Consideration of Comments

Project 2010-13.3 – Phase 3 of Relay Loadability: Stable Power Swings

The Stable Power Swings Drafting Team thanks all commenters who submitted comments on the standard. This standard was posted for a 45-day public comment period from April 25, 2014 through June 9, 2014. Stakeholders were asked to provide feedback on the standard and associated documents through a special electronic comment form. There were 70 sets of comments, including comments from approximately 181 different people from approximately 117 companies representing all 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Director of Standards, Valerie Agnew, at 404-446-2566 or at valerie.agnew@nerc.net . In addition, there is a NERC Reliability Standards Appeals Process.[1]

NERC Discussion on Proceeding(s) and Directives Regarding: Stable Power Swings

In the NOPR that led to Order No. 733, the Commission stated that the cascade during the August 2003 blackout was accelerated by zone 3/zone 2 relays that operated because they could not distinguish between a dynamic, but stable power swing and an actual fault. The Commission observed that PRC-023-1 does not address stable power swings, and pointed out that currently available protection applications and relays, such as pilot wire differential, phase comparison and blinder-blocking applications and relays, and impedance relays with non-circular operating characteristics, are demonstrably less susceptible to operating unnecessarily because of stable power swings. Given the availability of alternatives, the Commission stated that the use of protective relay systems that cannot differentiate between faults and stable power swings constitutes mis-coordination of the protection system and is inconsistent with entities' obligations under existing Reliability Standards. The Commission explained that a protective relay system that cannot refrain from operating under non-fault conditions because of a technological impediment is unable to achieve the performance required for Reliable Operation. Consequently, the Commission requested comments on whether it should direct the ERO to develop a new Reliability Standard or a modification to PRC-023-1 that requires the use of protective relay systems that can differentiate between faults and stable power swings and phases out protective relay systems that cannot meet this requirement.

NERC and other commenters urged the Commission to not direct modification of PRC-023-1 and instead allow NERC to determine the proper solution following technical analysis of the issue. Other

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf

commenters challenged the Commission's reasoning and assumptions for its proposed directive including challenging the validity of the assertion that stable power swings contributed to the cascade in the August 2003 blackout. Others argued that PRC-023-1 adequately covers the issue raised by the Commission. Despite the multiple avenues used to challenge the directive proposed by the Commission, the Commission ultimately directed NERC to create a new Reliability Standard that requires the use of protective relay systems that can differentiate between faults and stable power swings and, when necessary, phases out protective relay systems that cannot meet this requirement. The Commission stated that it found arguments that stable power swings did not contribute to the cascade in the August 2003 blackout to be unpersuasive.

Various organizations including NERC, APPA, EEI, NRECA, and TAPS sought rehearing of the Commission's directive. EEI made arguments that the Commission's directive was arbitrary and capricious and unsupported by the record. APPA asked the Commission to instead require NERC to examine whether and how operation of protective relays during stable power swings should be addressed through standards, or at minimum, clarify that it is leaving to NERC to determine the applicability of a requirement for relays to differentiate between faults and stable power swings and which relays must be phased out to achieve bulk power system reliability. NERC seeks clarification that it can use its industry technical experts to address the issue appropriately and asks for clarity as to whether the directive was intended to create an absolute requirement to highlight a concern that other approaches might satisfy.

The Commission maintained its position that not addressing stable power swings constitutes a gap in the current Reliability Standards and must be addressed. It did clarify in Order No. 733-A that NERC is able to use the standard development process to develop technical analysis and an approach to the Reliability Standard to meet the Commission's concern. The Commission also clarified that it did not direct the development of a Reliability Standard containing an absolute obligation to prevent protection relays from operating unnecessarily during stable power swings.

The EEI and NRECA jointly filed a timely motion and APPA/TAPS together filed a motion, in both instances, requesting clarification, or reconsideration of Order No. 733-A. In general, both motions assert the Commission based its directives on a faulty understanding of the Blackout Report[2] or an incorrect characterization of relay engineering. Both motions also reprise issues addressed in Order No. 733-A relating to the Commission exceeding its statutory authority by failing to give "due weight" to the technical expertise of the ERO and by giving overly prescriptive directives. Finally, EEI/NRECA seek clarification or reconsideration of language that they characterize as suggesting that the Commission expects 100 percent relay security and of the Commission's directive regarding generator relays. APPA and TAPS sought rehearing of Order No. 733-A. In summary, the Commission ruled, in Order No. 733-B, that the issues had been addressed in both Order Nos. 733 and 733-A and that further clarification is not necessary.

[2] http://www.nerc.com/pa/rrm/ea/Pages/Blackout-August-2003.aspx

In addition to the rehearing requests, NERC filed an informational filing to introduce and clarify certain aspects of the August 14, 2003 blackout investigation relative to operation of protective relays in response to stable power swings. NERC explained that the fourteen lines discussed in Order No. 733 did not trip due to stable power swings. NERC stated that ten of these lines tripped in response to the steady-state loadability issue addressed by Reliability Standard PRC-023, while the last four lines tripped in response to dynamic instability of the power system. Although the fourteen line trips by zone 2 and zone 3 relays discussed in the Blackout Report[3] did not occur as a result of stable power swings, the blackout investigation team did identify two transmission lines that tripped due to *protective relay operation in response to stable power swings*.

In August of 2013, the NERC System Protection and Control Subcommittee (SPCS) issued its report *Protection System Response to Power Swings*, August 2013[4] ("PSRPS Report"). In response to the FERC directive, NERC initiated this Project 2010-13.3 – Phase 3 of Relay Loadability: Stable Power Swings to address the issue of protection system performance during power swings. To support this effort, and in response to a request for research from the NERC Standards Committee, the SPCS, with support from the System Analysis and Modeling Subcommittee (SAMS), developed the PSRPS Report to promote understanding of the overall concepts related to the nature of power swings; the effects of power swings on protection system operation; techniques for detecting power swings and the limitations of those techniques; and methods for assessing the impact of power swings on protection system operation.

Based on its review of historical events, consideration of the trade-offs between dependability and security, and recognizing the indirect benefits of implementing the transmission relay loadability standard (PRC-023), the SPCS concluded that a NERC Reliability Standard to address relay performance during stable power swings is not needed, and could result in unintended adverse impacts to Bulk-Power System reliability. While the SPCS recommended that a Reliability Standard is not needed, the SPCS recognized the directive in Order No. 733 and the Standards Committee request for research to support Project 2010-13.3. Therefore, the SPCS provided recommendations for applicability and requirements that can be used if NERC chooses to develop a standard. The SPCS recommended that if a standard is developed, the most effective and efficient use of industry resources would be to limit applicability to protection systems on circuits where the potential for observing power swings has been demonstrated through system operating studies, transmission planning assessments, event analyses, and other studies, such as UFLS assessments, that have identified locations at which a system separation may occur.

Following the issuance of the PSRPS Report and prior to initiating standard development, NERC staff met with FERC staff to discuss the findings in the PSRPS Report in relation to its directive on creation of

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[3] Ibid.

[4] NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)

a stable power swings Reliability Standard. FERC staff acknowledged the work of the SPCS and agreed that it could be persuasive as technical support for the approach to the Reliability Standard to be developed. It was clear from this meeting that FERC staff was open to an approach designed by NERC and industry and that the expectation remained that the directive must be met. NERC staff proceeded with Project 2010-13.3 to design a Reliability Standard to meet the directive.

Summary of Changes to the Standard

Purpose Statement

The standard's purpose was revised from ensuring "relays do not trip" to "relays are expected to not trip" … in response to stable power swings during non-Fault conditions.

Applicability

The Reliability Coordinator and Transmission Planner were removed from the standard to address concerns about overlap and potential gaps when identifying Elements.

Applicability for the Generator Owner and Transmission Owner was augmented to refer to an appended "Attachment A" which describes load-responsive protective relays that are included in the standard and associated exclusions.

Requirements

Requirement R1 was revised substantively to remove the Reliability Coordinator and Transmission Planner functions. The drafting team concurred that having the Planning Coordinator as the single source for identifying Elements prevents potential duplication of work and a possible gap should an entity believe another is making the identification and notification. The Requirement now allows a full calendar year to notify the respective Generator Owner and Transmission Owner of an identified Element. This was done to eliminate the burden of providing notification each January. The following describes the changes made to each of the original four criteria including the addition of a fifth criterion.

1. Added "angular" to clarify that this is not referring to other constraints such as voltage. Also replaced "Special Protection System (SPS)" with "Remedial Action Scheme (RAS)" to comport with expected changes to these NERC defined terms.
2. Clarified that criterion 2 applies only to "monitored" Elements of a System Operating Limit (SOL). Also, added "angular" to clarify that this is not referring to other constraints such as voltage.

3. Revised the "islanding" criterion to remove ambiguity about islands that formed during planning assessments. Islanding is now associated with an Element that forms the boundary of an island due to angular instability within an underfrequency load shedding (UFLS) assessment. Also, added "angular" to clarify that this is not referring to other constraints such as voltage.
4. Replaced the term "Disturbance" with the phrase "simulated disturbance." because it generally refers to an actual and not simulated event. The lowercase term "disturbance" was considered to be consistent with the NERC TPL-001-4 Reliability Standard, but it was determined that its usage would continue to create questions so "simulated" was added. The phrase "stable or unstable" was inserted to clarify that both are applicable to power swings because the goal of the standard is to identify Elements susceptible to either.
5. This criterion was added as a mechanism to require the Planning Coordinator to continue identifying any Element that has been reported by a Generator Owner due to a stable or unstable power swing during an actual system Disturbance or by the Transmission Owner due to a stable or unstable power swing during an actual system Disturbance or islanding event. Reported Elements will continue to be identified by the Planning Coordinator until the Planning Coordinator determines the Element is no longer susceptible to power swings.

Requirement R2 was revised to remove the Generator Owner performance because the Generator Owner does not "island." Also, the January 1, 2003 date was removed due to industry confusion and concern about compliance with such a date and how enforcement would be handled should an entity not have good records. In order to maintain continuity of actual Disturbances and to raise awareness of power swing and islanding events, the Transmission Owner is required to report the affected Element to its Planning Coordinator. The only timeframe assigned to the Requirement is the notice to the Planning Coordinator of an Element that tripped due to a stable or unstable power swing. There is no requirement to review the Protection System operation as such activities are addressed by other NERC Reliability Standards.

Requirement R3 is a new requirement created from the previous Requirement R2 specifically for the Generator Owner. In order to maintain continuity of actual Disturbances and to raise awareness of power swing events, the Generator Owner is required to report the affected Element to its Planning Coordinator. The only timeframe assigned to the Requirement is the notice to the Planning Coordinator of an Element that tripped due to a stable or unstable power swing. There is no requirement to review the Protection System operation as such activities are addressed by other NERC Reliability Standards.

Requirement R4 (previously R3) has been substantially rewritten to eliminate multiple and varying activities such as, demonstrate, develop, and obtain agreement. The Requirement was further simplified to reference PRC-026-1 – Attachment B which contains the criteria for evaluating load-responsive protective relays by the Generator Owner and Transmission Owner. The timing for evaluating load-responsive protective relays, initially, is 12 full calendar month. As identified Elements are reported year after year, the Generator Owner and Transmission Owner are only required to re-evaluate its load-responsive protective relays applied on the terminals of the identified Element where the previous evaluation had not been performed in the last three calendar years. This reduced the burden to the entities over Draft 1. Note that the Implementation Plan period for Requirement R4 is 336 calendar months.

Requirement R5 was added to address the requirement for developing a Corrective Action Plan (CAP) that was contained in the previous Draft 1, Requirement R3.

Requirement R6 was previously R4 and only received comporting updates due to numbering changes.

PRC-026-1 – Attachment A

The PRC-026-1 – Attachment A was added to the standard due to reduce stakeholder confusion about what load-responsive protective relays are in scope and to provide specific exclusions. The attachment is referenced in the Applicability section of the standard.

PRC-026-1 – Attachment B

The PRC-026-1 – Attachment B was added to the standard to remove the "Criteria" for evaluating load-responsive protective relays from within the Requirement itself and provide it in an attachment for referencing by Requirement R4. Among other things, the criteria found in the attachment received these modifications:

1. The sending and receiving voltages were changed to 0.7 to 1.0 from 0 to 1.0 per unit. This increases the lens characteristic that the impedance characteristic (e.g., zone 2) must be completely contained within (Attachment B). It was determined that using the 0.7 per unit is not in conflict with other NERC Reliability Standards or accepted industry practice for setting protective relays.
2. In developing the lens characteristic formed in the impedance (R-X) plane that connects the endpoints of the total system impedance, the criteria now requires the "parallel transfer impedance" to be removed.
3. Although previously addressed within the standards' Application Guidelines, criteria as to whether the transient or sub-transient may be used are now specified. The criteria are further defined as the "saturated (transient or sub-transient) reactance. The option to use either transient or sub-transient is provided to entities because either will provide a lens characteristic that is sufficiently conservative to determine the relay's susceptibility to tripping in response to a stable power swing. Also, providing this option reduces the burden on entities from changing which value it uses when it is already using one or the other preset in software applications. Saturated reactances are specified since they result in lower system impedances. Most notable, this criterion now requires the "parallel transfer impedance" to be removed when using the criteria to determine the relay's susceptibility to tripping in response to a stable power swing.

4. The PRC-026-1 – Attachment B now includes an additional Criteria B which provides criteria for overcurrent-based protective relays. Like the original Criteria A for impedance-based relays, it uses the 120 degree system separation angle, all Elements in service, and saturated (transient or sub-transient) reactance. This criterion also requires the "parallel transfer impedance" to be removed.

The industry segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-Serving Entities
4 — Transmission-Dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	David Burke	Orange and Rockland Utilities Inc.	NPCC	3
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Québec TransÉnergie	NPCC	1
5.	Wayne Sipperly	New York Power Authority	NPCC	5
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Matt Goldberg	ISO - New England	NPCC	2
9.	Michael Jones	National Grid	NPCC	1
10.	Mark Kenny	Northeast Utilities	NPCC	1
11.	Christina Koncz	PSEG Power LLC	NPCC	5

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

12.	Helen Lainis	Independent Electricity System Operator	NPCC	2
13.	Alan MacNaughton	New Brunswick Power Corporation	NPCC	9
14.	Bruce Metruck	New York Power Authority	NPCC	6
15.	Ben Wu	Orange and Rockland Utilities Inc.	NPCC	1
16.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
17.	Robert Pellegrini	The United Illuminating Company	NPCC	1
18.	Si Truc Phan	Hydro-Québec TransÉnergie	NPCC	1
19.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
20.	Brian Robinson	Utility Services	NPCC	8
21.	Ayesha Sabouba	Hydro One Networks Inc.	NPCC	1
22.	Brian Shanahan	National Grid	NPCC	1

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2. Group	Sandra Shaffer	PacifiCorp						X				

N/A

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3. Group	Joe DePoorter	MRO NERC Standards Review Forum	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alice Ireland	Xcel Energy	MRO	1, 3, 5, 6
2.	Chuck Wicklund	Otter Tail Power		1, 3, 5
3.	Dan Inman	Minnkota Power Cooperative	MRO	1, 3, 5, 6
4.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
5.	Kayleigh Wilkerson	Lincoln Electric System	MRO	1, 3, 5, 6
6.	Jodi Jensen	WAPA	MRO	1, 6
7.	Joe DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6
8.	Ken Goldsmith	Alliant Energy	MRO	4
9.	Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5, 6
10.	Marie Knox	MISO	MRO	2
11.	Mike Brytrowski	Great River Energy	MRO	1, 3, 5, 6
12.	Randi Nyholm	Minnesota Power	MRO	1, 6
13.	Scott Nickels	Rochester Public Utilities	MRO	4
14.	Terry Harbour	MidAmerican	MRO	1, 3, 5, 6

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
15.	Tom Breene	Wisconsin Public Service	MRO	3, 4, 5, 6
16.	Tony Eddleman	Nebraska Public Power District	MRO	1, 3, 5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	Paul Haase	Seattle City Light	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Pawel Krupa	Seattle City Light	WECC	1
2.	Dana Wheelock	Seattle City light	WECC	3
3.	Hao Li	Seattle City Light	WECC	4
4.	Mike Haynes	Seattle City Light	WECC	5
5.	Dennis Sismaet	Seattle City Light	WECC	6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5.	Group	Joe Tarantino	SMUD/BANC	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Kevin Smith	BANC	WECC	1

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	Dennis Chastain	Tennessee Valley Authority	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	DeWayne Scott		SERC	1
2.	Ian Grant		SERC	3
3.	David Thompson		SERC	5
4.	Marjorie Parsons		SERC	6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Robert Rhodes	SPP Standards Review Group		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Bud Averill	Grand River Dam Authority	SPP	1
2.	Mo Awad	Westar Energy	SPP	1, 3, 5, 6
3.	Derek Brown	Westar Energy	SPP	1, 3, 5, 6
4.	Karl Diekevers	Nebraska Public Power District	MRO	1, 3, 5
5.	Don Hargrove	Oklahoma Gas & Electric	SPP	1, 3, 5
6.	Jonathan Hayes	Southwest Power Pool	SPP	2
7.	Brian Holmes	Nebraska Public Power District	MRO	1, 3, 5
8.	Stephanie Johnson	Westar Energy	SPP	1, 3, 5, 6

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

9.	Bo Jones	Westar Energy	SPP	1, 3, 5, 6
10.	Mike Kidwell	Empire District Electric	SPP	1, 3, 5
11.	Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6
12.	James Nail	City of Independence, MO	SPP	3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Wayne Johnson	Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	X		X		X	X				

N/A

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Group	Greg Campoli	ISO RTO Council Standards Review Committee		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Stephanie Monzon	PJM	RFC	2
2.	Charles Yeung	SPP	SPP	2
3.	Lori Spence	MISO	MRO	2
4.	Cheryl Moseley	ERCOT	ERCOT	2
5.	Matt Goldberg	ISONE	NPCC	2
6.	Ben Li	IESO	NPCC	2
7.	Ali Miremadi	CAISO	WECC	2

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	Mike Garton	Dominion	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Louis Slade	Dominion	RFC	5, 6
2.	Randi Heise	Dominion	NPCC	6
3.	Connie Lowe	Dominion	SERC	5, 6
4.	Larry Nash	Dominion	SERC	1, 3
5.	Chip Humphrey	Dominion	SERC	5
6.	Jeffrey Bailey	Dominion	NPCC	5

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
11.	Group	Jason Marshall	ACES Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Shari Heino	Brazos Electric Power Cooperative	ERCOT	1, 5
2.	Mark Ringhausen	Old Dominion Electric Cooperative	RFC	3, 4
3.	Scott Brame	North Carolina Electric Membership Corporation	SERC	1, 3, 4, 5
4.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
5.	Brian Hobbs	Western Farmers Electric Cooperative	SPP	1, 5
6.	Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
7.	Bernard Johnson	Oglethorpe Power Cooperative	SERC	5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12.	Group	Richard Hoag	FirstEnergy Corp.	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	William Smith	FirstEnergy Corp	RFC	1
2.	Cindy Stewart	FirstEnergy Corp	RFC	3
3.	Doug Hohlbaugh	Ohio Edison	RFC	4
4.	Ken Dresner	FirstEnergy Solutions	RFC	5
5.	Kevin Querry	FirstEnergy Solutions	RFC	6
6.	Richard Hoag	FirstEnergy Corp	RFC	NA
7.	Brian Orians	FirstEnergy Solutions	RFC	NA
8.	Rusty Loy	FirstEnergy Solutions	RFC	NA
9.	Dave Barber	FirstEnergy Corp	RFC	NA

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13.	Group	Mike O'Neil	Florida Power & Light	X									

N/A

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
14.	Group	Brent Ingebrigtson	PPL NERC Registered Affiliates	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Charlie Freibert	LG&E and KU Energy, LLC	SERC	3
2.	Brenda Truhe	PPL Electric Utilities Corporation	RFC	1
3.	Annette Bannon	PPL Generation, LLC	RFC	5
4.		PPL Susquehanna, LLC	RFC	5

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
5.		PPL Montana, LLC	WECC	5
6.	Elizabeth Davis	PPL EnergyPlus, LLC	MRO	6
7.			NPCC	6
8.			RFC	6
9.			SERC	6
10.			SPP	6
11.			WECC	6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
15.	Group	Michael Lowman	Duke Energy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Doug Hils		RFC	1
2.	Lee Schuster		FRCC	3
3.	Dale Goodwine		SERC	5
4.	Greg Cecil		RFC	6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
16.	Group	Patricia Robertson	BC Hydro	X									

	Additional Member	Additional Organization	Region	Segment Selection
1.	Venkataramakrishnan Vinnakota	BC Hydro	WECC	2
2.	Pat G. Harrington	BC Hydro	WECC	3
3.	Clement Ma	BC Hydro	WECC	5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
17.	Group	Tom McElhinney	JEA	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ted Hobson		FRCC	1
2.	Garry Baker		FRCC	3
3.	John Babik		FRCC	5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
18.	Group	Frank Gaffney	Florida Municipal Power Agency	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Tim Beyrle	City of New Smyrna Beach	FRCC	4
2.	Jim Howard	Lakeland Electric	FRCC	3
3.	Greg Woessner	Kissimmee Utility Authority	FRCC	3

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

4. Lynne Mila	City of Clewiston	FRCC	3
5. Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4
6. Randy Hahn	Ocala Utility Services	FRCC	3
7. Stanley Rzad	Keys Energy Services	FRCC	1
8. Don Cuevas	Beaches Energy Services	FRCC	1
9. Mark Schultz	City of Green Cove Springs	FRCC	3

				1	2	3	4	5	6	7	8	9	10
19.	Group	Kathleen Black	DTE Electric			X	X	X					

Additional Member	Additional Organization	Region	Segment Selection
1. Kent Kujala	NERC Compliance	RFC	3
2. Daniel Herring	NERC Training & Standards Development	RFC	4
3. Mark Stefaniac	Regulated Marketing	RFC	5
4. David Szulczewski	DO SEE Relay Engineering		

				1	2	3	4	5	6	7	8	9	10
20.	Group	Kaleb Brimhall	Colorado Springs Utilities	X		X		X	X				

N/A

				1	2	3	4	5	6	7	8	9	10
21.	Group	Eleanor Ewry	Puget Sound Energy	X				X					

Additional Member	Additional Organization	Region	Segment Selection
1. Denise Lietz	Puget Sound Energy	WECC	1
2. Lynda Kupfer	Puget Sound Energy	WECC	5
3. Mariah Kennedy	Puget Sound Energy	WECC	3

				1	2	3	4	5	6	7	8	9	10
22.	Group	Andrea Jessup	Bonneville Power Administration	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Jim Burns	Technical Operations	WECC	1
2. Jim Gronquist	Transmission Planning	WECC	1

				1	2	3	4	5	6	7	8	9	10
23.	Group	Janet Smith	Arizona Public Service Co.	X		X		X	X				

N/A

				1	2	3	4	5	6	7	8	9	10
24.	Group	Erika Doot	Bureau of Reclamation	X				X					

Additional Member	Additional Organization	Region	Segment Selection
1. Rick Jackson		WECC	1

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
25.	Individual	Steve Wickel	CHPD - Public Utility District No. 1 of Chelan County	X		X		X					
26.	Individual	Rick Terrill	Luminant Generation Company LLC					X					
27.	Individual	Michelle R. D'Antuono	Ingleside Cogeneration LP					X					
28.	Individual	Venona Greaff	Occidental Chemical Corporation							X			
29.	Individual	John Seelke	Public Service Enterprise Group	X		X		X	X				
30.	Individual	Jared Shakespeare	Peak Reliability	X									
31.	Individual	Daniel Duff	Liberty Electric Power					X					
32.	Individual	Mauricio Guardado	Los Angeles Department of Water and Power	X		X		X	X				
33.	Individual	Brenda Hampton	Luminant Energy Company, LLC						X				
34.	Individual	Ayesha Sabouba	Hydro One	X		X							
35.	Individual	Frederikc R Plett	Masschusetts Attorney General								X		
36.	Individual	Rob Robertson	First Wind					X					
37.	Individual	Ronnie C. Hoeinghaus	City of Garland	X		X							
38.	Individual	Terry Harbour	MidAmerican Energy Company	X									
39.	Individual	Kayleigh Wilkerson	Lincoln Electric System	X		X		X	X				
40.	Individual	Thomas Foltz	American Electric Power	X		X		X	X				
41.	Individual	Chris de Graffenried	Consolidated Edison, Inc.	X		X		X	X				
42.	Individual	Cheryl Moseley	Electric Reliability Council of Texas, Inc.		X								
43.	Individual	Amy Casuscelli	Xcel Energy	X		X		X	X				
44.	Individual	Andrew Z. Pusztai	American Transmission Company, LLC	X									
45.	Individual	Jo-Anne Ross	Manitoba Hydro	X		X		X	X				
46.	Individual	Mark Wilson	Independent Electricity System Operator		X								

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
47.	Individual	David Kiguel	David Kiguel								X		
48.	Individual	Richard Vine	California ISO		X								
49.	Individual	Chris Mattson	Tacoma Power	X		X	X	X	X				
50.	Individual	David Jendras	Ameren	X		X		X	X				
51.	Individual	Scott Langston	City of Tallahassee	X									
52.	Individual	Bob Thomas	Illinois Municipal Electric Agency				X						
53.	Individual	Bill Fowler	City of Tallahassee			X							
54.	Individual	John Pearson	ISO New England		X								
55.	Individual	Chris Scanlon	Exelon	X		X	X	X	X				
56.	Individual	Shivaz Chopra	New York Power Authority	X		X		X	X			X	
57.	Individual	Roger Dufresne	Hydro-Québec Production					X					
58.	Individual	Gul Khan	Oncor Electric Delivery LLC	X									
59.	Individual	Glenn Pressler	CPS Energy	X		X		X					
60.	Individual	Karin Schweitzer	Texas Reliability Entity										X
61.	Individual	Michael Moltane	ITC	X									
62.	Individual	Thomas Standifur	Austin Energy	X		X		X					
63.	Individual	Bill Temple	Northeast Utilities	X									
64.	Individual	Jonathan Meyer	Idaho Power Co.	X									
65.	Individual	Patrick Farrell	Southern California Edison Company	X		X		X	X				
66.	Individual	Russell Noble	Public Utility District No. 1 of Cowlitz County, WA			X	X	X					
67.	Individual	Melissa Kurtz	US Army Corps of Engineers					X					
68.	Individual	Anthony Jablonski	ReliabiltiyFirst										X
69.	Individual	Joshua Andersen	Salt River Project	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
70.	Individual	Kenneth A Goldsmith	Alliant Energy				X						
71.	Individual	David Dockery	Associated Electric Cooperative, Inc.	X		X		X					

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Summary Consideration: The drafting team appreciates the entities below supporting the comments of others. Having single sets of comments with documented support greatly improves the efficiency of the standard drafting team (SDT). This format also ensures the drafting team has a clearer picture of the number of stakeholders supporting the same concerns or suggestions as the case may be.

Organization	Agree	Supporting Comments of “Entity Name”
Ameren	Agree	Public Service Enterprise Group (PSEG)
City of Garland	Agree	Public Service Enterprise Group - comments submitted by John Seelke
City of Tallahassee	Agree	FMPA
City of Tallahassee	Agree	FMPA
Colorado Springs Utilities	Agree	Public Service Enterprise Group and Florida Municipal Power Agency
CPS Energy	Agree	FMPA and PSEG
First Wind	Agree	PSEG Fossil, T.J. Kucey
Hydro One	Agree	NPCC-RSC
Hydro-Québec Production	Agree	NPCC and Hydro-Québec TransÉnergie

Organization	Agree	Supporting Comments of "Entity Name"
Illinois Municipal Electric Agency	Agree	Florida Municipal Power Agency, and Public Service Enterprise Group
JEA	Agree	FMPA
Luminant Energy Company, LLC	Agree	Luminant Generation Company, LLC (Rick Terrill)
New York Power Authority		NPCC RSC Committee
Occidental Chemical Corporation	Agree	Ingleside Cogeneration, LP
Seattle City Light		Sacramento Municipal Utility District (SMUD)
Tacoma Power		PSEG
US Army Corps of Engineers	Agree	MRO NSRF
Xcel Energy	Agree	Public Service Enterprise Group (PSEG)

1. Do you agree with the focused approach using the criteria (see R1 & R2) which came from recommendations in the PSRPS technical document (pg. 21 of 61)? If not, please explain why or why not (e.g., the approach should be more narrow or more broad, and if so, the basis for a different approach).

Summary Consideration: More than half of the 177 commenter disagreed with various aspects of the approach to the standard. The following lists the chief concerns that resulted in changes to the standard and those that did not.

<u>Comments that resulted in a change to the standard:</u>
There were 17 comments from 58 individuals that were concerned about the initial burden of evaluating load-responsive protective relays. To address this, the drafting team increased the Implementation Plan to 36 calendar months for Requirement R4 to provide for the initial influx of identified Elements under Requirement R1. The evaluation of relays under Requirement R4 (previously R3) is to be performed "within 12 full calendar months of receiving notification of an Element … where the evaluation has not been performed in the last three calendar years." The Implementation Plan provides an initial 36 calendar months from approval. Ten comments from 39 stakeholders were concerned about how the term "credible" would be interpreted. The term "credible" was removed from the standard. Requirement R1, Criterion 3 was clarified by framing the criterion in the present tense to refer to current assessment(s). The term "credible" was also removed from the previous Requirement R2 (and new R3) because the required performance should only refer to only current actual events.
Four significant issues were raised in Requirement R1 and its Criterion. First, there were five comments from 36 individuals that requested clarity as to what "stability constraint" meant. To clarify this issue the term "angular" was added to "stability constraint" to clarify the intent in Requirement R1, both Criterion 1 and 2. Second, there were five comments from 38 stakeholders questioning if "power swings" meant both "stable" and "unstable" power swings. Requirement R1 – Criterion 4, Requirement R2 – Criterion 1, and the new Requirement R3 – Criterion 1, were clarified by adding both "stable and unstable" to the power swings language. Both stable and unstable power swings determine whether an Element will be identified as being affected by a power swing. Four comments supported by 13 individuals believed the term "associated" was not clear; therefore, the term "associated" was removed and the criteria was clarified that the Element is the "monitored" Element. Last, there were three comments from 11 stakeholders that were concerned about how to apply Requirement R1, Criterion 3. Because of this, Requirement R1, Criterion 3 was revised include island boundaries due to angular instability within an underfrequency load shedding (UFLS) assessment. Additionally, the Generator Owner function was moved from Requirement R2 to the new Requirement R3 in order to remove the "islanding" criteria for Generator Owners.

<u>Comments that did not result in a change to the standard</u>:
There were 21 comments from 58 stakeholders for varying reasons that a standard was not necessary with the primary reason being based on the conclusions of the technical report by the NERC System Protection and Control Subcommittee called *Protection System Response to Power Swings*, August 2013 (PSRPS Report). To address this concern and the need for a standard, the drafting team prepared information found at the beginning

of this document called, “NERC Discussion on Proceeding(s) and Directives Regarding: Stable Power Swings” for a complete background. The drafting team understands that NERC staff re-engaged FERC staff following the completion of the PSRPS Report and that the Commission still desired NERC to pursue its work to meet the directive. However, FERC staff was open to an approach designed by NERC. NERC staff has informally received positive feedback on the narrow approach to address the regulatory directive. The directive itself was challenged by commenters prior to the issuance of Order No. 733 and was already the subject of multiple rehearing requests in the Order No. 733-A and Order No. 733-B proceedings. Similar arguments to the conclusions of the NERC System Protection and Control Subcommittee were advanced in these FERC proceedings.
Five comments by 34 individuals questioned the use of a System Operating Limit (SOL) in Requirement R1, Criterion 2 to determine Elements that needed evaluation because they were not necessarily associated with wide-area problems. The drafting team contends that not only SOLs that have been shown to expose a widespread area to instability, uncontrolled separation(s) or cascading outages should be considered. Identified localized instability issues also point to Elements that should reduce the likelihood of tripping for stable power swings. There were four comments by 18 individual that believe the standard required the inclusion of protective relay models. The standard does not require the inclusion of relay models. Requirement R1 – Criterion 4 is not requiring a study, but the identification of any Element that was observed as tripping in the most recent Planning Assessment.

Organization	Yes or No	Question 1 Comment
Northeast Power Coordinating Council	No	We agree with a focused approach as outlined in the technical document. However, we have the following serious concerns with criteria in the requirements: 1. The term “credible event” should be clearly defined. The basis to determine a credible event is missing from the requirement and application guide. This basis should be provided in the standard requirement. Response: The term “credible” has been removed from the standard. The drafting team clarified Requirement R1, Criterion 3 by framing the criterion in the present tense to refer to current assessment(s). The term “credible” was removed from the previous Requirement R2 (and new R3) because the required performance refers to only current actual events. Change made. 2. Why is the standard focused on SOL rather than IROL? The basis for specifying SOL is not supported by the example in the application guideline since the example did not show inter-area impact. Response: Several commenters questioned the use of a System Operating Limit (SOL) to determine Elements that needed evaluation because they were not necessarily associated with wide-area problems.

Organization	Yes or No	Question 1 Comment
		The drafting team contends that not only SOLs that have been shown to expose a widespread area to instability, uncontrolled separation(s) or cascading outages should be considered. Identified localized instability issues also point to Elements that should reduce the likelihood of tripping for stable power swings. No change made. 3. It is not clear in R1, criteria number 4 whether the assessment should include relay tripping or just stable power swing or both stable and unstable power swing. Response: Requirement R1 – Criterion 4, Requirement R2 – Criterion 1, and the new Requirement R3 – Criterion 1, were clarified by adding both “stable and unstable” power swings. Both stable and unstable power swings determine whether an Element will be identified as experiencing a power swing. Change made. 4. In R2, it is unrealistic to require an entity to provide data on an Element that had tripped since 2003. There is no existing NERC continent-wide disturbance monitoring or misoperation standard that requires data be retained more than 12 months. We recommend that this requirement be removed from the standard or include only Elements that were tripped in the last calendar year. Response: The “January 1, 2003” date has been removed from the standard. Requirement R2 (and new R3) are based on actual Disturbances that occur after the Effective Date of the standard. Change made. It must be noted that the standard is unsupported by the Protection System Response to Power Swings, System Protection and Control Subcommittee, August, 2013 document. Referring to p. 20, the “Need for a Standard” section, states “Based on its review of historical events, consideration of the trade-offs between dependability and security, and recognizing the indirect benefits of implementing the transmission relay loadability standard (PRC-023), the SPCS concludes that a NERC Reliability Standard to address relay performance during stable swings is not needed, and could result in unintended adverse impacts to Bulk-Power System reliability.” (Emphasis added). Response: The “January 1, 2003” date has been removed from the standard. Requirement R2 (and new R3) are based on actual Disturbances that occur after the Effective Date of the standard. Change made.

Organization	Yes or No	Question 1 Comment
		The following report references support the PSRPS document's conclusion that this standard is not needed: 1) Page 8 of 61, 1965 Northeast Blackout Conclusion, first sentence "Relays tripping due ..." 2) Page 8 of 61, 1977 New York Blackout Conclusions, first sentence, "Relays tripping due..." 3) Page 9 of 61, July 2-3, 1996: West Coast Blackout Conclusions, first sentence "Relays tripping due..." 4) Page 10 of 61, August 10, 1996 Conclusions, first sentence, "Relays tripping due..." 5) Page 16 of 61, 2003 Northeast Blackout Conclusion, "Relays tripping due..." 6) Page 17 of 61, Overall Observations from Review of Historical Events, first and second sentences, "Relays tripping..." 7) Page 19 of 61, final paragraph, "Given the ...."NERC's informational filing in Docket No. RM08-13-000 dated July 21, 2011 concluded that there is a need for a standard on stable power swings. The subsequently developed PSRPS document, which was developed by industry experts and approved by the NERC Planning Committee, clearly refutes the FERC directive in Order No. 773 (Docket No. RM08-13-000), that was subsequently affirmed in Order Nos. 773-A and 773-B, that a standard is needed to ensure that load-responsive protective relays do not trip in response to stable power swings during non-Fault conditions. We recommend that the NERC Standards Committee explore means to utilize the more recent PSRPS document to obtain relief from the aforementioned FERC directive that is driving this project. Response: Please see the section at the beginning of this document called, "NERC Discussion on Proceeding(s) and Directives Regarding: Stable Power Swings" for a complete background. The SDT understands that NERC staff re-engaged FERC staff following the completion of the PSRPS Report and that the Commission still desired NERC to pursue its work to meet the directive. However, FERC staff was open to an approach designed by NERC. NERC staff has informally received positive feedback on the approach to address the regulatory directive. The directive itself was challenged by commenters prior to the

Organization	Yes or No	Question 1 Comment
		issuance of Order No. 733 and was already the subject of multiple rehearing requests in the Order No. 733-A and Order No. 733-B proceedings. Similar arguments to the conclusions of the NERC System Protection and Control Subcommittee were advanced in these FERC proceedings.
SMUD/BANC	No	(1) Collected data and subsequent analysis has not identified tripping during stable power swings. This phenomenon is rare if at all. Any tripping during stable power swings would more appropriately included as a mis-operation and addressed as such. Response: Please see the section at the beginning of this document called, “NERC Discussion on Proceeding(s) and Directives Regarding: Stable Power Swings” for a complete background. The SDT understands that NERC staff re-engaged FERC staff following the completion of the PSRPS Report and that the Commission still desired NERC to pursue its work to meet the directive. However, FERC staff was open to an approach designed by NERC. NERC staff has informally received positive feedback on the approach to address the regulatory directive. The directive itself was challenged by commenters prior to the issuance of Order No. 733 and was already the subject of multiple rehearing requests in the Order No. 733-A and Order No. 733-B proceedings. Similar arguments to the conclusions of the NERC System Protection and Control Subcommittee were advanced in these FERC proceedings. (2) The requirement R2 is particularly unacceptable as it requires data for pre June 18, 2007; effective date of Order 693 standards. Response: The “January 1, 2003” date has been removed from the standard. Requirement R2 (and new R3) are based on actual Disturbances that occur after the Effective Date of the standard. Change made.
ISO RTO Council Standards Review Committee	No	Conditions (2) and (3) are unclear. Condition (2) stipulates that the responsible entity notify the facility owner of an Element that is associated with a System Operating Limit (SOL) that has been established based on stability constraints. It’s not clear whether the Element is the contingent Element or the monitored Element or both. This needs to be clarified/specified in the standard/requirement.

Organization	Yes or No	Question 1 Comment
		Response: For Requirement R1, Criterion 2, the drafting team removed the term "associated" and revised the criteria to clarify that the Element is the "monitored" Element. Change made. Condition (3) stipulates that the responsible entity notify the facility owner of an Element that has formed the boundary of an island within an angular stability planning simulation where the system Disturbance(s) that caused the islanding condition continues to be a credible event. The term "credible event" is hard to determine since the Disturbance could be caused by one of those events listed in the TPL standards, or could be one that is beyond those listed, such as natural phenomena. We realize that the Application Guideline provides some general guidance on assessing the credibility of a Disturbance, but we do not agree that a Disturbance is no longer credible when it is deemed no longer capable of occurring in the future due to actual changes to the BES. Changes to the BES may reduce the possibility of the same Disturbance, but such Disturbances (e.g. loss of right of way or an entire station) may still occur due to other means. If the SDT should continue to hold the position that the criteria for excluding a Disturbance is that BES changes are made to mitigate (but not totally eliminate) the recurrence, then it should be clearly stated in the requirement itself. In short, the basis with which to deem a Disturbance "credible" is missing from the requirements, which needs to be provided/clarified in the standard/requirement. Response: The term "credible" has been removed from the standard. The drafting team clarified Requirement R1, Criterion 3 by framing the criterion in the present tense to refer to current assessment(s). The term "credible" was removed from the previous Requirement R2 (and new R3) because the required performance refers to only current actual events. Change made.
ACES Standards Collaborators	No	(1) This requirement needs to be further clarified that it is not intended to require additional studies. Rather, the TP, PC and RC are to identify the information in bullets 1 through 4 based on their existing knowledge and studies. Response: Requirement R1 sufficiently conveys that no new or additional studies are required. Additional clarification has been added to the Guidelines and Technical Basis. Change made.

Organization	Yes or No	Question 1 Comment
		(2) Part 2 needs further clarification regarding which SOLs should be applied. Are the SOLs established from the planning horizon per FAC-010-2.1 or the SOLs established in the operating horizon per FAC-011-2 applicable? We recommend that only SOLs from the operating horizon should be applied because the SOLs from the planning horizon may include the impact of proposed or retired facilities which could result in unnecessary relay modifications or miss necessary relay modifications. Response: Requirement R1, Criterion 1 and 2 address operating limits associated with angular stability limits; therefore, System Operating Limits (SOL) specified in Requirement R1, Criterion 2 includes both operations and planning horizons. In the event that a Corrective Action Plan (CAP) is necessary based on future system conditions, the CAP can specify a timeframe that does not enact changes until those system conditions require modification. An example has been added to clarify this scenario in the Guidelines and Technical Basis. Change made. (3) Requirement R1 as a whole is problematic because it is based partly on planning studies. Planning studies include proposed system additions and retirements which could result in the identification of unnecessary relay modifications or a failure to identify necessary relay modifications. Response: In the event that a Corrective Action Plan (CAP) is necessary based on future system conditions, the CAP can specify a timeframe that does not enact changes until the actual system modifications have occurred. No change made. (4) R1 should be split based on responsibilities. Some of the bullets should apply to only one entity. For example, an RC is required to monitor the status of Special Protection Systems per IRO-005-3.1a R1.1. The RC would also have to be aware of generating plant stability constraints. Thus, the RC could provide all of the information for bullet 1. Bullets 3 and 4 are based on planning studies and should only apply to the Planning Coordinator. If only SOLs from the operating horizon are to be evaluated, then bullet 2 should only apply to the RC. Response: The Reliability Coordinator and Transmission Planner have been removed from the standard's Applicability; therefore, Requirement R1 is now only applicable to the Planning Coordinator as a single entity source of identifying Elements. The drafting team asserts that the Planning Coordinator has or has

Organization	Yes or No	Question 1 Comment
		access to the knowledge including the wide-area view. Change made to the Requirement. (5) Part 2 should be modified to limit application to IROLs and not all stability related SOLs. By definition, if an SOL is stability related and is not an IROL, it cannot have a wide area impact on reliability and is limited to local reliability. If it had a wide area impact, it would cause "instability, uncontrolled separation or Cascading outages that adversely impact the reliability of the Bulk Electric System" and would be an IROL. Response: Several commenters questioned the use of a System Operating Limit (SOL) to determine Elements that needed evaluation because they were not necessarily associated with wide-area problems. The drafting team contends that not only SOLs that have been shown to expose a widespread area to instability, uncontrolled separation(s) or cascading outages should be considered. Identified localized instability issues also point to Elements that should reduce the likelihood of tripping for stable power swings. No change made. (6) Part 4 is problematic because it now requires relay tripping to be evaluated in transient studies performed by the Planning Coordinator and Transmission Planner. These entities may not include all relays in their studies but this part creates a de facto requirement for them to include all relays. Otherwise, how can a PC or TP determine if relay tripping would occur? Response: The drafting team asserts that the standard does not require the inclusion of relay models. Requirement R1 – Criterion 4 is not requiring a study, but the identification of any Element that was observed as tripping in the most recent Planning Assessment. No change made. (7) The language of the requirement needs to be clarified that the TP, PC and RC are to only identify elements in their area. This could be accomplished by adding "in its area" after "each Element." Response: The drafting team clarified that the responsible entity is to identify Elements in its area. Change made. (8) The format of the sub-part numbering does not follow the convention that NERC established several years ago and notified the Commission that it would use for sub-parts. When all sub-parts are required then they are to be numbered. When only one sub-part is requirement (i.e. one of the list has to be

Organization	Yes or No	Question 1 Comment
		selected), they are to be bulleted. The draft appears to stray because of the language "one or more" in the main requirement. In other words, one item could be met or more than one. However, we argue that bullets should be used because while more than one could apply, if one applies the Element is to be identified by the PC, TP, or RC. There is no additional need for any tests once one is met. Thus each Element will only be identified as meeting one of the bullets because that means it qualifies even though it could meet more than one. Response: The NERC convention for use of bullets and numbering is for identifying which items are "options" and which items are "all-inclusive:" however, in the use of criteria a numbered list (i.e., not using sub-part conventions) is acceptable. No change was made based on the comment. (9) Why can't the islanding evaluation conducted per PRC-006-1 R1 be used as the basis for identifying Elements rather than writing a new bullet 3 in the requirement? Response: The drafting team modified Requirement R1, Criterion 3 to include island boundaries due to angular instability within an underfrequency load shedding (UFLS) assessment. Also, the Generator Owner was moved from Requirement R2 to the new Requirement R3 in order to remove the "islanding" criteria for Generator Owners. Change made.
FirstEnergy Corp.	No	FirstEnergy agrees with the focus approach using the criteria but has the following concern. It is understood that the "... since January 1, 2003" verbiage is intended to capture applicable relay operations during the Aug. 14, 2003 event. It will be difficult if not nearly impossible for a GO, especially in a deregulated environment, to piece together details of relay operations prior to record-keeping requirements for NERC PRC-004. We recommend that these Criteria be reworded to include only incidents which have occurred since the inception of NERC PRC-004. Response: The "January 1, 2003" date has been removed from the standard. Requirement R2 (and new R3) are based on actual Disturbances that occur after the Effective Date of the standard. Change made.
Duke Energy	No	(1) Based on the SPCS report stated below (dated August 2013), Duke Energy does not believe that adequate technical justification has been identified for this project to become a standard. The SDT and

Organization	Yes or No	Question 1 Comment
		NERC should consider moving this project to a Guideline document until such time as a standard is warranted. "Based on its review of historical events, consideration of the trade-offs between dependability and security, and recognizing the indirect benefits of implementing the transmission relay loadability standard (PRC-023), the SPCS concludes that a NERC Reliability Standard to address relay performance during stable power swings is not needed, and could result in unintended adverse impacts to Bulk-Power System reliability." Response: Please see the section at the beginning of this document called, "NERC Discussion on Proceeding(s) and Directives Regarding: Stable Power Swings" for a complete background. The SDT understands that NERC staff re-engaged FERC staff following the completion of the PSRPS Report and that the Commission still desired NERC to pursue its work to meet the directive. However, FERC staff was open to an approach designed by NERC. NERC staff has informally received positive feedback on the approach to address the regulatory directive. The directive itself was challenged by commenters prior to the issuance of Order No. 733 and was already the subject of multiple rehearing requests in the Order No. 733-A and Order No. 733-B proceedings. Similar arguments to the conclusions of the NERC System Protection and Control Subcommittee were advanced in these FERC proceedings. (2) Duke Energy does not agree with the criteria specified in R1 because sufficient tools have not been developed at this time for the industry to conduct the appropriate assessment and identification of the Elements in Criteria 4. However, if this project moves forward as a standard we suggest the following revision to Criteria 4: "4. An Element identified in the most recent Planning Assessment where relay tripping occurred as a result of a power swing during the simulated Disturbance. Generic modeling of relays is acceptable when conducting this initial Planning Assessment." This would provide the necessary flexibility until such a time as tools are developed to conduct a more accurate Planning Assessment and identification of Elements for Criteria 4. Response: The drafting team asserts that the standard does not require the inclusion of relay models.

Organization	Yes or No	Question 1 Comment
		Requirement R1 – Criterion 4 is not requiring a study, but the identification of any Element that was observed as tripping in the most recent Planning Assessment. No change made.
BC Hydro	No	Any approach should be based on experience with improper operation during stable power swings. If there has been no experience of undesired operation during stable power swings then checking against the criteria just results in fruitless work. Response: Please see the section at the beginning of this document called, "NERC Discussion on Proceeding(s) and Directives Regarding: Stable Power Swings" for a complete background. The SDT understands that NERC staff re-engaged FERC staff following the completion of the PSRPS Report and that the Commission still desired NERC to pursue its work to meet the directive. However, FERC staff was open to an approach designed by NERC. NERC staff has informally received positive feedback on the approach to address the regulatory directive. The directive itself was challenged by commenters prior to the issuance of Order No. 733 and was already the subject of multiple rehearing requests in the Order No. 733-A and Order No. 733-B proceedings. Similar arguments to the conclusions of the NERC System Protection and Control Subcommittee were advanced in these FERC proceedings. The drafting team asserts that the standard is proactively addressing the risk of load-responsive protective relays applied on Elements that are expected to have the greatest risk of exposure to power swings. The standard is based on guidance from the PSRPS Report and includes Elements that trip during future events. No change made.
Florida Municipal Power Agency	No	As recognized by the SCPS, the standard is not needed and will result in a reduction of reliability to the bulk-power system (see report of footnote 1, Chapter 3, section titled "Need for a Standard"). FMPA strongly agrees with the SCPS that it is better for bulk-power system reliability to bias the "Art of Protection" to enable the power system to separate for unstable power swings than to bias the art of protection to prevent operation for stable power swings since it is very difficult, if not impossible, to distinguish stable from unstable power swings. We ought to enable the power system to gracefully degrade for unstable events rather than cause entire Interconnections to become unstable. We cannot with accuracy pre-determine where the separation points are or ought to be since we cannot know in

Organization	Yes or No	Question 1 Comment
		advance where or what the cause of instability may occur. As such, having relays throughout the system that can cause separation as needed to prevent the entire Interconnection from going unstable is recommended. As such, and recognizing that we are directed to have a standard, the standard should not require PCs, RCs and TPs to identify that for every Element that meets the criteria of R1, something needs to be done (which is implied in R3). Rather, the PC, RC and TP ought to have discretion as to whether they want a potential issue resolved or not within R1. That is, the PC, RC and TP should have discretion as to whether to bias the performance towards separation for unstable power swings (graceful degradation for instability, but possibly contribute to cascading for stable power swings - although there is no evidence of the latter from past events), or bias the performance to prevent operation for stable power swings (which would have a tendency to cause blackouts to be greater in magnitude, but possibly reduce the risk of cascading for stable power swings, although there is no evidence of the latter), noting that there is no dependable way to distinguish between stable and unstable power swings. As such, the PC, RC and TP ought to be able to identify a subset of Elements that meet the criteria of R1 that would then be analyzed in R2 and R3. Response: The drafting team asserts that it has implemented an approach consistent with the recommendations of the NERC System Protection and Control Subcommittee (SPCS) technical report, *Protection System Response to Power Swings*, August 2013[5] (PSRPS Report). The standard does not preclude the Planning Coordinator providing information to the Generator Owner or Transmission Owner about the Element and any known stability issues, power swings, or apparent impedance characteristics; however, the Elements need to be reported as a part of ensuring the Generator Owner and Transmission Owner are aware of Elements that are susceptible. Modifications were made to have only the Planning Coordinator identify Elements and in Requirement R5 to have the Generator Owner and Transmission Owner develop a Corrective Action Plan to meet the criteria PRC-026-1 – Attachment B while maintaining

[5] NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)

Organization	Yes or No	Question 1 Comment
		dependable fault detection and dependable out-of-step tripping. The drafting team asserts protective relays that meet the PRC-026-1 – Attachment B criteria are expected to not trip during stable power swings. Change made. Note also that "Element" is the wrong term and "Facility" should be used. "Element" applies to both BES and non-BES (including distribution), Facilities is BES. Standards cannot be written to distribution. Response: Section 4.2, Facilities provides sufficient language that the standard is applicable to only "BES Elements." No change made to the standard based upon the comment.
Puget Sound Energy	No	For systems that have not experienced a power swing that caused a trip or islanding condition, there is the burden of proving the negative to demonstrate compliance with the standard. It is recommended that Requirement R2 be rewritten in such a way that entities will not have to prove the negative. Response: The drafting team contends it is up to the entity to certify that no trips occurred due to stable or unstable power swings during audit period. The intent is not for an entity to prove the negative, but for an entity to certify that no Elements met the criteria in Requirement R2.No Change made. It is also recommended that the standard be revised to address the situation where historical data is not avaialable as far back as 2003. We also request that a NERC definition be provided for what constitutes a stable power swing and what criteria can be applied to historical data to determine if a stable power swing has occurred. Response: The "January 1, 2003" date has been removed from the standard. Requirement R2 (and new R3) are based on actual Disturbances that occur after the Effective Date of the standard. Change made.
Bonneville Power Administration	No	BPA agrees with the approach, with two exceptions. First, BPA feels more clarity is needed regarding which Elements are associated with System Operating Limits (SOLs), relevant to the Standard. Stability constraints can depend on the overall topology of the system, in which case nearly every Element in the power system would meet the criteria of item 2. For example, BPA may determine a stability constraint on WECC Path 66 due to poorly damped oscillations.

Organization	Yes or No	Question 1 Comment
		Taking almost any 500 kV or 345 kV line out of service on the western side of WECC could change the value of this limit, in which case all of these Elements meet the criteria of item 2. BPA suggests the language be changed to: 2. An Element that has been shown to have a substantial effect on a System Operating Limit (SOL) that has been established based on stability constraints identified in system planning or operating studies (including line-out conditions.) **Response: For Requirement R1, Criterion 2, the drafting team removed the term "associated" and revised the criteria to clarify that the Element is the "monitored" Element. Change made.** Secondly, BPA feels the Glossary definition of Disturbance lacks sufficient clarity as it relates to this and other existing Standards. **Response: The drafting team revised Requirement R1, Criterion 4 by changing "Disturbance" to "simulated disturbance" to comport with the approved Reliability Standard TPL-001-4. The use of "Disturbance" in Requirements R2 (TO) and R3 (GO) relates to an actual system disturbance. Change made.**
Luminant Generation Company LLC	No	The focused approach is too narrow for Generation Owners in that it restricts to the Transmission Planner and Generation Owner to events that have occurred and not a Planning Assessment transient stability study results that indicate load responsive relay operation is challenged. Item #4 in Requirement R1 may not capture all power system swings since it is focused on previous events. Luminant recommends that the Transmission Planner be responsible for transient stability studies and reporting the information to the Generation Owner for locations where load responsive relays are challenged. **Response: The drafting team revised Requirement R1, Criterion 4 by changing "Disturbance" to "simulated disturbance" to comport with the approved Reliability Standard TPL-001-4. The use of "Disturbance" in Requirements R2 (TO) and R3 (GO) relates to an actual system disturbance. The Reliability Coordinator and Transmission Planner have been removed from the standard's Applicability; therefore, Requirement R1 is now only applicable to the Planning Coordinator as a single entity source of**

Organization	Yes or No	Question 1 Comment
		identifying Elements. The drafting team asserts that the Planning Coordinator has or has access to the knowledge including the wide-area view. Change made to the Requirement. The date of 2003 needs to be removed from the standard as it prefaces compliance on data that predates the approval of the standard. Response: The "January 1, 2003" date has been removed from the standard. Requirement R2 (and new R3) are based on actual Disturbances that occur after the Effective Date of the standard. Change made. Also, the Generation Owner and Transmission Owner (in cases where the Transmission Planner and Transmission Owner are not the same entity) do not have the tools to determine if the BES is configured such that a Disturbance event is still credible. Luminant believes that R2 criteria 1 and 2 need to be modified as follows: "1. An Element that load responsive relaying has tripped during the past calendar year due to a power swing during an actual system Disturbance. " "2. An Element that has formed the boundary of an island during the past calendar year during an actual system Disturbance." Response: The term "credible" has been removed from the standard. The drafting team clarified Requirement R1, Criterion 3 by framing the criterion in the present tense to refer to current assessment(s). The term "credible" was removed from the previous Requirement R2 (and new R3) because the required performance refers to only current actual events. Change made.
Ingleside Cogeneration LP	No	Ingleside Cogeneration LP ("ICLP") believes that the drafting team has generally captured the intent of FERC Order 733 by specifying the planning and operations criteria used to identify susceptible Elements. Clearly those load responsive relays that protect Elements that have a stability constraint or are tripped in response to a stable power swing should be in scope. However, we do not agree that those Elements that form the boundary of an island during planning assessments or as a result of an actual Disturbance should be subject to PRC-026-1.

Organization	Yes or No	Question 1 Comment
		Response: The drafting team removed the islanding requirement from the responsibility of the Generator Owner (now Requirement R3). The islanding criteria remains in Requirement R1 (Planning Coordinator) and the new Requirement R2 (Transmission Owner); therefore, keeping the standard approach consistent with the PSRPS Report recommendation. Change made. Our assertion is based upon a reading of the FERC directive in Order 733, which responds to a stakeholder suggestion that islanding strategies are a reasonable approach to limit the effect of a relay that improperly reacts to a stable power swing. Instead, the project team has interpreted the ruling as a means to identify susceptible Elements - adding an unnecessary burden to every relay owner and planner in the annual assessment process. In our view, the item should be re-positioned as a bullet point in R3, which allows the TO or GO to show that an islanding scheme sufficiently protects the greater BES against instability. This would be similar to the acknowledgement that power swing blocking limits the effect of a load relay trip - essentially another mitigation strategy that may be used address a situation where the relay settings themselves cannot be changed for some reason. Response: The drafting team contends that it followed the FERC directive to consider islanding strategies and simply includes the Elements that form the boundaries of islands to be evaluated with regard to tripping during stable power swings. The team contends that islanding strategies are developed to isolate the system from unstable power swings, which is still allowed under the proposed PRC-026-1. No change made.
Public Service Enterprise Group	No	The entire standard is unsupported by the PSRPS document. See p. 20 in the "Need for a Standard" section, which states "Based on its review of historical events, consideration of the trade-offs between dependability and security, and recognizing the indirect benefits of implementing the transmission relay loadability standard (PRC-023), THE SPCS CONCLUDES THAT A NERC RELIABILITY STANDARD TO ADDRESS RELAY PERFORMANCE DURING STABLE POWER SWINGS IS NOT NEEDED, AND COULD RESULT IN UNINTENDED ADVERSE IMPACTS TO BULK-POWER SYSTEM RELIABILITY." (Emphasis added by CAPITALIZATION.) See the specific report references below that support the PSRPS document's conclusion that this standard is not needed:

Organization	Yes or No	Question 1 Comment
		1) Page 8 of 61, 1965 Northeast Blackout Conclusion, first sentence “Relays tripping due ...” 2) Page 8 of 61, 1977 New York Blackout Conclusions, first sentence, “Relays tripping due...” 3) Page 9 of 61, July 2-3, 1996: West Coast Blackout Conclusions, first sentence “Relays tripping due...” 4) Page 10 of 61, August 10, 1996 Conclusions, first sentence, “Relays tripping due...” 5) Page 16 of 61, 2003 Northeast Blackout Conclusion, “Relays tripping due...” 6) Page 17 of 61, Overall Observations from Review of Historical Events, first and second sentences, “Relays tripping...” 7) Page 19 of 61, final paragraph, “Given the ....”The PSRPS document, developed by industry experts and approved by the NERC Planning Committee, clearly disputes the FERC directive in Order No. 773 (Docket No. RM08-13-000), that was subsequently affirmed in Order Nos. 773-A and 773-B, that a standard is needed to ensure that load-responsive protective relays do not trip in response to stable power swings during non-Fault conditions. NERC’s informational filing in Docket No. RM08-13-000 dated July 21, 2011 concluded that there is a need for a standard on stable power swings. This conclusion is the opposite of what the PSRPS document concluded. We recommend that the NERC Standards Committee explore means to utilize the more recent PSRPS document to obtain relief from the aforementioned FERC directive that is driving this project. Response: Please see the section at the beginning of this document called, “NERC Discussion on Proceeding(s) and Directives Regarding: Stable Power Swings” for a complete background. The SDT understands that NERC staff re-engaged FERC staff following the completion of the PSRPS Report and that the Commission still desired NERC to pursue its work to meet the directive. However, FERC staff was open to an approach designed by NERC. NERC staff has informally received positive feedback on the approach to address the regulatory directive. The directive itself was challenged by commenters prior to the issuance of Order No. 733 and was already the subject of multiple rehearing requests in the Order No. 733-A and Order No. 733-B proceedings. Similar arguments to the conclusions of the NERC System Protection and Control Subcommittee were advanced in these FERC proceedings.

Organization	Yes or No	Question 1 Comment
Los Angeles Department of Water and Power	No	LADWP opposes the criteria from Requirement 2 that proposed looking back on Elements since 2003. Requirements cannot be applied retroactively. Response: The "January 1, 2003" date has been removed from the standard. Requirement R2 (and new R3) are based on actual Disturbances that occur after the Effective Date of the standard. Change made.
Masschusetts Attorney General	No	R2 requires GOs and TOs to evaluate Disturbance records "since January 1, 2003," a time that will precede the effective date of this standard. A requirement cannot rely upon records that precede the effective date of a standard. Response: The "January 1, 2003" date has been removed from the standard. Requirement R2 (and new R3) are based on actual Disturbances that occur after the Effective Date of the standard. Change made.
MidAmerican Energy Company	No	The approach for R2 is incorrect. NERC standards cannot require compliance prior to the effective date of the standard itself. All references to 2003 should be deleted from the requirements and any guidance. Deleting the references to 2003 would make the requirement effective upon the effective date of the standard. Response: The "January 1, 2003" date has been removed from the standard. Requirement R2 (and new R3) are based on actual Disturbances that occur after the Effective Date of the standard. Change made.
Consolidated Edison, Inc.	No	We agree with a focused approach as outlined in the technical document. However, we have the following serious concerns with criteria in the requirements: 1. The term "credible event" should be clearly defined. The basis to determine a credible event is missing from the requirement and application guide. This basis should be provided in the standard requirement. Response: The term "credible" has been removed from the standard. The drafting team clarified Requirement R1, Criterion 3 by framing the criterion in the present tense to refer to current assessment(s). The term "credible" was removed from the previous Requirement R2 (and new R3) because the required performance refers to only current actual events. Change made.

Organization	Yes or No	Question 1 Comment
		2. Why is the standard focused on SOL rather than IROL? The basis for specifying SOL is not supported by the example in the application guideline since the example did not show inter-area impact. Response: Several commenters questioned the use of a System Operating Limit (SOL) to determine Elements that needed evaluation because they were not necessarily associated with wide-area problems. The drafting team contends that not only SOLs that have been shown to expose a widespread area to instability, uncontrolled separation(s) or cascading outages should be considered. Identified localized instability issues also point to Elements that should reduce the likelihood of tripping for stable power swings. No change made. 3. It is not clear in R1, criteria number 4 whether the assessment should include relay tripping or just stable power swing or both stable and unstable power swing. Response: Requirement R1 – Criterion 4, Requirement R2 – Criterion 1, and the new Requirement R3 – Criterion 1, were clarified by adding both “stable and unstable” power swings. Both stable and unstable power swings determine whether an Element will be identified as experiencing a power swing. Change made. 4. In R2, it is unrealistic to require an entity to provide data on an Element that had tripped since 2003. There is no existing NERC continent-wide disturbance monitoring or misoperation standard that requires data be retained more than 12 months. We recommend that this requirement be removed from the standard or include only Elements that were tripped in the last calendar year. Response: The “January 1, 2003” date has been removed from the standard. Requirement R2 (and new R3) are based on actual Disturbances that occur after the Effective Date of the standard. Change made.
Electric Reliability Council of Texas, Inc.	No	The time periods in the requirements are unnecessarily restrictive, particularly R1, which essentially requires the work to be done in January of each year. There does not appear to be a reliability reason to have the work completed in January as long as the GO and TO perform the necessary actions in R3 in a timely manner. We suggest taking an approach similar to PRC-023 R6. In this case R1 would begin: “Each Planning Coordinator, Reliability Coordinator, and Transmission Planner shall conduct an

Organization	Yes or No	Question 1 Comment
		assessment at least once each calendar year, with no more than 15 months between assessments…” R2 through R4 could use a similar approach. Response: The Requirement R1 language about “January of each calendar” has been removed and replaced with “each calendar year.” Based on time period changes in other Requirements, the drafting team determined that an annual periodicity in Requirement R1 is more appropriate. Change made. The identification of Elements in R1 seems to be unnecessarily redundant between the applicable entities for some criteria and inappropriate for other criteria. ERCOT suggests splitting R1 into two separate requirements based on the responsible entity: one requirement for the Planning Coordinator to identify elements per criteria 2, 3, and 4; and one requirement for the Reliability Coordinator to identify elements per criterion 1. The Transmission Planner should be removed from the Applicability of the standard, including removal from R3. Response: The Reliability Coordinator and Transmission Planner have been removed from the standard’s Applicability; therefore, Requirement R1 is now only applicable to the Planning Coordinator as a single entity source of identifying Elements. The drafting team asserts that the Planning Coordinator has or has access to the knowledge including the wide-area view. Change made to the Requirement.
Independent Electricity System Operator	No	The criteria used to limit the applicability of the transmission lines are unclear. Specifically, • Regarding Criteria 1 in Requirement 1, entities’ may employ SPS to avoid tripping of any Element for stable power swings under all normal recognized contingencies included in the TPL standards. Given that the SPS is used as a mitigation measure, should this proposed standard be applicable to those elements that are susceptible to trip for stable power swings, when a failure of the SPS is considered? Response: The drafting team contends that the Special Protection System (SPS) as stated in Requirement

Organization	Yes or No	Question 1 Comment
		R1 is in place to prevent angular instability. The standard does not address a failing SPS, but is addressing the Elements associated with an SPS that would be susceptible to a power swing. (Note: The use of SPS has been replaced with Remedial Action Scheme (RAS) for consistency with a current project to revise the definition of "Special Protection System"). No change made. • Similar to the above, for Criteria 2 in Requirement 1, entities' may establish an SOL to avoid tripping of any Element for stable power swings under all normal recognized contingencies included in TPL standards. Given that SOL is used as a mitigation measure, should those elements susceptible to trip for stable power swings, when the SOL is exceeded (and which is not allowed in normal operation conditions) be applicable to this proposed standard? Response: The drafting team contends that a System Operating Limit (SOL) as stated in Requirement R1 is in place to prevent angular instability. The standard addresses Elements associated with an SOL as an Element that would be susceptible to a power swing. No change made. • Requirement 1 stipulates that the responsible entity notify the facility owner of an Element that meets Criteria 2 (i.e., an Element associated with a System Operating Limit (SOL) that has been established based on stability constraints). It is not clear whether the Element is the contingent Element or the monitored Element or both. This needs to be clarified/specified in the standard/requirement. Response: For Requirement R1, Criterion 2, the drafting team removed the term "associated" and revised the criteria to clarify that the Element is the "monitored" Element. Change made. • Requirement 1 stipulates that the responsible entity notify the facility owner of an Element that meets Criteria 3 (i.e., has formed the boundary of an island within an angular stability planning simulation where the system Disturbance(s) that caused the islanding condition continues to be a credible event. The term "credible event" is hard to determine since the Disturbance could be caused by one of those events listed in the TPL standards, or could be one that is beyond those listed, such as natural phenomena. • We realize that the Application Guideline provides some general guidance on assessing the

Organization	Yes or No	Question 1 Comment
		creditability of a Disturbance, but we do not agree that a Disturbance is no longer credible when it is deemed no longer capable of occurring in the future due to actual changes to the BES. Changes to the BES may reduce the possibility of the same Disturbance, but such Disturbances (e.g. loss of right of way or an entire station) may still occur due to other means. If the SDT should continue to hold the position that the criteria for excluding a Disturbance is that BES changes are made to mitigate (but not totally eliminate) the recurrence, then it should be clearly stated in the requirement itself. • In short, the basis with which to deem a Disturbance "credible" is missing from the requirements, which needs to be provided/clarified in the standard/requiremen Response: The term "credible" has been removed from the standard. The drafting team clarified Requirement R1, Criterion 3 by framing the criterion in the present tense to refer to the current assessment(s). Islands caused by natural phenomena (i.e., Disturbances) are covered under Requirement R2. Change made.
David Kiguel	No	1. The second criterion in R1 refers to "An Element that is associated with a System Operating Limit (SOL)." Clarification is necessary to specify the meaning of "associated." Does it refer to an Element in the SOL itself or monitored and protected but outside the SOL (or both)? Response: For Requirement R1, Criterion 2, the drafting team removed the term "associated" and revised the criteria to clarify that the Element is the "monitored" Element. Change made. 2. The draft repeatedly uses the term "credible event." In some instances, e.g. past disturbance(s) it might be subject to interpretation. In general, without a probabilistically quantified criterion, the term "credible" is subjective and subject to interpretation, thus should be avoided in this context. Response: The term "credible" has been removed from the standard. The drafting team clarified Requirement R1, Criterion 3 by framing the criterion in the present tense to refer to current assessment(s). The term "credible" was removed from the previous Requirement R2 (and new R3) because the required performance refers to only current actual events. Change made.

Organization	Yes or No	Question 1 Comment
		3. Clarification is required in regards to load-responsive relays in a Protection System. It is unclear as to what relays/components should not trip during power swing. Response: The term "load-responsive protective relays" is widely understood and is any protective functions which could trip with or without time delay, on load current. A clarification has been provided in PRC-026-1 – Attachment A. Change made. 4. R2 requires GOs and TOs to evaluate Disturbance records "since January 1, 2003," a time that will precede the effective date of this standard. A requirement cannot rely upon records that precede the effective date of a standard. Response: The "January 1, 2003" date has been removed from the standard. Requirement R2 (and new R3) are based on actual Disturbances that occur after the Effective Date of the standard. Change made.
California ISO	No	As "line-out conditions" used in Requirement R1 Criteria 1 and 2 is not a defined term, please clarify the intent of "line-out conditions", particularly addressing if "line-out conditions" are expected to go beyond the TPL Standard(s) of what the Planning Coordinator and Transmission Planner already study. Response: The phrase "line-out conditions" has been removed. Elements should be identified based on the Requirement R1 criterion regardless of the outage conditions that may be necessary to trigger enforcement of the System Operating Limit (SOL) or arming of the Special Protection System (SPS). The Guidelines and Technical Basis have been supplemented to provide additional information. (Note: The use of SPS has been replaced with Remedial Action Scheme (RAS) for consistency with a current project to revise the definition of "Special Protection System"). Change made.
Tacoma Power	No	Tacoma Power supports PSEG's response to Question 1. Setting aside the previous comment (that is, assuming FERC does not provide reflief from its directive to develop this standard), Tacoma Power supports a narrower approach. That is, the screening criteria should be refined and made simpler. For example, PRC-023 applies relatively straightforward screening criteria, yet PRC-023 addresses a greater reliability risk than the proposed PRC-026-1.

Organization	Yes or No	Question 1 Comment
		Presently, PRC-026-1 Requirement R1 (and R2) could pose a greater burden on entities than PRC-023 for screening to identify applicable Facilities. Alternatives might be to conduct a data request to collect better information so that Requirements R1 and R2 could be consolidated and then provide more refined and simpler criteria. Response: The drafting team contends that the standard approach is consistent with the PSRPS Report recommendation. Also, PRC-023 includes all BES Elements above 200 kV and select Elements below 200 kV and the proposed PRC-026-1 is a narrow focus on BES Elements at greater risk of power swings. Requirement R1 is not requiring additional or new studies; it is relying on existing studies. The burden of Requirement R2 (and new R3) has been reduced by eliminating the need to evaluate Disturbances prior to the Effective Date of the standard. Changes made. Setting aside the previous comment, Criterion 4 needs more clarification. Response: Requirement R1 – Criterion 4, Requirement R2 – Criterion 1, and the new Requirement R3 – Criterion 1, were clarified by adding both "stable and unstable" power swings. Both stable and unstable power swings determine whether an Element will be identified as experiencing a power swing. Change made. Response: The drafting team asserts that the standard does not require the inclusion of relay models. Requirement R1 – Criterion 4 is not requiring a study, but the identification of any Element that was observed as tripping in the most recent Planning Assessment. No change made. What is the technical basis in Requirement R1 for identification and notification to occur in January of each year? Response: The Requirement R1 language about "January of each calendar" has been removed and replaced with "each calendar year." Based on time period changes in other Requirements, the drafting team determined that an annual periodicity in Requirement R1 is more appropriate. Change made.
Ameren	No	(1) Along with our comments we agree with and adopt the Public Service Enterprise Group (PSEG)

Organization	Yes or No	Question 1 Comment
		Comments by reference. Response: Thank you for your comment. (2) If this standard does proceed, we generally can accept the focused approach, but believe it should be narrower. We believe that R2 reaching all the way back to 1/1/2003 creates an ex post facto compliance obligation. Response: The "January 1, 2003" date has been removed from the standard. Requirement R2 (and new R3) are based on actual Disturbances that occur after the Effective Date of the standard. Change made. (3) In our opinion R1 needs to limit the Criteria 3 and 4 time horizon to Operations Planning to be consistent with R3 which deals with the existing Protection System. We believe that resetting an existing relay for a future, but not present, stability issue could harm present reliability. Although, we do understand the benefits of identifying a future stability concern, and a future need to possibly alter relaying schemes or reset relays in an orderly fashion is important; we believe that such activity is part of the planning process and need not be governed by this standard. However, if the SDT intended that the R3 CAP (3rd bullet) apply to future scenarios, then please add the timing of such an example in the Application Guidelines. Response: Requirement R1 has been revised to only include the Planning Coordinator and due to this revision, the Criterion that identifies Elements is now specifically assigned the Time Horizon: Long-term Planning. In the event that a Corrective Action Plan (CAP) is necessary based on future system conditions, the CAP can specify a timeframe that does not enact changes until those system conditions require modification. An example has been added to clarify this scenario in the Guidelines and Technical Basis. Change made. (4) We ask the drafting team to include a broader explanation of changed conditions that would discontinue credibility in R2, item 2 ("...during an actual system Disturbance where the Disturbance(s) that caused the islanding condition continues to be credible."). Include items such as completed PRC-004 CAPs that have fixed a contributing cause, and procedures to

Organization	Yes or No	Question 1 Comment
		avoid a unique maintenance switching topology that was causal. Response: The term “credible” has been removed from the standard. The drafting team clarified Requirement R1, Criterion 3 by framing the criterion in the present tense to refer to current assessment(s). The term “credible” was removed from the previous Requirement R2 (and new R3) because the required performance refers to only current actual events. Change made. Following the notification of a Disturbance to the Planning Coordinator in Requirements R2 by the Transmission Owner or by Requirement R3 by the Generator Owner, the Planning Coordinator in Requirement R1 will continue notifying the respective Generator Owner and Transmission Owner of the Element, unless the Planning Coordinator determines the Element is no longer susceptible to power swings.
ISO New England	No	ISO New England recommends that requirements R1, R2, and R3 be changed from an annual requirement to once every 60 months. We also think that the approach should be narrower. Response: The Requirement R1 language about “January of each calendar” has been removed and replaced with “each calendar year.” Based on time period changes in other Requirements, the drafting team determined that an annual periodicity in Requirement R1 is more appropriate. The drafting team revised Requirement R4 (previous R3) from “each calendar year” to “within 12 full calendar months of receiving notification of an Element pursuant to Requirement R1 or within 12 full calendar months of identifying an Element pursuant to Requirement R2 and R3,” and “where the evaluation has not been performed in the last three calendar years.” Three calendar years was selected over five calendar years because the implementation plan provides a greater length of time to implement the standard and future occurrences would be incremental. Change made. Criteria 1 should be limited to IROL’s and read as follows: 1. An Element that is located or terminates at a generating plant, where a generating plant stability constraint exists and is addressed by an IROL.

Organization	Yes or No	Question 1 Comment
		Criteria 2 should be deleted. This criteria appears to be redundant to Criteria 1. Response: Criterion 1 is for identifying Bulk Electric System (BES) Elements associated with a Special Protection System (SPS) or operating limit associated generating plant. Criterion 2 is associated with identifying BES Elements with a System Operating Limit SOL that has been established based on angular stability constraints. (Note: The use of SPS has been replaced with Remedial Action Scheme (RAS) for consistency with a current project to revise the definition of “Special Protection System”). The drafting team contends that the standard approach is consistent with the PSRPS Report recommendation. No change made. Several commenters questioned the use of a System Operating Limit (SOL) to determine Elements that needed evaluation because they were not necessarily associated with wide-area problems. The drafting team contends that not only SOLs that have been shown to expose a widespread area to instability, uncontrolled separation(s) or cascading outages should be considered. Identified localized instability issues also point to Elements that should reduce the likelihood of tripping for stable power swings. No change made. In Criteria 3, Disturbance is too broad. It should be limited to single or multiple contingencies but not extreme contingencies. Criteria 3 should read as follows: 3. An Element that has formed the boundary of an island within an angular stability planning simulation where the system Disturbance(s) that caused the islanding is a single or multiple contingency but not an extreme contingency. Response: The drafting team modified Requirement R1, Criterion 3 to include island boundaries due to angular instability within an underfrequency load shedding (UFLS) assessment. Also, the Generator Owner was moved from Requirement R2 to the new Requirement R3 in order to remove the “islanding” criteria for Generator Owners. Change made. Criteria 4 should be narrower in scope and read as follows: 4. An Element identified in the most recent Planning Assessment where relay tripping occurred for a power swing during a Disturbance caused by a single or multiple contingency but not an extreme

Organization	Yes or No	Question 1 Comment
		contingency. Response: The drafting team asserts that the most recent Planning Assessment provides a concrete reference to the information used in identifying BES Elements. Since the Planning Assessments (i.e., TPL-001-4) are performed annually, any other description would create confusion as to whether an entity should use past information or information revealed during preparation of a Planning Assessment. No change made. Again, Disturbance is too broad. It should be limited to single or multiple contingencies but not extreme contingencies. Response: The drafting team revised Requirement R1, Criterion 4 by changing “Disturbance” to “simulated disturbance” to comport with the approved Reliability Standard TPL-001-4. The use of “Disturbance” in Requirements R2 (TO) and R3 (GO) relates to an actual system disturbance. Change made.
New York Power Authority	No	The PSRPS technical document does not recommend this Standard. This is stated in pages 5, 20, and 24:”Based on its review of historical events, consideration of the trade-offs between dependability and security, and recognizing the indirect benefits of implementing the transmission relay loadability standard (PRC-023), the SPCS concludes that a NERC reliability Standard to address relay performance during stable power swings is not needed, and could result in unintended adverse impacts to Bulk-Power System reliability.” Response: Please see the section at the beginning of this document called, “NERC Discussion on Proceeding(s) and Directives Regarding: Stable Power Swings” for a complete background. The SDT understands that NERC staff re-engaged FERC staff following the completion of the PSRPS Report and that the Commission still desired NERC to pursue its work to meet the directive. However, FERC staff was open to an approach designed by NERC. NERC staff has informally received positive feedback on the approach to address the regulatory directive. The directive itself was challenged by commenters prior to the issuance of Order No. 733 and was already the subject of multiple rehearing requests in the Order No. 733-A and Order No. 733-B proceedings. Similar arguments to the conclusions of the NERC System

Organization	Yes or No	Question 1 Comment
		Protection and Control Subcommittee were advanced in these FERC proceedings. We only agree with R1. R1 calls upon the Planning Coordinator, Reliability Coordinator, & Transmission Planner, (all single ISO in our region) to provide notification to GOs and TOs of what the specific “Elements” are. R2 seems to again call for Elements by the GOs and TOs. R2 can easily be combined into R1 for a simpler answer. In addition, by practice all registered entities report to the ISO/RC any disturbances, being they are the System Operator and keep records of events in the region. Response: The Generator Owner (GO) in Requirement R3 and Transmission Owner (GO) in Requirement R2 are required to report the Element that tripped during a Disturbance in response to a power swing. These Requirements allow the Planning Coordinator to be the sole source of funneling the “identified Elements” to the GO and TO. A fifth Criterion was added to Requirement R1 that requires the Planning Coordinator (PC) to continue identifying an Element “unless the PC determines the Element is no longer susceptible to power swings.” This ensures visibility of the Elements reported by the GO or TO on an ongoing basis since the Element tripped in response to a power swing. Change made.
Oncor Electric Delivery LLC	No	Oncor does not agree that the approach of this Standard came from recommendations in the PSRPS technical document, but rather negates the need for the Standard altogether. Specifically, on page 5 paragraph 4 of the document it states “Based on its review of historical events, consideration of the trade-offs between dependability and security, and recognizing the indirect benefits of implementing the transmission relay loadability standard (PRC-023), the SPCS concludes that a NERC Reliability Standard to address relay performance during stable power swings is not needed, and could result in unintended adverse impacts to Bulk-Power System reliability”. Response: Please see the section at the beginning of this document called, “NERC Discussion on Proceeding(s) and Directives Regarding: Stable Power Swings” for a complete background. The SDT understands that NERC staff re-engaged FERC staff following the completion of the PSRPS Report and that the Commission still desired NERC to pursue its work to meet the directive. However, FERC staff was open to an approach designed by NERC. NERC staff has informally received positive feedback on the approach to address the regulatory directive. The directive itself was challenged by commenters prior to the

Organization	Yes or No	Question 1 Comment
		issuance of Order No. 733 and was already the subject of multiple rehearing requests in the Order No. 733-A and Order No. 733-B proceedings. Similar arguments to the conclusions of the NERC System Protection and Control Subcommittee were advanced in these FERC proceedings. Oncor agrees with this notion and does not want to add any adverse issues to the power system. This is also repeated on page 20 paragraph 1. In regards to the specific requirements, R1 criteria 1 states "An Element that is located or terminates at a generating plant, where a generating plant stability constraint exists and is addressed by an operating limit or a Special Protection System (SPS) (including line-out conditions)." This requirement duplicates the efforts in TPL-002 (R1.3.10), TPL-003(R1.3.10), TPL-004(R1.3.7), and TPL-001-4(R 2.7.1) where the effect of a SPS, which is a protection system, is already studied. Oncor recommends the SDT aligns the Requirements to eliminate duplication. Response: The drafting team contends that the Requirements do not duplicate the transmission (i.e., TPL standards) Requirements. The TPL standards address the effects of the planned actions of the Special Protection System (SPS), which is installed to address a stability constraint. The Elements are included because other relays protecting the Element may operate for a stable power swing across the Element. (Note: The use of SPS has been replaced with Remedial Action Scheme (RAS) for consistency with a current project to revise the definition of "Special Protection System"). No change made.
Austin Energy	No	(1) City of Austin dba Austin Energy (AE) notes the following statement from the PSRPS technical document on page 20: "Based on its review of historical events, consideration of the trade-offs between dependability and security, and recognizing the indirect benefits of implementing the transmission relay loadability standard (PRC-023), the SPCS concludes that a NERC Reliability Standard to address relay performance during stable swings is not needed, and could result in unintended." AE believes more background work is necessary in justifying the creation of this standard before proceeding. Response: Please see the section at the beginning of this document called, "NERC Discussion on Proceeding(s) and Directives Regarding: Stable Power Swings" for a complete background. The SDT understands that NERC staff re-engaged FERC staff following the completion of the PSRPS Report and that

Organization	Yes or No	Question 1 Comment
		the Commission still desired NERC to pursue its work to meet the directive. However, FERC staff was open to an approach designed by NERC. NERC staff has informally received positive feedback on the approach to address the regulatory directive. The directive itself was challenged by commenters prior to the issuance of Order No. 733 and was already the subject of multiple rehearing requests in the Order No. 733-A and Order No. 733-B proceedings. Similar arguments to the conclusions of the NERC System Protection and Control Subcommittee were advanced in these FERC proceedings. (2) Further, AE disagrees with the R2 criteria of evaluating Disturbance records "since January 1, 2003." The criteria not only predate the enforcement date of this standard, it goes back to a time before any of the NERC Reliability Standards were enforceable. Response: The "January 1, 2003" date has been removed from the standard. Requirement R2 (and new R3) are based on actual Disturbances that occur after the Effective Date of the standard. Change made.
Northeast Utilities	No	We agree with a focused approach as outlined in the technical document. However, we have the following serious concerns with criteria in the requirements: 1. The term "credible event" should be clearly defined. The basis to determine a credible event is missing from the requirement and application guide. This basis should be provided in the standard requirement. Response: The term "credible" has been removed from the standard. The drafting team clarified Requirement R1, Criterion 3 by framing the criterion in the present tense to refer to current assessment(s). The term "credible" was removed from the previous Requirement R2 (and new R3) because the required performance refers to only current actual events. Change made. 2. Why is the standard focused on SOL rather than IROL? The basis for specifying SOL is not supported by the example in the application guideline since the example did not show inter-area impact. Response: Several commenters questioned the use of a System Operating Limit (SOL) to determine Elements that needed evaluation because they were not necessarily associated with wide-area problems. The drafting team contends that not only SOLs that have been shown to expose a widespread area to instability, uncontrolled separation(s) or cascading outages should be considered. Identified localized

Organization	Yes or No	Question 1 Comment
		instability issues also point to Elements that should reduce the likelihood of tripping for stable power swings. No change made. 3. It is not clear in R1, criteria number 4 whether the assessment should include relay tripping or just stable power swing or both stable and unstable power swing. Response: Requirement R1 – Criterion 4, Requirement R2 – Criterion 1, and the new Requirement R3 – Criterion 1, were clarified by adding both "stable and unstable" power swings. Both stable and unstable power swings determine whether an Element will be identified as experiencing a power swing. Change made. 4. In R2, it is unrealistic to require an entity to provide data on an Element that had tripped since 2003. There is no existing NERC continent-wide disturbance monitoring or misoperation standard that requires data be retained more than 12 months. We recommend that this requirement be removed from the standard or include only Elements that were tripped in the last calendar year. Response: The "January 1, 2003" date has been removed from the standard. Requirement R2 (and new R3) are based on actual Disturbances that occur after the Effective Date of the standard. Change made.
Idaho Power Co.	No	No. R1 seems to be an acceptable approach for Planners to use. However, R2 is not acceptable. Having a dated requirement prior to the effective date of a Standard is not appropriate. While it may be reasonable to look at these earlier disturbances, making a Requirement of that review is not. This requirement should be removed or rewritten to require only the review of disturbances past the effective date of the Standard where tripping of Protection Systems during a stable power swing was a causal factor. Response: The "January 1, 2003" date has been removed from the standard. Requirement R2 (and new R3) are based on actual Disturbances that occur after the Effective Date of the standard. Change made. In addition, the PSRPS technical document does not use the NERC Glossary term for Disturbances, yet the Standard does. The Glossary term is not specific which makes these criterion also non specific. Criterion similar to those in EOP-004 would seem to better identify the disturbances that are included in this

Organization	Yes or No	Question 1 Comment
		Standard. Response: The drafting team revised Requirement R1, Criterion 4 by changing "Disturbance" to "simulated disturbance" to comport with the approved Reliability Standard TPL-001-4. The use of "Disturbance" in Requirements R2 (TO) and new R3 (GO) relates to an actual system Disturbance. Change made. M2 appears to require the utility to have evidence it did not know it needed to maintain. Response: The "January 1, 2003" date has been removed from the standard. Requirement R2 (and new R3) are based on actual Disturbances that occur after the Effective Date of the standard; therefore, the Measure now only requires the entity to have evidence from the Effective Date forward. Change made. The PSRPS technical document suggests that the FERC directive to develop this standard may have been based on misinformation or a misunderstanding of the 2003 Northeast Blackout investigation report and furthermore suggests such a standard could result in unintended adverse impacts to the Bulk-Power System. Recommend NERC utilize the findings of the PSRPS technical document to obtain a stay of development of PRC-026-1 from FERC until FERC can develop a position based on the conclusions presented in the PSRSP document. Response: Please see the section at the beginning of this document called, "NERC Discussion on Proceeding(s) and Directives Regarding: Stable Power Swings" for a complete background. The SDT understands that NERC staff re-engaged FERC staff following the completion of the PSRPS Report and that the Commission still desired NERC to pursue its work to meet the directive. However, FERC staff was open to an approach designed by NERC. NERC staff has informally received positive feedback on the approach to address the regulatory directive. The directive itself was challenged by commenters prior to the issuance of Order No. 733 and was already the subject of multiple rehearing requests in the Order No. 733-A and Order No. 733-B proceedings. Similar arguments to the conclusions of the NERC System Protection and Control Subcommittee were advanced in these FERC proceedings. The NERC System Protection and Control Subcommittee (SPCS) concern is that an overly prescriptive standard as contemplated in Order No. 733 could lead to unintended adverse impacts. The focused

Organization	Yes or No	Question 1 Comment
		approach recommended by the SPCS, and implemented by the drafting team, addresses the concern by requiring entities implement Corrective Action Plans to improve security for stable power swings by meeting the criteria in PRC-026-1 – Attachment B while maintaining dependable fault detection and dependable out-of-step tripping. No change made. If development of PRC-026-1 continues: I agree with the focused approach. R1.1 and R1.2 need to contain clarity about what constitutes a "line out condition" - does this mean N-1, N-2, N-X, transformers, etc? Response: The phrase "line-out conditions" has been removed. Elements should be identified based on the Requirement R1 criterion regardless of the outage conditions that may be necessary to trigger enforcement of the System Operating Limit (SOL) or arming of the Special Protection System (SPS). The Guidelines and Technical Basis have been supplemented to provide additional information. (Note: The use of SPS has been replaced with Remedial Action Scheme (RAS) for consistency with a current project to revise the definition of "Special Protection System"). Change made. Concerning R1.3, who is the judge of whether an event is "credible"? Response: The term "credible" has been removed from the standard. The drafting team clarified Requirement R1, Criterion 3 by framing the criterion in the present tense to refer to the current assessment(s). Islands caused by natural phenomena (i.e., Disturbances) are covered under Requirement R2. Change made.
Public Utility District No. 1 of Cowlitz County, WA	No	Cowlitz PUD agrees with the intent of standard PRC-026-1 (Standard) requirements R1 & R2 focused approach, but finds the current Standard draft creates a compliance difficulty. The Standard should clearly define the "specific criterion" which will be used to identify Elements, and compare the load-responsive protective relay characteristics to establish "credible" risk. The Standard lacks specificity as currently written. Response: The drafting team modified Requirement R1 to add clarity. For example, Criterion 1 – added "angular" to "stability constraint, Criterion 2 – "monitored" to identify which Element, Criterion 3 – to

Organization	Yes or No	Question 1 Comment
		include island boundaries due to angular instability within an underfrequency load shedding (UFLS) assessment, and Criterion 4 – that a "power swing" refers to both "stable" and "unstable." Also, the Generator Owner was moved from Requirement R2 to the new Requirement R3 in order to remove the "islanding" criteria for Generator Owners. The term "credible" has been removed from the standard. The drafting team clarified Requirement R1, Criterion 3 by framing the criterion in the present tense to refer to current assessment(s). The term "credible" was removed from the previous Requirement R2 (and new R3) because the required performance refers to only current actual events. Change made. --(New Paragraph)— This draft assumes incorrectly that an entity will have retained operational historical records since 2003. If such records do not exist, an entity will have no proof of having established a null or complete list which satisfies requirement R2. Further, there is no requirement to retain such operational records to facilitate future compliance. The CEA must either accept attestations, or require applicable entities to develop documentation for each section 4.2 applicable Element which establishes no credible risk of a trip during a [stable] power swing exists. Cowlitz PUD proposes the SDT identify specific documentation and establish an official listing, such as all pertinent RE and NERC disturbance studies/reports dated 2003 or later be used to identify past poorly performing Elements during a Disturbance. Response: The "January 1, 2003" date has been removed from the standard. Requirement R2 (and new R3) are based on actual Disturbances that occur after the Effective Date of the standard. Change made. We are also unclear on how Elements might be identified purely from system modeling studies when strictly looking at Requirement R1 (ignoring R3 or other standard requirements outside of this Standard). Response: The drafting team has included ways for Elements to be identified other than through system modeling studies, but it contends that some Elements may be identified and included through that process. Requirement R1 – Criterion 4 is not requiring additional studies, but the identification of any

Organization	Yes or No	Question 1 Comment
		Element that was observed as tripping in the most recent Planning Assessment (i.e., TPL-001-4) would be included. No change made. Further, “credible” is a subjective term which does not establish a clear compliance line. It may be better to state “...actual system Disturbance where current system modeling continues to identity a repeat of the Disturbance possible under an n-3 event.” Another possible method would be to tie “credible” to a probability of one in a thousand; this method would require probability model development. This is not to say that “credible” should not be used, but it will require extensive guidance in the RSAW of how the “credible” benchmark is established. In fairness, the benchmark should be established during Standard development to allow stakeholder review and comment. Response: The term “credible” has been removed from the standard. The drafting team clarified Requirement R1, Criterion 3 by framing the criterion in the present tense to refer to the current assessment(s). Islands caused by natural phenomena (i.e., Disturbances) are covered under Requirement R2. Change made.
PacifiCorp	Yes	R1, which states “Any Element that is located or terminates at a generating plant, where a generating plant stability constraints exists and is addressed by an operating limit or a Special Protection System (SPS) (including line-out condition)”.... raises concerns. In WECC region, a SPS or RAS has to be redundant. Language needs to be added to make a redundant system an exemption from this requirement. Response: The drafting team contends that the Special Protection System (SPS) as stated in Requirement R1 is in place to prevent angular instability. The standard does not address a failing SPS, but is addressing the Elements associated with an SPS that would be susceptible to a power swing. (Note: The use of SPS has been replaced with Remedial Action Scheme (RAS) for consistency with a current project to revise the definition of “Special Protection System”). No change made.
MRO NERC Standards Review Forum	Yes	

Organization	Yes or No	Question 1 Comment
Tennessee Valley Authority	Yes	
SPP Standards Review Group	Yes	Establishing criteria that determine which Elements must be assessed according to Requirements R1 and R2 reduce the compliance burden on Generator Owners and Transmission Owners. This is the right approach. That said, we concur with AEP in that the SDT should limit the use of the term 'stability' in the standard to oscillatory and transient stability in order to avoid confusion with voltage and steady state stability. Response: The drafting team added "angular" to "stability constraint" to clarify the intent in Requirement R1, both Criterion 1 and 2. Change made.
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	Yes, in part. Addressing situations and occurrences of undesired relay operations is an appropriate method to minimize future undesired operations. The review period should be a rolling time period (previous 5 years) rather than > 10 years ago, as many entities will not have historical records to validate potential mis-operations. Entities were not required to keep such records to the date specified in R1 and R2. Response: The "January 1, 2003" date has been removed from the standard. Requirement R2 (and new R3) are based on actual Disturbances that occur after the Effective Date of the standard. A fifth Criterion was added to Requirement R1 that requires the Planning Coordinator to continue identifying an Element "unless the Planning Coordinator determines the Element is no longer susceptible to power swings." This ensures visibility of the Elements reported by the Generator Owner or Transmission Owner on an ongoing basis since the Element tripped in response to a power swing. Change made. R1 #4 and R2 #1 should specify the inclusion of Elements that trip due to "stable power swings" instead of all power swings. Response: Requirement R1 – Criterion 4, Requirement R2 – Criterion 1, and the new Requirement R3 –

Organization	Yes or No	Question 1 Comment
		Criterion 1, were clarified by adding both "stable and unstable" power swings. Both stable and unstable power swings are included because both are indicators that load-responsive protective relays may be challenged by power swing conditions. Clarification made.
Dominion	Yes	
Florida Power & Light	Yes	The language for Criteria 3 & 4 in Requirement 1 should be modified. Criteria 3 should consider underfrequency planning simulations in addition to angular stability planning simulations. Response: The drafting team modified Requirement R1, Criterion 3 to include island boundaries due to angular instability within an underfrequency load shedding (UFLS) assessment. Also, the Generator Owner was moved from Requirement R2 to the new Requirement R3 in order to remove the "islanding" criteria for Generator Owners. Change made. Criteria 4 should consider Planning Assessments in the last year as opposed to "the most recent Planning Assessment." Response: The drafting team asserts that the most recent Planning Assessment provides a concrete reference to the information used in identifying BES Elements. Since the Planning Assessments (i.e., TPL-001-4) are performed annually, any other description would create confusion as to whether an entity should use past information or information revealed during preparation of a Planning Assessment. No change made.
PPL NERC Registered Affiliates	Yes	These comments are submitted on behalf of the following PPL NERC Registered Affiliates: LG&E and KU Energy, LLC; PPL Electric Utilities Corporation, PPL EnergyPlus, LLC; PPL Generation, LLC; PPL Susquehanna, LLC; and PPL Montana, LLC. The PPL NERC Registered Affiliates are registered in six regions (MRO, NPCC, RFC, SERC, SPP, and WECC) for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TS Comments:

Organization	Yes or No	Question 1 Comment
		We agree with the general approach, but have some implementation concerns as expressed below. Response: Thank you for your comment.
Arizona Public Service Co.	Yes	While AZPS agrees with the focused approach, AZPS would like to ask the drafting team to consider revising R1 and R2. APS recommends that the drafting team require an initial identification and notification of each Element that meets the criteria described in R1. A review of the assessment should not be required annually if there are no additions to the entity system meeting the criteria. It would be more practical to require a comprehensive review every five years. In addition, the standard should require that if Elements are added to the entity system that meet the criteria in R1, the applicable entity should provide updates within 90 days of the commissioning of a new Element. Response: The drafting team increased the Implementation Plan to three years to provide for the initial influx of identified Elements under Requirement R1. The evaluation of relays under Requirement R4 (previously R3) is to be performed “within 12 full calendar months of receiving notification of an Element … where the evaluation has not been performed in the last three calendar years.” Change made. APS believes that the current draft requirement is administrative in nature and represents a reporting burden. Response: The drafting asserts that notifying the other entities is not administrative and provides a reliability necessity to communicate the BES Elements that meet the defined criteria or Elements that have experienced an actual stable or unstable power swing. No change made.
Bureau of Reclamation	Yes	
Peak Reliability	Yes	

Organization	Yes or No	Question 1 Comment
American Electric Power	Yes	We agree with the focused approach. We would recommend qualifying the term “stability,” in R1.2 in particular, as “transient or oscillatory stability” so that voltage or steady-state stability, which would not cause power swings, are not mistakenly construed by an auditor. TPL-001-4 permits use of generic relay models in dynamic simulation planning studies, so the reference in R1.4 to relay tripping in planning assessments may not end up being based on the relays actually installed. Response: The drafting team added “angular” to “stability constraint” to clarify the intent in Requirement R1, both Criterion 1 and 2. Change made.
American Transmission Company, LLC	Yes	
Manitoba Hydro	Yes	
Exelon	Yes	
Texas Reliability Entity	Yes	
ITC	Yes	In general we agree. However, the SDT should clarify what constitutes an island with regard to this standard as it’s not a defined term. Should this standard pertain to lines which contain both generation and load, which when tripped form an island? We suggest not. Response: The drafting team modified Requirement R1, Criterion 3 to include island boundaries due to angular instability within an underfrequency load shedding (UFLS) assessment. Also, the Generator Owner was moved from Requirement R2 to the new Requirement R3 in order to remove the “islanding” criteria for Generator Owners. Change made. Also, the term “credible” is unclear. If an event involves scenarios beyond TPL’s “broad spectrum of

Organization	Yes or No	Question 1 Comment
		System conditions" and "wide range of probably Contingencies", is it really credible? The example in Application Guideline involved a single bus outage, which is credible in TPL standards. However, a Disturbance may occur involving multiple contingencies but well beyond normal planning criteria and now that e``xtreme event must be studied. If this approach is desired, then it leaves a gap for other extreme events to occur, just which we've had the good fortune not to have experienced yet. We suggest limiting the definition of "credible" into include those scenarios within the bounds of TPL-001-4. Response: The term "credible" has been removed from the standard. The drafting team clarified Requirement R1, Criterion 3 by framing the criterion in the present tense to refer to the current assessment(s). Islands caused by natural phenomena (i.e., Disturbances) are covered under Requirement R2. Change made.
Southern California Edison Company	Yes	
Salt River Project	Yes	
DTE Electric		No comment
Xcel Energy	Yes	The frequency of performing the tasks within these requirements is unnecessarily aggressive; power systems dynamics do not change that fast. We should recommend changing the frequency to every 3 to 4 years. Response: The drafting team increased the Implementation Plan to three years to provide for the initial influx of identified Elements under Requirement R1. The evaluation of relays under Requirement R4 (previously R3) is to be performed "within 12 full calendar months of receiving notification of an Element … where the evaluation has not been performed in the last three calendar years." Change made.

2. Do you agree that the Planning Coordinator, Reliability Coordinator, and Transmission Planner are the appropriate entities to identify the Elements that meet the criteria in Requirement R1? If not, please explain why an entity is not appropriate and/or suggest an alternative that should identify the Elements according to the criteria

Summary Consideration: About two-thirds of the commenters for Question 2 agreed with the proposed applicable entities; however, the drafting team did remove two of the applicable entities as noted here. There were three primary concerns in this area all of which resulted in a revision to the standard. The chief issue was the use of a historical date (January 1, 2003) in the Requirements. The intent of this language was to provide a "current day look" back into history concerning Disturbances. The historical information would then be used to assess Elements and/or relays concerning power swings. This concern was raised in 34 comments supported by 144 stakeholders. To address the concern, this reference was removed and all of the associated requirements and criteria have been worded in the present tense to make clear that that no historical review is being required. Seventeen comments from 75 individuals raised varying issues about having the Planning Coordinator, Reliability Coordinator, and the Transmission Planner all identifying Elements pursuant to Requirement R1. The comments were considered and it was determined that the Planning Coordinator should be designated as a single entity source of identifying Elements. The reasoning is that the Planning Coordinator has or has access to the knowledge including the wide-area view and having a single entity will avoid duplication and potential gaps should multiple entities believe the other is identifying Elements. Last, 8 comments from 24 stakeholders argued that one month at the beginning of each calendar year for notifying the respective Generator Owner and Transmission Owner is onerous. Although the idea was to keep activities synchronized on an annual basis, the drafting team understood the concerns; therefore, the Requirement R1 language about "January of each calendar" has been removed and replaced with "each calendar year." This revision was based on comment and on time period changes in other Requirements and determined to be more appropriate.

Organization	Yes or No	Question 2 Comment
SMUD/BANC	No	Collected data and subsequent analysis has not identified tripping during stable power swings. This phenomenon is rare if at all. Any tripping during stable power swings would more appropriately included as a mis-operation and addressed as such. Response: Tripping for stable power swings were observed in the August 14, 2003 Blackout.[6] Misoperation standard is a reactive standard and PRC-026-1 is a proactive standard aiming to prevent load-responsive protective relay operations for stable power swings. This standard is different from the

[6] http://www.nerc.com/pa/rrm/ea/Pages/Blackout-August-2003.aspx

Organization	Yes or No	Question 2 Comment
		Misoperations standard because it requires notification to the Planning Coordinator of Elements that have tripped due to stable or unstable power swings. Response: Please see the section at the beginning of this document called, "NERC Discussion on Proceeding(s) and Directives Regarding: Stable Power Swings" for a complete background. The SDT understands that NERC staff re-engaged FERC staff following the completion of the PSRPS Report and that the Commission still desired NERC to pursue its work to meet the directive. However, FERC staff was open to an approach designed by NERC. NERC staff has informally received positive feedback on the approach to address the regulatory directive. The directive itself was challenged by commenters prior to the issuance of Order No. 733 and was already the subject of multiple rehearing requests in the Order No. 733-A and Order No. 733-B proceedings. Similar arguments to the conclusions of the NERC System Protection and Control Subcommittee were advanced in these FERC proceedings. This comment is the same as SMUD/BANC, Question 1, #1. See response in Question 1.
SPP Standards Review Group	No	The Reliability Coordinator may not be aware of Elements identified in Criteria 3 and 4, since that knowledge is based upon the Planning Coordinator or the Transmission Planner notifying the Reliability Coordinator of the situation. Yet the Reliability Coordinator is held accountable for the identification and notification '...of each Element that meets one or more...' of the criteria. Similarly, there may be situations where the Planning Coordinator or Transmission Planner may not be aware of Elements identified by the Reliability Coordinator yet they are also held accountable for identification and notification of each Element. There should be one, single list of all the Elements that satisfy the criteria but the responsible entities may not, individually, reach the same conclusions regarding the make-up of that list. Their individual lists may not contain all the Elements to be identified but a composite of all their lists should result in the one, true list of all Elements. The requirement needs to be modified to include this consideration. Response: The Reliability Coordinator and Transmission Planner have been removed from the standard's Applicability; therefore, Requirement R1 is now only applicable to the Planning Coordinator as a single entity source of identifying Elements. The drafting team asserts that the Planning Coordinator has or has

Organization	Yes or No	Question 2 Comment
		access to the knowledge including the wide-area view. Change made to the Requirement.
ISO RTO Council Standards Review Committee	No	These three entities are appropriate for the R1 requirement. However, there should be a requirement that only one of the three is deemed responsible to provide notice to the facility owner. Every facility that falls under the R1 criteria is under the authority of all three entities. It would be repetitious and redundant to require all three entities to provide the same information to the same facility owner. However, if the intent of the requirement is that the Reliability Coordinator will address the Operations Planning Horizon, while the Planning Coordinator and Transmission Planner will address the Long-Term Planning Horizon, then it may not be repetitious nor redundant to require these entities to address Requirement R1. Also, the entity who is registered as the RC may differ from the entity who is registered as the PC and TP. For example, in the Western Interconnection, Peak Reliability is the RC, the CAISO is the PC for much of California (but not all), and the Participating Transmission Owners are registered as the TP. In CAISO's case, the three registered entities of RC, PC, and TP are represented by different entities. Response: The Reliability Coordinator and Transmission Planner have been removed from the standard's Applicability; therefore, Requirement R1 is now only applicable to the Planning Coordinator as a single entity source of identifying Elements. The drafting team asserts that the Planning Coordinator has or has access to the knowledge including the wide-area view. Change made to the Requirement.
ACES Standards Collaborators	No	We do not believe that the Transmission Planner should be an applicable entity. Any studies completed by the TP will be duplicated in a larger PC study thus making the inclusion of the TP unnecessary. Response: The Reliability Coordinator and Transmission Planner have been removed from the standard's Applicability; therefore, Requirement R1 is now only applicable to the Planning Coordinator as a single entity source of identifying Elements. The drafting team asserts that the Planning Coordinator has or has access to the knowledge including the wide-area view. Change made to the Requirement.
Duke Energy	No	Duke Energy disagrees with the applicability of the Reliability Coordinator (RC) to Requirement R1. From a NERC Reliability Functional Model standpoint, the RC does not directly interface with a Generator Owner

Organization	Yes or No	Question 2 Comment
		(GO) or Transmission Owner (TO) as Requirement R1 is proposing. The RC receives facility and operational data such as maintenance plans from TOs and GOs for reliability analysis, but this is mostly done through automation i.e. SDX (System Data Exchange). The Functional Model even states that the RC coordinates with other RCs, Transmission Planners, and Transmission Service Providers on transmission system limitations, not to TOs or GOs. Communication from an RC is most always directed to the Balancing Authority (BA) or Transmission Operator (TOP), and the RC reliability analyses is provided to TOPs, BAs and Generator Operators in its area as well as other RCs. An RC, per FAC-011, is required to establish a methodology for the identification of SOLs/IROLs and communicate the methodology to the TOP. RCs assist TOPs in calculating and coordinating SOLs, but the TOP is the Functional Entity that implements the RC methodology to identify and communicate the SOLs/IROLs to its RC in the Operations Horizon. Lastly, we feel that this standard would create a precedent requiring the RC to unnecessarily communicate and interface with GOs and TOs; an action that is not required by the current enforceable Reliability Standards. We recommend that the TOP should supplant the RC as the applicable entity responsible for communicating the criterion list in the proposed PRC-026-1 Requirement R1. Duke Energy proposes the following alternative language for Requirement R1. "Each Planning Coordinator, Transmission Operator, and Transmission Planner shall, within the first month of each calendar year, identify and provide notification to its Reliability Coordinator, and to the respective Generator Owner and Transmission Owner of each Element that meets one or more of the following criteria, if any:" Response: The Reliability Coordinator and Transmission Planner have been removed from the standard's Applicability; therefore, Requirement R1 is now only applicable to the Planning Coordinator as a single entity source of identifying Elements. The drafting team asserts that the Planning Coordinator has or has access to the knowledge including the wide-area view. Change made to the Requirement.
BC Hydro	No	BC Hydro does not agree that the criteria of R1 are reasonable. Therefore cannot suggest why an entity is not appropriate. Response: The drafting team asserts that it has implemented the recommended approach provided in the

Organization	Yes or No	Question 2 Comment
		NERC System Protection and Control Subcommittee (SPCS) technical report, *Protection System Response to Power Swings*, August 2013[7] (PSRPS Report). No change made.
Florida Municipal Power Agency	No	Unless there is a requirement somewhere in the standards for Reliability Coordinators to perform stability analyses (there currently is not, SOLs/IROLs are studied by the TOP in accordance with the RC's methodology); then, this requirement would cause all RCs to have to perform stability studies. Response: The Reliability Coordinator and Transmission Planner have been removed from the standard's Applicability; therefore, Requirement R1 is now only applicable to the Planning Coordinator as a single entity source of identifying Elements. The drafting team asserts that the Planning Coordinator has or has access to the knowledge including the wide-area view. Change made to the Requirement. Also, "corrective action plans" for protection systems will more likely be a planning horizon activity (e.g., changing out relays) and hence, the studies should be planning horizon studies, not operating horizon studies and the RC should not be included. Response: The time period for Requirement R4 (previously R3) has been changed to be within twelve full calendar months of notification of the Elements pursuant to Requirement R1. Requirement R4 (previous R3) and new R5 are applicable to the Generator Owner and Transmission Owner. The Reliability Coordinator has been removed from the applicability of the standard.. Change made. Response: The "Operations Planning" time horizon for Requirement R6 (previously R4) regarding the implementation of the Corrective Action Plan (CAP) was eliminated, leaving the "Long-term Planning" time horizon. Change made.
Bonneville Power Administration	No	BPA feels the Standard needs to delineate which entity performs which role, and under which conditions. For example, the Reliability Coordinator (RC) only identifies the Elements tripped during islanding and disturbance, while the Planning Coordinator (PC) and Transmission Planner (TP) do so for long term

[7] NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)

Organization	Yes or No	Question 2 Comment
		planning. Response: The Reliability Coordinator and Transmission Planner have been removed from the standard's Applicability; therefore, Requirement R1 is now only applicable to the Planning Coordinator as a single entity source of identifying Elements. The drafting team asserts that the Planning Coordinator has or has access to the knowledge including the wide-area view. Change made to the Requirement.
Public Service Enterprise Group	No	We disagree with the need for this standard. Response: Thank you for your comment. Please see response in Question 1 above.
Peak Reliability	No	The TP's relationship to the PC is synonymous with the TOP's relationship with the RC, so leaving the TOP out as an applicable entity creates a reliability gap. The TOP is responsible for establishing SOLs. Response: The Reliability Coordinator and Transmission Planner have been removed from the standard's Applicability; therefore, Requirement R1 is now only applicable to the Planning Coordinator as a single entity source of identifying Elements. The drafting team asserts that the Planning Coordinator has or has access to the knowledge including the wide-area view. Change made to the Requirement. The drafting team contends that a System Operating Limit (SOL) as stated in Requirement R1 is in place to prevent angular instability. The standard addresses Elements associated with an SOL as an Element that would be susceptible to a power swing. No change made.
Electric Reliability Council of Texas, Inc.	No	See our comments to Q1. Response: Thank you for your comment. Please see response in Question 1 above.
Tacoma Power	No	See Tacoma Power's response to Question 9. At least in WECC, not all of these entities may be appropriate to lead the identification effort. Response: Thank you for your comment. Please see response in Question 9 below.

Organization	Yes or No	Question 2 Comment
Ameren	No	We believe that even if these are the right entities, it is unclear who is driving the identification process or if they even agree. Please change to 'Each Transmission Planner with the Planning Coordinator's and Reliability Coordinator's concurrence shall, within the first month of each calendar year, identify and provide notification to the respective Generator Owner and Transmission Owner of each Element that meets one or more of the following criteria...' In most cases, we believe the TP would identify these with their studies and therefore should take the lead. Response: The Reliability Coordinator and Transmission Planner have been removed from the standard's Applicability; therefore, Requirement R1 is now only applicable to the Planning Coordinator as a single entity source of identifying Elements. The drafting team asserts that the Planning Coordinator has or has access to the knowledge including the wide-area view. Change made to the Requirement. The Requirement R1 language about "January of each calendar" has been removed and replaced with "each calendar year." Based on time period changes in other Requirements, the drafting team determined that an annual periodicity in Requirement R1 is more appropriate. Change made.
Public Utility District No. 1 of Cowlitz County, WA	No	Cowlitz PUD questions whether the Transmission Planner (TP) is nothing more than an extension of the Transmission Owner (TO), Generation Owner (GO), or Planning Coordinator (PC) registrations. Further, we believe the majority of those entities registered as a TP consider their TP footprint equal to their TO/GO/PC footprint. Therefore, it may be more appropriate for the TP to simply report Requirement R1 findings to the PC and RC. Finally, we believe it more efficient that a single entity be responsible to give notice to the TO and GO. Since every TO and GO must be under a Planning Coordinator and Reliability Coordinator, either the PC or the RC should be designated to send out the notice after their review is complete. Response: The Reliability Coordinator and Transmission Planner have been removed from the standard's Applicability; therefore, Requirement R1 is now only applicable to the Planning Coordinator as a single entity source of identifying Elements. The drafting team asserts that the Planning Coordinator has or has access to the knowledge including the wide-area view. Change made to the Requirement.

Organization	Yes or No	Question 2 Comment
PacifiCorp	Yes	
MRO NERC Standards Review Forum	Yes	
Tennessee Valley Authority	Yes	
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	The PC, RC and TP, or some combination is the appropriate entity to identify elements that meet the criteria in Requirement R1. R1 should allow collaboration between the PC, RC and TP to produce a single list of Elements that will satisfy compliance for all three entities. Response: The Reliability Coordinator and Transmission Planner have been removed from the standard's Applicability; therefore, Requirement R1 is now only applicable to the Planning Coordinator as a single entity source of identifying Elements. The drafting team asserts that the Planning Coordinator has or has access to the knowledge including the wide-area view. Change made to the Requirement.
Dominion	Yes	
FirstEnergy Corp.	Yes	

Organization	Yes or No	Question 2 Comment
Florida Power & Light	Yes	
PPL NERC Registered Affiliates	Yes	
DTE Electric	Yes	
Puget Sound Energy	Yes	
Arizona Public Service Co.	Yes	
Bureau of Reclamation	Yes	
Luminant Generation Company LLC	Yes	
Ingleside Cogeneration LP	Yes	
Los Angeles Department of Water and Power	Yes	
Masschusetts	Yes	

Organization	Yes or No	Question 2 Comment
Attorney General		
MidAmerican Energy Company	Yes	
Consolidated Edison, Inc.	Yes	
American Transmission Company, LLC	Yes	
Manitoba Hydro	Yes	
Independent Electricity System Operator	Yes	
David Kiguel	Yes	
ISO New England	Yes	
Exelon	Yes	
New York Power Authority	Yes	The Planning Coordinator, Reliability Coordinator, and Transmission Planner would have the necessary data and capabilities to perform such functions for internal control areas and interregional ties. Response: The Reliability Coordinator and Transmission Planner have been removed from the standard's Applicability; therefore, Requirement R1 is now only applicable to the Planning Coordinator as a single entity source of identifying Elements. The drafting team asserts that the Planning Coordinator has or has

Organization	Yes or No	Question 2 Comment
		access to the knowledge including the wide-area view. Change made to the Requirement.
Oncor Electric Delivery LLC	Yes	Oncor agrees that the three registered functions defined are those that should identify the elements in R1; however, if each criterion, except for criteria 4 as it would clearly come from the Transmission Planner, is assigned to a registered entity it would provide a more clear process. Response: The Reliability Coordinator and Transmission Planner have been removed from the standard's Applicability; therefore, Requirement R1 is now only applicable to the Planning Coordinator as a single entity source of identifying Elements. The drafting team asserts that the Planning Coordinator has or has access to the knowledge including the wide-area view. Change made to the Requirement. Additionally, R1 calls for "within the first month of each calendar year, identify and provide notification to the respective Generator Owner and Transmission Owner of each Element that meets one or more of the following criteria, if any" and then looking at criteria 1 and 2, Oncor recommends the SDT clarify the time frame, either real time/short term or future/long term, required. The Time Horizon does state "Long-term Planning" but it also calls for identification of the element within the first month of the calendar year. This would assist with whether or not planning data, which is done one year out, would be valid. See "line out condition" statement in Oncor's response to #6. Response: The Reliability Coordinator and Transmission Planner have been removed from the standard's Applicability; therefore, Requirement R1 is now only applicable to the Planning Coordinator as a single entity source of identifying Elements. The drafting team asserts that the Planning Coordinator has or has access to the knowledge including the wide-area view. Change made to the Requirement. The Requirement R1 language about "January of each calendar" has been removed and replaced with "each calendar year." Based on time period changes in other Requirements, the drafting team determined that an annual periodicity in Requirement R1 is more appropriate. Change made.
Texas Reliability Entity	Yes	A TOP may also provide an analyses in the Operations horizon that could identify other lines pursuant to the PSRSP technical document. Has the SDT considered the inclusion of TOP in the applicability?

Organization	Yes or No	Question 2 Comment
		Response: The Reliability Coordinator and Transmission Planner have been removed from the standard's Applicability; therefore, Requirement R1 is now only applicable to the Planning Coordinator as a single entity source of identifying Elements. The drafting team asserts that the Planning Coordinator has or has access to the knowledge including the wide-area view. The Planning Coordinator is believed to be the best single-source of information and not the Transmission Operator. Change made. The requirement as written implies that both the identification and notification of Elements must both be accomplished in January of each year. Identification can happen anytime each year, but notification must occur annually by January 31 each year. Suggest "Each year, each Planning Coordinator, Reliability Coordinator, and Transmission Planner shall identify, and by January 31 of each calendar year, provide notification..." Response: The Requirement R1 language about "January of each calendar" has been removed and replaced with "each calendar year." Based on time period changes in other Requirements, the drafting team determined that an annual periodicity in Requirement R1 is more appropriate. Change made.
Northeast Utilities	Yes	
Idaho Power Co.	Yes	Yes, although I suggest adding the stipulation that the PC, RC, and TP must be in agreement about whether an Element meets the criteria in R1. Response: The Reliability Coordinator and Transmission Planner have been removed from the standard's Applicability; therefore, Requirement R1 is now only applicable to the Planning Coordinator as a single entity source of identifying Elements. The drafting team asserts that the Planning Coordinator has or has access to the knowledge including the wide-area view. Change made to the Requirement.
Southern California Edison Company	Yes	
Salt River Project	Yes	

Organization	Yes or No	Question 2 Comment
Xcel Energy	Yes	We should recommend changing the frequency to every 3 to 4 years and changing the window to 3 to 6 months. It is troubling that the criteria (#4 in special) suggest that software used by planners should include detailed relay model. If approved, this will be huge work load for system protection engineering (SPE) and the planning department. Response: The Requirement R1 language about "January of each calendar" has been removed and replaced with "each calendar year." Based on time period changes in other Requirements, the drafting team determined that an annual periodicity in Requirement R1 is more appropriate. Change made. The drafting team asserts that the standard does not require the inclusion of relay models. Requirement R1 – Criterion 4 is not requiring a study, but the identification of any Element that was observed as tripping in the most recent Planning Assessment pursuant to TPL-001-4, Requirement R4, Part 4.3.1.3 – "Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models" which will become effective January 1, 2015 (U.S.). Other clarifying changes were made to Requirement R1 – Criterion 4.

3. Do you agree that the Generator Owner and Transmission Owner are the appropriate entities to identify the Elements that meet the criteria in Requirement R2? If not, please explain why an entity is not appropriate and/or suggest an alternative that should identify the Elements according to the criteria.

Summary Consideration: This section was evenly split between comments as to whether or not the Generator Owner and Transmission Owner are the appropriate entities to identify the Elements that meet the criteria in Requirement R2. Of the comments, there were two primary concerns not addressed in previous sections, one which resulted in a revision to the standard and the other no revision.

There were five comments by 18 stakeholders that were concerned about how the Generator Owner (GO) and Transmission Owner (GO) in Requirement R2 (now split between R2-TO and R3-GO) are to manage the record keeping for identified Elements as a result of a trip due to an actual power swing related Disturbance. In order to address this main concern, Requirement R2 (and the new R3) was modified to require the GO and TO to report any identified Elements to the Planning Coordinator. These Requirements allow the Planning Coordinator to be the sole source of channeling the "identified Elements" back to the GO and TO each year; therefore, a fifth Criterion was added to Requirement R1 that requires the Planning Coordinator (PC) to continue identifying a reported Element unless it determines the Element is no longer susceptible to power swings. This ensures visibility of the Elements reported by the GO or TO on an ongoing basis because the Element tripped in response to a power swing.

No change was made based on three comments by 34 individuals that the Generator Owner and Transmission Owners are not the most appropriate entities to evaluate load-responsive protective relay operations due to power swings. The drafting team contends that the Protection System owner (i.e., Generator Owner and Transmission Owner) is the appropriate entity for reviewing operations.

Organization	Yes or No	Question 3 Comment
Northeast Power Coordinating Council	No	Requirement R2 requires GOs and TOs to evaluate Disturbance records "since January 1, 2003," a time that will precede the effective date of this standard. A requirement CANNOT RELY UPON RECORDS THAT PRECEDE THE EFFECTIVE DATE OF A STANDARD. As an example, PRC-005-1, which was approved in Order 693, became effective on June 11, 2007, does not require a Registered Entity to have maintenance records available for the period of time that preceded the effective date in order to calculate the next maintenance interval for a relay. We recommend that this requirement be removed from the standard or include only Elements that were tripped in the last calendar year. Response: The "January 1, 2003" date has been removed from the standard. Requirement R2 (and new

Organization	Yes or No	Question 3 Comment
		R3) are based on actual Disturbances that occur after the Effective Date of the standard. Change made.
PacifiCorp	No	These functions would be more appropriate assigned to the GOP and TOP. Response: The drafting team contends that the Protection System owner (i.e., Generator Owner and Transmission Owner) is the appropriate entity for reviewing operations. No change made.
SMUD/BANC	No	The requirement R2 is particularly unacceptable as it requires data for pre June 18, 2007; effective date of Order 693 standards. Response: The "January 1, 2003" date has been removed from the standard. Requirement R2 (and new R3) are based on actual Disturbances that occur after the Effective Date of the standard. Change made.
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	No	The TOs and GOs are the owners of the protection systems whose operation is being addressed, but the GO does not have a system view of stable power swings. Response: The Generator Owner (GO) in Requirement R3 and Transmission Owner (GO) in Requirement R2 are required to report the Element that tripped during a Disturbance in response to a power swing. These Requirements allow the Planning Coordinator to be the sole source of funneling the "identified Elements" to the GO and TO. A fifth Criterion was added to Requirement R1 that requires the Planning Coordinator (PC) to continue identifying an Element "unless the PC determines the Element is no longer susceptible to power swings." This ensures visibility of the Elements reported by the GO or TO on an ongoing basis since the Element tripped in response to a power swing. Based on this comment and other comments, the Generator Owner was moved from Requirement R2 to the new Requirement R3 in order to remove the "islanding" criteria for Generator Owners. Change made. Requiring the GO and TO to look back to 2003 every year as specified by R2 is unreasonable. Looking backwards to consider problems known to have occurred is understandable, but requiring this every year is not reasonable. These trip investigations have been occurring in the industry long before the mandated PRC-004 operation reviews. Most responsible utilities have addressed undesirable protection system

Organization	Yes or No	Question 3 Comment
		misoperations to maximize availability - the market forces have long driven utilities to correct undesirable relay operations so they can be available to the market. Response: The "January 1, 2003" date has been removed from the standard. Requirement R2 (and new R3) are based on actual Disturbances that occur after the Effective Date of the standard. Change made.
ISO RTO Council Standards Review Committee	No	We ask whether the TO or GO, especially a GO, will have access to studies and fault analysis reports that will determine if the Disturbance remains credible. There seems to be an assumption in R2 that a fault analysis study was performed that documents the Disturbance and system conditions at the time. There must be a requirement in some NERC standard that obligates appropriate entities are notified of these results. Response: The term "credible" has been removed from the standard. The drafting team clarified Requirement R1, Criterion 3 by framing the criterion in the present tense to refer to the current assessment(s). Islands caused by natural phenomena (i.e., Disturbances) are covered under Requirement R2. Change made. We are unclear on the relevance or need to trace back to 2003 for Disturbances that caused an Element to trip due to a power swing or which formed the boundary of an island. Further, the term credible Disturbance needs clarification. Please see our comment under Q1, above. Response: The Generator Owner (GO) in Requirement R3 and Transmission Owner (GO) in Requirement R2 are required to report the Element that tripped during a Disturbance in response to a power swing. These Requirements allow the Planning Coordinator to be the sole source of funneling the "identified Elements" to the GO and TO. A fifth Criterion was added to Requirement R1 that requires the Planning Coordinator (PC) to continue identifying an Element "unless the PC determines the Element is no longer susceptible to power swings." This ensures visibility of the Elements reported by the GO or TO on an ongoing basis since the Element tripped in response to a power swing. Change made. This requirement should not be written with a date specific start point. Over time, this date would be meaningless and inappropriate for applying the standard. Instead this requirement could be written in a

Organization	Yes or No	Question 3 Comment
		rolling calendar basis, e.g. - “prior twelve months”. Response: The “January 1, 2003” date has been removed from the standard. Requirement R2 (and new R3) are based on actual Disturbances that occur after the Effective Date of the standard. Change made.
ACES Standards Collaborators	No	(1) We do not believe the GO or TO are appropriate entities. In fact, we do not believe any entity is appropriate to identify the Elements in R2 and that the requirements are not enforceable as written. NERC cannot compel evidence from dates prior to June 18, 2007, which is when FERC approved the first set of reliability standards. Furthermore, a new standard cannot compel data and evidence from before a time period that the standard was in effect. In today’s litigious society, many companies have data retention programs that result in the destruction of data that is not required to be retained. Thus, GOs and TOs may not have the data. How would they comply? We simply will never be able to support a standard requiring data retroactively. (2) The topology of the transmission system has changed significantly in many areas since the January 1, 2003. That is over 11 years from the drafting of the standard. It is simply unreasonable to assume that power swings that occurred in 2003 would occur in the same way and that the data is still applicable. Relying on 11-year old data simply does not provide a sound engineering basis. Response: The “January 1, 2003” date has been removed from the standard. Requirement R2 (and new R3) are based on actual Disturbances that occur after the Effective Date of the standard. Change made. (3) The islanding analysis conducted for PRC-006-1 R1 would form a better basis for identifying these Elements and could be used in place of this requirement. The PC could notify the TO and GO of the Elements at the boundaries of the islands and R2 could then be removed avoiding the issue of retroactive compliance. Response: The drafting team modified Requirement R1, Criterion 3 – to include island boundaries due to angular instability within an underfrequency load shedding (UFLS) assessment (i.e., PRC-006), and moved the Generator Owner to the new Requirement R3 in order to remove the “islanding” criteria for Generator Owners. Change made.

Organization	Yes or No	Question 3 Comment
FirstEnergy Corp.	No	It is understood that the "... since January 1, 2003" verbiage is intended to capture applicable relay operations during the Aug. 14, 2003 event. It will be difficult if not nearly impossible for a GO, especially in a deregulated environment, to piece together details of relay operations prior to record-keeping requirements for NERC PRC-004. We recommend that these Criteria be reworded to include only incidents which have occurred since the inception of NERC PRC-004. Response: The "January 1, 2003" date has been removed from the standard. Requirement R2 (and new R3) are based on actual Disturbances that occur after the Effective Date of the standard. Change made.
PPL NERC Registered Affiliates	No	We agree with R2 in principle, but there are presently some barriers to the specified stand-alone nature of GO and TO obligations: - R2 should state that, where Elements meet one or more of criteria 1-4, the TO must provide GOs with the system impedance data necessary to perform their studies (ref. the comment on p.24 of the Application Guidelines regarding taking into account the strength of the transmission system). GOs typically do not have automatic access to this data, and their "firewall" separation from TOs may impede such an information exchange unless it is mandated by NERC standards. Response: The standard is based on planning impedance models used in Protection System coordination that is commonly shared among entities. This information is not related to system status that would reveal that certain Elements that are not in-service; therefore, the drafting team does not see a conflict with the exchange of information or standards of conduct. The criteria requires all generation is in service and all transmission Elements are in their normal operating state when calculating the system impedance. - There has been to-date no obligation for entities to maintain records pertaining to the criteria specified in R2, so it may not be possible in all cases to perform the look-back to Jan. 1, 2003 mandated in this requirement. The criteria should therefore be changed to begin, "An Element that is known to have..," instead of, "An Element that has...." Response: The "January 1, 2003" date has been removed from the standard. Requirement R2 (and new

Organization	Yes or No	Question 3 Comment
		R3) are based on actual Disturbances that occur after the Effective Date of the standard. Change made. - GOs may not know whether their Elements formed the boundary of an island (ref. R2.2 GOs should not be required to take any actions under either R2.1 or R2.2 until and unless the PC/RC/TOP gives notification and provides the relevant necessary information to the GO. Response: The Generator Owner was moved from Requirement R2 to the new Requirement R3 in order to remove the "islanding" criteria for Generator Owners. Change made.
BC Hydro	No	BC Hydro does not agree that the criteria of R2 are reasonable. Only experience of tripping during STABLE power swings should be used. Response: Requirement R1 – Criterion 4, Requirement R2 – Criterion 1, and the new Requirement R3 – Criterion 1, were clarified by adding both "stable and unstable" power swings. Both stable and unstable power swings determine whether an Element will be identified as experiencing a power swing. Change made.
DTE Electric	No	It would seem that the GO and TO could need input from the PC, RC and TP to determine if the conditions are still credible, based on system studies. Response: Requirements R2 (TO) and the new R3 (GO) require the GO and TO to report the Element that tripped in response to a power swing. These requirements allow the Planning Coordinator to be the sole source of funneling the "identified Elements" to the GO and TO. A fifth Criterion was added to Requirement R1 that requires the PC to continue identifying an Element "unless the Planning Coordinator determines the Element is no longer susceptible to power swings." This ensures visibility of the Elements reported by the GO or TO on an ongoing basis since the Element tripped in response to a power swing. Change made.
Arizona Public Service Co.	No	AZPS believes that the GO and TO are not the appropriate entities to identify the Elements that meet the criteria in R2. The criteria of R2 would be determined based on event analysis and the GO's and TO's have

Organization	Yes or No	Question 3 Comment
		limited access to this information. Response: The drafting team contends that the Protection System owner (i.e., Generator Owner and Transmission Owner) is the appropriate entity for reviewing operations. No change made. Also, there are often joint participation projects which then include multiple owners. This would create confusion regarding who is supposed to complete the analysis. AZPS recommends that the RC be required to provide this information since they are necessarily involved in all significant system event analyses. Response: While a BES interrupting device may be contractually owned by multiple entities that are not jointly registered, all of the entities would ultimately be responsible for the requisite documentation and results. Contractually organized entities may share or designate compliance responsibilities as well as associated documentation. No change made.
Bureau of Reclamation	No	The Bureau of Reclamation (Reclamation) believes that the Transmission Planner or Planning Coordinator would be in the best position to determine whether Disturbances continue to be credible. Therefore, Reclamation suggests that the Transmission Planner or Planning Coordinator would be in the best position to identify the Elements in R2. The Transmission Planner or Planning Coordinator should be required to notify the Transmission Owner or Generator Owner of which Elements meet the criteria so that the Transmission Owner or Generator Owner can perform the R3 analysis. Response: The Reliability Coordinator and Transmission Planner have been removed from the standard's Applicability; therefore, Requirement R1 is now only applicable to the Planning Coordinator as a single entity source of identifying Elements. The drafting team asserts that the Planning Coordinator has or has access to the knowledge including the wide-area view. Change made to the Requirement. Reclamation also suggests that the criteria be rephrased to require analysis of data from the previous year only. As written, R2 would require Transmission Owners and Generator Owners to re-analyze data going back to 2003 each year. Response: The "January 1, 2003" date has been removed from the standard. Requirement R2 (and new

Organization	Yes or No	Question 3 Comment
		R3) are based on actual Disturbances that occur after the Effective Date of the standard. Change made. Reclamation believes that the costs of re-analyzing this data would outweigh the benefits. Reclamation believes that NERC should develop a data request to develop a robust initial data set covering January 2003 to present. Response: The drafting team increased the Implementation Plan to three years to provide for the initial influx of identified Elements under Requirement R1. The evaluation of relays under Requirement R4 (previously R3) is to be performed "within 12 full calendar months of receiving notification of an Element … where the evaluation has not been performed in the last three calendar years." Change made.
Luminant Generation Company LLC	No	See the response to Question 1. If R2 were modified as proposed in Question 1, then Luminant would agree that these are the appropriate entities. Response: Thank you for your comment. Please see response to Question 1.
Public Service Enterprise Group	No	We disagree with the need for this standard. However, this requirement is so egregious with regard to one item that we offer these comments so that similar language may never appear in any future standards.R2 requires GOs and TOs to evaluate Disturbance records "since January 1, 2003," a time that will precede the effective date of this standard. A requirement cannot rely upon records that precede the effective date of a standard. As an example, PRC-005-1, which was approved in Order 693, became effective on June 11, 2007, does not require a Registered Entity to have maintenance records available for the period of time that preceded the effective date in order to calculate the next maintenance interval for a relay. Response: The "January 1, 2003" date has been removed from the standard. Requirement R2 (and new R3) are based on actual Disturbances that occur after the Effective Date of the standard. Change made.
American Electric Power	No	Generator Owners may not have the information or expertise needed to determine if their Element formed the boundary of an island (R2 Criteria 2) or if the Disturbance that caused a trip or islanding

Organization	Yes or No	Question 3 Comment
		condition remains to be credible. Response: The term "credible" has been removed from the standard. The drafting team clarified Requirement R1, Criterion 3 by framing the criterion in the present tense to refer to the current assessment(s). Islands caused by natural phenomena (i.e., Disturbances) are covered under Requirement R2. The drafting team modified Requirement R1, Criterion 3 – to include island boundaries due to angular instability within an underfrequency load shedding (UFLS) assessment (i.e., PRC-006), and moved the Generator Owner to the new Requirement R3 in order to remove the "islanding" criteria for Generator Owners. Change made. It is unclear how the operation of Automatic Load Rejection (ALR) on a power generation unit during a system event affects applicability to R2 of the standard. The proper operation of a unit's ALR controls should not result in its automatic inclusion. Clarity is needed in this standard so that only those relays that operated for the observed or simulated power swings in R1 or R2 are applicable to R3. Response: Automatic Load Rejection controls are not load-responsive and therefore are not applicable to this standard. PRC-026-1 – Attachment A has been added to clarify the protective relay elements that are subject to the standard. Change made.
Tacoma Power	No	Tacoma Power disagrees with the need for this standard. Response: Thank you for your comment.
ISO New England	No	In R2, it is unrealistic to require an entity to provide data on an Element that had tripped since 2003. There is no existing NERC continent-wide disturbance monitoring or misoperation standard that requires data be retained more than 12 months. We recommend that this requirement be removed from the standard or include only Elements that were tripped in the last calendar year. Response: The "January 1, 2003" date has been removed from the standard. Requirement R2 (and new R3) are based on actual Disturbances that occur after the Effective Date of the standard. Change made.

Organization	Yes or No	Question 3 Comment
New York Power Authority	No	The Planning and Reliability Coordinator (ISO in our region) would have records of such disturbances for their control areas. TOs and GOs defer to the ISO to render all final decisions and designations in these types of matters. Response: Thank you for your comment.
MRO NERC Standards Review Forum	Yes	
Tennessee Valley Authority	Yes	
SPP Standards Review Group	Yes	
Dominion	Yes	
Florida Power & Light	Yes	
Duke Energy	Yes	Duke Energy does not agree with the TO and GO combing through 12 years of historical data and determining the events that were a result of a power swing. In addition, the GO and TO would have to maintain documentation of power swing events that have occurred since 2003 for every compliance audit. This would cause an unnecessary administrative burden on the responsible entity and should be viewed as a P81 candidate. A more appropriate set of criteria would be for the TO and GO to identify Elements in R2 that have occurred in the previous calendar year or in the previous audit cycle. Response: The “January 1, 2003” date has been removed from the standard. Requirement R2 (and new

Organization	Yes or No	Question 3 Comment
		R3) are based on actual Disturbances that occur after the Effective Date of the standard. Change made.
Florida Municipal Power Agency	Yes	There is a significant issue with R2 in that it “requires” entities to have records before 1/1/2003. Entities had no knowledge of needing to retain such records (i.e., the cause of a relay trip as a stable power swing). Even if PRC-004 misoperations are the source of such data, there is no requirement to retain records for longer than 12 months (PRC-004 has a 12 month data retention in Section D1.4), and certainly not before June 18, 2007. The requirement should only be on a going forward basis, not going back. Response: The “January 1, 2003” date has been removed from the standard. Requirement R2 (and new R3) are based on actual Disturbances that occur after the Effective Date of the standard. Change made. Note also that “Element” is the wrong term and “Facility” should be used. “Element applies to both BES (including distribution) and non-BES, Facilities is BES. Standards cannot be written to distribution. Response: Section 4.2, Facilities provides sufficient language that the standard is applicable to only “BES Elements.” No change made to the standard based upon the comment.
Puget Sound Energy	Yes	
Bonneville Power Administration	Yes	
Ingleside Cogeneration LP	Yes	
Los Angeles Department of Water and Power	Yes	
Masschusetts	Yes	

Organization	Yes or No	Question 3 Comment
Attorney General		
MidAmerican Energy Company	Yes	
Consolidated Edison, Inc.	Yes	See comment #4 under Question #1. In R2, it is unrealistic to require an entity to provide data on an Element that had tripped since 2003. There is no existing NERC continent-wide disturbance monitoring or misoperation standard that requires data be retained more than 12 months. We recommend that this requirement be removed from the standard or include only Elements that were tripped in the last calendar year. Response: The "January 1, 2003" date has been removed from the standard. Requirement R2 (and new R3) are based on actual Disturbances that occur after the Effective Date of the standard. Change made.
Electric Reliability Council of Texas, Inc.	Yes	
American Transmission Company, LLC	Yes	
Manitoba Hydro	Yes	
Independent Electricity System Operator	Yes	We agree that the Generator Owner and Transmission Owner are the appropriate entities to identify the Elements that meet the criteria in Requirement R2. However, we question the relevance or need to trace back to 2003 for Disturbances that caused an Element to trip due to a power swing or which formed the boundary of an island. Response: The "January 1, 2003" date has been removed from the standard. Requirement R2 (and new

Organization	Yes or No	Question 3 Comment
		R3) are based on actual Disturbances that occur after the Effective Date of the standard. Change made. Further, the term credible Disturbance needs clarification. Please see our comment under Q1, above. Response: Thank you for your comment. Please see the response in Question 1 above.
David Kiguel	Yes	
Ameren	Yes	
Exelon	Yes	
Oncor Electric Delivery LLC	Yes	As currently drafted, R2 requires GOs and TOs to evaluate Disturbance records "since January 1, 2003," a time that will precede the effective date of this standard. A requirement cannot rely upon records that precede the effective date of a standard. As an example, PRC-005-1, which was approved in Order 693, became effective on June 11, 2007, does not require a Registered Entity to have maintenance records available for the period of time that preceded the effective date in order to calculate the next maintenance interval for a relay. CAN-0008 specifically states "CEAs are not to require registered entities to produce records of testing and maintenance activities conducted prior to June 18, 2007, because keeping such records was not mandatory at that time. Therefore, CEAs are only to require production of actual maintenance and testing records from June 18, 2007 forward." Oncor would hope the same applies across all Standards and Requirements. Response: The "January 1, 2003" date has been removed from the standard. Requirement R2 (and new R3) are based on actual Disturbances that occur after the Effective Date of the standard. Change made.
Texas Reliability Entity	Yes	The GO and TO are the appropriate responsible entities. The timeframe appears identified in Criteria 1 and 2 back to January 1, 2003 appears onerous. The Northeast Blackout should provide the impetus to look at power swings but may not need to be the basis for the timeframe. Suggestion is to leave date out; auditor discretion would tend to indicate "since last audit".

Organization	Yes or No	Question 3 Comment
		Response: The "January 1, 2003" date has been removed from the standard. Requirement R2 (and new R3) are based on actual Disturbances that occur after the Effective Date of the standard. Change made. Clarification is requested for Criteria 1 and 2 regarding the term "credible"; who is responsible for determining "credible" (is it tied to TPL-001-4)? Response: The term "credible" has been removed from the standard. The drafting team clarified Requirement R1, Criterion 3 by framing the criterion in the present tense to refer to the current assessment(s). Islands caused by natural phenomena (i.e., Disturbances) are covered under Requirement R2. Change made.
ITC	Yes	We agree the GO and TO are the appropriate entities. However, we suggest removing the inclusion of events prior to the effective date of this standard. Response: The "January 1, 2003" date has been removed from the standard. Requirement R2 (and new R3) are based on actual Disturbances that occur after the Effective Date of the standard. Change made.
Northeast Utilities	Yes	See comment #4 under Question #1. In R2, it is unrealistic to require an entity to provide data on an Element that had tripped since 2003. There is no existing NERC continent-wide disturbance monitoring or misoperation standard that requires data be retained more than 12 months. We recommend that this requirement be removed from the standard or include only Elements that were tripped in the last calendar year. Response: The "January 1, 2003" date has been removed from the standard. Requirement R2 (and new R3) are based on actual Disturbances that occur after the Effective Date of the standard. Change made.
Idaho Power Co.	Yes	Yes if the Requirement is better written to address the comments of question 1. In addition, the GOP and TOP may also need to be included to fully identify disturbances. Response: The Reliability Coordinator and Transmission Planner have been removed from the standard's Applicability; therefore, Requirement R1 is now only applicable to the Planning Coordinator as a single

Organization	Yes or No	Question 3 Comment
		entity source of identifying Elements. The drafting team asserts that the Planning Coordinator has or has access to the knowledge including the wide-area view. Change made to the Requirement. R2 requires entities to rely on records prior to the effective date of the standard - records the entities did not know they were required to keep for this purpose. Either strike R2 or change the wording such that R2 applies to Disturbances that have happened after the effective date of the standard Response: The “January 1, 2003” date has been removed from the standard. Requirement R2 (and new R3) are based on actual Disturbances that occur after the Effective Date of the standard. Change made.
Southern California Edison Company	Yes	
Public Utility District No. 1 of Cowlitz County, WA	Yes	Provided the SDT finds a way to clearly establish the documentation from which the GO and TO will identify the Elements. Response: The drafting team modified Requirement R1, Criterion 3 – to include island boundaries due to angular instability within an underfrequency load shedding (UFLS) assessment (i.e., PRC-006), and moved the Generator Owner to the new Requirement R3 in order to remove the “islanding” criteria for Generator Owners. Change made.
Salt River Project	Yes	
Xcel Energy	Yes	This requirement is a labor intensive, and it is meaningless to perform annually as the system dynamics do not change as fast. It should be recommended to change the frequency to every 4 years. Response: The drafting team increased the Implementation Plan to three years to provide for the initial influx of identified Elements under Requirement R1. The evaluation of relays under Requirement R4 (previously R3) is to be performed “within 12 full calendar months of receiving notification of an Element … where the evaluation has not been performed in the last three calendar years.” Change made. Further, it is unreasonable to set up the criteria to date back to 2003; this should be 4 years from the date

Organization	Yes or No	Question 3 Comment
		of approval at maximum. Response: The "January 1, 2003" date has been removed from the standard. Requirement R2 (and new R3) are based on actual Disturbances that occur after the Effective Date of the standard. Change made. There is no mechanism specified to permit Generation and Transmission Owners to challenge the results of R2. In the event of a dispute, who arbitrates? Response: The Generator Owner (GO) in Requirement R3 and Transmission Owner (GO) in Requirements R2 are required to report the Element that tripped in response to a power swing. These requirements allow the Planning Coordinator to be the sole source of funneling the "identified Elements" to the GO and TO. A fifth Criterion was added to Requirement R1 that requires the Planning Coordinator (PC) to continue identifying an Element "unless the PC determines the Element is no longer susceptible to power swings." This ensures visibility of the Elements reported by the GO or TO on an ongoing basis since the Element tripped in response to a power swing. The term "credible" has been removed from the standard. Change made.

4. Do you agree with the approach in Requirement R3 to ensure that load-responsive protective relays do not trip in response to stable power swings during non-Fault conditions for an identified Element? If not, please explain.

Summary Consideration: Overwhelmingly 68% of commenter disagreed with the approach in Requirement R3 to ensure that load-responsive protective relays do not trip in response to stable power swings during non-Fault conditions for an identified Element. There were two significant revisions based on comments. The first revision came as a result of 14 comments supported by 88 stakeholders that, in summary, were confused about the performance of Requirement R3 (now R4 in draft 2). To address all of the concerns, the previous Requirement R3 was split into a new Requirement R4 (evaluation) and a new R5 (corrective action). The requirement for reaching agreements with the Planning Coordinator, Reliability Coordinator, and Transmission Planner has been eliminated from Requirements R4 and R5. The new Requirement R4 requires an evaluation of the existing load-responsive protective relays against the criteria now defined in PRC-026-1 – Attachment B. If the existing load-responsive protective relays do not meet the criteria, the new Requirement R5 requires the applicable entity to develop a Corrective Action Plan (CAP) to modify the Protection System to meet the PRC-026-1 – Attachment B Criteria while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the Element).

Second, 8 comments by 39 individuals questioned what is a “load-responsive protective relay.” The term and type of relay is widely understood and is any protective functions which could trip with or without time delay on load current. To address the concerns, a clarification has been provided in PRC-026-1 – Attachment A to not only list what is included, but also certain exclusions.

Organization	Yes or No	Question 4 Comment
Northeast Power Coordinating Council	No	The Purpose of the standard is “To ensure that load-responsive protective relays do not trip in response to stable power swings during non-Fault conditions.” The last sentence of Background, Section 5 implies that a protective relay, while blocking for a stable power swing also allows for dependable operation for fault and unstable power swing. Requirement R3 Bullet #4 is contrary to the Purpose of the standard. The sub-Parts of R3 Bullet 4 are “or”, which means that if there isn’t dependable fault detection or dependable out-of-step tripping, agreement would just have to be obtained from the respective Planning Coordinator, Reliability Coordinator, and Transmission Planner of the Element that the existing Protection System design and settings are acceptable. The sub-Parts of R3 Bullet should be an “and”. Item b under the fourth bullet in Requirement R3 is not stated using clear and unambiguous language whereby responsible entities, using reasonable judgment, are able to arrive at a consistent interpretation of the required

Organization	Yes or No	Question 4 Comment
		performance. The R3 Rationale and the Protection System Response to Power Swings technical document provide some clarity; however, the fourth bullet is not clear and troublesome from a compliance perspective. Suggest to consider revising the fourth bullet to ensure the responsible entity understands the balance between security and dependability and how that is to be achieved by either sub-parts “a” or “b”. The standard does not specify any time parameters for developing and correcting the conditions addressed by a CAP. We suggest that time parameters for developing and correcting the conditions addressed by the CAP be addressed within the requirements of the standard. Response: The Purpose statement was modified to note that the purpose is to ensure that relays “are expected to not trip.” The previous Requirement R3 has been split into a new Requirement R4 (evaluation) and a new R5 (corrective action). The new Requirement R4 requires an evaluation of the existing load-responsive protective relays against the criteria now defined in PRC-026-1 – Attachment B. If the existing load-responsive protective relays do not meet the criteria, the new Requirement R5 requires the applicable entity to develop a Corrective Action Plan (CAP) to modify the Protection System to meet the PRC-026-1 – Attachment B Criteria while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the Element). Change made. Response: The Corrective Action Plan (CAP) has its own timetable and set of actions that are determined by the entity. The work necessary under the CAP may vary greatly depending on the work being performed; therefore, the drafting team has not specified any timeframes. No change made.
MRO NERC Standards Review Forum	No	The NSRF requests that the SDT provide additional details on how the Lens characteristic is derived and examples of its use with the system parameters that were calculated from the example. Response: Additional clarifications and examples have been added to the Guidelines and Technical Basis. Change made.
Tennessee Valley Authority	No	1) Every year is too often for this requirement. We recommend changing this to every 5 years. Response: The drafting team increased the Implementation Plan to three years to provide for the initial influx of identified Elements under Requirement R1. The evaluation of relays under Requirement R4

Organization	Yes or No	Question 4 Comment
		(previously R3) is to be performed "within 12 full calendar months of receiving notification of an Element … where the evaluation has not been performed in the last three calendar years." Change made. 2) We believe that the criterion is too specific for a regulatory document. It should allow entities to use their preferred methods for determining if a line is likely to trip during a stable power swing. Recommend changing the first bullet to: "...in response to a stable power swing based on either the criterion below or by another industry accepted method." Response: The criteria included in the standard are consistent with the NERC System Protection and Control (SPCS), *Protection System Response to Power Swings*, August 2013[8] (PSRPS Report). The basis for the criteria is documented in the Guidelines and Technical Basis. The drafting team has concluded that a single method for evaluating load-responsive protective relays is the most effective and efficient approach to achieve the reliability objective of the FERC order. No change made. 3) At the end of the fourth bullet it states "dependable out-of-step tripping". We recommend changing this to "dependable unstable power swing tripping". Response: The drafting team asserts that out-of-step tripping is understood as occurring during unstable power swings. No change made.
SPP Standards Review Group	No	We question the need for the annual assessment required in Requirement R3. PRC-005-2 satisfactorily covers the routine maintenance and testing of protective relays and this requirement would be redundant with those requirements. Additionally, only system changes (topology changes, load/generation changes, etc.) would impact the application of the relays applicable to this requirement. Thus they should only need to be reviewed or re-assessed if those types of changes occurred on the system. Response: The drafting team increased the Implementation Plan to three years to provide for the initial influx of identified Elements under Requirement R1. The evaluation of relays under Requirement R4

[8] NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)

Organization	Yes or No	Question 4 Comment
		(previously R3) is to be performed "within 12 full calendar months of receiving notification of an Element … where the evaluation has not been performed in the last three calendar years." Change made. We suggest that the 4th bullet under Requirement R3 be made a notification rather than the existing agreement. As stated, the requirement for agreement places unintended risk on the Planning Coordinator, Reliability Coordinator and Transmission Planner. While we agree that if there is no dependable fault detection or out of step tripping the Planning Coordinator, Reliability Coordinator and Transmission Planner would need to be notified, we are unclear how these registered functional entities would have the knowledge of each applicable entity's protection systems to be able to agree to a correct relay setting. Would the fact that the Planning Coordinator, Reliability Coordinator and Transmission Planner accepted the settings place the responsibility of a cascading event due to the undependable fault detection or out of step tripping on the shoulders of these entities? This risk should be solely placed with the experts that design and maintain protection systems. Both a. and b. under the last bullet of Requirement R3 require the Generator Owner and Transmission Owner to obtain agreement with the Planning Coordinator, Reliability Coordinator and Transmission Planner yet nothing in the standard requires the Planning Coordinator, Reliability Coordinator or Transmission Planner to provide that agreement. Generator Owner and Transmission Owner compliance may hinge on that agreement but there is no incentive for the Planning Coordinator, Reliability Coordinator or Transmission Planner to reach that agreement. We concur with AEP in that rather than requiring agreement, the requirement should only require notification of the Planning Coordinator, Reliability Coordinator and Transmission Planner by the Generator Owner and Transmission Owner. Response: The previous Requirement R3 has been split into a new Requirement R4 (evaluation) and a new R5 (corrective action). The requirement for reaching agreements with the Planning Coordinator, Reliability Coordinator, and Transmission Planner has been eliminated from Requirements R4 and R5. The new Requirement R4 requires an evaluation of the existing load-responsive protective relays against the criteria now defined in PRC-026-1 – Attachment B. If the existing load-responsive protective relays do not meet the criteria, the new Requirement R5 requires the applicable entity to develop a Corrective Action Plan (CAP) to modify the Protection System to meet the PRC-026-1 – Attachment B Criteria while

Organization	Yes or No	Question 4 Comment
		maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the Element). Change made.
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	No	The method defined in R3 should be an option for determining susceptibility of a given relay, but the requirement should be for the responsible entity to develop criteria to determine susceptibility of a given relay to tripping for stable power swings and then other requirements to demonstrate the adherence to and compliance with those criteria. Response: The criteria included in the standard are consistent with the NERC System Protection and Control (SPCS), *Protection System Response to Power Swings*, August 2013[9] (PSRPS Report). The basis for the criteria is documented in the Guidelines and Technical Basis. The drafting team has concluded that a single method for evaluating load-responsive protective relays is the most effective and efficient approach to achieve the reliability objective of the FERC order. No change made. If the prescriptive method of R3 remains in the standard, R3, bullet #4 (b), should explicitly state that it is acceptable for the modifications specified in the CAP not to result in meeting the criteria of R3. Response: The previous Requirement R3 has been split into a new Requirement R4 (evaluation) and a new R5 (corrective action). The requirement for reaching agreements with the Planning Coordinator, Reliability Coordinator, and Transmission Planner has been eliminated from Requirements R4 and R5. The new Requirement R4 requires an evaluation of the existing load-responsive protective relays against the criteria now defined in PRC-026-1 – Attachment B. If the existing load-responsive protective relays do not meet the criteria, the new Requirement R5 requires the applicable entity to develop a Corrective Action Plan (CAP) to modify the Protection System to meet the PRC-026-1 – Attachment B Criteria while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the Element). The drafting team contends that meeting the criteria in Requirement R4 (previously R3) while maintaining

[9] NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)

Organization	Yes or No	Question 4 Comment
		dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the Element) is achievable. Therefore, the items 'a' and 'b' under previous Requirement R3, bullet #4 were removed from the standard. The criteria in the PRC-026-1 – Attachment B referenced in Requirement R4 (previously R3) allows some flexibility in the separation angle if supported by a documented stability analysis. Change made.
ISO RTO Council Standards Review Committee	No	R3 and its bulleted items need to be clarified that they apply to the load-responsive relays only, to be consistent with the purpose and scope of the standard, not the Protection System which could include other protective relays or components. However, if the standard is to ensure that Elements do not trip in response to stable power swings during non-Fault conditions, then all references to Protection Systems should be replaced with load-responsive relays. Response: The term "load-responsive protective relays" is widely understood and is any protective functions which could trip with or without time delay, on load current. A clarification has been provided in PRC-026-1 – Attachment A. The drafting team split the previous Requirement R3 into a new Requirement R4 (evaluation) and R5 (corrective action) and included the phrase "load-responsive protective relays" where it uniquely applies to a Protection System. Change made. We are concerned that holding relay engineers to limit load-responsive protection schemes to meet these settings in order to be compliant may not always be in the best interest of bulk power system reliability. Although it is good practice to see that facilities can withstand transients that are expected to dissipate and not pose a recurring threat to the grid, requiring these settings to always be adhered to takes away the ability for the relay engineer to apply engineering judgment if there are conflicting needs to allow for tripping the load-responsive relays in order to protect from another more imposing system threat. These relays are primarily to protect from a specific condition identified by studied and credible faults. This setting may be inside the trip circle identified by the stable power swing. In these cases, the relay engineer makes a best judgment to ensure a balance between which threat is more relevant or immediate to make the appropriate setting. The standard should allow for entities to provide technical evidence that a load-

Organization	Yes or No	Question 4 Comment
		responsive relay may have to be set within a trip circle of a stable power swing, if there is no other protection scheme available to mitigate the primary threat. Response: The previous Requirement R3 has been split into a new Requirement R4 (evaluation) and a new R5 (corrective action). The requirement for reaching agreements with the Planning Coordinator, Reliability Coordinator, and Transmission Planner has been eliminated from Requirements R4 and R5. The new Requirement R4 requires an evaluation of the existing load-responsive protective relays against the criteria now defined in PRC-026-1 – Attachment B. If the existing load-responsive protective relays do not meet the criteria, the new Requirement R5 requires the applicable entity to develop a Corrective Action Plan (CAP) to modify the Protection System to meet the PRC-026-1 – Attachment B Criteria while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the Element). Change made.
Dominion	No	Item b under the 4th bullet in Requirement R3 is not stated using clear and unambiguous language whereby responsible entities, using reasonable judgment, are able to arrive at a consistent interpretation of the required performance. The R3 rationale and the Protection System Response to Power Swings technical document provide some clarity; however, the simple fact is the 4th bullet is not clear and troublesome from a compliance perspective. Dominion suggest revising the 4th bullet to ensure the responsible entity understands the balance between security and dependability and how that is to be achieved by either sub-parts a or b. Response: The previous Requirement R3 has been split into a new Requirement R4 (evaluation) and a new R5 (corrective action). The requirement for reaching agreements with the Planning Coordinator, Reliability Coordinator, and Transmission Planner has been eliminated from Requirements R4 and R5. The new Requirement R4 requires an evaluation of the existing load-responsive protective relays against the criteria now defined in PRC-026-1 – Attachment B. If the existing load-responsive protective relays do not meet the criteria, the new Requirement R5 requires the applicable entity to develop a Corrective Action Plan (CAP) to modify the Protection System to meet the PRC-026-1 – Attachment B Criteria while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is

Organization	Yes or No	Question 4 Comment
		applied at the terminal of the Element). The drafting team contends that meeting the criteria in Requirement R4 (previously R3) while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the Element) is achievable. Therefore, the items 'a' and 'b' under previous Requirement R3, bullet #4 were removed from the standard. The criteria in the PRC-026-1 – Attachment B referenced in Requirement R4 (previously R3) allows some flexibility in the separation angle if supported by a documented stability analysis. Change made.
FirstEnergy Corp.	No	It would be most helpful to specify protective functions (e.g., 78, 21, 67, 40?) to be included in this analysis, similar to what was done with the Criteria Tables in PRC-025. If the reference to "load-responsive protective relay" in PRC-026-1 R2 means the same as where this terminology is used (and defined) in PRC-025, the scope of work required for the detailed analysis specified in PRC-026-1 R3 is quite significant. Response: The term "load-responsive protective relays" is widely understood and is any protective functions which could trip with or without time delay, on load current. A clarification has been provided in PRC-026-1 – Attachment A. Change made. Technical resources to perform this analysis on each applicable relay could be difficult for many GOs to commit or obtain, and it would be difficult to accomplish the analyses in a short timeframe. One year is unrealistic, especially considering the concern stems from an incident that occurred nearly eleven years ago. Response: The "January 1, 2003" date has been removed from the standard. Requirement R2 (and new R3) are based on actual Disturbances that occur after the Effective Date of the standard. The drafting team revised Requirement R4 (previously R3) from "each calendar year" to "within 12 full calendar months of receiving notification of an Element pursuant to Requirement R1 or within 12 full calendar months of identifying an Element pursuant to Requirement R2 or R3," "where the evaluation has

Organization	Yes or No	Question 4 Comment
		not been performed in the last three calendar years." Change made. Further, an annual demonstration with associated evidence is potentially financially burdensome, and seemingly unnecessary if there are no changes to a Unit's protection system. Changes to applied protection are already captured via the coordination requirement in PRC-001, and are available to the PC, RC and TP. Response: The drafting team modified the Implementation Plan (to 36 months) and several Requirements to provide additional time to reduce the burden. Also, the standard is consistent with the PSRPS Report which recommends a focused approach to identifying Elements that are most susceptible to power swings and therefore reduces the financial burden by not requiring all relays to be in scope. Changes made. Again, in a regulated vs. competitive environment, it may be difficult to obtain system data needed for such calculations. However, if the only piece of information needed from the TO is a Thévenin impedance (system equivalent) at the Point of Interconnection, acquiring this should not be a problem. Response: The Application Guidelines have been clarified that the only requirement for the GO is to have the Thévenin impedance (system equivalent). Change made.
PPL NERC Registered Affiliates	No	We agree with R3 in principle, but there are presently some barriers to the specified stand-alone nature of GO and TO obligations: - The statement, "Demonstrate that the existing Protection System is not expected to trip in response to a stable power swing based on the criterion below," in R3 should be replaced by, "Demonstrate that the existing Protection System is programmed per the criterion below." The reason for this change is that, while the criterion on p.6 of PRC-026-1 is the appropriate "textbook" way of setting-up an out-of-step relay, the genuinely authoritative means of showing that tripping will not occur for stable power swings is by use of a transient stability program as discussed in the first paragraph on p.24 of the Application Guidelines. Such programs are far from simple to set-up and operate however, GOs do not typically have or run them, and the system data required is known only to the TO and TOP. The requirements and Application Guidelines should make it clear that GOs have no involvement with transient stability

Organization	Yes or No	Question 4 Comment
		programs. Response: The drafting team modified the criteria now contained in PRC-026-1 – Attachment B from “an angle less than 120 degrees as agreed upon” to “an angle less than 120 degrees where a documented stability analysis demonstrates the expected maximum stable separation angle is less than 120 degrees.” Change made. The Guidelines and Technical Basis have been supplemented to address the concern of how to perform the evaluation of the relays. Examples demonstrate a means other than the use of stability analysis programs. The same techniques or concepts used in transmission applications are also used for generator applications. Change made. - The statement, “For cases where infeed affects the apparent impedance (multiple unit connected generators connected to a transmission switchyard), the Generator Owner will provide the unit and relay data to the Transmission Planner for analysis,” indicates that compliance responsibility can as a matter of practicality shift to another entity under certain circumstances, but the requirements do not ensure that such transactions happen. The, “obtain agreement,” alternatives under the 4th bull-dot of R3 do not obligate the PC/RC/TOP to perform studies or take other actions to help facilitate compliance under R3. PRC-026-1 needs revision to explicitly define the circumstances and mechanisms for multiple-entity collaboration in performing analyses. Response: The previous Requirement R3 has been split into a new Requirement R4 (evaluation) and a new R5 (corrective action). The requirement for reaching agreements with the Planning Coordinator, Reliability Coordinator, and Transmission Planner has been eliminated from Requirements R4 and R5. The new Requirement R4 requires an evaluation of the existing load-responsive protective relays against the criteria now defined in PRC-026-1 – Attachment B. If the existing load-responsive protective relays do not meet the criteria, the new Requirement R5 requires the applicable entity to develop a Corrective Action Plan (CAP) to modify the Protection System to meet the PRC-026-1 – Attachment B Criteria while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the Element). Change made.

Organization	Yes or No	Question 4 Comment
Florida Municipal Power Agency	No	See response to Question 1, the TO/GO should only respond to those issued identified by the PC/TP and not all Facilities that meet the criteria of R1. Response: The drafting team asserts that it has implemented an approach consistent with the recommendations of the NERC System Protection and Control Subcommittee (SPCS) technical report, *Protection System Response to Power Swings*, August 2013[10] (PSRPS Report). The standard does not preclude the Planning Coordinator providing information to the Generator Owner or Transmission Owner about the Element and any known stability issues, power swings, or apparent impedance characteristics; however, the Elements need to be reported as a part of ensuring the Generator Owner and Transmission Owner are aware of Elements that are susceptible. Change made.
DTE Electric	No	Based on the criterion for R3, it appears that only impedance relays are in scope. What about other relay types? Specific criteria for all relay types should be provided along with examples on how to demostrate a no trip response. Response: The term "load-responsive protective relays" is widely understood and is any protective functions which could trip with or without time delay, on load current. A clarification has been provided in PRC-026-1 – Attachment A. Change made.
Arizona Public Service Co.	No	AZPS would recommend changing Protection System to load-responsive protective relays and define what type of relays qualifies as load-responsive protective relays. If the drafting team does not agree with defining load-responsive relays, they should specifically state the relay type (i.e. zone protection) rather than using the broader term Protection System. Response: The term "load-responsive protective relays" is widely understood and is any protective functions which could trip with or without time delay, on load current. A clarification has been provided in

[10] NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)

Organization	Yes or No	Question 4 Comment
		PRC-026-1 – Attachment A. Change made.
Luminant Generation Company LLC	No	Requirement R3 focuses on a method commonly used for transmission application. Generator Owners will not be able to use this method for elements that satisfy the criteria in Requirement R1 and R2 for impedance relays used at the generator terminals or at the high voltage side of the Generator Step-up Transformer. Transmission Planners have the tools and data to perform these studies. A requirement should be added for Transmission Planners to provide the data to the Generation Owners for elements that have stable power swings that challenge the relay. Luminant recommends the following additional requirement. "Each Planning Coordinator, Reliability Coordinator, and Transmission Planner shall, within the first quarter month of each calendar year provide to the identified Generator Owner or Transmission Owner pursuant to R1, the stable power swing characteristics (i.e. R-X vs time, current vs time plots, voltage and current vs time) and identified event information." In addition, the criterion in Requirement R3 considers distance relays which is a subset of load responsive relays used in Generating Facilities. Protective relays such as loss of field, time overcurrent, and voltage controlled overcurrent relays should be excluded and listed in an Attachment similar to PRC-023. Response: The standard does not preclude the Planning Coordinator from providing information to the Generator Owner (GO) or Transmission Owner (TO) about the Element and any known stability issues, power swings, or apparent impedance characteristics; however, the Elements need to be reported as a part of ensuring the GO and TO are aware of Elements that are susceptible. The Guidelines and Technical Basis have been supplemented to address the concern of how to perform the evaluation of the relays. Examples demonstrate a means other than the use of stability analysis programs. The same techniques or concepts used in transmission applications are also used for generator applications. The term "load-responsive protective relays" is widely understood and is any protective functions which could trip with or without time delay, on load current. A clarification has been provided in PRC-026-1 – Attachment A. Change made.

Organization	Yes or No	Question 4 Comment
Ingleside Cogeneration LP	No	ICLP agrees that the Transmission Owner and Generator Owner is in the best position to provide the equipment models and relay settings necessary to perform an adequate assessment. However, the application guidelines contain several statements that infer that the Transmission Planner must be involved in the process (e.g.; the TP must be consulted to validate the slip rates of power swing blocking schemes or if infeed affects the apparent impedance). In our view, there must be a mandatory means to engage the TP when such coordination is required. Otherwise, a TP could refuse to support the analysis for any reason, leaving the TO or GO to look for other less sufficient alternatives. Even if the Transmission Planner's reasons are justified, the Element owner may be found in violation of R3 due to circumstances out of their control. ICLP suggests that the same situation was addressed in the generator validation standards - which also requires GO/TP coordination to evaluate local system performance - and could be applied in PRC-026-1. Response: The previous Requirement R3 has been split into a new Requirement R4 (evaluation) and a new R5 (corrective action). The requirement for reaching agreements with the Planning Coordinator, Reliability Coordinator, and Transmission Planner has been eliminated from Requirements R4 and R5. The new Requirement R4 requires an evaluation of the existing load-responsive protective relays against the criteria now defined in PRC-026-1 – Attachment B. If the existing load-responsive protective relays do not meet the criteria, the new Requirement R5 requires the applicable entity to develop a Corrective Action Plan (CAP) to modify the Protection System to meet the PRC-026-1 – Attachment B Criteria while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the Element). The drafting team removed the Application Guidelines text regarding "slip rates" to avoid confusion. Change made.
Public Service Enterprise Group	No	We disagree with the need for this standard. Response: Thank you for your comment. Please see response in Question 1 above.
MidAmerican Energy Company	No	While the reliability concept of preventing unnecessary overtripping is understood, the NERC white paper supporting the PRC-026 standard indicated that tripping due to stable power swings neither contributed

Organization	Yes or No	Question 4 Comment
		to blackouts or increased the severity of blackouts since 1965. The NERC standards drafting team should consider limiting the scope in R1 and R3 to out-of-step transmission related protection systems specifically designed and installed to monitor weak ties between areas or islands. These systems would open tie-lines in predetermined locations between areas in an attempt to balance load and generation between groups of generators that swing together during the identified power swings. Response: The proposed standard is consistent with the PSRPS Report which recommends a focused approach to identifying Elements that are most susceptible to power swings. No change made.
American Electric Power	No	In reference to R3, bullet point four, sub items a and b, we do not believe it is necessary to obtain further agreement with the PC, RC and TP, as there is no benefit to reliability (since it was not possible to achieve dependability) and represents an unnecessary administrative burden. Rather, the TO should be required only to *notify* the PC, RC, and TP. The bullet points of R3 should be revised to replace “Demonstrate that the existing protection system is not expected to trip...” with “Demonstrate that the existing Protection System satisfies the criteria...”. This would prevent the GO or TO from being found non-compliant if they were to set the relaying in accordance with the criterion, but unforeseen events caused a relay to operate. Response: The previous Requirement R3 has been split into a new Requirement R4 (evaluation) and a new R5 (corrective action). The requirement for reaching agreements with the Planning Coordinator, Reliability Coordinator, and Transmission Planner has been eliminated from Requirements R4 and R5. The new Requirement R4 requires an evaluation of the existing load-responsive protective relays against the criteria now defined in PRC-026-1 – Attachment B. If the existing load-responsive protective relays do not meet the criteria, the new Requirement R5 requires the applicable entity to develop a Corrective Action Plan (CAP) to modify the Protection System to meet the PRC-026-1 – Attachment B Criteria while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the Element). Change made. We agree with the approach, but do not believe that R3 would need to be executed annually. It should

Organization	Yes or No	Question 4 Comment
		only need to be done once per relay until something about the relay in question or the transmission system in the immediate vicinity changes. Response: The drafting team increased the Implementation Plan to three years to provide for the initial influx of identified Elements under Requirement R1. The evaluation of relays under Requirement R4 (previously R3) is to be performed "within 12 full calendar months of receiving notification of an Element … where the evaluation has not been performed in the last three calendar years." Change made.
Consolidated Edison, Inc.	No	The purpose of the standard is "to ensure that load responsive relay do not trip in response to stable power swing during non-fault condition." The last sentence of Background, Section 5 implies that protective relay while blocking for a stable power swing also allows for dependable operation for fault and unstable power swing. Bullet #4 in R3 indicates that the GO and TO must obtain agreement if dependable protection or dependable out-of-step tripping is not provided by a protection system that is immune to a stable power swing. Bullet #4 seems to imply that the purpose of the standard is to ensure blocking for a stable power swing and dependable tripping for unstable power swing. The drafting team needs to be very clear in the standard what the intention is. For instance, a line current differential scheme is immune to stable and unstable power swing and will provide dependable tripping for fault. The criteria as written implies that this type of scheme will need to be modified or an agreement will need to be obtained from the PC, RC and TP to deploy since it does not provide dependable out-of-step tripping. Response: The Purpose statement was modified to note that the purpose is to ensure that relays "are expected to not trip." The previous Requirement R3 has been split into a new Requirement R4 (evaluation) and a new R5 (corrective action). The new Requirement R4 requires an evaluation of the existing load-responsive protective relays against the criteria now defined in PRC-026-1 – Attachment B. If the existing load-responsive protective relays do not meet the criteria, the new Requirement R5 requires the applicable entity to develop a Corrective Action Plan (CAP) to modify the Protection System to meet the PRC-026-1 – Attachment B Criteria while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the Element). Change made. An exclusion for current differential relay, pilot wire relay, and phase comparison relay was added to

Organization	Yes or No	Question 4 Comment
		Attachment A.
American Transmission Company, LLC	No	ATC requests that the SDT provide additional details on how the Lens characteristic is derived and examples of its use with the system parameters that were calculated from the example. Response: The Guidelines and Technical Basis have been supplemented to address the concern of how to perform the evaluation of the relays. Change made.
Independent Electricity System Operator	No	R3 and its bulleted items need to be clarified that they apply to the load-responsive relays only, to be consistent with the purpose and scope of the standard, not the Protection System which could include other protective relays or components. However, if the standard is to ensure that Elements do not trip in response to stable power swings during non-Fault conditions, then all references to Protection Systems should be replaced with load-responsive relays. Response: The drafting team split the previous Requirement R3 into a new Requirement R4 (evaluation) and R5 (corrective action) and included the phrase "load-responsive protective relays" where it uniquely applies to a Protection System. Change made. Bullet number four requires to prove dependable out-of-step tripping. However the entity may decide to use selective tripping when out- of-step conditions are detected. Studies show that in case of severe disturbance selective tripping when out-of step conditions are detected can increase the chance of creating successfully islands. We suggest changing the wording from "dependable out-of-step tripping" to "dependable out-of-step detection". Response: Requirement R4 (previously R3) and the new Requirement R5 were modified to provide clarity that dependable out-of-step tripping only applies if out-of-step tripping is applied at the terminal of an Element. Change made.
Tacoma Power	No	Tacoma Power disagrees with the need for this standard. However, assuming FERC does not provide reflief from its directive to develop this standard, the transient, rather than sub-transient, impedance may represent a better model. Granted, as noted in the Application Guidelines, the sub-transient impedance

Organization	Yes or No	Question 4 Comment
		would yield a more conservative assessment. Response: The drafting team made a modification to allow entities the option of using transient or sub-transient reactance. Change made.
Ameren	No	Even though we may be able to accept and appreciate the SDT's approach; our recommended changes to this approach are as follows: (1) Change 1st sentence of Criterion to "Only load sensitive, high speed distance relays are within scope (e.g. zone 1 phase distance, pilot zone phase distance). For such a distance relay impedance characteristic, used for tripping, that is completely…." which adds the first sentence for clarity. We believe that this comment is consistent with the SDT's answers in NERC's 5/12/2014 webinar. Response: A clarification has been provided in PRC-026-1 – Attachment A. For example, relay elements that are intended to trip after time delays of 15 cycles or greater are excluded. Change made. (2) Change Criterion #3 to transient reactance, because it aligns better with power swing time constants (see Reimert text pages 40, 289, 291, and particularly bottom of page 302). Response: The drafting team made a modification to allow entities the option of using transient or sub-transient reactance. Change made. (3) Change 'once each calendar year' to 'within 2 calendar years of initial identification, and once every 5 calendar years thereafter' because once each calendar year is too frequent. Response: The drafting team increased the Implementation Plan to three years to provide for the initial influx of identified Elements under Requirement R1. The evaluation of relays under Requirement R4 (previously R3) is to be performed "within 12 full calendar months of receiving notification of an Element … where the evaluation has not been performed in the last three calendar years." Change made.
ISO New England	No	The option under the fourth bullet requires that the Generator Owner and Transmission Owner obtain agreement from the respective Planning Coordinator, Reliability Coordinator and Transmission Planner of the Element that either: (a) the existing Protection System design and settings are acceptable, or (b) a

Organization	Yes or No	Question 4 Comment
		modification of the Protection System design, settings or both are acceptable and develop a corrective action plan for this modification of the corrective action plan. This requires specialized knowledge and coordination that is not typical for Planning and Reliability Coordinators. Response: The previous Requirement R3 has been split into a new Requirement R4 (evaluation) and a new R5 (corrective action). The requirement for reaching agreements with the Planning Coordinator, Reliability Coordinator, and Transmission Planner has been eliminated from Requirements R4 and R5. The new Requirement R4 requires an evaluation of the existing load-responsive protective relays against the criteria now defined in PRC-026-1 – Attachment B. If the existing load-responsive protective relays do not meet the criteria, the new Requirement R5 requires the applicable entity to develop a Corrective Action Plan (CAP) to modify the Protection System to meet the PRC-026-1 – Attachment B Criteria while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the Element). Change made.
New York Power Authority	No	The more relevant approach, as is recommended by the PSRPS technical document, is that you do take corrective actions for unstable power swings. This was determined to be a far greater concern than not taking actions for stable swings. Response: The previous Requirement R3 has been split into a new Requirement R4 and a new R5. The new Requirement R4 requires an evaluation of the existing relays against the criteria now defined in PRC-026-1 – Attachment B. If the existing relays do not meet the criteria, the new Requirement R5 requires an entity to develop a Corrective Action Plan (CAP) to modify the Protection System to meet the PRC-026-1 – Attachment B Criteria A and B while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the Element). These changes remove the ambiguity around the previous Requirement R3 language. Change made. A more accurate description of "load responsive" protective relays is also necessary. Response: The term "load-responsive protective relays" is widely understood and is any protective functions which could trip with or without time delay, on load current. A clarification has been provided in

Organization	Yes or No	Question 4 Comment
		PRC-026-1 – Attachment A. Change made. This Standard seems to just repeat what is in the PSRPS technical document, without the necessary elaborations needed for proper understanding. Response: The Guidelines and Technical Basis have been supplemented to address the concern of how to perform the evaluation of the relays. Change made.
Oncor Electric Delivery LLC	No	See response to question #1. Response: See response in Question 1.
ITC	No	In general we agree with this approach. However, we disagree with requiring compliance of one entity to be contingent on another entities agreement. We recommend changing to require notification instead of "agreement" in the fourth bullet and Criterion 1, second bullet. Response: The Purpose statement was modified to note that the purpose is to ensure that relays "are expected to not trip." The previous Requirement R3 has been split into a new Requirement R4 (evaluation) and a new R5 (corrective action). The new Requirement R4 requires an evaluation of the existing load-responsive protective relays against the criteria now defined in PRC-026-1 – Attachment B. If the existing load-responsive protective relays do not meet the criteria, the new Requirement R5 requires the applicable entity to develop a Corrective Action Plan (CAP) to modify the Protection System to meet the PRC-026-1 – Attachment B Criteria while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the Element). The agreement has been removed from Bullet #2 of the criterion (now PRC-026-1 – Attachment B). The criterion now allows an angle less than 120 degrees to be used where a documented stability analysis demonstrates the expected maximum stable separation angle is less than 120 degrees. Change made.
Northeast Utilities	No	The purpose of the standard is "to ensure that load responsive relay do not trip in response to stable power swing during non-fault condition." The last sentence of Background, Section 5 implies that

Organization	Yes or No	Question 4 Comment
		protective relay while blocking for a stable power swing also allows for dependable operation for fault and unstable power swing. Bullet #4 in R3 indicates that the GO and TO must obtain agreement if dependable protection or dependable out-of-step tripping is not provided by a protection system that is immune to a stable power swing. Bullet #4 seems to imply that the purpose of the standard is to ensure blocking for a stable power swing and dependable tripping for unstable power swing. The drafting team needs to be very clear in the standard what the intention is. For instance, a line current differential scheme is immune to stable and unstable power swing and will provide dependable tripping for fault. The criteria as written implies that this type of scheme will need to be modified or an agreement will need to be obtained from the PC, RC and TP to deploy since it does not provide dependable out-of-step tripping. Response: The Purpose statement was modified to note that the purpose is to ensure that relays "are expected to not trip." The previous Requirement R3 has been split into a new Requirement R4 and a new R5. The new Requirement R4 requires an evaluation of the existing relays against the criteria now defined in PRC-026-1 – Attachment B. If the existing relays do not meet the criteria, the new Requirement R5 requires an entity to develop a Corrective Action Plan (CAP) to modify the Protection System to meet the PRC-026-1 – Attachment B Criteria A and B while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the Element). An exclusion for current differential relay, pilot wire relay, and phase comparison relay was added to PRC-026-1 – Attachment A. Change made.
Idaho Power Co.	No	No. The Requirement as written is onerous to perform annually. Performing these checks during an initial implementation period for the standard is appropriate to ensure the relays will perform as designed (for tripping or blocking). After an initial assessment period, a re-check at longer intervals or triggered by system changes would also be appropriate. Response: The drafting team increased the Implementation Plan to three years to provide for the initial influx of identified Elements under Requirement R1. The evaluation of relays under Requirement R4 (previously R3) is to be performed "within 12 full calendar months of receiving notification of an Element … where the evaluation has not been performed in the last three calendar years." Change made.

Organization	Yes or No	Question 4 Comment
		Further, as currently written, the R3 language requires one of the 4 bulleted items to be done, but the language on the 4th bullet implies that the first three be attempted first. If the first three are to be done prior to the 4th, should that bullet not be its own Requirement, such as an R3.1? Response: The previous Requirement R3 has been split into a new Requirement R4 and a new R5. The new Requirement R4 requires an evaluation of the existing relays against the criteria now defined in PRC-026-1 – Attachment B. If the existing relays do not meet the criteria, the new Requirement R5 requires an entity to develop a Corrective Action Plan (CAP) to modify the Protection System to meet the PRC-026-1 – Attachment B Criteria A and B while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the Element). These changes remove the ambiguity around the previous Requirement R3 language. Change made. The general approach is reasonable but an annual review is excessive. Bi-annually at the most and then by exception for any relay or system changes. Response: See response to first comment.
Southern California Edison Company	No	Although we appreciate the drafting team's efforts, we believe that Requirement R3 is unnecessarily burdensome from a compliance perspective. We would suggest that the analyses of Elements be performed on an initial basis, and then when changes occur. An annual analyses of all the Elements assets is not efficient or warranted. Response: The drafting team increased the Implementation Plan to three years to provide for the initial influx of identified Elements under Requirement R1. The evaluation of relays under Requirement R4 (previously R3) is to be performed “within 12 full calendar months of receiving notification of an Element … where the evaluation has not been performed in the last three calendar years.” Change made.
PacifiCorp	Yes	
ACES Standards	Yes	(1) We agree generally with the approach but note that there are specific issues.

Organization	Yes or No	Question 4 Comment
Collaborators		(2) First, we disagree with the sub-bullet requiring the GO or TO to obtain agreement from the PC, TP, and RC to retain existing Protection System settings to maintain dependable fault detection. Dependable fault detection is a safety issue. A TO or GO should not have to get agreement to maintain Protection System settings that are safe. The TO and GO should notify the PC, TP, RC and TOP of such issues and then the PC and TP can plan the system accordingly (i.e. meet the TPL standards) and the TOP can operate the system accordingly (i.e. meet the IROL standards). Response: The previous Requirement R3 has been split into a new Requirement R4 (evaluation) and a new R5 (corrective action). The requirement for reaching agreements with the Planning Coordinator, Reliability Coordinator, and Transmission Planner has been eliminated from Requirements R4 and R5. The new Requirement R4 requires an evaluation of the existing load-responsive protective relays against the criteria now defined in PRC-026-1 – Attachment B. If the existing load-responsive protective relays do not meet the criteria, the new Requirement R5 requires the applicable entity to develop a Corrective Action Plan (CAP) to modify the Protection System to meet the PRC-026-1 – Attachment B Criteria while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the Element). Change made. (3) Obtaining the agreement of the PC, RC, and TP is problematic and repeats similar problems that are associated with PRC-023 R3. PRC-023-2 R3 requires the GO, TO, and DP to obtain the agreement of the PC, RC and TOP to set the relay loadability using certain criteria. The problem is there is no obligation for the PC, RC or TOP to agree and they often are reluctant to agree due to legal liability. In other words, no one really knows what they are agreeing to or the implications except that the standard requires it. These same problems will be experienced here with this requirement. The need for the PC, TP and RC to agree should be removed or more specification should be provided for what this means. Response: The previous Requirement R3 has been split into a new Requirement R4 (evaluation) and a new R5 (corrective action). The requirement for reaching agreements with the Planning Coordinator, Reliability Coordinator, and Transmission Planner has been eliminated from Requirements R4 and R5. The new Requirement R4 requires an evaluation of the existing load-responsive protective relays against the criteria now defined in PRC-026-1 – Attachment B. If the existing load-responsive protective relays do not

Organization	Yes or No	Question 4 Comment
		meet the criteria, the new Requirement R5 requires the applicable entity to develop a Corrective Action Plan (CAP) to modify the Protection System to meet the PRC-026-1 – Attachment B Criteria while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the Element). Change made. (4) For the criterion, we disagree with the need to require the PC, RC, and TP to agree to use a system separation angle of less than 120 degrees. All that should be required is for the TO or GO to provide sound engineering justification for using an angle less than 120 degrees. Response: The drafting team modified the criteria now contained in PRC-026-1 – Attachment B from "an angle less than 120 degrees as agreed upon" to "an angle less than 120 degrees where a documented stability analysis demonstrates the expected maximum stable separation angle is less than 120 degrees." Change made.
Duke Energy	Yes	
BC Hydro	Yes	
Puget Sound Energy	Yes	While this approach seems reasonable, there is currently a lack of ability to model the load-responsive protective relays to determine whether a protection system is expected to trip in response to a stable power swing. While this capability is currently being implemented, it will not be completed by the proposed implementation date of this standard. Response: The drafting team asserts that the standard does not require the inclusion of relay models. Requirement R1, Criterion 4 is not requiring a study, but the identification of any Element that was observed as tripping in the most recent Planning Assessment pursuant to TPL-001-4, R4, Part 4.3.1.3 – "Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models" which becomes effective January 1, 2015 (U.S.). Other clarifying changes were made to Requirement R1, Criterion 4.

Organization	Yes or No	Question 4 Comment
Bonneville Power Administration	Yes	BPA believes R3 should be modified for greater clarity and to allow for intentional power swing relays designed to be tripped in a controlled manner to protect the BES. Additionally, the wording in the fourth bullet appears to be inconsistent with the Rationale for R3. Response: The previous Requirement R3 has been split into a new Requirement R4 (evaluation) and a new R5 (corrective action). The requirement for reaching agreements with the Planning Coordinator, Reliability Coordinator, and Transmission Planner has been eliminated from Requirements R4 and R5. The new Requirement R4 requires an evaluation of the existing load-responsive protective relays against the criteria now defined in PRC-026-1 – Attachment B. If the existing load-responsive protective relays do not meet the criteria, the new Requirement R5 requires the applicable entity to develop a Corrective Action Plan (CAP) to modify the Protection System to meet the PRC-026-1 – Attachment B Criteria while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the Element). Change made.
Bureau of Reclamation	Yes	
Masschusetts Attorney General	Yes	
Manitoba Hydro	Yes	
David Kiguel	Yes	
Exelon	Yes	
Texas Reliability Entity	Yes	Suggest substituting “R1 and R2” for “R1 or R2” to avoid the possibility of confusion. As written, it could be construed that GOs and TOs can choose to address either R1 or R2 and not address both R1 and R2. Response: The drafting team contends that the “or” in Requirement R3 (now R4) is correct. The Generator

Organization	Yes or No	Question 4 Comment
		Owner and Transmission Owner must evaluate its relays for each Element identified by the Planning Coordinator in Requirement R1, the Transmission Owner in Requirement R2, or Generator Owner in Requirement R3.
Salt River Project	Yes	
Xcel Energy	Yes	This requirement is a labor intensive, and it is meaningless to perform annually as the system dynamics do not change as fast. It should be recommended to change the frequency to every 4 years. Response: The drafting team increased the Implementation Plan to three years to provide for the initial influx of identified Elements under Requirement R1. The evaluation of relays under Requirement R4 (previously R3) is to be performed “within 12 full calendar months of receiving notification of an Element … where the evaluation has not been performed in the last three calendar years.” Change made. When seeking agreement from the Planning or Reliability Coordinator that existing settings or specific modifications are adequate, a specified response time is required to permit alternate actions to be undertaken, should agreement not be obtained. Response: The previous Requirement R3 has been split into a new Requirement R4 (evaluation) and a new R5 (corrective action). The requirement for reaching agreements with the Planning Coordinator, Reliability Coordinator, and Transmission Planner has been eliminated from Requirements R4 and R5. The new Requirement R4 requires an evaluation of the existing load-responsive protective relays against the criteria now defined in PRC-026-1 – Attachment B. If the existing load-responsive protective relays do not meet the criteria, the new Requirement R5 requires the applicable entity to develop a Corrective Action Plan (CAP) to modify the Protection System to meet the PRC-026-1 – Attachment B Criteria while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the Element). Change made.

5. Do you agree with the proposed Violation Risk Factors (VRF) and Violation Severity Levels (VSL) for the proposed requirements? If not, please provide a basis for revising a VRF and/or what would improve the clarity of the VSLs

Summary Consideration: Sixty percent of commenters favor the proposed Violation Risk Factors (VRF) and Violation Severity Levels (VSL) for the proposed requirements. There were no specific common comments and due to the significant changes to the Requirements in Draft 2, a summary is not being provided.

Organization	Yes or No	Question 5 Comment
SPP Standards Review Group	No	The VSLs for Requirement R1 should be changed in consideration to the point we made in our response to Question 2. Insert an 'an' between 'identified' and 'Element' in the VSLs for Requirement R2. Response: Correction made. References to 30-, 60-, and 90-calendar days should be hyphenated in the VSLs for Requirements R1, R2 and R3. Response: The use of a hyphen as suggested is not consistent with the NERC style guide.
ACES Standards Collaborators	No	(1) We agree that the VRFs for Requirement R1 through R3 should be no higher than medium. To be higher than medium, a violation of the requirement would have to lead directly to cascading, instability or system separation. Power swings were not direct causes to the August 14, 2003 blackout but rather occurred after other events had already happened. Response: Thank you for your comment. (2) We disagree with the VRF for Requirement R4. Requirement R4 is an administrative requirement to update paperwork (i.e. update the CAP). It does not and should compel completion of the CAP because it is impossible to complete construction by a certain date due to the unpredictability (e.g. weather, logistical, legal, or operational delays) of issues that delays construction.

Organization	Yes or No	Question 5 Comment
		Response: Requirement R6 (previously R4) requires the Corrective Action Plan to be updated in order to show progress and for measurability of implementation. No change made. (3) We cannot agree with the VSLs because we do not agree with the requirements. Furthermore, the VSLs anticipate that the only violation that could occur is a time violation. VSLs that are not just time-based need to be written. Response: The Violation Severity Levels are both performance of the activity and time-based. Generally, the first VSLs (i.e., Low, Med, High) are for performance that was done, but late. The VSL of Severe is generally for failure to perform the reliability activity. No change made.
PPL NERC Registered Affiliates	No	The VSL for failure to identify an Element in accordance with R2 needs to take into account the potential impossibility of performing a look-back to Jan. 1, 2003, as stated above. Response: The "January 1, 2003" date has been removed from the standard. Requirement R2 (and new R3) are based on actual Disturbances that occur after the Effective Date of the standard. Change made.
BC Hydro	No	BC Hydro does not agree with R1 and R2, therefore do not agree with violation risk factors or violation severity levels. Response: Thank you for your comment.
Florida Municipal Power Agency	No	Since a standard is not needed in the first place, then, there should be no VRF above a Low. All requirements should be Planning Horizon and none in Operating Horizon. Response: Thank you for your comment.
Arizona Public Service Co.	No	APS suggests the timelines associated with the proposed VSL for Requirement 1 be adjusted to a longer time period if drafting team addresses the APS issue associated with the timing requirements on R1. Response: The drafting team made revisions to the timing of Requirement R1 and did not make changes to the incremental timing of violations for tardiness in the Violation Severity Level (VSL) for Requirement

Organization	Yes or No	Question 5 Comment
		R1 based on the NERC Guidelines for VSLs.
Public Service Enterprise Group	No	We disagree with the need for this standard. Response: Thank you for your comment. Please see response in Question 1 above.
Peak Reliability	No	Peak Reliability disagrees with the assignment of the multiple VSL's for Requirements R1, R2 and R3 because the proposed VSLs simply increase the penalty for tardiness. Any delay in identifying and element is a reliability concern. Recommend changing the VSL as follows: R1 Lower VSL: The responsible entity identified an Element and provided notification in accordance with Requirement R1, but was late by less than or equal to 7 calendar days. R1 Severe VSL: The responsible entity failed to identify an Element or to provide notification in accordance with Requirement R1 or was late by more than 7 calendar days. Response: The drafting team contends that based on the revision to allow the Planning Coordinator a complete calendar year to identify Elements that meet the criteria, an incremental Violation Severity Level (VSL) meets the NERC Guidelines with the failure to identify an Element having a VSL of Severe (i.e., binary). No change made. R2 Lower VSL: The responsible entity identified Element in accordance with Requirement R2, but was late by less than or equal to 7 calendar days. R2 Severe VSL: The responsible entity failed to identify an Element in accordance with Requirement R2 or was late by more than 7 calendar days. Response: The drafting team contends that based on the revisions made to Requirement R2 and the new R3, an incremental Violation Severity Level (VSL) meets the NERC Guidelines with the failure to notify the Planning Coordinator of an Element having a VSL of Severe (i.e., binary). No change made. R3 Lower VSL: The responsible entity performed one of the options in accordance with Requirement R3, but was less than or equal to 7 calendar days late.

Organization	Yes or No	Question 5 Comment
		R# Severe VSL: The responsible entity performed one of the options in accordance with Requirement R3, but was more than 7 calendar days late or the responsible entity failed to perform one of the options in accordance with Requirement R3. Response: The drafting team contends that based on the revisions made to Requirement R4 (previously R3), an incremental Violation Severity Level (VSL) meets the NERC Guidelines with the failure to evaluate its load-responsive protective relays having a VSL of Severe (i.e., binary). No change made.
American Electric Power	No	The severe VSL for R1 and R2 could be interpreted that a lack of applicable elements would be a violation. It should be revised so that it is clear that the entity owns an element that should have been identified, but did not identify that element. Response: The drafting team modified the Violation Severity Levels (VSL) for Requirements R1, R2, and the new R3 to address the concern.
Tacoma Power	No	Tacoma Power disagrees with the need for this standard. In particular, Tacoma Power has significant concerns with Requirements R1 and R2. It is therefore difficult to provide additional feedback on the VRFs and VSLs at this time. Response: Thank you for your comment.
New York Power Authority	No	We do NOT agree with the need for this standard. Response: Thank you for your comment.
Oncor Electric Delivery LLC	No	See response to question #1. Response: Thank you for your comment. Please see the response in Question 1.
ITC	No	R2 and R3 essentially leave an entity with 11 months to meet compliance. The Violation Severity Levels should be longer, considering the timeframe allowed to complete the task and the minimal risk to the BES.

Organization	Yes or No	Question 5 Comment
		Response: The drafting team asserts that the incremental value for tardiness is consistent with the time periods provided in the revisions to the Requirement. The Violation Severity Levels have been updated to align with the Requirement changes.
Xcel Energy	No	As recommended above, it is recommended that the frequency to complete the tasks related to this standard to be changed to every 4 years. It is also recommended that the window for completing the tasks change to 3 to 6 months. The proposed VSL should change accordingly. Response: The drafting team asserts that the incremental value for tardiness is consistent with the time periods provided in the revisions to the Requirement. The Violation Severity Levels have been updated to align with the Requirement changes.
MRO NERC Standards Review Forum	Yes	
Tennessee Valley Authority	Yes	
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern	Yes	The requirement language should be finalized before establishing VRFs, VSLs. and measures. Response: Thank you for your comments.

Organization	Yes or No	Question 5 Comment
Company Generation; Southern Company Generation and Energy Marketing		
Dominion	Yes	
FirstEnergy Corp.	Yes	
Florida Power & Light	Yes	
Duke Energy	Yes	
Puget Sound Energy	Yes	
Bureau of Reclamation	Yes	
Luminant Generation Company LLC	Yes	
Ingleside Cogeneration LP	Yes	
Masschusetts Attorney General	Yes	

Organization	Yes or No	Question 5 Comment
MidAmerican Energy Company	Yes	
Consolidated Edison, Inc.	Yes	
American Transmission Company, LLC	Yes	
Manitoba Hydro	Yes	
Independent Electricity System Operator	Yes	
David Kiguel	Yes	
ISO New England	Yes	
Exelon	Yes	
Texas Reliability Entity	Yes	
Northeast Utilities	Yes	
Idaho Power Co.	Yes	

Organization	Yes or No	Question 5 Comment
Southern California Edison Company	Yes	
Public Utility District No. 1 of Cowlitz County, WA	Yes	
Salt River Project	Yes	
PacifiCorp		No comment
DTE Electric		No comment

6. Does PRC-026-1, Application Guidelines and Technical Basis provide sufficient guidance, basis for approach, and examples to support performance of the requirements? If not, please provide specific detail that would improve the Guidelines and Technical Basis

Summary Consideration: Over 75% of commenters disagreed that the PRC-026-1, Application Guidelines and Technical Basis provide sufficient guidance, basis for approach, and examples to support performance of the Requirements. Many of the comments here were also raised in previous questions. A summary of those are provided in other questions summaries. Among other things, the drafting team greatly enhanced the Guidelines and Technical Basis to include numerous examples, calculations, and figures.

Organization	Yes or No	Question 6 Comment
Northeast Power Coordinating Council	No	In the Application Guidelines, the wording under Requirement 2 for credible event is very ambiguous and needs specificity. Response: The term "credible" has been removed from the standard. The drafting team clarified Requirement R1, Criterion 3 by framing the criterion in the present tense to refer to the current assessment(s). Islands caused by natural phenomena (i.e., Disturbances) are covered under Requirement R2. Change made.
MRO NERC Standards Review Forum	No	The NSRF believes there is some significant discussion in the guidelines and technical basis. However, we recommend that the SDT provide more clear explanation of all of the important parameters. Response: Thank you for your comments.
SPP Standards Review Group	No	Requirement R2 calls for the responsible entities to identify Elements based on performance since January 1, 2003 which is before the effective date of the standard. During the webinar, the SDT indicated that although this requirement was included in the standard, it was not the intent of the SDT to hold the responsible entities accountable for this data. This exception should be included in the Application Guideline and especially in the RSAW. Response: The "January 1, 2003" date has been removed from the standard. Requirement R2 (and new R3) are based on actual Disturbances that occur after the Effective Date of the standard. Change made.

Organization	Yes or No	Question 6 Comment
		One-line diagrams for the examples in the explanations for Requirements R1 and R2 would be helpful. Response: The drafting team added clarifications and examples in the Guidelines and Technical Basis for Generator Owners. Change made. In the 3rd paragraph on Page 15, the SDT attempts to clarify the 2nd option under Requirement R3. The 1st sentence in the paragraph does just that. However, the next two sentences seem to go beyond the requirement by expanding the scope of the requirement. We propose to delete these last two sentences. Response: This problem has been addressed due to other changes to the Requirements.
ACES Standards Collaborators	No	(1) In general the guidelines provide a good explanation; however, we do identify some suggested improvements below. (2) We suggest modifying the end of the “Applicability” section on page 13 to clearly state that these load-serving facilities by definition would not be part of the BES. Thus, standards would not apply. Response: Section 4.2, Facilities provides sufficient language that the standard is applicable to only “BES Elements.” No change made to the standard based upon the comment. (3) The last sentence of the “Requirement R1” section on page 14 is too vague. As written, it could be interpreted that the PC and TP must include any Elements identified in the Planning Assessment for any reason (i.e. including non-power swing issues). This is inaccurate. Part 4 of the requirement is very specific to only those Elements with relays that trip due to stable power swings as identified in studies. Please update the guidelines to match the language of the requirement more closely. Response: The drafting team contends the requirement only applies to inclusions that are based on Elements tripping on stable or unstable power swings. The Guidelines and Technical Basis has changed significantly and provide additional guidance for Criterion 4. The sentence noted above has been removed. Change made.
FirstEnergy Corp.	No	It would be most helpful to specify protective functions (e.g., 78, 21, 67, 40?) to be included in this analysis, similar to what was done with the Criteria Tables in PRC-025. If the reference to “load-responsive

Organization	Yes or No	Question 6 Comment
		protective relay" in PRC-026-1 R2 means the same as where this terminology is used (and defined) in PRC-025, the scope of work required for the detailed analysis specified in PRC-026-1 R3 is quite significant. Response: The term "load-responsive protective relays" is widely understood and is any protective functions which could trip with or without time delay, on load current. A clarification has been provided in PRC-026-1 – Attachment A. Change made. Technical resources to perform this analysis on each applicable relay could be difficult for many GOs to commit or obtain, and it would be difficult to accomplish the analyses in a short timeframe. One year is unrealistic, especially considering the concern stems from an incident that occurred nearly eleven years ago. Response: The "January 1, 2003" date has been removed from the standard. Requirement R2 (and new R3) are based on actual Disturbances that occur after the Effective Date of the standard. Events that occur will be reported to the Planning Coordinator in order to maintain the Element as an "identified Element." Change made. This requirement should also be worded in such a way as to be sensitive to GOs operating in a competitive environment, where FERC Standard of Conduct issues make it difficult if not impossible to even know about power swings or other disturbances on the power system. Response: The drafting team contends that the Protection System owner (i.e., Generator Owner and Transmission Owner) is the appropriate entity for reviewing operations. No change made. Please define "stable power swing". The diagrams ("Figures") in the Application Guidelines appear to be typical. Response: The drafting team provided the general definitions in the Guidelines and Technical Basis. Change made. Is there enough information contained in the Application Guidelines that a GO can determine Power Swing Stability Boundaries for each specific application? Response: The Generator Owner was moved from Requirement R2 to the new Requirement R3 in order to

Organization	Yes or No	Question 6 Comment
		remove the "islanding" criteria for Generator Owners. Change made.
PPL NERC Registered Affiliates	No	In addition to our comments elsewhere in this document, the term, "load-responsive protective relays," needs definition, especially since its meaning appears to change from one standard to another. We view "out-of-step" devices as not being among the load-responsive protective relays governed by PRC-025-1, for example, but being included under PRC-026-1. Is the list on p.23 of the Application Guidelines meant to be exclusive? Response: The term "load-responsive protective relays" is widely understood and is any protective functions which could trip with or without time delay, on load current. A clarification has been provided in PRC-026-1 – Attachment A. Change made. The drafting team provided both inclusions ("including, but not limited to") and specific exclusions.
Duke Energy	No	On page 16 of the Application Guideline and Technical Basis document, paragraph 3 states, "...the Element passes the evaluation (Figures 6 and 7)." However, Figure 7 on page 23 states, "This Element does not pass the Requirement R3 evaluation." It appears that Figure 7 is incorrect with the statement on page 16. Response: The drafting team has rewritten of the Guidelines and Technical Basis to address inconsistencies, errors, and lack of detail. Change made.
BC Hydro	No	The technical basis should be improved to apply only to cases where stable power swings have historically caused undesirable tripping of transmission lines. Response: The drafting team asserts that the standard is proactively addressing the risk of load-responsive protective relays applied on Elements that are expected to have the greatest risk of exposure

Organization	Yes or No	Question 6 Comment
		to power swings. The standard is based on guidance from the NERC System Protection and Control Subcommittee (SPCS) *Protection System Response to Power Swings*, August 2013[11] (PSRPS Report) and includes Elements that trip during future events. No change made.
DTE Electric	No	Paragraph four on Page 23 of 61 of the PSRPS Report states that current-only based protection is immune to operating during power swingw, but the Application to Generator Owners paragraph on page 23 of 25 of the draft standard implies that time overcurrent relays are subject to incorrect operation caused by stable power swings. Perhaps this could be clarified. Response: The PSRPS Report pg. 23 states: "*Although current-only-based protection is immune to operating during power swings, exclusive use of current-only-based protection is not practical and would reduce dependability of tripping for system faults and unstable power swings. A power system with no remote backup protection is susceptible to uncleared faults and the inability to separate during unstable power swings during extreme system events. Although current-only-based protection is secure for stable power swings and can be used on lines which require tripping on out-of-step conditions, additional separate out-of-step protection is required. Application of impedance-based backup protection and, where necessary, out-of-step protection, reintroduces the need to discriminate between stable and unstable power swings*." The drafting team understands the section above to refer to line current differential schemes which are immune to power swings and not phase overcurrent schemes that are applicable to the standard. No change made. Since relay engineers are typically not familiar with transient stability studies, it would be helpful if more examples were provided for specific generator relay types that would be prone to operate for power

[11] NERC System Protection and Control Subcommittee. *Protection System Response to Power Swings*. August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf.

Organization	Yes or No	Question 6 Comment
		swings. Response: The drafting team added clarifications and examples in the Guidelines and Technical Basis for Generator Owners. Change made.
Luminant Generation Company LLC	No	The Application Guide should include examples for Generator Owners using distance relays. The example should provide illustrations of transient stability R-X plots in the time domain provided by the Transmission Planner in a format that allows the Transmission Owner and Generation Owner to plot distance relay settings. Response: The drafting team added clarifications and examples in the Guidelines and Technical Basis for Generator Owners. Change made.
Public Service Enterprise Group	No	We disagree with the need for this standard. Response: Thank you for your comment. Please see response in Question 1 above.
American Electric Power	No	The Application Guidelines and Technical Basis section makes a number of assumptions and expectations, which would be difficult to prove. For example, "If PSB is applied, it is expected that the relays were set in consultation with the Transmission Planner to verify maximum slip rates." Does such a quote imply an obligation to prove such consultation took place? This section should not imply or specify any obligations not contained elsewhere in the requirements. Response: The drafting team removed this text and notes the Guidelines and Technical Basis do not obligate the entity under the standard. Change made.
Consolidated Edison, Inc.	No	1. In the Application Guidelines, the wording under Requirement 2 for "credible event" is very open-ended. Response: The term "credible" has been removed from the standard. The drafting team clarified Requirement R1, Criterion 3 by framing the criterion in the present tense to refer to the current assessment(s). Islands caused by natural phenomena (i.e., Disturbances) are covered under Requirement

Organization	Yes or No	Question 6 Comment
		R2. Change made. 2. An example of how line differential protection would be treated with respect to Requirement 3 would be helpful. See the comment above in Question 4. Response: The drafting team added an exclusion for “current differential” elements to PRC-026-1 – Attachment A. Change made.
American Transmission Company, LLC	No	ATC believes there is some significant discussion in the guidelines and technical basis, however, recommends that the SDT provide more clear explanation of all of the important parameters. Response: The drafting team has provided additional information in the Guidelines and Technical Basis about the PRC-026-1 - Attachment B Criteria. Change made.
Tacoma Power	No	: Tacoma Power disagrees with the need for this standard. In particular, Tacoma Power has significant concerns with Requirements R1 and R2. The Application Guidelines and Technical Basis do not provide sufficient clarification related to these two requirements. Response: The drafting team has rewritten of the Guidelines and Technical Basis to address inconsistencies, errors, and lack of detail. Change made.
Ameren	No	These are generally well written considering this complex situation that we feel is very rare, but we do have the following recommendations for the drafting team: (1) The variables in Figure 2 need to be defined; Response: The figures have been cleaned up and clarified. Change made. (2) The issue of aligning the planning assessment time horizon with present Protection System settings (see our 2nd comment Q1) needs to be clarified; Response: Requirement R1 has been revised to only include the Planning Coordinator and due to this revision, the Criterion that identify Elements is now specifically assigned the Time Horizon: Long-term

Organization	Yes or No	Question 6 Comment
		Planning. In the event that a Corrective Action Plan (CAP) is necessary based on future system conditions, the CAP can specify a timeframe that does not enact changes until those system conditions require modification. An example has been added to clarify this scenario in the Guidelines and Technical Basis. Change made. (3) On page 24 change "the generator unsaturated generator X"d," to "the generator saturated generator transient reactance X'd," because transient time constant aligns better with power swing timeframe, and faults most often are the triggering event in such power swing scenarios (also see Reimert text pages 40, 289, 291, and particularly bottom of page 302). Response: The drafting team made a modification to allow entities the option of using transient or sub-transient reactance. The drafting team clarified that the "saturated" (transient or sub-transient) reactance is used. Change made. (4) On page 23 add "Overcurrent relays usually have long enough time delays that they can be excluded from consideration." at the end of the 'Application to Generator Owners' section. Response: The drafting team did not add the proposed suggestion, but did add a clarification that standard is applicable to load-responsive protective relays (including overcurrent) which could trip instantaneously or with a time delay of less than 15 cycles. Change made. (5) To clarify when the simplified method instead of transient stability simulations can be used on page 24 in the last paragraph of the 'Impedance Type Relays' section change 'is' to 'can' and add "only" in the third line so it reads "The simplified method used in the Application to Transmission Owners section can also be used here to provide a helpful understanding of a stable power swing on load-responsive protective relays for only those cases where the generator is connected to the transmission system and there are no infeed effects to be considered." Response: The drafting team provided additional detail in the Guidelines and Technical Basis. Change made.

Organization	Yes or No	Question 6 Comment
ISO New England	No	While the Application Guidelines and Technical Basis provide guidance, we disagree with the current roles of functional entities to which the standard applies. Response: The Reliability Coordinator and Transmission Planner have been removed from the standard's Applicability; therefore, Requirement R1 is now only applicable to the Planning Coordinator as a single entity source of identifying Elements. The drafting team asserts that the Planning Coordinator has or has access to the knowledge including the wide-area view. Change made to the Requirement.
New York Power Authority	No	This proposed Standard would be better suited as a TPL, or OP Standard, not a PRC one. This is because the functions and study capabilities required for the Standard are done by Transmission Planning/Operations Organizations, and are not in the realm of Protective Relay Departments of a GO/TO. Response: The drafting team contends that there is not a practical way to specify the exact planning studies under the TPL standards that would result in the worst case stable power swing; similarly, under the TOP standards, operators would not be capable of taking action during the timeframe of a power swing. Therefore, the drafting team has established the graphical approach under the PRC body of NERC Reliability Standards by providing the standard's proposed PRC-026-1 - Attachment B Criteria that load-responsive protective relays must meet on an identified Element. No change made.
Oncor Electric Delivery LLC	No	Oncor agrees with the recommendation of the NERC PC (SCPS) and recommends if this has not been reviewed by NERC RISC, this may be an opportunity for the NERC Standard Committee (SC) to bring back to RISC for discussion in conjunction with the PSRPS technical document. Response: The NERC RISC evaluates emerging issues and this project is the result of FERC directives. The NERC RISC does not evaluate directives. No change made. If RISC and SC find the Standard should be developed, a clearer explanation as to what contingency the term "line out conditions" refers to should be included as this will determine the data source we use to generate our list of elements. Response: The phrase "line-out conditions" has been removed. Elements should be identified for

Organization	Yes or No	Question 6 Comment
		Requirement R1 criterion regardless of the outage conditions that may be necessary to trigger enforcement of the System Operating Limits (SOL) or arming of the Special Protection System (SPS). Change made
Northeast Utilities	No	1. In the Application Guidelines, the wording under Requirement 2 for "credible event" is very open-ended. Response: The term "credible" has been removed from the standard. The drafting team clarified Requirement R1, Criterion 3 by framing the criterion in the present tense to refer to the current assessment(s). Islands caused by natural phenomena (i.e., Disturbances) are covered under Requirement R2. Change made. 2. An example of how line differential protection would be treated with respect to Requirement 3 would be helpful. See the comment above in Question 4. Response: The drafting team added an exclusion for "current differential" elements to PRC-026-1 – Attachment A. Change made.
Public Utility District No. 1 of Cowlitz County, WA	No	It is not clear how past events and Disturbance reports that must be considered in the identification of Elements will be archived and made available. Response: The "January 1, 2003" date has been removed from the standard. Requirement R2 (and new R3) are based on actual Disturbances that occur after the Effective Date of the standard. Events that occur will be reported to the Planning Coordinator in order to maintain the Element as an "identified Element." Change made.
Alliant Energy	No	In the Application Guide there is guidance provided for the determination of apparent impedance for Impedance Type Relays on page 23 of 25, under the "Application to Generator Owners" portion of the document. As noted in this section the process is complex. As such, we recommend adding a detailed example of how the Transmission Planner should conduct this analysis on the behalf of the Generation

Organization	Yes or No	Question 6 Comment
		Owner. Response: The drafting team has rewritten this section of the Technical Basis and Guidelines.
PacifiCorp	Yes	
Tennessee Valley Authority	Yes	
Dominion	Yes	
Florida Power & Light	Yes	
Puget Sound Energy	Yes	
Bonneville Power Administration	Yes	
Arizona Public Service Co.	Yes	
Bureau of Reclamation	Yes	
Ingleside Cogeneration LP	Yes	
Masschusetts	Yes	

Organization	Yes or No	Question 6 Comment
Attorney General		
MidAmerican Energy Company	Yes	
Manitoba Hydro	Yes	
Independent Electricity System Operator	Yes	
Exelon	Yes	
ITC	Yes	The App Guide will be sufficient, considering the improvements mentioned in the webinar. In addition, we request more details regarding islanding scenarios and explanation of “credible” along the lines of our answer to Question 1. Response: The term “credible” has been removed from the standard. The drafting team clarified Requirement R1, Criterion 3 by framing the criterion in the present tense to refer to the current assessment(s). Islands caused by natural phenomena (i.e., Disturbances) are covered under Requirement R2. Change made.
Idaho Power Co.	Yes	In the present form of R1-R4 Response: Thank you for your comment.
Southern California Edison Company	Yes	
Salt River Project	Yes	

Organization	Yes or No	Question 6 Comment
Xcel Energy	Yes	

7. Do you agree with implementation period of the proposed standard based on the considerations listed in the Implementation Plan? If not, please provide a justification for changing the proposed implementation period

Summary Consideration: About two-thirds (64%) disagreed with the implementation period of the proposed standard based on the considerations listed in the Implementation Plan. The chief concern, from 12 comments by 56 stakeholders, related to the initial influx of Elements and performing the evaluations. To address this concern the implementation plan was modified. Requirements R1-R3, R5, and R6 all become effective 12 months following approval. An implementation of 36 months is provided in Requirement R4 to evaluate identified Elements pursuant to Requirement R1. The Planning Coordinator is to become compliant with the initial identification of Elements in Requirement R1 during the calendar year 12 calendar months after approval and perform Requirement R1 each calendar year thereafter.

Again, Requirement R4 (previously R3) will become effective 36 calendar months after approval of the standard. During the implementation of the standard, notifications (i.e., from R1-R3) are likely to occur prior to Requirement R4 becoming effective. Where notification under R1 or identification under Requirement R2 or R3 occurs prior to the Effective Date of Requirement R4, the 12 month time period in Requirement R4 will begin from the Effective Date of Requirement R4. Thereafter, entities will follow the 12 month time period in R4. The intention of the additional time for Requirement R4 to become effective is to handle the initial influx of notifications and identifications.

Organization	Yes or No	Question 7 Comment
MRO NERC Standards Review Forum	No	The NSRF believes there may be many elements, questions or unexpected problems in preparing for the first compliance deadline. Therefore, 24 months may be more reasonable than 12 months. Response: Requirements R1-R3, R5, and R6 all become effective following approval and require evaluation under the time period allotted in Requirement R4 (previously R3) for any identified Elements. The Planning Coordinator is to become compliant with the initial identification of Elements in Requirement R1 during the calendar year after 12 calendar months of approval and perform Requirement R1 each calendar year thereafter. Requirement R4 (previously R3) will become effective 36 calendar months following approval of the standard. During the implementation of the standard, notifications (i.e., from R1-R3) are likely to occur prior to Requirement R4 becoming effective. Where notification under R1 or identification under Requirement R2 or R3 occurs prior to the Effective Date of Requirement R4, the 12 month time period in

Organization	Yes or No	Question 7 Comment
		Requirement R4 will begin from the Effective Date of Requirement R4. Thereafter, entities will follow the 12 month time period in R4. The intention of the additional time for R4 to become effective is to handle the initial influx of notifications and identifications. Change made.
SPP Standards Review Group	No	We would prefer to see the twelve months increased to twenty-four months to allow adequate time to complete all the studies and analyses that will be needed to comply with the standard. Response: Requirements R1-R3, R5, and R6 all become effective following approval and require evaluation under the time period allotted in Requirement R4 (previously R3) for any identified Elements. The Planning Coordinator is to become compliant with the initial identification of Elements in Requirement R1 during the calendar year after 12 calendar months of approval and perform Requirement R1 each calendar year thereafter. Requirement R4 (previously R3) will become effective 36 calendar months following approval of the standard. During the implementation of the standard, notifications (i.e., from R1-R3) are likely to occur prior to Requirement R4 becoming effective. Where notification under R1 or identification under Requirement R2 or R3 occurs prior to the Effective Date of Requirement R4, the 12 month time period in Requirement R4 will begin from the Effective Date of Requirement R4. Thereafter, entities will follow the 12 month time period in R4. The intention of the additional time for R4 to become effective is to handle the initial influx of notifications and identifications. Change made. Change made.
ACES Standards Collaborators	No	(1) We disagree with the implementation plan and believe that a staggered implementation is necessary. If the standard were approved such that it would become effective on March 1, 2016, the TO and GO would not have any Elements identified per R1 until approximately 10 months later in January 2017. How could they comply in 2016 with R3 when they don't have any Elements identified per R1? Response: Requirements R1-R3, R5, and R6 all become effective following approval and require evaluation under the time period allotted in Requirement R4 (previously R3) for any identified Elements. The Planning Coordinator is to become compliant with the initial identification of Elements in Requirement R1 during the calendar year after 12 calendar months of approval and perform Requirement

Organization	Yes or No	Question 7 Comment
		R1 each calendar year thereafter. Requirement R4 (previously R3) will become effective 36 calendar months following approval of the standard. During the implementation of the standard, notifications (i.e., from R1-R3) are likely to occur prior to Requirement R4 becoming effective. Where notification under R1 or identification under Requirement R2 or R3 occurs prior to the Effective Date of Requirement R4, the 12 month time period in Requirement R4 will begin from the Effective Date of Requirement R4. Thereafter, entities will follow the 12 month time period in R4. The intention of the additional time for R4 to become effective is to handle the initial influx of notifications and identifications. Change made. Change made.
FirstEnergy Corp.	No	This current situation has continued for 11 years and an implementation plan of 1 year is unrealistically short. Two years is more appropriate unless the period is modified to include only incidents which have occurred since the inception of NERC PRC-004 then 1 year would be reasonable. Response: Requirements R1-R3, R5, and R6 all become effective following approval and require evaluation under the time period allotted in Requirement R4 (previously R3) for any identified Elements. The Planning Coordinator is to become compliant with the initial identification of Elements in Requirement R1 during the calendar year after 12 calendar months of approval and perform Requirement R1 each calendar year thereafter. Requirement R4 (previously R3) will become effective 36 calendar months following approval of the standard. During the implementation of the standard, notifications (i.e., from R1-R3) are likely to occur prior to Requirement R4 becoming effective. Where notification under R1 or identification under Requirement R2 or R3 occurs prior to the Effective Date of Requirement R4, the 12 month time period in Requirement R4 will begin from the Effective Date of Requirement R4. Thereafter, entities will follow the 12 month time period in R4. The intention of the additional time for R4 to become effective is to handle the initial influx of notifications and identifications. Change made. Change made.
PPL NERC Registered Affiliates	No	It is not evident why applicable Elements owned by GOs require a new R3 analysis annually. Their calculations should remain valid until and unless impedances change significantly. We suggest that the TO

Organization	Yes or No	Question 7 Comment
		should provide a system impedance update annually (ref. comment #2 above), and a new study should be required of the GO only if the generator, GSU or system impedance changes by 10% or more. Response: The drafting team increased the Implementation Plan to three years to provide for the initial influx of identified Elements under Requirement R1. The evaluation of relays under Requirement R4 (previously R3) is to be performed "within 12 full calendar months of receiving notification of an Element … where the evaluation has not been performed in the last three calendar years." Change made.
BC Hydro	No	BC Hydro does not agree with implementation of the proposed standard at all. Response: Thank you for your comment.
Puget Sound Energy	No	As noted in question 4, the modeling of protective relays needed to evaluate the system will not be implemented by by the proposed implementation date for the standard. Response: The drafting team asserts that the standard does not require the inclusion of relay models. Requirement R1 – Criterion 4 is not requiring a study, but the identification of any Element that was observed as tripping in the most recent Planning Assessment Response: The drafting team asserts that the standard does not require the inclusion of relay models. Requirement R1 – Criterion 4 is not requiring a study, but the identification of any Element that was observed as tripping in the most recent Planning Assessment. No change made.
Bonneville Power Administration	No	BPA feels 12 months is insufficient time for the initial implementation. Response: Requirements R1-R3, R5, and R6 all become effective following approval and require evaluation under the time period allotted in Requirement R4 (previously R3) for any identified Elements. The Planning Coordinator is to become compliant with the initial identification of Elements in Requirement R1 during the calendar year after 12 calendar months of approval and perform Requirement R1 each calendar year thereafter. Requirement R4 (previously R3) will become effective 36 calendar months following approval of the

Organization	Yes or No	Question 7 Comment
		standard. During the implementation of the standard, notifications (i.e., from R1-R3) are likely to occur prior to Requirement R4 becoming effective. Where notification under R1 or identification under Requirement R2 or R3 occurs prior to the Effective Date of Requirement R4, the 12 month time period in Requirement R4 will begin from the Effective Date of Requirement R4. Thereafter, entities will follow the 12 month time period in R4. The intention of the additional time for R4 to become effective is to handle the initial influx of notifications and identifications. Change made. Change made.
Arizona Public Service Co.	No	AZPS suggests the timeline for the implementation plan be increased to allow for two years for requirements one and two and requirements three and four be adjusted accordingly. APS believes significant effort will be required to identify relays that may qualify for inclusion. Response: Requirements R1-R3, R5, and R6 all become effective following approval and require evaluation under the time period allotted in Requirement R4 (previously R3) for any identified Elements. The Planning Coordinator is to become compliant with the initial identification of Elements in Requirement R1 during the calendar year after 12 calendar months of approval and perform Requirement R1 each calendar year thereafter. Requirement R4 (previously R3) will become effective 36 calendar months following approval of the standard. During the implementation of the standard, notifications (i.e., from R1-R3) are likely to occur prior to Requirement R4 becoming effective. Where notification under R1 or identification under Requirement R2 or R3 occurs prior to the Effective Date of Requirement R4, the 12 month time period in Requirement R4 will begin from the Effective Date of Requirement R4. Thereafter, entities will follow the 12 month time period in R4. The intention of the additional time for R4 to become effective is to handle the initial influx of notifications and identifications. Change made. Change made.
Public Service Enterprise Group	No	We disagree with the need for this standard. Response: Thank you for your comment. Please see response in Question 1 above.
Peak Reliability	No	The expectations of the RC need to be clarified, and until they are clarified, it is unclear whether the

Organization	Yes or No	Question 7 Comment
		implementation period is reasonable. It is unclear whether the annual list of Elements provided by the RC is intended to be a result of a new and different one-time analysis performed by the RC or TOP, or if the list of Elements is intended to be compiled over time as a result of ongoing operations planning analyses and real-time assessments already being performed. The RC performs many assessments throughout the Operations Planning horizon, Same-Day horizon, and Real-time horizons for expected and actual operating conditions. As related to the RC specifically, is the intent of R1 for the RC to continuously add to this list of Elements based on the results from all of these RC studies performed throughout the year, and to report this compiled list to the GOs and TOs once per calendar year? This approach would seem to add the most reliability benefit. Response: The Reliability Coordinator and Transmission Planner have been removed from the standard's Applicability; therefore, Requirement R1 is now only applicable to the Planning Coordinator as a single entity source of identifying Elements. The drafting team asserts that the Planning Coordinator has or has access to the knowledge including the wide-area view. The Planning Coordinator is believed to be the best single-source of information and not the Transmission Operator. Requirement R1 has been modified to state that at least once per calendar year the Elements in its area meeting the Requirement R1 criteria are to be identified. Requirement R1 is not intended to require new studies, but to identify Elements based on existing information. Change made.
American Electric Power	No	The implementation plan only allows the GO/TO 11 months to complete their initial R3 study of all Elements identified in R1. We believe the time allowed is too short for the initial implementation of the standard, as the GO/TO will need to research all Elements, not just those incrementally added from the previous year's planning analysis. The implementation plan should be revised to guarantee the GO/TO a minimum of at least 36 months to complete their initial R2 and R3 studies. The timing of the sequence as proposed in the standard is acceptable after the initial implementation. However, as currently written, the initial implementation plan does not guarantee adequate time for the applicable Entities to become compliant. Response: Requirements R1-R3, R5, and R6 all become effective following approval and require

Organization	Yes or No	Question 7 Comment
		evaluation under the time period allotted in Requirement R4 (previously R3) for any identified Elements. The Planning Coordinator is to become compliant with the initial identification of Elements in Requirement R1 during the calendar year after 12 calendar months of approval and perform Requirement R1 each calendar year thereafter. Requirement R4 (previously R3) will become effective 36 calendar months following approval of the standard. During the implementation of the standard, notifications (i.e., from R1-R3) are likely to occur prior to Requirement R4 becoming effective. Where notification under R1 or identification under Requirement R2 or R3 occurs prior to the Effective Date of Requirement R4, the 12 month time period in Requirement R4 will begin from the Effective Date of Requirement R4. Thereafter, entities will follow the 12 month time period in R4. The intention of the additional time for R4 to become effective is to handle the initial influx of notifications and identifications. Change made. Change made.
American Transmission Company, LLC	No	ATC believes there may be many elements, questions or unexpected problems in preparing for the first compliance deadline. Therefore, 24 months may be more reasonable than 12 months. Response: Requirements R1-R3, R5, and R6 all become effective following approval and require evaluation under the time period allotted in Requirement R4 (previously R3) for any identified Elements. The Planning Coordinator is to become compliant with the initial identification of Elements in Requirement R1 during the calendar year after 12 calendar months of approval and perform Requirement R1 each calendar year thereafter. Requirement R4 (previously R3) will become effective 36 calendar months following approval of the standard. During the implementation of the standard, notifications (i.e., from R1-R3) are likely to occur prior to Requirement R4 becoming effective. Where notification under R1 or identification under Requirement R2 or R3 occurs prior to the Effective Date of Requirement R4, the 12 month time period in Requirement R4 will begin from the Effective Date of Requirement R4. Thereafter, entities will follow the 12 month time period in R4. The intention of the additional time for R4 to become effective is to handle the initial influx of notifications and identifications. Change made. Change made.

Organization	Yes or No	Question 7 Comment
Independent Electricity System Operator	No	
Tacoma Power	No	Tacoma Power disagrees with the need for this standard. In particular, Tacoma Power has significant concerns with Requirements R1 and R2. Response: Please see the section at the beginning of this document called, "NERC Discussion on Proceeding(s) and Directives Regarding: Stable Power Swings" for a complete background. The SDT understands that NERC staff re-engaged FERC staff following the completion of the PSRPS Report and that the Commission still desired NERC to pursue its work to meet the directive. However, FERC staff was open to an approach designed by NERC. NERC staff has informally received positive feedback on the approach to address the regulatory directive. The directive itself was challenged by commenters prior to the issuance of Order No. 733 and was already the subject of multiple rehearing requests in the Order No. 733-A and Order No. 733-B proceedings. Similar arguments to the conclusions of the NERC System Protection and Control Subcommittee were advanced in these FERC proceedings. See responses to Question 1 comments on R1 and R2.
Ameren	No	(1) We request that the SDT provide a 1 year implementation period for R1 and R2 combined, followed by a 2 year implementation period for R3. (2) We believe that this standard poses a considerable burden on the TO and GO and the first pass may be a significant amount of work. Response: Requirements R1-R3, R5, and R6 all become effective following approval and require evaluation under the time period allotted in Requirement R4 (previously R3) for any identified Elements. The Planning Coordinator is to become compliant with the initial identification of Elements in Requirement R1 during the calendar year after 12 calendar months of approval and perform Requirement R1 each calendar year thereafter.

Organization	Yes or No	Question 7 Comment
		Requirement R4 (previously R3) will become effective 36 calendar months following approval of the standard. During the implementation of the standard, notifications (i.e., from R1-R3) are likely to occur prior to Requirement R4 becoming effective. Where notification under R1 or identification under Requirement R2 or R3 occurs prior to the Effective Date of Requirement R4, the 12 month time period in Requirement R4 will begin from the Effective Date of Requirement R4. Thereafter, entities will follow the 12 month time period in R4. The intention of the additional time for R4 to become effective is to handle the initial influx of notifications and identifications. Change made. Change made.
ISO New England	No	Given that the currently proposed scope of the standard is very broad, twelve months is not a long enough timeframe to become compliant with the requirements of this standard, which will create additional workload for the functional entities subject to the standard. ISO New England suggests 36 months. Response: Requirements R1-R3, R5, and R6 all become effective following approval and require evaluation under the time period allotted in Requirement R4 (previously R3) for any identified Elements. The Planning Coordinator is to become compliant with the initial identification of Elements in Requirement R1 during the calendar year after 12 calendar months of approval and perform Requirement R1 each calendar year thereafter. Requirement R4 (previously R3) will become effective 36 calendar months following approval of the standard. During the implementation of the standard, notifications (i.e., from R1-R3) are likely to occur prior to Requirement R4 becoming effective. Where notification under R1 or identification under Requirement R2 or R3 occurs prior to the Effective Date of Requirement R4, the 12 month time period in Requirement R4 will begin from the Effective Date of Requirement R4. Thereafter, entities will follow the 12 month time period in R4. The intention of the additional time for R4 to become effective is to handle the initial influx of notifications and identifications. Change made. Change made.
New York Power Authority	No	Implementation periods should be consistent with the more relevant approach described in the PSRPS technical document.

Organization	Yes or No	Question 7 Comment
		Response: The drafting team modified the Implementation Plan (to 36 months) and several Requirements to provide additional time to reduce the burden. Also, the standard is consistent with the PSRPS Report which recommends a focused approach to identifying Elements that are most susceptible to power swings and therefore reduces the financial burden by not requiring all relays to be in scope. Changes made.
Oncor Electric Delivery LLC	No	Please see response #1, #6 and #10 Response: Thank you for your comment. Please see responses to your comments in Questions 1, 6, and 10.
Idaho Power Co.	No	The requirements need work before an implementation plan can be defined. It should be adjusted based on changes proposed in #4. Response: Thank you for your comment. Please see the response in Question #4.
Xcel Energy	No	The implementation window and the implementation frequency is unnecessarily aggressive as powers system dynamics do not changes as fast. Four year frequency and 3 to 6 months implementation window are reasonable. R1 and R2 should be released earlier for the initial completion of R3. Additional time may be required to ensure appropriate relays are installed in the field. Response: Requirements R1-R3, R5, and R6 all become effective following approval and require evaluation under the time period allotted in Requirement R4 (previously R3) for any identified Elements. The Planning Coordinator is to become compliant with the initial identification of Elements in Requirement R1 during the calendar year after 12 calendar months of approval and perform Requirement R1 each calendar year thereafter. Requirement R4 (previously R3) will become effective 36 calendar months following approval of the standard. During the implementation of the standard, notifications (i.e., from R1-R3) are likely to occur prior to Requirement R4 becoming effective. Where notification under R1 or identification under

Organization	Yes or No	Question 7 Comment
		Requirement R2 or R3 occurs prior to the Effective Date of Requirement R4, the 12 month time period in Requirement R4 will begin from the Effective Date of Requirement R4. Thereafter, entities will follow the 12 month time period in R4. The intention of the additional time for R4 to become effective is to handle the initial influx of notifications and identifications. The standard is requiring that a CAP be created to modify the relaying to increase its security for stable power swings. It also requires the CAP to be implemented, but it does not state specific time frames for relay replacements to be done. Change made.
PacifiCorp	Yes	
Tennessee Valley Authority	Yes	
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	Yes, provided the R2 review period begins with the enforcement date of the stantard looking forward. Response: The “January 1, 2003” date has been removed from the standard. Requirement R2 (and new R3) are based on actual Disturbances that occur after the Effective Date of the standard. Change made.

Organization	Yes or No	Question 7 Comment
Dominion	Yes	
Duke Energy	Yes	
Bureau of Reclamation	Yes	
Luminant Generation Company LLC	Yes	
Ingleside Cogeneration LP	Yes	
Masschusetts Attorney General	Yes	
MidAmerican Energy Company	Yes	
Consolidated Edison, Inc.	Yes	
Manitoba Hydro	Yes	
David Kiguel	Yes	
Exelon	Yes	

Organization	Yes or No	Question 7 Comment
Texas Reliability Entity	Yes	
Northeast Utilities	Yes	
Southern California Edison Company	Yes	
Public Utility District No. 1 of Cowlitz County, WA	Yes	
Salt River Project	Yes	
DTE Electric		No comment

8. If you are aware of any conflicts between the proposed standard and any regulatory function, rule, order, tariff, rate schedule, legislative requirement, or agreement please identify the conflict here.

Summary Consideration: No conflicts between the proposed standard and any regulatory function, rule, order, tariff, rate schedule, legislative requirement, or agreement were identified.

Organization	Question 8 Comment
FirstEnergy Corp.	In a competitive/unregulated environment a GO does not have access to the information pertaining to power swings (stable or otherwise) due to the FERC Standard of Conduct. Therefore the GO would not know the cause of a relay operation. Response: Thank you for your comment.
Luminant Generation Company LLC	NERC standards requirements should not reference data that predates the approval of the standard; therefore, rendering the Requirement R2 January 2003 date unenforceable. Response: The “January 1, 2003” date has been removed from the standard. Requirement R2 (and new R3) are based on actual Disturbances that occur after the Effective Date of the standard. Change made.
Dominion	No
Consolidated Edison, Inc.	No
Northeast Utilities	No
DTE Electric	No comment
Northeast Power Coordinating Council	No.

Organization	Question 8 Comment
PPL NERC Registered Affiliates	No
ITC	No
Salt River Project	None
CHPD - Public Utility District No. 1 of Chelan County	R1.2 - Is this an SOL for the planning (FAC-010) or operating (FAC-011) horizon? This requirement seems to be duplicating, at least in part, FAC-014 R6 (The Planning Authority shall identify the subset of multiple contingencies (if any), from Reliability Standard TPL-003 which result in stability limits.). SOLs are generally established to facilitate performance under a NERC TPL Category B performance. Select NERC TPL category C and limited D criteria are added by the WECC regional criteria. Response: Requirement R1, Criterion 1 and 2 address operating limits associated with angular stability limits; therefore, System Operating Limits (SOL) specified in Requirement R1, Criterion 2 includes both operations and planning horizons. In the event that a Corrective Action Plan (CAP) is necessary based on future system conditions, the CAP can specify a timeframe that does not enact changes until those system conditions require modification. An example has been added to clarify this scenario in the Guidelines and Technical Basis. Change made. R1.3 - TPL studies require transient stability simulations, not angular stability simulations. There is no standard that requires angular stability simulations. There is no mention of angular stability simulations in FAC-010, FAC-011, or the new TPL-001-4 either. Response: The drafting team contends that a System Operating Limit (SOL) as stated in Requirement R1 is in place to prevent angular instability. The standard addresses Elements associated with an SOL as an Element that would be susceptible to a power swing. No change made. R1.4 - WECC is slowly coming on board with this as a result of the San Diego outage and is adding

Organization	Question 8 Comment
	overcurrent relays to system models at this time. However, the relay tripping addressed in this proposed standard may also occur by distance or other elements, which are not required to be modeled in WECC at this time in its base case process. There is also a lack of a performance category for these reporting requirements (such as for Category B and C events). Performance issues may show up for extreme Category D events in the assessment, but in the language as it stands, these must also be identified and the GO and TO notified even for category D extreme events. This is a significant departure from traditional practice, which emphasizes category B and C issue communication. In the existing TPL standards, severe power swings are considered a Category D.14 event. Response: The drafting team asserts that the standard does not require the inclusion of relay models. Requirement R1, Criterion 4 is not requiring a study, but the identification of any Element that was observed as tripping in the most recent Planning Assessment pursuant to TPL-001-4, R4, Part 4.3.1.3 – "Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models" which becomes effective January 1, 2015 (U.S.). Other clarifying changes were made to Requirement R1, Criterion 4.
SPP Standards Review Group	We are not aware of any conflicts between the proposed standard and any regulatory function, rule, order, tariff, rate schedule, legislative requirement, or agreement. Response: Thank you for your comment.
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	We are not aware of any conflicts. Response: Thank you for your comment.

Organization	Question 8 Comment
SMUD/BANC	YES! The requirement R2 is particularly unacceptable as it requires data for pre June 18, 2007; effective date of Order 693 standards. Response: Thank you for your comment.
Xcel Energy	No

9. If you are aware of the need for a regional variance or business practice that should be considered with this phase of the project, please identify it here:

Summary Consideration: No need for a regional variance or business practice that should be considered with this phase of the project was identified.

Organization	Question 9 Comment
Dominion	No
Consolidated Edison, Inc.	No
ITC	No
Northeast Utilities	No
DTE Electric	No comment
Northeast Power Coordinating Council	No
PPL NERC Registered Affiliates	No
FirstEnergy Corp.	None
Salt River Project	None
Tacoma Power	Tacoma Power disagrees with the need for this standard. However, assuming FERC does not provide reflief from its directive to develop this standard, a regional variance should be considered, at least for WECC. The footprint of a typical Planning Coordinator or Transmission Planner in WECC may not be large enough to adequately perform the desired assessments in the

Organization	Question 9 Comment
	planning horizon. Instead, it may be more effective to perform this analysis more regionally. The Reliability Coordinator may have a large enough vantage, but most of their focus is in the operating horizon. Response: Thank you for your comment.
BC Hydro	The WECC region should be exempt from this rule. In this region, transmission power along many lines is subject to stability limits. It is an unnecessary use of resources to check the stability of protection systems on so many lines, considering there have been a negligible number of undesirable trips on stable power swings. Response: The drafting team asserts that it has provided the criteria for identifying Elements susceptible to power swings that are consistent with the PSRPS Report. The proposed standard does not require entities to check the stability of any Protection Systems. Notification of the identified Elements is required to be provided to the respective Generator Owner and Transmission Owner for evaluation. No change made.
SPP Standards Review Group	No. We are not aware of any need for a regional variance or business practice. Response: Thank you for your comment.
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	No. We are not aware of any needs for exceptions. Response: Thank you for your comment.
Bonneville Power Administration	Western Interconnection has many long lines and remote generation.

Organization	Question 9 Comment
	Response: The drafting team asserts that it has provided the criteria for identifying Elements susceptible to power swings that are consistent with the PSRPS Report. The proposed standard does not require entities to check the stability of any Protection Systems. Notification of the identified Elements is required to be provided to the respective Generator Owner and Transmission Owner for evaluation. No change made.
Xcel Energy	No

NERC

10. If you have any other comments on this Standard that you haven't already mentioned above, please provide them here

Summary Consideration: This question mainly generated comments that were submitted in the previous questions and are too varying and numerous to summarize coherently. There were two remarkable comments that generated a revision to the standard. The first concerns the assignment of Time Horizons. For Requirement R1, the drafting team eliminated the "Time-Horizon: Operation Planning" because it occurs on an annual basis and violating the Requirement beyond a year without mitigation would have little impact. Under the definition, "Time Horizon: Long-term Planning" is a planning horizon of one year or longer.

Furthermore, Requirement R2 (and the new R3) eliminated the "Time Horizon: Operation Planning" and kept "Time Horizon: Long-term Planning" because the information would be used by the PC in its annual assessments and violating the Requirement beyond a year and would have little impact to the Planning Coordinator's assessments. The drafting team eliminated "Time Horizon: Long-term Planning" and kept "Time Horizons: Operations Planning" for Requirement R4 (previously R3) and the new Requirement R5 because the associated timeframes comport with a "Time Horizon: Operations Planning." For Requirement R6 (previously R4), the drafting team eliminated the "Time Horizon: Operation Planning" because the failure to implement the CAP beyond a year without mitigation would have little impact when the length of CAPs that are generally implemented over several years.

The second remarkable comment relates to cost. The drafting team recognizes that cost is a consideration; however, this standard's approach narrowly focuses the reliability objectives to a select set of BES Elements (i.e., Requirement R1) to address the power swing concern where it is expected to be of greatest risk. This minimizes the cost to entities and compliance burden by not developing the standard to be applicable to the entire BES.

Organization	Question 10 Comment
David Kiguel	The PSRPS document, developed by industry experts and approved by the NERC Planning Committee, clearly disputes the FERC directive in Order No. 773 (Docket No. RM08-13-000), that was subsequently affirmed in Order Nos. 773-A and 773-B, that a standard is needed to ensure that load-responsive protective relays do not trip in response to stable power swings during non-Fault conditions. NERC's informational filing in Docket No. RM08-13-000 dated July 21, 2011 concluded that there is a need for a standard on stable power swings. This conclusion is the opposite of what the PSRPS document concluded. The SPCS concludes that a NERC Reliability Standard to address relay performance during stable swings is not needed, and could result in unintended adverse impacts to Bulk-Power System reliability. I support the recommendation that the NERC Standards Committee explore means to utilize the more recent PSRPS document to obtain relief from the aforementioned

Organization	Question 10 Comment
	FERC directive that is driving this project. Response: Please see the section at the beginning of this document called, "NERC Discussion on Proceeding(s) and Directives Regarding: Stable Power Swings" for a complete background. The SDT understands that NERC staff re-engaged FERC staff following the completion of the PSRPS Report and that the Commission still desired NERC to pursue its work to meet the directive. However, FERC staff was open to an approach designed by NERC. NERC staff has informally received positive feedback on the approach to address the regulatory directive. The directive itself was challenged by commenters prior to the issuance of Order No. 733 and was already the subject of multiple rehearing requests in the Order No. 733-A and Order No. 733-B proceedings. Similar arguments to the conclusions of the NERC System Protection and Control Subcommittee were advanced in these FERC proceedings.
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation;	a) The phrase "continues to be credible" in R2 needs explanation. Is the intended meaning either 1) the trip was believed to be caused by the Disturbance, 2) a repeat trips susceptibility continues to be possible or likely, or 3) something else? Response: The term "credible" has been removed from the standard. The drafting team clarified Requirement R1, Criterion 3 by framing the criterion in the present tense to refer to the current assessment(s). Islands caused by natural phenomena (i.e., Disturbances) are covered under Requirement R2. Change made. b) Is the consequence of R2/M2 having to analyze and document every relay operation (trip) which occurs for determination of if it was caused by a system Disturbance? Also, do all system Disturbances have to be reviewed for possible relay (trip) operations, for subsequent validation of desired operation? The NERC glossary definition of a Disturbance is very much open-ended and not specifically defined in part 2: "2. Any perturbation to the electric system." Response: The Requirement was structured to determine if the tripping was caused by a power swing, not a Disturbance. The drafting team revised Requirement R2 (and the new R3) to reference both stable and unstable power swing. This standard does not address the review of Protection System operations, only the actions required as a result of determining that tripping occurred due to a stable or unstable power swing. No change made. Is this requirement duplicative of PRC-004 relay mis-operation determination? Does PRC-026 subject entities to possible

Organization	Question 10 Comment
Southern Company Generation and Energy Marketing	violation of two standards for a single possible (lack of) action? Response: This standard does not address the review of Protection System operations, only the actions required as a result of determining that tripping occurred due to a stable or unstable power swing. The drafting team does not see this as duplicative of another standard. No change made. c) An annual requirement for R1, R2, and R3 seems excessive. Extended periodicity intervals or triggers from system topographic changes should be considered rather than annual reviews. For example, PRC-006 and PRC-010 prescribe evaluation intervals of 5 years for UVLS and UFLS. Five years seems to be a reasonable interval for this analysis. Response: The drafting team increased the Implementation Plan to three years to provide for the initial influx of identified Elements under Requirement R1. The evaluation of relays under Requirement R4 (previously R3) is to be performed "within 12 full calendar months of receiving notification of an Element … where the evaluation has not been performed in the last three calendar years." Change made. D) Does any specific item on the Identified Element list ever get removed from the list? The resolution of a review in a previous year should eliminate it from future reviews. Response: The drafting team notes that Elements do need to be identified when the Element no longer meets the Criteria in Requirement R1. No change made.
ACES Standards Collaborators	(1) Requirement R4 is unnecessary and inconsistent with the Reliability Assurance Initiative which is attempting to move NERC away from paper-driven compliance to reliability-driven compliance. The only practical violation of R4 will be a failure to update the paperwork. As written, if an implementation date slips, the TO or GO can update their CAP. We agree they should have the flexibility to do this since construction schedules nearly always have to be adjusted. Thus, if a milestone is not completed for any reason, a violation will not occur unless the CAP is not updated. How does this support reliability? Because it is not practical to require a TO or GO to complete their CAP by the dates established in the initial version due to unpredictable changes and unforeseen circumstances always faced in construction, the only real practical solution is to remove Requirement R4. NERC and the Regional Entities have the authority to request copies of the CAPs and progress reports and have other methods to encourage completion of CAPs if they are not satisfied with the progress. Response: The drafting team contends that updating actions and timeframes provides measurable evidence of

Organization	Question 10 Comment
	implementation of the CAP. In addition, implementation may require months or years to schedule and complete due to outages and other factors. No change made. (2) We are concerned that the RSAW is not consistent with the principle of the Reliability Assurance Initiative (RAI). RAI is intended to refocus NERC's compliance efforts to be forward looking rather than backwards looking and focus on the matters that impact reliability the most. This RSAW has reverted to the historical looking compliance review. On every requirement, there are multiple statements that evidence will be requested for each calendar year since the last audit and that the compliance assessment approach will evaluate every year since the last compliance audit. For a TO or GO, this would represent six to seven years of evidence and review that would provide no reliability benefit. This RSAW needs to be revamped to be consistent with RAI principles. Response: The drafting team has provided your comments to NERC Compliance who develops the RSAW. (3) Thank you for the opportunity to comment.
Manitoba Hydro	1) In R1, please clarify what you mean by "Stability constrained", does it mean the constraint for angular stability only or does it include other stability concerns such as transient voltage violations? Response: The drafting team added "angular" to "stability constraint" to clarify the intent in Requirement R1, both Criterion 1 and 2. Change made. 2) Also in R1, does "Line-out conditions" mean "N-1" condition? Response: The phrase "line-out conditions" has been removed. Elements should be identified based on the Requirement R1 criterion regardless of the outage conditions that may be necessary to trigger enforcement of the System Operating Limit (SOL) or arming of the Special Protection System (SPS). The Guidelines and Technical Basis have been supplemented to provide additional information. (Note: The use of SPS has been replaced with Remedial Action Scheme (RAS) for consistency with a current project to revise the definition of "Special Protection System"). Change made. 3) What definition of an island is used in the standard? Response: The drafting team modified Requirement R1, Criterion 3 to include island boundaries due to angular instability within an underfrequency load shedding (UFLS) assessment. Also, the Generator Owner was moved from Requirement R2 to

Organization	Question 10 Comment
	the new Requirement R3 in order to remove the "islanding" criteria for Generator Owners. Change made. 4) In R1 through R4, why is long-term planning included in the time horizon? The standard is not clear that an assessment of the 10-year planning horizon is expected. It seems the assessment is more based on the current system or at most plans proposed to be implemented in the next year, which makes this applicable to Operations Planning only. The Table of compliance elements discussing notification deadlines of 30-90 days is more applicable to an Operations Planning time horizon. If we see an issue in 2020, due to a new proposed Facility, why do we have to notify anyone within 30 days today in order to be compliant with the standard? We have time to investigate alternatives, new settings etc. If the problem still exists in the operations horizon, this standard is applicable. Response: For Requirement R1, the drafting team eliminated the "Time-Horizon: Operation Planning" because it occurs on an annual basis and violating the Requirement beyond a year without mitigation would have little impact. Under the definition, "Time Horizon: Long-term Planning" is a planning horizon of one year or longer.[12] Requirement R2 (and the new R3) eliminated the "Time Horizon: Operation Planning" and kept "Time Horizon: Long-term Planning" because the information would be used by the PC in its annual assessments and violating the Requirement beyond a year and would have little impact to the Planning Coordinator's assessments. The drafting team eliminated "Time Horizon: Long-term Planning" and kept "Time Horizons: Operations Planning" for Requirement R4 (previously R3) and the new Requirement R5 because the associated timeframes comport with a "Time Horizon: Operations Planning." For Requirement R6 (previously R4), the drafting team eliminated the "Time Horizon: Operation Planning" because the failure to implement the CAP beyond a year without mitigation would have little impact when the length of CAPs that are generally implemented over several years. Change made.
Northeast Utilities (Bill Temple)	1. The annual frequency requirements listed in R1 & R2 are not necessary and that a less frequent (ie: Every 5 years) would be more appropriate. Response: The drafting team increased the Implementation Plan to three years to provide for the initial influx of identified Elements under Requirement R1. The evaluation of relays under Requirement R4 (previously R3) is to be performed "within 12 full calendar months of receiving notification of an Element … where the evaluation has not been performed in the last

[12] http://www.nerc.com/pa/Stand/Resources/Documents/Time_Horizons.pdf

Organization	Question 10 Comment
	three calendar years." Change made. 2. Please provide more examples to help further illustrate the criteria in listed in R1. Response: The drafting team provided additional detail in the Guidelines and Technical Basis. Change made. 3. Please differentiate between Stable and Unstable power swings. Response: The drafting team provided the general definitions in the Guidelines and Technical Basis. Change made.
Northeast Utilities, supplemental comment (Mark Kenny)	Northeast Utilities is voting Negative based on the following concerns: • Potential Costs associated with relay upgrades Response: The drafting team recognizes that cost is a consideration; however, this standard's approach narrowly focuses the reliability objectives to a select set of BES Elements (i.e., Requirement R1) to address the power swing concern where it is expected to be of greatest risk. This minimizes the cost to entities and compliance burden by not requiring the standard to be applicable to the entire BES. No change made. • Lack of clarity in some of the criteria in requirements o What is considered a credible event? Response: The term "credible" has been removed from the standard. The drafting team clarified Requirement R1, Criterion 3 by framing the criterion in the present tense to refer to current assessment(s). The term "credible" was removed from the previous Requirement R2 (and new R3) because the required performance refers to only current actual events. Change made. o Should Planning assessment be used to capture relay tripping or just stable power swing or both stable and unstable power swing? Response: Requirement R1, Criterion 4 requires identification of any Element that was observed as tripping in the most recent Planning Assessment pursuant to TPL-001-4, R4, Part 4.3.1.3 – "Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models" which becomes effective January 1, 2015 (U.S.). Other clarifying changes were made to Requirement R1, Criterion 4.

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	o Is the purpose of the standard is to ensure blocking for a stable power swing and dependable tripping for unstable power swing? Response: The Purpose statement was modified to note that the purpose is to ensure that relays “are expected to not trip.” This may include the use of power swing blocking. • Annual analysis is to frequent Response: Requirements R1-R3, R5, and R6 all become effective following approval and require evaluation under the time period allotted in Requirement R4 (previously R3) for any identified Elements. The Planning Coordinator is to become compliant with the initial identification of Elements in Requirement R1 during the calendar year after 12 calendar months of approval and perform Requirement R1 each calendar year thereafter. Requirement R4 (previously R3) will become effective 36 calendar months following approval of the standard. During the implementation of the standard, notifications (i.e., from R1-R3) are likely to occur prior to Requirement R4 becoming effective. Where notification under R1 or identification under Requirement R2 or R3 occurs prior to the Effective Date of Requirement R4, the 12 month time period in Requirement R4 will begin from the Effective Date of Requirement R4. Thereafter, entities will follow the 12 month time period in R4. The intention of the additional time for R4 to become effective is to handle the initial influx of notifications and identifications. Change made. • Requiring an entity to provide data on an Element that had tripped since 2003 is inconsistent with other NERC Standards related to disturbance monitoring or misoperations, where data does not need to be retained for more than 12 months. Response: The “January 1, 2003” date has been removed from the standard. Requirement R2 (and new R3) are based on actual Disturbances that occur after the Effective Date of the standard. Events that occur will be reported to the Planning Coordinator in order to maintain the Element as an “identified Element.” Change made.
American Electric Power	AEP supports the proposed standard’s scope and overall direction, but has chosen to vote negative based on the various concerns expressed in our response. AEP envisions voting in the affirmative once sufficient concerns have been addressed in future drafts. R2 should be revised to be forward-looking only. Generator Owners and Transmission Owners were not required in the past

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	to keep comprehensive records of these events and cannot be expected to know all applicable Elements as implied by the standard. If after the initial standard implementation period, an Entity identifies an applicable Element based on a Disturbance occurring between 1/1/2003 and the standard effective date, the Entity could be found non-compliant with R2 and R3. If the drafting team feels it is absolutely necessary to go back to 2003, the standard should be revised to allow an Entity to remain fully compliant with R2 and R3 at any time an Element is identified based on a Disturbance occurring between 1/1/2003 and the effective date of the standard. This could be accomplished by adding wording to bring newly identified Elements into scope of R2 and R3 during the first full calendar year after they are identified. The R2 criterion assumes that registered entities have had a process in place to flag events due to power swings and retain information related to them. We do not believe that industry should be required to identify and provide information on events that have occurred in the past. There has been no established standard requirement to capture this information, so there is no way to reliably conclude that all events caused by power swings have been identified. In the event such historical information *is* required, the standard should explicitly state that such information is needed only once rather than once every calendar year. Response: The "January 1, 2003" date has been removed from the standard. Requirement R2 (and new R3) are based on actual Disturbances that occur after the Effective Date of the standard. Events that occur will be reported to the Planning Coordinator in order to maintain the Element as an "identified Element." Change made. The standard should require the Transmission Owner to make the system impedance available to the Generator Owner annually or within 30 days of a written request. The Generator Owner would not normally have this information, but will need it in order to meet their obligations under R3. Response: The standard does not preclude the Planning Coordinator from providing information to the Generator Owner or Transmission Owner about a particular Element (e.g., known stability issues, power swings, or apparent impedance characteristics). The drafting team has not included a Requirement for the exchange of information; that is being managed by entities outside of Reliability Standard requirements. It is not clear why R3 will require the TO/GO's Elements to be studied annually. A study's result should remain valid until either the relay setting changes or the impedance changes significantly. The standard should be revised to only require a study be repeated if the relay setting is changed or if the generator, GSU or system impedances change by 10% or more. Response: The drafting team increased the Implementation Plan to three years to provide for the initial influx of identified

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	Elements under Requirement R1. The evaluation of relays under Requirement R4 (previously R3) is to be performed "within 12 full calendar months of receiving notification of an Element … where the evaluation has not been performed in the last three calendar years." Change made. The standard should not require the study of voltage controlled/restrained overcurrent relays or loss of field relays. In stable power swings, the voltage should remain above the threshold that allows these voltage controlled/restrained overcurrent relays to operate. Failure to set the relay appropriately should be reported and corrected under the requirements of PRC-004. Loss of field relays are installed as part of the generator protection and should be permitted to trip when necessary to protect the generator, regardless of whether the power swing is stable or unstable. Response: The drafting team provided an exclusion for voltage controlled/restrained overcurrent relays in PRC-026-1 – Attachment A; however, the standard remains applicable to loss of field relays. This draft of the proposed standard is now consistent with the approach generally employed by industry for ensuring loss of field relays do not trip in response to a stable power swing. Change made.
Lincoln Electric System	Although appreciative of the drafting team's efforts in developing PRC-026-1, LES questions whether the development of a Reliability Standard is necessary for addressing relay performance during stable power swings. Further consideration should instead be given to the recommendations of the System Protection and Control Subcommittee which noted that "a NERC Reliability Standard to address relay performance during stable power swings is not needed, and could result in unintended adverse impacts to Bulk Power System reliability". In lieu of the standards development process, LES suggests communicating to FERC an alternative to a Reliability Standard such as an industry guidance or reference document. Response: Please see the section at the beginning of this document called, "NERC Discussion on Proceeding(s) and Directives Regarding: Stable Power Swings" for a complete background. The SDT understands that NERC staff re-engaged FERC staff following the completion of the PSRPS Report and that the Commission still desired NERC to pursue its work to meet the directive. However, FERC staff was open to an approach designed by NERC. NERC staff has informally received positive feedback on the approach to address the regulatory directive. The directive itself was challenged by commenters prior to the issuance of Order No. 733 and was already the subject of multiple rehearing requests in the Order No. 733-A and Order No. 733-B proceedings. Similar arguments to the conclusions of the NERC System Protection and Control Subcommittee were advanced in these FERC proceedings.

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Arizona Public Service Co.	APS recommends that the drafting team require an initial identification and notification of each Element that meets the criteria described R1. A review of the assessment should not be required yearly if there are no additions to the entity system meeting the criteria. It would be more practical to require a comprehensive review every five years. Response: The drafting team increased the Implementation Plan to three years to provide for the initial influx of identified Elements under Requirement R1. The evaluation of relays under Requirement R4 (previously R3) is to be performed "within 12 full calendar months of receiving notification of an Element … where the evaluation has not been performed in the last three calendar years." Change made. In addition, the standard should require that if Elements are added to the entity system that meet the criteria in R1, the applicable entity should provide updates within 90 days of the commissioning of a new Element. Response: The drafting team contends that Requirement R1 does not preclude the Planning Coordinator from providing notice of an identified Element more frequently. No change made. APS believes that the current draft requirement is administrative in nature and represents a reporting burden. Response: The proposed standard is consistent with the PSRPS Report which recommends a focused approach to identifying Elements that are most susceptible to power swings. No change made.
New York Power Authority	As previously answered, the referenced 61-page PSRPS technical document, from which much of this Standard's wording is copied from, specifically recommends against this standard. Again, as stated in Pages 5, 20, and 24: "Based on its review of historical events, consideration of the trade-offs between dependability and security, and recognizing the indirect benefits of implementing the transmission relay loadability standard (PRC-023), the SPCS concludes that a NERC reliability Standard to address relay performance during stable power swings is not needed, and could result in unintended adverse impacts to Bulk-Power System reliability." Response: Please see the section at the beginning of this document called, "NERC Discussion on Proceeding(s) and Directives Regarding: Stable Power Swings" for a complete background. The SDT understands that NERC staff re-engaged FERC staff following the completion of the PSRPS Report and that the Commission still desired NERC to pursue its work to meet the directive. However, FERC staff was open to an approach designed by NERC. NERC staff has informally received positive

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	feedback on the approach to address the regulatory directive. The directive itself was challenged by commenters prior to the issuance of Order No. 733 and was already the subject of multiple rehearing requests in the Order No. 733-A and Order No. 733-B proceedings. Similar arguments to the conclusions of the NERC System Protection and Control Subcommittee were advanced in these FERC proceedings.
Puget Sound Energy	As stated in the document entitled "Protection System Response to Power Swings" by PSRPS, a review of historical system disturbances determined that operation of transmission line protection systems during stable power swings was not causal or contributory to any of the disturbances reviewed. The final conclusion of PSRPS was that a NERC Reliability Standard is not needed to address relay performance due to stable power swings and could result in unintended adverse impacts to Bulk Power System reliability. In light of this conclusion, as well as the comments contained in this form, we have voted 'no' on this standard. Response: Please see the section at the beginning of this document called, "NERC Discussion on Proceeding(s) and Directives Regarding: Stable Power Swings" for a complete background. The SDT understands that NERC staff re-engaged FERC staff following the completion of the PSRPS Report and that the Commission still desired NERC to pursue its work to meet the directive. However, FERC staff was open to an approach designed by NERC. NERC staff has informally received positive feedback on the approach to address the regulatory directive. The directive itself was challenged by commenters prior to the issuance of Order No. 733 and was already the subject of multiple rehearing requests in the Order No. 733-A and Order No. 733-B proceedings. Similar arguments to the conclusions of the NERC System Protection and Control Subcommittee were advanced in these FERC proceedings. Response: Minor clarification to the above comment. The NERC System Protection and Control Subcommittee (SPCS) authored the *Protection System Response to Power Swings*, August 2013[13] (PSRPR Report) technical document. This drafting team took on the Protection System Response to Power Swings Standard Drafting Team (PSRPS SDT) designation. The drafting team has drafted the standard consistent with the approach provided by the PSRPS Report.

[13] NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)

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American Transmission Company, LLC	ATC recommends the SDT consider the following changes to add clarity to the Standard: a. Applicability (Section 4.1.1 & 4.1.4), Requirement R2 - Replace “load responsive” protective relays with “impedance based” protective relays. Response: The drafting team did not add the proposed suggestion, but did add a clarification that standard is applicable to load-responsive protective relays (including overcurrent) which could trip instantaneously or with a time delay of less than 15 cycles. Change made. b. Requirement R1 - ATC questions the necessity of performing the identification and notification in any particular month. Why does the requirement stipulate “within the first month of each calendar year”? ATC believes that it should be sufficient to use wording like, “at least once each calendar year”. Response: The drafting team adjusted the time periods in the proposed Requirements and Implementation Plan to account for varying activities. Change made. c. Requirements R.1.1, R1.2 - What is meant by “stability constraints” (e.g. steady state voltage, transient voltage, steady state angle, transient angle)? ATC recommends that the SDT use descriptive adjectives before “stability constraint” to clarify which one, or ones, are intended. Response: The drafting team added “angular” to “stability constraint” to clarify the intent in Requirement R1, both Criterion 1 and 2. Change made. d. Requirements R1.3, R1.4 - What is meant by “Disturbances” (e.g. Category B, Category C, P1-P7)? ATC recommends that the SDT use descriptive adjectives before “Disturbances” to clarify which one, or ones, are intended. Response: The drafting team revised Requirement R1, Criterion 4 by changing “Disturbance” to “simulated disturbance” to comport with the approved Reliability Standard TPL-001-4. The use of “Disturbance” in Requirements R2 (TO) and new R3 (GO) relates to an actual system Disturbance. Change made. e. Requirements R1.3, R2.1, R2.2 - What is meant by the term “credible” when discussing Disturbances (e.g. Disturbances associated with islands that were selected through R2 of PRC-006-1)? ATC suggests developing proposed alternate language like, “relevant”, which is easier to demonstrate simply with power flow analysis, rather than valid statistical analysis.

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	Response: The term "credible" has been removed from the standard. The drafting team clarified Requirement R1, Criterion 3 by framing the criterion in the present tense to refer to the current assessment(s). Islands caused by natural phenomena (i.e., Disturbances) are covered under Requirement R2. Change made. f. Requirement R1.4 - What is meant by "most recent Planning Assessment"? (e.g. TPL-002/TPL-003 annual assessment, FAC-002-1 interconnection assessment) ? ATC recommends to specify which type, or types, are intended. Response: The drafting team asserts that the most recent Planning Assessment provides a concrete reference to the information used in identifying BES Elements. Since the Planning Assessments (i.e., TPL-001-4) are performed annually, any other description would create confusion as to whether an entity should use past information or information revealed during preparation of a Planning Assessment. No change made. g. Requirement R2, Criteria 1 and 2 - ATC has concerns about requiring entities to refer to data on power swings and forming an island back to 1 Jan 2003. ATC recommends additional text in the Criteria such as "if available prior to the effective date" immediately after "since January 1, 2003". Retaining this data prior 1 Jan 2003 was not required as implied by the proposed Standard. Another approach for SDT consideration would be to require retention of data from the effective date of the Standard. Response: The "January 1, 2003" date has been removed from the standard. Requirement R2 (and new R3) are based on actual Disturbances that occur after the Effective Date of the standard. Change made. h. Requirements R2.1, R2.2 - ATC questions the inclusion of the statement "since January 1, 2003". ATC believes that a specific historical time frame would be more appropriate, such as "in the past 10 years". Referring to "since January 1, 2003" makes an ever expanding historical time frame, which at some point, should no longer be relevant. Response: The "January 1, 2003" date has been removed from the standard. Requirement R2 (and new R3) are based on actual Disturbances that occur after the Effective Date of the standard. Change made. i. R3 - The "Criterion" text only applies to bullet 1 and 3 only, but due to the indentation appears to be a sub element of bullet 4. Therefore, ATC suggests that the "Criterion" be moved more to the left move to avoid the appearance of only applying to bullet 4. Response: The drafting team has revised Requirement R4 (previously R3) and moved the criteria to PRC-026-1 – Attachment B

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	to increase the understandability of the Requirement. Change made.
Bonneville Power Administration	BPA feels the Glossary definition of Disturbance lacks sufficient clarity as it relates to this and other existing Standards. BPA also requests a descriptive title be used for the Criterion (e.g. Criterion for Swing Protection Analysis). Response: The drafting team revised Requirement R1, Criterion 4 by changing "Disturbance" to "simulated disturbance" to comport with the approved Reliability Standard TPL-001-4. The use of "Disturbance" in Requirements R2 (TO) and new R3 (GO) relates to an actual system Disturbance. Change made. Response: The drafting team has revised Requirement R4 (previously R3) and moved the criteria to PRC-026-1 – Attachment B to increase the understandability of the Requirement. Change made.
Dominion	Dominion suggests that Associated Documents (at least those where there are no copyright concerns) be included in the standard as attachments or appendices as we are concerned that cited URLs will change over time. Response: Thank you for your comment. Requirement R2 Criteria 1 and 2 require review of Disturbances since January 1, 2003. While Dominion recognizes the desire to consider Disturbances since January 1, 2003 in order to capture the August 14, 2003 Blackout, it is important to note that NERC Reliability Standards were not mandatory at that point and data may or may not be available. Dominion recommends changing the criteria dates to June 18, 2007 to be consistent with the establishment of mandatory and enforceable Reliability Standards. Response: The "January 1, 2003" date has been removed from the standard. Requirement R2 (and new R3) are based on actual Disturbances that occur after the Effective Date of the standard. Change made.
Duke Energy	Duke Energy would like to reiterate that we do not believe adequate technical justification has been identified for this project to become a standard. Based on the SPCS recommendation, the SDT and NERC should consider moving this project to a Guideline document until such time as a standard is warranted. Response: Please see the section at the beginning of this document called, "NERC Discussion on Proceeding(s) and Directives Regarding: Stable Power Swings" for a complete background. The SDT understands that NERC staff re-engaged FERC staff

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	following the completion of the PSRPS Report and that the Commission still desired NERC to pursue its work to meet the directive. However, FERC staff was open to an approach designed by NERC. NERC staff has informally received positive feedback on the approach to address the regulatory directive. The directive itself was challenged by commenters prior to the issuance of Order No. 733 and was already the subject of multiple rehearing requests in the Order No. 733-A and Order No. 733-B proceedings. Similar arguments to the conclusions of the NERC System Protection and Control Subcommittee were advanced in these FERC proceedings.
Electric Reliability Council of Texas, Inc.	ERCOT agrees with the NERC System Protection and Control Subcommittee August 2013 report titled Protection System Response to Power Swings which states: "Based on its review of historical events, consideration of the trade-offs between dependability and security, and recognizing the indirect benefits of implementing the transmission relay loadability standard (PRC-023), the SPCS concludes that a NERC Reliability Standard to address relay performance during stable power swings is not needed, and could result in unintended adverse impacts to Bulk-Power System reliability." Accordingly, ERCOT recommends that the standard not move forward. Response: Please see the section at the beginning of this document called, "NERC Discussion on Proceeding(s) and Directives Regarding: Stable Power Swings" for a complete background. The SDT understands that NERC staff re-engaged FERC staff following the completion of the PSRPS Report and that the Commission still desired NERC to pursue its work to meet the directive. However, FERC staff was open to an approach designed by NERC. NERC staff has informally received positive feedback on the approach to address the regulatory directive. The directive itself was challenged by commenters prior to the issuance of Order No. 733 and was already the subject of multiple rehearing requests in the Order No. 733-A and Order No. 733-B proceedings. Similar arguments to the conclusions of the NERC System Protection and Control Subcommittee were advanced in these FERC proceedings. If the standard does move forward ERCOT recommends that requirements R1, R2, and R3 be changed from an annual requirement to once every 60 months in order to minimize unintended adverse impacts to Bulk-Power System reliability. Response: The drafting team increased the Implementation Plan to three years to provide for the initial influx of identified Elements under Requirement R1. The evaluation of relays under Requirement R4 (previously R3) is to be performed "within 12 full calendar months of receiving notification of an Element … where the evaluation has not been performed in the last three calendar years." Change made.

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Ingleside Cogeneration LP	ICLP believes that the findings by NERC's System Protection and Control Subcommittee (SPCS) compellingly demonstrate that the initial findings from the 2003 Northeastern blackout were flawed. There is no doubt some load responsive relays did trip during the event when unusual, but non-threating transients manifested themselves as a result of a downstream Fault. However, the SPCS found that in every case, a subsequent unstable power swing followed within seconds - and the relay would have tripped anyways. Furthermore, planning simulations confirmed that had the stable power swing in question had taken place under N-1 and N-2 contingencies - the norm to which the electric system is designed - those relays would not have reacted. Even more concerning, the report goes on to say that "over-emphasizing secure operation for stable powers swings could be detrimental to Bulk-Power System reliability" (see page 19). This means that FERC Order 733, which relies heavily on the 2003 investigative task force recommendations, may actually increase the threat of wide-area instability or Cascading. ICLP does not question FERC's authority to order the development of a Reliability Standard - and we agree the subject matter is ultra-complex. Nevertheless, FERC should be operating to the best information available, which may have changed over time. There are far too many other pressing priorities for Registered Entities, CEAs, and even the Commission to expend this much effort on one that has little or even negative benefit. At the very least, we would like NERC or the SPCS to request a Technical Conference on the subject. Other such conferences in the past seem to have resulted in effective, yet reasonable, approaches to similarly complex issues. Response: Please see the section at the beginning of this document called, "NERC Discussion on Proceeding(s) and Directives Regarding: Stable Power Swings" for a complete background. The SDT understands that NERC staff re-engaged FERC staff following the completion of the PSRPS Report and that the Commission still desired NERC to pursue its work to meet the directive. However, FERC staff was open to an approach designed by NERC. NERC staff has informally received positive feedback on the approach to address the regulatory directive. The directive itself was challenged by commenters prior to the issuance of Order No. 733 and was already the subject of multiple rehearing requests in the Order No. 733-A and Order No. 733-B proceedings. Similar arguments to the conclusions of the NERC System Protection and Control Subcommittee were advanced in these FERC proceedings.
Los Angeles	LADWP is voting "Negative" on PRC-026-1 for the reason that the reference document entitled "Protection System Response

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Department of Water and Power	to Power Swings" (the PSRPS document) used to justify the standard does not support the need for a reliability standard. Response: Please see the section at the beginning of this document called, "NERC Discussion on Proceeding(s) and Directives Regarding: Stable Power Swings" for a complete background. The SDT understands that NERC staff re-engaged FERC staff following the completion of the PSRPS Report and that the Commission still desired NERC to pursue its work to meet the directive. However, FERC staff was open to an approach designed by NERC. NERC staff has informally received positive feedback on the approach to address the regulatory directive. The directive itself was challenged by commenters prior to the issuance of Order No. 733 and was already the subject of multiple rehearing requests in the Order No. 733-A and Order No. 733-B proceedings. Similar arguments to the conclusions of the NERC System Protection and Control Subcommittee were advanced in these FERC proceedings.
MidAmerican Energy Company	MidAmerican has concerns about the actual reliability benefit the proposed PRC-026 standards would provide versus the incremental compliance analysis work. There is also the potential for scope creep and the industry needs to focus on appropriate risks. The criteria specified under R1 could be broad. Criterion 4 seems susceptible to significant scope creep stating, "An Element identified in the more recent Planning Assessment where relay tripping occurred for a power swing during a disturbance." Planning Assessments are performed regularly in the TPL standards. Response: The drafting team asserts that if the Planning Assessment (i.e., TPL-001-4) shows tripping for a power swing, the Element would be identified under the Requirement. Additional discussion is provided in the Guidelines and Technical Basis regarding Criterion 4 under the heading "Requirement R1." No change made. The new TPL-001-4 planning standard and R3.1.1 requires the simulated "removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention". At a minimum, this will require generic protection models for each BES line, generator, and transformer. If the Planning assessment shows a protection model trip, will that element require a PRC-026 analysis? Response: The drafting team would not expect an entity to model tripping under TPL-001-4, R3 (R3.3.1 as referenced by the quote). Tripping of an Element observed in the stability section under Requirement R4, 4.3.1.3 would be an Element identified under PRC-026-1, Requirement R1, Criteria 4 and analyzed by the Generator Owner or Transmission Owner under the proposed Requirement R4 (previously R3). No change made.

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	Many entities are performing stability studies for existing TOP standards on a short-term to nearly daily basis to verify that entities are not entering and "unknown state". While such studies aren't a traditional "Planning Assessments", could short-term TOP related dynamic analyses that show potential trippling (such as exceeding a protection setting limit) be forced to prove tripping wasn't due to stable power swings in PRC-026? Response: The drafting team asserts "operations assessments" are not considered within the scope of the proposed standard. The standard addresses the risk for specific Elements and conditions revealed in operations assessments and could be communicated to the Planning Coordinator for evaluation and possible identification under PRC-026-1, Requirement R1, Criterion 4. No change made. Will the criteria in R1 inappropriately identify suggested islands required by PRC-006? The NERC PRC-006 UFLS standards require entities to identify and simulate islands. Will PRC-026 inappropriately identify PRC-006 islands (which may not have a real UFLS event as a basis) because PRC-006 required an island be developed and a simulation be performed by a powerflow stability simulation which considers angular stability? Criterion 3 mentions both island boundaries and angular stability. There is a qualifier of a credible event. But entities will construct reasonable events for PRC-006. Are reasonable and credible the same? Response: The term "credible" has been removed from the standard. The drafting team clarified Requirement R1, Criterion 3 by framing the criterion in the present tense to refer to the current assessment(s). Islands caused by natural phenomena (i.e., Disturbances) are covered under Requirement R2. Change made.
DTE Electric	No comment
FirstEnergy Corp.	None
Oncor Electric Delivery LLC	R1 criteria 4 states to identify the following element: "An Element identified in the most recent Planning Assessment where relay tripping occurred for a power swing during a Disturbance." In the statement above it is not clear whether the disturbance is actual or simulated. Response: The drafting team revised Requirement R1, Criterion 4 by changing "Disturbance" to "simulated disturbance" to

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	comport with the approved Reliability Standard TPL-001-4. The use of "Disturbance" in Requirements R2 (TO) and new R3 (GO) relates to an actual system Disturbance. Change made. R4 should state Each Generator Owner and Transmission Owner shall implement each CAP developed pursuant to Requirement R3 if option 3 or option 4 are chosen, and update each CAP if actions or timetables change, until all actions are complete. There should be no CAP required if R3 option 2 is chosen and the application of power swing blocking must be applied to specific relay locations. Response: The drafting team has modified the Requirements to be clearer that a CAP is required when the entity must develop a Corrective Action Plan (CAP) to modify a Protection System to meet the PRC-026-1 – Attachment B. Change made. Oncor agrees with the recommendation of the NERC PC (SCPS) and recommends if this has not been reviewed by NERC RISC, this may be an opportunity for the NERC Standard Committee (SC) to bring back to RISC for discussion in conjunction with the PSRPS technical document. Response: Please see the section at the beginning of this document called, "NERC Discussion on Proceeding(s) and Directives Regarding: Stable Power Swings" for a complete background. The SDT understands that NERC staff re-engaged FERC staff following the completion of the PSRPS Report and that the Commission still desired NERC to pursue its work to meet the directive. However, FERC staff was open to an approach designed by NERC. NERC staff has informally received positive feedback on the approach to address the regulatory directive. The directive itself was challenged by commenters prior to the issuance of Order No. 733 and was already the subject of multiple rehearing requests in the Order No. 733-A and Order No. 733-B proceedings. Similar arguments to the conclusions of the NERC System Protection and Control Subcommittee were advanced in these FERC proceedings.
CHPD - Public Utility District No. 1 of Chelan County	R1.1 - There should be a clarification or definition of a line-out condition. The meaning and intent of this note is not clear. Response: The phrase "line-out conditions" has been removed. Elements should be identified based on the Requirement R1 criterion regardless of the outage conditions that may be necessary to trigger enforcement of the System Operating Limit (SOL) or arming of the Special Protection System (SPS). The Guidelines and Technical Basis have been supplemented to provide additional information. (Note: The use of SPS has been replaced with Remedial Action Scheme (RAS) for consistency with a current project to revise the definition of "Special Protection System"). Change made.

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Liberty Electric Power	R2 requires Generator Operators to possess evidence prior to the enforcement date of the Standards, and prior to the passage of the Energy Act of 2005. No standard should be written which requires an entity to possess, analyze, or have knowledge of an event prior to the effective date of the standard. The beginning date of analysis should be the first full calander year after the FERC approval date of the standard. Response: The term "credible" has been removed from the standard. The drafting team clarified Requirement R1, Criterion 3 by framing the criterion in the present tense to refer to the current assessment(s). Islands caused by natural phenomena (i.e., Disturbances) are covered under Requirement R2. Change made.
Bureau of Reclamation	Reclamation suggests that R2 be rephrased to only require analysis of data from the previous year. As written, R2 would require Transmission Owners and Generator Owners to re-analyze data going back to 2003 each year. Reclamation believes that the costs of re-analyzing this data would outweigh the benefits. Reclamation believes that NERC should develop a data request to develop a robust initial data set covering January 2003 to present. Response: The "January 1, 2003" date has been removed from the standard. Requirement R2 (and new R3) are based on actual Disturbances that occur after the Effective Date of the standard. Events that occur will be reported to the Planning Coordinator in order to maintain the Element as an "identified Element." Change made.
ReliabiltiyFirst	ReliabilityFirst offers the following comments for consideration. 1. Requirement R1 - To be consistent with other NERC Reliability Standards, ReliabilityFirst suggests reclassifying the "criteria" as "sub-parts" of the requirement. Response: The drafting team has revised Requirement R4 (previously R3) and moved the criteria to PRC-026-1 – Attachment B to increase the understandability of the Requirement. Change made. 2. Requirement R2 - R2 requires GOs and TOs to evaluate Disturbances "since January 1, 2003". It appears that the intent of this requirement is to include Elements where actual system events caused a trip due to a known power swing and, by including the 2003 date, ensured that events associated with the 2003 Blackout were included. However, this may imply that events prior to 2003 need not be considered, especially in areas other than the Northeast where the blackout occurred. If an Element had a known trip for power swings associated with a Disturbance, they should be included. Therefore, ReliabilityFirst

Organization	Question 10 Comment
	recommends the flowing for consideration for the two criteria:" 1. An Element that has tripped since January 1, 2003 [(or known historical Element that tripped prior to January 1, 2003)], due to a power swing during an actual system Disturbance where the Disturbance(s) that caused the trip due to a power swing continues to be credible. 2. An Element that has formed the boundary of an island since January 1, 2003 [(or known historical Element that formed the boundary of an island prior to January 1, 2003)], during an actual system Disturbance where the Disturbance(s) that caused the islanding condition continues to be credible." Response: The "January 1, 2003" date has been removed from the standard. Requirement R2 (and new R3) are based on actual Disturbances that occur after the Effective Date of the standard. Events that occur will be reported to the Planning Coordinator in order to maintain the Element as an "identified Element." Change made. 3. Requirement R3 - ReliabilityFirst requests clarification on how the Criterion in Requirement R3 fits into the requirement. Is this criterion part of the requirement or is it additional information? If it is the later, ReliabilityFirst believes this guidance is already covered in the "Guidelines and Technical Basis" section and should be removed from the requirements. NERC Reliability Requirements should address "what" is required and not "how" an entity will comply. Response: The drafting team has revised Requirement R4 (previously R3) and moved the criteria to PRC-026-1 – Attachment B to increase the understandability of the Requirement. Change made.
Salt River Project	Salt River Project is concerned that system protection should not be "de-tuned" at the expense of the protection provided the Bulk Electric System for the sake of reliability. Response: Please see the section at the beginning of this document called, "NERC Discussion on Proceeding(s) and Directives Regarding: Stable Power Swings" for a complete background. The SDT understands that NERC staff re-engaged FERC staff following the completion of the PSRPS Report and that the Commission still desired NERC to pursue its work to meet the directive. However, FERC staff was open to an approach designed by NERC. NERC staff has informally received positive feedback on the approach to address the regulatory directive. The directive itself was challenged by commenters prior to the issuance of Order No. 733 and was already the subject of multiple rehearing requests in the Order No. 733-A and Order No. 733-B proceedings. Similar arguments to the conclusions of the NERC System Protection and Control Subcommittee were

Organization	Question 10 Comment
	advanced in these FERC proceedings.
Texas Reliability Entity	Section 1.2 - Evidence Retention: Language as written appears to be unnecessarily complicated. Suggest changing to: “Functional Entities shall retain evidence demonstrating compliance since the last audit or for three calendar years, whichever is longer.” Response: NERC staff has informed the drafting team that the language in the evidence retention section is pro-forma language used in each Reliability Standard. After reviewing the language and consulting with NERC staff, no change has been made. The drafting team encourages TRE to contact NERC standards staff to determine whether a change is necessary to its pro-forma language.
BC Hydro	Since the SPCS has concluded that no lines were tripped due to stable power swings, in any of the major disturbances, the FERC directive is flawed, and this regulation should not be implemented. Response: The drafting team acknowledges BC Hydro’s position on the FERC directive. However, the validity of the directive was challenged at multiple stages of the FERC proceeding and despite the arguments made, FERC issued its directive and has since maintained its position that a standard is needed to meet the directive. The drafting team is charged with designing a standard to meet the Commission directive. The drafting team understands that NERC staff re-engaged FERC staff following the completion of the PSRPS Report and that the Commission still desired NERC to pursue its work to meet the directive, but they were open to an approach designed by NERC. The drafting team thanks you for your comment.
Northeast Power Coordinating Council	Suggest that Associated Documents (at least those where there are no copyright concerns) be included in the standard as attachments or appendices as we are concerned that cited URLs will change over time. The information in the Criteria and Criterion in the standard should not be in the requirements, but in the Rationale Boxes. Response: It is more appropriate to cite a specific work where applicable. The drafting team has provided sufficient citations of the work and URL links, if available.
Tacoma Power	Tacoma Power supports the spirit of PSEG’s response to Question 3. Furthermore, Tacoma Power has the following, additional comments related to the January 1, 2003, date.

Organization	Question 10 Comment
	1) Not all Generator Owners and Transmission Owners may be required to retain records going back to January 1, 2003. Response: The "January 1, 2003" date has been removed from the standard. Requirement R2 (and new R3) are based on actual Disturbances that occur after the Effective Date of the standard. Change made. 2) Apart from including the 2003 Northeast Blackout, no other technical justification has been provided for why the January 1, 2003, date was selected. Alternatives might be to indicate specific disturbances for which documentation likely exists or to conduct a data request to collect better information so that Requirements R1 and R2 could be consolidated and then provide more refined and simpler criteria. Response: The "January 1, 2003" date has been removed from the standard. Requirement R2 (and new R3) are based on actual Disturbances that occur after the Effective Date of the standard. Change made. Setting aside the previous comment, does Requirement R2 Criterion 2 add any value beyond that provided by Criterion 1? If so, the term 'island' may need to be better defined. Response: The drafting team has provided additional discussion and example why Criterion 2 is providing additional value. Change made. What is the technical basis in Requirement R2 for identification to occur in January of each year? Response: The Requirement R1 language about "January of each calendar" has been removed and replaced with "each calendar year." Based on time period changes in other Requirements, the drafting team determined that an annual periodicity in Requirement R1 is more appropriate. Change made.
Luminant Generation Company LLC	The Attachments to the standard should include a listing of the specific load responsive relays that are included in the scope of the standard. Response: The drafting team has provided PRC-026-1 – Attachment A to address which relays are included and excluded. Change made.
MRO NERC Standards	The NSRF recommends the SDT consider the following changes to add clarity to the Standard: a. Applicability (Section 4.1.1 and 4.1.4), Requirement R2 - Replace "load responsive" protective relays with "impedance

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Review Forum	based" protective relays. Response: The drafting team did not add the proposed suggestion, but did add a clarification that standard is applicable to load-responsive protective relays (including overcurrent) which could trip instantaneously or with a time delay of less than 15 cycles. Change made. b. Requirement R1 - The NSRF questions the necessity of performing the identification and notification in any particular month. Why does the requirement stipulate "within the first month of each calendar year"? THE NSRF believes that it should be sufficient to use wording like, "at least once each calendar year". Response: The Requirement R1 language about "January of each calendar" has been removed and replaced with "each calendar year." Based on time period changes in other Requirements, the drafting team determined that an annual periodicity in Requirement R1 is more appropriate. Change made. c. Requirements R.1.1, R1.2 - What is meant by "stability constraints" (e.g. steady state voltage, transient voltage, steady state angle, transient angle)? The NSRF recommends that the SDT use descriptive adjectives before "stability constraint" to clarify which one, or ones, are intended. Response: The drafting team added "angular" to "stability constraint" to clarify the intent in Requirement R1, both Criterion 1 and 2. Change made. d. Requirements R1.3, R1.4 - What is meant by "Disturbances" (e.g. Category B, Category C, P1-P7)? THE NSRF recommends that the SDT use descriptive adjectives before "Disturbances" to clarify which one, or ones, are intended. Response: The drafting team revised Requirement R1, Criterion 4 by changing "Disturbance" to "simulated disturbance" to comport with the approved Reliability Standard TPL-001-4. The use of "Disturbance" in Requirements R2 (TO) and new R3 (GO) relates to an actual system Disturbance. Change made. e. Requirements R1.3, R2.1, R2.2 - What is meant by the term "credible" when discussing Disturbances (e.g. Disturbances associated with islands that were selected through R2 of PRC-006-1)? THE NSRF suggests developing proposed alternate language like, "relevant", which is easier to demonstrate simply with power flow analysis, rather than valid statistical analysis. Response: The term "credible" has been removed from the standard. The drafting team clarified Requirement R1, Criterion 3 by framing the criterion in the present tense to refer to the current assessment(s). Islands caused by natural phenomena (i.e.,

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	Disturbances) are covered under Requirement R2. Change made. f. Requirement R1.4 - What is meant by "most recent Planning Assessment"? (e.g. TPL-002/TPL-003 annual assessment, FAC-002-1 interconnection assessment) ? THE NSRF recommends to specify which type, or types, are intended. Response: The drafting team asserts that the most recent Planning Assessment provides a concrete reference to the information used in identifying BES Elements. Since the Planning Assessments (i.e., TPL-001-4) are performed annually, any other description would create confusion as to whether an entity should use past information or information revealed during preparation of a Planning Assessment. No change made. g. Requirements R2.1, R2.2 - The NSRF questions the inclusion of the statement "since January 1, 2003". THE NSRF believes that a specific historical time frame would be more appropriate, such as "in the past 10 years". Referring to "since January 1, 2003" makes an ever expanding historical time frame, which at some point, should no longer be relevant. Response: The "January 1, 2003" date has been removed from the standard. Requirement R2 (and new R3) are based on actual Disturbances that occur after the Effective Date of the standard. Change made. h. R3 - The "Criterion" text only applies to bullet 1 and 3 only, but due to the indentation appears to be a sub element of bullet 4. Therefore, THE NSRF suggests that the "Criterion" be moved more to the left move to avoid the appearance of only applying to bullet 4. Response: The drafting team has revised Requirement R4 (previously R3) and moved the criteria to PRC-026-1 – Attachment B to increase the understandability of the Requirement. Change made. NSRF has concerns about not having data back to 1 Jan 2003. R2 needs to have "if available prior to the effective date ". The SDT is looking for data before the effective date of the proposed Standard. We believe the intention of having the data but we did not know that the required data was needed to be saved from 1 Jan 2003. From the effective date of this Standard is another approach in retaining the required data. Response: The "January 1, 2003" date has been removed from the standard. Requirement R2 (and new R3) are based on actual Disturbances that occur after the Effective Date of the standard. Change made.
Idaho Power	The PSRPS report and the SPS report no need for this Standard, stating that "operation of transmission line protection systems

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Co.	during stable power swings was not causal or contributory to any of these disturbances." This statement conflicts with the need for the Standard and causes added Compliance burden to entities without reason. Response: Please see the section at the beginning of this document called, "NERC Discussion on Proceeding(s) and Directives Regarding: Stable Power Swings" for a complete background. The SDT understands that NERC staff re-engaged FERC staff following the completion of the PSRPS Report and that the Commission still desired NERC to pursue its work to meet the directive. However, FERC staff was open to an approach designed by NERC. NERC staff has informally received positive feedback on the approach to address the regulatory directive. The directive itself was challenged by commenters prior to the issuance of Order No. 733 and was already the subject of multiple rehearing requests in the Order No. 733-A and Order No. 733-B proceedings. Similar arguments to the conclusions of the NERC System Protection and Control Subcommittee were advanced in these FERC proceedings.
Exelon	The SPCS white paper "Protection System Response to Power Swings" (August 2013), found, "Based on its review of historical events, consideration of the trade-offs between dependability and security, and recognizing the indirect benefits of implementing the transmission relay loadability standard (PRC-023), the System Protection and Control Subcommittee (SPCS) concludes that a NERC Reliability Standard to address relay performance during stable swings is not needed, and could result in unintended adverse impacts to Bulk-Power System reliability." Notwithstanding that recommendation, the white paper also outlined an approach for developing a power swing reliability standard in the event a standard is proposed to address the FERC Directive. We agree that the SDT has adhered to the SPCS's recommendations in the present draft, but we do not believe that the technical basis for the SPCS recommendation against creating a standard has been challenged and that there is sufficient justification for continuing with the effort to write a standard addressing this issue. To the best of our knowledge, our operating companies, ComEd, BGE and PECO, have never experienced a relay trip due to a power swing. We recognize and appreciate the Drafting team's work in responding to comments to the SAR suggesting that alternative means of meeting the Directive should be explored. As discussed by numerous stakeholders in the previous response to comments, we believe further work in this area should continue. Response: Please see the section at the beginning of this document called, "NERC Discussion on Proceeding(s) and Directives Regarding: Stable Power Swings" for a complete background. The SDT understands that NERC staff re-engaged FERC staff following the completion of the PSRPS Report and that the Commission still desired NERC to pursue its work to meet the

Organization	Question 10 Comment
	directive. However, FERC staff was open to an approach designed by NERC. NERC staff has informally received positive feedback on the approach to address the regulatory directive. The directive itself was challenged by commenters prior to the issuance of Order No. 733 and was already the subject of multiple rehearing requests in the Order No. 733-A and Order No. 733-B proceedings. Similar arguments to the conclusions of the NERC System Protection and Control Subcommittee were advanced in these FERC proceedings.
Seattle City Light	The Standard is very complicated and confusing. It appears to be a lot like FERC Order 754 effort that we recently went through, which required two or three rounds of submissions before industry was providing the information envisioned by the framers of the process. Proposed PRC-026 involves considerable new interaction between the Planning and Protection groups. The Application Guidelines, while somewhat helpful, need to include much more explicit examples. A flow chart, or something similar, is necessary to fully delineate the steps in the process. Much more guidance is definitely needed before the Standard can be implemented. Response: The drafting team has substantively revised the standard and Guidelines and Technical Basis to improve the understandability. Change made. This draft of the Standard represents a work in progress, at best. Before any such untried process be mandated as a Standard (if it is ultimately deemed necessary that a Standard is required) Seattle City Light recommends a non-mandatory trial period of at least two years, long enough to work the bugs out of the system and ensure that entities understand and are able to perform the activities as envisioned and required. Perhaps such a trail could be conducted as a NERC request for data under Section 1600 Rules of Procedure. Response: Please see the section at the beginning of this document called, “NERC Discussion on Proceeding(s) and Directives Regarding: Stable Power Swings” for a complete background.
ITC	We are voting Negative primarily for two reasons: 1) the issues we raised need to be addressed to close some gaps and 2) we support the conclusion of SPCS in the PSRPS report that this standard “is not needed, and could result in unintended adverse impacts to Bulk-Power System reliability.”

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	Response: Please see the section at the beginning of this document called, "NERC Discussion on Proceeding(s) and Directives Regarding: Stable Power Swings" for a complete background. The SDT understands that NERC staff re-engaged FERC staff following the completion of the PSRPS Report and that the Commission still desired NERC to pursue its work to meet the directive. However, FERC staff was open to an approach designed by NERC. NERC staff has informally received positive feedback on the approach to address the regulatory directive. The directive itself was challenged by commenters prior to the issuance of Order No. 733 and was already the subject of multiple rehearing requests in the Order No. 733-A and Order No. 733-B proceedings. Similar arguments to the conclusions of the NERC System Protection and Control Subcommittee were advanced in these FERC proceedings. As written, the standard only addresses distance and not overcurrent elements. This question was raised in the webinar and a clear answer was not given. The standard refers to "load-responsive" relays, which includes overcurrent, but does not provide criteria for evaluation in R3. Also, should the standard include time-delayed tripping elements, which are commonly ignored for swing tripping consideration? Response: The drafting team added a clarification that standard is applicable to load-responsive protective relays (including overcurrent) which could trip instantaneously or with a time delay of less than 15 cycles. Change made. We also request examples for R3, fourth bullet, of scenarios which do not result in "dependable fault detection or dependable out-of-step tripping", perhaps in the App Guide. Specifically, we are concerned about load/swings with subsequent phase faults which result in time-delayed tripping when power swing blocking is enabled. Even the most modern SEL-400 relays with zero-setting OOS logic includes additional time delayed tripping for subsequent phase faults. For a standard around swings and stability, delayed fault clearing seems to counterproductive. Is this the scenario which could apply to R3, fourth bullet? Response: The drafting team has concluded that it is possible to comply with the PRC-026-1 – Attachment B, Criteria while providing dependable fault detection or dependable out-of-step tripping and has removed this bullet from Requirement R4 (previously R3).
Public Utility District No. 1 of Cowlitz	We believe this Standard will address a Reliability gap, but also feel that it can overlap into PRC-004. Load responsive relays that trip on a stable power swing should be addressed by PRC-004 as a Protection System Misoperation; subsequently after PRC-004 is satisfied, the affected element should be subject to PRC-026-1 until a repeat is demonstrated to be remote or

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County, WA	nonexistent. However, a violation of PRC-004 should not automatically bleed into a violation of PRC-026-1. Response: There should be no conflict here. If an entity determines a protective relay operation was a Misoperation, it would address the cause of the miss operation under PRC-004. A Misoperation in and of itself is not a violation according to the effective version PRC-004-2.1a. If the operation was due to a stable power swing, then the Element for which the load-responsive relay is applied at the terminals, would then become an identified Element under PRC-026-1.
SPP Standards Review Group	We note that the SPCS concluded that this standard was not needed based on their review and analysis of past disturbances. They went on to say that such a standard '...could result in unintended adverse impacts to Bulk-Power System reliability.' Given their conclusion, has NERC and/or the SDT given any consideration to requesting FERC reconsider their directive to develop this standard? Response: Yes. The drafting team understands that NERC staff re-engaged FERC staff following the completion of the PSRPS Report and that the Commission still desired NERC to pursue its work to meet the directive. However, FERC staff was open to an approach designed by NERC. NERC staff has informally received positive feedback on the approach to address the regulatory directive. The directive itself was challenged by commenters prior to the issuance of Order No. 733 and was already the subject of multiple rehearing requests in the Order No. 733-A and Order No. 733-B proceedings. Similar arguments to the conclusions of the NERC System Protection and Control Subcommittee (SPCS) were advanced in these FERC proceedings. The following are comments on the draft RSAW. We recommend that a specific reference be made to the question of providing evidence based on experience prior to the effective date of the standard. Please see our response to Question 6 above. The industry needs assurances from NERC Compliance that auditors will not be holding responsible entities accountable for providing data on events that occurred prior to the effective date of the standard. The 1st and 2nd cells of the Evidence Requested and Compliance Assessment Approach tables for both Requirements R1 and R2 insert additional requirements that are not contained in the requirements in the standard. These items request evidence/documentation on the methodology and the utilization of that methodology by the responsible entity in the identification of the Elements called for in the two requirements. Neither Requirement R1 nor Requirement R2 mention

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	anything about requiring the responsible entity to 1) have a methodology for performing that identification and 2) use the methodology in the identification process. These items need to be deleted from the RSAW along with the Note to Auditor under the Registered Entity Response for both Requirements R1 and R2. These notes refer to these two items. In the Note to Auditor under the Compliance Assessment Approach Specific to PRC-026-1, R2 replace the 'all' at the end of the 3rd line with 'a'. Still within this section, does the SDT concur with the interpretation of the example at the top of Page 9? If not, we ask that the SDT inform the RSAW developers. Response: Thank you for your comments. The Reliability Standard Audit Worksheet (RSAW) comments have been provided to NERC Compliance as they are responsible for the content of the RSAW.
Xcel Energy	R2 states that elements involved in a power swing since 2003 are targeted for evaluation, with the caveat that the "power swing continues to be credible." It seems that what constitutes a credible threat is widely open for debate. If it's not credible once, is it eliminated from consideration going forward? Response: The "January 1, 2003" date has been removed from the standard. Requirement R2 (and new R3) are based on actual Disturbances that occur after the Effective Date of the standard. The term "credible" has been removed from the standard. The drafting team clarified Requirement R1, Criterion 3 by framing the criterion in the present tense to refer to current assessment(s). The term "credible" was removed from the previous Requirement R2 (and new R3) because the required performance refers to only current actual events. Change made.
Associated Electric Cooperative, Inc.	1. This standard is the result of a FERC directive. Yet the reference document entitled "Protection System Response to Power Swings" (the PSRPS document) used to justify the standard does not support the need for the standard. The reference document was prepared by the NERC System Protection and Control Subcommittee and was approved by the NERC Planning Committee. It is posted at http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf. Our comments explains this concern and recommends that "the NERC Standards Committee explore means to utilize the more recent PSRPS document to obtain relief from the aforementioned FERC directive that is driving this project."

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	Response: Please see the section at the beginning of this document called, "NERC Discussion on Proceeding(s) and Directives Regarding: Stable Power Swings" for a complete background. The SDT understands that NERC staff re-engaged FERC staff following the completion of the PSRPS Report and that the Commission still desired NERC to pursue its work to meet the directive. However, FERC staff was open to an approach designed by NERC. NERC staff has informally received positive feedback on the approach to address the regulatory directive. The directive itself was challenged by commenters prior to the issuance of Order No. 733 and was already the subject of multiple rehearing requests in the Order No. 733-A and Order No. 733-B proceedings. Similar arguments to the conclusions of the NERC System Protection and Control Subcommittee were advanced in these FERC proceedings. 2. Although we object to the standard in its entirety, R2 is particularly egregious and we are objecting to it so that similar language will never appear in a NERC standard. R2 requires GOs and TOs to evaluate Disturbance records "since January 1, 2003," a time that will precede the effective date of this standard. A requirement cannot rely upon records that precede the effective date of a standard. As an example, PRC-005-1, which was approved in Order 693, became effective on June 11, 2007, does not require a Registered Entity to have maintenance records available for the period of time that preceded the effective date in order to calculate the next maintenance interval for a relay. Response: The "January 1, 2003" date has been removed from the standard. Requirement R2 (and new R3) are based on actual Disturbances that occur after the Effective Date of the standard. Events that occur will be reported to the Planning Coordinator in order to maintain the Element as an "identified Element." Change made.

Additional Comments (Response follows)

Si Truc PHAN
Hydro-QuébecTransÉnergie
Author: .Eric Loiselle, eng. Automatismes, Hydro-Québec TransÉnergie
Date 2014-05-19

Requirement R3 Application Guidelines, Application to Transmission Owners, page 16 to 19

The 120° lens shape criterion with system impedance including all parallel paths defines a boundary limit corresponding to $Z_{busA\_allowable} = \frac{V_A}{I_{total}}$. The Application Guidelines should explain that distance relay R, at the line L of bus A, measures I_L, and not I_{total}. $I_L = I_{total} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$.

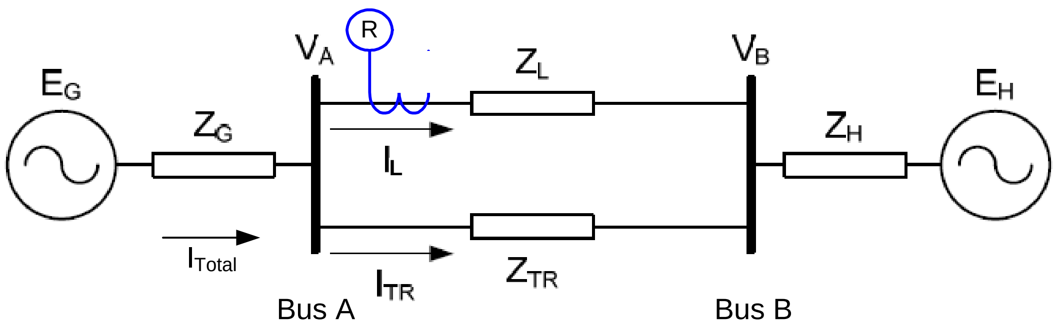


Figure 1[14] : Two- Machine Equivalent of a Power System with Parallel System Transfer Impedance.

[14] Figure 29, SPCS Power Swings Report, 20131015

The distance reach allowable before the relay R trip is:

$Z_{relayR\_allowable} = \frac{V_A}{I_L}$
$= \frac{(Z_L + Z_{TR})}{Z_{TR}} \frac{V_A}{I_{total}}$
$Z_{relayR\_allowable} == Z_{busA\_allowable} \frac{(Z_L + Z_{TR})}{Z_{TR}}$

The distance element of a relay R, measuring I_L , can be set greater that the distance element of a relay measuring I_{total}. Therefore, the lens characteristic of the total system impedance cannot directly be compared with the distance characteristic of a line. To juxtapose the two characteristics in the same R-X plane, either the lens or the distance element need to be scale by a factor $\frac{(Z_L + Z_{TR})}{Z_{TR}}$

Example: Hydro-Quebec 735 kV network

Typical Hydro-Quebec network configuration is 3 parallel 735 kV lines connecting into 2 substations. See figure below.

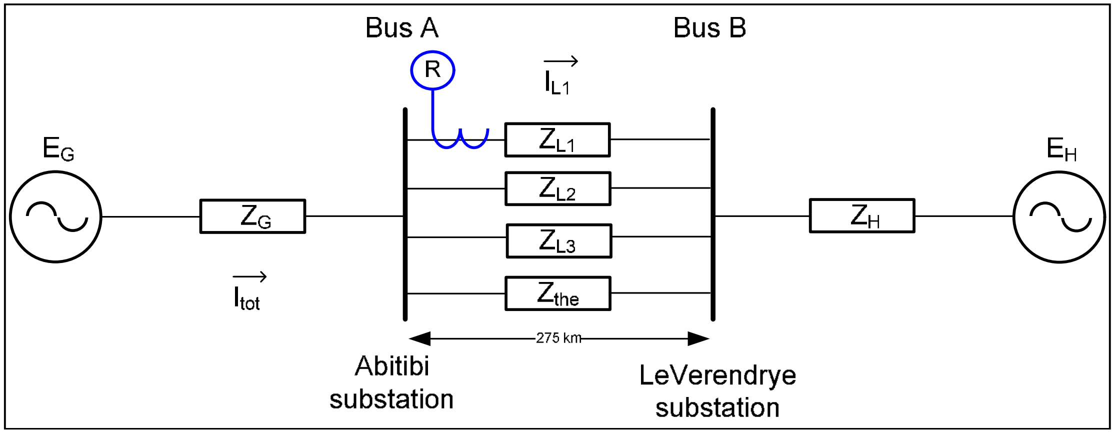
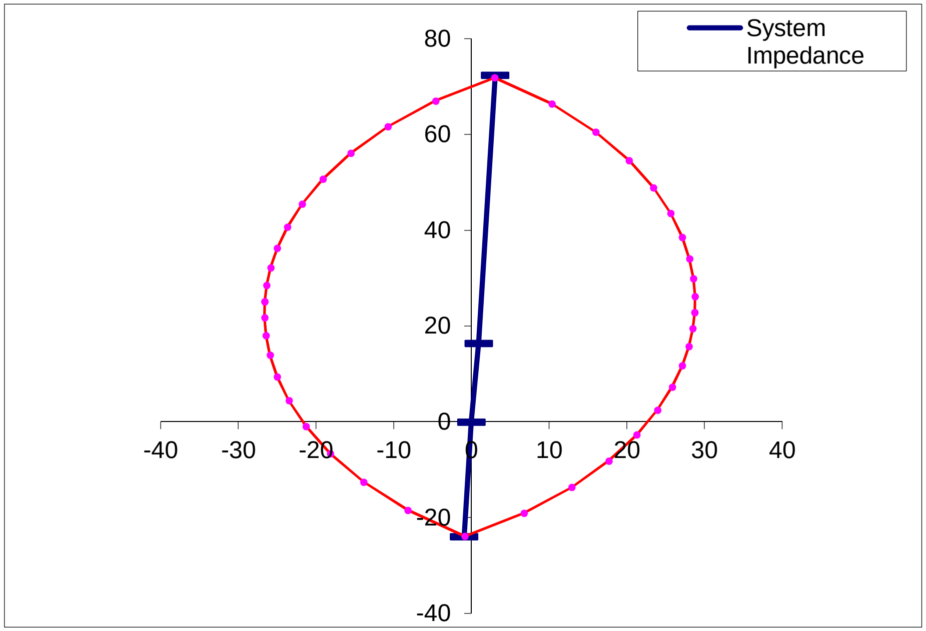


Figure 2: Two- Machine Equivalent of a typical Hydro-Quebec network.

	R	X	Notes
Zg	0,9	23,9	Subtransient impedance, nominal generator and load
ZL1	3,2	55,8	Include -32 j ohms of series compensation CXC
ZL2	2,9	50,6	Include -32 j ohms of series compensation CXC
ZL3	2,9	50,6	Include -32 j ohms of series compensation CXC
Zthe	14,6	325,9	Thevenin equivalent of other links between Bus A and B
Zh	2,1	55,5	Subtransient impedance, nominal generator and load

The 120° lens characteristic and the total system impedance at bus A are drawn at the figure below.



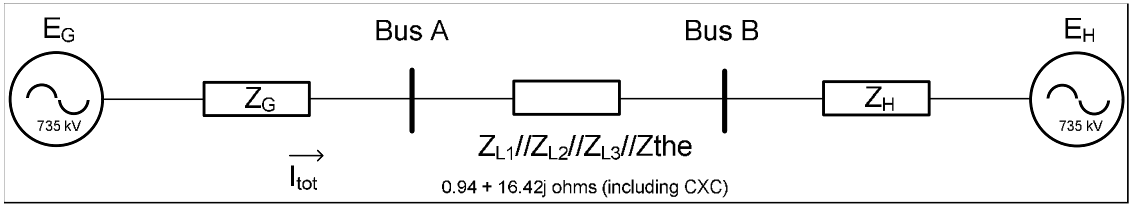


Figure 3: Stability boundary at 120° and total system impedance at bus A.

Typical 735 kV lines are protected by main A and main B current differential protections. Back up distance protection is also used. This distance protection is subject to PRC-026 and need to be evaluated. The larger tripping element of this protection is typically a zone 3 MHO set at 130% of the line impedance without CXC compensation. See next figure.

$$Z_{relayR\_allowable} = \frac{V_A}{I_L}$$

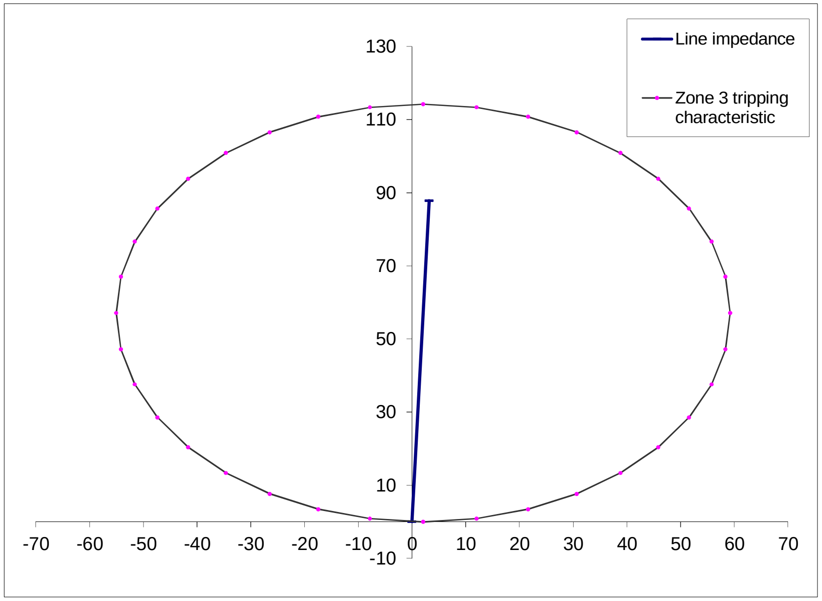


Figure 4: Relay R zone 3 MHO set at 130% of the line impedance without CXC compensation.

This distance relay R measures I_{L1}, not I_{total}. The distance element of figure 4 cannot be juxtaposed with figure 3 lens shape.

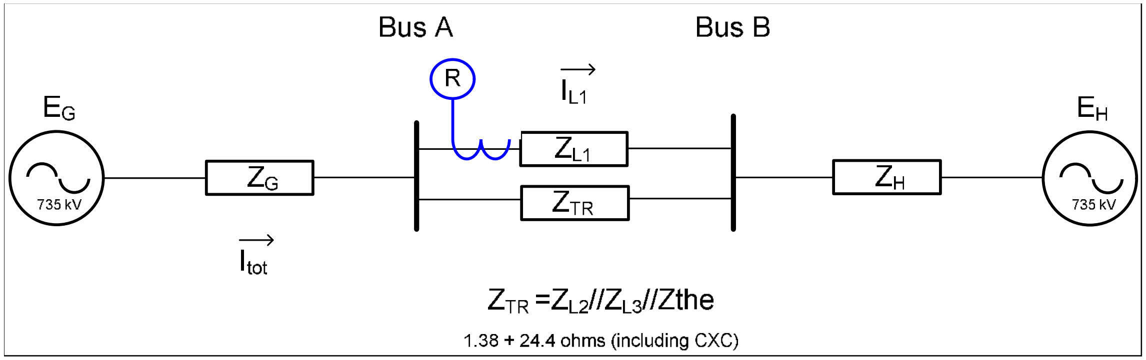


Figure 5: Calculation of the ratio between I_{L1} and I_{total}.

$$\boxed{\frac{(Z_{L1} + Z_{TR})}{Z_{TR}} = 4.6}$$

The distance relay measures 1/4.6 of the total system current. Therefore, the zone element of the line 1 is divided by 4.6 before being juxtaposed with the total system boundary stability.

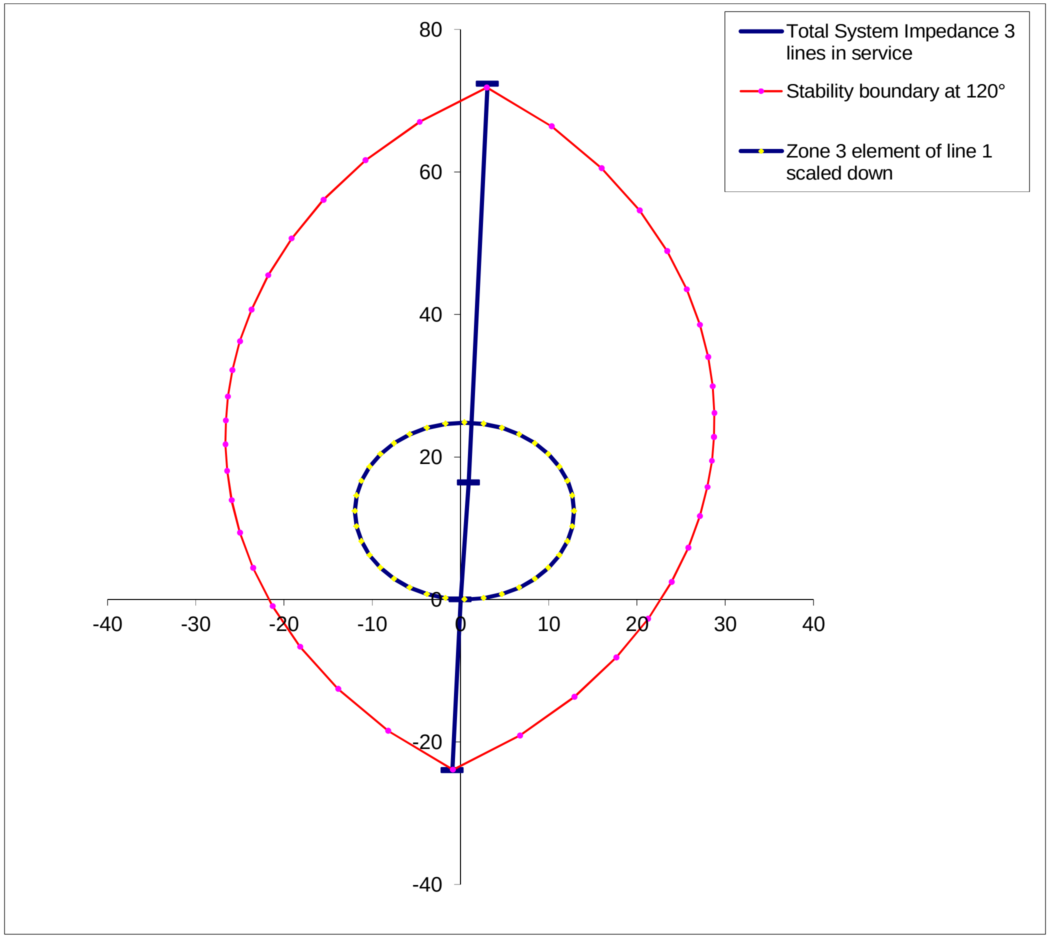


Figure 6: Juxtaposition of zone 3 line element and 120° lens shape, in the total system R-X plane, at bus A

The MHO 130% elements is clearly inside the 120° lens characteristic. With three735 kV lines interconnecting bus A and B, power swings are unlikely to occur. As mentioned by the SPCS power swing report, considering all the parallel transfer impedance is more accurate and allows a greater relay reach.

The 735 kV Hydro-Quebec is more likely to swing when two of the three 735 kV lines are out of service. PRC-026 R3 doesn't impose to evaluate this case. However, it's an interesting topology to study.

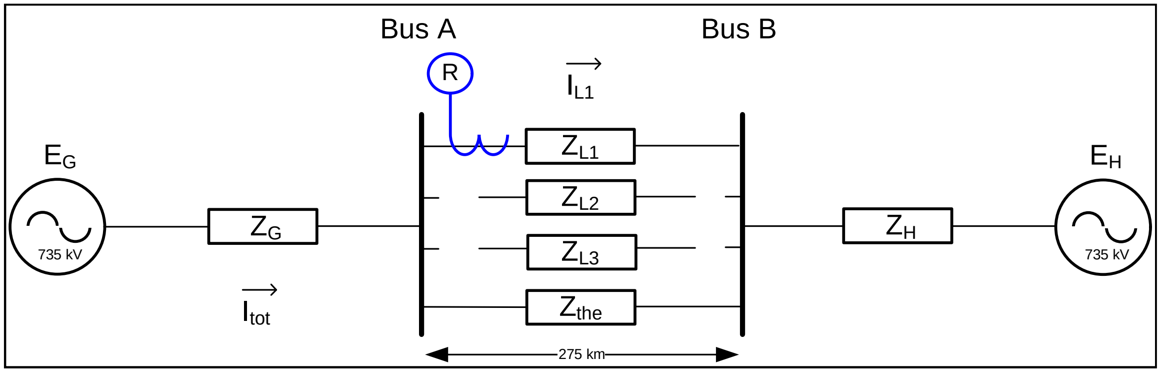


Figure 7: Two- Machine Equivalent of a typical Hydro-Quebec network with two 735 kV lines out of service.

Here, the transfer impedance is increased approximately by three. The line current I_{L1} measures by the relay R is almost equal to the total system current I_{total}.

The scale factor is reduced: $\boxed{\frac{(Z_{L1}+Z_{TR})}{Z_{TR}}=1.2}$

With this special topology, the MHO Zone 3 element is no more contain within the 120° stability boundary, as shown at the next figure.

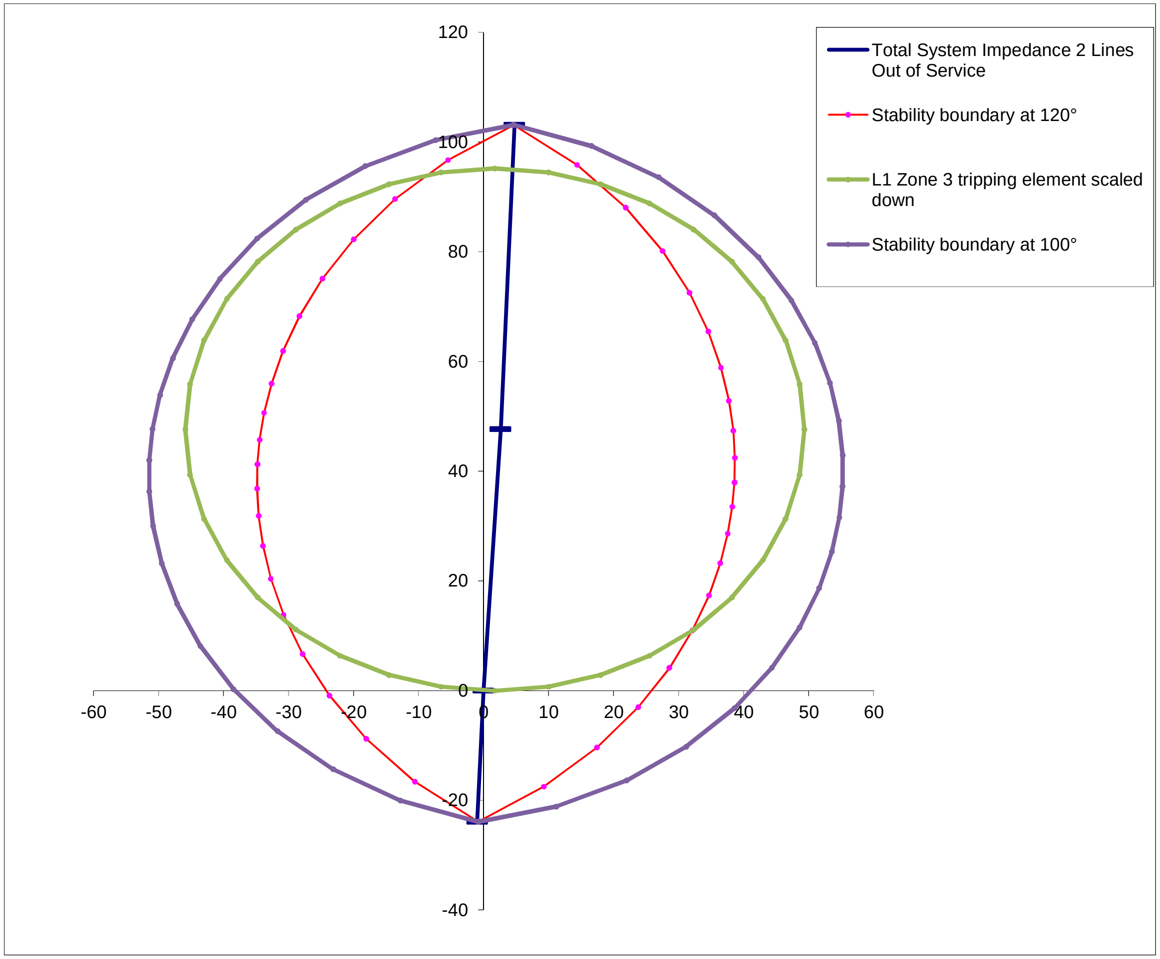


Figure 7: Juxtaposition of zone 3 line element and total system 120° lens shape, in the same R-X plane.

With only one 735 kV in service, nominal generation and load are not allowed. In case of a sudden loss of two 735 kV lines, specials protection systems will reject generation and load within 20 cycles. Zg and Zh will be increased, so as the lens shape representing the stability boundary.

The total system impedance of figure 7 can only exist for a maximum of 20 cycles. Zone 3 is a delayed tripping element of 30 cycles. It can be assumed that it won't trip in this condition. As allowed by PRC-026-R3, maybe a reduced stability angle could be used to evaluate this particular topology. The last figure shows that the zone 3 tripping element is within a 100° lens shape.

Response: On May 9, 2014, Eric Loiselle of Hydro-Québec presented a technical document showing that the impedance seen by a relay on a line being evaluated for PRC-026-1 compliance is affected by the parallel transfer impedance in the reduced system network. Inclusion of the transfer impedance in the lens evaluation results in an "apparent lens" impedance as observed by the relay in question that is larger than the observed impedance without the parallel transfer impedance. It was the opinion of Hydro-Quebec that this transfer impedance should be considered when performing the lens evaluation.

The drafting team agrees with the analysis in the technical document presented by Hydro-Quebec, but disagrees with their assessment that the parallel transfer impedance should be included in the lens evaluation.

The drafting team asserts that the parallel transfer impedance should be removed when calculating the total system impedance so that the most conservative portion of a lens characteristic is formed. When the parallel transfer impedance is included, the split in current through the parallel transfer impedance path results in actual measured relay impedances that are larger than those measured when the parallel transfer impedance is removed, which would make it more likely for an impedance relay element to be completely contained within the portion of the lens characteristic. If the transfer impedance is included in the lens evaluation, a distance relay element could be deemed passing, but could subsequently trip for a stable power swing during an actual event if the system was weakened to the point where the lines that make up the parallel transfer impedance were removed.

Other changes have been made to alleviate some of the concerns shown in Hydro-Quebec's example. In their example, they show a zone 3 relay with a trip time delay of 30 cycles. This relay would be exempted from evaluation per the revised Standard since it trips in a time delay of 15 cycles or greater. Also, the lens evaluation in the criteria has been modified to a portion of a lens. The first posted draft 1 of the proposed standard used a complete lens characteristic by varying the system voltages from 0 to 1.0 per unit. Draft 2 of the proposed standard changed this voltage range from 0.7 to 1.0 so that only a portion of a lens is formed. These voltage ranges are more realistic and sufficiently conservative, and will make it more likely for an impedance relay element to meet the criteria.

It was additionally noted in Hydro-Quebec's zone 3 example that it would pass with a system angle of 100 degrees. This reduced system angle is still allowed in the Criteria if a documented stability analysis shows the reduced angle is acceptable.

END OF REPORT