NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Emergency Operations and Preparedness

Technical Rationale and Justification for Reliability Standard EOP-011-2

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RELIABILITY | RESILIENCE | SECURITY




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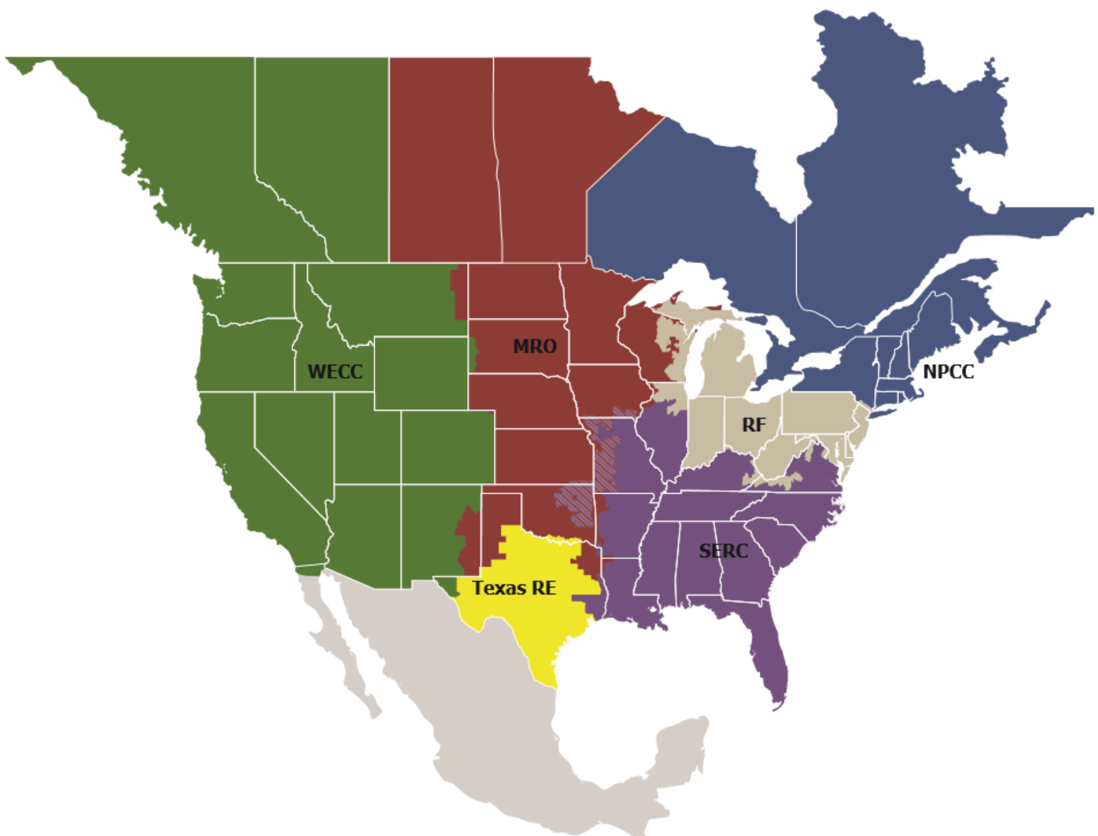
Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities (REs), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security
Because nearly 400 million citizens in North America are counting on us

The North American BPS is divided into six RE boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one RE while associated Transmission Owners (TOs)/Operators (TOPs) participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

Introduction

This document explains the technical rationale and justification for the proposed Reliability Standard EOP-011-2. It provides stakeholders and the ERO Enterprise with an understanding of the Cold Weather requirements in the Reliability Standard. It also contains information on the intent of the Standard Drafting Team (SDT) in drafting the requirements. This Technical Rationale and Justification for EOP-011-2 is not a Reliability Standard, which is not mandatory and enforceable.

Requirement R7 and R8

Rationale for Requirement R7

The *2019 FERC and NERC Staff Report on The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018* (Report) recommends modified Reliability Standards to require Generator Owners to implement "winterization activities on generating units to prepare for [cold weather]." The Generator Owner plans and procedures should include, but are not limited to, necessary and appropriate freeze protection measures, periodic maintenance and inspection of such measures, accurate ambient temperature design specifications, and generating unit limitations and expected performance in cold weather.

To address these recommendations contained in the Report, the SDT developed Requirement R7 to require each Generator Owner to implement and maintain one or more cold weather preparedness plans for its generating unit(s) subject to the standard. The standard requires the cold weather preparedness plan to contain a generating-units operating limitations during cold weather and other availability and capability information, and an annual requirement to inspect with associated maintenance of the generating unit(s).

Additionally, Requirement R7 requires the Generator Owner to develop accurate data to include the generating unit(s)' minimum design temperature (i.e., faceplate capability) during cold weather. If such information is not available due to the status of the generating unit(s), the SDT developed two additional options to produce an equivalent proxy to the design specification: minimum historical operating temperature or engineering analysis to determine current minimum cold weather performance temperature.

Rationale for Requirement R8

To address the recommendation contained in the Report to require Generator Operators and Generator Owners to "[c]onduct winter-specific and plant-specific operator awareness training," the SDT developed Requirement R8. Requirement R8 requires each Generator Operator or Generator Owner to provide generating unit-specific training to its maintenance and operations personnel responsible for implementing the cold weather preparedness plan(s) required under Requriement R7. The SDT created R8 as applicable to both the Generator Owner and the Generator Operator based on the roles and responsibilities identified in the Functional Model, whereas both entities may have personnel that are responsible to implement the cold weather preparedness plan(s) and require training.

See the Glossary terms for Generator Operator and Generator Owner.

1. Generator Operator – "The entitiy that operates generating Favility(ies) and performs the functions of supplying energy and Interconnected Opeartions Services."[1]
2. Geneartor Onwer – "Entity that owns and maintains generating Facility(ies)."[2]

[1] See NERC Glossary of Terms (page 13 of 49): https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf
[2] See NERC Glossary of Terms (page 13 of 49): https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf

Appendix 1: Technical Rational for Reliability Standard EOP-011-1

Guidelines and Technical Basis

Rationale:
During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R1:
The EOP SDT examined the recommendation of the EOP Five-Year Review Team (FYRT) and FERC directive to provide guidance on applicable entity responsibility that was included in EOP-001-2.1b. The EOP SDT removed EOP-001-2.1b, Attachment 1, and incorporated it into this standard under the applicable requirements. This also establishes a separate requirement for the Transmission Operator to create an Operating Plan(s) for mitigating operating Emergencies in its Transmission Operator Area.

The Operating Plan(s) can be one plan, or it can be multiple plans.

"Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency" was retained. This is a process in the plan(s) that determines when the Transmission Operator must notify its Reliability Coordinator.

To meet the associated measure, an entity would likely provide evidence that such an evaluation was conducted along with an explanation of why any overlap of Loads between manual and automatic load shedding was unavoidable or reasonable.

An Operating Plan(s) is implemented by carrying out its stated actions.

If any Parts of Requirement R1 are not applicable, the Transmission Operator should note "not applicable" in the Operating Plan(s). The EOP SDT recognizes that across the regions, Operating Plan(s) may not include all the elements listed in this requirement due to restrictions, other methods of managing situations, and documents that may already exist that speak to a process that already exists. Therefore, the entity must provide in the plan(s) that the element is not applicable and detail why it is not applicable for the plan(s).

With respect to automatic Load shedding schemes that include both UVLS and UFLS, the EOP SDT's intent is to keep manual and automatic Load shed schemes as separate as possible, but realizes that sometimes, due to system design, there will be overlap. The intent in Requirement R1 Part 1.2.5. is to minimize, as much as possible, the use of manual Load shedding which is already armed for automatic Load shedding. The automatic Load shedding schemes are the important backstops against Cascading outages or System collapse. If any entity manually sheds a Load which was included in an automatic scheme, it reduces the effectiveness of that automatic scheme. Each entity should review their automatic Load shedding schemes and coordinate their manual processes so that any overlapping use of Loads is avoided to the extent reasonably possible.

Rationale for R2:
To address the recommendation of the FYRT and the FERC directive to provide guidance on applicable entity responsibility in EOP-001-2.1b, Attachment 1, the EOP SDT removed EOP-001-2.1b, Attachment 1, and incorporated it into this standard under the applicable requirements. EOP-011-1 also establishes a separate requirement for the Balancing Authority to create its Operating Plan(s) to address Capacity and Energy Emergencies.

The Operating Plan(s) can be one plan, or it can be multiple plans.

An Operating Plan(s) is implemented by carrying out its stated actions.

If any Parts of Requirement R2 are not applicable, the Balancing Authority should note "not applicable" in the Operating Plan(s). The EOP SDT recognizes that across the regions, Operating Plan(s) may not include all the elements listed in this requirement due to restrictions, other methods of managing situations, and documents that may already exist that speak to a process that already exists. Therefore, the entity must provide in the plan(s) that the element is not applicable and detail why it is not applicable for the plan(s).

The EOP SDT retained the statement "Operator-controlled manual Load shedding," as it was in the current EOP-003-2 and is consistent with the intent of the EOP SDT.

With respect to automatic Load shedding schemes that include both UVLS and UFLS, the EOP SDT's intent is to keep manual and automatic Load shedding schemes as separate as possible, but realizes that sometimes, due to system design, there will be overlap. The intent in Requirement R2 Part 2.2.8. is to minimize as much as possible the use manual Load shedding which is already armed for automatic Load shedding. The automatic Load shedding schemes are the important backstops against Cascading outages or System collapse. If an entity manually sheds a Load that was included in an automatic scheme, it reduces the effectiveness of that automatic scheme. Each entity should review its automatic Load shedding schemes and coordinate its manual processes so that any overlapping use of Loads is avoided to the extent possible.

The EOP SDT retained Requirement R8 from EOP-002-3.1 and added it to the Parts in Requirement R2.

Rationale for R3:
The SDT agreed with industry comments that the Reliability Coordinator does not need to approve BA and TOP plan(s). The SDT has changed this requirement to remove the approval but still require the RC to review each entity's plan(s), looking specifically for reliability risks. This is consistent with the Reliability Coordinator's role within the Functional Model and meets the FERC directive regarding the RC's involvement in Operating Plan(s) for mitigating Emergencies.

Rationale for Requirement R4:
Requirement R4 supports the coordination of Operating Plans within a Reliability Coordinator Area in order to identify and correct any Wide Area reliability risks. The EOP SDT expects the Reliability Coordinator to make a reasonable request for response time. The time period requested by the Reliability Coordinator to the Transmission Operator and Balancing Authority to update the Operating Plan(s) will depend on the scope and urgency of the requested change.

Rationale for R5
The EOP SDT used the existing requirement in EOP-002-3.1 for the Balancing Authority and added the words "within 30 minutes from the time of receiving notification" to the requirement to communicate the intent that timeliness is important, while balancing the concern that in an Emergency there may be a need to alleviate excessive notifications on Balancing Authorities and Transmission Operators. By adding this time limitation, a measurable standard is set for when the Reliability Coordinator must complete these notifications.

Rationale for Introduction
LSEs were removed from Attachment 1, as an LSE has no Real-time reliability functionality with respect to EEAs.

EOP-002-3.1 Requirement R9 was in place to allow for a Transmission Service Provider to change the priority of a service request, as permitted in its transmission tariff, informing the Reliability Coordinator so that the service would not be curtailed by a TLR; and since the Tagging Specs did not allow profiles to be changed, this was the only method to accomplish it. Under NAESB WEQ E-tag Specification v1811 R3.6.1.3, this has been modified and now the TSP has the ability to change the Transmission priority which, in turn, is reflected in the IDC. This technology change allows for the deletion of Requirement R9 in its entirety. Requirement R9 meets with Criterion A of Paragraph 81 and should be retired.

Rationale for (2) Notification

The EOP SDT deleted the language, "*The Reliability Coordinator shall also notify all other Reliability Coordinators of the situation via the Reliability Coordinator Information System (RCIS). Additionally, conference calls between RCs shall be held as necessary to communicate system conditions. The RC shall also notify the other RCs when the alert has ended*" as duplicative to proposed IRO-014-3 Requirement R1:

R1. Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following:

Communications and notifications, and the process to follow in making those notifications.

Energy and capacity shortages.

Control of voltage, including the coordination of reactive resources.

Exchange of information including planned and unplanned outage information to support its Operational Planning Analyses and Real-time Assessments.

Authority to act to prevent and mitigate system conditions which could adversely impact other Reliability Coordinator Areas.

Provisions for weekly conference calls.

Rationale for EEA 2:

The EOP SDT modified the "Circumstances" for EEA 2 to show that an entity will be in this level when it has implemented its Operating Plan(s) to mitigate Emergencies but is still able to maintain Contingency Reserves.

Rationale for EEA 3:

This rationale was added at the request of stakeholders asking for justification for moving a lack of Contingency Reserves into the EEA3 category.

The previous language in EOP-002-3.1, EEA 2 used "Operating Reserve," which is an all-inclusive term, including all reserves (including Contingency Reserves). Many Operating Reserves are used continuously, every hour of every day. Total Operating Reserve requirements are kind of nebulous since they do not have a specific hard minimum value. Contingency Reserves are used far less frequently. Because of the confusion over this issue, evidenced by the comments received, the drafting team thought that using minimum Contingency Reserve in the language would eliminate some of the confusion. This is a different approach but the drafting team believes this is a good approach and was supported by several commenters.

Using Contingency Reserves (which is a subset of Operating Reserves) puts a BA closer to the operating edge. The drafting team felt that the point where a BA can no longer maintain this important Contingency Reserves margin is a most serious condition and puts the BA into a position where they are very **close to shedding Load ("imminent or in progress"). The drafting team felt that this warrants categorization at the highest level of EEA.**