Individual or group. (70 Responses)
Name (46 Responses)
Organization (46 Responses)
Group Name (24 Responses)
Lead Contact (24 Responses)
Question 1 (49 Responses)
Question 1 Comments (56 Responses)
Question 2 (45 Responses)
Question 2 Comments (56 Responses)
Question 3 (47 Responses)
Question 3 Comments (56 Responses)
Question 4 (42 Responses)
Question 4 Comments (56 Responses)
Question 5 (39 Responses)
Question 5 Comments (56 Responses)
Question 6 (40 Responses)
Question 6 Comments (56 Responses)
Question 7 (39 Responses)
Question 7 Comments (56 Responses)
Question 8 (0 Responses)
Question 8 Comments (56 Responses)
Question 9 (0 Responses)
Question 9 Comments (56 Responses)
Question 10 (0 Responses)
Question 10 Comments (56 Responses)

Group
Northeast Power Coordinating Council
Guy Zito
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. 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. 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. 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. 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). 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.
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.
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 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.
No
In the Application Guidelines, the wording under Requirement 2 for credible event is very ambiguous and needs specificity.
No.
No.
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.
Individual
Steve Wickel
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. 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. R1.4 - WECC is slowly coming on board with this as a result of the San Diego outage and is adding 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.
R1.1 – There should be a clarification or definition of a line-out condition. The meaning and intent of this note is not clear.
Individual
Rick Terrill
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. The date of 2003 needs to be removed from the standard as it prefaces compliance on data that predates the approval of the standard. 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. “
Yes
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.
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.
Yes
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.
Yes
NERC standards requirements should not reference data that predates the approval of the standard; therefore, rendering the Requirement R2 January 2003 date unenforceable.
The Attachments to the standard should include a listing of the specific load responsive relays that are included in the scope of the standard.
Individual
Michelle R. D'Antuono
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. 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.
Yes
Yes
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.
Yes
Yes
Yes
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.
Individual
Venona Greaff
Occidental Chemical Corporation
Individual
John Seelke
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: 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.
No
We disagree with the need for this standard.
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.
No
We disagree with the need for this standard.
No
We disagree with the need for this standard.
No
We disagree with the need for this standard.
No
We disagree with the need for this standard.
Individual
Jared Shakespeare
Peak Reliability
Yes
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.
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. 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. 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. 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.
No
• The expectations of the RC need to be clarified, and until they are clarified, it is unclear whether the 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.
Individual
Daniel Duff
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.
Individual
Mauricio Guardado
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.
Yes
Yes

LADWP is voting “Negative” on PRC-026-1 for the reason that the reference document entitled “Protection System Response to Power Swings” (the PSRPS document) used to justify the standard does not support the need for a reliability standard.
Individual
Brenda Hampton
Luminant Energy Company, LLC
Group
PacifiCorp
Sandra Shaffer
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.
Yes
No
These functions would be more appropriate assigned to the GOP and TOP.
Yes
No comment
Yes
Yes
Individual
Ayesha Sabouba
Hydro One
Individual
Frederikc R Plett
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.
Yes
Yes
Yes
Yes
Yes

Yes
Individual
Rob Robertson
First Wind
Individual
Ronnie C. Hoeinghaus
City of Garland
Group
MRO NERC Standards Review Forum
Joe DePoorter
Yes
Yes
Yes
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.
Yes
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.
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.
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 based” protective relays. 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”. 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. 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. 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. 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. 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. 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. The 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.
Individual
Terry Harbour
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.
Yes
Yes
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 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.
Yes
Yes
Yes
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. 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? 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? 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?
Individual
Kayleigh Wilkerson
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.
Group
Seattle City Light
Paul Haase
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. 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.

Individual
Thomas Foltz
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.
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 condition remains to be credible. 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.
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. We agree with the approach, but do not believe that R3 would need to be executed annually. It should only need to be done once per relay until something about the relay in question or the transmission system in the immediate vicinity changes.
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.
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.
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.
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 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. 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. 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. 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.
Individual
Chris de Graffenried
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. 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. 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. 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.
Yes
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.
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.
Yes
No
1. In the Application Guidelines, the wording under Requirement 2 for “credible event” is very open-ended. 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.
Yes
No
No
Individual
Cheryl Moseley
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 assessment at least once each calendar year, with no more than 15 months between assessments…” R2 through R4 could use a similar approach. 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.
No
See our comments to Q1.
Yes
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. 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.
Individual
Amy Casuscelli
Xcel Energy
Individual
Andrew Z. Pusztai
American Transmission Company, LLC
Yes
Yes
Yes
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.
Yes
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.
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.
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. 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". 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. 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. 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. 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. 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. 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. 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.
Individual
Jo-Anne
Ross
Yes
Yes
Yes
Yes
Yes
Yes
Yes
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? 2) Also in R1, does “Line-out conditions” mean “N-1” condition? 3) What definition of an island is used in the standard? 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.
Individual
Mark Wilson
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? • 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? • 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. • 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 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
Yes
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. Further, the term credible Disturbance needs clarification. Please see our comment under Q1, above.
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. 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”.
Yes
Yes
No
Individual
David Kiguel
n/a
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)? 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. 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. 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.
Yes
Yes
Yes
Yes
Yes
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 FERC directive that is driving this project.
Group
SMUD/BANC
Joe Tarantino
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. (2) The requirement R2 is particularly unacceptable as it requires data for pre June 18, 2007; effective date of Order 693 standards.
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.
No
The requirement R2 is particularly unacceptable as it requires data for pre June 18, 2007; effective date of Order 693 standards.
YES! The requirement R2 is particularly unacceptable as it requires data for pre June 18, 2007; effective date of Order 693 standards.

Individual
Richard
Vine
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.
Individual
Chris Mattson
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. 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. Setting aside the previous comment, Criterion 4 needs more clarification. What is the technical basis in Requirement R1 for identification and notification to occur in January of each year?
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.
No
Tacoma Power disagrees with the need for this standard.
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 would yield a more conservative assessment.
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.
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.
No

Tacoma Power disagrees with the need for this standard. In particular, Tacoma Power has significant concerns with Requirements R1 and R2.
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 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.
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. 1) Not all Generator Owners and Transmission Owners may be required to retain records going back to January 1, 2003. 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. 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. What is the technical basis in Requirement R2 for identification to occur in January of each year?
Individual
David Jendras
Ameren
No
(1) Along with our comments we agree with and adopt the Public Service Enterprise Group (PSEG) Comments by reference. (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. (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. (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 avoid a unique maintenance switching topology that was causal.
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.
Yes
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. (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). (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.
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; (2) The issue of aligning the planning assessment time horizon with present Protection System settings (see our 2nd comment Q1) needs to be clarified; (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). (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. (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.”
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.
Group
Tennessee Valley Authority
Dennis Chastain
Yes
Yes
Yes
No
1) Every year is too often for this requirement. We recommend changing this to every 5 years. 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.” 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”.
Yes
Yes
Yes

Group
SPP Standards Review Group
Robert Rhodes
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.
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.
Yes
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. 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.
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. References to 30-, 60-, and 90-calendar days should be hyphenated in the VSLs for Requirements R1, R2 and R3.

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. One-line diagrams for the examples in the explanations for Requirements R1 and R2 would be helpful. 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.
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.
We are not aware of any conflicts between the proposed standard and any regulatory function, rule, order, tariff, rate schedule, legislative requirement, or agreement.
We are not aware of any need for a regional variance or business practice.
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? 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 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.
Group
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
Wayne Johnson
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. R1 #4 and R2 #1 should specify the inclusion of Elements that trip due to "stable power swings" instead of all power swings.
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.
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. 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 misoperations to maximize availability - the market forces have long driven utilities to correct undesirable relay operations so they can be available to the market.
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. 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.
Yes
The requirement language should be finalized before establishing VRFs, VSLs. and measures.
Yes
Yes, provided the R2 review period begins with the enforcement date of the stantard looking forward.
We are not aware of any conflicts.
We are not aware of any needs for exceptions.
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? 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." Is this requirement duplicative of PRC-004 relay mis-operation determination? Does PRC-026 subject entities to possible violation of two standards for a single possible (lack of) action? 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. 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.
Group
ISO RTO Council Standards Review Committee
Greg Campoli
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. 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.
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.
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. 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. 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 rolling calendar basis, e.g. – “prior twelve months”.
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. 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-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.
Group
Dominion

Mike Garton
Yes
Yes
Yes
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.
Yes
Yes
Yes
No
No
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. 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.
Individual
Scott Langston
City of Tallahassee
Individual
Bob Thomas
Illinois Municipal Electric Agency
Individual
Bill Fowler
City of Tallahassee
Individual
John Pearson
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. • 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. • Criteria 2 should be deleted. This criteria appears to be redundant to Criteria 1. • 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. • 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 contingency. Again, Disturbance is too broad. It should be limited to single or multiple contingencies but not extreme contingencies.
Yes
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.
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 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.
Yes
No
While the Application Guidelines and Technical Basis provide guidance, we disagree with the current roles of functional entities to which the standard applies.
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.
Group
ACES Standards Collaborators
Jason Marshall
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. (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. (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. (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. (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. (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? (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." (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 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. (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?
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.
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. (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.
Yes
(1) We agree generally with the approach but note that there are specific issues. (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). (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. (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.
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. (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. (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.
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. (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.
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?
(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. (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. (3) Thank you for the opportunity to comment.
Group
FirstEnergy Corp.
Richard Hoag
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.
Yes
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.
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. 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. 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. 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 Thevenin impedance (system equivalent) at the Point of Interconnection, acquiring this should not be a problem.
Yes
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. 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. 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. Please define "stable power swing". The diagrams ("Figures") in the Application Guidelines appear to be typical. Is there enough information contained in the Application Guidelines that a GO can determine Power Swing Stability Boundaries for each specific application?
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.
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.
None
None

Group
Florida Power & Light
Mike O'Neil
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. Criteria 4 should consider Planning Assessments in the last year as opposed to “the most recent Planning Assessment.”
Yes
Yes
Yes
Yes
Group
PPL NERC Registered Affiliates
Brent Ingebrigtson
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: We agree with the general approach, but have some implementation concerns as expressed below.
Yes
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. - 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….” - GOs may not know whether their Elements formed the boundary of an island (ref. R2.2GOs 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.
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 programs. - 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.
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.
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?
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 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.
No.
No.
Individual
Chris Scanlon
Exelon
Yes
Yes
Yes
Yes
Yes
Yes
Yes

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.
Group
Duke Energy
Michael Lowman
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 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.” (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.
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 (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:”
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.
Yes
Yes
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.
Yes
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.
Individual
Shivaz Chopra
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.” 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.
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.
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.
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. A more accurate description of “load responsive” protective relays is also necessary. This Standard seems to just repeat what is in the PSRPS technical document, without the necessary elaborations needed for proper understanding.
No
We do NOT agree with the need for this standard.
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.
No
Implementation periods should be consistent with the more relevant approach described in the PSRPS technical document.
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.”
Group
BC Hydro
Patricia Robertson
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.
No
BC Hydro does not agree that the criteria of R1 are reasonable. Therefore cannot suggest why an entity is not appropriate.
No
BC Hydro does not agree that the criteria of R2 are reasonable. Only experience of tripping during STABLE power swings should be used.
Yes
No
BC Hydro does not agree with R1 and R2, therefore do not agree with violation risk factors or violation severity levels.
No
The technical basis should be improved to apply only to cases where stable power swings have historically caused undesirable tripping of transmission lines.
No
BC Hydro does not agree with implementation of the proposed standard at all.
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.

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.
Individual
Roger Dufresne
Hydro-Quebec Production
Group
JEA
Tom McElhinney
Individual
Gul Khan
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”. 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.
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. 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.
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.
No
See response to question #1.
No
See response to question #1.
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. 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.
No
Please see response #1, #6 and #10
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. 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. 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.
Individual
Glenn Pressler
CPS Energy
Group
Florida Municipal Power Agency
Frank Gaffney
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 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. 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.
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. 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.
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. 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.
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.
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.
Group
DTE Electric
Kathleen Black
No comment
Yes
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.
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.
No comment
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. 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 swings.
No comment
No comment
No comment
No comment
Individual
Karin Schweitzer

Texas Reliability Entity
Yes
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? 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…”
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”. 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)?
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.
Yes
Yes
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.”
Individual
Michael Moltane
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. Also, the term “credible” is unclear. If an event involves scenarios beyond TPL’s “broad spectrum of 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 extreme 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.
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.
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.
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.
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.
No.
No
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.” 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? 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?
Individual
Thomas Standifur
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. (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.
Individual
Bill Temple

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. 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. 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. 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.
Yes
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.
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.
Yes
No
1. In the Application Guidelines, the wording under Requirement 2 for “credible event” is very open-ended. 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.
Yes
No
No
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. 2. Please provide more examples to help further illustrate the criteria in listed in R1. 3. Please differentiate between Stable and Unstable power swings.
Individual
Jonathan Meyer
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. 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 Standard. M2 appears to require the utility to have evidence it did not know it needed to maintain. 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. 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? Concerning R1.3, who is the judge of whether an event is "credible"?
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.
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. 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
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. 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? 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.
Yes
Yes
In the present form of R1-R4
No
The requirements need work before an implementation plan can be defined. It should be adjusted based on changes proposed in #4.
The PSRPS report and the SPS report no need for this Standard, stating that "operation of transmission line protection systems 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.
Individual
Patrick Farrell
Southern California Edison Company
Yes

Yes
Yes
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.
Yes
Yes
Yes
Individual
Russell Noble
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. --(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. 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). 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.
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.

Yes
Provided the SDT finds a way to clearly establish the documentation from which the GO and TO will identify the Elements.
No comment at this time.
Yes
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.
Yes
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 nonexistent. However, a violation of PRC-004 should not automatically bleed into a violation of PRC-026-1.
Individual
Melissa Kurtz
US Army Corps of Engineers
Group
Colorado Springs Utilities
Kaleb Brimhall
Group
Puget Sound Energy
Eleanor Ewry
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. 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.
Yes
Yes
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.
Yes
Yes
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.

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.
Individual
Anthony Jablonski
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. 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 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.” 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.
Group
Bonneville Power Administration
Andrea Jessup
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. 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.) Secondly, BPA feels the Glossary definition of Disturbance lacks sufficient clarity as it relates to this and other existing Standards.
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 planning.
Yes
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.
Yes
No
BPA feels 12 months is insufficient time for the initial implementation.
Western Interconnection has many long lines and remote generation.
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).
Individual
Joshua Andersen
Salt River Project
Yes
Yes
Yes
Yes
Yes
Yes
Yes
None
None
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.
Group
Arizona Public Service Co.
Janet Smith
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. APS believes that the current draft requirement is administrative in nature and represents a reporting burden.
Yes
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 limited access to this information. 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.
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.
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.
Yes
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.
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. 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. APS believes that the current draft requirement is administrative in nature and represents a reporting burden.
Individual
Kenneth A Goldsmith
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 Owner.
Group
Bureau of Reclamation
Erika Doot
Yes
Yes
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. 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. 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.
Yes
Yes
Yes
Yes
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.