NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Extreme Cold Weather Preparedness

Technical Rationale and Justification for EOP-011-4

~~February~~August 2023

RELIABILITY | RESILIENCE | SECURITY




3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

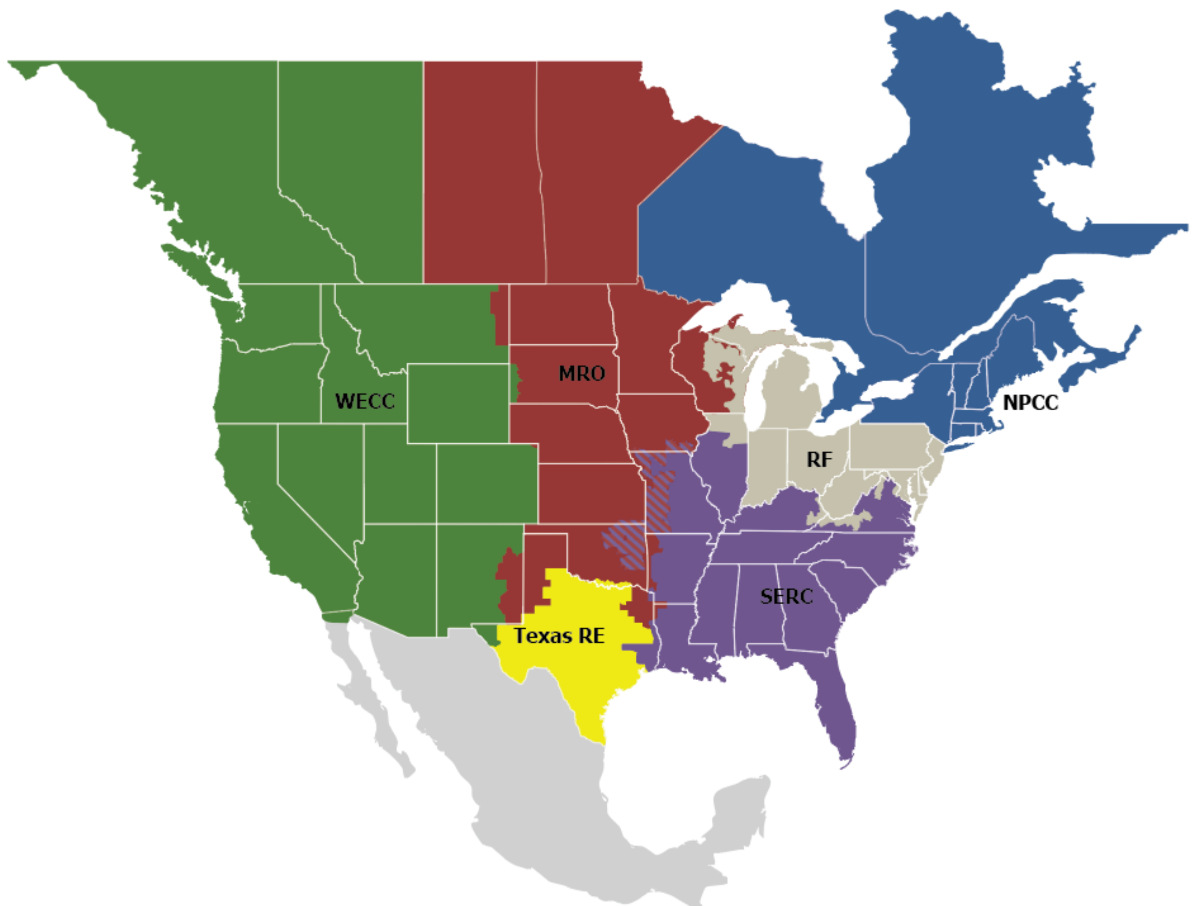
Table of Contents

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, 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 made up of six Regional Entity boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some ~~load-serving entities~~Load-Serving Entities participate in one Regional Entity while associated Transmission Owners/Operators 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 ~~Standards~~Standard EOP-011-4. It provides stakeholders and the ERO Enterprise with an understanding of the technology and technical requirements in the Reliability Standard. This Technical Rationale and Justification for EOP-011-4 ~~and EOP-NEW~~ is not a Reliability Standard and should not be considered mandatory and enforceable.

Background

From February 8 through February 20, 2021, extreme cold weather and precipitation caused large numbers of generating units to experience outages, derates, or failures to start, resulting in energy and transmission emergencies (referred to as “the Event”). The total Event firm Load shed was the largest controlled firm Load shed event in U.S. history and was the third largest in quantity of outaged megawatts (MW) of Load after the August 2003 ~~Northeast~~northeast blackout and the August 1996 ~~West Coast~~west coast blackout. The Event was most severe from February 15 through February 18, 2021, and it contributed to power outages affecting millions of electricity customers throughout the regions of ERCOT, SPP, and MISO South. Additionally, the February 2021 event is the fourth cold weather event in the past 10 years~~,~~ which jeopardized bulk-power system reliability. A joint inquiry was conducted to discover reliability-related findings and recommendations from FERC, NERC, and Regional Entity staff. The FERC, NERC, and Regional Entity Staff Joint Staff Inquiry into the February 2021 Cold Weather Grid Operations (“Joint Inquiry Report”) was published on November 16, 2021.

The scope of the proposed project is to address the ~~ten~~10 recommendations for new or enhanced NERC Reliability Standards proposed by the Joint Inquiry Report. In November 2021, the NERC Board of Trustees ~~(Board)~~ approved a Board Resolution directing that new or revised Reliability Standards addressing these recommendations be completed in accordance with the timelines recommended by the joint inquiry team, as follows:

- New and revised Reliability Standards to be submitted for regulatory approval before Winter 2022/2023: development was completed by September 30, 2022, and submitted for the Board’s consideration in October 2022 to address Key Recommendations 1d, 1e, 1f, and 1j;
- New and revised Reliability Standards to be submitted for regulatory approval before Winter 2023/2024: development completed by September 30, 2023~~,~~ for the Board’s consideration in October 2023 to address Key Recommendations 1a, 1b, 1c, 1g, 1h, and 1i.

~~Applicability~~

*~~**4.1.** Functional Entities:~~*

*~~**4.1.1** Balancing Authority~~*

*~~**4.1.2** Reliability Coordinator~~*

*~~**4.1.3** Transmission Operator~~*

*~~**4.1.4** Distribution Provider identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area~~*

*~~**4.1.5** UFLS-Only Distribution Provider identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area~~*

*~~**4.1.6** Transmission Owner identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area~~*

Requirement R1, R7, and ~~R7~~R8

R1. *Each Transmission Operator shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: ~~[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]~~*

__1.1.__ Roles and responsibilities for activating the Operating Plan(s);

__1.2.__ Processes to prepare for and mitigate Emergencies including:

__1.2.1.__ Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency;

__1.2.2.__ Cancellation or recall of Transmission and generation outages;

__1.2.3.__ Transmission system reconfiguration;

__1.2.4.__ Redispatch of generation request;

__1.2.5.__ Operator-controlled manual ~~or~~Load shedding and automatic Load shedding during an Emergency that accounts for each of the following:

__1.2.5.1.__ Provisions for manual Load shedding capable of being implemented in a timeframe adequate for mitigating the Emergency;

__1.2.5.2.__ Provisions to minimize the overlap of circuits that are designated for manual or automatic Load shed and circuits that serve designated critical loads which are essential to the reliability of the BES;

__1.2.5.3.__ Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for underfrequency load shed (UFLS) or undervoltage load shed (UVLS);

__1.2.5.4.__ Provisions for limiting the utilization of UFLS or UVLS circuits for manual Load shed to situations where warranted by system conditions;

1.2.5.5. *Provisions for the identification and prioritization of designated critical natural gas ~~infrastructure loads~~loads which are essential to the reliability of the BES; and*

~~***1.2.5.6.*** *Provisions for the identification of Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners required to mitigate operating Emergencies in its Transmission Operator Area.*~~

1.2.6. *Provisions to determine reliability impacts of:*

1.2.6.1. *Cold weather conditions; and*

1.2.6.2. *Extreme weather conditions.*

~~***R7***~~**R7.** *Each Transmission Operator shall annually identify and notify Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding or automatic Load shedding.*

R8*.* *Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner ~~identified in~~notified by* a Transmission ~~Operator's Operating Plan(s)~~*Operator per R7* to ~~mitigate~~*assist with the mitigation of* operating Emergencies in its Transmission Operator Area, shall develop, maintain, *and implement ~~one or more Operating Plan(s).~~ a Load shedding plan, within 30 months of being notified by the Transmission Operator. The ~~Operating Plan(s) shall be provided to the Transmission Operator. The Operating Plan(s)~~Load shedding plan shall include the following, as applicable: ~~[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]~~*

~~***7.1.***~~***8.1.*** *Operator-controlled manual ~~or~~Load shedding and automatic Load shedding during an Emergency that accounts for each of the following:*

~~***7.1.1.***~~***8.1.1.*** *Provisions for manual Load shedding capable of being implemented in a timeframe adequate for mitigating the Emergency;*

~~***7.1.2.***~~***8.1.2.*** *Provisions to minimize the overlap of circuits that are designated for manual or automatic Load shed and circuits that serve designated critical loads which are essential to the reliability of the BES;*

~~***7.1.3.***~~***8.1.3.*** *Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for underfrequency load shed (UFLS) or undervoltage load shed (UVLS);*

~~***7.1.4.***~~***8.1.4.*** *Provisions for limiting the utilization of UFLS or UVLS circuits for manual Load shed to situations where warranted by system conditions; and*

~~***7.1.5.***~~***8.1.5.*** *Provisions for the identification and prioritization of designated critical natural gas infrastructure loads~~.~~ which are essential to the reliability of the BES.*

8.2. *Provisions to provide the Load shedding plan to the Transmission Operator for review.*

Key Recommendation 1i: To protect critical natural gas infrastructure loads from manual and automatic load shedding (to avoid adversely affecting Bulk Electric System reliability):

- *To require Balancing ~~Authorities~~Authorities' and Transmission ~~Operators~~Operators' provisions for operator-controlled manual load shedding to include processes for identifying and protecting critical natural gas infrastructure loads in their respective areas;*
- *To require Balancing ~~Authorities~~Authorities', Transmission ~~Operators~~Operators', Planning ~~Coordinators~~Coordinators', and Transmission ~~Planners~~Planners' respective provisions and programs for manual and automatic (e.g., underfrequency load shedding, undervoltage load shedding) load shedding to protect identified critical natural gas infrastructure loads from manual and automatic load shedding by manual and automatic load shed entities within their footprints;*
- *To require manual and automatic load shed entities to distribute criteria to natural gas infrastructure entities that they serve and request the natural gas infrastructure entities to identify their critical natural gas infrastructure loads; and*
- *To require manual and automatic load shed entities to incorporate the identified critical natural gas infrastructure loads into their plans and procedures for protection against manual and automatic load shedding. (Winter 2023-2024)*

Applicability, Requirement ~~R1.2.5.6~~R7 and ~~Requirement R7~~R8

Expansion of Applicability

In many cases, Transmission Operators ~~(TOP)~~ are dependent on Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners to implement portions of Requirement R1.2.5. The Project 2021-07 standard drafting team (SDT) determined that it is necessary to expand the Applicability of EOP-011-4 to these Functional Entities in order to address all entities responsible for performing operator-controlled manual Load shedding or automatic ~~load~~Load shedding per Key Recommendation 1i. Planning Coordinators and Transmission Planners were purposely excluded from applicability even though they are mentioned in Key Recommendation 1i because they are not responsible for performing operator-controlled manual Load shedding or automatic Load shedding.

EOP-011-4 Requirement ~~R1.2.5.6~~R7 is a new requirement that was added to require that Transmission Operators annually identify and notify any Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners that are required to ~~mitigate~~assist with mitigation of operating Emergencies in their Transmission Operator Area. The Transmission Operator has the overarching responsibility to mitigate operating Emergencies. If a Transmission Operator relies on other ~~Functional Entities to accomplish~~functional entities in accomplishing various aspects of manual or automatic Load shedding, they must be identified ~~in~~and notified per R7. Those identified and notified entities are subject to Requirement R8. The initial performance of R7 is required upon the ~~TOP's~~effective date of EOP-011-4, which is on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority. This approach to Requirement R7 ensures that newly applicable entities who will be subject to Requirement R8 are identified and notified in a timely manner thus minimizing any delay in implementing Requirement R8. Requirement R7 includes an annual provision to ensure that any additional entities, or changes to existing entities, required to assist with the mitigation of Operating ~~Plan(s).~~emergencies are appropriately identified and notified on an ongoing basis.

EOP-011-4 Requirement ~~R7~~R8 is a new requirement that is specific to Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners identified by the Transmission Operator in Requirement ~~R1.2.5.6.~~ R7. It includes the relevant portions ~~EOP-011-4~~of Requirement R1.2.5 that address operator-controlled manual Load shedding or automatic ~~load~~Load shedding. The SDT found it appropriate to place these requirements specifically on Distribution

Providers, UFLS-Only Distribution Providers, and Transmission Owners because many times they are the entities performing operator-controlled manual Load shedding or automatic Load shedding and have the capability of ensuring that these requirements are appropriately implemented for the Loads they represent. Entities that are subject to R8 have 30 months after being notified by a Transmission Operator in R7 to become compliant with these requirements.

Requirement R1, Part 1.2.5 and Requirement ~~R7~~R8, Part ~~7~~8.1

~~*Identify and Prioritize Critical Natural Gas Loads*~~

EOP-011-4 Requirement R1.2.5.5 was added to require Transmission Operators to include provisions to identify and prioritize critical natural gas ~~loads~~infrastructure Loads which are essential to the reliability of the BES in their Operating Plan(s). EOP-011-4 Requirement ~~R7~~R8.1.5 mirrors this requirement and is applicable to Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners. In addition to the following content, entities are encouraged to review guidance from ~~Reliability Guideline: Gas and Electrical Operational Coordination Considerations (add hyperlink).~~*Reliability Guideline: Gas and Electrical Operational Coordination Considerations* in developing their approach to identify and prioritize critical natural gas infrastructure loads.

Manual ~~AND~~and Automatic

EOP-011-4 Requirement 1.2.5 was modified to include "automatic Load shedding" in addition to "operator-controlled manual Load shedding." The result of this modification is that Requirement R1.2.5.5, which requires the identification and prioritization of critical natural gas Loads which are essential to the reliability of the BES, is also applicable to automatic Load shedding. It is important to identify and prioritize critical natural gas Loads not just for the purposes of manual Load shed but also in consideration of automatic Load shedding schemes. This modification does not prohibit the inclusion of critical natural gas Loads in automatic Load shedding, but it does require the prioritization of critical natural gas Loads~~.~~ which are essential to the reliability of the BES. This change was also incorporated into the new EOP-011-4 Requirement ~~R7~~R8.1.

Critical Natural Gas Infrastructure Loads

The SDT has elected to add clarifying language in the applicable requirements and expand content in this Technical Rationale document in lieu of making "critical natural gas infrastructure Load" a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may necessarily have been overly broad; and would not provide substantial additional clarity given the diversity of these types of facilities throughout the BES footprint.

A reasonable application of this term should be informed by the entity's approved governing documents and guidance established by applicable regulatory authorities. A practical example of guidance that provides reasonable direction and flexibility has been developed by the Public Utility Commission of Texas in response to Winter Storm Uri (*Guidance Document for Power Delivery and Restoration During Energy Emergencies*). It is essential for entities to recognize that being overly broad in the application of this term may negatively impact reliability. If everything is critical, then nothing is truly critical.

The various regions covered by NERC requirements will have large variances in natural gas infrastructure that might be considered essential to the reliability of the BES. For example, Texas considers a single forced stoppage of natural gas transportation capacity a "major" event only if it disrupts greater than 200 MMcf per day. The entire state of Vermont used less than 70 times that amount of gas over the course of the entire year in 2021 and would therefore likely consider any infrastructure that moves a small fraction of the Texas quantity of gas "critical." Some locations would consider large gas collection sites (wellheads) as critical while others simply have no gas collection systems. Gas compression stations may be critical in some locations while others, potentially located near large underground high-pressure storage sites, may not be considered as critical. Entities should develop critical load classifications and criteria for prioritizing critical loads for BES reliability based on the unique features of its system.

Identification of Critical Natural Gas Infrastructure Loads

Critical natural gas ~~loads~~Loads must be identified so that they can then be prioritized from an operator-controlled manual Load shedding and automatic Load shedding perspective. The identification and prioritization of critical natural gas loads requires coordination with natural gas facility owners and operators. This can be accomplished in ~~several~~a number of ways and the SDT did not prescribe specific methods in the drafting of EOP-011-4. Methods may include:

- Distribution of criteria to natural gas infrastructure entities soliciting information to identify critical facilities that would likely adversely affect BES reliability if de-energized;
- Reliance on self-identification of critical gas infrastructure driven by local jurisdictional requirements;
- Use of historical ~~info~~information and coordination with resources and gas suppliers from existing Operating Plans.

The SDT recognizes that entities are dependent upon the cooperation of natural gas facility owners and operators to complete this task. However, it is outside the scope of the SDT to develop methods to compel natural gas owners and operators to cooperate and provide specific information to various entities.

It is also recognized that BES registered entities are not expected to become experts in natural gas infrastructure, nor are natural gas entities expected to become experts in electrical generation. Those natural gas Loads determined to be critical to the reliability of the BES may also change gradually over time as changes occur in the BES and natural gas supply system, requiring regular review of prioritization schemes. The goal of pre-event planning and emergency response is to promote sufficient knowledge so that discussions of natural gas facility criticality can be conducted prior to and during extreme cold weather events. This allows Reliability Coordinators, Balancing Authorities, Regional Entities, Transmission Operators, Transmission Owners, and Distribution Providers to adjust Load shedding schemes as necessary to maximize availability of natural gas resources and to minimize impacts on the BES.

Prioritization of Critical Natural Gas Infrastructure Loads

The SDT recognizes that it is not reasonable to set a broad expectation of "protecting" critical natural gas Loads as initially recommended in the Joint Inquiry Report. Instead, it is more appropriate for entities to consider how critical natural gas infrastructure ~~loads~~Loads are prioritized under various conditions. It is important to recognize that criticality designations must be considered in the context of the situation. Critical ~~loads~~Loads should not all receive the same level of priority, and the characteristics of a Load shed event (depth/duration/season) will impact the treatment of certain critical ~~loads.~~ Loads. Transmission Operators should consider establishing priorities for different types of critical ~~loads~~Loads. The critical Load designation, priority, and conditions during the event will influence which critical ~~loads~~Loads may be included in manual Load shed. For example, if system conditions continue to deteriorate and other Load shed options are exhausted, then some critical ~~loads~~Loads may need to be shed in the interest of preserving the system. It is important to have the awareness and flexibility to include or exclude certain loads based on the Load shed scenario. Continued communication between electricity and natural gas providers is crucial to maintain situational awareness to avoid unintended consequences of Load shedding of critical natural gas infrastructure Loads. Prioritization should ~~consider~~take into account the relative criticality of various loads within the natural gas supply chain ~~as compared to~~and their potential impact to BES reliability. For example, critical natural gas ~~loads~~Loads such as compression facilities that directly impact gas pipelines serving gas-fired generators should be prioritized above gas production facilities.

Most entities will find it appropriate to completely exclude a subset of the most critical natural gas infrastructure Loads that directly impact BES generators from manual and automatic Load shed. It is recommended to prioritize other critical natural gas Loads so that they are only shed if necessary, based on the Load shed magnitude.

An example method of prioritizing critical natural gas ~~loads~~Loads may include:

- Identifying critical natural gas infrastructure Loads with the highest level of criticality and potential impact to BES reliability such that they can be completely excluded from operator-controlled manual Load shed and automatic Load shed programs;
- Prioritizing other critical natural gas infrastructure Loads not included in automatic Load shed programs such that they are only shed if necessary, based on the Load shed magnitude; and
- Prioritizing other critical natural gas infrastructure Loads included in automatic Load shed programs such that they are allocated to the lower frequency, or longer time-delay, steps in a UFLS program to ensure that they are less likely to be interrupted.

Requirement R2

R2. *Each Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

2.1. *Roles and responsibilities for activating the Operating Plan(s);*

2.2. *Processes to prepare for and mitigate Emergencies including:*

2.2.1. *Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency;*

2.2.2. *Requesting an Energy Emergency Alert, per Attachment 1;*

2.2.3. *Managing generating resources in its Balancing Authority Area to address:*

2.2.3.1. *Capability and availability;*

2.2.3.2. *Fuel supply and inventory concerns;*

2.2.3.3. *Fuel switching capabilities; and*

2.2.3.4. *Environmental constraints.*

2.2.4. *Public appeals for voluntary Load reductions;*

2.2.5. *Requests to government agencies to implement their programs to achieve necessary energy reductions;*

2.2.6. *Reduction of internal utility energy use;*

2.2.7. *Use of Interruptible Load, curtailable Load~~,~~ and demand response;*

2.2.8. *Provisions for excluding critical natural gas infrastructure loads which are essential to the reliability of the BES as Interruptible Load, curtailable Load, and demand response during extreme cold weather periods ~~when it would adversely impact the reliable operation of the BES~~within each Balancing Authority Area;*

2.2.9. *Provisions for Transmission Operators to implement operator-controlled manual Load ~~shed~~shedding or automatic Load shedding in accordance with Requirement R1 Part 1.2.5; and*

2.2.10. *Provisions to determine reliability impacts of:*

2.2.10.1. *~~Cold~~cold weather conditions; and*

2.2.10.2. *~~Extreme~~extreme weather conditions.*

Key Recommendation 1h: *To require Balancing Authorities' operating plans (for contingency reserves and to mitigate capacity and energy emergencies) to prohibit use for demand response of critical natural gas infrastructure loads.*

Requirement R2, Part 2.2.8

EOP-011-4 Requirement 2.2.8 was added to ~~require Balancing Authorities to include provisions to identify and prioritize~~address Key Recommendation 1h by prohibiting the use of certain critical natural gas infrastructure loads ~~in their Operating Plan(s), similar to EOP-011-4 Requirements R1.2.5 and R7.1.5 applicable to Transmission Operators, Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners. The Technical Rationale verbiage above regarding the identification and prioritization of~~ for demand response. This prohibition does not apply to all natural gas infrastructure loads. Instead, the Balancing Authority is only required to exclude those critical natural gas ~~Loads applicable~~infrastructure loads which are essential to ~~Requirements R1.2.5 and R7.1.5 is also applicable to Requirement R2.2.8.~~

~~It is important to stress that in~~ the ~~verbiage above applicable to R1.2.5 and R7.1.5, and~~reliability of the ~~Key Recommendation 1h and Recommendation 28 from the Joint Inquiry Report~~BES. Additionally, it is recognized that ~~"critical" is situational, i.e. depending on the local conditions, and may change during the course of~~ a ~~severe weather event. That is, during an event, any element of natural gas processing and delivery may become "critical". Continued communication between electricity and~~ complete prohibition is not necessary at all times given the natural gas ~~providers is crucial to maintain situational awareness to avoid unintended consequences of load shedding of critical natural gas loads.~~

~~It is also recognized that BES registered entities are not expected to become experts in natural gas infrastructure, nor are natural gas entities expected to become experts in electrical generation. Those natural gas loads determined to be critical may also change more gradually over time as changes occur in the BES and natural gas supply~~ system~~,~~ ~~requiring regular review of prioritization schemes. The goal of pre-event planning and emergency response is to promote sufficient knowledge so that discussions of natural gas facility~~ does not have the same limitations and criticality ~~can be conducted prior to and during severe~~during all seasons and weather conditions. For this reason, the SDT has limited the exclusion of these loads from Interruptible Load, curtailable Load, and demand response only to periods of extreme cold weather ~~to allow Reliability Coordinators, Balancing Authorities, Regional Entities, Transmission Operators, Transmission Owners, and Distribution Providers to adjust load shedding schemes as necessary to maximize availability of natural gas resources and minimize impact on the BES~~.

Requirement R2, Part 2.2.9

Key Recommendation 1i requires the Balancing Authorities to include in their Operating Plan(s) for their Balancing Authority Areas provisions for operator-controlled manual ~~load~~Load shedding that identifies and protects critical natural gas infrastructure loads in their respective areas. Further, the recommendation also includes provisions within these operating plans to require manual and automatic ~~load~~Load shed entities within their respective footprints to protect identified critical natural gas infrastructure loads from manual and automatic ~~load~~Load shedding.

The current provision~~-~~, Requirement R2 Part 2.2.9, which references Transmission Operator responsibilities under R1 Part 1.2.5~~.~~, satisfies the requirements of Key Recommendation 1i with respect to the Balancing Authority. Requirement R1 Part 1.2.5 ~~identifies and protects~~requires that Transmission Operators have provisions to identify and prioritize critical natural gas infrastructure loads ~~from manual and automatic load shedding within the Transmission Operator's Operating Plan(s),~~ which ~~the~~ are essential to the reliability of the BES from a manual Load shedding and automatic Load shedding perspective. The Balancing Authority relies on the Transmission Operator when it directs ~~load~~ Load shedding~~ provisions (*See* Requirement R2 Part 2.2.9).~~. In addition, as described above, Requirement ~~R7~~ R8 extends these requirements to the applicable ~~to the~~ Distribution ~~Provider~~Providers, UFLS-Only Distribution ~~Provider~~Providers, and Transmission ~~Owner, identifies and protects critical natural gas infrastructure loads from manual and automatic load shedding, and are essential~~ Owners who are identified in ~~the implementation of~~ a Transmission Operator's Operating Plan to assist with the mitigation of Operating ~~Plan(s).~~emergencies. Therefore, the objectives of the recommendation that ~~load~~ Load shedding entities identify and protect critical natural gas infrastructure loads are satisfied~~ within the Transmission Operator's Operating Plan(s).~~.