ERCOT Impact Analysis Report

NPRR Number	<u>1189</u>	NPRR Title	Updates to Language to Clarify the Allowable Regulation Ancillary Service Trades
Impact Analysis Date	June 28, 2023		
Estimated Cost/Budgetary Impact	None.		
Estimated Time Requirements	No project required. This Nodal Protocol Revision Request (NPRR) can take effect upon implementation of NPRR1136, Updates to Language Regarding a QSE Moving Ancillary Service Responsibility Between Resources.		
ERCOT Staffing Impacts (across all areas)	Ongoing Requirements: No impacts to ERCOT staffing.		
ERCOT Computer System Impacts	No impacts to ERCOT computer systems.		
ERCOT Business Function Impacts	No impacts to ERCOT business functions.		
Grid Operations & Practices Impacts	No impacts to ERCOT grid operations and practices.		

Evaluation of Interim Solutions or Alternatives for a More Efficient Implementation
None offered.

Comments
There are no additional impacts to this NPRR beyond what was captured in the Impact Analysis for NPRR1136.

Board Report

LPGRR Number	070	LPGRR Title	Discontinuation of Interval Data Recorder (IDR) Meter Weather Sensitivity Process
Date of Decision		August 31, 2023	
Action		Recommended Approval	
Timeline		Normal	
Proposed Effective Date		Upon system implementation	
Priority and Rank Assigned		Not applicable	
Load Profiling Guide Sections Requiring Revision		11.3.8, Comparison of Weather Sensitivity Code to Meter Data Type Code 14.2.1, Disputes Involving ERCOT 19.2, ACRONYMS Appendix D, Profile Decision Tree – Start --2014 v1.8 Appendix D, Profile Decision Tree – FAQ Appendix D, Profile Decision Tree – Use of Components Appendix D, Profile Decision Tree – Definitions	
Related Documents Requiring Revision/Related Revision Requests		Nodal Protocol Revision Request (NPRR) 1163, Related to LPGRR070, Discontinuation of Interval Data Recorder (IDR) Meter Weather Sensitivity Process	
Revision Description		This Load Profiling Guide Revision Request (LPGRR) discontinues the process of evaluating Interval Data Recorder (IDR) Meters to determine if they are Weather Sensitive (WS).	
Reason for Revision		[X] Addresses current operational issues. [ ] Meets Strategic goals (tied to the ERCOT Strategic Plan or directed by the ERCOT Board). [X] Market efficiencies or enhancements [ ] Administrative [ ] Regulatory requirements [ ] Other: (explain) *(please select all that apply)*	

Board Report

Business Case	The weather sensitivity classifications Non-Weather Sensitive (NWS) or WS are only used during IDR estimation if ERCOT has not received interval data for the operating day. The classification of Electric Service Identifiers (ESI IDs) with IDRs into a WS group and a NWS group determines the proxy day method used for estimation purposes. Since the inception of the BUSLRG and BUSLRGDG profile type codes, which allow for daily submission of interval data, there has been a significant drop in the number of IDR Meters. By the end of this year, CenterPoint plans to begin their conversion of IDR Meters to BUSLRG/BUSLRGDG profile type codes which will lead to another significant drop. The Profiling Working Group (PWG) and other retail Market Participants have discussed the development of this NPRR which reflects the conclusion that the process of evaluating IDR Meters to determine if they are WS is no longer necessary. Discontinuation of this process will allow the Transmission and/or Distribution Service Providers (TDSPs) to focus their efforts on more important matters.
RMS Decision	On 3/7/23, RMS voted unanimously to table LPGRR070 and refer the issue to the Profiling Working Group (PWG). All Market Segments participated in the vote. On 4/4/23, RMS voted unanimously to recommend approval of LPGRR070 as amended by the 3/28/23 ERCOT comments. The Independent Power Marketer (IPM) Market Segment did not participate in the vote. On 6/6/23, RMS voted unanimously to endorse and forward to TAC the 4/4/23 RMS Report and the 4/11/23 Revised Impact Analysis for LPGRR070. All Market Segments participated in the vote.
Summary of RMS Discussion	On 3/7/23, participants reviewed LPGRR070. Stakeholders indicated that there have been discussions regarding the need to create additional profiles, and it was agreed to refer the issue to PWG to continue those discussions. On 4/4/23, participants reviewed the 3/28/23 ERCOT comments. On 6/6/23, participants reviewed the 4/11/23 Revised Impact Analysis.
TAC Decision	On 6/27/23, TAC voted unanimously to recommend approval of LPGRR070 as recommended by RMS in the 6/6/23 RMS Report. All Market Segments participated in the vote.
Summary of TAC Discussion	On 6/27/23, TAC reviewed the ERCOT Opinion, ERCOT Market Impact Statement, and Independent Market Monitor (IMM) Opinion for LPGRR070.

Board Report

ERCOT Board Decision	On 8/31/23, the ERCOT Board voted unanimously to recommend approval of LPGRR070 as recommended by TAC in the 6/27/23 TAC Report.

Opinions	
Credit Review	Not applicable
Independent Market Monitor Opinion	IMM has no opinion on LPGRR070.
ERCOT Opinion	ERCOT supports the approval of LPGRR070.
ERCOT Market Impact Statement	ERCOT Staff has reviewed LPGRR070 and believes the market impact for LPGRR070 appropriately discontinues the process of evaluating IDR Meters to determine if they are Weather Sensitive, a process that has become unnecessary with the increased use of BUSLRG/BUSLRGDG profile type codes.

Sponsor	
Name	Randy Roberts
E-mail Address	Randy.Roberts@ercot.com
Company	ERCOT
Phone Number	512-248-3943
Cell Number	
Market Segment	Not Applicable

Market Rules Staff Contact	
Name	Erin Wasik-Gutierrez
E-Mail Address	erin.wasik-gutierrez@ercot.com
Phone Number	413-886-2474

Comments Received	
Comment Author	**Comment Summary**
ERCOT 032823	Specified that ERCOT shall use the NWS proxy day method for BUSLRG and BUSLRGDG profile types even though their classification is set to WS

Market Rules Notes

None

Proposed Guide Language Revision

11.3.8 Comparison of Weather Sensitivity Code to Meter Data Type Code

(1) ERCOT shall verify that all ESI IDs with a Meter Data Type of Non-Interval Data Recorder (NIDR) are assigned a ~~W~~weather ~~S~~sensitivity code of Non-Weather Sensitiv~~ity~~e (NWS).~~ ERCOT shall also verify that only ESI IDs having a Meter Data Type of IDR which were identified by ERCOT during the most recent weather sensitivity analysis as being weather sensitive are assigned a weather sensitivity code of WS. Any discrepancies shall be reported to the TDSP. The annual procedures for reviewing of the weather sensitivity code are located in Protocol Section 11.4.3.1, Weather Responsiveness Determination.~~

14.2.1 Disputes Involving ERCOT

(1) Disputes involving ERCOT should be submitted using the MarkeTrak system for any of the following cases:

(a) Requests to remove an ESI ID from a default Load Profile ID - such requests should only be made after adequate monthly data becomes available; and

(b) Disputes regarding ERCOT calculations made as a part of Annual Validation.~~; and~~

~~(c) Disputes regarding ERCOT calculations relating to the weather sensitivity code.~~

(2) ERCOT is responsible for all disputes defined in this Section, all Profile Decision Tree versions, and all Annual Validation years.

19.2 ACRONYMS

The defined terms in this Section are limited to those used specifically in the Load Profiling Guide (LPG). Any additional defined terms used in the LPG can be found in Protocol Section 2, Definitions and Acronyms.

DR	Demand Response
HIWR	High Winter Ratio
LOWR	Low Winter Ratio
LPG	Load Profiling Guide
LPGRR	Load Profiling Guide Revision Request
MAD	Mean Absolute Deviation
MAPE	Mean Absolute Percent Error
NIDR	Non-Interval Data Recorder

NOAA	National Oceanic and Atmospheric Administration
NODEM	Non-Demand
NOTOU	Non-Time Of Use
~~**NWS**~~	~~Non-Weather Sensitive~~
RMSE	Root Mean Square Error
~~**WS**~~	~~Weather Sensitive~~

Appendix D, Profile Decision Tree – "Start – 2014 v1.8" worksheet

Getting Started

This sheet serves as an overview of the process to assign a Profile ID to an ESI ID. Profile ID assignments are to be based on the historical data of the ESI ID, without regard to the specific customer(s) of the premises. Regarding Annual Validation Load Profile ID assignments, ERCOT is responsible for the determination of the Profile Segment as directed by this Profile Decision Tree. TDSPs are responsible for verifying that ERCOT's Profile Segment determination is consistent with the tariff under which the ESI ID is currently served, and for submitting the necessary Profile ID change transactions reflecting the ERCOT determined Load Profile Segment.

Additionally, TDSPs must assign a valid code for each of the five Profile ID components. These components are: Profile Type, Weather Zone, Meter Data Type, Weather Sensitivity and Time-Of-Use Schedule. Please note that the Profile Type is comprised of the Profile Group and the Profile Segment.

For new ESI IDs TDSPs are responsible for assigning a complete Profile ID, using default components as directed by this Profile Decision Tree. Reference the various tabs within this workbook to complete the assignments.

Non-Opt In Entities should proceed directly to the NOIEs tab.

Profile ID assignments must adhere to the Protocols--even if all details are not listed within this document.

Example of a completed Profile ID: RESLOWR_EAST_NIDR_NWS_NOTOU

1. Determine the Profile Type Code

A. Select the Profile Group

Select the appropriate Profile Group from the following: NM (for Non-Metered), RES (for Residential), or BUS (for Business).

B. Select the Profile Segment

Valid Profile Segments are dependent upon the Profile Group and other factors. Please see the Segment Assignment tab.

Valid Segments for NM are: LIGHT and FLAT.

Valid Segments for RES are: LOWR, HIWR, LOPV, HIPV, LOWD, HIWD, LODG, and HIDG.

Valid Segments for BUS are: NODEM, LOLF, MEDLF, HILF, IDRRQ, OGFLT, NODPV, LOPV, MEDPV, HIPV, OGFPV, NODWD, LOWD, MEDWD, HIWD, OGFWD, NODDG, LODG, MEDDG, HIDG, and OGFDG, LRG, and LRGDG.

C. Concatenate the Profile Group and Profile Segment to form the Profile Type Code

Convert the Profile Group and Profile Segment to one field, e.g., BUSLOLF.

2. Select the Weather Zone Code

A. Locate the ESI ID's service address ZIP Code on the ZipToZone tab.

B. Cross reference the ZIP Code to the Weather Zone.

C. Assign the valid Weather Zone Code: COAST, EAST, FWEST, NORTH, NCENT, SOUTH, SCENT, or WEST.

3. Select the Meter Data Type Code

A. Assign IDR for ESI IDs that have an IDR used for Settlement.

B. Assign NIDR to all other ESI IDs.

4. Select the Weather Sensitivity Code

Assign the Weather Sensitivity Code as follows~~: unless notified by ERCOT to assign a different Weather Sensitivity Code~~~~, per Protocol Section 11, Data Acquisition and Aggregation.~~

A. The default assignment for customer choice areas will be as follows:

(a) Non-Weather Sensitive (NWS) shall be used for ESI IDs with a meter type code of NIDR;

(b) NWS shall be used for ESI IDs with a profile type code~~s~~ of BUSIDRRQ~~, BUSLRG, and BUSLRGDG~~; and

(c) Weather Sensitive (WS) shall be used for IDR ESI IDs with profile type codes other than BUSIDRRQ~~, BUSLRG, and BUSLRGDG~~.

B. The default assignment for NOIE areas shall be WS.

~~**A.** Assign NWS for ESI IDs with a meter data type code of NIDR.~~

~~**B.** Assign NWS for ESI IDs that have a profile type code of BUSIDRRQ.~~

~~**C.** Assign WS to all other ESI IDs.~~

5. Select the Time-Of-Use Schedule Code

A. Assign NOTOU for ESI IDs not served under a Time-Of-Use schedule (for kWh), or if Profile Type is BUSIDRRQ.

B. For ESI IDs served under a TOU schedule (for kWh), assign the appropriate Time-Of-Use Schedule Code from the TOU Schedules tab.

6. Concatenate the five appropriate components (separated by underscores) to produce a Profile ID

Example of a completed Profile ID: BUSHILF_FWEST_NIDR_NWS_NOTOU

Appendix D, Profile Decision Tree – "FAQ" worksheet

Frequently Asked Questions

1. **Q.** In calculating Usage Month values, should a zero (0) be treated the same as a missing or null value?

   A. No. For any variable such as kWh, kW, or kVA, a zero (0) is a number and should be treated as such. A missing value should not be treated as a zero.

2. **Q.** If an ESI ID has an Advanced Meter, should the Meter Data Type 'IDR' be assigned?

   A. Yes--if the ESI ID is to be settled on its interval data.

3. **Q.** What if an ESI ID's service address is in a ZIP Code that is not in the ZipToZone tab?

   A. Verify that the ZIP Code is currently recognized by the U.S. Postal Service (http://www.usps.com) and that the ZIP Code corresponds to the city of the service address. If the ZIP Code is recognized by the U.S Postal Service and it is for a service address within ERCOT, ask your ERCOT Account Manager to have the ZIP Code added to the Profile Decision Tree.

4. **Q.** If an ESI ID has less than 16 days of data for a specific month, should I go ahead and calculate the Load Factor for a BUS ESI ID?

   A. After applying the Usage Month methodology, you either will or will not have a value for each usage month (see the Usage Month Methodology tab). For BUS ESI IDs Usage Month values are needed for all twelve months of the applicable Assignment Year. ESI IDs that do not have the required usage month values shall be assigned the corresponding default Profile Segment.

5. **Q.** How should I treat negative meter read values in the Usage Month calculations?

A. Treat negative kWh or demand values as null or missing. The values used in the Usage Month calculations should be the ones that were submitted to ERCOT as meter reads--none of which should be negative kWh or demand values.

6. **Q.** During the Profile ID assignment process, the Segment Assignment of this document states that if a BUS ESI ID has a computed AvgLF (Average Load Factor) of less than 40%, then BUSLOLF should be assigned. Given this, why are the load factors of the daily BUSLOLF load profiles virtually always greater than 40%?

A. The biggest reasons are the length of time over which the load factors are calculated and the diversity of the load reflected by the profile. For a given ESI ID (or group of ESI IDs), its daily Load Factor will almost always be greater than its monthly load factor. Also, the BUSLOLF load profiles represent a group of ESI IDs and because of the diversity of the individuals' loads (e.g., varying usage patterns), the load factor will be higher than it is for most or all of the individual ESI IDs to which the load profile is applied.

~~7.~~ ~~**Q.**~~ ~~For a premise that has a Profile Type code of 'BUSIDRRQ', when should a TDSP change the Weather Sensitivity code to 'WS' ?~~

~~**A.**~~ ~~When specified on the report resulting from the annual weather responsiveness determination, per Protocol Section 11, Data Acquisition and Aggregation.~~

~~8~~7. **Q.** What was the number of valid Profile IDs in the previous version of the Profile Decision Tree, and how does that number change in this version?

A. The version of the Profile Decision Tree immediately prior to this one had 1656 valid Profile IDs. This version contains no changes to the list of valid Profile IDs.

Appendix D, Profile Decision Tree – "Use of Components" worksheet

ERCOT Use of the Profile ID Components

Board Report

This tab is intended to provide Market Participants with a better understanding of how each Load Profile ID component is used
by ERCOT in the settlement process.

Profile Type example: RESLOWR

The Profile Group and Segment (which together comprise the Profile Type), in addition to the Weather Zone are used to determine which profile the monthly energy will be applied to in the settlement process. During Profile ID validation, the Profile Group is compared to the Registration database to verify whether the premise has been reported to be Residential or Non-Residential (either small or large, per §25.43).

Weather Zone example: NORTH

The weather data for each Weather Zone are used in generating profiles for each Profile Type, specific to the Weather Zone. During validation of the Weather Zone component, the service address ZIP Code that was submitted to ERCOT for each ESI ID is compared to the ZipToZone table in this Profile Decision Tree to verify that the correct Weather Zone was assigned.

Meter Data Type example: NIDR

Meter Data Type is used to determine whether the ESI ID is settled using interval data or a Load Profile. ESI IDs that have 'IDR' as the Meter Data Type will normally be settled on their interval data, and not a load profile. The exception to this is when no (ESI ID-specific) applicable data are available for a proxy-day routine to be used for settlement. In this case, the default profile shall be applied. ESI IDs that have 'NIDR' as the Meter Data Type will be settled with their cumulative usage applied to the assigned profile. The Meter Data Type is also referenced to determine what type of meter information is expected (cumulative or interval), each time meter data are submitted to ERCOT. If the meter data are not the correct type, a rejection notice will be sent.

Weather Sensitivity example: NWS

This component is utilized only if the Meter Data Type is 'IDR' and the ESI ID's interval data have not been received by ERCOT for a specific settlement period. In this case, the ~~W~~weather ~~S~~sensitivity component of the Profile ID dictates whether a ~~w~~Weather ~~s~~Sensitive (WS) or ~~n~~Non-~~w~~Weather ~~s~~Sensitive (NWS) proxy day routine will be used to estimate the interval data. ~~For ESI IDs that have the BUSIDDRQ Profile Type assignment, ERCOT will determine which ones are weather sensitive (per Protocols Section 11) and will contact the TDSPs to have them implement the appropriate changes.~~

Time-Of-Use Schedule example: NOTOU	The Time-Of-Use Schedule (TOU) is used to determine how cumulative metered usage will be applied to Load Profiles for NIDRs. (A TOU Schedule other than 'NOTOU' for ESI IDs with a Meter Data Type of 'IDR' is used for the TDSP to pass TOU data to the REP, and will not be used in settlement.) The cumulative metered usage of NIDR ESI IDs that have a TOU Schedule of 'NOTOU' will be applied to the entire profile. NIDR ESI IDs that have a TOU Schedule other than 'NOTOU' will have the usage for each TOU period applied to the corresponding intervals of the Load Profile. Each time meter usage is submitted to ERCOT, the number of usage readings will be verified against the respective TOU Schedule. If the usage data do not match the expected time periods from the TOU schedule, a rejection notice will be sent.

Appendix D, Profile Decision Tree – "Definitions" worksheet

Definitions Used in Profile ID Assignments

Term	Description/Definition	Additional info @
$ActiveDays_m$	Denotes the number of days in a particular Usage Month in which the ESI ID received service (please see ESI ID Status for further clarification).	ESI ID Status definition
$ADUse_m$	Denotes the Average Daily Usage (in kWh) for a specific Usage Month. This is derived by dividing the Total kWh (kWh_m) in the Usage Month by the Number of Active Days ($ActiveDays_m$) in the same Usage Month, and rounding to two decimal places per the Rounding instructions on this tab.	Usage Month Methodology tab
$ADUse_p$	Denotes the Average Daily Usage (in kWh) for a specific Meter Read Period. This is derived by dividing the Metered Usage (in kWh) for the Meter Read Period by the Number of Days in the Meter Read Period, and rounding to two decimal places per the Rounding instructions on this tab.	Usage Month Methodology tab
$AHUse_m$	Denotes the Average Hourly Usage (in kWh) for Usage Month m.	Segment Assignment tab

Assignment Year	Assignment Year refers to a specific set of 12 Usage Months used to determine Business Profile ID assignments. An Assignment Year normally runs from May through the following April. However, to determine Profile ID assignments it may be necessary to obtain data from outside the May through April period. For example, to calculate complete Usage Months for May 2005 and April 2006, meter read data from April 2005 and May 2006 will most likely be required.	
AvgLF	The Average Load Factor is defined as a weighted average of the individual monthly load factors, where demand levels are used to define the weights.	Segment Assignment tab
Business (BUS)	Profile Group designation for non-residential ESI IDs whose service is metered. This encompasses rate classes for business ESI IDs, in addition to other classes.	
Daily Demand	Daily Demand is based on Max Metered Demand (in kW) and represents the kW applied to each day in that period.	
Daily Usage	Daily Usage is based on $ADUse_p$ and represents the kWh used for each day of that period.	
$Days_p$	The Meter Read Stop Date minus the Meter Read Start Date for a specific meter read.	
ESI ID Status	**Active** -- ESI ID is presently receiving service (energized) and a REP is currently assigned to it in ERCOT's system.	
	De-Energized -- ESI ID does not have a REP assigned in ERCOT's system, but has not been retired. An 814_16 Move-In is necessary to change to Active status.	
	Inactive -- ESI ID is retired and is to never again receive service.	
ESI ID Year Use	Denotes the sum of the kWh_p for each year value of an ESI ID.	Segment Assignment tab
FLAT	Profile Segment designation for any Non-Metered load that is not identified as lighting.	
HIDG	Denotes a High Winter Ratio or High Load Factor Profile Segment for premises with Distributed Generation other than PV or wind.	DG tab
HILF	Denotes a High Load Factor Profile Segment designation where AvgLF > 0.60.	Segment Assignment tab
HIPV	Denotes a High Winter Ratio or High Load Factor Profile Segment for Premises with photovoltaic-generation, applicable to ESI IDs that meet the criteria on the DG tab.	Segment Assignment tab

HIWD	Denotes a High Winter Ratio or High Load Factor Profile Segment for Premises with -wind generation, applicable to ESI IDs that meet the criteria on the DG tab.	Segment Assignment tab
HIWR	Denotes a High Winter Ratio Profile Segment designation as derived per the Segment Assignment tab.	Segment Assignment tab
IDR	Interval Data Recorder -- A device that is capable of recording electrical usage in each settlement interval.	Protocol Sections 9 & 10
IDRRQ	Denotes Premises billed on a 4-CP tariff where the TDSP cannot support a 4-CP billing rate with an AMS profile (aka IDR Metered Premise).	Segment Assignment tab
$kWDays_m$	Denotes the number of days in a particular Usage Month for which there are Daily Demand values.	
kWh_m	Denotes the total energy consumed (in kilowatthours) in Usage Month m. This is calculated by summing the values for Daily Usage over the entire Usage Month.	
kWh_p	Denotes the total energy consumed (in kilowatthours) in Meter Read Period. This is calculated by summing the values for Daily Usage over the entire Meter Read Period.	Segment Assignment tab
LIGHT	Profile Segment designation for all Non-Metered lighting load.	
Load Profile Group	A high-level classification of a set of customers who have similar characteristics. The Load Profile Groups are: Non-Metered, Residential, and Business. Together, the Load Profile Group and the Load Profile Segment form the Load Profile Type.	
Load Profile ID	The load profile designation string that contains: 1) the Load Profile Type Code; 2) the Weather Zone Code; 3) the Meter Data Type Code; 4) the Weather Sensitivity Code; and 5) the Time-Of-Use Schedule Code. An example of a Profile ID: RESLOWR_FWEST_NID	Start tab
Load Profile Segment	A sub-classification of a Load Profile Group. High Winter Ratio (HIWR) is an example of a Load Profile Segment. Together, the Load Profile Group and the Load Profile Segment form the Load Profile Type.	
Load Profile Type	From Protocols, Section 2: "A classification of a group of Customers having similar energy usage patterns and that are assigned the same Load Profile." Load Profile Type is also the concatenation of the Load Profile Group and Load Profile Segment.	

LODG	Denotes a Low Winter Ratio or Low Load Factor Profile Segment for premises with Distributed Generation other than PV or wind.	DG tab
LOLF	Denotes a Low Load Factor Profile Segment designation where AvgLF < 0.40.	Segment Assignment tab
LOPV	Denotes a Low Winter Ratio or Low Load Factor Profile Segment for Premises with photovoltaic generation, applicable to ESI IDs that meet the criteria on the DG tab.	Segment Assignment tab
LOWD	Denotes a Low Winter Ratio or Low Load Factor Profile Segment for Premises with Distributed Generation other than PV, applicable to ESI IDs that meet the criteria on the DG tab.	Segment Assignment tab
LOWR	Denotes a Low Winter Ratio Profile Segment designation as derived per the Segment Assignment tab. (This is sometimes assigned as the default if data not available.)	Segment Assignment tab
LRG	Denotes Premises billed on a 4-CP tariff where the TDSP can support a 4-CP billing rate with an AMS profile and does not have Distributed Generation.	Segment Assignment tab
LRGDG	Denotes Premises billed on a 4-CP tariff where the TDSP can support a 4-CP billing rate with an AMS profile and has Distributed Generation.	Segment Assignment tab
Max Metered Demand	The highest measured demand (kW) during a Usage Period. Please see the kVA to kW tab if demand is measured in kVA.	
$MaxkW_m$	Denotes the straight average of the demand values assigned to the days in the Usage Month. The values used for Daily Demand should be the maximum demand (kW) that occurred during that Usage Period.	
MEDDG	Denotes a Medium Load Factor Profile Segment for premises with Distributed Generation other than PV or wind.	DG tab
MEDLF	Denotes a Medium Load Factor Profile Segment designation where 0.40 ≤ AvgLF ≤ 0.60. (This is sometimes assigned as the default if data not available or if the denominator equals zero.)	Profile Segments tab
MEDPV	Denotes a Medium Load Factor Profile Segment for Premises with photovoltaic generation, applicable to ESI IDs that meet the criteria on the DG tab.	Segment Assignment tab

MEDWD	Denotes a Medium Load Factor Profile Segment for Premises with wind generation, applicable to ESI IDs that meet the criteria on the DG tab.	Segment Assignment tab
Meter Read Start Date	The Meter Read Start Date for a Usage Period corresponds with the date the meter was actually read. For any given Usage Period the Meter Read Start Date is the prior meter read date, regardless of the time the meter was read. If no prior meter read date exists, the date the account was energized or activated shall be considered the Meter Read Start Date.	
Meter Read Stop Date	The Meter Read Stop Date for a Usage Period corresponds with the date the meter was actually read. For any given Usage Period the Meter Read Stop Date is the date of the meter read that ends that period, regardless of what time the meter is read.	
Metered Usage	In the context of Usage Month, Metered Usage is the total electricity consumption (in kWh) measured during a Usage Period. This includes estimated usage if the values were submitted to ERCOT and actual measured usage for the same period was never submitted to ERCOT.	
$NADUse_p$	Denotes the normalized Average Daily Usage (in kWh) for a specific Meter Read Period. This is derived by subtracting the mean Average Daily Usage over the Usage Period from the Average Daily Usage for a specific Meter Read Period and dividing by the standard deviation of the Average Daily Usage for the Usage Period, and rounding to two decimal places per the Rounding instructions on this tab.	Segment Assignment tab
NIDR	An electricity meter that is not an Interval Data Recorder. NIDR designation shall include IDRs installed for Load Research purposes and Time-Of-Use meters.	Segment Assignment tab
NODDG	Denotes a Non-Demand Profile Segment for premises with Distributed Generation other than PV or wind, applicable to ESI IDs that meet the criteria on the DG tab.	DG tab
NODEM	NODEM stands for Non-Demand. The TDSP may assign the NODEM Profile Segment for non-residential ESI IDs which are not billed demand.	-
NODPV	Denotes a Non-Demand Profile Segment for Premises with photovoltaic generation, applicable to ESI IDs that meet the criteria on the DG tab.	Segment Assignment tab
NODWD	Denotes a Non-Demand Profile Segment for Premises with wind generation, applicable to ESI IDs that meet the criteria on the DG tab.	Segment Assignment tab

Non-Metered (NM)	Profile Group designation for ESI IDs served within a rate class specifically for non-metered loads, e.g., Street Lights and Traffic Signals. Assignment of NM is not valid for any load that is metered.	
Number of Days in the Meter Read Period	The Number of Days in the Meter Read Period is defined as the Meter Read Stop Date minus the Meter Read Start Date. For example, if a meter was read on August 1st and again on August 31st, the Number of Days in the Meter Read Period is 30. In another example, if a meter was read on June 12th and the next read occurred on July 13th, the Number of Days in the Meter Read Period is 31.	
NWS	Non-Weather Sensitive designation of the ~~W~~weather ~~S~~sensitivity ~~C~~code.	-
OGFDG	Denotes an Oil and Gas Flat Profile Segment for Premises with Distributed Generation other than PV or wind, applicable to ESI IDs that meet the criteria on the DG tab and the Oil & Gas tab.	DG tab
OGFLT	Denotes a Profile Segment of Oil and Gas Flat, applicable to ESI IDs that meet the criteria on the Oil & Gas tab.	Oil & Gas tab
OGFPV	Denotes a Profile Segment with photovoltaic generation, applicable to ESI IDs that meet the criteria on the DG tab	Segment Assignment tab
OGFWD	Denotes a Profile Segment for Premises with wind generation, applicable to ESI IDs that meet the criteria on the DG tab	Segment Assignment tab
RESHIWR kWh_p	Denotes the sum of the kWh interval values for the RESHIWR backcasted profiles of a specific weather zone for the specific days in the Meter Reading Period p.	Segment Assignment tab
RESHIWR Year Use	Denotes the sum of the RESHIWR kWh_p for a specific weather zone for each year value of an ESI ID.	Segment Assignment tab
Residential (RES)	Profile Group designation for ESI IDs served within a residential rate class.	
RESLOWR kWh_p	Denotes the sum of the kWh interval values for the RESLOWR backcasted profiles for a specific weather zone for the specific days in the Meter Reading Period p.	Segment Assignment tab

RESLOWR Year Use	Denotes the sum of the RESLOWR kWh_p for a specific weather zone for each year value of an ESI ID.	Segment Assignment tab
Rounding	The following applies to all numbers that are to be rounded to two decimal places. If the digit in the thousandth's place of a number is four or less, all digits to the right of the hundredth's place are dropped and the digit in the hundredth's place does not change. For example, rounding 1.574 to the nearest hundredth's place would yield 1.57. If the digit in the thousandth's place is five through nine, all digits to the right of the hundredth's place are dropped and the remaining number is increased by 0.01. The number 1.235 rounded to the hundredth's place is 1.24. Some more examples: original number / rounded number / original number / rounded number 1.77743 / 1.78 / 1.320 / 1.32 1.024 / 1.02 / 1.1557 / 1.16 1.232 / 1.23 / 1.999 / 2.00 1.57482 / 1.57 / 1.6449 / 1.64 1.379 / 1.38 / 1.2583 / 1.26	
S RESHIWR kWh_p	Scaled RESHIWR kWh_P calculated by multiplying RESHIWR kWh_P by the ESI ID Year Use and dividing by the RESHIWR Year Use.	Segment Assignment tab
S RESLOWR kWh_p	Scaled RESLOWR kWh_P calculated by multiplying RESLOWR kWh_P by the ESI ID Year Use and dividing by the RESLOWR Year Use.	Segment Assignment tab
Season	Refers to the classification of Shoulder or Winter for each meter reading within the Usage Time Period of each ESI ID.	
Shoulder	Refers to a meter read which falls between September 21 and November 15 inclusive or between March 15 and May 10 inclusive.	
Usage Month	Each Usage Month corresponds with a calendar month and is a combination of one or more Usage Periods for the purpose of applying usage and demand values in a consistent manner.	

Usage Period	The time period that data from a meter read encompasses. The Usage Period covers the Usage Period Start Time through the Usage Period Stop Time.	
Usage Period Start Time	A Usage Period begins at 00:00:00 (midnight) of the Meter Read Start Date. This convention helps to facilitate a smooth transfer of ESI ID 'ownership' between CRs, should a transfer occur (a transfer of ownership takes effect at 00:00:00).	
Usage Period Stop Time	A Usage Period ends at 23:59:59 on the **DAY BEFORE** the Meter Read Stop Date.	
Usage Time Period	Refers to a specific set of Meter Read Periods used to determine Residential Profile ID assignments.	
WS	Weather Sensitive designation of the ~~W~~weather ~~S~~sensitivity ~~C~~code.~~ (calculated by ERCOT)~~	Protocol Section 11.4.3.1
Winter	Refers to a meter read which falls between November 16 and March 14 inclusive.	
Winter Max $ADUse_p$	For the ESI ID's entire Usage Time Period, identify the highest $ADUse_p$ of all meter readings classified as a Winter season.	

Revised ERCOT Impact Analysis Report

LPGRR Number	070	LPGRR Title	Discontinuation of Interval Data Recorder (IDR) Meter Weather Sensitivity Process
Impact Analysis Date	April 11, 2023		
Estimated Cost/Budgetary Impact	Less than $10k, which will be absorbed by the Operations & Maintenance (O&M) budgets of affected department.		
Estimated Time Requirements	No project required. This Load Profiling Guide Revision Request (LPGRR) can take effect within 2-3 months after Public Utility Commission of Texas (PUCT) approval.		
ERCOT Staffing Impacts (across all areas)	Implementation Labor: 100% ERCOT; 0% Vendor Ongoing Requirements: No impacts to ERCOT staffing.		
ERCOT Computer System Impacts	The following ERCOT systems would be impacted: • Settlements & Billing Systems 80% • ERCOT Website and MIS Systems 10% • Channel Management Systems 10%		
ERCOT Business Function Impacts	No impacts to ERCOT business functions.		
Grid Operations & Practices Impacts	No impacts to ERCOT grid operations and practices.		

Evaluation of Interim Solutions or Alternatives for a More Efficient Implementation
None offered.

Comments
None.

Board Report

NOGRR Number	**215**	**NOGRR Title**	**Limit Use of Remedial Action Schemes**
Date of Decision	August 31, 2023		
Action	Recommended Approval		
Timeline	Normal		
Proposed Effective Date	Upon system implementation – Greyboxed paragraph (3) of Section 11.1 and paragraph (1) of Section 11.2 November 1, 2023 – All remaining language		
Priority and Rank Assigned	Priority – 2026; Rank – 4700		
Nodal Operating Guide Sections Requiring Revision	8, Attachment K, Remedial Action Scheme (RAS) Template 11.1, Introduction 11.2, Remedial Action Schemes 11.2.1, Reporting of RAS Operations		
Related Documents Requiring Revision/Related Revision Requests	None		
Revision Description	This Nodal Operating Guide Revision Request (NOGRR) will allow new Remedial Action Schemes (RASs) to be used only to address an actual or anticipated violation of transmission security criteria when market tools are insufficient to address those violations. This NOGRR also clarifies the procedures for retiring RASs.		
Reason for Revision	[X] Addresses current operational issues. [ ] Meets Strategic goals (tied to the ERCOT Strategic Plan or directed by the ERCOT Board). [ ] Market efficiencies or enhancements [ ] Administrative [ ] Regulatory requirements [ ] Other: (explain) *(please select all that apply)*		
Business Case	ERCOT has noted an increase in the number of RASs that are being proposed for new Generation Resources that are being planned in areas where the Resources would need to be curtailed on a near constant basis to maintain the reliability of the transmission grid in		

	the immediate area. It is expected that the number of such RAS proposals will continue to significantly increase, based on the locations and unit sizes being considered in the interconnection process. ERCOT is concerned that such a large increase in the number of RASs could significantly and negatively impact the reliability of the ERCOT System. ERCOT notes the following ways in which RASs increase reliability risks: 1. It is difficult or impossible to assess all possible impacts of RASs on the ERCOT System during the RAS approval process. As a result, an increased burden and risk is imposed in Real-Time or near Real-Time operations to catch issues and evaluate the impacts of those issues. 2. Because all combinations of Outage and system dispatch conditions cannot feasibly be studied during the RAS approval process, the approval studies may not recognize that a particular RAS may need to be disabled during certain Outage conditions. As issues of this type are identified due to subsequent Outage coordination or operational studies, ERCOT keeps a list of these issues and manually checks for them during subsequent Outage evaluations. As the number of RASs increases, this manual process to identify when RASs need to be disabled will become infeasible, and the risk that ERCOT may overlook the need to disable one or more RASs also increases. 3. In addition, the need to recognize issues with and disable RASs introduces even more risk during Forced Outages because the need to disable the RAS may not immediately be recognized. This risk goes up as the number of RASs increases. 4. RASs are modeled in the Energy Management System (EMS) in such a way that they are expected to fully alleviate the conditions for which they have been implemented all the time, but ERCOT's experience has shown this not to be the case. For example, certain dispatch patterns or other operating conditions not considered during the RAS approval process could be sufficiently severe to cause cascading Outages before the RAS has time to operate. 5. Similarly, RASs are modeled in the Market Management System (MMS) in such a way that they are expected to fully alleviate all overloads for a given condition that triggers the RAS all the time. There could be a reliability concern unrelated to, or unprotected by, a RAS for a given

	contingency where generation may need to be committed to manage that reliability concern, and the MMS tools will never reflect that need. 6. The risk of RAS misoperation can be a significant reliability issue. In some areas of the network, the implementation of one or more RAS in a particular area could result in a situation where the post-contingency, pre-RAS condition would exceed a local or regional stability limit. If the RAS(s) were to fail or misoperate, the region could experience instability that could lead to cascading Outages or voltage collapse. 7. If the number of RASs increase, especially if there are multiple RASs in a particular area, there is a heightened possibility of RAS-RAS interaction or cascading RAS operation resulting in unforeseen reliability consequences. 8. As the number of RASs in the ERCOT System increase, so does the amount of maintenance needed in ERCOT systems and situational awareness tools related to RASs. 9. The design of a RAS can lead to a condition where a constraint that is easily resolved by ERCOT market tools (e.g., Security-Constrained Economic Dispatch (SCED)) is replaced with post-RAS congestion that does not have a market solution. 10. North American Electric Reliability Corporation (NERC) Reliability Standards associated with the implementation and maintenance of RAS facilities place compliance burdens upon both the RAS owners as well as ERCOT. Given these significant reliability risks, ERCOT believes that a RAS should only be used when it is necessary to address an actual or anticipated violation of transmission security criteria that cannot be resolved by ERCOT market tools.
ROS Decision	On 7/9/20, ROS voted unanimously to table NOGRR215. All Market Segments participated in the vote. On 3/2/23, ROS voted to recommend approval of NOGRR215 as amended by the 3/1/23 LCRA comments as revised by ROS. There were two opposing votes from the Consumer (OPUC) and Cooperative (STEC) Market Segments, and seven abstentions from the Consumer (2) (Air Liquide, Sierra Club), Independent Generator (Calpine), Independent Power Marketer (IPM) (SENA), and Investor Owned Utility (IOU) (3) (Oncor, CNP, TNMP) Market Segments. All Market Segments participated in the vote.

Board Report

	On 4/6/23, ROS voted to table NOGRR215. There was one abstention from the IPM (SENA) Market Segment. All Market Segments participated in the vote. On 7/6/23, ROS voted unanimously to table NOGRR215. All Market Segments participated in the vote. On 8/3/23, ROS voted unanimously to endorse and forward to TAC the 7/6/23 ROS Report as amended by the 7/31/23 ERCOT comments and 7/10/23 Revised Impact Analysis for NOGRR215 with a recommended priority of 2026 and rank of 4700. All Market Segments participated in the vote.
Summary of ROS Discussion	On 7/9/20, ERCOT Staff provided an overview of NOGRR215 and noted the intent to schedule a workshop for further discussion on related topics. Market Participants briefly discussed the history and potential future impacts of RASs in ERCOT. On 3/2/23, participants discussed the 1/3/23 LCRA, 1/31/23 LCRA, 1/31/23 AEP, 3/1/23 LCRA, 3/1/23 AEP, and 3/1/23 STEC comments. ERCOT Staff emphasized the RAS's diminished usefulness and purpose in correlation with the ERCOT System's evolution, and cited SCED as a more capable, comparable tool. ERCOT Staff also expressed support for the 3/1/23 AEP comments, arguing that the 3/1/23 LCRA comments' preservation of the RAS undermines reliability. LCRA Staff remarked upon the similarities found between AEP's and their 3/1/23 comments. At LCRA's suggestion and with Market Participants' support, Market Rules transferred redlines from the 3/1/23 AEP comments regarding exit strategy and review time period in Section 8, Attachment K, and Section 11.2 as edits on top of LCRA's 3/1/23 comments. ERCOT Staff reaffirmed support for the 3/1/23 AEP comments but not the 3/1/23 LCRA comments. On 4/6/23, participants reviewed the 3/27/23 ERCOT comments. On 7/6/23, ERCOT Staff provided an overview of the 6/27/23 Revised Impact Analysis and confirmed that, if a contingency triggers a RAS, then all overloaded elements will be ignored in the Day-Ahead Market (DAM). ERCOT Staff also proposed prioritization after completion of the Real-Time Co-Optimization (RTC) project and an associated Priority/Rank of 2027/4800. ERCOT Staff assured Market Participants that ERCOT would remain mindful of NOGRR215 requirements during RTC project execution. Participants agreed to table NOGRR215 to provide ERCOT time to determine which edits require greyboxing and which edits can be made effective upon PUCT approval in order to grant ERCOT the availability to approve RAS for dispatchable generation prior to 2027.

Board Report

	On 8/3/23, ERCOT Staff reviewed the 7/31/23 ERCOT comments and 7/10/23 Revised Impact Analysis. Participants also discussed additional priority and rank options.
TAC Decision	On 8/22/23, TAC voted unanimously to recommend approval of NOGRR215 as recommended by ROS in the 8/3/23 ROS Report as revised by TAC; with a recommended effective date of 10/1/23 for all sections except greyboxed paragraph (3) of Section 11.1 and paragraph (1) of Section 11.2 and which will be effective upon system implementation. All Market Segments participated in the vote.
Summary of TAC Discussion	On 8/22/23, TAC reviewed the ERCOT Opinion, ERCOT Market Impact Statement, and Independent Market Monitor (IMM) Opinion for NOGRR215; and a proposed correction to references to Section 4.1.1.7, Minimum Deliverability Criteria, located within Sections 11.1 and 11.2.
ERCOT Board Decision	On 8/31/23, the ERCOT Board voted unanimously to recommend approval of NOGRR215 as recommended by TAC in the 8/22/23 TAC Report; with a recommended effective date of 11/1/23 for all sections except greyboxed paragraph (3) of Section 11.1 and paragraph (1) of Section 11.2 and which will be effective upon system implementation.

Opinions	
Credit Review	Not applicable
Independent Market Monitor Opinion	IMM has no opinion on NOGRR215.
ERCOT Opinion	ERCOT supports approval of NOGRR215.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NOGRR215 and believes that it has a positive market impact by addressing current operational issues by allowing new RASs to be used only to address an actual or anticipated violation of transmission security criteria when market tools are insufficient to address those violations or to allow dispatchable Generation Resources to meet the Planning Guide minimum deliverability criteria.

Submitter's Information	
Name	Freddy Garcia
E-mail Address	Freddy.Garcia@ercot.com

Board Report

Company	ERCOT
Phone Number	512-248-4245
Cell Number	
Market Segment	Not applicable

Market Rules Staff Contact	
Name	Jordan Troublefield
E-Mail Address	Jordan.Troublefield@ercot.com
Phone Number	512-248-6521

Comments Received	
Comment Author	**Comment Summary**
WMS 071420	Requested ROS table NOGRR215 until after a workshop, and requested an opportunity to consider NOGRR215 after the workshop
Joint Commenters 010821	Argued that NOGRR215's changes to ERCOT's binding documents (e.g., Protocols, Planning Guides, Operating Guides, etc.) are currently unwarranted, so that historic levels of reliability and open access are preserved
DME 011121	Supported the 1/8/21 Joint Commenters comments and recommended that NOGRR215 be rejected and expressed a willingness to support a small increase to the ERCOT Admin Fee if increasing the Interconnect Fee is not workable
ERCOT 051822	Urged stakeholders to recommend approval of NOGRR215 as originally submitted, acknowledged that other recent policy changes might allow for congestion relief without the use of RASs, and expressed openness in considering other policy changes in order to limit the impact of congestion without negatively impacting reliability
LCRA 053122	Requested that ERCOT Staff file substantive comments responding to the 1/8/21 Joint Commenters' comments and provide the data that ERCOT Staff indicated they intended to bring to stakeholders over the course of 2021, so that interested parties may fully evaluate NOGRR215 and develop potential alternative approaches
Lancium 060122	Requested that ROS continue to table NOGRR215 while the Large Flexible Load Task Force (LFLTF) discusses interconnections of large loads that may impact RAS/Constraint Management Plan (CMP) policy in unforeseen ways
LCRA and Luminant	Requested that stakeholders continue to allow NOGRR215 to be

083122	tabled while parties continue to develop a workable compromise in procedural modifications
LCRA 010323	Recommends that ERCOT be required to consider a new RAS proposal if it supports dispatchable generation and a viable transmission project that meets an existing ERCOT planning criterion that can be identified as a long-term solution to replace the RAS
LCRA 013123	Submitted revisions to further elaborate on the proposal outlined in its 1/3/23 comments
AEP 013123	Proposed changes to ERCOT's revisions that allows for use of RAS when there is an identified and approved exit strategy to mitigate a reliability problem; reinforces that RAS is only used for reliability purposes; and reduces the review period for existing RAS from five to three years
LCRA 030123	Updated Sections 8, Attachment K, 11.2, and 11.2.1's baseline of their 1/31/23 LCRA comments in order to reflect the October 1, 2020 incorporation of NOGRR183, Remedial Action Scheme (RAS) Submittal and Review Requirements, into the Nodal Operating Guide and requested that stakeholders consider the 3/1/23 LCRA comments in place of their 1/31/23 comments
AEP 030123	Updated Sections 8, Attachment K, 11.2, and 11.2.1's baseline of their 1/31/23 AEP comments in order to reflect the October 1, 2020 incorporation of NOGRR183 into the Nodal Operating Guide and requested that stakeholders consider the 3/1/23 AEP comments in place of their 1/31/23 comments
STEC 030123	Argued that it is premature to remove the RAS until the costs and expected decreases in reliability risks are defined
ERCOT 032723	Proposed an alternative schedule to complete a Revised Impact Analysis for NOGRR215 prior to the May 4, 2023 ROS meeting
ERCOT 042523	Proposed an alternative schedule to complete a Revised Impact Analysis for NOGRR215 prior to the June 8, 2023 ROS meeting
ERCOT 060723	Proposed an alternative schedule to complete a Revised Impact Analysis for NOGRR215 prior to the July 6, 2023 ROS meeting
ERCOT 073123	Addressed the anticipation of years-long resource constraints as multiple high-priority improvement projects that impact ERCOT systems are developed and implemented; and proposed edits that distinguish between which revisions do not require a project and therefore may take effect upon PUCT approval and which project-causing revisions must remain greyboxed until ERCOT's completion

	of the project
PRS 081123	Endorsed the ROS-recommended priority of 2026 and rank of 4700 for NOGRR215

Market Rules Notes

Administrative changes to the language were made and authored as "ERCOT Market Rules."

Please note the baseline language in the following Section has been updated to reflect the incorporation of the following NOGRR(s) into the Nodal Operating Guides:

- NOGRR183, Remedial Action Scheme (RAS) Submittal and Review Requirements (unboxed 10/1/20)
  - Section 8, Attachment K
  - Section 11.2
  - Section 11.2.1

Proposed Guide Language Revision

ERCOT Nodal Operating Guides
Section 8
Attachment K

Remedial Action Scheme (RAS) Template

~~October 1, 2020~~TBD

Board Report

This attachment provides a template to be used by an entity for the proposal, modification, ~~or deactivations~~ and/or retirement of a Remedial Action Scheme (RAS). If an item in this template does not apply to a specific RAS, a response of "Not Applicable" for that item is appropriate. All submittals related to RAS must be emailed to ras_cmp@ercot.com.

I. General

1. Information such as maps, one-line drawings, substation and schematic drawings that identify the physical and electrical location of the RAS and related facilities.
2. Functionality of new RAS or proposed functional modifications to existing RAS and documentation of the pre- and post-modified functionality of the RAS.
3. The corrective action plan if RAS modifications are proposed in a corrective action plan.
4. Data to populate the RAS database:
   a. RAS name;
   b. RAS Entity and contact information;
   c. Expected or actual in-service date, most recent ERCOT approval date, most recent ERCOT evaluation date, and date of retirement;
   d. System performance issue or reason for installing the RAS (e.g., thermal overload, angular instability, poor oscillation damping, voltage instability, under- or over-voltage, or slow voltage recover;
   e. Description of the contingencies or system conditions for which the RAS was designed;
   f. Action(s) to be taken by the RAS;
   g. Identification of Limited Impact RAS; and
   h. Any additional explanation relevant to high-level understanding of RAS.

II. Functional Description and Transmission Planning Information

1. Contingencies and system conditions that the RAS is intended to remedy.
2. The action(s) to be taken by the RAS in response to disturbance conditions.
3. A summary of technical studies, if applicable, demonstrating that the proposed RAS actions satisfy system performance objectives for the scope of system events and conditions that the RAS is intended to remedy. The technical studies summary shall also include information such as the study year(s), system conditions, and contingencies analyzed on which the RAS design is based, and the date those technical studies were performed.
4. Information regarding any future system plans that will impact the RAS.
5. Exit Strategy that has been identified including the approved transmission project or ERCOT's recommendation to mitigate the need for the RAS. For example, reconductor Point A to Point B.

6~~5~~. RAS Entity proposal and justification for Limited Impact RAS designation.

7~~6~~. Documentation describing the system performance resulting from the possible inadvertent operation of the RAS, except for Limited Impact RAS, caused by any single RAS component malfunction. Single component malfunctions in a RAS not determined to be a Limited Impact RAS must satisfy the requirements in paragraph (3)(f) of Section 11.2, Remedial Action Schemes.

8~~7~~. An evaluation indicating that the RAS settings and operation avoid adverse interactions with other RASs, and protection and control systems.

9~~8~~. Identification of other affected non-ERCOT Control Areas.

III. Implementation

1. Documentation describing the applicable equipment used for detection, dc supply, communications, transfer trip, logic processing, control applications, and monitoring.
2. Information on detection logic and settings/parameters that control the operation of the RAS.
3. Documentation showing that any multifunction device used to perform RAS function(s), in addition to other functions such as protective relaying or Supervisory Control and Data Acquisition (SCADA), does not compromise the reliability of the RAS when the device is not in service or is being maintained.
4. For a RAS not designated as a Limited Impact RAS, documentation describing the system performance resulting from a single component failure in the RAS, except for a Limited Impact RAS, when the RAS was intended to operate. A single component failure in a RAS not designated as a Limited Impact RAS must not prevent the bulk electric system from meeting the same performance requirements as those required for the events and conditions for which the RAS is designed. The documentation should describe or illustrate how the design achieves this objective.
5. Documentation describing the functional testing process.

IV. RAS Retirement

1. Information necessary to ensure that ERCOT is able to understand the physical and electrical location of the RAS and related facilities;
2. A summary of applicable technical studies and technical justifications upon which the decision to retire the RAS is based; and
3. The anticipated date of RAS retirement.

11.1 Introduction

(1) Constraint Management Plans (CMPs) are developed in accordance to the guidelines set forth in the sections below, and are defined in Protocol Section 2.1, Definitions. CMPs include, but are not limited to the following:

(a) Remedial Action Plans (RAPs) which are modeled in Network Security Analysis (NSA) where practicable;

(b) Automatic Mitigation Plans (AMPs) which are modeled in NSA where practicable;

(c) Pre-Contingency Action Plans (PCAPs);

(d) Temporary Outage Action Plans (TOAPs); and

(e) Mitigation Plans.

(2) When developing CMPs, ERCOT shall first attempt to utilize the 15-Minute Rating of the impacted Transmission Facilities, where available, to develop RAPs such that the ERCOT Transmission Grid is utilized to the fullest extent.

~~(3) Remedial Action Schemes (RASs) and/or AMPs may also be implemented in order to allow Generation Resources or Transmission Facilities that would otherwise be subject to restrictions to operate to their full Rating.~~ ~~(3)Remedial Action Schemes (RASs) and/or AMPs may also be implemented in order to allow Generation Resources described in paragraph (3) of Planning Guide Section 4.1.1.7, Minimum Delivery Criteria, or Transmission Facilities that would otherwise be subject to restrictions to meet the minimum deliverability criteria in Planning Guide Section 4.1.1.7.~~

[NOGRR215: Insert paragraph (3) below upon system implementation and renumber accordingly:]

(3) Remedial Action Schemes (RASs) and/or AMPs may also be implemented in order to allow Generation Resources described in paragraph (3) of Planning Guide Section 4.1.1.7, Minimum Deliverability Criteria, to meet the minimum deliverability criteria in Planning Guide Section 4.1.1.7, or Transmission Facilities that would otherwise be subject to restrictions to operate without such restrictions.

(~~3~~4~~4~~3) ERCOT shall provide notification to the market of any approved, amended, or removed CMP or ~~Remedial Action Scheme (~~Remedial Action Scheme (RAS)~~)~~. ERCOT shall provide notification to the market of any RAP, AMP, or RAS that cannot be modeled in the Network Operations Model. ERCOT shall post to the Market Information System (MIS) Secure Area all CMPs and RASs and any unmodeled CMPs or RASs.

(~~45~~54) ERCOT shall provide notification to the market of any proposed RASs or PCAPs on the MIS Secure Area.

(~~56~~65) ERCOT is not required to provide notification to the market of any proposed TOAPs.

(~~67~~76) All submittals related to CMPs or RASs must be emailed to ras_cmp@ercot.com.

11.2 Remedial Action Schemes

(1) Remedial Action Schemes (RASs) are designed to detect abnormal predetermined ERCOT System conditions and automatically take corrective actions to maintain a secure system. Any RAS proposed on or after June 24, 2020 may not be approved or implemented unless ERCOT has first determined that the RAS is necessary to avoid an actual or anticipated violation of transmission security criteria, as defined in Operating Guide Section 2.2.2, Security Criteria, that cannot be resolved through ERCOT market tools~~, or unless the RAS would allow a Generation Resource of the type described in paragraph (3) of Planning Guide Section 4.1.1.7, Minimum Delivery Criteria, to operate at its full Rating~~.

[NOGRR215: Replace paragraph (1) above with the following upon system implementation:]
(1) Remedial Action Schemes (RASs) are designed to detect abnormal predetermined ERCOT System conditions and automatically take corrective actions to maintain a secure system. Any RAS proposed on or after June 24, 2020 may not be approved or implemented unless ERCOT has first determined that the RAS is necessary to avoid an actual or anticipated violation of transmission security criteria, as defined in Operating Guide Section 2.2.2, Security Criteria, that cannot be resolved through ERCOT market tools, or unless the RAS would allow a Generation Resource of the type described in paragraph (3) of Planning Guide Section 4.1.1.7, Minimum Deliverability Criteria, to operate at a level that comports with the minimum deliverability criteria in Planning Guide Section 4.1.1.7.

(2) The following do not individually constitute a RAS:

(a) Protection systems installed for the purpose of detecting faults on Transmission Elements and isolating the faulted Transmission Elements;

(b) Schemes for automatic Under-Frequency Load Shedding (UFLS) and automatic Under-Voltage Load Shedding (UVLS) comprised of only distributed relays;

(c) Out-of-step tripping and power swing blocking;

(d) Automatic reclosing schemes;

(e) Schemes applied on a Transmission Element for non-fault condition, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, overvoltage or overload to protect the Transmission Element against damage by removing it from service;

(f) Controllers that switch or regulate one or more of the following: series or shunt reactive devices, flexible alternating current transmission system (FACTS) devices, phase-shifting transformers, variable-frequency transformers, or tap-changing transformers; and that are located at and monitor quantities solely at the same station as the Transmission Element being switched or regulated;

(g) FACTS controllers that remotely switch static shunt reactive devices located at other stations to regulate the output of a single FACTS device;

(h) Schemes or controllers that remotely switch shunt reactors and shunt capacitors for voltage regulation that would otherwise be manually switched;

(i) Schemes that automatically de-energize a line for a non-faults operation when one end of the line is open;

(j) Schemes that provide anti-islanding protection (e.g. protect Load from effects of being isolated with generation that may not be capable of maintaining acceptable frequency and voltage);

(k) Automatic sequences that proceed when manually initiated solely by a System Operator;

(l) Modulation of high voltage, direct current (HVDC) or FACTS via supplementary controls, such as angle damping or frequency damping applied to damp local or inter-area oscillation;

(m) Sub-synchronous resonance protection schemes that directly detect sub-synchronous quantities (e.g. currents or torsional oscillations); or

(n) Generation controls such as, but not limited to, Automatic Generation Control (AGC), generation excitation (e.g. Automatic Voltage Regulation (AVR) and Power System Stabilizers (PSSs)), fast valving, and speed governing.

(3) In addition to the requirements in the Protocols and applicable North American Electric Reliability Corporation (NERC) Reliability Standards, RASs shall also meet the following requirements:

(a) A RAS may be proposed by a Transmission Service Provider (TSP) or Resource Entity, and be approved by ERCOT and the TSP(s) and/or Resource Entity(ies) included in the RAS prior to implementation;

(b) The design, implementation, and testing of the RAS shall be coordinated within the RAS Entity;

(c) The RAS shall be automatically armed when appropriate;

(d) The RAS shall not operate unnecessarily;

(e) A RAS designated as a Limited Impact RAS shall be reviewed according to the process described in paragraph (4)(e) below and subject to ERCOT approval;

(f) For a RAS not designated by ERCOT as a Limited Impact RAS, the possible inadvertent operation of the RAS, resulting from any single RAS component malfunction satisfies all of the following as determined by the review process in paragraph (4)(e) below and subject to ERCOT approval:

  (i) The ERCOT System shall remain stable;

  (ii) Cascading shall not occur;

  (iii) Applicable Facility Ratings shall not be exceeded;

  (iv) ERCOT System voltages shall be within post-contingency voltage limits and post-contingency voltage deviation limits;

  (v) Transient voltage responses shall be within acceptable limits.

(g) To avoid unnecessary RAS operation, the RAS Entity may provide a Real-Time status indication to the owner of any Generation Resource controlled by the RAS to show when the flow on one or more of the RAS monitored Facilities exceeds 90% of the flow necessary to arm the RAS. The cost necessary to provide such status indication shall be the responsibility of the RAS Entity;

(h) The status indication of any automatic or manual arming/activation or operation of the RAS shall be provided as Supervisory Control and Data Acquisition (SCADA) alarm inputs to the owner(s) of any Facility controlled by the RAS;

(i) When a RAS is removed from service, the RAS Entity or a Designated Agent shall immediately notify ERCOT;

(j) When a RAS is returned to service, the RAS Entity or its Designated Agent shall immediately notify ERCOT. ERCOT shall modify its reliability constraints to recognize the availability of the RAS;

(k) The RAS Entity shall telemeter the status indication of the following items by SCADA to ERCOT for incorporation into ERCOT systems:

  (i) Any automatic or manual arming/activation or operation of the RAS;

  (ii) The in-service/out-of-service status of the RAS; and

  (iii) Any additional related telemetry that already exists pertinent to the monitoring of the RAS (e.g. status indication of communications links between associated RAS equipment and the owner's control center, arming limits of associated RAS equipment); and

(l) The TSP may receive telemetry for a Resource Entity owned RAS through ERCOT or through the RAS Entity, at the option of the TSP. The RAS Entity, at its own cost, must provide telemetry for Resource Entity owned RASs to the TSP upon request.

(4) The RAS Entity shall submit to ERCOT documentation of an existing, modified, proposed, or retiring RAS for review and compilation into an ERCOT RAS database using the form in Section 8, Attachment K, Remedial Action Scheme (RAS) Template. The documentation shall detail the design, operation, modeling, functional testing, and coordination of the RAS with other RASs, Automatic Mitigation Plans (AMPs), protection and control systems. The exit strategy described in the RAS submission shall identify the ERCOT endorsed transmission project or near term mitigation that will address the constraint. ~~If an exit strategy has been identified by an Entity proposing a RAS, the exit strategy shall be described in the RAS submission.~~

(a) ERCOT shall conduct a review of each proposed new or modified RAS~~,~~ and each proposed ~~modification, and proposed~~ retirement of a RAS~~indefinite deactivation, and/or termination of an existing RAS~~. ~~Additionally, it shall conduct a review of each existing RAS at least once every five years or as required by changes in system conditions. Upon receipt~~Within five Business Days of receipt, ERCOT shall post the proposal to the MIS Secure Area and shall issue a Market Notice describing the proposal and inviting submission of Market Participant comments. Within 30 Business Days of receiving the proposal, ERCOT shall ~~initiate a 30 Business Day review period to~~ complete an evaluat~~e~~ion of ~~each~~ the proposal in accordance with paragraph (4)(e) below and shall issue a Market Notice approving or rejecting the proposal. ERCOT shall coordinate any additional time needed for the evaluation with the RAS Entity. ~~Additionally, ERCOT shall conduct a review of each existing RAS at least once every five years, and a review of each new RAS approved after March 1, 2023 at least once every three years or as required by changes in system conditions.~~ Additionally, ERCOT shall conduct a review of each existing RAS at least once every three years or as required by changes in system conditions.

(b) The review of a proposed RAS shall be completed before the RAS is placed in service. The timing of placing the RAS into service must be coordinated with and approved by ERCOT. The implementation schedule must be confirmed through submission of a Network Operations Model Change Request (NOMCR) to ERCOT.

(c) Existing RASs that have already undergone at least one review shall remain in service during any subsequent review. Modifications to existing RASs may be implemented upon approval by ERCOT.

(d) The schedule for placing a RAS into service must be coordinated among ERCOT and the RAS Entity, and shall provide sufficient time to perform any necessary functional testing prior to its being placed in service.

(e) For any proposed, modified, or existing RAS, ERCOT's review of ~~a~~the RAS shall:

(i) Validate that RAS is needed to mitigate the system condition(s) or contingency(ies) for which it was designed, and that the RAS actions, designed timing, and arming conditions mitigate those system condition(s) or contingency(ies)~~ for which it was designed~~;

(ii) Identify any conflicts with the Protocols, NERC Reliability Standards, and this Operating Guide;

(iii) Validate that transient voltage responses are within acceptable limits as established by ERCOT;

(iv) Evaluate and document the consequences of misoperation, incorrect operation, unintended operation, or failure of a RAS. Additionally, validate that the RAS is designed to meet the requirements in paragraphs (3)(e) and (3)(f) above;

(v) Validate that the proposed RAS facilitates periodic testing and maintenance;

(vi) Determine whether or not the RAS is a Limited Impact RAS;

(vii) Validate that the proposed RAS avoids adverse interactions with other RASs, AMPs, protection and control systems, and applicable emergency procedures;

(viii) Evaluate the effects of future bulk electric system modifications on the design and operation of the RAS where applicable;

(ix) Validate the implementation of RAS logic appropriately correlates desired actions (outputs) with events and conditions (inputs);

(x) Validate the mechanism of procedure by which the RAS is armed is clearly described, and is appropriate for reliable arming and operation of the RAS for the conditions and events for which it is designated to operate;

(xi) Evaluate future transmission project(s) that will eliminate the need for the RAS; and

~~(xii) Validate that for proposed RAS retirements, system performance and security will not be affected.~~

(f) Upon completion of ERCOT's RAS review, ERCOT shall provide all results and underlying studies to the RAS Entity and each impacted TSP.

(g) If deficiencies are identified for a new, functionally modified, or retiring RAS by ERCOT or other parties' comments, the RAS Entity shall either submit an amended RAS proposal or withdraw the RAS proposal. The amended RAS proposal shall undergo the review process specified in paragraph (4)(e) above using the 30 Business Day RAS review timeline in paragraph (4)(a) above until the identified deficiencies have been resolved to the satisfaction of ERCOT.

(h) For any proposed retirement of a RAS, ERCOT shall evaluate whether the proposed retirement will cause any reliability concern, including whether the proposed retirement will adversely impact the dispatch of a Generation Resource subject to the minimum deliverability criteria set forth in Planning Guide Section 4.1.1.7, Minimum Deliverability Criteria. After considering any comments submitted, if ERCOT does not identify any reliability concern, ERCOT shall issue a Market Notice indicating its approval of the proposed retirement of the RAS. If ERCOT does identify a reliability concern or an adverse impact to the dispatch of a Generation Resource subject to the minimum deliverability criteria set forth in Planning Guide Section 4.1.1.7, ERCOT shall issue a Market Notice denying the retirement.

(~~h~~i) As part of the ERCOT review, ERCOT may notify the Steady State Working Group (SSWG), the Dynamics Working Group (DWG), and the System Protection Working Group (SPWG) of the RAS proposal, and each working group or any member of each working group may provide any comments, questions, or issues to ERCOT. ERCOT may work with the owner(s) of Facilities affected by the RAS as necessary to address all issues.

(j~~i~~) ERCOT shall develop a method to include the RAS where practicable in Security-Constrained Economic Dispatch (SCED), Outage coordination, and Reliability Unit Commitment (RUC).

(k~~j~~) ERCOT's review shall provide an opportunity for and include consideration of comments submitted by Market Participants affected by the RAS.

(~~k~~l) ERCOT shall update the RAS database at least once every 12 calendar months.

~~(5) ERCOT shall conduct an evaluation of each RAS at least once every five years to determine the following:~~

~~(a) The RAS mitigates the system condition(s) or contingency(ies) for which it was designed;~~

~~(b) The RAS avoids adverse interactions with other RAS, and protection and control systems; and~~

~~(c) The RAS meets the requirements in paragraphs (3)(e) and (3)(f) above.~~

(~~6~~5) ERCOT shall provide the results of the RAS evaluation including any identified deficiencies to the RAS Entity and impacted TSPs. If ERCOT's RAS evaluation identifies a deficiency, then ~~W~~within six calendar months, the RAS Entity shall develop and submit a corrective action plan, subject to ERCOT approval, to correct the deficiencies. For each plan developed, the RAS Entity shall implement the approved plan, update the plan if actions or timetables change, and notify ERCOT via email at ras_cmp@ercot.com if plan actions or timetables change and when the plan is completed.

(6) If ERCOT determines that a RAS is no longer needed, either as part of an ERCOT-initiated review or as a consequence of ERCOT's determination that a transmission project has addressed the condition(s) or contingency(ies) the RAS was designed to address, ERCOT shall issue a Market Notice proposing to retire the RAS and inviting comments from Market Participants on the proposed retirement. After considering all comments, if ERCOT confirms that the RAS is not needed, then ERCOT shall retire the RAS on a date specified in a separate Market Notice.

(7) The RAS Entity shall perform a functional test of each of its RAS to verify the overall RAS performance and the proper operation of non-protection system components at least once every six calendar years for a RAS not designated as a Limited Impact RAS, and once every 12 calendar years for a RAS designated as a Limited Impact RAS. For any identified deficiencies, the RAS Entity shall develop and submit a corrective action plan within six calendar months, and subject to ERCOT approval, to correct the deficiencies. For each plan developed, the RAS Entity shall implement the approved plan, update the plan if actions or timetables change, and notify ERCOT via email at ras_cmp@ercot.com if plan actions or timetables change and when the plan is completed.

11.2.1 Reporting of RAS Operations

(1) RAS Entity shall notify ERCOT of all RAS operations. Documentation of RAS failures or misoperations shall be provided to ERCOT using the Relay Misoperation Report form as an email to ras_cmp@ercot.com. Within 120 calendar days, the RAS Entity shall conduct an analysis of all RAS operations, misoperations, and failures. If deficiencies are identified, the RAS Entity shall develop and submit a corrective action plan within six calendar months, and subject to ERCOT approval, correct the deficiencies. For each plan developed, the RAS Entity shall implement the approved plan, update the plan if actions or timetables change, and notify ERCOT via email at ras_cmp@ercot.com if plan actions or timetables change and when the plan is completed. Analysis of RAS operational performance shall include, but is not limited to:

(a) Determination of whether system events or conditions appropriately armed or triggered the RAS;

(b) Determination of whether the RAS responded as designed;

(c) Determination of whether the RAS was effective in mitigating the performance issues it was designed to address; and

(d) Determination of whether the RAS operation resulted in any unintended or adverse system response.

(2) ERCOT shall report all RAS operations and misoperations to the Reliability Monitor for review. RAS arming or activation that ramps generation back is not considered an operation or misoperation with respect to reporting requirements to the Reliability Monitor and the NERC Regional Entity. A misoperation of a RAS with respect to reporting requirements to the Reliability Monitor and the NERC Regional Entity occurs when one of the items specified in paragraph (4) of Section 6.2.3, Performance Analysis Requirements for ERCOT System Facilities, occur. RAS Entities will provide a monthly report to ERCOT by the 15th of each month describing each instance a RAS armed/activated and reset during the previous month. The report will include the date and time of arming/activation and reset. ERCOT shall consolidate the monthly reports and forward to the Reliability Monitor and NERC Regional Entity on a quarterly basis.

(3) If a RAS which removes generation from service operates more than two times within a six month period and the operations are not a direct result of an ERCOT System disturbance or a contingency operation, ERCOT may require the Generation Resource Entity(ies) to decrease the available capability on the affected Generation Resource(s). The amount of available capacity to be decreased shall be determined by ERCOT. The decreased available capacity on the Generation Resource(s) shall remain until the Generation Resource Entity(ies) provides documentation that demonstrates the Generation Resource(s) can properly control output in a pre-contingency or normal ERCOT System condition.

~~(4) For each RAS, the RAS Entity shall either identify a preferred exit strategy or explain why no exit strategy is needed to ERCOT. Once an exit strategy is complete and a RAS is no longer needed, the RAS Entity shall notify ERCOT, whenever the RAS is to be permanently disabled, and shall do so according to a timetable coordinated with and approved by ERCOT and the owners of all Facilities controlled by the RAS.~~

Revised ERCOT Impact Analysis Report

NOGRR Number	<u>215</u>	NOGRR Title	Limit Use of Remedial Action Schemes
Impact Analysis Date	July 10, 2023		
Estimated Cost/Budgetary Impact	Between $1.0M and $1.5M Annual Recurring Operations and Maintenance (O&M) Budget Cost: Between $180k and $220k See Comments and ERCOT Staffing Impacts		
Estimated Time Requirements	The timeline for implementing this Nodal Operating Guide Revision Request (NOGRR) is dependent upon Public Utility Commission of Texas (PUCT) prioritization and approval. Estimated project duration: 12 to 18 months		
ERCOT Staffing Impacts (across all areas)	Implementation Labor: 35% ERCOT; 65% Vendor There will be ongoing operational impacts to the following ERCOT department totaling 0.5 Full-Time Employees (FTEs) to support this NOGRR: • Operations Stability Analysis (0.5 FTE Effort) ERCOT has assessed its ability to absorb the ongoing efforts of this NOGRR with current staff and concluded the need for one additional FTE in the Operations Stability Analysis Department: * 1000 hours - To support stability assessments related to Remedial Action Scheme (RAS) review. Assuming no more than 3 RAS stability study annually.		
ERCOT Computer System Impacts	The following ERCOT systems would be impacted: • Market Operation Systems 67% • Energy Management Systems 29% • Data Management & Analytic Systems 3%		
ERCOT Business Function Impacts	ERCOT will update its business processes to implement this NOGRR.		
Grid Operations & Practices Impacts	No impacts to ERCOT grid operations and practices.		

Revised ERCOT Impact Analysis Report

Evaluation of Interim Solutions or Alternatives for a More Efficient Implementation
None offered.

Comments
If approved, this Impact Analysis is based on the assumption that RASs are limited for the relief of dispatchable generation as proposed by the 3/1/23 LCRA comments.

Board Report

NOGRR Number	**230**	**NOGRR Title**	**WAN Participant Security**
Date of Decision	August 31, 2023		
Action	Recommended Approval		
Timeline	Normal		
Proposed Effective Date	November 1, 2023		
Priority and Rank Assigned	Not applicable		
Nodal Operating Guide Sections Requiring Revision	7.1.2, WAN Participant Responsibilities		
Related Documents Requiring Revision/Related Revision Requests	Nodal Protocol Revision Request (NPRR) 1150, Related to NOGRR230, WAN Participant Security		
Revision Description	This Nodal Operating Guide Revision Request (NOGRR) ensures integrity of Wide Area Network (WAN) Data transmission by adding a requirement to share data in a way that prevents Denial of Service (DoS) and Distributed Denial of Service (DDoS) attacks.		
Reason for Revision	☒ Addresses current operational issues. ☐ Meets Strategic goals (tied to the ERCOT Strategic Plan or directed by the ERCOT Board). ☒ Market efficiencies or enhancements ☐ Administrative ☐ Regulatory requirements ☐ Other: (explain) *(please select all that apply)*		
Business Case	When transmission of data over the WAN is negatively impacted by shared Internet connected hardware/software outages or a DDoS attack from the Internet, this creates an undesirable risk to the operation of the ERCOT Bulk Electric System. The market should take measures to prevent such risks against dependencies on or		

	connectivity from the Internet to the WAN.
ROS Decision	On 9/2/21, ROS voted unanimously to table NOGRR230. All Market Segments participated in the vote. On 5/4/23, ROS voted unanimously to recommend approval of NOGRR230 as amended by the 4/20/23 ERCOT comments. All Market Segments participated in the vote. On 6/8/23, ROS voted to endorse and forward to TAC the 5/4/23 ROS Report and 8/11/21 Impact Analysis for NOGRR230. There was one abstention from the Independent Generator (Calpine) Market Segment. All Market Segments participated in the vote.
Summary of ROS Discussion	On 9/2/21, ERCOT Staff provided an overview, and requested ROS table NOGRR230 in anticipation of pending ERCOT comments. On 5/4/23, participants reviewed the 4/20/23 ERCOT comments. On 6/8/23, participants reviewed the 8/11/21 Impact Analysis.
TAC Decision	On 6/27/23, TAC voted unanimously to recommend approval of NOGRR230 as recommended by ROS in the 6/8/23 ROS Report. All Market Segments participated in the vote.
Summary of TAC Discussion	On 6/27/23, TAC reviewed the ERCOT Opinion, ERCOT Market Impact Statement, and Independent Market Monitor (IMM) Opinion for NOGRR230.
ERCOT Board Decision	On 8/31/23, the ERCOT Board voted unanimously to recommend approval of NOGRR230 as recommended by TAC in the 6/27/23 TAC Report.

Opinions	
Credit Review	Not applicable
Independent Market Monitor Opinion	IMM has no opinion on NOGRR230.
ERCOT Opinion	ERCOT supports approval of NOGRR230.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NOGRR230 and believes that it has a positive market impact by both addressing current operational issues and providing market efficiencies or enhancements by adding a requirement to share data in a way that prevents DoS and DDoS

	attacks.

Sponsor	
Name	Mike Allgeier
E-mail Address	Michael.Allgeier@ercot.com
Company	ERCOT
Phone Number	512-248-4750
Cell Number	
Market Segment	Not applicable

Market Rules Staff Contact	
Name	Jordan Troublefield
E-Mail Address	Jordan.Troublefield@ercot.com
Phone Number	512-248-6521

Comments Received	
Comment Author	**Comment Summary**
ERCOT 100722	Proposed more explicit requirements related to usage of a Secure Private Network (SPN); included additional defined terms
ERCOT 102422	Relocated four definitions from Section 1.4, Definitions, to Protocol Section 2.1, Definitions, in conjunction with 10/24/22 ERCOT comments on NPRR1150
ACES 110422	Proposed the inclusion of alternative means in order to ensure the integrity of the WAN Data transmission from DoS and DDoS attacks
ERCOT 042023	Revised paragraph (n) of Section 7.1.2 to permit non-SPN networks provided that the network offers equivalent protection against internet DoS or DDoS attacks

Market Rules Notes

None

Proposed Guide Language Revision

1.4 Definitions

~~**Secure Private Network (SPN)**~~

~~A network that is utilized to transmit Wide Area Network (WAN) Data between a Resource and WAN Participant, including any portions of the network that are owned or controlled by intermediate Entities. The SPN must utilize network service vendors that provide a service level agreement for the network and the components of the SPN shall not utilize the Internet. The SPN infrastructure must be designed to avoid outages relating to a Denial of Service (DoS) or Distributed Denial of Service (DDoS) attacks that may affect a Market Participant's Internet-connected equipment. Examples of an SPN would include dedicated connections such as Multi-Protocol Label Switching (MPLS), Time Division Multiplexing Digital Signal 1 (TDM DS1), Metro Ethernet, or other networks that do not rely upon the Internet and are approved by ERCOT's telecommunications and security groups.~~

~~**Wide Area Network (WAN)**~~

~~The WAN is a fully redundant, highly available network designed for Real-Time data transport and used by ERCOT and WAN Participants to communicate and exchange certain data as described in Section 7, Telemetry and Communication.~~

~~**Wide Area Network (WAN) Data**~~

~~Any data that has been received from or will be transmitted to ERCOT across the WAN in the format of Inter-Control Center Communication Protocol (ICCP) Data or Resource-Specific Extensible Markup Language (XML) Data.~~

~~**Wide Area Network (WAN) Participant**~~

~~A Transmission Operator (TO), Qualified Scheduling Entity (QSE) representing a Resource, QSE representing an Emergency Response Service (ERS) Resource, Data Agent-Only QSE (designated under ERCOT's QSE Agency Agreement form), or other Market Participant that is required under the ERCOT Protocols to gather, transmit, or exchange Inter-Control Center Communication Protocol (ICCP) Data, Resource-Specific Extensible Markup Language (XML) Data, or any of the operational voice data described in Section 7.1, ERCOT Wide Area Network.~~

7.1.2 WAN Participant Responsibilities

(1) WAN Participant responsibilities include the following:

(a) A prospective WAN Participant is required to complete a WAN application, signed by the WAN Participant's Authorized Representative, and sign the ERCOT Private WAN Agreement, which governs installation, operation, and maintenance of the WAN hardware. Appropriate WAN documents can be obtained by contacting ERCOT. The WAN application shall include the following information at a minimum:

(i) WAN circuit termination location and requested functionality specifications;

(ii) WAN Participant's primary and backup contacts for WAN facilities management and services;

(iii) WAN Participant's primary and backup contacts for WAN emergency restoration;

(iv) WAN Invoicing contact information;

(v) WAN Participant's 24x7 operations desk long distance number; and

(vi) WAN Participant's 24x7 analog line for maintenance.

(b) Each WAN Participant must timely update information provided to ERCOT in the application process, and must promptly respond to any reasonable request by ERCOT for updated information regarding the WAN Participant or the information provided to ERCOT in item (a) above. Changes to any of the information listed in item (a) above shall be submitted to ERCOT using a Notice of Change of Information (NCI) form.

(c) A WAN Participant shall provide physical security systems compliant with the applicable Critical Infrastructure Protection (CIP) requirement of the North American Electric Reliability Corporation (NERC) Reliability Standards.

(d) WAN Participant equipment provided by ERCOT that exchanges ICCP Data, Resource-Specific XML Data, or operational voice communications with ERCOT shall connect directly to the ERCOT WAN. ERCOT will work with each WAN Participant to determine the most appropriate WAN demarcation point. Criteria for determining demarcation points include:

(i) Reliability;

(ii) Location of data centers;

(iii) Location of control centers and/or communication centers;

(iv) Location of disaster recovery facilities;

(v) Location of Energy and Market Management System (EMMS) equipment;

(vi) Location of ICCP equipment;

(vii) Location of Resource-Specific XML equipment; and

(viii) Location of private branch exchange (PBX) or call management equipment installation.

(e) ERCOT is responsible for designating necessary WAN equipment for the reliable transport of communications over the ERCOT WAN and will make the ultimate determination of the demarcation point location.

(f) A WAN Participant that serves both Transmission Service Provider (TSP) and QSE functions at one location may have a single ERCOT WAN connection as defined in Section 7.1, ERCOT Wide Area Network, at that location.

(g) If a TSP and QSE share a centralized PBX or call management, separate OPX circuits will be terminated for each participant.

(h) Each WAN Participant is required to extend the ERCOT OPX and Hotline voice circuits into its 24x7 operations desk. The OPX and Hotline voice circuits are transported across the ERCOT WAN. If a WAN Participant is designated to represent another Market Participant through an agency agreement approved by ERCOT, the WAN Participant must have dedicated OPX circuits for each Market Participant represented, in addition to a dedicated OPX for the WAN Participant if it is also representing Resources. In these cases, a single Hotline button will be used for the WAN Participant and all of the represented Market Participants. The Market Participant and its agent, if applicable, are both responsible for delivering the Hotline and the OPX to the Market Participant's 24x7 operations desk in a manner that reasonably assures continuous communication with ERCOT and is not affected by calling features such as automatic transfer or roll to voice mail. Also, a touchtone keypad is required for the Hotline to be able to provide an acknowledged receipt. The demarcation point for all voice circuits is the WAN Participant's router.

(i) Each WAN Participant must provide internal facilities and communications to collect and furnish data and voice signals to the ERCOT WAN as required by the Protocols. For TSPs and TOs such data includes, but is not limited to, voice communications, ICCP Data, and Supervisory Control and Data Acquisition (SCADA) for substations and other Transmission Facilities. For QSEs such data includes, but is not limited to, operational voice communications, ICCP Data, Resource-Specific XML Data, and SCADA for Resources.

(j) A WAN Participant shall provide adequate physical facilities to support the ERCOT WAN communications equipment. The physical facilities and communications equipment requirements include the following:

(i) Provide an analog business phone line or PBX analog extension for troubleshooting and maintenance of equipment;

(ii) Provide a height of 24" of rack space in a 19" wide rack;

(iii) Provide two separate uninterruptible power supply single-phase 115 VAC 20 amp circuits, each with four receptacles in the 19" rack listed above;

(iv) Provide building wiring from circuit termination to equipment rack;

(v) Within 24-hours notice, provide ERCOT employees or contractors access to the communication facility;

(vi) Within one-hour notice, provide ERCOT employees or contractors emergency access to the communication facility;

(vii) Provide onsite personnel to escort ERCOT employees or contractors;

(viii) Provide a firewall or router, located at the WAN Participant site, for the network address translation of internal WAN Participant addresses to external addresses on the ERCOT LAN;

(ix) Provide connectivity from WAN Participant firewall or router to ERCOT LAN located at WAN Participant site. WAN Participants are responsible for their own security through this connection;

(x) Dual cable entrances to WAN Participant, connecting to different Telco Central Offices are highly recommended; and

(xi) Provide ERCOT with internal IP addressing scheme as needed for network design. This will be kept confidential.

(k) A WAN Participant shall supply, implement, and maintain all data and voice communication facilities required to fulfill the obligations set forth in these Operating Guides.

(l) A WAN Participant's installation of data and voice communication facilities described in paragraph (k) above must complete qualification testing as specified by ERCOT before ERCOT will grant approval to commence operational use of the WAN connection. A WAN Participant shall request prior approval from ERCOT of any changes in data and voice communication facilities that impact connectivity through the WAN and shall coordinate with ERCOT before commencing operational use.

(m) If a WAN Participant~~: i) transmits or exchanges ICCP Data or Resource-Specific XML Data with another WAN Participant, or ii)~~ extends its network or otherwise transmits ~~ICCP Data, Resource-Specific XML~~ WAN Data~~,~~ or operational voice communications to another of its control and/or data center or another WAN Participant's control and/or data center, then such communications shall ~~only~~ be ~~exchanged~~ transmitted or received using a ~~s~~Secure ~~P~~Private ~~n~~Network (SPN). ~~Examples of a secure private network would include, but would not be limited to, dedicated connections such as Multi-Protocol Label Switching (MPLS), Time Division Multiplexing Digital Signal 1 (TDM DS1), and Metro Ethernet. This~~

~~requirement does not apply to communications directly between the physical Resource location and a WAN Participant location. Furthermore, the secure private network infrastructure shall not be shared in such a way that Denial of Service (DoS) or Distributed Denial of Service (DDoS) attacks against a WAN Participant's Internet accessible services could negatively impact the WAN data transmission.~~

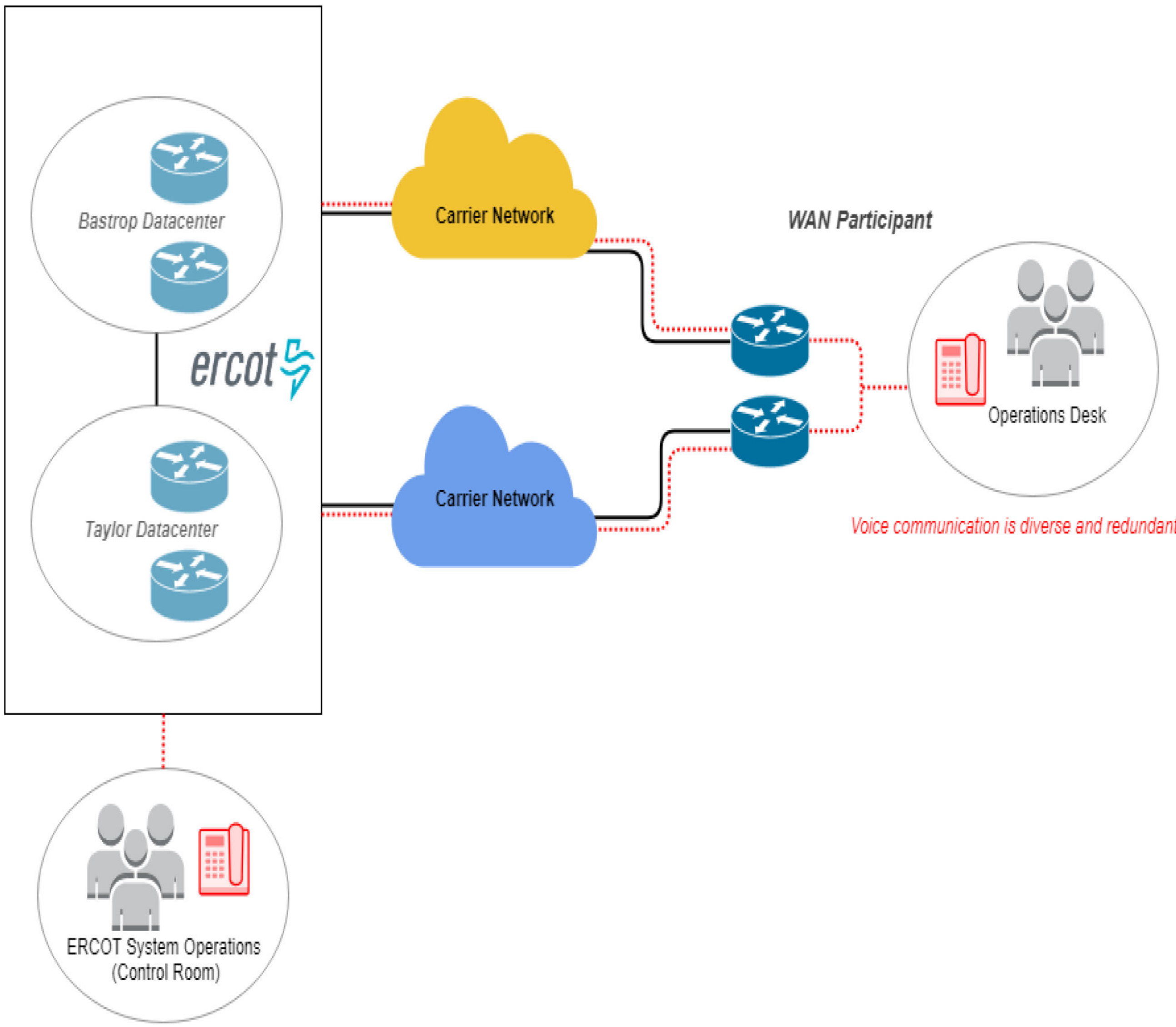

Figure 1 ERCOT Wide Area Network Overview

(n) If a WAN Participant is a QSE that represents a Resource Entity, ERS Resource, or another QSE ~~and~~for whom it receives or transmits WAN Data, the WAN Participant shall utilize an SPN or other network that provides equivalent protection against internet Denial of Service (DoS) or Distributed Denial of Service (DDoS) attacks for the transmission or receipt of WAN Data between it and the Resource Entity, ERS Resource, or QSE it represents.

[NOGRR177: Replace Section 7.1.2 above with the following upon system implementation of NPRR857:]

7.1.2 WAN Participant Responsibilities

(1) WAN Participant responsibilities include the following:

(a) A prospective WAN Participant is required to complete a WAN application, signed by the WAN Participant's Authorized Representative, and sign the ERCOT Private WAN Agreement, which governs installation, operation, and maintenance of the WAN hardware. Appropriate WAN documents can be obtained by contacting ERCOT. The WAN application shall include the following information at a minimum:

(i) WAN circuit termination location and requested functionality specifications;

(ii) WAN Participant's primary and backup contacts for WAN facilities management and services;

(iii) WAN Participant's primary and backup contacts for WAN emergency restoration;

(iv) WAN Invoicing contact information;

(v) WAN Participant's 24x7 operations desk long distance number; and

(vi) WAN Participant's 24x7 analog line for maintenance.

(b) Each WAN Participant must timely update information provided to ERCOT in the application process, and must promptly respond to any reasonable request by ERCOT for updated information regarding the WAN Participant or the information provided to ERCOT in item (a) above. Changes to any of the information listed in item (a) above shall be submitted to ERCOT using a Notice of Change of Information (NCI) form.

(c) A WAN Participant shall provide physical security systems compliant with the applicable Critical Infrastructure Protection (CIP) requirement of the North American Electric Reliability Corporation (NERC) Reliability Standards.

(d) WAN Participant equipment provided by ERCOT that exchanges ICCP Data, Resource-Specific XML Data, or operational voice communications with ERCOT shall connect directly to the ERCOT WAN. ERCOT will work with each WAN Participant to determine the most appropriate WAN demarcation point. Criteria for determining demarcation points include:

(i) Reliability;

(ii) Location of data centers;

(iii) Location of control centers and/or communication centers;

(iv) Location of disaster recovery facilities;

(v) Location of Energy and Market Management System (EMMS) equipment;

(vi) Location of ICCP equipment;

(vii) Location of Resource-Specific XML equipment; and

(viii) Location of private branch exchange (PBX) or call management equipment installation.

(e) ERCOT is responsible for the reliable transport of communications over the ERCOT WAN and will make the ultimate determination of the demarcation point location.

(f) A WAN Participant that serves both TO and QSE functions at one location may have a single ERCOT WAN connection as defined in Section 7.1, ERCOT Wide Area Network, at that location.

(g) If a TO and QSE share a centralized PBX or call management with a QSE, the QSE's OPX circuits will be terminated separately from the OPX circuits of the TO.

(h) Each WAN Participant is required to extend the ERCOT OPX and Hotline voice circuits into its 24x7 operations desk. The OPX and Hotline voice circuits are transported across the ERCOT WAN. If a WAN Participant is designated to represent another Market Participant through an agency agreement approved by ERCOT, the WAN Participant must have dedicated OPX circuits for each Market Participant represented, in addition to a dedicated OPX for the WAN Participant if it is also representing Resources. In these cases, a single Hotline button will be used for the WAN Participant and all of the represented Market Participants. The Market Participant and its agent, if applicable, are both responsible for delivering the Hotline and the OPX to the Market Participant's 24x7 operations desk in a manner that reasonably assures continuous communication with ERCOT and is not affected by calling features such as automatic transfer or roll to voice mail. Also, a touchtone keypad is required for the Hotline to be able to provide an acknowledged receipt. The demarcation point for all voice circuits is the WAN Participant's router.

(i) Each WAN Participant must provide internal facilities and communications to collect and furnish data and voice signals to the ERCOT WAN as required by the Protocols. For TOs such data includes, but is not limited to, operational voice communications, ICCP Data, and Supervisory Control and Data Acquisition (SCADA) for substations and other Transmission Facilities. For QSEs, such data includes, but is not limited to, operational voice communications, ICCP Data, Resource-Specific XML Data, and SCADA for Resources.

(j) A WAN Participant shall provide adequate physical facilities to support the ERCOT WAN communications equipment. The physical facilities and communications equipment requirements include the following:

(i) Provide an analog business phone line or PBX analog extension for troubleshooting and maintenance of equipment;

(ii) Provide a height of 24" of rack space in a 19" wide rack;

(iii) Provide two separate uninterruptible power supply single-phase 115 VAC 20 amp circuits, each with four receptacles in the 19" rack listed above;

(iv) Provide building wiring from circuit termination to equipment rack;

(v) Within 24-hours notice, provide ERCOT employees or contractors access to the communication facility;

(vi) Within one-hour notice, provide ERCOT employees or contractors emergency access to the communication facility;

(vii) Provide onsite personnel to escort ERCOT employees or contractors;

(viii) Provide a firewall or router, located at the WAN Participant site, for the network address translation of internal WAN Participant addresses to external addresses on the ERCOT LAN;

(ix) Provide connectivity from WAN Participant firewall or router to ERCOT LAN located at WAN Participant site. WAN Participants are responsible for their own security through this connection;

(x) Dual cable entrances to WAN Participant, connecting to different Telco Central Offices are highly recommended; and

(xi) Provide ERCOT with internal IP addressing scheme as needed for network design. This will be kept confidential.

(k) A WAN Participant shall supply, implement, and maintain all data and voice communication facilities required to fulfill the obligations set forth in these Operating Guides.

(l) A WAN Participant's installation of data and voice communication facilities described in paragraph (k) above must complete qualification testing as specified by ERCOT before ERCOT will grant approval to commence operational use of the WAN connection. A WAN Participant shall request prior approval from ERCOT of any changes in data and voice communication facilities that impact connectivity through the WAN and shall coordinate with ERCOT before commencing operational use.

(m) If a WAN Participant~~: i) transmits or exchanges ICCP Data or Resource-Specific XML Data with another WAN Participant, or ii)~~ extends its network or otherwise transmits ~~ICCP Data, Resource-Specific XML~~WAN Data~~,~~ or operational voice communications to another of its control and/or data center or another WAN Participant's control and/or data center, then such communications shall ~~only~~ be ~~exchanged~~ transmitted or received using a ~~secure~~ Secure ~~private~~ Private ~~network~~Network (SPN). ~~Examples of a secure private network would include, but would not be limited to, dedicated connections such as MPLS, Time Division Multiplexing Digital Signal 1 (TDM DS1), and Metro Ethernet. This requirement does not apply to communications directly between the physical Resource location and a WAN Participant location. Furthermore, the secure private network infrastructure shall not be shared in such a way that Denial of Service (DoS) or Distributed Denial of Service (DdoS) attacks against a WAN Participant's Internet accessible services could negatively impact the WAN data transmission.~~

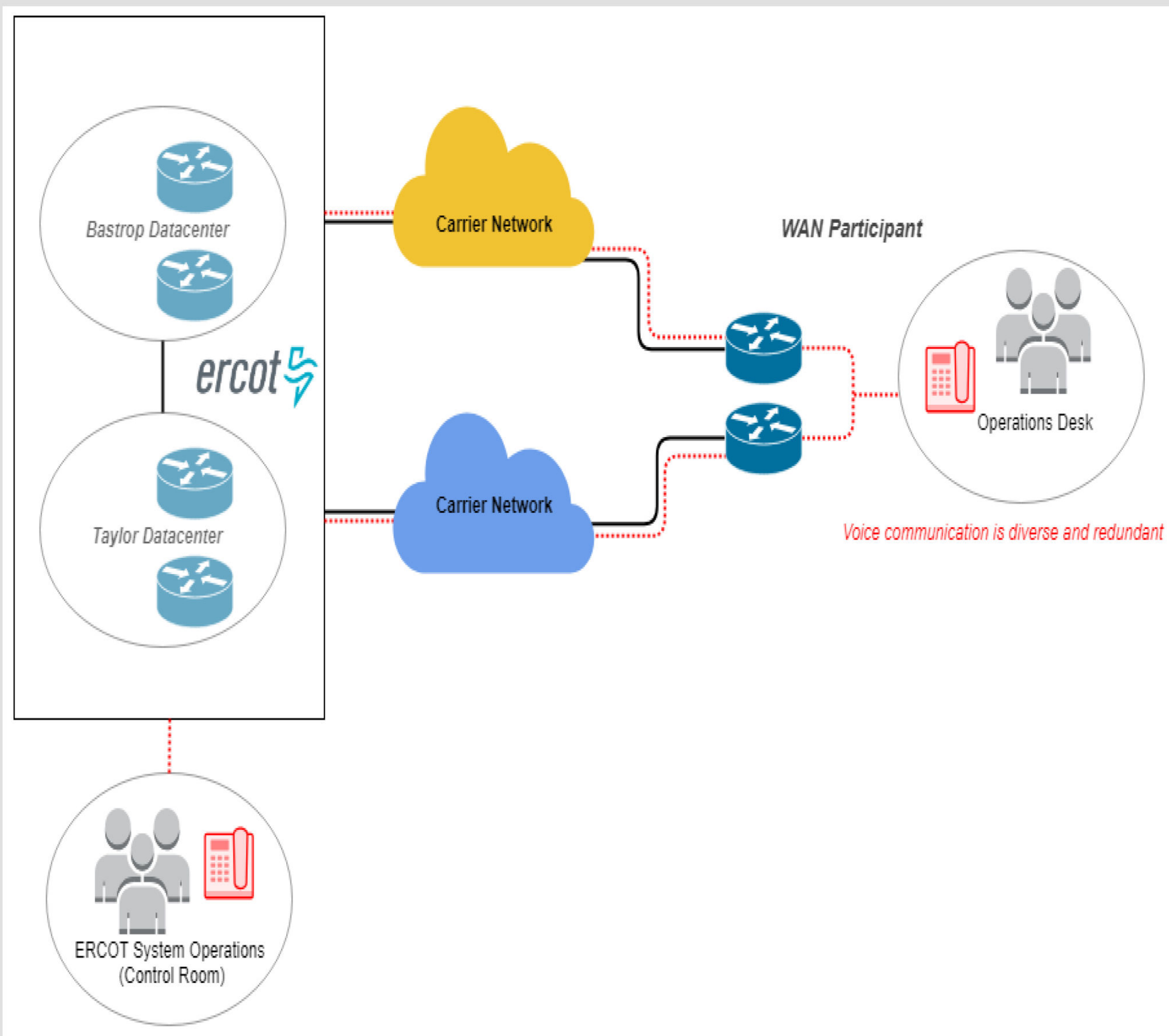

Figure 1 ERCOT Wide Area Network Overview

(n) If a WAN Participant is a QSE that represents a Resource Entity, ERS Resource, or another QSE ~~and~~for whom it receives or transmits WAN Data, the WAN Participant shall utilize an SPN or other network that provides equivalent protection against internet Denial of Service (DoS) or Distributed Denial of Service (DDoS) attacks for the transmission or receipt of WAN Data between it and the Resource Entity, ERS Resource, or QSE it represents.

ERCOT Impact Analysis Report

NOGRR Number	**230**	**NOGRR Title**	**WAN Participant Security**
Impact Analysis Date	August 11, 2021		
Estimated Cost/Budgetary Impact	None.		
Estimated Time Requirements	No project required. This Nodal Operating Guide Revision Request (NOGRR) can take effect upon Public Utility Commission of Texas (PUCT) approval.		
ERCOT Staffing Impacts (across all areas)	Ongoing Requirements: No impacts to ERCOT staffing.		
ERCOT Computer System Impacts	No impacts to ERCOT computer systems.		
ERCOT Business Function Impacts	No impacts to ERCOT business functions.		
Grid Operations & Practices Impacts	No impacts to ERCOT grid operations and practices.		

Evaluation of Interim Solutions or Alternatives for a More Efficient Implementation
None offered.

Comments
None.

Board Report

NOGRR Number	247	NOGRR Title	Change UFLS Stages and Load Relief Amounts
Date of Decision	August 31, 2023		
Action	Recommended Approval		
Timeline	Normal		
Proposed Effective Date	Upon system implementation		
Priority and Rank Assigned	Not applicable		
Nodal Operating Guide Sections Requiring Revision	2.6.1, Automatic Firm Load Shedding		
Related Documents Requiring Revision/Related Revision Requests	None		
Revision Description	This Nodal Operating Guide Revision Request (NOGRR) modifies the ERCOT automatic Under-Frequency Load Shed (UFLS) program by increasing the number of Load shed stages from three to five and changing the Transmission Operator (TO) Load relief amounts to uniformly increment by 5% for each stage. The NOGRR also adds a UFLS minimum time delay of six cycles (0.1 seconds), and adds 59.1 Hz to the list of UFLS stages in paragraph (3) of Section 2.6.1. Additionally, this NOGRR revises the grey-boxed language from NOGRR226, Addition of Supplemental UFLS Stages, in Section 2.6.1 to provide that the TO Load value used to determine the TO Load at each frequency threshold in Table 1 will be the value of TO Load at the time frequency reaches 59.5 Hz, rather than the value of TO Load at the time of reaching each successive frequency threshold, consistent with the current method for determining TO Load in Table 1, and proposes an effective date of October 1, 2026 for both NOGRR226 and NOGRR247 grey-boxed language.		
Reason for Revision	☒ Addresses current operational issues ☐ Meets Strategic goals (tied to the ERCOT Strategic Plan or directed by the ERCOT Board). ☐ Market efficiencies or enhancements		

Board Report

	☐ Administrative ☐ Regulatory requirements ☐ Other: (explain) *(please select all that apply)*
Business Case	The current ERCOT automatic UFLS program design includes three stages of TO Load relief of approximately 5%, 10%, and 10%, respectively. It was observed on February 15, 2021 that some steam turbine generators experienced instability when frequency rose rapidly from a low frequency to 60 Hz (and beyond) during Energy Emergency Alert (EEA) directed Load shed. Based on observations from February 15, 2021, the frequency swing induced by an automatic and directed Load shed of 10% of system Load may result in some generators experiencing instability during a Load shed event. Furthermore, ERCOT is not aware of any reliability justification for having a Load shed stage as large as 10%. Therefore, this NOGRR changes the minimum Load shed amount per UFLS stage to 5% and keeps the overall minimum Load shed amount at 25%, in alignment with North American Electric Reliability Corporation (NERC) Reliability Standard PRC-006-5, Automatic Underfrequency Load Shedding. Also, the NOGRR adds a minimum time delay of six cycles (0.1 seconds) to ensure that UFLS is not triggered for any localized and/or transient frequency excursions. Finally, the NOGRR revises the description of the method for determining the TO Load value in the grey-boxed language from NOGRR226 in paragraph (1) of Section 2.6.1 because ERCOT has determined the language would not require the desired amount of Load shed at each stage.
ROS Decision	On 3/2/23, ROS voted unanimously to table NOGRR247 and refer the issue to the Dynamics Working Group (DWG), Operations Working Group (OWG), Performance, Disturbance, Compliance Working Group (PDCWG), and System Protection Working Group (SPWG). All Market Segments participated in the vote. On 6/8/23, ROS voted to recommend approval of NOGRR247 as amended by the 4/27/23 CenterPoint Energy comments. There was one abstention from the Independent Generator (Calpine) Market Segment. All Market Segments participated in the vote. On 7/6/23, ROS voted unanimously to endorse and forward to TAC the 6/8/23 ROS Report and 2/15/23 Impact Analysis for NOGRR247. All Market Segments participated in the vote.

Board Report

Summary of ROS Discussion	On 3/2/23, ERCOT Staff reviewed NOGRR247. Some participants expressed concern that NOGRR247 may be too complex to implement alongside NOGRR226 and requested tabling for further review. On 6/8/23, participants reviewed the 4/25/23 Oncor comments and 4/27/23 CenterPoint Energy comments. On 7/6/23, there was no discussion.
TAC Decision	On 7/25/23, TAC voted unanimously to recommend approval of NOGRR247 as recommended by ROS in the 7/6/23 ROS Report. All Market Segments participated in the vote.
Summary of TAC Discussion	On 7/25/23, TAC reviewed the ERCOT Opinion, ERCOT Market Impact Statement, and Independent Market Monitor (IMM) Opinion for NOGRR247.
ERCOT Board Decision	On 8/31/23, the ERCOT Board voted unanimously to recommend approval of NOGRR247 as recommended by TAC in the 7/25/23 TAC Report.

Opinions	
Credit Review	Not applicable
Independent Market Monitor Opinion	IMM has no opinion on NOGRR247.
ERCOT Opinion	ERCOT supports approval of NOGRR247.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NOGRR247 and believes it will have a positive market impact by reducing the risk of generator instability during an underfrequency Load shed event.

Sponsor	
Name	Jeff Billo
E-mail Address	jbillo@ercot.com
Company	ERCOT
Phone Number	512-248-6334
Cell Number	
Market Segment	Not applicable

Board Report

Market Rules Staff Contact	
Name	Cory Phillips
E-Mail Address	Cory.phillips@ercot.com
Phone Number	512-248-6464

Comments Received	
Comment Author	**Comment Summary**
Oncor 042523	Proposed an effective date of October 1, 2026 for both NOGRR226 and NOGRR247
CenterPoint Energy 042723	Proposed additional edits to the 4/25/23 Oncor comments to add 59.1 Hz to the list of standard UFLS blocks available to satisfy supplemental anti-stall Load relief requirements

Market Rules Notes

Please note that the following NOGRR(s) also propose revisions to Section 2.6.1:

- NOGRR250, Related to NPRR 1171, Requirements for DGRs and DESRs on Circuits Subject to Load Shedding

Proposed Guide Language Revision

2.6.1 Automatic Firm Load Shedding

Commented [CP1]: Please note NOGRR250 also proposes revisions to this section.

(1) At least 25% of the ERCOT System Load shall be equipped at all times with provisions for automatic Under-Frequency Load Shedding (UFLS) as described in this paragraph. In the event of an under-frequency event, each Transmission Operator (TO) shall provide Load relief by shedding the required percentage of its Distribution Service Provider (DSP)-connected Load and transmission-level Customer Load using automatic under-frequency relays, as specified in Table 1, Standard UFLS Stages, below. TOs may, but are not required to, provide supplemental anti-stall under-frequency Load relief in the amounts described in Table 2, Supplemental Anti-Stall UFLS Stages, below. If the TOs provide supplemental anti-stall under-frequency Load relief, the under-frequency relays shall be set to use the frequency thresholds and time delays described in Table 2. For the purposes of this paragraph, the TO Load will be the amount of Load being served by the DSPs that the TO represents, as well as the TO's transmission-level Customer Load, when the ERCOT frequency drops to the 59.5 Hz threshold. As such, TO Load that has already been removed from the system without restoration prior to the 59.5 Hz frequency threshold will not apply to meeting TO Load relief percentage requirements as stated in Table 1 and Table 2 below.

Board Report

[NOGRR226: Replace paragraph (1) above with the following upon system implementation but no earlier than October 1, 2026~~4~~:]

(1) At least 25% of the ERCOT System Load shall be equipped at all times with provisions for automatic Under-Frequency Load Shedding (UFLS) as described in this paragraph. In the event of an under-frequency event, each Transmission Operator (TO) shall provide Load relief by shedding the required percentage of its Distribution Service Provider (DSP)-connected Load and transmission-level Customer Load using automatic under-frequency relays, as specified in the tables below. For the purposes of this paragraph, the TO Load will be the amount of Load being served by the DSPs that the TO represents, as well as the TO's transmission-level Customer Load, when the ERCOT frequency drops to ~~each identified frequency~~the 59.5 Hz threshold. As such, TO Load that has already been removed from the system without restoration prior to the 59.5 Hz frequency threshold will not apply to meeting TO Load relief percentage requirements as stated in Table 1 and Table 2 below.

Table 1: Standard UFLS Stages

Frequency Threshold	TO Load Relief	Delay to Trip
59.3 Hz	At least 5% of the TO Load	No more than 30 cycles
59.1 Hz	A total of at least 5% of the TO Load	No more than 30 cycles
58.9 Hz	A total of at least 15% of the TO Load	No more than 30 cycles
58.7 Hz	A total of at least 15% of the TO Load	No more than 30 cycles
58.5 Hz	A total of at least 25% of the TO Load	No more than 30 cycles

[NOGRR247: Replace Table 1 above with the following upon system implementation but no earlier than October 1, 2026~~4~~:]

Frequency Threshold	TO Load Relief	Delay to Trip
59.3 Hz	At least 5% of the TO Load	At least six cycles but no more than 30 cycles
59.1 Hz	A total of at least 10% of the TO Load	At least six cycles but no more than 30 cycles
58.9 Hz	A total of at least 15% of the TO Load	At least six cycles but no more than 30 cycles

58.7 Hz	A total of at least 20% of the TO Load	At least six cycles but no more than 30 cycles
58.5 Hz	A total of at least 25% of the TO Load	At least six cycles but no more than 30 cycles

Table 2: Supplemental Anti-Stall UFLS Stages

Frequency Threshold	**TO Load Relief**	**Delay to Trip**
59.5 Hz	At least 1.5% of the TO Load	90 seconds
59.5 Hz	A total of at least 3.0% of the TO Load	120 seconds
59.5 Hz	A total of at least 4.5% of the TO Load	150 seconds

(2) ERCOT will, prior to the peak each year, survey each TO's compliance with the automatic Load shedding requirements described in paragraph (1) above, and report its findings to the Technical Advisory Committee (TAC). For purposes of determining a TO's compliance with this annual survey requirement, TO Load will be the total amount of Load being served by the DSPs that the TO represents, as well as the TO's transmission-level Customer Load, at the specified time of the survey. The TO shall identify those circuits armed with under-frequency relays, the corresponding amount of Load, and identify the frequency threshold. A TO shall not equip the entirety of its Load shed obligation in any one tier, and should endeavor to shed in controlled amounts that equal the difference between the TO Load relief required for each tier. If ERCOT identifies potential reliability issues related to distribution of Load shed across the tiers, ERCOT may require the TO to redistribute Load relief closer to the minimum amount required after submitting ERCOT's proposal to redistribute Load relief to the TO and considering any comments submitted by the TO regarding the proposal. Compliance with this annual survey does not excuse the TO from compliance with the requirements of paragraph (1) above in an actual frequency event. To assist TOs, ERCOT will provide the TO's inventory, including substation and capacity amounts, of registered Load Resources in its area within ten Business Days of receiving a request in writing from a TO.

(3) A TO may meet the Load relief requirements of the Supplemental anti-stall UFLS stages by utilizing Load that would otherwise be utilized to meet the 59.1 Hz, 58.9 Hz, 58.7 Hz, and 58.5 Hz standard UFLS stages. In this circumstance, the TO's Load relief responsibility at the 59.1 Hz, 58.9 Hz, 58.7 Hz, and 58.5 Hz standard UFLS stages is reduced by the amount of Load already shed in the supplemental anti-stall UFLS stages. A TO may not meet the Load relief requirements of the supplemental anti-stall UFLS stages by utilizing Load that the TO needs to meet the 59.3 Hz ~~and 59.1 Hz~~ standard UFLS stages.

(4) Additional under-frequency relays may be installed on Transmission Facilities with the approval of ERCOT provided the relays are set at 58.0 Hz or below, are not directional, and have at least 2.0 seconds time delay. A DSP may by mutual agreement arrange to have all or part of its automatic Load shedding requirement performed by another entity. ERCOT will be notified and provided with the details of any such arrangement prior to implementation.

(5) DSPs shall ensure, to the extent possible, and under the direction of ERCOT, that Loads equipped with under-frequency relays are dispersed geographically throughout the ERCOT Region to minimize the impact of Load shedding within a given geographical area. Customers equipped with under-frequency relays shall be dispersed without regard to which Load Serving Entity (LSE) serves the customer. DSPs shall ensure that Distribution Generation Resources (DGRs) and Distribution Energy Storage Resources (DESRs) are connected to circuits that are not subject to disconnection during UFLS events, except as permitted by Protocol Section 3.8.6, Distribution Generation Resources (DGRs) and Distribution Energy Storage Resources (DESRs). DSPs shall ensure that the under-frequency relays connected to each Load will operate with a fixed time delay as specified in paragraph (1) above. Total time from the time when a sustained under-frequency condition first reaches one of the values specified above to the time Load is interrupted ~~should~~ shall be no more than the maximum fixed time delay specified in paragraph (1) above plus 10 cycles, including all relay and breaker operating times, and no less than any applicable minimum fixed time delay specified in paragraph (1) above. If the frequency drops below 58.5 Hz, ERCOT shall determine additional steps to continue operation.

(6) If a loss of Load occurs due to the operation of under-frequency relays, a DSP or its designee may rotate the physical Load interrupted to minimize the duration of interruption experienced by individual Customers or to restore the availability of under-frequency Load-shedding capability. In no event shall the initial total amount of Load without service be decreased without the approval of ERCOT. TOs, in coordination with DSPs, shall make every reasonable attempt to restore Load, either by automatic or manual means, to preserve system integrity. Restoration of any Load shed by UFLS systems, including supplemental anti-stall UFLS Load, shall be coordinated with ERCOT by the TO. In the event frequency drops below any of the frequency thresholds specified in the tables in paragraph (1) above, and a TO's UFLS relays that previously activated as a result of reaching that same frequency threshold have not been restored since the previous excursion, the Load on the feeders controlled by those relays shall be counted toward the TO's satisfaction of the percentages in paragraph (1) above for that subsequent frequency excursion.

ERCOT Impact Analysis Report

NOGRR Number	**247**	**NOGRR Title**	**Change UFLS Stages and Load Relief Amounts**
Impact Analysis Date	February 15, 2023		
Estimated Cost/Budgetary Impact	Less than $10k, which will be absorbed by the Operations & Maintenance (O&M) budgets of affected department.		
Estimated Time Requirements	No project required. This Nodal Operating Guide Revision Request (NOGRR) can take effect within 1-2 months after Public Utility Commission of Texas (PUCT) approval.		
ERCOT Staffing Impacts (across all areas)	Implementation Labor: 100% ERCOT; 0% Vendor Ongoing Requirements: No impacts to ERCOT staffing.		
ERCOT Computer System Impacts	The following ERCOT systems would be impacted: • Energy Management Systems 83% • Grid Decision Support Systems 17%		
ERCOT Business Function Impacts	No impacts to ERCOT business functions.		
Grid Operations & Practices Impacts	ERCOT will update grid operations and practices to implement this NOGRR.		

Evaluation of Interim Solutions or Alternatives for a More Efficient Implementation
None offered.

Comments
None.

Board Report

NOGRR Number	249	NOGRR Title	Communication of System Operating Limit Exceedances
Date of Decision	August 31, 2023		
Action	Recommended Approval		
Timeline	Normal		
Proposed Effective Date	April 1, 2024		
Priority and Rank Assigned	Not applicable		
Nodal Operating Guide Sections Requiring Revision	3.7, Transmission Operators		
Related Documents Requiring Revision/Related Revision Requests	None		
Revision Description	This Nodal Operating Guide Revision Request (NOGRR) specifies the methods for Transmission Operators (TOs) to receive electronic communication of system operating limit exceedances from ERCOT.		
Reason for Revision	☐ Addresses current operational issues. ☐ Meets Strategic goals (tied to the ERCOT Strategic Plan or directed by the ERCOT Board). ☐ Market efficiencies or enhancements ☐ Administrative ☒ Regulatory requirements ☐ Other: (explain) *(please select all that apply)*		
Business Case	The North American Electric Reliability Corporation (NERC) Reliability Standards FAC-011-4, System Operating Limits Methodology for the Operations Horizon, and IRO-008-3, Reliability Coordinator Operational Analyses and Real-time Assessments, become effective on April 1, 2024. These Reliability Standards specify that ERCOT, as the Reliability Coordinator, is to develop and		

	implement a methodology that communicates system operating limit exceedances to impacted TOs. In order to meet the new requirements by April 1, 2024, ERCOT will utilize two existing electronic methods of communication to notify impacted TOs of all system operating limit exceedances. ERCOT will post active pre- and post-contingency exceedances on the MIS Secure Area. Pre- and post-contingency exceedances will also be communicated to TOs via the GridGeo application. These electronic communication methods are the minimum forms of notification and do not prevent the use of other means of communication as needed (i.e., verbal notification). All TOs will be required to have the ability to monitor both the MIS Secure Area and the GridGeo application, but are only required to monitor either the MIS Secure Area or the GridGeo application for system operating limit exceedance communications. This is to ensure TOs will continue to receive notifications should one form of communication become inoperable. ERCOT currently provides any Generic Transmission Limits (GTLs) and their respective flows via the Inter-Control Center Communications Protocol (ICCP). As a long-term solution, ERCOT is evaluating the provision of additional functionality to the application that will be delivered as part of SCR 820, Operator Real-Time Messaging During Emergency. The electronic system operating limit exceedance communication within the Operator Real-Time Messaging During Emergency application will be considered as an improvement of the application, in addition to the required scope of SCR 820 being delivered.
ROS Decision	On 4/6/23, ROS voted to table NOGRR249 and refer the issue to the Operations Working Group (OWG). There was one abstention from the Independent Power Marketer (IPM) (SENA) Market Segment. All Market Segments participated in the vote. On 7/6/23, ROS voted unanimously to recommend approval of NOGRR249 as amended by the 6/27/23 OWG comments. All Market Segments participated in the vote. On 8/3/23, ROS voted unanimously to endorse and forward to TAC the 7/6/23 ROS Report and 3/17/23 Impact Analysis for NOGRR249. All Market Segments participated in the vote.
Summary of ROS Discussion	On 4/6/23, participants reviewed NOGRR249. Certain stakeholders noted that not all TOs were in agreement with ERCOT's approach, and expressed concern that they may not be able to achieve three-part communication. On 7/6/23, participants reviewed the 6/27/23 OWG comments.

	On 8/3/23, participants reviewed the 3/17/23 Impact Analysis.
TAC Decision	On 8/22/23, TAC voted unanimously to recommend approval of NOGRR249 as recommended by ROS in the 8/3/23 ROS Report. All Market Segments participated in the vote.
Summary of TAC Discussion	On 8/22/23, TAC reviewed the ERCOT Opinion, ERCOT Market Impact Statement, and Independent Market Monitor (IMM) Opinion for NOGRR249.
ERCOT Board Decision	On 8/31/23, the ERCOT Board voted unanimously to recommend approval of NOGRR249 as recommended by TAC in the 8/22/23 TAC Report with a recommended effective date of 4/1/24.

Opinions	
Credit Review	Not applicable
Independent Market Monitor Opinion	IMM has no opinion on NOGRR249.
ERCOT Opinion	ERCOT supports approval of NOGRR249.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NOGRR249 and believes the market impact for NOGRR249 is the establishment of an effective method for communicating system operating limit exceedances to impacted TOs in accordance with The North American Electric Reliability Corporation (NERC) Reliability Standards FAC-011-4, System Operating Limits Methodology for the Operations Horizon, and IRO-008-3, Reliability Coordinator Operational Analyses and Real-time Assessments.

Sponsor	
Name	Stephen Solis, Fred Huang
E-mail Address	Stephen.Solis@ercot.com; shun-hsien.huang@ercot.com
Company	ERCOT
Phone Number	512-248-6772; 512-248-6665
Cell Number	
Market Segment	Not applicable

Board Report

Market Rules Staff Contact	
Name	Erin Wasik-Gutierrez
E-Mail Address	Erin.Wasik-Gutierrez@ercot.com
Phone Number	413-886-2474

Comments Received	
Comment Author	**Comment Summary**
Oncor 062223	Proposed clarifying edits to reflect Oncor's understanding the proposal does not require TOs to take independent action in response to the new MIS Secure Area and existing GridGeo system operating limit exceedance postings other than to notify ERCOT of any failure of these exceedances to post in either location
OWG 062723	Indicated its support of the 6/22/23 Oncor comments and proposed additional clarifying edits

Market Rules Notes

Administrative changes to the language were made and authored as "ERCOT Market Rules."

Proposed Guide Language Revision

3.7 Transmission Operators

(1) Transmission Operators (TOs) shall follow ERCOT instructions:

(a) Performing the physical operation of the ERCOT Transmission Grid, including circuit breakers, switches, voltage control equipment, protective relays, metering and Load shedding equipment;

(b) Directing changes in the operation of transmission voltage control equipment per Section 2.7.3, Real-Time Operational Voltage Control;

(c) Managing Voltage Profiles established by ERCOT and Voltage Set Points per Section 2.7.3; and

(d) Taking those additional actions required to prevent an imminent Emergency Condition or to restore the ERCOT Transmission Grid to a secure state in the event of a system emergency.

<u>(e) In response to a System Operating Limit (SOL) exceedance communicated by ERCOT.</u>

(2) TOs must meet all requirements identified in the Protocols for TOs in addition to those requirements stated below for all Transmission Facilities represented:

(a) Monitor system conditions and notify ERCOT when Transmission Facility elements reach maximum safe operating limits as soon as practicable;

(b) Notify ERCOT of any changes in its Transmission Facility status within ten seconds of the change of status as specified in Protocol Section 3.10.7.5, Telemetry Requirements;

(c) Operate and manage Transmission Facilities between energy sources and the point of delivery;

(d) Coordinate emergency communications between a represented Transmission Service Provider (TSP) system and ERCOT;

[NOGRR177: Replace paragraph (d) above with the following upon system implementation of NPRR857:]

(d) Coordinate emergency communications between a represented Transmission Service Provider (TSP) or Direct Current Tie Operator (DCTO) system and ERCOT;

(e) Monitor the loading of the transmission system(s);

(f) Notify ERCOT of all changes to the status of all Transmission Elements and Transmission Facilities;

(g) Act as Single Point of Contact for transmission Outages;

(h) Maintain continuous communication (24x7) with ERCOT;

(i) Ensure Dispatch Instructions, received for their system or on behalf of represented TSPs or Distribution Service Providers (DSPs), are carried out as issued;

[NOGRR177: Replace paragraph (i) above with the following upon system implementation of NPRR857:]

(i) Ensure Dispatch Instructions, received for their system or on behalf of represented TSPs, DCTOs, or Distribution Service Providers (DSPs), are carried out as issued;

(j) Maintain operational metering; ~~and~~

(k) Implement Black Start;

(l) Ensure the ability to receive pre- and post-contingency system operating limit exceedences communicated by ERCOT through at least one of the following methods at all times, unless both systems are unavailable:

(i) Postings on the MIS Secure Area~~.~~; ~~and~~or

(ii) The GridGeo application.

Upon observation of a failure of ~~either~~the method that is being utilized, the TO will notify ERCOT as soon as practicable.

~~(l) Ensure they have the ability to monitor pre- and post-contingency system operating limit exceedances communicated by ERCOT via postings on the MIS Secure Area, and notify ERCOT of any failure of the postings on the MIS Secure Area as soon as practicable;~~

~~(m) Ensure they have the ability to monitor pre- and post-contingency system operating limit exceedances communicated by ERCOT via the GridGeo application, and notify ERCOT of any failure of the GridGeo application as soon as practicable;~~

~~(n) Monitor pre- and post-contingency system operating limit exceedances communicated by ERCOT with at least one of the methods identified in paragraph (l) or (m) above at all times;~~

(~~o~~m) Ensure ~~they have~~ the ability to monitor Generic Transmission Limits (GTLs) and the associated flows that affect their system via the Inter-Control Center Communications Protocol (ICCP); and

(~~p~~n) Monitor GTLs and the associated flows that affect their system.

(3) TOs shall submit to ERCOT, by March 15 of each year, a written back-up control plan to continue operation in the event the TOs control center becomes inoperable. Back-up control plans shall be submitted to ERCOT via secured webmail or encrypted data transfer. TOs shall request that a secure email account be created with ERCOT by sending an email to shiftsupervisors@ercot.com.

(4) Each back-up control plan shall be reviewed and updated annually and shall meet the following minimum requirements:

(a) Include descriptions of actions to be taken by TO personnel to avoid placing a prolonged burden on ERCOT and other Market Participants;

(b) Include descriptions of specific functions and responsibilities to be performed to continue operations from an alternate location;

(c) Include procedures and responsibilities for maintaining basic voice communications capabilities with ERCOT; and

(d) Include procedures for back-up control function testing and the training of personnel.

(5) As an option, the back-up control plan may include arrangements made with another Entity to provide the minimum back-up control functions in the event the TO's primary functions are interrupted.

(6) By February 15 of each year, each TO shall submit to ERCOT its emergency operations plan to mitigate operating emergencies, as required by the applicable North American Electric Reliability Corporation (NERC) Reliability Standards, and in accordance with Section 8, Attachment L, Emergency Operations Plan. The emergency operations plan shall be submitted to ERCOT via secured webmail or encrypted data transfer. A TO may request a secure email account by sending an email to ERCOT at transrep@ercot.com. If no changes have been made from the previous submission, the TO shall resubmit the emergency operations plan with a new revision date indicating that it has been reviewed and no changes were made. If a TO revises its emergency operations plan, the TO shall submit the revised emergency operations plan to ERCOT within 45 calendar days of the effective date of the revised plan and must include a summary of revisions.

(7) ERCOT shall review each TO's emergency operations plan to ensure it addresses all relevant reliability risks and will notify the TO of its conclusions within 30 calendar days of receipt of a TO's new or revised emergency operations plan. ERCOT shall coordinate with the TO on a mutually agreeable time frame for the resubmittal of the emergency operations plan if ERCOT determines that reliability concerns require revision to the emergency operations plan. Plans submitted for the annual review before February 15 will be deemed to have been received on February 15 for ERCOT to initiate the review described in this section.

ERCOT Impact Analysis Report

NOGRR Number	249	NOGRR Title	Communication of System Operating Limit Exceedances
Impact Analysis Date	March 17, 2023		
Estimated Cost/Budgetary Impact	None.		
Estimated Time Requirements	No project required. This Nodal Operating Guide Revision Request (NOGRR) can take effect following Public Utility Commission of Texas (PUCT) approval.		
ERCOT Staffing Impacts (across all areas)	Ongoing Requirements: No impacts to ERCOT staffing.		
ERCOT Computer System Impacts	No impacts to ERCOT computer systems.		
ERCOT Business Function Impacts	No impacts to ERCOT business functions.		
Grid Operations & Practices Impacts	No impacts to ERCOT grid operations and practices.		

Evaluation of Interim Solutions or Alternatives for a More Efficient Implementation
None offered.

Comments
None.

Board Report

NOGRR Number	250	NOGRR Title	Related to NPRR1171, Requirements for DGRs and DESRs on Circuits Subject to Load Shedding
Date of Decision	August 31, 2023		
Action	Recommended Approval		
Timeline	Normal		
Proposed Effective Date	Upon implementation of Nodal Protocol Revision Request (NPRR) 1171, Requirements for DGRs and DESRs on Circuits Subject to Load Shedding		
Priority and Rank Assigned	Not Applicable		
Nodal Operating Guide Sections Requiring Revision	2.6.1, Automatic Firm Load Shedding		
Related Documents Requiring Revision/Related Revision Requests	NPRR1171 Resource Registration Glossary Revision Request (RRGRR) 035, Related to NPRR1171, Requirements for DGRs and DESRs on Circuits Subject to Load Shedding		
Revision Description	This Nodal Operating Guide Revision Request (NOGRR) removes language that prohibits Distribution Service Providers (DSPs) from connecting Distribution Generation Resources (DGRs) and Distribution Energy Storage Resources (DESRs) to circuits included in an Under-Frequency Load Shed (UFLS) scheme to align with NPRR1171. NPRR1171 recognizes that some DGRs and DESRs may be connected to circuits that are subject to Load shed.		
Reason for Revision	[X] Addresses current operational issues [ ] Meets Strategic goals (tied to the ERCOT Strategic Plan or directed by the ERCOT Board). [X] Market efficiencies or enhancements [ ] Administrative [ ] Regulatory requirements [ ] Other: (explain) *(please select all that apply)*		

Board Report

Business Case	NPRR1171 modifies Nodal Protocol Section 3.8.6, Distribution Generation Resources (DGRs) and Distribution Energy Storage Resources (DESRs), to allow DGRs and DESRs that are connected to circuits subject to Load shed to provide some Ancillary Services. This NOGRR aligns the Nodal Operating Guide with this allowance.
ROS Decision	On 5/4/23, ROS voted unanimously to table NOGRR250 and refer the issue to the Operations Working Group (OWG). All Market Segments participated in the vote. On 7/6/23, ROS voted unanimously to recommend approval of NOGRR250 as submitted. All Market Segments participated in the vote. On 8/3/23, ROS voted unanimously to endorse and forward to TAC the 7/6/23 ROS Report and 3/29/23 Impact Analysis for NOGRR250. All Market Segments participated in the vote.
Summary of ROS Discussion	On 5/4/23, participants requested OWG review NOGRR250 along with NPRR1171 and RRGRR035. On 7/6/23, participants noted the OWG recommendation to endorse NPRR1171 as submitted, and advanced the related NOGRR250 and RRGRR035. On 8/3/23, ROS reviewed the 3/29/23 Impact Analysis.
TAC Decision	On 8/22/23, TAC voted unanimously to recommend approval of NOGRR250 as recommended by ROS in the 8/3/23 ROS Report. All Market Segments participated in the vote.
Summary of TAC Discussion	On 8/22/23, TAC reviewed the ERCOT Opinion, ERCOT Market Impact Statement, and Independent Market Monitor (IMM) Opinion for NOGRR250.
ERCOT Board Decision	On 8/31/23, the ERCOT Board voted unanimously to recommend approval of NOGRR250 as recommended by TAC in the 8/22/23 TAC Report.

Opinions	
Credit Review	Not Applicable
Independent Market Monitor Opinion	IMM has no opinion on NOGRR250.
ERCOT Opinion	ERCOT supports approval of NOGRR250.

Board Report

ERCOT Market Impact Statement	ERCOT Staff has reviewed NOGRR250 and believes the market impact for NOGRR250 is identification of Ancillary Services that can be provided by DGRs and DESRs on feeders subject to Load shedding.

Sponsor	
Name	Clayton Stice
E-mail Address	clayton.stice2@ercot.com
Company	ERCOT
Phone Number	512-248-6806
Cell Number	512-627-5020
Market Segment	Not Applicable

Market Rules Staff Contact	
Name	Brittney Albracht
E-Mail Address	Brittney.Albracht@ercot.com
Phone Number	512-225-7027

Comments Received	
Comment Author	**Comment Summary**
None	

Market Rules Notes

Please note that the following NOGRR(s) also propose revisions to the following section(s):

- NOGRR247, Change UFLS Stages and Load Relief Amounts
  - Section 2.6.1

Proposed Guide Language Revision

2.6.1 Automatic Firm Load Shedding

Commented [BA1]: NOGRR247 also proposes revisions to this section.

(1) At least 25% of the ERCOT System Load shall be equipped at all times with provisions for automatic Under-Frequency Load Shedding (UFLS) as described in this paragraph. In the event of an under-frequency event, each Transmission Operator (TO) shall provide Load relief by shedding the required percentage of its Distribution Service Provider

(DSP)-connected Load and transmission-level Customer Load using automatic under-frequency relays, as specified in Table 1, Standard UFLS Stages, below. TOs may, but are not required to, provide supplemental anti-stall under-frequency Load relief in the amounts described in Table 2, Supplemental Anti-Stall UFLS Stages, below. If the TOs provide supplemental anti-stall under-frequency Load relief, the under-frequency relays shall be set to use the frequency thresholds and time delays described in Table 2. For the purposes of this paragraph, the TO Load will be the amount of Load being served by the DSPs that the TO represents, as well as the TO's transmission-level Customer Load, when the ERCOT frequency drops to the 59.5 Hz threshold. As such, TO Load that has already been removed from the system without restoration prior to the 59.5 Hz frequency threshold will not apply to meeting TO Load relief percentage requirements as stated in Table 1 and Table 2 below.

[NOGRR226: Replace paragraph (1) above with the following upon system implementation but no earlier than October 1, 2024:]

(1) At least 25% of the ERCOT System Load shall be equipped at all times with provisions for automatic Under-Frequency Load Shedding (UFLS) as described in this paragraph. In the event of an under-frequency event, each Transmission Operator (TO) shall provide Load relief by shedding the required percentage of its Distribution Service Provider (DSP)-connected Load and transmission-level Customer Load using automatic under-frequency relays, as specified in Table 1, Standard UFLS Stages, and Table 2, Supplemental/Anti-Stall UFLS Stages, below. For the purposes of this paragraph, the TO Load will be the amount of Load being served by the DSPs that the TO represents, as well as the TO's transmission-level Customer Load, when the ERCOT frequency drops to each identified frequency Hz threshold. As such, TO Load that has already been removed from the system without restoration prior to the 59.5 Hz frequency threshold will not apply to meeting TO Load relief percentage requirements as stated in Table 1 and Table 2 below.

Table 1: Standard UFLS Stages

Frequency Threshold	TO Load Relief	Delay to Trip
59.3 Hz	At least 5% of the TO Load	No more than 30 cycles
58.9 Hz	A total of at least 15% of the TO Load	No more than 30 cycles
58.5 Hz	A total of at least 25% of the TO Load	No more than 30 cycles

Table 2: Supplemental/Anti-Stall UFLS Stages

Frequency	TO Load Relief	Delay to Trip

Board Report

Threshold		
59.5 Hz	At least 1.5% of the TO Load	90 seconds
59.5 Hz	A total of at least 3.0% of the TO Load	120 seconds
59.5 Hz	A total of at least 4.5% of the TO Load	150 seconds

(2) ERCOT will, prior to the peak each year, survey each TO's compliance with the automatic Load shedding requirements described in paragraph (1) above, and report its findings to the Technical Advisory Committee (TAC). For purposes of determining a TO's compliance with this annual survey requirement, TO Load will be the total amount of Load being served by the DSPs that the TO represents, as well as the TO's transmission-level Customer Load, at the specified time of the survey. The TO shall identify those circuits armed with under-frequency relays, the corresponding amount of Load, and identify the frequency threshold. A TO shall not equip the entirety of its Load shed obligation in any one tier, and should endeavor to shed in controlled amounts that equal the difference between the TO Load relief required for each tier. If ERCOT identifies potential reliability issues related to distribution of Load shed across the tiers, ERCOT may require the TO to redistribute Load relief closer to the minimum amount required after submitting ERCOT's proposal to redistribute Load relief to the TO and considering any comments submitted by the TO regarding the proposal. Compliance with this annual survey does not excuse the TO from compliance with the requirements of paragraph (1) above in an actual frequency event. To assist TOs, ERCOT will provide the TO's inventory, including substation and capacity amounts, of registered Load Resources in its area within ten Business Days of receiving a request in writing from a TO.

(3) A TO may meet the Load relief requirements of the Supplemental anti-stall UFLS stages by utilizing Load that would otherwise be utilized to meet the 58.9 Hz and 58.5 Hz standard UFLS stages. In this circumstance, the TO's Load relief responsibility at the 58.9 and 58.5 Hz standard UFLS stages is reduced by the amount of Load already shed in the supplemental anti-stall UFLS stages. A TO may not meet the Load relief requirements of the supplemental anti-stall UFLS stages by utilizing Load that the TO needs to meet the 59.3 Hz standard UFLS stage.

(4) Additional under-frequency relays may be installed on Transmission Facilities with the approval of ERCOT provided the relays are set at 58.0 Hz or below, are not directional, and have at least 2.0 seconds time delay. A DSP may by mutual agreement arrange to have all or part of its automatic Load shedding requirement performed by another entity. ERCOT will be notified and provided with the details of any such arrangement prior to implementation.

(5) DSPs shall ensure, to the extent possible, and under the direction of ERCOT, that Loads equipped with under-frequency relays are dispersed geographically throughout the ERCOT Region to minimize the impact of Load shedding within a given geographical area. Customers equipped with under-frequency relays shall be dispersed without regard

to which Load Serving Entity (LSE) serves the customer. ~~DSPs shall ensure that Distribution Generation Resources (DGRs) and Distribution Energy Storage Resources (DESRs) are connected to circuits that are not subject to disconnection during UFLS events, except as permitted by Protocol Section 3.8.6, Distribution Generation Resources (DGRs) and Distribution Energy Storage Resources (DESRs).~~ DSPs shall ensure that the under-frequency relays connected to each Load will operate with a fixed time delay as specified in paragraph (1) above. Total time from the time when a sustained under-frequency condition first reaches one of the values specified above to the time Load is interrupted should be no more than the fixed time delay specified in paragraph (1) above plus 10 cycles, including all relay and breaker operating times. If the frequency drops below 58.5 Hz, ERCOT shall determine additional steps to continue operation.

(6) If a loss of Load occurs due to the operation of under-frequency relays, a DSP or its designee may rotate the physical Load interrupted to minimize the duration of interruption experienced by individual Customers or to restore the availability of under-frequency Load-shedding capability. In no event shall the initial total amount of Load without service be decreased without the approval of ERCOT. TOs, in coordination with DSPs, shall make every reasonable attempt to restore Load, either by automatic or manual means, to preserve system integrity. Restoration of any Load shed by UFLS systems, including supplemental anti-stall UFLS Load, shall be coordinated with ERCOT by the TO. In the event frequency drops below any of the frequency thresholds specified in the tables in paragraph (1) above, and a TO's UFLS relays that previously activated as a result of reaching that same frequency threshold have not been restored since the previous excursion, the Load on the feeders controlled by those relays shall be counted toward the TO's satisfaction of the percentages in paragraph (1) above for that subsequent frequency excursion.

ERCOT Impact Analysis Report

NOGRR Number	250	NOGRR Title	Related to NPRR 1171, Requirements for DGRs and DESRs on Circuits Subject to Load Shedding
Impact Analysis Date	March 29, 2023		
Estimated Cost/Budgetary Impact	None.		
Estimated Time Requirements	No project required. This Nodal Operating Guide Revision Request (NOGRR) can take effect following implementation of Nodal Protocol Revision Request (NPRR) 1171.		
ERCOT Staffing Impacts (across all areas)	Ongoing Requirements: No impacts to ERCOT staffing.		
ERCOT Computer System Impacts	No impacts to ERCOT computer systems.		
ERCOT Business Function Impacts	No impacts to ERCOT business functions.		
Grid Operations & Practices Impacts	No impacts to ERCOT grid operations and practices.		

Evaluation of Interim Solutions or Alternatives for a More Efficient Implementation
None offered.

Comments
There are no additional impacts to this NOGRR beyond what was captured in the Impact Analysis for NPRR1171.

Board Report

NOGRR Number	251	NOGRR Title	Add Cold Weather Conditions to Template for Emergency Operations Plan
Date of Decision	August 31, 2023		
Action	Recommended Approval		
Timeline	Normal		
Proposed Effective Date	November 1, 2023		
Priority and Rank Assigned	Not applicable		
Nodal Operating Guide Sections Requiring Revision	8, Attachment L, Emergency Operations Plan		
Related Documents Requiring Revision/Related Revision Requests	None		
Revision Description	This Nodal Operating Guide Revision Request (NOGRR) aligns Section 8, Attachment L with North American Electric Reliability Corporation (NERC) Reliability Standard EOP-011-2, Emergency Preparedness and Operations, by adding cold weather conditions to the template used for the development of emergency operations plans.		
Reason for Revision	☐ Addresses current operational issues. ☐ Meets Strategic goals (tied to the ERCOT Strategic Plan or directed by the ERCOT Board). ☐ Market efficiencies or enhancements ☐ Administrative ☒ Regulatory requirements ☐ Other: (explain) *(please select all that apply)*		
Business Case	NERC Reliability Standard EOP-011-2 went into effect on April 1, 2023, requiring applicable entities to include provisions to determine the reliability impacts of cold weather conditions within their		

	operating plan(s) to mitigate operating emergencies. ERCOT submits this NOGRR to align the template used by Transmission Operators (TOs) to develop their emergency operations plans with the EOP-011-2 requirement. Per Section 3.7, Transmission Operators, ERCOT reviews the emergency operations plans submitted by TOs and either approves or denies these submittals within 30 days. The proposed revisions will also clarify what elements ERCOT considers during its review of each emergency operations plan. Providing this clarity up front will streamline the administrative process for both ERCOT and TOs.
ROS Decision	On 5/4/23, ROS voted unanimously to recommend approval of NOGRR251 as submitted. All Market Segments participated in the vote. On 6/8/23, ROS voted to endorse and forward to TAC the 5/4/23 ROS Report and 4/17/23 Impact Analysis for NOGRR251. There was one abstention from the Independent Generator (Calpine) Market Segment. All Market Segments participated in the vote.
Summary of ROS Discussion	On 5/4/23, ERCOT Staff presented NOGRR251. On 6/8/23, participants reviewed the 4/17/23 Impact Analysis.
TAC Decision	On 6/27/23, TAC voted unanimously to recommend approval of NOGRR251 as recommended by ROS in the 6/8/23 ROS Report. All Market Segments participated in the vote.
Summary of TAC Discussion	On 6/27/23, TAC reviewed the ERCOT Opinion, ERCOT Market Impact Statement, and Independent Market Monitor (IMM) Opinion for NOGRR251.
ERCOT Board Decision	On 8/31/23, the ERCOT Board voted unanimously to recommend approval of NOGRR251 as recommended by TAC in the 6/27/23 TAC Report.

Opinions	
Credit Review	Not applicable
Independent Market Monitor Opinion	IMM has no opinion on NOGRR251.
ERCOT Opinion	ERCOT supports approval of NOGRR251.

Board Report

ERCOT Market Impact Statement	ERCOT Staff has reviewed NOGRR251 and believes the market impact for NOGRR251 aligns the template used by TOs to develop their emergency operations plans with the NERC Reliability Standard requiring applicable entities to include provisions to determine the reliability impacts of cold weather conditions within their operating plan(s) to mitigate operating emergencies.

Sponsor	
Name	Thinesh Devadhas Mohanadhas
E-mail Address	Thinesh.DevadhasMohanadhas@ercot.com
Company	ERCOT
Phone Number	512-248-6922
Cell Number	
Market Segment	Not applicable

Market Rules Staff Contact	
Name	Erin Wasik-Gutierrez
E-Mail Address	erin.wasik-gutierrez@ercot.com
Phone Number	413-886-2474

Comments Received	
Comment Author	**Comment Summary**
None	

Market Rules Notes

None

Proposed Guide Language Revision

ERCOT Nodal Operating Guides
Section 8
Attachment L

Emergency Operations Plan

~~February 1, 2017~~TBD

ROS Report

This attachment provides a template to be used by each Transmission Operator (TO) for the development of its emergency operations plan to mitigate operating emergencies, as required by the applicable North American Electric Reliability Corporation (NERC) Reliability Standard. The emergency operations plan can be made up of multiple parts and does not need to be a single document. When multiple parts are used, the TO shall include documentation describing the location of each element required by the applicable NERC Reliability Standard. Each plan should include each of the elements listed below:

I. PURPOSE – The purpose statement will address the TO's operations plan to mitigate operating emergencies.

II. SCOPE – The scope statement shall provide, in a brief summary, the boundaries of the emergency operations plan and to whom the emergency operations plan applies.

III. DEFINITIONS – Definitions of terms that are used in the TO emergency operations plan that are not common to the ERCOT Region. Define what is considered an operating emergency.

IV. KEY PERSONNEL ROLES AND RESPONSIBILITIES – Identify roles and responsibilities of key personnel that are responsible for activating the plan.

V. PROCESSES TO PREPARE FOR AND MITIGATE EMERGENCIES – Include the following:

A. Notification to ERCOT to include current and known projected Real-Time conditions, when experiencing an operating emergency;

B. Cancellation of Transmission Facility Outages;

C. Transmission system reconfiguration;

D. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and that is capable of being implemented in a timeframe adequate for mitigating the emergency; and

E. Provisions to determine ~~R~~reliability impacts of:

1. cold weather conditions and;

2. extreme weather conditions.

ERCOT Impact Analysis Report

NOGRR Number	**<u>251</u>**	**NOGRR Title**	**Add Cold Weather Conditions to Template for Emergency Operations Plan**
Impact Analysis Date	April 17, 2023		
Estimated Cost/Budgetary Impact	None.		
Estimated Time Requirements	No project required. This Nodal Operating Guide Revision Request (NOGRR) can take effect following Public Utility Commission of Texas (PUCT) approval.		
ERCOT Staffing Impacts (across all areas)	Ongoing Requirements: No impacts to ERCOT staffing.		
ERCOT Computer System Impacts	No impacts to ERCOT computer systems.		
ERCOT Business Function Impacts	No impacts to ERCOT business functions.		
Grid Operations & Practices Impacts	No impacts to ERCOT grid operations and practices.		

Evaluation of Interim Solutions or Alternatives for a More Efficient Implementation
None offered.

Comments
None.

Board Report

NOGRR Number	252	**NOGRR Title**	**Related to NPRR1176, Update to EEA Trigger Levels**
Date of Decision	August 31, 2023		
Action	Recommended Approval		
Timeline	Normal		
Proposed Effective Date	Upon implementation of Nodal Protocol Revision Request (NPRR) 1176, Update to EEA Trigger Levels		
Priority and Rank Assigned	Not Applicable		
Nodal Operating Guide Sections Requiring Revision	4.2.2, Advisory 4.5.3, Implementation 4.5.3.1, General Procedures Prior to EEA Operations		
Related Documents Requiring Revision/Related Revision Requests	NPRR1176 Section 4.5.3.3, EEA Levels		
Revision Description	This Nodal Operating Guide Revision Request (NOGRR) aligns Nodal Operating Guide language with NPRR1176, which revises the Energy Emergency Alert (EEA) procedures to require a declaration of EEA Level 3 when Physical Responsive Capability (PRC) cannot be maintained above 1,500 MW and will require ERCOT to shed firm Load to recover 1,500 MW of reserves within 30 minutes, modifies the trigger levels for EEA Level 1 and EEA Level 2, changes the trigger for ERCOT's consideration of alternative transmission ratings or configurations from Advisory to Watch when PRC drops below 3,000 MW, and restores a frequency trigger for the declaration of EEA Level 3 if the steady-state frequency drops below 59.8 Hz for any period of time.		
Reason for Revision	☒ Addresses current operational issues ☐ Meets Strategic goals (tied to the ERCOT Strategic Plan or directed by the ERCOT Board). ☐ Market efficiencies or enhancements ☐ Administrative ☐ Regulatory requirements		

Board Report

	☐ Other: (explain) *(please select all that apply)*
Business Case	This NOGRR aligns Nodal Operating Guide language with Protocol language.
ROS Decision	On 6/8/23, ROS voted to recommend approval of NOGRR252 as submitted. There was one abstention from the Independent Generator (Calpine) Market Segment. All Market Segments participated in the vote. On 7/6/23, ROS voted unanimously to endorse and forward to TAC the 6/8/23 ROS Report and 4/25/23 Impact Analysis for NOGRR252. All Market Segments participated in the vote.
Summary of ROS Discussion	On 6/8/23, ERCOT Staff reviewed NOGRR252. Participants discussed actions in steady state versus transient state, and noted that the Operations Working Group (OWG) has reviewed NOGRR252. On 7/6/23, there was no discussion.
TAC Decision	On 7/25/23, TAC voted unanimously to recommend approval of NOGRR252 as recommended by ROS in the 7/6/23 ROS Report. All Market Segments participated in the vote.
Summary of TAC Discussion	On 7/25/23, TAC reviewed the ERCOT Opinion, ERCOT Market Impact Statement, and Independent Market Monitor (IMM) Opinion for NOGRR252.
ERCOT Board Decision	On 8/31/23, the ERCOT Board voted unanimously to recommend approval of NOGRR252 as recommended by TAC in the 7/25/23 TAC Report.

Opinions	
Credit Review	Not applicable
Independent Market Monitor Opinion	IMM has no opinion on NOGRR252.
ERCOT Opinion	ERCOT supports approval of NOGRR252.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NOGRR252 and believes it is necessary to increase the minimum PRC level that must be maintained so that the ERCOT grid can withstand the loss up to ERCOT's single largest contingency and not trigger Under-Frequency Load Shed (UFLS)

	during the operating conditions the grid typically operates with lower reserves.

Sponsor	
Name	Nitika Mago
E-mail Address	Nitika.Mago@ercot.com
Company	ERCOT
Phone Number	512-248-6601
Cell Number	512-689-1360
Market Segment	Not Applicable

Market Rules Staff Contact	
Name	Brittney Albracht
E-Mail Address	Brittney.Albracht@ercot.com
Phone Number	512-225-7027

Comments Received	
Comment Author	**Comment Summary**
None	

Market Rules Notes

Please note the baseline language in the following section(s) has been updated to reflect the incorporation of the following NOGRR(s) into the Nodal Operating Guide:

- NOGRR237, Related to NPRR1106, Deployment of Emergency Response Service (ERS) Prior to Declaration of Energy Emergency Alert (EEA) (unboxed 6/9/23)
    - Section 4.5.3.1

Proposed Guide Language Revision

4.2.2 Advisory

(1) An Advisory will be issued by ERCOT in accordance with Protocol Section 6.5.9.3.2, Advisory, when it recognizes that conditions are developing or have changed such that

QSE and/or TO actions may be prudent in anticipation of possible Emergency Conditions.

(2) ERCOT may require information from QSEs and TOs. Typical information requested may include, but is not limited to:

(a) Resource fuel capabilities;

(b) Resource condition details; and

(c) Actual weather conditions.

~~(3) When an Advisory is issued for Physical Responsive Capability (PRC) below 3,000 MW and ERCOT expects system conditions to deteriorate to the extent that an Energy Emergency Alert (EEA) Level 2 or 3 may be experienced, ERCOT shall evaluate constraints active in Security-Constrained Economic Dispatch (SCED) and determine which constraints have the potential to limit generation output.~~

~~(a) Upon identification of such constraints, ERCOT shall coordinate with the TSPs that own or operate the overloaded Transmission Facilities associated with those constraints, as well as the Resource Entities whose generation output may be limited, to determine whether:~~

~~***[NOGRR177: Replace paragraph (a) above with the following upon system implementation of NPRR857:]***~~

~~(a) Upon identification of such constraints, ERCOT shall coordinate with the TSPs and DCTOs that own or operate the overloaded Transmission Facilities associated with those constraints, as well as the Resource Entities whose generation output may be limited, to determine whether:~~

~~(i) A 15-Minute Rating is available that allows for additional transmission capacity for use in congestion management, if an EEA Level 2 or 3 is declared, and post-contingency actions can be taken within 15 minutes to return the flow to within the Emergency Rating. Such actions may include, but are not limited to, reducing the generation that increased output as a result of enforcing the 15-Minute Rating rather than the Emergency Rating;~~

~~(ii) Post-contingency loading of the Transmission Facilities is expected to be at or below Normal Rating within two hours; or~~

~~(iii) Additional transmission capacity could allow for additional output from a limited Generation Resource by taking one of the following actions:~~

~~(A) Restoring Transmission Elements that are out of service;~~

~~(B) Reconfiguring the transmission system; or~~

~~(C) Making adjustments to phase angle regulator tap positions.~~

~~If ERCOT determines that one of the above-mentioned actions allows for additional output from a limited Generation Resource, ERCOT may instruct the TSPs to take the action(s) during the Advisory to allow for additional output from the limited Generation Resource.~~

~~(b) ERCOT shall also coordinate with TSPs who own and operate the Transmission Facilities associated with the double-circuit contingencies for the constraints identified above to determine whether the double-circuit failures are at a high risk of occurring due to system conditions, which may include: severe weather conditions forecasted by ERCOT in the vicinity of the double-circuit, weather conditions that indicate a high risk of insulator flashover on the double-circuit, repeated Forced Outages of the individual circuits that are part of the double-circuit in the preceding 48 hours, or fire in progress in the right of way of the double-circuit.~~

~~***[NOGRR177: Replace paragraph (b) above with the following upon system implementation of NPRR857:]***~~

~~(b) ERCOT shall also coordinate with TSPs and DCTOs who own and operate the Transmission Facilities associated with the double-circuit contingencies for the constraints identified above to determine whether the double-circuit failures are at a high risk of occurring due to system conditions, which may include: severe weather conditions forecasted by ERCOT in the vicinity of the double-circuit, weather conditions that indicate a high risk of insulator flashover on the double-circuit, repeated Forced Outages of the individual circuits that are part of the double-circuit in the preceding 48 hours, or fire in progress in the right of way of the double-circuit.~~

~~(c) The actions detailed in this Section shall be supplemental to the development and maintenance of Constraint Management Plans (CMPs) as otherwise directed by the Protocols or Operating Guides.~~

(3~~4~~) ERCOT shall provide verbal notice of an Advisory to TOs and QSEs representing Resources through the TO and QSE Hotlines and shall post the message electronically to the ERCOT website. When an Advisory is issued, it does not place ERCOT in an Emergency Condition. QSEs shall notify, as appropriate, their represented QSEs, Resources, REPs and LSEs of Advisories. TOs should notify, as appropriate, their represented TSPs and DSPs of Advisories.

[NOGRR177: Replace paragraph (3~~4~~) above with the following upon system implementation of NPRR857:]

(3~~4~~) ERCOT shall provide verbal notice of an Advisory to TOs and QSEs representing Resources through the TO and QSE Hotlines and shall post the message electronically to the ERCOT website. When an Advisory is issued, it does not place ERCOT in an Emergency Condition. QSEs shall notify, as appropriate, their represented QSEs, Resources, REPs, and LSEs of Advisories. TOs should notify, as appropriate, their represented TSPs, DSPs and/or DCTOs of Advisories.

4.5.3 Implementation

(1) ERCOT shall be responsible for monitoring system conditions, initiating the EEA levels below, notifying all Qualified Scheduling Entities (QSEs) representing Resources and Transmission Operators (TOs), and coordinating the implementation of the EEA conditions while maintaining transmission security limits. QSEs and TOs will notify all the Market Participants they represent of each declared EEA level.

(2) During the EEA, ERCOT has the authority to obtain energy from non-ERCOT Control Areas using Direct Current Tie(s) (DC Tie(s)) or by using Block Load Transfers (BLTs) to move load to non-ERCOT Control Areas. ERCOT maintains the authority to curtail energy schedules flowing into or out of the ERCOT System across the DC Ties in accordance with North American Electric Reliability Corporation (NERC) scheduling guidelines.

(3) ERCOT, at management's discretion, may at any time issue an ERCOT-wide appeal through the public news media for voluntary energy conservation.

(4) There may be insufficient time to implement all levels in sequence. ERCOT may immediately implement EEA Level 2 when clock-minute average system frequency falls below 59.91 Hz for 15 consecutive minutes. ERCOT may immediately implement Level 3 of the EEA any time the clock-minute average system frequency falls below 59.91 Hz for 20 consecutive minutes or when steady-state frequency falls below 59.8 Hz for any duration of time. ~~and~~ ERCOT shall immediately implement Level 3 any time the steady-state frequency is below 59.5 Hz for any duration.

(5) Percentages for Level 3 Load shedding will be based on the previous year's TSP peak Loads, as reported to ERCOT, and will be reviewed by ERCOT and modified annually.

(6) The ERCOT System Operator shall declare the EEA levels to be taken by QSEs and TSPs. QSEs and TSPs shall implement actions under that level (and all above if not previously accomplished) and if ordered by the ERCOT shift supervisor or his designate, shall report back to the ERCOT System Operator when the requested level has been completed.

[NOGRR177: Replace paragraph (6) above with the following upon system implementation of NPRR857:]

(6)	The ERCOT System Operator shall declare the EEA levels to be taken by QSEs, TSPs, and DCTOs. QSEs, TSPs, and DCTOs shall implement actions under that level (and all above if not previously accomplished) and if ordered by the ERCOT shift supervisor or his designate, shall report back to the ERCOT System Operator when the requested level has been completed.

(7) During EEA Level 3, ERCOT must be capable of shedding sufficient firm Load to arrest frequency decay and to prevent generator tripping. The amount of firm Load to be shed may vary depending on ERCOT Transmission Grid conditions during the event. Each TSP will be capable of shedding its allocation of firm Load, without delay. The maximum time for the TSP to interrupt firm Load will depend on how much Load is to be shed and whether the Load is to be interrupted by Supervisory Control and Data Acquisition (SCADA) or by the dispatch of personnel to substations. Since the need for firm Load shed is immediate, interruption by SCADA is preferred. The following requirements apply for an ERCOT instruction to shed firm Load:

(a) Load interrupted by SCADA will be shed without delay and in a time period not to exceed 30 minutes;

(b) Load interrupted by dispatch of personnel to substations to manually shed Load will be implemented within a time period not to exceed one hour;

(c) The initial clock on the firm Load shed shall apply only to Load shed amounts up to 1000 MW total. Load shed amount requests exceeding 1000 MW on the initial clock may take longer to implement; and

(d) If, after the first Load shed instruction, ERCOT determines that an additional amount of firm Load should be shed, another clock will begin anew. The time frames mentioned above will apply.

(8) Each TSP, or its designated agent, will provide ERCOT a status report of Load shed progress within 30 minutes of the time of ERCOT's instruction or upon ERCOT's request.

(9) During EEA Level 2 or 3, for those constraints that meet the criteria identified in paragraph (3)(a) of Section ~~4.2.2~~4.5.3.1, ~~Advisory~~General Procedures Prior to EEA Operations, ERCOT may control the post-contingency flow to within the 15-Minute Rating in Security-Constrained Economic Dispatch (SCED). After Physical Responsive Capability (PRC) is restored to at least 3,000 MW or the Emergency Condition has ended, whichever is later, and ERCOT has determined that system conditions have improved such that the chance of re-entering into an EEA Level 2 or 3 is low, ERCOT shall restore control to the post-contingency flow to within the Emergency Rating for these constraints that utilized the 15-Minute Rating in SCED.

(10) During EEA Level 2 or 3, for those constraints that meet the criteria identified in paragraph (3)(b) of Section ~~4.2.2~~4.5.3.1, ERCOT shall continue to enforce constraints associated with double-circuit contingencies throughout an EEA if the double-circuit failures are determined to be at high risk of occurring, due to system conditions. For all

other double-circuit contingencies identified in paragraph (3)(b) of Section ~~4.2.2~~4.5.3.1, ERCOT will enforce only the associated single-circuit contingencies during EEA Level 2 or 3. ERCOT shall resume enforcing such constraints as a double-circuit contingency after PRC is restored to at least 3,000 MW or the Emergency Condition has ended, whichever is later, and ERCOT has determined that system conditions have improved such that the chance of re-entering into an EEA Level 2 or 3 is low. For constraints related to stability limits that are not IROLs, ERCOT may elect not to enforce double-circuit contingencies during EEA Level 3 only.

4.5.3.1 General Procedures Prior to EEA Operations

(1) Prior to declaring EEA Level 1 detailed in Section 4.5.3.3, EEA Levels, ERCOT may perform the following operations consistent with Good Utility Practice:

(a) Provide Dispatch Instructions to QSEs for specific Resources to operate at an Emergency Base Point to maximize Resource deployment so as to increase Responsive Reserve (RRS) levels on other Resources;

(b) Commit specific available Resources as necessary that can respond in the timeframe of the emergency. Such commitments will be settled using the Hourly Reliability Unit Commitment (HRUC) process;

(c) Start Reliability Must-Run (RMR) Units available in the time frame of the emergency. RMR Units should be loaded to full capability;

(d) Utilize available Resources providing RRS, ERCOT Contingency Reserve Service (ECRS), and Non-Spinning Reserve (Non-Spin) services as required;

(e) Instruct TSPs and Distribution Service Providers (DSPs) or their agents to reduce Customer Load by using existing, in-service distribution voltage reduction measures if ERCOT determines that the implementation of these measures could help avoid entering into EEA and ERCOT does not expect to need to use these measures to reduce the amount of Load shedding that may be needed in EEA Level 3. A TSP, DSP, or their agent shall implement these instructions if distribution voltage reduction measures are available and already installed. If the TSP, DSP, or their agent determines in their sole discretion that the distribution voltage reduction would adversely affect reliability, the voltage reduction measure may be reduced, modified, or otherwise changed from maximum performance to a level of exercise that has no negative impact to reliability; and

(f) ERCOT shall use the PRC and system frequency to determine the appropriate Emergency Notice and EEA levels.

(2) When PRC falls below 3,000 MW and is not projected to be recovered above 3,000 MW within 30 minutes following the deployment of Non-Spin, ERCOT may deploy available contracted Emergency Response Service (ERS)-10 and ERS-30 via an Extensible Markup Language (XML) message followed by a Verbal Dispatch Instruction (VDI) to

the QSE Hotline. The ERS-10 and ERS-30 ramp periods shall begin at the completion of the VDI.

(a) ERS-10 and ERS-30 may be deployed at any time in a Settlement Interval. ERS-10 and ERS-30 may be deployed either simultaneously or separately, and in any order, at the discretion of ERCOT operators.

(b) Upon deployment, QSEs shall instruct their ERS Resources in ERS-10 and ERS-30 to perform at contracted levels consistent with the criteria described in Section 8.1.3.1.4, Event Performance Criteria for Emergency Response Service Resources, until either ERCOT releases the ERS-10 and ERS-30 deployment or the ERS-10 and ERS-30 Resources have reached their maximum deployment time.

(c) ERCOT shall notify QSEs of the release of ERS-10 and ERS-30 via an XML message followed by VDI to the QSE Hotline. The VDI shall represent the official notice of ERS-10 and ERS-30 release.

(d) Upon release, an ERS Resource shall return to a condition such that it is capable of meeting its ERS performance requirements as soon as practical, but no later than ten hours following the release.

(3) When a Watch is issued for PRC below 3,000 MW and ERCOT expects system conditions to deteriorate to the extent that an EEA Level 2 or 3 may be experienced, ERCOT shall evaluate constraints active in SCED and determine which constraints have the potential to limit generation output.

(a) Upon identification of such constraints, ERCOT shall coordinate with the TSPs that own or operate the overloaded Transmission Facilities associated with those constraints, as well as the Resource Entities whose generation output may be limited, to determine whether:

[NOGRR177: Replace paragraph (a) above with the following upon system implementation of NPRR857:]

(a) Upon identification of such constraints, ERCOT shall coordinate with the TSPs and DCTOs that own or operate the overloaded Transmission Facilities associated with those constraints, as well as the Resource Entities whose generation output may be limited, to determine whether:

(i) A 15-Minute Rating is available that allows for additional transmission capacity for use in congestion management, if an EEA Level 2 or 3 is declared, and post-contingency actions can be taken within 15 minutes to return the flow to within the Emergency Rating. Such actions may include, but are not limited to, reducing the generation that increased output as a result of enforcing the 15-Minute Rating rather than the Emergency Rating;

(ii) Post-contingency loading of the Transmission Facilities is expected to be at or below Normal Rating within two hours; or

(iii) Additional transmission capacity could allow for additional output from a limited Generation Resource by taking one of the following actions:

(A) Restoring Transmission Elements that are out of service;

(B) Reconfiguring the transmission system; or

(C) Making adjustments to phase angle regulator tap positions.

If ERCOT determines that one of the above-mentioned actions allows for additional output from a limited Generation Resource, ERCOT may instruct the TSPs to take the action(s) during the Advisory to allow for additional output from the limited Generation Resource.

(b) ERCOT shall also coordinate with TSPs who own and operate the Transmission Facilities associated with the double-circuit contingencies for the constraints identified above to determine whether the double-circuit failures are at a high risk of occurring due to system conditions, which may include: severe weather conditions forecasted by ERCOT in the vicinity of the double-circuit, weather conditions that indicate a high risk of insulator flashover on the double-circuit, repeated Forced Outages of the individual circuits that are part of the double-circuit in the preceding 48 hours, or fire in progress in the right of way of the double-circuit.

[NOGRR177: Replace paragraph (b) above with the following upon system implementation of NPRR857:]

(b) ERCOT shall also coordinate with TSPs and DCTOs who own and operate the Transmission Facilities associated with the double-circuit contingencies for the constraints identified above to determine whether the double-circuit failures are at a high risk of occurring due to system conditions, which may include: severe weather conditions forecasted by ERCOT in the vicinity of the double-circuit, weather conditions that indicate a high risk of insulator flashover on the double-circuit, repeated Forced Outages of the individual circuits that are part of the double-circuit in the preceding 48 hours, or fire in progress in the right of way of the double-circuit.

(c) The actions detailed in this Section shall be supplemental to the development and maintenance of Constraint Management Plans (CMPs) as otherwise directed by the Protocols or Operating Guides.

(4) When a Watch is issued for PRC below 3,000 MW, QSEs shall suspend any ongoing ERCOT-required Resource performance testing.

ERCOT Impact Analysis Report

NOGRR Number	<u>252</u>	NOGRR Title	Related to NPRR1176, Update to EEA Trigger Levels
Impact Analysis Date	April 25, 2023		
Estimated Cost/Budgetary Impact	None.		
Estimated Time Requirements	No project required. This Nodal Operating Guide Revision Request (NOGRR) can take effect upon implementation of Nodal Protocol Revision Request (NPRR) 1176, Update to EEA Trigger Levels.		
ERCOT Staffing Impacts (across all areas)	Ongoing Requirements: No impacts to ERCOT staffing.		
ERCOT Computer System Impacts	No impacts to ERCOT computer systems.		
ERCOT Business Function Impacts	No impacts to ERCOT business functions.		
Grid Operations & Practices Impacts	No impacts to ERCOT grid operations and practices.		

Evaluation of Interim Solutions or Alternatives for a More Efficient Implementation
None offered.

Comments
There are no additional impacts to this NOGRR beyond what was captured in the Impact Analysis for NPRR1176.

Board Report

OBDRR Number	**045**	**OBDRR Title**	**Additional Revisions to Demand Response Data Definitions and Technical Specifications**
Date of Decision	August 31, 2023		
Action	Recommended Approval		
Proposed Effective Date	November 1, 2023		
Priority and Rank Assigned	Not Applicable		
Other Binding Document Requiring Revision	Demand Response Data Definitions and Technical Specifications		
Supporting Protocol or Guide Section(s) / Related Documents	Protocol Section 3.10.7.2.2, Annual Demand Response Report		
Revision Description	This Other Binding Document Revision Request (OBDRR) incorporates minor edits to the Other Binding Document Demand Response Data Definitions and Technical Specifications. Changes include modifications to the list of Electric Service Identifiers (ESI IDs) provided to Retail Electric Providers (REPs) as well as a correction of several dates.		
Reason for Revision	☐ Addresses current operational issues. ☐ Meets Strategic goals (tied to the ERCOT Strategic Plan or directed by the ERCOT Board). ☐ Market efficiencies or enhancements ☒ Administrative ☐ Regulatory requirements ☐ Other: (explain) *(please select all that apply)*		
Business Case	While completing the 2022 Demand Response Survey, ERCOT identified several changes to the OBDRR that would facilitate future surveys. ERCOT requests that this OBDRR be approved in time to be made effective by the August 1 start of the 2023 Demand Response Survey process.		