(2) Upon the completion of the LLIS, as described in Section 9.4, the interconnecting TSP shall update the preliminary ~~Load Commissioning Plan~~LCP to reflect any changes in~~not exceed~~ the ILLE's timeline that are needed to account for the ~~time needed to~~ completeion of the required transmission upgrades identified in the LLIS~~level(s) of Demand approved in the LLIS~~. If one or more levels of Demand in the Load Commissioning Plan are contingent on one or more transmission upgrade projects, as determined in paragraph (6) of Section 9.4, those transmission projects shall be identified in the updated ~~Load Commissioning Plan~~LCP.

(3) Upon the execution of any required agreements prescribed in Section~~s~~ 9.5~~.1 or 9.5.2~~, the interconnecting TSP shall update the ~~Load Commissioning Plan~~LCP to reflect changes to the ILLE's load increments and implementation timeline ~~amount of peak Demand~~ in the executed ~~i~~Interconnection ~~a~~Agreement~~interconnection agreement~~.

(4) The interconnecting TSP shall continue to maintain the ~~Load Commissioning Plan~~LCP after Initial Energization until the Large Load reaches its full requested peak Demand.

9.2.5 Required Interconnection Equipment

(1) Each ~~Point of Interconnection (POI) or~~ Service Delivery Point for a Large Load not co-located with a Generation Resource, Energy Storage Resource (ESR), or Settlement Only Generator (SOG) interconnected at transmission voltage to the ERCOT System must have a permanent configuration consisting of one or more breakers capable of interrupting fault current to isolate the Large Load from the ERCOT System without interrupting flow on the associated transmission lines. The ~~disconnect devices~~breakers shall be under the remote control of the applicable TO ~~and capable of being operated remotely to comply with an instruction from ERCOT~~.

(2) Each Large Load co-located with a Generation Resource, ESR, or SOG interconnected at transmission voltage to the ERCOT System must have a permanent configuration consisting of one or more breakers capable of interrupting fault current to isolate the Large Load from the ERCOT System without isolating any of the co-located generators. The breakers shall be remotely controllable at the direction~~under the remote control~~ of the applicable QSE ~~and capable of being operated remotely to comply with an instruction from ERCOT~~.

(3) Projects with an initial LLIS submission date ~~of~~on or after June~~March~~ 1, 2025 ~~or later~~ shall not have an interconnection configuration such that any category P1 or P7 event described in the NERC Reliability Standard addressing Transmission Planning Performance Requirements results in more than 1,000 MW of consequential Load loss. ~~that would permit more than 1 GW of consequential load loss to occur as a result of a single contingency, as further described in paragraph (1)(g) of Section 4.1.1.2. A maximum of 1,000 MW of peak Demand may be served from a single Transmission Service Bus (TSB).~~

(a) ~~Calculation of peak Demand in this paragraph shall include the totalized peak Demand of all~~All Loads co~~l~~-located with a Generation Resource as described in

Protocol Section 10.3.2.3, Generation Netting for ERCOT-Polled Settlement Meters shall be subject to the requirements of this paragraph.

~~(b) A TSB that serves a peak Demand greater than 1000 MW on or before January 1, 2025 shall be exempt from the requirements of paragraph (3) of this Section. However, such a TSB shall nevertheless comply if, on or after January 1, 2025, the peak Demand served from that point exceeds by 75 MW or more the peak Demand served on January 1, 2025.~~

(4~~3~~) Projects with an initial LLIS submission date before June~~March~~ 1, 2025 shall comply with the requirements of paragraph (3) of this Section if, on or after June~~March~~ 1, 2025 a modification to the Large Load subject to the requirements of Section 9.2.1, Applicability of the Large Load Interconnection Study Process, is made.

9.3 Interconnection Study Procedures for Large Loads

(1) This Section establishes the procedures for conducting a Large Load Interconnection Study (LLIS) for new or modified Large Loads, as defined by Section 9.2.1, Applicability of the Large Load Interconnection Study Process.

9.3.1 Large Load Interconnection Study (LLIS)

(1) An LLIS consists of the set of steady-state, stability, short-circuit and~~/or~~ other relevant studies that are necessary to determine the reliability impact of a Large Load interconnection on affected Transmission Facilities and identify the Transmission Facilities that are needed to reliably interconnect the new or modified Large Load to the ERCOT System.

(2) If an Interconnecting Entity (IE) or Resource Entity (RE) submits a large Generation Resource interconnection request, as defined in Section 5.3, Interconnection Study Procedures for Large Generators, that also includes a co-located Large Load, the Full Interconnection Study (FIS) may be used in place of a separate LLIS. The FIS shall reflect the full requested Load amount and conform to all study requirements detailed in Sections 5.3 and 9.3 of this Planning Guide. For any deadlines or timelines set out in this section that conflict with the deadlines or timelines in Sections 5.2 and 5.3, the deadlines or timelines in Sections 5.2 and 5.3 shall govern.

(3) During the LLIS, the interconnecting TSP shall be the lead TSP unless otherwise designated by ERCOT during the study scoping process detailed in Section 9.3.2.

(4) For an interconnection request involving a Large Load interconnecting at distribution voltage, the LLIS shall evaluate only the proposed Load's transmission-level impacts, if any. The affected Distribution Service Provider (DSP) shall provide the lead TSP with all information concerning the DSP's facilities needed to complete any required studies.

9.3.2 Large Load Interconnection Study Scoping Process

(1) ERCOT will notify the interconnecting Transmission Service Provider (TSP) after~~once~~~~Within five Business Days from the date~~ all requirements detailed in paragraph (1) of Section 9.2.2 have been met. Within ten Business Days of this notification, the lead~~interconnecting Transmission Service Provider (~~TSP~~)~~ shall schedule a kick-off meeting with ERCOT and the certificated DSP to occur soon thereafter. If the proposed project is co-located with a Generation Resource, the kick-off meeting must also include the affected Resource Entity (RE) or Interconnecting Entity (IE). The lead~~interconnecting~~ TSP shall invite the Interconnecting Large Load Entity (ILLE) to attend the kick-off meeting. The ILLE may attend at its option.

(2) ERCOT will notify all other TSPs of the LLIS request. Each TSP may evaluate if it is directly affected by the interconnection request and determine if it should participate in the LLIS. Examples of a directly affected TSP may include, but are not limited to, a TSP whose facilities are likely to experience changes in voltage or power flow because of the Load interconnection request.

(3) Each directly affected TSP desiring to participate in the LLIS shall promptly notify the lead TSP and ERCOT and must provide a description of the expected effect of the Load interconnection on the TSP's facilities in its notification. The lead TSP shall include all directly affected TSP(s) in the LLIS kickoff meeting.

(4) At the LLIS kickoff meeting, the ~~interconnecting~~lead TSP will present the proposed project and facilitate a general discussion of the preliminary study scope of work for the LLIS.

(5) Any reactive studies required under Protocol Section 3.15, Voltage Support, or SSO studies required under Protocol Section 3.22.1.4, Large Load Interconnection Assessment, shall be scoped simultaneously with the LLIS but do not need to be included as part of the LLIS. The Resource Entity responsible for the reactive study shall provide it to ERCOT directly.

(6) The lead TSP will develop a preliminary LLIS study scope within ~~three~~ten Business Days following the kickoff meeting.

(a) The study scope must include all study elements required by Section 9.3.4, Large Load Interconnection Study Elements, unless ERCOT ~~and~~in collaboration with the TSP(s) determine that one or more studies are unnecessary. If a study element is deemed unnecessary, the lead TSP shall provide a written technical justification for not performing the analysis in lieu of the study report.

~~(i) The study scope shall document any transmission facilities that will not be in service before Initial Energization of the proposed Load that may significantly impact the study results, as initially identified by the Lead TSP during the project kickoff meeting.~~

(b) The study scope shall specify the base cases ~~and~~, study assumptions, and scenarios that will be used in each LLIS element. Any transmission facilities that will not be in service before Initial Energization of the proposed Load that may significantly impact the study results, as initially identified by the lead TSP during the project kickoff meeting, shall be documented in the study scope. All study assumptions related to maintenance outage scenarios required under Section 4.1.1.8, Maintenance Outage Criteria, shall be explicitly identified in the study scope.

(c) The study scope shall specify the involvement of any directly affected TSPs in the study process. In some cases, it may be necessary for the ILLE to execute study agreements with multiple TSP(s).

(d) The lead TSP may propose interconnection design alternatives during the scoping process. Such alternative options shall be fully studied in all required LLIS study elements.

(7) The lead TSP shall submit the preliminary study scope for review by ERCOT and all directly affected TSPs, including TSPs which may ~~now~~ be directly affected due to proposed interconnection topology. Directly affected TSPs and ERCOT may provide comments on the preliminary study scope within ~~five~~ten Business Days of posting.

(8) Upon closing of the comment period described in paragraph (7) above, the lead TSP shall, within ~~five~~ten Business Days, submit a final study scope that addresses submitted comments to the extent possible. ~~If the lead TSP, directly affected TSPs, orand ERCOT cannot reach agreement on one or more aspects of the study scope.~~ ERCOT in collaboration with the TSP(s) shall ~~resolve any remaining dispute(s)~~determine the study scope.

(9) Within five Business Days of the lead TSP submitting the final study scope, ERCOT shall approve the final study scope or return the scope to the lead TSP with comments. The lead TSP shall promptly address ERCOT comments and resubmit according to paragraph (8) above.

9.3.3 Large Load Interconnection Study Description and Methodology

(1) The primary purpose of the LLIS is to determine whether the ~~the~~ amount of Load being requested~~that may be interconnected~~ by the ILLE~~'s~~ can be placed in service by the desired Initial Energization date while maintaining the reliability of the ERCOT System and ensuring compliance with all North American Electric Reliability Corporation (NERC) Reliability Standards, Protocols, this Planning Guide, and the Operating Guides. The LLIS will also identify any transmission improvements needed to serve the full requested Load amount, including individual load increments requested by the ILLE in the initial Load Commissioning Plan (LCP).

(2) The LLIS consists of a series of distinct study elements. The specific elements included in a particular LLIS will be stated in the LLIS scope.

(3) Each proposed Large Load interconnection that ~~requires~~requests ~~a separate~~more than one physical transmission interconnection will be ~~treated~~studied as an individual study for each interconnection to be analyzed separately from all other such requests unless otherwise agreed by the ~~ILLEinterconnecting load and~~ TSP(s) in the interconnection study agreement.

(4) The LLIS process includes developing and analyzing various computer model simulations of the existing and proposed ERCOT transmission system. The results from these simulations will be utilized by the TSP(s) to determine the impact of the proposed interconnection.

(5) The study shall include an analysis demonstrating the adequate reliability of any temporary interconnection configurations.

9.3.4 *Large Load Interconnection Study Elements*

9.3.4.1 *Steady-State Analysis*

(1) The steady-state interconnection study base case shall be created from the most recently approved Steady State Working Group (SSWG) base case appropriate for the desired Initial Energization date of the Load. The lead TSP shall remove from the study base case all ~~t~~Transmission Facilities it determines may significantly impact study results that will not be in service before Initial Energization of the proposed Load, as identified in the preliminary LLIS study scope. The steady-state analysis shall include other relevant Large Loads and any transmission upgrades included in the Load Commissioning Plans (LCPs) for those Large Loads that have a complete LLIS per paragraph (6) of Section 9.4, LLIS Report and Follow-up, and that have met the requirements of Section 9.5, Interconnection Agreements and Responsibilities. The lead TSP may include other transmission projects and ~~load interconnection~~ Substantiated Load ~~requests~~ in the study base case. All modifications to the SSWG base case made as part of the study assumptions shall be documented in the LLIS report.

(2) The lead TSP shall perform contingency analyses as required by the NERC Reliability Standards, ERCOT Nodal Protocols, this Planning Guide, and the Operating Guides to identify any additional Facilities that may be necessary to ensure that results of the system performance conform to these standards. The study shall identify any system limitations that would prevent the ILLE from achieving the requested load in the desired timeframe. If the study identifies system limitations, the lead TSP shall identify potential transmission system improvements necessary to achieve the requested Load. The results of this analysis shall be shared with TSP(s) that have Facilities identified with planning criteria violations, and those affected TSP(s) will be responsible for evaluating the impact of the Large Load and the validity of the anticipated violations.

~~(3) When studying the addition of a Large Load the lead TSP shall perform a steady-state analysis using the system Load level defined in the SSWG Procedure Manual. The lead TSP shall also study any additional scenarios under this section where the addition of the Large Load might impact system reliability.~~

Board Report

(4~~3~~) Upon completion of the steady-state study as described in paragraph (2) above, the lead TSP shall identify any modifications to the levels of Demand and timeline specified in the ILLE's initial LCP that are needed to account for all transmission upgrades required to support the full requested amount of Load ~~the amount of load that may be reliably connected by the ILLE's desired Initial Energization date. The lead TSP shall also identify additional levels of Demand that may be served contingent on transmission upgrades identified in the study becoming operational~~.

9.3.4.2 System Protection (Short-Circuit) Analysis

(1) The short-circuit study ~~base case shall be created from~~shall use the most recently approved ~~Steady State~~System Protection Working Group (SP~~S~~WG~~SSWG~~) base case appropriate for the desired Initial Energization date of the Load. The initial transmission configuration of the study area shall ~~be identical~~correspond to the configuration used in the corresponding steady-state study to the extent practicable.

(2) The lead TSP will determine the maximum available fault currents at the interconnection substation for determining switching device interrupting capabilities and protective relay settings.

9.3.4.3 Dynamic and Transient Stability ~~(Load Stability, Voltage)~~ Analysis

(1) The lead TSP shall not initiate the stability study prior to receiving from the ILLE dynamic load modeling information sufficient to properly model the l~~L~~oad in the stability studies. The TSP ~~will~~ shall check the ~~reasonability of the~~ dynamic load information according to the procedure specified in Section 3.4.4 of the DWG Procedure Manual ~~prior to providing the dynamic load model to ERCOT~~.

(2) The stability study base case shall be created from the most recently approved ~~Steady State~~Dynamics Working Group (~~SS~~DWG~~SSWG~~) base case appropriate for the desired Initial Energization date of the Load~~, consistent with the most recently approved Dynamics Working Group (DWG) stability database~~. The initial transmission configuration of the study area shall be ~~identical to~~consistent with the configuration used in the corresponding steady-state study to the extent practicable.

(3~~2~~) All stability studies shall be performed in accordance with NERC Reliability Standards, Protocols, this Planning Guide, and the Operating Guides. Transient stability studies will analyze the performance of the ERCOT System in terms of angular stability, voltage stability, and excessive frequency excursions. Additional studies may include small signal stability or critical clearing time analyses. Such studies should incorporate reasonable and conservative assumptions regarding impacted facility operating conditions. ERCOT in collaboration with the TSP(s) shall determine the stability analysis to be performed.

(4~~3~~) The stability study portion of the LLIS shall document any identified instability ~~identified~~.

(~~5~~4) If the lead TSP identifies instability (other than instability identified for extreme events) in the stability portion of the LLIS, the TSP shall investigate alternative solutions, including transmission improvements, to mitigate the instability. The lead TSP shall identify any modifications to the levels of Demand and the timeline specified in the ILLE's initial LCP that are needed to account for all transmission upgrades required to support the full requested amount of Load. The TSP shall implement ~~the~~any mitigation measure that may be needed to address a stability risk before the Initial Energization of the Large Load in accordance with Protocol Section 3.11.4, Regional Planning Group Project Review Process. ~~If the mitigation cannot be implemented prior to the desired Large Load Energization date, the TSP shall identify the amount of load that may be reliably connected by the ILLE's desired Initial Energization date.~~

9.4 LLIS Report and Follow-up

(1) For each of the LLIS study elements, the lead TSP shall submit ~~to ERCOT~~ a preliminary study report to ERCOT and other directly affected TSPs. The report shall include a description of the study methodology and assumptions, findings, and recommendations. The report shall also identify any changes to the ILLE's Load Commissioning Plan (LCP) to allow for transmission upgrades in accordance with~~the amount of load that can be reliably interconnected by the ILLE's desired Initial Energization date per~~ the criteria in Section 9.3.4. The lead TSP may include additional information in the study report and may combine multiple LLIS study elements into a single report.

(2) ERCOT shall review the preliminary study report within ten Business Days and provide to the lead TSP any questions, comments, and proposed revisions necessary to ensure the report complies with the requirements in Section 9.3, Interconnection Study Procedures for Large Loads. ERCOT may extend this review period by an additional 20 Business Days and shall notify in writing the lead and directly affected TSPs of the extension. ~~The lead TSP will provide the preliminary study report to the d~~Directly~~directly~~ affected TSPs ~~, who~~ may also provide questions, comments, and proposed revisions during this review period. All comments from ERCOT and directly affected TSPs~~feedback~~ shall be provided to the lead TSP in writing.

(3) If, after considering the responses~~feedback~~ received from ERCOT and directly affected TSPs, ERCOT ~~or~~in collaboration with the lead TSP determines if an additional study is required, the lead TSP shall promptly perform the additional study and submit an updated preliminary study report for review as described in paragraph (1) above.

(4) If no additional study is required as described in paragraph (3) above, the lead TSP shall prepare a final LLIS study report that incorporates all relevant feedback received in paragraph (2) above~~, to the extent practical,~~ within ten Business Days.

(5) When~~Once~~ complete, the lead TSP shall provide the final report for the LLIS study element(s) to ERCOT and the directly affected TSPs only.

(6) The LLIS is deemed complete when the final reports ~~has~~~~ve~~~~have~~ been provided for all LLIS study elements. Within ~~fiveten~~ Business Days following the completion of the LLIS, ERCOT shall:

(a) Determine whether system upgrades recommended to support the full requested Load amount specified in the initial LCP are sufficient based on the report in paragraph (5) above~~the amount of Load approved to interconnect byon the proposed Initial Energization date before any transmission upgrades identified in the LLIS are operational. This amount shall be informed by the most limiting amount identified by the lead TSP from among all the LLIS study elements as described in paragraph (1) above;~~

(b) Grant conditional approval for the interconnection of Load in accordance with the schedule in the final LCP, as may be revised by the TSP, ~~of additional Load amounts identified in the LLIS that is conditioned on RPG approved~~ as the necessary transmission upgrades identified in the LCP ~~and transmission upgrades not subject to RPG approval~~ becom~~eing~~ operational, if ERCOT has determined pursuant to paragraph (a) above that the system upgrades recommended in the LLIS are sufficient to address the reliability risks associated with the proposed load additions; ~~and~~

(i) For transmission upgrades that are subject to RPG review as described in Protocol Section 3.11.4, Regional Planning Group Project Review Process, ERCOT shall grant conditional approval if it determines that a project with an equivalent impact on the ability to serve the requested Load has become operational; and

~~(c) Identify any remaining amount of Load requiring one or more new transmission upgrades subject to RPG review as described in Section 3.11.4, Regional Planning Group Project Review Process, in the Nodal Protocols; and.~~

(~~d~~c) Communicate the completion of the LLIS and the ~~amount(s) of Load approved in paragraphs (a) (c) above~~ resulting LCP to the lead TSP and directly affected TSPs.

~~(7) ERCOT shall promptly communicate the completion of the LLIS and the amount(s) of Load approved in paragraph (6) to the lead TSP and directly affected TSPs.~~

(~~8~~7) The lead TSP may provide a redacted copy of the final report for each LLIS study element to the ILLE upon request. The redacted report(s) shall conform with Nodal Protocols Section 1.3.

(~~9~~8) If a material change that impacts one or more LLIS study assumptions occurs before the requirements of Section 9.5, Interconnection Agreements and Responsibilities, have been met, ERCOT or the lead TSP may require one or more LLIS study elements be updated. ERCOT ~~and~~in collaboration with the lead TSP shall have ~~sole~~ discretion to determine if a change impacts any LLIS study assumptions and to require a modification of the study or a restudy be performed. Any modification of the study report shall be treated as a preliminary study and reviewed according to paragraph (1) above.

(~~10~~9) If the requirements of Section 9.5, Interconnection Agreements and Responsibilities, have not been satisfied within 180 days after the communication of the completion of the LLIS by ERCOT as described in paragraph (~~7~~6) above, ERCOT ~~may consider the project cancelled~~may notify the lead TSP that the project is subject to cancellation. Upon receipt of this notification, the lead TSP may submit a project status update to ERCOT that includes a request for an extension and provides an opinion on whether any of the completed LLIS elements require restudy. If no such project status update is received within 30 days from the date the notice is issued, ERCOT may consider the project cancel~~l~~ed.

(~~11~~10) If the Large Load has not met the requirements for Initial Energization as described in paragraph (1) of Section 9.6, Initial Energization and Continuing Operations for Large Loads, within 365 days after the Initial Energization date identified in the LLIS study report, the lead TSP shall provide an opinion to ERCOT on whether any of the completed LLIS elements require restudy. ERCOT may require one or more LLIS study elements be updated prior to approval of Initial Energization.

9.5 Interconnection Agreements and Responsibilities

9.5.1 Interconnection Agreement for Large Loads not Co-Located with a Generation Resource Facility ~~Registered as a Private Use Network~~

(1) For a Large Load not co-located with a Generation Resource Facility ~~registered as a Private Use Network (PUN)~~, ERCOT shall not allow Initial Energization prior to receiving one of the following:

(a) Confirmation from the interconnecting TSP that:

(i) All required interconnection agreements or equivalent service extension agreements with the Interconnecting Large Load Entity (ILLE) and, if applicable, directly affected TSP(s) have been executed;

(ii) The interconnecting TSP has received written acknowledgement from the ILLE of the ILLE's obligations to:

(A) Notify the interconnecting TSP of changes to the Large Load project information or to the ~~L~~load composition, technology, or ~~load~~ parameters, as described in Section 9.2.3 Modification of Large Load Project Information; and

(B) Maintain Load consumption at or below the level(s) of peak Demand established in the Load Commissioning Plan;

(~~ii~~iii) The interconnecting TSP has received notice to proceed with the construction of all required interconnection Facilities; and

(~~iii~~iv) The interconnecting TSP and, if applicable, directly affected TSP(s) ~~has~~have received the financial security ~~and/or~~, applicable payments, and/or other agreements required to fund all required interconnection Facilities; or

(b) A letter from a duly authorized person from a Municipally Owned Utility (MOU) or Electric Cooperative (EC) confirming its intent to construct and operate applicable Large Load and interconnect such Large Load to its transmission system.

9.5.2 Interconnection Agreement for Large Loads Co-Located with one or more Generation Resource Facilities ~~Registered as a Private Use Network~~

(1) For a Large Load co-located with a Generation Resource Facility ~~registered as a Private Use Network (PUN)~~, ERCOT shall not allow Initial Energization prior to receiving one of the following:

(a) Confirmation from the interconnecting TSP that:

(i) All required interconnection agreements and/or equivalent service extension or other agreements with the Resource Entity (RE), Interconnecting Entity (IE), and Interconnecting Large Load Entity (ILLE) have been executed;

(A) If the required agreements include a new Standard Generation Interconnection Agreement (SGIA) or an amendment to an existing SGIA, a copy of this agreement shall be provided to ERCOT once executed, per Section 5.2.8.1, Standard Generation Interconnection Agreement for Transmission-Connected Generators; or~~.~~

(B) If no new or amended agreements are required, the interconnecting TSP shall so notify ERCOT and state affirmatively it agrees to energize the new Load per the approved LLIS studies;~~.~~

(ii) The interconnecting TSP has received written acknowledgement from either the ILLE, or the RE on behalf of the ILLE, of the obligations to:

(A) Notify the interconnecting TSP of changes to the Large Load project information or to the ~~L~~load composition, technology, or ~~load~~ parameters, as described in Section 9.2.3 Modification of Large Load Project Information; and

(B) Maintain Load consumption at or below the level(s) of peak Demand established in the Load Commissioning Plan; and

(~~ii~~iii) The interconnecting TSP has received notice to proceed with the construction of all required interconnection Facilities; and

(~~iii~~iv) The interconnecting TSP and, if applicable, directly affected TSP(s) ~~has~~have received the financial security required, ~~and/or~~ applicable payments, and/or other agreements to fund all required interconnection Facilities; or

(b) A letter from a duly authorized person from a Municipally Owned Utility (MOU) or Electric Cooperative (EC) confirming its intent to construct and operate applicable Large Load and interconnect such Large Load to its transmission system.

9.6 Initial Energization and Continuing Operations for Large Loads

(1) Each Large Load shall meet the conditions established by ERCOT before proceeding to Initial Energization. These conditions may include, but are not limited to:

(a) Inclusion of the Load in the Network Operations Model in accordance with Section 6.6, Modeling of Large Loads;

(b) Verification that all required telemetry is operational and accurate;

(c) Completion of the requirements of Planning Guide Section 5.3.5, ERCOT Quarterly Stability Assessment;

(d) Completion and approval of any required Subsynchronous Oscillation (SSO) studies, SSO Mitigation Plan, SSO Countermeasures, and SSO monitoring, if required; and

(e) Submission of a current Load Commissioning Plan meeting the requirements of Section 9.2.4, Load Commissioning Plan.

(2) During continuing operations:

(a) The interconnecting TSP or, if applicable, the RE shall notify ERCOT if it identifies that a Large Load has exceeded a limit on peak Demand established in the LLIS and Load Commissioning Plan. ~~communicate to not permit a Large Load that it is not to exceed any limits on peak Demand established by ERCOT, and the TSP will notify ERCOT if it identifies such an exceedance.~~

(b) The ~~interconnecting~~applicable TSP shall notify ERCOT when a transmission upgrade identified in a Load Commissioning Plan becomes operational. ERCOT must give written approval before Demand may increase.

(c) Pursuant to Section 9.5, Interconnection Agreements and Responsibilities, if a Large Load modifies its facilities such that a previously provided dynamic load model is invalid, the Large Load shall notify and provide an updated model to the TDSP that provides service to the Large Load. The TDSP shall subsequently provide this updated dynamic load model to ERCOT.~~Pursuant to Section 6.2, Dynamics Model Development, the interconnecting TSP shall provide updated dynamics data about the Large Load to ERCOT when required.~~

ERCOT Impact Analysis Report

PGRR Number	115	**PGRR Title**	**Related to NPRR1234, Interconnection Requirements for Large Loads and Modeling Standards for Loads 25 MW or Greater**
Impact Analysis Date	May 28, 2024		
Estimated Cost/Budgetary Impact	None.		
Estimated Time Requirements	No project required. This Planning Guide Revision Request (PGRR) can take effect upon implementation of Nodal Protocol Revision Request (NPRR) 1234, Interconnection Requirements for Large Loads and Modeling Standards for Loads 25 MW or Greater.		
ERCOT Staffing Impacts (across all areas)	Ongoing Requirements: No impacts to ERCOT staffing.		
ERCOT Computer System Impacts	No impacts to ERCOT computer systems.		
ERCOT Business Function Impacts	No impacts to ERCOT business functions.		
Grid Operations & Practices Impacts	No impacts to ERCOT grid operations and practices.		

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

Comments
There are no additional impacts to this PGRR beyond what was captured in the Impact Analysis for NPRR1234.

Board Report

PGRR Number	**119**	**PGRR Title**	**Stability Constraint Modeling Assumptions in the Regional Transmission Plan**
Date of Decision	April 8, 2025		
Action	Recommended Approval		
Timeline	Normal		
Estimated Impacts	Cost/Budgetary: None Project Duration: No project required		
Proposed Effective Date	The first of the month following Public Utility Commission of Texas (PUCT) approval		
Priority and Rank Assigned	Not applicable		
Planning Guide Sections Requiring Revision	3.1.4.1.1, Regional Transmission Plan Cases		
Related Documents Requiring Revision/Related Revision Requests	None		
Revision Description	This Planning Guide Revision Request (PGRR) revises the Planning Guide to codify that a reliability margin consistent with expected operations procedures for the study period will be utilized when limits associated with a stability constraint are modeled in the Regional Transmission Plan reliability and economic base cases.		
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	When stability constraints are modeled in the Regional Transmission Plan reliability and economic base cases, ERCOT currently applies a reliability margin on the stability constraint limits, which is consistent with ERCOT's operating procedures. This PGRR clarifies and codifies the transmission planning assumptions related to the modeling of stability constraints in the Regional Transmission Plan base case.
ROS Decision	On 10/3/24, ROS voted unanimously to table PGRR119 and refer the issue to the Planning Working Group (PLWG). All Market Segments participated in the vote. On 2/6/25, ROS voted unanimously to recommend approval of PGRR119 as amended by the 1/22/25 Joint Commenters comments. All Market Segments participated in the vote. On 3/6/25, ROS voted unanimously to endorse and forward to TAC the 2/6/25 ROS Report and 9/9/24 Impact Analysis for PGRR119. All Market Segments participated in the vote.
Summary of ROS Discussion	On 10/3/24, participants reviewed PGRR119. On 2/6/25, participants reviewed the 1/22/25 Joint Commenters comments and noted that the 1/22/25 Joint Commenters comments are responsive to the 11/6/24 OPUC comments. On 3/6/25, there was no discussion.
TAC Decision	On 3/26/25, TAC voted unanimously to recommend approval of PGRR119 as recommended by ROS in the 3/6/25 ROS Report. All Market Segments participated in the vote.
Summary of TAC Discussion	On 3/26/25, 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

	[X] Comments were reviewed and discussed (if applicable) [ ] Other: (explain)
ERCOT Board Decision	On 4/8/25, the ERCOT Board voted unanimously to recommend approval of PGRR119 as recommended by TAC in the 3/26/25 TAC Report.

Opinions	
Credit Review	Not applicable
Independent Market Monitor Opinion	IMM has no opinion on PGRR119.
ERCOT Opinion	ERCOT supports approval of PGRR119.
ERCOT Market Impact Statement	ERCOT Staff has reviewed PGRR119 and believes it provides a positive market impact by clarifying and codifying the transmission planning assumptions related to the modeling of stability constraints in the Regional Transmission Plan base case.

Sponsor	
Name	Ping Yan
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Company	ERCOT
Phone Number	512-248-4153
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**

OPUC 110624	Expressed concern that the proposed "reliability margin" is undefined and could have a significant cost impact; requested ERCOT provide additional comments to further amend Section 3.1.4.1.1 that clarify how it will develop the size of any proposed reliability margin for an Interconnection Reliability Operating Limit (IROL)
Joint Commenters 120224	Clarified that operational practice is the source of the reliability margin to be used; removed "base" in reference to cases as both base and change cases should reflect appropriate margins in economic evaluations
Joint Commenters 012225	Incorporated additional stakeholder and ERCOT Staff feedback to simplify language previously added in paragraph (7) of Section 3.1.4.1.1 to allow ERCOT Staff to incorporate quantifiable future system changes when known but does not impose a significant modeling burden if the impact of system changes on stability limits or margins is not clear

Market Rules Notes

Please note that the baseline Planning Guide language in Section 3.1.4.1.1 has been updated to reflect the incorporation of the following PGRR:

- PGRR118, Related to NPRR1246, Energy Storage Resource Terminology Alignment for the Single-Model Era (incorporated 4/1/25)

Proposed Guide Language Revision

3.1.4.1.1 Regional Transmission Plan Cases

(1) The starting base cases for the Regional Transmission Plan development are created by removing all Tier 1, 2, and 3 projects that have not received RPG acceptance or, if applicable, ERCOT endorsement from the most recent SSWG base cases.

(2) ERCOT shall set all non-seasonal Mothballed Generation Resources to out of service in the Regional Transmission Plan reliability base cases. ERCOT shall add proposed Generation Resources that have met the criteria for inclusion in Section 6.9, Addition of Proposed Generation to the Planning Models, to the Regional Transmission Plan base cases.

[PGRR118: Replace paragraph (2) above with the following upon system implementation of NPRR1246:]

(2) ERCOT shall set all non-seasonal Mothballed Generation Resources and Mothballed ESRs to out of service in the Regional Transmission Plan reliability base cases. ERCOT shall add proposed Generation Resources and ESRs that have met the criteria

for inclusion in Section 6.9, Addition of Proposed Generation to the Planning Models, to the Regional Transmission Plan base cases.

(3) ERCOT shall update the Regional Transmission Plan reliability and economic base cases to reflect any updates to the amount of Switchable Generation Resource (SWGR) capacity available to the ERCOT Region.

(4) ERCOT may, in its discretion, set a Generation Resource to out of service in the Regional Transmission Plan base cases prior to receiving a Notification of Suspension of Operations (NSO) if the Resource Entity notifies ERCOT of its intent to retire/mothball the Generation Resource and/or makes a public statement of its intent to retire/mothball the Generation Resource. ERCOT must provide reasonable advance notice to the RPG of any proposed Generation Resource retirements/mothballs and allow an opportunity for stakeholder comments.

(a) ERCOT will post and maintain the current list of Generation Resources that will be set to out of service pursuant to paragraph (4) above on the ERCOT website.

[PGRR118: Replace paragraph (4) above with the following upon system implementation of NPRR1246:]

(4) ERCOT may, in its discretion, set a Generation Resource or ESR to out of service in the Regional Transmission Plan base cases prior to receiving a Notification of Suspension of Operations (NSO) if the Resource Entity notifies ERCOT of its intent to retire/mothball the Resource and/or makes a public statement of its intent to retire/mothball the Resource. ERCOT must provide reasonable advance notice to the RPG of any proposed Resource retirements/mothballs and allow an opportunity for stakeholder comments.

(a) ERCOT will post and maintain the current list of Generation Resources and ESRs that will be set to out of service pursuant to paragraph (4) above on the ERCOT website.

(5) In its Regional Transmission Plan studies, ERCOT shall first consider transmission needs without Remedial Action Scheme (RAS) actions. After evaluating these needs, ERCOT may model a RAS in the Regional Transmission Plan cases only if ERCOT's initial studies did not identify a transmission project to exit the RAS or if a transmission project to exit the RAS is not expected to be in service by the season and year the case represents.

[PGRR113: Replace paragraph (5) above with the following upon system implementation of NPRR1198:]

(5) In its Regional Transmission Plan studies, ERCOT shall first consider transmission needs without Remedial Action Scheme (RAS) or Constraint Management Plan (CMP)

actions. After evaluating these needs, ERCOT may model a RAS or CMP in the Regional Transmission Plan cases only if ERCOT's initial studies did not identify a transmission project to exit the RAS or CMP, or if a transmission project to exit the RAS or CMP is not expected to be in service by the season and year the case represents.

(6) ERCOT may, in its discretion, make other adjustments to any Regional Transmission Plan base case to ensure that the case reaches a solution. ERCOT must provide reasonable advance notice to the RPG of any proposed adjustments and an opportunity for stakeholder comment on them.

(7) ERCOT shall apply a reliability margin on applicable Interconnection Reliability Operating Limits (IROLs) and/or stability-related System Operating Limits (SOLs), consistent with the ERCOT operating procedures when such limits are modeled in the Regional Transmission Plan reliability and economic ~~base~~ cases. ERCOT shall use the current operating limit with reliability margin applied or best available information in determining the appropriate modeled limit for the future year being evaluated. ~~The future expected operational reliability margins for Generic Transmission Limits (GTLs) shall be used. The GTLs modeled in planning cases shall reflect the most likely operational limit for the future year being evaluated, including reliability margin discounts for System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) required margins or other likely reductions. In the absence of specific and quantifiable planned system changes that would increase or decrease a GTC limit in the planning horizon, the appropriate reliability margin discount shall be applied to the GTL as it is in operations at the time of study.~~

ERCOT Impact Analysis Report

PGRR Number	<u>119</u>	PGRR Title	**Stability Constraint Modeling Assumptions in the Regional Transmission Plan**
Impact Analysis Date	September 9, 2024		
Estimated Cost/Budgetary Impact	None.		
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)	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

SCR Number	**829**	**SCR Title**	**API for the NDCRC Application**
Date of Decision	April 8, 2025		
Action	Recommended Approval		
Timeline	Normal		
Estimated Impacts	Cost/Budgetary: Between $100k and $200k Project Duration: 7 to 10 months		
Proposed Effective Date	Upon system implementation		
Priority and Rank Assigned	Priority – 2025; Rank – 4560		
Supporting Protocol or Guide Sections/Related Documents	None		
System Change Description	This System Change Request (SCR) adds an Application Programming Interface (API) to upload unit testing data and download unit testing data from the Net Dependable Capability and Reactive Capability (NDCRC) application.		
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) ☐ Regulatory requirements ☐ ERCOT Board/PUCT Directive *(please select ONLY ONE – if more than one apply, please select the ONE that is most relevant)*		

Board Report

Justification of Reason for Revision and Market Impacts	The NDCRC application is a standalone system that was designed to track test data for a few specific types of tests such as Automatic Voltage Regulator (AVR)/Power System Stabilizer (PSS) and reactive capability curve. It does not provide an API for Qualified Scheduling Entities (QSEs) to upload or download data, nor does it communicate with other systems. As such, it is not suitable for any expanded usage. In April 2024, ERCOT decided to expand the use of this application to require that all unit testing requests be submitted through NDCRC. Since the system is a standalone system, QSEs must manually enter and/or modify every single testing request and ensure that the data submitted is consistent with what is in other QSE systems. In addition to the manual work, this new process increases the opportunity for errors. By including API functionality, this SCR will enable direct communication with other systems in ERCOT like the Outage Scheduler, increasing the efficiency and accuracy of market and system operations in general. The drastic change of the scope of this application as well as the heavy manual work involved on the QSE side highlight an urgent need to implement an API to streamline the process. For these reasons, this effort should be prioritized by ERCOT as soon as ERCOT resources are free from Real-Time Co-optimization plus Batteries (RTC+B) system development obligations.
PRS Decision	On 1/15/25, PRS voted unanimously to recommend approval of SCR829 as submitted. All Market Segments participated in the vote. On 2/12/25, PRS voted unanimously to table SCR829. All Market Segments participated in the vote. On 3/12/25, PRS voted unanimously to endorse and forward to TAC the 1/15/25 PRS Report and 3/11/25 Impact Analysis for SCR829 with a recommended priority of 2025 and rank of 4560. All Market Segments participated in the vote.
Summary of PRS Discussion	On 1/15/25, participants reviewed SCR829, noting it was discussed extensively at the Technology Working Group (TWG). On 2/12/25, participants reviewed the 2/7/25 ERCOT comments. On 3/12/25, participants reviewed the 3/11/25 Impact Analysis and considered a priority and rank for SCR829.
TAC Decision	On 3/26/25, TAC voted unanimously to recommend approval of SCR829 as recommended by PRS in the 3/12/25 PRS Report. All Market Segments participated in the vote.
Summary of TAC Discussion	On 3/26/25, there was no additional discussion beyond TAC review of the items below.

Board Report

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 4/8/25, the ERCOT Board voted unanimously to recommend approval of SCR829 as recommended by TAC in the 3/26/25 TAC Report.

Opinion	
Credit Review	Not applicable
Independent Market Monitor Opinion	IMM has no opinion on SCR829.
ERCOT Opinion	ERCOT supports approval of SCR829.
ERCOT Market Impact Statement	ERCOT Staff has reviewed SCR829 and believes it provides a positive market impact by enabling QSEs to upload and download unit testing data from the NDCRC application, reducing manual demands and opportunities for error.

Sponsor	
Name	Shuye Teng, Andy Nguyen, Amanda Deleon, Bill Barnes, Blake Holt ("Joint Sponsors")
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Company	Constellation Energy Generation, Tenaska Power Services, NRG Texas Power LLC, Lower Colorado Review Authority
Phone Number	512-777-0848, 512-705-8618, 817-462-8058, 512-691-6137, 254-913-8096
Cell Number	512-777-0848, 512-705-8618, 832-528-8370, 512-691-6137, 254-913-8096
Market Segment	Independent Generator, Independent Power Marketeter (IPM), Independent Generator, Cooperative

Board Report

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 020725	Proposed an alternative schedule for the development of an Impact Analysis for SCR829

Market Rules Notes

None

Proposed System Change

Issue:

The Net Dependable Capability and Reactive Capability (NDCRC) application is a standalone system that was designed to track test data for a few specific types of tests such as Automatic Voltage Regulator (AVR)/Power System Stabilizer (PSS) and reactive capability curve. It does not provide an Application Programming Interface (API) for Qualified Scheduling Entities (QSEs) to upload or download data, nor does it communicate with other systems. As such, it is not suitable for any expanded usage. In April 2024, ERCOT decided to expand the use of this application to require that all unit testing requests be submitted through NDCRC. Since the system is a standalone system, QSEs must manually enter and/or modify every single testing request and ensure that the data submitted is consistent with what is in other QSE systems. In addition to the manual work, this new process increased the opportunity for errors. Including API functionality, as proposed in this System Change Request (SCR), will also enable direct communication with other systems in ERCOT like the Outage Scheduler and thus increase the efficiency and accuracy of market and system operations in general. The drastic change of the scope of this application as well as the heavy manual work involved on the QSE side highlight an urgent need to implement an API to streamline the process.

Resolution:

ERCOT provides an API for the NDCRC which will greatly improve the submission process and enhance accurate communication between ERCOT and QSEs, enable automated data uploading and downloading, and facilitate seamless communication with various QSE systems such as market operations and energy management systems.

ERCOT Impact Analysis Report

SCR Number	**829**	**SCR Title**	**API for the NDCRC Application**
Impact Analysis Date	March 11, 2025		
Estimated Cost/Budgetary Impact	Between $100k and $200k		
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: • Net Dependable Capability and Reactive Capability 96% • Software Development or Enablement Tools 4%		
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	028	SMOGRR Title	Add Series Reactor Compensation Factors
Date of Decision	April 8, 2025		
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		
Settlement Metering Operating Guide Sections Requiring Revision	8, Transformer and Line Loss Compensation Factors 8.1, Introduction 8.5, Calculating Series Reactor Loss Constants (new) 8.5, Reference Materials 8.6.1, Transformer and Line Loss Compensation Sheet		
Related Documents Requiring Revision/Related Revision Requests	None		
Revision Description	This Settlement Metering Operating Guide Revision Request (SMOGRR) gives guidance for allowing loss compensation for current limiting reactors.		
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)		

	☐ 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 SMOGRR is needed to extend the guidelines for loss compensation (previously limited to transmission lines and transformers) to include current limiting reactors which have seen increased use in renewable generation. The need for current limiting reactors (a protection device to reduce fault current) may be identified later in the design process and permitting loss compensation for current limiting reactors would allow for greater flexibility in meter installation location without requiring additional metering structures to be constructed.
WMS Decision	On 10/11/23, WMS voted unanimously to table SMOGRR028 and refer the issue to the Metering Working Group (MWG). All Market Segments participated in the vote. On 2/5/25, WMS voted unanimously to recommend approval of SMOGRR028 as amended by the 1/14/25 MWG comments. All Market Segments participated in the vote. On 3/5/25, WMS voted unanimously to endorse and forward to TAC the 2/5/25 WMS Report and 2/20/25 Impact Analysis for SMOGRR028. All Market Segments participated in the vote.
Summary of WMS Discussion	On 10/11/23, participants requested MWG review SMOGRR028. On 2/5/25, participants reviewed the 1/14/25 MWG comments. On 3/5/25, participants reviewed the 2/20/25 Impact Analysis.
TAC Decision	On 3/26/25, TAC voted unanimously to recommend approval of SMOGRR028 as recommended by WMS in the 3/5/25 WMS Report. All Market Segments participated in the vote.
Summary of TAC Discussion	On 3/26/25, 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

Board Report

	☒ Comments were reviewed and discussed (if applicable) ☐ Other: (explain)
ERCOT Board Decision	On 4/8/25, the ERCOT Board voted unanimously to recommend approval of SMOGRR028 as recommended by TAC in the 3/26/25 TAC Report.

Opinions	
Credit Review	Not Applicable
Independent Market Monitor Opinion	IMM has no opinion on SMOGRR028.
ERCOT Opinion	ERCOT supports approval of SMOGRR028.
ERCOT Market Impact Statement	ERCOT Staff has reviewed SMOGRR028 and believes it provides a positive market impact by extending the guidelines for loss compensation to include current limiting reactors, which may be identified as needed later in the design process, the use of which allowing greater flexibility in meter installation location without requiring additional metering structures.

Sponsor	
Name	Thomas Burke
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Cell Number	
Market Segment	Independent Generator

Market Rules Staff Contact	
Name	Brittney Albracht
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Phone Number	512-225-7027

Comments Received

Comment Author	Comment Summary
MWG 011425	Proposed series reactor language and other revisions resulting from discussions at 2024 MWG meetings

Market Rules Notes

None

Proposed Protocol Language Revision

8 TRANSFORMER~~, AND~~ LINE LOSS, AND SERIES REACTOR COMPENSATION FACTORS

8.1 Introduction

(1) Transformer~~, and~~ line loss, and series reactor compensation refers to the practice of metering electrical energy delivered at a ~~high-voltage~~ billing point using metering equipment connected ~~on the low-voltage side of~~away from the delivery point. The metering equipment is provided with a means of correction that adds to, or subtracts from, the actual active and reactive metered values in proportion to losses that are occurring in the transformer~~, and~~ lines, and series reactors.

(2) ERCOT approval is required for loss compensation performed in the Data Aggregation System (DAS). For a specific site, where a Transmission and/or Distribution Service Provider (TDSP) is requesting ERCOT to perform loss compensation in DAS, the TDSP shall submit to ERCOT, for approval, a single percent loss correction value and supporting documentation verifying such value. Such loss compensation percentage values and supporting documentation shall be resubmitted to ERCOT on an annual basis or upon circuit parameter changes.

(3) Transformer losses are divided into two parts:

(a) The core or iron loss (referred to as the no-load loss); and

(b) The copper loss (referred to as the load loss).

(i) Both the no-load loss and the load loss are further divided into Watt and VAr components.

(ii) The no-load (iron) loss is composed mostly of eddy current and hysteresis losses in the core. No-load loss varies in proportion to applied voltage and is present with or without load applied. Dielectric losses and copper loss due to exciting current are also present, but are generally small enough to be neglected.

(iii) The load (copper) watt loss (I^2 + stray loss) is primarily due to the resistance of conductors and essentially varies as the square of the load current. The VAr component of transformer load loss is caused by the leakage reactance between windings and varies as the square of the load current.

(4~~iv~~) Line losses are considered to be resistive and have I2R losses. The lengths, spacings and configurations of lines are usually such that inductive and capacitive effects can be ignored. If line losses are to be compensated, they are included as part of the load losses (Watts copper).

(5) Series Reactor losses are to be calculated and compensated as percent Watt copper loss and percent VAR copper loss.

(6) The calculation for compensation of components on the Resource side of the billing point should result in a compensation that will raise the measured load values and lower generation values. The calculation for compensation of components on the TDSP side of the billing point should result in a compensation that will lower the measured load values and raise generation values. Once the data is made available, the TDSP shall ensure correct calculation and meter programming is utilized to correctly adjust the recorded values as required for the specific meter point configuration.

(7) The owner of any device for which compensation is required, i.e. a device connected between the meter point and the billing point, shall provide to the TDSP all data required to perform the calculation of the compensation factors for that device.

~~8.5 Calculating Series Reactor Loss Constants~~

~~(1) Current limiting reactor loss compensation calculations with electronic meters are accomplished internally with firmware. Various information and test data about the current limiting reactor is required to program the meter. The following information is required regarding meter installations:~~

~~(a) Current limiting reactor Rated Current~~

~~(b) Current limiting reactor Rated Voltage~~

~~(2) The following data is required from the Current limiting reactor test report:~~

~~(a) Current limiting reactor Test Inductance (mH)~~

~~(b) Current limiting reactor DC Resistance at Reference Temperature (Ohms)~~

~~(c) Current limiting reactor Total AC Losses (Watts)~~

~~(3) The test data required may be obtained from the following sources:~~

~~(a) The manufacturer's test report; or~~

~~(b) A test completed by a utility or independent electrical testing company.~~

8.65~~5~~ Reference Materials

(1) The following additional references may be referred to for assistance when calculating the compensation factors referred to in this Section 8, Transformer and Line Loss Compensation Factors.

(a) Handbook For Electricity Metering, Edison Electric Institute, Ninth Edition, 1992.

(b) Institute of Electrical and Electronics Engineers (IEEE) Std. C57.12.00-2000, IEEE Standard General Requirements for Liquid Immersed Distribution, Power and Regulating Transformer.

(c) IEEE Std. C57.16-2011, IEEE Standard for Requirements, Terminology, and Test Code for Dry-Type Air-Core Series Connected Reactors.

8.~~7~~66.1 Transformer and Line Loss Compensation Sheet

Name:
Delivery:
Location:
Rev. Date:

HV Rated Voltage:	V	VT Ratio:	:1
HV Tap:	V	CT Ratio:	:5
LV Tap:	V	Joint Use (Y/N):	
Trf. Conn. (Y/D):		Metering Trf. Use:	100 %
Trf. Phase (1 or 3)		Contract kW:	kW
# Meter Elem.:		Power Factor:	%

Comments:

TRANSFORMER DATA

Serial Number	KVa Rating	No Load (Fe) Loss	Load (Cu) Loss	(Z) Impedance	(IE) Exciting Current

Total kVa rating:	Max Available kVa:

LINE DATA

	Resistance	Length
#1 Line Type:	Ohms/mile	Miles
#2 Line Type:	Ohms/mile	Miles
#3 Line Type:	Ohms/mile	Miles
#4 Line Type:	Ohms/mile	Miles
#5 Line Type:	Ohms/mile	Miles
#6 Line Type:	Ohms/mile	Miles

SERIES REACTOR DATA

Serial Number	Rated Current	Rated Voltage	~~Total AC (Cu) Loss~~	~~Test Inductance (mH)~~

			~~(W)~~Resistance (Ohms)	

****TRANSFORMER LOSS COMPENSATION TEST POINTS FOR WATTHOURS****

SERIES TEST

Test Load	% Total
Full	
0.5 P.F.	
Light	

****TRANSFORMER LOSS COMPENSATION TEST POINTS FOR VARHOURS****

SERIES TEST

Test Load	% Total
Full	
Light	

Example: Transformer, Series Reactor, and Line Loss Compensation Calculation Sheet

Date: ~~12~~XX/~~14~~XX/~~2000~~20XX

Transformer Information		Transmission Line Information		Series Reactor Information		Meter Information	
Xfmr Manufacturer	ABB	Line Type	4/0 ACSR	Reactor Manufacturer	GE	PTR (xxx/1)	60
Xfmr Serial Number	1000001	Line Length (miles)	7.360	Reactor Serial Number	3543130010, 3543130011, 3543130012	CTR (xxx/1)	120
Xfmr size (KVA)	12000	Line Res. @ 50 C	0.592	Reactor Rated Current	1200	Meter Rated volt (V)	120
Xfmr Pri. test volt (p-p-v)	110000	*Total Line Res.	4.357	Average Series Reactor Reactance~~Average Reactor Test Inductance (mH)~~ (Ohms=2*π *60Hz*mH*10^{-3})	0.12*π *2.477	Meter class (amp)	20
Xfmr. sec. test volt (p-p-v)	13090	*Line Loss (VA)	266549	Average Series Reactor Resistance~~Average Reactor DC Resistance at Reference Temperature~~ (Ohms)	.00731323	Number of elements	3
Xfmr. No-Load loss (Watts)	22200			~~Reactor Total Three Phase AC (Cu) Losses (Watts)~~	~~39349~~	*Meter Nominal Watts (Watts)	3600
Xfmr. Excitation Current (%)	0.45			~~*Reactor Reactance (Ohms):~~	~~0.933807~~	*Nominal CT Primary amp (A)	1200
Xfmr. Load loss (Watts)	51360			~~*Reactor Impedance (Ohms):~~	~~0.933836~~	* Meter secondary test volt (V)	125.9586

Board Report

Xfmr Impedance (%)	8.84			~~*Reactor Impedance (%)~~	~~5.63~~	*Nominal Primary VA (VA)	25920000
*Xfmr sec. Test amp (A)	529.27						
*Xfmr Pri Amps @ 1/2 Mtr Cl (A)	142.80						

XFMR Loss Constants

*No Load VA loss (VA)	54000
*No Load loss phase angle (alpha)	65.73
*No Load VAr loss (VAr)	49226
*Load VA loss (VA)	1060800
*Load loss phase angle (beta)	87.22
*Load VAr loss (VAr)	1059556

Series Reactor Losses ~~Constants~~

*SR Loss Watts~~*Load VA Loss (VA)~~	10531.0512~~4034169.953~~
*SR Loss Vars~~*Load loss phase angle (beta)~~	3566880.00~~89.44113~~
*SR % Watt Cu Losses~~*Load Var loss (VAr):~~	-0.040629~~4033978~~
*SR % Vars Cu Losses	-13.761111

% Transformer Losses		**% Transmission Line Losses**		**% Series Reactor Losses**		**% Total Losses**	
% Xfmr Watt Fe Loss	0.07774					%Tot. Watt Fe Loss	0.07774
% Xfmr Watt Cu Loss	1.01857	% Line Watt Cu Loss	1.02835	SR % Watt Cu Losses	-0.040629~~0.026024~~	%Tot. Watt Cu Loss	2.000632~~2.04692~~

% Xfmr VAr Fe Loss	0.15645				~~% Var Cu Losses~~	~~2.66797~~	%Tot. VAr Fe Loss	0.15645
% Xfmr VAr Cu Loss	21.01307				SR % Var Cu Losses	-13.761111	%Tot. VAr Cu Loss	7.25195921.01307

***Calculated Values for the Transformer, Series Reactor and Line Loss Compensation Calculation Sheet**	
Where:	Xfmr Sec. test amps=(Xfmr rating in VA)/(Xfmr secondary test p-p volt x Sqrt 3)
	Xfmr Pri. Amp @ 1/2Mtr CL=(Xfmr Secondary test p-p volt/Xfmr Primary test p-p volt) x Nominal CT Primary Amp
	Total Line Res.=Line Length x Line Res. (per mile)
	Line Loss=3 x Total Line Res. x (Xfmr Primary Amp @ 1/2 Meter Class amp)^2
	Average Series Reactor (SR) Resistance (3 Element)=(Phase A Reactor Resistance + Phase B Reactor Resistance + Phase C Reactor Resistance)/3
	Average Series Reactor (SR) Resistance (2 Element)=(Phase A Reactor Resistance + Phase C Reactor Resistance)/2
	Average Series Reactor (SR) Reactance (3 Element)=(Phase A Reactor Reactance + Phase B Reactor Reactance + Phase C Reactor Reactance)/3
	Average Series Reactor (SR) Reactance (2 Element)=(Phase A Reactor Reactance + Phase C Reactor Reactance)/2
	SR Loss Watts=((Nominal CT Primary Amps)^2)*Average SR Resistance
	SR Loss Vars=((Nominal CT Primary Amps)^2)*Average SR Reactance
	Meter Test Current=(Number of Elements * 1/2 Class Amps of Meter)
	SR % Watt Cu Losses= -(SR Loss Watts * 100)/(CTR*PTR*Meter Test Current*Meter Rated Volt)
	SR % Var Cu Losses= -(SR Loss Vars * 100)/(CTR*PTR*Meter Test Current*Meter Rated Volt)
	Meter Nominal Watts=(Meter Class amp/2) x Meter Rated voltage x Number of elements
	Nominal CT Primary Amps=(Meter Class amp/2) x CTR
	Meter secondary test Volt=(Xfmr sec test volt)/(PTR x Sqrt 3) for 3 elm; (Xfmr sec test volt)/(PTR) for 2 elm
	Nominal Primary VA=CTR x PTR x Meter Nominal Watts
	No Load VA loss=(Xfmr Excitation current x Xfmr rating in VA) / 100
	No Load loss phase angle=acos(Xfmr No Load watts loss/No Load VA loss)
	No Load VAr Loss=No Load VA loss x sin(No Load loss phase angle (alpha))
	Load VA loss=(Xfmr Impedance x Xfmr rating in VA) / 100
	Load loss ph angle (beta)=acos(Xfmr load loss/Load VA loss)

	Load VAr loss=Load VA loss x sin(Load loss phase angle (beta)
	% Watt Fe Loss=((Xfmr No-load loss x (Meter rated volt/Meter sec. test volt)^2) / Nominal Primary VA) x 100
	% Watt Cu Loss=((Xfmr Load loss x ((Meter Class amp/2) x (CTR/Xfmr sec. test amp))^2) / Nominal Primary VA) x 100
	% VAr Fe Loss=((No Load VAr loss x (Meter Rated volt/Meter Sec. test volt)^4) / Nominal Primary VA) x 100
	% VAr Cu Loss=((Load VAr loss x ((Meter Class amp/2) x (CTR/Xfmr sec. test amp))^2) / Nominal Primary VA) x 100
	% Line Cu Loss=(Line Loss VA/ Nominal Primary VA) x 100
	% Total Losses= %Xfmr(Fe or Cu) losses + %Line(Fe or Cu) losses
	~~SR Load VA loss=(SR calculated % Impedance x SR rating in VA) / 100~~
	~~SR Load loss ph angle (beta)=acos(SR load loss/Load VA loss)~~
	~~SR Load Var loss=Load VA loss x sin(Load loss phase angle (beta)~~

Percent Error Calculations for Meters		
With Transformer/Line Loss Compensation		
FL = 120 VOLTS @ 5 AMPS @ UNITY	**FL=**	**1.179**
LL = 120 VOLTS @ .5 AMPS @ UNITY	**LL=**	**1.657**
PF = 120 VOLTS @ 5 AMPS @ 50%	**PF=**	**2.358**
Calculations for Watt Loss Compensation		
FL = 1/2 Watt CU losses + 2 * Watt FE losses		
LL = 1/20th Watt CU losses + 20 * Watt FE losses		
PF = UNITY * 2		

ERCOT Impact Analysis Report

SMOGRR Number	**028**	**SMOGRR Title**	**Add Series Reactor Compensation Factors**
Impact Analysis Date	February 20, 2025		
Estimated Cost/Budgetary Impact	None.		
Estimated Time Requirements	No project required. This Settlement Metering Operating Guide Revision Request (SMOGRR) 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	ERCOT will update its business processes to implement this SMOGRR.		
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

VCMRR Number	**042**	**VCMRR Title**	**SO_2 and NO_X Emission Index Prices Used in Verifiable Cost Calculations**
Date of Decision	April 8, 2025		
Action	Recommended Approval		
Timeline	Normal		
Estimated Impacts	Cost/Budgetary: Between $90K and $140K Project Duration: 6 to 9 months		
Proposed Effective Date	Upon system implementation		
Priority and Rank Assigned	Priority – 2026; Rank – 4720		
Verifiable Cost Manual Sections Requiring Revision	2.6, Additional Rules for Submitting Emission Costs Appendix 5, Specification of Relevant Equations		
Related Documents Requiring Revision/Related Revision Requests	Nodal Protocol Revision Request (NPRR) 1242, Related to VCMRR042, SO_2 and NO_x Emission Index Prices Used in Verifiable Cost Calculations (Withdrawn)		
Revision Description	This Verifiable Cost Manual Revision Request (VCMRR) adds the use of seasonal nitrogen oxide (NO_X) prices obtained from indices to calculate emission costs from May through September. Annual index prices would continue to be used for SO_2 from January through December.		
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 ☐ Administrative		

	☐ 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 VCMRR is needed to ensure ERCOT has access to seasonal emissions data due to volatility in index prices as a result of reductions in allowances and reliance on the market to meet compliance obligations. The swings in index prices are particularly impactful on Verifiable Startup Emission Costs and Verifiable Minimum-Energy Emission Costs, outlined in Appendix 5, Specification of Relevant Equations, and need to be taken into account in Generation Resources' offer curves. While there has been attention on the Environmental Protection Agency (EPA) rules and a recent Supreme Court ruling on the Good Neighbor Rule, this does not eliminate seasonal index prices. Further, it seems appropriate for ERCOT to maintain access to the vendor data needed to include seasonal index prices as EPA is expected to reinstate prior Cross-State Air Pollution Rule (CSAPR) obligations while the legal challenge to the Good Neighbor Rule continues to be litigated. Although trading has temporarily been suspended, obligations to hold and obtain sufficient allowances consistent with CSAPR obligations are expected to be clarified with relative speed. Eliminating the need to engage in a new vendor selection process allows ERCOT to quickly respond to the changes in the emissions allowances and resulting prices. Further, the inventory of allowances is reflected in terms of opportunity costs. They can be used by Luminant to meet compliance obligations or sold if there are potential excess allowances. Therefore, there is a value attached to them even absent trading.
WMS Decision	On 8/7/24, WMS voted unanimously to table VCMRR042 and refer the issue to the Resource Cost Working Group (RCWG). All Market Segments participated in the vote. On 12/4/24, WMS voted unanimously to recommend approval of VCMRR042 as amended by the 11/11/24 Luminant comments. All Market Segments participated in the vote. On 1/8/25, WMS voted unanimously to table VCMRR042. All Market Segments participated in the vote. On 2/5/25, WMS voted unanimously to endorse and forward to TAC the 12/4/24 WMS Report, as amended by the 2/4/25 ERCOT

	comments as revised by WMS, and the 1/31/25 Impact Analysis for VCMRR042, with a recommended priority of 2026 and rank of 4720. All Market Segments participated in the vote.
Summary of WMS Discussion	On 8/7/24, participants supported the concept of using seasonal index values and requested additional review by the RCWG. On 12/4/24, participants reviewed the 11/11/24 Luminant comments and noted RCWG review and support of the same. On 1/8/25, participants reviewed the 12/19/24 ERCOT comments requesting additional time to develop the Impact Analysis for VCMRR042. On 2/5/25, participants reviewed the 2/5/25 ERCOT comments and suggested a clarification to the Revision Description, reviewed the 1/31/25 Impact Analysis, and considered a priority and rank.
TAC Decision	On 2/27/25, TAC voted unanimously to recommend approval of VCMRR042 as recommended by WMS in the 2/5/25 WMS Report. All Market Segments participated in the vote.
Summary of TAC Discussion	On 2/27/25, 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 4/8/25, the ERCOT Board voted unanimously to recommend approval of VCMRR042 as recommended by TAC in the 2/27/25 TAC Report.

Opinions	
Credit Review	Not applicable
Independent Market Monitor Opinion	IMM supports VCMRR042.

Board Report

ERCOT Opinion	ERCOT supports approval of VCMRR042.
ERCOT Market Impact Statement	ERCOT Staff has reviewed VCMRR042 and agrees that seasonal NOx emissions prices are a better valuation of NOx emissions costs than annual NOx emissions prices currently used. Also, when automated, this VCMRR will enable daily SO2 and NOx prices to be included in the verifiable Operations and Maintenance (O&M) costs, capturing price changes more promptly than the current use of monthly averages.

Sponsor	
Name	Katie Rich
E-mail Address	katie.rich@vistracorp.com
Company	Luminant Generation Company LLC
Phone Number	
Cell Number	737-313-9351
Market Segment	Independent Generator

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 080224	Noted that, as written, VCMRR042 conflicts with VCMRR041, SO_2 and NO_x Emission Prices Used in Verifiable Cost Calculations, and that both cannot be implemented if approved; and that VCMRR042 eliminates the current manual process to calculate monthly arithmetic average values for annual emission prices without providing an alternative methodology
Luminant 111124	Refined the proposal on the calculation of seasonal NO_x and annual SO_2 index prices and recommended that upon adoption of the VCMRR, ERCOT should continue to calculate the monthly indices using the arithmetic average of the prices published during Business Days for the first 15 days of the month prior to the effective month

ERCOT 121924	Proposed an alternative schedule for the development of an Impact Analysis for VCMRR042
ERCOT 020425	Proposed revisions to better distinguish the monthly manual process from the automated daily process, adding gray box language to allow time for system implementation; and to describe the indices used for SO_2 and NO_x and the corresponding periods
PRS 021425	Endorse the WMS-recommended priority of 2026 and rank of 4720 for Verifiable Cost Manual Revision Request (VCMRR) 042

Market Rules Notes

None

Proposed Verifiable Cost Manual Language Revision

2.6 Additional Rules for Submitting Emission Costs

(1) Verifiable cost data may include the cost of purchasing emission credits but only to the extent necessary to meet environmental regulations associated with the operation of the specific Resource. ERCOT will not approve emission costs of any type unless they are sufficiently documented. When submitting emission costs the following procedures apply:

(a) Filing Entities submitting emission costs per-start must do so for each start type, cold, hot and intermediate. ERCOT will calculate Verifiable Startup Emission Costs ($/start) for a Resource by using Equation 4 described in Section 14, Appendices, Appendix 5, Specification of Relevant Equations.

(b) Emission costs incurred while operating the Resource at the Minimum-Energy level or above Low Sustained Limit (LSL) are calculated on a $/MWh basis. ERCOT will calculate Verifiable emission costs ($/MWh) at LSL by using Equation 5 described in Section 14, Appendices, Appendix 5.

(c) Resources may include the cost of NOx, and SO2 emissions requirements as part of the verifiable cost for:

(i) Non-attainment Area for NOx in Houston-Galveston-Brazoria

(ii) The Cross-State Air Pollution Rule (~~CASPR~~CSAPR) ~~Clean Air Interstate Rule (CAIR)~~ or other federal regulations for NOx and SO2, using Equations 4 and 5 as described in Section 14, Appendices, Appendix 5.

(d) For verifying the emission rates, the Filing Entity may submit the historic calendar annual average for the unit-specific emission rates reported to Texas Commission on Environmental Quality (TCEQ) and or Environmental Protection Agency (EPA) by April 30 of the applicable year, if deemed necessary by the Filing Entity.

(e) Emission prices for SO_2 ~~and NOx~~ will be obtained by ERCOT and will be based on ~~annual~~CSAPR Group 2 index prices, applicable to all months of the year. Emission prices for NO_X will be obtained by ERCOT based on published CSAPR Group 2 seasonal index prices for the months~~April through August~~ May through September. ~~NO_X index prices are applicable only during the Ozone Season, months May through September, as shown in Table A below.~~ ~~seasonal index prices for the months May through September and annual index prices for October through April~~ ~~average monthly index prices~~ ERCOT will selected~~ed~~ index prices ~~by ERCOT~~ that are generally accepted in the industry and regularly published. ERCOT will calculate monthly indices using the arithmetic average of the prices published during the Business Days for the first 15 days of the month prior to the effective month as shown in Table A below. ~~ERCOT will calculate monthly indices using the arithmetic average of the prices published during business days for the first 15 days of the month prior to the effective month.~~

Table A: The reference index prices for the arithmetic average will be as follows:

Effective Month	**SO_2 Reference ~~Annual~~ Index Price**	**NOx Reference Seasonal Index Price**
January	December	N/A
February	January	N/A
March	February	N/A
April	March	N/A
May	April	April
June	May	May
July	June	June
August	July	July
September	August	August
October	September	N/A
November	October	N/A
December	November	N/A

[VCMRR 042: Replace paragraph (e) above with the following upon system implementation:]

(e) Emission prices for SO_2 will be obtained by ERCOT ~~and will be~~ based on daily CSAPR Group 2 index prices, applicable to all days of the year. Emission prices for NO_X will be obtained by ERCOT based on published seasonal daily index prices during months May through September of each year. ERCOT will select index prices that are generally accepted in the industry and regularly published. If an index price is not available, the effective price for the most recent preceding Operating Day shall be used. For the period October through April, the NO_X price will be set to zero.

(f) ERCOT will disclose to Market Participants the source of its selected price indices, along with descriptions of the nature and derivation of the indices as available from the publishers of those indices. In the event that an ERCOT selected index becomes unavailable or unsuitable for the intended purpose, ERCOT will select a substitute index source. ERCOT will notify Market Participants of any change in the index, along with a description of the nature and derivation of the substitute index and a summary of the reasons for the change, 60 days prior to the beginning of its use. However, in the event that 60 days notice cannot be given for any reason, ERCOT will notify Market Participants as far prior to use as practical.

(g) On a monthly basis, ERCOT will recalculate each Resource's emission costs for SO2 and NOx utilizing the emission prices taken from the indices described in paragraph 1(e) above. The new emission costs will replace the emission costs in the previously approved Operations & Maintenance (O&M) Verifiable Costs totals.

(h) ERCOT emission cost calculations for each Resource will be completed by and the new approved O&M Verifiable Costs will be made available to Filing Entities eight days prior to the first day of each effective month. The effective period for use of these new emission costs will be the first day of each calendar month through the end of the same month.

[VCMRR 042: Replace paragraphs (g) and (h) above with the following upon system implementation:]

(g) On a daily basis, ERCOT will recalculate each Resource's emission costs for SO_2 and NO_X utilizing the emission prices taken from the indices described in paragraph 1(e) above. The new emission costs will replace the emission costs in the previously approved Operations & Maintenance (O&M) Verifiable Costs totals.

(h) ERCOT emission cost calculations for each Resource will be calculated daily and added to approved O&M Verifiable Costs.

(i) As a trading market develops pertaining to emissions limits at a state and or regional level, the costs associated with~~to~~ complying with emission restrictions may be eligible to be recovered and be part of the verifiable cost methodology. At the appropriate time, any market participant may propose a methodology to the Wholesale Market Subcommittee (WMS)~~Resource Cost Working Group (RCWG)~~ to recuperate the emission costs in the applicable non-attainment area, which will be addressed in the Verifiable Cost Manual.

Appendix 5: Specification of Relevant Equations

Equation 1: Verifiable Startup Offer Cap ($/Start)

Verifiable Startup Offer Cap ($/Start) = DAFCRS (MMBtu/Start) * [(GASPERSU*FIP + OILPERSU*FOP)/100] + VOMS

Where: DAFCRS = Total Fuel * (1+VOXR)
Total Fuel = [$\text{Fuel}_{\text{Startup-BC}}$ + $\text{Fuel}_{\text{BC-LSL}}$ + $\text{Fuel}_{\text{BO-Shutdown}}$]

The bill determinants utilized above are defined as:

DAFCRS = the adjusted verified fuel consumption for the start type (MMBtu/Start)
GASPERSU = Percentage of natural gas used for a start
FIP = Fuel Index Price ($/MMBtu)
OILPERSU = Percentage of oil used for a start
FOP = Fuel Oil Price ($/MMBtu)
VOMS = the verified O&M cost for a hot start ($/Start)
VOXR= Value of X for the Resource
$\text{Fuel}_{\text{Startup-BC}}$= Fuel quantity required to bring Resource from Startup to Breaker Close (MMBtu)
$\text{Fuel}_{\text{BC-LSL}}$= Fuel quantity required to bring Resource from Breaker Close to Minimum Energy at LSL (MMBtu)
$\text{Fuel}_{\text{BO-Shutdown}}$= Fuel quantity required to take Resource from Breaker Open to Shutdown (MMBtu)

Note 1: GASPERSU and OILPERSU are decimal percentages in the Settlements equations and will be multiplied by 100 during the Integration process.

Note 2: ERCOT will use the solid fuel price and percentages to create Startup offers when no offer is submitted by the QSE for solid fuel Resources.

Note 3: This equation does not include any adjustments made to the final calculation of the Startup Offer cap, as described in Protocol Section 4.4.9.2.1, Startup Offer and Minimum-Energy Offer Criteria.

Equation 2: Verifiable Minimum-Energy Offer Cap ($/MWh)

Verifiable Minimum-Energy Offer Cap ($/MWh) = AHR*[(GASPERME*FIP + OILPERME*FOP)/100] + VOMLSL

Where: AHR[(1)]= Fuel Rate (MMBtu/Hour) divided by LSL (MW)
GASPERME = Percentage of natural gas used at LSL

FIP = Fuel Index Price ($/MMBtu)
OILPERME = Percentage of oil used at LSL
FOP = Fuel Oil Price ($/MMBtu)
VOMLSL = the verified O&M cost at Minimum-Energy ($/MWh)

(1) Adjusted by VOXR

And: AHR= (verified fuel consumption/LSL)*(1+VOXR)

Note 1: GASPERME and OILPERME are decimal percentages in the Settlements equations and will be multiplied by 100 during the Integration process.

Note 2: ERCOT will use the solid fuel price and percentages to create Startup offers when no offer is submitted by the QSE for solid fuel Resources.

Note 3: This equation does not include any adjustments made to the final calculation of the Minimum-Energy Offer cap, as described in Protocol Section 4.4.9.2.1, Startup Offer and Minimum-Energy Offer Criteria.

Equation 3: Calculation of Composite Unit Parameters using Alternate Unit Specifications

Composite Unit Parameter = [Alt_Unit_Par*Alt_Unit_HSL + Non_Alt_Unit_Par* Non_Alt_Unit_HSL] / [Alt_Unit_HSL + Non_Alt_Unit_HSL]

Where: Alt_Unit_Par = Relevant parameter of Alternate Unit
Alt_Unit_HSL = High Sustained Limit of Alternate Unit
Non_Alt_Unit_Par = Relevant parameter of non-Alternate Unit
Non_Alt_Unit_HSL = High Sustained Limit of non-Alternate Unit

This calculation would be executed for all relevant parameters of the alternate and non-alternate units. This would include for example Startup Cost data, Minimum-Energy Cost data and heat rate data.

Equation 4: Equation for Calculation of Verifiable Startup Emission Costs

Verifiable Startup Emission Cost ($/Start) = RAFCRS * ∑Emission Rate i * Emission Cost Index i~~m~~

Where RAFCRS = Quantity of approved startup fuel consumed by Resource (including fuel used to shutdown Resource (MMBtu/Start)
Emission Rate i = Quantity of emission i emitted by resource (lbs/MMBtu)
Emission Cost Index i~~m~~ = Published ~~cost~~ index price of emission i~~m~~ ($/lb)
~~Im~~ i = Index for each emittent approved for inclusion in Startup Cost

~~m = Determinant for the use of seasonal index prices for months of May through September for NO_X andor annual index prices for October through AprilSO_2~~

Equation 5: Equation for Calculation of Verifiable Minimum-Energy Emission Costs

Verifiable Minimum-Energy Emission Costs ($/MWh) =
[AHR] * ∑Emission Rate i * Emission Cost Index $i_{\cancel{m}}$

Where AHR = Average heat rate at Minimum Energy (MMBtu/Hr)-
Emission Rate i = Quantity of emission i emitted by resource (lbs/MMBtu)
Emission Cost Index $i_{\cancel{m}}$ = Published ~~cost~~ index price of emission $i_{\cancel{m}}$
i~~I~~$_{\cancel{m}}$ = Index of each emittent approved for inclusion in Minimum-Energy Cost
~~m = Determinant for the use of seasonal index prices for months of May through September for NO_X andor annual index prices for October through AprilSO_2~~

Equation 6: Verifiable Startup Costs (VERISU) ($/Start)

A) For RUC Settlements, the Verifiable Startup Costs are calculated as follows:

VERISU = AFCRS + VOMS

Where AFCRS = [Total Fuel - PHR * AVGEN + Total Fuel*VOXR] * [FIP*GASPERSU(%) + FOP*OILPERSU(%) + SFP*SFPERSU(%)]

Total Fuel = [$Fuel_{Startup\text{-}BC}$ + $Fuel_{BC\text{-}LSL}$ + $Fuel_{BO\text{-}Shutdown}$]

VOMS = $IO\&M_{Start\text{-}LSL}$ +$IO\&M_{BO\text{-}Shutdown}$ + Verifiable Startup Emission Costs

B) For DAM Make-Whole Payments, the Verifiable Startup Costs are calculated as follows:

VERISU = DAFCRS + VOMS

Where DAFCRS = [Total Fuel + Total Fuel*VOXR] * [FIP*GASPERSU(%) + FOP*OILPERSU(%) + SFP*SFPERSU(%)]

Total Fuel = [$Fuel_{Startup\text{-}BC}$ + $Fuel_{BC\text{-}LSL}$ + $Fuel_{BO\text{-}Shutdown}$]

VOMS = $IO\&M_{Start\text{-}LSL}$ +$IO\&M_{BO\text{-}Shutdown}$ + Verifiable Startup Emission Costs

The bill determinants utilized above are defined as:
VERISU = Verifiable Startup Costs ($/Start)
AFCRS = Verifiable Startup Fuel Costs adjusted by VOXR and PHR ($/Start)

DAFCRS = the adjusted verified fuel consumption rate for the start type (MMBtu/Start)
VOMS = Verifiable Operations and Maintenance Costs ($/Start)
$Fuel_{Startup\text{-}BC}$ = Fuel Quantity required to bring Resource from Startup to Breaker Close (MMBtu)
$Fuel_{BC\text{-}LSL}$ = Fuel Quantity required to bring Resource from Breaker Close to Minimum Energy at LSL (MMBtu)
$Fuel_{BO\text{-}Shutdown}$ = Fuel Quantity required to take Resource from Breaker Open to Shutdown (MMBtu)
PHR = Proxy Heat Rate (MMBtu/MWh)
AVGEN = Average Generation between Breaker Close and LSL (MWh)
VOXR = Value of X for the Resource
FIP = Fuel Price Index for gas ($/MMBtu)
FOP = Fuel Price Index for oil ($/MMBtu)
SFP = Fuel Price Index for solid fuel = $1.50/MMBtu
GASPERSU = Percent of gas used during startup
OILPERSU = Percent of oil used during startup
SFPERSU = Percent of solid fuel used during startup
$IO\&M_{Start\text{-}LSL}$ = Incremental O&M costs incurred to bring Resource from Start to LSL ($/Start)
$IO\&M_{BO\text{-}Shutdown}$ = Incremental O&M costs incurred to take Resource from Breaker Open to Shutdown ($/Start)
Verifiable Startup Emission Costs = The allowable costs of acquiring emission credits required to start up Resource and defined in Equation 4 above.

Equation 7: The Equation for calculating Verifiable Minimum Energy Costs ($/MWh)

VERIME = FCLSL + VOMLSL

Where VERIME = Verifiable Minimum Energy Costs
FCLSL = Verifiable Fuel Costs at Minimum Energy
VOMLSL = Verifiable variable O&M costs at Minimum Energy

FCLSL = [(AHR)] * [FIP*GASPERME(%) + FOP*OILPERME(%) + SFP*SFPERME(%)]

Where AHR = Adjusted average heat rate at Minimum Energy (MMBtu/Hr)
FIP = Fuel Price Index for gas ($/MMBtu)
FOP = Fuel Price Index for oil ($/MMBtu)
SFP = Fuel Price Index for solid fuel = $1.50/MMBtu
GASPERME = Percent of gas used at minimum energy
OILPERME = Percent of oil used at minimum energy
SFPERME = Percent of solid fuel used at minimum energy

VOMLSL = $IO\&M_{LSL}$ + Verifiable Emission Costs at Minimum Energy
Where $IO\&M_{LSL}$ = Incremental O&M costs at minimum energy

Verifiable Emission Costs at Minimum Energy = The allowable costs of acquiring emission credits required to operate Resource at minimum energy and defined in Equation 5 above.

ERCOT Impact Analysis Report

VCMRR Number	042	VCMRR Title	SO_2 and NO_X Emission Index Prices Used in Verifiable Cost Calculations
Impact Analysis Date	January 31, 2025		
Estimated Cost/Budgetary Impact	Between $90k and $140k		
Estimated Time Requirements	The timeline for implementing this Verifiable Cost Manual Revision Request (VCMRR) is dependent upon Public Utility Commission of Texas (PUCT) prioritization and approval. Estimated project duration: 6 to 9 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: • Market Settlements 63% • Enterprise Integration Nodal Services 37%		
ERCOT Business Function Impacts	ERCOT will update its business processes to implement this VCMRR.		
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.

Alignment Nodal Operating Guide Revision Request

NOGRR Number	276	NOGRR Title	Alignment Changes for June 1, 2025 Nodal Operating Guide – NPRR1246 and NPRR1270
Date Posted		April 8, 2025	
Status		Alignment Change	

Nodal Operating Guide Sections Requiring Revision	4.5.3.3, EEA Levels
Related Documents Requiring Revision/Related Revision Requests	Nodal Protocol Revision Request (NPRR) 1246, Energy Storage Resource Terminology Alignment for the Single-Model Era NPRR1270, Additional Revisions Required for Implementation of RTC
Revision Description	This Nodal Operating Guide Revision Request (NOGRR) aligns Energy Emergency Alert (EEA) language in Section 4.5.3.3 with Protocol Section 6.5.9.4.2, EEA Levels. On February 4, 2025 and April 8, 2025, the ERCOT Board recommended approval of NPRR1246 and NPRR1270, respectively, which modified language in Protocol Section 6.5.9.4.2. Paragraph (6) of Section 1.3.1, Introduction, provides that ERCOT may make changes to the Nodal Operating Guide to maintain duplicate language between the Protocols and the related sections of the Nodal Operating Guide, and requires that Section 4.5.3.3 be modified only by an Alignment NOGRR.
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) ☒ Regulatory requirements ☐ ERCOT Board/PUCT Directive

	(please select ONLY ONE – if more than one apply, please select the ONE that is most relevant)
ERCOT Opinion	ERCOT supports approval of NOGRR276.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NOGRR276 and believes the market impact of NOGRR276 will be alignment of the Nodal Operating Guide with current Protocols.

Sponsor	
Name	Cory Phillips
E-mail Address	cory.phillips@ercot.com
Company	ERCOT
Phone Number	512-248-6464
Market Segment	Not applicable

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

Proposed Guide Language Revision

4.5.3.3 EEA Levels

(1) ERCOT will declare an EEA Level 1 when PRC falls below 2,500 MW and is not projected to be recovered above 2,500 MW within 30 minutes without the use of the following actions that are prescribed for EEA Level 1:

(a) ERCOT shall take the following steps to maintain steady state system frequency near 60 Hz and maintain PRC above 2,000 MW:

(i) Request available Generation Resources, that can perform within the expected timeframe of the emergency, to come On-Line by initiating manual HRUC or through Dispatch Instructions;

[NOGRR276: Replace paragraph (i) above upon system implementation NPRR1246:]

(i) Request available Generation Resources that can perform within the expected timeframe of the emergency to come On-Line by initiating manual HRUC or through Dispatch Instructions, and request available ESRs that can perform within the expected timeframe of the emergency to come On-Line through Dispatch Instructions;

(ii) Use available DC Tie import capacity that is not already being used;

(iii) Issue a Dispatch Instruction for Resources to remain On-Line which, before start of emergency, were scheduled to come Off-Line; and

(iv) Instruct QSEs to deploy undeployed ERS-10 and ERS-30.

[NOGRR221: Insert item (v) below upon system implementation of NPRR1010:]

(v) At ERCOT's discretion, manually deploy, through Inter-Control Center Communications Protocol (ICCP), available RRS and ERCOT Contingency Reserve Service (ECRS) capacity from Generation Resources having a Resource Status of ONSC and awarded RRS or ECRS.

(b) QSEs shall:

(i) Ensure COPs, telemetered status, and telemetered High Sustained Limits (HSLs) are updated and reflect all Resource delays and limitations; and

[NOGRR221: Replace paragraph (i) above with the following upon system implementation of NPRR1010:]

(i) Ensure COPs, telemetered status, and telemetered HSLs, Normal Ramp Rates, Emergency Ramp Rates, and Ancillary Service capabilities are updated and reflect all Resource delays and limitations; and

(ii) Ensure that each of its Energy Storage Resources (ESRs) suspends charging until the EEA is recalled, except under the following circumstances:

(A) The ESR has a current SCED Base Point Instruction, Load Frequency Control (LFC) Dispatch Instruction, or manual Dispatch Instruction to charge the ESR;

(B) The ESR is actively providing Primary Frequency Response; or

(C) The ESR is co-located behind a Point of Interconnection (POI) with onsite generation that is incapable of exporting additional power to the ERCOT System, in which case the ESR may continue to charge as long as maximum output to the ERCOT System is maintained.

[NOGRR229: Replace paragraph (ii) above upon system implementation of NPRR995:]

(ii) Ensure that each of its Energy Storage Resources (ESRs) and Settlement Only Energy Storage Systems (SOESSs) suspends charging until the EEA is recalled, except under the following circumstances:

(A) The ESR has a current SCED Base Point Instruction, Load Frequency Control (LFC) Dispatch Instruction, or manual Dispatch Instruction to charge the ESR;

(B) The ESR or SOESS is actively providing Primary Frequency Response; or

(C) The ESR or SOESS is co-located behind a Point of Interconnection (POI) with onsite generation that is incapable of exporting additional power to the ERCOT System, in which case the ESR may continue to charge as long as maximum output to the ERCOT System is maintained.

(2) ERCOT may declare an EEA Level 2 when the clock-minute average system frequency falls below 59.91 Hz for 15 consecutive minutes. ERCOT will declare an EEA Level 2 when PRC falls below 2,000 MW and is not projected to be recovered above 2,000 MW within 30 minutes without the use of the following actions that are prescribed for EEA Level 2:

(a) In addition to the measures associated with EEA Level 1, ERCOT shall take the following steps to maintain steady state system frequency at a minimum of 59.91 Hz and maintain PRC above 1,500 MW:

(i) Instruct TSPs and DSPs or their agents to reduce Customer Load by using existing, in-service distribution voltage reduction measures that have not already been implemented. A TSP, DSP or their agent shall implement these instructions if distribution voltage reduction measures are available and already installed. If the TSP, DSP, or their agent determines in their sole discretion that the distribution voltage reduction would adversely affect reliability, the voltage reduction measure may be reduced, modified, or otherwise changed from maximum performance to a level of exercise that has no negative impact to reliability.

(ii) Instruct TSPs and DSPs to implement any available Load management plans to reduce Customer Load.

(iii) Instruct QSEs to deploy ECRS or RRS (controlled by high-set under-frequency relays) supplied from Load Resources. ERCOT may deploy ECRS or RRS simultaneously or separately, and in any order. ERCOT shall issue such Dispatch Instructions in accordance with the deployment methodologies described in paragraph (iv) below.

[NOGRR276: Replace paragraph (iii) above upon system implementation NPRR1270:]

(iii) Instruct QSEs to deploy ECRS or RRS (controlled by high-set under-frequency relays) supplied from Load Resources. ERCOT may deploy ECRS or RRS from Load Resources simultaneously or separately. ERCOT shall issue such Dispatch Instructions in accordance with the deployment methodologies described in paragraph (iv) below.

(iv) Load Resources providing ECRS that are not controlled by high-set under-frequency relays shall be deployed prior to Group 1 deployment. ERCOT shall deploy ECRS and RRS capacity supplied by Load Resources (controlled by high-set under-frequency relays) in accordance with the following:

[NOGRR276: Replace paragraph (iv) above upon system implementation NPRR1270:]

(iv) Load Resources providing ECRS that are not controlled by high-set under-frequency relays shall be deployed prior to deployment of those that have armed under-frequency relays. ERCOT shall deploy ECRS and RRS capacity supplied by Load Resources (controlled by high-set under-frequency relays) in accordance with the following:

(A) Instruct QSEs to deploy RRS with a Group 1 designation and all of the ECRS that is supplied from Load Resources (controlled by high-set under-frequency relays) by instructing the QSE representing the specific Load Resources to interrupt Group 1 Load Resources providing ECRS and RRS. QSEs shall deploy Load Resources according to the group designation and will be given some discretion to deploy additional Load Resources from any of the groups not designated for deployment if Load Resource operational considerations require such. ERCOT shall issue notification of the deployment via XML message. The deployment time within the ERCOT XML deployment message shall initiate the ten-minute deployment period;

[NOGRR276: Replace paragraph (A) above upon system implementation NPRR1270:]

(A) Instruct QSEs to deploy ECRS that is supplied from Load Resources (controlled by high-set under-frequency relays) that are only providing ECRS and then instruct QSEs to deploy Load Resources (controlled by high-set under-frequency relays) providing ECRS and RRS. QSEs will be given some discretion to deploy additional Load Resources not designated for deployment if Load Resource operational considerations require such. ERCOT shall issue notification of the deployment via XML message. The deployment time within the ERCOT XML deployment message shall initiate the ten-minute deployment period;

(B) At the discretion of the ERCOT Operator, instruct QSEs to deploy RRS that is supplied from Load Resources (controlled by high-set under-frequency relays) by instructing the QSE representing the specific Load Resource to interrupt additional Load Resources providing RRS based on their group designation. ERCOT shall issue notification of the deployment via XML message. The deployment time within the ERCOT XML deployment message shall initiate the ten-minute deployment period;

[NOGRR276: Replace paragraph (B) above upon system implementation NPRR1270:]

(B) At the discretion of the ERCOT Operator, instruct QSEs to deploy RRS that is supplied from Load Resources (controlled by high-set under-frequency relays) by instructing the QSE representing the specific Load Resource to interrupt additional Load Resources that are only providing RRS. ERCOT shall issue notification of the deployment via XML message. The deployment time within the ERCOT XML deployment message shall initiate the ten-minute deployment period;

(C) The ERCOT Operator may deploy Load Resources providing only ECRS (not controlled by high-set under-frequency relays) and all groups of Load Resources providing RRS and ECRS at the same time. ERCOT shall issue notification of the deployment via XML message. The deployment time within the ERCOT XML deployment message shall initiate the ten-minute deployment period; and

[NOGRR276: Replace paragraph (C) above upon system implementation NPRR1270:]

(C) The ERCOT Operator may deploy all Load Resources providing RRS and ECRS at the same time. ERCOT shall issue notification of the deployment via XML message. The deployment time within the ERCOT XML deployment message shall initiate the ten-minute deployment period; and

(D) ERCOT shall post a list of Load Resources on the Market Information System (MIS) Certified Area immediately following the Day-Ahead Reliability Unit Commitment (DRUC) for each QSE with a Load Resource obligation which may be deployed to interrupt under paragraph (A) and paragraph (B). ERCOT shall develop a process for determining which individual Load Resource to place in each group based on a random sampling of individual Load Resources. At ERCOT's discretion, ERCOT may deploy all Load Resources at any given time during EEA Level 2.

[NOGRR221 and NOGRR276: Replace applicable portions of paragraph (D) above with the following upon system implementation of NPRR1010 or NPRR1270, respectively:]

(D) ~~ERCOT shall post a list of Load Resources on the MIS Certified Area immediately following the DRUC for each QSE with a Load Resource RRS or ECRS award, which may be deployed to interrupt under paragraph (A) and paragraph (B).~~ ERCOT shall develop a Real-Time process for deploying~~determining which individual~~ Load Resources ~~to place in each group~~ based on a random sampling of individual Load Resources. At ERCOT's discretion, ERCOT may deploy all Load Resources at any given time during EEA Level 2.

(v) Unless a media appeal is already in effect, ERCOT shall issue an appeal through the public news media for voluntary energy conservation; and

(vi) With the approval of the affected non-ERCOT Control Area, TSPs, DSPs, or their agents may implement transmission voltage level BLTs, which transfer Load from the ERCOT Control Area to non-ERCOT Control Areas in accordance with BLTs as defined in the Operating Guides.

(b) Confidentiality requirements regarding transmission operations and system capacity information will be lifted, as needed to restore reliability.

(3) ERCOT may declare an EEA Level 3 when the clock-minute average system frequency falls below 59.91 Hz for 20 consecutive minutes or when steady-state frequency falls below 59.8 Hz. ERCOT will declare an EEA Level 3 when PRC cannot be maintained above 1,500 MW or when the clock-minute average system frequency falls below 59.91 Hz for 25 consecutive minutes. Upon declaration of an EEA Level 3, ERCOT shall take any of the following measures as necessary to recover frequency or PRC to the minimum required levels:

(a) Instruct ESRs to suspend charging. For ESRs, ERCOT shall issue the suspension instruction via a SCED Base Point instruction, or, if otherwise necessary, via a manual Dispatch Instruction. An ESR shall suspend charging unless it is providing Primary Frequency Response, has received a charging instruction via SCED Base Point, or is carrying Regulation Down Service (Reg-Down) and has received a charging instruction from LFC. However, an ESR co-located behind a POI with onsite generation that is incapable of exporting additional power to the ERCOT System may continue to charge as long as maximum output to the ERCOT System is maintained.

[NOGRR229: Replace paragraph (a) above upon system implementation NPRR995:]

(a) Instruct ESRs to suspend charging. For ESRs, the suspension instruction shall be issued via a SCED Base Point, or, if otherwise necessary, via a manual Dispatch Instruction. An ESR shall suspend charging unless it is providing Primary Frequency Response, has received a charging instruction via SCED Base Point, or is carrying Regulation Down Service (Reg-Down) and has received a charging instruction from LFC. An SOESS shall suspend charging unless it is providing Primary Frequency Response. However, an ESR or SOESS co-located behind a POI with onsite generation that is incapable of exporting additional power to the ERCOT System may continue to charge as long as maximum output to the ERCOT System is maintained.

(b) Direct all TOs to shed firm Load, in 100 MW blocks, distributed as documented in these Operating Guides in order to maintain a steady state system frequency at a minimum of 59.91 Hz and to recover 1,500 MW of PRC within 30 minutes.

(i) TOs and TDSPs may:

(A) Manually shed Load connected to under-frequency relays and/or under-voltage relays pursuant to an ERCOT Load shed directive issued during EEA Level 3 so long as the TO has determined that system conditions warrant utilizing Load connected to under-frequency and/or under-voltage relays and each affected TO continues to comply with its Under-Frequency Load Shed (UFLS) obligation as described in Section 2.6.1, Automatic Firm Load Shedding, and its Load shed obligation as described in Section 4.5.3.4, Load Shed Obligation.

(B) Manually shed Load that is armed to deploy as part of the 58.5 Hz, 58.7 Hz, and anti-stall UFLS stages, such that the UFLS Load falls below the TO's 25% Load relief obligation, as described in Section 2.6.1, in order to meet ERCOT operating instructions for manual Load shed if all Load identified for manual Load shed and the Load identified in paragraph (A) above has been shed.

(c) Implement any appropriate measures associated with EEA Levels 1 and 2 that have not already been implemented.