# Comment Report

**Project Name:** 2023-06 CIP-014 Risk Assessment Refinement | Standard Authorization Request

Comment Period Start Date: 7/26/2023

Comment Period End Date: 8/24/2023

Associated Ballots:

There were 43 sets of responses, including comments from approximately 117 different people from approximately 92 companies representing 10 of the Industry Segments as shown in the table on the following pages.

**Questions**

**1. Do you agree with the proposed scope as described in the Project 2023-06 CIP-014 SAR? If you do not agree, or if you agree but have comments or suggestions for the project scope please provide your recommendation and explanation.**

**2. Provide any additional comments for the SAR drafting team to consider, if desired.**

| Organization Name | Name | Segment(s) | Region | Group Name | Group Member Name | Group Member Organization | Group Member Segment(s) | Group Member Region |
|---|---|---|---|---|---|---|---|---|
| Midcontinent ISO, Inc. | Bobbi Welch | 2 | MRO,RF,SERC | ISO/RTO Council Standards Review Committee 2023-06 CIP-014 Risk Assessment SAR | Kennedy Meier | Electric Reliability Council of Texas, Inc. | 2 | Texas RE |
| | | | | | Bobbi Welch | MISO | 2 | RF |
| | | | | | Gregory Campoli | New York Independent System Operator | 2 | NPCC |
| | | | | | Elizabeth Davis | PJM | 2 | RF |
| | | | | | Charles Yeung | SPP | 2 | MRO |
| Tacoma Public Utilities (Tacoma, WA) | Jennie Wike | 1,3,4,5,6 | WECC | Tacoma Power | Jennie Wike | Tacoma Public Utilities | 1,3,4,5,6 | WECC |
| | | | | | John Merrell | Tacoma Public Utilities (Tacoma, WA) | 1 | WECC |
| | | | | | John Nierenberg | Tacoma Public Utilities (Tacoma, WA) | 3 | WECC |
| | | | | | Hien Ho | Tacoma Public Utilities (Tacoma, WA) | 4 | WECC |
| | | | | | Terry Gifford | Tacoma Public Utilities (Tacoma, WA) | 6 | WECC |
| | | | | | Ozan Ferrin | Tacoma Public Utilities (Tacoma, WA) | 5 | WECC |
| ACES Power Marketing | Jodirah Green | 1,3,4,5,6 | MRO,RF,SERC,Texas RE,WECC | ACES Collaborators | Bob Soloman | Hoosier Energy Electric Cooperative | 1 | RF |
| | | | | | Jennifer Bray | Arizona Electric Power Cooperative, Inc. | 1 | WECC |
| | | | | | Nick Fogleman | Prairie Power, Inc. | 1,3 | SERC |
| | | | | | Marcus Perkins | Southern Maryland Electric | 3 | RF |

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| | | | | | | Cooperative | | |
| MRO | Jou Yang | 1,2,3,4,5,6 | MRO | MRO NSRF | Bobbi Welch | Midcontinent ISO, Inc. | 2 | MRO |
| | | | | | Chris Bills | City of Independence, Power and Light Department | 5 | MRO |
| | | | | | Fred Meyer | Algonquin Power Co. | 3 | MRO |
| | | | | | Christopher Bills | City of Independence Power & Light | 3,5 | MRO |
| | | | | | Larry Heckert | Alliant Energy Corporation Services, Inc. | 4 | MRO |
| | | | | | Marc Gomez | Southwestern Power Administration | 1 | MRO |
| | | | | | Matthew Harward | Southwest Power Pool, Inc. (RTO) | 2 | MRO |
| | | | | | Bryan Sherrow | Board of Public Utilities | 1 | MRO |
| | | | | | Terry Harbour | Berkshire Hathaway Energy - MidAmerican Energy Co. | 1 | MRO |
| | | | | | Terry Harbour | MidAmerican Energy Company | 1,3 | MRO |
| | | | | | Jamison Cawley | Nebraska Public Power District | 1,3,5 | MRO |
| | | | | | Seth Shoemaker | Muscatine Power & Water | 1,3,5,6 | MRO |
| | | | | | Michael Brytowski | Great River Energy | 1,3,5,6 | MRO |
| | | | | | Shonda McCain | Omaha Public Power District | 6 | MRO |
| | | | | | George E Brown | Pattern Operators LP | 5 | MRO |
| | | | | | George Brown | Acciona | 5 | MRO |

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| | | | | | | Energy USA | | |
| | | | | | Jaimin Patel | Saskatchewan Power Cooperation | 1 | MRO |
| | | | | | Kimberly Bentley | Western Area Power Administration | 1,6 | MRO |
| | | | | | Jay Sethi | Manitoba Hydro | 1,3,5,6 | MRO |
| | | | | | Michael Ayotte | ITC Holdings | 1 | MRO |
| FirstEnergy - FirstEnergy Corporation | Mark Garza | 1,3,4,5,6 | | FE Voter | Julie Severino | FirstEnergy - FirstEnergy Corporation | 1 | RF |
| | | | | | Aaron Ghodooshim | FirstEnergy - FirstEnergy Corporation | 3 | RF |
| | | | | | Robert Loy | FirstEnergy - FirstEnergy Solutions | 5 | RF |
| | | | | | Mark Garza | FirstEnergy-FirstEnergy | 1,3,4,5,6 | RF |
| | | | | | Stacey Sheehan | FirstEnergy - FirstEnergy Corporation | 6 | RF |
| Pacific Gas and Electric Company | Michael Johnson | 1,3,5 | WECC | PG&E All Segments | Marco Rios | Pacific Gas and Electric Company | 1 | WECC |
| | | | | | Sandra Ellis | Pacific Gas and Electric Company | 3 | WECC |
| | | | | | Frank Lee | Pacific Gas and Electric Company | 5 | WECC |
| Southern Company - Southern Company Services, Inc. | Pamela Hunter | 1,3,5,6 | SERC | Southern Company | Matt Carden | Southern Company - Southern Company Services, Inc. | 1 | SERC |
| | | | | | Joel Dembowski | Southern Company - Alabama Power Company | 3 | SERC |
| | | | | | Jim Howell, Jr. | Southern Company - Southern | 5 | SERC |

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| | | | | | | Company Generation | | |
| | | | | | Ron Carlsen | Southern Company - Southern Company Generation | 6 | SERC |
| Northeast Power Coordinating Council | Ruida Shu | 1,2,3,4,5,6,7,8,9,10 | NPCC | NPCC RSC | Gerry Dunbar | Northeast Power Coordinating Council | 10 | NPCC |
| | | | | | Alain Mukama | Hydro One Networks, Inc. | 1 | NPCC |
| | | | | | Deidre Altobell | Con Edison | 1 | NPCC |
| | | | | | Jeffrey Streifling | NB Power Corporation | 1 | NPCC |
| | | | | | Michele Tondalo | United Illuminating Co. | 1 | NPCC |
| | | | | | Stephanie Ullah-Mazzuca | Orange and Rockland | 1 | NPCC |
| | | | | | Michael Ridolfino | Central Hudson Gas & Electric Corp. | 1 | NPCC |
| | | | | | Randy Buswell | Vermont Electric Power Company | 1 | NPCC |
| | | | | | James Grant | NYISO | 2 | NPCC |
| | | | | | John Pearson | ISO New England, Inc. | 2 | NPCC |
| | | | | | Harishkumar Subramani Vijay Kumar | Independent Electricity System Operator | 2 | NPCC |
| | | | | | Randy MacDonald | New Brunswick Power Corporation | 2 | NPCC |
| | | | | | Dermot Smyth | Con Ed - Consolidated Edison Co. of New York | 1 | NPCC |
| | | | | | David Burke | Orange and Rockland | 3 | NPCC |
| | | | | | Peter Yost | Con Ed - | 3 | NPCC |

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| | | | | | | Consolidated Edison Co. of New York | | |
| | | | | | Salvatore Spagnolo | New York Power Authority | 1 | NPCC |
| | | | | | Sean Bodkin | Dominion - Dominion Resources, Inc. | 6 | NPCC |
| | | | | | David Kwan | Ontario Power Generation | 4 | NPCC |
| | | | | | Silvia Mitchell | NextEra Energy - Florida Power and Light Co. | 1 | NPCC |
| | | | | | Glen Smith | Entergy Services | 4 | NPCC |
| | | | | | Sean Cavote | PSEG | 4 | NPCC |
| | | | | | Jason Chandler | Con Edison | 5 | NPCC |
| | | | | | Tracy MacNicoll | Utility Services | 5 | NPCC |
| | | | | | Shivaz Chopra | New York Power Authority | 6 | NPCC |
| | | | | | Vijay Puran | New York State Department of Public Service | 6 | NPCC |
| | | | | | ALAN ADAMSON | New York State Reliability Council | 10 | NPCC |
| | | | | | David Kiguel | Independent | 7 | NPCC |
| | | | | | Joel Charlebois | AESI | 7 | NPCC |
| | | | | | Joshua London | Eversource Energy | 1 | NPCC |
| Western Electricity Coordinating Council | Steven Rueckert | 10 | | WECC CIP | Steve Rueckert | WECC | 10 | WECC |
| | | | | | Morgan King | WECC | 10 | WECC |
| | | | | | Deb McEndaffer | WECC | 10 | WECC |
| | | | | | Tom Williams | WECC | 10 | WECC |

**1. Do you agree with the proposed scope as described in the Project 2023-06 CIP-014 SAR? If you do not agree, or if you agree but have comments or suggestions for the project scope please provide your recommendation and explanation.**

**Tony Eddleman - Nebraska Public Power District - 1,3,5**

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| **Answer** | No |
| **Document Name** | |

**Comment**

Due to the critical interdependency between requirement 1 and requirement 2, requirement 2 should be added to the project scope for the drafting team.

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| Likes 0 | |
| Dislikes 0 | |

**Response**

**Jennie Wike - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6 - WECC, Group Name** Tacoma Power

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| **Answer** | No |
| **Document Name** | |

**Comment**

Tacoma Power endorses the comments from MRO NSRF.

In addition to the MRO NSRF comments, Tacoma Power does not agree with the description in the Cost Impact Assessment section of the SAR. Specifically, the statement that “cost impacts for the proposed changes to CIP-014-3 are expected to be minimal.” The cost impacts are significant for Detail 5, “Revise the risk assessment and clarify how to account for adjacent Transmission stations or Transmission substations of differing ownership as well as for those Transmission stations or Transmission substations within line-of-sight to each other.” Tacoma Power recommends revising the cost impact section of the SAR to recognize that the work necessary to implement Detail 5 would be significant and may result in additional applicable substations.

The SAR is also not clear as to how Detail 5 would impact the Section 4.1.1 applicable facility determination. There are facilities that do not meet the Section 4.1.1 applicability criteria when evaluated separately, but may meet that criteria if Detail 5 is applied.

Tacoma Power recommends that the SAR scope include an additional Detail to clarify the evidence required to demonstrate that an entity does not have applicable facilities. Throughout the ERO Enterprise, there is inconsistency on whether entities with a null list of applicable facilities are required to comply with CIP-014 R1-R3.

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| Likes 0 | |
| Dislikes 0 | |

**Response**

**Stephen Stafford - Georgia Transmission Corporation - 1 - SERC**

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| **Answer** | No |
| **Document Name** | |

| **Comment** |
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| Items 1 – 4 in the Project Scope section of the SAR suggest the standard should be modified to clarify “methods for studying”, “study period”, “frequency of study”, “base cases”, “study decisions”, and other terminology that suggests a planning function is being performed. CIP-014 is only applicable to the owner functional entities who do not perform planning analyses. It does not seem appropriate to add planning analysis requirements in the CIP-014 standard when it is not applicable to planning entities. |

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| Likes 0 | |
| Dislikes 0 | |

| **Response** |
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**Bobbi Welch - Midcontinent ISO, Inc. - 2, Group Name** ISO/RTO Council Standards Review Committee 2023-06 CIP-014 Risk Assessment SAR

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| **Answer** | No |
| **Document Name** | |

**Comment**

The **ISO/RTO Council (IRC) Standards Review Committee (SRC)**[1] appreciates the opportunity to comment. The SRC agrees that additional clarity and specificity will increase the efficacy of CIP-014. In support of that objective, the SRC recommends that the scope be revised to direct the drafting team to clarify the following areas of ambiguity.

- For a transmission station or substation connecting to a collector bus for a generation plant, clarify whether the collector bus is still not considered a Transmission Facility for purposes of Applicability criteria 4.1.1.1 and 4.1.1.2 if the collector bus is the Point of Interconnection for the generation plant.
- For Applicability criterion 4.1.1.2, clarify whether the Weight Value per Line is applied per transmission line or per transmission circuit. For example, clarify whether a double-circuit 345-kV line has a weight value of 2600 or 1300.
- Clarify the extent to which radial facilities qualify as Transmission Facilities for purposes of the Applicability criteria for CIP-014-3. The Guidelines and Technical Basis for CIP-014-3 (page 21 of the standard) indicates that the Applicability section of CIP-014-3 mirrors the bright line criteria for Medium Impact Transmission Facilities under CIP-002-5.1a. Page 27 of CIP-002-5.1a, in turn, indicates that Criterion 2.5 for identifying Medium Impact Transmission Facilities excludes “radial facilities that would only provide support for single generation facilities.” It is not clear how this exclusion fits in with the Applicability criteria of CIP-014-3. Specifically, it is not clear if these radial facilities should be included in the determination of how many stations or substations a given station or substation connects to, and it is not clear if these radial facilities should be assigned a weight value as incoming or outgoing BES Transmission Lines that connect to another Transmission station or substation.
- Clarify how the exclusion for “radial facilities that would only provide support for single generation facilities” (discussed above) interacts with the statement on page 23 of CIP-002-5.1a that “[w]hen the drafting team uses the term ‘Facilities,’ there is some latitude to Responsible Entities to determine included Facilities,” and with CIP-014-3 Requirement R2, Part 2.3’s authorization for TOs to document the technical basis for not modifying an identification in accordance with a recommendation from an unaffiliated verifying entity. Specifically, clarify how much latitude TOs have to interpret the exclusion for “radial facilities that would only provide support for single generation facilities."

[1] For purposes of these comments, the IRC SRC includes the following entities: ERCOT, MISO, NYISO, PJM and SPP.

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| Likes 0 | |

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| Dislikes 0 | |
| **Response** | |
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| **Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2** | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| ERCOT joins the comments submitted by the ISO/RTO Council (IRC) Standards Review Committee (SRC) and adopts them as its own. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
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| **Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name** MRO NSRF | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |

The MRO NSRF agrees with the scope of the SAR as having identified the aspects of CIP-014 R1 that require clarification, but disagrees with some of the subsequent detailed instructions to the drafting team as follows:

Detail 1, please replace the final bolded item “BPS” with “BES.” Industry has already identified all BES Transmission Elements when the term was redefined for 2014. There are no such defined lists of BPS equipment. Applicability Section 4.1.1 and parts already provide such specificity as has already been validated as sufficient by the NERC report filed with FERC. There is no justification to arbitrarily reference a broader BPS within this standard, and Section 4.1.1 renders the change moot.

Detail 3 takes the general guidance of Scope item 3 but specifies “defining ‘inoperable’ or ‘damaged’ substations”, which is inconsistent with Scope item 4 that will require simulating complete loss. The sentence “Criteria should include defining “inoperable” or “damaged” substations such that the intent of the risk assessment is clear.” binds the drafting team to maintain and define language inconsistent with Scope item 4 and should be removed. Removing this sentence would free the drafting team to replace this language with something like “destroyed” which could then be defined in accordance with Scope item 4.

Detail 5 can provide a list of items requiring consideration, but it must be made clear to the drafting team that while these items must be considered, they do not necessarily have to be modeled as also lost if an entity’s evaluation cites mitigating circumstances such as the adjacent or line-of-sight Facility already having or implementing security measures to counter these threats before the next risk assessment is due (consistent with Scope item 2). Any items listed for required consideration should be sufficiently defined and limited so as not to require the equivalent performance of a full R4

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| threat assessment. | |
| Likes 1 | Tacoma Public Utilities (Tacoma, WA), 1,3,4,5,6, Wike Jennie |
| Dislikes 0 | |
| **Response** | |
| | |
| **Mark Garza - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6, Group Name** FE Voter | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| FirstEnergy supports the scope of the SAR and further supports EEI comments. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| AEPC has signed on to ACES comments below:<br><br>Every critical station within the scope of CIP-014 poses different challenges and risks to consider. Each entity has different people, constraints (physical, technological, electrical, etc.), and risks; therefore, the expectation that entities would have "reasonably consistent" approaches to CIP-014 is not a reasonable expectation.<br><br>This SAR's proposed changes are similar to previous changes to the CIP standards, such as CIP-002-3 (risk based) versus CIP-002-5.1a (bright line). This SAR should seek to establish a minimum baseline of risks/risk attributes that NERC, FERC, and the industry believe need to be evaluated to have a more "reasonably consistent" approach. Establishing a baseline, such as logging and monitoring in CIP-007, or bright line in CIP-002, would provide some of the consistency the SAR proposes to provide, but each approach may still be different. If the Standards Drafting Team (SDT) were to add baseline risks for consideration, they should not be overly prescriptive, rather they should provide a minimum list of risks to consider and any exclusions to allow the entity flexibility in its approach.<br><br>The cost impact cannot be overlooked in the SAR. If a set of risk criteria is established as a result of this project and an entity did not previously consider one or more of those risk, a control would need to be created to mitigate the risk, which could come with a cost. The proposed changes to CIP-014 will require each entity within the scope to rewrite its CIP-014 program and reevaluate each risk assessment, which could also come with a cost. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |

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| **Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name** NPCC RSC | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| While we agree that the identification of applicable facilities criteria could benefit from more clarity on the initiating event(s) triggering the resulting consequence "…that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection.", changes, as proposed in the SAR, will impose a tremendous effort on entities to achieve compliance. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **April Ford - Southern Indiana Gas and Electric Co. - 3,5,6 - RF** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana (SIGE) agrees with the proposed scope of the SAR. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
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| **Lucinda Bradshaw - Oncor Electric Delivery - 1 - Texas RE** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| Oncor encourages NERC to consider the vast diversity of the Bulk Power Systems owned and operated by the Registered Entities to which the new CIP-014 would apply (*e.g.,* the varied operating environments or different market structures in which those Registered Entities do business) and to acknowledge in the revised Standard the possibility that the criteria for the required risk assessment may be revised as needed to enable the affected Registered Entity to properly assess its Transmission stations and Transmission Substations. | |
| Likes 0 | |
| Dislikes 0 | |

| Response |
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| Michael Johnson - Pacific Gas and Electric Company - 1,3,5 - WECC, Group Name PG&E All Segments | |
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| **Answer** | Yes |
| **Document Name** | |

**Comment**

PG&E has the following input related to the Detailed Description in the SAR starting on page 3:

**For Item 1;** PG&E concurs and supports the clarification of the risk assessment methods for studying instability, uncontrolled separation, and Cascading. PG&E also recommends that as part of the clarification, it is important for NERC to consider that registered entities will need to evaluate each broad type of stability based on their regional requirements. For instance, PG&E is currently following the TPL 001-WECC-CRT-3.2 criterion for voltage and frequency performance to assess the results of the Transient Stability analysis.

**For Item 2**; PG&E agrees that the statement “including only the projects that are appropriate to the periodicity of the entity’s risk assessment studies” should be clarified, as the existing language could have different interpretations.

**For Item 3**; PG&E has no comment.

**For Item 4**; PG&E supports the input has a comment regarding the following statement “it is not clear that the risk assessment requires registered entities to use models that correlate to periods of high flows or high stress on their system”.  Since each region experiences different high flow patterns and stressed conditions, PG&E suggests that NERC provide clarifications and guidelines for defining the high stressed scenarios but allows entities to define their scenarios based on their unique system conditions and their respective region.

**For Item 5**; PG&E encourages clarification regarding what physically adjacent elements shall be considered within the risk assessment.  In addition, if a substation is identified as critical based on the study and related substation (asset) is not owned by the registered entity that performed the study, clarification should be provided regarding the responsibilities between that registered entity and the other asset owner.

**For the Cost Impact Assessment on page 5**, PG&E provides the following; PG&E understands that the NERC proposed changes are targeting to add clarity to the current standard and not changing the existing requirements. However, implementing the proposed clarifications may result in more substations requiring security upgrades and that would impact the associated costs.

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| Likes 0 | |
| Dislikes 0 | |

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**Chantal Mazza - Hydro-Quebec (HQ) - 1 - NPCC**

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| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |

While we agree that the identification of applicable facilities criteria could benefit from more clarity on the initiating event(s) triggering the resulting consequence "…that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection.", changes, as proposed in the SAR, will impose a tremendous effort on entities to achieve compliance.

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| Likes 0 | |
| Dislikes 0 | |
| **Response** | |

**Brad Harris - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE**

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| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |

CenterPoint Energy Houston Electric, LLC (CEHE) agrees with the proposed scope of the SAR.

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| Likes 0 | |
| Dislikes 0 | |
| **Response** | |

**Jay Sethi - Manitoba Hydro - 1,3,5,6 - MRO**

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| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |

Manitoba Hydro agrees with the scope of the SAR. Further clarification of CIP-014 R1 as proposed in the SAR will help the industry as a whole. Manitoba Hydro is requesting additionally that the SAR provide clarity on whether past studies can be relied upon if there are no material changes in the network since the last CIP-014 assessment, provided that the Transmission Owner has performed an acceptable risk assessment which meets the requirements identified in the scope of this SAR? This would reduce study burden on industry; especially on entities studying every 30 months.

Manitoba Hydro also has some comments relating to the detailed description items and suggests the following changes:

In detailed description number 1, replace the term "BPS" with "BES" which is well defined and for which a well established inventory of elements exists.

In detailed description number 3, it takes the general guidance of Scope item 3 but specifies “defining ‘inoperable’ or ‘damaged’ substations”, which is inconsistent with Scope item 4 that will require simulating complete loss. The sentence “Criteria should include defining “inoperable” or “damaged” substations such that the intent of the risk assessment is clear.” binds the drafting team to maintain and define language inconsistent with Scope item 4 and should be removed. The standard drafting team should be free to review the option of changing the wording to add clarity, as well as the option to further define the terms.

In detailed description number 5, it can provide a list of items requiring consideration, but it must be made clear to the drafting team that while these items must be considered, they do not necessarily have to be modeled as also lost if an entity’s evaluation cites mitigating circumstances such as the adjacent or line-of-sight Facility already having or implementing security measures to counter threats before the next risk assessment is due (consistent with Scope item 2). Any items listed for required consideration should be sufficiently defined and limited so as not to require the equivalent performance of a full R4 threat assessment.

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| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
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| **John Pearson - ISO New England, Inc. - 2** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |

ISO New England supports the changes to make the standard result in more uniform determinations that will most appropriately identify critical infrastructure and evaluate whether the physical security protection requirements are adequate to address the risks associated with physical attacks on Bulk Power System (BPS) Facilities. The owners of the BPS Facilities are the most appropriate entities to make initial determinations and appropriate identification.

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| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
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| **Michael Jones - National Grid USA - 1,3,5** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |

RE: Project Scope Item 2: Please consider adding to the Project Scope and Detailed Description that the amount of time between risk assessments should be clarified. Requirement R1 Part 1.1 of CIP-014-3 states “Subsequent risk assessments shall be performed: At least once every 30 calendar months… or, At least once every 60 calendar months… (as verified according to Requirement R2)” This could be interpreted as the 30 or 60 calendar

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| months clock for the next subsequent risk assessment starts when Requirement R2 is completed, i.e., up to 90 + 60 days after Requirement R1 was completed. This could potentially also be interpreted as the 30 or 60 calendar months clock for the next subsequent risk assessment starts once Requirement R1 has been completed. Please consider that the SAR should specifically give the drafting team the ability to resolve this issue. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| EEI supports adding requirements that provide additional clarity to existing risk assessment methods for studying instability, uncontrolled separation, and cascading. However, we would not support changes to requirements that resulted in modifications that deviated from the clearly defined project scope as contained in this SAR or added prescriptive requirements that did not consider regional differences and geography. Standards should be flexible, and risk based.<br><br>EEI asks for clarity to Item 3 in the SAR Project Scope where it uses the term “adequacy”. As currently written this Item could be understood to require changes to CIP-014 that would require the development of prescriptive requirements for both documentation and entity studies that could be interpreted as deviating from the current Risk Based Reliability Standard processes.<br><br>EEI also requests clarity on the intended scope of Item 5 in the SAR Project Scope. Specifically, clarity is needed as it relates to Transmission stations or substations of differing ownership, as well as transmission stations or substations within line-of-site to each other. However, it should be clear that responsible entities need the authority to request certain information from the responsible entities identified in Item 5, to conduct their CIP-014 studies (i.e., models, actual clearing times, etc.). | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
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| **Alan Kloster - Evergy - 1,3,5,6 - MRO** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) for question #1. | |
| Likes 0 | |
| Dislikes 0 | |

| Response |  |
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| **Clay Walker - Cleco Corporation - 1,3,5,6 - SERC** |  |
| **Answer** | Yes |
| **Document Name** |  |
| **Comment** |  |
| Cleco support the comments provided by EEI. |  |
| Likes 0 |  |
| Dislikes 0 |  |
| **Response** |  |
|  |  |
| **Richard Vendetti - NextEra Energy - 5** |  |
| **Answer** | Yes |
| **Document Name** |  |
| **Comment** |  |
| NEE is in agreement with EEI's comments.<br><br>EEI supports adding requirements that provide additional clarity to existing risk assessment methods for studying instability, uncontrolled separation, and cascading. However, we would not support changes to requirements that resulted in modifications that deviated from the clearly defined project scope as contained in this SAR or added prescriptive requirements that did not consider regional differences and geography. Standards should be flexible, and risk based.<br><br>EEI asks for clarity to Item 3 in the SAR Project Scope where it uses the term "adequacy". As currently written this Item could be understood to require changes to CIP-014 that would require the development of prescriptive requirements for both documentation and entity studies that could be interpreted as deviating from the current Risk Based Reliability Standard processes.<br><br>EEI also requests clarity on the intended scope of Item 5 in the SAR Project Scope. Specifically, clarity is needed as it relates to Transmission stations or substations of differing ownership, as well as transmission stations or substations within line-of-site to each other. However, it should be clear that responsible entities need the authority to request certain information from the responsible entities identified in Item 5, to conduct their CIP-014 studies (i.e., models, actual clearing times, etc.). |  |
| Likes 0 |  |
| Dislikes 0 |  |
| **Response** |  |
|  |  |
| **Ellese Murphy - Duke Energy - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF** |  |
| **Answer** | Yes |

| | |
|---|---|
| **Document Name** | |
| **Comment** | |
| Duke Energy supports EEI's comments. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Rachel Coyne - Texas Reliability Entity, Inc. - 10** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| Texas RE supports this project to ensure adequacy and consistency in the CIP-014 approach.  Texas RE recommends the SAR indicate whether the terms “inoperable” or “damaged” will be defined in the NERC Glossary. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Junji Yamaguchi - Hydro-Quebec (HQ) - 1,5** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| While we agree that the identification of applicable facilities criteria could benefit from more clarity on the initiating event(s) triggering the resulting consequence “…that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection.”, changes, as proposed in the SAR, will impose a tremendous effort on entities to achieve compliance. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name** ACES Collaborators | |
| **Answer** | Yes |

| | |
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| **Document Name** | |
| **Comment** | |

ACES agrees with the scope of the SAR, with the following comments:

Every critical station within the scope of CIP-014 poses different challenges and risks to consider.  Each entity has different people, constraints (physical, technological, electrical, etc.), and risks; therefore, the expectation that entities would have “reasonably consistent” approaches to CIP-014 is not a reasonable expectation.

This SAR’s proposed changes are similar to previous changes to the CIP standards, such as CIP-002-3 (risk based) versus CIP-002-5.1a (bright line). This SAR should seek to establish a minimum baseline of risks/risk attributes that NERC, FERC, and the industry believe need to be evaluated to have a more “reasonably consistent” approach. Establishing a baseline, such as logging and monitoring in CIP-007, or bright line in CIP-002, would provide some of the consistency the SAR proposes to provide, but each approach may still be different. If the Standards Drafting Team (SDT) were to add baseline risks for consideration, they should not be overly prescriptive, rather they should provide a minimum list of risks to consider and any exclusions to allow the entity flexibility in its approach.

The cost impact cannot be overlooked in the SAR. If a set of risk criteria is established as a result of this project and an entity did not previously consider one or more of those risk, a control would need to be created to mitigate the risk, which could come with a cost. The proposed changes to CIP-014 will require each entity within the scope to rewrite its CIP-014 program and reevaluate each risk assessment, which could also come with a cost.

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| Likes     0 | |
| Dislikes     0 | |
| **Response** | |
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| **Dwanique Spiller - Berkshire Hathaway - NV Energy - 5** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |

NV Energy agrees with the scope of the SAR as having identified the aspects of CIP-014 R1 that require clarification, but disagrees with some of the subsequent detailed instructions to the drafting team as follows:

Detail 1, please replace the final bolded item “BPS” with “BES.” Industry has already identified all BES Transmission Elements when the term was redefined for 2014. There are no such defined lists of BPS equipment. Applicability Section 4.1.1 and parts already provide such specificity as has already been validated as sufficient by the NERC report filed with FERC. There is no justification to arbitrarily reference a broader BPS within this standard, and Section 4.1.1 renders the change moot.

Detail 3 takes the general guidance of Scope item 3 but specifies “defining ‘inoperable’ or ‘damaged’ substations”, which is inconsistent with Scope item 4 that will require simulating complete loss. The sentence “Criteria should include defining “inoperable” or “damaged” substations such that the intent of the risk assessment is clear.” binds the drafting team to maintain and define language inconsistent with Scope item 4 and should be removed. Removing this sentence would free the drafting team to replace this language with something like “destroyed” which could then be defined in accordance with Scope item 4.

Detail 5 can provide a list of items requiring consideration, but it must be made clear to the drafting team that while these items must be considered, they do not necessarily have to be modeled as also lost if an entity's evaluation cites mitigating circumstances such as the adjacent or line-of-sight Facility already having or implementing security measures to counter these threats before the next risk assessment is due (consistent with Scope item 2). Any items listed for required consideration should be sufficiently defined and limited so as not to require the equivalent performance of a full R4 threat assessment.

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| Likes 0 | |
| Dislikes 0 | |

**Response**

**Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name** Southern Company

| | |
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| **Answer** | Yes |
| **Document Name** | |

**Comment**

Southern Company agrees with the submitted comments by EEI.

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| Likes 0 | |
| Dislikes 0 | |

**Response**

**Daniel Gacek - Exelon - 1,3**

| | |
|---|---|
| **Answer** | Yes |
| **Document Name** | |

**Comment**

Exelon generally supports the proposed scope of this project, and we support the comments submitted by the EEI.

We offer the following additional comments to help refine the scope.

For Item 4, there is inconsistency between the Project Scope section and the Detailed Description, specifically in the Project Scope section it states "simultaneous loss of all station elements and does not rely on local system protection for relay clearance", however in the Detailed Description section it seems to leave open to the SDT to determine how to resolve the initiating event assumptions.

The word simultaneous in the Project Scope section is also potentially problematic. In dynamic studies there may be a significant difference between literally simultaneous and a couple cycles (milliseconds) of delay. Some physical threats can result in simultaneous loss of station elements, other physical threats may result in delay between loss of station elements. Modifications to the standard should include the latitude for the planning analysis to align with the physical threats with regard to delay or lack of delay between the loss of substation elements.

For Item 5, similar to Item 4, the standard should include the latitude for the planning analysis to align with the identified physical threats with regard to

| | |
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| delay or lack of delay between the loss of substation elements. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Marcus Bortman - APS - Arizona Public Service Co. - 1,3,5,6** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| AZPS agrees with EEI in supporting the development of standards which provide clarity to existing risk assessment methods for studying instability, uncontrolled separation, and cascading while maintaining standards that are flexible and risk based. In regard to item 5, AZPS would also like clarity as to the intended scope of changes relating to transmission substations within close physical proximity/line of sight and the required information sharing between entities when differing ownership is a factor. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Lori Frisk - Allete - Minnesota Power, Inc. - 1** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| Minnesota Power supports the comments submitted by Edison Electric Institute (EEI) and the MRO NERC Standards Review Forum (NSRF). | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **David Jendras Sr - Ameren - Ameren Services - 1,3,6** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |

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| Ameren agress with and supports EEI comments. In addition we would like more clarity around two items in this SAR:<br>(1) the word "posting" used in Page 3, Project Scope, Item 3.<br>(2) the phrase "all station elements" used in Page 4, Project Scope, Item 4. Does this include control houses, one or multiple? | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Kent Feliks - AEP - 3,5,6** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| Kent Feliks on behalf of AEP in Segments 1, 3, 5, 6<br>We recommend removal of the statement, “To ensure that no instability occurs in simulation, registered entities can cover each broad type of stability analysis via Contingency analysis, governor power flow analysis, and transient stability analysis.” The standard does not seek to ensure that "no instability occurs in simulation". It seeks to indentify "widespread instability... within an Interconnection". Per FERC Order 802, only instability “critical to the operation of the Interconnection” is necessary to identify. The SDT must therefore qualify “instability” so that only critical instabilities are identified, for example, instability that results in such a loss of generation as to cause UFLS activation or that may lead to further cascading or to uncontrolled separation. Additionally, listing three methods of identifying instability as “via Contingency analysis, governor power flow analysis, and transient stability analysis” is contrary to other statements implying that dynamic simulations must be run to determine if there is instability. Contingency powerflow analysis and governor powerflow analysis are not forms of dynamic simulation. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Lindsey Mannion - ReliabilityFirst - 10** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
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| Likes 0 | |
| Dislikes 0 | |
| **Response** | |

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|---|---|
| **Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Donna Wood - Tri-State G and T Association, Inc. - 1,3,5** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
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| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Joshua London - Eversource Energy - 1,3** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Dave Krueger - SERC Reliability Corporation - 10** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |

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|---|---|
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Alain Mukama - Hydro One Networks, Inc. - 1,3** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name** WECC CIP | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Israel Perez - Salt River Project - 1,3,5,6 - WECC** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |

| Gail Elliott - International Transmission Company Holdings Corporation - NA - Not Applicable - MRO,RF | |
|---|---|
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |

| Matt Lewis - Lower Colorado River Authority - 1,5 | |
|---|---|
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |

| Teresa Krabe - Lower Colorado River Authority - 1,5 | |
|---|---|
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |

**2. Provide any additional comments for the SAR drafting team to consider, if desired.**

| **Kent Feliks - AEP - 3,5,6** | |
|---|---|
| **Answer** | |
| **Document Name** | |
| **Comment** | |

**Regarding SAR Scope #5**:There are no recommended changes on the explicit language as written, however it is important for the drafting team to note that outages based on some of these recommended distance criteria would not be simultaneous. It is critical that the the outage scenarios required for study by the standard do not open the requirement up to studying nonsimultaneous outages of multiple stations, as this would create unbounded combined-outage analysis scenarios. In addition, loosely described distance criteria (line-of-sight, ease of access, etc.) may also create unreasonable unbounded analysis scenarios. Any such increase in risk assessment scope must be clearly and unambiguously defined within the standard.

**Regarding Cost Impact Assessment**s: We strongly disagree with and recommend removal of the statement, "The cost impacts for the proposed changes to CIP-014-3 are expected to be minimal."

For small entities not currently performing analysis to determine local voltage angle instability, rotor angle instability, and frequency instability, given their small footprint's minimal impact on the stability of the Interconnection - these changes will require hiring/training new dynamic analysis expertise or outsourcing their CIP-014 risk assessment to cosultants with this expertise. This will likely have a significant cost impact for these entities.

For large entities performing these types of stability analyses on a subset of applicable stations whose loss pose a critical impact on the operation of the Interconnection, studying all stations for all types of local instability, even those that pose little to no risk to the operation of the Interconnection, will significantly increase the time to perform the risk assessment, and may also require staff augmentation or outside consultants to complete in a timely manner. This will also have a significant cost impact for these entities.

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| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
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| **David Jendras Sr - Ameren - Ameren Services - 1,3,6** | |
|---|---|
| **Answer** | |
| **Document Name** | |
| **Comment** | |

None.

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| Likes 0 | |
| Dislikes 0 | |

| **Response** | |
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| | |
| **Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2** | |
| **Answer** | |
| **Document Name** | |
| **Comment** | |
| ERCOT joins the comments submitted by the IRC SRC and adopts them as its own. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Marcus Bortman - APS - Arizona Public Service Co. - 1,3,5,6** | |
| **Answer** | |
| **Document Name** | |
| **Comment** | |
| AZPS does not have any additional comments for the SAR to consider at this time. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Bobbi Welch - Midcontinent ISO, Inc. - 2, Group Name** ISO/RTO Council Standards Review Committee 2023-06 CIP-014 Risk Assessment SAR | |
| **Answer** | |
| **Document Name** | |
| **Comment** | |
| The SRC notes that page 5 of the SAR lists Transmission Owners and Transmission Operators as the functional entities to which the standard should apply. The SRC agrees that these are the appropriate functional entities to which the standard should apply; however, the SRC also recommends that the standard drafting team include representatives from Planning Coordinators (PCs), Reliability Coordinators (RCs) and Transmission Planners (TPs), as these entities often perform verifications of risk assessments, and representatives from these functional entities will therefore be able to provide important perspectives to the drafting team even though the standard does not and should not apply to these functional entities. In the event the standard drafting team does not include representatives from one or more of these functional entities, the SRC recommend that the drafting team solicit feedback from these functional entities in the course of developing modifications to the standard. | |
| Likes 0 | |

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| Dislikes 0 | |
| **Response** | |
| | |
| **Daniel Gacek - Exelon - 1,3** | |
| **Answer** | |
| **Document Name** | |
| **Comment** | |
| In the current Requirement 1, the 24-month study period in-service window limits the planners ability to consider projects that may mitigate the identified risk. The SAR drafting team should consider evaluating the 24-month study period in-service window and consider extending the window to 30-month. With a 30-month window, enties would be able to consider all substation elements expected to be placed into service, or retired, prior to the R1.1 30-month subsequent risk assessment required of entites that have identified one or more substations subject to the standard. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name** Southern Company | |
| **Answer** | |
| **Document Name** | |
| **Comment** | |
| No additional comments. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Dwanique Spiller - Berkshire Hathaway - NV Energy - 5** | |
| **Answer** | |
| **Document Name** | |
| **Comment** | |
| None at this time. | |
| Likes 0 | |

| | |
|---|---|
| Dislikes 0 | |

**Response**

**Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name** ACES Collaborators

| | |
|---|---|
| **Answer** | |
| **Document Name** | |

**Comment**

Thank you for the opportunity to comment.

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| Likes 0 | |
| Dislikes 0 | |

**Response**

**Junji Yamaguchi - Hydro-Quebec (HQ) - 1,5**

| | |
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| **Answer** | |
| **Document Name** | |

**Comment**

The following changes from item number one of the Detailed Description should be made:
Clarity should be added to the risk assessment to assure that instability is studied and that professional judgment assumptions are based on the investigation of instability.
Including the word "fully" leads to increased difficulty in proving to an auditor that the stability studies being performed meet the expected threshold, the word should be removed. By saying "Clarity should be added to the risk assessment to assure that instability is studied," there is still the expectation to study for instability without the added compliance pressure of being pseudo-zero-defect.
As such, the revision should outline technical supporting expectations to clearly identify when an Applicable substation has demonstrated any form of instability. At a minimum, this revision should include specificity regarding the inclusion of transient dynamic studies to evaluate the conditions of the BPS.
The word "not" should be removed. Entities should identify the Applicable substations that have demonstrated instability to ease the administrative burden by justifying the basis that any one substation has demonstrated instability through the studies performed versus proving that a station did not have instability.
Entities should identify the Applicable substations that have demonstrated instability to ease the administrative burden by justifying the basis that any one substation has demonstrated instability through the studies performed versus proving that a station did not have instability.
After reviewing the 5 criteria, the consistency between the risk-based approach established in CIP-002, the Facility is different than the proposed CIP-014 risk criteria. An example is relay clearance times to justify deeper physical security but CIP-002 may rate it as a low impact, but from a CIP-014 perspective it may require higher physical security controls that may not be commensurate with the risk assessed in CIP-002. This may include scenarios that end up requiring significant physical security controls, but not the equivalent level of cybersecurity-related controls; despite being the same station / Facility.
The proposed SAR is a parallel scoping criterion to CIP-002 based more on the function/impact of the system as opposed to rudimentary bright-line criteria. Please consider criteria 1-4 to be incorporated into another standard such as TPL-001, CIP-002, PRC, etc.
Criteria 5 is security specific and could be incorporated in CIP-014.
Consider that if a physical evaluation requires the CIP-014 table 4.1.1.2 match the CIP-002 bright-line criteria.
Recommending an objective-based input.

| |
|---|
| This assessment impacts not only changed scope but impacts downstream considerations which; therefore, will impact cost and may require long implementation timelines which address the risks identified in the risk assessment.<br>We strongly disagree with the Cost Impact Assessment of the SAR's proposed methodology as being minimal. Conducting a large-scale stability study on a system of any reasonable size is very labor-intensive and can take anywhere from 3 to 6 months or more for a team of transmission planners. |

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| Likes 0 | |
| Dislikes 0 | |

**Response**

**Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name** WECC CIP

| | |
|---|---|
| **Answer** | |
| **Document Name** | |

**Comment**

None

| | |
|---|---|
| Likes 0 | |
| Dislikes 0 | |

**Response**

**Alain Mukama - Hydro One Networks, Inc. - 1,3**

| | |
|---|---|
| **Answer** | |
| **Document Name** | |

**Comment**

None

| | |
|---|---|
| Likes 0 | |
| Dislikes 0 | |

**Response**

**John Pearson - ISO New England, Inc. - 2**

| | |
|---|---|
| **Answer** | |
| **Document Name** | |

**Comment**

Regarding the cost impact assessment, the SAR states that cost impacts for the proposed changes to CIP-014-3 are expected to be minimal. The assessment appears to be based solely on modifications to system studies and does not seem to contemplate the additional spending that would be necessary on any stations newly identified as requiring physical security upgrades as a result of changes to the standard.

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| Likes 0 | |
| Dislikes 0 | |

**Response**

**Brad Harris - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE**

| | |
|---|---|
| **Answer** | |
| **Document Name** | |

**Comment**

CEHE would like to take this opportunity to support and amplify the statement in the SAR Scope Detailed Description item #1: “This revision should not preclude entities from only conducting an evaluation for long-term studies (e.g., steady-state) or from only conducting dynamic simulations in some instances (e.g., not requiring additional study types once a site is already identified as critical).” CEHE does not want the R1 Risk Assessment requirements to limit flexibility.

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| Likes 0 | |
| Dislikes 0 | |

**Response**

**Chantal Mazza - Hydro-Quebec (HQ) - 1 - NPCC**

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|---|---|
| **Answer** | |
| **Document Name** | |

**Comment**

The following changes from item number one of the Detailed Description should be made:

Clarity should be added to the risk assessment to assure that instability is studied and that professional judgment assumptions are based on the investigation of instability. Including the word “fully” leads to increased difficulty in proving to an auditor that the stability studies being performed meet the expected threshold, the word should be removed. By saying “Clarity should be added to the risk assessment to assure that instability is studied,” there is still the expectation to study for instability without the added compliance pressure of being pseudo-zero-defect.

As such, the revision should outline technical supporting expectations to clearly identify when an Applicable substation has demonstrated any form of instability. At a minimum, this revision should include specificity regarding the inclusion of transient dynamic studies to evaluate the conditions of the BPS.

The word "not" should be removed. Entities should identify the Applicable substations that have demonstrated instability to ease the administrative burden by justifying the basis that any one substation has demonstrated instability through the studies performed versus proving that a station did not have instability.

Entities should identify the Applicable substations that have demonstrated instability to ease the administrative burden by justifying the basis that any one substation has demonstrated instability through the studies performed versus proving that a station did not have instability.

After reviewing the 5 criteria, the consistency between the risk-based approach established in CIP-002, the Facility is different than the proposed CIP-014 risk criteria. An example is relay clearance times to justify deeper physical security but CIP-002 may rate it as a low impact, but from a CIP-014 perspective it may require higher physical security controls that may not be commensurate with the risk assessed in CIP-002. This may include scenarios that end up requiring significant physical security controls, but not the equivalent level of cybersecurity-related controls; despite being the same station / Facility.

he proposed SAR is a parallel scoping criterion to CIP-002 based more on the function/impact of the system as opposed to rudimentary bright-line criteria. Please consider criteria 1-4 to be incorporated into another standard such as TPL-001, CIP-002, PRC, etc.

Criteria 5 is security specific and could be incorporated in CIP-014.

Consider that if a physical evaluation requires the CIP-014 table 4.1.1.2 match the CIP-002 bright-line criteria.

Recommending an objective-based input.

This assessment impacts not only changed scope but impacts downstream considerations which; therefore, will impact cost and may require long implementation timelines which address the risks identified in the risk assessment.

We strongly disagree with the Cost Impact Assessment of the SAR's proposed methodology as being minimal. Conducting a large-scale stability study on a system of any reasonable size is very labor-intensive and can take anywhere from 3 to 6 months or more for a team of transmission planners.

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|---|---|
| Likes 0 | |
| Dislikes 0 | |

**Response**

**Michael Johnson - Pacific Gas and Electric Company - 1,3,5 - WECC, Group Name** PG&E All Segments

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| **Answer** | |
| **Document Name** | |

**Comment**

PG&E has no other input.

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|---|---|
| Likes 0 | |
| Dislikes 0 | |

**Response**

| Lucinda Bradshaw - Oncor Electric Delivery - 1 - Texas RE | |
|---|---|
| **Answer** | |
| **Document Name** | |
| **Comment** | |
| No Comment | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |

| **Dave Krueger - SERC Reliability Corporation - 10** | |
|---|---|
| **Answer** | |
| **Document Name** | |
| **Comment** | |
| Under Project scope in #3, suggest adding "within each Interconnection is consistent" after the word Cascading.<br><br>Under Detailed Description, suggest adding to #3 after the last sentence ending "application of a study method":<br><br>For example, there should be a consistent method to establish the maximum amount of acceptable generation/load loss within each Interconnection. The methods might include coordination between PA/TP areas, RC areas, or with NERC Interconnection study groups.  Entities should not have total flexibility when determining what does or does not affect the Interconnection. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |

| **Jennie Wike - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6 - WECC, Group Name** Tacoma Power | |
|---|---|
| **Answer** | |
| **Document Name** | |
| **Comment** | |
| Tacoma Power recommends that if “line of sight” is used in the revised CIP-014 Standard, then it needs to be clearly defined. For example, substations located within 100 yards of each other. | |
| Likes 0 | |

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|---|---|
| Dislikes 0 | |

**Response**

**April Ford - Southern Indiana Gas and Electric Co. - 3,5,6 - RF**

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|---|---|
| **Answer** | |
| **Document Name** | |

**Comment**

SIGE requests clarity around differing ownership for SAR Scope Detailed Description item #5: “The risk assessment should be revised to provide clear expectations regarding the inclusion of physically adjacent elements for the purpose of evaluating the impact from a physical attack.”

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| Likes 0 | |
| Dislikes 0 | |

**Response**

**Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name** NPCC RSC

| | |
|---|---|
| **Answer** | |
| **Document Name** | |

**Comment**

The following changes from item number one of the Detailed Description should be made:

**Clarity should be added to the risk assessment to assure that instability is studied and that professional judgment assumptions are based on the investigation of instability.**

Including the word “fully” leads to increased difficulty in proving to an auditor that the stability studies being performed meet the expected threshold, the word should be removed. By saying “Clarity should be added to the risk assessment to assure that instability is studied,” there is still the expectation to study for instability without the added compliance pressure of being pseudo-zero-defect.

**As such, the revision should outline technical supporting expectations to clearly identify when an Applicable substation has demonstrated any form of instability. At a minimum, this revision should include specificity regarding the inclusion of transient dynamic studies to evaluate the conditions of the BPS.**

The word "not" should be removed. Entities should identify the Applicable substations that *have* demonstrated instability to ease the administrative burden by justifying the basis that any one substation has demonstrated instability through the studies performed versus proving that a station did not have instability.

Entities should identify the Applicable substations that ***have*** demonstrated instability to ease the administrative burden by justifying the basis that any one substation has demonstrated instability through the studies performed versus proving that a station did not have instability.

After reviewing the 5 criteria, the consistency between the risk-based approach established in CIP-002, the Facility is different than the proposed CIP-014 risk criteria. An example is relay clearance times to justify deeper physical security but CIP-002 may rate it as a low impact, but from a CIP-014 perspective it may require higher physical security controls that may not be commensurate with the risk assessed in CIP-002. This may include scenarios that end up requiring significant physical security controls, but not the equivalent level of cybersecurity-related controls; despite being the same station / Facility.

The proposed SAR is a parallel scoping criterion to CIP-002 based more on the function/impact of the system as opposed to rudimentary bright-line criteria. Please consider criteria 1-4 to be incorporated into another standard such as TPL-001, CIP-002, PRC, etc.

Criteria 5 is security specific and could be incorporated in CIP-014.

Consider that if a physical evaluation requires the CIP-014 table 4.1.1.2 match the CIP-002 bright-line criteria.

Recommending an objective-based input.

This assessment impacts not only changed scope but impacts downstream considerations which; therefore, will impact cost and may require long implementation timelines which address the risks identified in the risk assessment.

We strongly disagree with the Cost Impact Assessment of the SAR's proposed methodology as being minimal. Conducting a large-scale stability study on a system of any reasonable size is very labor-intensive and can take anywhere from 3 to 6 months or more for a team of transmission planners.

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| Likes 0 | |
| Dislikes 0 | |

**Response**

**Joshua London - Eversource Energy - 1,3**

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| **Answer** | |

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| **Document Name** | |
| **Comment** | |

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| Likes 0 | |
| Dislikes 0 | |
| **Response** | |

**Donna Wood - Tri-State G and T Association, Inc. - 1,3,5**

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| **Answer** | |
| **Document Name** | |
| **Comment** | |

NA

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| Likes 0 | |
| Dislikes 0 | |
| **Response** | |

**Mark Garza - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6, Group Name** FE Voter

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| **Answer** | |
| **Document Name** | |
| **Comment** | |

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| See our response to Question 1. |
| Likes 0 |
| Dislikes 0 |
| **Response** |
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