WHY ARE WE HERE

Thomas Teafatiller, Principal Engineer, Engineering and System Performance

RF Protection System Workshop

Aug. 7, 2024

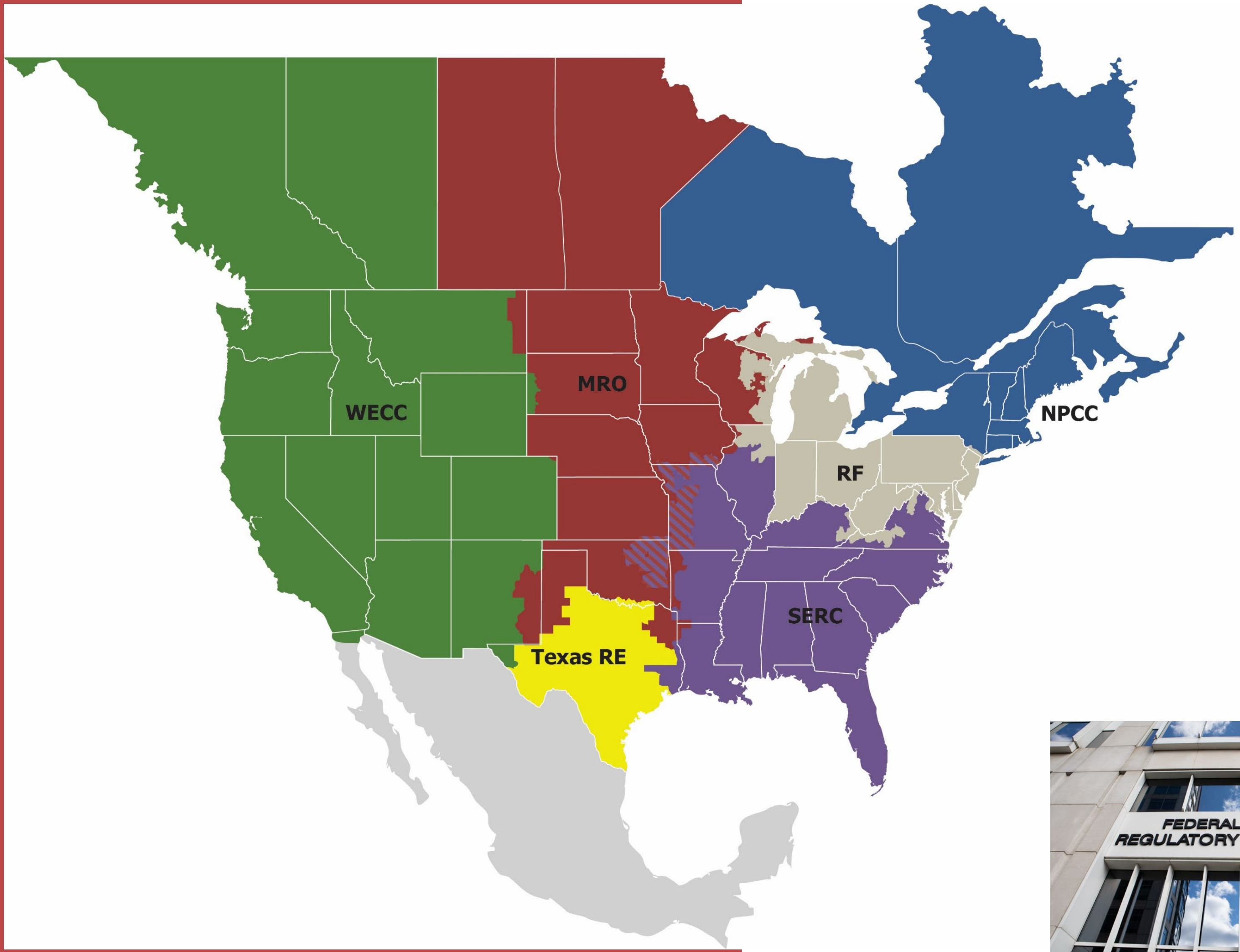
RELIABILITY FIRST

FORWARD TOGETHER RELIABILITYFIRST

OVERVIEW

- Review RF misoperation performance across the Electric Reliability Organization (ERO) Enterprise
- Analyze the misoperation performance of RF in 2023 and discuss performance trends
- Provide update on capacitor misoperations
- Analyze human performance misoperations

ELECTRIC RELIABILITY ORGANIZATION



- ERO consists of NERC and six (6) Regional Entities
- Regional Entities are the Compliance Enforcement Authority (CEA) for their respective footprints

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

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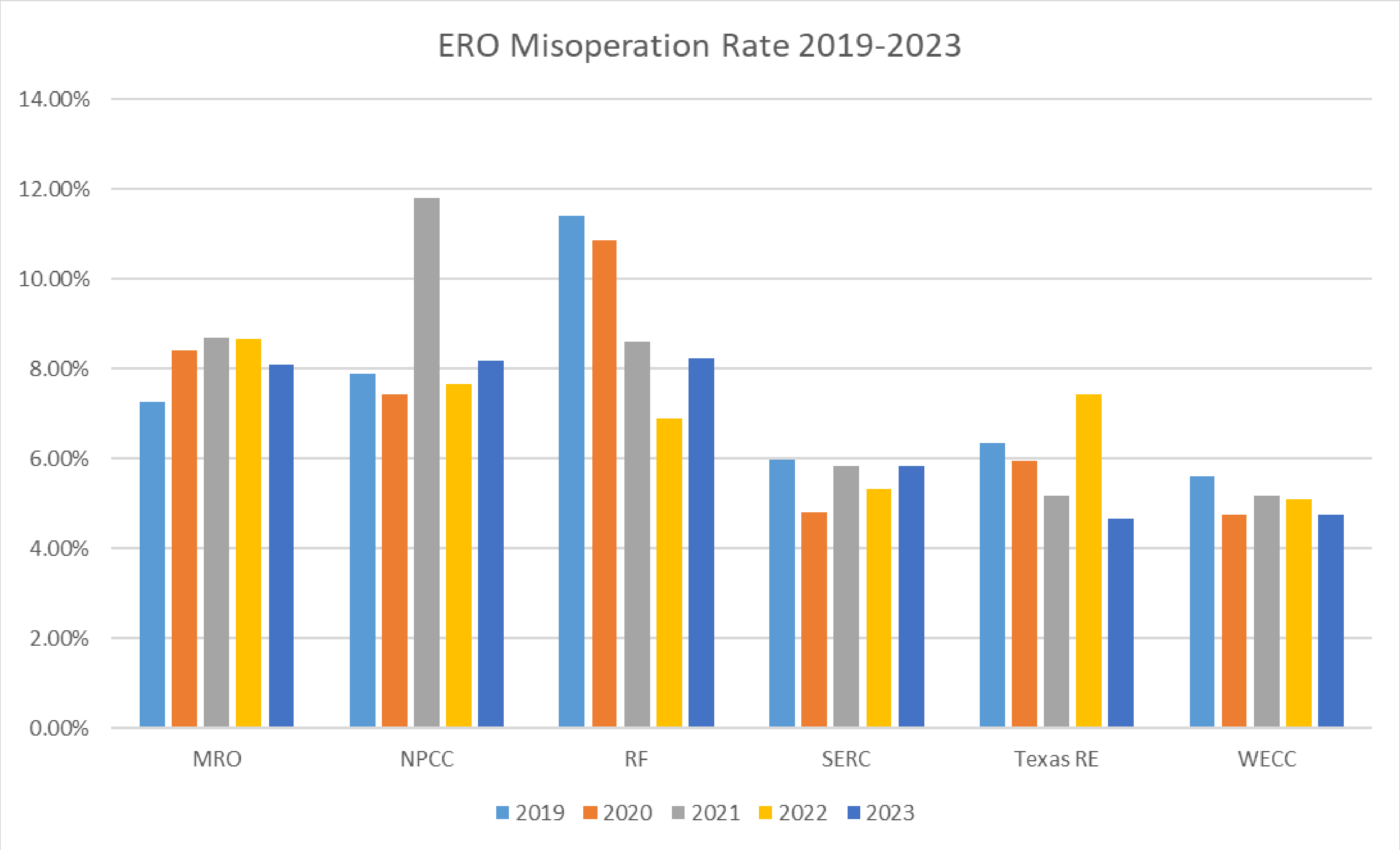
ERO MISOPERATIONS



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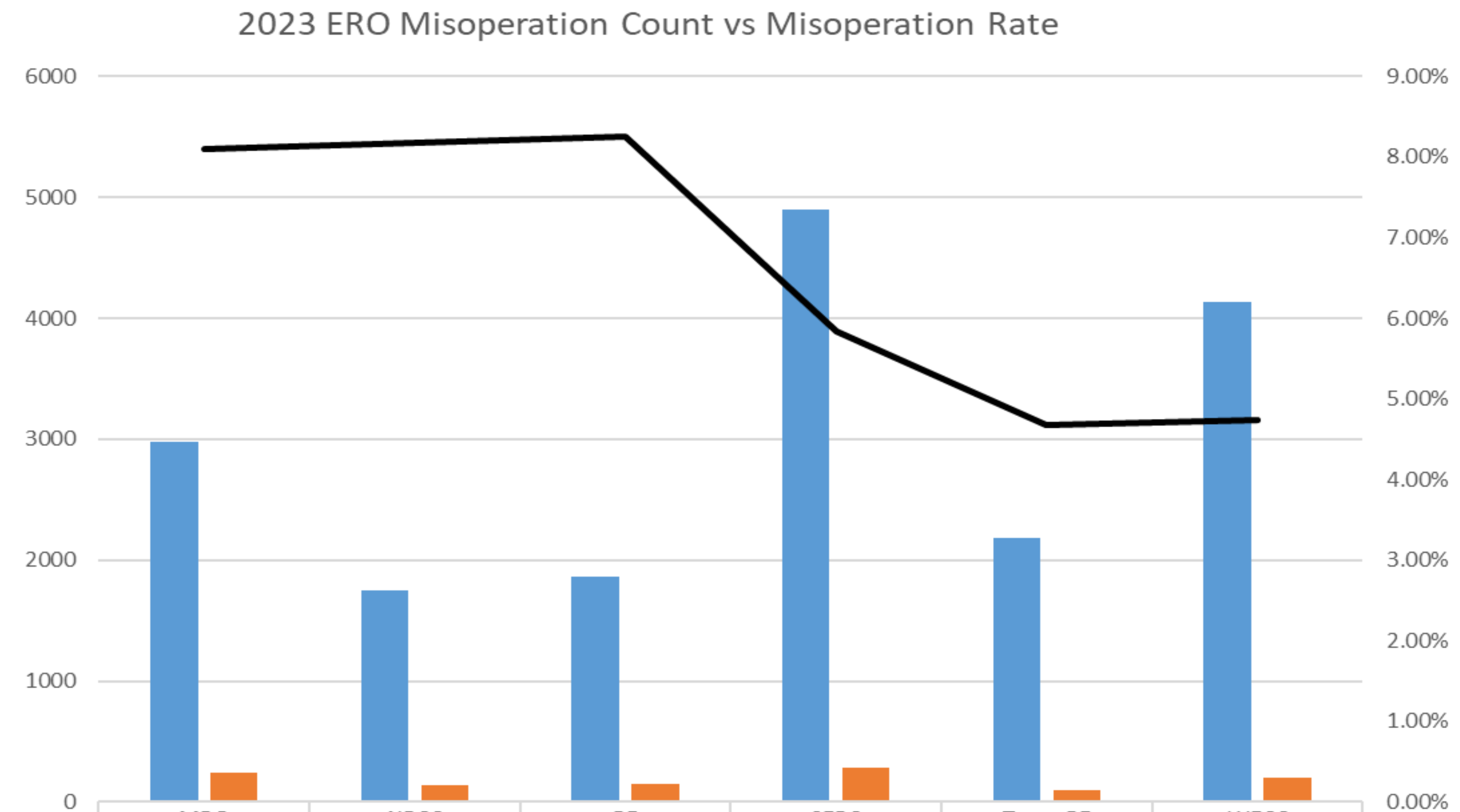
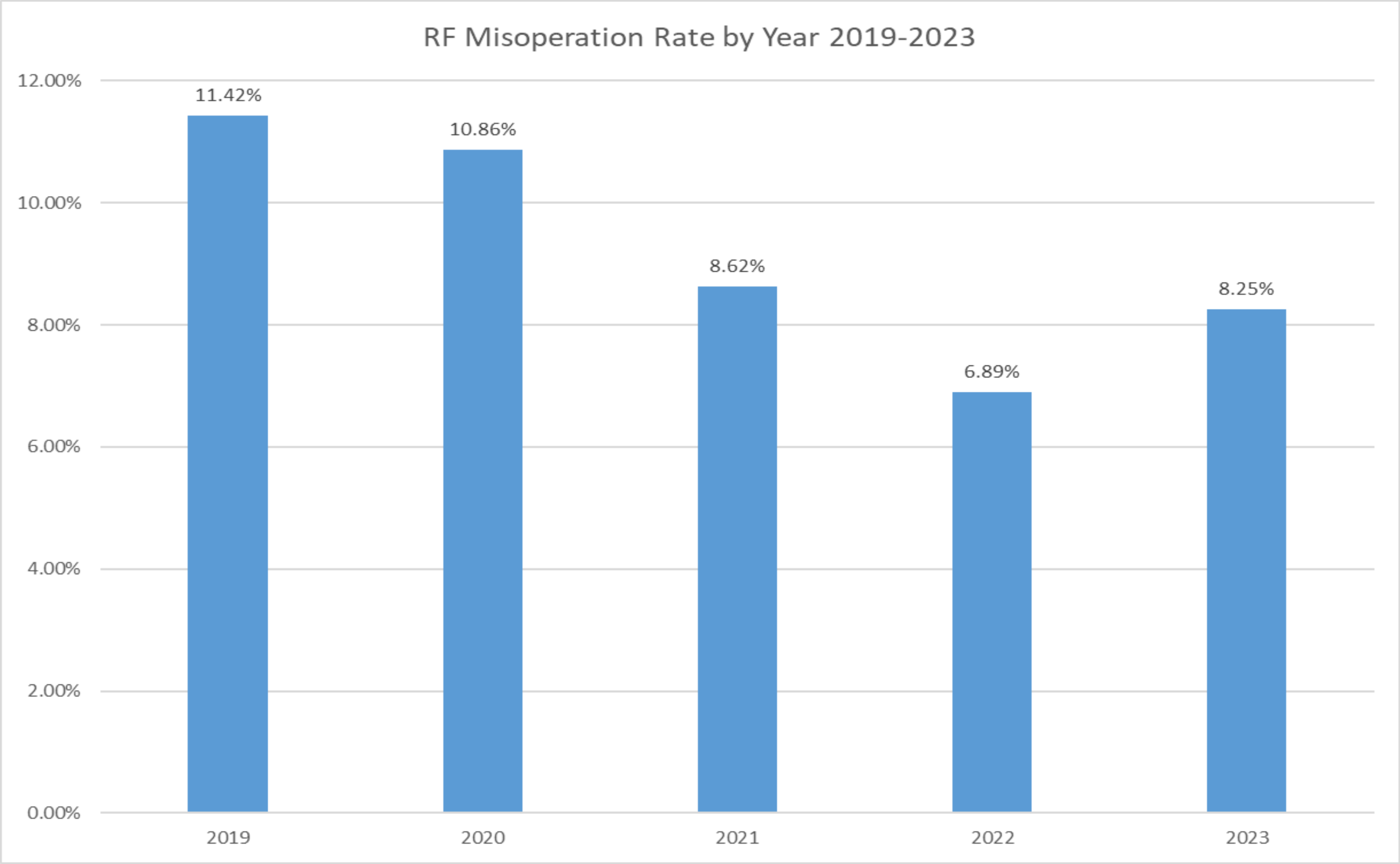
ERO MISOPERATIONS

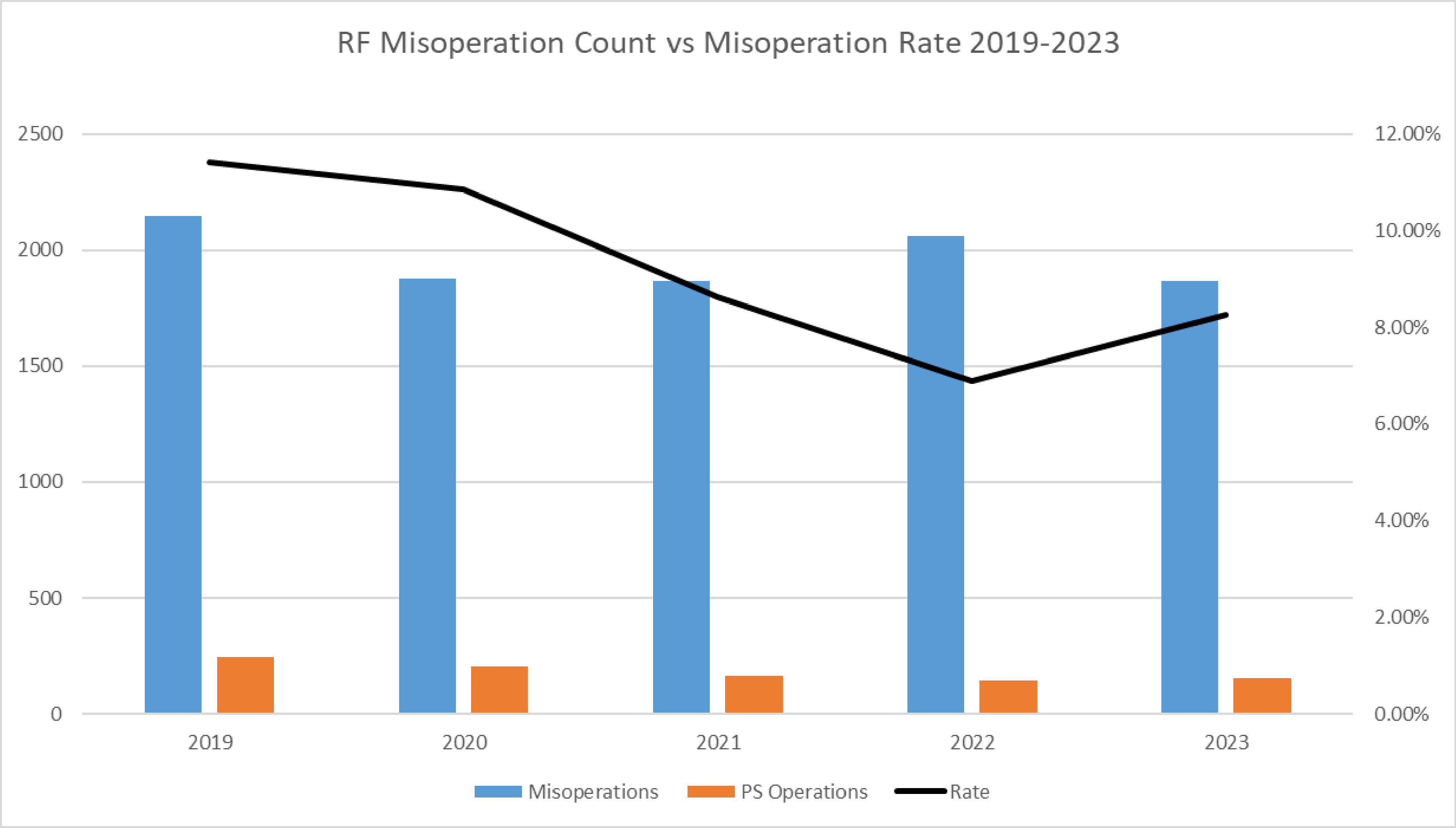


	MRO	NPCC	RF	SERC	Texas RE	WECC
PS Operations	2977	1750	1867	4897	2182	4138
Misoperations	241	143	154	286	102	196
Rate	8.10%	8.17%	8.25%	5.84%	4.67%	4.74%

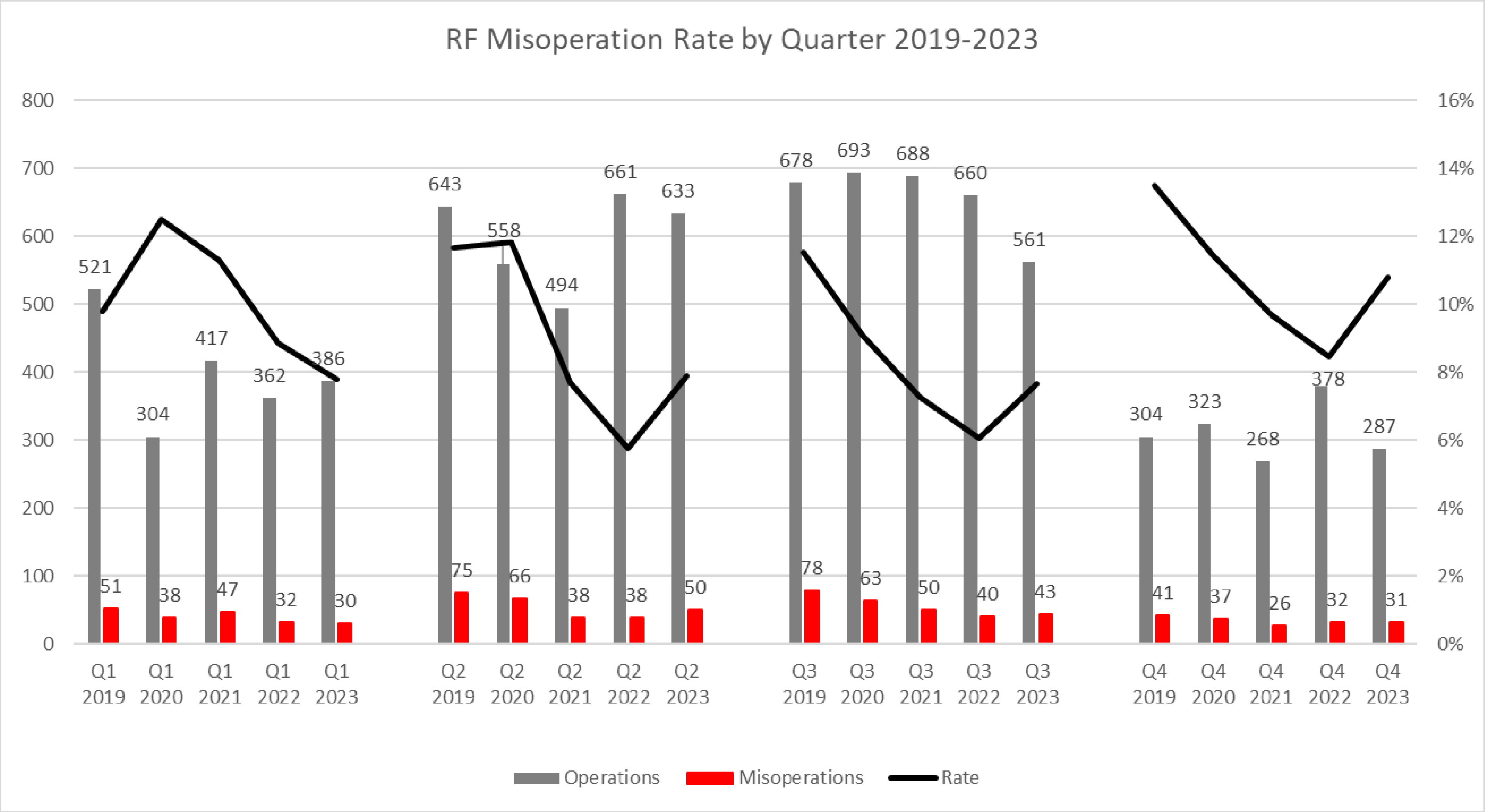
RF MISOPERATIONS



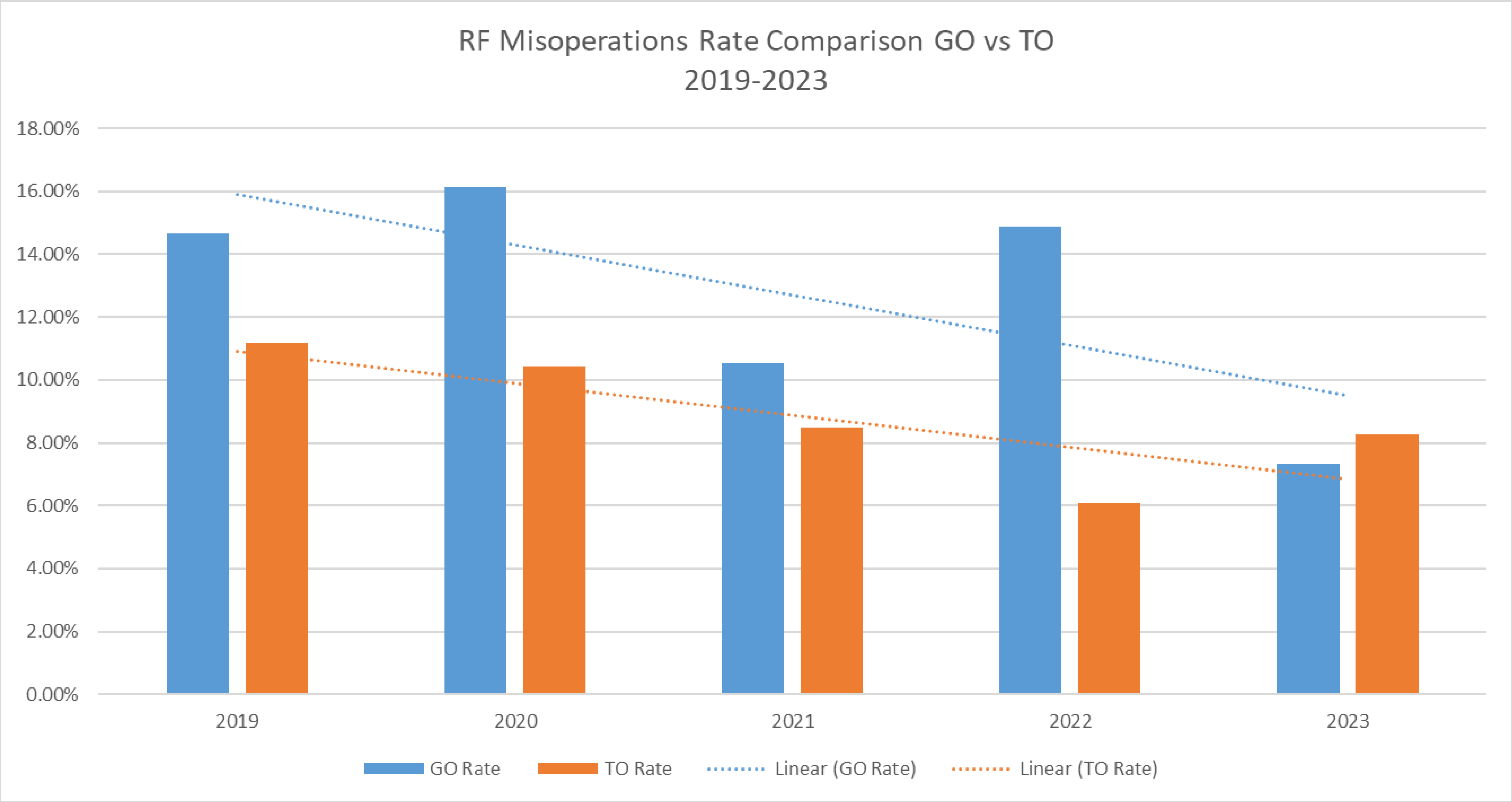
RF MISOPERATIONS



RF MISOPERATIONS

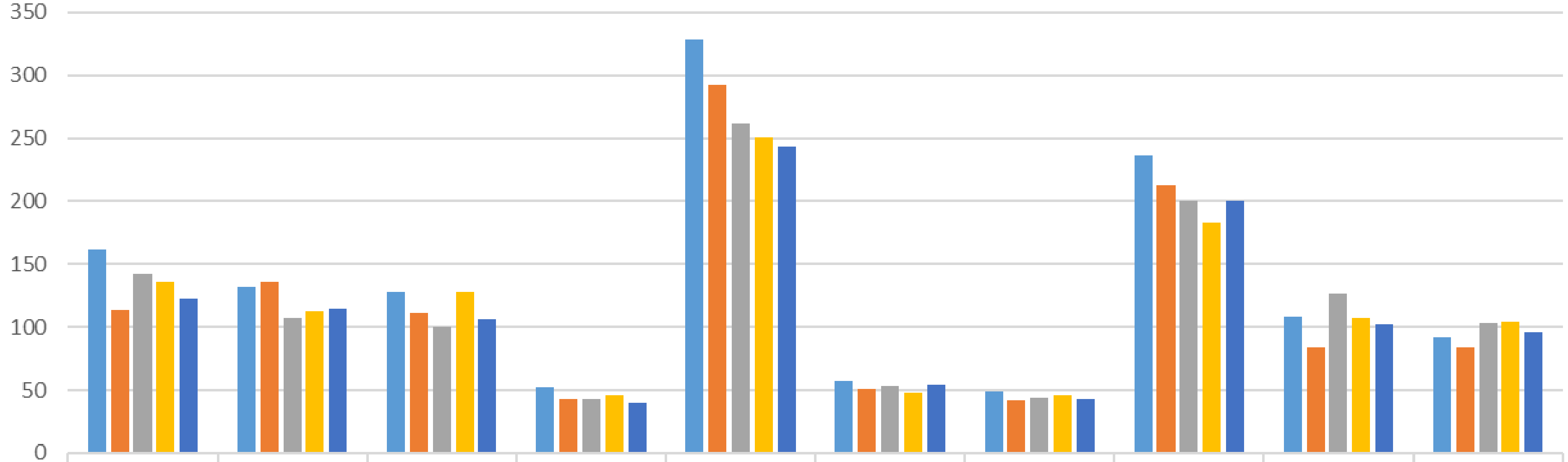


RF GENERATOR OWNER (GO) VS TRANSMISSION OWNER (TO) 2019-2023



ERO MISOPERATIONS

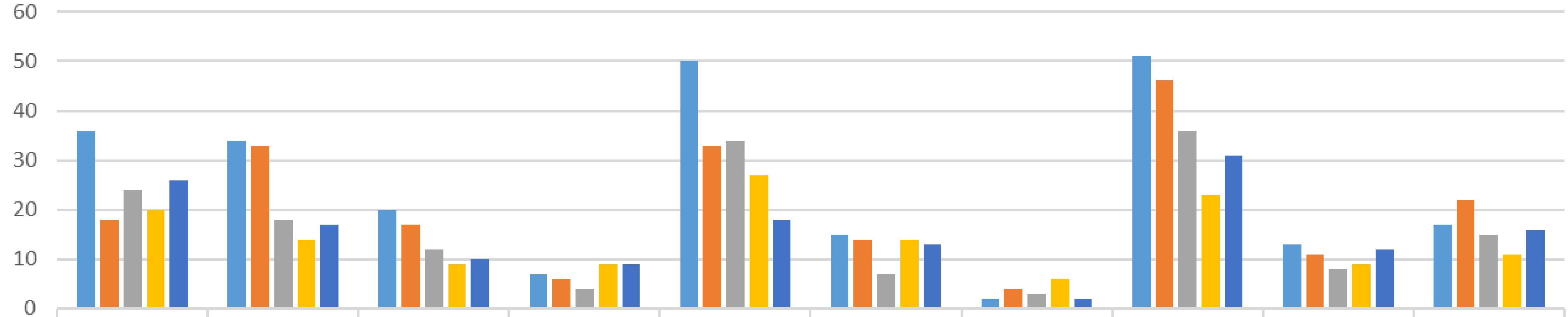
ERO Misoperation Count by Cause
2019-2023



	AC System	As Left	Comm Fail	DC System	Settings	Design	Logic	Relay Fail	Other	Unknown
2019	162	132	128	52	328	57	49	236	108	92
2020	114	136	111	43	293	51	42	213	84	84
2021	142	107	100	43	262	53	44	201	127	103
2022	136	112	128	46	251	48	46	183	107	104
2023	123	115	106	40	243	54	43	200	102	96

RF MISOPERATIONS

RF Misoperation Count by Cause
2019-2023

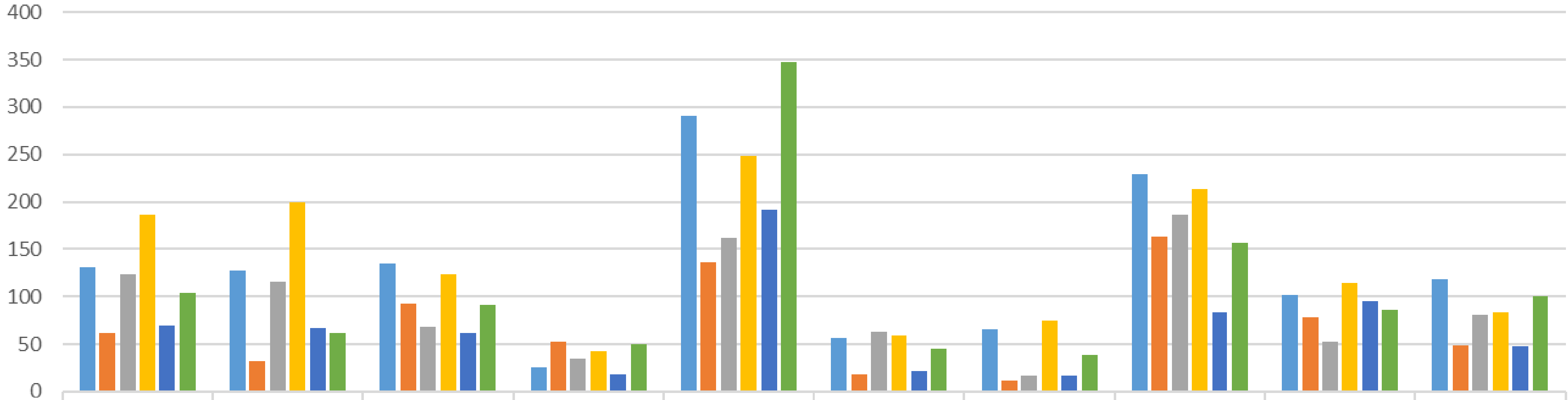


	AC System	As Left	Comm Fail	DC System	Settings	Design	Logic	Relay Fail	Other	Unknown
2019	36	34	20	7	50	15	2	51	13	17
2020	18	33	17	6	33	14	4	46	11	22
2021	24	18	12	4	34	7	3	36	8	15
2022	20	14	9	9	27	14	6	23	9	11
2023	26	17	10	9	18	13	2	31	12	16

2019 2020 2021 2022 2023

ERO MISOPERATIONS

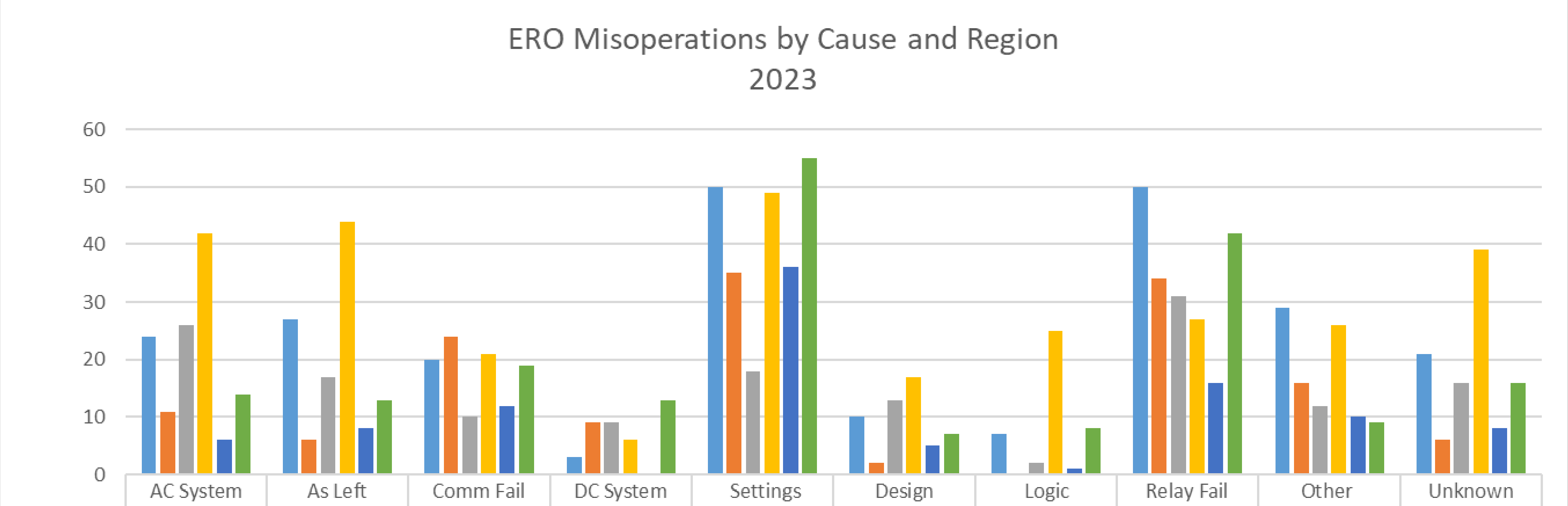
ERO Misoperations by Cause and Region
2019-2023



	AC System	As Left	Comm Fail	DC System	Settings	Design	Logic	Relay Fail	Other	Unknown
MRO	131	127	135	26	291	56	65	229	101	118
NPCC	62	32	93	53	136	18	11	163	78	49
RF	124	116	68	35	162	63	17	187	53	81
SERC	187	199	124	42	248	59	75	214	115	84
TRE	69	67	62	18	192	22	17	83	95	47
WECC	104	61	91	50	348	45	39	157	86	100

MRO NPCC RF SERC TRE WECC

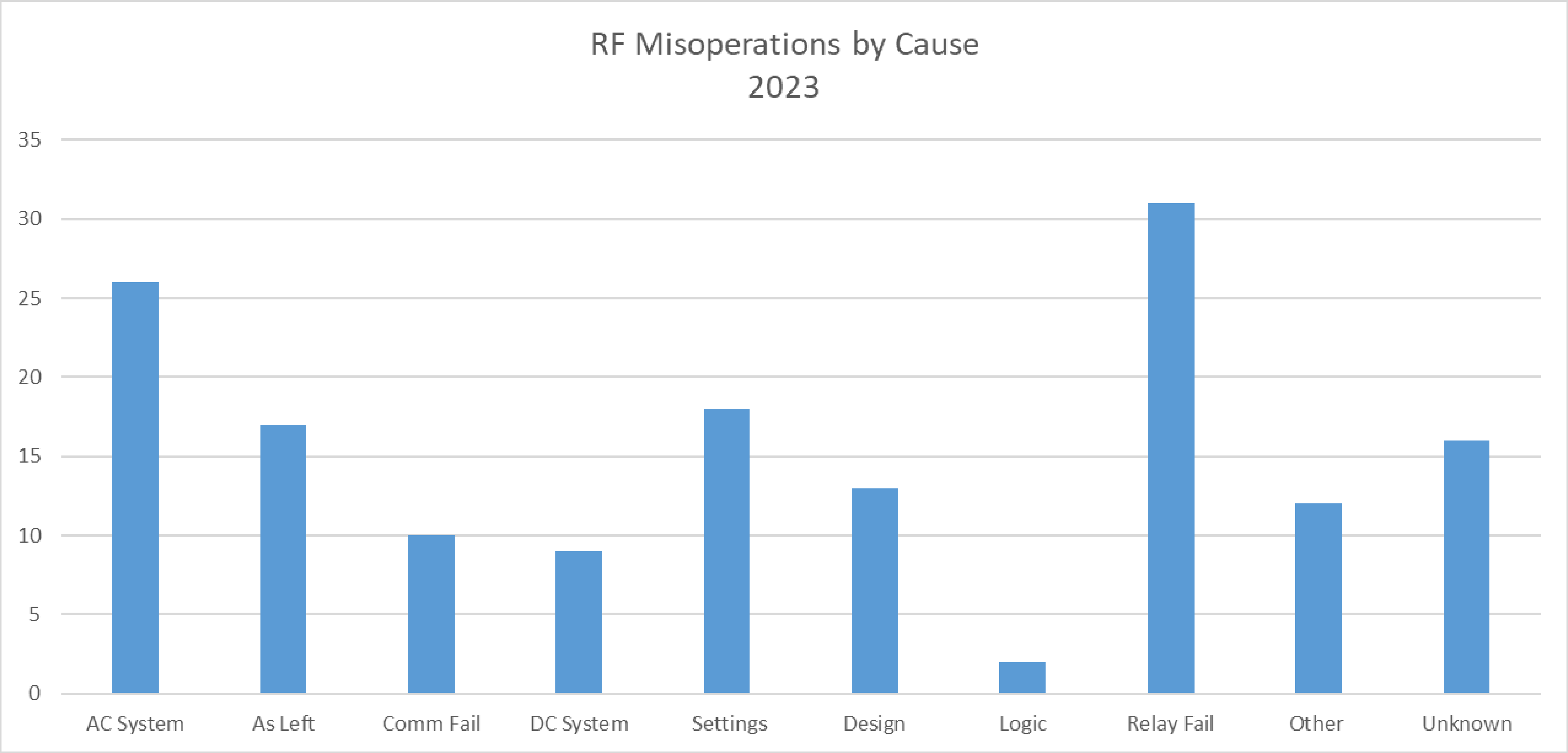
ERO MISOPERATIONS



	AC System	As Left	Comm Fail	DC System	Settings	Design	Logic	Relay Fail	Other	Unknown
MRO	24	27	20	3	50	10	7	50	29	21
NPCC	11	6	24	9	35	2	0	34	16	6
RF	26	17	10	9	18	13	2	31	12	16
SERC	42	44	21	6	49	17	25	27	26	39
TRE	6	8	12	0	36	5	1	16	10	8
WECC	14	13	19	13	55	7	8	42	9	16

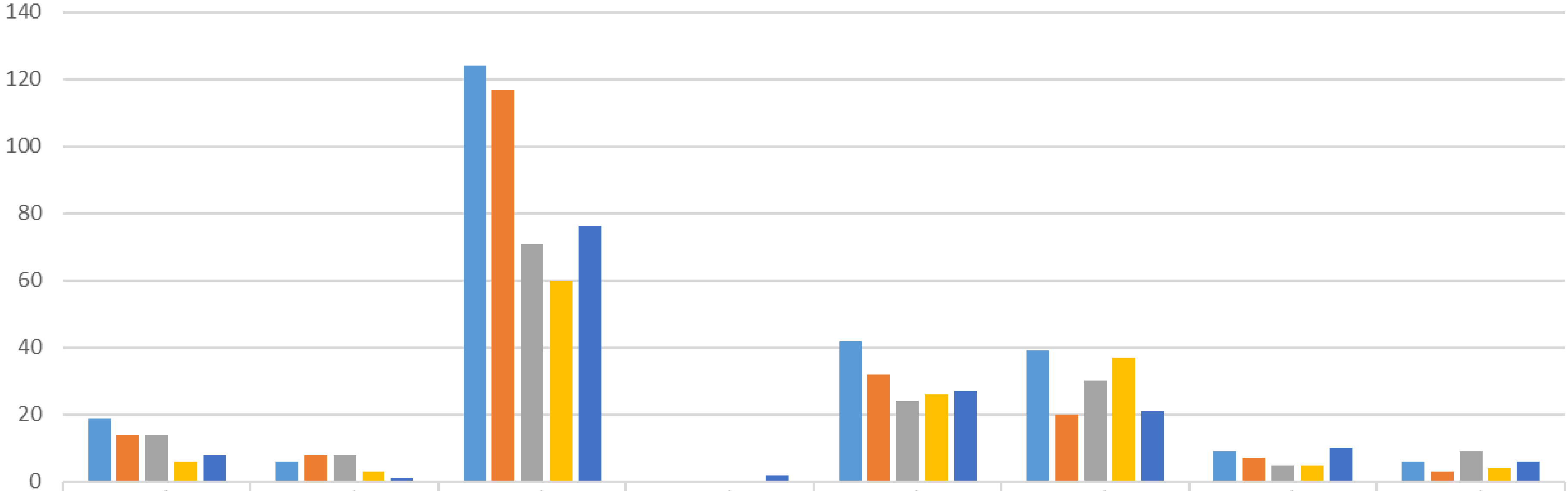
MRO NPCC RF SERC TRE WECC

RF MISOPERATIONS



RF MISOPERATIONS

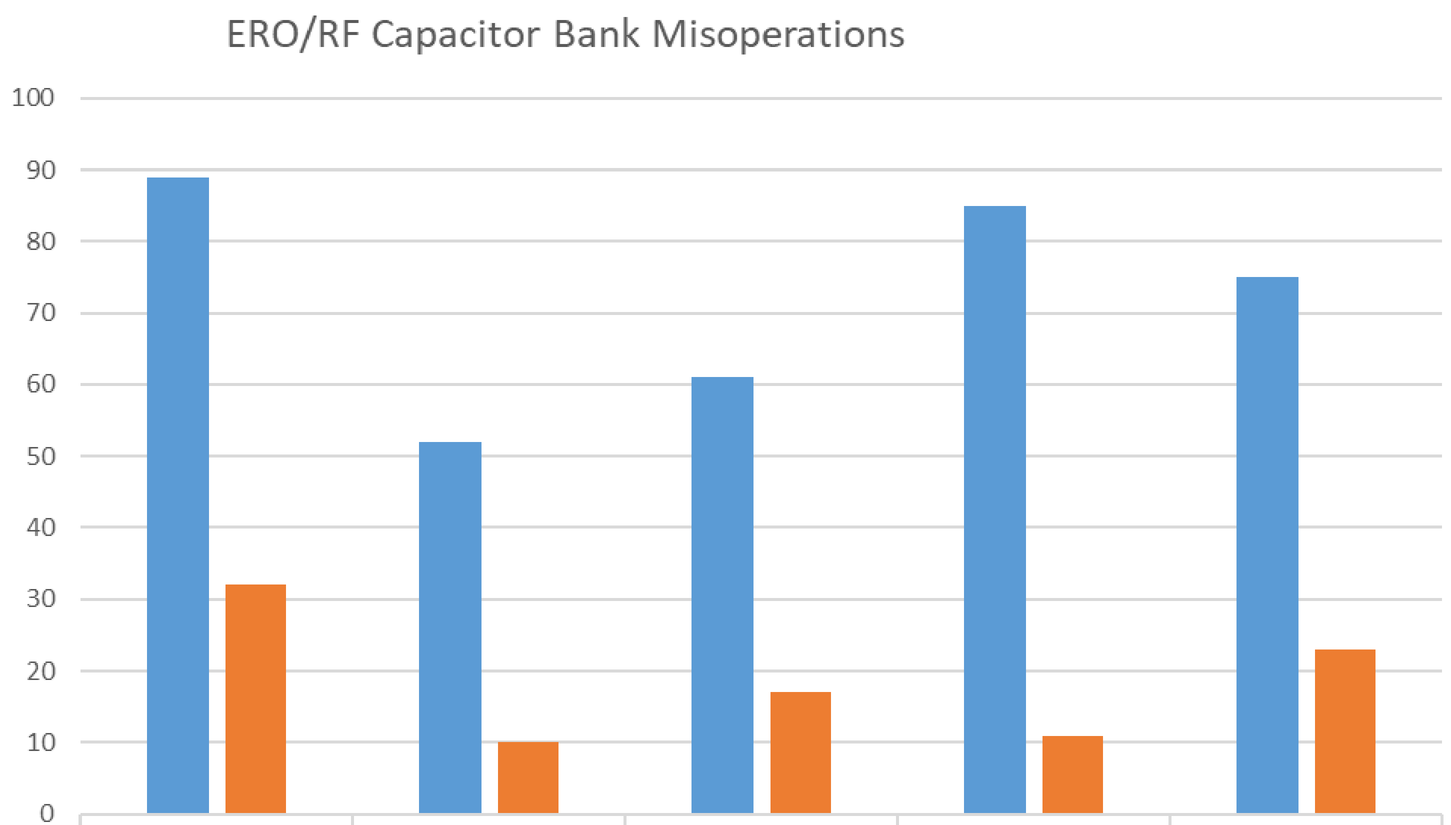
Misoperations Count by Voltage and Year



	115kV	120kV	138kV	161kV	230kV	345kV	500kV	765kV
2019	19	6	124		42	39	9	6
2020	14	8	117		32	20	7	3
2021	14	8	71		24	30	5	9
2022	6	3	60		26	37	5	4
2023	8	1	76	2	27	21	10	6

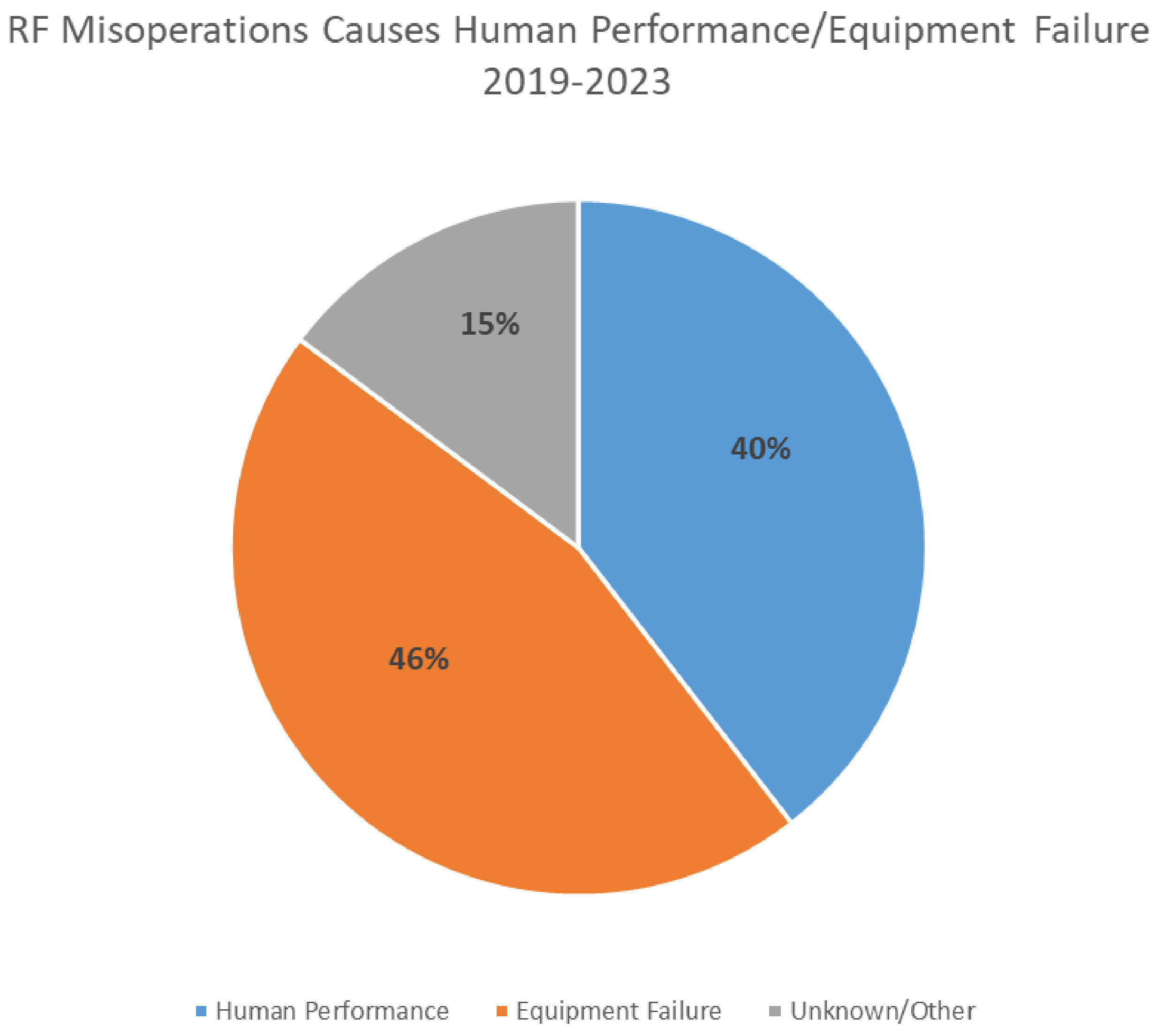
2019 2020 2021 2022 2023

CAPACITOR BANK MISOPERATIONS



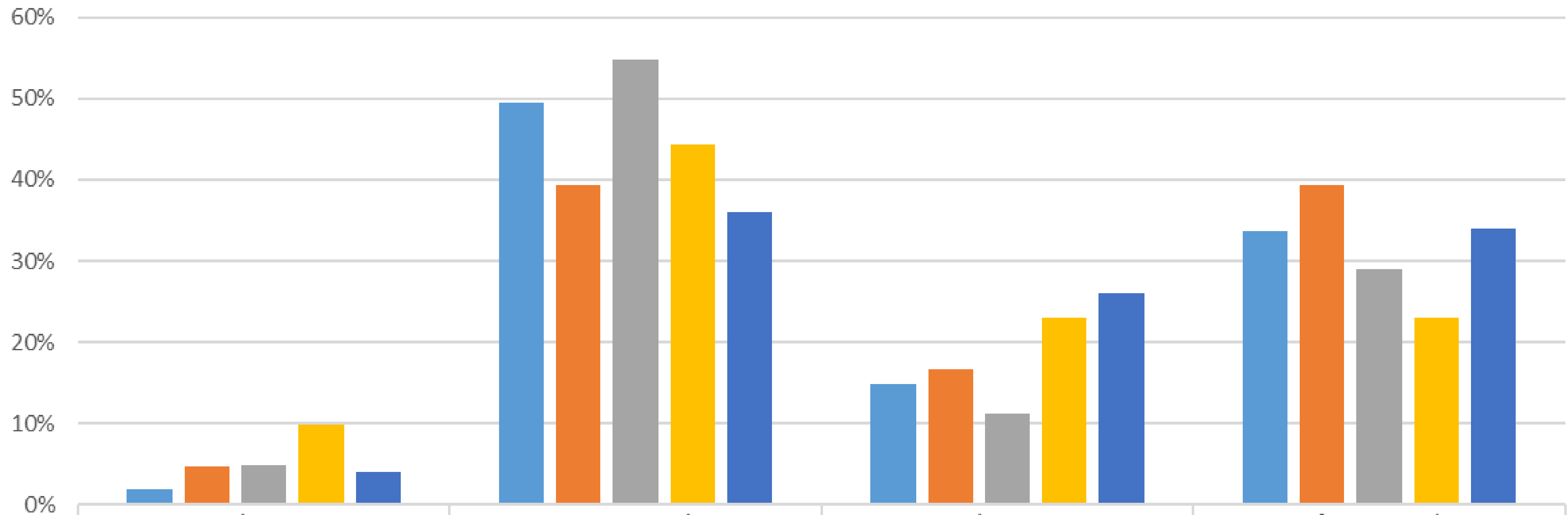
	2019	2020	2021	2022	2023
ERO Cap Bank Misoperations	89	52	61	85	75
RF Cap Bank Misoperations	32	10	17	11	23

RF MISOPERATIONS



RF MISOPERATIONS

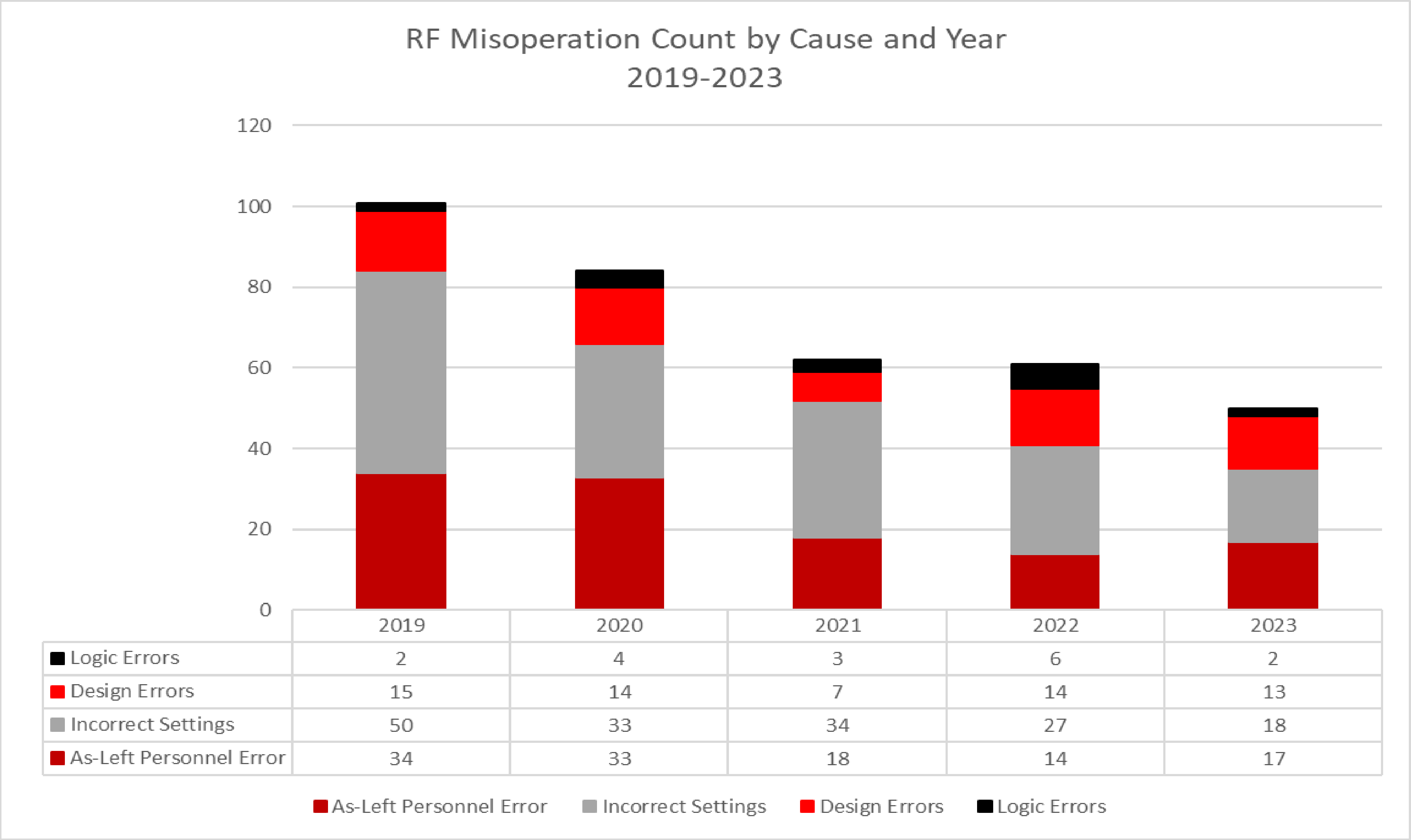
Causes of Human Performance Misoprations
2019-2023



	Logic Errors	Incorrect Settings	Design Errors	As-Left Personnel Error
2019	2%	50%	15%	34%
2020	5%	39%	17%	39%
2021	5%	55%	11%	29%
2022	10%	44%	23%	23%
2023	4%	36%	26%	34%

2019 2020 2021 2022 2023

RF MISOPERATIONS



	2019	2020	2021	2022	2023
Logic Errors	2	4	3	6	2
Design Errors	15	14	7	14	13
Incorrect Settings	50	33	34	27	18
As-Left Personnel Error	34	33	18	14	17

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SUMMARY

- RF misoperation rate had been on a downward trend in recent years, but 2023 rates returned to the 2021 rates near 8%
- RF misoperation counts have continued their overall downward trend
- Both GO and TO misoperation rates have continued downward
- Capacitor bank misoperations have increased in 2023, we will watch how this trends going forward
- Incorrect setting misoperations have been on a downward trend since 2021, design errors have been on an upward trend during that same time period

Technical Talk with RF

- Save the date for our next event: Monday, Aug. 19, 2-3:30 p.m.

- August's Tech Talk will be an "un-Tech Talk," as we delve into the human performance side of electric grid reliability – see our website for more details.

No Registration Required
Calendar Reminder

Fall Reliability & Security Summit 2024

Monday, Sept. 16, 5-8 p.m.

Tuesday, Sept. 17, 8:30 a.m. – 5 pm

Wednesday, Sept. 18, 8:30 a.m. – 1 p.m.

Location: Conrad Indianapolis Hotel,

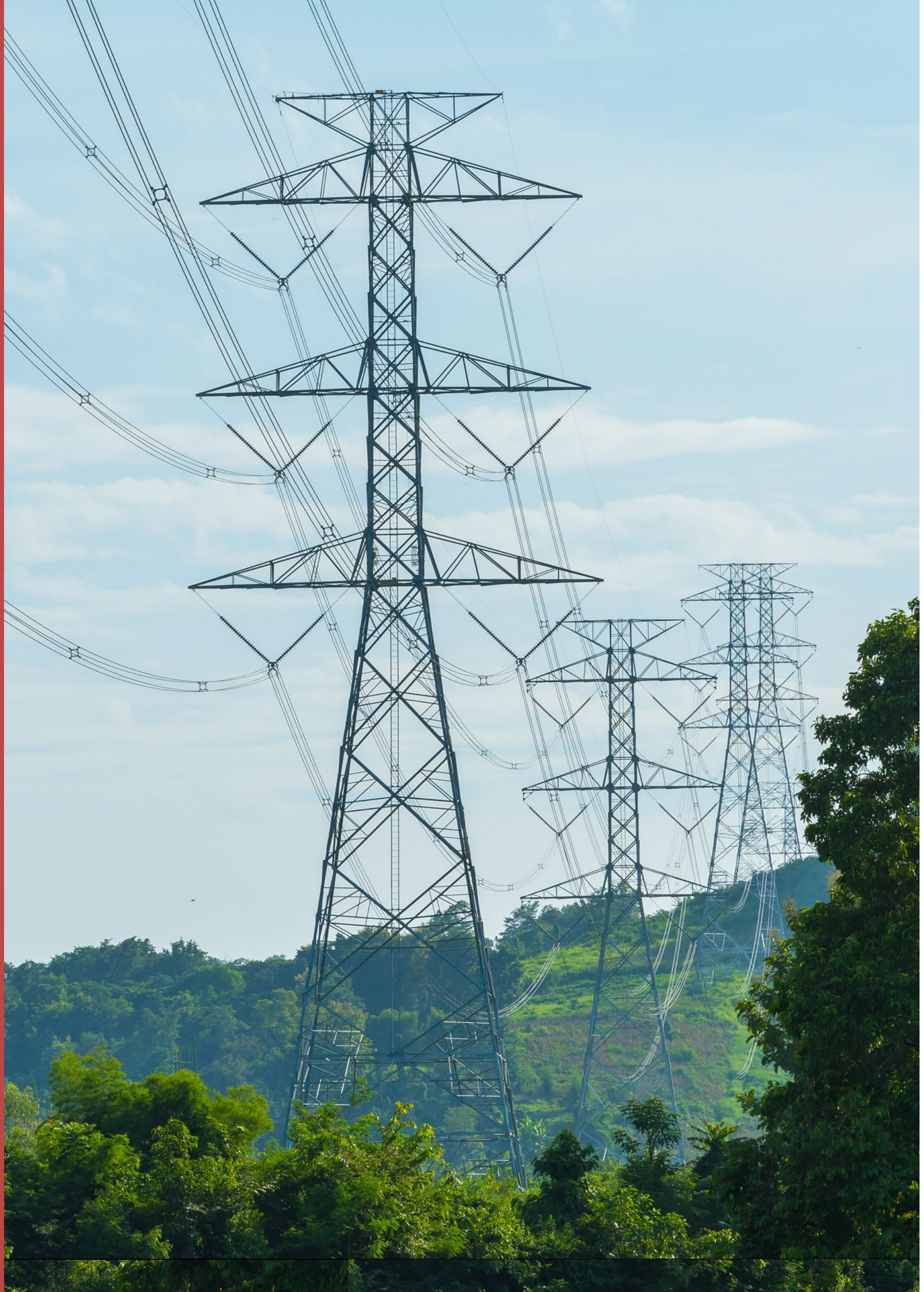
50 W. Washington St., Indianapolis, IN 46204

Join RF in Indianapolis for the 2024 Fall Reliability & Security Summit. We'll dive into the intersection of energy policy with reliability and security, as we navigate the challenges of a changing generation mix. Find additional agenda details and registration information on the event page on our website.

Please encourage your coworkers, staff, and stakeholders to sign-up to attend.

REGISTRATION LINK

FORWARD TOGETHER RELIABILITYFIRST



QUESTIONS & ANSWERS

Thomas Teafatiller

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Limited Disclosure

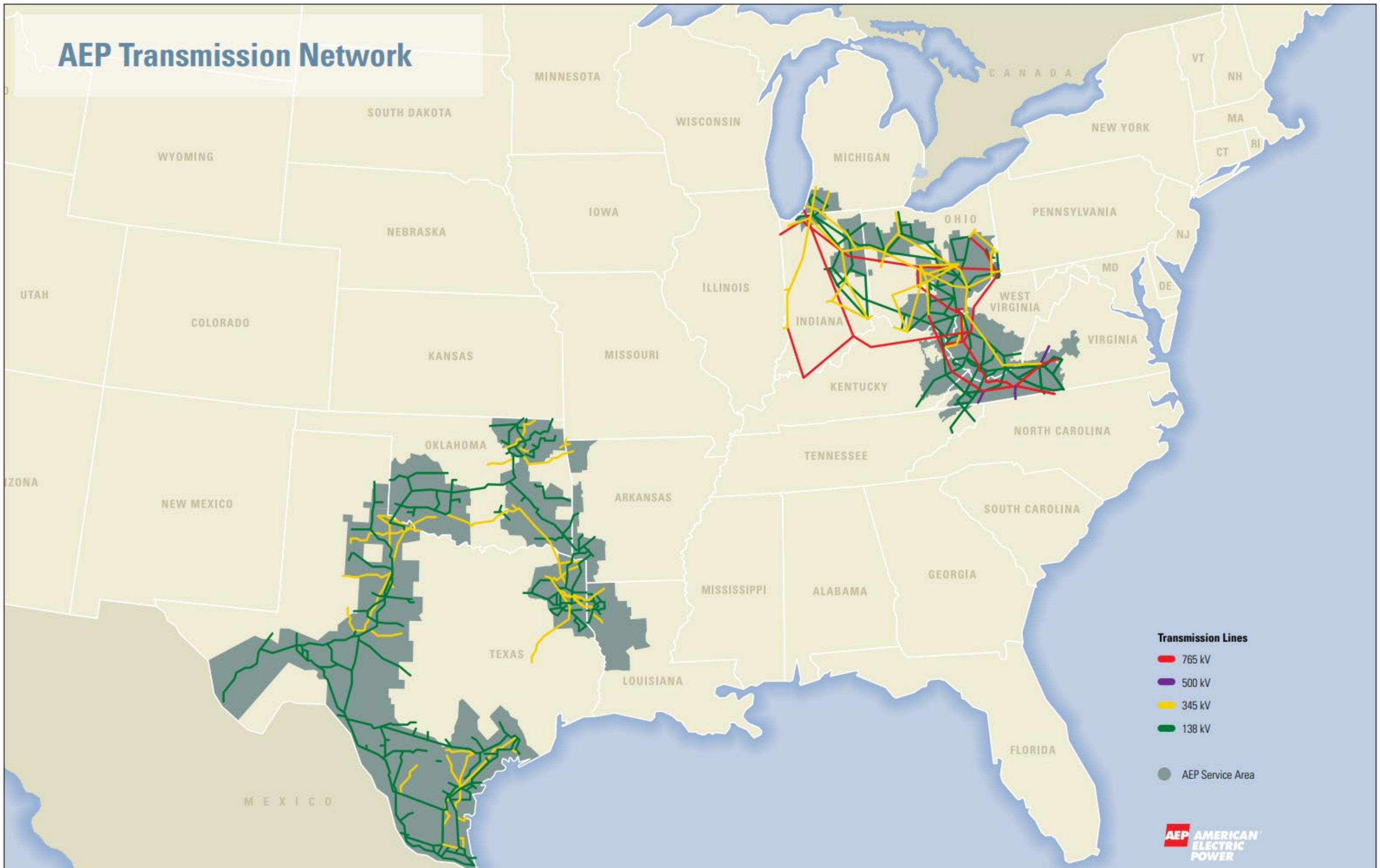
Automated Solutions and Remote Settings Changes - AEP's Approach to Implementing PRC-027-1

Jeff Iler and Nelson Doe

American Electric Power

Limited Disclosure

AEP Serves 5.5 million Customers in 11 States



Limited Disclosure

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:

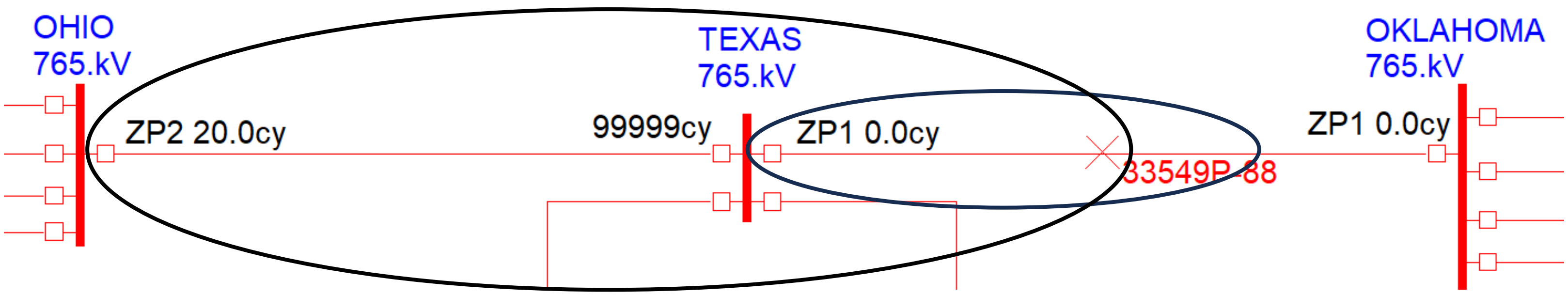
- Ensures that Protection Systems are coordinated
- Potentially reduces misoperations caused by incorrect relay settings
- May be more costly and time consuming than Option 2

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

21 – Distance

- 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

50 – Instantaneous overcurrent

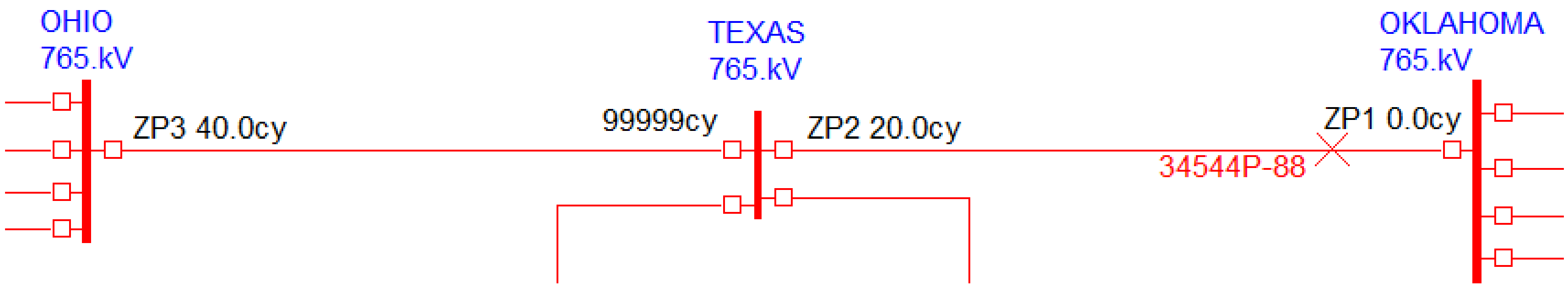
- Instantaneous Elements have adequate margin for remote bus fault

51/67 –AC overcurrent

- 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

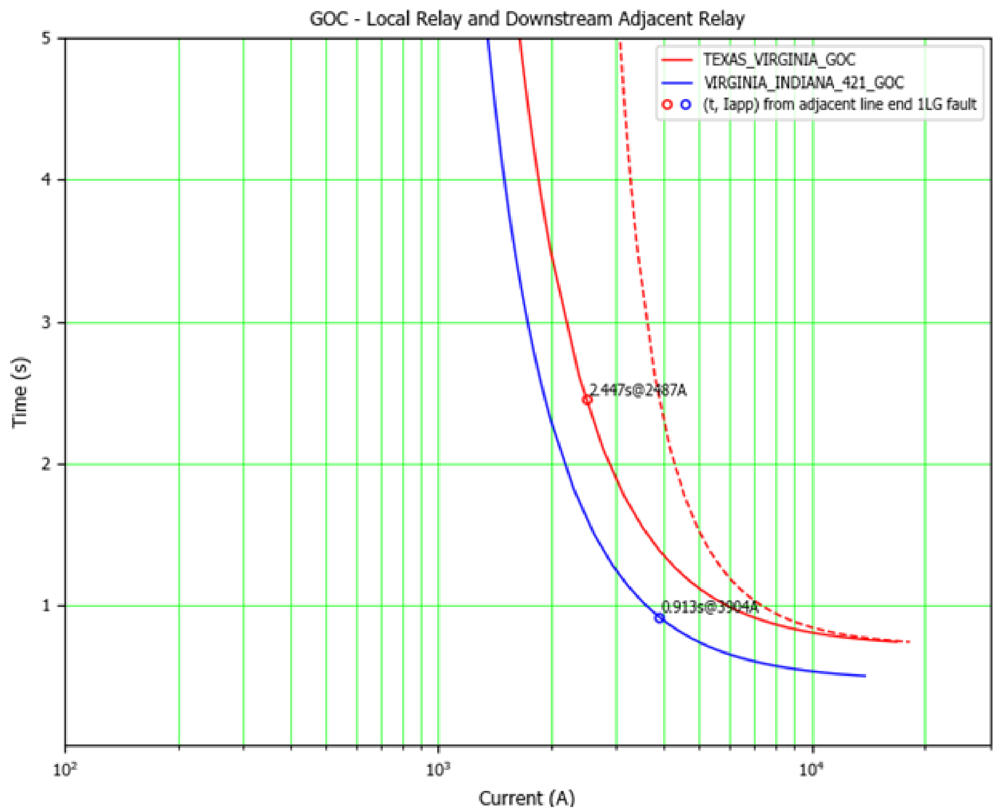
Lessons Learned from Initial 765KV Study

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

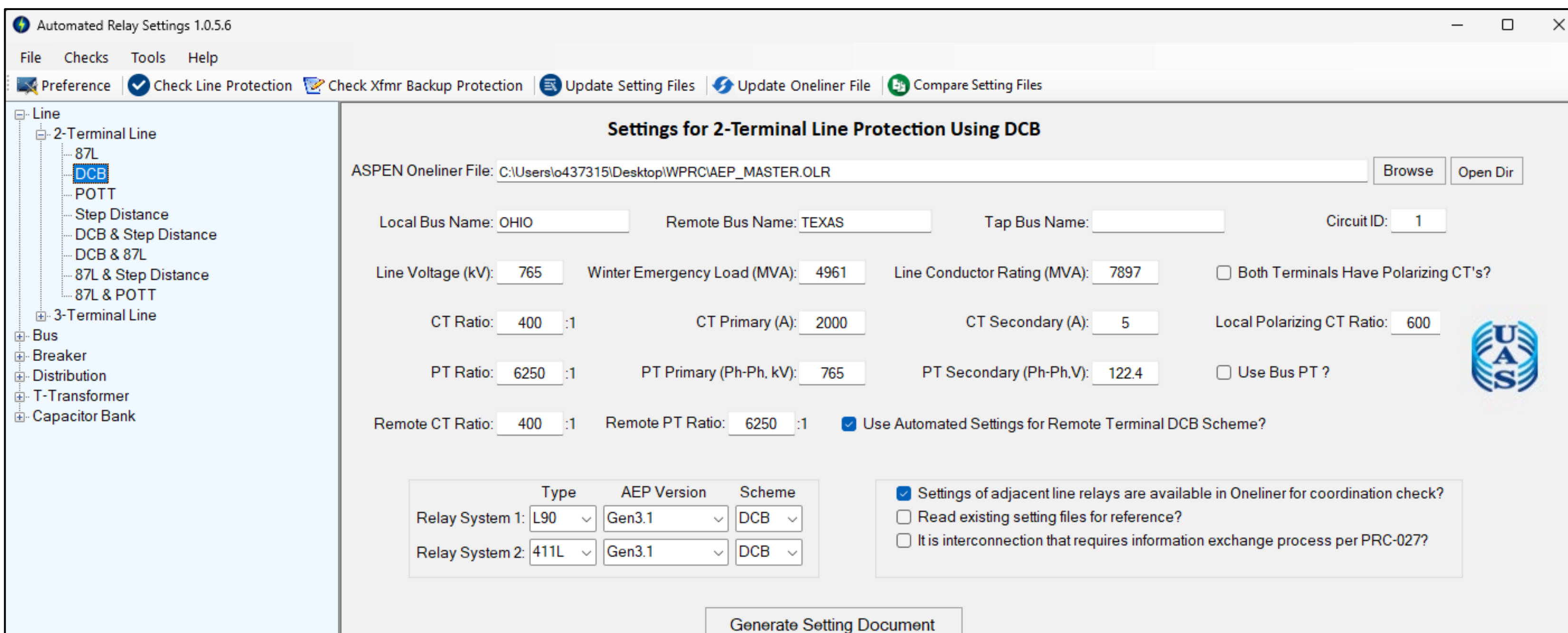
Initial study identified GOC settings as leading cause of coordination errors

- 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

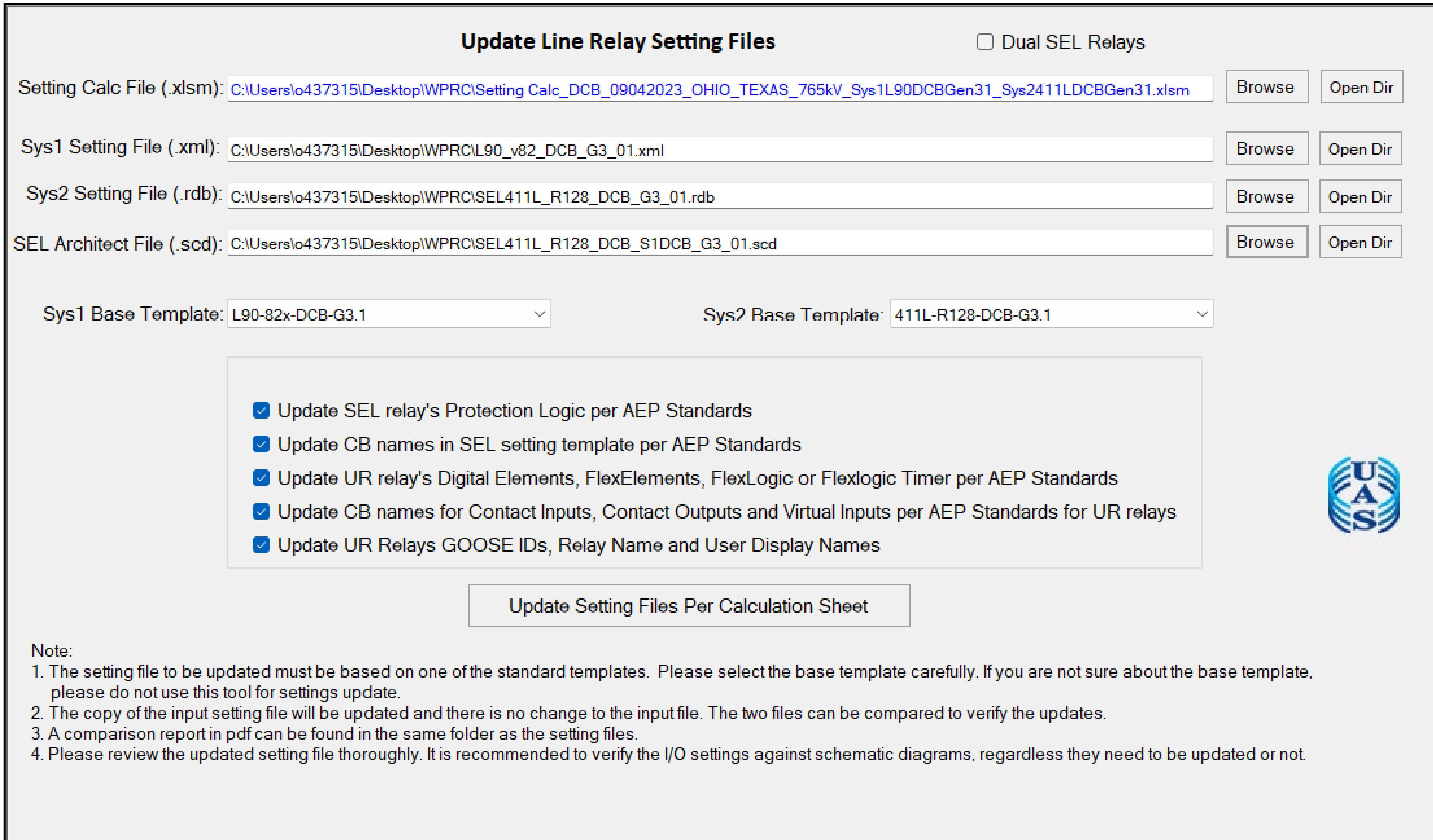
- Automated Relay Settings (ARS) developed by Utility Automation Solutions (UAS)
- ARS was initially used for the 765kV PRC-027 settings – 56 line terminals



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



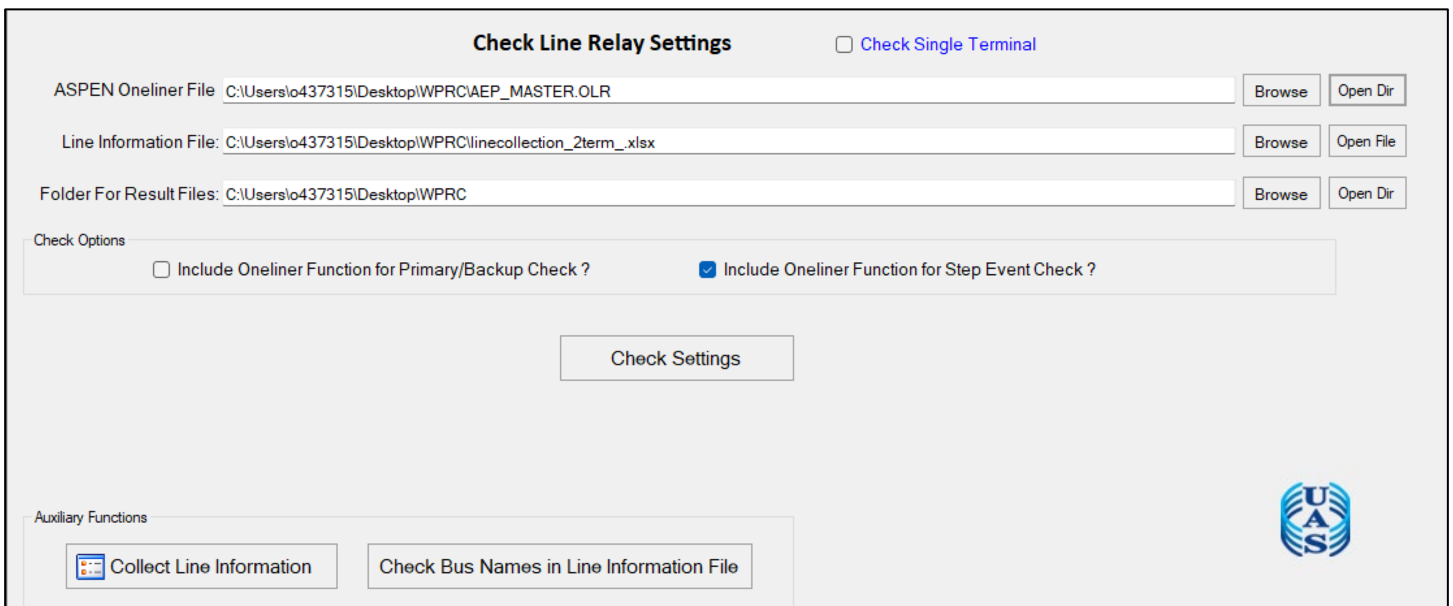
Adjusted Criteria for Protection System Coordination Studies

	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

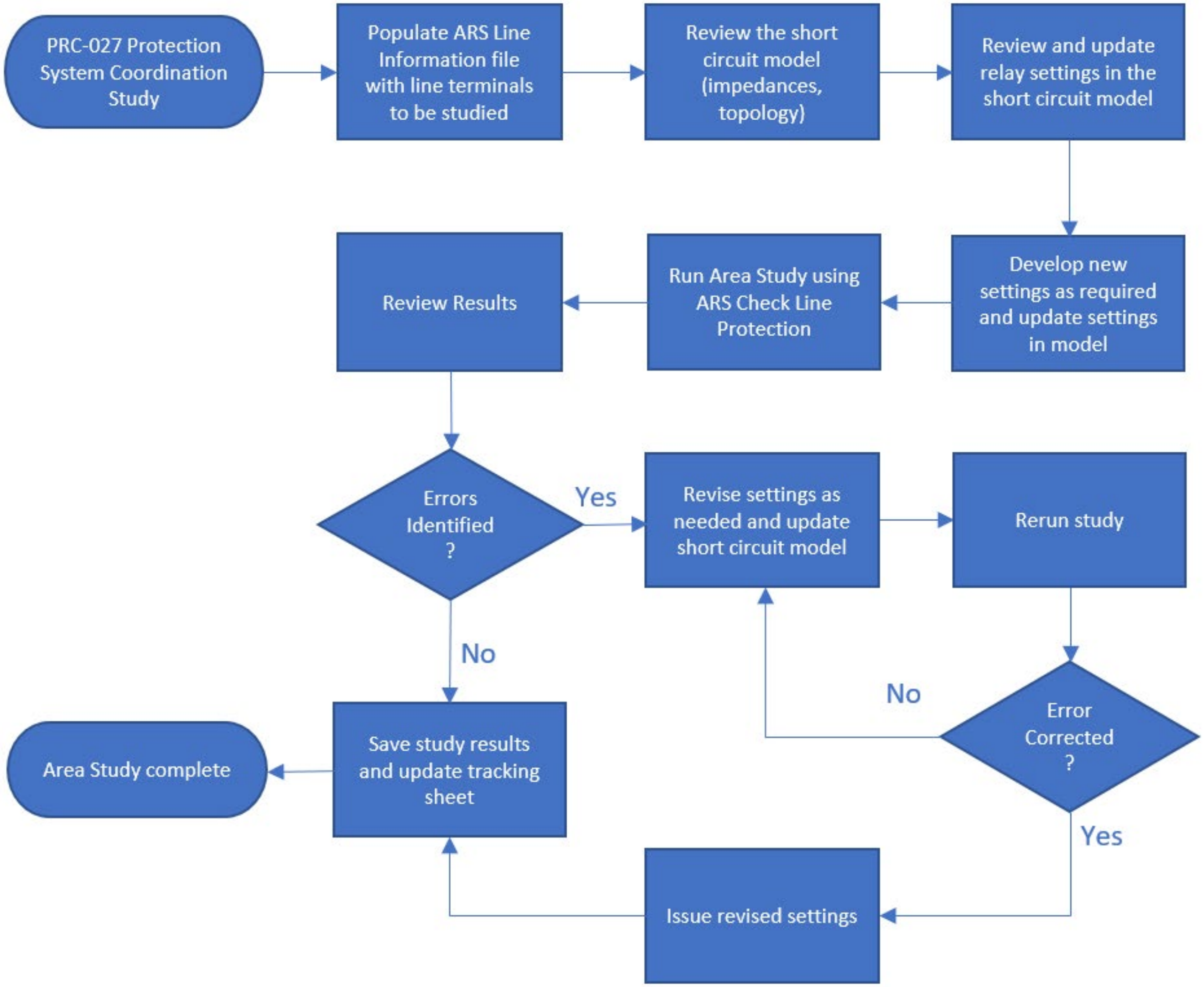
Downstream adjacent Relay ID	Op Time (s)	Local Relay ID	Op Time (s)	Z2P/Zapp	Check	
TEXAS_KENTUCKY_D60_PDS	0.333	OHIO_TEXAS_421_PDS	9999.000	50%	OK	Plot
TEXAS_KENTUCKY_D60_PDS	0.333	OHIO_TEXAS_D60_PDS	9999.000	42%	OK	Plot
TEXAS_KENTUCKY_421_PDS	0.333	OHIO_TEXAS_421_PDS	9999.000	50%	OK	Plot
TEXAS_KENTUCKY_421_PDS	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 ?

AMERICAN ELECTRIC POWER

Limited Disclosure

Managing System Oscillations in the ERCOT System

Yunzhi Cheng
Manager of Operations Stability Analysis, ERCOT
Co-Chair of IEEE IBR SSO Taskforce

RF PF Workshop

August 7, 2024

OUTLINE

- Introduction to IBR SSO
- About ERCOT and ERCOT IBR SSO Events
- ERCOT's Efforts to manage the IBR SSO
  - MQT (model quality test) – Planning
  - Large scale PSCAD simulation – Planning
  - GTC (generic transmission constrain) – Operations
  - WSCR (weighted short-circuit ratio) – Planning & Operations
  - GFM (grid-forming) – Planning & Operations
  - Synchronous Condenser & Series Capacitor – Planning & Operations

IEEE IBR SSO Taskforce

316 IEEE TRANSACTIONS ON POWER SYSTEMS, VOL. 38, NO. 1, JANUARY 2023

Real-World Subsynchronous Oscillation Events in Power Grids With High Penetrations of Inverter-Based Resources

Yunzhi Cheng, *Senior Member, IEEE*, Lingling Fan, *Fellow, IEEE*, Jonathan Rose, Shun-Hsien Huang, John Schmall, Xiaoyu Wang, *Senior Member, IEEE*, Xiaorong Xie, *Senior Member, IEEE*, Jan Shair, Jayanth R. Ramamurthy, *Senior Member, IEEE*, Nilesh Modi, Chun Li, *Senior Member, IEEE*, Chen Wang, Shahil Shah, *Senior Member, IEEE*, Bikash Pal, *Fellow, IEEE*, Zhixin Miao, *Senior Member, IEEE*, Andrew Isaacs, Jean Mahseredjian, *Fellow, IEEE*, and Jenny Zhou, *Senior Member, IEEE*

***Abstract*—This paper presents a survey of real-world subsynchronous oscillation events associated with inverter-based resources (IBR) over the past decade. The focus is on those oscillations in the subsynchronous frequency range known to be influenced by power grid characteristics, e.g., series compensation or low system strength. A brief overview of the historical events is presented followed by detailed descriptions of a series of events. This paper also examines causation mechanisms and proposes future research directions to meet grid needs worldwide.**

***Index Terms*—Inverter-based resources, oscillations, stability.**

I. Introduction

PENETRATIONS of inverter-based resources (IBRs) are increasing worldwide. The maximum instantaneous penetration levels of IBRs in South Australia, Texas, Ireland, and Tasmania have reached 150%, 66%, 92%, and 95%, respectively [1]. The operation with such high levels of IBRs has introduced undesirable dynamics, including subcycle overvoltage [2], ac overcurrents [3] and subsynchronous oscillations (SSOs) [4], [5]. Stability issues related to IBRs have caught attention by

IBR SSO

IBR SSO

Series Capacitor + Type 3 WTG

Typical Example: 2009 South Texas SSCI Event

High Penetration of IBRs in Weak Grid

Typical Example: 2015 Northwest China SSO Event

Y. Cheng *et al.*, "Real-World Subsynchronous Oscillation Events in Power Grids with High Penetrations of Inverter-Based Resources," in *IEEE Transactions on Power Systems*, 2023

Some Reported IBR SSO Events

Year	Location	Frequency (Hz)	Mechanism
2021	Scotland	8	Offshore WTG + Weak grid (?)
2020 – 2021	West Murray, Australia	15 – 20	IBR + Weak grid (?)
2019	Great Britain	9	Offshore WTG + Weak Grid
2015 – 2019	West Murray, Australia	7	IBR + Weak Grid
2017	First Solar, USA	7	Solar PV + Weak Grid
2015	Northwest China	27 – 34	Type 4 WTG + Weak Grid
2015	Hydro One, Canada	20	Solar PV + Weak Grid
2011	Texas, USA	4	Type 4 WTG + Weak Grid
2023	South Texas, USA	20 – 30	Type 3 WTG + Series Cap.
2017	South Texas, USA	20 – 30	Type 3 WTG + Series Cap.
2012 – 2016	North China	3 – 12	Type 3 WTG + Series Cap.
2009	South Texas, USA	20 – 30	Type 3 WTG + Series Cap.

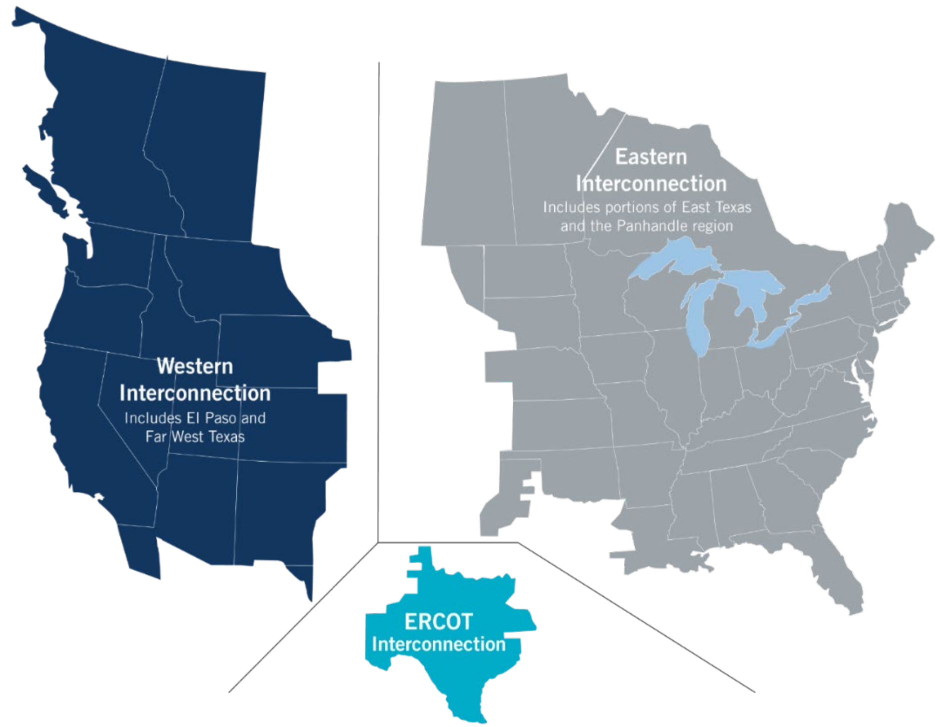
Y. Cheng *et al.*, "Real-World Subsynchronous Oscillation Events in Power Grids with High Penetrations of Inverter-Based Resources," in *IEEE Transactions on Power Systems*, 2023

The ERCOT Region

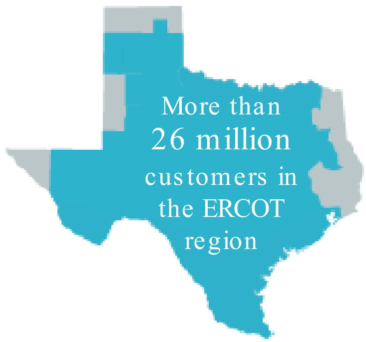
The interconnected electrical system serving most of Texas, with limited external connections

- 90% of Texas electric load; 75% of Texas land
- 85,508 MW peak, August 10, 2023
- More than 54,100 miles of transmission lines
- 1250+ generation units (including PUNs)

ERCOT connections to other grids are limited to ~1,220 MW of direct current (DC) tie capacity



ERCOT Quick Facts



90% of Texas Load

75% of load is competitive choice customers

1 MW of electricity can power about 200 Texas homes during periods of peak demand

1,100+
generating units, including PUNs

52,700+
miles of high-voltage transmission

98,000+ MW
of expected capacity for summer 2023 peak demand

$3,3 billion
transmission projects endorsed in 2022

1,873+
active market participants that generate, move, buy, sell or use wholesale electricity

85,508 MW
Record peak demand
(August 10, 2023, 5-6 pm)

85,116 MW
Weekend peak demand record
(August 20, 2023, 4-5 pm)

37,725 MW
of installed wind capacity

17,040 MW
of installed solar capacity

27,548 MW
Wind generation record
(Jan. 7, 2024)

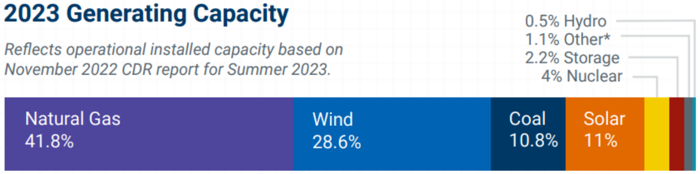
13,944 MW
Solar generation record
(Dec. 29, 2023)

69.15%
Wind penetration record
(April 10, 2022, 1 am)

32.93%
Solar penetration record
(April 30, 2023, 10 am)

2023 Generating Capacity

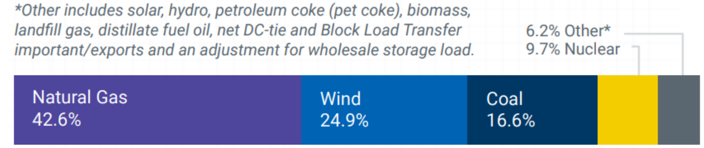
Reflects operational installed capacity based on November 2022 CDR report for Summer 2023.



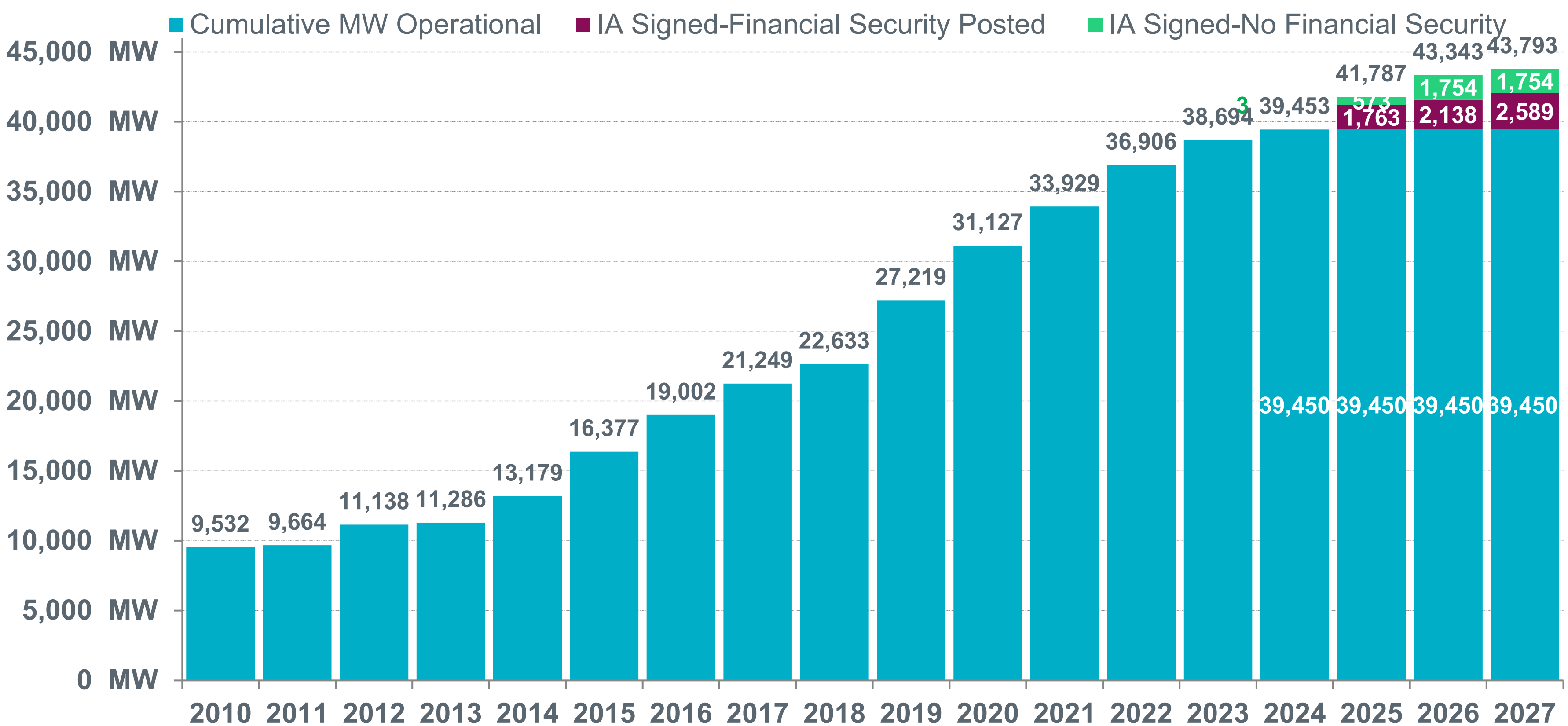
The sum of the percentages may not equal 100% due to rounding.
**Other includes biomass and DC Tie capacity.*

2022 Energy Use

**Other includes solar, hydro, petroleum coke (pet coke), biomass, landfill gas, distillate fuel oil, net DC-tie and Block Load Transfer important/exports and an adjustment for wholesale storage load.*

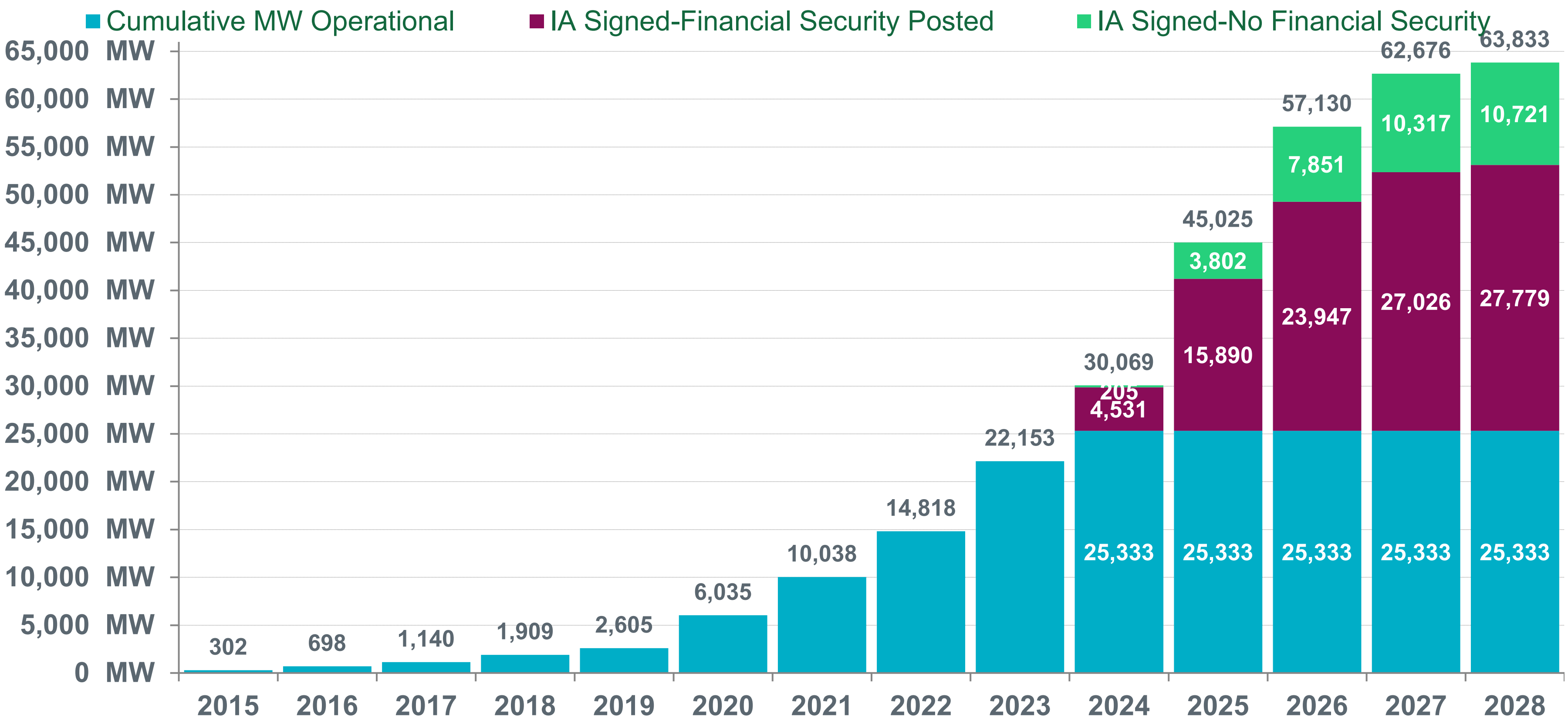


ERCOT Wind Additions by Year



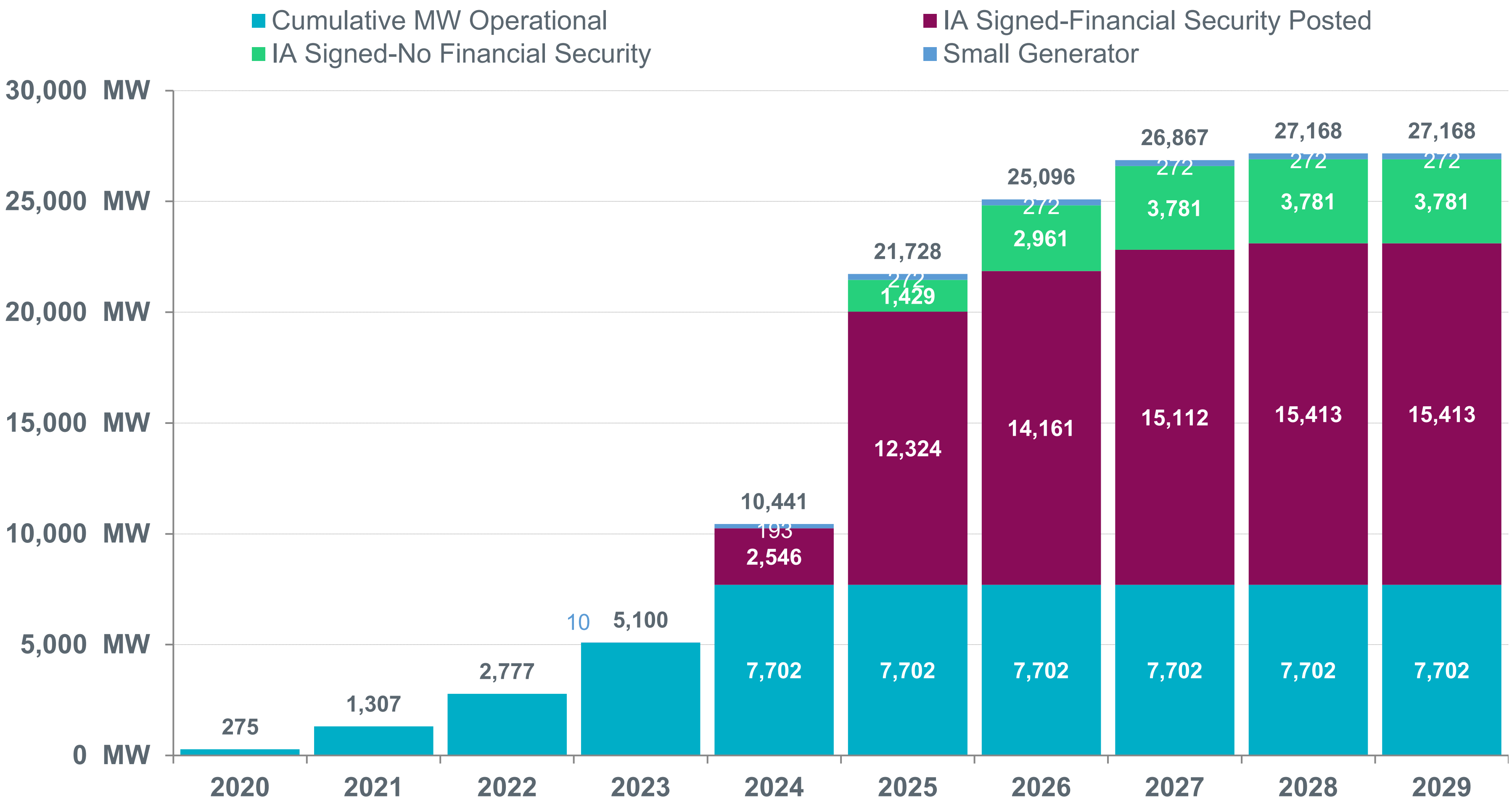
*as of June 30, 2024

ERCOT Solar Additions by Year



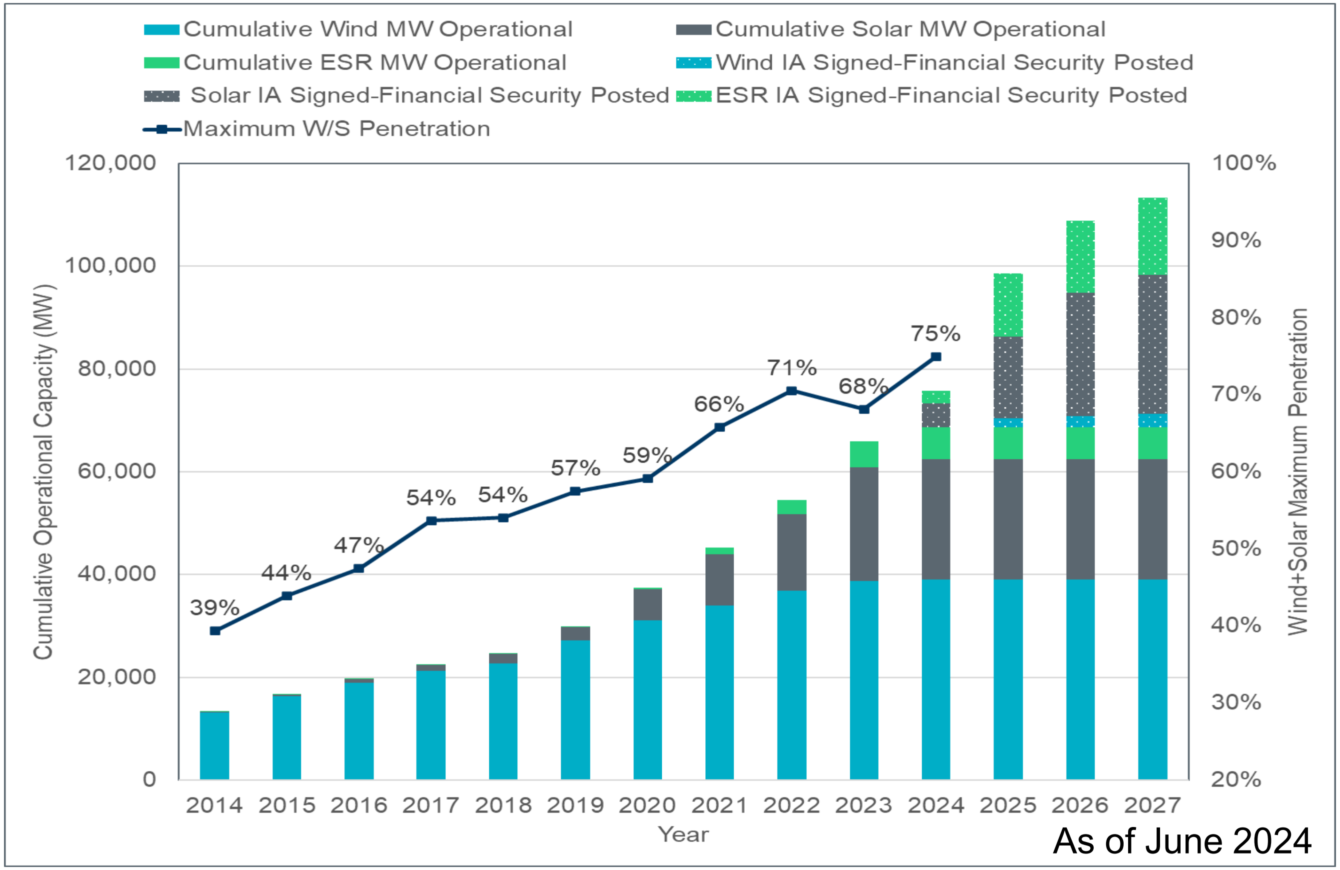
*as of June 30, 2024

ERCOT Battery Additions by Year



*as of June 30, 2024

ERCOT IBR Growth

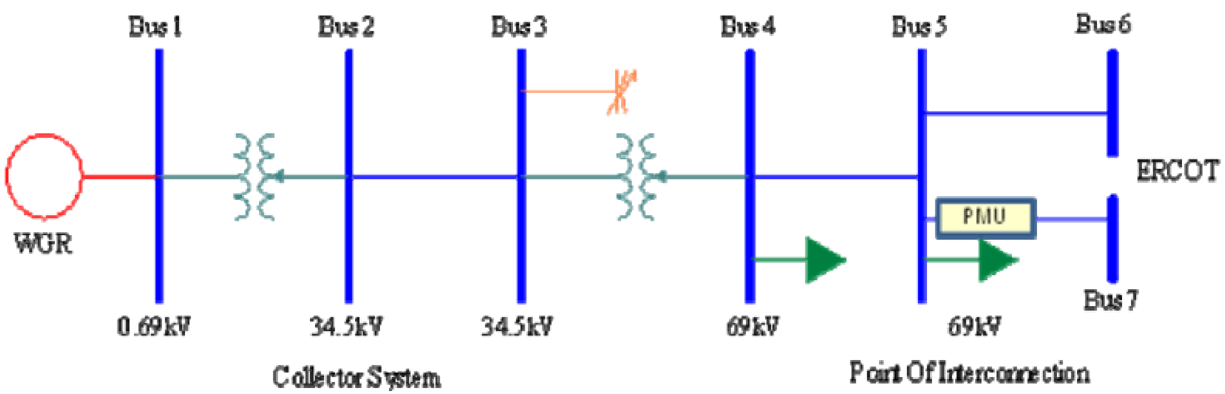


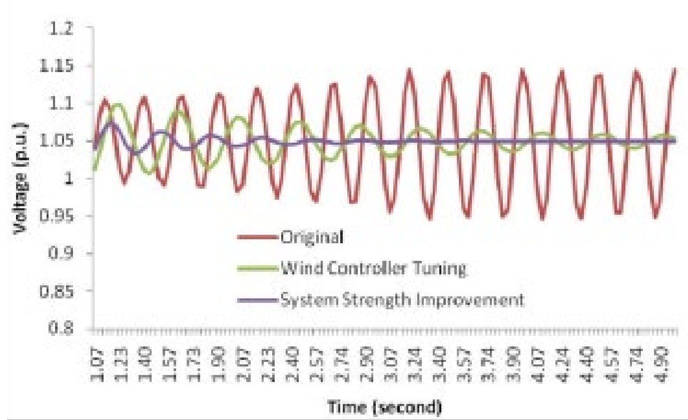
ERCOT could exceed 100 GW IBRs connection by 2025. Further growth is also projected based on the current ERCOT resource capacity trend.

https://www.ercot.com/gridinfo/resource

Weak Grid related SSO Event in ERCOT

- Local SSO event in 2011
- Undamped oscillation (~4 Hz) was observed at high wind speed with the line of Bus 5 – 6 in outage (SCR dropped to 2)

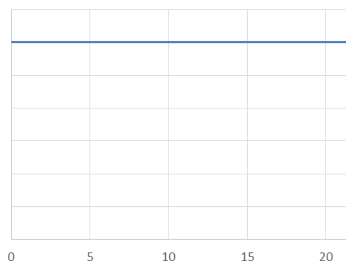


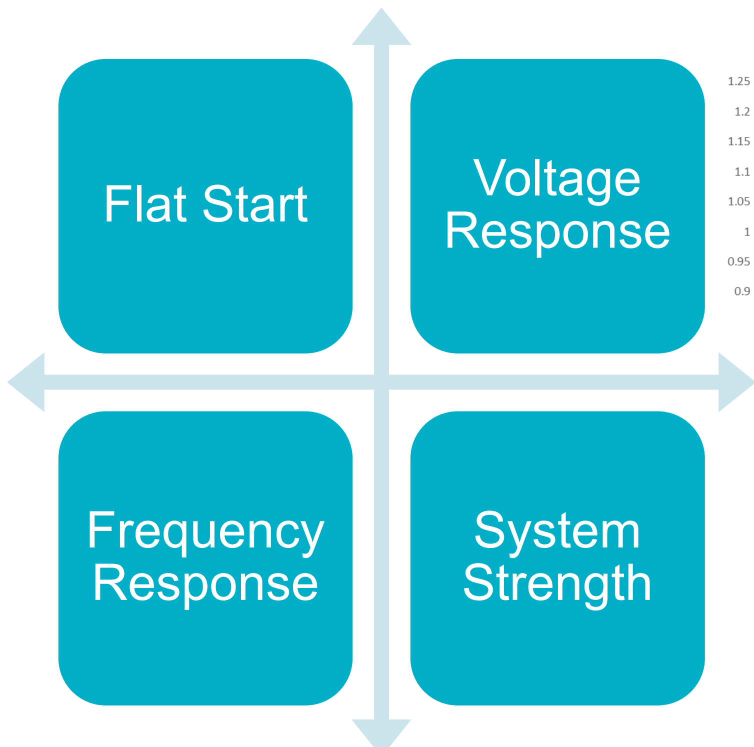


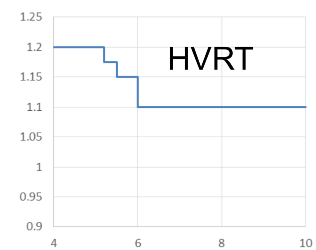
Reference: Shun-Hsien (Fred) Huang, etc., "Voltage Control Challenges on Weak Grids with High Penetration of Wind Generation: ERCOT Experience", 2012 IEEE PES GM

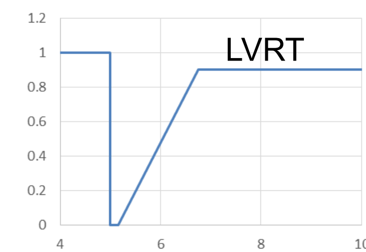
Model Quality Test (MQT)

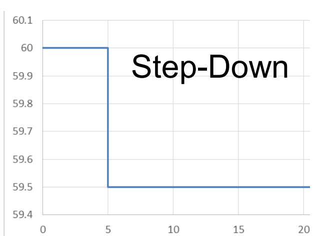
- System Strength (SCR) Test with minimum requirement of SCR = 1.5
- DMView tool for PSS/e available at https://sites.google.com/view/dmview/home
- PMView tool for PSCAD available at https://sites.google.com/view/pmview/home

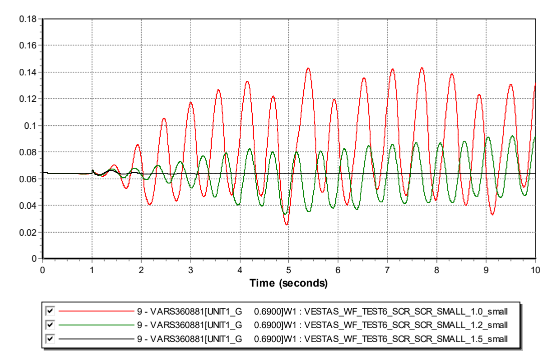






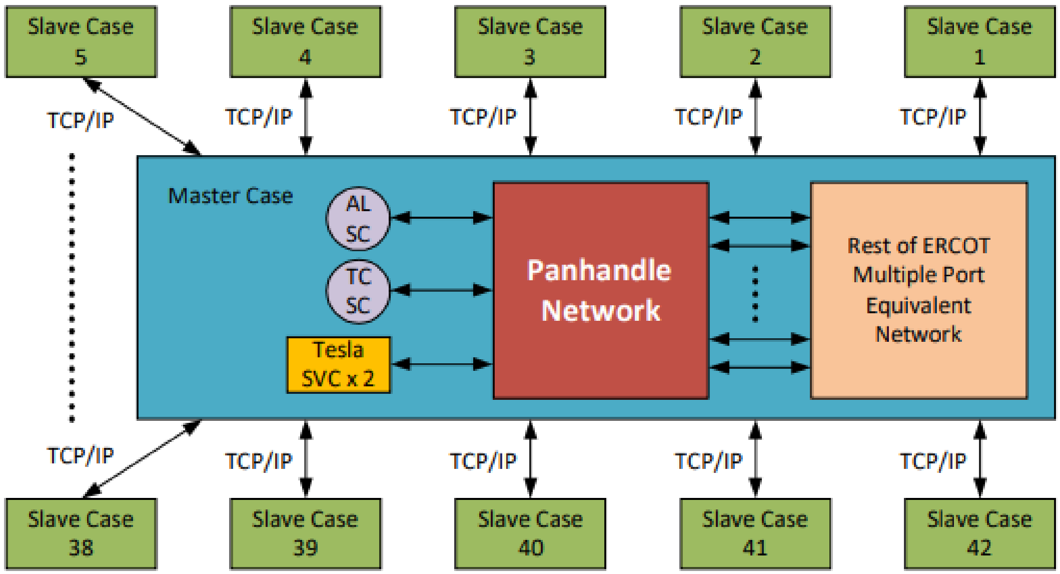






Large Scale PSCAD Simulation

- 2020 Panhandle Study (PSS/e & PSCAD)
  - 46 IBR projects (>10GW)
  - 43 PSCAD cases created for parallel simulation
  - ETRAN Plus tool is used for PSCAD parallel simulation

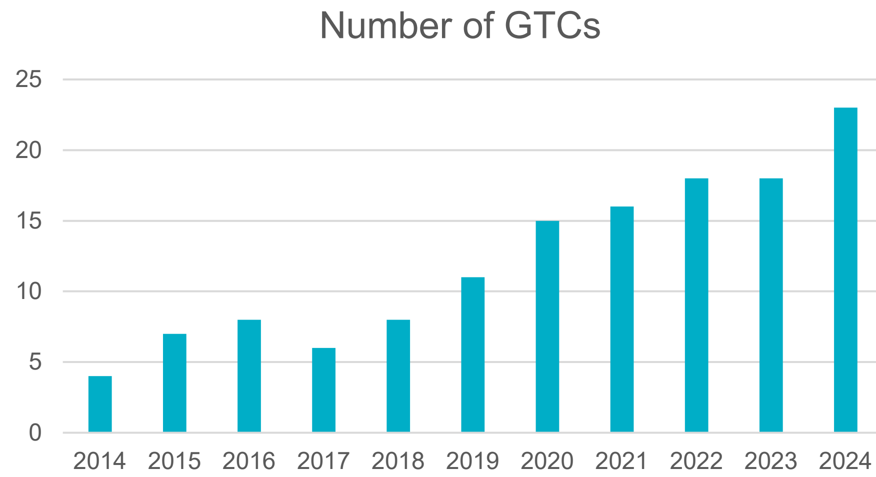


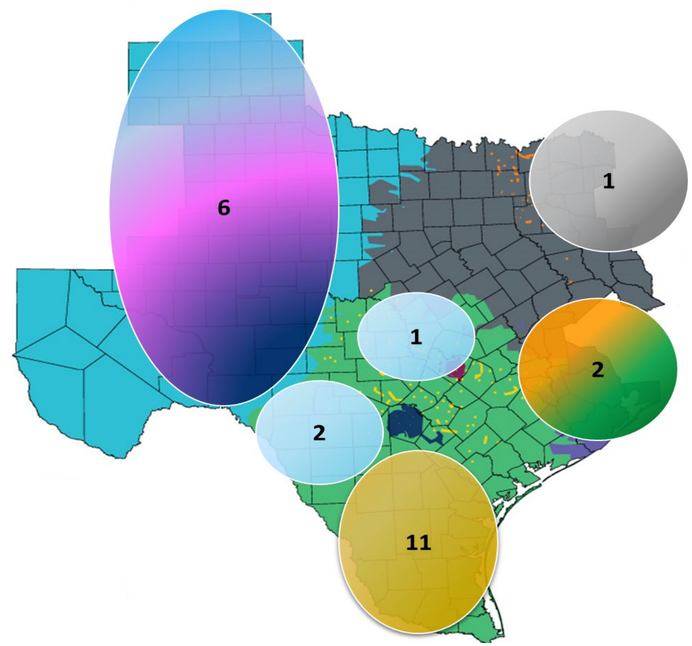
  - For the stable scenarios, the overall performances from PSCAD simulations were consistent with that from PSS/e simulations
  - PSCAD studies are necessary to evaluate potential control stability issues

"2020 Panhandle Regional Stability Study, available at "https://www.ercot.com/files/docs/2020/11/27/2020_PanhandleStudy_public_final__004_.pdf

GTC (Generic Transmission Constrain)

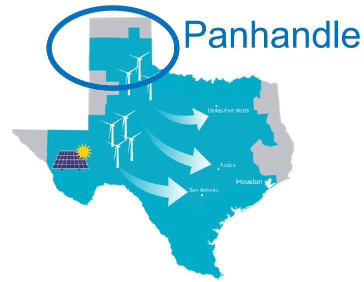
- A Generic Transmission Constraint (GTC) is a tool that ERCOT uses to manage stability limitations (including weak grid related SSO) in real-time operations.
- ERCOT has seen an increase in stability constraints in recent years, particularly in West Texas and South Texas, which has led to an overall increase in the number of GTCs.
- Most of GTC are based on off-line PSS/e dynamic simulation. ERCOT is in the process of implementing real-time stability assessment tool (TSAT) to identify and determine the proper stability constraints based on the real time system conditions. Damping ratio is one of criteria for the stability assessment.





System Strength (Weak Grid) and WSCR

- System strength identified in the simulation of Panhandle area
  - Far away from load centers
  - No synchronous generators
  - No Load
  - All the resources are IBRs (~5GW)



- Two synchronous condensers (175MVA each) were added to Panhandle in 2018
- ERCOT proposed the concept of WSCR (Weighted Short Circuit Ratio) to measure the Panhandle system strength based on actual output of the Panhandle IBRs

$$WSCR = \frac{\sum_i^N S_{SCMVAi} * P_i}{\left(\sum_i^N P_i\right)^2}$$

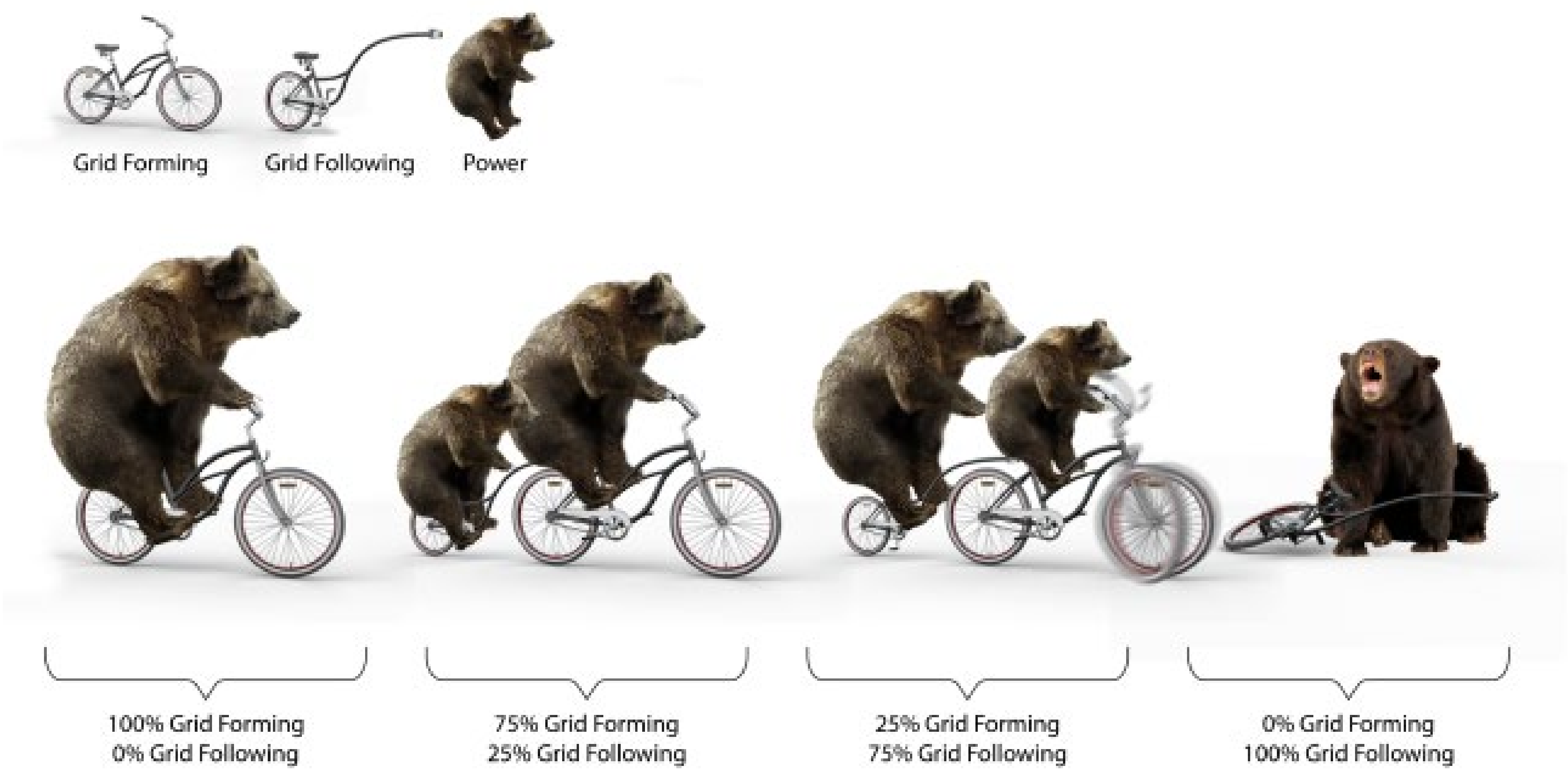
- WSCR=1.5 was proposed as the minimum pre-contingency system strength and implemented in real time operations to limit the Panhandle IBRs output based on the system strength
- WSCR index was retried in 2021 with transmission system upgrade in Panhandle

Y. Zhang, etc., "*Evaluating System Strength for Large-Scale Wind Plant Integration*," in Power and Energy Society General Meeting, 2014 IEEE

Grid Forming

- NERC definition: GFM (Grid Forming) IBR controls **maintain an internal voltage phasor that is constant or nearly constant in the sub-transient to transient time frame**. This allows the IBR to immediately respond to changes in the external system and maintain IBR control stability during challenging network conditions. The voltage phasor must be controlled to maintain synchronism with other devices in the grid and must also regulate active and reactive power appropriately to support the grid

Grid Forming vs Grid Following



https://www.nrel.gov/docs/fy20osti/75848.pdf

Grid Forming

- ERCOT contracted Electranix in late 2023 to help recommend the required IBR advanced grid support capability and test framework
- ERCOT also reached out to major IBR OEMs to understand the existing and potential advanced grid support capability (like GFM)
  - OEMs for inverter-based ESRs, including Tesla, SMA, Sungrow, and Power Electronics, shared their GFM BESS models to support this project
  - OEMs for wind and solar currently **<u>don't</u>** have commercially available product

https://www.ercot.com/files/docs/2024/07/09/2024_07_ERCOT_IBRWG_ERCOT%20Advanced%20Grid%20Support%20Inverter-based%20ESRs%20Assessment%20and%20Adoption%20Discussion_v1_.pdf

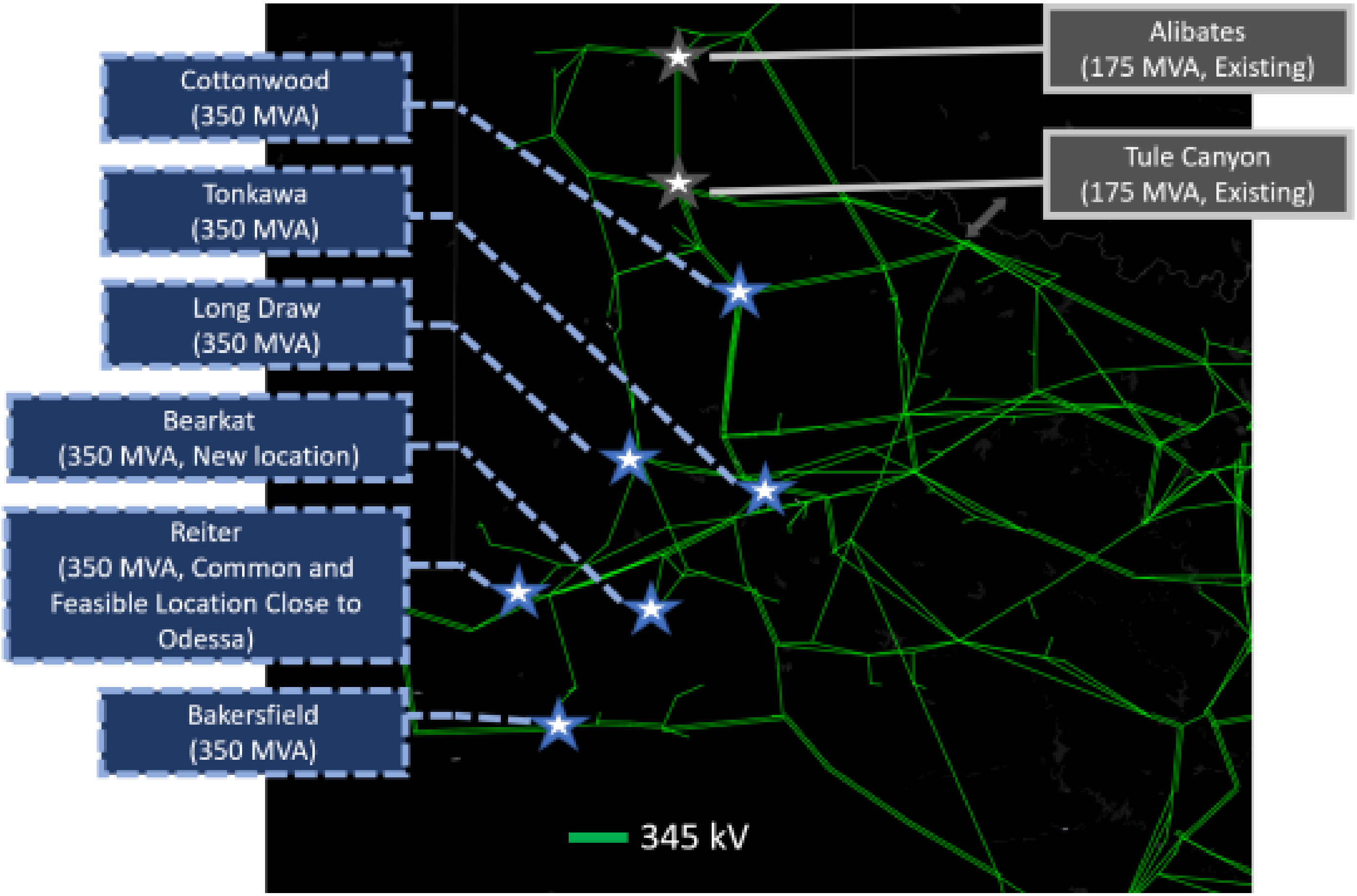
Grid Forming

- ERCOT plans to propose standards for GFM inverter-based Energy Storage Resources (ESRs)
  - Voluntary first; mandatory for new inverter-based ESRs at a near future date
- Inverter-based ESRs are commercially available today to provide advanced grid support; and generally, only require software/control changes with no impact to the hardware or commercial operations
- ERCOT's preliminary assessments have identified the improvement of system stability performance and the benefits to the generic transmission constraints (GTCs)

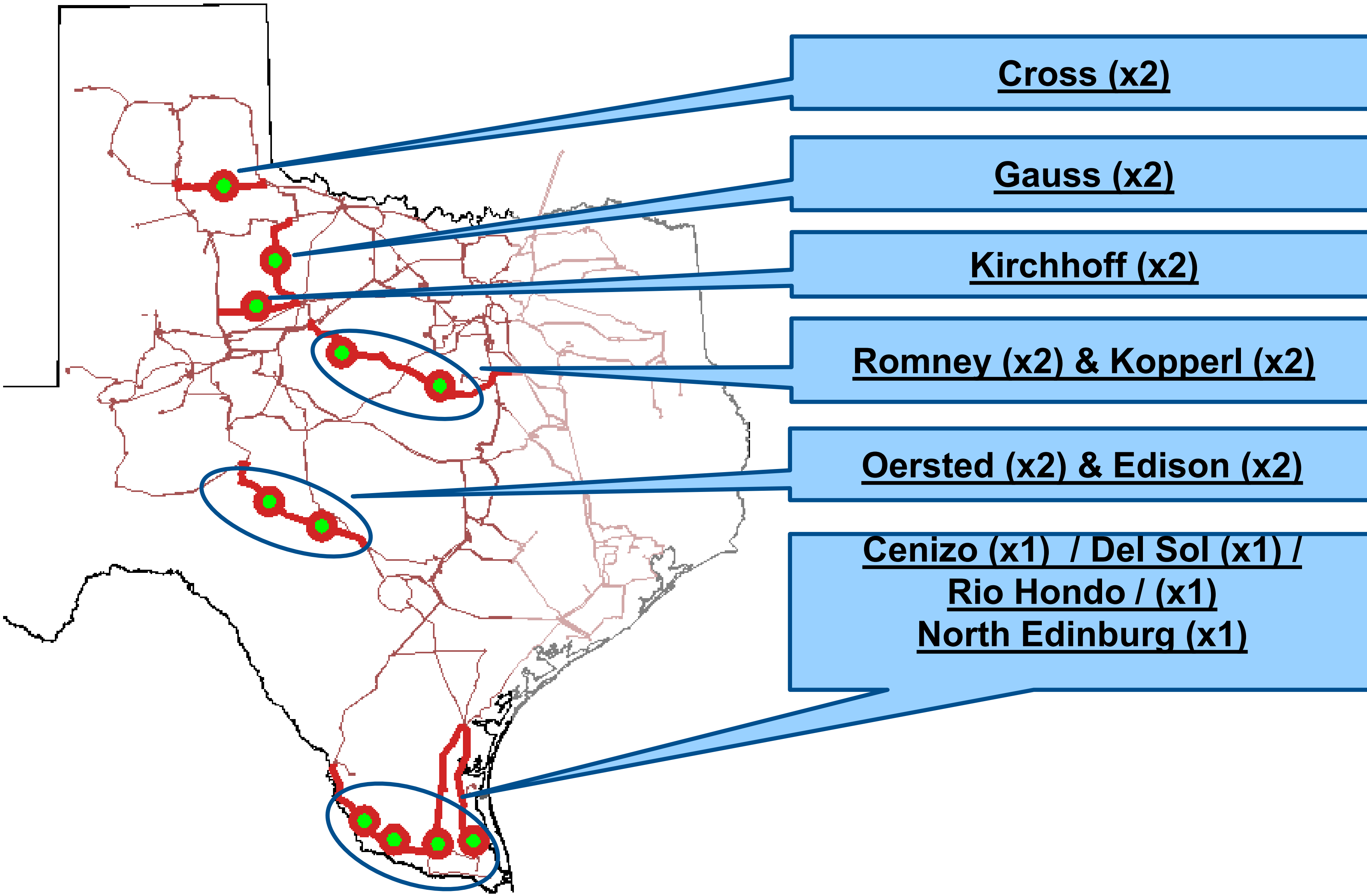
https://www.ercot.com/files/docs/2024/07/09/2024_07_ERCOT_IBRWG_ERCOT%20Advanced%20Grid%20Support%20Inverter-based%20ESRs%20Assessment%20and%20Adoption%20Discussion_v1_.pdf

Six Synchronous Condensers (SynCons) in WTX

- A total of six new SynCons (2100MVA) were identified to increase the system strength of WTX (>40GW IBRs)



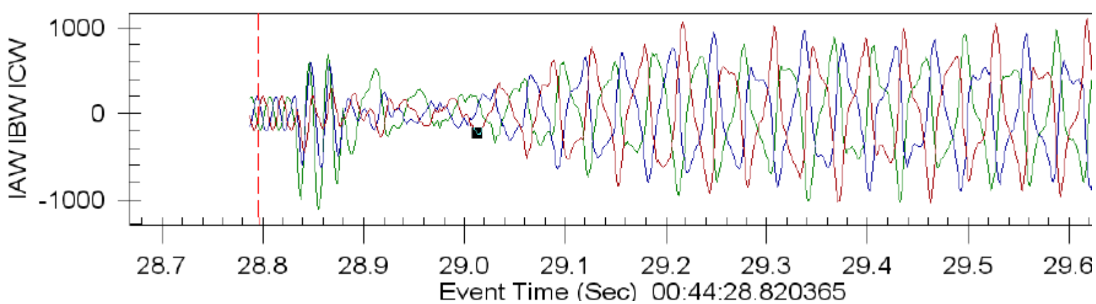
Series Capacitors in ERCOT

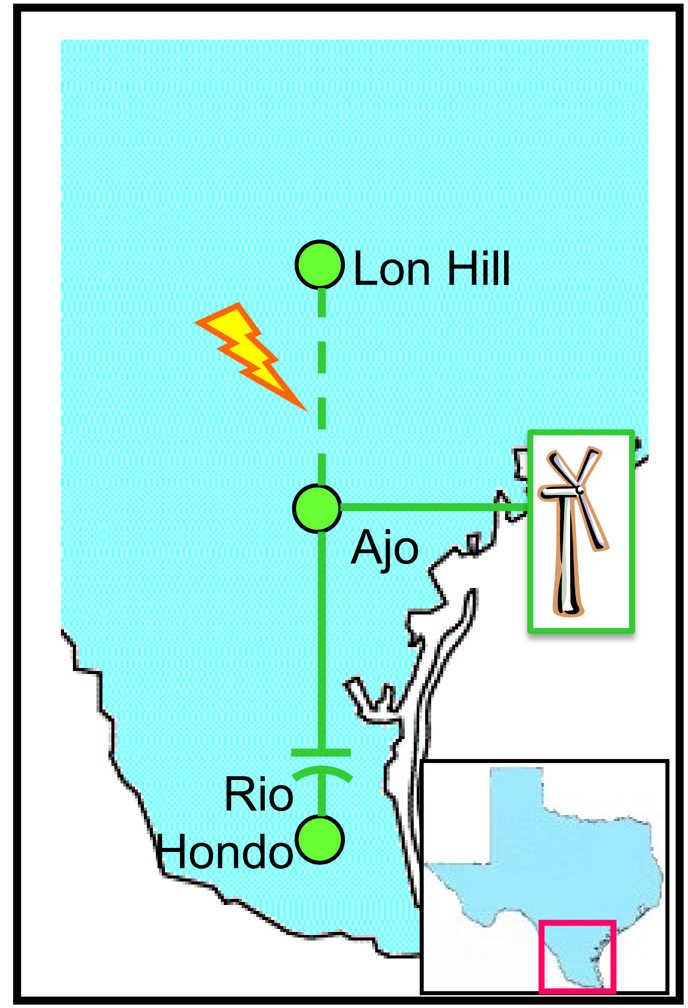


Limited Disclosure

South Texas 2009 Event

- Series capacitors installed on long 345 kV line in South Texas.
- A cluster of wind farms (DFIG) connected to Ajo.
- In 2009, a fault caused LonHill – Ajo line to trip, leaving wind radially connected to series caps.
- Very high currents resulted in damage.





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American Electric Power's Experience with Protection System Misoperations and Improvements

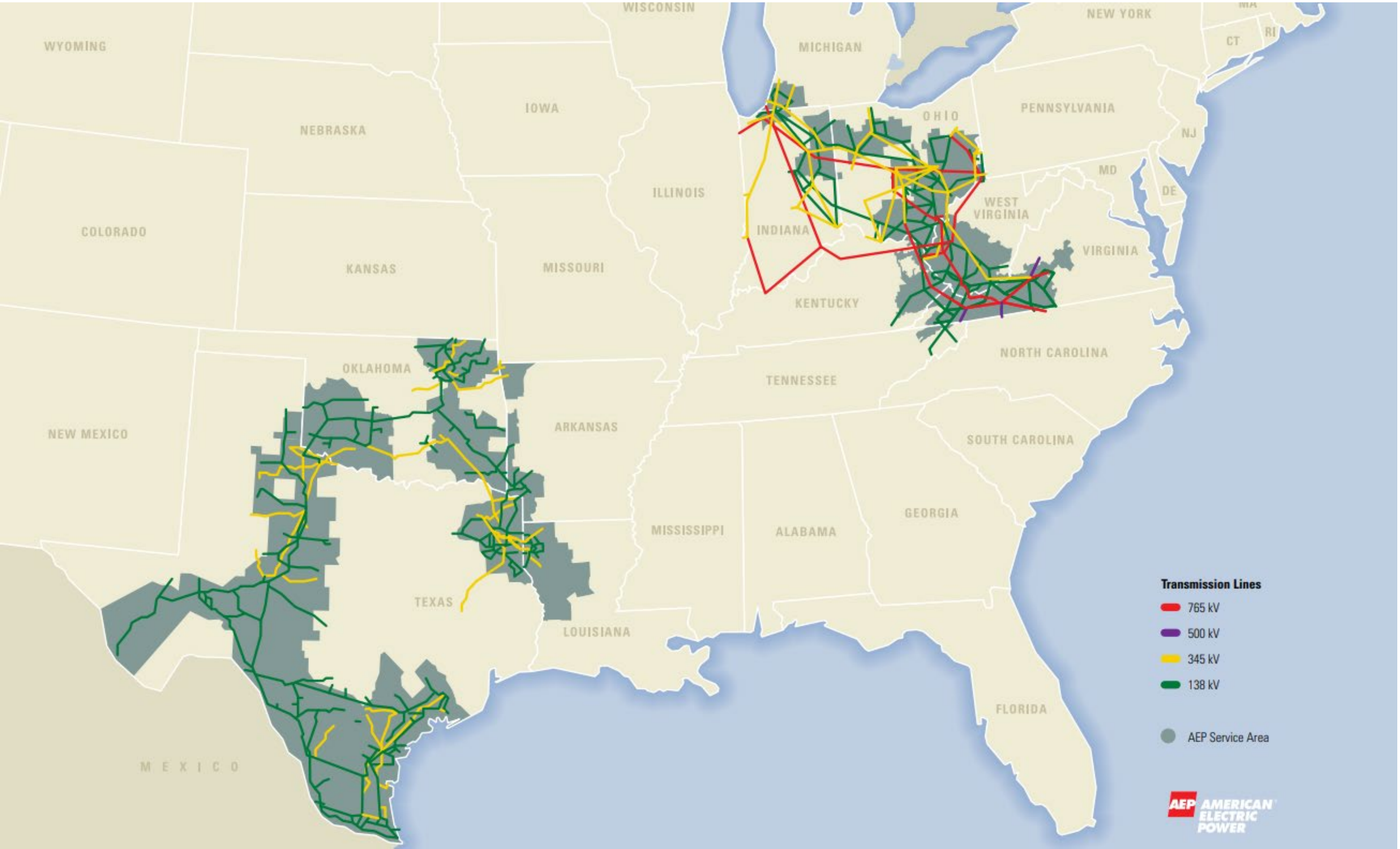
Ross D. Stienecker

(American Electric Power)

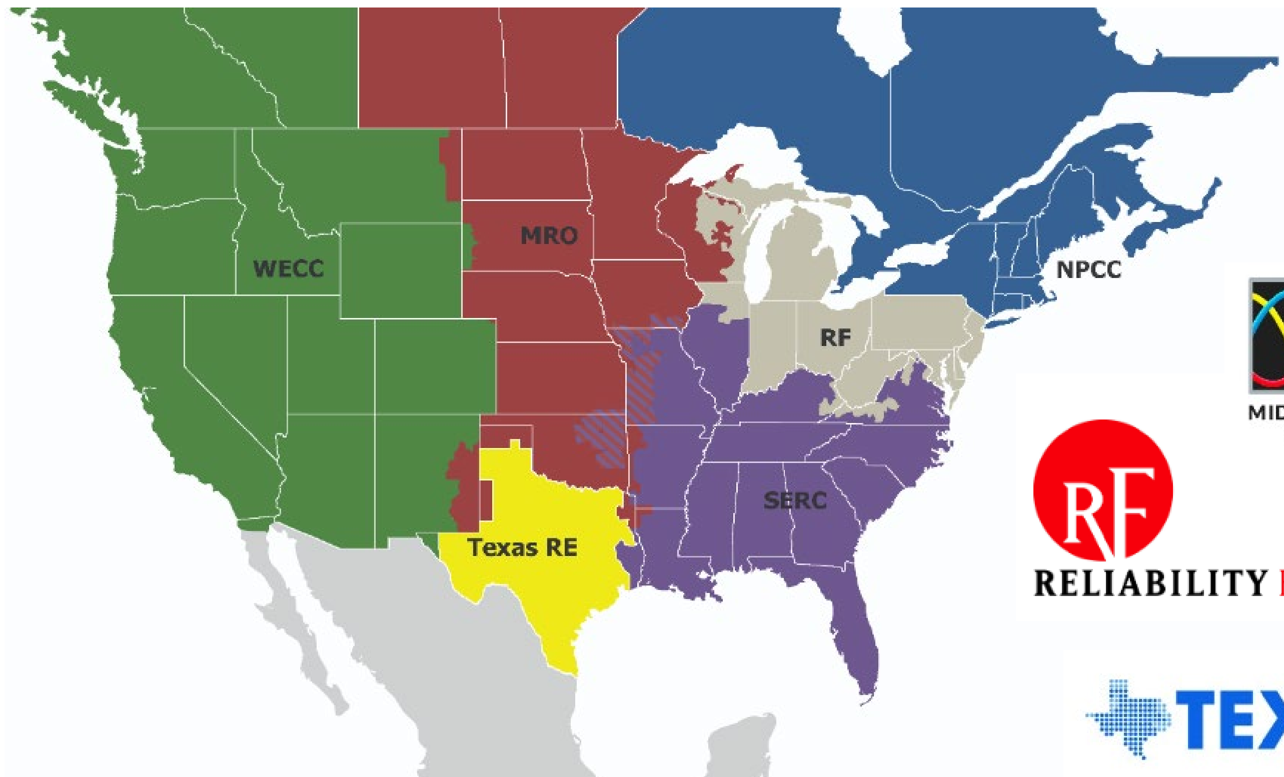
Introduction

- AEP Key Statistics:
  - 16,800 employees
  - 5.5 million regulated customers
  - 30,000 MW generation capacity
  - 40,000 miles of transmission line (including 765kV)
  - Operates in 11 different states
  - Headquartered in Columbus, Ohio

AEP Transmission Network



AEP Regional Entities



MIDWEST RELIABILITY ORGANIZATION

RELIABILITY FIRST

TEXAS RE

New Technologies

Grid Transformation

Challenges

- Protection system technology changes
- Decentralized renewable generation
- Inverter based generation vs traditional inertia
- Younger experience level in the industry
- Large capital investment workplans
- FACTs transmission devices (series capacitors, SVCs, PSTs, etc…)

Reliability

- All these challenges lead to increased complexity which if not properly accounted for can lead to protection system misoperations
- Misoperations are a key risk to the Bulk Electric System's (BES) reliability
- AEP has a goal of ZERO protection system misoperations

Path to Zero Misoperations

- **Leverage automation**
- **Embrace industry best practices**
- **Simplify protection and control schemes**
- **Incorporate lessons learned from system misoperations into key engineering processes**

Identifying Misoperations

- AEP has a separate team outside of engineering (TFS P&C) that first reviews the operation
- TFS P&C reviews all available data
- If an operation is determined a misoperation, then engineering (PCE) gets involved

Cause Identification

- A group of experienced technical engineers representing all regions and departments of PCE meet to analyze the event
- Very important to find the true root cause so that the appropriate corrective action plan (CAP) can be developed (ex: Z1P overreaches; is setting bad or is model bad)
- The formal group setting helps raise awareness

Corrective Action Plan

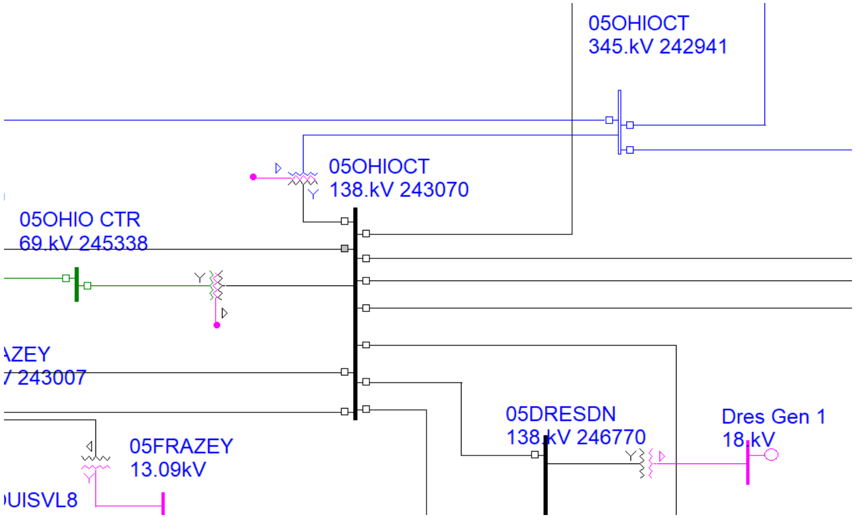
- Develop a CAP
- Implement CAP within 2 weeks (avoid repeats)
- Express Settings when applicable
- Prioritize model verification

Assessing Applicability

- Group determines if misoperation is isolated event
- Does CAP have applicability to other protection systems
- If so, filter and define list of affected assets
- Create mitigation project (proactive way to reduce risk & prevent future misoperations)
- Express Settings method speeds up mitigation

Modelling

- Formalized how power elements such as lines and transformers are modelled
- Dedicated short circuit modelling group
- Modelling process includes a peer review before given to engineering
- All settings work requires a verified model even if an existing asset and no planned changes



Formalized Settings Peer Reviews

- Human error is a top driver of settings related misoperations
- Peer review adds extra layer of protection
- Past reviews were not performed consistently and not well documented
- Have a peer review process document, defines expectations
- Review is now integrated with setting issue workflow
- BES line settings need reviewed by qualified peer reviewer

Formalized Settings Peer Reviews

- Reviews are stored electronically, and reviewer name is included
- Instituted a Line Settings Robust Checklist
- This checklist includes items that may often get overlooked and items that past experiences have deemed need extra attention from the setter and also the peer reviewer.

Formalized Settings Peer Reviews

Item	Task	Enter Value	Executed	Executed Time	User
1-	**PCE Peer Review**				
1.1.	Select the type of settings that are being peer reviewed	Line Settings	☑	9/27/2022	s233645
2-	**Aspen Model**				
2.1.	Aspen Model was reviewed and updated as per TEPD-2450	Yes	☑	9/27/2022	s233645
2.2.	*Comments*				
2.3.	Relay devices and coordination pairs are modelled correctly.	Yes	☑	9/27/2022	s233645
2.4.	*Comments*				
2.5.	Proposed settings coordinate with relay devices in the area.	Yes	☑	9/27/2022	s233645
2.6.	*Comments*				
3-	**Calculations**				
3.1.	All calculations required for this asset are accurate and complete	Yes	☑	9/27/2022	s233645
3.2.	*Calculation Comments*				
4-	**TOps Sheet**				
4.1.	*Settings match the RSRF*				
4.2.	*Comments*				
5-	**Settings Templates**				
5.1.	Correct relay settings template was used and populated accurately	Yes	☑	9/27/2022	s233645
5.2.	*Comments*				
5.3.	Relay settings file addresses legacy issues detailed in the robust checklist	Yes	☑	9/27/2022	s233645
5.4.	*Comments*				
6-	**RPA**				
6.1.	*Data points match with RPA file*				
6.2.	*RPA comments*				
7-	**Comments/Attachments**				
7.1.	Attachment any other documents that are required	Import...	☑	9/27/2022	s233645
7.2.	Settings are approved and are good to be issued for implementation	Yes	☑	9/27/2022	s233645
7.3.	*Please enter the comments on why the settings were not approved*				

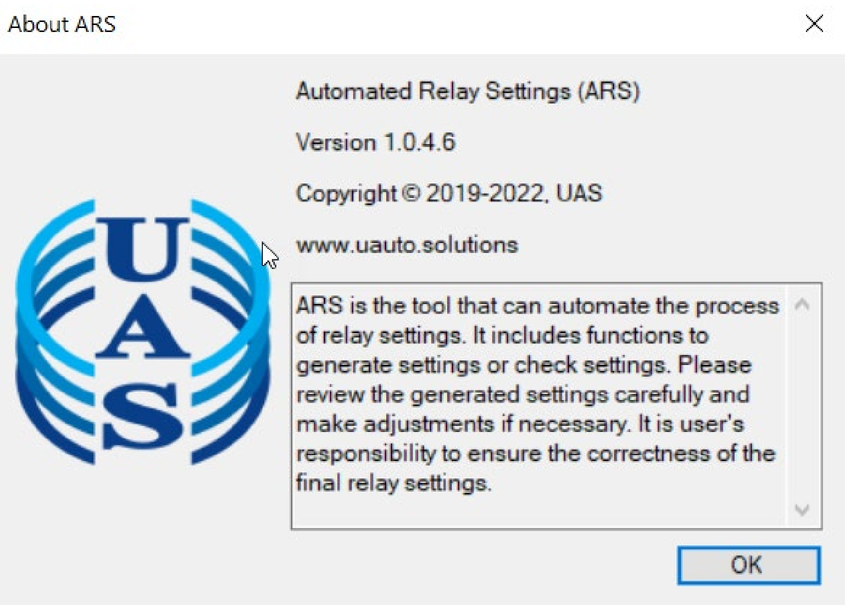
Line Settings Robust Checklist

Model	Function	Setting	Description
L90	Ph Dist Z1, Ph Dist Z2, Grd Dist Z1, Grd Dist Z2	Volt Level	Firmare version 7.x and later must set volt level to 0.001
L90	Ground Directional Elements		Verify the correct ground directional element is used per SS-451010 (zero sequence or negative sequence). Verify the Block for Neutral TOC and IOC are set to use the correct element. (It was not uncommon in the past to use Negative sequence for the DCB or POTT scheme and keep the TOC and IOC using Zero Sequence. These should all match)
L90	Neutral Dir OC1	Fwd/Rev Pickup	Verify local and remote pickup values are coordinated, in primary amps, if used in a DCB or POTT
L90	Neutral Dir OC1	Polarizing	Verify polarizing is set per SS-451010 and matches at remote terminal if used in a DCB or POTT
L90	Neutral Dir OC1	POS Seq Restraint	All terminals of a line must use the same POS Seq Restraint setting if used in a DCB or POTT scheme. Firmware version 3.x and earlier has a hard coded POS Seq Restraint of 0.0625.
L90	Neg Seq Dir (Zero seq type)	Fwd/Rev Pickup	Firmware version 5.5x and earlier based on I0 and later versions based on 3I0. Confirm remote ends are coordinated for this mismatch if used in a DCB or POTT scheme
L90	Neg Seq Dir (Zero seq type)	POS Seq Restraint	All terminals of a line must use the same POS Seq Restraint setting if used in a DCB or POTT scheme. Firmware version 3.x and earlier has a hard coded POS Seq Restraint of 0.0625.
L90	Neg Seq Dir OC2 (NEG seq type)	Fwd/Rev Pickup	Firmare V5.8x and newer uses Neg Seq Dir OC2 to supervise Neg Seq Dir OC1. If the Negative Sequence Directional elements are used in a DCB or POTT scheme verify this logic exists and remote terminal and the Fwd and Rev pickups are coordinated in primay amps.
L90	1P Blocking Scheme/1P Hybrid POTT	Grn Dir OC Fwd/Rev	All teminals of a line must use the same setting (Grd Dir OC Fwd/Rev) at all terminals of a line. Some settings are developed in Flexlogic.
L90	Phase Distance Z1	Reach	Make sure the reach is below 85% so that it does not show up during PRC-027 checks.
L90	Ground Distance Z1	Reach	Make sure the reach is below 85% so that it does not show up during PRC-027 checks. Confirm that mutuals were considered when setting was made.
L90	Phase Instantaneous (Phase IOC1)	Enable/Disable	Disable or desensitize if possible. Should be able to disable if Phase Distance Z1 and Line Pickup are enabled and set per SS-451010. Coordination must be maintanied. Update comm workbook as necessary.
L90	Ground Instantaneous (Neutral IOC1)	Enable/Disable	Disable or desensitize if possible. Should be able to desensitize if Ground Distance Z1 and Line Pickup are enabled and set per SS-451010. Coordination must be maintanied.
L90	Phase Distance trip and block supervision		Ensure that the phase distance trip supervision element at one end coordinates with the phase distance block supervision element at the other end, in primary amps, in a DCB or POTT scheme.
L90	Ground Distance trip and block supervision		Ensure that the ground distance trip supervision element at one end coordinates with the ground distance block supervision element at the other end, in primary amps, in a DCB or POTT scheme.
L90	Line Pickup	Autoreclose Coordination Bypass	Ensure that this is set to Disabled. Update comm workbook as necessary.
L90	Current Differential	Fault Detector	Confirm whether tap load exists on the circuit (ASPEN tap buses are indication of tapped load). If it does confirm whether fault detectors are enabled and set properly (fault detedtors are enabled/disabled by either flex logic or a switch).
L90	DCB	Rx Coord Pickup Delay	Set to 0.024 sec regardless of whether or not the remote relay(s) are similar or mismatched. The remote terminals do not have to be changed at the same time.
L90	DTT Trip input	S5a; S7a	If your relay has a contact input that is used for direct tripping such as DTT Trip Receive or DTT Keying the input must have a 10msec debounce time.
L90	Relay Mismatch with Remote End Relay while using DCB	EDG-20 & Ground DCB OC	If you are using DCB and your relay does not match the remote end relay, make sure all terminals are using EDG-20, if possible, and to desensitize the ground DCB overcurrent elements. Reference SS-451010 8.2.4.6

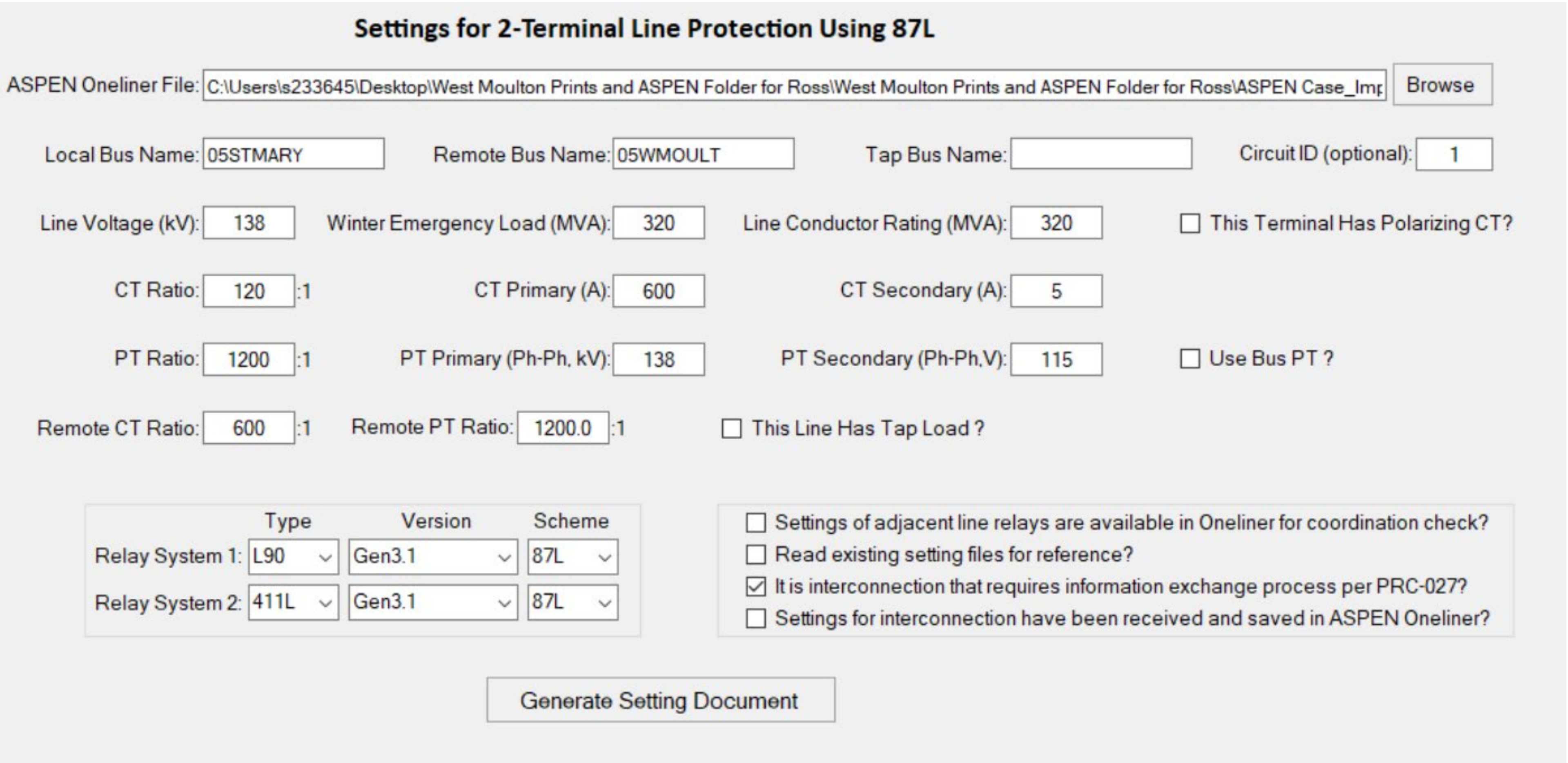
General | Revision History | Checklist | App A-L90-CS | App B-411L-CS | App C-D60-CS | App D-421-CS | App E

Automated Relay Settings

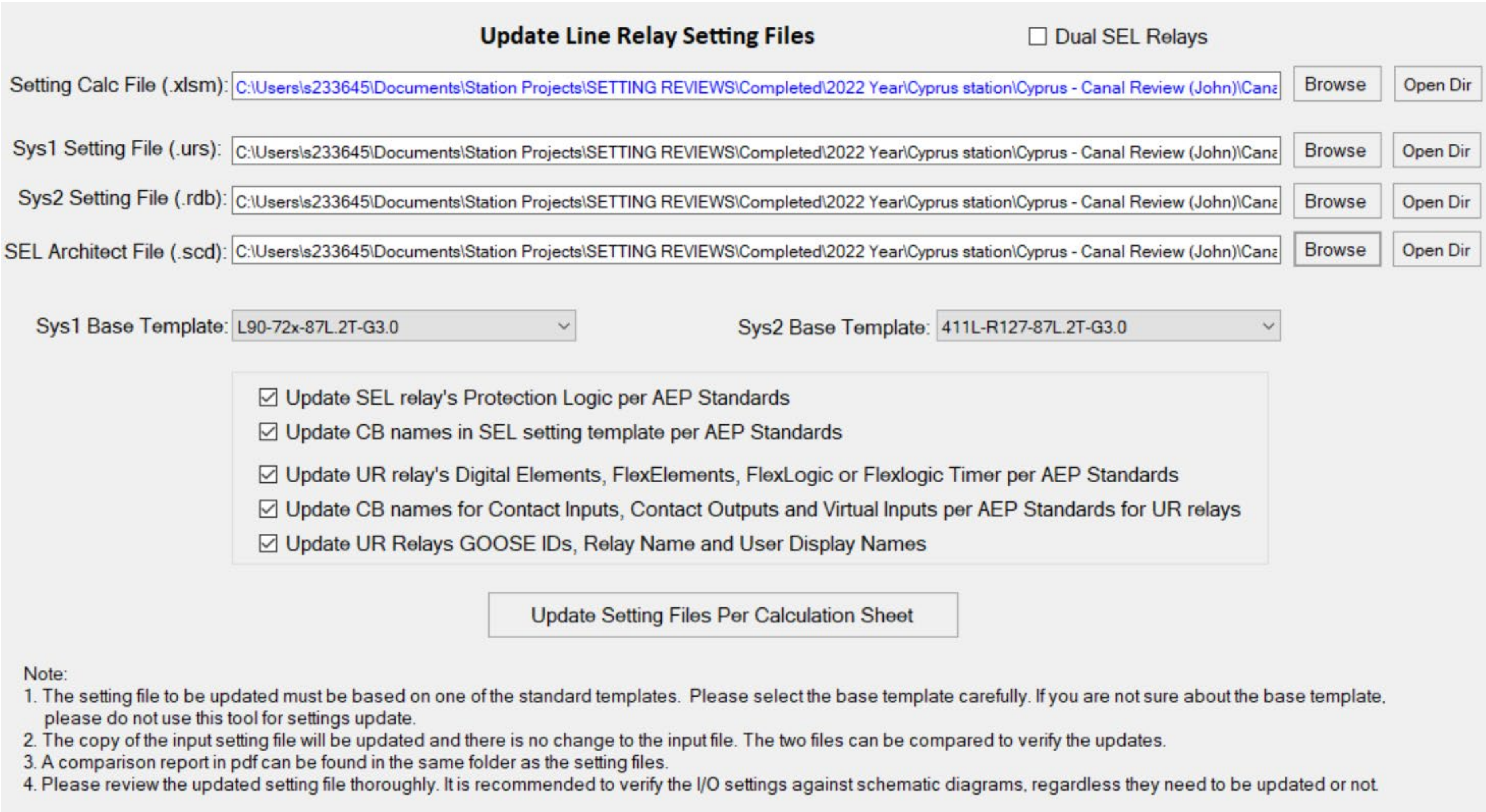
- PCE has worked with an outside consultant to development an Automated Relay Settings (ARS) tool
- ARS has many different benefits, but the three most important are its ability to **reduce human error**, its ability to **reduce engineering labor time/cost**, and its ability to **enforce consistent setting criteria/philosophies**



Automated Relay Settings



Automated Relay Settings



Automated Relay Settings

- Interfaces with short circuit software
- Interfaces with raw setting files
- Promotes consistent settings
- Easy to update software
- Is a tool, not a complete solution, still requires some engineering and sanity checks

PRC-027 Area Coordination Reviews

- One of the standard's requirements calls for performing a periodic relay system coordination review every six-calendar years.
- PCE has taken the approach of completely resetting all of its BES terminal so that they are up to modern criteria/philosophies "The Great Reset"
- 500-765kV complete, 345kV expected complete by end of 2022, 100-161kV complete by end of 2023
- Heavily proactive approach that requires a lot of resources, but will pay off in reducing risk and misoperations

Relay Failures

- Trending misoperation cause for AEP
- AEP still has a lot of Electromechanical relays that we are upgrading via capital projects
- Older first generation IED relays are now starting to reach the end of their lives and we are starting to proactively replace with newer hardware

Relay Failures

- IED relays from a particular vendor have periodically suffered from a memory corruption also referred to as a “bit flip” which results in the relay asserting protection elements during non-fault conditions.
- AEP has worked with this vendor to prevent future misoperations from “bit flips” by implementing a change in the relay firmware

Relay Settings Criteria / Philosophy Improvements

- No longer set phase or ground instantaneous overcurrents if distance elements are available
- Enhanced its directional settings guidance for carrier-based schemes that are very reliant on correct direction assessments. Rely heavily on negative sequence, force one common method at all terminals of line
- Increased carrier coordination timer to 24 milliseconds for all carrier relays

Relay Settings Criteria / Philosophy Improvements

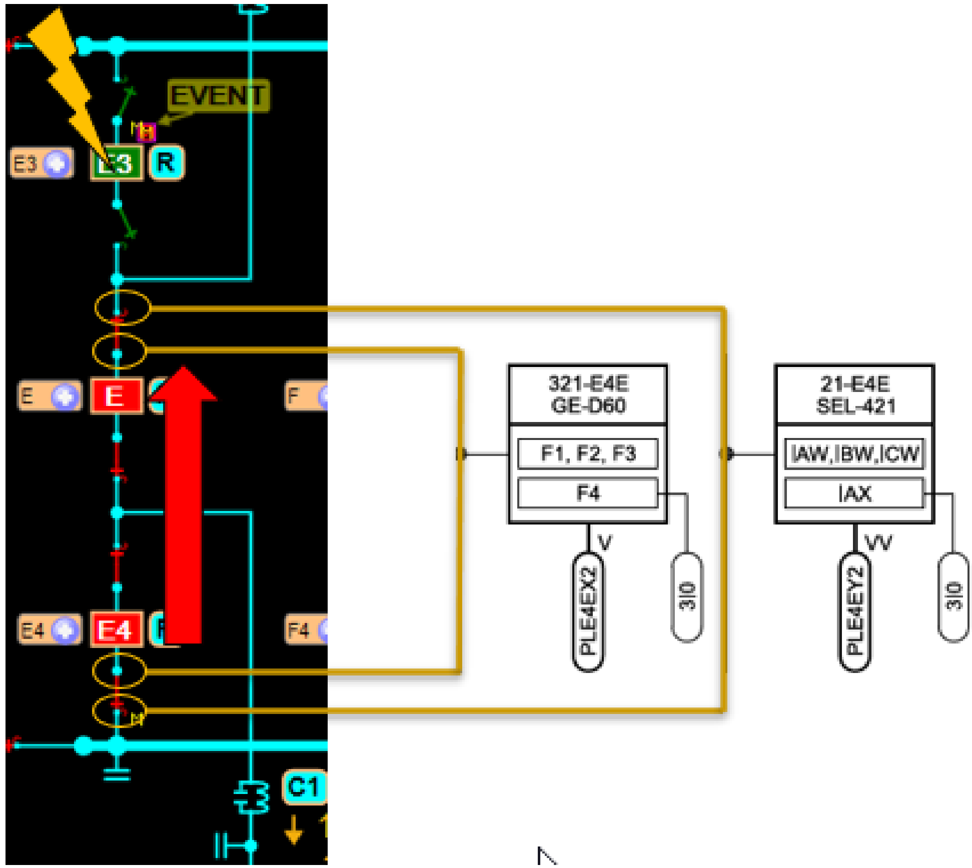
- Desensitize carrier forward ground overcurrent elements so that the schemes aren’t being tested as much. The guidance is to try to set at 600 Amps primary and only reduce if you have sensitivity issues
- Delay carrier forward ground overcurrent elements by 8 cycles, to allow carrier forward ground distance elements to act first

Relay Settings Criteria / Philosophy Improvements

- Desensitize current differential schemes by settings at 5A secondary and only lowering if needed
- No longer use negative sequence differential for lines
- Moving towards all line schemes using individual currents and summing internally as opposed to externally
- Changed our capacitor bank design from ungrounded wye to grounded wye

CT Saturation

- Trending misoperation cause for AEP
- Often when dealing with multiple CTs that sum external
- Have not been consistent in past on how CT ratios are selected



Scoping CT Sizing Calculator

- PCE has developed a formal CT sizing calculator for scoping
- Helps get correct max ratio CTs ordered
- Identifies potential problems way in advance

Fault Data Provided by Planning Engineer (Only Make Changes to Yellow Cells)					
3LG Expected Bus Fault Level (kA)	10				
3LG Expected Bus Fault X/R Ratio	5				
1LG Expected Bus Fault Level (kA)	10				
1LG Expected Bus Fault X/R Ratio	5				
Possible CT Selections					
Full Ratio	1200	2000	3000	4000	5000
Accuracy Ratio @ C800	1200	1200	2000	3000	4000
Is CT selection acceptable?	YES	YES	YES	YES	YES
Minimum Acceptable CT Cable	4C	4C	4C	4C	4C
Max CT Secondary Current @ Full Ratio	42	25	17	13	10
CT Saturation Results @ Full Ratio					
3LG (4C/#10 CT cables)	48%	22%	19%	19%	18%
1LG (4C/#10 CT cables)	77%	32%	27%	24%	22%
3LG (12C/#10 CT cables)	29%	15%	14%	15%	14%
1LG (12C/#10 CT cables)	39%	18%	17%	17%	16%

Detailed CT Ratio Selection Calculator

600A	1200A	2000A	3000A	4000A	5000A
50	100	300	300	500	500
100	200	400	500	1000	1000
150	300	500	800	1500	1500
200	400	800	1000	2000	2000
250	500	1100	1200	2500	2500
300	600	1200	1500	3000	3000
400	800	1500	2000	3500	3500
450	900	1600	2200	4000	4000
500	1000	2000	2500		5000
600	1200		3000		

CT Information

Full Ratio	1200:5			
Connected Ratio	1200:5		CTR =	240
Accuracy Ratio	1200:5			
Accuracy Class	C800			
Thermal Rating Factor	3.0			
Winding Resistance	0.0027	ohms/turn		
Winding Connection	WYE			
Lead Conductor Size	#10		0.9989	ohms per 1000 feet
Lead Conductors per phase	1			
Lead Length (feet, one-way)	1000'			
Remnance	0	percent		

Burden Calculation (ohms secondary)

CT Winding Resistance	0.65
CT Lead Resistance One-Way	1.00
Relay Burden	0.02
Maximum Rated CT Burden	8.00
CT Burden (3LG or LL)	1.67
CT Burden (LG)	2.67

CT Saturation for 3LG & LL Faults

saturation current	20,752	amps primary
maximum fault current	10,000	amps primary
maximum fault X/R ratio	5	
% of saturation current	48%	

CT Saturation for 1LG Faults

saturation current	12,976	amps primary
maximum fault current	10,000	amps primary
maximum fault X/R ratio	5	
% of saturation current	77%	

CT Loadability

CT Thermal Limit	3,600	amps primary
Bus Voltage	138	kV
Winter Emergency Rating	400	MVA
NERC required current	2,513	amps (@ 150% WE)
% of CT Thermal Limit	70%	
AEP required current	1,675	amps (@ 100% WE)
% of CT Thermal Limit	47%	

Sensitivity Check (Remote End Fault with Strongest Source Out of Service)

Strongest Source	Enter Strongest Source Name Here	
LG	3000	amps primary
LL	3000	amps primary
Minimum CT Current	12.5	amps secondary
Maximum CT Current	42	amps secondary

Mathcad

Rated CT Terminal Voltage	800	volts
Max CT Secondary Current	100	amps
Rated CT Excitation Voltage	865	volts
3LG Fault CT Excitation Voltage	417	volts
% saturated	48%	
1LG Fault CT Excitation Voltage	666	volts
% saturated	77%	

Reference Documents

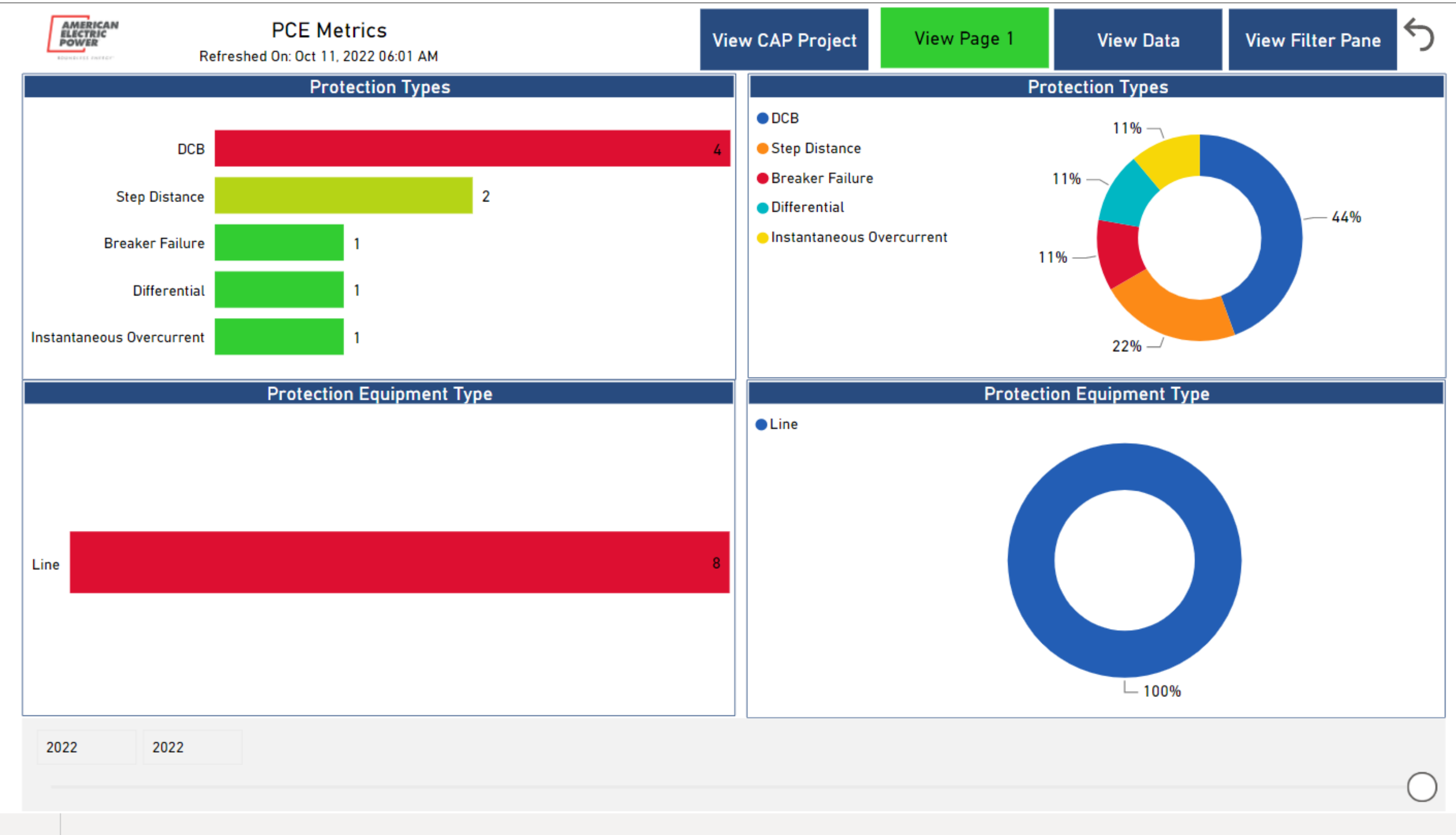
AEP SS-451010 Rev.11, Section 4.12.3.3 - Line Relay CT Ratio Selection Guidelines, page 42

IEEE Guide for the Application of Current Transformers Used for Protective Relaying Purposes - IEEE Std C37.1110-2007

"Selecting CTs to Optimize Relay Performance" by Gabriel Benmouyal (IREQ), Jeff Roberts (SEL) and Stanley E. Zocholl (SEL)

Advanced Misoperation Metrics Dashboard

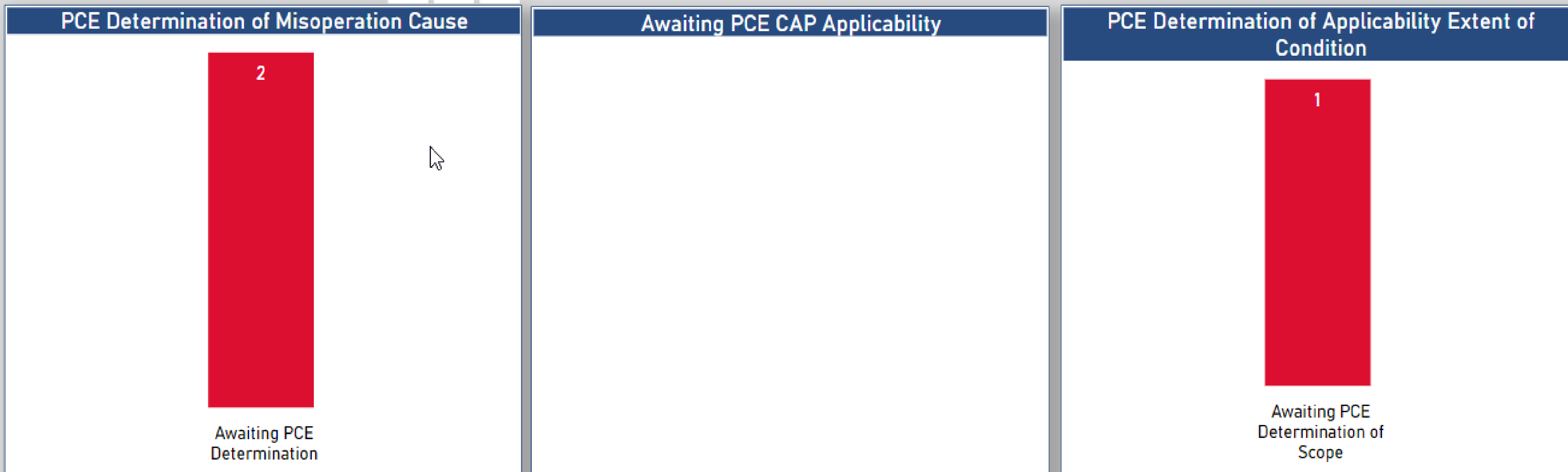
Advanced Misoperation Metrics Dashboard



Advanced Misoperation Metrics Dashboard

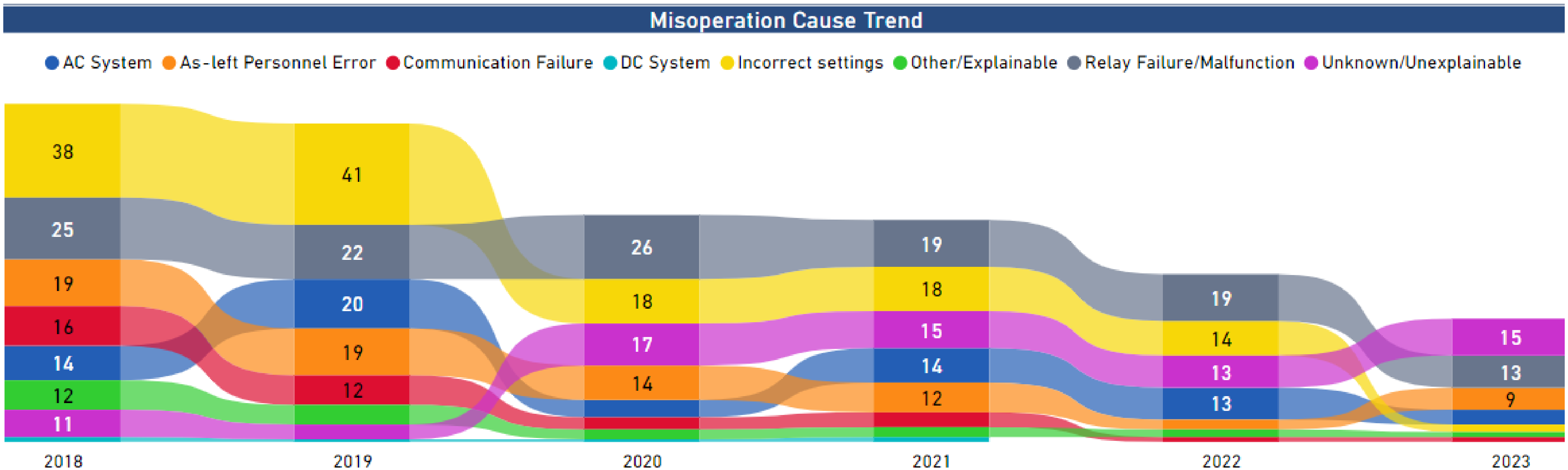
PCE Workflow

Refreshed On: Oct 11, 2022 06:01 AM



AEIR ID	Event Date	Outage Category	Misop Cause	NERC Reportable	Transmission Region	Station	Protected Equipment Name	Components That Misoperated
209623	2/15/2022	Misoperation	Incorrect settings	Yes	Columbus	Clinton	Clinton - Huntley - Karl	L90 line current differential tapped load
209767	3/30/2022	Misoperation	Unknown/Unexplainable	Yes	Tulsa	Center	Center-Tenaha	
211103	9/20/2022	Misoperation	Unknown/Unexplainable	Yes	Corpus Christi	Laredo VFT South	Laredo VFT South-CAP-1417	351S SV15T (time delay UV trip)

Advanced Misoperation Metrics Dashboard




ANY
QUESTIONS?

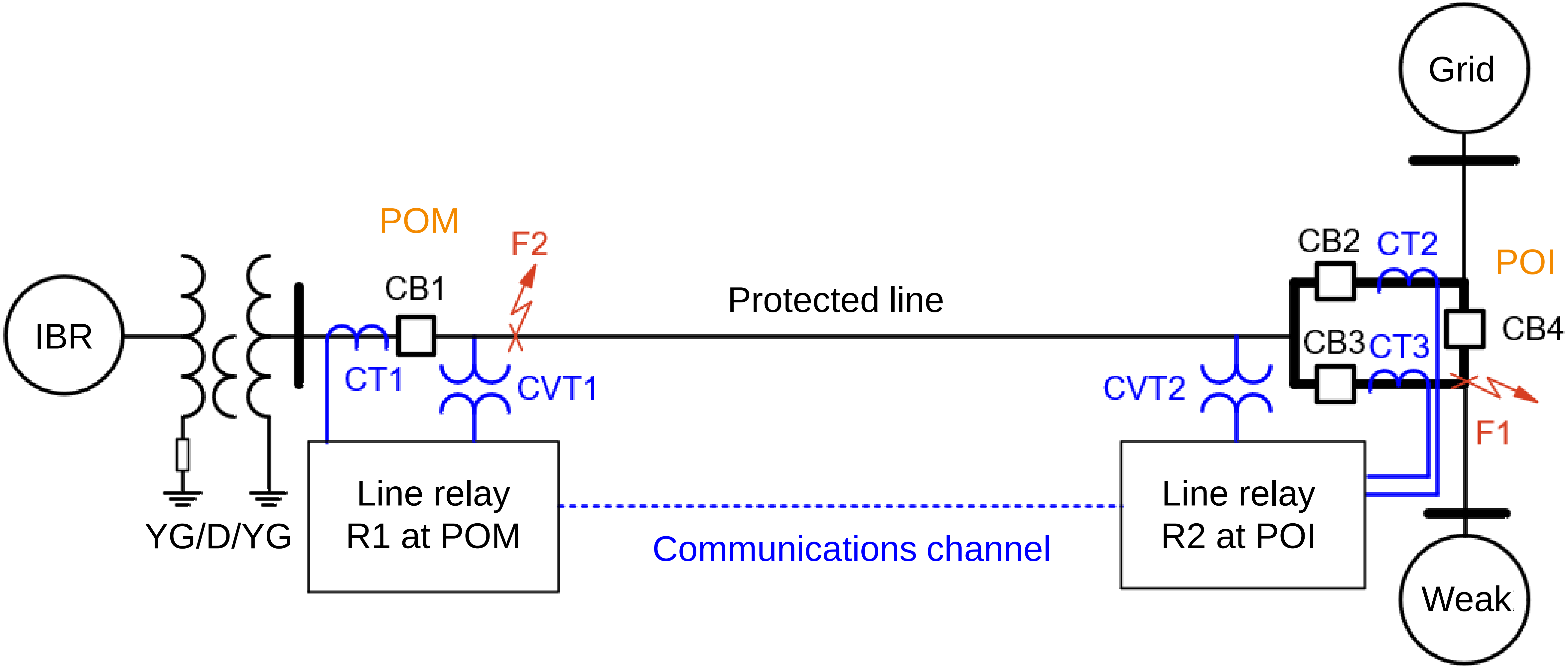
Line protection considerations for systems with inverter-based resources

Ritwik Chowdhury
Schweitzer Engineering Laboratories, Inc.
August 7, 2024

Overview

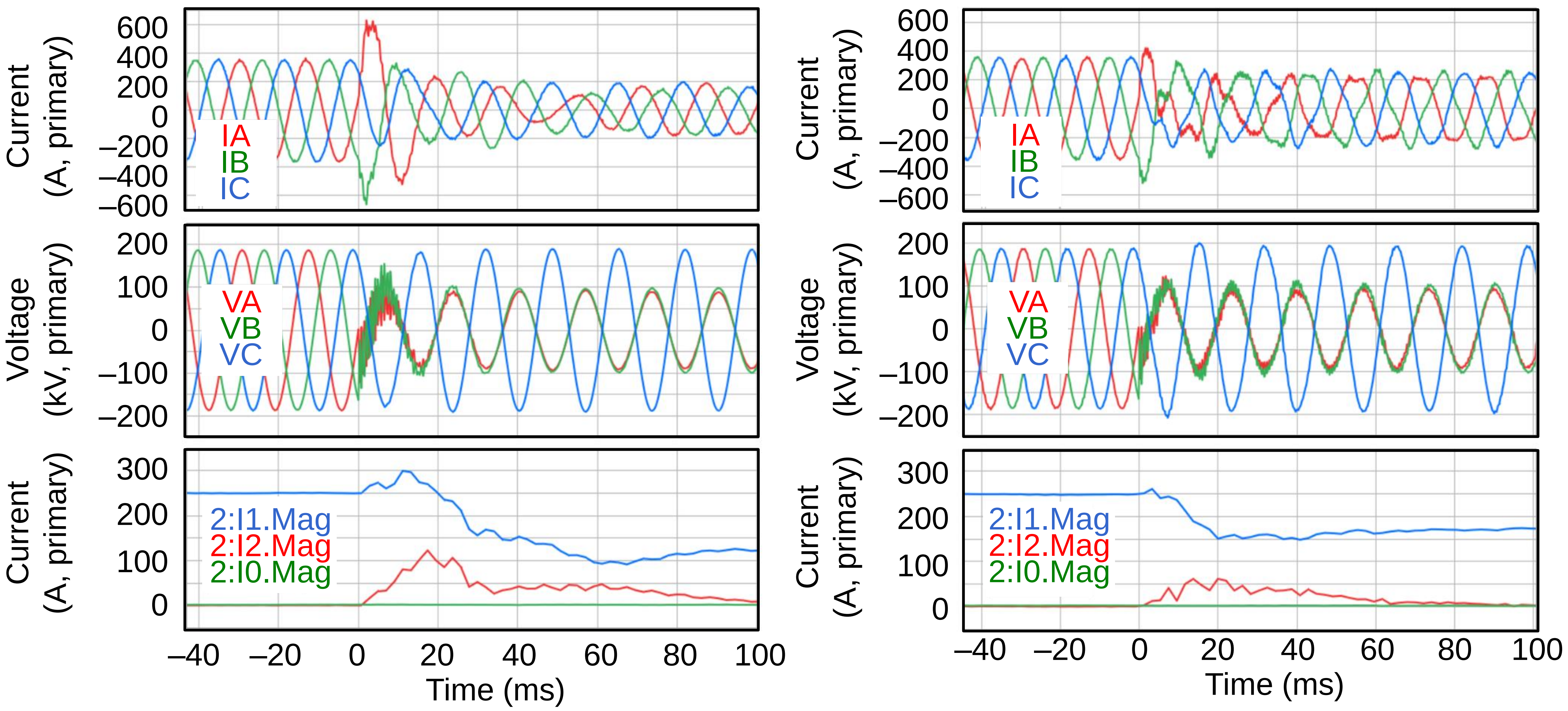
- Negative-sequence current challenges
- Distance element considerations
- Transient-based line protection and fault locating
- Source-to-line impedance ratio (SIR)
- Directional comparison pilot schemes
- Line current differential
- Power swing blocking
- Conclusion and References

One-line diagram

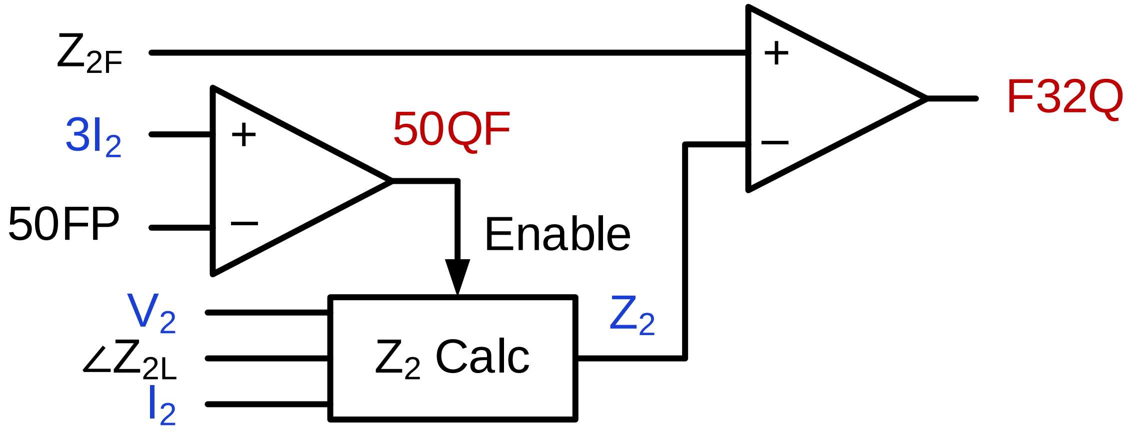


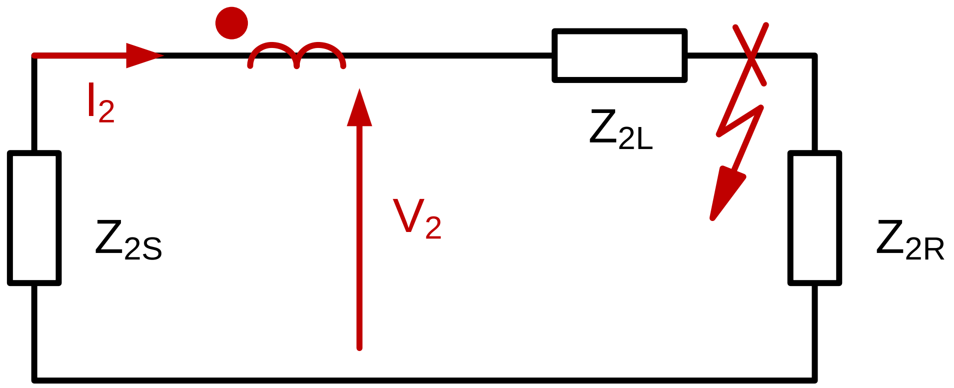
Negative-sequence current challenges

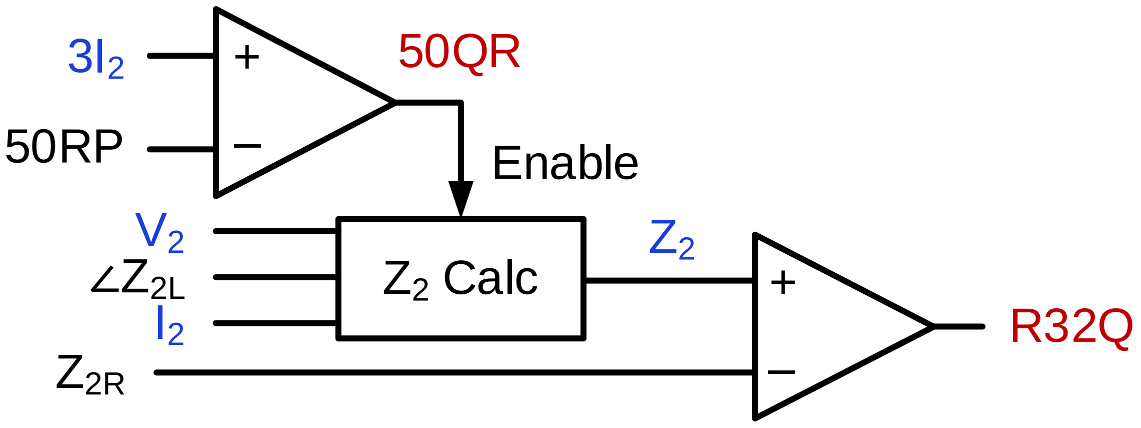
Type 4 Wind AB fault at remote bus

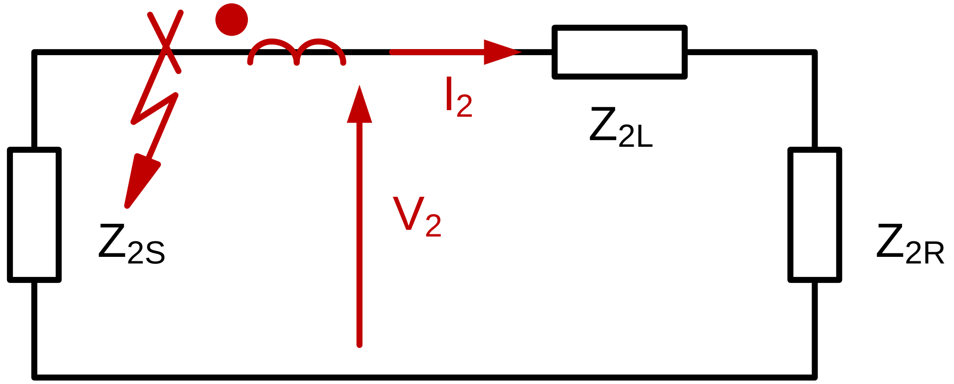


Directional element (32)



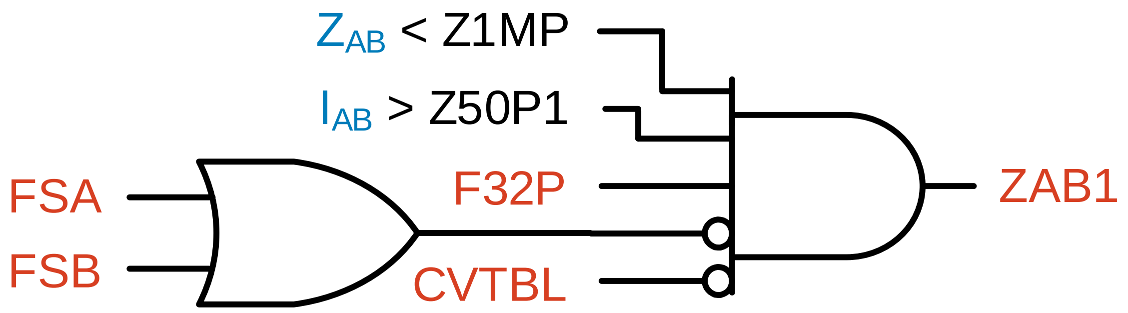


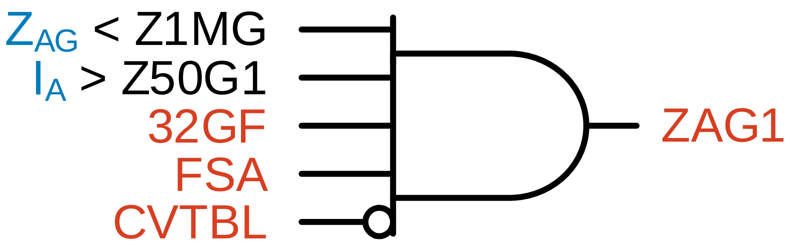




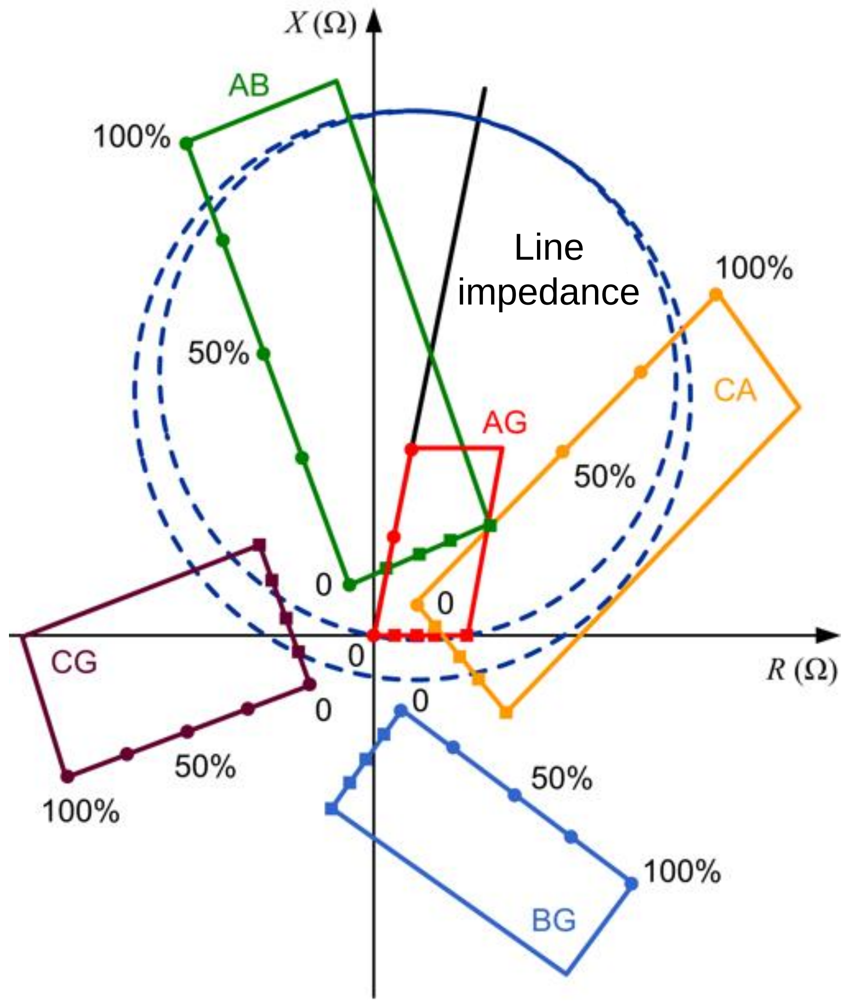
Distance element (21)

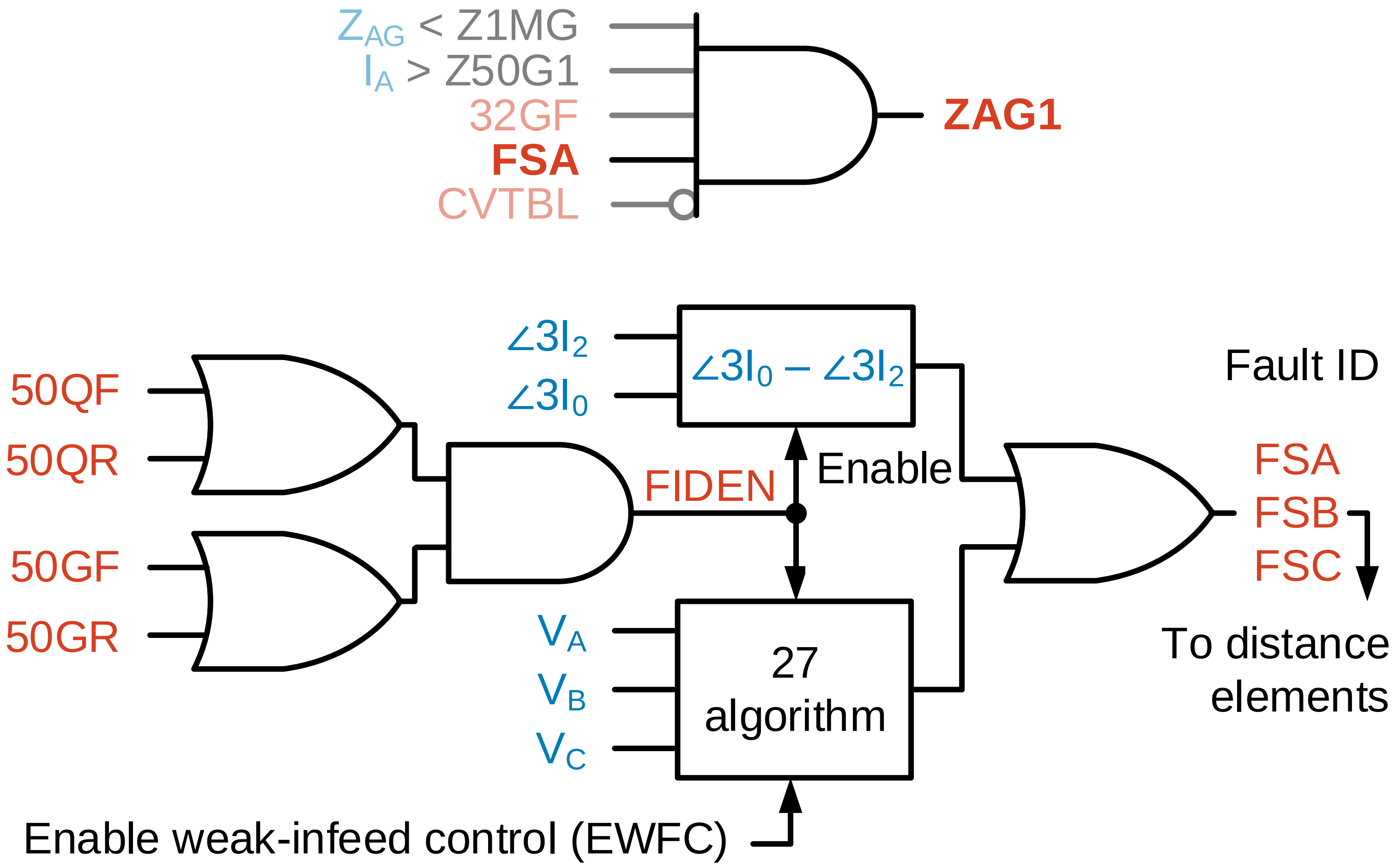
- Calculated impedance is less than set reach
- Loop current greater than fault-detector threshold (Zone 1)
- Directional element supervision (forward/reverse)
- Fault-type Identification and Selection (FIDS) logic does not block element
- No CVT transients detected (Zone 1)





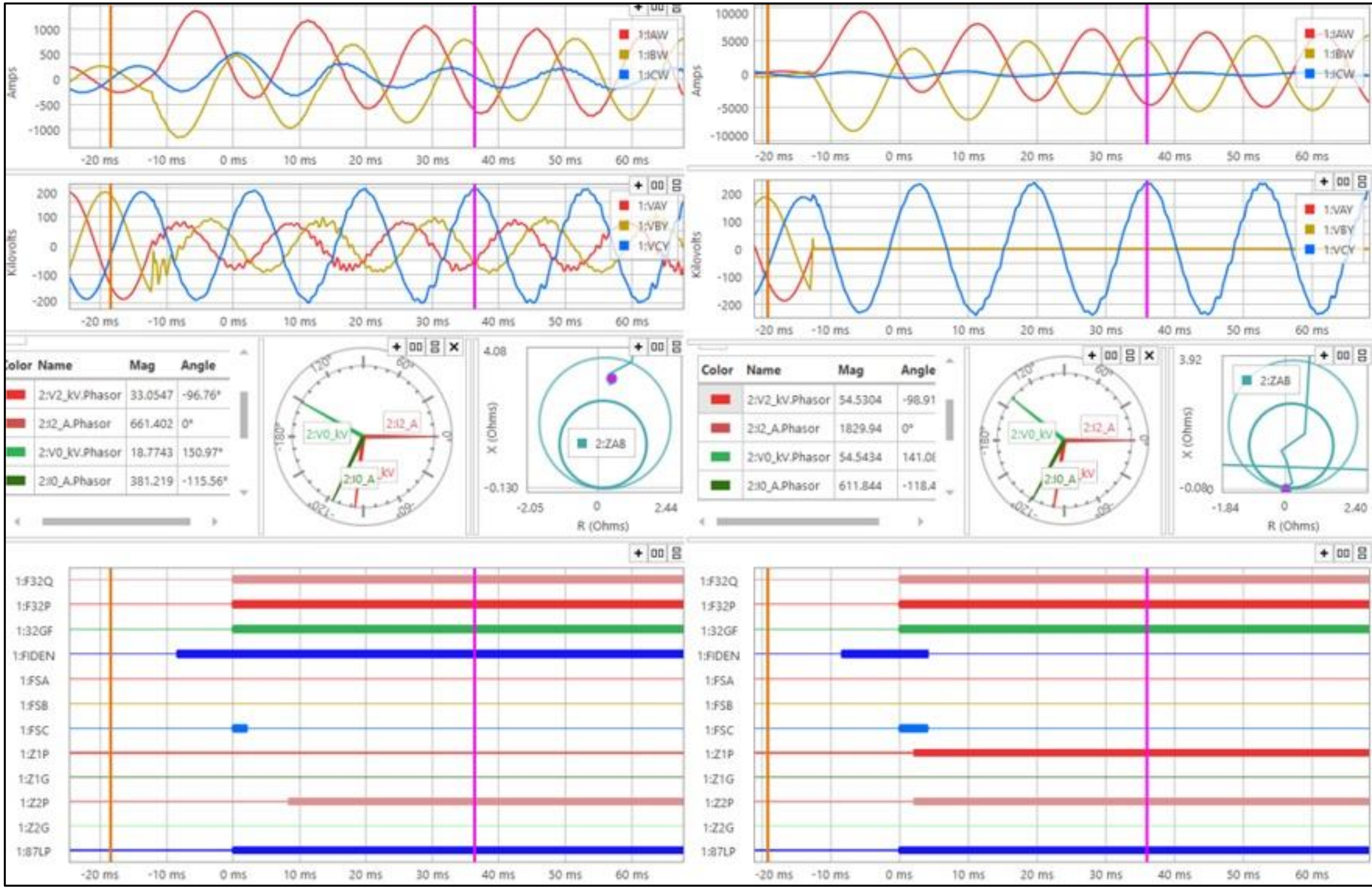
FIDS – AG fault





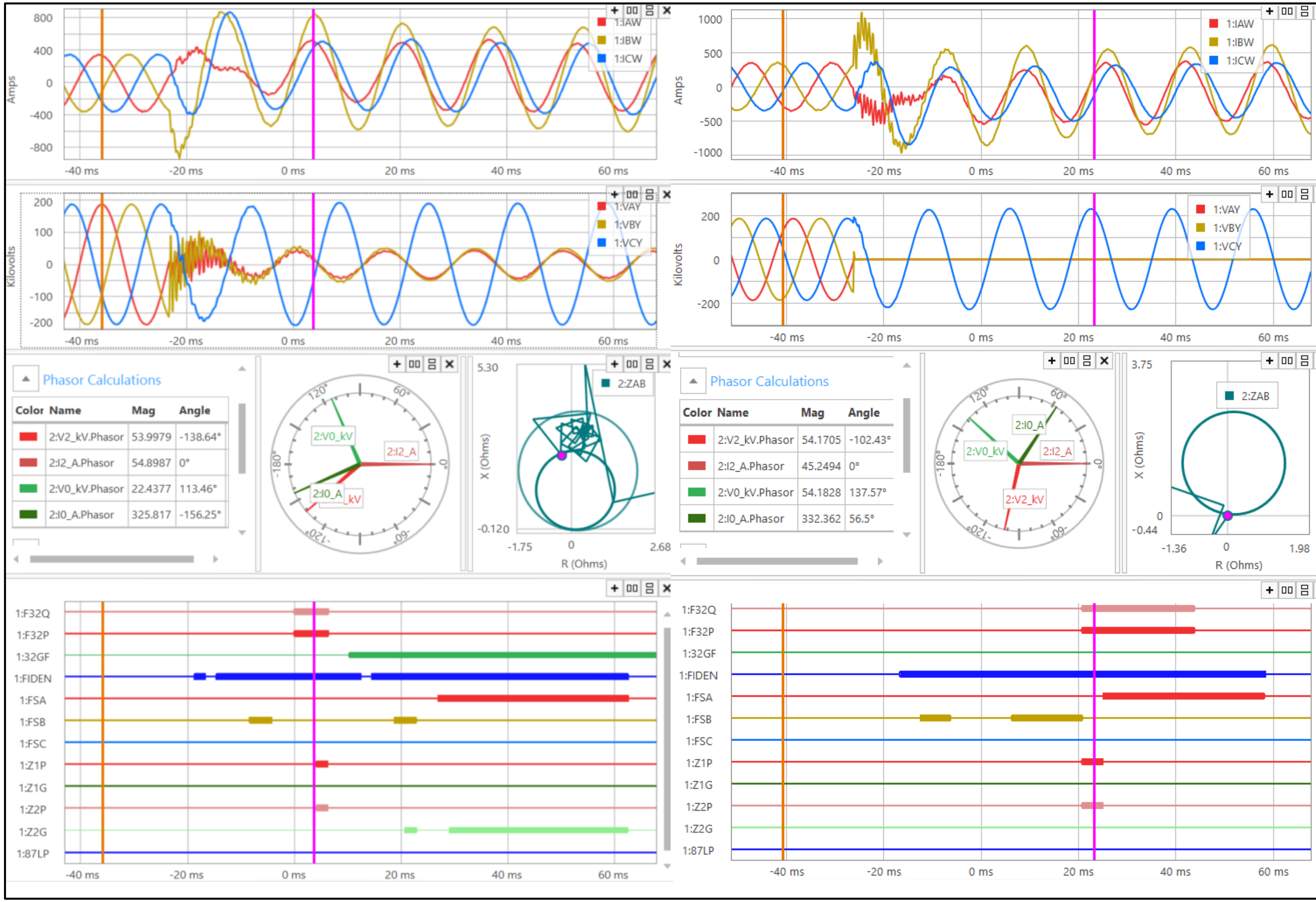
Internal ABG fault (reference)

Internal fault



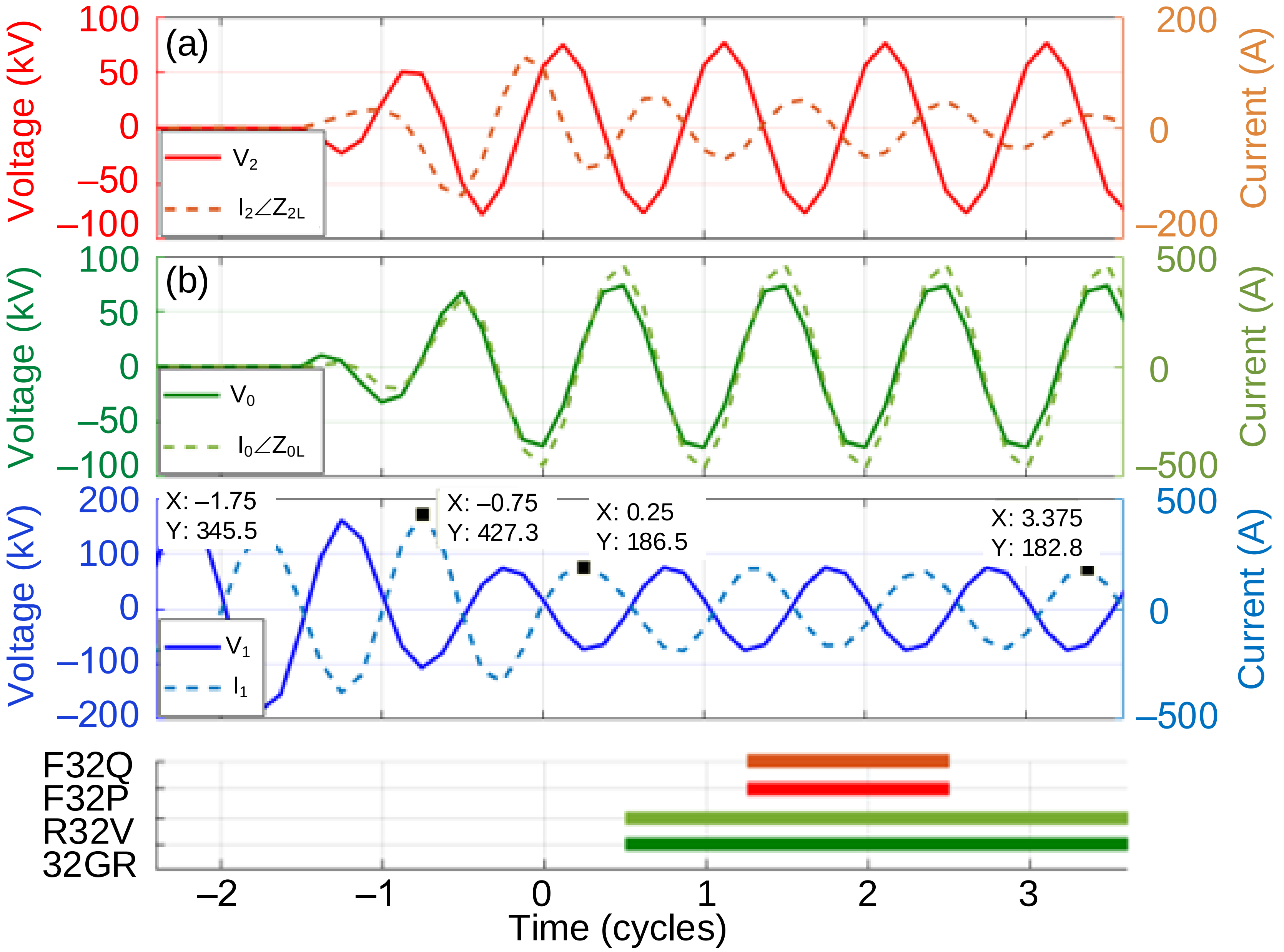
Type 4 Wind ABG fault

External fault

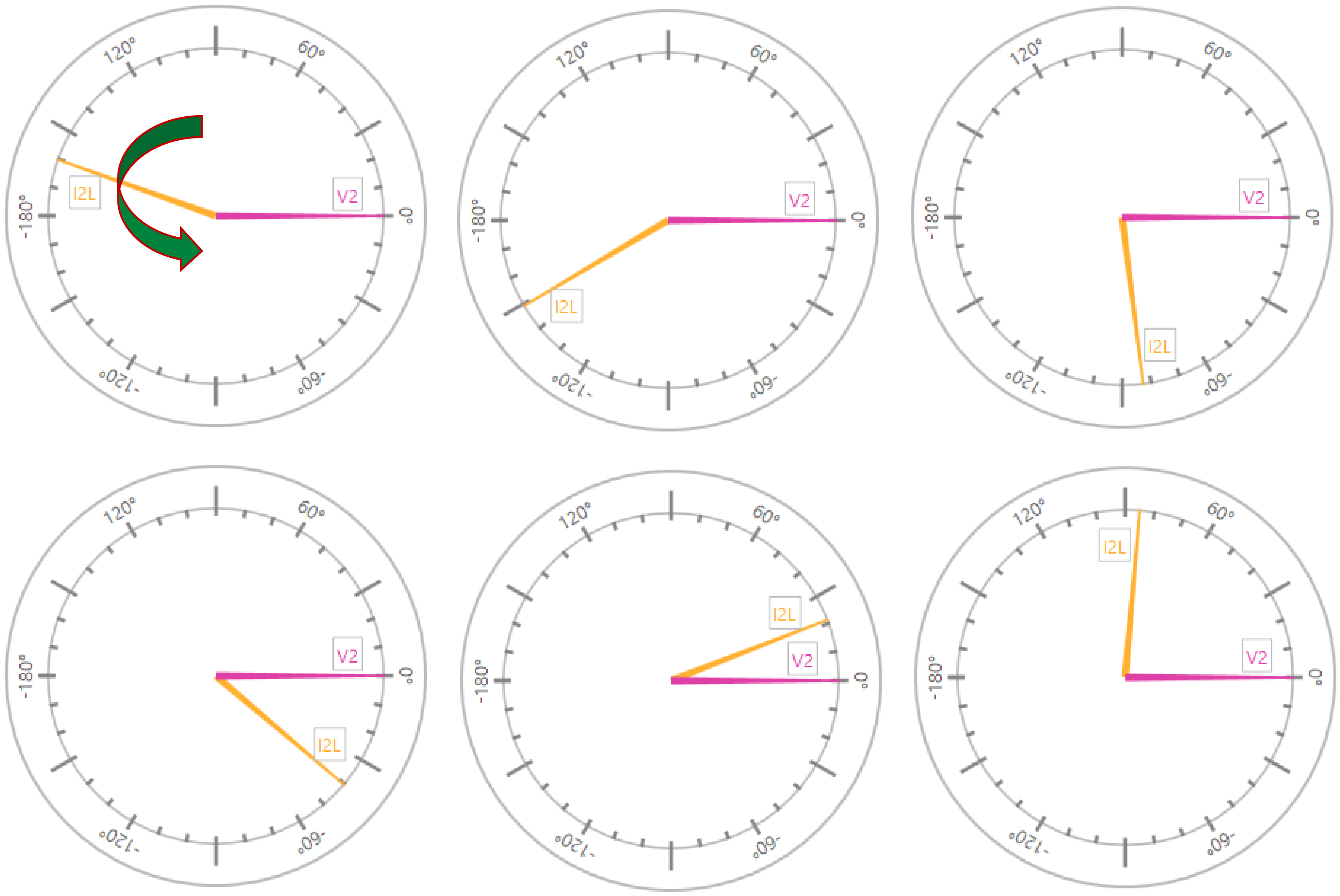


Type 4 Wind ABG fault

Sequence element behavior



I2 vs. V2



Improved performance of directional and fault type selection

IEEE Std 2800-2022 performance requirements

For unbalanced faults, in addition to increased positive-sequence reactive current, the *IBR unit* shall inject negative sequence current:

- Dependent on *IBR unit* terminal (POC) negative sequence voltage and
- That leads the *IBR unit* terminal (POC) negative sequence voltage by an allowable range as specified below:
  - 90 degrees to 100 degrees[106] for full converter-based *IBR units*
  - 90 degrees to 150 degrees for type III WTGs[107]

Table 13—Voltage ride-through performance requirements

Parameter	Type III WTGs	All other IBR units
Step response time[b, c, d]	NA[a]	≤ 2.5 cycles
Settling time[b, c, d]	≤ 6 cycles	≤ 4 cycles
Settling band	–2.5%/+10% of *IBR unit maximum current*	–2.5%/+10% of *IBR unit maximum current*

[a] The initial response from the type III WTG is driven by machine characteristics and not the control system. DC component, if present, has an impact on response, which is driven by machine parameters and time of fault occurrence. Even though the control system takes an action, it cannot control machine's natural response. As such, defining response time for type III WTGs is not necessary.

[b] System conditions may require a slower response time, or *IBR units* may not be able to meet response times noted in this table for certain system conditions. If so, greater response time and *settling time* are allowed with mutual agreement between an *IBR owner* and the *TS owner*.

[c] The DFT with a one-cycle moving average window is used to derive phasor quantities such as active, reactive, positive-sequence, negative-sequence currents, etc. The time delay required for the DFT measurements is included in the *step response time* and *settling time* specified in this table.

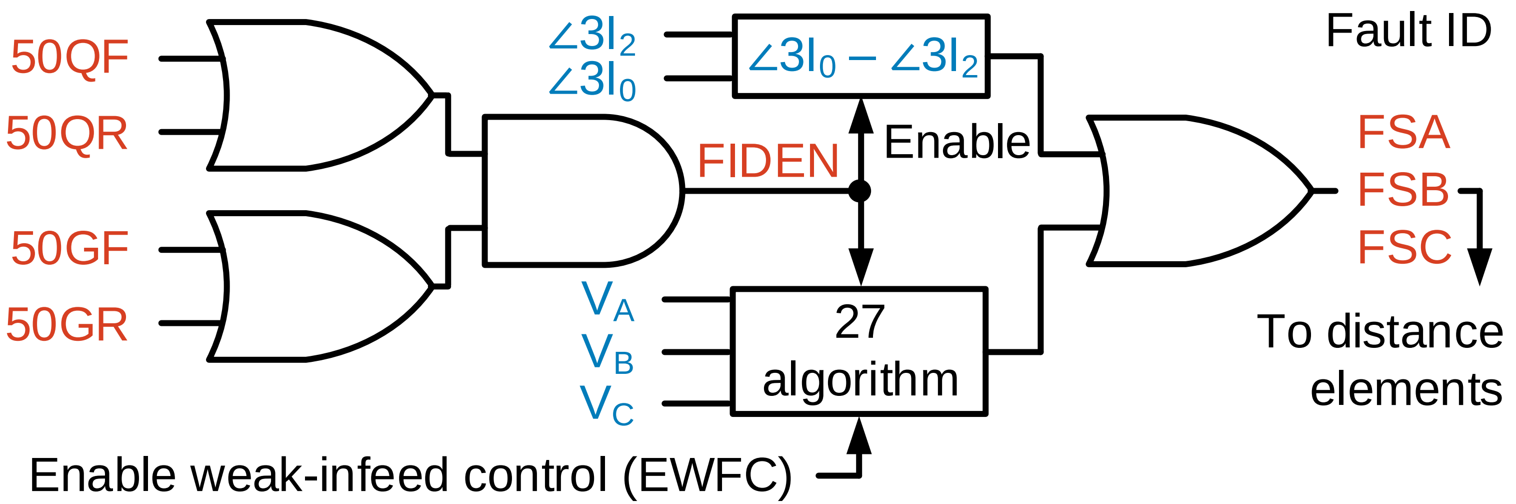
[d] The specified *step response time* and *settling time* applies to both 50 Hz and 60 Hz systems.

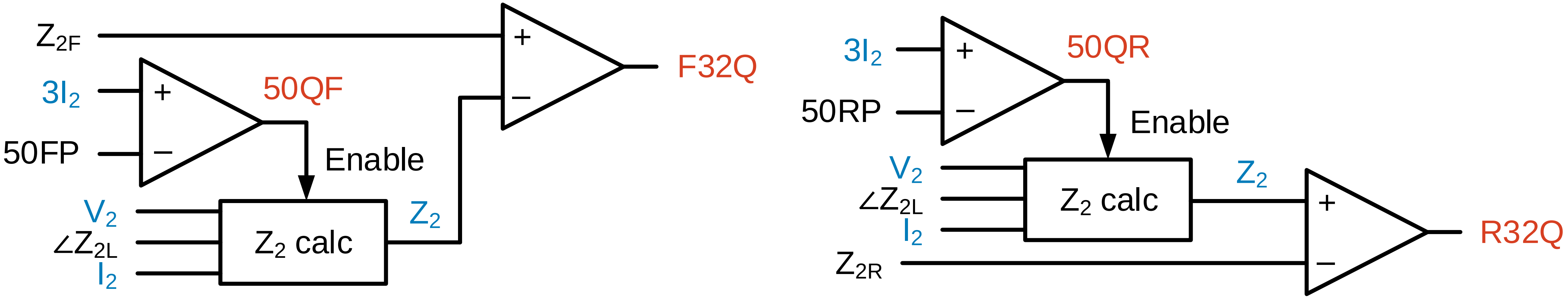
Improved performance of directional and FIDS

Increase overcurrent supervisory thresholds to improve 32Q security and FIDS security and dependability

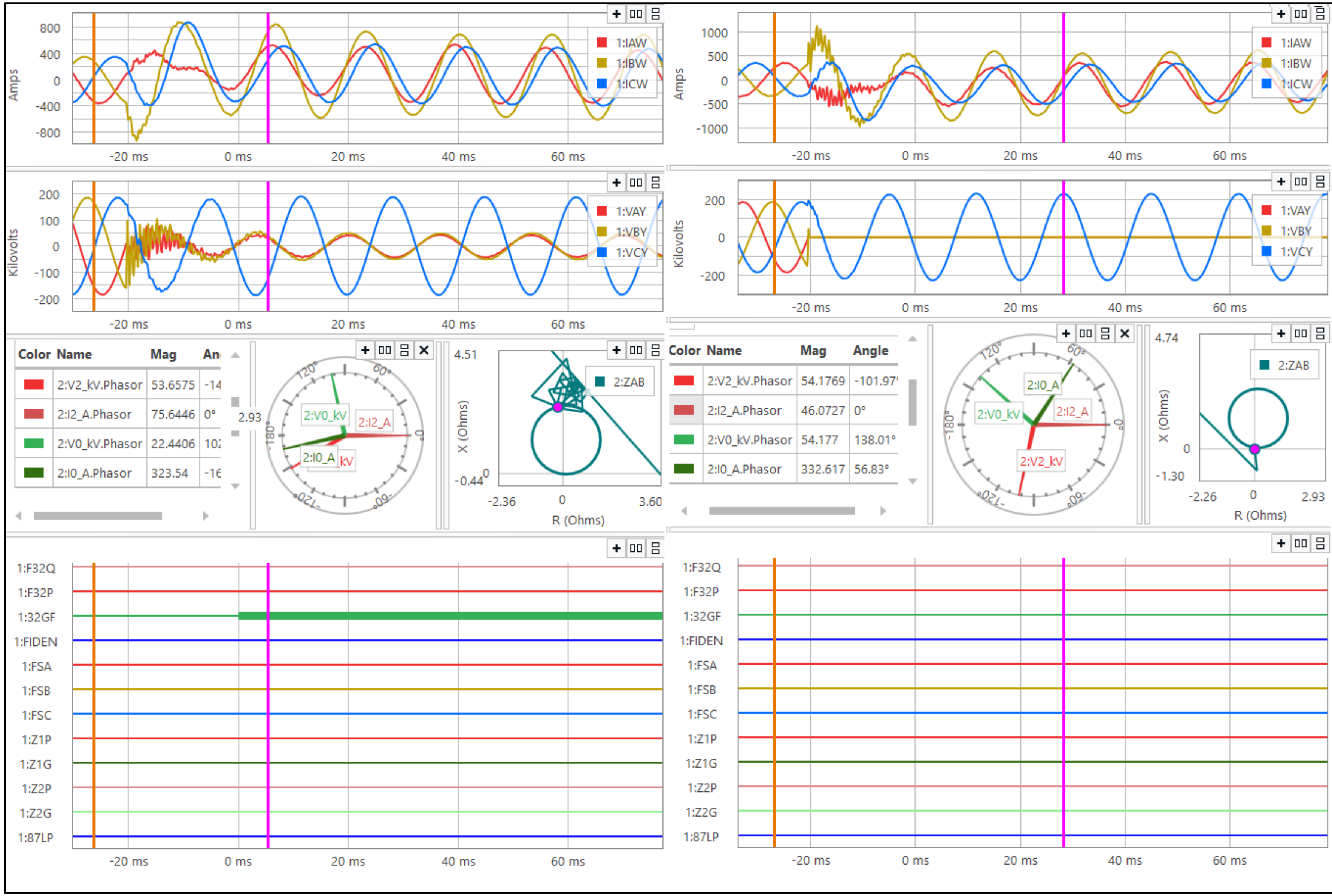
$$50FP = 1.25\ pu \cdot I_{MAX}$$

$$50RP = 1.00\ pu \cdot I_{MAX}$$



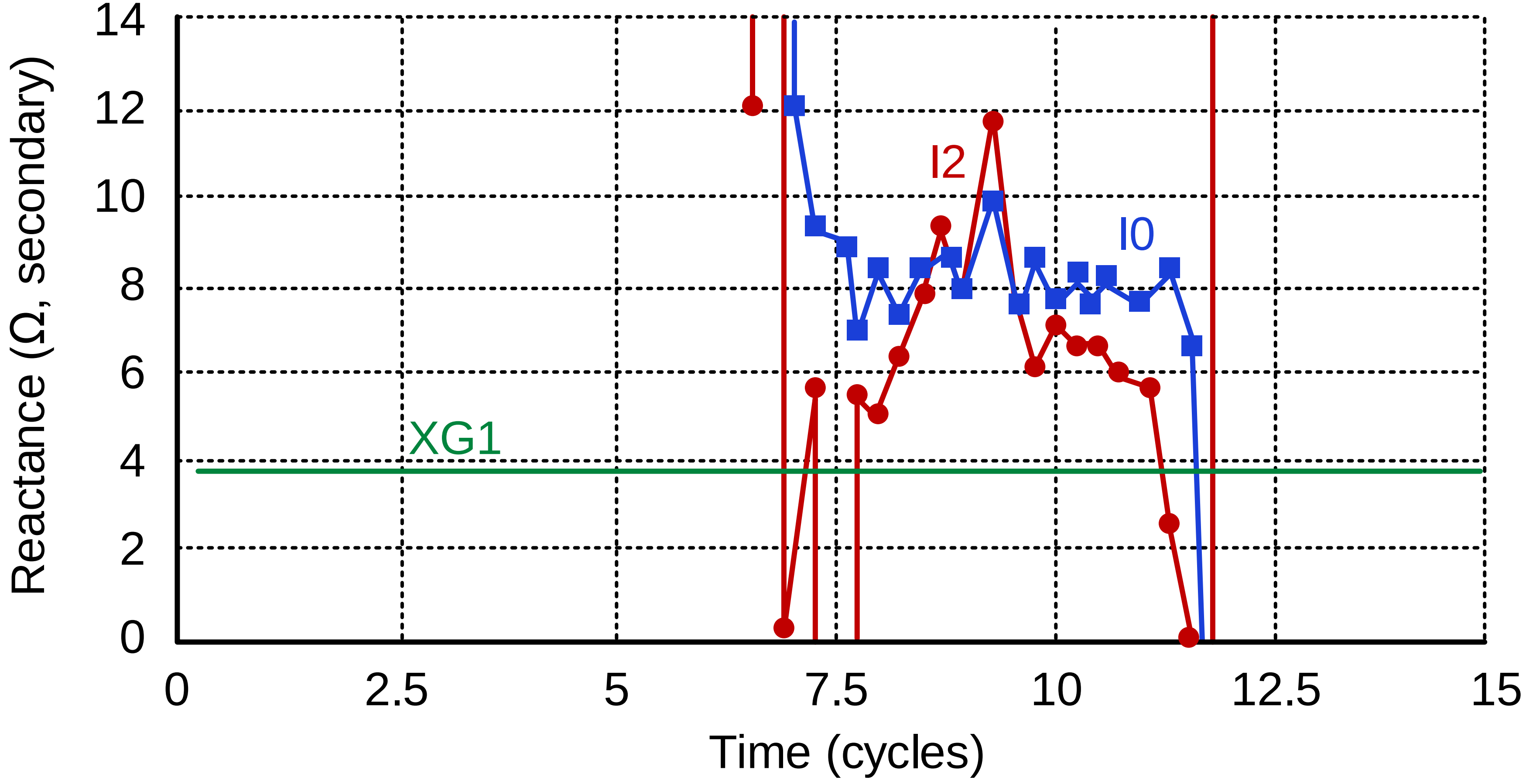


Type 4 Wind ABG fault

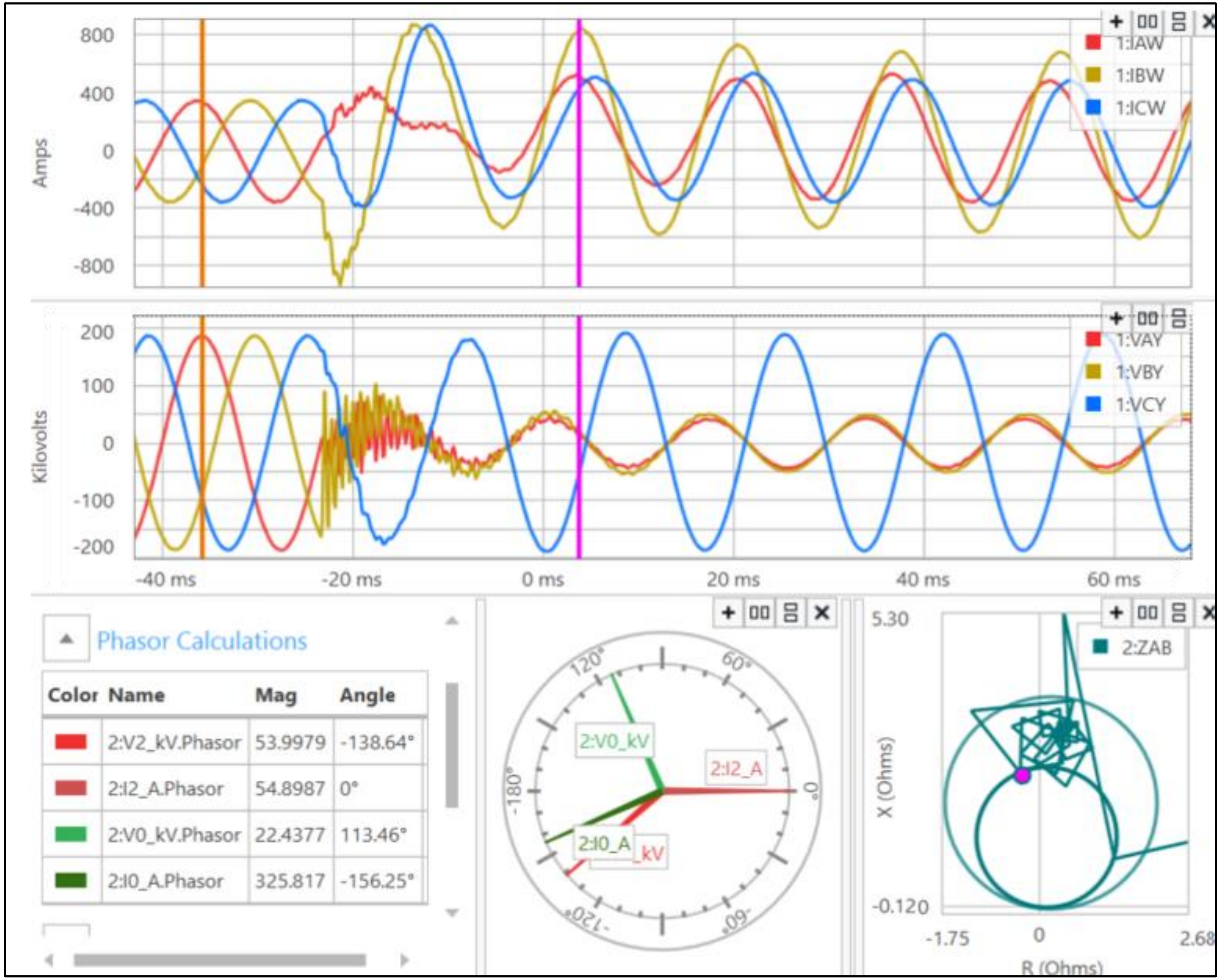


Distance element additional considerations

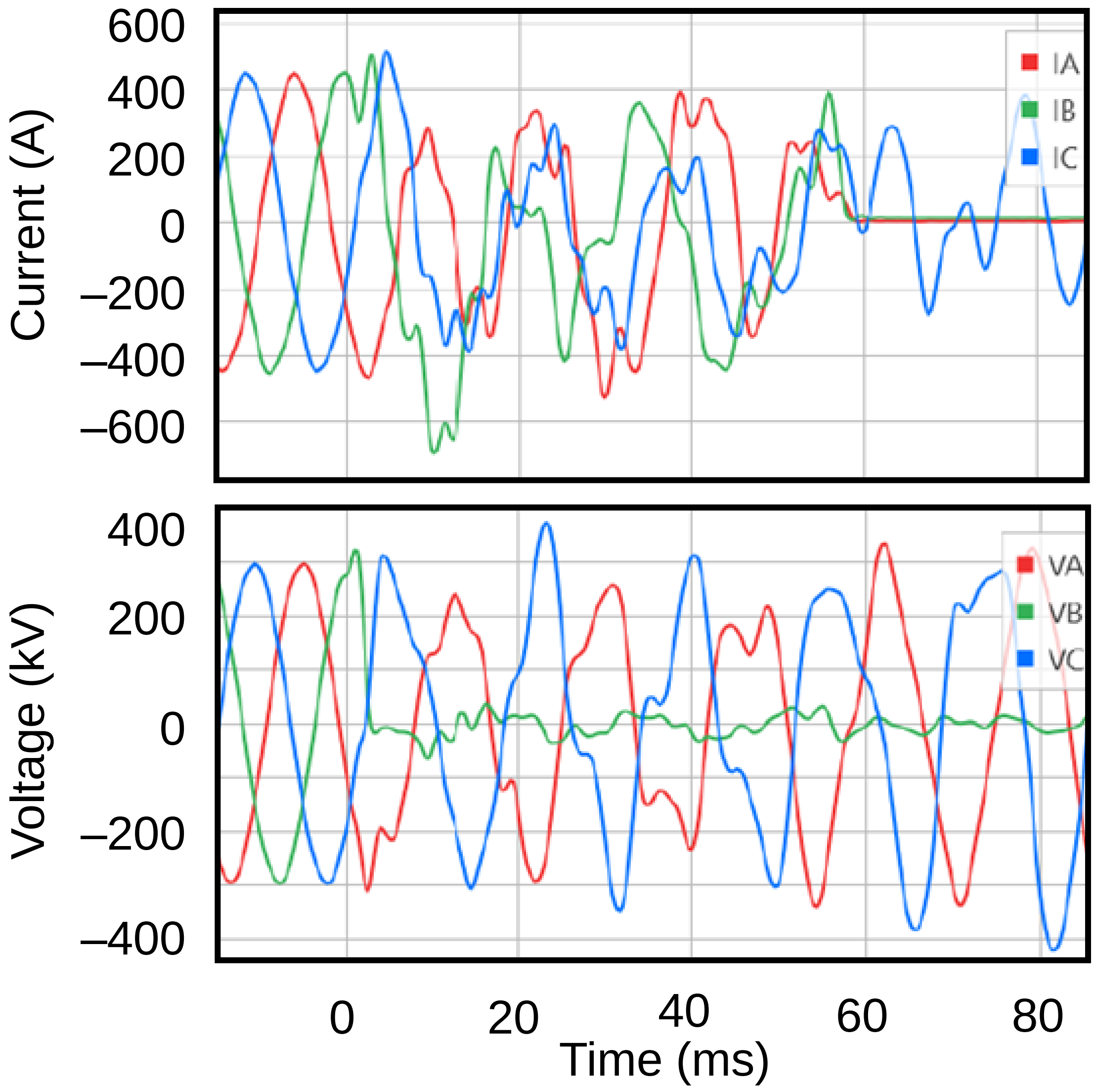
I2-polarized ground quadrilateral

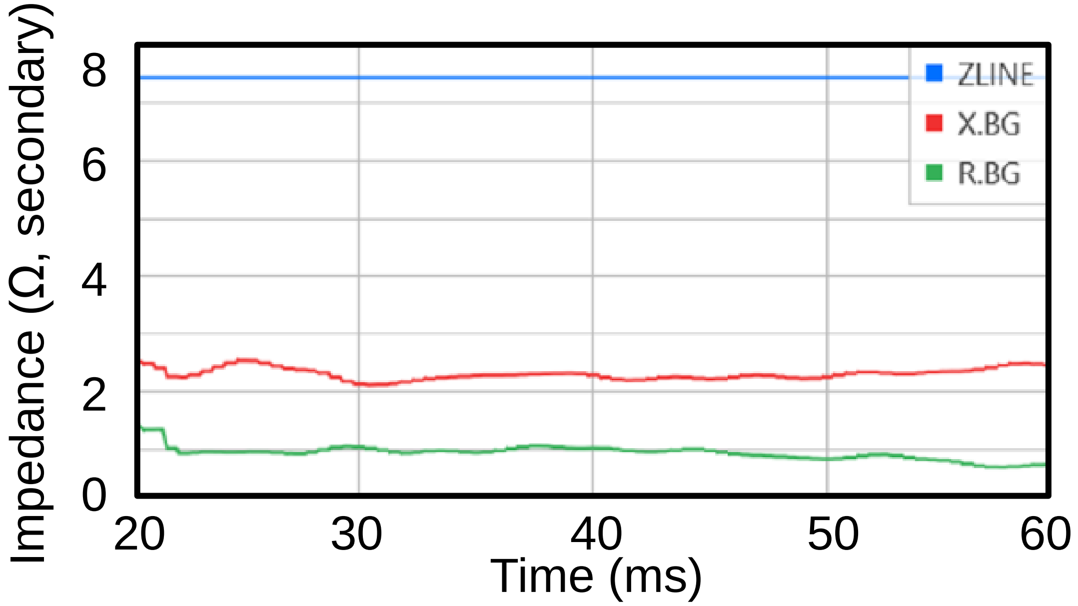


Memory-polarized phase mho

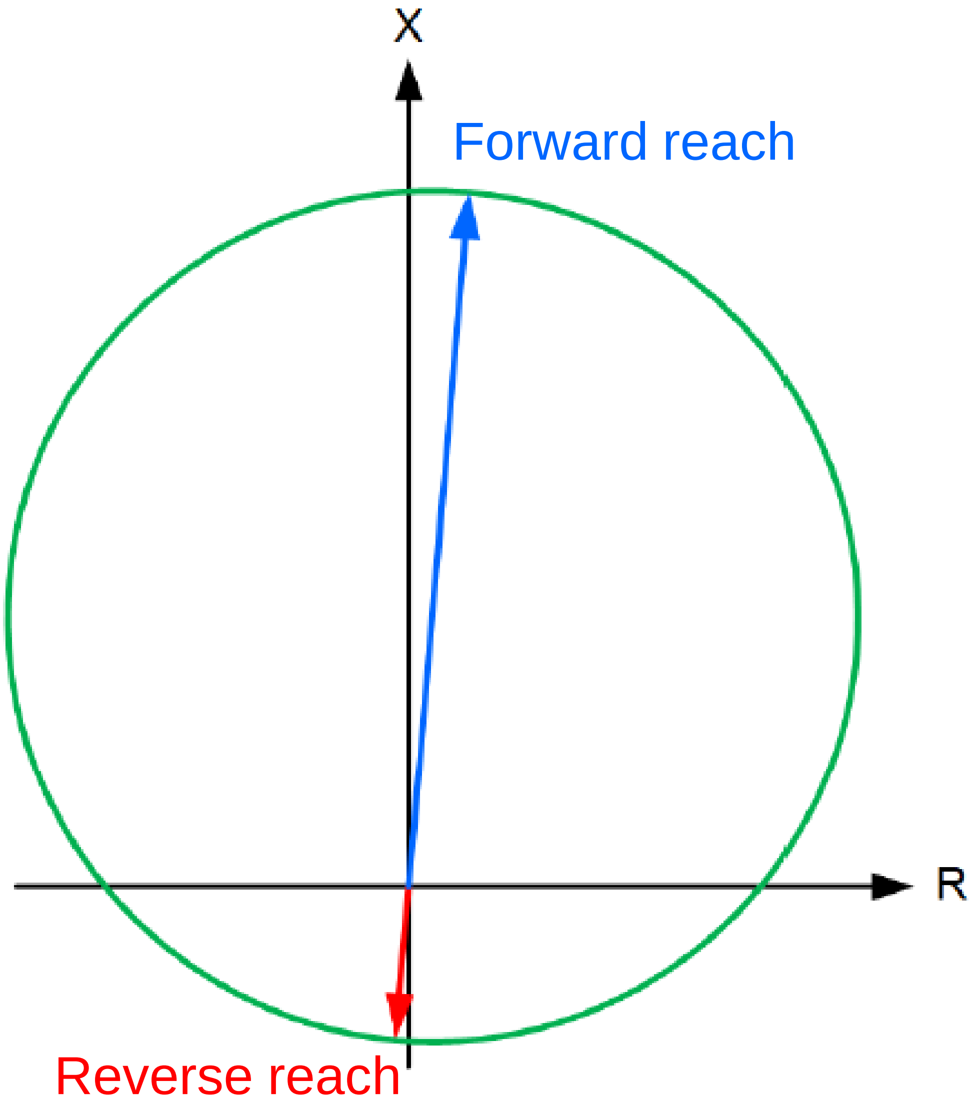


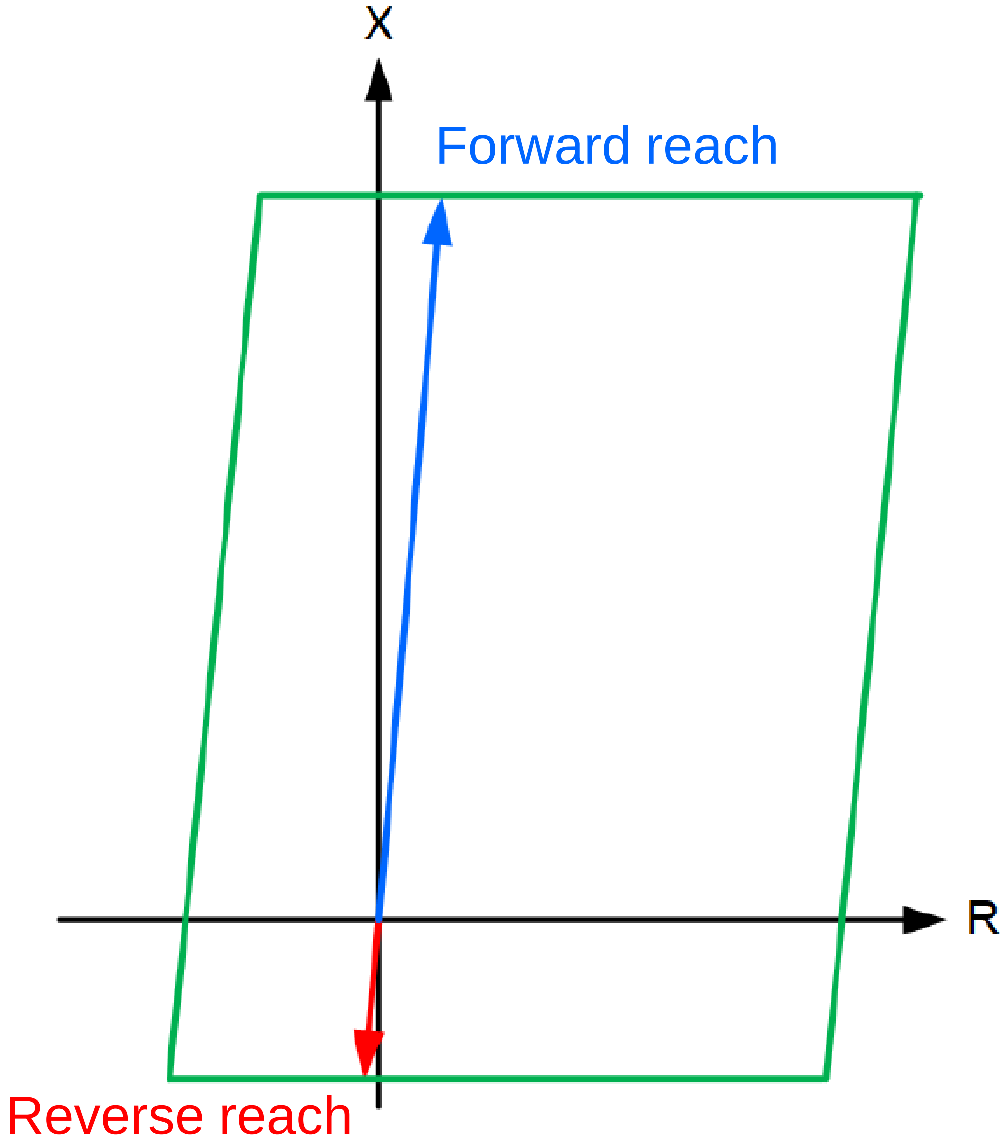
Distance element operating quantity



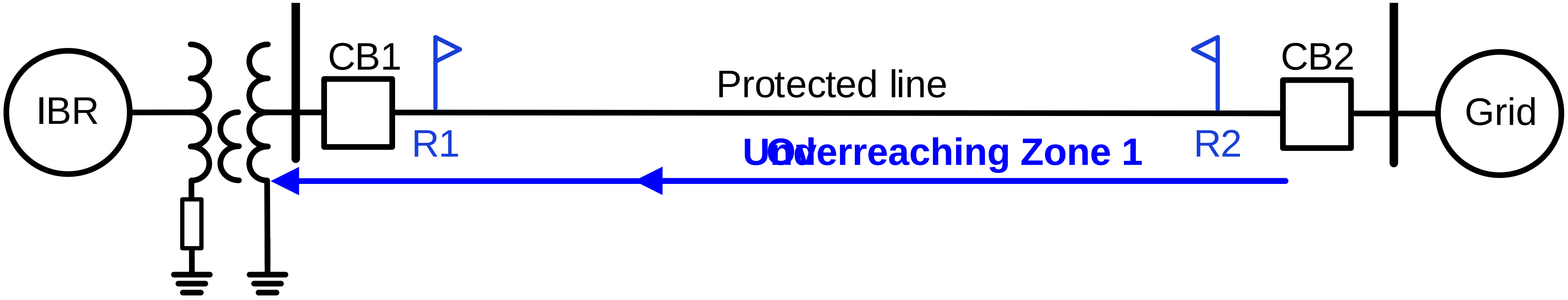


Self-polarized offset distance elements



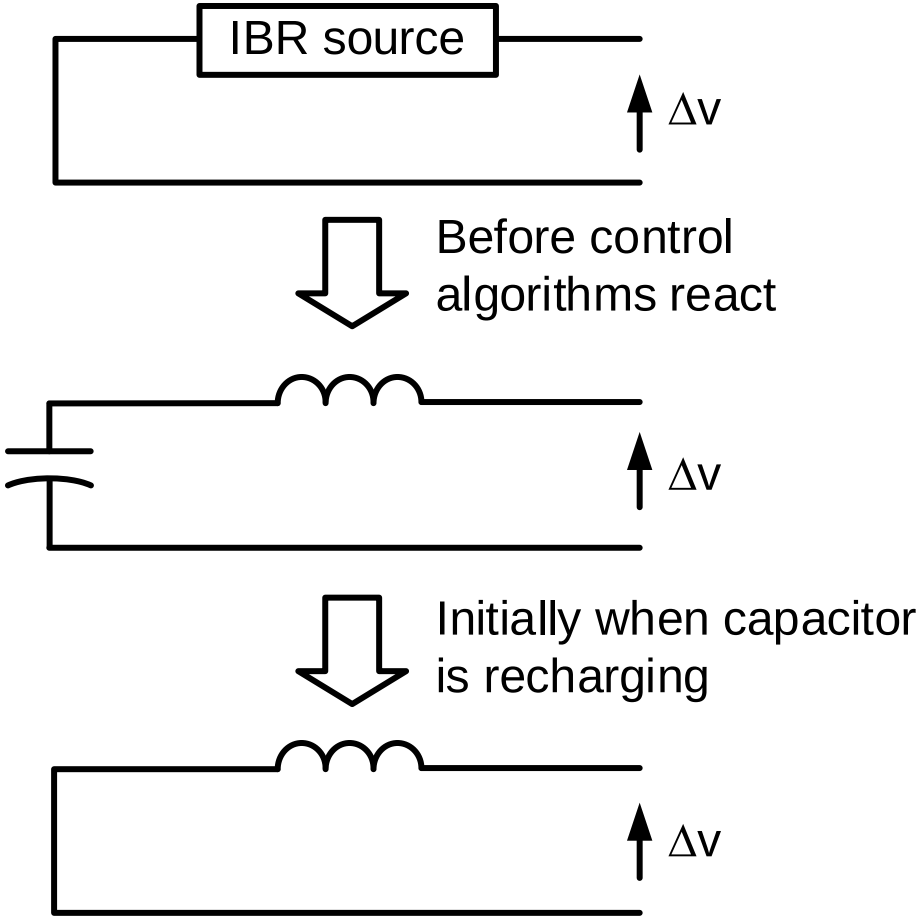


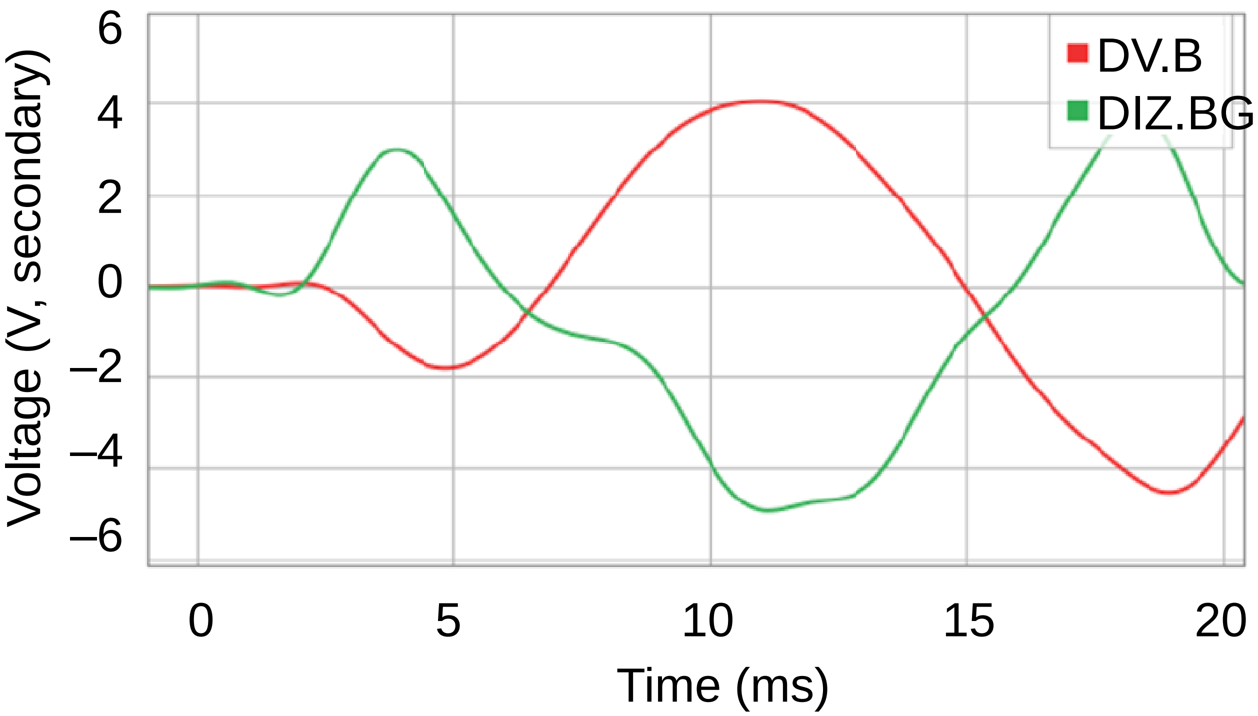
Increase Zone 1 reach for tie-lines without parallel path in a meshed network



Transient-based methods

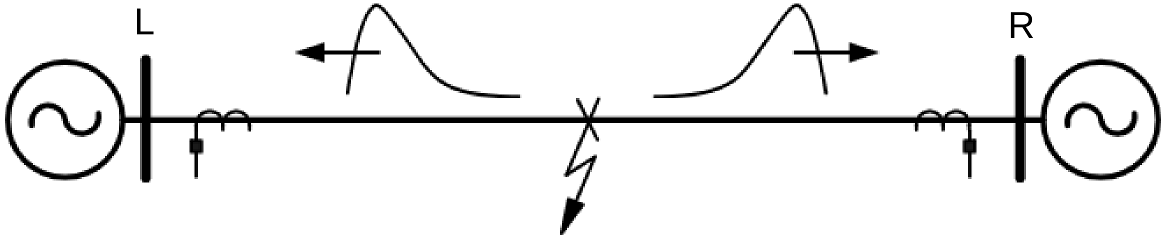
Transient-based directional element

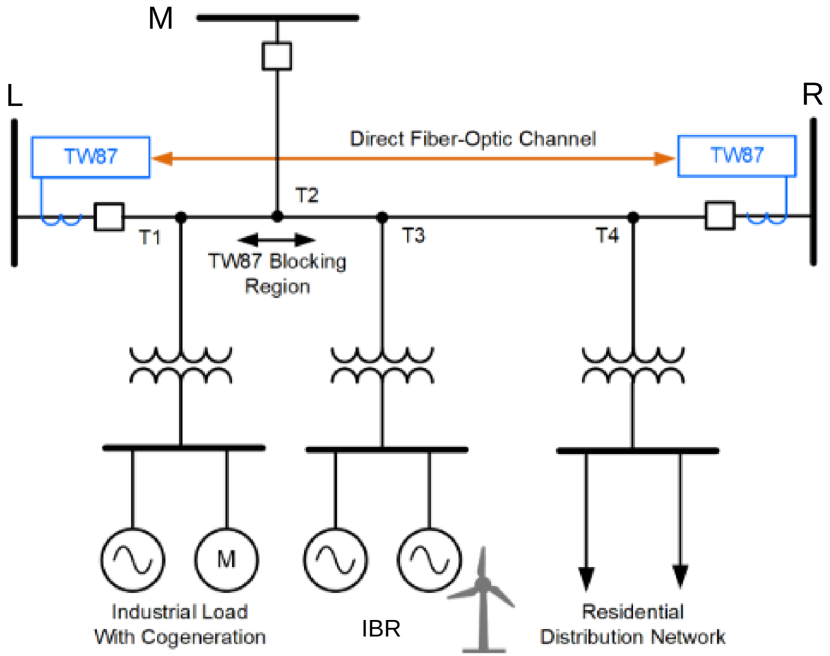


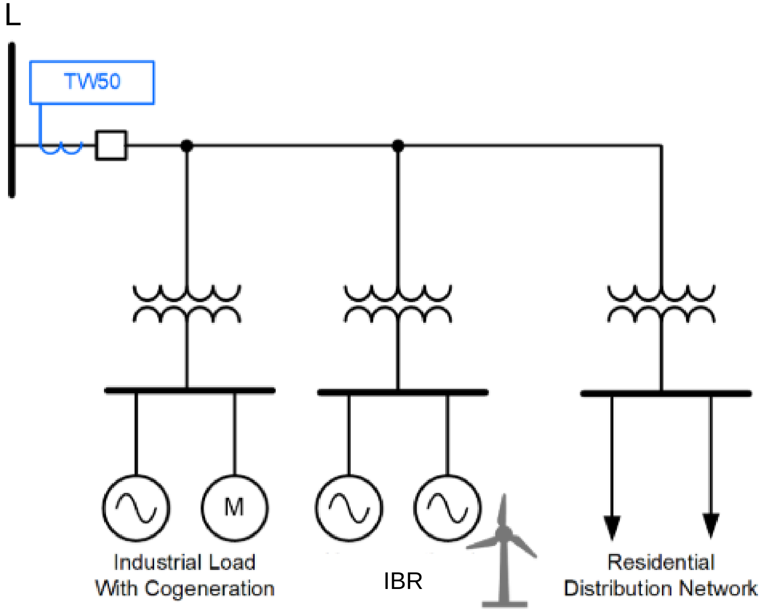


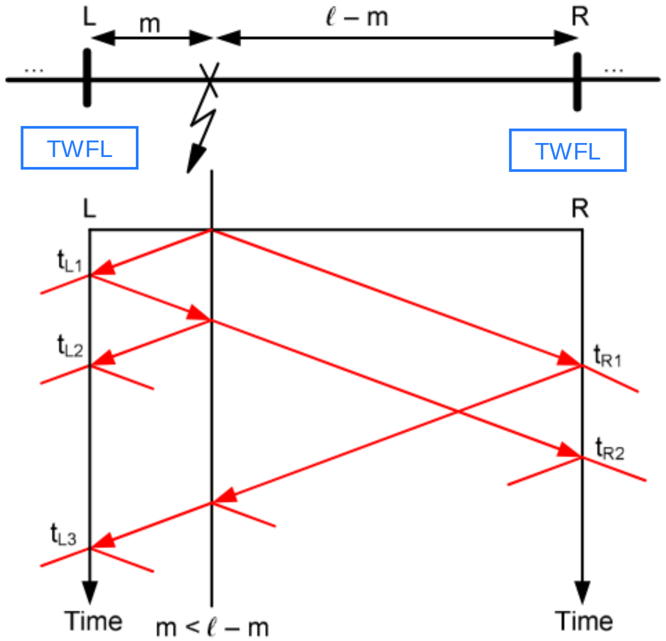
Traveling waves

Protection and fault location



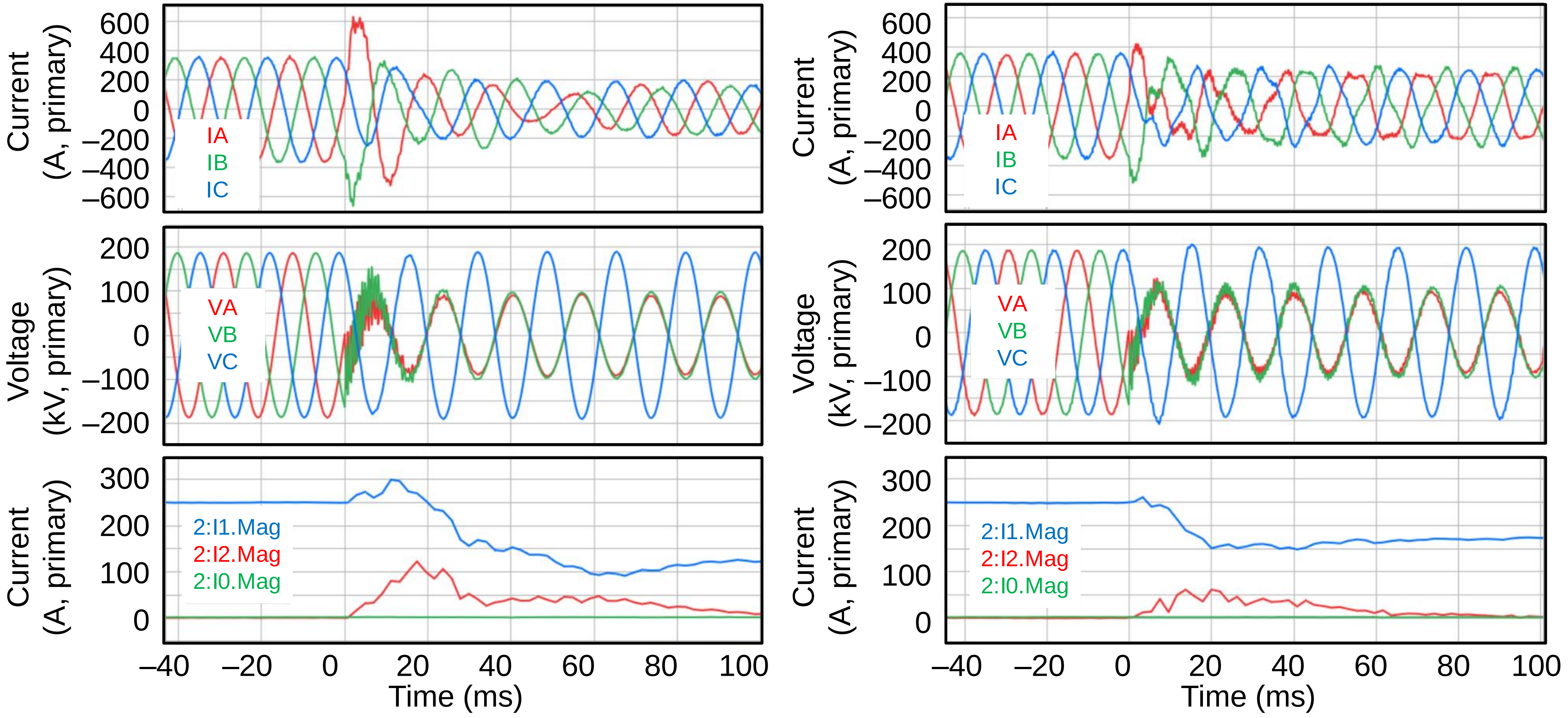






Source-to-line impedance ratio (SIR)

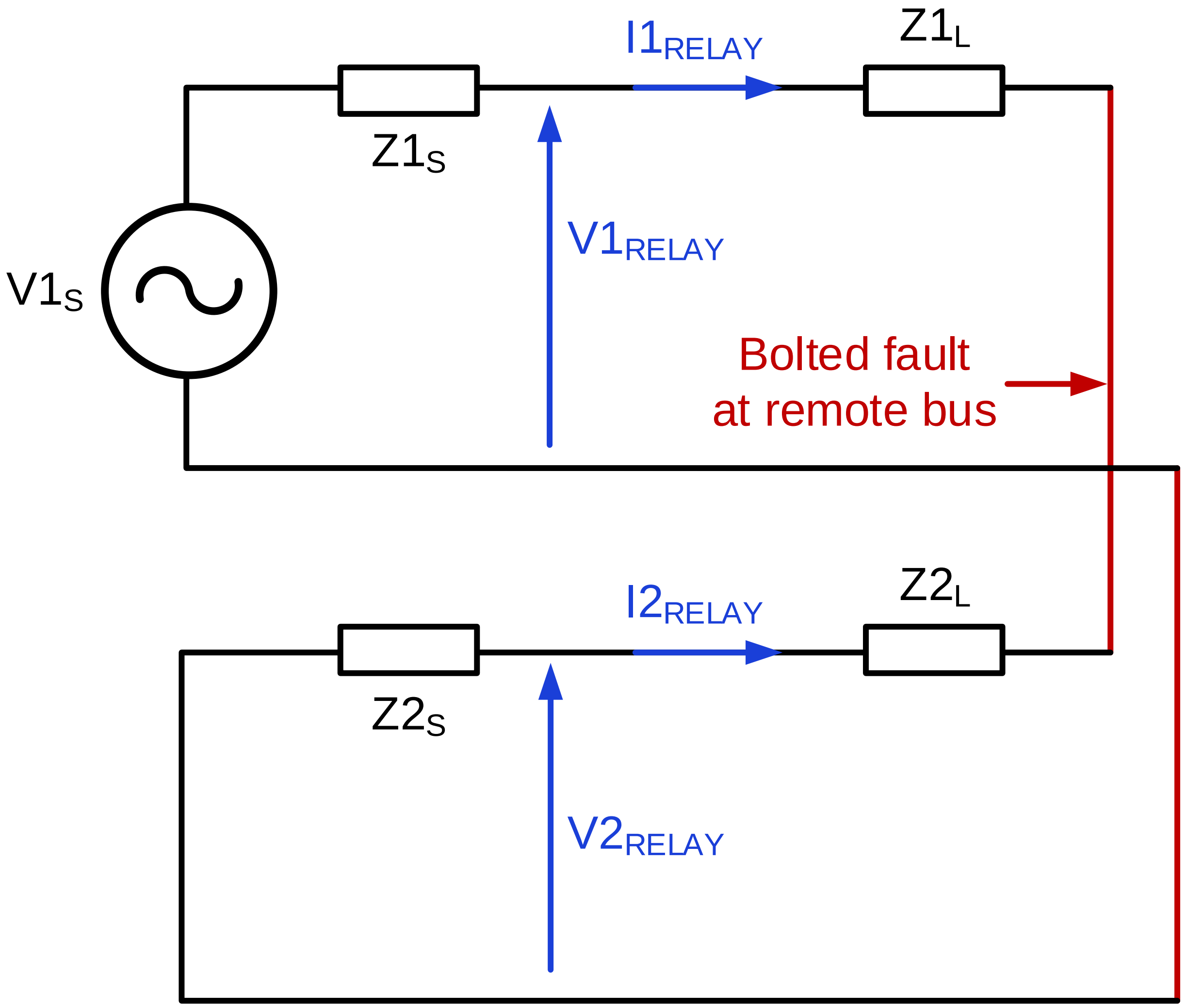
Line-to-line fault at remote bus



Relay voltage for line-to-line faults

$$\frac{V_{RELAY\ LL(LL\ FAULT)}}{V_{RELAY\ LL(3P\ FAULT)}} = \frac{Z1_S + Z1_L}{\left(\frac{Z1_S + Z2_S}{2}\right) + Z1_L}$$

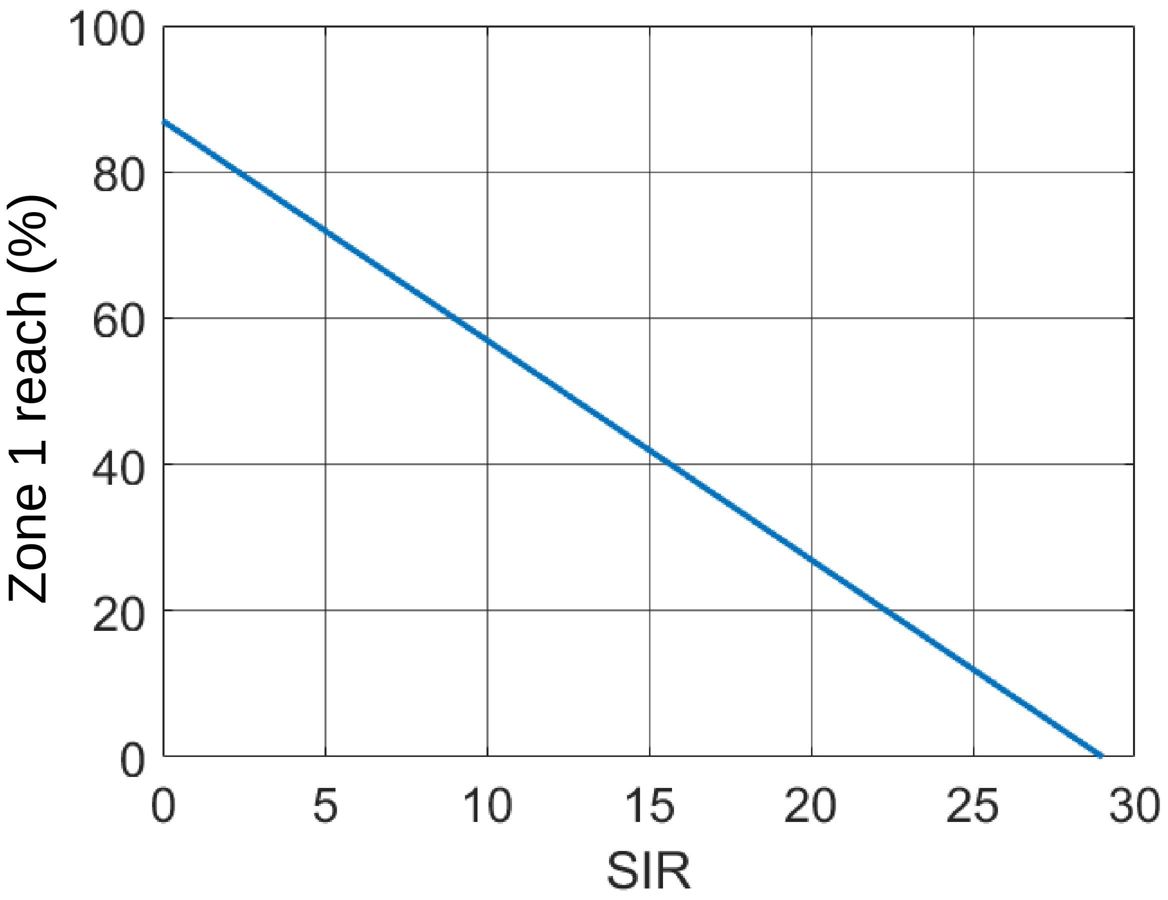
- If $Z1_S = 10 \cdot Z1_L$ and $Z2_S = 10 \cdot Z1_S$,
  - $SIR_{P(3P\_FAULT)} = 10$
  - $SIR_{P(LL\_FAULT)} = 50.9!$
- Consider LL faults also when calculating SIR_P



Improve 21P Zone 1 security due to high SIR

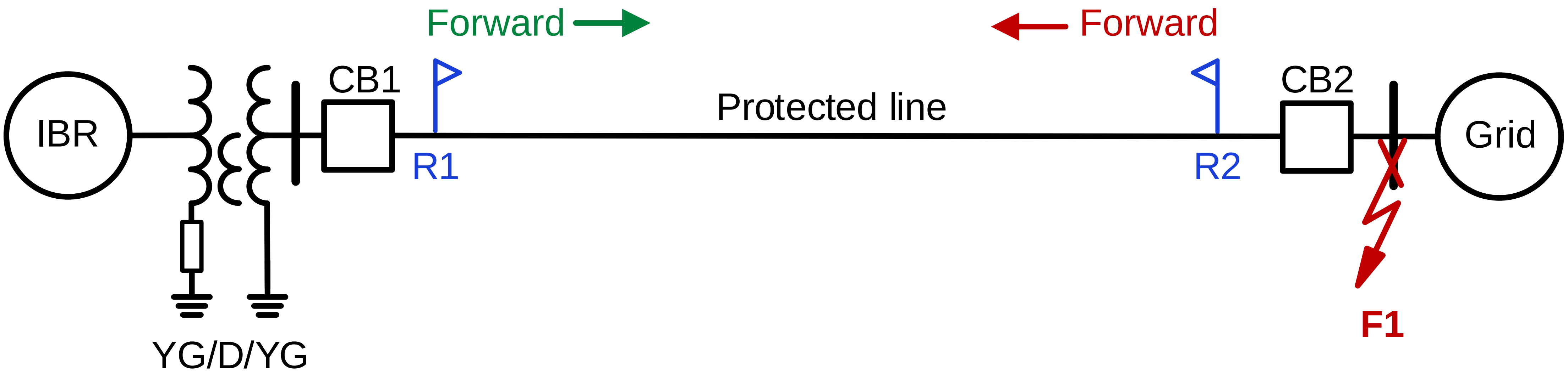
Reduce reach and/or add time delays

- m1 < m1RATIO – ESS • (SIR + 1)
  - m1 = secure reach considering SIR
  - m1RATIO = reach considering ratio errors (e.g., 0.90 pu)
  - ESS = Steady-state error (e.g., 0.03 pu)
- Consider transient CCVT errors

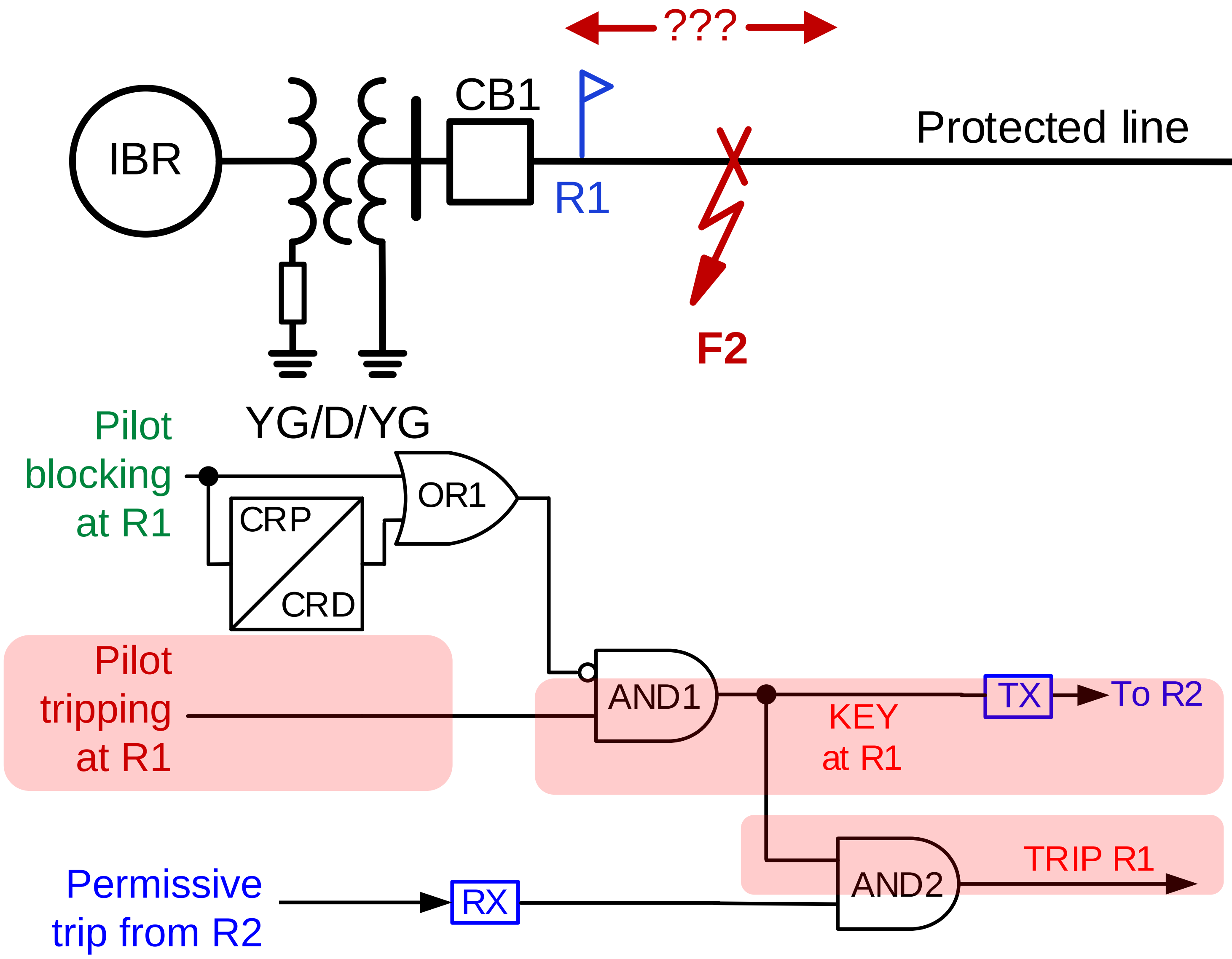


Directional comparison pilot schemes

Directional element security

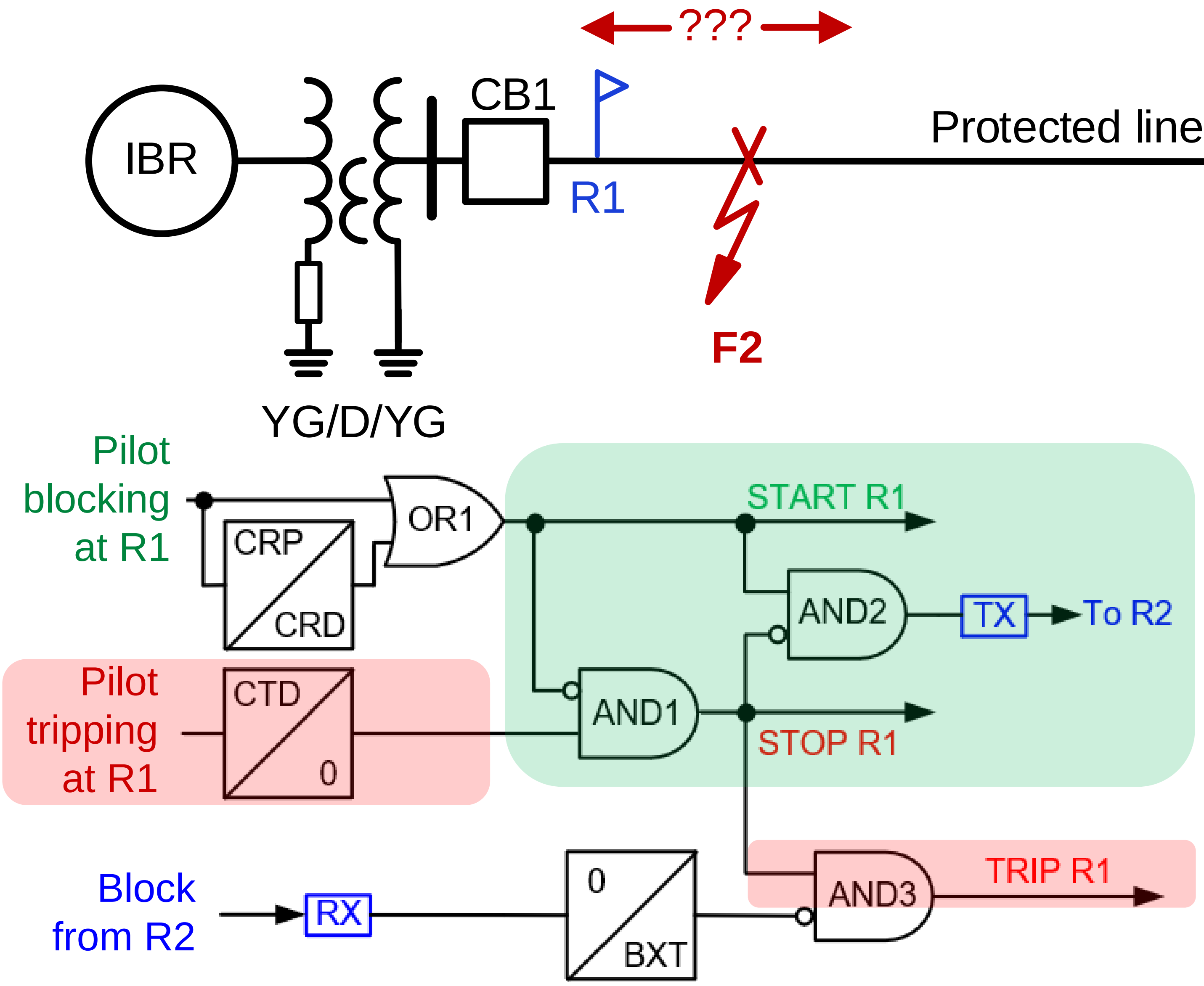


POTT scheme dependability



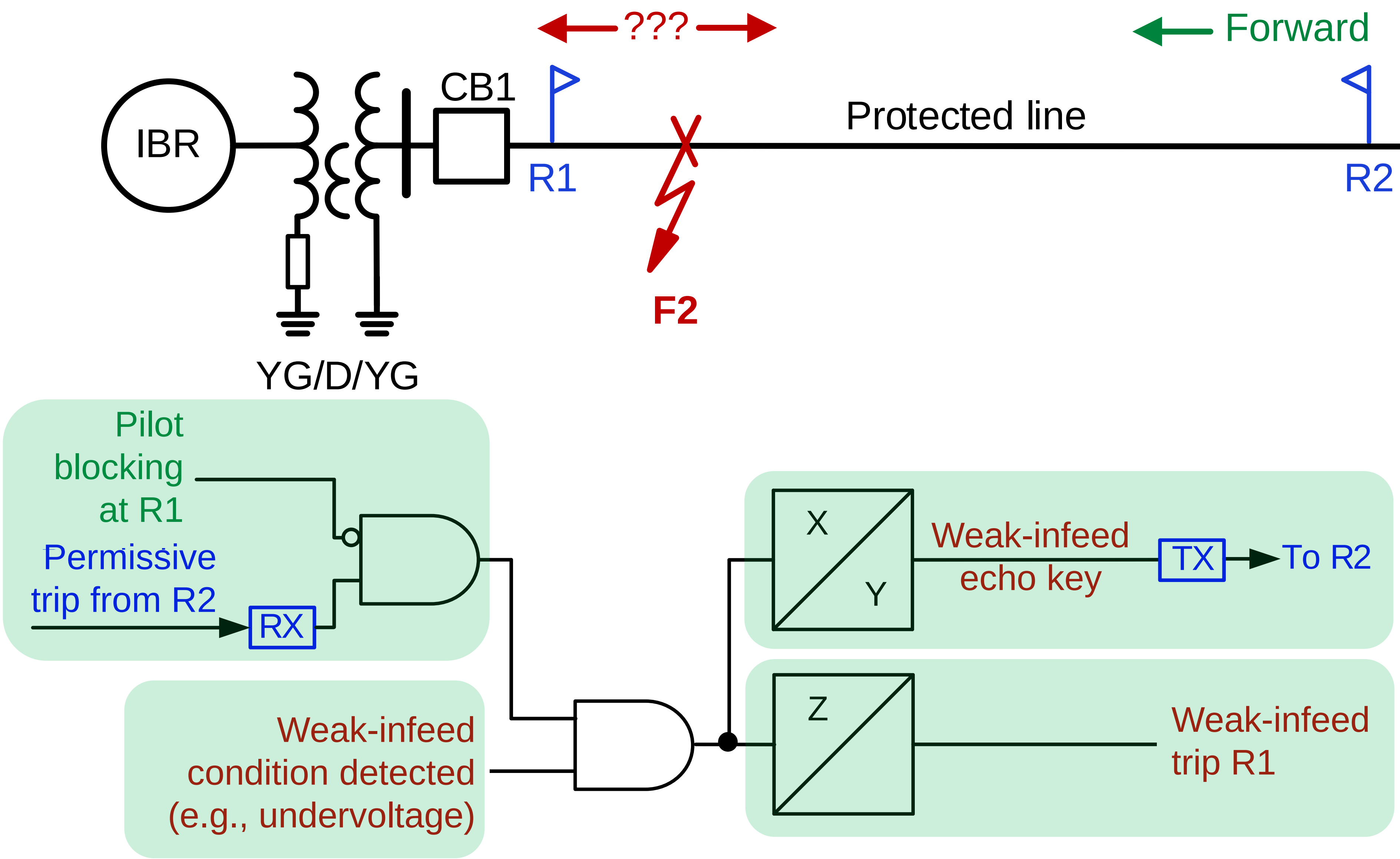
- R1 observes reduced dependability
- R2 also observes reduced dependability

DCB scheme dependability



- R1 observes reduced dependability
- R2 trips

Hybrid POTT with weak-infeed echo and trip

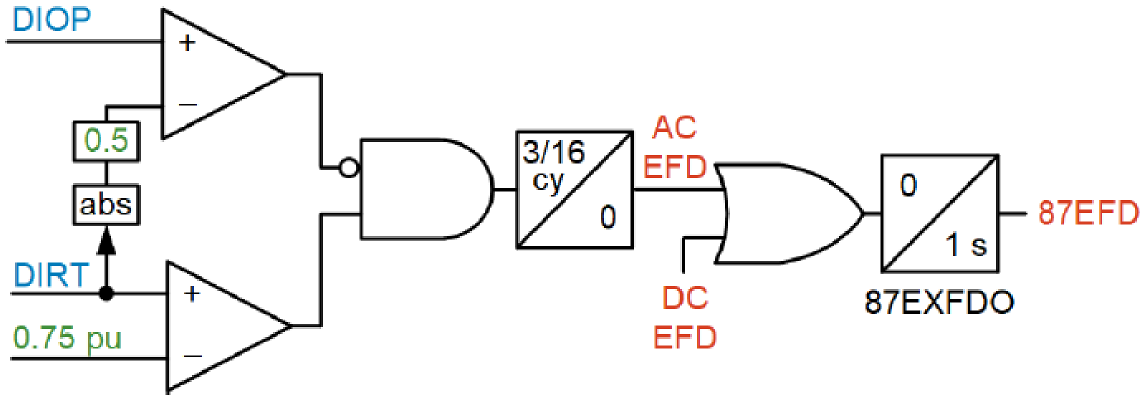


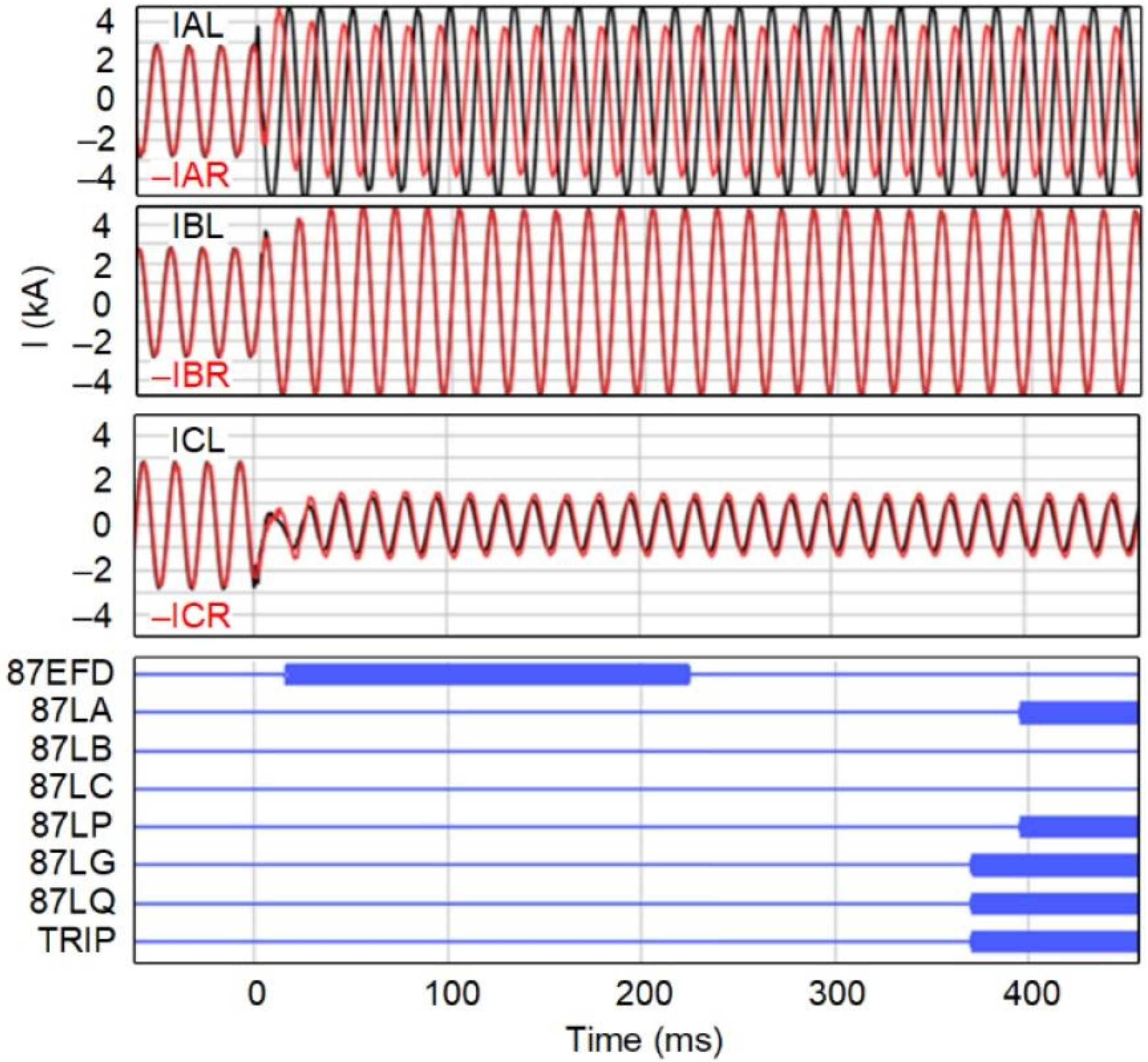
- R1 trips
- R2 trips

Line current differential

Internal AG fault

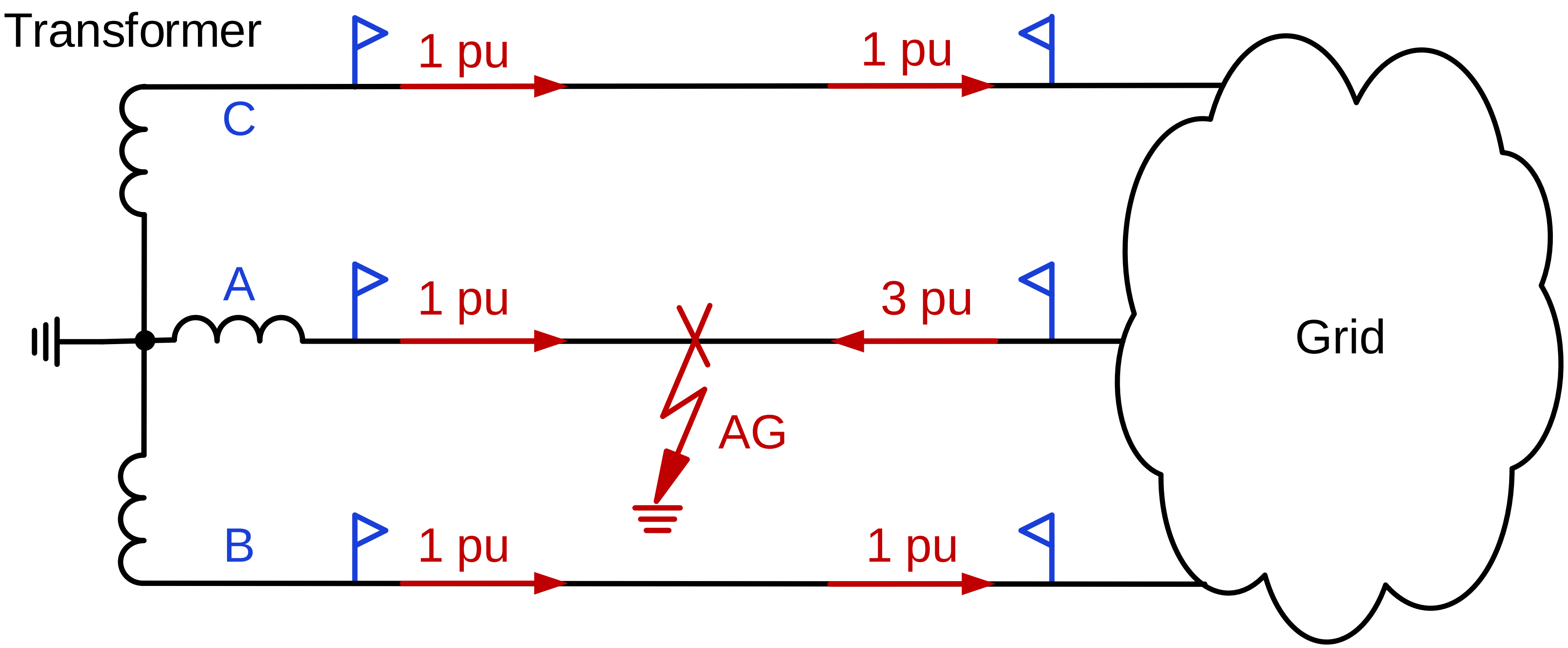
15 ohms



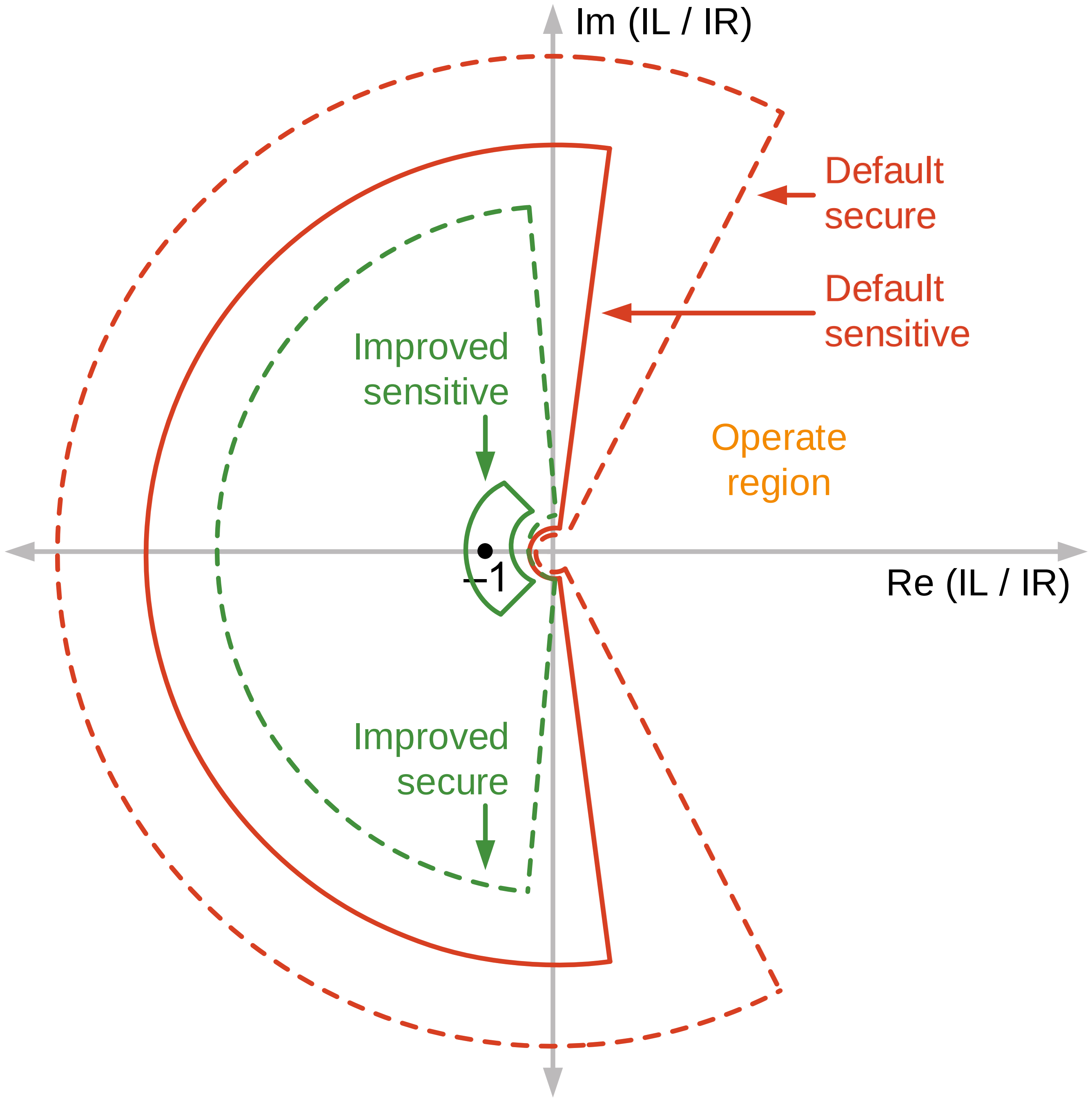


IBR fault response

Strong zero-sequence, but weak otherwise

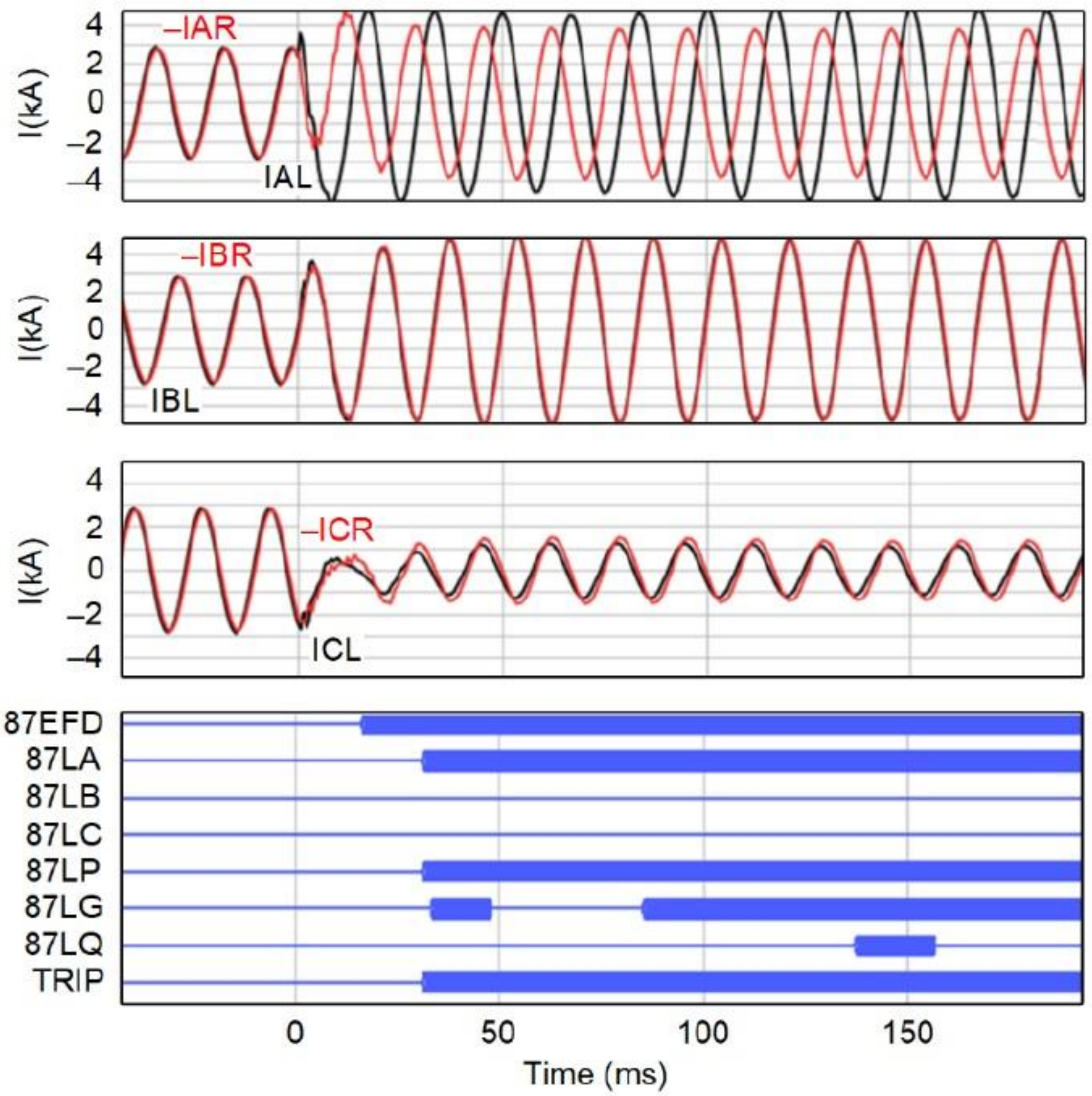


Improved dependability



Internal AG fault

Improved settings

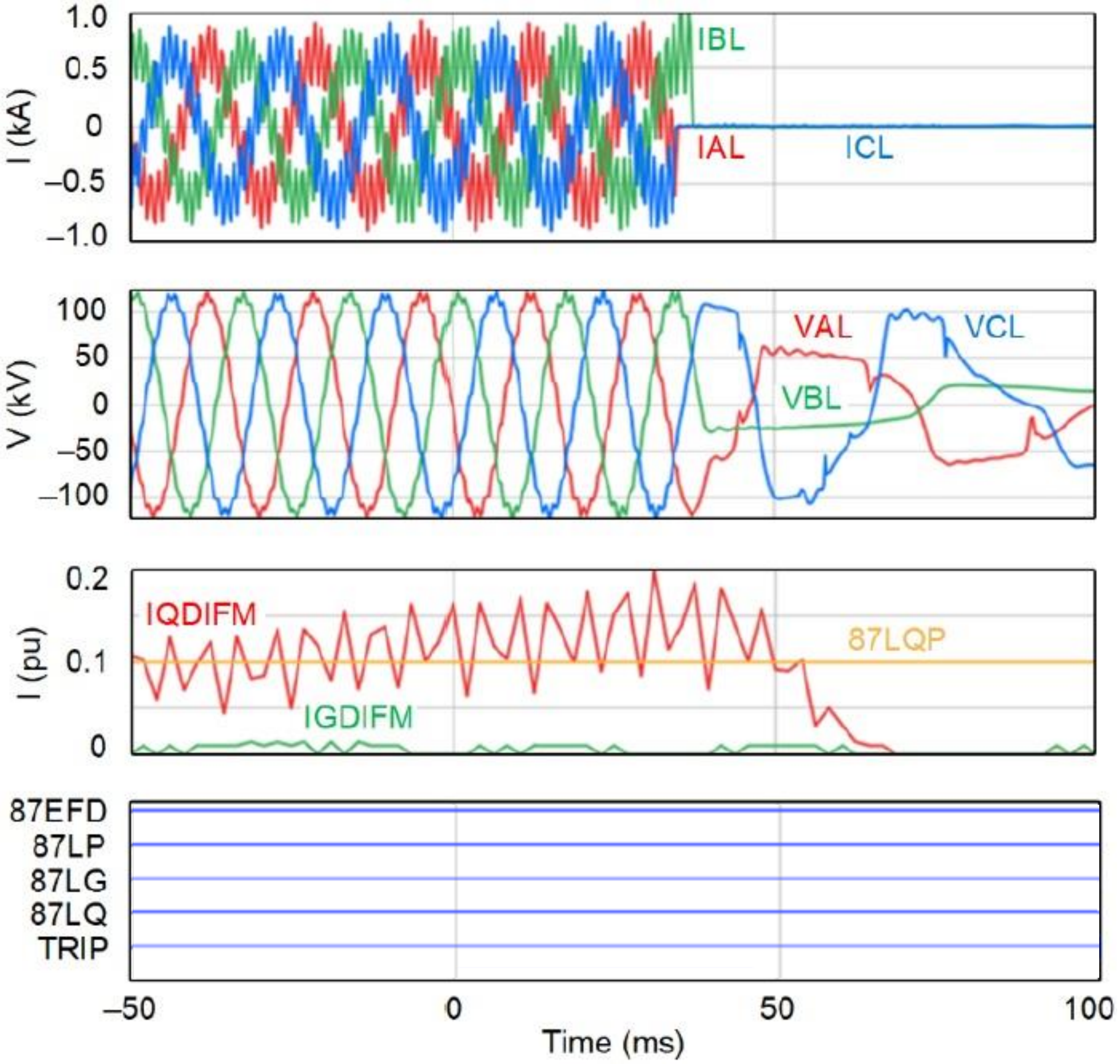


No fault
Harmonics

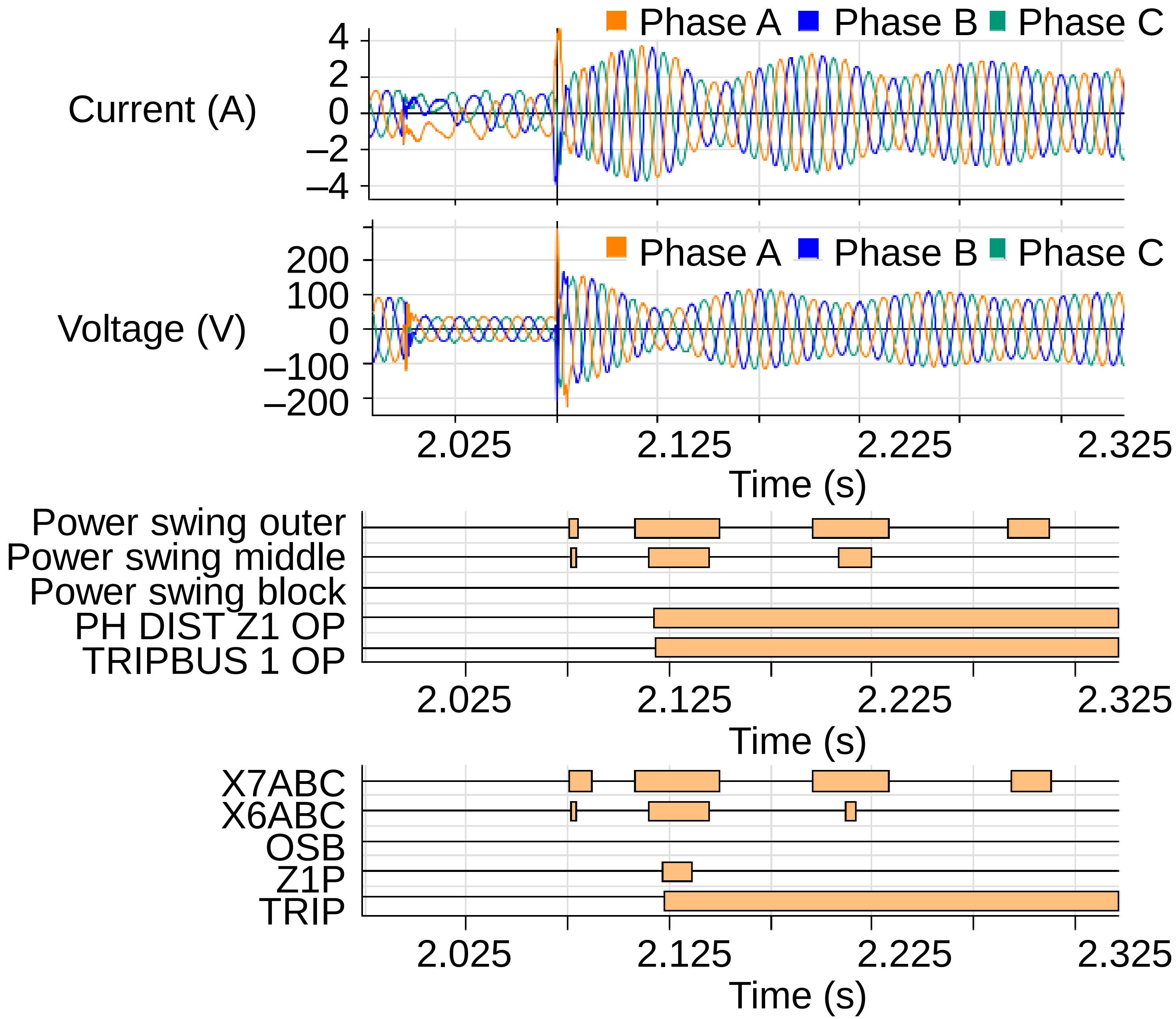
$$87LQP_{SENS} = 1.25 \cdot \frac{S_{IBR}}{\sqrt{3} \cdot V_{HV} \cdot (CTR \cdot I_{NOM})} \text{pu}$$

$$87LQP_{SECURE} = 1.30 \cdot 87LQP_{SENS} \text{ pu}$$

- $87LQP_{SENS}$ = 0.48 pu
- $87LQP_{SECURE}$ = 0.63 pu

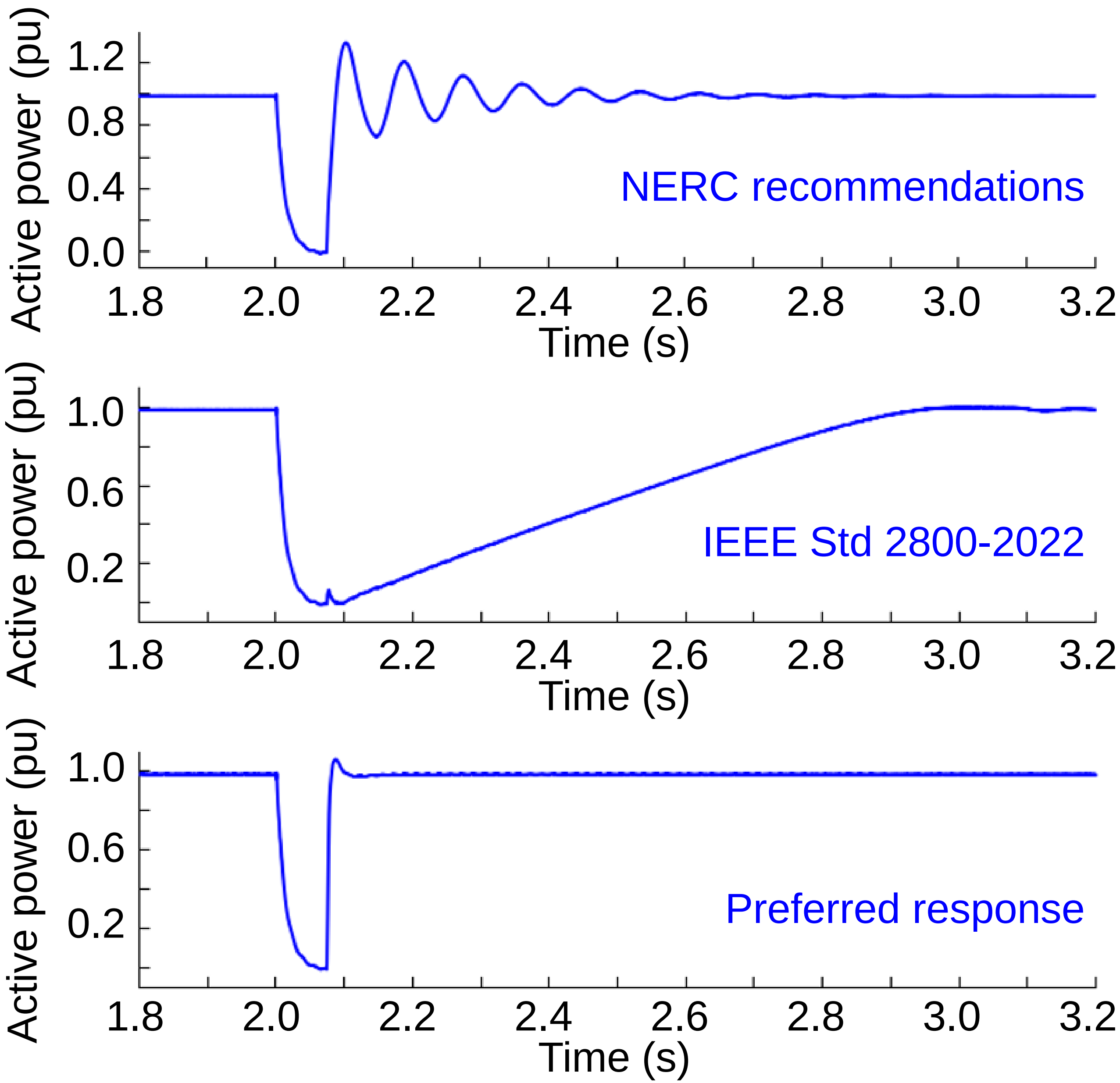


Power swing blocking



Power swing blocking

Transient security challenges



IBR active power

Control responses

Conclusion

Conclusion

1. Raise negative-sequence current thresholds to improve directional element and FIDS logic performance
   – Reliable directionality, especially for phase-to-phase faults in which 32Q may be the only element to provide directionality
   – Voltage-based FIDS logic adds dependability and security
2. Use self-polarized phase distance with possibly offset characteristics supplemented by transient directional elements
3. Use ground mho or zero-sequence polarized quadrilateral
4. Increase Zone 1 reach at strong terminal in tie-line applications without parallel paths

Conclusion

5. Source-to-line impedance ratio (SIR) can be very high
   - Consider line-to-line faults also to calculate SIR
   - Reduce Zone 1 reach and/or add time delay for security or, if required, disable Zone 1 and rely on communications-assisted protection
6. Use Hybrid POTT scheme with weak-infeed echo and trip
7. Use line current differential protection with improved settings
8. Re-evaluate power swing blocking application and settings
9. Transient-based line protection elements including traveling-wave-based schemes can add dependability

References for further reading

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Questions?