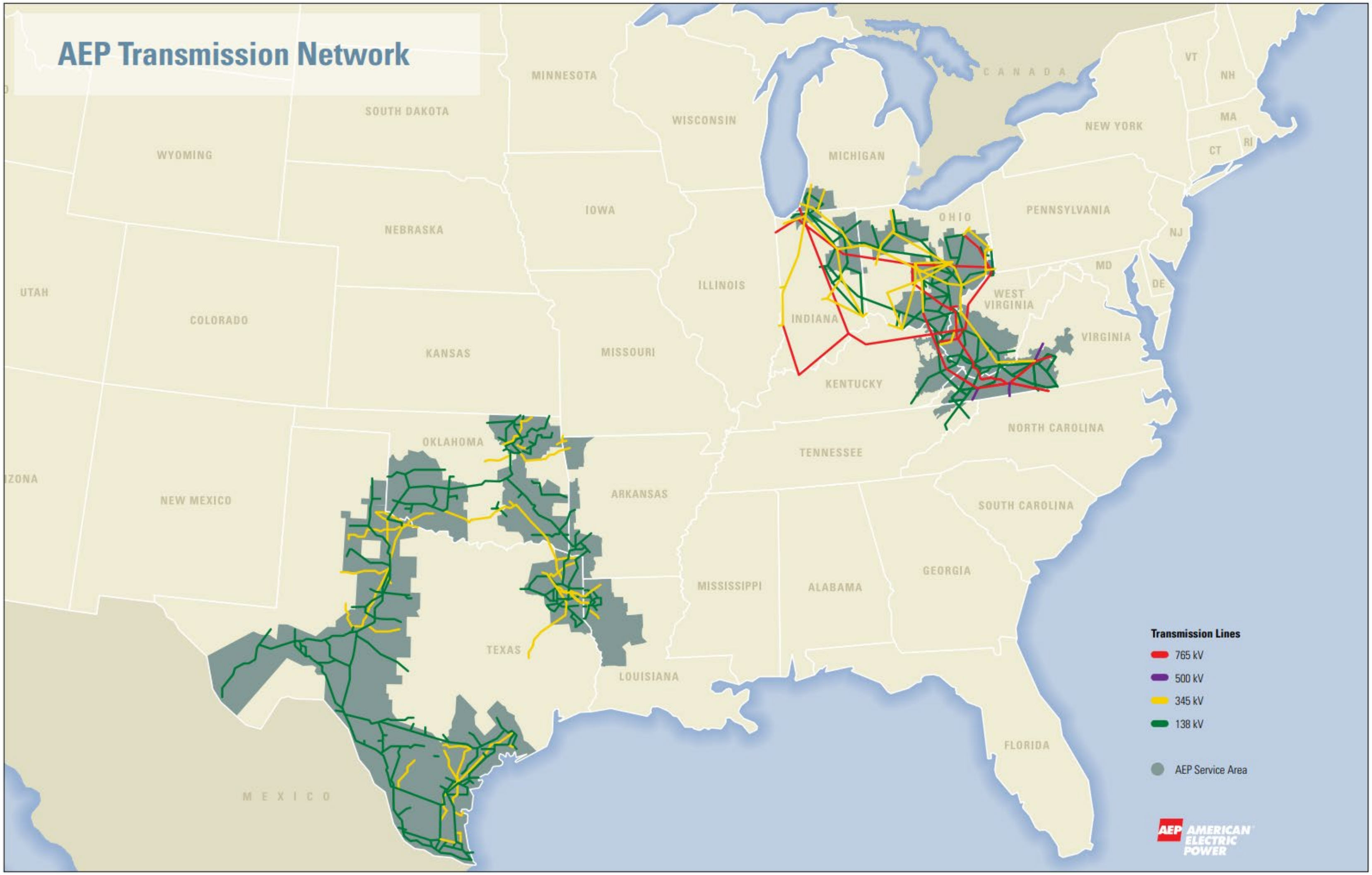
Automated Solutions and Remote Settings Changes - AEP's Approach to Implementing PRC-027-1

Jeff Iler and Nelson Doe

American Electric Power

AEP Serves 5.5 million Customers in 11 States



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:

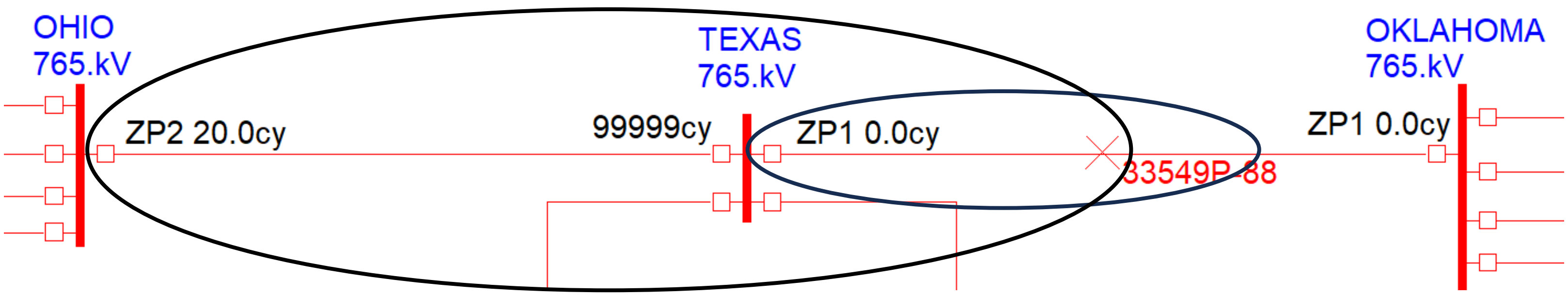
- Ensures that Protection Systems are coordinated
- Potentially reduces misoperations caused by incorrect relay settings
- May be more costly and time consuming than Option 2

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

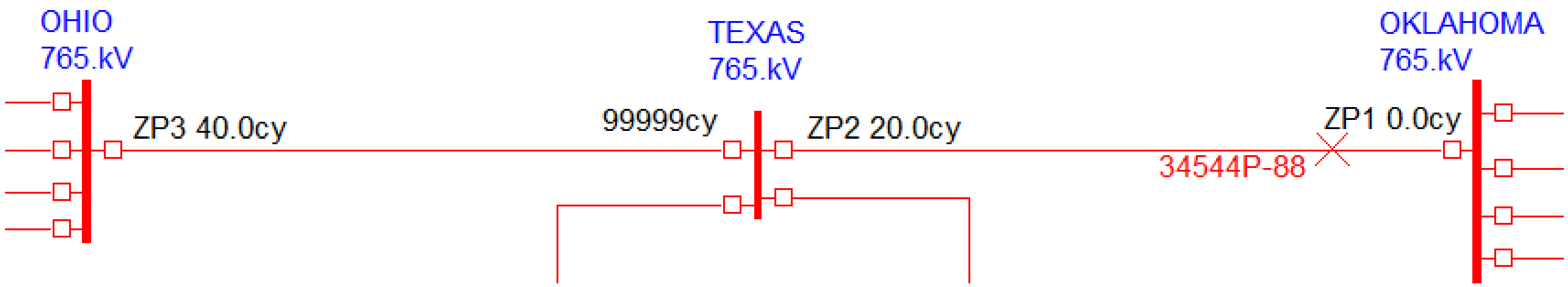
- Instantaneous Elements have adequate margin for remote bus fault

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

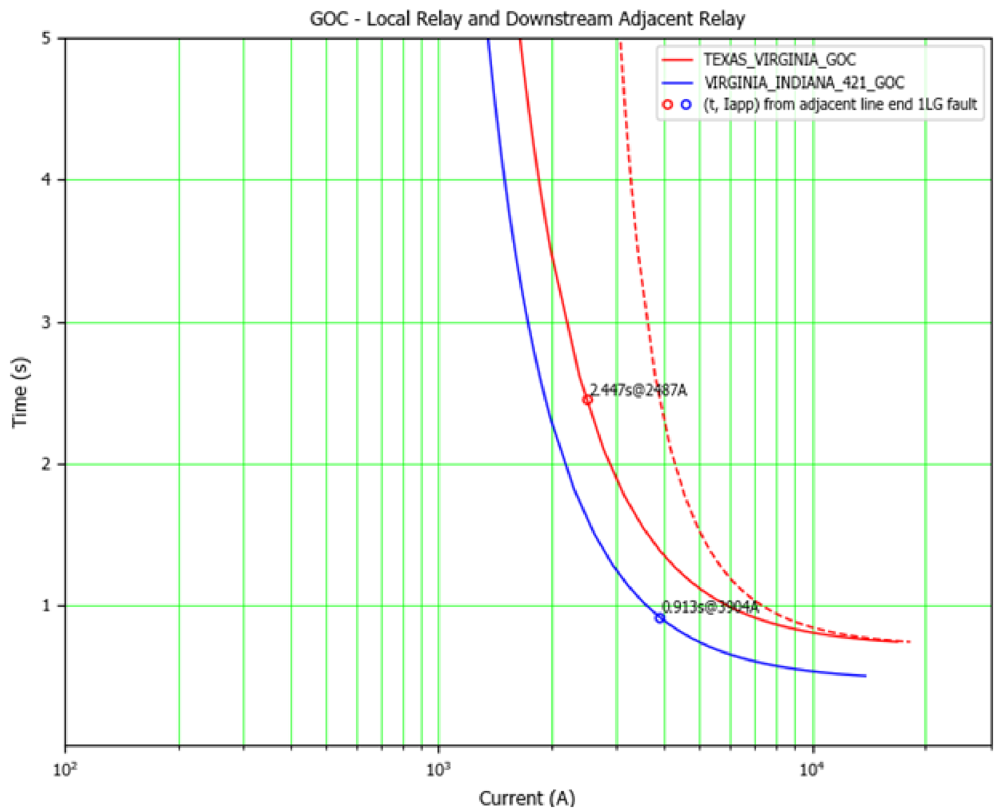
Lessons Learned from Initial 765KV Study

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

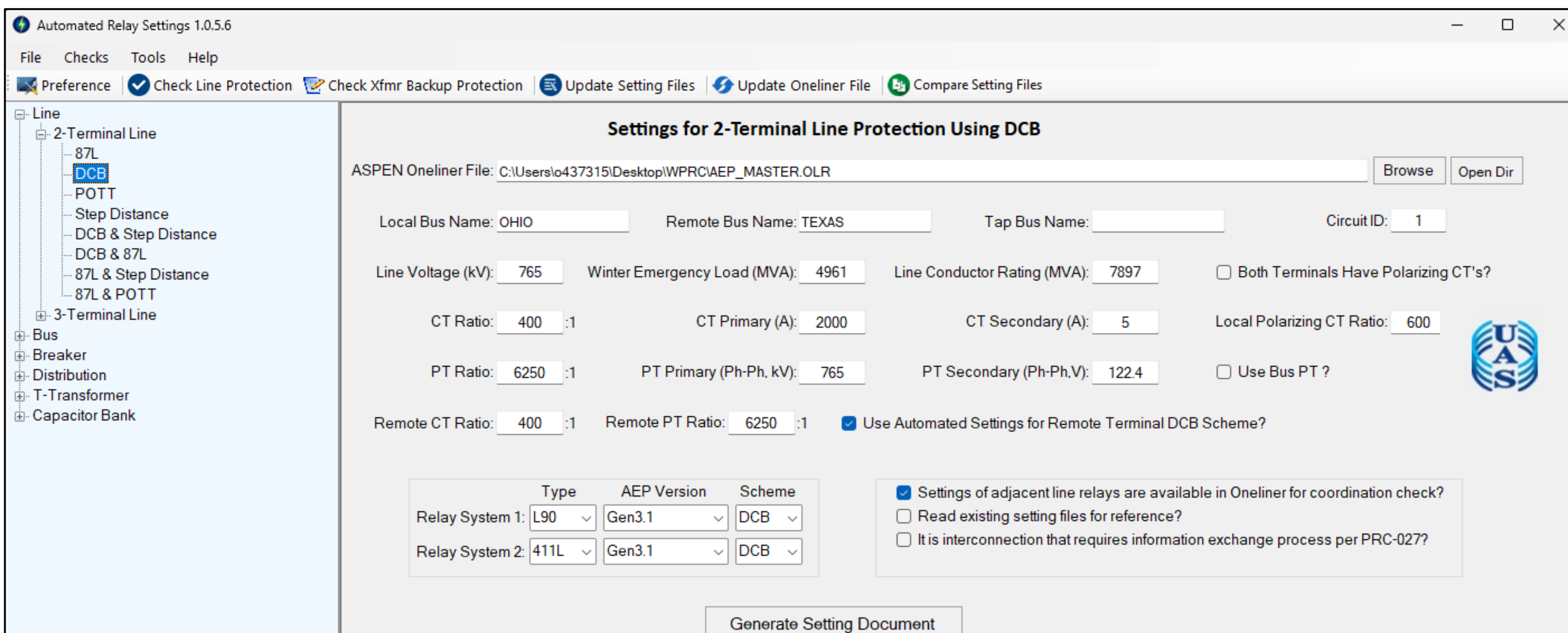
Initial study identified GOC settings as leading cause of coordination errors

- 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

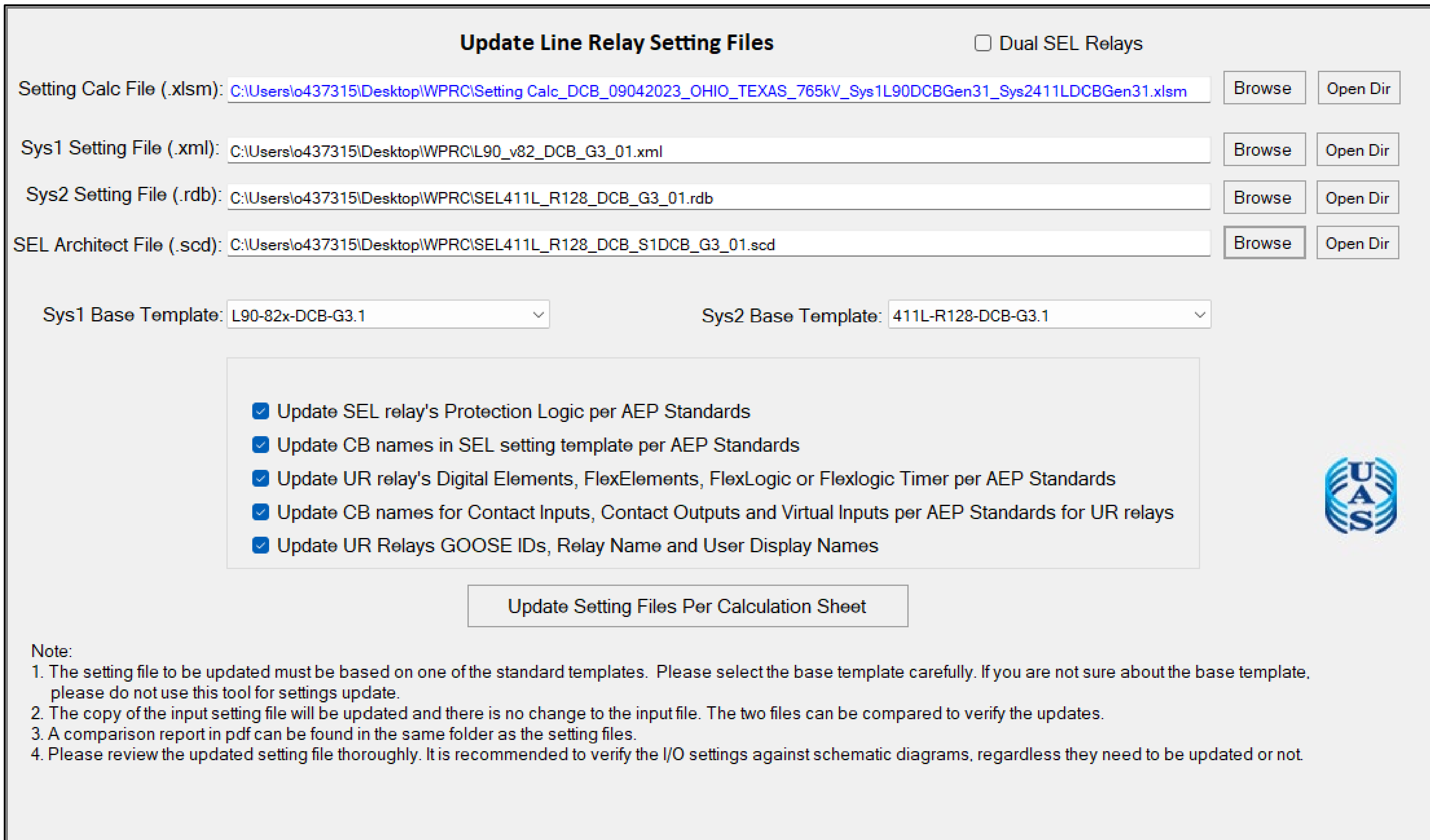
- Automated Relay Settings (ARS) developed by Utility Automation Solutions (UAS)
- ARS was initially used for the 765kV PRC-027 settings – 56 line terminals



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



Limited Disclosure

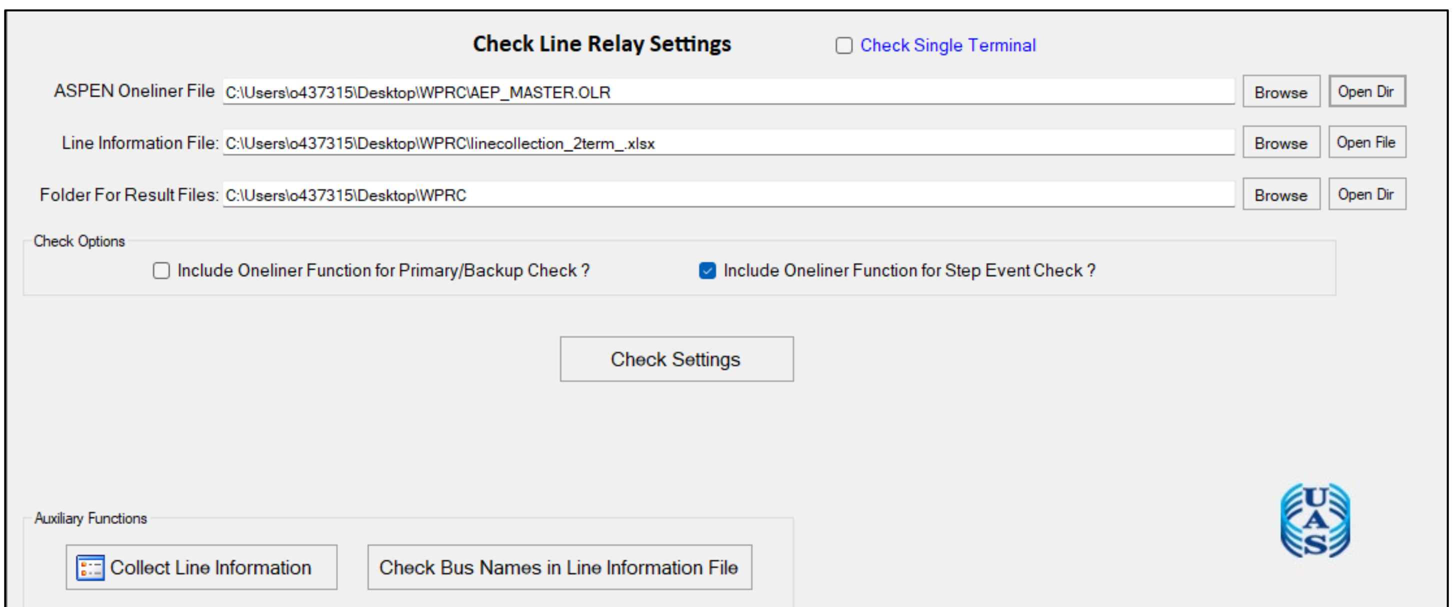
Adjusted Criteria for Protection System Coordination Studies

	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

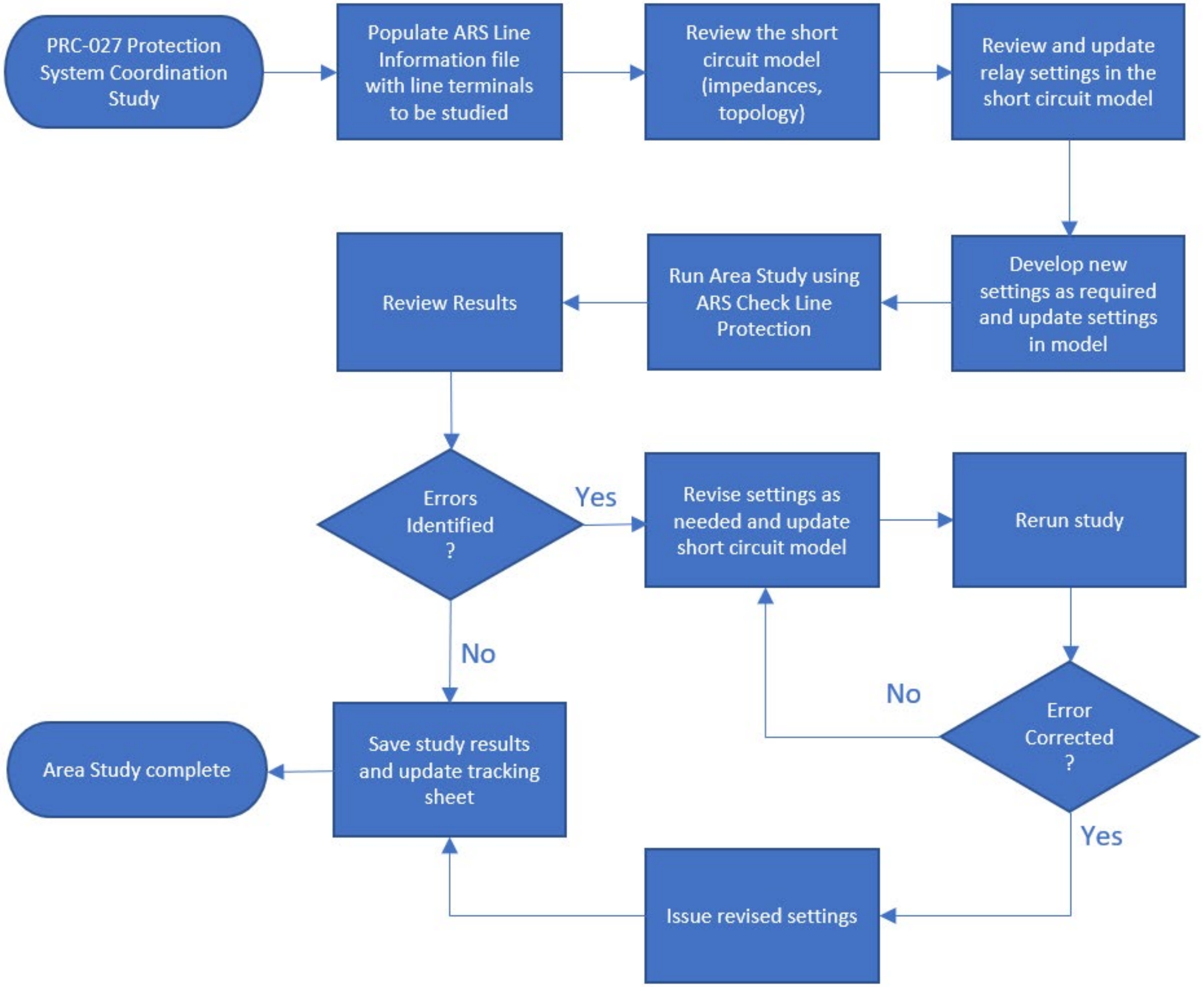
Downstream adjacent Relay ID	Op Time (s)	Local Relay ID	Op Time (s)	Z2P/Zapp	Check	
TEXAS_KENTUCKY_D60_PDS	0.333	OHIO_TEXAS_421_PDS	9999.000	50%	OK	Plot
TEXAS_KENTUCKY_D60_PDS	0.333	OHIO_TEXAS_D60_PDS	9999.000	42%	OK	Plot
TEXAS_KENTUCKY_421_PDS	0.333	OHIO_TEXAS_421_PDS	9999.000	50%	OK	Plot
TEXAS_KENTUCKY_421_PDS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