Individual or group. (45 Responses)
Name (29 Responses)
Organization (29 Responses)
Group Name (16 Responses)
Lead Contact (16 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (5 Responses)
Comments (45 Responses)
Question 1 (40 Responses)
Question 1 Comments (40 Responses)

Group
Northeast Power Coordinating Council
Guy Zito
No
In PRC-024-1(X), A. Introduction 5. Effective Date was removed, and replaced by the Effective Date paragraph. This change is not only not indicated in the redline, but more importantly it removed the “phased-in” implementation of PRC-024-1 which was necessitated by the requirements of the standard. Is the intent to remove the “phase-in” percentages by the single effective date indicated by the Effective Date paragraph in PRC-024-1(X)? Under A.5 Effective Date: of PRC-025-1(X) the words “See Implementation Plan” were deleted. PRC-025-1(X) has its own Implementation Plan which is part of the standard’s “package”. However, to ensure clarity and avoid misunderstanding, suggest leaving “See Implementation Plan” in A.5. The Implementation Plan must be revised to be consistent with the intended revisions. It should be made clear that all aspects of the Implementation Plans for PRC-024-1 and PRC-025-1 will remain applicable to those standards. In part (b) on page 1, what is meant by “distributed relays”? Are “distributed relays” intended to be distribution system relays? The wording needs clarification. Please add the following to “The following do not individually constitute a RAS:” list: The controllers at each terminal of a High Voltage direct current (HVdc) Facility that may or may not rely on communications with the other terminals of the same HVdc Facility, that perform the intended control functions for that HVdc Facility.
Group
Arizona Public Service Co
Janet Smith
Yes
Individual

Thomas Foltz
American Electric Power
Yes
Within the section “The following do not individually constitute a RAS”, AEP recommends the following changes: Item a: Delete “BES” so that it reads “Protection Systems installed for the purpose of detecting Faults on Elements and isolating the faulted Elements”. Item e: Add the qualifier “reverse power” so that it reads “Schemes applied on an Element for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, overvoltage, reverse power, or overload to protect the Element against damage by removing it from service.” Item k: Delete the phrase “that proceed when” and add the text “that proceeds directly to a desired system state” so that it reads “Automatic sequences manually initiated solely by a System Operator that proceeds directly to a desired system state.”
Individual
Barbara Kedrowski
Wisconsin Electric Power Co
No
We propose that the following changes be made to the list of exclusions: Item (e) – To “schemes applied to an Element for non-Fault conditions”, add the following: overexcitation, over/under- frequency, motoring, load rejection, and unbalanced system conditions. We believe these are abnormal, non-Fault system conditions for which protection is commonly applied, and should not be considered RAS. Item (n) Replace “Generator controls …” with “Generator or turbine controls…” Add a new exclusion for protective functions for black start generators that may be implemented to allow greater than normal voltage or frequency tolerance during restoration conditions.
Individual
Amy Casuscelli
Xcel Energy
Yes
While Xcel Energy agrees with the revised definition, we offer the comments below for the Drafting Team's consideration: We observe that the proposed new RAS definition is substantively and structurally very similar to the existing SPS/RAS definition. The most significant change in the proposed new definition is the detailed list of 14 exclusions versus the 3 exclusions in the existing definition – we agree that the additional exclusions are a useful enhancement. However, the functional description of RAS characterized by its purpose and actions is almost the same in both definitions – we note that the first sentence in both definitions contains identical verbiage “designed to detect predetermined System conditions and (automatically) take corrective actions…”. In the new definition, this is followed by a

listing of typical corrective actions before stating the reliability objectives in the second sentence – whereas the existing definition enumerates them both in the second sentence. However, the three examples provided for corrective actions and objectives are common to both definitions, and are supplemented with two additional reliability objectives in the proposed new definition. Given these substantive commonalities, we recommend that the proposed new definition be restructured as follows to make it easier to discern the similarities retained and the enhancements introduced relative to the existing definition, as well as improve its contextual clarity and readability. [A scheme designed to detect predetermined System conditions and automatically take corrective actions <to> accomplish <BES reliability> objectives such as: (1) Meet requirements identified in the NERC Reliability Standards (2) Maintain Bulk Electric System (BES) stability (3) Maintain acceptable BES voltages (4) Maintain acceptable BES power flows(5) Limit the impact of Cascading or extreme events. Corrective actions may include, but are not limited to, adjusting or tripping generation (MW and Mvar), tripping load, or reconfiguring System(s).] Irrespective of whether the proposed restructuring of the definition is implemented or not, we suggest that the reliability objectives be re-sequenced. Due to the non-specific “catch-all” nature of the first objective (meet requirements in reliability standards), we recommend that it be listed as the last objective to follow the four specific attributes of reliable system performance.
Group
Colorado Springs Utilities
Kaleb Brimhall
No
1. The last bullet of the definition, before all the exclusions, says “Limit the impact of Cascading or extreme events. We recommend that rather than introducing another variable that is not defined (extreme events) that the language already commonly used be included so it would read as follows: a.“Limit the impact of instability, uncontrolled separation, or Cascading. 2.On exclusion “n.” local generator output controls should be included as well General Notes: Colorado Springs Utilities does not agree with the exclusion list in the proposed definition. We do not think that it is reasonable or prudent to create a comprehensive list of exclusions. There will always be just one more exception that will force us to continue to modify the list of exclusions. Also, if it is not explicitly defined as an exception then by default it is automatically included whether it could affect reliability or not. The definition should clearly define what a RAS so as to include those schemes identified as essential to reliability. The only implicit exclusion we would recommend would be to exclude protection schemes that meet the definition of a RAS and are explicitly covered under other NERC reliability standards. Utilities would then use the definition to make sure that essential protection systems that meet the definition are included and document any further assumptions or judgement used in delineating between RAS and non-RAS schemes. Trying to micro-manage every possible exclusion or inclusion we think is not realistic and should not be necessary.
Group

Peak Reliability
Jared Shakespeare
No
The new exclusion (n) that reads: “Generator controls such as, but not limited to, automatic generation control (AGC), generation excitation [e.g. automatic voltage regulation (AVR) and power system stabilizers (PSS)], fast valving, and speed governing” excludes certain historical RAS actions such as AGC blocking. It is agreed some generator controls like AVR and PSS are not RAS. See added inclusion list below. Adding BES to the possible objectives can be confusing to interpret. It can be interpreted that RAS are restricted to BES elements when that is not the intention of the standard. Peak recommends either removing “BES” from possible objectives or adding “(including sub-100 kV facilities identified as necessary by the Reliability Coordinator)” as shown below. Note this language is consistent with IRO-002-4 R3. It might be beneficial in the background information to include that RAS is distinctly different than industry standard (IEEE) definition for System Integrated Protection Scheme (SIPS). Proposed definition: A scheme designed to detect predetermined System conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation (MW and Mvar), tripping load, or reconfiguring a System(s). RAS accomplish objectives such as: • Meet requirements identified in the NERC Reliability Standards; • Maintain Bulk Electric System (BES) (including sub-100 kV facilities identified as necessary by the Reliability Coordinator) stability; • Maintain acceptable BES (including sub-100 kV facilities identified as necessary by the Reliability Coordinator) voltages; • Maintain acceptable BES (including sub-100 kV facilities identified as necessary by the Reliability Coordinator) power flows; • Limit the impact of Cascading or extreme events. The following constitute RAS: • AGC blocking • Fast valving The following do not individually constitute a RAS: a. Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating the faulted Elements b. Schemes for automatic underfrequency load shedding (UFLS) and automatic undervoltage load shedding (UVLS) comprised of only distributed relays c. Out-of-step tripping and power swing blocking d. Automatic Reclosing schemes e. Schemes applied on an Element for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, overvoltage, or overload to protect the Element against damage by removing it from service f. Controllers that switch or regulate one or more of the following: series or shunt reactive devices, flexible alternating current transmission system (FACTS) devices, phase-shifting transformers, variable-frequency transformers, or tap-changing transformers; and, that are located at and monitor quantities solely at the same station as the Element being switched or regulated g. FACTS controllers that remotely switch static shunt reactive devices located at other stations to regulate the output of a single FACTS device h. Schemes or controllers that remotely switch shunt reactors and shunt capacitors for voltage regulation that would otherwise be manually switched i. Schemes that automatically de-energize a line for a non-Fault operation when one end of the line is open j. Schemes that provide anti-islanding protection (e.g., protect load from effects of being isolated with generation that may not be capable of maintaining acceptable frequency and voltage) k. Automatic sequences that proceed when manually initiated solely by a System Operator l.

Modulation of HVdc or FACTS via supplementary controls, such as angle damping or frequency damping applied to damp local or inter-area oscillations m. Sub-synchronous resonance (SSR) protection schemes that directly detect sub-synchronous quantities (e.g., currents or torsional oscillations) n. Generator controls such as, but not limited to, automatic generation control (AGC), generation excitation [e.g. automatic voltage regulation (AVR) and power system stabilizers (PSS)], fast valving, and speed governing
Individual
Hamid Zakery
Calpine Corp
No
Calpine appreciated the efforts by the Special Protection System SDT team. We support the idea of having a sigle clear definition. However, it is not clear why existing widely used SPS definition is being revised to be replaced with a Remedial Action Scheme (RAS)that is not commonly known. We believe this change will create even more confusion as there is no clarrification for what is an "scheme". Is it a protection system, turbine control, static VAR Compensator(SVC) operation, large shunt capacitor controls connected at the BES level to maintain acceptable BES voltage. We suggest adding the word protective to the RAS definition as following " A protective scheme designed to detect predetermined ...." This may clarify potential confusions may be caused by listing all protection system schemes in the " do not individually constitute as RAS" section.
Individual
David Thorne
Pepco Holdings Inc
Yes
Individual
Andrew Z. Pusztai
American Transmission Company, LLC
Yes
However, ATC suggests the addition of parenthetical verbiage similar to today's SPS definition to exclusion (c). The suggested change to exclusion (c) would read "Out-of-step tripping and power swing blocking (not designed as an integral part of an RAS)."
Individual
Mark Wilson
Independent Electricity System Operator
Yes

Group
MRO NERC Standards Review Forum
Joe DePoorter
No
Please consider the following: Exclusion item (c) - Retain the parenthetical text from the existing SPS Definition in the new RAS Definition, namely “c. Out-of-step tripping and power swing blocking (not designed as an integral part of an RAS)”. There is an existing power swing blocking scheme where this parenthetical language is key for clarifying the SPS exclusion. Exclusion item (e) – Add reverse power relays to include this clarification, with wording like, “Schemes applied on an Element for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, overvoltage, overload, or reverse power to protect the Element against damage by removing it from service.” Add Exclusion item (o) – Add an exclusion item that identifies some minimum impact thresholds for applicability to NERC Reliability Standards (e.g. Section 215, EOP-004-2 disturbance reporting). For example, if an RAS would not cause any loss of firm load, any loss of BES generation, any damage to BES Elements, any loss of nuclear plant off-site power, any widespread instability, uncontrollable separation or cascading, etc., then it is not be subject to any RAS requirements in NERC Reliability Standards. Implementation Plan – In almost all circumstances the twelve month timeframe for the RAS definition or revised Reliability Standard should be sufficient for the introduction of new RAS or identification of existing scheme as RAS. However, it is also possible the identification of an existing scheme as RAS might require BES system upgrades that could take years to design, approve, and build (e.g. 7 year provision in the TPL-001-4 standard). Therefore, consider including a provision in the Implementation Plan of an effective date of seven years for existing schemes that were not previously identified as SPS.
Individual
Jonathan Meyer
Idaho Power
Yes
Individual
Terry Harbour
MidAmerican Energy
No
Exclusion item (c) - Retain the parenthetical text from the existing SPS Definition in the new RAS Definition, namely “c. Out-of-step tripping and power swing blocking (not designed as an integral part of an RAS)”. There is an existing power swing blocking scheme where this parenthetical language is key for clarifying the SPS exclusion. Exclusion item (e) – Add reverse

power relays to include this clarification, with wording like, “Schemes applied on an Element for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, overvoltage, overload, or reverse power to protect the Element against damage by removing it from service.” Add Exclusion item (o) – Add an exclusion item that identifies some minimum impact thresholds for applicability to NERC Reliability Standards (e.g. Section 215, or the EOP-004-2 disturbance reporting standard). If an RAS would not cause loss of load and or generation of more than 100 MW then the event would be local and would not meet the need for “special” consideration in the NERC standards. Criteria consistent with NERC standard EOP-004-2 such as the following could be considered: 1. No automatic firm load shedding ≥ 100 MW (excluding automatic undervoltage or underfrequency load shedding schemes needed to meet other NERC standards). 2. No Loss of firm load for ≥ 15 Minutes or greater than ≥ 100 MW. 3. No total generation loss, within one minute, of ≥ 100 MW. Implementation Plan – Identification of existing or new RAS /SPS schemes might require BES system upgrades that could take years to design, approve, and build (e.g. 7 year provision in the TPL-001-4 standard). Therefore, consider including a provision in the Implementation Plan of an effective date of seven years for existing schemes that were not previously identified as SPS / RAS schemes.
Individual
Richard Pienkos
Consumers Energy Company
No
The sentence originally read “RAS accomplish one or more of the following objectives:”. This implies that it has to meet at least one of these criteria to be an applicable RAS. It was changed to read “RAS accomplish objectives such as:” . This now implies that this is a just a list of examples but there may be other objectives that apply. I was relying on this original wording to limit the compliance exposure to BES systems only. The way it is written now it can be interpreted to apply to schemes on the non-BES system. Consumers Energy will vote negative on this ballot until this wording is changed back or some other way is used to limit this definition to only BES schemes.
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
Group
Con Edison, Inc.
Kelly Dash

No
In PRC-024-1(X), "A. Introduction 5. Effective Date" was removed, and replaced by the Effective Date paragraph. This change is not only not indicated in the redline, but more importantly it removed the “phased-in” implementation of PRC-024-1 which was necessitated by the requirements of the standard. Under A.5 Effective Date: of PRC-025-1(X) the words “See Implementation Plan” were deleted. PRC-025-1(X) has its own Implementation Plan which is part of the standard’s “package”. However, to ensure clarity and avoid misunderstanding, suggest leaving “See Implementation Plan” in A.5. The Implementation Plan must be revised to be consistent with the intended revisions. It should be made clear that all aspects of the Implementation Plans for PRC-024-1 and PRC-025-1 will remain applicable to those standards.
Individual
Michelle D'Antuono
Ingleside Cogeneration LP
Yes
Ingleside Cogeneration LP (ICLP) agrees that the latest version of the RAS definition is a distinct improvement over its predecessor. The removal of the catch-all inclusion for schemes that address “other Bulk Electric System (BES) reliability concerns” is the primary reason for our “Yes” vote this time around. With it, the definition inferred that every automated system that has even the most tenuous tie to reliability could be considered as RAS – which clearly is not the intent of this initiative. Another positive modification in our view is the new exclusion for generator control systems like AGC, PSS, AVR’s, and governors. These clearly are not Remedial Action Schemes, but without the exclusion it is possible to construe them as such. While not affecting our vote, ICLP would like a better explanation to the elimination of categories of RAS – as originally recommended by the SPCS. The only response we saw was a statement that “informal feedback from many stakeholders” led to this decision. Perhaps there are very good reasons they were only shared with the project team, but the Standards Development Process is expected to be open and deliberative. The informal process is important in order to stimulate good ideas and discussion, but should not play a part in the review/ballot unless it is documented and vetted by all participating stakeholders.
Individual
Michael Moltaned
ITC
No
Remove “such as” from “RAS accomplish objectives such as:”. Exclusion A should remove “BES”. E.g. non-BES transformers connected to BES lines or buses have fault protection which must trip for transformer faults to accomplish RAS objectives. However, these should be excluded from RAS. Reverse power relaying on distribution-transmission interface should be excluded from RAS. This could be a separate exclusion or a modification to Exclusion J.

Group
PacifiCorp
Sandra Shaffer
No
Western requests the SDT to re-consider an additional exclusion for “cross-tripping schemes within the same station”. We continue to believe such a simplistic localized scheme should be outside the purview of a RAS and its associated scrutiny and approval, which particularly does not lend itself to the operating horizon. By and large, implementation of a cross-trip within the same station is utilized to mitigate a thermal SOL by tripping another element in lieu of the overloaded element. Not only does this action mitigate a thermal SOL, it most often improves the robustness and reliability of the remaining BES system to deliver firm commitments. The proposed exceptions are appropriate; however, they are still inadequate. The end effect of the proposed RAS definition includes any protection action and/or scheme that is beyond standard/historical individual relaying protection package functions, thereby limiting the ‘art’ of system protection to include the objective of ‘maximizing the robustness of the remaining BES system’. On this basis, Western suggests the SDT reconsider the definition strictly including “reconfiguring a System(s)”. The suggestion of excluding “cross-tripping schemes within the same station” for sake of mitigating a potential thermal overload is more benign should it fail to operate than failure of the currently proposed exclusion of “out-of-step tripping and power swing blocking”, as an example. Further, the definition does not delineate lower risk “localized” schemes. Consequently, there is no expeditious avenue to implement a localized benign scheme within a reasonable timeframe for the operating horizon. This is a real issue. As example, following the flood of 2011, Western had transmission lines toppling in standing water and needed to quickly implement a cross-trip scheme to facilitate needed and urgent outages for maintenance/repair (within days). Western suggests the SDT recognize “localized” benign schemes either outside the scrutiny of a RAS all together, or at minimum, allow such schemes to be implemented for 1 year with the caveat that the scheme be vetted through an expedited stakeholder process. If the “localized” scheme ultimately must receive RAS review and scrutiny, it should be done expeditiously. Currently, the WECC RASRS attempts to streamline “localized’ schemes.
Individual
Philip R. Kleckley
South Carolina Electric & Gas Co.
Yes
Individual
Sonya Green-Sumpter
South Carolina Electric & Gas
Agree

Individual
Karen Webb
City of Tallahassee
Agree
Individual
Sergio Banuelos
Tri-State Generation and Transmission Association, Inc.
No
1. The first bullet after the opening definition seems very vague; especially since the next three bullets are examples of those requirements referenced in the first bullet. 2. The fifth bullet does not seem to apply unless an entity has identified the “Cascading or extreme events” resulting from some “predetermined System conditions.” Tri-State believes that it may be better to revert to the previous language that included “abnormal or,” i.e., “A scheme designed to detect abnormal or predetermined System conditions…” 3. Reword exclusion (e.) such that local monitoring can be used to disconnect other Elements than the one Element being monitored as long as communications to a different location is not required. For example, “Schemes applied locally for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, overvoltage, or overload to remove a local Element from service to protect it against damage.” 4. While Tri-State agrees with exclusion (e.) in principle (with our suggested wording changes), it seems that the inclusion of “overvoltage, or overload” is in conflict with the third and fourth bullets in the main definition. Perhaps “the use of communication” needs to be included in parts of the definition. 5. Tri-State thinks exclusion (f.) should start with the word “Automatic” so as not to be confused with remote manual control. 6. Exclusion (g.) seems to be in conflict with the last phrase of exclusion (f.). 7. Exclusion (h.) seems to be in conflict with the last phrase of exclusion (f.).
Group
Santee Cooper
Shawn Tom Abrams
No
“Santee disagrees with using RAS as a replacement for SPS. An SPS is used as an automatic system designed to detect abnormal or pre-determined system conditions and take pre-planned corrective action. This term applies to and is referenced in numerous guides, procedures and protocols.” “The term SPS should not be based upon normal operational schemes like a RAS. These are “special” systems designed to maintain reliability until solutions can be added to remove or “exit” their changes. We also anticipate other Reliability Coordinators having to go through a similar effort in regards to the SPS terminology change.”

Individual
Gul Khan
Oncor Electric Delivery LLC
Yes
Individual
Chris Scanlon
Exelon Companies
Yes
We think the following should be considered. Exclusion “e” specifically includes “transformer top-oil temperature”. Other common transformer protection such as “winding temperature” and “loss of cooling” measure distinctly different parameters from top oil temperature but share a similar goal. These protection schemes seem conspicuous by their absence from exclusion “e” . They are arguably covered under the “but not limited to” clause but especially the former seems common enough that it merits specific mention.
Individual
Venona Greaff
Occidental Chemical Corporation
Agree
Ingleside Cogeneration, LP
Group
SPP Standards Review Group
Robert Rhodes
Yes
We appreciate the effort of the drafting team in developing the proposed revised definition. The new revision is much clearer. The expansion of the list of exclusions has been a big help. Whenever the NERC Glossary of Terms is referenced in the standard and in the Background and FAQ document, the full name is used – Glossary of Terms Used in NERC Reliability Standards. This is the case with one exception, in the 1st line of the answer to the 1st question under the FAQ section of the Background and FAQ document. Please make the appropriate change here.
Individual
Bill Fowler
City of Tallahassee
No

In order to eliminate uncertainty, TAL believes criteria should be established that defines acceptable BES power flows.
Group
Dominion NERC Compliance Policy
Randi Heise
No
Section D: Under section d; reclosing should not be capitalized, this is not a defined term in the NERC Glossary of terms. Section F: Although the SDT responded to Dominion's prior comments, Dominion believes that the SDT's response is deficient." in that Dominion does not support the inclusion of the phrase, "and that are located at and monitor quantities solely at the same station as the Element being switched or regulated." Why does it make a difference whether the controller is local or remote? The advent of high-speed phase measurement units (PMUs) and faster computer systems will eventually allow wide area control. This will become essential as the customer's load characteristic evolves (less voltage and frequency dependency means local PSSs will be less effective). We are concerned that the definition in general will hamper innovation. Right now there are schemes that control LTC's and capacitors to minimize losses. Certainly these are not RAS. There are EMS controls such as what PJM uses that dispatch generation precontingency to avoid overloads/voltage problems. These are not RAS either. Eventually computer EMS systems will become fast and robust enough to drop load or reconfigure the system so quickly that wide area blackouts will be virtually eliminated. Recall that only 500 MWs of load drop would have stopped the 2003 blackout. Therefore wide area systems that generically react to problems (not designed for a single specific contingency (if line A opens, do xyz action)) should not be RAS. Section N: Dominion does not agree with addition of (n) as written. The first paragraph of the definition states "A scheme designed to detect predetermined System conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation…. So, to the extent automatic generation control (AGC), generation excitation [e.g. automatic voltage regulation (AVR) and power system stabilizers (PSS)], fast valving, or speed governing is used in such a scheme it can't be excluded. It may help clarify if the SDT expanded upon the intent of the phrase "The following do not individually constitute a RAS" General comment: The elimination of SPS terminology , the move to one term- RAS and the addition of exclusion language only complicates the historical view on "special" schemes. This change will cause many US utilities burden due to references to SPS's that will result in numerous revisions to existing compliance documentation, training programs, reference prints, and scheme application operating procedures. The majority of US utilities and at Protection Conferences the term SPS is used while the minority (most in WECC region) use the term RAS. Many times these schemes are made up primarily of protective relays to implement "special" applications. This change in definition is unnecessary and only introduces more questions when exclusions are introduced.
Individual
John Merrell

Tacoma Power
No
Regarding one comment previously submitted by Tacoma Power, the drafting team responded that they “did not try to create an exhaustive list of examples.” While Tacoma Power acknowledges that it is difficult to create an exhaustive list, Tacoma Power does believe that the following clarification, either in the definition, or in the FAQ document, needs to be made. The following type of scheme should be explicitly identified as an exclusion since classification of this type of scheme has been a gray area; clarification is needed: “Thermal protection systems intended to mitigate thermal damage, within expected system re-dispatch response times, such as 10 minutes or greater.” However, if the drafting team intended for this type of scheme generally to be RAS, then clarification is also needed. In the proposed RAS definition, change “MW and Mvar” to “MW and/or Mvar.” Otherwise, the definition suggests that both MW and Mvar must be adjusted, which might not be the case for every RAS. In the proposed RAS definition, would automatic sequences that proceed when manually initiated solely by plant personnel, substation operators, or similar on-site personnel still be considered an exclusion if directed by a System Operator? Tacoma Power believes that the answer should be yes. In the FAQ document, under “Automatic Reclosing schemes,” the drafting team stated that “system reconfiguration which transfers the load to another source typically would be a RAS.” Tacoma Power believes that system reconfiguration primarily intended to restore load following a loss of that load should typically fall under the exclusion (d). When the FAQ document states that “system reconfiguration which transfers the load to another source typically would be a RAS,” Tacoma Power understands this would be a true statement if and only if the system reconfiguration is intended to support one of the five bulleted objectives identified in the proposed RAS definition. In the FAQ document, under “Schemes applied on an Element for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, overvoltage, or overload to protect the Element against damage by removing it from service,” Tacoma Power maintains that, in lieu of removing the Element from service due to an overload, taking action such as adjusting generation, especially at the same location (power plant) of the overload, would equally satisfy the exclusion, especially if removal of the Element, after time delay, is employed as a fallback. Regarding the implementation plan for PRC-024-1(X), it appears that the 40%, 60%, and 80% milestones contained in PRC-024-1 may have been eliminated. If this is not true, please provide clarification as to where these milestones will be documented if PRC-024-1(X) is approved. In any event, these milestones should be maintained.
Group
National Grid
Michael Jones
No
Please add the following item, to the lists of items, that do not individually constitute a RAS: "The controllers at each terminal of an High Voltage direct current (HVdc) Facility, that may or

may not rely on communications with the other terminals of the same HVdc Facility, that perform the intended control functions for that HVdc Facility." Rationale: HVdc controllers performing the intended control functions for that HVdc Facility, should have equal treatment as FACTS controllers in the exclusion list. HVdc control functions such as: Pole Loss Compensation, Fast Metallic Return, and Permanent Mode Shift Compensation should be excludable controllers.
Individual
Scott Langston
City of Tallahassee
No
In order to eliminate uncertainty, TAL believes criteria should be established that defines acceptable BES power flows.
Individual
Laurie Williams
PNM Resources Inc.
Yes
PNM Resources appreciates the work of the Drafting team and would request that there be a clarification that 'Temporary Outage Action Plans' or 'TOAPs' (used in the TRE/ERCOT area) are not included in the definition of RAS. It appears that TOAPs used by ERCOT entities would primarily be subject to 'Exclusion E' as they are temporary schemes that would switch elements based on voltage or to avoid thermal overload on non-faulted elements. They could additionally fall under 'Exclusion K' and would take the action that would normally be executed by System Operators manually. TOAPs are developed to protect against a temporary condition that could arise during a planned maintenance outage which are utilized widely in the TRE/ERCOT area and in PNM Resources' opinion should not be considered RAS which would then require that any Temporary Outage Action Plan would trigger CIP-002-5 inclusion of a BES asset to evaluate and have to apply CIP protections to systems not typically included in CIP scope.
Individual
Chris de Graffenried
Con Edison, Inc.
Agree
Northeast Power Coordinating Council (NPCC)
Individual
John Pearson/Matt Goldberg
ISO New England
No

Exclusion “c” should be revised to include the word “stable” before the words “power swing blocking” so that it reads “c. Out-of-step tripping and stable power swing blocking.” This is because the exclusion should only apply to stable power swing blocking and not all power swing blockings. Exclusion “e” Schemes applied on an Element for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, overvoltage, or overload to protect the Element against damage by removing it from service, unless the operation of the scheme is relied on to allow reliable operation at more stressed transfers on the system. Example: Loss of a 345 kV line on an interface overloads a parallel 115 kV line at a transfer of 1,000 MW. If the 115 kV line overload is detected by a scheme and removed from service, the interface can then reliably transfer 1,500 MW. This should be considered to be a RAS. Exclusion “j” currently reads “Schemes that provide anti-islanding protection (e.g., protect load from effects of being isolated with generation that may not be capable of maintaining acceptable frequency and voltage).” This language is confusing because the first phrase describes schemes designed to prevent an island from forming but the parenthetical describes actions taken after an island is formed. To avoid this confusion, exclusion “j” should be revised to read: “j. Schemes that protect load from effects of being isolated with generation that may not be capable of maintaining acceptable frequency and voltage.” For exclusion “m,” in response to a comment we had made during the previous commenting period, the Standard Drafting Team explained that “Exclusion (m) is consistent with present industry practices and the drafting team declined to make the suggested change. The proposed definition excludes schemes that directly detect sub-synchronous quantities; however, SSR mitigation schemes installed to detect distinct System configurations and loading conditions (that studies have shown may make a generator vulnerable to SSR), and take action to trip the generator or bypass the series capacitor, are classified as RAS.” While we agree with the Standard Drafting Team’s explanation, in order to clearly reflect that explanation in the RAS definition, exclusion “m” should read: “m. Sub-synchronous resonance (SRR) protection schemes that directly detect and only take local action due to sub-synchronous quantities (e.g., currents or torsional oscillations).” The definition should decouple all possible HVDC Converter controls from the RAS definition. Add an additional Exclusion to RAS definition for HVDC Based on NERC Terms of Glossary - Facility, here is the suggested exclusion language: The controllers at each terminal of an High Voltage direct current (HVdc) Facility, that may or may not rely on communications with the other terminals of the same HVdc Facility, that perform the intended control functions for that HVdc Facility.
Group
Florida Municipal Power Agency
Carol Chinn
Yes
FMPA agrees with the changes to the definition of Remedial Action Scheme but maintains that a thorough review of all standards should be conducted to look for uses of the terms Protection System(s) and protection system(s) to determine if it was intended to include SPS/RAS as part of the requirement. Simply removing the statement “These schemes are not

Protection Systems; however, they may share components with Protection Systems" does not accomplish the same objective. As an example, PER-005-1 R3.1 may or may not be interpreted to include Remedial Actions Schemes.
Group
Tennessee Valley Authority
Dennis Chastain
No
We agree that using a single term should help bring the industry toward a common understanding/usage of the term. However, we disagree with the revised draft definition. Bullets 2-5 can be interpreted to cover objectives beyond NERC Reliability Standards, when taken in context with the first bullet. The scope of the definition should be limited to applications that are relevant to the NERC Reliability Standards in which the term is used. We think it's appropriate to address exclusions, however when the exclusion list is this long (and perhaps growing) it highlights the challenge in developing a good base definition for what constitutes a RAS NERC-wide. An alternative would be to "catalog" the RAS exclusions in a separate NERC reference document that could be revised without revising the base RAS definition. We feel that the implementation period should be extended to 5 years or more for existing schemes that are categorized as RAS by this definition change. Since the definition affects many additional standards, this could entail more work than anticipated to ensure full compliance with each one under the new definition.
Individual
Catherine Wesley
PJM Interconnection
Yes
Individual
Jo-Anne Ross
Manitoba Hydro
Yes
Group
ACES Standards Collaborators
Brian Van Gheem
No
(1) We agree with the need to modify the existing definition of SPS and RAS and that use of a single term will provide a more consistent use in applicable NERC standards and among the

various NERC regions. We also appreciate the efforts of the SDT and incorporating many of our previous comments and recommendations into this latest proposed definition. However, we still feel the proposed definition still needs further clarification with its objectives and list of exclusions. (2) The definition identifies that one objective of a RAS is to "Meet requirements identified in the NERC Reliability Standards". As we identified in previously submitted comments, the reference of this term is ambiguous, and the SDT should remove it from the definition. According to the consideration of comments posted from the last comment period, the SDT believes this term needs to highlight the importance of risk on reliability when a RAS fails to operate or operate not as designed. We believe such an importance is already captured in the other objectives such as "Limit the impact of Cascading or extreme events" and "Maintain Bulk Electric System (BES) stability". Moreover, operation failure of the RAS measures the effectiveness of the actions taken by the RAS, not why an entity would install and maintain a RAS on their system. Furthermore, NERC declares on its website that its standards "define the reliability requirements for planning and operating the North American bulk power system and are developed using a results-based approach that focuses on performance, risk management, and entity capabilities." NERC and its regions assign these requirements to registered entities, not to individual BES elements or related system components. (3) The SDT added the NERC-defined term, "System Operator", to exclusion "k" in the list of items that do not individually constitute a RAS. We believe the possibility exists when non-NERC certified operators, such as a local TO operations center in PJM that performs switching, could manually initiate a sequence that further leads to activation of automated operations. This possibility exists due to the staffing requirements listed in the requirements of NERC Standard PER-003-1. We suggest the SDT add "…or personnel under their direct supervision" to this exclusion item to address this possibility. (4) The addition of "extreme events" to the last objective bullet is ambiguous and confusing. The objectives already cover Cascading and stability in other bullets. What other "extreme events" is the definition intended to cover? System islanding or separation? If so, then just state specifically these extreme events and remove the vague term "extreme events". (5) We would like to thank the SDT on its continual efforts to include comments from industry during the development of this definition and this opportunity to comment.
Group
PacifiCorp
Sandra Shaffer
No
(1) PacifiCorp strongly suggests further revision of the proposed RAS definition to provide an exclusion for schemes that trip adjacent circuits within a single substation, commonly referred to as cross-tripping schemes. Cross-trip schemes are often hard-wired or implemented with simple mirrored-bit type communications between relays in a single substation. These schemes are employed in instances when tripping of an element or elements in addition to or instead of the directly-monitored system element within a substation will provide superior electrical performance. Cross-trip schemes utilize simple Boolean logic, and system impacts of

the schemes are typically local in nature. It is therefore PacifiCorp's contention that inclusion of these schemes in the RAS catalogs will do little to improve system performance or reliability, and further, their inclusion may hinder the transmission planning process by encumbering planners with information that is not useful. PacifiCorp does recognize the importance of capturing the actions of these cross-trip schemes in transmission system planning models; however this is best accomplished in contingency definitions. (2) The RAS definition does not provide any delineation between schemes that may have a significant impact on the bulk electric system and schemes that have limited impacts to the local system. PacifiCorp suggests that the drafting team reconsider inclusion of the Local Area, Wide Area, and Safety Net scheme designations in the RAS definition. These designations have been successfully defined and implemented within the WECC RRO territory with good results. As such, PacifiCorp suggests adoption of the WECC criteria for scheme delineation utilizing TPL criteria violations, load and generation impacts to provide clear and consistent delineation between the various types of schemes.
Individual
William Temple
Northeast Utilities
Agree
Northeast Power Coordinating Council
Individual
Steve Johnson
WAPA
No
Western requests the SDT re-consider an additional exclusion for "cross-tripping schemes within the same station". We continue to believe such a simplistic localized hard-wired scheme should be outside the purview of a RAS and its associated scrutiny and approval, which particularly does not lend itself to the operating horizon. By and large, implementation of a cross-trip within the same station is utilized to mitigate a thermal SOL by tripping another element in lieu of the overloaded element. Not only does this action mitigate an SOL, it most often improves the robustness and reliability of the remaining BES system to deliver firm commitments. Without such exclusion, the SOL element often must be opened pre-contingent, thus further degrading the robustness of the BES. The proposed exceptions are appropriate; however, they are still inadequate. The end effect of the proposed RAS definition basically captures any protection action and/or scheme that is beyond standard/historical individual relaying protection package functions, thereby limiting the 'art' of system protection to 'maximize the robustness of the post-contingent BES system'. On this basis, Western suggests the SDT reconsider the definition's strict inclusion of "reconfiguring a System(s)". Western's suggestion of excluding "cross-tripping schemes within the same station" for sake of mitigating a potential SOL is more benign should it fail to operate than failure of the currently proposed exclusion of "out-of-step tripping and power swing blocking", as an example. Did the last SPS definition's use of the language "acceptable

voltage, or power flow" intend to capture the granularity of localized SOLs versus larger and/or regional BES impacts? Further, the definition does not delineate lower risk "localized" schemes. Consequently, there is no expeditious approval mechanism to implement a benign localized scheme within a reasonable timeframe for the operating horizon. This is a real issue. Several years ago following spring flooding, Western had transmission lines toppling in standing water and needed to quickly implement a cross-trip scheme to facilitate needed and urgent outages for maintenance/repair (within days). Without such flexibility, customer service and reliability is further reduced. Western suggests the SDT recognize "localized" benign schemes either outside the scrutiny of a RAS all together, or at minimum, allow such schemes to be implemented for 1 year with the caveat that the scheme be vetted through an expedited stakeholder process. If the "localized" scheme ultimately must receive RAS review and scrutiny, it should be done expeditiously. Currently, the WECC RASRS are attempting to streamline "localized' schemes.

Additional Comments:

Associated Electric Cooperative, Inc.
Phil Hart

1. No
Comments:

The purpose of this project is stated as, "...assist the industry with the application of the revised definition." However the current revision seems to be providing more confusion than clarity. Because both the Inclusions and Exclusions are so broad, it would seem everything is first included in a RAS, and then excluded, leaving nothing. AECI would suggest the SDT at least limit such broad inclusions to begin with, and in turn this would require fewer exclusions on the back-end.