~~(a) A Generation Resource; or~~

~~(b) A Load Resource providing ECRS triggered with or without under frequency relays set at 59.70 Hz.~~

(6~~4~~) The table below shows the ECRS trades that are allowed for each type of original responsibility:

	Allowable ECRS Ancillary Service Trades		
Original Responsibility	**SCED-dispatchable ECRS not from DGRs and DESRs on a Load shed circuit**	**SCED-dispatchable ECRS from DGRs and DESRs on a Load shed circuit**	**Manually dispatched ECRS**
SCED-dispatchable ECRS not from DGRs and DESRs on a Load shed circuit	Yes	No	No
SCED-dispatchable ECRS from DGRs and DESRs on a Load shed circuit	Yes	Yes	No
Manually dispatched ECRS	Yes	No	Yes

(9~~5~~) The table below shows the RRS trades that are allowed for each type of original responsibility:

	Allowable RRS Ancillary Service Trades		
Original Responsibility	**Resource providing Primary Frequency Response**	**Resource providing FFR triggered at 59.85 Hz**	**Load Resource triggered at 59.7 Hz**

Resource providing Primary Frequency Response	Yes	No	No
Resource providing FFR triggered at 59.85 Hz	Yes	Yes	Yes
Load Resource triggered at 59.7 Hz	Yes	No	Yes

(8) The table below shows the Non-Spin trades that are allowed for each type of original responsibility:

	Allowable Non-Spin Ancillary Service Trades		
Original Responsibility	**Generation Resource not DGRs and DESRs on a Load shed circuit or Controllable Load Resource**	**DGRs and DESRs on a Load shed circuit**	**Load Resource other than a Controllable Load Resource**
Generation Resource not on circuits subject to Load shed or Controllable Load Resource	Yes	No	No
DGRs and DESRs on a Load shed circuit	Yes	Yes	No
Load Resource other than a Controllable Load Resource	Yes	No	Yes

(9) A QSE with an Ancillary Service Supply Responsibility for Regulation Service may transfer that portion of its Ancillary Service Supply Responsibility via Ancillary Service Trade(s) to another QSE only if that QSE provides the transferred portion with Regulation Service that is not Fast Responding Regulation Service (FRRS). The table

below shows the Regulation Service trades that are allowed for each type of original responsibility. The same limitations apply separately to both Reg-Up and Reg-Down:

	Allowable Regulation Ancillary Service Trades	
Original Responsibility	**Regulation Service that is not FRRS**	**FRRS**
Regulation Service that is not FRRS	Yes	No
FRRS	Yes	No

4.4.7.3.1 Ancillary Service Trade Criteria

(1) Each Ancillary Service Trade must be reported by a QSE and must include the following information:

(a) The buying QSE;

(b) The selling QSE;

(c) The type of Ancillary Service;

(d) The quantity in MW; and

(e) The first and last hours of the trade.

(f) For RRS, the QSE shall indicate the quantity of the service that is provided from:

(i) Resources providing Primary Frequency Response;

(ii) FFR Resources; and

(iii) Load Resources controlled by high-set under-frequency relays.

[NPRR1014: Replace paragraph (f) above with the following upon system implementation:]

(f) For RRS, the QSE shall indicate the quantity of the service that is provided from:

(i) Resources capable of providing Primary Frequency Response;

(ii) ESRs and Load Resources providing FFR; and

(iii) Load Resources controlled by high-set under-frequency relays.

(2) For ECRS, the QSE shall indicate the quantity of the service that is provided from: ~~Resources that are~~

(a) M~~m~~anually dispatched Resources; ~~and~~

(b) ~~those that are~~ SCED-dispatchable Resources that are not DGRs and DESRs on circuits subject to Load shed; and

(c) DGRs and DESRs on circuits subject to Load shed.

(3) For Non-Spin, the QSE shall indicate the quantity of the service that is provided from:

(a) Load Resources that are not Controllable Load Resources;

(b) Generation Resources that are not DGRs or DESRs on circuits subject to Load shed and Controllable Load Resources; and

(c) DGRs and DESRs on circuits subject to Load shed.

(~~3~~4) An Ancillary Service Trade must be confirmed by both the buying QSE and selling QSE to be considered valid and to be used in an ERCOT process.

Revised ERCOT Impact Analysis Report

NPRR Number	1213	NPRR Title	Allow DGRs and DESRs on Circuits Subject to Load Shed to Provide ECRS
Impact Analysis Date		February 12, 2024	
Estimated Cost/Budgetary Impact		Between $350K and $450K	
Estimated Time Requirements		The timeline for implementing this Nodal Protocol Revision Request (NPRR) is dependent upon Public Utility Commission of Texas (PUCT) prioritization and approval; and upon system implementation of NPRR1171, Requirements for DGRs and DESRs on Circuits Subject to Load Shedding. Estimated project duration: 8 to 12 months See Comments.	
ERCOT Staffing Impacts (across all areas)		Implementation Labor: 58% ERCOT; 42% Vendor Ongoing Requirements: No impacts to ERCOT staffing.	
ERCOT Computer System Impacts		The following ERCOT systems would be impacted: • Market Operation Systems 87% • Data Management & Analytic Systems 12% • Energy Management Systems 1%	
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
ERCOT estimates that if NPRR1213 and NPRR1171 are implemented concurrently, a cost savings of 10% to 20% could be realized from project efficiencies.

Board Report

LPGRR Number	074	LPGRR Title	Align Definitions of IDRRQ, LRG, and LRGDG
Date of Decision		February 27, 2024	
Action		Recommended Approval	
Timeline		Normal	
Estimated Impacts		Cost/Budgetary: None Project Duration: No project required	
Proposed Effective Date		First of the month following Public Utility Commission of Texas (PUCT) approval	
Priority and Rank Assigned		Not applicable	
Load Profiling Guide Sections Requiring Revision		Appendix D, Profile Decision Tree – Definitions	
Related Documents Requiring Revision/Related Revision Requests		None	
Revision Description		This Load Planning Guide Revision Request (LPGRR) aligns IDRRQ, LRG, and LRGDG term language in the Profile Decision Tree "Definitions" worksheet with Profile Segment language that was added to the "Segment Assignment" worksheet upon the PUCT's approval of LPGRR069, Add Lubbock Zip Codes and Clarify BUSIDRRQ/BUSLRG (DG) Assignments, at their December 15, 2022 meeting.	
Reason for Revision		☐ Strategic Plan Objective 1 – Be an industry leader for grid reliability and resilience ☐ Strategic Plan Objective 2 - Enhance the ERCOT region's economic competitiveness with respect to trends in wholesale power rates and retail electricity prices to consumers ☐ Strategic Plan Objective 3 - Advance ERCOT, Inc. as an independent leading industry expert and an employer of choice by fostering innovation, investing in our people, and emphasizing the importance of our mission	

Board Report

	☒ General system and/or process improvement(s) ☐ Regulatory requirements ☐ ERCOT Board and/or PUCT Directive *(please select ONLY ONE – if more than one apply, please select the ONE that is most relevant)*
Justification of Reason for Revision and Market Impacts	This LPGRR applies consistency across the Profile Decision Tree, in alignment with approved LPGRR069 language.
RMS Decision	On 1/9/24, RMS voted unanimously to recommend approval of LPGRR074 as submitted. All Market Segments participated in the vote. On 2/6/24, RMS voted unanimously to endorse and forward to TAC the 1/9/24 RMS Report and the 1/23/24 Impact Analysis for LPGRR074. All Market Segments participated in the vote.
Summary of RMS Discussion	On 1/9/24, RMS reviewed LPGRR074. On 2/6/24, RMS reviewed the 1/23/24 Impact Analysis.
TAC Decision	On 2/14/24, TAC voted unanimously to recommend approval of LPGRR074 as recommended by RMS in the 2/6/24 RMS Report. All Market Segments participated in the vote.
Summary of TAC Discussion	On 2/14/24, there was no additional discussion beyond TAC review of the items below.
TAC Review/Justification of Recommendation	☒ Revision Request ties to Reason for Revision as explained in Justification ☒ Impact Analysis reviewed and impacts are justified as explained in Justification ☒ Opinions were reviewed and discussed ☒ Comments were reviewed and discussed (if applicable) ☐ Other: (explain)
ERCOT Board Decision	On 2/27/24, the ERCOT Board voted unanimously to recommend approval of LPGRR074 as recommended by TAC in the 2/14/24 TAC Report.

Board Report

Opinions	
Credit Review	Not Applicable
Independent Market Monitor Opinion	IMM has no opinion on LPGRR074.
ERCOT Opinion	ERCOT supports approval of LPGRR074.
ERCOT Market Impact Statement	ERCOT Staff has reviewed LPGRR074 and believes that it provides a positive market impact by offering general system and/or process improvement(s) by aligning IDRRQ, LRG, and LRGDG term language in the Profile Decision Tree with Profile Segment language that was added upon the PUCT's approval of LPGRR069.

Sponsor	
Name	Sam Pak on behalf of Profile Working Group (PWG)
E-mail Address	sam.pak@oncor.com
Company	Oncor
Phone Number	214-486-4120
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**
None	

Market Rules Notes

None

Proposed Guide Language Revision

Board Report

Appendix D, Profile Decision Tree - "Definitions" worksheet

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), or if 4-CP is not applicable to utility tariffs, a peak Demand greater than 700 kW or kVA.	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, or if 4-CP is not applicable to utility tariffs, a peak Demand greater than 700 kW or kVA.	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, or if 4-CP is not applicable to utility tariffs, a peak Demand greater than 700 kW or kVA.	Segment Assignment tab

ERCOT Impact Analysis Report

LPGRR Number	074	LPGRR Title	Align Definitions of IDRRQ, LRG, and LRGDG
Impact Analysis Date		January 23, 2024	
Estimated Cost/Budgetary Impact		None.	
Estimated Time Requirements		No project required. This Load Planning Guide Revision Request (LPGRR) 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	261	NOGRR Title	Move OBD to Section 8 – Procedure for Calculating RRS Limits for Individual Resources
Date of Decision		February 27, 2024	
Action		Recommended Approval	
Timeline		Normal	
Estimated Impacts		Cost/Budgetary: Less than $5k (Operations & Maintenance (O&M)) Project Duration: No project required	
Proposed Effective Date		Upon system implementation	
Priority and Rank Assigned		Not applicable	
Nodal Operating Guide Sections Requiring Revision		2.3.1.2.1, Limit on Generation Resources and Controllable Load Resources Providing RRS Section 8, Attachment N, Procedure for Calculating Responsive RRS Limits for Individual Resources (new)	
Related Documents Requiring Revision/Related Revision Requests		Procedure for Calculating Responsive Reserve (RRS) Limits for Individual Resources (Upon approval of this NOGRR, this will be removed from the Other Binding Documents List.)	
Revision Description		This Nodal Operating Guide Revision Request (NOGRR) incorporates the Other Binding Document "Procedure for Calculating Responsive Reserve (RRS) Limits for Individual Resources" into the Nodal Operating Guide.	
Reason for Revision		☐ Strategic Plan Objective 1 – Be an industry leader for grid reliability and resilience ☐ Strategic Plan Objective 2 - Enhance the ERCOT region's economic competitiveness with respect to trends in wholesale power rates and retail electricity prices to consumers ☐ Strategic Plan Objective 3 - Advance ERCOT, Inc. as an independent leading industry expert and an employer of choice by fostering innovation, investing in our people, and emphasizing the importance of our mission ☒ General system and/or process improvement(s)	

Board Report

	☐ Regulatory requirements ☐ ERCOT Board/PUCT Directive *(please select ONLY ONE – if more than one apply, please select the ONE that is most relevant)*
Justification of Reason for Revision and Market Impacts	This NOGRR is published for transparency and to standardize the approval process for all binding language.
ROS Decision	On 1/8/24, ROS voted unanimously to waive notice to consider NOGRR261, and to recommend approval of NOGRR261 as submitted. All Market Segments participated in the vote. On 2/1/24, ROS voted unanimously to endorse and forward to TAC the 1/8/24 ROS Report and 12/21/23 Impact Analysis for NOGRR261. All Market Segments participated in the vote.
Summary of ROS Discussion	On 1/8/24, participants noted NOGRR261 is part of an ongoing effort to move Other Binding Documents into the Protocols and Guides. On 2/1/24, participants reviewed the 12/21/23 Impact Analysis.
TAC Decision	On 2/14/24, TAC voted unanimously to recommend approval of NOGRR261 as recommended by ROS in the 2/1/24 ROS Report. All Market Segments participated in the vote.
Summary of TAC Discussion	On 2/14/24, there was no additional discussion beyond TAC review of the items below.
TAC Review/Justification of Recommendation	☒ Revision Request ties to Reason for Revision as explained in Justification ☒ Impact Analysis reviewed and impacts are justified as explained in Justification ☒ Opinions were reviewed and discussed ☒ Comments were reviewed and discussed (if applicable) ☐ Other: (explain)
ERCOT Board Decision	On 2/27/24, the ERCOT Board voted unanimously to recommend approval of NOGRR261 as recommended by TAC in the 2/14/24 TAC Report.

Opinions

Board Report

Credit Review	Not applicable
Independent Market Monitor Opinion	The Independent Market Monitor (IMM) has no opinion on NOGRR261.
ERCOT Opinion	ERCOT supports approval of NOGRR261.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NOGRR261 and believes it has a positive market impact by standardizing the approval process for binding language.

Sponsor	
Name	Ann Boren
E-mail Address	Ann.Boren@ercot.com
Company	ERCOT
Phone Number	512-248-6465
Cell Number	
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

To improve transparency, existing Other Binding Document language for new Section 8, Attachment N, is represented as blackline, with only proposed changes marked as redline.

Proposed Nodal Operating Guide Language Revision

2.3.1.2.1 Limit on Generation Resources and Controllable Load Resources Providing RRS

(1) ERCOT shall establish MW limits on individual Resource's ability to provide RRS using Primary Frequency Response. The MW limit shall be based on Generating Resource and Controllable Load Resource performance during Frequency Measurable Events (FME).

~~(2) ERCOT shall develop a Technical Advisory Committee (TAC) approved procedure that describes the methodology to calculate the MW limit on individual Resources using the Resource's actual performance during FMEs.~~

(2~~3~~) The default maximum MW limit of Primary Frequency Response shall be set to 20% of its High Sustained Limit (HSL) for any newly RRS-qualified Generation Resource or Generation Resource not yet evaluated per ~~the TAC-approved methodology~~Section 8, Attachment N, Procedure for Calculating RRS Limits for Individual Resources, for measuring actual performance.

(3~~4~~) A Private Use Network with a registered Resource may use the gross HSL for qualification and establishing a limit on the amount of RRS capacity that the Resource within the Private Use Network can provide.

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ERCOT Nodal Operating Guide

Section 8

Attachment N: Procedure for Calculating ~~Responsive~~ ~~Reserve (~~RRS~~)~~ Limits for Individual Resources

~~Effective Date: August 1, 2020~~

Date TBD

~~Protocol Disclaimer~~

~~This document describes ERCOT Systems and the response of these systems to Market Participant submissions incidental to the conduct of operations in the ERCOT Texas Nodal Market implementation and is not intended to be a substitute for the ERCOT Nodal Protocols (available at http://www.ercot.com/mktrules/nprotocols/current), as amended from time to time. If any conflict exists between this document and the ERCOT Nodal Protocols, the ERCOT Nodal Protocols shall control in all respects.~~

Table of Contents

1. Introduction

~~Nodal Operating Guide Section 2.3.1.2.1, Limit on Generation Resources and Controllable Load Resources Providing RRS, requires that ERCOT develop a Technical Advisory Committee (TAC) approved procedure that describes the methodology to calculate megawatt (MW) limits for Resources providing Responsive Reserve (RRS).~~

~~2. Change Control Process~~

~~The Performance, Disturbance, Compliance Working Group (PDCWG) is responsible for maintaining and updating the "Procedure for Calculating Responsive Reserve (RRS) Limits for Individual Resources".~~ Changes to this ~~document~~ attachment shall be reviewed by the Performance, Disturbance, Compliance Working Group (PDCWG) ~~and Reliability and Operations Subcommittee (ROS) prior to approval by TAC~~.

~~In the following cases, after review and recommendation by TAC, revisions to this document must be approved by the ERCOT Board:~~

~~a. The revisions require an ERCOT project for implementation; and~~

~~b. The revisions are related to a Nodal Protocol Revision Request (NPRR), a Planning Guide Revision Request (PGRR), or a revision request requiring an ERCOT project for implementation.~~

~~Upon approval of revisions, ERCOT shall post the revised procedure to the ERCOT website within three Business Days.~~

23. Responsive Reserve Service

Response Reserve (RRS) is an operating reserve on Generation Resources, Load Resources, and Resources capable of providing Fast Frequency Response (FFR) maintained by ERCOT to help control the frequency of the system. RRS on Generation Resources and Controllable Load Resources that are capable of providing Primary Frequency Response can be released to Security-Constrained Economic Dispatch (SCED) during scarcity conditions as outlined in ~~Nodal Operating Guide~~ Section 4.8, Responsive Reserve Service During Scarcity Conditions.

34. RRS MW Limits for Individual Resources

Thermal Resources that do not meet the 12 months or the last eight Frequency Measurable Events (FMEs) (applicable if a minimum threshold of eight FMEs within the 12 month period is not met) rolling average criteria, or have failed to score greater than or equal to 0.75 for Primary Frequency Response initial or Primary Frequency Response sustained measures (computed per ~~Nodal Operating Guide~~ Section 8, Attachment J, Initial and Sustained Measurements for Primary Frequency Response)

for three consecutive FMEs, where the unit was evaluated, over a minimum period of two calendar months, will be subject to review of their respective RRS limit using the process outlined in Section 4~~5~~ below. All other thermal Resources shall continue to be limited to 20% of their respective High Sustained Limit (HSL) as their RRS limit.

The default MW limit for any new thermal Generation Resource or Controllable Load Resource providing RRS shall be set to 20% of its HSL or Maximum Power Consumption (MPC), as appropriate. A Private Use Network with a registered Resource may use its gross HSL for qualifying and establishing a limit on the amount of RRS capacity that the Resources within the Private Use Network can provide.

RRS limits for non-thermal Resources or Generation Resources with a Resource Category of either (i) aeroderivative simple cycle commissioned after 1996, or (ii) Reciprocating Engines may be updated to be higher or lower than 20% threshold based on their droop performance characteristics, actual tests, and the need to keep the frequency responsive capability fairly distributed across multiple Resources. Based on Protocol Section 3.18, Resource Limits in Providing Ancillary Service, (i) Generation Resources operating in synchronous condenser fast-response mode may provide RRS up to the Generation Resource's ERCOT-validated 20-second response capability (which may be 100% of their HSL), and (ii) Resources providing RRS as FFR may provide RRS up to the Resource's ERCOT-validated 15-minute capability.

4~~5~~. Calculating RRS MW Limits for Individual Resources

For Resources that fail the Primary Frequency Response initial or Primary Frequency Response sustained measures for three consecutive FMEs, where the unit was evaluated, over a minimum period of two calendar months or are failing the 12 months or the last eight FMEs (applicable if a minimum threshold of eight FMEs within the 12 month period is not met) rolling average criteria, ERCOT shall establish MW limit for providing RRS based on their respective performance during FMEs, any limitations exhibited within its dynamic models, or through droop performance tests on as needed basis.

If the RRS limit is to be determined based upon the Resource's performance during an FME, then such RRS limit shall be calculated as follows,

1. The MW Limit for each Generation Resource and Controllable Load Resource will be calculated using the droop performance during an FME. The Calculated Droop Performance and RRS MW Limit for an FME is calculated as follows:

$$Calculated\ Droop\ Performance\ (Droop) = \frac{(HSL - PA\ Capacity)\ *\ (\Delta Hz\ -\ Deadband_{max})}{ScheduledFrequency\ *\ \Delta MW}$$

$$Calculated\ RRS\ MW\ Limit\ (\%) = \frac{0.01 * ScheduledFrequency - Deadband_{max}}{ScheduledFrequency * Droop} * 100$$

Delta Hertz (ΔHz): The pre-perturbation [the 16-second period of time before t(0)] average frequency minus the post-perturbation [the 32-second period of time starting 20 seconds after t(0)] average frequency

Delta MW (ΔMW): The pre-perturbation average MW of the Resource minus the post-perturbation average MW of the Resource

Scheduled Frequency: The frequency value to be maintained on the system, always 60 Hz

Power Augmentation (PA) Capacity: The telemetered portion of a Generation Resource's HSL that represents the sustainable non-Dispatched power augmentation capability from duct firing, inlet air cooling, auxiliary boilers, or other methods which does not immediately respond, arrest, or stabilize frequency excursions during the first minutes following a disturbance without secondary frequency response or instructions from ERCOT

Deadband ($Deadband_{max}$): The range of deviations of system frequency (+/-) that produces no PFR

2. The median of the calculated MW Limits in the last five FMEs where the unit was evaluated will be computed for each individual Generation Resource and Controllable Load Resource. If Resource hasn't participated in five FMEs, proceed to Step 3.

3. The median of all FMEs during previous three months where the unit was evaluated will be computed for each individual Generation Resource and Controllable Load Resource.

4. RRS MW limit will be established based on lower of the values computed in Steps 2 and 3.

If a Generation Resource's or Controllable Load Resource's performance during an FME is excluded per the current process (NERC Reliability Standard BAL-TRE-001) from the rolling average calculation, the Resource's performance will also be excluded from the RRS MW Limit calculation. Also note that all members of a Combined Cycle Generation Resource will be evaluated as one Generation Resource for the purposes of this evaluation.

56. Timeline to Establish RRS MW Limits

ERCOT will recalculate the MW Limit on each individual Generation Resource and Controllable Load Resource on a monthly basis. ERCOT shall post on the Market Information System (MIS) Certified area the MW limit for each Resource qualified to provide RRS by the 10th day of each month. These RRS limits will be effective in

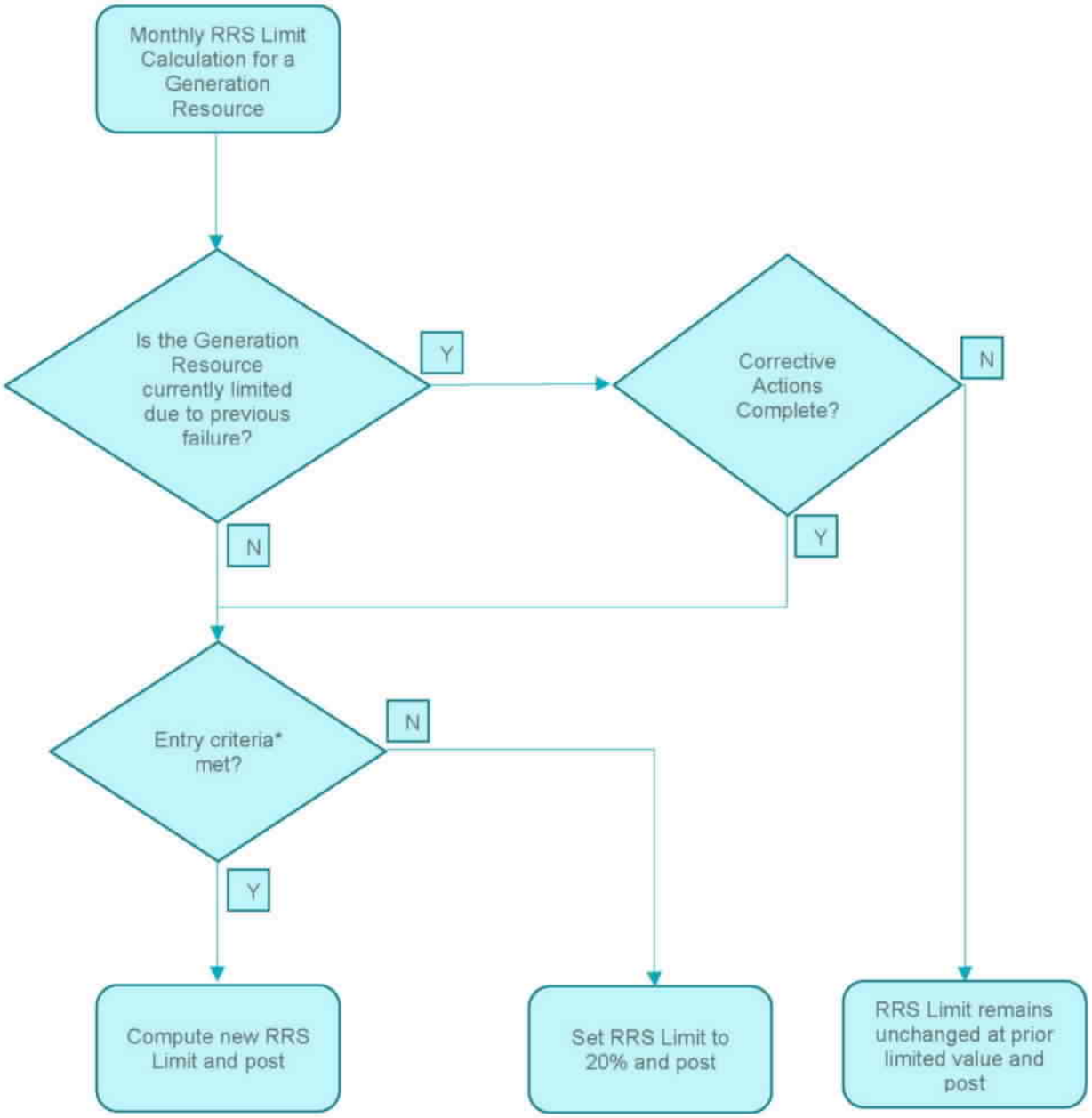
ERCOT systems coincident with first Network Model Database Load[1] two months later. For example, ERCOT shall post the MW Limit for each Resource by January 10, 2020. These RRS Limits will be effective in ERCOT systems beginning March 4, 2020. These recalculated values will follow any threshold limitations as expressed in Section 34 above.

If at the time of recalculation, a Generation Resource or Controllable Load Resource was previously limited due to any failure mentioned in Section 45 above, then the established RRS limit will continue to apply. In order to reset the RRS limit, Generation Resource or Controllable Load Resource may use dynamic models, droop performance tests, or documentation of an implemented corrective action plan to demonstrate that it is capable of carrying standard RRS limit as mentioned in Section 34 above.

[1] The most recent Network Model Database Load Schedules can be accessed at the following link.
http://www.ercot.com/gridinfo/transmission/opsys-change-schedule.html

Appendix RRS Limit Decision Tree

The diagram below describes at a high level the decision tree this procedure will compute a RRS limit for every Generation Resource. In the event there is a conflict between the diagram below and text stated in the sections above, the language stated in text above takes precedence.



*failed rolling average or score in last three evaluated events in two consecutive months < 0.75

ERCOT Impact Analysis Report

NOGRR Number	261	NOGRR Title	Move OBD to Section 8 – Procedure for Calculating RRS Limits for Individual Resources
Impact Analysis Date		December 21, 2023	
Estimated Cost/Budgetary Impact		Less than $5k, 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 3-5 days 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: • ERCOT Website and MIS Systems 67% • Channel Management Systems 33%	
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

PGRR Number	109	PGRR Title	Dynamic Model Review Process Improvement for Inverter-Based Resource (IBR) Modification
Date of Decision		February 27, 2024	
Action		Recommended Approval	
Timeline		Normal	
Estimated Impacts		Cost/Budgetary: None Project Duration: Not applicable	
Proposed Effective Date		First of month following Public Utility Commission of Texas (PUCT) approval	
Priority and Rank Assigned		Not applicable	
Planning Guide Sections Requiring Revision		5.2.1, Applicability 5.5, Generator Commissioning and Continuing Operations 6.2, Dynamics Model Development	
Related Documents Requiring Revision/Related Revision Requests		None	
Revision Description		This Planning Guide Revision Request (PGRR) introduces a new requirement for Interconnecting Entities (IEs) associated with Inverter-Based Resources (IBRs) to undergo a dynamic model review process prior to the Resource Commissioning Date. Additionally, this PGRR mandates that Resource Entities owning or controlling operational IBRs must undergo a review process before implementing modification to any control settings or equipment that impact the dynamic response (e.g., voltage, frequency, and current injections) at the Point of Interconnection (POI). As part of the review process, ERCOT shall review the model quality tests submitted by an IE or Resource Entity. In the case of operational IBRs, the review process may require the interconnecting Transmission Service Provider (TSP) conducting a limited dynamic stability study to compare and evaluate the electrical performance before and after the proposed modifications.	
Reason for Revision		[X] Strategic Plan Objective 1 – Be an industry leader for grid reliability and resilience	

Board Report

	☐ Strategic Plan Objective 2 - Enhance the ERCOT region's economic competitiveness with respect to trends in wholesale power rates and retail electricity prices to consumers ☐ Strategic Plan Objective 3 - Advance ERCOT, Inc. as an independent leading industry expert and an employer of choice by fostering innovation, investing in our people, and emphasizing the importance of our mission ☐ General system and/or process improvement(s) ☐ Regulatory requirements ☐ ERCOT Board/PUCT Directive *(please select ONLY ONE – if more than one apply, please select the ONE that is most relevant)*
Justification of Reason for Revision and Market Impacts	IBRs have distinct design and operational characteristics compared to conventional synchronous generators. Unlike synchronous generators, the performance of IBRs relies mainly on power electronics controls, which make them highly responsive and sensitive to even minor adjustments in control settings. Therefore, even minor adjustments to control settings can have a substantial impact on the grid. Currently, there is no review process in place for IBRs before the Resource Commissioning Date to ensure that the "as-built" data accurately represent the parameters and performance of the as-studied data that were used in the quarterly stability assessment. Before a new IBR can commence commercial operation, it should provide substantial evidence demonstrating that its as-built performance and installed control parameters align with the model utilized in the quarterly stability assessment. In addition, if modifications to operational IBRs fall outside of applicability as described in paragraph (1)(c) of Section 5.2.1 Resource Entities are not required to undergo any review process. The only requirement is for Resource Entities to submit dynamic model updates, model quality tests, and plant verification reports after implementing the changes in the field. Modifications made to settings or equipment by Resource Entities without undergoing a review process can potentially result in unexpected trips or unstable responses during disturbances. Having a proper review process in place is crucial to ensuring that such modifications are thoroughly reviewed before being implemented in the field.

Board Report

	This PGRR is aligned with the recommendations from the North American Electric Reliability Corporation (NERC) as described in the 2022 Odessa Disturbance report.
ROS Decision	On 8/3/23, ROS voted unanimously to table PGRR109 and refer the issue to the Inverter-Based Resource Working Group (IBRWG) and Planning Working Group (PLWG). All Market Segments participated in the vote. On 12/7/23, ROS voted unanimously to recommend approval of PGRR109 as amended by the 11/17/23 ERCOT comments. All Market Segments participated in the vote. On 1/8/24, ROS voted unanimously to endorse and forward to TAC the 12/7/23 ROS Report and the 7/18/23 Impact Analysis for PGRR109. All Market Segments participated in the vote.
Summary of ROS Discussion	On 8/3/23, participants reviewed PGRR109 and commented that details such as modifications to settings need to be discussed further and recommended this item be referred to the PLWG and IBRWG. On 12/7/23, participants reviewed the 11/17/23 ERCOT comments. On 1/8/24, participants reviewed the 7/18/23 Impact Analysis.
TAC Decision	On 1/24/24, TAC voted unanimously to recommend approval of PGRR109 as recommended by ROS in the 1/8/24 ROS Report. All Market Segments participated in the vote.
Summary of TAC Discussion	On 1/24/24, there was no discussion beyond TAC review of the items below.
TAC Review/Justification of Recommendation	[X] Revision Request ties to Reason for Revision as explained in Justification [X] Impact Analysis reviewed and impacts are justified as explained in Justification [X] Opinions were reviewed and discussed [X] Comments were reviewed and discussed (if applicable) [ ] Other: (explain)
Board Decision	On 2/27/24, the ERCOT Board voted unanimously to recommend approval of PGRR109 as recommended by TAC in the 1/24/24 TAC Report.

Opinions

Board Report

Credit Review	Not applicable
Independent Market Monitor Opinion	IMM has no opinion on NPRR1207.
ERCOT Opinion	ERCOT supports approval of PGRR109.
ERCOT Market Impact Statement	ERCOT Staff has reviewed PGRR109 and believes the market impact for PGRR109 is that it improves the dynamic model review process for IBRs by establishing a new requirement for IEs associated with IBRs to undergo a dynamic model review process prior to Resource Commissioning Date, and requiring a review process for operational IBRs before implementing modification to any control settings or equipment that impact the dynamic response (such as voltage, frequency, and current injections) at the POI. In certain cases for operational IBRs, it requires the interconnecting TSPs conducting a limited dynamic stability study to compare and evaluate the electrical performance before and after the proposed modifications.

Sponsor	
Name	Sun Wook Kang
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Company	ERCOT
Phone Number	512-248-4159
Cell Number	
Market Segment	Not applicable

Market Rules Staff Contact	
Name	Erin Wasik-Gutierrez
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Phone Number	413-886-2474

Comments Received	
Comment Author	**Comment Summary**
TAEBA 100423	Proposed revisions condensing the process for new interconnections
ERCOT 101023	Indicated ERCOT does not support the 10/4/23 TAEBA comments

Joint Commenters 101723	Explained PGRR109 would create a burdensome pre-approval process and may result in redundant efforts on IBR owners, TSPs and ERCOT Staff and proposed revisions to address these concerns
ERCOT 110723	Indicated ERCOT does not support most of the revisions reflected in the 10/17/23 Joint Commenters comments
ERCOT 111723	Clarified language concerning the temporary implementation of proposed modifications

Market Rules Notes

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

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

- PGRR103, Establish Time Limit for Generator Commissioning Following Approval to Synchronize (incorporated 11/1/23)
  - Section 5.5

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

- PGRR114, Related to NPRR1212, Clarification of Distribution Service Provider's Obligation to Provide an ESI ID
  - Section 5.5

Proposed Guide Language Revision

5.2.1 Applicability

(1) The requirements in Section 5, Generator Interconnection or Modification, apply to the following:

(a) Any Entity proposing to interconnect any generator with an aggregate nameplate capacity of one MW or greater, including but not limited to any Generation Resource or Energy Storage Resource (ESR), to the ERCOT System;

(b) Any Entity proposing to interconnect a Settlement Only Generator (SOG) to the ERCOT System; or

(c) Any Resource Entity seeking to modify a Generation Resource, ESR, or SOG that is connected to the ERCOT System by:

(i) Increasing the real power rating from that shown in the latest Resource Registration data by one MW or greater within a single year;

(ii) Changing the inverter, turbine, generator, or power converter associated with a facility with an aggregate real power rating of ten MW or greater, unless the replacement is in-kind;

(iii) ~~(iii)~~ Modifying any control settings or equipment of Inverter-Based Resources (IBRs) that impact the dynamic response (such as voltage, frequency, and current injections) at the Point of Interconnection (POI) in a manner that is deemed to require further study in accordance with the process outlined in paragraph (5) of Section 5.5, Generator Commissioning and Continuing Operations; ~~Changing any settings or equipment associated with Inverter-Based Resources (IBRs) in a manner that is deemed to require further study in accordance with the process outlined in paragraph (4) of Section 5.5, Generator Commissioning and Continuing Operations.~~

(~~iii~~iv~~iii~~v) Changing or adding a ~~Point of Interconnection (~~POI~~)~~ to a facility with an aggregate real power rating of ten MW or greater; or

(~~ii~~v) Increasing the aggregate nameplate capacity of a generator less than ten MW to ten MW or greater.

(2) For the purposes of Section 5, the term "generator" includes but is not limited to a Generation Resource, SOG, and ESR.

(3) For the purposes of determining the appropriate requirements in Section 5, a generator is considered a "large generator" if it currently has or is proposed to have an aggregate nameplate capacity of ten MW or greater. A generator is considered a "small generator" if it currently has or is proposed to have an aggregate nameplate capacity of less than ten MW.

(4) Notwithstanding paragraph (3), above, if a Resource Entity is proposing to increase the real power rating of an existing generator by one MW or greater but less than ten MW, that generator shall be considered a small generator for the purposes of the interconnection process described in Section 5.

(5) Notwithstanding paragraphs (3) and (4), above, if a Resource Entity is proposing to increase a generator's real power rating by ten MW or more, or is proposing to increase a generator's real power rating from less than ten MW to ten MW or more, that generator shall be considered a large generator for the purposes of the interconnection process described in Section 5.

(6) For the purposes of determining the appropriate requirements in Section 5, ERCOT may require two or more separate generator interconnection requests to the same substation to follow the interconnection process applicable to the large generators, if, following the proposed change, those generators would have an aggregate nameplate capacity of ten MW or greater, and the projects are proposed by the same Entity or Affiliates.

(7) For a new or modified generator that has been designated as a Self-Limiting Facility or as a component of a Self-Limiting Facility, the categorization of the generator as a small generator or large generator pursuant to paragraphs (3) through (5) above shall be determined using the Self-Limiting Facility's established limit on the total MW Injection, or if applicable, the proposed increase in that value instead of the nameplate capacity of the Self-Limiting Facility.

5.5 Generator Commissioning and Continuing Operations

Commented [EWG1]: Please note PGRR114 also proposes revisions to this section.

(1) For each interconnecting Generation Resource or Energy Storage Resource (ESR), each Interconnecting Entity (IE) shall meet the conditions established by ERCOT before proceeding to Initial Energization, Initial Synchronization, and commercial operations. These conditions may require proof of meeting applicable ERCOT requirements, which may include, but are not limited to, reactive capability, voltage ride-through standards, dynamic model template submission, Automatic Voltage Regulator (AVR), Primary Frequency Response, Power System Stabilizer (PSS), Subsynchronous Resonance (SSR) models, and telemetry.

(2) Within 300 days of receiving ERCOT's approval for Initial Synchronization above 20 MVA of a new or repowered Generation Resource or ESR, a Resource Entity shall ensure the Resource meets the conditions established by ERCOT for commercial operations and shall submit a request to ERCOT to commission the Resource.

In the event a Generation Resource or ESR will be unable to complete all necessary construction and required testing to commence commercial operations and connect reliably to the ERCOT System within the 300 days, the Generation Resource or ESR may request a good cause exception with sufficient detail, and shall notify ERCOT prior to the planned commercial operation date and provide ERCOT with an updated commercial operation date that the Generation Resource or ESR can reasonably expect to commence operations in a reliable manner.

(~~2~~3) Prior to the Resource Commissioning Date of an Inverter-Based Resource (IBR), the IE associated with the IBR shall submit the appropriate dynamic models for the "as-built" data and the data submitted for the quarterly stability assessment, documentation clearly indicating any differences, results of the model quality tests of the "as-built" data overlaid with the results of the data submitted for the quarterly stability assessment, and associated simulation files pursuant to paragraph (5)(c) of Section 6.2, Dynamics Model Development. Submissions shall be sent electronically to Dynamicmodels@ercot.com for ERCOT review, and the phrase "IBR prior to commissioning" must be included in the subject line of the submission email. ERCOT shall respond to the IE within 10 Business Days of the submission, indicating whether the submission is acceptable or if additional information is required. If additional time is needed for review, ERCOT can extend this review period by ~~up to~~ an additional 20 Business Days, and an email will be sent to notify the IE that it needs additional time to review the submission. The time for ERCOT to review models and associated documentation will be a qualified cause to extend the allowed time to complete the conditions established by ERCOT for commercial

operations. ~~The IE shall track and include accumulated delays in any request for extension of the time limit for completion of the conditions for commercial operations.~~

(~~3~~4) No later than 30 days following the Resource Commissioning Date, the Resource Entity shall submit updates to the resource dynamic planning and operations models through the online Resource Integration and Ongoing Operations (RIOO) system based on "as-built" ~~or "as-tested"~~ data and provide a plant verification report as required by paragraph (5)(b) of Section 6.2~~, Dynamics Model Development~~. Pursuant to paragraph (5)(c) of Section 6.2, the ~~IE~~ Resource Entity shall include model updates with model quality tests.

(~~4~~35) During continuing operations:

(a) Prior to the implementation of ~~any~~ modification to ~~settings or~~ any control settings or equipment ~~associated with~~of an IBRs~~s~~ that impacts ~~affects electrical performance would alter~~ the dynamic response (such as voltage, frequency, and current injections) ~~of the facility~~ at the Point of Interconnection (POI), ~~and requires dynamic model updates, and not already described in paragraph (1)(e) of Section 5.2.1, Applicability,~~ the proposed modification shall be reviewed by the interconnecting Transmission Service Provider (TSP) and ERCOT:~~;~~

(i) The Resource Entity shall submit the appropriate dynamic model for the proposed modification, results of the model quality tests overlaid with the results before the modification, and associated simulation files pursuant to paragraph (5)(c) of Section 6.2. Submissions shall be sent electronically to Dynamicmodels@ercot.com for ERCOT review, and the phrase "IBR proposed modification" must be included in the subject line of the submission email. The Resource Entity may withdraw its modification plan at any time during the review process if the Resource Entity no longer wishes to proceed with the modification.

(ii) ERCOT shall respond to the Resource Entity within 10 Business Days of the submission in paragraph (i) above, indicating whether the submission is acceptable or if additional information is required. ERCOT can extend this review period by ~~up to~~ an additional 20 Business Days, and an email will be sent to notify the Resource Entity that it needs additional time to review the submission.

(iii) Upon completing its review of the model quality tests, ERCOT shall notify the Resource Entity and the interconnecting TSP of its determination. The notification will indicate one of the following:

(A) ERCOT recommends that the interconnecting TSP conduct a limited dynamic stability study comparing electrical performance before and after the proposed modification, and reasonably evaluate whether the proposed modification may present dynamic stability risks that should be subject to further study.

(B) The proposed modification is applicable to paragraph (1)(c)(iii) of Section 5.2.1. The Resource Entity shall initiate a Generator Interconnection or Modification (GIM) request through RIOO.

(C) The proposed modification is deemed unacceptable.

(D) The proposed modification is deemed acceptable without need for a dynamic stability study.

~~ERCOT recommends that the interconnecting TSP conduct a limited dynamic stability study comparing electrical performance before and after the proposed modification, and reasonably evaluate whether the proposed modification may present dynamic stability risks that should be subject to further study.~~

~~The proposed modification is applicable to paragraph (1)(c)(iii) of Section 5.2.1, Applicability. The Resource Entity shall initiate a Generator Interconnection or Modification (GIM) request through RIOO.~~

~~The proposed modification is deemed unacceptable.~~

~~The proposed modification is deemed acceptable without need for a dynamic stability study.~~

(iv) Within 90 days of the receipt of the accepted submission in paragraph (iii)(A) above, the interconnecting TSP shall submit its dynamic stability study report to ERCOT electronically to Dynamicmodels@ercot.com.

(v) ERCOT shall review the dynamic stability study report submitted by the interconnecting TSP within 10 Business Days. ERCOT can extend this review period by ~~up to~~ an additional 20 Business ~~d~~Days, and an email will be sent to notify the interconnecting TSP and the Resource Entity that it needs additional time to review the dynamic stability study report.

(vi) Upon completing its review and ERCOT acceptance of the dynamic stability study report, ERCOT shall notify the Resource Entity and the interconnecting TSP of its determination. The notification will indicate one of the following:

(A) The proposed modification is deemed acceptable.

(B) The proposed modification is applicable to paragraph (1)(c) of Section 5.2.1. The Resource Entity shall initiate a GIM request through RIOO.

~~The proposed modification is deemed acceptable.~~

~~The proposed modification is applicable to paragraph (1)(c)(iii) of Section 5.2.1. The Resource Entity shall initiate a GIM request through RIOO.~~

(vii) ERCOT, in consultation with the interconnecting TSP, may allow the proposed changes to be temporarily implemented prior to the ~~completion of the~~ above review process in order to address any identified performance deficiency.

~~(b) When there have been modifications to settings associated with IBRs that alter the dynamic response of the facility at the POI and require dynamic model updates as required by paragraph (5) of Section 6.2, the Resource Entity will notify ERCOT of the modification in RIOO as soon as practicable and those updated models shall be submitted to ERCOT within 180 days of making the modification(s) and be reviewed by the interconnecting TSP and ERCOT:~~

~~(i) The Resource Entity shall submit the appropriate dynamic model reflecting the modification(s), results of the model quality tests overlaid with the results before the modification(s), and associated simulation files pursuant to paragraph (5)(c) of Section 6.2. Submissions shall be sent electronically to Dynamicmodels@ercot.com for ERCOT review, and the phrase "IBR settings modification" must be included in the subject line of the submission email. The Resource Entity may withdraw its model modification at any time during the review process if the Resource Entity reverts the modification of settings.~~

~~(ii) ERCOT shall respond to the Resource Entity within 10 Business Days of the submission in paragraph (i) above, indicating whether the submission is acceptable or if additional information is required. ERCOT can extend this review period by up to an additional 20 Business Days, and an email will be sent to notify the Resource Entity that it needs additional time to review the submission.~~

~~(iii) Upon completing its review of the model quality tests, ERCOT shall notify the Resource Entity and the interconnecting TSP of its determination. The notification will indicate one of the following:~~

~~(A) ERCOT recommends that the interconnecting TSP conduct a limited dynamic stability study comparing electrical performance before and after the settings modification, and reasonably evaluate whether the settings modification may present unintended dynamic stability risks that should be subject to further study.~~

~~(B) The settings modification is deemed unacceptable, and settings changes should be reverted.~~

~~(C) The settings modification is deemed acceptable without need for a dynamic stability study.~~

~~(iv) Within 90 days of the receipt of the accepted submission in paragraph (iii)(A) above, the interconnecting TSP shall submit its dynamic stability study report to ERCOT electronically to Dynamicmodels@ercot.com.~~

~~(v) ERCOT shall review the dynamic stability study report submitted by the interconnecting TSP within 10 Business Days. ERCOT can extend this review period by up to an additional 20 Business Days, and an email will be sent to notify the interconnecting TSP and the Resource Entity that it needs additional time to review the dynamic stability study report.~~

~~(vi) Upon completing its review and ERCOT acceptance of the dynamic stability study report, ERCOT shall notify the Resource Entity and the interconnecting TSP of its determination. The notification will indicate one of the following:~~

~~(A) The modification is deemed acceptable.~~

~~(B) The settings modification is deemed unacceptable, and settings changes should be reverted within five days of notification.~~

(~~b~~eb) Pursuant to paragraph (5)(c) of Section 6.2, the Resource Entity shall include model updates with model quality tests.

(~~b~~edc) The Resource Entity shall provide ERCOT with a plant verification report as required by paragraph (5)(b) of Section 6.2 at the following times:

(i) No later than 30 days after implementing a settings change as required by paragraph (7) of Section 6.2~~ for changes that do not require dynamic model updates, and no later than 180 days after implementing settings changes that do require model updates~~;

(ii) No earlier than 12 months and no later than 24 months following the later of the Resource Commissioning Date or March 1, 2021; and

(iii) A minimum of every ten years.

6.2 Dynamics Model Development

(1) To adequately simulate dynamic and transient events in the ERCOT System, it is necessary to establish and maintain dynamics data and simulation-ready study cases representing the dynamic capability and frequency characteristics of machines and equipment connected to the ERCOT System.

(2) Dynamics data is the network data and mathematical models required in accordance with the Reliability and Operations Subcommittee (ROS)-approved Dynamics Working Group Procedure Manual for simulation of dynamic and transient events in the ERCOT System.

(3) For Resource Entities, dynamics data includes the data needed to represent the dynamic and transient response of Resource Entity-owned devices and/or Loads including but not limited to generating units, plants, and other equipment when connected to the ERCOT System including the data for any privately owned transmission system or collection system used to connect the Resource to the ERCOT System.

(4) For Transmission Service Providers (TSPs), dynamics data needed to represent the dynamic and transient capability of TSP-owned devices including but not limited to Load shedding relays, protective relays, FACTS devices (e.g., SVC, STATCOMs), Direct Current Ties (DC Ties), variable-frequency transformers, automatically switched shunts, and transformers with automatic load tap changers.

[PGRR101: Replace paragraph (4) above with the following upon system implementation of NPRR1133:]

(4) For Transmission Service Providers (TSPs) and owners of Direct Current Ties (DC Ties), dynamics data includes the data needed to represent the dynamic and transient capability of dynamic devices including but not limited to Load shedding relays, protective relays, FACTS devices (e.g., SVC, STATCOMs), DC Ties, variable-frequency transformers, automatically switched shunts, and transformers with automatic load tap changers.

(5) The owner of a generator Facility or any dynamic device shall provide appropriate dynamics data to ERCOT, including the data for a planned Facility, in accordance with the Dynamics Working Group Procedure Manual. The dynamic data shall include the following:

(a) A model with parameters that accurately represent the dynamics of the device and that is compatible with the current version of the planning and operations model software as described in the Dynamics Working Group Procedure Manual. If a user written model is provided:

(i) A model manual containing a technical description of the model characteristics, including descriptions for all model parameters and variables, a list of which parameters are commonly tuned for site-specific settings, and a description of procedures and considerations for using the model in dynamic simulations, including steady state representation and limitations for model adequacy and usability in the planning and operations model software; and

(ii) The user-written model shall allow the user to determine the allocation of machine identifiers (bus numbers, bus names, machine IDs etc.) without restriction.

(b) Verification reports that support the model data based on documented field settings shall be provided as specified in the Dynamics Working Group Procedure Manual for Generation Resources, Energy Storage Resources (ESRs), and for

Transmission Elements represented by a dynamic model. The reports shall demonstrate that the model parameters which are commonly tuned match site-specific settings implemented in the field. For new Generation Resources and ESRs, these reports shall be provided as required in paragraph (~~2~~34) of Section 5.5, Generator Commissioning and Continuing Operations. For existing Generation Resources and ESRs, these reports shall be provided as required in paragraph (~~3~~45) of Section 5.5. For Transmission Elements represented by a dynamic model, these reports shall be provided no later than two years following energization of new equipment and updated a minimum of every ten years.

(c) Results of model quality tests and associated simulation files that demonstrate acceptable performance of the models in the planning model and operations software as described in the Dynamics Working Group Procedure Manual. The Facility owner shall provide updated information whenever it provides a new or updated dynamic model to ERCOT representing a Generation Resource, ESR, or Transmission Element. These tests ensure the quality of the provided dynamic data and models for use in numerous system studies and consistency across planning and operations software platforms. Therefore, the Facility owner shall also assess sufficient sensitivities, including but not limited to Voltage Set Point at the Point of Interconnection (POI), real power output, and Reactive Power output to ensure acceptable model performance over the entire range of operating conditions. The Facility owner shall provide an explanation if model responses do not match.

(i) Facility owners shall include all site-specific dynamic models representing the Facility in the model quality tests. Facility owners can perform the tests in a simple test system without requiring ERCOT System information.

(ii) For Intermittent Renewable Resource (IRR) equipment aggregated together to form an IRR in accordance with paragraph (13) of Protocol Section 3.10.7.2, Modeling of Resources and Transmission Loads, the dynamic model shall represent the aggregated IRR.

(iii) Results for the following model quality tests shall be provided to demonstrate acceptable model performance. Additional details about each test, including the set up and description of desirable response, are included in the Dynamics Working Group Procedure Manual.

(A) Flat start test: A no-disturbance test shall be performed to demonstrate appropriate model initialization and the Facility's dynamic response under a no-disturbance condition.

(B) Small voltage disturbance test: A voltage step increase and decrease shall be applied to the POI to demonstrate the Facility's dynamic response.

(C) Large voltage disturbance test:

(1) For IRRs, ESRs, and inverter-based transmission equipment, the high and low voltage ride-through profiles as described in Nodal Operating Guide Section 2.9.1, Voltage Ride-Through Requirements for Intermittent Renewable Resources Connected to the ERCOT Transmission Grid, shall be applied to the POI to demonstrate the Facility's dynamic response.

(2) For Resources other than IRRs, ESRs, and inverter-based equipment, a fault shall be applied to the POI to demonstrate the Facility's dynamic response.

(D) Small frequency disturbance test: A frequency step increase and decrease shall be applied to the POI to demonstrate the Facility's dynamic response.

(E) System strength test: The model for IRRs and inverter-based Resources shall be tested under a few equivalent short circuit ratios, as described in the Dynamics Working Group Procedure Manual. This tests the robustness of the model to varying system conditions.

(d) Inverter-Based Resources (IBRs) shall provide results of the unit model validation to demonstrate that the PSCAD model, as described in the Dynamics Working Group Procedure Manual, accurately represents the dynamic responses of all inverter-based dynamic devices within the Facility. This validation is not intended to be site-specific; rather it is intended to be a hardware type test, where models representing different inverter hardware are benchmarked for accuracy. Validation results for a specific model of inverter can be submitted for multiple uses of that model of inverter.

(i) The validation results shall be included when submitting a PSCAD model to ERCOT.

(ii) Results for the following unit model validation tests shall be provided to demonstrate model accuracy. Additional details about each test are included in the Dynamics Working Group Procedure Manual.

(A) Step change in voltage;

(B) Large voltage disturbance (voltage ride-through tests);

(C) System strength test;

(D) Phase angle jump test; and

(E) Subsynchronous test.

(6) Dynamics data for a planned Facility will be updated by the Facility owner upon completion of the design for the Facility.

(7) Updated dynamics data for an existing Facility shall be provided to ERCOT when field tests, inspections, or other information demonstrates that the dynamics data should be changed to accurately represent the dynamic characteristics of the Facility.

(8) Dynamics Data is considered Protected Information pursuant to Protocol Section 1.3, Confidentiality.

(9) Dynamics data shall be provided with the legal authority to provide the information to all TSPs. If any of the information is considered Protected Information, the Facility owner shall indicate as such.

ERCOT Impact Analysis Report

PGRR Number	109	PGRR Title	Dynamic Model Review Process Improvement for Inverter-Based Resource (IBR) Modification
Impact Analysis Date		July 18, 2023	
Estimated Cost/Budgetary Impact		None. See ERCOT Staffing Impacts.	
Estimated Time Requirements		No project required. This Planning Guide Revision Request (PGRR) can take effect following Public Utility Commission of Texas (PUCT) approval.	
ERCOT Staffing Impacts (across all areas)		There will be ongoing operational impacts to the following ERCOT department totaling 0.6 Full-Time Employee (FTE) to support this PGRR: • Dynamic Studies (0.6 FTE Effort) ERCOT has assessed its ability to absorb the ongoing efforts of this NPRR with current staff. The ERCOT 2024 budget included staff which would allow this work to be absorbed after fully approved.	
ERCOT Computer System Impacts		No impacts to ERCOT computer systems.	
ERCOT Business Function Impacts		ERCOT will update its business processes to implement this PGRR.	
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

RMGRR Number	179	RMGRR Title	TDSP Temporary Emergency Electric Energy Facility (TEEEF) Deployment Transactional Processing
Date of Decision		February 27, 2024	
Action		Recommended Approval	
Timeline		Urgent	
Estimated Impacts		Cost/Budgetary: Less than $10k to Operations & Maintenance (O&M) Project Duration: Not applicable	
Proposed Effective Date		Upon implementation of PR409-01, TX SET 5_0 and System Change Request (SCR) 817, Related to NPRR1095, MarkeTrak Validation Revisions Aligning with Texas SET V5.0	
Priority and Rank Assigned		Not applicable	
Retail Market Guide Sections Requiring Revision		7.13, Transmission and/or Distribution Service Provider (TDSP) Temporary Emergency Electric Energy Facility (TEEEF) Deployment Transactional Processing (new) 7.14, Out-flow Energy from Distributed Generation Facilities 7.14.4, Transmittal of Out-flow Energy Data for Unregistered Distributed Generation 7.14.5, Transmittal of Out-flow Energy Data for Settlement Only Distribution Generators 7.14.6, ERCOT Processing of Meter Data for Unregistered Distributed Generation Out-flow Energy 7.14.7, ERCOT Processing of Meter Data for Settlement Only Distribution Generator Out-flow Energy	
Related Documents Requiring Revision/Related Revision Requests		None	
Revision Description		This Retail Market Guide Revision Request (RMGRR) adds new Section 7.13 which introduces one method of communication in which Transmission and/or Distribution Service Providers (TDSPs), at their own discretion, may utilize Texas Standard Electronic Transaction (Texas SET) transactions to inform Retail Electric Providers (REPs) of record which Electric Service Identifiers (ESI IDs) were impacted by a TDSP's mobile generation or "Temporary Emergency Electric Energy Facility" (TEEEF) deployment, therefore minimizing manual work-arounds that are created due to invoicing as	

	opposed to usage exceptions that may impact Customers' billing and increase MarkeTrak issue volumes for resolution. This RMGRR also clarifies in Section 7.14.4 that the REF~JH~I data element is dedicated exclusively to Customer-owned generation. Lastly, this RMGRR is in support of Texas SET Change Control 2023-845, Update the 867_03 to Add a New Unique Identifier of "M" (Mobile Generation) Into Existing REF~JH (Meter Role) Segment, which RMS voted unanimously to approve for Texas SET Version 5.0 release at their December 5, 2023 meeting.
Reason for Revision	☐ Strategic Plan Objective 1 – Be an industry leader for grid reliability and resilience ☐ Strategic Plan Objective 2 - Enhance the ERCOT region's economic competitiveness with respect to trends in wholesale power rates and retail electricity prices to consumers ☐ Strategic Plan Objective 3 - Advance ERCOT, Inc. as an independent leading industry expert and an employer of choice by fostering innovation, investing in our people, and emphasizing the importance of our mission ☐ General system and/or process improvements ☒ Regulatory requirements ☐ ERCOT Board and/or PUCT Directive *(please select ONLY ONE – if more than one apply, please select the ONE that is most relevant)*
Justification of Reason for Revision and Market Impacts	Section 7.13 describes a process that uses a new unique indicator in the REF~JH (meter role) which allows Market Participants more flexibility to develop and implement automated processes that provide Market Participants with the ability to: • Uniquely identify all ESI IDs that are affected by TDSPs' mobile generation or TEEEF deployment(s), especially when large volumes of ESI IDs may be impacted over an extended length of time; • Automatically report mobile generation or TEEEF deployment(s) since the "REF~JH~M" data element would apply strictly to ESI ID(s) involved into mobile generation or TEEEF deployment by the TDSP; and • Systematically process impacted mobile generation or TEEEF 867_03, Monthly or Final Usage, transactions since this new "REF~JH~M" data element could be a key identifier to assist

	REPs to update their validation rules when the 867_03 beginning and ending meter readings, when subtracted, don't match mobile generation or TEEEF kWh adjusted usage that was billed to the REP of record in the matching 810_02, TDSP Invoice, transaction.
RMS Decision	On 1/9/24, RMS voted unanimously to grant RMGRR179 Urgent status; to recommend approval of RMGRR179 as revised by RMS; and to forward to TAC RMGRR179. All Market Segments participated in the vote.
Summary of RMS Discussion	On 1/9/24, RMS reviewed RMGRR179. Participants requested urgency to more closely align RMGRR179 with the Texas SET V5.0 release. Concerns with accuracy and applicability were resolved by deleting paragraph (1)(b) of Section 7.13.
TAC Decision	On 1/24/24, TAC voted unanimously to recommend approval of RMGRR179 as recommended by RMS in the 1/9/24 RMS Report as revised by TAC; and the 1/23/24 Impact Analysis. All Market Segments participated in the vote.
Summary of TAC Discussion	On 1/24/24, TAC reviewed the items below and applied a corrective desktop edit to Section 7.13 in response to the 1/9/24 RMS desktop edits for RMGRR179.
TAC Review/Justification of Recommendation	[X] Revision Request ties to Reason for Revision as explained in Justification [X] Impact Analysis reviewed and impacts are justified as explained in Justification [X] Opinions were reviewed and discussed [X] Comments were reviewed and discussed (if applicable) [ ] Other: (explain)
ERCOT Board Decision	On 2/27/24, the ERCOT Board voted unanimously to recommend approval of RMGRR179 as recommended by TAC in the 1/24/24 TAC Report.

Opinions	
Credit Review	Not Applicable
Independent Market Monitor Opinion	IMM has no opinion on RMGRR179.

Board Report

ERCOT Opinion	ERCOT supports approval of RMGRR179.
ERCOT Market Impact Statement	ERCOT Staff has reviewed RMGRR179 and believes that it provides a positive market impact by offering regulatory requirements by introducing a method in which TDSPs may utilize Texas SET transactions to communicate with REPs to minimize manual work-arounds and clarifying that the REF~JH~I data element is dedicated exclusively to Customer-owned generation.

Sponsor	
Name	Kyle Patrick on behalf of Texas SET Working Group
E-mail Address	Kyle.Patrick@nrg.com
Company	NRG
Phone Number	713-304-0698
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Market Segment	Not Applicable

Market Rules Staff Contact	
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Comments Received	
Comment Author	**Comment Summary**
None	

Market Rules Notes

None

Proposed Guide Language Revision

7.13 ~~*[RESERVED]*~~Transmission and/or Distribution Service Provider (TDSP) Temporary Emergency Electric Energy Facility (TEEEF) Deployment Transactional Processing

(1) At the Transmission and/or Distribution Service Provider's (TDSP's) discretion, ~~the following~~this is one method in which a TDSP may utilize Texas Standard Electronic

Transaction (Texas SET) transactions to communicate to the Retail Electric Provider(s) (REP(s)) of record their impacted Electric Service Identifier(s) (ESI ID(s)) that were affected by a "Temporary Emergency Electric Energy Facility" (TEEEF) deployment by the TDSP.

~~(a)~~ This transactional methodology includes 867_03, Monthly or Final Usage, transaction(s) with the addition of a REF~JH~M data element identified as mobile generation or TEEEF that was deployed by the TDSP.

~~(b) This unique data element REF~JH~M offers Market Participant(s) systematic programming flexibility that allows:~~

~~(i) Easier identification of ESI ID(s) impacted by the TEEEF deployment(s), regardless of ESI ID volumes or duration;~~

~~(ii) Simpler reporting selection criteria since the REF~JH~M data element would apply strictly to TEEEF deployment(s); and~~

~~(iii) Elimination of REP of records' manual intervention that could impact Customers' billing that is created when there is a mismatch between 867_03 transaction, when compared to the kWh reductions that are reflected in the matching 810_02, TDSP Invoice, transaction for the same service period(s).~~

7.14 Out-flow Energy from Customers' Distributed Generation Facilities

(1) Retail Electric Providers (REPs) or Resource Entities, via their Qualified Scheduling Entities (QSEs), can receive wholesale Settlement for out-flow energy, according to the processes and requirements outlined below. This section details the requirements and processes for ERCOT to provide wholesale Settlement for out-flow energy submitted by a Transmission and/or Distribution Service Provider (TDSP).

7.14.4 Transmittal of Customers' Out-flow Energy Data for Unregistered Distributed Generation

(1) The requirements of a Premise are:

(a) The Electric Service Identifier (ESI ID) must be assigned to a DG Load Profile as per the Load Profiling Guide, Appendix D, Profile Decision Tree; and

(b) The ~~total~~ out-flow energy value (kWh) total will be supplied in the QTY~QD of the PTD~PL loop having a REF~MT of "KHMON" that is designated with the REF~JH~I ~~segment~~ data element on the 867_03, Monthly or Final Usage, and the 867_02, Historical Usage for non-IDR ESI IDs. The REF~JH~I data element shall only be used to represent Customers' Distributed Generation (DG) values. For instances where there has been no out-flow energy, the ~~segment~~ data element should either be omitted or included and populated with zero. In the absence of a

meter that measures out-flow energy, the REF~JH~I shall not be included on the 867_02 or 867_03 transactions.

(2) For IDR metering, interval out-flow energy values must be provided in the ERCOT specified file format in accordance with Section 7.15, Advanced Meter Interval Data File Format and Submission.

7.14.5 Transmittal of Customers' Out-flow Energy Data for Settlement Only Distribution Generators

(1) All Settlement Only Distribution Generators (SODGs) must have IDR metering and an RID assigned. RID data submittal method shall be designated in the document titled "TDSP Read Generation Registration Form" as 867 or .lse.

(a) If the RID data submittal method is 867, the interval out-flow energy values provided for Settlement will have data submitted via the 867_03 transaction as described in the Texas Standard Electronic Transaction Implementation Guides.

(b) If the RID data submittal method is .lse, the interval out-flow energy values provided for Settlement will have data submitted via the ERCOT specified file format as described in Section 7.15, Advanced Meter Interval Data File Format and Submission, below.

7.14.6 ERCOT Processing of Meter Data for Customers' Unregistered Distributed Generation Out-flow Energy

(1) ERCOT will process out-flow energy values for Settlement when data is submitted to ERCOT in accordance with Section 7.14.4, Transmittal of Customers' Out-flow Energy Data for Unregistered Distributed Generation, provided the DG is not registered as an SODG.

(2) For a detailed description of the wholesale Settlement impact of Load reductions for out-flow energy values, see Protocol Sections 11.4.4.2, Load Reduction for Excess PhotoVoltaic and Wind Distributed Renewable Generation, and 11.4.4.3, Load Reduction for Excess from Other Distributed Generation.

7.14.7 ERCOT Processing of Meter Data for Customers' Settlement Only Distribution Generator Out-flow Energy

(1) ERCOT will process out-flow energy values for Settlement of generation when data is submitted to ERCOT in accordance with Section 7.14.5, Transmittal of Customers' Out-flow Energy Data for Settlement Only Distribution Generators, above, provided the ERCOT registration process has been completed for the Resource Entity and the SODG. For more detailed information about the Resource registration process, Market Participants should contact their designated ERCOT Retail Account Manager.

ERCOT Impact Analysis Report

RMGRR Number	179	RMGRR Title	TDSP Temporary Emergency Electric Energy Facility (TEEEF) Deployment Transactional Processing
Impact Analysis Date		January 23, 2024	
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 Retail Market Guide Revision Request (RMGRR) can take effect following implementation of PR409-01, TX SET 5_0 and System Change Request (SCR) 817, Related to NPRR1095, MarkeTrak Validation Revisions Aligning with Texas SET V5.0.	
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: • Integration Systems 100%	
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

SCR Number	825	SCR Title	ERCOT Voice Communications Aggregation
Date of Decision		February 27, 2024	
Action		Recommended Approval	
Timeline		Normal	
Estimated Impacts		Cost/Budgetary: Between $150K and $250K Project Duration: 7 to 10 months	
Proposed Effective Date		Upon system implementation	
Priority and Rank Assigned		Priority – 2025; Rank – 4510	
Supporting Protocol or Guide Sections/Related Documents		Nodal Operating Guide Section 7.1, ERCOT Wide Area Network Nodal Operating Guide Section 7.1.2, WAN Participant Responsibilities Protocol Section 23, Form F, Qualified Scheduling Entity (QSE) Agency Agreement	
System Change Description		This System Change Request (SCR) modifies ERCOT's current control room voice communication configuration(s) to allow for greater flexibility for Qualified Scheduling Entities (QSEs) and their Subordinate QSEs (Sub-QSE) when assigning Agent(s), including allowing Sub-QSEs to assign Agents different than those used by the parent QSE.	
Reason for Revision		[X] Strategic Plan Objective 1 – Be an industry leader for grid reliability and resilience [ ] Strategic Plan Objective 2 - Enhance the ERCOT region's economic competitiveness with respect to trends in wholesale power rates and retail electricity prices to consumers [ ] Strategic Plan Objective 3 - Advance ERCOT, Inc. as an independent leading industry expert and an employer of choice by fostering innovation, investing in our people, and emphasizing the importance of our mission [ ] General system and/or process improvement(s) [ ] Regulatory requirements [ ] ERCOT Board and/or PUCT Directive	

Board Report

	(please select ONLY ONE – if more than one apply, please select the ONE that is most relevant)
Justification of Reason for Revision and Market Impacts	Currently, ERCOT's control room voice communications system is configured to require a control room communication button for each QSE that the agent represents. Increases in the number of Sub-QSEs and use of QSE agents, including Data Agent-Only QSEs, has stretched the limits in the number of buttons possible for voice communication between the ERCOT control room and QSEs. ERCOT systems need to aggregate voice communication for Resources based on the responsible entity for voice communication (QSE or agent) to limit the growth in voice communications contact points and still have reliable communications paths. Nodal Protocol Revision Request (NPRR) 1162, Single Agent Designation for a QSE and its Sub-QSEs for Voice Communications over the ERCOT WAN, is an attempt to fix an aggregation problem for technology. It is doing this without taking advantage of Protocol Section 23, Form F, that allows ERCOT to communicate with the QSE agent for all voice communication related to Resources represented by QSEs and Sub-QSEs represented by the agent. Current ERCOT communication systems limit the flexibility of QSEs and Sub-QSEs to independently designate QSE agents utilizing existing Wide Area Network (WAN) equipment. The intent of the original Section 23 Form F is to use the currently installed off-premise exchanges (OPXs) of the QSE agent for voice communications. No new WAN equipment is required as shown in the Nodal Operating Guide. The Nodal Protocols and Operating Guides do not need to be changed to limit the effect of technology sprawl. Instead, the Protocols and Nodal Operating Guides can remain in place, and current technology can be reconfigured to address this issue. Paragraph (4)(c) of Nodal Operating Guide Section 7.1 states the WAN shall be used for: "(c) Operational voice communications for both normal and emergency use. The ERCOT WAN includes support for, but not limited to, off-premise exchanges (OPX) with ERCOT's control facilities and the ERCOT Hotlines." Paragraph (1)(g) of Nodal Operating Guide Section 7.1.2 states: "(g) If a TSP and QSE share a centralized PBX or call management, separate OPX circuits will be terminated for each participant"

	The word "participant" points to the separation of "TSP and QSE" not each QSE.
PRS Decision	On 9/13/23, PRS voted unanimously to table SCR825 and refer the issue to WMS. The Independent Retail Electric Provider (IREP) Market Segment did not participate in the vote. On 10/12/23, PRS voted unanimously to recommend approval of SCR825 as submitted. All Market Segments participated in the vote. On 11/9/23, PRS voted unanimously to table SCR825. All Market Segments participated in the vote. On 1/11/24, PRS voted unanimously to endorse and forward to TAC the 12/15/23 PRS Report and 1/9/24 Impact Analysis for SCR825 with a recommended priority of 2025 and rank of 4510. All Market Segments participated in the vote.
Summary of PRS Discussion	On 9/13/23, the sponsor provided an overview of SCR825. Participants requested additional review of SCR825 by WMS alongside NPRR1162. On 10/12/23, participants noted the WMS endorsement of SCR825 and the desire to trigger development of an Impact Analysis for SCR825 to better assess its viability. On 11/9/23, participants noted the 11/7/23 ERCOT comments for an alternative schedule for the Impact Analysis. On 1/11/24, participants review the 1/9/24 Impact Analysis and discussed the appropriate priority and rank for SCR825; noting that SCR825 would not have to be implemented until a participant requires this change.
TAC Decision	On 1/24/24, TAC voted unanimously to recommend approval of SCR825 as recommended by PRS in the 1/11/24 PRS Report. All Market Segments participated in the vote.
Summary of TAC Discussion	On 1/24/24, there was no additional discussion beyond TAC review of the items below.
TAC Review/Justification of Recommendation	[X] Revision Request ties to Reason for Revision as explained in Justification [X] Impact Analysis reviewed and impacts are justified as explained in Justification [X] Opinions were reviewed and discussed [X] Comments were reviewed and discussed (if applicable)

Board Report

	☐ Other: (explain)
ERCOT Board Decision	On 2/27/24, the ERCOT Board voted unanimously to recommend approval of SCR825 as recommended by TAC in the 1/24/24 TAC Report.

Opinions	
Credit Review	Not applicable
Independent Market Monitor Opinion	IMM has no opinion on SCR825.
ERCOT Opinion	ERCOT supports approval of SCR825.
ERCOT Market Impact Statement	ERCOT Staff has reviewed SCR825 and believes the market impact for SCR825 enables ERCOT to recognize QSEs that serve as agents for voice communication with ERCOT and allows a more granular assignment of Agent to Sub QSE voice communication relationships within impacted system(s) which may be requested by currents QSEs and in the future.

Sponsor	
Name	John Varnell
E-mail Address	jvarnell@tnsk.com
Company	Tenaska Power Services
Phone Number	817-462-1037
Cell Number	
Market Segment	Independent Power Marketer (IPM)

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**

Board Report

WMS 101123	Endorsed SCR825 as submitted
ERCOT 110723	Proposed an alternative schedule for completion of the Impact Analysis for SCR825 prior to the December 14, 2023 PRS meeting
ERCOT 120623	Proposed an alternative schedule for completion of the Impact Analysis for SCR825 prior to the January 11, 2024 PRS meeting

Market Rules Notes

None

Proposed System Change

Issue:

ERCOT's current configuration of its communication system does not take full advantage of the Nodal Operating Guides and Protocols and requires QSEs and any Sub-QSEs to use a single QSE agent for WAN voice communications.

Resolution:

Reconfigure aggregation of voice communication between ERCOT and QSEs represented by agents using ERCOT Protocols Section 23 Form F, Qualified Scheduling Entity (QSE) Agency Agreement, to allow the sharing of OPXs, as contemplated in Section 7 of the Nodal Operating Guide, and aggregate voice communication (or other system changes) for Resources based on the responsible entity for voice communication (QSE or agent) and to allow flexibility in designation of QSE agents for voice communication by QSEs and Sub-QSEs.

ERCOT Impact Analysis Report

SCR Number	825	SCR Title	ERCOT Voice Communications Aggregation
Impact Analysis Date		January 9, 2024	
Estimated Cost/Budgetary Impact		Between $150K and $250K	
Estimated Time Requirements		The timeline for implementing this System Change Request (SCR) is dependent upon Public Utility Commission of Texas (PUCT) prioritization and approval. Estimated project duration: 7 to 10 months	
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: • CRM & Registration Systems 38% • Energy Management Systems 27% • Market Operation Systems 16% • Integration Systems 14% • Telecom Management Systems 5%	
ERCOT Business Function Impacts		No impacts to ERCOT business functions.	
Grid Operations & Practices Impacts		ERCOT will update grid operations and practices to implement this SCR.	

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

Comments
None.

Board Report

SMOGRR Number	027	SMOGRR Title	Move OBD to Settlement Metering Operating Guide – EPS Metering Design Proposal
Date of Decision		February 27, 2024	
Action		Recommended Approval	
Timeline		Normal	
Estimated Impacts		Cost/Budgetary: Less than $5k (Operations & Maintenance (O&M)) Project Duration: No project required	
Proposed Effective Date		Upon system implementation	
Priority and Rank Assigned		Not applicable	
Settlement Metering Operating Guide Sections Requiring Revision		3.4, EPS Metering Facility Processes and Forms 12, Attachment A, EPS Metering Design Proposal (new)	
Related Documents Requiring Revision/Related Revision Requests		EPS Metering Design Proposal (Upon approval of this Settlement Metering Operating Guide Revision Request (SMOGRR), this will be removed from the Other Binding Documents List.) Nodal Protocol Revision Request (NPRR) 1193, Related to SMOGRR027, Move OBD to Settlement Metering Operating Guide – EPS Metering Design Proposal	
Revision Description		This SMOGRR moves the EPS Metering Design Proposal from the Other Binding Documents List into the Settlement Metering Operating Guide to standardize the approval process, and deletes references to the Resource Asset Registration Form (RARF) in the ERCOT-Polled Settlement (EPS) Metering Design Proposal form.	
Reason for Revision		☐ Strategic Plan Objective 1 – Be an industry leader for grid reliability and resilience ☐ Strategic Plan Objective 2 - Enhance the ERCOT region's economic competitiveness with respect to trends in wholesale power rates and retail electricity prices to consumers ☐ Strategic Plan Objective 3 - Advance ERCOT, Inc. as an independent leading industry expert and an employer of choice	

Board Report

	by fostering innovation, investing in our people, and emphasizing the importance of our mission ☒ General system and/or process improvement(s) ☐ Regulatory requirements ☐ ERCOT Board/PUCT Directive *(please select ONLY ONE – if more than one apply, please select the ONE that is most relevant)*
Justification of Reason for Revision and Market Impacts	This SMOGRR is published for transparency and to standardize the approval process for all binding language.
WMS Decision	On 9/6/23, WMS voted unanimously to table SMOGRR027 and refer the issue to the Metering Working Group (MWG). All Market Segments participated in the vote. On 1/10/24, WMS voted unanimously to recommend approval of SMOGRR027 as amended by the 12/5/23 ERCOT comments. All Market Segments participated in the vote. On 2/7/24, WMS voted unanimously to endorse and forward to TAC the 1/10/24 WMS Report and 9/8/23 Impact Analysis for SMOGRR027. All Market Segments participated in the vote.
Summary of WMS Discussion	On 9/6/23, participants requested MWG review SMOGRR027. On 1/10/24, participants noted MWG review of SMOGRR027 and recommendation of the 12/5/23 ERCOT comments. On 2/7/24, participants reviewed the 9/8/23 Impact Analysis.
TAC Decision	On 2/14/24, TAC voted unanimously to recommend approval of SMOGRR027 as recommended by WMS in the 2/7/24 WMS Report. All Market Segments participated in the vote.
Summary of TAC Discussion	On 2/14/24, there was no additional discussion beyond TAC review of the items below.
TAC Review/Justification of Recommendation	☒ Revision Request ties to Reason for Revision as explained in Justification ☒ Impact Analysis reviewed and impacts are justified as explained in Justification ☒ Opinions were reviewed and discussed ☒ Comments were reviewed and discussed (if applicable)

Board Report

	☐ Other: (explain)
ERCOT Board Decision	On 2/27/24, the ERCOT Board voted unanimously to recommend approval of SMOGRR027 as recommended by TAC in the 2/14/24 TAC Report.

Opinions	
Credit Review	Not Applicable
Independent Market Monitor Opinion	The Independent Market Monitor (IMM) has no opinion on SMOGRR027.
ERCOT Opinion	ERCOT supports approval of SMOGRR027.
ERCOT Market Impact Statement	ERCOT Staff has reviewed SMOGRR027 and believes it has a positive market impact by standardizing the approval process for binding language.

Sponsor	
Name	Calvin Opheim
E-mail Address	Calvin.Opheim@ercot.com
Company	ERCOT
Phone Number	512-248-3944
Cell Number	
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**
ERCOT 120523	Removed proposed language to require additional information identifying any and all Distribution Service Providers (DSPs) that

	have the right to serve a project; restored and revised language in Section 3.4

Market Rules Notes

To improve transparency, existing Other Binding Document language for new Section 12, Attachment A, is represented as blackline, with only proposed changes marked as redline.

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

- SMOGRR030, Move OBD to Settlement Metering Operating Guide – EPS Metering Facility Temporary Exemption Request Application Form
  - Section 3.4

Proposed Protocol Language Revision

~~3.4 EPS Metering Facility Processes and Forms~~

~~(1) ERCOT shall make all reasonable efforts to establish consensus for all revisions to any existing or new procedures or forms in discussions with the Metering Working Group (MWG) prior to implementation. Unless included in Section 11, Appendices, such processes and forms shall be located on the ERCOT website.~~

3.4 EPS Metering Facility Processes and Forms

(1) ERCOT shall make reasonable efforts to establish consensus in discussions with the Metering Working Group (MWG) prior to implementation of substantive revisions to existing or proposed EPS Metering Facility forms listed on the ERCOT-Polled Settlement Metering webpage.

Commented [BA1]: Please note SMOGRR030 also proposes revisions to this section.

ERCOT Settlement Metering Operating Guide

Section 12

Attachment A

EPS Metering Design Proposal

Date TBD

~~EPS Metering Design Proposal~~

Board Report

Purpose

The EPS Metering Design Proposal is the initial document required from a Transmission and/or Distribution Provider (TDSP) to obtain ERCOT approval of a proposed EPS Metering Facility design. The EPS metering design proposal includes general facility information, contact information, metering facility details, and a one line drawing showing an overview of the metering facility design. The Resource owner (if the design proposal is for a generation site) must agree with the design proposal submitted by the TDSP.

The following forms are provided to document the EPS metering design proposal with a description of each field in pages 7 through 9:

A. Facility Information and Contact Information (page 2)
B. Metering Facility Details (page 3 or 4). Add more pages if necessary. Utilize page 4 for parallel CTs and throw-over VT schemes. Complete one Section B for each metering point.
C. TDSP one line drawing (page 5)
D. Auxiliary Load Telemetry Details (page 6). Add more pages if necessary. Complete one Section D for each metering point that has an auxiliary load telemetered.

When completing the forms, please provide all requested information and use the comments section to provide any additional information to clarify the facility metering design. Please feel free to attach other documents that are needed to facilitate the understanding of the EPS Metering Design Proposal. Completed design proposals should be submitted to EPSMetering@ercot.com

~~Revisions to the EPS Metering Design Proposal shall be made according to the approval process as prescribed in the Settlement Metering Operating Guide Section 3.4, EPS Metering Facility Processes and Forms.~~

Board Report

A. FACILITY INFORMATION AND CONTACT INFORMATION					
1. Facility Name					
2. Facility Address					
3. TDSP		7. Total Metered Loads (MW)			
4. TDSP Design Contact		8. Power Generation Co.			
5. Design Contact Phone #		9. TDSP Project #			
6. Design Contact E-Mail		10. Facility Gross Capacity (MW)			
11. TDSP Substation Name					
12. Total # Gen. Meters		Total # Gen. Primary Meters		Total # Gen. Back-up Meters	
13. Total # Load Meters		Total # Load Primary Meters		Total # Load Back-up Meters	
14. Metering Purpose					
~~15. Name of the DSP(s) responsible for serving Load~~					

1565. Netting Information	Describe any netting requirements for this installation. (e.g., Auxiliary loads fed from a common switchyard, load netting behind the metering point, etc.) Specify under which section of Protocol Section 10.3.2.3, Generation Netting for ERCOT-Polled Settlement Meters, netting is being requested.

1676. Facility Comments	Please include any clarifying information.

~~1787~~ Resource Owner Agreement with the EPS Metering Design Proposal			
1808. Resource contact		192019. Resource contact E-mail	
2010. Resource contact phone #		2121. Resource owner agreement with design proposal	

Board Report

B. METERING FACILITY DETAILS			
2232. Unit or Load Name		2454. TDSP Project #	
2343. Unit Capacity		2565. Meter ID as shown on one-line	
2676. Meter Form Designation			
2787. Load description and size			
2898. Metering Purpose			
292930. Loss Compensation Information	Please describe any loss compensation that will be required at the installation. Include whether the compensation will be calculated in the meter (preferred) or if ERCOT will need to perform this calculation in the data aggregation system. State if loss compensation will not be programmed per paragraph (3) of the Section8MOG 8.4(3), Calculating Line Loss Constants, and provide a clarifying statement and/or supporting calculation.		

3010. Voltage Transformer Information				3121. Current Transformer Information			
Name Plate	**A ∅**	**B ∅**	**C ∅**	**Name Plate**	**A ∅**	**B ∅**	**C ∅**
Manufacturer				Manufacturer			
Type				Type			
Ratio				Ratio/Rating factor			
Burden Rating				Burden Rating			
Acc. Class				Acc. Class			

3232. Meter Point Comments

Board Report

B. METERING FACILITY DETAILS			
2232. Unit or Load Name		2454. TDSP Project #	
2343. Unit Capacity		2565. Meter ID as shown on one-line	
2676. Meter Form Designation			
2787. Load description and size			
2898. Metering Purpose			
292930. Loss Compensation Information	Please describe any loss compensation that will be required at the installation. Include whether the compensation will be calculated in the meter (preferred) or if ERCOT will need to perform this calculation in the data aggregation system. State if loss compensation will not be programmed per paragraph (3) of ~~SMOG~~Section 8.4~~(3)~~ and provide a clarifying statement and/or supporting calculation.		

3010(A). Voltage Transformer Information				3121(A). Current Transformer Information			
Name Plate	**A ∅**	**B ∅**	**C ∅**	**Name Plate**	**A ∅**	**B ∅**	**C ∅**
Manufacturer				Manufacturer			
Type				Type			
Ratio				Ratio/Rating factor			
Burden Rating				Burden Rating			
Acc. Class				Acc. Class			

3010(B). Voltage Transformer Information				3121(B). Current Transformer Information			
Name Plate	**A ∅**	**B ∅**	**C ∅**	**Name Plate**	**A ∅**	**B ∅**	**C ∅**
Manufacturer				Manufacturer			
Type				Type			
Ratio				Ratio/Rating factor			
Burden Rating				Burden Rating			
Acc. Class				Acc. Class			

3232. Meter Point Comments

Board Report

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C. TDSP ONE LINE DRAWING			
3343. Drawing Number(s)			
3454. TDSP Project #		3565. TDSP	
TDSP		ERCOT	
Approved By	Date Approved	Approved By	Date Approved

D. AUXILIARY LOAD TELEMETRY DETAILS			
3676. Unit or Load Name			
3787. TDSP Project #			
3898. Meter ID as shown on TDSP one-line			
394039. ESR Auxiliary Load Max Expected Value			
4010. WSL Calculation Location: Meter or Data Aggregation		If WSL Calculation will be performed in the meter, supporting documents must be provided. List any supporting documents under Additional Comments\Documents in D48.	
Resource Entity Provided Supporting Documents	Please provide the name of the documents/drawings provided by the Resource Entity and submitted to support the auxiliary load calculation.		
4121. Confirmation that ESR Auxiliary Load Cannot be Separately Metered			
4232. Load calculation equipment and methodology			
4343. Description of performed or planned testing to support accuracy			
Resource Entity Contact		Name(s) of Resource Entity contact(s) providing the supporting documents.	
4454. Provided By		4565. Date Provided	
4676. Contact Email Address(es)		4787. Contact Phone Number(s)	
4898. Additional Comments\Documents			

Board Report

A. FACILITY INFORMATION AND CONTACT INFORMATION

Facility Information and Contact Information

Specific information for the entire facility covered by the EPS Metering Design Proposal. Only one Facility Information and Contact Information section should be completed for each design proposal.

1. Facility name:
The name the Resource Entity lists ~~as the "Resource Site Name"~~ in the Resource Registration information ~~(currently located on RARF)~~ used to register the Resource with ERCOT. When Resource Registration information is not available, it should be the name the TDSP uses to describe the NOIE meter point or DC Tie facility.

2. Facility address (physical):
This should be the physical address or location by description of the EPS metering facility. PO Box # or other type of address that does not define the geographical or physical location is unacceptable.

3. TDSP:
The Transmission and/or Distribution Service Provider that is responsible for the installation and maintenance of this EPS Metering Facility.

4. TDSP Design contact:
The individual that will be assigned to this project and can answer questions about the proposed design and installation.

5. TDSP design contact phone number:
The phone number at which the TDSP design contact can be reached during business hours.

6. TDSP design contact e-mail address:
TDSP design contact E-mail address

7. Total metered Loads (MW):
The total MW of Loads served by EPS Meters for the EPS Metering Design Proposal.

Note: For Bi-directional metering points, the total metered Loads is the sum of the estimated peak loads that will flow for this site as recorded be channel 1 of the EPS meters.

8. Power Generation Company:
The company name registered with ERCOT of the Market Participant (Resource owner) that owns/operates the generation facility.

9. TDSP project number:
A unique tracking number created by the TDSP for each EPS Metering Design Proposal package submitted to ERCOT.

*Note: a dash 1, 2, 3, or a dash A, B, C etc.... after the "base" project number is allowable for the metering facility details and one line drawings.

10. Facility gross capacity (MW):
The total rated **M**ega **W**att capacity of the facility. In the case of generation facilities with multiple generating units, this would be the sum of all the units included in the EPS Metering Design Proposal and should match the total generation capacity listed in the Resource Registration information ~~(currently located on RARF)~~.
*Note: For Bi-directional metering points, the gross capacity is the sum of the estimated peak generation that will flow into the ERCOT System for this site as recorded by channel 4 of the EPS meters.

11. TDSP substation name:
The name the TDSP will use to identify the substation in which the EPS Meter is physically located.

12. Total number of generation meters:
Count of EPS Meters metering the generation output at the facility. This shall be the total count of all primary and back-up generation meters.
*Note: Bi-directional metering points shall be listed as generation meters.

13. Total number of Load meters:
Count of EPS Meters metering only Loads at the facility. This shall be the total count of all primary and back-up load meters.

14. Metering purpose:
Why is this facility being metered? (i.e. Market Participant generation, radial load point, Bi-directional NOIE metering Point, DC Tie between ERCOT and Non-ERCOT transmission system, Elected optional NOIE lateral feed meter point, etc.)

~~**15. Distribution Service Provider(s):**~~
~~Name of the DSP whose certificated service area includes the facility Load(s). For a facility with multiple Loads spanning more than one DSP's certificated service area, include the names of all DSPs. This requirement does not apply to Wholesale Storage Load (WSL).~~

15~~65~~. Netting Information:
Netting information that ERCOT will use to determine the "Net Generation" or "Load" of the facilities, represented by the EPS Metering Design Proposal, for settlement purposes. TDSP to provide a statement specifying the section of Protocol Section~~s~~ 10.3.2.3 netting is being requested under. The statement shall confirm that the resource site meets the requirements in the specified section of Protocol Section 10.3.2.3.

16~~76~~. Facility Comments:
Any information that further describes a unique EPS metering arrangement that the TDSP needs to convey to help clarify the installation for settlement purposes as it applies to the whole facility.

17~~87~~. Resource owner agreement with the EPS Metering Design Proposal:
For a design proposal connecting a generation unit, the Resource owner needs to review and be in agreement with the EPS Metering Design Proposal. The TDSP is

responsible to communicate the EPS Metering Facility design to the Resource owner and that the Resource owner is in agreement with all aspects of the design proposal.

18~~8~~. Resource Owner Contact:
For a design proposal connecting a generation unit, the representative for the Resource owner that is in agreement with the EPS Metering Design Proposal.

19~~20~~19. Resource contact e-mail address:
For a design proposal connecting a generation unit, the Resource owner's contact E-mail address.

20~~1~~0. Resource contact phone number:
For a design proposal connecting a generation unit, the telephone-number where the Resource owner's contact can be reached during business hours.

21~~2~~1. Resource owner agreement with design proposal:
For a design proposal connecting generation unit the Resource owner's agreement with the design proposal is indicated with a "yes" or "Y".

B. METERING FACILITY DETAILS

Metering Facility Details Form:

Specific information for each metering point included in the EPS Metering Design Proposal. A "Metering Facility Details" form will need to be completed for each EPS meter point. Please use the appropriate version of Part B throw-over voltage transformers and/or parallel current transformers are utilized. This section should be duplicated and additional copies of Section B should be used for each meter point of the facility.

22~~3~~2. Unit or Load Name:
This field refers to the individual Resource or Load being metered by the EPS metering installation. For Resources, this is the name the Generation Unit used to register the Resource. For Loads this is a name describing the metering point.

23~~4~~3. Unit Capacity:
This is the rated gross generation unit capacity in MW for the EPS Metering point as recorded in the meter by channel 4.
*Note: For Bi-directional metering points, the unit capacity is the estimated peak generation that will flow through this point.

24~~5~~4. TDSP Project #:
A number assigned by the TDSP to each EPS Metering Design Proposal. This number should be limited to ten (10) alphanumeric characters and should match the number assigned in box A10.

25~~6~~5. Meter ID as shown on one-line:

All one-line diagrams submitted to ERCOT showing EPS metering installation locations shall have an ID designated by the TDSP to label each meter point shown with a unique identifier designated by the TDSP.

2~~6~~76. Meter Form Designation:
The form designation identifies a meter for a particular application.

2~~7~~87. Load:
Describe the type and size (in Megawatts) of the Load served by the EPS Meter for the EPS Metering point as recorded in the meter by channel 1.
*Note: For Bi-directional metering points, the Load is the estimated peak consumption that will flow through this point.

2~~8~~98. Metering purpose:
Why is this facility being metered? (i.e. Market participant generation, radial load point, Bi-directional NOIE metering Point, DC Tie between ERCOT and Non-ERCOT transmission system, Elected optional NOIE lateral feed meter point, etc.…)

~~29~~2930. Loss Compensation:
Describe any loss compensation that will be required at the installation. Include whether the compensation will be calculated in the meter or if ERCOT is being requested to perform this calculation. If ERCOT is being request to perform the calculation, please provide the fixed loss compensation value indicating the value for load and/or generation channels. If using a fixed value, please submit additional documentation along with the design proposal indicating how the values were derived.
If the meter is not located at the POI and line loss compensation will not be programmed per paragraph (3) of ~~SMOG~~ Section 8.4~~(3)~~, a statement regarding connections per paragraph (3)(a) of Section 8.4~~(3)(a)~~ or the calculation required per paragraph (3)(b) of ~~SMOG~~ Section 8.4~~(3)(b)~~ must be provided.

3~~0~~10. Voltage Transformer Information:
This is industry standard nameplate information available on instrument transformers.

3~~1~~21. Current Transformer Information:
This is industry standard nameplate information available on instrument transformers.

3~~2~~32. Meter Point Comments:
Provide any clarifying comments specific to the meter point. Examples include manufacture statements regarding CT accuracy, elaborations on instrument transformer selection or any other supporting information for the meter point.

C. TDSP ONE LINE DRAWING

A one line drawing should be of sufficient detail to allow verification of the accurate settlement metering of Resources and Loads at EPS Metering Facilities. The drawing should allow the design philosophy, instrument transformer locations, netting scheme, compensation scheme and any breakers isolating loads from generation to be understood.

For current transformer (CT), indicate CT ratio, accuracy, and rating factor on the one-line drawing. The CT polarity should also be shown along with the meter connections to the CT to allow for verification that energy will be recorded in the correct channels. For voltage transformer (VT), indicate VT ratio and accuracy. Meter ID(s) must also be on the one-line drawing.

D. AUXILIARY LOAD TELEMETRY DETAILS

Telemetry Details Form:

Specific information for each ESR Auxiliary Load Telemetry being supplied to an EPS meter included in the EPS Metering Design Proposal. A "Auxiliary Load Telemetry Details" form will need to be completed for each EPS meter point that has ESR Auxiliary Load Telemetry supplied. This section should be duplicated and additional copies of Section D should be used for each ESR Auxiliary Load Telemetry provided to an EPS meter. The information in this section should be provided by the resource owner to the TDSP.

36~~7~~6. Unit or Load Name:
This field refers to the individual meter point that the ESR Auxiliary Load Telemetry is being supplied to. This name should match the TDSP supplied name from B22.

37~~8~~7. TDSP Project #:
A number assigned by the TDSP to each EPS Metering Design Proposal. This number should be limited to ten (10) alphanumeric characters and should match the number assigned in box A10.

38~~9~~8. Meter ID as shown on TDSP one-line:
This should be the name of the meter that will be supplied ESR Auxiliary Load Telemetry as listed on the TDSP one-line diagrams supplied with the Design Proposal. This name should match the TDSP supplied name from B25.

394~~0~~39. ESR Auxiliary Load Max Expected Value:
The maximum of load value that the resource entity expects the ESR auxiliary load to draw while the ESR is charging.

40~~1~~10. WSL Calculation Location: Meter or Data Aggregation:
Indicate if the wholesale storage load value will be calculated in the EPS meter or if it will be performed in the ERCOT Data Aggregation system. If the WSL will be calculated in the meter, include supporting documents showing how the calculations will be performed in compliance with paragraph (3)(a) of Protocol Section 11.1.6,~~(3)(a)~~ERCOT-Polled Settlement Meter Netting, and paragraph (1)(c) of ~~SMOG~~Section 4.1~~(1)(d)~~, Standard IDR Channel Assignments. Supporting documents should be listed in box D4~~9~~8 "Additional Comments\Documents".

41~~2~~1. Confirmation that ESR Auxiliary Load Cannot be Separately Metered:
Documentation describing the reason that the auxiliary load meets the requirement of paragraph (1) of Protocol Section10.2.4~~(1)~~, Resource Entity Calculation and Telemetry of ESR Auxiliary Load Values, and cannot be separately metered and must be

calculated. This shall include a one-line drawing that includes facility details necessary to understand the calculation and data flow.

4232. Load calculation Equipment and Methodology:
A description of the equipment and method used to determine the auxiliary load value and telemeter the auxiliary load value to the appropriate EPS meter shall be provided. This description shall include how the calculated auxiliary load will always be equal to or greater than the true auxiliary load, the equipment used in determining the auxiliary load calculation, and the accuracy of equipment used. If a zero load value will be telemetered while the ESR is discharging, the methodology for determining when zero will be telemetered must be included in the description.

4343. Description of performed or planned testing to support accuracy:
A description of the anticipated annual certification process, and any laboratory or field testing that has already been performed. Documentation will describe what actions have been taken and will be taken on an ongoing basis, to ensure that the overall initial correction factor applied to the calculated auxiliary AC load of each battery system component will not understate the load value reported via site telemetry. This includes confirmation by the Texas Professional Engineer that laboratory testing and/or field testing has been or will be conducted on the specified sensor models used at the site, to establish the long-term accuracy of the sensor as a result of long-term degradation which may occur naturally in the field. Such documentation may reference utilization of sensor OEM test data, sensor OEM specifications, and/or analysis of the materials and design of the sensor. It may also include the results of accelerated life cycling conducted to represent the intended life of the deployed system on the sensor suite, a proposal to remove a sample of sensors to test their accuracy using NIST-traceable test equipment under anticipated field conditions, or, other actions required by a Texas Professional Engineer.

4454. Provided By:
Name of the Resource Entity representative that is providing the supporting documents. This may be multiple contacts.

4565. Date Provided:
Date the Resource Entity contact in D45 provided the supporting documents.

4676. Contact Email Address(es):
Contact email address for the Resource Entity representative(s) listed in D44.

4787. Contact Phone Number(s):
Contact phone number(s) for the Resource Entity representative(s) listed in D44.

4898. Additional Comments\Documents:
Provide any clarifying comments or names of additional supporting documents.

ERCOT Impact Analysis Report

SMOGRR Number	027	SMOGRR Title	Move OBD to Settlement Metering Operating Guide – EPS Metering Design Proposal
Impact Analysis Date		August 9, 2023	
Estimated Cost/Budgetary Impact		Less than $5k, which will be absorbed by the Operations & Maintenance (O&M) budgets of affected department.	
Estimated Time Requirements		No project required. This Settlement Metering Operating Guide Revision Request (SMOGRR) can take effect within 3-5 days 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: • ERCOT Website and MIS Systems 67% • Channel Management Systems 33%	
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

SMOGRR Number	030	SMOGRR Title	Move OBD to Settlement Metering Operating Guide – EPS Metering Facility Temporary Exemption Request Application Form
Date of Decision		February 27, 2024	
Action		Recommended Approval	
Timeline		Normal	
Estimated Impacts		Cost/Budgetary: Less than $5k (Operations & Maintenance (O&M)) Project Duration: No project required	
Proposed Effective Date		Upon system implementation	
Priority and Rank Assigned		Not applicable	
Settlement Metering Operating Guide Sections Requiring Revision		3.4, EPS Metering Facility Processes and Forms 12, Attachment B, EPS Metering Facility Temporary Exemption Request Application Form (new)	
Related Documents Requiring Revision/Related Revision Requests		EPS Metering Facility Temporary Exemption Request Application Form (Upon approval of this Settlement Metering Operating Guide Revision Request (SMOGRR), this will be removed from the Other Binding Documents List.)	
Revision Description		This SMOGRR moves the EPS Metering Facility Temporary Exemption Request Application Form from the Other Binding Documents List into the Settlement Metering Operating Guide to standardize the approval process.	
Reason for Revision		☐ Strategic Plan Objective 1 – Be an industry leader for grid reliability and resilience ☐ Strategic Plan Objective 2 - Enhance the ERCOT region's economic competitiveness with respect to trends in wholesale power rates and retail electricity prices to consumers ☐ Strategic Plan Objective 3 - Advance ERCOT, Inc. as an independent leading industry expert and an employer of choice by fostering innovation, investing in our people, and emphasizing the importance of our mission	

Board Report

	☒ General system and/or process improvement(s) ☐ Regulatory requirements ☐ ERCOT Board/PUCT Directive *(please select ONLY ONE – if more than one apply, please select the ONE that is most relevant)*
Justification of Reason for Revision and Market Impacts	This SMOGRR is published for transparency and to standardize the approval process for all binding language.
WMS Decision	On 1/10/24, WMS voted unanimously to recommend approval of SMOGRR030 as submitted. All Market Segments participated in the vote. On 2/7/24, WMS voted unanimously to endorse and forward to TAC the 1/10/24 WMS Report and 12/21/23 Impact Analysis for SMOGRR030. All Market Segments participated in the vote.
Summary of WMS Discussion	On 1/10/24, ERCOT Staff presented SMOGRR030. On 2/7/24, participants reviewed the 12/21/23 Impact Analysis.
TAC Decision	On 2/14/24, TAC voted unanimously to recommend approval of SMOGRR030 as recommended by WMS in the 2/7/24 WMS Report. All Market Segments participated in the vote.
Summary of TAC Discussion	On 2/14/24, there was no additional discussion beyond TAC review of the items below.
TAC Review/Justification of Recommendation	☒ Revision Request ties to Reason for Revision as explained in Justification ☒ Impact Analysis reviewed and impacts are justified as explained in Justification ☒ Opinions were reviewed and discussed ☒ Comments were reviewed and discussed (if applicable) ☐ Other: (explain)
ERCOT Board Decision	On 2/27/24, the ERCOT Board voted unanimously to recommend approval of SMOGRR030 as recommended by TAC in the 2/14/24 TAC Report.

Board Report

Opinions	
Credit Review	Not Applicable
Independent Market Monitor Opinion	The Independent Market Monitor (IMM) has no opinion on SMOGRR030.
ERCOT Opinion	ERCOT supports approval of SMOGRR030.
ERCOT Market Impact Statement	ERCOT Staff has reviewed SMOGRR030 and believes it has a positive market impact by standardizing the approval process for binding language.

Sponsor	
Name	Ann Boren
E-mail Address	Ann.Boren@ercot.com
Company	ERCOT
Phone Number	512-248-6465
Cell Number	
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

To improve transparency, existing Other Binding Document language for new Section 12, Attachment B, is represented as blackline, with only proposed changes marked as redline.

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

Board Report

- SMOGRR027, Move OBD to Settlement Metering Operating Guide – EPS Metering Design Proposal
  - Section 3.4

Proposed Guide Language Revision

3.4 EPS Metering Facility Processes and Forms

Commented [BA1]: Please note SMOGRR027 also proposes revisions to this section.

(1) ERCOT shall make all reasonable efforts to establish consensus ~~for all revisions to any existing or new procedures or forms~~ in discussions with the Metering Working Group (MWG) prior to implementation of substantive revisions to existing or proposed EPS Metering Facility forms listed on the ERCOT-Polled Settlement Metering webpage. ~~Unless included in Section 11, Appendices, such processes and forms shall be located on the ERCOT website.~~

Board Report

ERCOT Settlement Metering Operating Guide

Section 12

Attachment B

EPS Metering Facility Temporary Exemption Request Application Form

Date TBD

Board Report

Application Form for an EPS Metering Facility Temporary Exemption Request ***Submit completed form to epsmetering@ercot.com***		Application Date	
Applicants Name		Applicants Phone #	
TDSP Project #		TDSP Name	
Design Proposal Approval Date			
Design Proposal Facility Name			
Design Proposal Unit or Load Name			
Design Proposal Meter ID			
Resource owner contact that has agreed to this exemption request.	Name	E-mail	
Provide a detailed description of the exemption request below			
Provide the relevant section of Protocols or SMOG the exemption will apply to			
Provide a detailed statement on the reason for seeking the exemption			
Proposed Start Date of exemption			
Proposed Stop Date of exemption			
Note: If the proposed start or stop dates change, notify epsmetering@ercot.com with the changes			
Will ERCOT be able to poll the meter during the exemption period? ***(Yes/No)***			
If no, explain how meter data will be provided / estimated for Settlement			
Does the exemption request affect the accuracy of the registered energy flow? ***(Yes/No)***			
If yes, provide a detailed explanation			
Approved by ERCOT			
Date		Person	

~~Revisions to the Temporary Exemption Request Form shall be made according to the approval process as prescribed in the Settlement Metering Guide Section 3.4, EPS Metering Facility Processes and Forms.~~

ERCOT Impact Analysis Report

SMOGRR Number	030	SMOGRR Title	**Move OBD to Settlement Metering Operating Guide – EPS Metering Facility Temporary Exemption Request Application Form**
Impact Analysis Date		December 21, 2023	
Estimated Cost/Budgetary Impact		Less than $5k, which will be absorbed by the Operations & Maintenance (O&M) budgets of affected department.	
Estimated Time Requirements		No project required. This Settlement Metering Operating Guide Revision Request (SMOGRR) can take effect within 3-5 days 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: • ERCOT Website and MIS Systems 67% • Channel Management Systems 33%	
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.