    02/25/2001  01:11:30.0157  Z1P                 Asserted
6    02/25/2001  01:11:30.0157  TRIP                Asserted
5    02/25/2001  01:11:30.0157  TMB1A               Asserted
4    02/25/2001  01:11:30.0342  Z2P                 DEASSERTED
3    02/25/2001  01:11:30.0342  Z1P                 Deasserted
2    02/25/2001  01:11:30.0342  TMB1A               Deasserted
1    02/25/2001  01:11:30.2152  TRIP                Deasserted

=>
```

AB fault at 10%. PUTT.

Megger

Test Scenarios and Results – Cloud-Based End-to-End

Test Case 4: Cloud-Based Test PUTT

Prefault

Test Set A

Relay A

Relay B

Test Set B

	CURRENT I (A)	φ (°)	f (Hz)	VOLTAGE	V (V)	φ (°)	f (Hz)
I1	5.0000	0.000	60.000	V1	69.000	0.000	60.000
I2	5.0000	-120.000	60.000	V2	69.000	-120.000	60.000
I3	5.0000	120.000	60.000	V3	69.000	120.000	60.000
I4	5.0000	0.000	60.000	V4	69.000	0.000	60.000
I5	5.0000	-120.000	60.000	V5	69.000	-120.000	60.000
I6	5.0000	120.000	60.000	V6	69.000	120.000	60.000

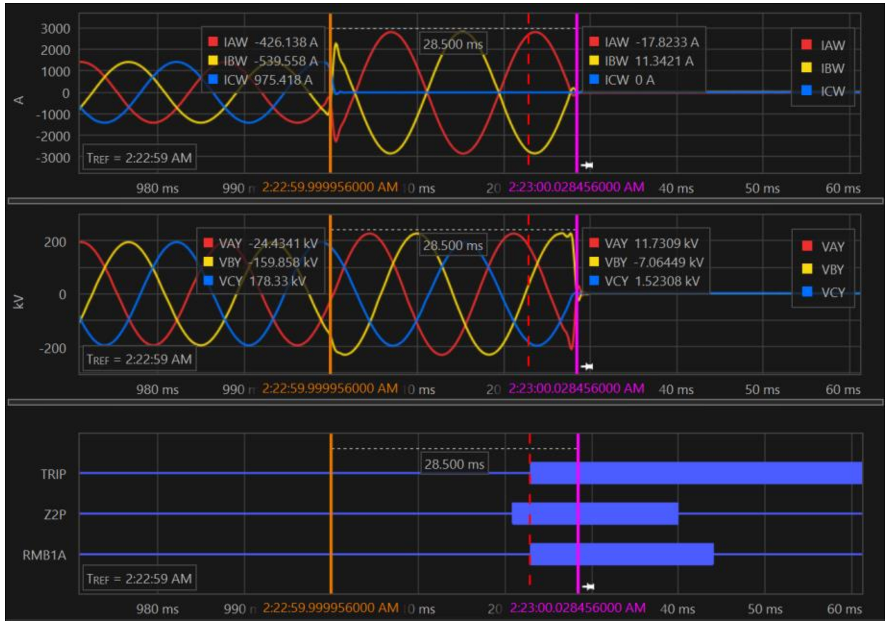
Fault

	CURRENT I (A)	φ (°)	f (Hz)	VOLTAGE	V (V)	φ (°)	f (Hz)
I1	10.000	-54.000	60.000	V1	35.371	-47.260	60.000
I2	10.000	126.000	60.000	V2	35.371	-72.740	60.000
I3	0.0000	0.000	60.000	V3	69.000	120.000	60.000
I4	10.000	-54.000	60.000	V4	81.060	0.000	60.000
I5	10.000	126.000	60.000	V5	81.060	-120.000	60.000
I6	0.0000	0.000	60.000	V6	69.000	120.000	60.000

Test Scenarios and Results – Cloud-Based End-to-End

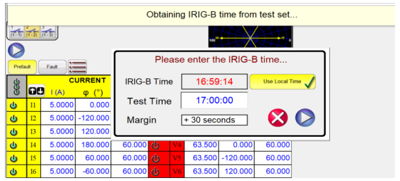
Test Case 4: Cloud-Based Test PUTT

Relay A

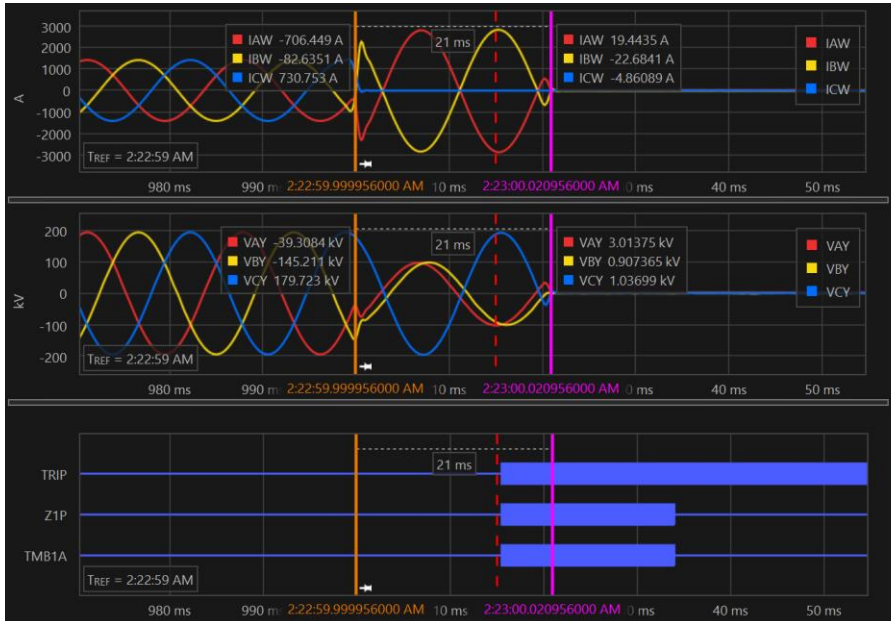



```
Relay 1                                  Date: 02/25/2024  Time: 02:03:49.156
Station A                                Serial Number: 1170370041

FID=SEL-411L-1-R124-V2-Z015003-D20201009

#     DATE        TIME           ELEMENT            STATE
14    02/25/2024  01:11:30.0182  Z2P                ASSERTED
13    02/25/2024  01:11:30.0267  TRIP               Asserted
12    02/25/2024  01:11:30.0267  RMB1A              Asserted
11    02/25/2024  01:11:30.0452  Z2P                DEASSERTED
10    02/25/2024  01:11:30.0472  RMB1A              Deasserted
9     02/25/2024  01:11:30.2267  TRIP               Deasserted
8     02/25/2024  02:02:00.0187  Z2P                ASSERTED
7     02/25/2024  02:02:00.0227  TRIP               Asserted
6     02/25/2024  02:02:00.0227  RMB1A              Asserted
5     02/25/2024  02:02:00.0332  Z2P                DEASSERTED
4     02/25/2024  02:02:00.0372  Z2P                ASSERTED
3     02/25/2024  02:02:00.0397  Z2P                DEASSERTED
2     02/25/2024  02:02:00.0437  RMB1A              Deasserted
1     02/25/2024  02:02:00.2227  TRIP               Deasserted
```

AB fault at 90%. PUTT.



Relay B




```
=>ser

Relay 1                                  Date: 02/25/2001  Time: 02:10:32.401
Station A                                Serial Number: 1170370042

FID=SEL-411L-1-R124-V2-Z015003-D20201009

#     DATE        TIME           ELEMENT            STATE
16    02/25/2001  01:11:30.0132  Z2P                ASSERTED
15    02/25/2001  01:11:30.0157  Z1P                Asserted
14    02/25/2001  01:11:30.0157  TRIP               Asserted
13    02/25/2001  01:11:30.0157  TMB1A              Asserted
12    02/25/2001  01:11:30.0342  Z2P                DEASSERTED
11    02/25/2001  01:11:30.0342  Z1P                Deasserted
10    02/25/2001  01:11:30.0342  TMB1A              Deasserted
9     02/25/2001  01:11:30.2152  TRIP               Deasserted
8     02/25/2001  02:02:00.0147  Z2P                ASSERTED
7     02/25/2001  02:02:00.0147  Z1P                Asserted
6     02/25/2001  02:02:00.0147  TRIP               Asserted
5     02/25/2001  02:02:00.0147  TMB1A              Asserted
4     02/25/2001  02:02:00.0337  Z2P                DEASSERTED
3     02/25/2001  02:02:00.0337  Z1P                Deasserted
2     02/25/2001  02:02:00.0337  TMB1A              Deasserted
1     02/25/2001  02:02:00.2147  TRIP               Deasserted
```

AB fault at 10%. PUTT.

Test Scenarios and Results – Traditional End-to-End

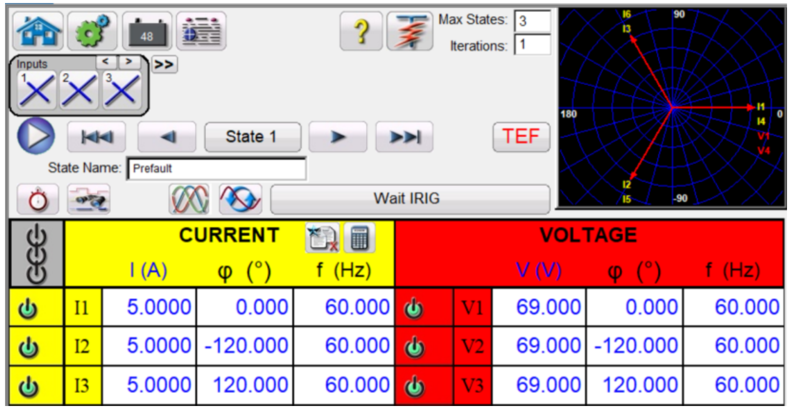
Test Case 5: Traditional Test Line Differential Shot Test

Prefault

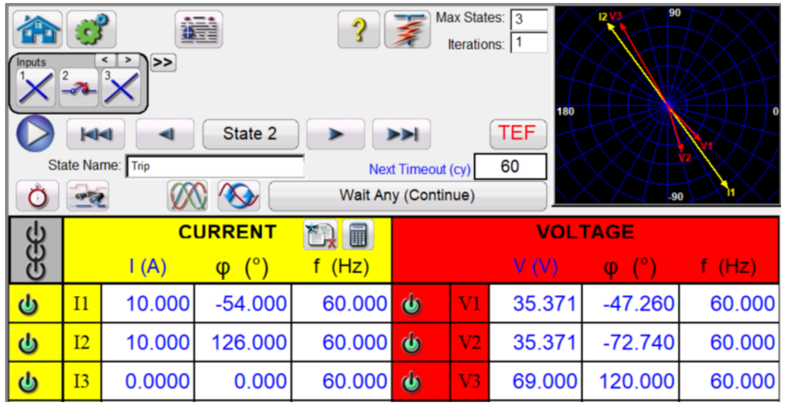
Fault

Relay A

Test Set A



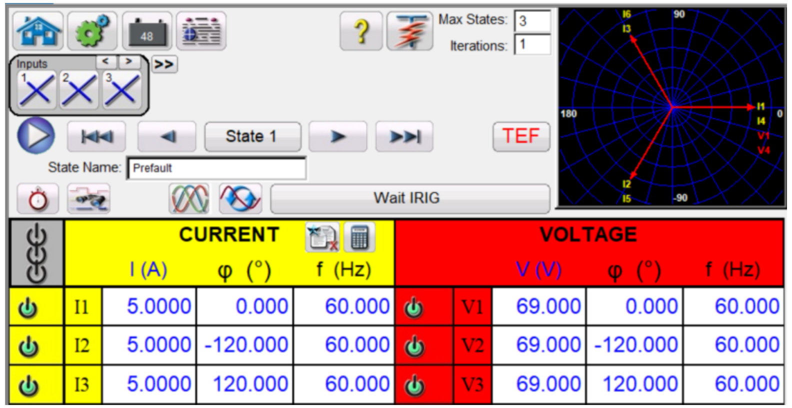
	CURRENT				VOLTAGE		
	I (A)	φ (°)	f (Hz)		V (V)	φ (°)	f (Hz)
I1	5.0000	0.000	60.000	V1	69.000	0.000	60.000
I2	5.0000	-120.000	60.000	V2	69.000	-120.000	60.000
I3	5.0000	120.000	60.000	V3	69.000	120.000	60.000



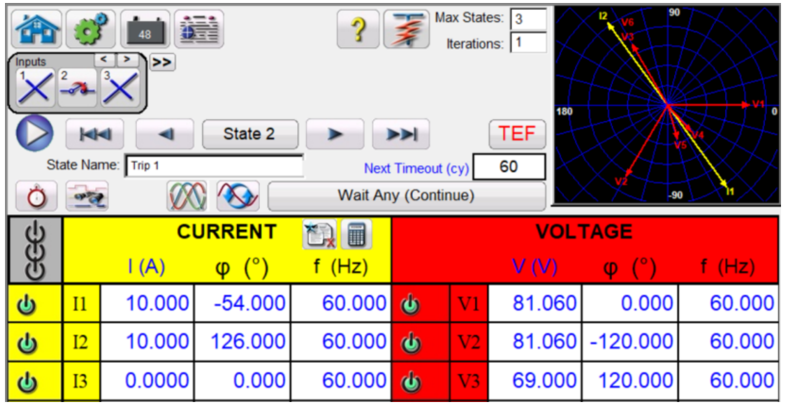
	CURRENT				VOLTAGE		
	I (A)	φ (°)	f (Hz)		V (V)	φ (°)	f (Hz)
I1	10.000	-54.000	60.000	V1	35.371	-47.260	60.000
I2	10.000	126.000	60.000	V2	35.371	-72.740	60.000
I3	0.0000	0.000	60.000	V3	69.000	120.000	60.000

Relay B

Test Set B



	CURRENT				VOLTAGE		
	I (A)	φ (°)	f (Hz)		V (V)	φ (°)	f (Hz)
I1	5.0000	0.000	60.000	V1	69.000	0.000	60.000
I2	5.0000	-120.000	60.000	V2	69.000	-120.000	60.000
I3	5.0000	120.000	60.000	V3	69.000	120.000	60.000

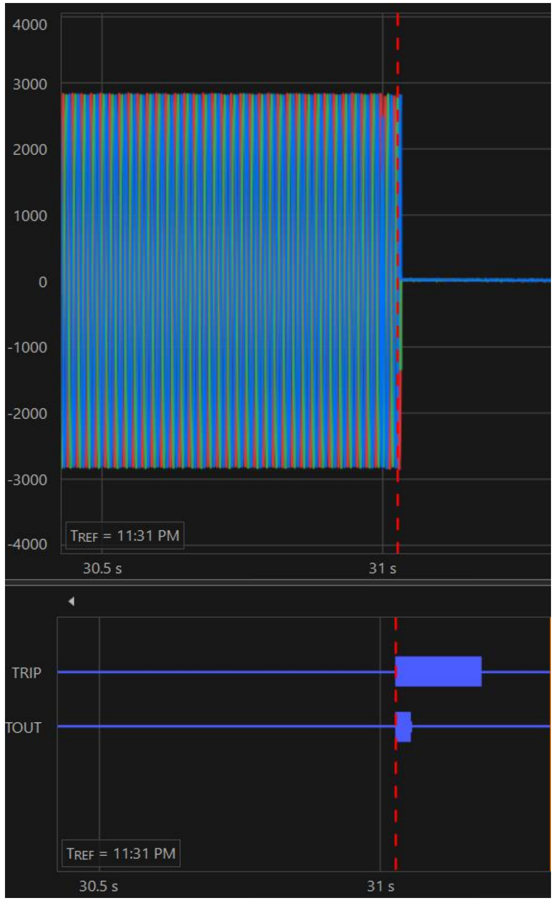


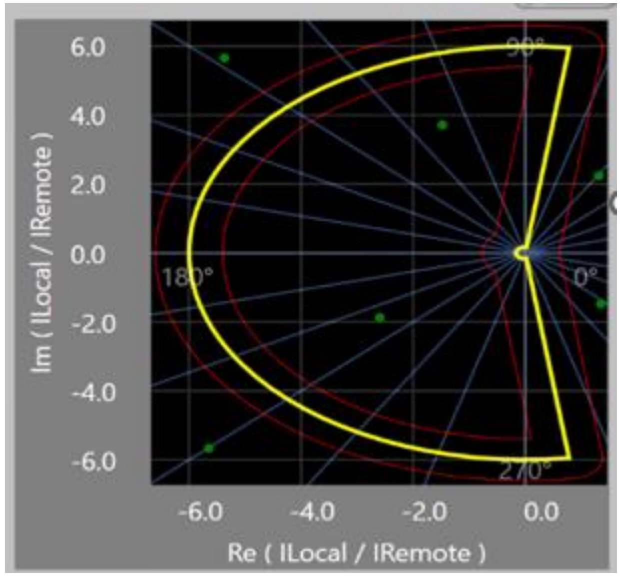
	CURRENT				VOLTAGE		
	I (A)	φ (°)	f (Hz)		V (V)	φ (°)	f (Hz)
I1	10.000	-54.000	60.000	V1	81.060	0.000	60.000
I2	10.000	126.000	60.000	V2	81.060	-120.000	60.000
I3	0.0000	0.000	60.000	V3	69.000	120.000	60.000

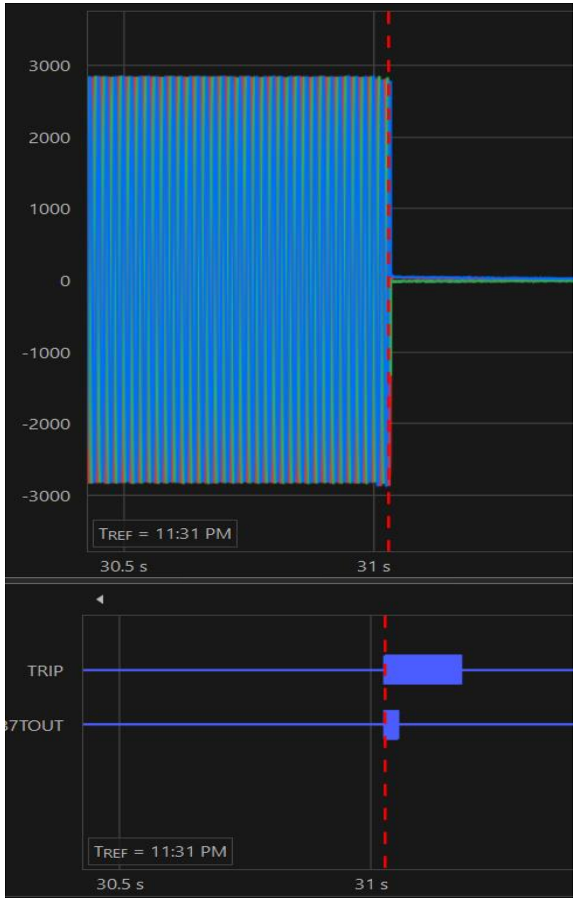
Megger.

Test Scenarios and Results – Traditional End-to-End

Test Case 5: Traditional Test Line Differential Shot Test



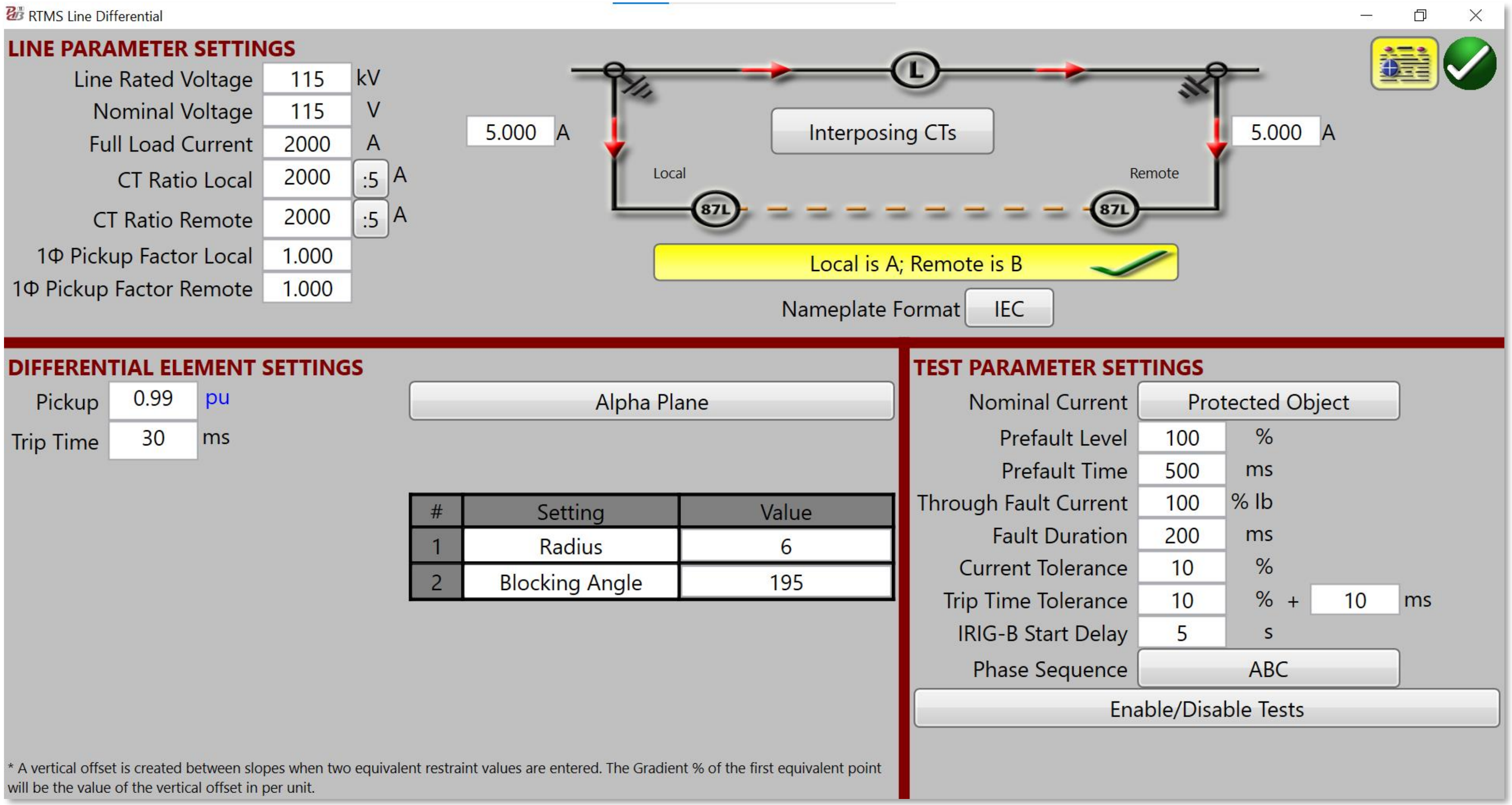




NOTE: Visualization of Alpha plane characteristics (or any) test is not possible with traditional testing

Test Scenarios and Results – Cloud-Based End-to-End

Test Case 6: Cloud-Based Line Differential Test - Stability



Test Scenarios and Results – Cloud-Based End-to-End

Test Case 6: Cloud-Based Line Differential Test - Stability

RTMS Line Differential

Abort | Finish | Simulate

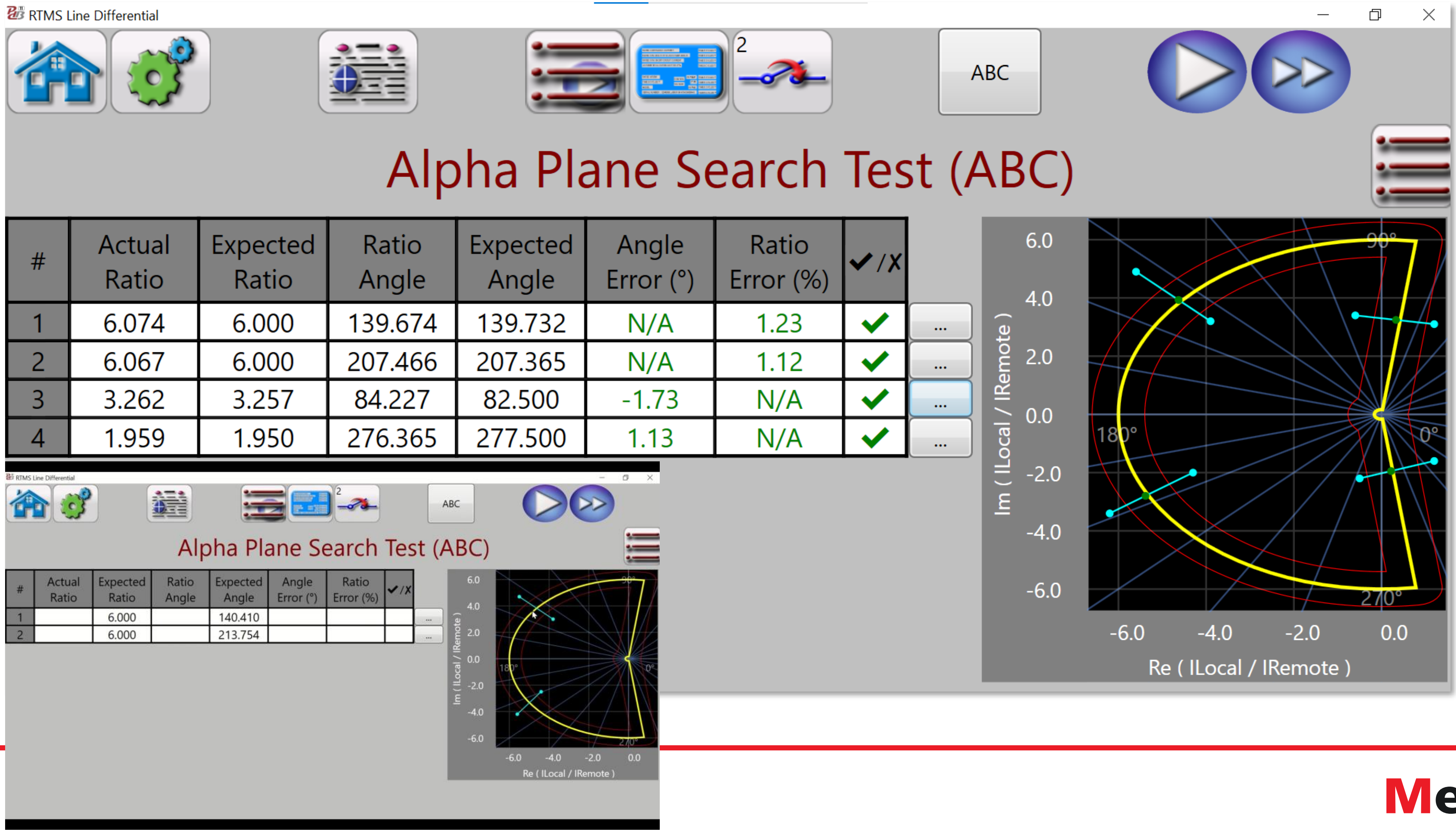
Stabilization Test (ABC)

Stability I 100 %

Phase	Injected Currents (Primary)				Currents Observed From Relay					
	Local		Remote		Local		Remote		Ibias	Idiff
	I (A)	φ (°)	I (A)	φ (°)	I (A)	φ (°)	I (A)	φ (°)		
A	2000.00	0	2000.00	180	1999.8	0	1999.4	180	0	0.001
B	2000.00	-120	2000.00	60	2000.6	-120	2000.1	60	0	0.002
C	2000.00	120	2000.00	-60	1999.6	120	2000.4	-59.8	0	0.001

Test Scenarios and Results – Cloud-Based End-to-End

Test Case 6: Cloud-Based Line Differential Test - Search



#	Actual Ratio	Expected Ratio	Ratio Angle	Expected Angle	Angle Error (°)	Ratio Error (%)	✔/✗
1	6.074	6.000	139.674	139.732	N/A	1.23	✔
2	6.067	6.000	207.466	207.365	N/A	1.12	✔
3	3.262	3.257	84.227	82.500	-1.73	N/A	✔
4	1.959	1.950	276.365	277.500	1.13	N/A	✔

#	Actual Ratio	Expected Ratio	Ratio Angle	Expected Angle	Angle Error (°)	Ratio Error (%)	✔/✗
1		6.000		140.410			
2		6.000		213.754			

Megger.

Test Scenarios and Results – Cloud-Based End-to-End

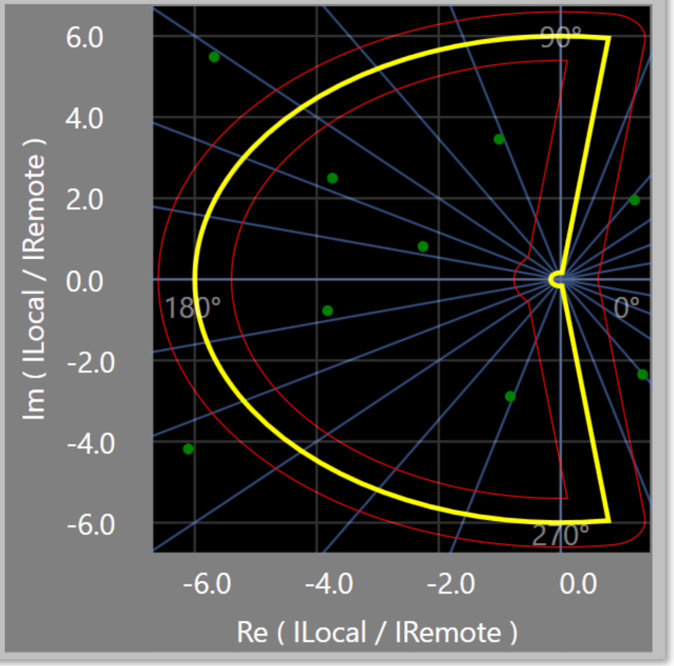
Test Case 6: Cloud-Based Line Differential Test - Shot

RTMS Line Differential

ABC

Alpha Plane Shot Test (ABC)

#	Ratio	Ratio Angle	Expected (ms)	Actual (ms)	Error (%)	✓/✗
1	4.5	146.3	NOP	NOP	NOP	✓
2	7.9	136	30	30	0 ms 0.00 %	✓
3	3.9	191.4	NOP	NOP	NOP	✓
4	7.4	214.4	30	28	-2 ms	✓
5	2.4	160.2	NOP	NOP	NOP	✓
6	3.6	106.3	NOP	NOP	NOP	✓
7	2.3	58.2	30	26	-4 ms	✓
8	3	254	NOP	NOP	NOP	✓
9	2.7	299.8	30	30	0 ms 0.00 %	✓



Summary

Centralized Testing: This technology allows for centralized control of testing procedures, where a single operator can manage tests from one end, enhancing efficiency and reducing manpower requirements.

Synchronization and Accuracy: It leverages GPS-based synchronization for precise timing across disparate locations, ensuring high accuracy in test signal injections and fault simulations.

Real-Time Data Sharing: The cloud-based platform enables real-time data sharing and analysis, allowing for immediate troubleshooting and enhanced collaborative efforts.

Resource Optimization: By reducing the need for physical presence at both ends of a testing location, it optimizes resources and potentially lowers the costs associated with traditional testing methods.

Innovative Approach: The system represents a significant innovation in the field of teleprotection testing. Its unique method is **patent-pending**, highlighting its novel contribution to the industry.

Conclusion

- **Improved Efficiency**: Cloud-based testing reduces the need for on-site personnel, enabling remote testing and lowering operational costs.
- **Enhanced Accuracy**: Real-time data monitoring and GPS synchronization ensure more precise and faster fault detection.
- **Broader Testing Capabilities**: Cloud-based systems allow for testing a wider range of fault scenarios, improving protection scheme reliability.
- **Reduced Human Error**: Automation and centralized control minimize the likelihood of mistakes during testing and setup.
- **Future of Testing**: As power systems continue to advance, cloud-based testing will play a crucial role in ensuring the reliability and efficiency of grid operations. This development enables seamless retrieval of data from both end relays, enhancing the accuracy and speed of the testing process.

NERC BES Protection System Misoperation Reduction Workshop

Protection System Redundancy Criteria for NERC TPL-001.5 Footnote 13

Scott Hayes and Davis Erwin
Pacific Gas and Electric

Purpose of Presentation

- Ensure Protection leaders are aware of the future costs, labor and timelines for compliance with NERC TPL-001.5 footnote 13 a-d.
- Briefly cover footnote 13 a-c including common problem areas.
- Cover footnote 13 d (control circuitry) in detail as well as discuss the SAR associated with 13 d.
- Protection groups may not be the asset owner for all components covered under footnote 13 a-d but we are the most qualified group to determine Single Point of Failure of Protection System components
- Several other entities have been contacted about their approach. The results were either:
  - Not aware of the concern.
  - Interpreted the exclusion in 13d to apply to all elements of the control circuit that are monitored and reported.
  - One Canadian Province is modifying 13d to change the requirement for local conditions to exclude <u>all</u> elements that are monitored and reported.

NERC TPL-001.5.1 Footnote 13

- NERC Standard TPL-001.5.1 is a Transmission System Planning Performance Standard
  - It requires an annual assessment of stability during specific faults with Delayed Fault Clearing due to failure of non redundant components of the Protection System
- TPL-001-5 mandates redundancy (or monitoring and reporting where allowed) of four Protection System components if stability studies reveal performance violations resulting from the failure of that Protection System component during a fault
- Identifying where redundancy exists, or monitoring and alarming exists is a very large effort and may require creating additional databases
- Exceptions/Exclusions are allowed for 13 b and c and are heavily used.

Public

Timeline

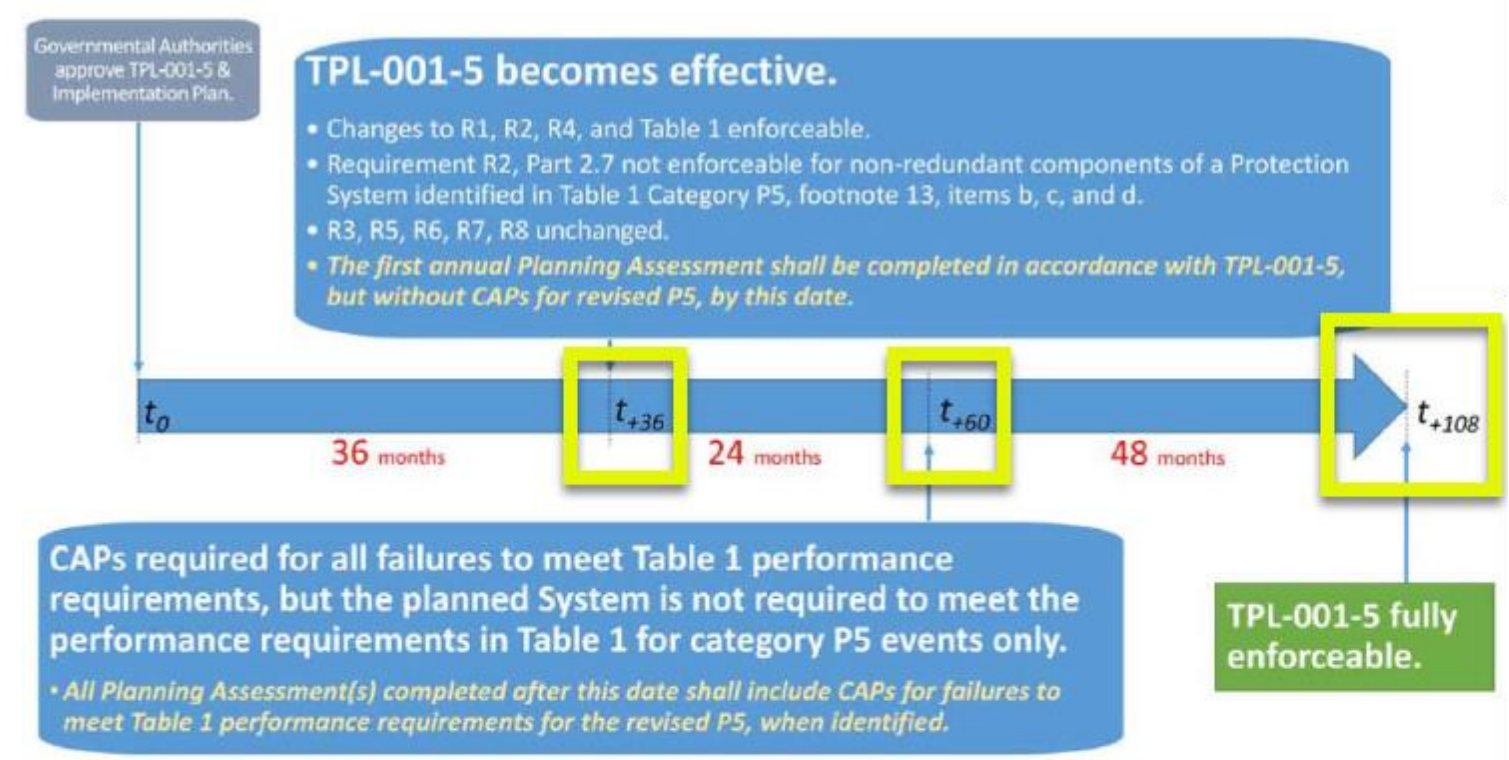


Figure 1 Implementation Plan Timeline

Figure from NERC TPL-001-5.1 Requirement Training

While there is some time until effective dates, the level of work requires action <u>now</u>.

- T+36 months: **Studies must be completed by 7/1/2023** (majority of TPL-001-5.1 R2). Studies must consider these footnotes.
- T+60 months: **Corrective action plans must be developed by 7/1/2025** (TPL-001-5.1 R2.7).
- T+108 months: **Corrective Action Plans must be completed by 7/1/2029** .

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P5 Multiple Contingency *(Fault plus non-redundant component of a Protection System failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant component of a Protection System[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	Loss of one of the following followed by System adjustments.[9] 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device[6] 4. Single pole of a DC line	Loss of one of the following: 1. Transmission Circuit 2. Transformer[5] 3. Shunt Device[6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes

Changes from TPL-001.4 to TPL-001.5

- TPL-001.4 footnote 13 included only one element of the NERC defined "Protection System" - Redundant protective relays.
- TPL-001.5 includes 4 of the 5 components of the "Protection System"
- Protection System redundancy must be determined from an interpretation of language in footnote 13 and supporting NERC documentation. It may be very different from how you would define redundancy.

NERC TPL-001.5 Footnote 13

- Footnote 13 requires elimination of all single points of failure. T/F
  - FALSE – Footnote 13 requires identification of locations where the redundancy tests of 13 a-d are not met to scope the transmission studies that will determine if mitigation is required
- Where redundancy tests are not met, backup clearing times, breakers, fault currents and Thevenin impedances must be provided for stability studies with SLG faults
  - Providing these values is complicated for SLG faults if you use 67N elements.

  i.e. Multistage sequential clearing – Not uniform Zone 2 times.
- Planning groups need to run studies with this information and determine where instabilities may occur.

NERC TPL-001.5 Footnote 13

- Exceptions/Exclusions are allowed for 13 b-d and are heavily used outside of NPCC
- 13 d exclusion is written distinctly different than those of 13.b and 13.c.
- 13 b and 13 c lists an exception for the circuit.
  - Communication System
  - DC Supply
- 13 d only lists a subset of equipment that is excluded (trip coil only), not the circuit.

TPL-001.5 Footnote 13.

For purposes of this standard, non-redundant components of a Protection System to consider are as follows:

a. A single protective relay which responds to electrical quantities, without an alternative (which may or may not respond to electrical quantities) that provides comparable Normal Clearing times;

b. A single communications system associated with protective functions, necessary for correct operation of a communication-aided protection scheme required for Normal Clearing (an exception is a single communications system that is both monitored and reported at a Control Center);

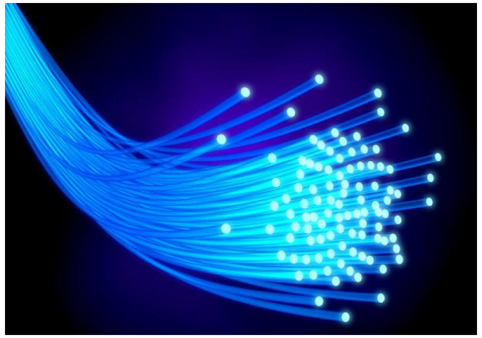
c. A single station dc supply associated with protective functions required for Normal Clearing (an exception is a single station dc supply that is both monitored and reported at a Control Center for both low voltage and open circuit);

d. A single control circuitry (including auxiliary relays and lockout relays) associated with protective functions, from the dc supply through and including the trip coil(s) of the circuit breakers or other interrupting devices, required for Normal Clearing (the trip coil may be excluded if it is both monitored and reported at a Control Center).

13a. A single protective relay which responds to electrical quantities, without an alternative (which may or may not respond to electrical quantities) that provides comparable Normal Clearing times

- At BES voltages all utilities likely apply two levels of microprocessor protective relays
- No exclusion for protective relays for monitoring or alarming is given
- Common problem areas
  - **Many electromechanical relays** and some solid state and microprocessor relays may lack redundancy
  - **Many older bus differential** relay schemes are not redundant-can have significant system impacts
  - **Bank differential** relaying needs to be checked for delayed clearing in some cases.
- Is redundant breaker failure protection required?
  - Footnote 13 does not apply to breaker failure protection, but the main standard includes a “stuck breaker” reference. This likely requires identifying any BES breakers without breaker failure.

13b. A single communications system associated with protective functions, necessary for correct operation of a communication-aided protection scheme required for Normal Clearing (an exception is a single communications system that is both monitored and reported at a Control Center);



- A single communication system used to be the norm below EHV lines
- With digital communications it is now inexpensive to have redundant communication schemes.
- To rely on redundant digital communications, do we need to check for redundancy in the “cloud”, components and redundant DC supplies to telecom equipment?
- An exception is given for a single scheme that is monitored and reported at a Control Center.
- Can you produce evidence that every communication system is monitored and reported to a Control Center?

13c. A single station dc supply associated with protective functions required for Normal Clearing (an exception is a single station dc supply that is both monitored and reported at a Control Center for both low voltage and open circuit)

- Some utilities have redundant DC batteries on some or all of their BES stations.
- Many utilities do not have redundant DC batteries at all BES stations.
- The exception for a single battery can be used but is complicated.
- **Monitoring and alarming from the battery charger is generally not sufficient to meet the exception**.
- See diagram on next slide.

DC Supply Monitoring

- Most companies have DC UV alarms
- New battery chargers have sophisticated monitoring/alarms but typically do not detect open battery cells or connectors
- Typical battery charger monitoring cannot detect an open cell if DC load is still connected.
- Battery Monitoring Systems are generally required to meet the monitoring exception.
- DC supply monitoring requirement of PRC-005 will meet TPL-001.5.

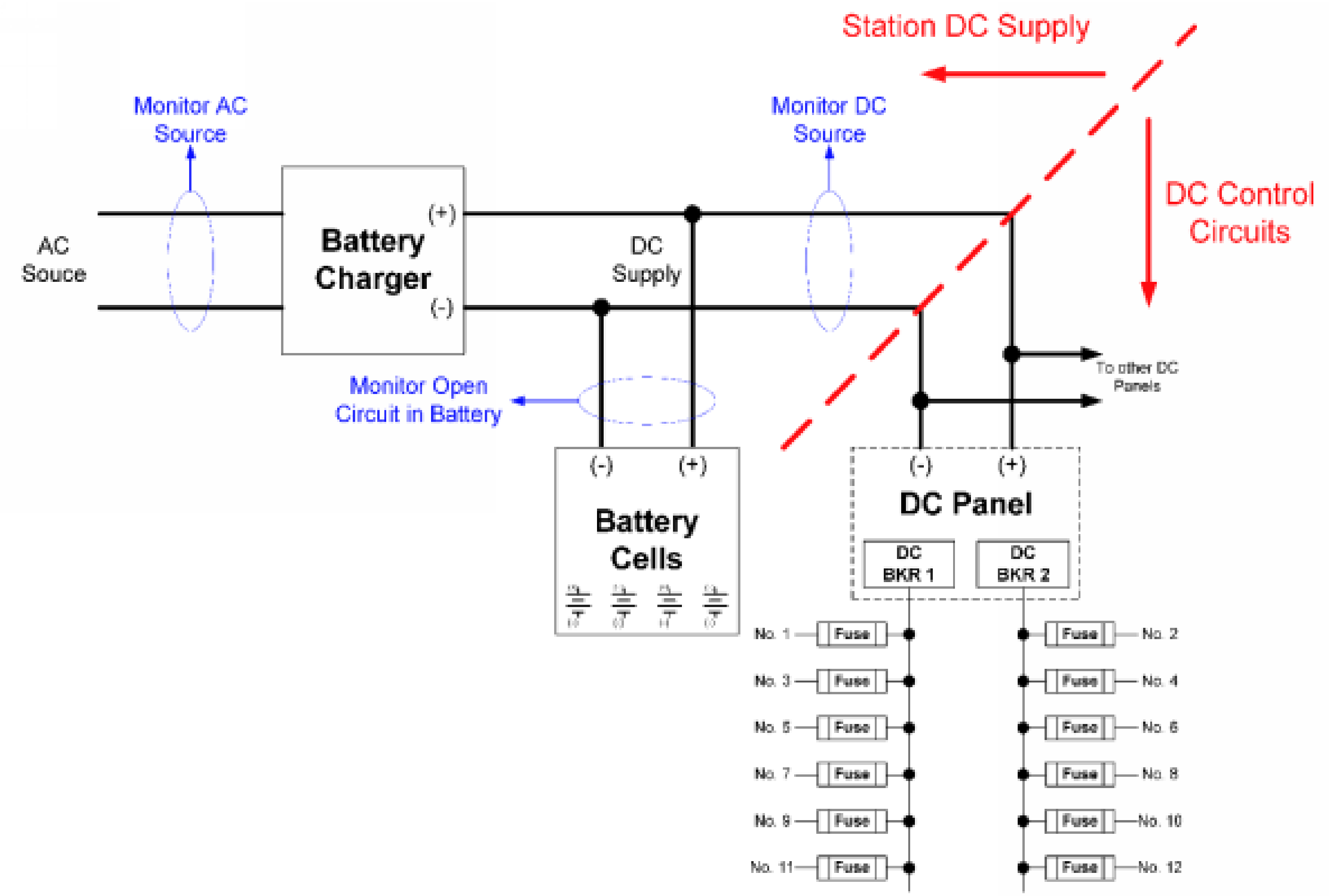


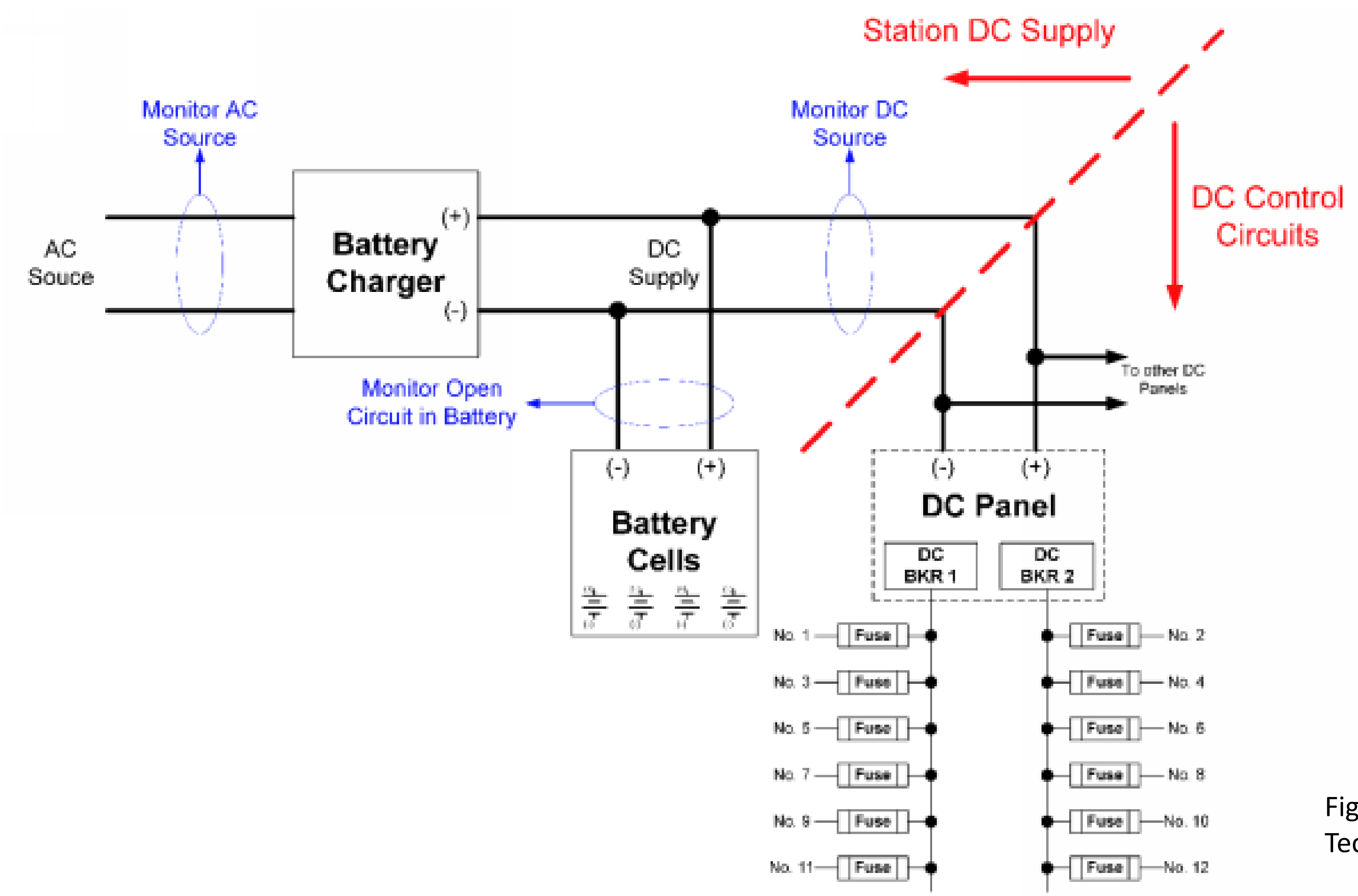
Figure from FERC Order No. 754 and NERC Technical Paper and Technical Rational for TPL-001.5

13d. A single control circuitry (including auxiliary relays and lockout relays) associated with protective functions, from the dc supply through and including the trip coil(s) of the circuit breakers or other interrupting devices, required for Normal Clearing (the trip coil may be excluded if it is both monitored and reported at a Control Center).

- Control circuitry in 13d is the most challenging part of footnote 13.
- Note the monitoring exclusion is **only for the trip coil** and no other components of the control circuit.
- The authors company has submitting a NERC Standard Authorization Request(SAR) to change 13d to allow excluding all components of the control circuit that are monitored and reported.
- See following figures

Decide Where to Draw the Line;

Drawing from the Technical Rationale for TPL-001.5

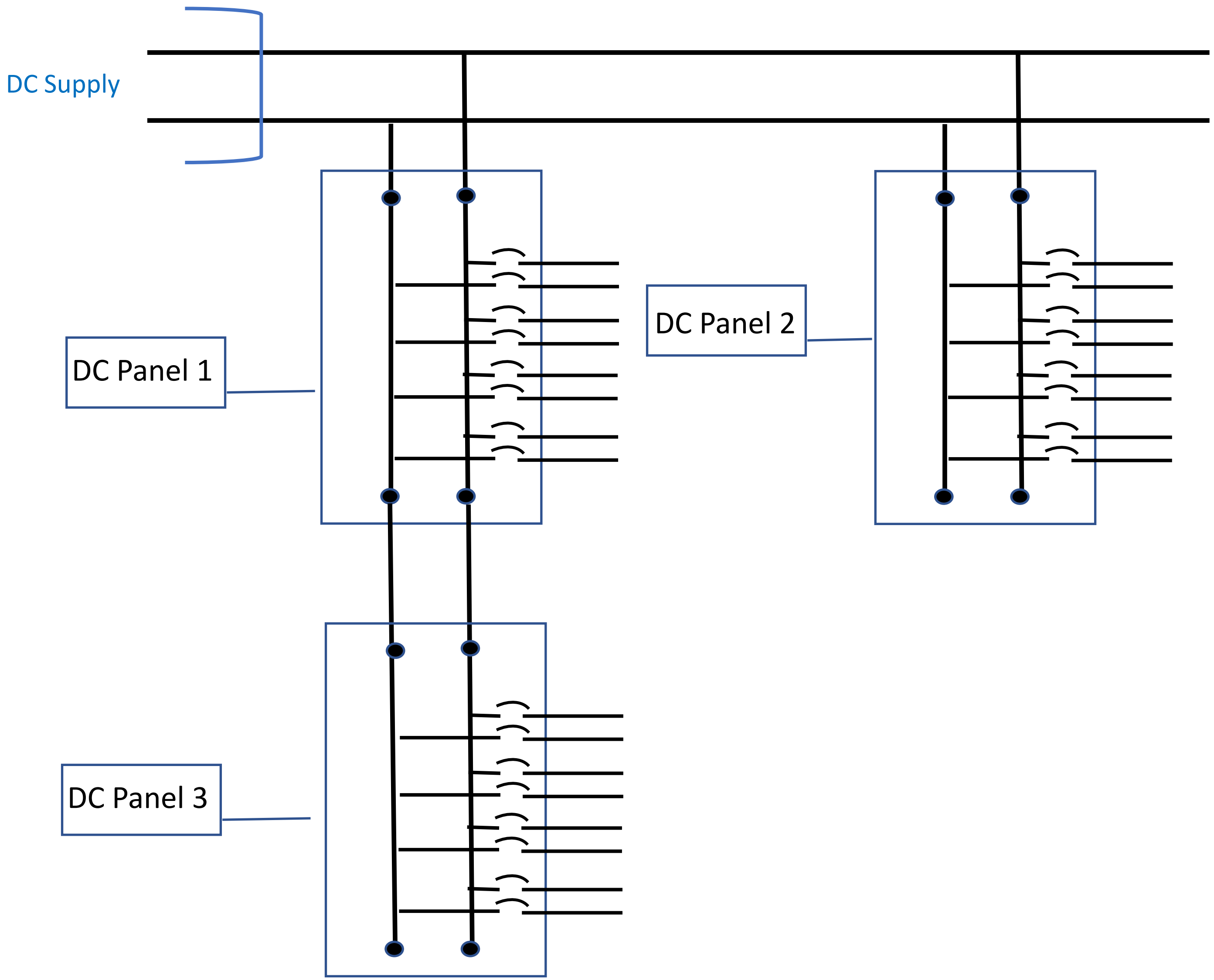


Public

- Can you draw the line of demarcation between DC Supply (footnote 13.c) and Control Circuits (footnote 13.d) anywhere?
- No gap should exist between DC Supply and Control Circuits.
- Have you ever had a complete DC panel failure?

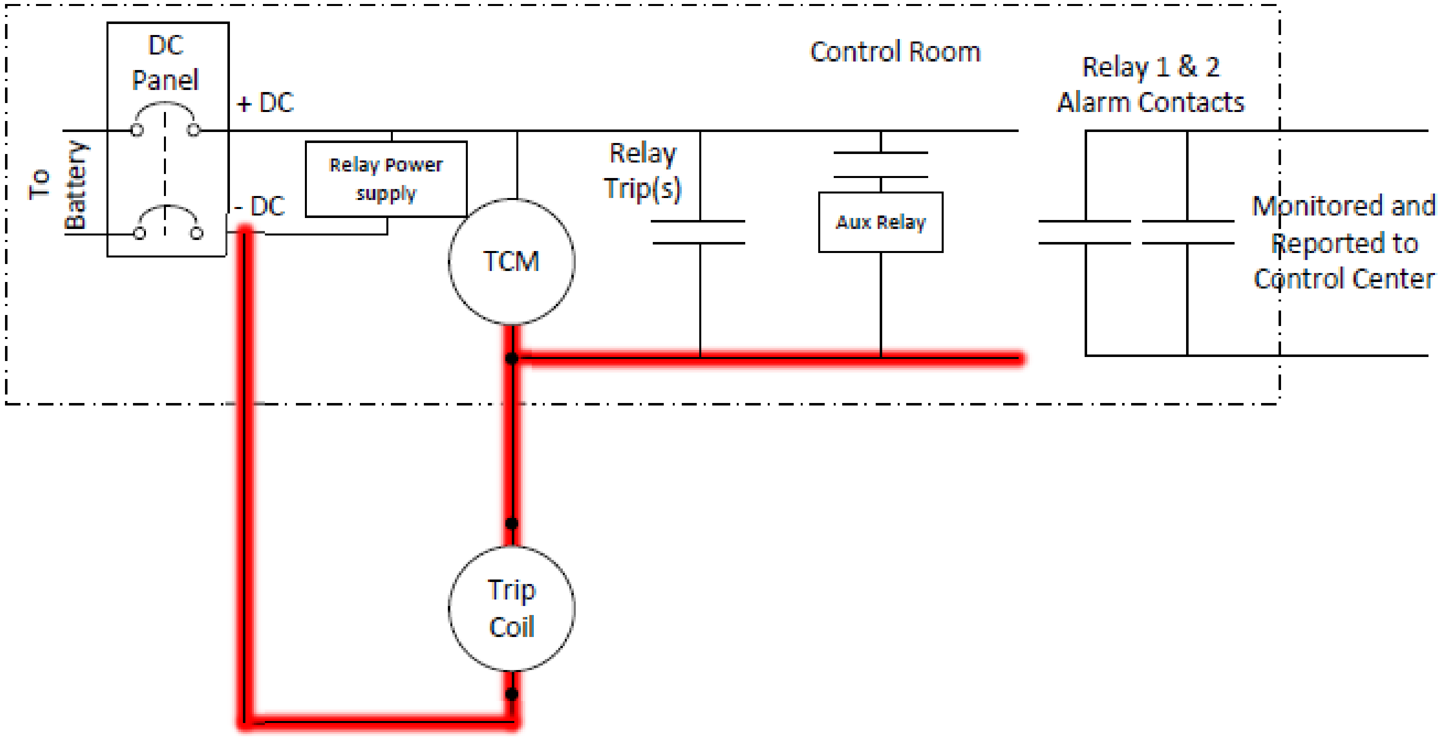
Figure from FERC Order No. 754 and NERC Technical Paper and Technical Rational for TPL-001.5

Control Circuitry – DC Panels



- If Primary and Backup Relays are both fed from the same DC Circuit they **fail** redundancy
- If Primary and Backup Relays are fed from separate circuits on DC Panel 1 they **fail** redundancy
- If Primary Relay is fed from DC Panel 1 and Backup Relay is fed from DC Panel 3 they **fail** redundancy
- If Primary Relay is fed from DC Panel 1 and Backup Relay is fed from DC Panel 2 they **pass** redundancy
- What if a breaker DC and Breaker Failure Relay DC are fed from the same panel?

Control Circuit – Monitored and Reported

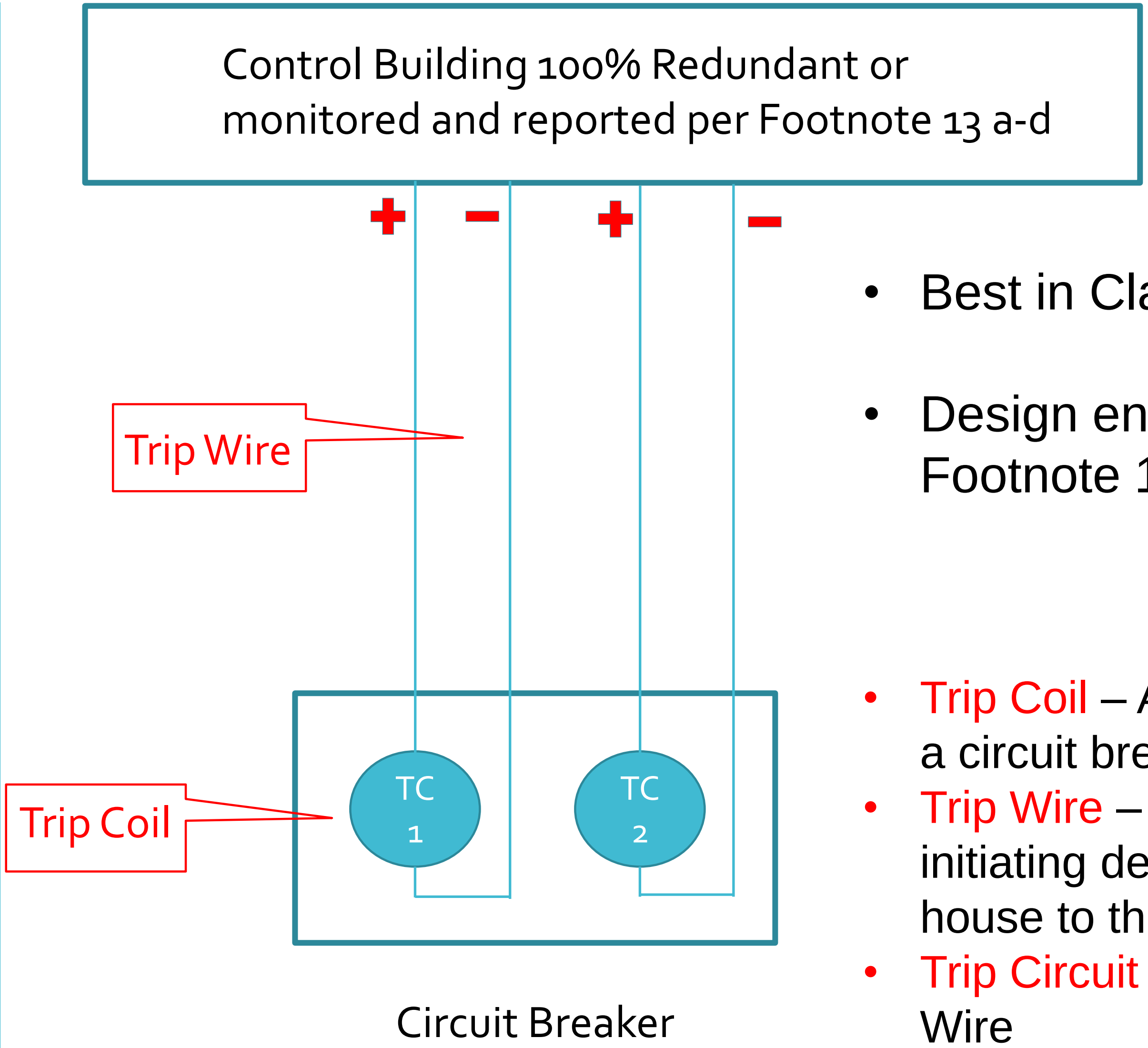


TCM is a Trip Coil Monitor or Trip Circuit Monitor?

- Note the number of elements in the control circuit: DC panel, fuses, breakers, control wire, aux relay, trip wire, trip coil
- This Installation provides redundancy or monitoring for every portion of the control circuit but does not meet the exclusion allowed in 13d. The exclusion only applies to the trip coil
- If the relay alarm contacts are connected to a separate control circuit, a failure in the DC panel will trigger the relay alarm, a failure in the relay will trigger the relay alarm, a failure of the trip circuit Including the trip coil will trigger the trip circuit monitor alarm if programmed.

Control Circuitry –

Dual Trip Wires and Dual Trip Coils



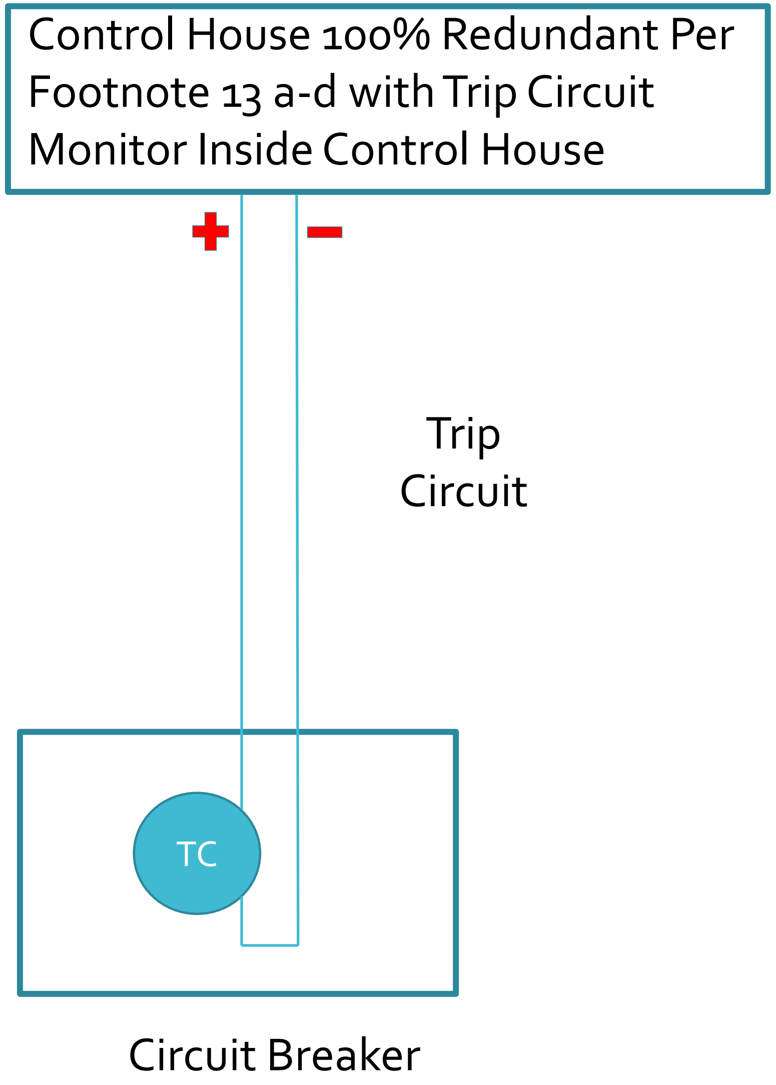
- Best in Class / NPCC Required
- Design encouraged by Footnote 13d.

- Trip Coil – A Solenoid and latch in a circuit breaker to initiate a trip
- Trip Wire – Wire from any trip initiating device in the control house to the circuit breaker
- Trip Circuit – Trip Coil and Trip Wire

Control Circuitry

Single Trip Wire and Single Trip Coil

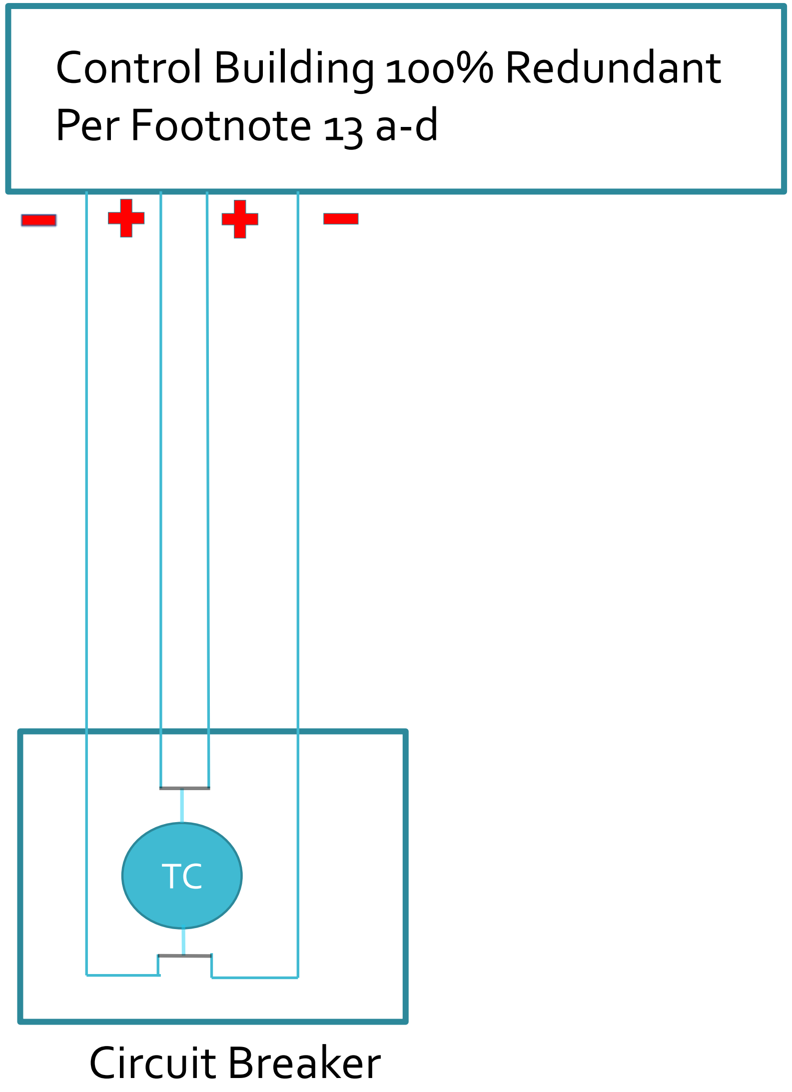
The only way to meet 13 d is to add a second trip wire and trip coil



- Many Companies have some legacy breakers with single Trip Coils.
- Breakers with one Trip Coil generally have one Trip Circuit
- Trip Circuit Monitor - A device/ function that monitors an associated circuit breaker's trip circuit for continuity and for the presence of tripping voltage and sets an externally readable alarm when continuity or tripping voltage is lost (a surrogate for the traditional red light on relay and control panels). IEEE Std 3004.8-2016
- A Trip Circuit Monitor In the Control House monitors the entire Trip Circuit (Trip Wire + Trip Coil) but does not meet the monitoring exclusion for this configuration.

Control Circuitry –

Dual Trip Circuits and Single Trip Coil



- Many companies have some legacy (old) breakers with single trip coils.
- An exclusion is provided for a single trip coil that is monitored and reported but the exclusion does not include the trip wire.
- This design is not practical. It will require combining separate DC trip wires onto common terminals of the Trip Coil creating a single point of failure.

Future Impacts Of Current Language

Current language in 13 d could require spending millions of dollars in a large substation with minimal benefit

Figure A: U/G Conduit Example

Figure B: Trench Example

- When TPL-001-5 R 2.7 becomes enforceable, it will require corrective actions for studies that do not meet stability criteria.
- Control circuits in scope of TPL-001-5 Footnote 13d that are non redundant, could require corrective action such as installation of a redundant trip wire and trip coil.
- Some installations utilize underground conduit (fig A) and some use trenches (figure B).
- Underground conduit may be fully utilized, plugged with mud or collapsed in older substations.
- Adding new conduit in energized substations frequently requires hand digging, which can be extremely expensive with no significant reliability improvement.

Track Future Changes to Your System

- Assuming your system is not perfect the following steps are required:
  - Determine all BES elements that do not meet footnote 13 Redundancies.
  - 13 d requires validating DC panel layout, DC circuit arrangement, Trip circuit redundancy, trip coil redundancy, Aux relay redundancy, etc. Detailed print review by experienced engineers is required. Estimates range from 2.5 to 5 hours per BES line.
- Creating a process or database for this information and keeping this up to date as equipment is installed or replaced will save large amounts of labor as you perform this evaluation for annual TPL -001 studies for gap analysis.
- Footnote 13 a-d cover parts of the Protection System but do Protection Engineers manage or own <u>all</u> of the assets covered?

Evidence of Monitor and Reported to a Control Center

- Evidence should be a list of Alarm Points displayed for Control Center Operators tied to every exception taken for Monitor and Reporting.
- Telling an auditor it is your standard practice may not be acceptable.
- Looking at alarms wired to an RTU at a substation may not be acceptable.
- The authors assumed that all required monitor and report elements were displayed at Control Center per company standards. This was determined to be inadequate due to SCADA mapping or naming errors on numerous points.

TPL-001.5.1 Footnote 13 d
Standards Authorization Request – Submitted by PG&E

Purpose of SAR

The goal is to enhance the language of the Footnote 13d exclusion to "**any non-redundant components of the control circuitry that are both monitored and reported**" in addition to the current exclusion of the single trip coil. The proposed modification will reduce the burden on the DP, GO, and TO that would be required to install redundant control circuitry to ensure the BES will operate reliably over a broad spectrum of system conditions and following a wide range of probable contingencies that are studied under the TPL-001-5.1 Reliability Standard. This goal can be accomplished by modifying the exclusion language to include monitored and reported components of the control circuitry while reducing risk to BES performance by avoiding additional Protection System complexity.

- Changing the monitoring and reporting exclusion from "trip coil" to "trip circuit" is not equivalent to "control circuitry"

TPL-001.5.1 Footnote 13 d
Standards Authorization Request – Submitted by PG&E

Timeline

Project 2022-02 was authorized to address multiple SAR's affecting modeling under MOD-032 and IBR issues related to TPL-001.5.

PG&E submitted SAR to NERC on December 8, 2022

SAR to modify TPL-001.5 footnote 13 accepted by NERC Board of Directors and assigned to existing SDT 2022-02.

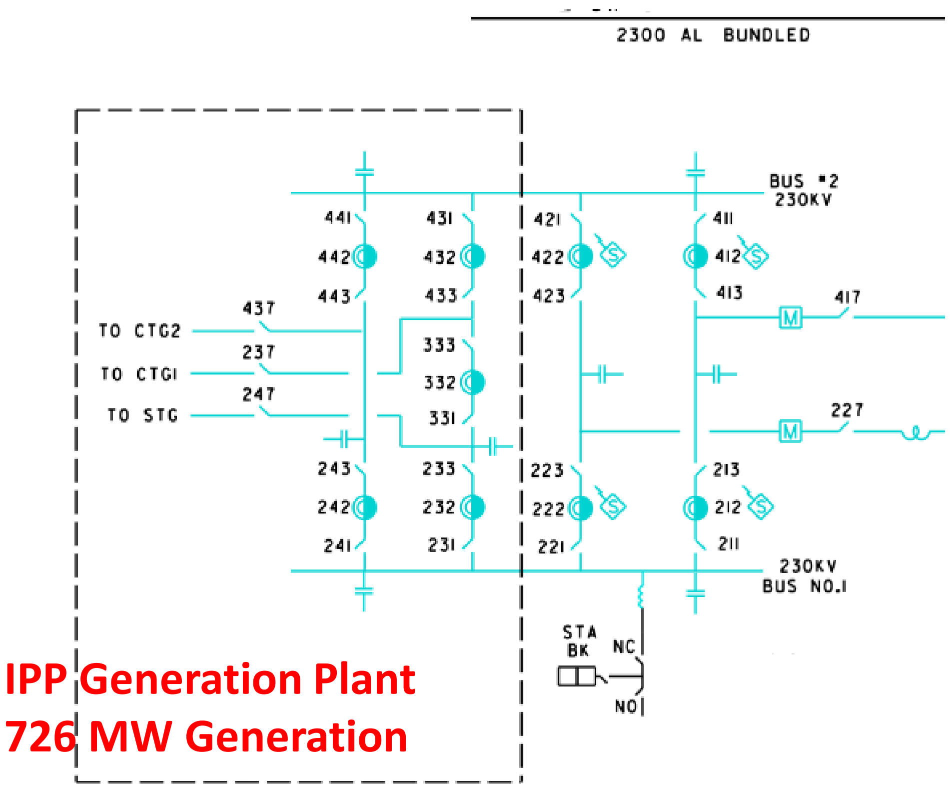
FERC Order 901 became effective on December 18, 2023.

Project 2022-02 phase 1 to modify MOD-032 is considered high priority and may be completed by the end of 2025

Project 2022-02 phase 2 to modify TPL-001.5 currently has no projected timeline.

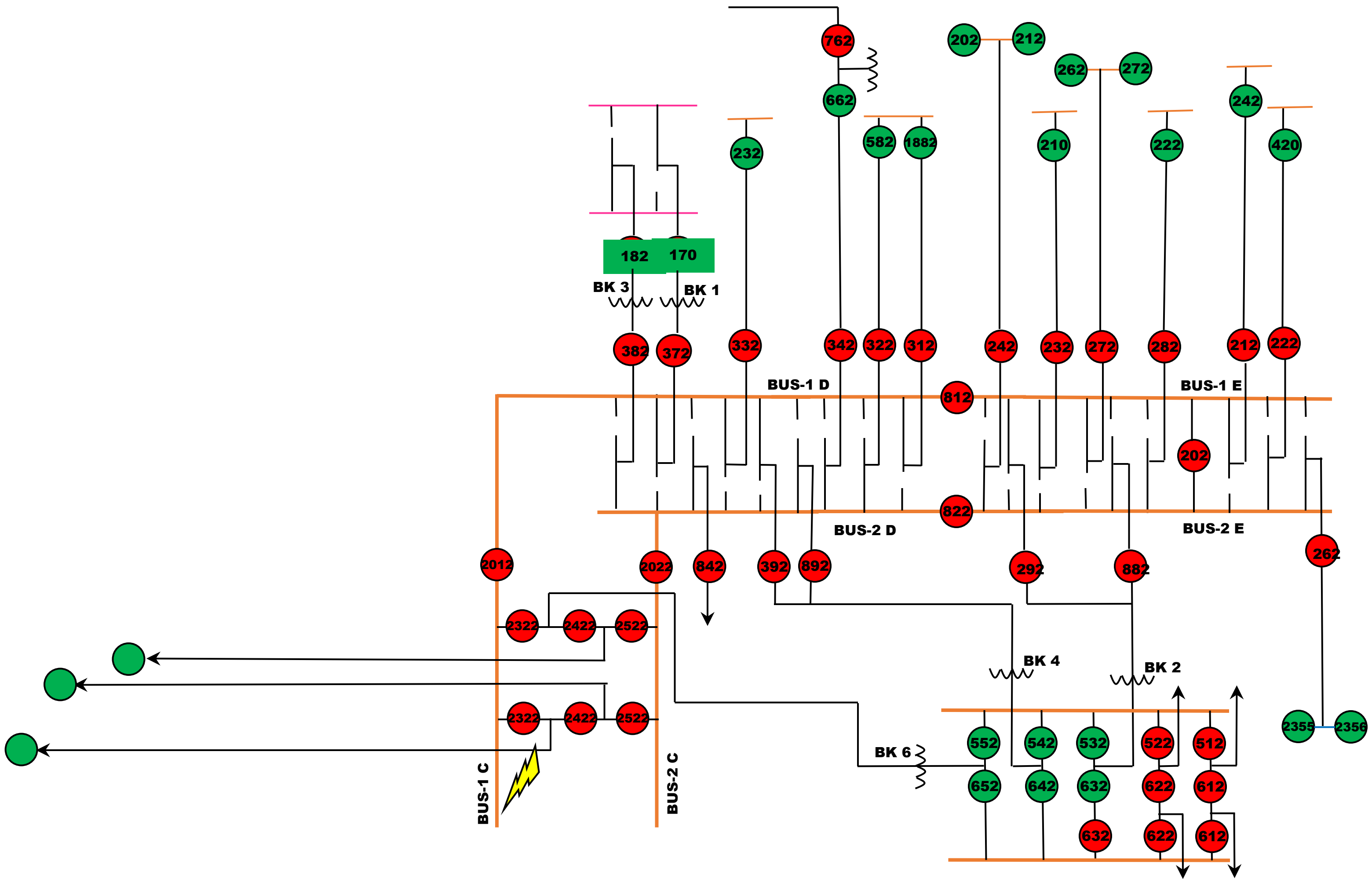
The NERC SPCWG has created a draft white paper to assist the SDT and a draft Implementation Guidance document related to TPL-001.5 footnote 13 d. Neither of these efforts has resulted in any change.

Shared Bus With Separate DC Supply and Control Circuitry



1. TPL-001.5 only applies to TP and TPC.
2. Bus fault with IPP battery failure.
3. Fault on CB 232, 242, 332, 432 or 442 with battery failure at IPP.
4. Fault on Switches 237, 247, or 437 with single point of failure in control circuitry.
5. These faults will result in delayed clearing.
6. **Should utility require IPP and load customers to meet TPL-001.5 footnote 13 requirements?**

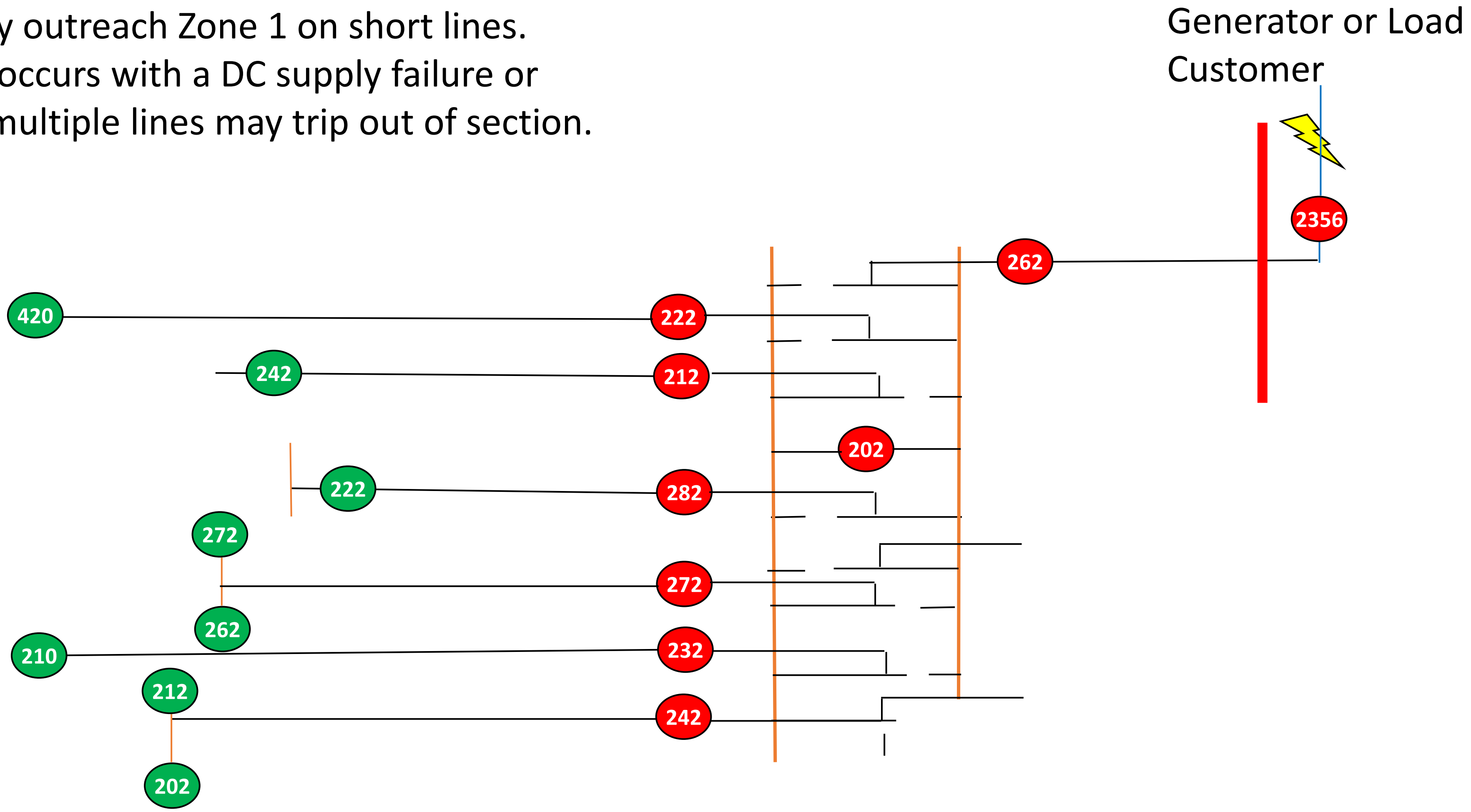
Questions?



BAAH bus fault. Non Redundant Bus Differential scheme fails

Short Line / Longer Line

- Short Line/Long Line can be an overtrip issue.
- Zone 2 on long lines may outreach Zone 1 on short lines.
- If a fault on a short line occurs with a DC supply failure or communication failure multiple lines may trip out of section.



Public

References

- NERC Project 2015-10 Technical Rational for TPL-001.5
- FERC Order No. 754. Single point of failure on Protection Systems
- NERC System Protection and Control Subcommittee Technical Paper of Protection System Reliability –Redundancy of Protection System Elements.
- NPCC Regional Reliability Reference Directory # 4 Bulk Power System Protection Criteria
- IEEE Std 3004.8-2016|View Definitions
  - Trip circuit monitor (TCM): A device/function that monitors an associated circuit breaker’s trip circuit for continuity and for the presence of tripping voltage, and sets an externally readable alarm when continuity or tripping voltage is lost (a surrogate for the traditional red light on relay and control panels).
- IEEE Std C37.20.10-2016|View Definitions
  - Trip coil (of a mechanical switching device): A coil that is part of the electromagnet that initiates the action of a release (trip).
- IEEE PSRC, WG I 19|Redundancy Considerations for Protective Relaying Systems:
  - Another factor that contributes to the compromises of implementing a fully redundant protection scheme is the interconnection to existing equipment. An example of a limited redundant protection system results from connecting to existing circuit breakers that were originally built with single trip coils. In this case the cost of replacing the breaker to complete a fully redundant protection scheme would likely outweigh the other before mentioned benefits.

Advancements in Relay Contact Output Self-Testing and Trip Circuit Monitoring Capabilities

Austin Wade, David Schmidt,
Brandon Nafsinger, and Jordan Bell
Schweitzer Engineering Laboratories, Inc.

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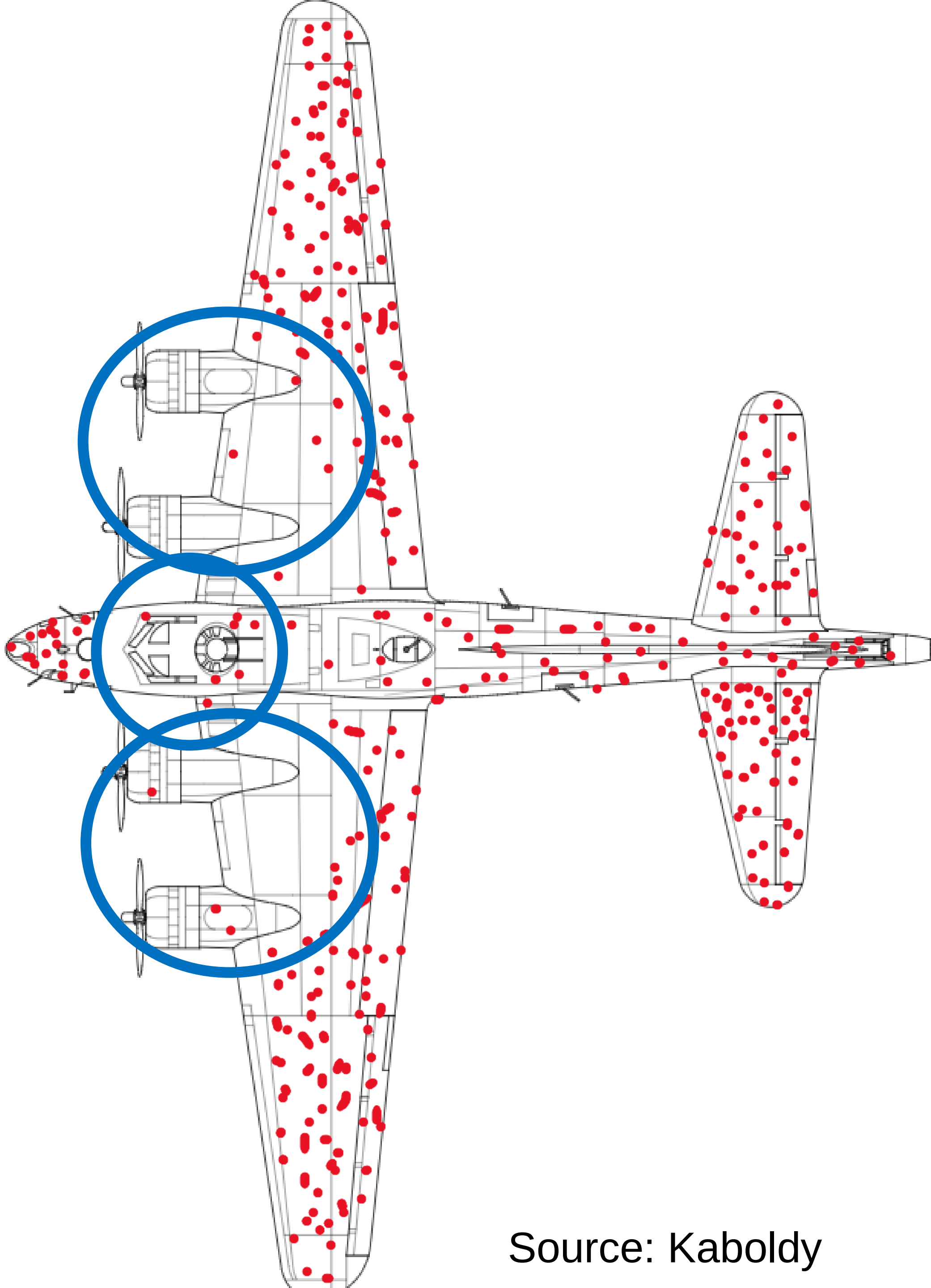


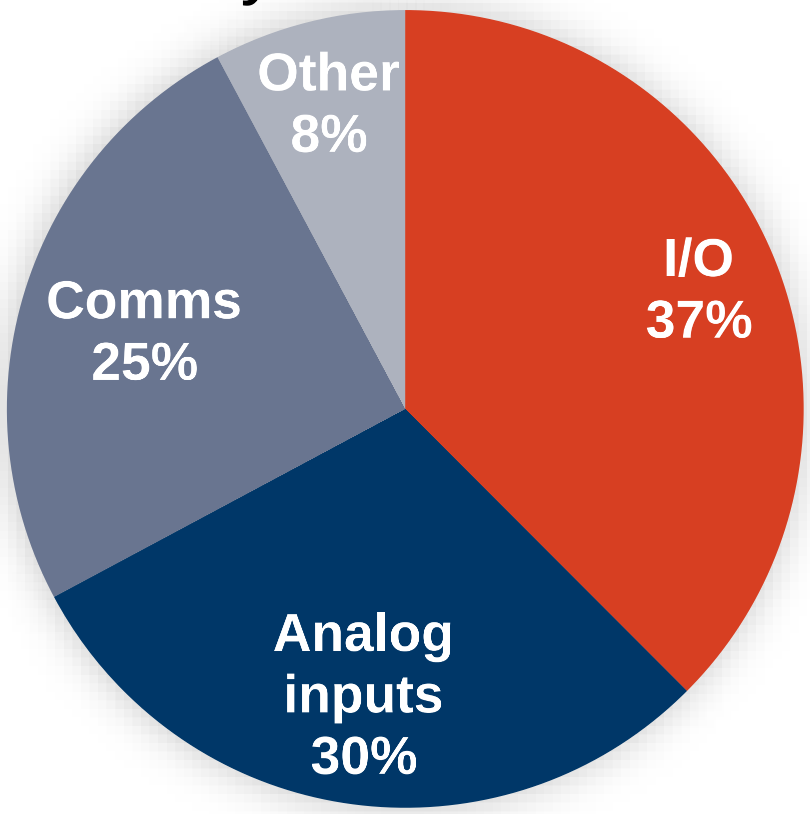
Source: Kaboldy


Do we have areas in our protection systems that have failed, yet we are missing the data?

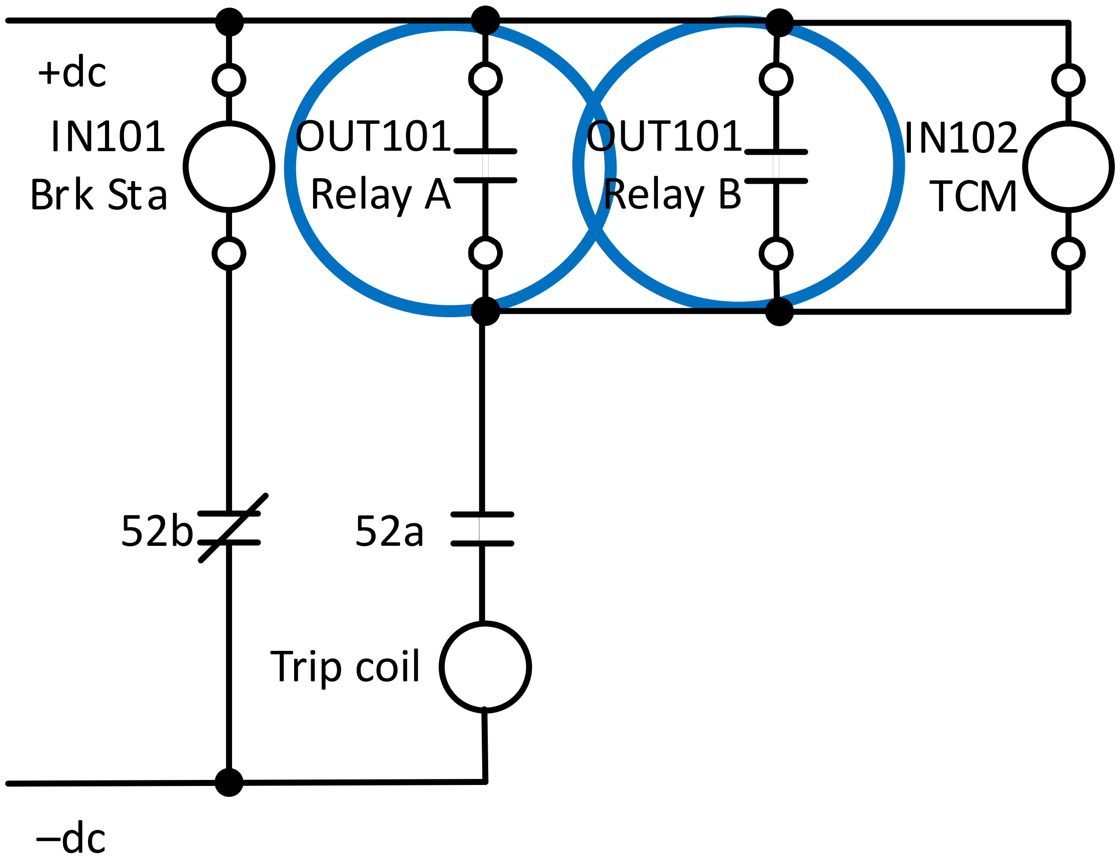
Field-returned data demonstrate self-testing effectiveness

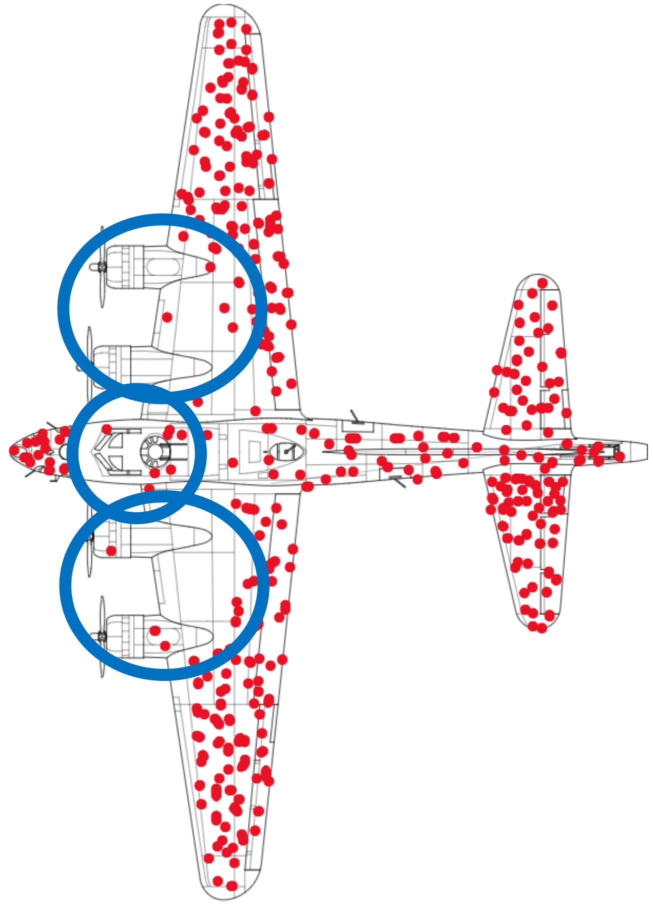
- Assessed 3,300 relays
- Recognized I/O as one of the last self-testing gaps

Critical failures not detected by self-tests



Trip circuit is critical to power system operation



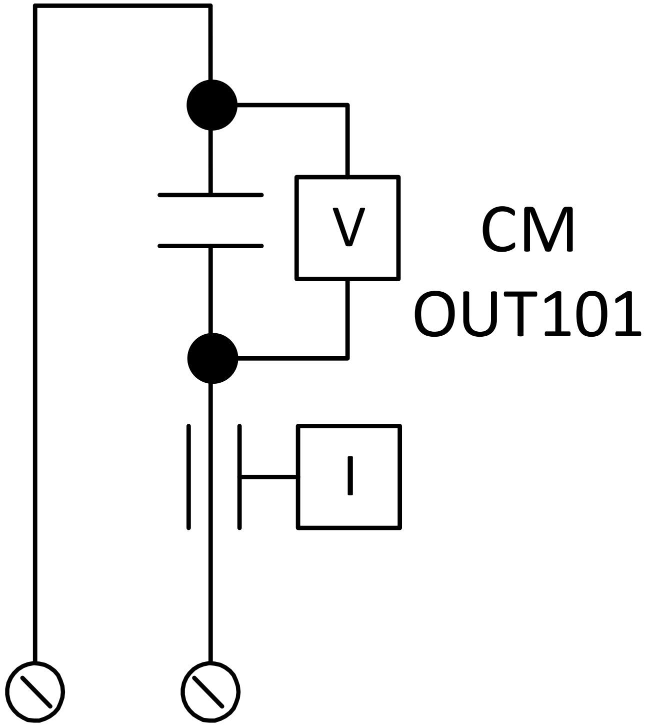


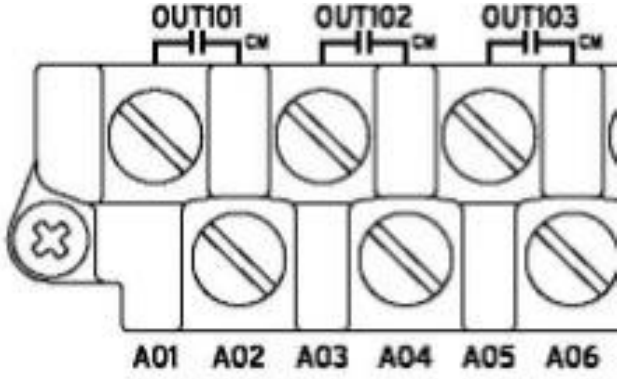
It is time to reevaluate our trip contacts?

New output contact provides comprehensive monitoring

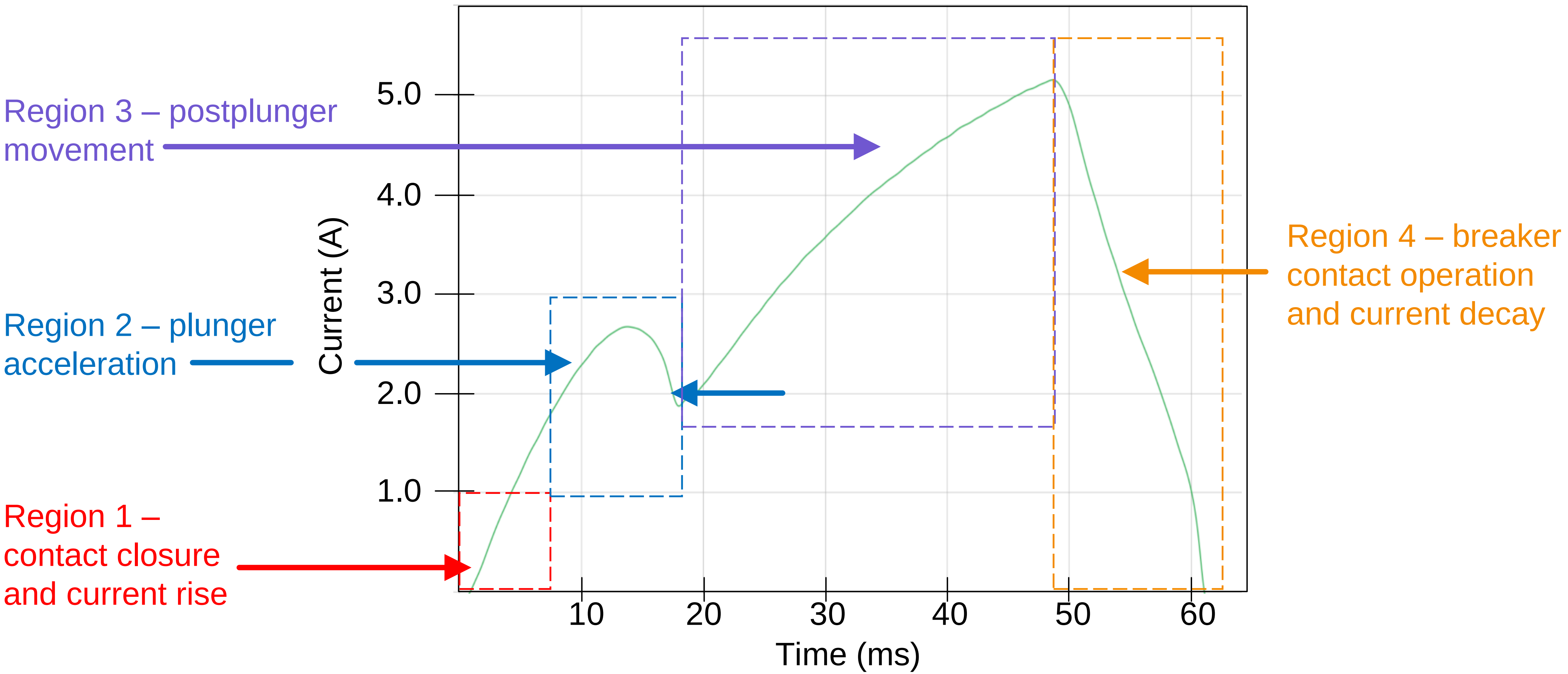
CM outputs

- Are built on proven high-speed, high-current output contact
- Incorporate
  - Voltage: 0–300 V
  - Current: 0–20 A

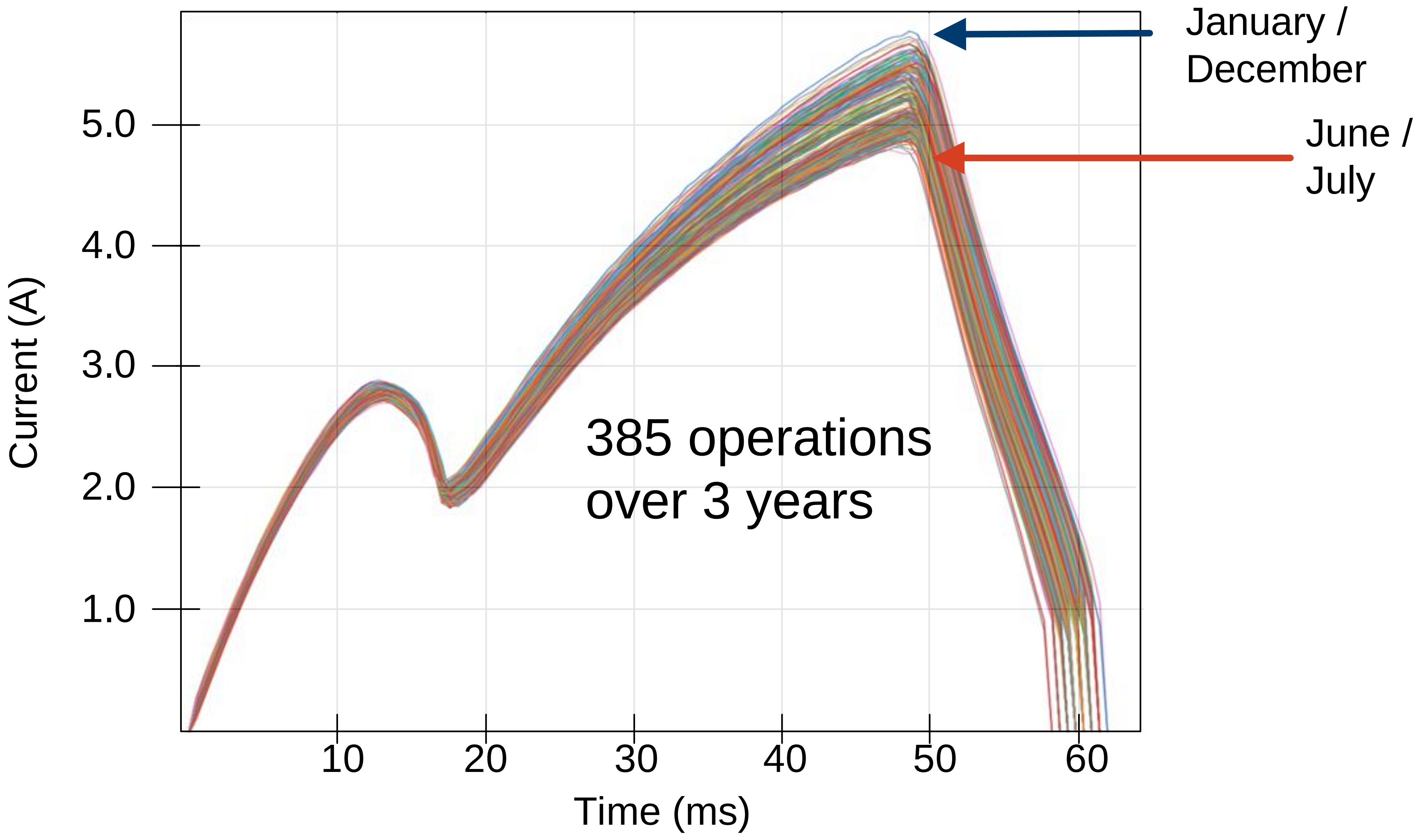




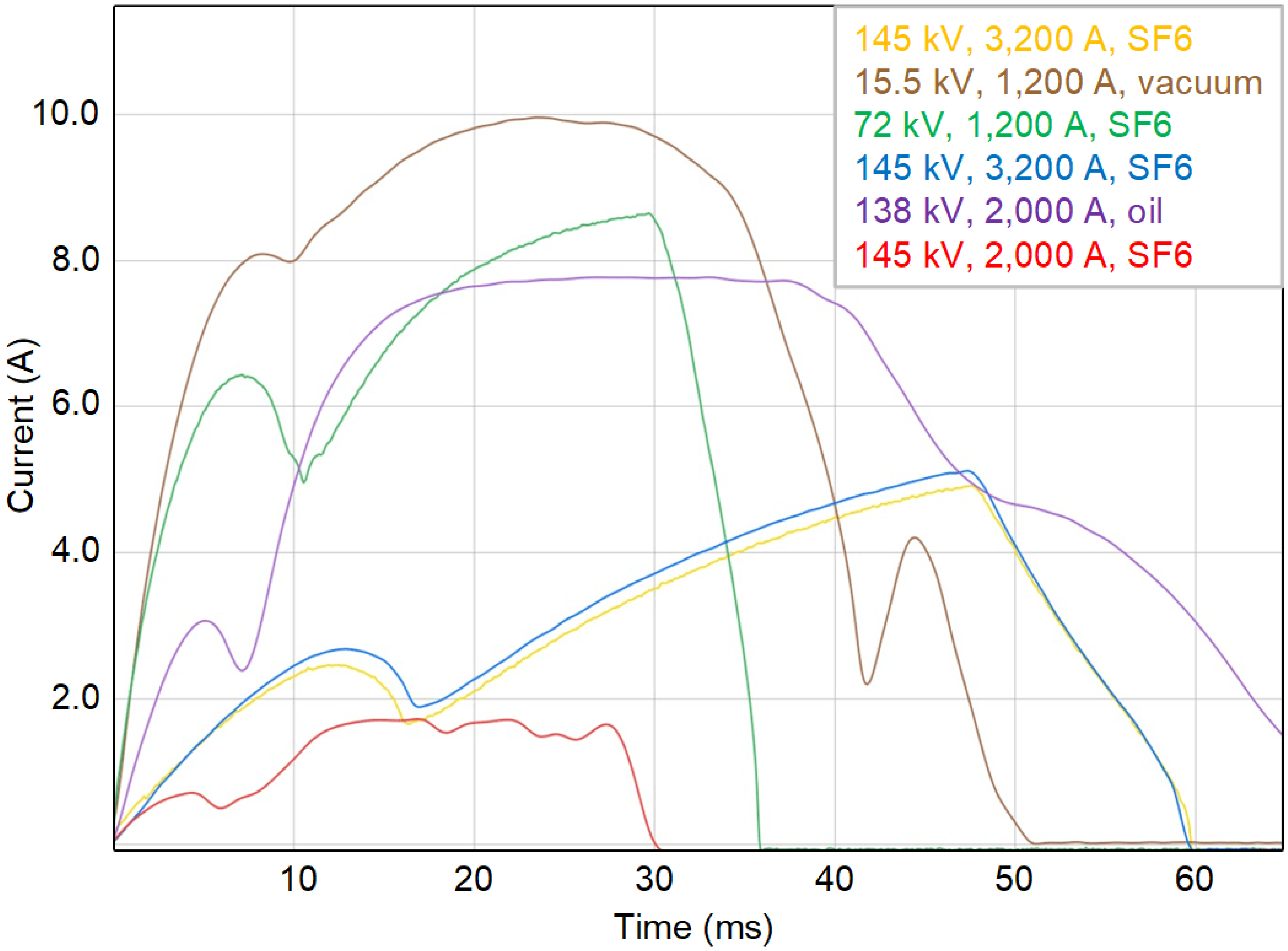
What does current tell us?



Consistent trip signature on same coil

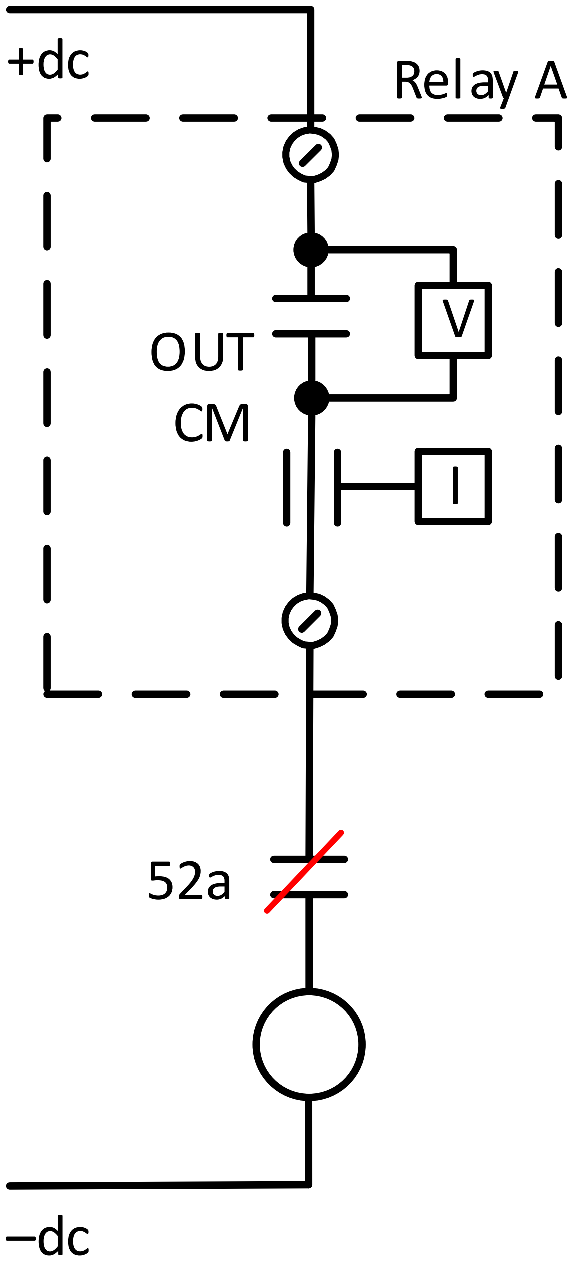


Different breaker types and ratings

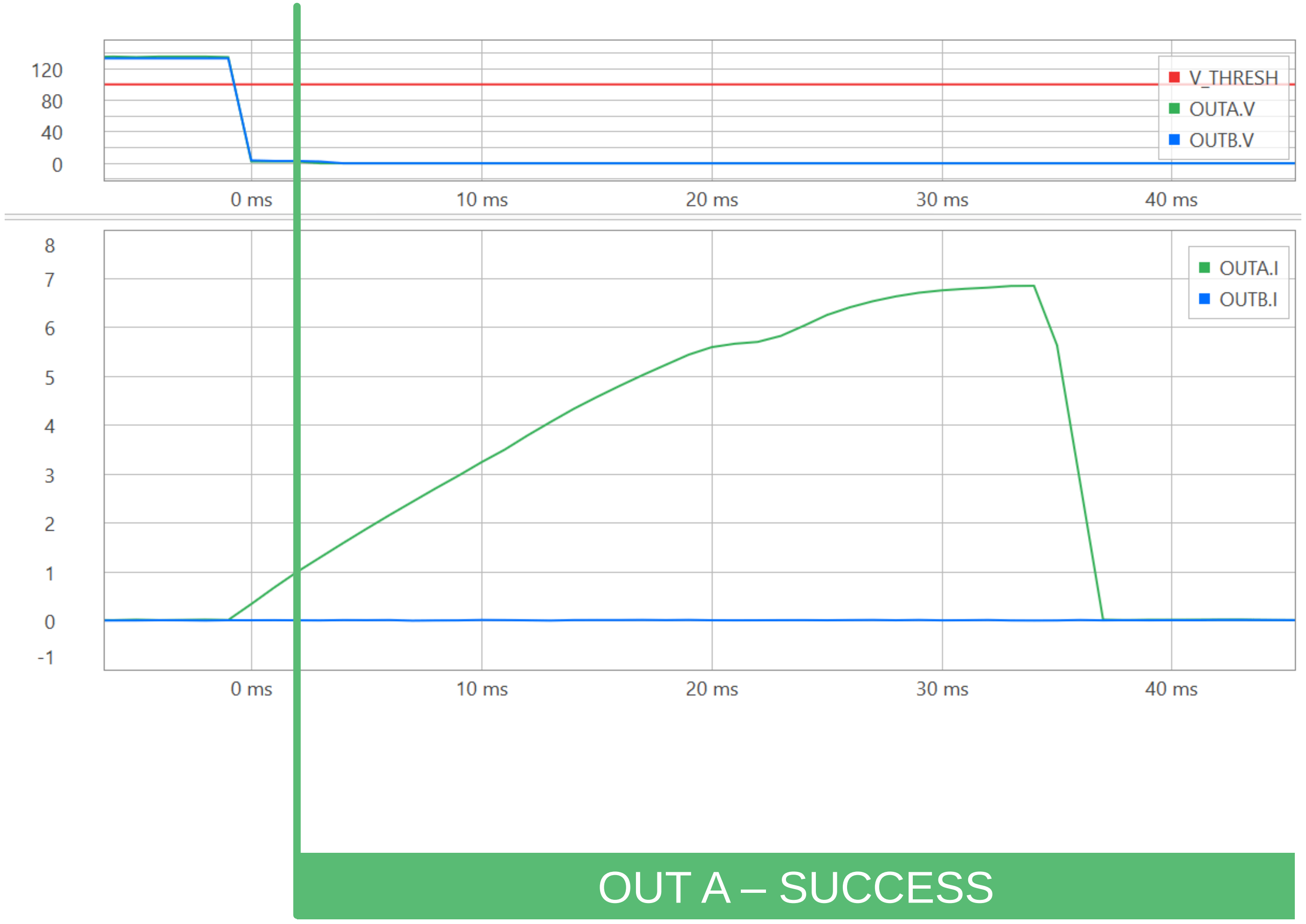


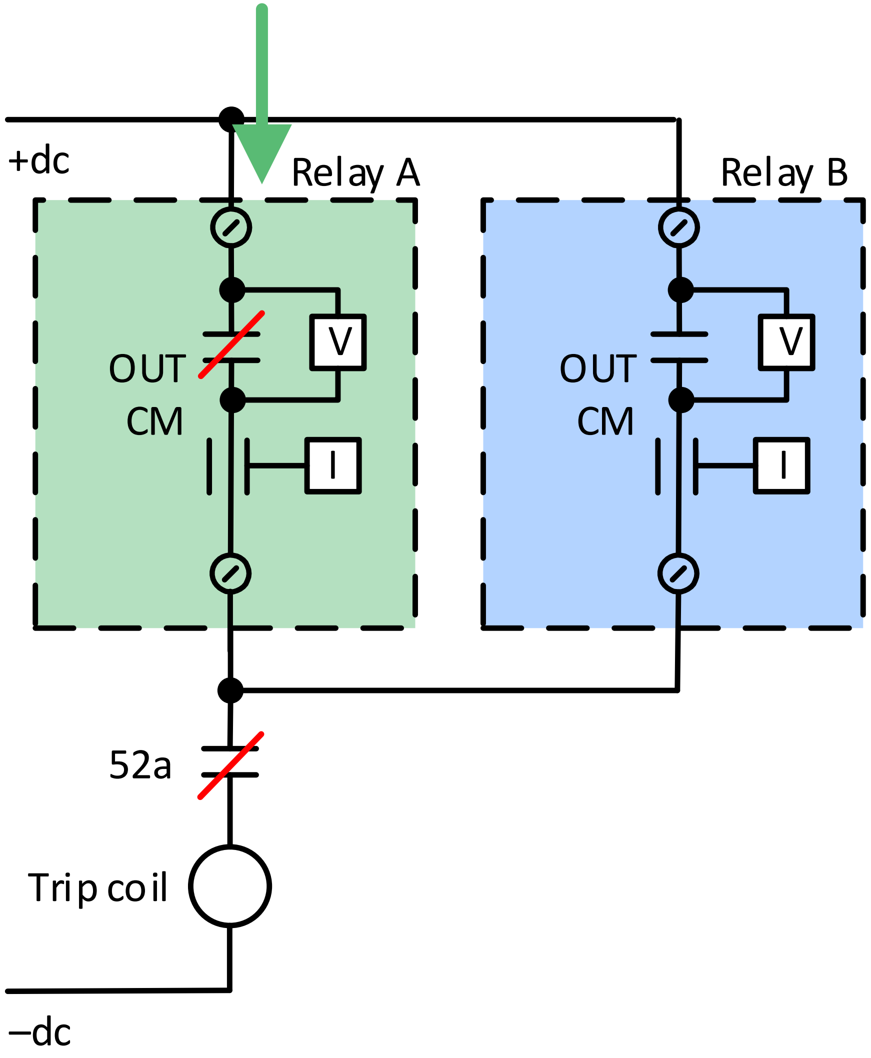
Simple algorithm for single contact

- Success when current is measured
- Fail when no current is measured

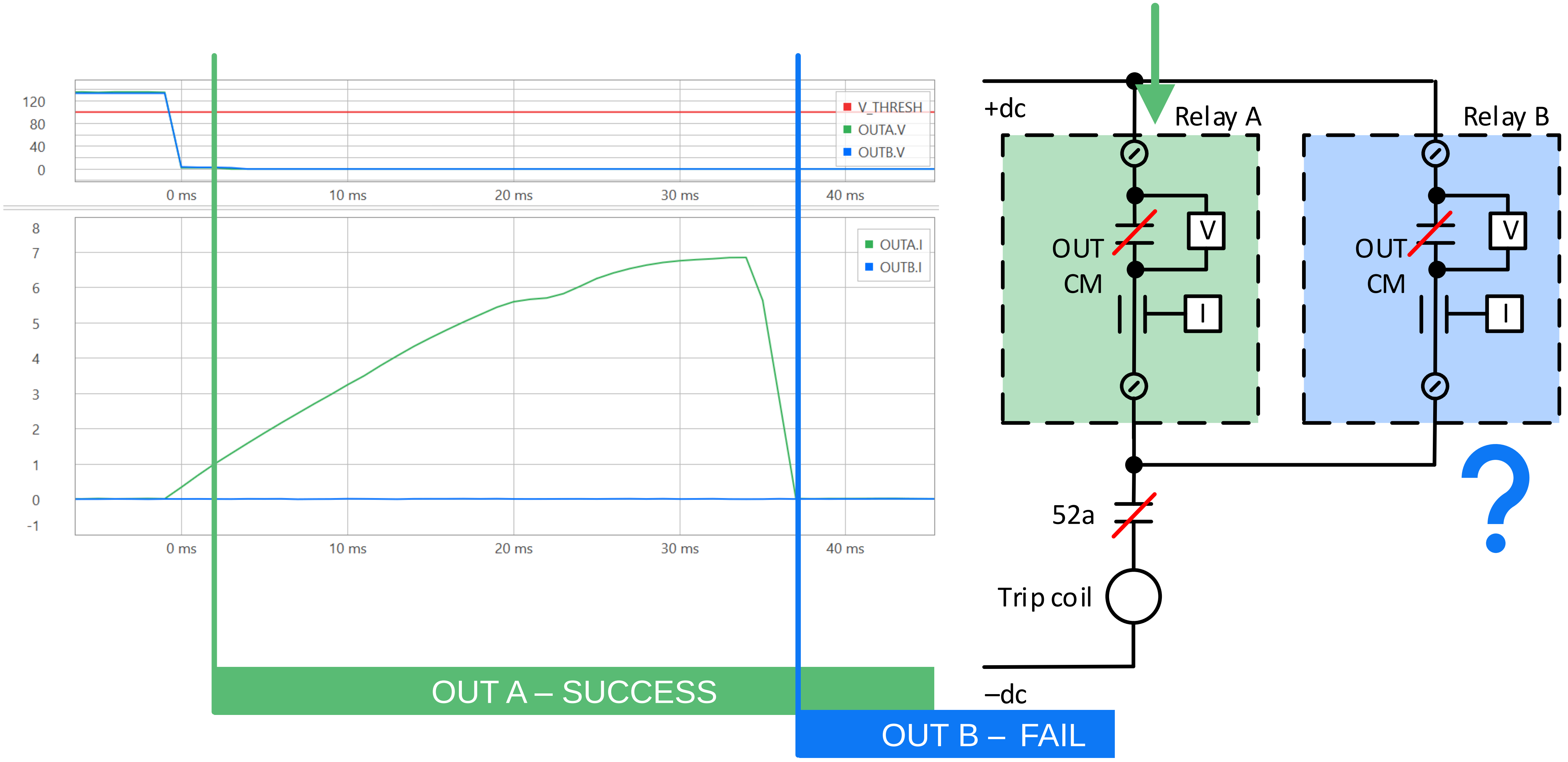


Success when current is measured

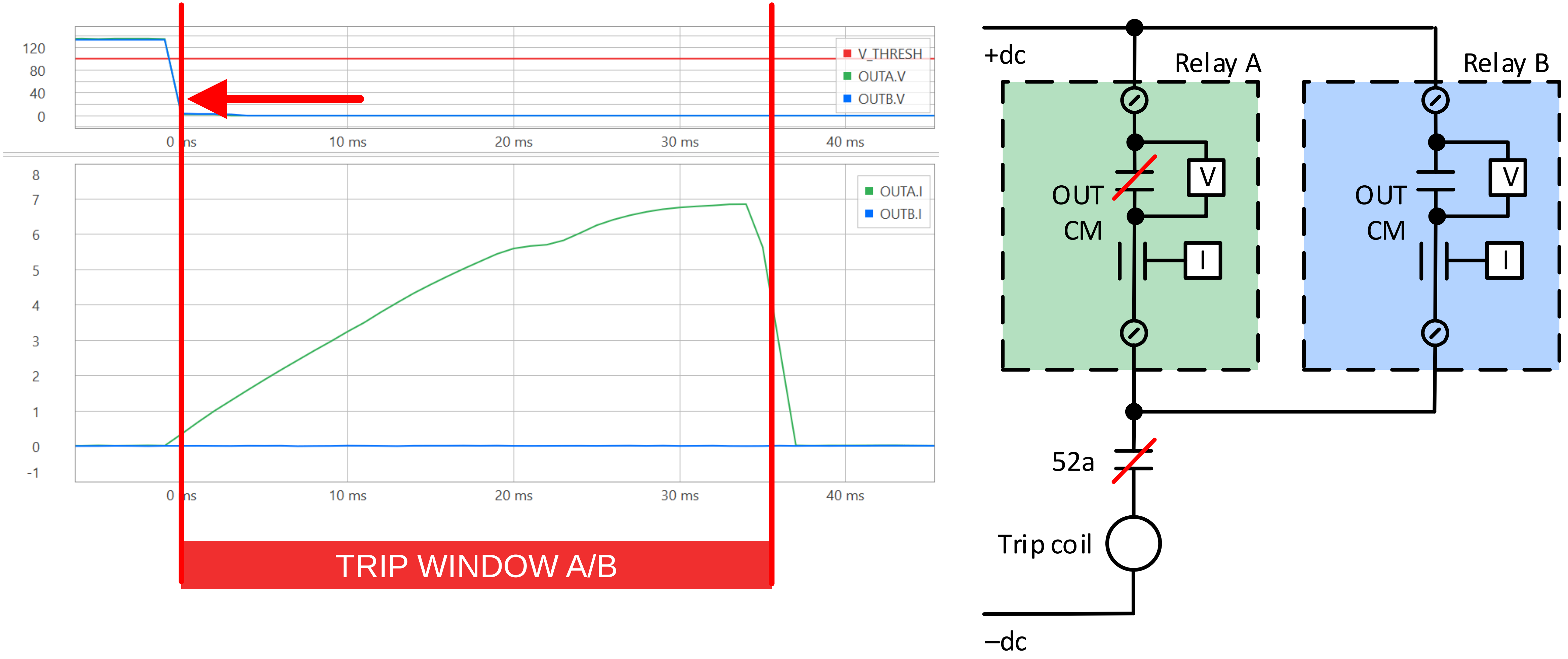




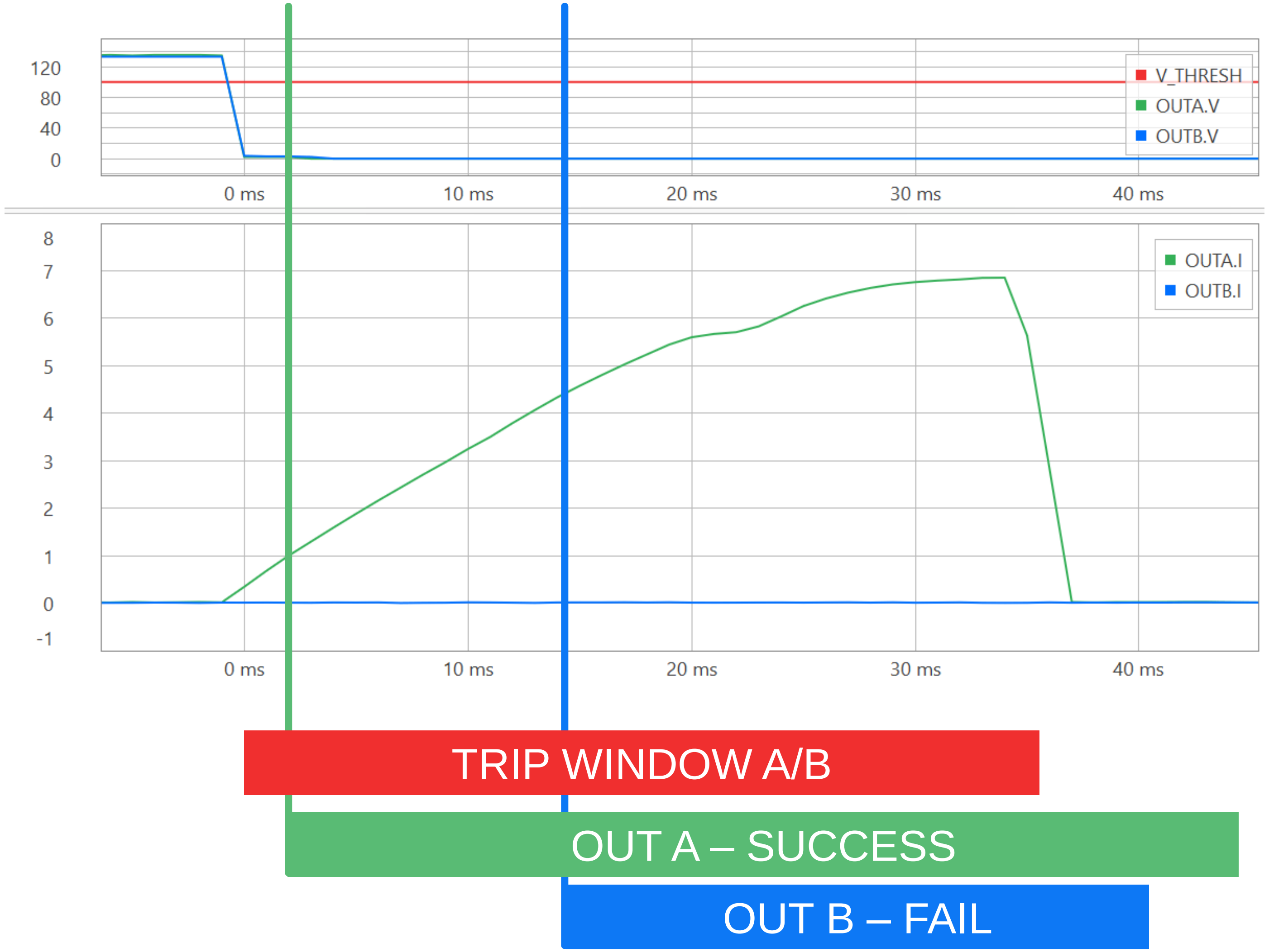
Declaring fail is not as simple

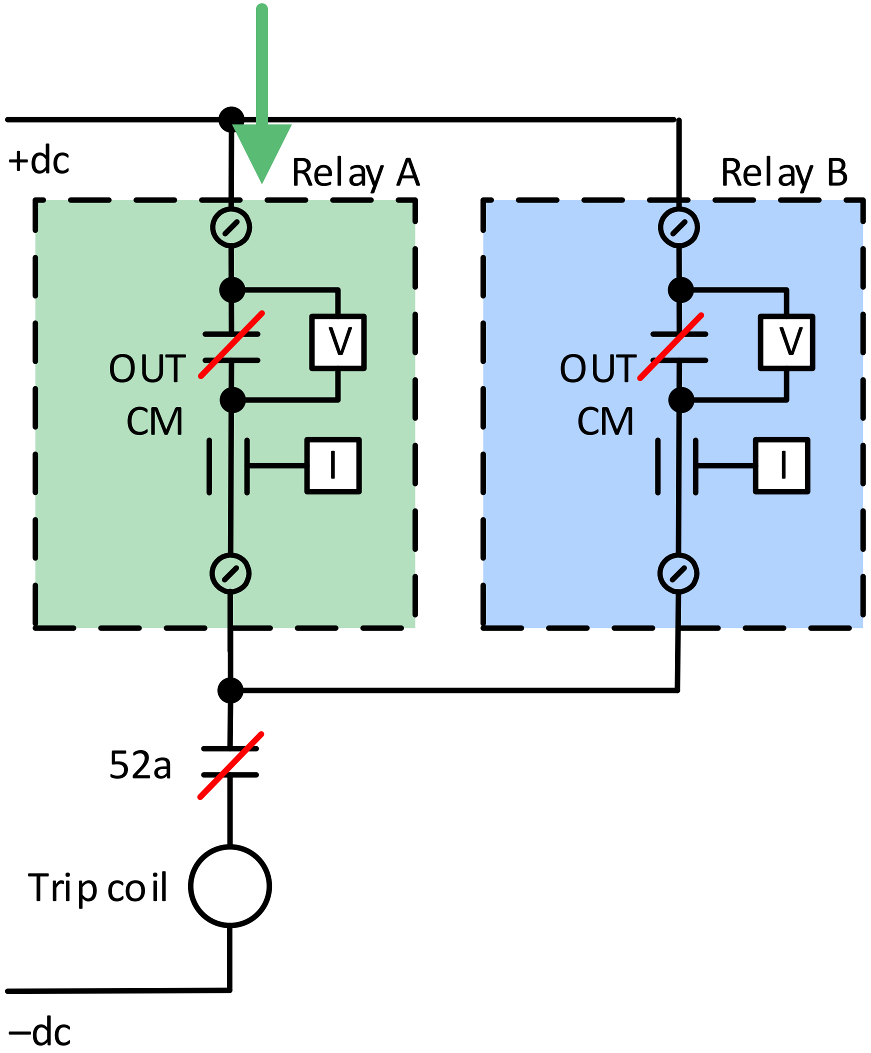


Relays know when closed output should measure current

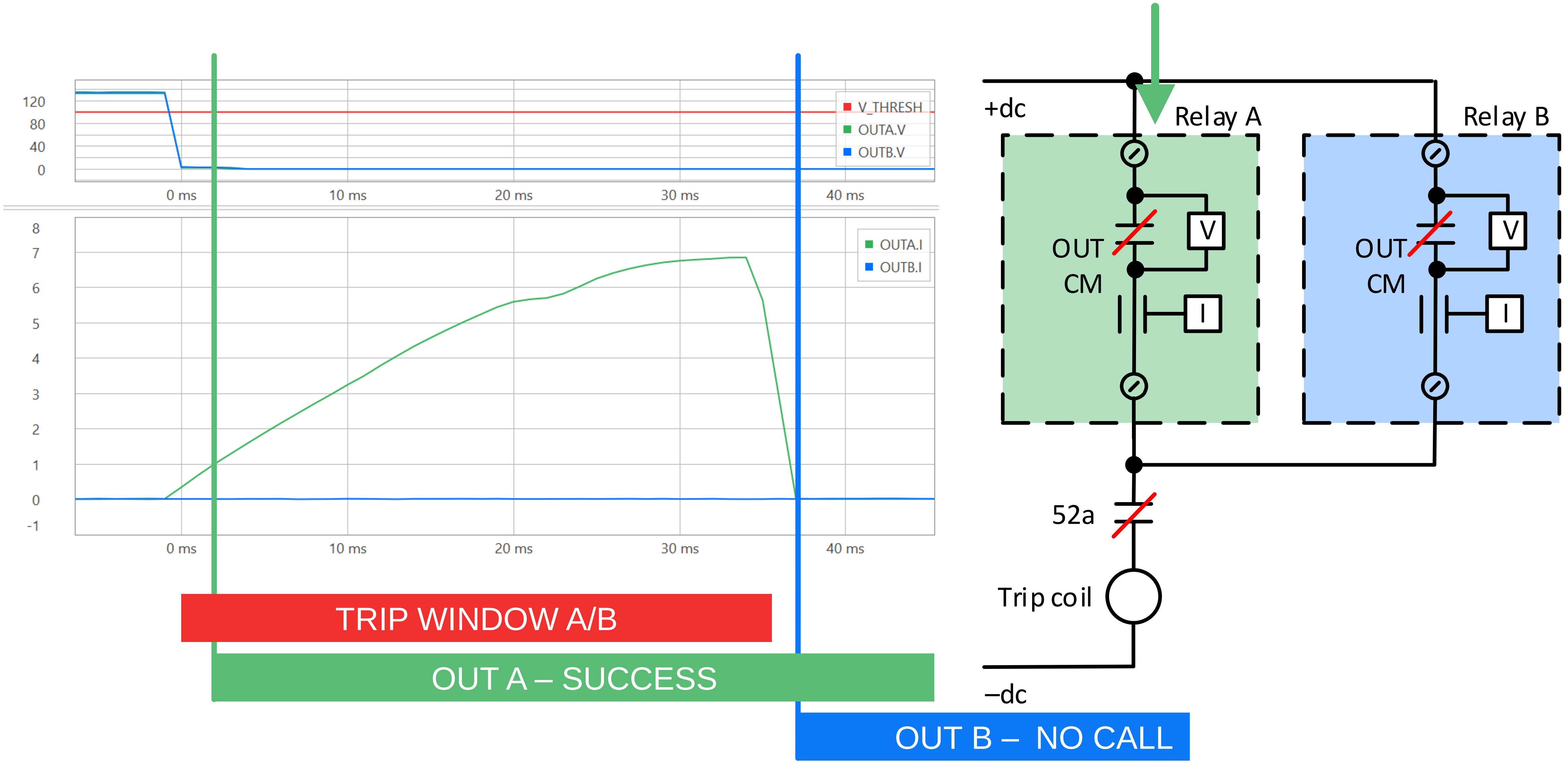


Fail is only declared in trip window

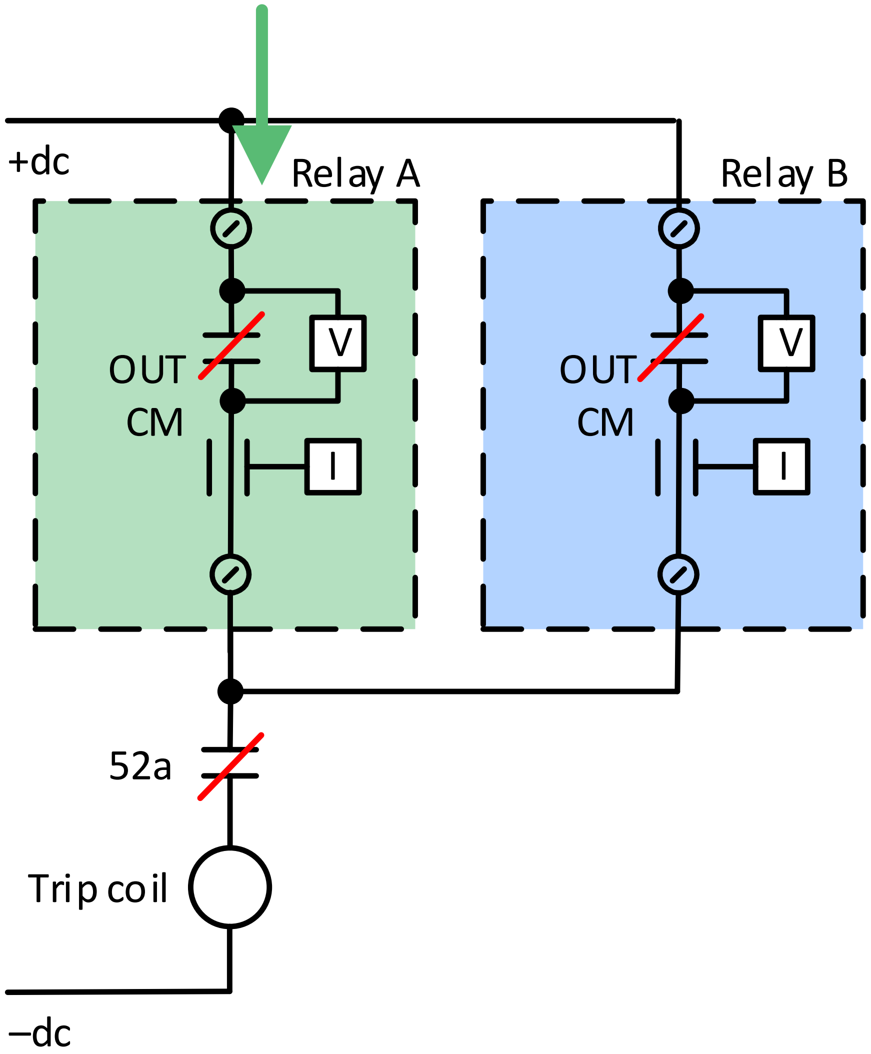




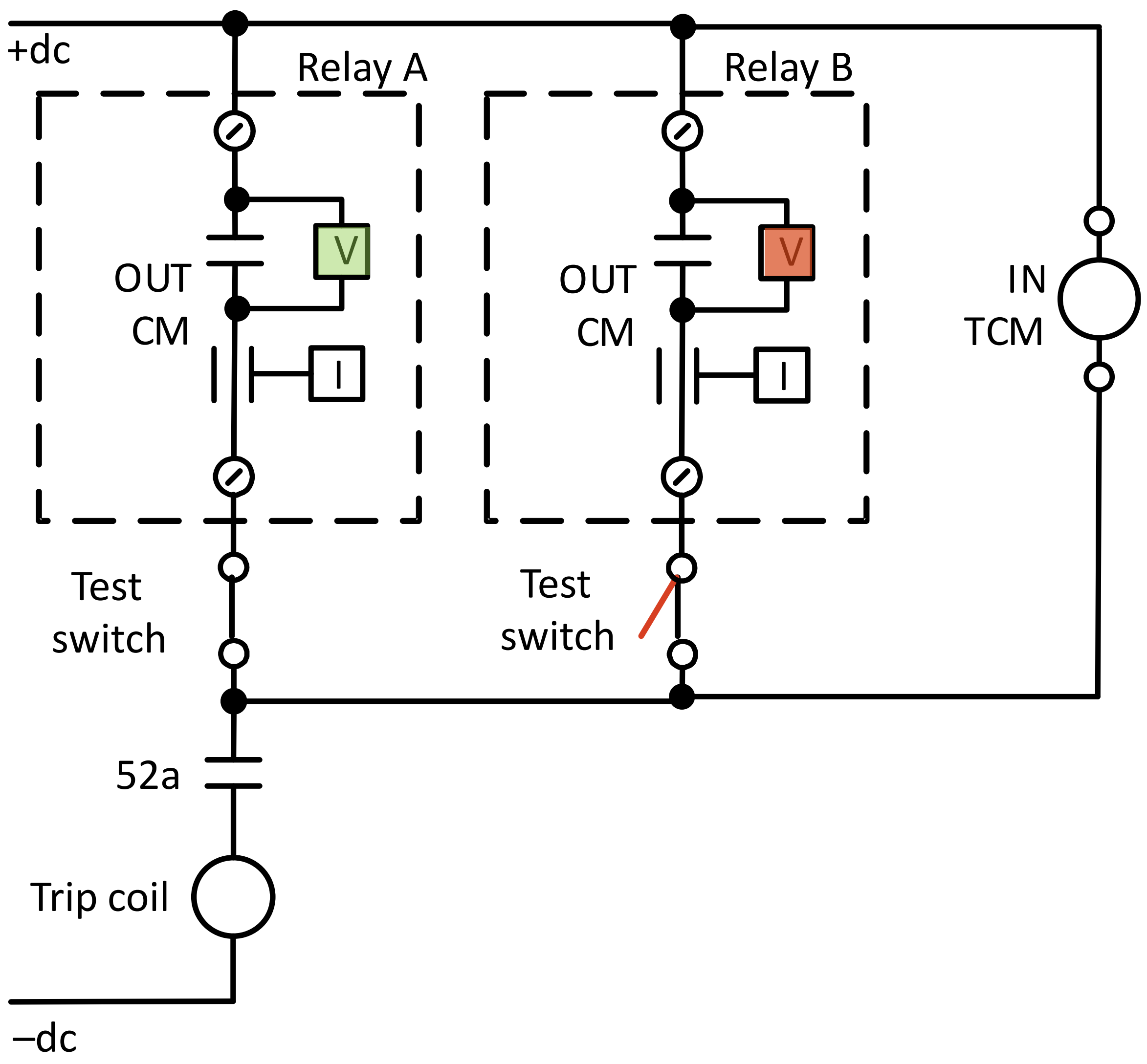
Output closes outside of trip window



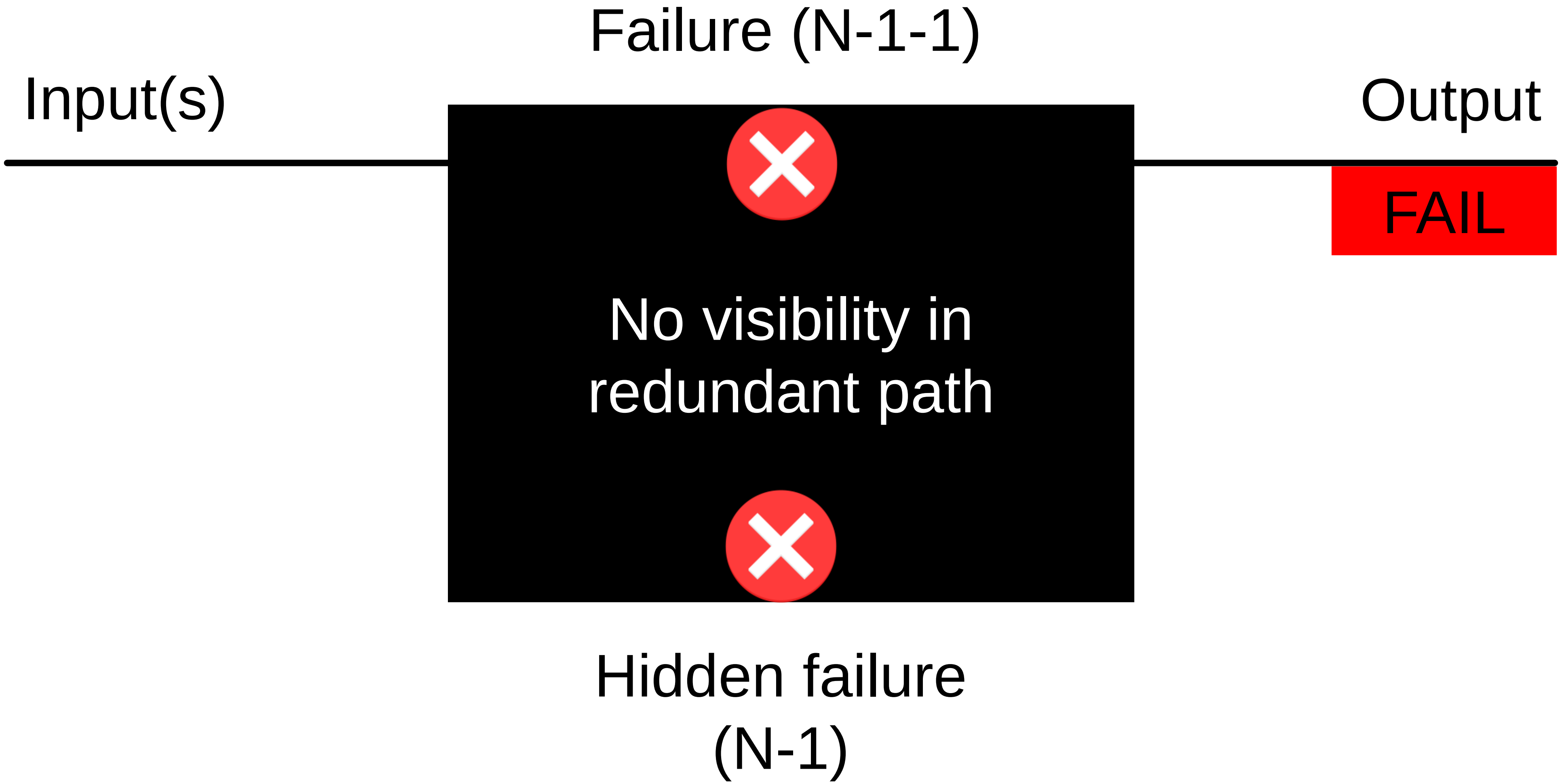
Both outputs declare success



Trip circuit monitor is built-in

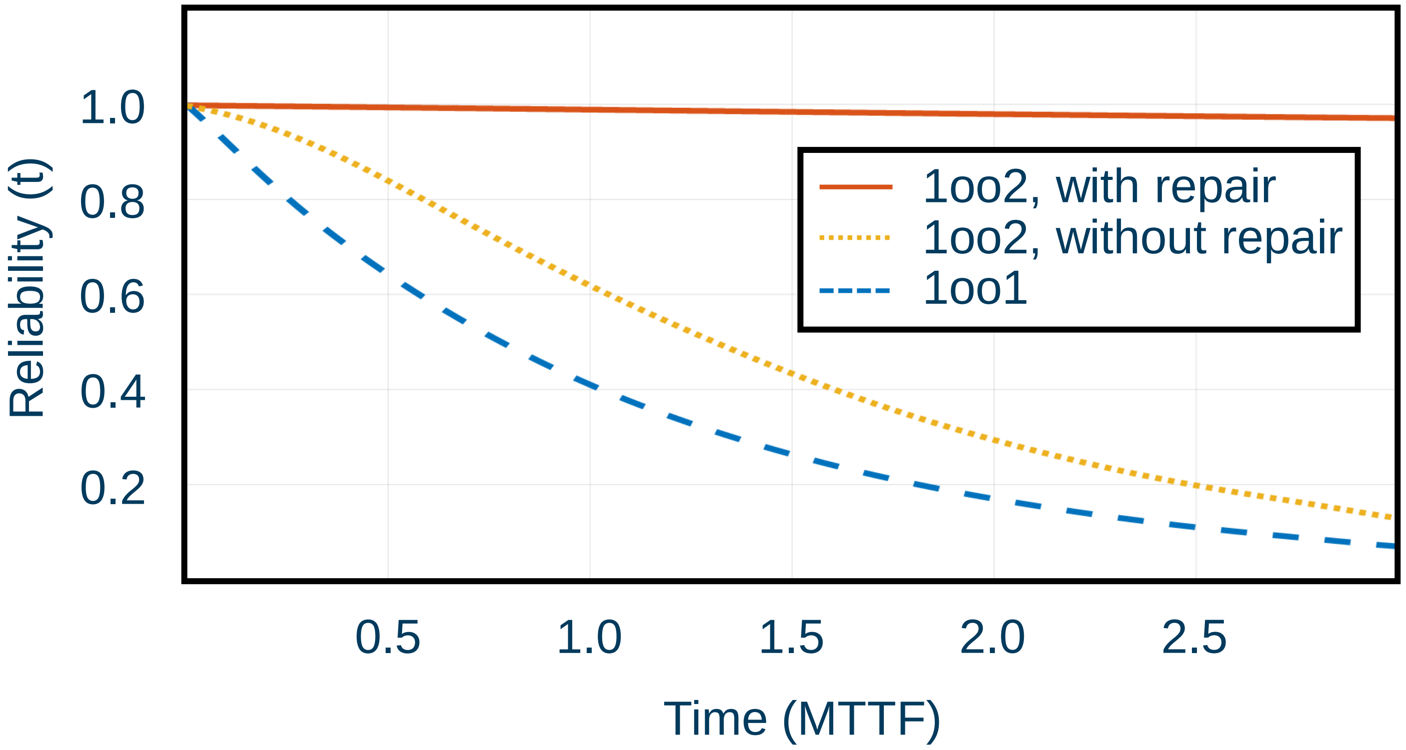


What is a hidden failure?



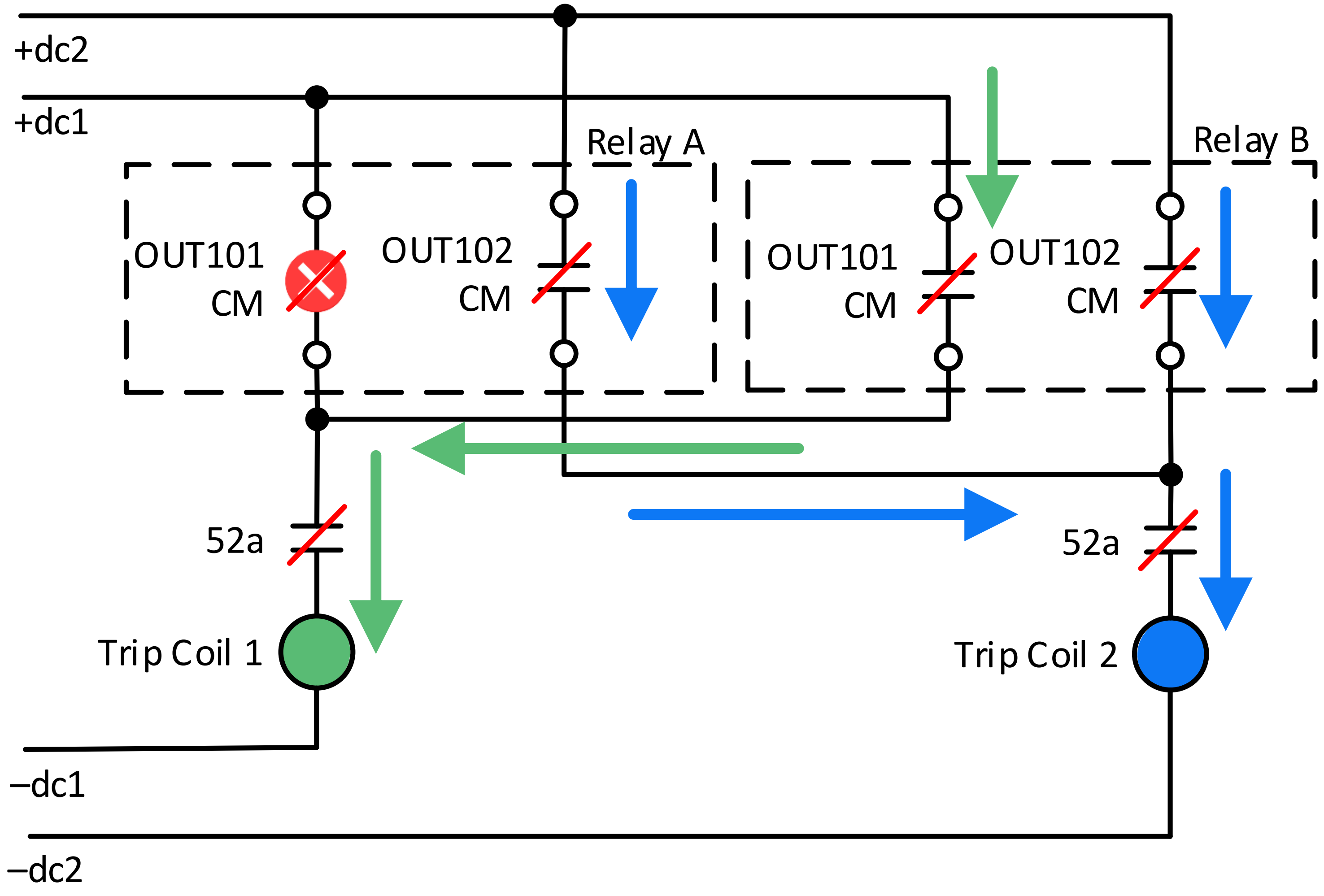
Redundancy is ineffective if not constantly supervised

- High expense
- Hidden problems

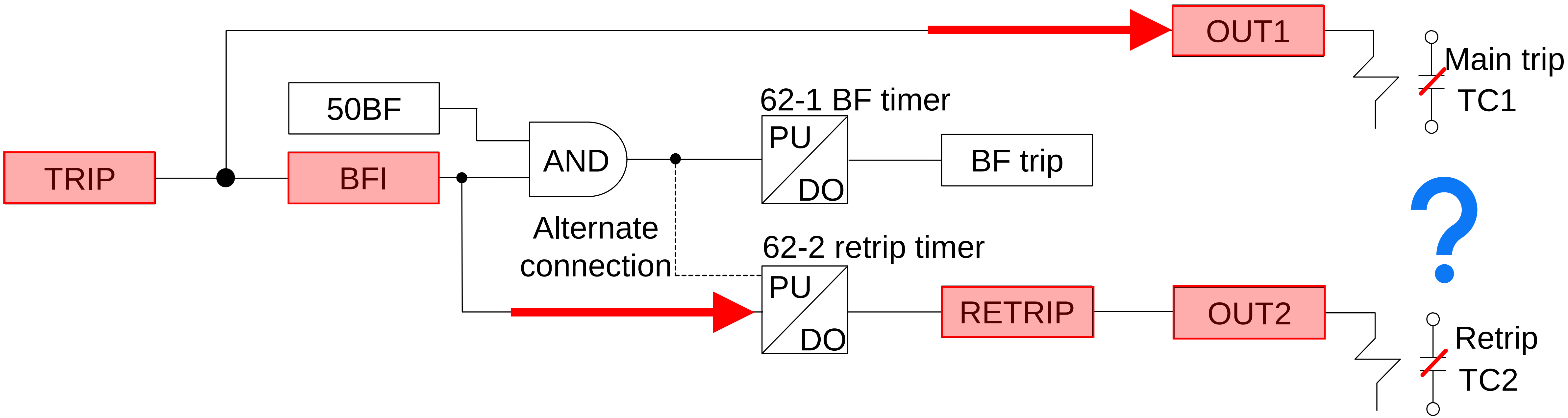


Reference: IEC TR 61850-90-12:2020

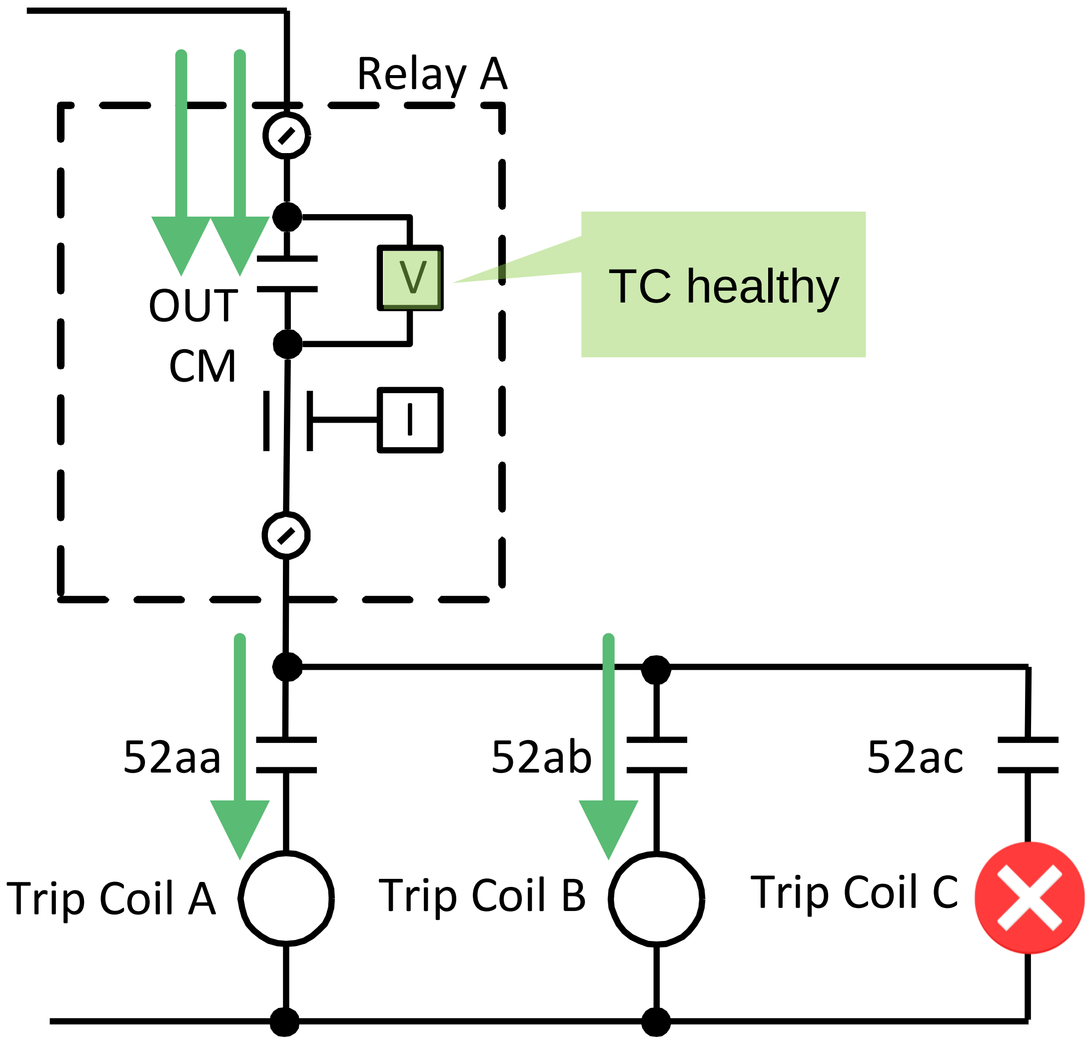
Hidden failures in cross-tripping scheme

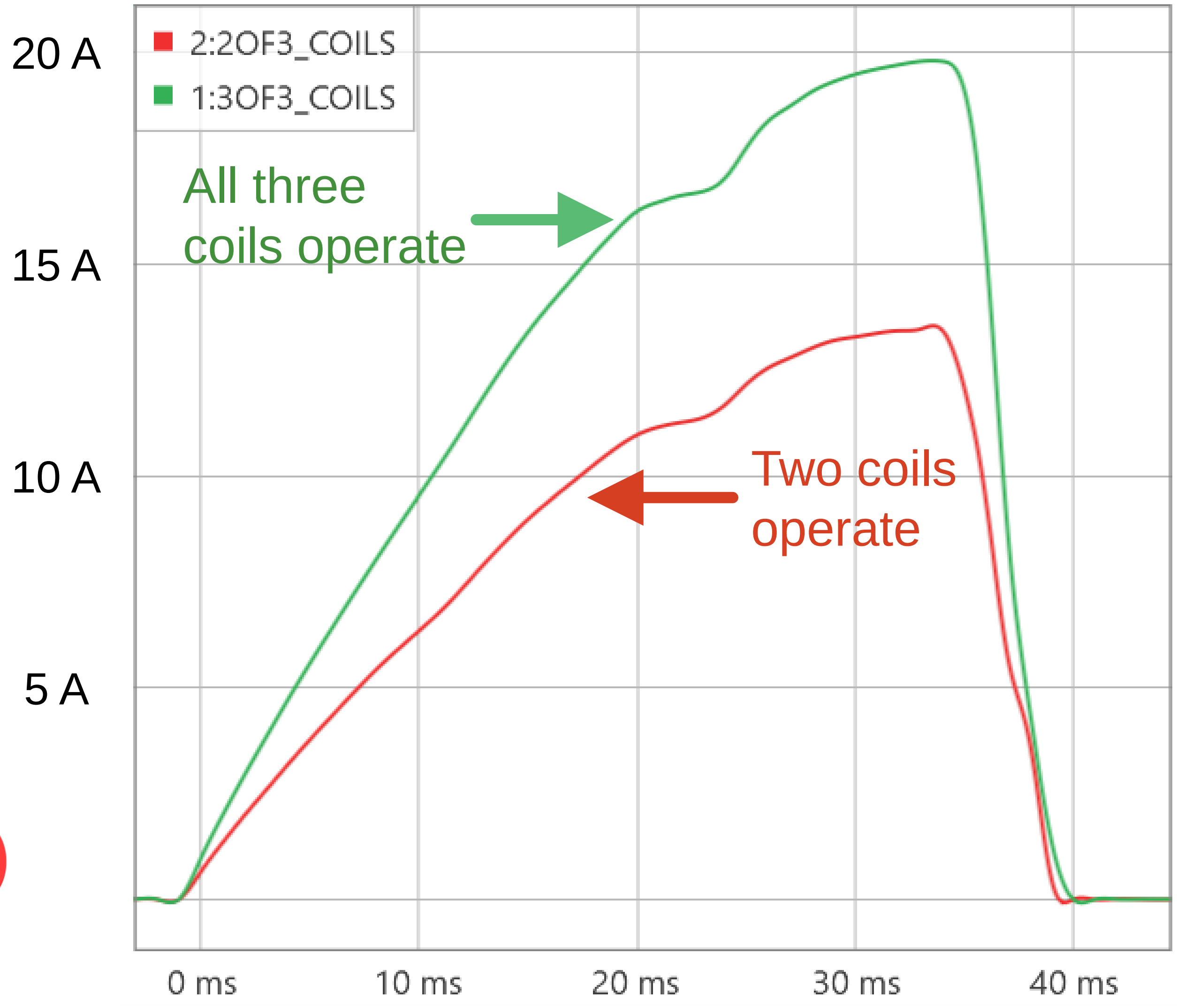


Which output trips the breaker?



SPT breaker wired to trip all three poles



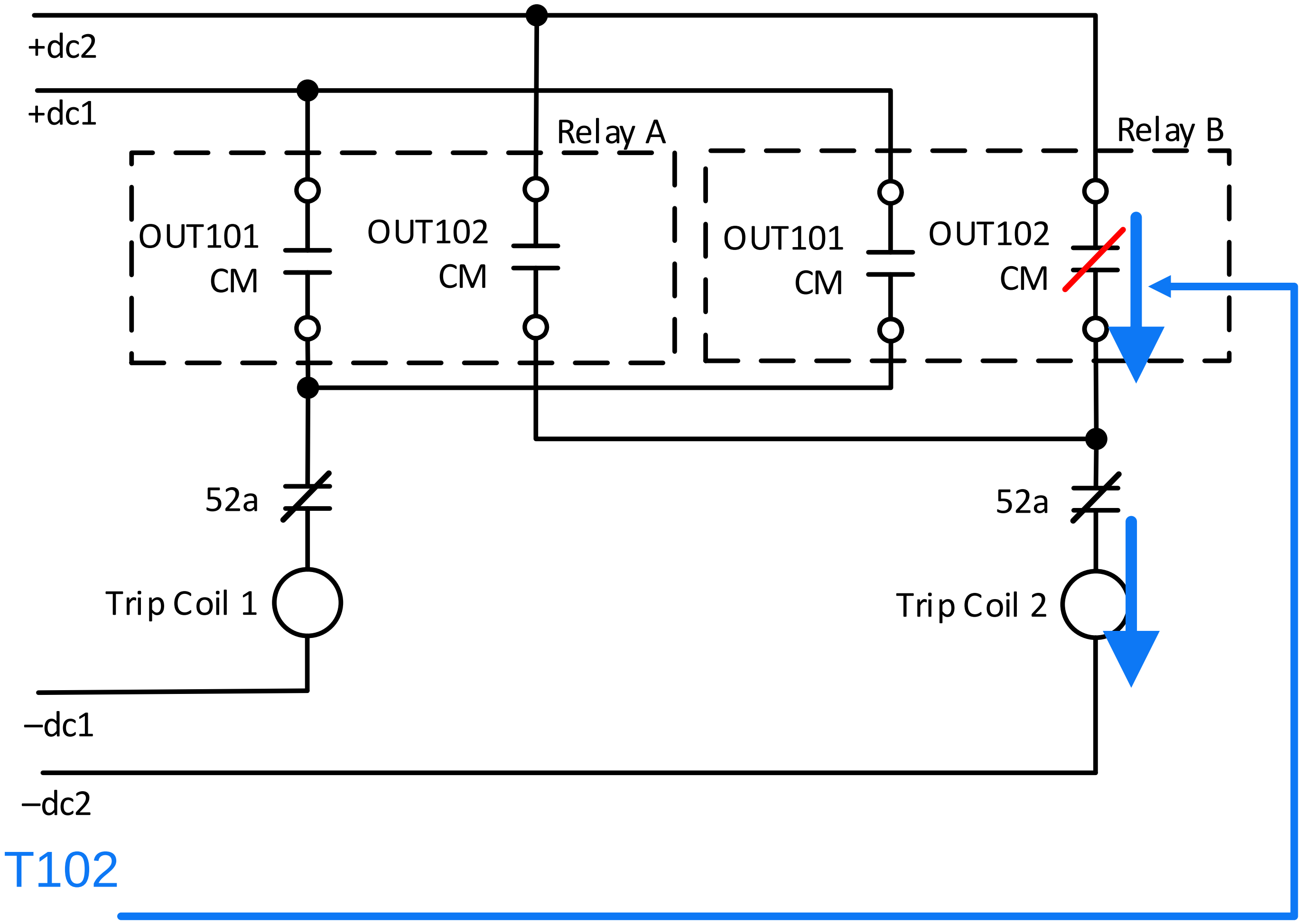


Use manual switching to validate trip circuits

Time since last successful operation

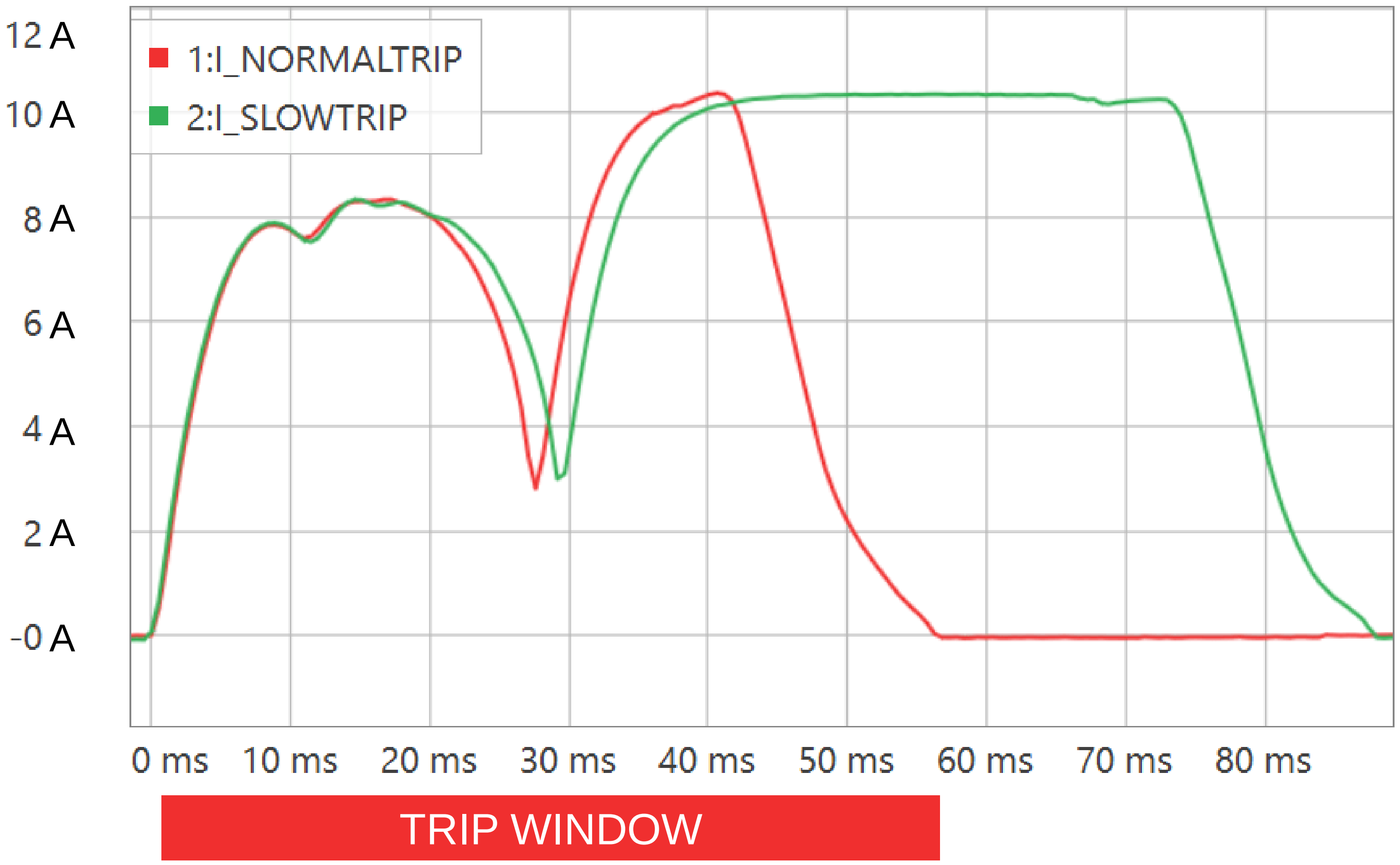
Relay A
OUT101 – 21 days
OUT102 – 21 days

Relay B
OUT101 – 163 days
OUT102 – 553 days



RTU selects Relay B OUT102 for manual trip

Slow breaker can indicate maintenance need



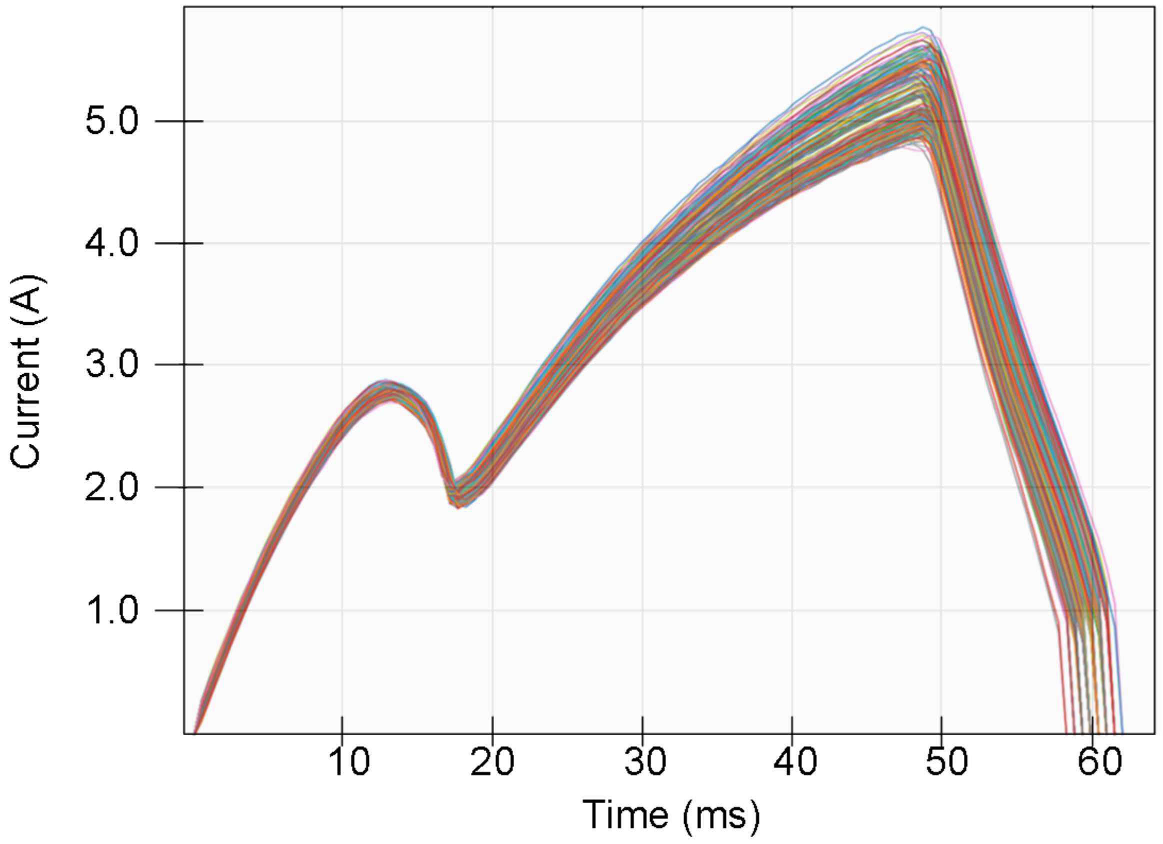
Use CM data to proactively monitor health

RTU/automation controller

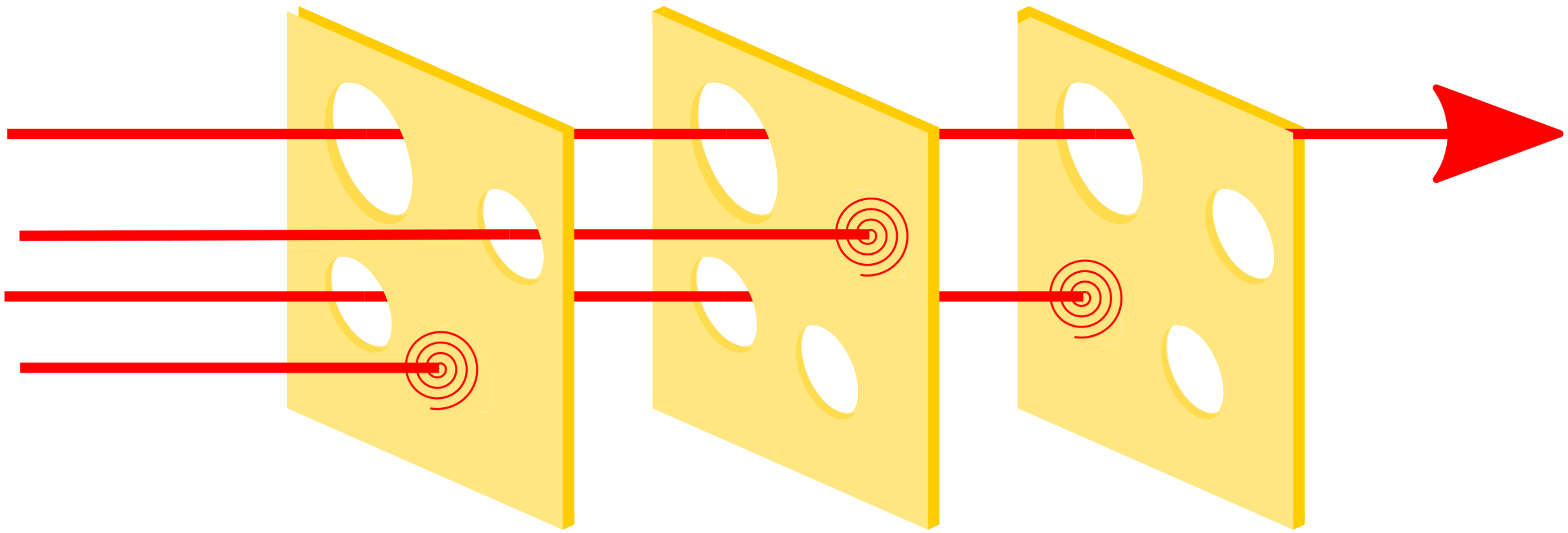
- TC profiles composites
- Basic profile analysis

SCADA/central repository

- TC profile of all similar equipment
- Advanced profile analysis



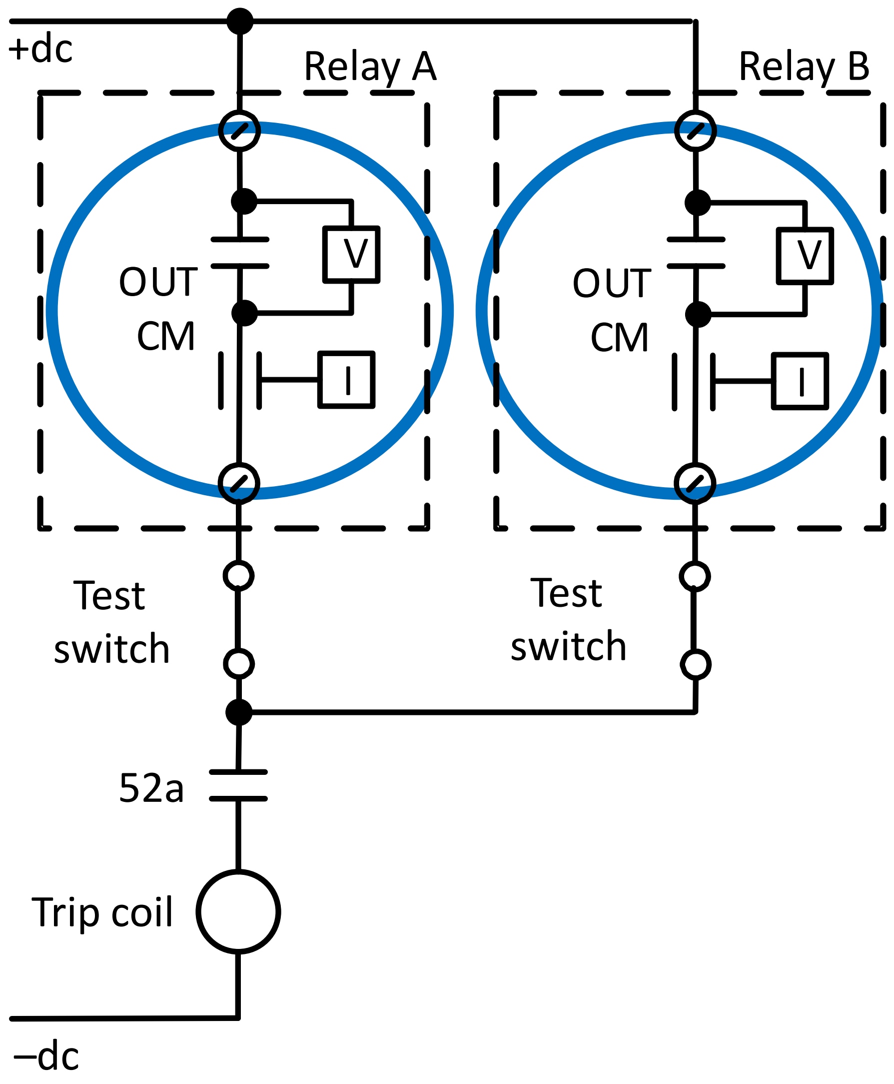
Hidden failures eventually line up



Source: BenAveling

Conclusion

- Detects previously hidden failures
- Complements traditional TCM
- Provides missing data for critical trip circuits
- Opens the door to condition-based monitoring… and more!



Questions?

Scan for corresponding technical paper