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PROJECT NO. 54445

CY 2023 REVIEW OF RULES ADOPTED BY THE INDEPENDENT ORGANIZATION	§ § §	**PUBLIC UTILITY COMMISSION OF TEXAS**

NOTICE OF RECOMMENDED APPROVAL OF REVISION REQUESTS BY ERCOT BOARD OF DIRECTORS

Effective June 8, 2021, rules adopted by Electric Reliability Council of Texas, Inc. (ERCOT) under delegated authority from the Public Utility Commission of Texas (Commission) are subject to Commission oversight and review and may not take effect before receiving Commission approval.

At its meeting on February 28, 2023, the ERCOT Board of Directors (Board) recommended Commission approval of the following proposed revisions to the ERCOT rules (Revision Requests) (Nodal Protocol Revision Requests (NPRRs), Planning Guide Revision Request (PGRR) and Reliability Market Guide Revision Request (RMGRR)):

- NPRR1144, Station Service Backup Power Metering;
- NPRR1147, Update and Improve Notification and Evaluation Processes Associated with Reliability Must-Run (RMR);
- NPRR1149, Implementation of Systematic Ancillary Service Failed Quantity Charges;
- NPRR1151, Protocol Revision Subcommittee Meeting Requirement;
- NPRR1153, ERCOT Fee Schedule Changes;
- NPRR1158, Remove Sunset Date for Weatherization Inspection Fees;
- NPRR1159, Related to RMGRR171, Changes to Transition Process that Require Opt-in MOU or EC that are Designating POLR to provide Mass Transition Methodology to ERCOT;
- PGRR102, Dynamic Operation Model Improvement; and
- RMGRR171, Changes to Transition Process that Require Opt-in MOU and EC that are Designating POLR to provide Mass Transition Methodology to ERCOT.

Included for Commission review are the Board Reports—each of which includes an ERCOT Market Impact Statement—and ERCOT Impact Analyses for these Revision Requests.

Dated: March 7, 2023

Respectfully submitted,

/s/ Jonathan Levine

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ATTORNEYS FOR ELECTRIC RELIABILITY COUNCIL OF TEXAS, INC.

Board Report

NPRR Number	**1144**	**NPRR Title**	**Station Service Backup Power Metering**
Date of Decision	February 28, 2023		
Action	Recommended Approval		
Timeline	Normal		
Proposed Effective Date	April 1, 2023		
Priority and Rank Assigned	Not Applicable		
Nodal Protocol Sections Requiring Revision	10.3.2.3, Generation Netting for ERCOT-Polled Settlement Meters		
Related Documents Requiring Revision/Related Revision Requests	None		
Revision Description	This Nodal Protocol Revision Request (NPRR) provides a limited exception to the requirement that all Loads included in the netting arrangement for an ERCOT-Polled Settlement (EPS) Metering Facility only be connected to the ERCOT Transmission Grid through the EPS metering point(s) for the Facility. The exception allows no more than 500kW of auxiliary Load connected to a station service transformer to be connected to a Transmission Service Provider's (TSP's) or Distribution Service Provider's (DSP's) Facilities through a separately metered point using an open transition Load transfer switch listed for emergency use.		
Reason for Revision	☐ Addresses current operational issues. ☐ Meets Strategic goals (tied to the ERCOT Strategic Plan or directed by the ERCOT Board). ☒ Market efficiencies or enhancements ☐ Administrative ☐ Regulatory requirements ☐ Other: (explain)		

	(please select all that apply)
Business Case	Allowing the relatively insignificant Load of backup station service in emergency and maintenance situations to be provided and metered by the DSP and/or alternate connection to the TSP would allow generators to eliminate the need for an on-site backup generator which has initial high costs and continued maintenance costs. It also requires a fuel source that would likely require further local permitting. Eliminating fuel storage also makes the site inherently safer. A meter that has the capability to function as an EPS Meter is also not a standard meter for most local distribution companies and the requirement of an EPS Meter would mean additional infrastructure to support the backup service.
PRS Decision	On 8/11/22, PRS voted unanimously to table NPRR1144 and refer the issue to WMS. All Market Segments participated in the vote. On 11/11/22, PRS voted to recommend approval of NPRR1144 as amended by the 8/29/22 Joint Commenters comments. There were three abstentions from the Consumer (Occidental), Cooperative (LCRA), and Investor Owned Utility (IOU) (CNP) Market Segments. All Market Segments participated in the vote. On 12/8/22, PRS voted to endorse and forward to TAC the 11/11/22 PRS Report and 11/22/22 Impact Analysis for NPRR1144. There was one abstention from the IOU (CNP) Market Segment. All Market Segments participated in the vote.
Summary of PRS Discussion	On 8/11/22, Plus Power revoked its request for Urgent status and requested that NPRR1144 be tabled in anticipation of further discussion at the August 25, 2022 Metering Working Group (MWG) meeting and pending comments. On 11/11/22, participants expressed that their abstentions for NPRR1144 were due to its conflict with company service standards. On 12/8/22, participants reviewed NPRR1144's 11/22/22 Impact Analysis.
TAC Decision	On 1/24/23, TAC voted to recommend approval of NPRR1144 as recommended by PRS in the 12/8/22 PRS Report. There was one abstention from the IOU (CNP) Market Segment. All Market Segments participated in the vote.
Summary of TAC	On 1/24/23, TAC reviewed the ERCOT Opinion, ERCOT Market

Discussion	Impact Statement, and Independent Market Monitor (IMM) Opinion for NPRR1144.
ERCOT Board Decision	On 2/28/23, the ERCOT Board voted unanimously to recommend approval of NPRR1144 as recommended by TAC in the 1/24/23 TAC Report.

Opinions	
Credit Review	ERCOT Credit Staff and the Credit Work Group (Credit WG) have reviewed NPRR1144 and do not believe that it requires changes to credit monitoring activity or the calculation of liability.
Independent Market Monitor Opinion	IMM has no opinion on NPRR1144.
ERCOT Opinion	ERCOT supports approval of NPRR1144.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NPRR1144 and believes NPRR1144 provides a defined and limited exception to EPS metering requirements for generation site auxiliary Loads, not exceeding 500kW, to be isolated and connected to an alternate feed through a TDSP read metering point.

Sponsor	
Name	Ravi Beeravalli
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Market Segment	Not Applicable

Market Rules Staff Contact	
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Comments Received	
Comment Author	**Comment Summary**

ERCOT 080422	Expressed confusion regarding NPRR1144's intent and suggested that additional guidance may be required in regard to how DSPs, TSPs, and Resources will be electrically connected; ERCOT also recommended that NPRR1144 be discussed at the August 25, 2022 MWG Meeting
Joint Commenters 081722	Proposed alternative language to clarify that NPRR1144 is not intended to change or impact the metering requirements or determination of Wholesale Storage Load (WSL)
Joint Commenters 082922	Proposed a requirement in paragraph (6) that the Resource Entity provide notice of the proposed connection to all DSPs that are certificated to serve the area in which the backup connection is proposed
WMS 091422	Requested PRS continue to table NPRR1144
WMS 110922	Endorsed NPRR1144 as amended by the 8/29/22 Joint Commenters comments

Market Rules Notes

None

Proposed Protocol Language Revision

10.3.2.3 Generation Netting for ERCOT-Polled Settlement Meters

(1) Each Generation Resource and Settlement Only Generator (SOG) and each Load that is designated to be netted with that Generation Resource or SOG, including construction and maintenance Load that is netted with existing generation auxiliaries, must be physically metered at its POI to the ERCOT Transmission Grid or Service Delivery Point, or, in accordance with Section 10.3.2.2, Loss Compensation of EPS Meter Data, loss-compensated to its POI to the ERCOT Transmission Grid. Interval Data Recorders (IDRs) must be used to determine generator output or Load usage. In the intervals where the generation output exceeds the Load, the net must be settled as generation. In the intervals where the Load exceeds the generation output, the net must be settled as Load, and carry any applicable Load shared charges and credits.

(2) For Settlement purposes, netting is not allowed except under the configurations described in paragraphs (2)(a) through (2)(e) below, and only if the service arrangement is otherwise lawful. ERCOT has no obligation to independently determine whether a site configuration that includes both Loads and Generation Resource(s) or SOGs complies with Public Utility Regulatory Act (PURA) or the Public Utility Commission of Texas (PUCT) Substantive Rules, and ERCOT's approval of a metering proposal for such a site is not a verification of the legality of that arrangement:

(a) Single POI or Service Delivery Point;

(b) Transmission-level interconnections where all POIs are located at the same substation, at the same voltage, and under normal operating conditions, are interconnected through common electrical equipment such as circuit breakers, connecting cables, bus bars, switches/isolators. Qualifying station arrangements include, but are not limited to, Generation and Load connected in a line bus, ring bus, double-breaker, or breaker-and-a-half configuration;

(c) Multiple POIs where the Loads and generator output are electrically connected to a common switchyard, as defined in paragraph (~~6~~7) below. In addition, there must be sufficient generator capacity to serve all plant Loads for netting to occur;

(d) A Qualifying Facility (QF) with POIs, where the QF is selling energy to a thermal host, may net the Load meters of the thermal host with the QF's generation meters when the Load and generation are electrically connected to a common switchyard. In instances in which Load is served by new on-site generation through a common switchyard, the TSP or DSP may install monitoring equipment necessary for measuring Load to determine stranded cost charges, if any are applicable, as determined under the PURA and applicable PUCT rules. For purposes of this Section, new on-site generation has the meaning as contained in Public Utility Regulatory Act, TEX. UTIL. CODE ANN. §§ 39.252 and 39.262(k) (Vernon 1998 & Supp. 2007) (PURA); or

(e) For Generation Resources and/or Load with flow-through on a private, contiguous transmission system (not included in a TSP or DSP rate base) and in a configuration existing as of October 1, 2000, the meters at the interconnections with the ERCOT Transmission Grid may be netted for the purpose of determining Generation Resources or Load. For Settlement purposes, when the net is a Load, the metered interconnection points must be assigned to the same Load Zone and Unaccounted for Energy (UFE) zone.

(3) For Energy Storage Resource (ESR) sites, Wholesale Storage Load (WSL) must be separately metered from all other Loads and generation, and must be metered using EPS Metering Facilities.

(a) For configurations where the Resource Entity telemeters an auxiliary Load value to the EPS Meter:

(i) The total energy into the ESR must be separately metered from all other Loads and generation, and must be metered using EPS Metering Facilities; and

(ii) The auxiliary Load energy shall be stored in the EPS Meter's IDR, per channel assignments defined in the SMOG.~~, with the exception of a backup station service used for security, protection and control so long as the projected backup station service energy is less than 4/1,000th of a~~

~~percent of the yearly battery Energy Storage Systems (ESS) charging energy assuming a round trip efficiency of 86%.~~

(b) For configurations where the WSL is not at a POI, it must be metered behind a single POI metering point, per the requirements in paragraph (3) or (3)(a) above; and

(c) WSL for a compressed air energy storage Load Resource is exempt from the requirement to be electrically connected to a common switchyard, as defined in paragraph (~~6~~7) below.

[NPRR995: Replace paragraph (3) above with the following upon system implementation:]

(3) For Energy Storage Resource (ESR), Settlement Only Distribution Energy Storage System (SODESS), or Settlement Only Transmission Energy Storage System (SOTESS) sites, Wholesale Storage Load (WSL) must be separately metered from all other Loads and generation, and must be metered using EPS Metering Facilities.

(a) For configurations where the Resource Entity telemeters an auxiliary Load value to the EPS Meter:

(i) The total energy into the ESR, SODESS, or SOTESS must be separately metered from all other Loads and generation, and must be metered using EPS Metering Facilities; and

(ii) The auxiliary Load energy shall be stored in the EPS Meter's IDR, per channel assignments defined in the SMOG.

(b) For configurations where the WSL is not at a POI, it must be metered behind a single POI metering point, per the requirements in paragraph (3) or (3)(a) above; and

(c) WSL for a compressed air energy storage Load Resource is exempt from the requirement to be electrically connected to a common switchyard, as defined in paragraph (~~6~~7) below.

(4) ERCOT shall maintain descriptions of the Metering Facilities of all common switchyards that contain multiple POIs of Loads (ESI IDs) and generation meters (EPS). The description is limited to identifying the Entities within a common switchyard and a simplified diagram showing the metering configuration of all Supervisory Control and Data Acquisition (SCADA) and Settlement Metering points.

(5) All Load(s) included in the netting arrangement for an EPS Metering Facility shall only be electrically connected to the ERCOT Transmission Grid through the EPS metering point(s) for such Facility. Such Loads shall not be electrically connected to the ERCOT Transmission Grid through electrical connections that are not metered by the EPS

metering point(s) for the Facility. ~~, with the exception of a backup station service used only for security, protection and control.~~

(6) Notwithstanding the requirements of paragraph (5) above, auxiliary Load(s) connected to the station service transformer not to exceed 500 kW in aggregate shall be permitted an additional electrical connection to a TSP's or DSP's Facilities through a separately metered Transmission and/or Distribution Service Provider (TDSP) read metering point. In locations subject to multiple certificated service areas, the Resource Entity shall notify each DSP that has the right to serve in the service area of the proposed connection. This configuration requires mutual agreement between the connecting~~a~~ TSP, DSP, and Resource Entity, and the connection shall be achieved through an open transition load transfer switch listed for emergency service and shall only be used in emergency and maintenance situations.

(7) For purposes of this Section, a common switchyard is defined as an electric substation Facility where the POI for Load and Generation Resources are located at the same Facility but where the interconnection points are physically not greater than 400 yards apart. The physical connections of the Load to its POI and the Generation Resource to its POI cannot be Facilities that have been placed in a TSP's or DSP's rate base.

(8)~~(7)~~ Notwithstanding any other provision in this Section, for any Generation Resource or ESR that is configured to serve a Customer Load as part of a Private Microgrid Island (PMI), the connection to the Customer Load in the PMI configuration shall be located behind the EPS metering point at the Resource's POI. For a PMI configuration that includes an ESR that is receiving WSL treatment for charging Load, an EPS Meter shall be located to measure the ESR's gross output net of any internal telemetered auxiliary Load, and a separate ~~Transmission and/or Distribution Service Provider (~~TDSP~~)~~ ESI ID (for nodal Settlement) with a Load Serving Entity (LSE) association must be established for the site prior to service of any Load.

[NPRR945: Insert paragraph (~~8~~9) below upon system implementation:]

(9)~~(8)~~ ERCOT shall post on the ERCOT website a report listing all Generation Resources or Settlement Only Generators (SOGs) that have achieved commercial operations, excluding Decommissioned Generation Resources, Mothballed Generation Resources, and decommissioned SOGs, whose Resource Registration data indicates that the Generation Resource or SOG is part of a Private Use Network. The report must identify the name of the Generation Resource or SOG site, its nameplate capacity, and the date the Generation Resource or SOG was added to the report. The report shall not identify any confidential, customer-specific information regarding netted loads. ERCOT shall update the list at least monthly.

ERCOT Impact Analysis Report

NPRR Number	1144	NPRR Title	Station Service Backup Power Metering
Impact Analysis Date	November 22, 2022		
Estimated Cost/Budgetary Impact	None.		
Estimated Time Requirements	No project required. This Nodal Protocol Revision Request (NPRR) 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 NPRR.		
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

NPRR Number	**1147**	**NPRR Title**	**Update and Improve Notification and Evaluation Processes Associated with Reliability Must-Run (RMR)**
Date of Decision	February 28, 2023		
Action	Recommended Approval		
Timeline	Normal		
Proposed Effective Date	April 1, 2023		
Priority and Rank Assigned	Not applicable		
Nodal Protocol Sections Requiring Revision	3.14.1.1, Notification of Suspension of Operations 3.14.1.2, ERCOT Evaluation Process 3.14.1.3, ERCOT Board Approval of RMR and MRA Agreements 3.14.1.5, Evaluation of Alternatives 3.14.1.9, Generation Resource Status Updates 3.14.1.10, Eligible Costs 22 Attachment E, Notification of Suspension of Operations		
Related Documents Requiring Revision/Related Revision Requests	None		
Revision Description	This Nodal Protocol Revision Request (NPRR): • Adds a 20 MW capacity threshold for conducting a Reliability Must-Run (RMR) reliability analysis; • Requires that an RMR study be conducted when a Resource Entity gives notice that a Generation Resource is ceasing operation permanently due to a Forced Outage; and • Updates Section 22, Attachment E to require Resource Entity to provide information about deactivation of Transmission Facilities as part of the suspension of operations of the unit.		
Reason for Revision	☐ Addresses current operational issues. ☐ Meets Strategic goals (tied to the ERCOT Strategic Plan or directed by the ERCOT Board). ☒ Market efficiencies or enhancements ☐ Administrative ☐ Regulatory requirements		

Board Report

	[X] Other: Clarification and consistency *(please select all that apply)*
Business Case	1. The capacities of the existing and proposed Generation Resources are getting smaller (e.g., Distribution Generation Resources (DGRs)), as indicated in the recent Report on Capacity, Demand and Reserves in the ERCOT Region ("CDR"). Currently, there is no minimum MW threshold in the RMR evaluation, and significant number of RMR evaluations could be required for small units that are not expected to have a material impact on the reliability of the system. This NPRR revises paragraph (3) of Section 3.14.1.2 to provide that an RMR reliability analysis is not required for units with a capacity less than or equal to 20 MW, but may be conducted at ERCOT's discretion. This will help ensure ERCOT's limited resources are focused on issues that are more likely to have a material impact on the reliability of the system. 2. Currently, the Protocols do not require an RMR study be conducted for a Resource that is being decommissioned due to a Forced Outage. However, requiring an RMR study when a Resource Entity gives notice that a Generation Resource is ceasing operations permanently due to a Forced Outage will allow ERCOT to assess the impact of the decommissioning on the reliability of the ERCOT system and allow ERCOT to consider whether an RMR or Must Run Alternative (MRA) Agreement should be executed to address any identified reliability need. 3. Section 22, Attachment E needs to be improved to clarify if any transmission equipment will be deactivated from service as part of the suspension of operations of a unit, in order to accurately develop study base case(s).
PRS Decision	On 9/15/22, PRS voted unanimously to table NPRR1147 and refer the issue to ROS. All Market Segments participated in the vote. On 11/11/22, PRS voted unanimously to recommend approval of NPRR1147 as submitted. All Market Segments participated in the vote. On 12/8/22, PRS voted unanimously to endorse and forward to TAC the 11/11/22 PRS Report and 8/15/22 Impact Analysis for NPRR1147. All Market Segments participated in the vote.
Summary of PRS Discussion	On 9/15/22, the sponsor provided an overview of NPRR1147. On 11/11/22, participants noted the ROS endorsement of NPRR1147 as submitted. On 12/8/22, there was no discussion.

Board Report

TAC Decision	On 1/24/23, TAC voted unanimously to recommend approval of NPRR1147 as recommended by PRS in the 12/8/22 PRS Report. All Market Segments participated in the vote.
Summary of TAC Discussion	On 1/24/23, TAC reviewed the ERCOT Opinion, ERCOT Market Impact Statement, and Independent Market Monitor (IMM) Opinion for NPRR1147.
ERCOT Board Decision	On 2/28/23, the ERCOT Board voted unanimously to recommend approval of NPRR1147 as recommended by TAC in the 1/24/23 TAC Report.

Opinions	
Credit Review	ERCOT Credit Staff and the Credit Work Group (Credit WG) have reviewed NPRR1147 and do not believe that it requires changes to credit monitoring activity or the calculation of liability.
Independent Market Monitor Opinion	IMM has no opinion on NPRR1147.
ERCOT Opinion	ERCOT supports approval of NPRR1147.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NPRR1147 and believes the market impact for NPRR1147 improves the efficiency of, and provides clarifications to, RMR analysis.

Sponsor	
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Market Segment	Not applicable

Market Rules Staff Contact	
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Comments Received	
Comment Author	**Comment Summary**
ROS 100422	Requested PRS continue to table NPRR1147 for further review by the Planning Working Group (PLWG)
ROS 111122	Endorsed NPRR1147 as submitted

Market Rules Notes

None

Proposed Protocol Language Revision

3.14.1.1 Notification of Suspension of Operations

(1) Except for the occurrence of a Forced Outage, a Resource Entity must notify ERCOT in writing no less than 150 days prior to the date on which the Resource Entity intends to cease or suspend operation of a Generation Resource for a period of greater than 180 days. If a Generation Resource is to be mothballed on a seasonal basis, the Resource Entity must notify ERCOT in writing no less than 90 days prior to the suspension date and identify its Seasonal Operation Period.

(2) The Resource Entity shall submit a completed Part I and Part II of the NSO (found in Section 22, Attachment E, Notification of Suspension of Operations). The Resource Entity may also complete Part III of the NSO and submit it along with Parts I and II, or may wait to submit Part III up to ten days after ERCOT makes a determination that the proposed suspension of the Generation Resource would result in a performance deficiency for which the Generation Resource has a material impact. Part I of the NSO must include the attestation of an officer of the Resource Entity that the Generation Resource is uneconomic to remain in service as currently designated and will be unavailable for Dispatch by ERCOT for a period specified in the NSO.

(3) A Resource Entity ceasing or suspending operations as a result of a Forced Outage lasting greater than 180 days shall notify ERCOT as soon as practicable by submitting an NSO. If ~~A~~an NSO is submitted for a Generation Resource that is suspending operations for greater than 180 days due to a Forced Outage but is not indefinitely or permanently ceasing operations, then:

(a) The Generation Resource w~~W~~ill not be evaluated for RMR status; ~~and~~

(b) The NSO ~~W~~will not be posted on the MIS, except that information contained in the NSO may be included in reports in accordance with Section 3.2.6.2.2, Total Capacity Estimate; and~~.~~

(c) ERCOT will not issue a Market Notice.

(4) At least 60 days before the expiration of an existing RMR Agreement, the Resource Entity may apply to renew the RMR Agreement by submitting a new NSO (including both Part I and Part II). Upon receipt of such a renewal request, ERCOT shall update and post to the MIS Secure Area studies as set forth in Section 3.14.1, Reliability Must Run, within 15 Business Days.

3.14.1.2 ERCOT Evaluation Process

(1) Except as provided in paragraph (3) of Section 3.14.1.1, Notification of Suspension of Operations, ~~U~~upon receipt of an NSO under Section 3.14.1.1~~, Notification of Suspension of Operations~~, ERCOT shall post the NSO on the MIS Secure Area and shall post all existing relevant studies and data and provide a Market Notice of the NSO and posting of the studies and data.

(2) Within 21 days after receiving the NSO described in paragraph (1) above, unless otherwise notified by ERCOT that a shorter comment period is required, Market Participants may submit comments to ERCOT on whether the Generation Resource(s) referenced in the NSO is necessary to support ERCOT System reliability or should qualify for a multi-year RMR Agreement. ERCOT shall consider and post all submitted comments on the MIS Secure Area.

(3) ERCOT shall conduct a reliability analysis of the need for ~~the~~ any Generation Resource(s) with a summer Seasonal Net Max Sustainable Rating greater than or equal to 20 MW~~,~~ to support ERCOT System reliability. For Generation Resource(s) with a summer Seasonal Net Max Sustainable Rating less than 20 MW, ERCOT may conduct a reliability analysis if deemed appropriate by ERCOT following consultation with affected Transmission Service Provider(s) (TSP(s)).

(a) ERCOT shall use a Load forecast consistent with current Regional Transmission Plan assumptions and methodologies for the appropriate season(s). If additional new Generation Resources meet the criteria in Planning Guide Section 6.9, Addition of Proposed Generation to the Planning Models, ERCOT shall include those additional Generation Resources with the appropriate seasonal ratings.

(b) If the NSO indicates that the Generation Resource(s) will decommission or suspend operation, or in the case of a Forced Outage, has permanently ceased operation, ERCOT, in its sole discretion, may perform transmission reliability analysis over a planning horizon as defined by the available base cases but not to exceed two years.

(c) For purposes of the reliability analysis, ERCOT shall use the following criteria to identify a performance deficiency that is materially impacted by the Generation Resource:

(i) Without the Generation Resource, there are one or more Transmission Facilities loaded above their Normal Rating under pre-contingency conditions.

(ii) Without the Generation Resource, there is any instability or cascading for any of the following conditions:

(A) Pre-contingency;

(B) Normal system conditions followed by the contingency loss of a generating unit, transmission circuit, common tower outage, transformer, shunt device, or flexible alternating current transmission system (FACTS) device;

(C) Unavailability of a generating unit, followed by Manual System Adjustments, followed by the contingency loss of a generating unit, transmission circuit, common tower outage, transformer, shunt device, or FACTS device; or

(D) Unavailability of a 345/138 kV transformer, followed by Manual System Adjustments, followed by the contingency loss of a generating unit, transmission circuit, common tower outage, transformer, shunt device, or FACTS device.

(iii) Without the Generation Resource, there are one or more Transmission Facilities loaded above 110% of the Emergency Rating under normal system conditions followed by the contingency loss of a generating unit, transmission circuit, common tower outage, transformer, shunt device, or FACTS device.

(iv) For paragraphs (i) through (iii) above, the Generation Resource will only be deemed to have a material impact on a performance deficiency that is caused by a thermal overload(s) if the Generation Resource has a more than 2% unloading Shift Factor on the Transmission Facility(s) that is overloaded and more than 5% unloading impact on the Transmission Facility(s) that is overloaded. For purposes herein, an unloading impact is a measure of a reduction in flow on a Transmission Facility as a percent of its Rating due to a unit injection of power from the Generation Resource.

(v) ERCOT may, in its sole discretion, deviate from the above criteria in order to maintain ERCOT System reliability. However, ERCOT shall present its reasons for deviating from the above criteria to the Technical Advisory Committee (TAC) and ERCOT Board.

(d) ERCOT, in consultation with affected Transmission Service Provider(s) (TSP(s)), may rely upon the results of past planning studies to determine if the Generation Resource is necessary to support ERCOT System reliability. The past planning studies must have used the same or more restrictive reliability criteria than the criteria described in paragraph (c) above.

(e) Additionally, ERCOT shall conduct any other analysis (e.g., operations studies) as required and shall post all study data and results and all analyses and its determination on the MIS Secure Area and issue a Market Notice of its determination.

(4) Within 30 days after receiving the NSO, ERCOT shall issue a Market Notice indicating the status of the reliability analysis referenced in paragraph (3) above. The Market Notice will indicate one of the following:

(a) ERCOT has completed its reliability analysis and the Generation Resource is not required to support ERCOT System reliability;

(b) ERCOT has completed its reliability analysis and the analysis identifies a performance deficiency for which the Generation Resource has a material impact; or

(c) ERCOT has not completed its reliability analysis and will need additional time to complete the assessment.

(5) Within 60 days after receiving Part I and Part II of the NSO, ERCOT shall complete its reliability analysis described in paragraph (3) above and shall issue a Market Notice describing the results of its reliability analysis if the results were not provided in the Market Notice issued under paragraph (4) above. If ERCOT determines that the Generation Resource is not needed to support ERCOT System reliability, then the Generation Resource may cease or suspend operations according to the schedule in its NSO, unless ERCOT in its sole discretion permits the Generation Resource to suspend operations at an earlier date, and ERCOT shall note this in the Market Notice.

(6) Within ten days after a determination by ERCOT that the proposed suspension of the Generation Resource would result in a performance deficiency on which the Generation Resource has a material impact, as described in this Section, ERCOT shall issue a Request for Proposal (RFP) for Must-Run Alternatives (MRAs). ERCOT shall include in the RFP reasonably available information that would enable potential MRAs to assess the feasibility of submitting a proposal to provide a more cost-effective alternative to the Generation Resource, including any known minimum technical requirements and/or operational characteristics required to eliminate the identified performance deficiency. The MRA RFP shall specify the expected number of hours that an MRA would be needed during the contract period, and the hours of the day, by season, that the MRA would be required to be available. ERCOT shall establish an RFP response schedule such that responses can be evaluated prior to 150 days after submittal of the NSO.

(7) Within ten days after a determination by ERCOT that the proposed suspension of the Generation Resource would result in a performance deficiency on which the Generation Resource has a material impact, as described in this Section, the Resource Entity shall, if it has not already done so, complete and submit to ERCOT Part III of the NSO (Section 22, Attachment E, Notification of Suspension of Operations). ERCOT shall post the Part III information on the MIS Secure Area. Concurrently, the Generation Resource shall submit an initial estimated budget used in the calculation of the proposed Standby Cost and RMR fuel adder, prepared in accordance with Section 3.14.1.11, Budgeting Eligible

Costs, and Section 3.14.1.20, Budgeting Fuel Costs, to ERCOT. On or before the 11th day after the determination or the receipt of Part III of the NSO, whichever comes first, ERCOT and the Resource Entity shall begin good faith negotiations on an RMR Agreement. These negotiations shall include the budgeting process for Eligible Costs and for fuel costs as detailed in Section 3.14.1.11 and Section 3.14.1.20.

(8) ERCOT shall issue a Market Notice on the status of the RMR Unit or MRA, including the start date, duration of the RMR or MRA Agreement, the Standby Cost ($/Hour) as applicable, and the amount of MW under contract, within 24 hours of signing an RMR or MRA Agreement with a Resource Entity.

(9) Except in cases where the Generation Resource is to be mothballed on a seasonal basis, if, after 150 days following ERCOT's receipt of Part I and Part II of the NSO, ERCOT has neither notified the Resource Entity that the continued operation of the Generation Resource is not required nor obtained ERCOT Board approval to enter into an RMR or MRA Agreement, then the Resource Entity may file a complaint with the Public Utility Commission of Texas (PUCT) under subsection (e)(1) of P.U.C. SUBST. R. 25.502, Pricing Safeguards in Markets Operated by the Electric Reliability Council of Texas. If the Generation Resource is to be mothballed on a seasonal basis, then the Resource Entity may file such a complaint with the PUCT under subsection (e)(1) of P.U.C. SUBST. R. 25.502 if ERCOT has neither notified the Resource Entity that the continued operation of the Generation Resource is not required nor obtained ERCOT Board approval to enter into an RMR Agreement within 90 days following ERCOT's receipt of Part I and Part II of the NSO.

(10) If the ERCOT Board approves entering into an RMR Agreement but ERCOT and the Resource Entity have not both executed the RMR Agreement by the date on which the Resource Entity intends to cease or suspend operation of the Generation Resource, then the Resource Entity shall maintain that Generation Resource(s) so that it is available for Reliability Unit Commitment (RUC) commitment until no longer required to do so under subsection (e)(2) of P.U.C. SUBST. R. 25.502. This paragraph does not apply to a Generation Resource that suspended operations due to a Forced Outage.

3.14.1.3 ERCOT Board Approval of RMR and MRA Agreements

(1) If ERCOT determines that an RMR or MRA Agreement is a cost-effective solution to remedy a performance deficiency for which the suspending Generation Resource has a material impact as described in paragraph (3) of Section 3.14.1.2, ERCOT Evaluation Process, or if ERCOT has identified such a performance deficiency but has determined that entering into an RMR or MRA Agreement is not a cost-effective solution to that performance deficiency, then ERCOT shall present this finding to the ERCOT Board for approval. In seeking such approval, ERCOT shall stipulate to the ERCOT Board that:

(a) The Resource Entity provided a complete and timely NSO including a sworn attestation supporting its claim of pending Generation Resource closure;

(b) ERCOT received all of the data necessary to evaluate the need for and provisions of the RMR or MRA Agreement, and that information was posted on the MIS Secure Area by ERCOT as it became available to ERCOT;

(c) When executed, the signed RMR or MRA Agreement will comply with the ERCOT Protocols and be posted on the MIS Secure Area;

(d) ERCOT evaluated:

(i) The reasonable alternatives to a specific RMR Agreement as set forth in Section 3.14.1, Reliability Must Run, and compared the alternatives against the feasibility, cost and reliability impacts of the signed RMR Agreement;

(ii) The timeframe in which ERCOT expects each unit to be needed for reliability; and

(iii) The specific type and scope of reliability concerns identified for each RMR Unit or MRA as applicable.

(2) ERCOT shall execute the RMR or MRA Agreement as soon as feasible after receiving ERCOT Board approval to do so.

(3) ERCOT shall post on the MIS Secure Area, as they become available, unit-specific studies, reports, and data, by which ERCOT justified entering into the RMR or MRA Agreement.

3.14.1.5 Evaluation of Alternatives

(1) In evaluating responses to the RFP for MRAs, ERCOT shall not consider any response that, in ERCOT's sole opinion, does not facially demonstrate that the proposed MRA meets the eligibility requirements specified in Section 3.14.4.1, Overview and Description of MRAs, and the availability criteria and other conditions specified in the RFP for MRAs.

(2) ERCOT shall consider any of the following options to resolve an identified performance deficiency:

(a) The Generation Resource proposed for ~~a~~ suspension of operations;

(b) All acceptable MRA proposals; and

(c) Any transmission upgrades that can be implemented prior to the time period for which the performance deficiency has been identified.

(3) ERCOT staff shall select the option or combination of options, if any, that most cost-effectively address the performance deficiency, as long as the cost of the selected options is justified given the possible impact to Customers due to the performance deficiency. If

ERCOT determines that no option cost-effectively resolves the performance deficiency, then ERCOT shall not select any option. In selecting the most cost-effective option, ERCOT will consider the following factors:

(a) The degree to which the option addresses the identified performance deficiency;

(b) The total expected cost of each option;

(c) Expected unit performance of the Generation Resource proposed for suspension of operations, including start-up time, minimum run-time, minimum down-time, and historical unit outage data;

(d) Operational limitations of proposed MRAs, including start-up times, minimum run-times, ramp periods, and return-to-service times;

(e) Other operational constraints or operational benefits of the proposed option; and

(f) Any other factors which ERCOT determines are relevant to the evaluation, and for which ERCOT can develop quantifiable criteria with which to evaluate all proposed options.

(4) In evaluating the expected impact to Customers due to the performance deficiency, ERCOT shall consider the following factors:

(a) Expected amount of Customer Demand affected (MWh);

(b) Expected number of hours during which Customers will be affected;

(c) Number of Customers affected;

(d) Possible additional Customer impacts due to unforeseen conditions, such as Generation Resource unavailability, transmission circuit Outages, or Load variation due to extreme weather; and

(e) Potential economic impact to Customers.

(5) ERCOT staff shall recommend the selected option or options to the ERCOT Board of Directors for approval, or shall recommend that the ERCOT Board of Directors decline to accept any option, if no eligible, cost-effective option has been identified. ERCOT staff shall provide sufficient information to justify its recommendation. The ERCOT Board of Directors may approve or reject the proposed recommendation, or may direct ERCOT staff to pursue an agreement to procure one or more options not proposed by ERCOT staff.

3.14.1.9 Generation Resource Status Updates

(1) By April 1st and October 1st of each year and when material changes occur, every Resource Entity that owns or controls a Mothballed Generation Resource or an RMR

Unit shall report to ERCOT, on a unit-specific basis, the estimated lead time required for each Resource to be capable of returning to service and, in percentage terms, report probable generation capacity from each Resource that the Resource Entity expects to return to service in each Season of each of the next ten years.

(2) For modeling purposes, ERCOT and TSPs shall rely on the most recent submittal of the following two Notifications with respect to an RMR Unit, Mothballed Generation Resource or Decommissioned Generation Resource: Section 22, Attachment E, Notification of Suspension of Operations, or Section 22, Attachment H, Notification of Change of Generation Resource Designation. Except in the case of an NSO submitted for a Generation Resource temporarily suspending operation due to a Forced Outage, ERCOT shall post each submitted NSO and Notification of Change of Generation Resource Designation to the MIS Secure Area and issue a Market Notice notifying Market Participants of the posting as soon as practicable, but no later than five Business Days after receipt.

(3) A Mothballed Generation Resource that is not mothballed indefinitely shall remain modeled in all ERCOT systems at all times, (i.e., will not be flagged as "mothballed" in ERCOT's models) and, when it is not available, the Resource Entity shall designate the Generation Resource as on Planned Outage in the Outage Scheduler.

(4) Except for Mothballed Generation Resources that operate under a Seasonal Operation Period, a Resource Entity with a Mothballed Generation Resource shall notify ERCOT in writing no less than 30 days prior to the date on which the Resource Entity intends to return a Mothballed Generation Resource to service by completing a Notification of Change of Generation Resource Designation.

(5) A Resource Entity must submit a Notification of Change of Generation Resource Designation no later than 60 days prior to the conclusion of an RMR Agreement.

(6) A Resource Entity with a Mothballed Generation Resource that operates under a Seasonal Operation Period shall notify ERCOT in writing no less than 15 days prior to the date on which the Resource Entity intends to begin its Seasonal Operation Period if the first date of operation is prior to the date designated by the Resource Entity in its NSO. A Resource Entity with a Mothballed Generation Resource that operates under a Seasonal Operation Period shall notify ERCOT in writing no less than 15 days prior to the end date designated by the Resource Entity in its NSO if the Resource Entity intends to suspend operation later than that date. Notifications under this section shall be provided by the Resource Entity by completing a Notification of Change of Generation Resource Designation form (Section 22, Attachment H).

(7) Once the Resource Entity notifies ERCOT that a Mothballed Generation Resource is operating under a Seasonal Operation Period, the Resource Entity does not need to annually notify ERCOT of such status.

(8) A Resource Entity with a Mothballed Generation Resource operating under a Seasonal Operation Period shall notify ERCOT in writing no less than 15 days prior to the date on

which the Resource Entity intends to return the Mothballed Generation Resource to year-round operation by completing a Notification of Change of Generation Resource Designation form (Section 22, Attachment H).

(9) A Resource Entity with a Mothballed Generation Resource that is not currently mothballed indefinitely must notify ERCOT in writing, by completing an NSO (Section 22, Attachment E), no less than 150 days before the date on which the Mothballed Generation Resource is to be suspended indefinitely or retired and decommissioned.

(10) ERCOT may request that a Mothballed Generation Resource operating under a Seasonal Operation Period be available for operation earlier than June 1st or later than September 30th of any given calendar year. If ERCOT identifies a specific Resource Entity or QSE with which it will discuss such a request in an attempt to reach a mutually agreeable resolution, ERCOT shall issue a Notice as soon as practicable. The Notice shall include the Resource name and, as applicable, the Resource mnemonic, the Resource MW Rating by Season, and the potential duration of the extended operation period, including anticipated start and end dates. If agreement is reached for the Mothballed Generation Resource to be available for operation earlier than June 1st or later than September 30th, the Resource Entity shall complete, within two Business Days, a Notification of Change of Generation Resource Designation form (Section 22, Attachment H).

(11) If ERCOT and the Resource Entity or QSE cannot reach a mutual agreement to make the Mothballed Generation Resource operating under a Seasonal Operation Period available earlier than June 1st or later than September 30th of any given calendar year, then ERCOT may exercise its ability to bring the Mothballed Generation Resource operating under a Seasonal Operating Period into the market under an RMR Agreement pursuant to paragraph (4) of Section 6.5.1.1, ERCOT Control Area Authority.

(12) ERCOT may evaluate, on an annual basis, Mothballed Generation Resources operating under a Seasonal Operation Period for RMR Service to address ERCOT System reliability during the portion of the year when the Mothballed Generation Resource would be unavailable.

(13) A Resource Entity that submitted an NSO as a result of a Forced Outage must notify ERCOT of its intent to return to service as soon as practicable by updating its status in the Outage Scheduler and Current Operating Plan (COP) and is not required to submit a Notification of Change of Generation Resource Designation.

(14) Before retiring and decommissioning either a Mothballed Generation Resource this is mothballed indefinitely or an RMR Unit that would otherwise become a Mothballed Generation Resource upon expiration of an RMR Agreement, a Resource Entity shall notify ERCOT of the expected retirement by submitting a completed Notification of Change of Generation Resource Designation form (Section 22, Attachment H). The date of retirement indicated on the form shall comply with the requirements of Section 3.10.1, Time Line for Network Operations Model Changes.

(15) If a Generation Resource is designated as decommissioned and retired pursuant to any of the above provisions, ERCOT will permanently remove the Generation Resource from the ERCOT registration systems in accordance with Section 3.10.1. Except as provided in paragraph (16) below, if a Resource Entity decides to bring a Decommissioned Generation Resource back to service at a later date, it will be considered a new Resource and must follow the Generator Interconnection or Modification (GIM) process detailed in the Planning Guide. If the Generation Resource is designated as mothballed, ERCOT and TSPs will consider the Generation Resource mothballed until the Resource Entity indicates a definitive return to service date pursuant to this Section.

(16) A Resource Entity may bring a Decommissioned Generation Resource back to service without following the GIM process if the operating characteristics of the Resource are materially identical to the characteristics of the Resource as it existed prior to the date of decommissioning and the Resource Entity submits a Notification of Change of Generation Resource Designation (Section 22, Attachment H) within three years of the date the Generation Resource was removed from the ERCOT Network Operations Model. The date of return proposed in the Notification must be a Network Operations Model load date that is no earlier than 45 days and no later than 180 days from the date of the Resource Entity's Notification. ERCOT may delay the Network Operations Model load date based on the timing of the Resource Entity's submission of complete Resource registration data. If the Resource Entity is not the Resource Entity that was associated with the Generation Resource at the time it was removed from the model, the Resource Entity shall provide ERCOT documentation that establishes the Resource Entity's ownership of the Generation Resource.

(a) Notwithstanding the proposed date of return reflected in the Notification, as a condition for the synchronization of the Resource, ERCOT or the interconnecting Transmission and/or Distribution Service Provider (TDSP) may require any studies, testing, metering, or facility upgrades that ERCOT or the TDSP deem necessary for the reliable interconnection of the Resource, and ERCOT may require the Resource Entity to resolve any operational concern associated with the Resource. The TDSP may require the Resource Entity to compensate the TDSP for any required studies or upgrades in the same manner contemplated for new Generation Resources by the ERCOT Planning Guide, the TDSP's tariff, and the Standard Generation Interconnection Agreement (SGIA).

(b) If ERCOT or the TDSP requires any studies, testing, metering or facility upgrades, or if ERCOT determines that operational concerns must be addressed, the Resource Entity must complete the commissioning process within 90 days of the date of synchronization, subject to any extension authorized by ERCOT for good cause.

(c) Any Generation Resource that returns to service pursuant to this paragraph is entitled to any exemption from ERCOT requirements that the Resource was entitled to at the time it was removed from the model if the exemption still exists under ERCOT rules.

3.14.1.10 Eligible Costs

(1) "Eligible Costs" are costs that would be incurred by the RMR Unit owner to provide the RMR Service, excluding fuel costs or other costs the RMR Unit would have incurred anyway had it been mothballed or shut down.

(a) Examples of Eligible Costs include the following to the extent they each meet the standard for eligibility:

(i) Direct labor to operate the RMR Unit during the term of the RMR Agreement;

(ii) Materials and supplies directly consumed or used in operation of the RMR Unit during the term of the RMR Agreement;

(iii) Services necessary to operate the RMR Unit during the term of the RMR Agreement;

(iv) Costs associated with emissions credits used as a direct result of operation of the RMR Unit under direction from ERCOT, or emissions reduction equipment as may be required according to terms of the RMR Agreement;

(v) Costs associated with maintenance:

(A) Due to required equipment maintenance;

(B) Due to replacement to alleviate unsafe operating conditions;

(C) Due to regulatory requirements, with compliance dates during the term of the RMR Agreement (any such compliance dates and requirements shall be explicitly defined in the RMR Agreement); or

(D) To ensure the ability to operate the RMR Unit consistent with Good Utility Practice;

(vi) Reservation and transportation costs associated with firm fuel supplies not recovered under Section 6.6.6.2, RMR Payment for Energy;

(vii) Property taxes and other taxes attributable to continuing to operate the RMR Unit during the term of the RMR Agreement;

(viii) General fund transfers or similar direct expenses incurred by a Municipally Owned Utility (MOU) if it is required to pay a portion of its revenues to the municipality. If the RMR payment to the MOU is subject to such a requirement, this expense is an incremental cost directly associated with the RMR Unit;

(ix) Costs based on a long-term service agreement (LTSA), provided that:

(A) The maintenance costs to be included are incremental and consistent with the definitions of the costs within the scope of the RMR Agreement and these Protocols;

(B) The cost of each component is specifically set by the LTSA;

(C) ERCOT must be able to verify the incremental or variable maintenance costs ($/MWh) or ($/start) described in the LTSA; and

(D) The LTSA is in effect during the term of the RMR Agreement and available to ERCOT for review; and

(x) Non-fuel costs to return a mothballed RMR Unit, or an RMR unit that had ceased operations permanently due to a Forced Outage, to service provided that:

(A) The costs were incurred between the effective date of the RMR Agreement and the termination date of the RMR Agreement; and

(B) The costs do not include costs the RMR Unit owner would have incurred had ~~it~~the RMR Unit remained mothballed or under Forced Outage.

(b) Examples of costs not included as Eligible Costs are:

(i) Depreciation expense, return on equity, and debt and interest costs;

(ii) Property taxes and other taxes not attributable to continuing to operate the RMR Unit;

(iii) Income taxes of the RMR Unit owner or operator;

(iv) Labor and material costs associated with other, non-RMR Generation Resources at the same facility;

(v) Cost of parts inventory not used by the RMR Unit during the term of the Agreement;

(vi) Costs attributed to other Resources in the power generation station; and

(vii) Any other costs the Resource Entity that owns the RMR Unit would have incurred even if the RMR Unit had been mothballed or shutdown.

ERCOT Nodal Protocols

Section 22

Attachment E: Notification of Suspension of Operations

~~February 12, 2020~~TBD

Notification of Suspension of Operations of a Generation Resource

This Notification is required for providing notification of any Generation Resource suspension lasting greater than 180 days. Information may be inserted electronically to expand the reply spaces as necessary.

The Notification must be signed, notarized and delivered to ERCOT. Delivery may be accomplished via email to MPRegistration@ercot.com (if a scanned copy) or via facsimile (Attention: Market Participant Registration) at (512) 225-7079.

ERCOT may request additional information as reasonably necessary to support operations under the ERCOT Protocols.

Part I:

Resource Entity: ______________________

DUNS Number: ______________________

Resource Site Name: ___________________

Resource Site Location (County): ____________________

Unit Name(s): __________________

Resource Name(s) (Unit Code/Mnemonic): ___________________

ESI ID: ____

Seasonal Net Max Sustainable Rating – Summer (MW): _____________________

Seasonal Net Minimum Sustainable Rating – Summer (MW): ______________________

Transmission Facilities that will be deactivated or removed from service as part of the suspension of operations of the unit(s): ____

Part II:

As of _____ [date],[1] the Generation Resource(s) will be limited or unavailable for Dispatch by ERCOT because Resource Entity will [check one]:

☐ decommission and retire the Generation Resource(s) permanently for a reason other than a Forced Outage,[2]

☐ suspend operation on a year-round basis (*i.e.*, mothball) and begin operation on a seasonal basis with a Seasonal Operation Period that begins on [Date] and ends on [Date] ~~[dates]~~. The Seasonal Operation Period must be inclusive of June 1 through September 30,

☐ temporarily suspend operation (*i.e.*, mothball) of the Generation Resource(s) for a period of not less than ___ months and not greater than ___ months due to some reason other than a Forced Outage, or

☐ indefinitely suspend operation (*i.e.*, mothball) of the Generation Resource(s) ~~indefinitely,~~. ~~or~~

On [Date], the Generation Resource experienced a Forced Outage. As a result of the Forced Outage, the Resource Entity intends to [check one]:

☐ decommission and retire the Generation Resource(s) permanently[2],

☐ temporarily suspend operation of the Generation Resource(s), ~~due to a Forced Outage;. Resource Entity intends to bring the Generation Resource(s) back to service on~~with an estimated return date of [Date]~~.~~, or

☐ indefinitely suspend operation (*i.e.*, mothball) of the Generation Resource(s).

~~Unless the Generation Resource(s) will be decommissioned and retired the estimated time to return the suspended Generation Resource(s) to service is ___ months.~~

Check if applicable: ☐ Resource Entity believes that this Generation Resource(s) is inoperable due to emissions limitations or not being repairable.

Operational and Environmental Limitations (check and describe all that apply):

(a) Operational:

☐ Maximum annual hours of operation: ___________

[1] Pursuant to Protocol Section 3.14.1.1, Notification of Suspension of Operations, this date must be at least 150 days (or 90 days if the Generation Resource will mothball and operate under a Seasonal Operation Period) from the date ERCOT receives this Notification~~, unless the suspension is the result of a Forced Outage, in which case the Generation Resource shall submit this Notification as soon as practicable~~.

[2] ERCOT will remove the Generation Resource(s) from its registration systems if this option is selected.

☐ Maximum annual MWhs: _______________

☐ Maximum annual starts: ________________

☐ Other: _____________

(b) Environmental:

☐ Maximum annual NOx emissions: ______________

☐ Maximum annual SO2 emissions: _______________

☐ Other: _____________

Part III:

Estimated RMR Fuel Adder ($/MMBtu): _____________________

Proposed Initial Standby Cost ($/hr): __________________

I understand and agree that this Notification is not confidential and does not constitute Protected Information under the ERCOT Protocols.

I hereby certify that the proposed, estimated Fuel Adder, Standby Costs, and attached budget are accurate at the time of submittal, necessary, and do not exceed fair-market value.

The undersigned certifies that I am an officer or executive of Resource Entity, that I am authorized to execute and submit this Notification on behalf of Resource Entity, and that the statements contained herein are true and correct.

____

Name: _____________

Title: _____________

Date: _____________

STATE OF _______________

COUNTY OF _____________

Board Report

Before me, the undersigned authority, this day appeared ___________________, known by me to be the person whose name is subscribed to the foregoing instrument, who, after first being sworn by me deposed and said:

> "I am an officer of ______________, I am authorized to execute and submit the foregoing Notification on behalf of ______________, and the statements contained in such Notification are true and correct."

SWORN TO AND SUBSCRIBED TO BEFORE ME, the undersigned authority on this the _____ day of ____________, 20__.

____

Notary Public, State of ___________

My Commission expires __________

ERCOT Impact Analysis Report

NPRR Number	1147	NPRR Title	Update and Improve Notification and Evaluation Processes Associated with Reliability Must-Run (RMR)
Impact Analysis Date		August 15, 2022	
Estimated Cost/Budgetary Impact		None.	
Estimated Time Requirements		No project required. This Nodal Protocol Revision Request (NPRR) can take effect following Public Utility Commission of Texas (PUCT) approval.	
ERCOT Staffing Impacts (across all areas)		There will be ongoing operational impacts across the following ERCOT departments totaling 0.3 Full-Time Employees (FTEs) to support this NPRR: • System Development (0.3 FTEs Effort) ERCOT has assessed its ability to absorb the ongoing efforts of this NPRR with current staff. The above department is able to absorb the effort and will not require additional staff.	
ERCOT Computer System Impacts		No impacts to ERCOT computer systems.	
ERCOT Business Function Impacts		ERCOT will update its business processes to implement this NPRR.	
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

NPRR Number	1149	NPRR Title	Implementation of Systematic Ancillary Service Failed Quantity Charges
Date of Decision	February 28, 2023		
Action	Recommended Approval		
Timeline	Normal		
Proposed Effective Date	Upon system implementation		
Priority and Rank Assigned	Priority – 2023; Rank – 3780		
Nodal Protocol Sections Requiring Revision	2.1, Definitions 4.4.7.4, Ancillary Service Supply Responsibility 6.3.2, Activities for Real-Time Operations 6.4.1, Capacity Trade, Energy Trade, Self-Schedule, and Ancillary Service Trades 6.4.9.1.3, Replacement of Ancillary Service Due to Failure to Provide 6.7.3, Charges for Ancillary Service Capacity Replaced Due to Failure to Provide 6.7.5, Real-Time Ancillary Service Imbalance Payment or Charge		
Related Documents Requiring Revision/Related Revision Requests	None		
Revision Description	This Nodal Protocol Revision Request (NPRR) charges a Qualified Scheduling Entity (QSE) an Ancillary Service failed quantity if the Ancillary Service Supply Responsibility held by the QSE is not met by Resources in their portfolio in Real-Time, based on a comparison of their Real-Time telemetry. The charges will be done systematically without ERCOT Operators having to take additional action. Specific Protocol changes include: • Details on the new calculations that will be used to do the comparison between Ancillary Service Supply Responsibility and Real-Time telemetry after the Operating Hour is complete; • Enhancing language in Section 4.4.7.4 to clarify that although a QSE may hold an Ancillary Service Supply Responsibility without having Resources, that responsibility must be met by Resources in Real-Time. The language proposed in this section does not create new responsibilities but clarifies existing requirements for how a QSE must meet its Ancillary Service Supply Responsibility;		

	• A check on Load Resources providing Responsive Reserve (RRS), Non-Spinning Reserve (Non-Spin), and ERCOT Contingency Reserve Service (ECRS), to ensure that during the deployment period their telemetered Ancillary Service Resource Responsibility does not exceed the amount of deployed MW and overstate the amount of responsibility being carried by that Resource; • Expanding the window of time during which a QSE can submit an Ancillary Service Trade to include the Operating Period; and • Other aligning edits. Under this NPRR, ERCOT Operators retain the ability to charge a failed quantity and replace the MW with a Supplemental Ancillary Services Market (SASM) if they so choose.
Reason for Revision	☒ Addresses current operational issues. ☐ Meets Strategic goals (tied to the ERCOT Strategic Plan or directed by the ERCOT Board). ☐ Market efficiencies or enhancements ☐ Administrative ☐ Regulatory requirements ☐ Other: (explain) *(please select all that apply)*
Business Case	In May 2019, ERCOT filed NPRR947, Clarification to Ancillary Service Supply Responsibility Definition and Improvements to Determining and Charging for Ancillary Service Failed Quantities, which proposed very similar changes as proposed in this NPRR. NPRR947 was withdrawn by ERCOT after months of deliberation because, although it is important to ensure that QSEs are providing the Ancillary Services for which they are being compensated, the improvements proposed in NPRR947 were deemed to be made obsolete and the issue would be resolved by the implementation of Real-Time Co-Optimization (RTC) of energy and Ancillary Services, scheduled for implementation in 2024. As is widely known today, the effort to implement RTC is currently on hold and a new date for expected implementation is unknown. Additionally, following winter storm Uri, the ERCOT Independent Market Monitor (IMM), Potomac Economics, filed a recommendation at the Public Utility Commission of Texas (PUCT) in Project 51812, Issues Related to the State of Disaster for the February 2021 Winter

	Weather Event, that ERCOT should charge failed quantities based on Real-Time telemetry and outcomes during the storm. The PUCT agreed with this recommendation (*See* Second Order Addressing Ancillary Services under Project No. 51812) and applicable charges were issued to QSEs by ERCOT. With that knowledge and experience, ERCOT again proposes to implement a systemic charging of Ancillary Service failed quantities. This NPRR implements that process permanently for all periods and in a more systematic way, ensuring that Load is not charged or is reimbursed for Ancillary Services that are not delivered in Real-Time. It also addresses short-comings in the previously applied process for Load Resources that are not Controllable Load Resources that were not included in ERCOT's application of the PUCT's Order in 2021.
PRS Decision	On 10/13/22, PRS voted to table NPRR1149 and refer the issue to WMS. There was one abstention from the Consumer (Occidental) Market Segment. All Market Segments participated in the vote. On 12/8/22, PRS voted unanimously to recommend approval of NPRR1149 as amended by the 12/1/22 ERCOT comments. All Market Segments participated in the vote. On 1/17/23, PRS voted unanimously to endorse and forward to TAC the 12/8/22 PRS Report and 9/20/22 Impact Analysis for NPRR1149 with a recommended priority of 2023 and rank of 3780. All Market Segments participated in the vote.
Summary of PRS Discussion	On 10/13/22, ERCOT Staff provided an overview of NPRR1149. On 12/8/22, PRS reviewed the 11/30/22 PUCT Staff comments and the 12/1/22 ERCOT comments. On 1/17/23, there was no discussion.
TAC Decision	On 1/24/23, TAC voted unanimously to recommend approval of NPRR1149 as recommended by PRS in the 1/17/23 PRS Report. All Market Segments participated in the vote.
Summary of TAC Discussion	On 1/24/23, TAC reviewed the ERCOT Opinion, ERCOT Market Impact Statement, and Independent Market Monitor (IMM) Opinion for NPRR1149. Participants confirmed they could continue to adjust Ancillary Services amongst Resources in their portfolio in Real-Time.
ERCOT Board Decision	On 2/28/23, the ERCOT Board voted unanimously to recommend approval of NPRR1149 as recommended by TAC in the 1/24/23 TAC Report.

Opinions

Board Report

Credit Review	ERCOT Credit Staff and the Market Credit Work Group (MCWG) have reviewed NPRR1149 and do not believe that it requires changes to credit monitoring activity or the calculation of liability.
Independent Market Monitor Opinion	The IMM supports the approval of NPRR1149 for reasons laid out in the 9/20/22 IMM comments.
ERCOT Opinion	ERCOT supports approval of NPRR1149.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NPRR1149 and believes the market impact for NPRR1149 is an improvement in the process for invoking "failure to provide" Settlement. This better ensures that Market Participants are not compensated for services that they were unable to provide in Real-Time and provides transparency as to how this Settlement will be applied.

Sponsor	
Name	Dave Maggio / Austin Rosel
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Company	ERCOT
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Comments Received	
Comment Author	**Comment Summary**
IMM 092022	Expressed support for NPRR1149 and encouraged stakeholders to approve NPRR1149 on an urgent timeline
ERCOT 092722	Provided additional redlines to Section 6.3.2, Activities for Real-Time Operations, which were inadvertently omitted from the original submission

WMS 110922	Requested PRS continue to table NPRR1149 for further review by the Wholesale Market Working Group (WMWG)
PUCT Staff 113022	Expressed support for NPRR1149 and encouraged prompt approval
ERCOT 120122	Proposed edits based to correct minor errors in a Settlement formula along with other clarifying edits

Market Rules Notes

Please note the baseline Protocol language in the following section(s) has been updated to reflect the incorporation of the following NPRR(s) into the Protocols:

- NPRR1085, Ensuring Continuous Validity of Physical Responsive Capability (PRC) and Dispatch through Timely Changes to Resource Telemetry and Current Operating Plans (COPs) (incorporated 10/1/22)
  - Section 6.7.5
- NPRR1131, Controllable Load Resource Participation in Non-Spin (incorporated 10/1/22)
  - Section 6.7.5
- NPRR1135, Add On-Line Status Check for Resources Telemetering OFFNS for Ancillary Service Imbalance Settlements (incorporated 10/1/22)
  - Section 6.7.5
- NPRR1058, Resource Offer Modernization (incorporated 12/1/22)
  - Section 6.3.2

Proposed Protocol Language Revision

2.1 Definitions

Ancillary Service Supply Responsibility

The net amount of Ancillary Service capacity that a QSE is obligated to deliver to ERCOT, by hour and service type~~, from Resources represented by the QSE~~.

4.4.7.4 Ancillary Service Supply Responsibility

(1) A QSE's Ancillary Service Supply Responsibility is the net amount of Ancillary Service capacity that the QSE is obligated to deliver to ERCOT, by hour and service type~~, from Resources represented by the QSE~~. The Ancillary Service Supply Responsibility is the difference in MW, by hour and service type, between the amounts specified in items (a) and (b) defined as follows:

(a) The sum of:

(i) The QSE's Self-Arranged Ancillary Service Quantity; plus

(ii) The total (in MW) of Ancillary Service Trades for which the QSE is the seller; plus

(iii) Awards to the QSE of Ancillary Service Offers in the DAM; plus

(iv) Awards to the QSE of Ancillary Service Offers in the SASM; plus

(v) RUC-committed Ancillary Service quantities to the QSE from its Resources committed by the RUC process to provide Ancillary Service; and

(b) The sum of:

(i) The total Ancillary Service Trades for which the QSE is the buyer; plus

(ii) The total Ancillary Service capacity identified as ~~to~~ the QSE's failure to provide, as described in Section 6.4.9.1.3, ~~Replacement of Ancillary Service Due to~~ Failure to Provide Ancillary Service; plus

(iii) The total Ancillary Service capacity identified as the QSE's infeasible Ancillary Service, as described in Section 6.4.9.1.2, Replacement of Infeasible Ancillary Service Due to Transmission Constraints; plus

(iv) The total Ancillary Service capacity identified as the QSE's reconfiguration amount, as described in Section 6.4.9.2, Supplemental Ancillary Services Market.

(2) A QSE may only use a RUC-committed Resource during that Resource's RUC-Committed Interval to meet the QSE's Ancillary Service Supply Responsibility if the Resource has been committed by the RUC process to provide Ancillary Service. The QSE shall only provide from the RUC-committed Resource the exact amount and type of Ancillary Service for which it was committed by RUC.

(3) By 1430 in the Day-Ahead, the QSE must notify ERCOT, in the QSE's COP, which Resources represented by the QSE will provide the Ancillary Service capacity necessary to meet the QSE's Ancillary Service Supply Responsibility, specified by Resource, hour, and service type. The DAM Ancillary Service awards are Resource-specific; the QSE must include those DAM awards in its COP, and the QSE may not change that Resource-specific DAM award information until after 1600 under the conditions set out in Section 3.9, Current Operating Plan (COP).

(4) Section 6.4.9.1.3 specifies what happens if the QSE fails ~~on~~to provide its Ancillary Service Supply Responsibility.

(5) A QSE's Ancillary Service Supply Responsibility must be met by identified Resources that are qualified to provide the Ancillary Service, per Section 8.1.1.2.1 Ancillary Service

Technical Requirements and Qualification Criteria and Test Methods, and available to act on Dispatch Instructions.

6.3.2 Activities for Real-Time Operations

(1) Activities for Real-Time operations begin at the end of the Adjustment Period and conclude at the close of the Operating Hour.

(2) The following table summarizes the timeline for the Operating Period and the activities of QSEs and ERCOT during Real-Time operations where "T" represents any instant within the Operating Hour. The table is intended to be only a general guide and not controlling language, and any conflict between this table and another section of the Protocols is controlled by the other section:

Operating Period	**QSE Activities**	**ERCOT Activities**
During the first hour of the Operating Period		Execute the Hour-Ahead Sequence, including HRUC, beginning with the second hour of the Operating Period Review the list of Off-Line Available Resources with a start-up time of one hour or less Review and communicate HRUC commitments and Direct Current Tie (DC Tie) Schedule curtailments Snapshot the Scheduled Power Consumption for Controllable Load Resources
Before the start of each SCED run	Update Output Schedules for DSRs	Validate Output Schedules for DSRs Execute Real-Time Sequence
SCED run		Execute SCED and pricing run to determine impact of reliability deployments on energy prices
During the Operating Hour	Telemeter the Ancillary Service Resource Responsibility for each Resource Acknowledge receipt of Dispatch Instructions Comply with Dispatch Instruction Review Resource Status to assure current state of the Resources is properly telemetered Update COP with actual Resource Status and limits and Ancillary Service Schedules	Communicate all binding Base Points, Dispatch Instructions, and the sum of each type of available reserves, including total Real-Time reserve amount for On-Line reserves, total Real-Time reserve amount for Off-Line reserves, Real-Time Reserve Price Adders for On-Line Reserves, and Real-Time Reserve Price Adders for Off-Line Reserves and LMPs for energy and Ancillary Services, and for the pricing run as described in Section 6.5.7.3.1, Determination of Real-Time On-Line Reliability Deployment Price Adder, the total Reliability Unit Commitment (RUC)/Reliability Must-Run (RMR) MW relaxed, total Load Resource MW deployed

Operating Period	QSE Activities	ERCOT Activities
	Communicate Resource Forced Outages to ERCOT Communicate to ERCOT Resource changes to Ancillary Service Resource Responsibility via telemetry in the time window beginning 30 seconds prior to the five-minute clock interval and ending ten seconds prior to that five-minute clock interval	that is added to the Demand, total Emergency Response Service (ERS) MW deployed that is added to the Demand, total emergency DC Tie MW that is added to or subtracted from the Demand, total Block Load Transfer (BLT) MW that is added to or subtracted from the Demand, total Low Ancillary Service Limit (LASL), total High Ancillary Service Limit (HASL), Real-Time On-Line Reliability Deployment Price Adder using Inter-Control Center Communications Protocol (ICCP) or Verbal Dispatch Instructions (VDIs) Monitor Resource Status and identify discrepancies between COP and telemetered Resource Status Restart Real-Time Sequence on major change of Resource or Transmission Element Status Monitor ERCOT total system capacity providing Ancillary Services Validate COP information Validate Ancillary Service Trades Monitor ERCOT control performance Distribute by ICCP, and post on the ERCOT website, System Lambda and the LMPs for each Resource Node, Load Zone and Hub, and the sum of each type of available reserves, including total Real-Time reserve amount for On-Line reserves, total Real-Time reserve amount for Off-Line reserves, Real-Time Reserve Price Adders for On-Line Reserves and Real-Time Reserve Price Adders for Off-Line Reserves, and for the pricing run as described in Section 6.5.7.3.1 the total RUC/RMR MW relaxed, total Load Resource MW deployed that is added to the Demand, total ERS MW deployed that is added to the Demand, total emergency DC Tie MW that is added to or subtracted from the Demand, total BLT MW that is added to or subtracted from the Demand, total On-Line LASL, total On-Line HASL, Real-Time On-Line Reliability Deployment Price Adder created for each SCED process. These prices shall be posted immediately subsequent to deployment of Base Points

Operating Period	QSE Activities	ERCOT Activities
		from SCED with the time stamp the prices are effective Post on the ERCOT website the nodal prices for Settlement Only Distribution Generators (SODGs) and Settlement Only Transmission Generator (SOTGs). These prices shall include all Real-Time Reserve Price Adders for On-Line Reserves and Real-Time On-Line Reliability Deployment Price Adders created for each SCED process. These prices shall be posted immediately subsequent to deployment of Base Points from SCED with the time stamp the prices are effective Post LMPs for each Electrical Bus on the ERCOT website. These prices shall be posted immediately subsequent to deployment of Base Points from each binding SCED with the time stamp the prices are effective Post on the ERCOT website the projected non-binding LMPs created by each SCED process for each Resource Node, the projected total Real-Time reserve amount for On-Line reserves and Off-Line reserves, the projected Real-Time On-Line Reserve Price Adders and Real-Time Off-Line Reserve Price Adders, and for the projected non-binding pricing runs as described in Section 6.5.7.3.1 the total RUC/RMR MW relaxed, total Load Resource MW deployed that is added to Demand, total emergency DC Tie MW that is added to or subtracted from the Demand, total BLT MW that is added to or subtracted from the Demand, total ERS MW deployed that are deployed that is added to the Demand, total LASL, total HASL, Real-Time On-Line Reliability Deployment Price Adder and the projected Hub LMPs and Load Zone LMPs. These projected prices shall be posted at a frequency of every five minutes from SCED for at least 15 minutes in the future with the time stamp of the SCED process that produced the projections Post on the MIS Certified Area the projected non-binding Base Points for each Resource created by each SCED process. These projected non-binding Base Points shall be posted at a frequency of every five minutes

Operating Period	QSE Activities	ERCOT Activities
		from SCED for at least 15 minutes in the future with the time stamp of the SCED process that produced the projections Post each hour on the ERCOT website binding SCED Shadow Prices and active binding transmission constraints by Transmission Element name (contingency /overloaded element pairs) Post on the ERCOT website the Settlement Point Prices for each Settlement Point and the Real-Time price for each SODG and SOTG immediately following the end of each Settlement Interval Post the Real-Time On-Line Reliability Deployment Price, Real-Time Reserve Price for On-Line Reserves and the Real-Time Reserve Price for Off-Line Reserves immediately following the end of each Settlement Interval Post parameters as required by Section 6.4.9, Ancillary Services Capacity During the Adjustment Period and in Real-Time, on the ERCOT website

[NPRR829, NPRR904, NPRR995, NPRR1000, NPRR1006, NPRR1010, NPRR1058, and NPRR1077: Replace applicable portions of paragraph (2) above with the following upon system implementation for NPRR829, NPRR904, NPRR995, NPRR1000, NPRR1006, NPRR1058, or NPRR1077; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010:]

(2) The following table summarizes the timeline for the Operating Period and the activities of QSEs and ERCOT during Real-Time operations where "T" represents any instant within the Operating Hour. The table is intended to be only a general guide and not controlling language, and any conflict between this table and another section of the Protocols is controlled by the other section:

Operating Period	QSE Activities	ERCOT Activities
During the first hour of the Operating Period		Execute the Hour-Ahead Sequence, including HRUC, beginning with the second hour of the Operating Period Review the list of Off-Line Available Resources with a start-up time of one hour or less Review and communicate HRUC commitments and Direct Current Tie (DC Tie) Schedule curtailments Snapshot the Scheduled Power Consumption for Controllable Load Resources
SCED run		Execute SCED and pricing run to determine impact of reliability deployments on energy and Ancillary Service prices
During the Operating Hour	Acknowledge receipt of Dispatch Instructions Comply with Dispatch Instruction Review Resource Status to assure current state of the Resources is properly telemetered Update COP and telemetry with actual Resource Status and limits and Ancillary Service capabilities Submit and update Ancillary Service Offers Communicate Resource Forced Outages to ERCOT Submit and update Energy Offer Curves and/or RTM Energy Bids	Communicate all binding Base Points, Updated Desired Set Points (UDSPs), Ancillary Service awards, Dispatch Instructions, LMPs for energy, Real-Time MCPCs for Ancillary Services, and for the pricing run as described in Section 6.5.7.3.1, Determination of Real-Time Reliability Deployment Price Adders, the total Reliability Unit Commitment (RUC)/Reliability Must-Run (RMR) MW relaxed, total Load Resource MW deployed that is added to the Demand, total Transmission and/or Distribution Service Provider (TDSP) standard offer Load management MW deployed that is added to the Demand, total Emergency Response Service (ERS) MW deployed that is added to the Demand, total ERCOT-directed DC Tie MW that is added to or subtracted from the Demand, total Block Load Transfer (BLT) MW that is added to or subtracted from the Demand Real-Time Reliability Deployment Price Adder for Energy, and Real-Time Reliability Deployment Price Adders for Ancillary Service using Inter-Control Center Communications Protocol (ICCP) or Verbal Dispatch Instructions (VDIs). In communicating Ancillary Service awards, the awards shall be broken out by Ancillary Service sub-type, where applicable Monitor Resource Status and identify discrepancies between COP and telemetered Resource Status

		Restart Real-Time Sequence on major change of Resource or Transmission Element Status Monitor ERCOT total system capacity providing Ancillary Services Validate COP information Validate Ancillary Service Trades Monitor ERCOT control performance Distribute by ICCP, and post on the ERCOT website, System Lambda and the LMPs for each Resource Node, Load Zone and Hub, and Real-Time MCPCs for each Ancillary Service, and for the pricing run as described in Section 6.5.7.3.1 the total RUC/RMR MW relaxed, total Load Resource MW deployed that is added to the Demand, total ERS MW deployed that is added to the Demand, total TDSP standard offer Load management MW deployed that is added to the Demand, total ERCOT-directed DC Tie MW that is added to or subtracted from the Demand, total BLT MW that is added to or subtracted from the Demand, Real-Time Reliability Deployment Price Adder for Energy, and Real-Time Reliability Deployment Price Adders for Ancillary Service created for each SCED process. These prices shall be posted immediately subsequent to deployment of Base Points and Ancillary Service awards from SCED with the time stamp the prices are effective Post on the ERCOT website the nodal prices for Settlement Only Distribution Generators (SODGs), Settlement Only Distribution Energy Storage Systems (SODESSs), Settlement Only Transmission Generators (SOTGs), and Settlement Only Transmission Energy Storage Systems (SOTESSs). These prices shall include Real-Time Reliability Deployment Price Adders for Energy created for each SCED process. These prices shall be posted immediately subsequent to deployment of Base Points from SCED with the time stamp the prices are effective Post LMPs for each Electrical Bus on the ERCOT website. These prices shall be posted immediately subsequent to

		deployment of Base Points from each binding SCED with the time stamp the prices are effective Post every 15 minutes on the ERCOT website the aggregate net injection from Settlement Only Generators (SOGs) and Settlement Only Energy Storage Systems (SOESSs) Post on the ERCOT website the projected non-binding LMPs for each Resource Node and Real-Time MCPCs for each Ancillary Service created by each SCED process and for the projected non-binding pricing runs as described in Section 6.5.7.3.1 the total RUC/RMR MW relaxed, total Load Resource MW deployed that is added to Demand, total TDSP standard offer Load management MW deployed that is added to the Demand, total ERCOT-directed DC Tie MW that is added to or subtracted from the Demand, total BLT MW that is added to or subtracted from the Demand, total ERS MW deployed that are deployed that is added to the Demand, Real-Time Reliability Deployment Price Adder for Energy, Real-Time On-Line Reliability Deployment Price Adders for Ancillary Service, and the projected Hub LMPs and Load Zone LMPs. These projected prices shall be posted at a frequency of every five minutes from SCED for at least 15 minutes in the future with the time stamp of the SCED process that produced the projections Post on the MIS Certified Area the projected non-binding Base Points and Ancillary Service awards for each Resource created by each SCED process. These projected non-binding Base Points shall be posted at a frequency of every five minutes from SCED for at least 15 minutes in the future with the time stamp of the SCED process that produced the projections. In posting Ancillary Service awards, the awards shall be broken out by Ancillary Service sub-type, where applicable Post each hour on the ERCOT website binding SCED Shadow Prices and active binding transmission constraints by Transmission Element name (contingency /overloaded element pairs)

		Post on the ERCOT website, the Settlement Point Prices for each Settlement Point and the Real-Time price for each SODG, SODESS, SOTG, and SOTESS immediately following the end of each Settlement Interval By Settlement Interval, post the 15-minute Real-Time Reliability Deployment Price for Energy, and the 15-minute Real-Time Reliability Deployment Price for Ancillary Service for each of the Ancillary Services

(3) At the beginning of each hour, ERCOT shall post on the ERCOT website the following information:

(a) Changes in ERCOT System conditions that could affect the security and dynamic transmission limits of the ERCOT System, including:

(i) Changes or expected changes, in the status of Transmission Facilities as recorded in the Outage Scheduler for the remaining hours of the current Operating Day and all hours of the next Operating Day; and

(ii) Any conditions such as adverse weather conditions as determined from the ERCOT-designated weather service;

(b) Updated system-wide Mid-Term Load Forecasts (MTLFs) for all forecast models available to ERCOT Operations, as well as an indicator for which forecast was in use by ERCOT at the time of publication;

(c) The quantities of RMR Services deployed by ERCOT for each previous hour of the current Operating Day; and

(d) Total ERCOT System Demand, from Real-Time operations, integrated over each Settlement Interval.

(4) No later than 0600, ERCOT shall post on the ERCOT website the actual system Load by Weather Zone, the actual system Load by Forecast Zone, and the actual system Load by Study Area for each hour of the previous Operating Day.

(5) ERCOT shall provide notification to the market and post on the ERCOT website Electrical Bus Load distribution factors and other information necessary to forecast Electrical Bus Loads. This report will be published when updates to the Load distribution factors are made. Private Use Network net Load will be redacted from this posting.

[NPRR1010: Insert paragraphs (6) and (7) below upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(6) After every SCED run, ERCOT shall post to the ERCOT website the total capability of Resources available to provide the following Ancillary Service combinations, based on the Resource telemetry from the QSE and capped by the limits of the Resource, for the most recent SCED execution:

(a) Capacity to provide Reg-Up, irrespective of whether it is capable of providing any other Ancillary Service;

(b) Capacity to provide RRS, irrespective of whether it is capable of providing any other Ancillary Service;

(c) Capacity to provide ECRS, irrespective of whether it is capable of providing any other Ancillary Service;

(d) Capacity to provide Non-Spin, irrespective of whether it is capable of providing any other Ancillary Service;

(e) Capacity to provide Reg-Up, RRS, or both, irrespective of whether it is capable of providing ECRS or Non-Spin;

(f) Capacity to provide Reg-Up, RRS, ECRS, or any combination, irrespective of whether it is capable of providing Non-Spin;

(g) Capacity to provide Reg-Up, RRS, ECRS, Non-Spin, or any combination; and

(h) Capacity to provide Reg-Down.

(7) Each week, ERCOT shall post on the ERCOT website the historical SCED-interval data described in paragraph (6) above.

6.4.1 Capacity Trade, Energy Trade, Self-Schedule, and Ancillary Service Trades

(1) A detailed explanation of Capacity Trade criteria and validations performed by ERCOT is provided in Section 4.4.1, Capacity Trades. A Qualified Scheduling Entity (QSE) may submit and update Capacity Trades during the Adjustment Period.

(2) A detailed explanation of Energy Trade criteria and validations performed by ERCOT is provided in Section 4.4.2, Energy Trades. A QSE may submit and update Energy Trades during the Adjustment Period and through 1430 on the day following the Operating Day for Settlement.

(3) A detailed explanation of Self-Schedule criteria and validations performed by ERCOT is provided in Section 4.4.3, Self-Schedules. A QSE may submit and update Self-Schedules during the Adjustment Period.

(4) A detailed explanation of Ancillary Service Trade criteria and validations performed by ERCOT is provided in Section 4.4.7.3, Ancillary Service Trades. A QSE may submit and update Ancillary Service Trades during the Adjustment Period and through the Operating Period for Settlement.

6.4.9.1.3 ~~Replacement of Ancillary Service Due to~~ Failure to Provide Ancillary Service

(1) ERCOT may procure Ancillary Services to replace those of a QSE that has failed ~~on~~to provide its Ancillary Services Supply Responsibility through a SASM, as described below in Section 6.4.9.2, Supplemental Ancillary Services Market.

(2) A QSE is considered to have failed ~~on~~to provide its Ancillary Services Supply Responsibility when ERCOT determines, in its sole discretion, that some or all of the QSE's ~~Resource-specific~~ Ancillary Service capacity will not be available in Real-Time, was not available during any interval for which the QSE had an Ancillary Service Supply Responsibility, or that the QSE assigned all or part of an Ancillary Service Supply Responsibility to a Resource that ~~has~~was not ~~been~~ qualified to provide that Ancillary Service. This Section does not apply to a failure to provide caused by events described in Section 6.4.9.1.2, Replacement of Infeasible Ancillary Service Due to Transmission Constraints.

(3~~2~~) Within a time frame acceptable to ERCOT, each affected QSE may either substitute capacity to meet its Ancillary Services Supply Responsibility or inform ERCOT that the Ancillary Services capacity needs to be replaced. If a QSE elects to substitute capacity, ERCOT shall determine the feasibility of the substitution. If the substitution is deemed infeasible by ERCOT or the QSE informs ERCOT that the Ancillary Services capacity needs to be replaced, then ERCOT shall procure, if in its sole discretion it finds that the service is still needed, the Ancillary Services capacity required under Section 6.4.9.2.

(4~~3~~) ERCOT shall charge each QSE that has failed ~~according to paragraph (1) on~~to provide its Ancillary Service Supply Responsibility, according to paragraph (2) above for a particular Ancillary Service for a specific hour, ~~as~~in the manner described in Section 6.7.3, Charges for a Failure to Provide Ancillary Service.

6.7.3 Charges for a Failure to Provide Ancillary Service ~~Capacity Replaced Due to Failure to Provide~~

(1) A charge to each QSE that fails ~~on~~to provide its Ancillary Service Supply Responsibility, whether or not a SASM is executed due to its failure to ~~supply~~provide, is calculated by service for a given Operating Hour, as follows: ~~calculated based on the greatest of the MCPC in the Day-Ahead Market (DAM) or any SASM for the same Operating Hour. Included in the failed quantity is the charge to each QSE that reduces its Ancillary Service Supply Responsibility by an RSASM, which is calculated based on the cleared~~

~~MCPC associated with the RSASM. By service, the charge to each QSE for a given Operating Hour is calculated as follows:~~

(a) The total charge of failure on Ancillary Service Supply Responsibility for Reg-Up by QSE, if applicable:

$$\mathbf{RUFQAMTQSETOT}_{\boldsymbol{q}} \quad = \quad \mathbf{RUFQAMT}_{\boldsymbol{q}} + \mathbf{RRUFQAMT}_{\boldsymbol{q}}$$

Where:

$$\text{RUFQAMT}_{q} \quad = \quad \text{Max}(\cancel{\underset{m}{\text{Max}}(}\text{MCPCRU}_{m}\cancel{)}, \text{AVGRTASIP}) * (\text{RUFQ}_{q} + \text{TRUFQ}_{q})$$

$$\text{RRUFQAMT}_{q} \quad = \quad \text{MCPCRU}_{rs} * \text{RRUFQ}_{q,\, rs}$$

$$\text{AVGRTASIP} \quad = \quad \sum_{i=1}^{4} (\text{RTRSVPOR}_{i} + \text{RTRDP}_{i}) / 4$$

Where for all Resources:

$$\text{TRUFQ}_{q} = \text{Max}\left([(\text{SARUQ}_{q} + \text{RUTRSQ}_{q} + \sum_{m} (\text{RTPCRU}_{q,\, m}) + \text{PCRU}_{q} + \text{RUCRUQ}_{q}) - (\text{RUTRPQ}_{q} + \text{RUFQ}_{q} + \text{RRUFQ}_{q,\, rs} + \text{RUINFQ}_{q})] - \sum_{r} \text{TELRUR}_{q,\, r}, 0\right)$$

$$\text{SARUQ}_{q} = \text{DASARUQ}_{q} + \text{RTSARUQ}_{q}$$

The above variables are defined as follows:

Variable	Unit	Description
RUFQAMTQSETOT_{q}	$	*Reg-Up Failure Quantity Amount per QSE*—The total charge to QSE *q* for its total capacity associated with failures and reconfiguration reductions on its Ancillary Service Supply Responsibility for Reg-Up, for the hour.
RRUFQAMT_{q}	$	*Reconfiguration Reg-Up Failure Quantity Amount per QSE*—The charge to QSE *q* for its total capacity associated with reconfiguration reductions on its Ancillary Service Supply Responsibility for Reg-Up, for the hour.
RUFQAMT_{q}	$	*Reg-Up Failure Quantity Amount per QSE*—The charge to QSE *q* for its total capacity associated with failures on its Ancillary Service Supply Responsibility for Reg-Up, for the hour.
MCPCRU_{m}	$/MW per hour	*Market Clearing Price for Capacity for Reg-Up by market*—The MCPC for Reg-Up in the market *m*, for the hour.
MCPCRU_{rs}	$/MW per hour	*Market Clearing Price for Capacity for Reg-Up by RSASM*—The MCPC for Reg-Up in the RSASM *rs*, for the hour.
RUFQ_{q}	MW	*Reg-Up Failure Quantity per QSE*—QSE *q* total capacity associated with failures on its Ancillary Service Supply Responsibility for Reg-Up, for the hour.

RRUFQ $_{q,\ rs}$	MW	*Reconfiguration Reg-Up Failure Quantity per QSE*—QSE *q* total capacity associated with reconfiguration reductions on its Ancillary Service Supply Responsibility for Reg-Up, for the hour.
RTRDP $_{i}$	$/MWh	*Real-Time On-Line Reliability Deployment Price*—The Real-Time price for the 15-minute Settlement Interval *i*, reflecting the impact of reliability deployments on energy prices that is calculated from the Real-Time On-Line Reliability Deployment Price Adder.
RTRSVPOR $_{i}$	$/MWh	*Real-Time Reserve Price for On-Line Reserves*—The Real-Time Reserve Price for On-Line Reserves for the 15-minute Settlement Interval *i*.
AVGRTASIP	$/MW per hour	*Average Real-Time Ancillary Service Imbalance Price*– The average of the sum of the Real-Time On-Line Reliability Deployment Price and the Real-Time Reserve Price for On-Line Reserves used in the calculation of Real Time Ancillary Service Imbalance Amount per Section 6.7.5, Real-Time Ancillary Service Imbalance Payment or Charge, for the Operating Hour.
SARUQ $_{q}$	MW	*Total Self-Arranged Reg-Up Quantity per QSE for all markets*—The sum of all self-arranged Reg-Up quantities submitted by QSE *q* for DAM and all SASMs.
RUTRSQ $_{q}$	MW	*Reg-Up Trade Sale per QSE* - QSE *q*'s total time-weighted average capacity Trade Sale for Reg-Up, for the hour. The time-weighted average value is rounded to 0.1 MW.
RTPCRU $_{q,\ m}$	MW	*Procured Capacity for Reg-Up by QSE by market*—The MW portion of QSE *q*'s Ancillary Service Offers cleared in the market *m* (SASM or RSASM) to provide Reg-Up, for the hour.
PCRU $_{q}$	MW	*Procured Capacity for Reg-Up per QSE in DAM*—The total Reg-Up Service capacity quantity awarded to QSE *q* in the DAM for all the Resources represented by the QSE, for the hour.
RUCRUQ $_{q}$	MW	*RUC-committed for Reg-Up per QSE* – The total quantity of Reg-Up Service committed by the RUC Process for Resources represented by QSE *q*, for the hour
RUTRPQ $_{q}$	MW	*Reg-Up Trade Purchases per QSE* - QSE *q*'s total time-weighted average capacity Trade Purchase for Reg-Up, for the hour. The time-weighted average value is rounded to 0.1 MW.
RUINFQ $_{q}$	MW	*Reg-Up Infeasible Quantity per QSE* —QSE *q*'s total capacity associated with infeasible Ancillary Service Supply Responsibilities for Reg-Up, for the hour.
TELRUR $_{q,\ r}$	MW	*Telemetered Reg-Up Responsibility for the Resource* - The time-weighted average telemetered Reg-Up Ancillary Service Resource Responsibility for the Resource *r*, represented by QSE *q*, for the hour. The time-weighted average value is rounded to 0.1 MW.
DASARUQ $_{q}$	MW	*Day-Ahead Self-Arranged Reg-Up Quantity per QSE*—The self-arranged Reg-Up quantity submitted by QSE *q* before 1000 in the Day-Ahead.
RTSARUQ $_{q}$	MW	*Self-Arranged Reg-Up Quantity per QSE for all SASMs*—The sum of all self-arranged Reg-Up quantities submitted by QSE *q* for all SASMs due to an increase in the Ancillary Service Plan per Section 4.4.7.1, Self-Arranged Ancillary Service Quantities.
TRUFQ $_{q}$	MW	*Telemetered Reg-Up Failure Quantity per QSE*— Calculated failure quantity for QSE *q* by comparing its average telemetered Reg-Up Responsibility sum to its Ancillary Service Supply Responsibility for Reg-Up as calculated per paragraph (1) of Section 4.4.7.4, for the hour.
i	none	A 15-minute Settlement Interval within the Operating Hour.
rs	none	The RSASM for the given Operating Hour.

m	none	The DAM, SASM, or RSASM for the given Operating Hour.
q	none	A QSE.
r	none	A Resource that is qualified to provide Reg-Up.

(b) The total charge of failure on Ancillary Service Supply Responsibility for Reg-Down by QSE, if applicable:

$$\mathbf{RDFQAMTQSETOT}_q = \mathbf{RDFQAMT}_q + \mathbf{RRDFQAMT}_q$$

Where:

$$RDFQAMT_q = \text{Max}\,(\cancel{\underset{m}{\text{Max}}(}MCPCRD_m\cancel{)}, AVGRTASIP) * (RDFQ_q + TRDFQ_q)$$

$$RRDFQAMT_q = MCPCRD_{rs} * RRDFQ_{q,\,rs}$$

$$AVGRTASIP = \sum_{i=1}^{4} (RTRSVPOR_i + RTRDP_i) / 4$$

Where for all Resources:

$$TRDFQ_q = \text{Max}\,([(SARDQ_q + RDTRSQ_q + \sum_{m} (RTPCRD_{q,\,m}) + PCRD_q + RUCRDQ_q) - (RDTRPQ_q + RDFQ_q + RRDFQ_q + RDINFQ_q)] - \sum_{r} TELRDR_{q,\,r}, 0)$$

$$SARDQ_q = DASARDQ_q + RTSARDQ_q$$

The above variables are defined as follows:

Variable	Unit	Description
$RDFQAMTQSETOT_q$	$	*Reg-Down Failure Quantity Amount per QSE*—The total charge to QSE *q* for its total capacity associated with failures and reconfiguration reductions on its Ancillary Service Supply Responsibility for Reg-Down, for the hour.
$RRDFQAMT_q$	$	*Reconfiguration Reg-Down Failure Quantity Amount per QSE*—The charge to QSE *q* for its total capacity associated with reconfiguration reductions on its Ancillary Service Supply Responsibility for Reg-Down, for the hour.
$RDFQAMT_q$	$	*Reg-Down Failure Quantity Amount per QSE*—The charge to QSE *q* for its total capacity associated with failures on its Ancillary Service Supply Responsibility for Reg-Down, for the hour.
$MCPCRD_m$	$/MW per hour	*Market Clearing Price for Capacity for Reg-Down by market*—The MCPC for Reg-Down in the market *m*, for the hour.
$MCPCRD_{rs}$	$/MW per hour	*Market Clearing Price for Capacity for Reg-Down by RSASM*—The MCPC for Reg-Down in the RSASM *rs*, for the hour.

RDFQ $_q$	MW	*Reg-Down Failure Quantity per QSE*—QSE *q*'s total capacity associated with failures on its Ancillary Service Supply Responsibility for Reg-Down, for the hour.
RRDFQ $_{q, rs}$	MW	*Reconfiguration Reg-Down Failure Quantity per QSE*—QSE *q*'s total capacity associated with reconfiguration reductions on its Ancillary Service Supply Responsibility for Reg-Down, for the hour.
RTRDP $_i$	$/MWh	*Real-Time On-Line Reliability Deployment Price*—The Real-Time price for the 15-minute Settlement Interval *i*, reflecting the impact of reliability deployments on energy prices that is calculated from the Real-time On-Line Reliability Deployment Price Adder.
RTRSVPOR $_i$	$/MWh	*Real-Time Reserve Price for On-Line Reserves*—The Real-Time Reserve Price for On-Line Reserves for the 15-minute Settlement Interval *i*.
AVGRTASIP	$/MW per hour	*Average Real-Time Ancillary Service Imbalance Price*—The average of the sum of the Real-Time On-Line Reliability Deployment Price and the Real-Time Reserve Price for On-Line Reserves used in the calculation of Real Time Ancillary Service Imbalance Amount per Section 6.7.5 for the Operating Hour.
SARDQ $_q$	MW	*Total Self-Arranged Reg-Down Quantity per QSE for all markets*—The sum of all self-arranged Reg-Down quantities submitted by QSE *q* for DAM and all SASMs.
RDTRSQ $_q$	MW	*Reg-Down Trade Sale per QSE*—QSE *q*'s total time-weighted average capacity Trade Sale for Reg-Down, for the hour. The time-weighted average value is rounded to 0.1 MW.
RTPCRD $_{q, m}$	MW	*Procured Capacity for Reg-Down by QSE by market*—The MW portion of QSE *q*'s Ancillary Service Offers cleared in the market *m* (SASM or RSASM) to provide Reg-Down, for the hour.
PCRD $_q$	MW	*Procured Capacity for Reg-Down per QSE in DAM*—The total Reg-Down capacity quantity awarded to QSE *q* in the DAM for all the Resources represented by the QSE, for the hour.
RUCRDQ $_q$	MW	*RUC-committed for Reg-Down per QSE*—The total quantity of Reg-Down committed by the RUC Process for Resources represented by QSE *q*, for the hour.
RDTRPQ $_q$	MW	*Reg-Down Trade Purchases per QSE*—QSE *q*'s total time-weighted average capacity Trade Purchase for Reg-Down, for the hour. The time-weighted average value is rounded to 0.1 MW.
RDINFQ $_q$	MW	*Reg-Down Infeasible Quantity per QSE*—QSE *q*'s total capacity associated with infeasible Ancillary Service Supply Responsibilities for Reg-Down, for the hour.
TELRDR $_{q, r}$	MW	*Telemetered Reg-Down Responsibility for the Resource*—The time-weighted average telemetered Reg-Down Ancillary Service Resource Responsibility for the Resource *r* that is qualified to provide Reg-Down Ancillary Service, represented by QSE *q*, for the hour. The time-weighted average value is rounded to 0.1 MW.
DASARDQ $_q$	MW	*Day-Ahead Self-Arranged Reg-Down Quantity per QSE*—The self-arranged Reg-Down quantity submitted by QSE *q* before 1000 in the Day-Ahead.
RTSARDQ $_q$	MW	*Self-Arranged Reg-Down Quantity per QSE for all SASMs*—The sum of all self-arranged Reg-Down quantities submitted by QSE *q* for all SASMs due to an increase in the Ancillary Service Plan per Section 4.4.7.1, Self-Arranged Ancillary Service Quantities.
TRDFQ $_q$	MW	*Telemetered Reg-Down Failure Quantity per QSE*—Calculated failure quantity for QSE *q* by comparing its average telemetered Reg-Down Responsibility sum to its Ancillary Service Supply Responsibility for Reg-Down as calculated per paragraph (1) of Section 4.4.7.4, for the hour.
i	none	A 15-minute Settlement Interval within the Operating Hour.

rs	none	The RSASM for the given Operating Hour.
m	none	The DAM, SASM, or RSASM for the given Operating Hour.
q	none	A QSE.
r	none	A Resource that is qualified to provide Reg-Down.

(c) The total charge of failure on Ancillary Service Supply Responsibility for RRS by QSE, if applicable:

$$\textbf{RRFQAMTQSETOT}_{q} = \textbf{RRFQAMT}_{q} + \textbf{RRRFQAMT}_{q}$$

Where:

$$\text{RRFQAMT}_{q} = \text{Max}(\cancel{\underset{m}{Max}(}\text{MCPCRR}_{m}\cancel{)}, \text{AVGRTASIP}) * (\text{RRFQ}_{q} + \text{TRRFQ}_{q})$$

$$\text{RRRFQAMT}_{q} = \text{MCPCRR}_{rs} * \text{RRRFQ}_{q,\,rs}$$

$$\text{AVGRTASIP} = \sum_{i=1}^{4} (\text{RTRSVPOR}_{i} + \text{RTRDP}_{i}) / 4$$

Where for all Resources:

$$\text{TRRFQ}_{q} = \text{Max}(\,[(\text{SARRQ}_{q} + \text{RRTRSQ}_{q} + \sum_{m} (\text{RTPCRR}_{q,\,m}) + \text{PCRR}_{q} + \text{RUCRRQ}_{q}) - (\text{RRTRPQ}_{q} + \text{RRFQ}_{q} + \text{RRRFQ}_{q} + \text{RRINFQ}\cancel{)}_{q})] - \sum_{r} \text{TELRRSRC}_{q,\,r}, 0)$$

Where for Load Resources, other than Controllable Load Resources, during an RRS deployment event:

$\text{TELRRSRC}_{q,\,r} = \text{Min}(\text{NPF}_{q,\,r} - \text{LPC}_{q,\,r}, \text{TELRRSR}_{q,\,r})$ snapshot to be used will be from the time of deployment until 180 minutes after recall or if the time between a recall of Load Resources and a redeployment is less than 180 minutes, the snapshot to be used will be the time of the first deployment

Where for Load Resources, other than Controllable Load Resources, prior to an RRS deployment event:

$$\text{TELRRSRC}_{q,\,r} = \text{Min}(\text{NPF}_{q,\,r} - \text{LPC}_{q,\,r}, \text{TELRRSR}_{q,\,r})$$

$$\text{SARRQ}_{q} = \text{DASARRQ}_{q} + \text{RTSARRQ}_{q}$$

The above variables are defined as follows:

Variable	Unit	Description
RRFQAMTQSETOT $_{q}$	$	*Responsive Reserve Failure Quantity Amount per QSE*—The total charge to QSE *q* for its total capacity associated with failures and reconfiguration

		reductions on its Ancillary Service Supply Responsibility for RRS, for the hour.
RRRFQAMT $_q$	$	*Reconfiguration Responsive Reserve Failure Quantity Amount per QSE*—The charge to QSE *q* for its total capacity associated with reconfiguration reductions on its Ancillary Service Supply Responsibility for RRS, for the hour.
RRFQAMT $_q$	$	*Responsive Reserve Failure Quantity Amount per QSE*—The charge to QSE *q* for its total capacity associated with failures on its Ancillary Service Supply Responsibility for RRS, for the hour.
MCPCRR $_m$	$/MW per hour	*Market Clearing Price for Capacity for Responsive Reserve per market*—The MCPC for RRS in the market *m*, for the hour.
MCPCRR $_{rs}$	$/MW per hour	*Market Clearing Price for Capacity for Responsive Reserve per RSASM*—The MCPC for RRS in the RSASM *rs*, for the hour.
RRFQ $_q$	MW	*Responsive Reserve Failure Quantity per QSE* - QSE *q*'s total capacity associated with failures on its Ancillary Service Supply Responsibility for RRS, for the hour.
RRRFQ $_{q, rs}$	MW	*Reconfiguration Responsive Reserve Failure Quantity per QSE*—QSE *q*'s total capacity associated with reconfiguration reductions on its Ancillary Service Supply Responsibility for RRS, for the hour.
RTRDP $_i$	$/MWh	*Real-Time On-Line Reliability Deployment Price*—The Real-Time price for the 15-minute Settlement Interval *i*, reflecting the impact of reliability deployments on energy prices that is calculated from the Real-time On-Line Reliability Deployment Price Adder.
RTRSVPOR $_i$	$/MWh	*Real-Time Reserve Price for On-Line Reserves*—The Real-Time Reserve Price for On-Line Reserves for the 15-minute Settlement Interval *i*.
AVGRTASIP	$/MW per hour	*Average Real-Time Ancillary Service Imbalance Price*—The average of the sum of the Real-Time On-Line Reliability Deployment Price and the Real-Time Reserve Price for On-Line Reserves used in the calculation of Real Time Ancillary Service Imbalance Amount per Section 6.7.5 for the Operating Hour.
SARRQ $_q$	MW	*Total Self-Arranged Responsive Reserve Quantity per QSE for all markets*—The sum of all self-arranged RRS quantities submitted by QSE *q* for DAM and all SASMs.
RRTRSQ $_q$	MW	*Responsive Reserve Trade Sale per QSE*—QSE *q*'s total time-weighted average capacity Trade Sale for RRS, for the hour. The time-weighted average value is rounded to 0.1 MW.
RTPCRR $_{q, m}$	MW	*Procured Capacity for Responsive Reserve per QSE by market*—The MW portion of QSE *q*'s Ancillary Service Offers cleared in the market *m* (SASM or RSASM) to provide RRS, for the hour.
PCRR $_q$	MW	*Procured Capacity for Responsive Reserve per QSE in DAM*—The total RRS capacity quantity awarded to QSE *q* in the DAM for all the Resources represented by the QSE, for the hour.
RUCRRQ $_q$	MW	*RUC-committed for Responsive Reserve per QSE*—The total quantity of RRS committed by the RUC Process for Resources represented by QSE *q*, for the hour.
RRTRPQ $_q$	MW	*Responsive Reserve Trade Purchases per QSE*—QSE *q*'s total time-weighted average capacity Trade Purchase for RRS, for the hour. The time-weighted average value is rounded to 0.1 MW.

RRINFQ $_q$	MW	*Responsive Reserve Infeasible Quantity per QSE*—QSE *q*'s total capacity associated with infeasible Ancillary Service Supply Responsibilities for RRS, for the hour.
TELRRSR $_{q,r}$	MW	*Telemetered Responsive Reserve Responsibility for the Resource*—The average time-weighted telemetered RRS Ancillary Service Resource Responsibility for the Resource *r*, represented by the QSE *q*, for the hour. The time-weighted average value is rounded to 0.1 MW.
TELRRSRC $_{q,r}$	MW	*Telemetered Responsive Reserve Responsibility for the Resource as Calculated*—The calculated comparison of the time-weighted average telemetered RRS Ancillary Service Resource Responsibility as compared to available capacity for the Resource *r*, represented by the QSE *q*, for the hour.
NPF $_{q,r}$	MW	*Non-Controllable Load Resource Net Power Consumption for the QSE*—The average NPF from Load Resource other than Controllable Load Resources *r*, represented by QSE *q*, for the hour.
LPC $_{q,r}$	MW	*Non-Controllable Load Resource Low Power Consumption for the QSE*—The average LPC from Load Resource other than Controllable Load Resources *r*, represented by QSE *q*, for the hour.
DASARRQ $_q$	MW	*Day-Ahead Self-Arranged Responsive Reserve Quantity per QSE*—The self-arranged RRS quantity submitted by QSE *q* before 1000 in the Day-Ahead.
RTSARRQ $_q$	MW	*Self-Arranged Responsive Reserve Quantity per QSE for all SASMs*—The sum of all self-arranged RRS quantities submitted by QSE *q* for all SASMs due to an increase in the Ancillary Service Plan per Section 4.4.7.1, Self-Arranged Ancillary Service Quantities.
TRRFQ $_q$	MW	*Telemetered Responsive Reserve Failure Quantity per QSE*—Calculated failure quantity for QSE q by comparing its average telemetered Responsive Reserve Responsibility sum to its Ancillary Service Supply Responsibility for RRS as calculated per paragraph (1) of Section 4.4.7.4, for the hour.
i	none	A 15-minute Settlement Interval within the Operating Hour.
rs	none	The RSASM for the given Operating Hour.
m	none	The DAM, SASM, or RSASM for the given Operating Hour.
q	none	A QSE.
r	none	A Resource that is qualified to provide RRS.

(d) The total charge of failure on Ancillary Service Supply Responsibility for Non-Spin by QSE, if applicable:

$$\textbf{NSFQAMTQSETOT}_{q} = \textbf{NSFQAMT}_{q} + \textbf{RNSFQAMT}_{q}$$

Where:

$$\text{NSFQAMT}_{q} = \text{Max}\left(\cancel{\underset{m}{Max}(}\text{MCPCNS}_{m}\cancel{)}, \text{AVGRTASIP}\right) * \left(\text{NSFQ}_{q} + \text{TNSFQ}_{q}\right)$$

$$\text{RNSFQAMT}_{q} = \text{MCPCNS}_{rs} * \text{RNSFQ}_{q,\,rs}$$

$$\text{AVGRTASIP} = \sum_{i=1}^{4} (\text{RTRSVPOR}_{i} + \text{RTRDP}_{i}) / 4$$

Where for all Resources:

$TNSFQ_{q} = Max([(SANSQ_{q} + NSTRSQ_{q} + \sum_{m} (RTPCNS_{q, m}) + PCNS_{q} + RUCNSQ_{q}) – (NSTRPQ_{q} + NSFQ_{q} + RNSFQ_{q} + NSINFQ_{q})] – \sum_{r} TELNSRC_{q, r}, 0)$

Where for Load Resources, other than Controllable Load Resources, during a Non-Spin deployment event:

$TELNSRC_{q, r} = Min(NPF_{q, r} – LPC_{q, r} – TELECRRC_{q, r}, TELNSR_{q, r})$ snapshot to be used will be from the time of deployment until 180 minutes after recall or if the time between a recall of Load Resources and a redeployment is less than 180 minutes, the snapshot to be used will be the time of the first deployment

Where for Load Resources, other than Controllable Load Resources, prior to a Non-Spin deployment event:

$TELNSRC_{q, r} = Min(NPF_{q, r} – LPC_{q, r} – TELECRRC_{q, r}, TELNSR_{q, r})$

$SANSQ_{q} = DASANSQ_{q} + RTSANSQ_{q}$

The above variables are defined as follows:

Variable	Unit	Description
$NSFQAMTQSETOT_{q}$	$	*Non-Spin Failure Quantity Amount per QSE*—The total charge to QSE *q* for its total capacity associated with failures and reconfiguration reductions on its Ancillary Service Supply Responsibility for Non-Spin, for the hour.
$RNSFQAMT_{q}$	$	*Reconfiguration Non-Spin Failure Quantity Amount per QSE*—The charge to QSE *q* for its total capacity associated with reconfiguration reductions on its Ancillary Service Supply Responsibility for Non-Spin, for the hour.
$NSFQAMT_{q}$	$	*Non-Spin Failure Quantity Amount per QSE*—The charge to QSE *q* for its total capacity associated with failures on its Ancillary Service Supply Responsibility for Non-Spin, for the hour.
$MCPCNS_{m}$	$/MW per hour	*Market Clearing Price for Capacity for Non-Spin by market*—The MCPC for Non-Spin in the market *m*, for the hour.
$MCPCNS_{rs}$	$/MW per hour	*Market Clearing Price for Capacity for Non-Spin by RSASM*—The MCPC for Non-Spin in the RSASM *rs*, for the hour.
$NSFQ_{q}$	MW	*Non-Spin Failure Quantity per QSE*—QSE *q*'s total capacity associated with failures on its Ancillary Service Supply Responsibility for Non-Spin, for the hour.
$RNSFQ_{q, rs}$	MW	*Reconfiguration Non-Spin Failure Quantity per QSE*—QSE *q*'s total capacity associated with reconfiguration reductions on its Ancillary Service Supply Responsibility for Non-Spin, for the hour.
$RTRDP_{i}$	$/MWh	*Real-Time On-Line Reliability Deployment Price*—The Real-Time price for the 15-minute Settlement Interval *i*, reflecting the impact of reliability deployments on energy prices that is calculated from the Real-time On-Line Reliability Deployment Price Adder.

RTRSVPOR $_i$	$/MWh	*Real-Time Reserve Price for On-Line Reserves*—The Real-Time Reserve Price for On-Line Reserves for the 15-minute Settlement Interval *i*.
AVGRTASIP	$/MW per hour	*Average Real-Time Ancillary Service Imbalance Price*—The average of the sum of the Real-Time On-Line Reliability Deployment Price and the Real-Time Reserve Price for On-Line Reserves used in the calculation of Real Time Ancillary Service Imbalance Amount per Section 6.7.5 for the Operating Hour.
SANSQ $_q$	MW	*Total Self-Arranged Non-Spin Quantity per QSE for all markets*—The sum of all self-arranged Non-Spin quantities submitted by QSE *q* for DAM and all SASMs.
NSTRSQ $_q$	MW	*Non-Spinning Reserve Trade Sale per QSE*—QSE *q*'s total time-weighted average capacity Trade Sale for Non-Spin, for the hour. The time-weighted average value is rounded to 0.1 MW.
RTPCNS $_{q,m}$	MW	*Procured Capacity for Non-Spin Reserve per QSE by market*—The MW portion of QSE *q*'s Ancillary Service Offers cleared in the market *m* (SASM or RSASM) to provide Non-Spin, for the hour.
PCNS $_q$	MW	*Procured Capacity for Non-Spin Reserve per QSE in DAM*—The total Non-Spin capacity quantity awarded to QSE *q* in the DAM for all the Resources represented by the QSE, for the hour.
RUCNSQ $_q$	MW	*RUC-committed for Non-Spin Reserve per QSE*—The total quantity of Non-Spin committed by the RUC Process for Resources represented by QSE *q*, for the hour.
NSTRPQ $_q$	MW	*Non-Spin Reserve Trade Purchases per QSE*—QSE *q*'s total time-weighted average capacity Trade Purchase for Non-Spin, for the hour. The time-weighted average value is rounded to 0.1 MW.
NSINFQ $_q$	MW	*Non-Spin Reserve Infeasible Quantity per QSE*—QSE *q*'s total capacity associated with infeasible Ancillary Service Supply Responsibilities for Non-Spin, for the hour.
TELNSR $_{q,r}$	MW	*Telemetered Non-Spin Reserve Responsibility for the Resource*—The time-weighted average telemetered Non-Spin Ancillary Service Resource Responsibility for the Resource, for the hour. The time-weighted average value is rounded to 0.1 MW.
TELNSRC $_{q,r}$	MW	*Telemetered Non-Spin Reserve Responsibility for the Resource as Calculated*—The time-weighted average calculated telemetered Non-Spin Ancillary Service Resource Responsibility as compared to available capacity for the Resource, for the hour.
NPF $_{q,r}$	MW	*Non-Controllable Load Resource Net Power Consumption for the QSE*—The average NPF from Load Resource other than Controllable Load Resources *r*, represented by QSE *q*, for the hour.
LPC $_{q,r}$	MW	*Non-Controllable Load Resource Low Power Consumption for the QSE*—The average LPC from Load Resource other than Controllable Load Resources *r*, represented by QSE *q*, for the hour.
DASANSQ $_q$	MW	*Day-Ahead Self-Arranged Non-Spin Reserve Quantity per QSE*—The self-arranged Non-Spin quantity submitted by QSE *q* before 1000 in the Day-Ahead.
RTSANSQ $_q$	MW	*Self-Arranged Non-Spinning Reserve Quantity per QSE for all SASMs*—The sum of all self-arranged Non-Spin quantities submitted by QSE *q* for all SASMs due to an increase in the Ancillary Service Plan per Section 4.4.7.1, Self-Arranged Ancillary Service Quantities.
TELECRRC $_{q,r}$	MW	*Telemetered ERCOT Contingency Reserve Service Responsibility for the Resource as Calculated*—The time-weighted average telemetered ECRS Ancillary Service Resource Responsibility as compared to available capacity for the Resource *r*, represented by QSE *q*, for the hour.

$TNSFQ_{q}$	MW	*Telemetered Non-Spin Failure Quantity per QSE*—Calculated failure quantity for QSE *q* by comparing its average telemetered Non-Spin Responsibility to its Ancillary Service Supply Responsibility for Non-Spin as calculated per paragraph (1) of Section 4.4.7.4, for the hour.
i	none	A 15-minute Settlement Interval within the Operating Hour.
rs	none	The RSASM for the given Operating Hour.
m	none	The DAM, SASM, or RSASM for the given Operating Hour.
q	none	A QSE.
r	none	A Resource that is qualified to provide Non-Spin.

[NPRR863: Insert paragraph (e) below upon system implementation:]

(e) The total charge of failure on Ancillary Service Supply Responsibility for ECRS by QSE, if applicable:

$$\mathbf{ECRFQAMTQSETOT}_{q} = \mathbf{ECRFQAMT}_{q} + \mathbf{RECRFQAMT}_{q}$$

Where:

$$ECRFQAMT_{q} = \text{Max}(\cancel{\underset{m}{\text{Max}}(}MCPCECR_{m}\cancel{)}, AVGRTASIP) * (ECRFQ_{q} + TECRFQ_{q})$$

$$RECRFQAMT_{q} = MCPCECR_{rs} * RECRFQ_{q, rs}$$

$$AVGRTASIP = \sum_{i=1}^{4} (RTRSVPOR_{i} + RTRDP_{i}) / 4$$

Where for all Resources:

$$TECRFQ_{q} = \text{Max}\left([(SAECRQ_{q} + ECRTRSQ_{q} + \sum_{m} (RTPCECR_{q, m}) + PCECR_{q} + RUCECRQ_{q}) - (ECRTRPQ_{q} + ECRFQ_{q} + RECRFQ_{q} + ECRINFQ_{q})] - \sum_{r} TELECRRC_{q, r}, 0\right)$$

Where for Load Resources, other than Controllable Load Resources, during an ECRS deployment event:

$TELECRRC_{q, r} = \text{Min}(NPF_{q, r} - LPC_{q, r}, TELECRR_{q, r})$ snapshot to be used will be from the time of deployment until 180 minutes after recall or if the time between a recall of Load Resources and a redeployment is less than 180 minutes, the snapshot to be used will be the time of the first deployment

Where for Load Resources, other than Controllable Load Resources, prior to an ECRS deployment event:

$$TELECRRC_{q, r} = Min(NPF_{q,r} - LPC_{q, r}, TELECRR_{q, r})$$

$$SAECRQ_{q} = DASAECRQ_{q} + RTSAECRQ_{q}$$

The above variables are defined as follows:

Variable	Unit	Description
$ECRFQAMTQSETOT_{q}$	$	*ERCOT Contingency Reserve Service Failure Quantity Amount per QSE*—The total charge to QSE *q* for its total capacity associated with failures and reconfiguration reductions on its Ancillary Service Supply Responsibility for ECRS, for the hour.
$RECRFQAMT_{q}$	$	*Reconfiguration ERCOT Contingency Reserve Service Failure Quantity Amount per QSE*—The charge to QSE *q* for its total capacity associated with reconfiguration reductions on its Ancillary Service Supply Responsibility for ECRS, for the hour.
$ECRFQAMT_{q}$	$	*ERCOT Contingency Reserve Service Failure Quantity Amount per QSE*—The charge to QSE *q* for its total capacity associated with failures on its Ancillary Service Supply Responsibility for ECRS, for the hour.
$RTRDP_{i}$	$/MWh	*Real-Time On-Line Reliability Deployment Price*—The Real-Time price for the 15-minute Settlement Interval *i*, reflecting the impact of reliability deployments on energy prices that is calculated from the Real-time On-Line Reliability Deployment Price Adder.
$RTRSVPOR_{i}$	$/MWh	*Real-Time Reserve Price for On-Line Reserves*—The Real-Time Reserve Price for On-Line Reserves for the 15-minute Settlement Interval *i*.
AVGRTASIP	$/MW per hour	*Average Real-Time Ancillary Service Imbalance Price*—The average of the sum of the Real-Time On-Line Reliability Deployment Price and the Real-Time Reserve Price for On-Line Reserves used in the calculation of Real Time Ancillary Service Imbalance Amount per Section 6.7.5 for the Operating Hour.
$SAECRQ_{q}$	MW	*Total Self-Arranged ERCOT Contingency Reserve Service Quantity per QSE for all markets*—The sum of all self-arranged ECRS quantities submitted by QSE *q* for DAM and all SASMs.
$ECRTRSQ_{q}$	MW	*ERCOT Contingency Reserve Service ~~Reserve~~ Trade Sale per QSE*—QSE *q's* total time-weighted average capacity Trade Sale for ECRS, for the hour. The time-weighted average value is rounded to 0.1 MW.
$RTPCECR_{q, m}$	MW	*Procured Capacity for ERCOT Contingency Reserve Service per QSE by market*—The MW portion of QSE *q's* Ancillary Service Offers cleared in the market m (SASM or RSASM) to provide ECRS, for the hour.
$PCECR_{q}$	MW	*Procured Capacity for ERCOT Contingency Reserve Service per QSE in DAM*—The total ECRS capacity quantity awarded to QSE *q* in the DAM for all the Resources represented by the QSE, for the hour.
$RUCECRQ_{q}$	MW	*RUC-committed for ERCOT Contingency Reserve Service per QSE*—The total quantity of ECRS committed by the RUC Process for Resources represented by QSE *q*, for the hour.
$ECRTRPQ_{q}$	MW	*ERCOT Contingency Reserve Service Trade Purchases per QSE*—QSE *q's* total time-weighted average capacity Trade Purchase for ECRS, for the hour. The time-weighted average value is rounded to 0.1 MW.
$ECRINFQ_{q}$	MW	*ERCOT Contingency Reserve Service Infeasible Quantity per QSE*—QSE *q's* total capacity associated with infeasible Ancillary Service Supply Responsibilities for ECRS, for the hour.

TELECRR $_{q,\ r}$	MW	*Telemetered ERCOT Contingency Reserve Service Responsibility for the Resource*—The time-weighted average telemetered ECRS Ancillary Service Resource Responsibility for the Resource *r*, represented by QSE *q*, for the hour. The time-weighted average value is rounded to 0.1 MW.
TELECRRC $_{q,\ r}$	MW	*Telemetered ERCOT Contingency Reserve Service Responsibility for the Resource as Calculated*—The time-weighted average telemetered ECRS Ancillary Service Resource Responsibility as compared to available capacity for the Resource *r*, represented by QSE *q*, for the hour.
NPF $_{q,\ r}$	MW	*Non-Controllable Load Resource Net Power Consumption for the QSE*—The average NPF from Load Resource other than Controllable Load Resources *r*, represented by QSE *q*, for the hour.
LPC $_{q,\ r}$	MW	*Non-Controllable Load Resource Low Power Consumption for the QSE*—The average LPC from Load Resource other than Controllable Load Resources *r*, represented by QSE *q*, for the hour.
DASAECRQ $_{q}$	MW	*Day-Ahead Self-Arranged ERCOT Contingency Reserve Service Quantity per QSE*—The self-arranged ECRS quantity submitted by QSE *q* before 1000 in the Day-Ahead.
RTSAECRQ $_{q}$	MW	*Self-Arranged ERCOT Contingency Reserve Service Quantity per QSE for all SASMs*—The sum of all self-arranged ECRS quantities submitted by QSE *q* for all SASMs due to an increase in the Ancillary Service Plan per Section 4.4.7.1.
MCPCECR $_{m}$	$/MW per hour	*Market Clearing Price for Capacity for ERCOT Contingency Reserve Service per market*—The MCPC for ECRS in the market *m*, for the hour.
MCPCECR $_{rs}$	$/MW per hour	*Market Clearing Price for Capacity for ERCOT Contingency Reserve Service per RSASM*—The MCPC for ECRS in the RSASM *rs*, for the hour.
ECRFQ $_{q}$	MW	*ERCOT Contingency Reserve Service Failure Quantity per QSE* - QSE *q*'s total capacity associated with failures on its Ancillary Service Supply Responsibility for ECRS, for the hour.
RECRFQ $_{q,\ rs}$	MW	*Reconfiguration ERCOT Contingency Reserve Service Failure Quantity per QSE*—QSE *q*'s total capacity associated with reconfiguration reductions on its Ancillary Service Supply Responsibility for ECRS, for the hour.
TECRFQ $_{q}$	MW	*Telemetered ERCOT Contingency Reserve Service Failure Quantity per QSE*—Calculated failure quantity for QSE *q* by comparing its average telemetered ECRS Responsibility to its Ancillary Service Supply Responsibility for ECRS as calculated per paragraph (1) of Section 4.4.7.4, for the hour.
i	none	A 15-minute Settlement Interval within the Operating Hour.
rs	none	The RSASM for the given Operating Hour.
m	none	The DAM, SASM, or RSASM for the given Operating Hour.
q	none	A QSE.
r	none	A Resource that is qualified to provide ECRS.

6.7.5 Real-Time Ancillary Service Imbalance Payment or Charge

(1) Based on the Real-Time On-Line Reliability Deployment Price Adders, Real-Time On-Line Reserve Price Adders and a Real-Time Off-Line Reserve Price Adders, ERCOT shall calculate Ancillary Service imbalance Settlement, which will make Resources indifferent to the utilization of their capacity for energy or Ancillary Service reserves, as set forth in this Section.

(2) The payment or charge to each QSE for Ancillary Service imbalance is calculated based on the price calculation set forth in paragraph (12) of Section 6.5.7.3, Security Constrained Economic Dispatch, and applied to the following amounts for each QSE:

(a) The amount of Real-Time Metered Generation from all Generation Resources, represented by the QSE for the 15-minute Settlement Interval;

[NPRR987: Replace paragraph (a) above with the following upon system implementation:]

(a) The amount of Real-Time Metered Generation from all Generation Resources and Energy Storage Resources (ESRs), represented by the QSE for the 15-minute Settlement Interval;

(b) The amount of On-Line capacity based on the telemetered High Sustained Limit (HSL) for all On-Line Generation Resources, the telemetered consumption from Load Resources with a validated Ancillary Service Schedule for RRS controlled by high-set under-frequency relay or Non-Spin, and the capacity from Controllable Load Resources available to SCED;

[NPRR863 and NPRR987: Replace applicable portions of paragraph (b) above with the following upon system implementation:]

(b) The amount of On-Line capacity based on the telemetered High Sustained Limit (HSL) for all On-Line Generation Resources and ESRs, the telemetered consumption from Load Resources with a validated Ancillary Service Schedule for ECRS or RRS controlled by high-set under-frequency relay or Non-Spin, and the capacity from Controllable Load Resources available to SCED, including capacity from modeled Controllable Load Resources associated with ESRs;

(c) The amount of Ancillary Service Resource Responsibility for Reg-Up, RRS and Non-Spin for ~~all Generation and Load Resources represented by~~ the QSE for the 15-minute Settlement Interval.

[NPRR863 and NPRR987: Replace applicable portions of paragraph (c) above with the following upon system implementation:]

(c) The amount of Ancillary Service Resource Responsibility for Reg-Up, ECRS, RRS and Non-Spin for ~~all Generation Resources, ESRs, and Load Resources represented by~~ the QSE for the 15-minute Settlement Interval.

(3) Resources meeting one or more of the following conditions will be excluded from the amounts calculated pursuant to paragraphs (2)(a) and (b) above:

(a) Nuclear Resources;

(b) Resources with a telemetered ONTEST, STARTUP (except Resources with Non-Spin Ancillary Service Resource Responsibility greater than zero), or SHUTDOWN Resource Status excluding Resources telemetering both STARTUP Resource Status and greater than zero Non-Spin Ancillary Service Responsibility; or

[NPRR1085: Replace paragraph (b) above with the following upon system implementation:]

(b) Resources with a telemetered ONTEST, ONHOLD, STARTUP (except Resources with Non-Spin Ancillary Service Resource Responsibility greater than zero), or SHUTDOWN Resource Status excluding Resources telemetering both STARTUP Resource Status and greater than zero Non-Spin Ancillary Service Responsibility; or

(c) Resources with a telemetered net real power (in MW) less than 95% of their telemetered Low Sustained Limit (LSL) excluding Resources telemetering both STARTUP Resource Status and greater than zero Non-Spin Ancillary Service Responsibility.

[NPRR987: Replace paragraph (c) above with the following upon system implementation:]

(c) Resources with a telemetered net real power (in MW) less than 95% of their telemetered Low Sustained Limit (LSL) excluding the following:

(i) Resources telemetering both STARTUP Resource Status and greater than zero Non-Spin Ancillary Service Responsibility; or

(ii) ESRs.

(4) Reliability Must-Run (RMR) Units and Reliability Unit Commitment (RUC) Resources On-Line during the hour due to an ERCOT instruction, except for any RUC Resource committed by a RUC Dispatch Instruction where that Resource's QSE subsequently opted out of RUC Settlement pursuant to paragraph (14) of Section 5.5.2, Reliability Unit Commitment (RUC) Process, those RUC Resources that had a Three-Part Supply Offer cleared in the DAM for the hour, or a Switchable Generation Resource (SWGR) released by a non-ERCOT Control Area Operator (CAO) to operate in the ERCOT Control Area due to an ERCOT RUC instruction for an actual or anticipated Energy Emergency Alert (EEA) condition, and any Combined Cycle Generation Resource that was RUC-committed from one On-Line configuration to a different configuration with additional capacity, as described in paragraph (3) of Section 5.5.2, will be excluded from the amounts calculated for the 15-minute Settlement Interval pursuant to paragraphs (2)(a), (b), and (c) above.

[NPRR885 and NPRR1092: Replace applicable portions of paragraph (4) above with the following upon system implementation:]

(4) Reliability Must-Run (RMR) Units, and Must-Run Alternatives (MRAs), and Reliability Unit Commitment (RUC) Resources On-Line during the hour due to an ERCOT instruction will be excluded from the amounts calculated for the 15-minute Settlement Interval pursuant to paragraphs (2)(a), (b), and (c) above except for:

(a) Those RUC Resources that had a Three-Part Supply Offer cleared in the DAM for the hour;

(b) A Switchable Generation Resource (SWGR) released by a non-ERCOT Control Area Operator (CAO) to operate in the ERCOT Control Area due to an ERCOT RUC instruction for an actual or anticipated Energy Emergency Alert (EEA) condition;

(c) Any Combined Cycle Generation Resource that was RUC-committed from one On-Line configuration to a different configuration with additional capacity, as described in paragraph (3) of Section 5.5.2, Reliability Unit Commitment (RUC) Process; or

(d) Any RUC Resource committed by a RUC Dispatch Instruction where that Resource's QSE subsequently opted out of RUC Settlement pursuant to paragraph (14) of Section 5.5.2.

(5) The Real-Time Off-Line Reserve Capacity for the QSE (RTOFFCAP) shall be administratively set to zero when the SCED snapshot of the Physical Responsive Capability (PRC) is less than or equal to the PRC MW at which EEA Level 1 is initiated.

(6) Resources that have a Under Generation Volume (UGEN) greater than zero, and are not-exempt from a Base Point Deviation Charge, as set forth in Section 6.6.5, Base Point Deviation Charge, or are not already excluded in paragraphs (3) or (4) above, for the 15-

minute Settlement Interval will have the UGEN amounts removed from the amounts calculated pursuant to paragraphs (2)(a) and (b) above.

[NPRR987: Replace paragraph (6) above with the following upon system implementation:]

(6) Resources that have an Under Generation Volume (UGEN) or an Under Performance Volume (UPESR) greater than zero, and are not exempt from a Base Point Deviation Charge, as set forth in Section 6.6.5, Base Point Deviation Charge, or are not already excluded in paragraphs (3) or (4) above, for the 15-minute Settlement Interval will have the UGEN or UPESR amounts removed from the amounts calculated pursuant to paragraphs (2)(a) and (b) above.

(7) The payment or charge to each QSE for the Ancillary Service imbalance for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTASIAMT}_{q} = \mathbf{(-1) * [(RTASOLIMB}_{q} \mathbf{* RTRSVPOR) + (RTASOFFIMB}_{q} \mathbf{* RTRSVPOFF)]}$$

$$\mathbf{RTRDASIAMT}_{q} = \mathbf{(-1) * (RTASOLIMB}_{q} \mathbf{* RTRDP)}$$

Where:

$$\text{RTASOLIMB}_{q} = \text{RTOLCAP}_{q} - [((\text{SYS\_GEN\_DISCFACTOR} * \text{RTASRESP}_{q}) * ¼) - \text{RTASOFF}_{q} - \text{RTRUCNBBRESP}_{q} - \text{RTCLRNSRESP}_{q} - \text{RTNCLRNSRESP}_{q} - \text{RTRMRRESP}_{q}]$$

[NPRR1131: Replace the formula "RTASOLIMB $_{q}$" above with the following upon system implementation:]

$$\text{RTASOLIMB}_{q} = \text{RTOLCAP}_{q} - [((\text{SYS\_GEN\_DISCFACTOR} * \text{RTASRESP}_{q}) * ¼) - \text{RTASOFF}_{q} - \text{RTRUCNBBRESP}_{q} - \text{RTNCLRNSRESP}_{q} - \text{RTRMRRESP}_{q}]$$

Where:

$$\text{RTASOFF}_{q} = \text{SYS\_GEN\_DISCFACTOR} * \sum_{r} \sum_{p} \text{RTASOFFR}_{q, r, p}$$

$$\text{RTRUCNBBRESP}_{q} = \text{SYS\_GEN\_DISCFACTOR} * \sum_{r} \text{RTRUCASA}_{q, r} * ¼$$

$$\text{RTCLRNSRESP}_{q} = \text{SYS\_GEN\_DISCFACTOR} * \sum_{r} \sum_{p} \text{RTCLRNSRESPR}_{q, r, p}$$

[NPRR1131: Delete the formula "RTCLRNSRESP $_q$" above upon system implementation.]

$$RTNCLRNSRESP_{q} = SYS\_GEN\_DISCFACTOR * \sum_{r} \sum_{p} RTNCLRNSRESPR_{q, r, p}$$

$$RTRMRRESP_{q} = SYS\_GEN\_DISCFACTOR * \sum_{q} \sum_{r} \sum_{p} (HRRADJ_{q, r, p} + HRUADJ_{q, r, p} + HNSADJ_{q, r, p}) * ¼$$

[NPRR863: Replace the formula "RTRMRRESP $_q$" above with the following upon system implementation:]

$$RTRMRRESP_{q} = SYS\_GEN\_DISCFACTOR * \sum_{q} \sum_{r} \sum_{p} (HRRADJ_{q, r, p} + HECRADJ_{q, r, p} + HRUADJ_{q, r, p} + HNSADJ_{q, r, p}) * ¼$$

$$RTOLCAP_{q} = (RTOLHSL_{q} - RTMGQ_{q} - SYS\_GEN\_DISCFACTOR * (\sum_{r} \sum_{p} UGENA_{q, r, p})) + RTCLRCAP_{q} + RTNCLRCAP_{q}$$

[NPRR987: Replace the formula "RTOLCAP $_q$" above with the following upon system implementation:]

$$RTOLCAP_{q} = (RTOLHSL_{q} - RTMGQ_{q} - SYS\_GEN\_DISCFACTOR * (\sum_{r} \sum_{p} (UGENA_{q, r, p} + UPESRA_{q, r, p}))) + RTCLRCAP_{q} + RTNCLRCAP_{q} + RTESRCAP_{q}$$

Where:

$$RTNCLRCAP_{q} = Min(Max(RTNCLRNPC_{q} - RTNCLRLPC_{q}, 0.0), RTNCLRRRS_{q} * 1.5)$$

[NPRR863: Replace the formula "RTNCLRCAP $_q$" above with the following upon system implementation:]

$$RTNCLRCAP_{q} = Min(Max(RTNCLRNPC_{q} - RTNCLRLPC_{q}, 0.0), (RTNCLRECRS_{q} + RTNCLRRRS_{q}) * 1.5)$$

$$RTNCLRRRS_{q} = SYS\_GEN\_DISCFACTOR * \sum_{r} \sum_{p} RTNCLRRRSR_{q, r, p}$$

[NPRR863: Insert the formula "RTNCLRECRS $_q$" below upon system implementation:]

$$RTNCLRECRS_{q} = SYS\_GEN\_DISCFACTOR * \sum_{r} \sum_{p} RTNCLRECRSR_{q, r, p}$$

$$RTNCLRNPC_{q} = SYS\_GEN\_DISCFACTOR * \sum_{r} \sum_{p} RTNCLRNPCR_{q, r, p}$$

$$RTNCLRLPC_{q} = SYS\_GEN\_DISCFACTOR * \sum_{r} \sum_{p} RTNCLRLPCR_{q, r, p}$$

$$RTOLHSL_{q} = SYS\_GEN\_DISCFACTOR * \sum_{r} \sum_{p} RTOLHSLRA_{q, r, p}$$

$$RTMGQ_{q} = SYS\_GEN\_DISCFACTOR * \sum_{r} \sum_{p} RTMGA_{q, r, p}$$

If $RTMGA_{q, r, p} > RTOLHSLRA_{q, r, p}$

Then $RTMGA_{q, r, p} = RTOLHSLRA_{q, r, p}$

[NPRR987: Insert the language below upon system implementation:]

Where for a Controllable Load Resource other than a modeled Controllable Load Resource associated with an Energy Storage Resource (ESR):

$$RTCLRCAP_{q} = RTCLRNPC_{q} - RTCLRLPC_{q} - RTCLRNS_{q} + RTCLRREG_{q}$$

[NPRR1131: Replace the formula "RTCLRCAP $_q$" above with the following upon system implementation:]

$$RTCLRCAP_{q} = RTCLRNPC_{q} - RTCLRLPC_{q} + RTCLRREG_{q}$$

$$RTCLRNPC_{q} = SYS\_GEN\_DISCFACTOR * \sum_{r} \sum_{p} RTCLRNPCR_{\mathbf{q, r, p}}$$

$$RTCLRLPC_{q} = SYS\_GEN\_DISCFACTOR * \sum_{r} \sum_{p} RTCLRLPCR_{\mathbf{q, r, p}}$$

$$RTCLRNS_{q} = SYS\_GEN\_DISCFACTOR * \sum_{r} \sum_{p} RTCLRNSR_{\mathbf{q, r, p}}$$

[NPRR1131: Delete the formula "RTCLRNS $_q$" above upon system implementation.]

$$RTCLRREG_q = SYS\_GEN\_DISCFACTOR * \sum_r \sum_p RTCLRREGR_{q,r,p}$$

Where:

$$RTRSVPOR = \sum_y (RNWF_y * RTORPA_y)$$

$$RTASOFFIMB_q = RTOFFCAP_q - (RTASOFF_q + RTCLRNSRESP_q + RTNCLRNSRESP_q)$$

[NPRR1131: Replace the formula "RTASOFFIMB $_q$" above with the following upon system implementation:]

$$RTASOFFIMB_q = RTOFFCAP_q - (RTASOFF_q + RTNCLRNSRESP_q)$$

$$RTOFFCAP_q = (SYS\_GEN\_DISCFACTOR * RTCST30HSL_q) + (SYS\_GEN\_DISCFACTOR * RTOFFNSHSL_q) + RTCLRNS_q + RTNCLRNSCAP_q$$

[NPRR1131: Replace the formula "RTOFFCAP $_q$" above with the following upon system implementation:]

$$RTOFFCAP_q = (SYS\_GEN\_DISCFACTOR * RTCST30HSL_q) + (SYS\_GEN\_DISCFACTOR * RTOFFNSHSL_q) + RTNCLRNSCAP_q$$

$$RTNCLRNSCAP_q = Min(Max(RTNCLRNPC_q - RTNCLRLPC_q, 0.0), RTNCLRNS_q * 1.5)$$

$$RTNCLRNS_q = SYS\_GEN\_DISCFACTOR * \sum_r \sum_p RTNCLRNSR_{q,r,p}$$

$$RTRSVPOFF = \sum_y (RNWF_y * RTOFFPA_y)$$

$$RTRDP = \sum_y (RNWF_y * RTORDPA_y)$$

$$RNWF_y = TLMP_y / \sum_y TLMP_y$$

[NPRR987: Insert the language below upon system implementation:]

Where for an ESR:

$$RTESRCAP_{q} = \sum_{g} (RTESRCAPR_{q,\,g,\,p})$$

Where:

$$RTESRCAPR_{q,\,g,\,p} = \text{Min}[(RTOLHSLRA_{q,\,r,\,p} - RTMGA_{q,\,r,\,p} + RTCLRNPCR_{q,\,r,\,p}), (RTCLRNPCR_{q,\,r,\,p} + SOCT_{q,\,r} - SOCOM_{q,\,r})]$$

The above variables are defined as follows:

Variable	Unit	Description
$RTASIAMT_{q}$	$	*Real-Time Ancillary Service Imbalance Amount*—The total payment or charge to QSE *q* for the Real-Time Ancillary Service imbalance associated with Operating Reserve Demand Curve (ORDC) for each 15-minute Settlement Interval.
$RTRDASIAMT_{q}$	$	*Real-Time Reliability Deployment Ancillary Service Imbalance Amount*—The total payment or charge to QSE *q* for the Real-Time Ancillary Service imbalance associated with Reliability Deployments for each 15-minute Settlement Interval.
$RTASOLIMB_{q}$	MWh	*Real-Time Ancillary Service On-Line Reserve Imbalance for the QSE*—The Real-Time Ancillary Service On-Line reserve imbalance for the QSE *q*, for each 15-minute Settlement Interval.
$RTORPA_{y}$	$/MWh	*Real-Time On-Line Reserve Price Adder per interval*—The Real-Time Price Adder for On-Line Reserves for the SCED interval *y*.
$RTOFFPA_{y}$	$/MWh	*Real-Time Off-Line Reserve Price Adder per interval*—The Real-Time Price Adder for Off-Line Reserves for the SCED interval *y*.
$TLMP_{y}$	second	*Duration of SCED interval per interval*—The duration of the SCED interval *y*.
RTRDP	$/MWh	*Real-Time On-Line Reliability Deployment Price*—The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that is calculated from the Real-Time On-Line Reliability Deployment Price Adder.
$RTORDPA_{y}$	$/MWh	*Real-Time On-Line Reliability Deployment Price Adder*—The Real-Time Price Adder that captures the impact of reliability deployments on energy prices for the SCED interval *y*.
$RNWF_{y}$	none	*Resource Node Weighting Factor per interval*—The weight used in the Resource Node Settlement Point Price calculation for the portion of the SCED interval *y* within the 15-minute Settlement Interval.
RTRSVPOR	$/MWh	*Real-Time Reserve Price for On-Line Reserves*—The Real-Time Reserve Price for On-Line Reserves for the 15-minute Settlement Interval.
RTRSVPOFF	$/MWh	*Real-Time Reserve Price for Off-Line Reserves*—The Real-Time Reserve Price for Off-Line Reserves for the 15-minute Settlement Interval.
$RTOLCAP_{q}$	MWh	*Real-Time On-Line Reserve Capacity for the QSE*—The Real-Time reserve capacity of On-Line Resources available for the QSE *q*, for the 15-minute Settlement Interval.

Variable	Unit	Description
RTOLHSLRA $_{q, r, p}$	MWh	*Real-Time Adjusted On-Line High Sustained Limit for the Resource*—The Real-Time telemetered HSL for the Resource *r* represented by QSE *q* at Resource Node *p* that is available to SCED, integrated over the 15-minute Settlement Interval, and adjusted pursuant to paragraphs (3) and (4) above.
RTOLHSL $_{q}$	MWh	*Real-Time On-Line High Sustained Limit for the QSE*—The Real-Time telemetered HSL for all Generation Resources available to SCED, pursuant to paragraphs (3) and (4) above, integrated over the 15-minute Settlement Interval for the QSE *q*, discounted by the system-wide discount factor. ***[NPRR987: Replace the description above with the following upon system implementation:]*** *Real-Time On-Line High Sustained Limit for the QSE*—The integrated Real-Time telemetered HSL for all Generation Resources, not including modeled Generation Resources associated with ESRs, available to SCED, pursuant to paragraphs (3) and (4) above, integrated over the 15-minute Settlement Interval for the QSE *q*, discounted by the system-wide discount factor.
RTASRESP $_{q}$	MW	*Real-Time Ancillary Service Supply Responsibility for the QSE*—The Real-Time Ancillary Service Supply Responsibility for Reg-Up, RRS and Non-Spin pursuant to Section 4.4.7.4, Ancillary Service Supply Responsibility, ~~for all Generation and Load Resources~~ for the QSE *q*, for the 15-minute Settlement Interval. ***[NPRR863: Replace the description above with the following upon system implementation:]*** *Real-Time Ancillary Service Supply Responsibility for the QSE*—The Real-Time Ancillary Service Supply Responsibility for Reg-Up, ECRS, RRS and Non-Spin pursuant to Section 4.4.7.4, Ancillary Service Supply Responsibility, ~~for all Generation and Load Resources~~ for the QSE *q*, for the 15-minute Settlement Interval.
RTCLRCAP $_{q}$	MWh	*Real-Time Capacity from Controllable Load Resources for the QSE*—The Real-Time capacity and Reg-Up minus Non-Spin available from all Controllable Load Resources available to SCED for the QSE *q*, integrated over the 15-minute Settlement Interval. ***[NPRR987: Replace the description above with the following upon system implementation:]*** *Real-Time Capacity from Controllable Load Resources for the QSE*—The Real-Time capacity and Reg-Up minus Non-Spin available from all Controllable Load Resources, not including modeled Controllable Load Resources associated with ESRs available to SCED for the QSE *q*, integrated over the 15-minute Settlement Interval.

Variable	Unit	Description
$RTNCLRCAP_{q}$	MWh	*Real-Time Capacity from Non-Controllable Load Resources carrying Responsive Reserve for the QSE*—The Real-Time capacity for all Load Resources other than Controllable Load Resources that have a validated Real-Time RRS Ancillary Service Schedule for the QSE *q*, integrated over the 15-minute Settlement Interval. ***[NPRR863: Replace the description above with the following upon system implementation:]*** *Real-Time Capacity from Non-Controllable Load Resources carrying ERCOT Contingency Reserve or Responsive Reserve for the QSE*—The Real-Time capacity for all Load Resources other than Controllable Load Resources that have a validated Real-Time ECRS or RRS Ancillary Service Schedule for the QSE *q*, integrated over the 15-minute Settlement Interval.
$RTNCLRRRS_{q}$	MWh	*Real-Time Non-Controllable Load Resources Responsive Reserve for the QSE*—The validated Real-Time telemetered RRS Ancillary Service Supply Responsibility for all Load Resources other than Controllable Load Resources for QSE *q* discounted by the system-wide discount factor, integrated over the 15-minute Settlement Interval.
$RTNCLRRRSR_{q, r, p}$	MWh	*Real-Time Non-Controllable Load Resource Responsive Reserve*—The validated Real-Time telemetered RRS Ancillary Service Resource Responsibility for the Load Resource *r* (which is not a Controllable Load Resource) represented by QSE *q* at Resource Node *p*, integrated over the 15-minute Settlement Interval.

[NPRR863: Insert the variables "$RTNCLRECRS_{q}$" and "$RTNCLRECRSR_{q, r, p}$" below upon system implementation:]

$RTNCLRECRS_{q}$	MWh	*Real-Time Non-Controllable Load Resources ERCOT Contingency Reserve for the QSE*—The validated Real-Time telemetered ECRS Ancillary Service Supply Responsibility for all Load Resources other than Controllable Load Resources for QSE *q* discounted by the system-wide discount factor, integrated over the 15-minute Settlement Interval.
$RTNCLRECRSR_{q, r, p}$	MWh	*Real-Time Non-Controllable Load Resource ERCOT Contingency Reserve* —The validated Real-Time telemetered ECRS Ancillary Service Resource Responsibility for the Load Resource *r* (which is not a Controllable Load Resource) represented by QSE *q* at Resource Node *p*, integrated over the 15-minute Settlement Interval.

Variable	Unit	Description
RTNCLRNPCR $_{q, r, p}$	MWh	*Real-Time Non-Controllable Load Resource Net Power Consumption*—The Real-Time net real power consumption from the Load Resource *r* (which is not a Controllable Load Resource) represented by QSE *q* at Resource Node *p* that has a validated Real-Time RRS or Non-Spin Ancillary Service Schedule integrated over the 15-minute Settlement Interval. ***[NPRR863: Replace the description above with the following upon system implementation:]*** *Real-Time Non-Controllable Load Resource Net Power Consumption*—The Real-Time net real power consumption from the Load Resource *r* (which is not a Controllable Load Resource) represented by QSE *q* at Resource Node *p* that has a validated Real-Time ECRS, RRS, or Non-Spin Ancillary Service Schedule integrated over the 15-minute Settlement Interval.
RTNCLRLPCR $_{q, r, p}$	MWh	*Real-Time Non-Controllable Load Resource Low Power Consumption*—The Real-Time Low Power Consumption (LPC) from the Load Resource *r* (which is not a Controllable Load Resource) represented by QSE *q* at Resource Node *p* that has a validated Real-Time RRS or Non-Spin Ancillary Service Schedule integrated over the 15-minute Settlement Interval. ***[NPRR863: Replace the description above with the following upon system implementation:]*** *Real-Time Non-Controllable Load Resource Low Power Consumption*—The Real-Time Low Power Consumption (LPC) from the Load Resource *r* (which is not a Controllable Load Resource) represented by QSE *q* at Resource Node *p* that has a validated Real-Time ECRS, RRS, or Non-Spin Ancillary Service Schedule integrated over the 15-minute Settlement Interval
RTNCLRNPC $_{q}$	MWh	*Real-Time Non-Controllable Load Resource Net Power Consumption for the QSE*—The Real-Time net real power consumption from all Load Resources other than Controllable Load Resources for QSE *q* that have a validated Real-Time RRS or Non-Spin Ancillary Service Schedule integrated over the 15-minute Settlement Interval discounted by the system-wide discount factor. ***[NPRR863: Replace the description above with the following upon system implementation:]*** *Real-Time Non-Controllable Load Resource Net Power Consumption for the QSE*—The Real-Time net real power consumption from all Load Resources other than Controllable Load Resources for QSE *q* that have a validated Real-Time ECRS, RRS, or Non-Spin Ancillary Service Schedule integrated over the 15-minute Settlement Interval discounted by the system-wide discount factor.

Variable	Unit	Description
RTNCLRLPC $_{q}$	MWh	*Real-Time Non-Controllable Load Resource Low Power Consumption for the QSE*—The Real-Time LPC from all Load Resources other than Controllable Load Resources for QSE *q* that have a validated Real-Time RRS or Non-Spin Ancillary Service Schedule integrated over the 15-minute Settlement Interval discounted by the system-wide discount factor. ***[NPRR863: Replace the description above with the following upon system implementation:]*** *Real-Time Non-Controllable Load Resource Low Power Consumption for the QSE*—The Real-Time LPC from all Load Resources other than Controllable Load Resources for QSE *q* that have a validated Real-Time ECRS, RRS, or Non-Spin Ancillary Service Schedule integrated over the 15-minute Settlement Interval discounted by the system-wide discount factor.
RTNCLRNSCAP $_{q}$	MWh	*Real-Time Capacity from Non-Controllable Load Resources carrying Non-Spin for the QSE*—The Real-Time capacity for all Load Resources that are not Controllable Load Resources and that have a validated Real-Time Non-Spin Ancillary Service Schedule for the QSE *q*, integrated over the 15-minute Settlement Interval.
RTNCLRNSR $_{q,\,r,\,p}$	MWh	*Real-Time Non-Spin Schedule for the Non-Controllable Load Resource* —The validated Real-Time telemetered Non-Spin Ancillary Service Schedule for the Load Resource *r* that is not a Controllable Load Resources represented by QSE *q* at Resource Node *p*, integrated over the 15-minute Settlement Interval.
RTNCLRNS $_{q}$	MWh	*Real-Time Non-Spin Schedule for Non-Controllable Load Resources for the QSE*—The Real-Time telemetered Non-Spin Ancillary Service Schedule for all Load Resources that are not Controllable Load Resources for the QSE *q*, integrated over the 15-minute Settlement Interval discounted by the system-wide discount factor.
RTNCLRNSRESP $_{q}$	MWh	*Real-Time Non-Controllable Load Resource Non-Spin Responsibility for the QSE*—The Real Time telemetered Non-Spin Ancillary Service Supply Responsibility for all Load Resources that are not Controllable Load Resources discounted by the system-wide discount factor for the QSE *q*, integrated over the 15-minute Settlement Interval.
RTNCLRNSRESPR $_{q,\,r,\,p}$	MWh	*Real-Time Non-Controllable Load Resource Non-Spin Responsibility for the Resource*—The Real-Time telemetered Non-Spin Ancillary Service Resource Responsibility for the Load Resource *r* that is not a Controllable Load Resource represented by QSE *q* at Resource Node *p* integrated over the 15-minute Settlement Interval.

Variable	Unit	Description
RTCLRNPCR $_{q, r, p}$	MWh	*Real-Time Net Power Consumption from the Controllable Load Resource*—The Real-Time net real power consumption from the Controllable Load Resource *r* represented by QSE *q* at Resource Node *p* available to SCED integrated over the 15-minute Settlement Interval. ***[NPRR987: Replace the description above with the following upon system implementation:]*** *Real-Time Net Power Consumption from the Controllable Load Resource*—The Real-Time net real power consumption from the Controllable Load Resource or modeled Controllable Load Resource associated with an ESR, *r* represented by QSE *q* at Resource Node *p* available to SCED integrated over the 15-minute Settlement Interval.
RTCLRNPC $_{q}$	MWh	*Real-Time Net Power Consumption from Controllable Load Resources for the QSE*—The Real-Time net real power consumption from all Controllable Load Resources available to SCED integrated over the 15-minute Settlement Interval for the QSE *q* discounted by the system-wide discount factor. ***[NPRR987: Replace the description above with the following upon system implementation:]*** *Real-Time Net Power Consumption from Controllable Load Resources for the QSE*—The Real-Time net real power consumption from all Controllable Load Resources, not including modeled Controllable Load Resources associated with ESRs, available to SCED integrated over the 15-minute Settlement Interval for the QSE *q* discounted by the system-wide discount factor.
RTCLRLPCR $_{q, r, p}$	MWh	*Real-Time Low Power Consumption for the Controllable Load Resource*—The Real-Time LPC from the Controllable Load Resource *r* represented by QSE *q* at Resource Node *p* available to SCED integrated over the 15-minute Settlement Interval. ***[NPRR987: Replace the description above with the following upon system implementation:]*** *Real-Time Low Power Consumption for the Controllable Load Resource*—The Real-Time LPC from the Controllable Load Resource or modeled Controllable Load Resource associated with an ESR, *r* represented by QSE *q* at Resource Node *p* available to SCED integrated over the 15-minute Settlement Interval.

Variable	Unit	Description
RTCLRLPC $_{q}$	MWh	*Real-Time Low Power Consumption from Controllable Load Resources for the QSE*—The Real-Time LPC from Controllable Load Resources available to SCED integrated over the 15-minute Settlement Interval for the QSE *q* discounted by the system-wide discount factor. ***[NPRR987: Replace the description above with the following upon system implementation:]*** *Real-Time Low Power Consumption from Controllable Load Resources for the QSE*—The Real-Time LPC from Controllable Load Resources, not including modeled Controllable Load Resources associated with ESRs, available to SCED integrated over the 15-minute Settlement Interval for the QSE *q* discounted by the system-wide discount factor.
RTCLRREG $_{q}$	MWh	*Real-Time Controllable Load Resources Regulation-Up Schedule for the QSE*—The Real-Time Reg-Up Ancillary Service Schedule from all Controllable Load Resources not available to SCED with Primary Frequency Response for the QSE *q*, integrated over the 15-minute Settlement Interval discounted by the system-wide discount factor.
RTCLRREGR $_{q, r, p}$	MWh	*Real-Time Controllable Load Resource Regulation-Up Schedule for the Resource*—The validated Real-Time Reg-Up Ancillary Service Schedule for the Controllable Load Resource not available to SCED *r* represented by QSE *q* at Resource Node *p* with Primary Frequency Response, integrated over the 15-minute Settlement Interval.
RTMGA $_{q, r, p}$	MWh	*Real-Time Adjusted Metered Generation per QSE per Settlement Point per Resource*—The adjusted metered generation, pursuant to paragraphs (3) and (4) above, of Generation Resource *r* represented by QSE *q* at Resource Node *p* in Real-Time for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
RTMGQ $_{q}$	MWh	*Real-Time Metered Generation per QSE*—The metered generation, discounted by the system-wide discount factor, of all generation Resources represented by QSE *q* in Real-Time for the 15-minute Settlement Interval, pursuant to paragraphs (3) and (4) above. ***[NPRR987: Replace the description above with the following upon system implementation:]*** *Real-Time Metered Generation per QSE*—The metered generation, discounted by the system-wide discount factor, of all Generation Resources, not including modeled Generation Resources associated with ESRs, represented by QSE *q* in Real-Time for the 15-minute Settlement Interval, pursuant to paragraphs (3) and (4) above.

Variable	Unit	Description
[NPRR987: Insert the variables "RTESRCAPR $_{q, g, p}$", "RTESRCAP $_{q}$", "SOCT $_{q, r}$", and "SOCOM $_{q, r}$" below upon system implementation:]		
RTESRCAPR $_{q, g, p}$	MWh	*Real-Time Capacity from an Energy Storage Resource* – Capacity provided by an ESR *g*, represented by QSE *q* at Resource Node *p,* which considers energy limitations of the ESR and potentially higher contribution when charging for the15-minute Settlement Interval.
RTESRCAP $_{q}$	MWh	*Real-Time Capacity from Energy Storage Resources per QSE* – Capacity provided by all ESRs, represented by QSE *q*, for the 15-minute Settlement Interval.
SOCT $_{q, r}$	MWh	*State of Charge Telemetered by an Energy Storage Resource* – The average telemetered state of charge of Resource *r*, represented by QSE *q*, over the 15-minute Settlement Interval.
SOCOM $_{q, r}$	MWh	*State of Charge Operating Minimum for an Energy Storage Resource* –The average telemetered state of charge operating minimum of Resource *r*, represented by QSE *q*, over the 15-minute Settlement Interval.
RTASOFFIMB $_{q}$	MWh	*Real-Time Ancillary Service Off-Line Reserve Imbalance for the QSE*—The Real-Time Ancillary Service Off-Line reserve imbalance for the QSE *q*, for each 15-minute Settlement Interval.
RTOFFCAP $_{q}$	MWh	*Real-Time Off-Line Reserve Capacity for the QSE*—The Real-Time reserve capacity of Off-Line Resources available for the QSE *q*, for the 15-minute Settlement Interval. ***[NPRR1069: Replace the description above with the following upon system implementation of NPRR987:]*** *Real-Time Off-Line Reserve Capacity for the QSE*—The Real-Time reserve capacity of Off-Line Resources, not including modeled Generation Resources associated with ESRs, available for the QSE *q*, for the 15-minute Settlement Interval.

Variable	Unit	Description
RTCST30HSL $_{q}$	MWh	*Real-Time Generation Resources with Cold Start Available in 30 Minutes*—The Real-Time telemetered HSLs of Generation Resources, excluding Intermittent Renewable Resources (IRRs), that have telemetered an OFF Resource Status and can be started from a cold temperature state in 30 minutes for the QSE *q*, time-weighted over the 15-minute Settlement Interval. ***[NPRR1069: Replace the description above with the following upon system implementation of NPRR987:]*** *Real-Time Generation Resources with Cold Start Available in 30 Minutes*—The Real-Time telemetered HSLs of Generation Resources, excluding Intermittent Renewable Resources (IRRs) and modeled Generation Resources associated with ESRs, that have telemetered an OFF Resource Status and can be started from a cold temperature state in 30 minutes for the QSE *q*, time-weighted over the 15-minute Settlement Interval.
RTOFFNSHSL $_{q}$	MWh	*Real-Time Generation Resources with Off-Line Non-Spin Schedule*—The Real-Time telemetered HSLs of Generation Resources that have telemetered an OFFNS Resource Status for the QSE *q*, time-weighted over the 15-minute Settlement Interval. ***[NPRR1069 and NPRR1135: Replace applicable portions of the description above with the following upon system implementation of NPRR987 for NPRR1069; or upon system implementation for NPRR1135:]*** *Real-Time Generation Resources with Off-Line Non-Spin Schedule*—The Real-Time telemetered HSLs of Off-Line Generation Resources, not including modeled Generation Resources associated with ESRs, that have telemetered an OFFNS Resource Status for the QSE *q*, time-weighted over the 15-minute Settlement Interval.
RTASOFFR $_{q, r, p}$	MWh	*Real-Time Ancillary Service Schedule for the Off-Line Generation Resource*—The validated Real-Time telemetered Ancillary Service Schedule for the Off-Line Generation Resource *r* represented by QSE *q* at Resource Node *p*, integrated over the 15-minute Settlement Interval.

Variable	Unit	Description
RTASOFF $_{q}$	MWh	*Real-Time Ancillary Service Schedule for Off-Line Generation Resources for the QSE*—The Real-Time telemetered Ancillary Service Schedule for all Off-Line Generation Resources discounted by the system-wide discount factor for the QSE *q*, integrated over the 15-minute Settlement Interval. ***[NPRR1069: Replace the description above with the following upon system implementation of NPRR987:]*** *Real-Time Ancillary Service Schedule for Off-Line Generation Resources for the QSE*—The Real-Time telemetered Ancillary Service Schedule for all Off-Line Generation Resources, not including modeled Generation Resources associated with ESRs, discounted by the system-wide discount factor for the QSE *q*, integrated over the 15-minute Settlement Interval.
HRRADJ $_{q, r, p}$	MW	*Ancillary Service Resource Responsibility Capacity for Responsive Reserve at Adjustment Period*—The RRS Ancillary Service Resource Responsibility for the Resource *r* represented by QSE *q* at Resource Node *p* as seen in the last Current Operating Plan (COP) and Trades Snapshot at the end of the Adjustment Period, for the hour that includes the 15-minute Settlement Interval.
[NPRR863: Insert the variable "HECRADJ $_{q, r, p}$" below upon system implementation:]		
HECRADJ $_{q, r, p}$	MW	*Ancillary Service Resource Responsibility Capacity for ERCOT Contingency Reserve Service at Adjustment Period*—The ECRS Ancillary Service Resource Responsibility for the Resource *r* represented by QSE *q* at Resource Node *p* as seen in the last Current Operating Plan (COP) and Trades Snapshot at the end of the Adjustment Period, for the hour that includes the 15-minute Settlement Interval.
HRUADJ $_{q, r, p}$	MW	*Ancillary Service Resource Responsibility Capacity for Reg-Up at Adjustment Period*—The Regulation Up Ancillary Service Resource Responsibility for the Resource *r* represented by QSE *q* at Resource Node *p* as seen in the last COP and Trades Snapshot at the end of the Adjustment Period, for the hour that includes the 15-minute Settlement Interval.
HNSADJ $_{q, r, p}$	MW	*Ancillary Service Resource Responsibility Capacity for Non-Spin at Adjustment Period*—The Non-Spin Ancillary Service Resource Responsibility for the Resource *r* represented by QSE *q* at Resource Node *p* as seen in the last COP and Trades Snapshot at the end of the Adjustment Period, for the hour that includes the 15-minute Settlement Interval.

Variable	Unit	Description
RTRUCNBBRESP $_q$	MWh	*Real-Time RUC Ancillary Service Supply Responsibility for the QSE in Non-Buy-Back hours*—The Real-Time Ancillary Service Supply Responsibility for Reg-Up, RRS and Non-Spin pursuant to the Ancillary Service awards, for the 15-minute Settlement Interval that falls within a RUC-Committed Hour, discounted by the system-wide discount factor for the QSE *q*. ***[NPRR863: Replace the description above with the following upon system implementation:]*** *Real-Time RUC Ancillary Service Supply Responsibility for the QSE in Non-Buy-Back hours*—The Real-Time Ancillary Service Supply Responsibility for Reg-Up, ECRS, RRS, and Non-Spin pursuant to the Ancillary Service awards, for the 15-minute Settlement Interval that falls within a RUC-Committed Hour, discounted by the system-wide discount factor for the QSE *q*.
RTRUCASA $_{q,\ r}$	MW	*Real-Time RUC Ancillary Service Awards*—The Real-Time Ancillary Service award to the RUC Resource *r* for Reg-Up, RRS, and Non-Spin for the hour that includes the 15-minute Settlement Interval that falls within a RUC-Committed Hour for the QSE *q*. ***[NPRR863: Replace the description above with the following upon system implementation:]*** *Real-Time RUC Ancillary Service Awards*—The Real-Time Ancillary Service award to the RUC Resource *r* for Reg-Up, ECRS, RRS, and Non-Spin for the hour that includes the 15-minute Settlement Interval that falls within a RUC-Committed Hour for the QSE *q*.
RTCLRNSRESP $_q$	MWh	*Real-Time Controllable Load Resource Non-Spin Responsibility for the QSE*—The Real Time telemetered Non-Spin Ancillary Service Supply Responsibility for all Controllable Load Resources available to SCED discounted by the system-wide discount factor for the QSE *q*, integrated over the 15-minute Settlement Interval. ***[NPRR1069: Replace the description above with the following upon system implementation of NPRR987:]*** *Real-Time Controllable Load Resource Non-Spin Responsibility for the QSE*—The Real Time telemetered Non-Spin Ancillary Service Supply Responsibility for all Controllable Load Resources, not including modeled Controllable Load Resources associated with ESRs, available to SCED discounted by the system-wide discount factor for the QSE *q*, integrated over the 15-minute Settlement Interval.

Variable	Unit	Description
[NPRR1131: Delete the variable "RTCLRNSRESP $_{q}$" above upon system implementation.]		
RTCLRNSRESPR $_{q, r, p}$	MWh	*Real-Time Controllable Load Resource Non-Spin Responsibility for the Resource*—The Real-Time telemetered Non-Spin Ancillary Service Resource Responsibility for the Controllable Load Resource *r* represented by QSE *q* at Resource Node *p* available to SCED, integrated over the 15-minute Settlement Interval. ***[NPRR1069: Replace the description above with the following upon system implementation of NPRR987:]*** *Real-Time Controllable Load Resource Non-Spin Responsibility for the Resource*—The Real-Time telemetered Non-Spin Ancillary Service Resource Responsibility for the Controllable Load Resource *r* or modeled Controllable Load Resource associated with an ESR represented by QSE *q* at Resource Node *p* available to SCED, integrated over the 15-minute Settlement Interval.
[NPRR1131: Delete the variable "RTCLRNSRESPR $_{q, r, p}$" above upon system implementation.]		
RTRMRRESP $_{q}$	MWh	*Real-Time Ancillary Service Supply Responsibility for RMR Units represented by the QSE*—The Real-Time Ancillary Service Supply Responsibility as set forth in the end of the Adjustment Period COP for Reg-Up, RRS, and Non-Spin for all RMR Units discounted by the system-wide discount factor for the QSE *q*, integrated over the 15-minute Settlement Interval. ***[NPRR863: Replace the description above with the following upon system implementation:]*** *Real-Time Ancillary Service Supply Responsibility for RMR Units represented by the QSE*—The Real-Time Ancillary Service Supply Responsibility as set forth in the end of the Adjustment Period COP for Reg-Up, ECRS, RRS, and Non-Spin for all RMR Units discounted by the system-wide discount factor for the QSE *q*, integrated over the 15-minute Settlement Interval.

Variable	Unit	Description
RTCLRNSR $_{q, r, p}$	MWh	*Real-Time Non-Spin Schedule for the Controllable Load Resource*—The validated Real-Time telemetered Non-Spin Ancillary Service Schedule for the Controllable Load Resource *r* represented by QSE *q* at Resource Node *p*, integrated over the 15-minute Settlement Interval. ***[NPRR987: Replace the description above with the following upon system implementation:]*** *Real-Time Non-Spin Schedule for the Controllable Load Resource* —The validated Real-Time telemetered Non-Spin Ancillary Service Schedule for the Controllable Load Resource or modeled Controllable Load Resource associated with an ESR, *r* represented by QSE *q* at Resource Node *p*, integrated over the 15-minute Settlement Interval.
[NPRR1131: Delete the variable "RTCLRNSR $_{q, r, p}$" above upon system implementation.]		
RTCLRNS $_{q}$	MWh	*Real-Time Non-Spin Schedule for Controllable Load Resources for the QSE*—The Real-Time telemetered Non-Spin Ancillary Service Schedule for all Controllable Load Resources for the QSE *q*, integrated over the 15-minute Settlement Interval discounted by the system-wide discount factor. ***[NPRR987: Replace the description above with the following upon system implementation:]*** *Real-Time Non-Spin Schedule for Controllable Load Resources for the QSE*—The Real-Time telemetered Non-Spin Ancillary Service Schedule for all Controllable Load Resources, not including modeled Controllable Load Resources associated with ESRs, for the QSE *q*, integrated over the 15-minute Settlement Interval discounted by the system-wide discount factor.
[NPRR1131: Delete the variable "RTCLRNS $_{q}$" above upon system implementation.]		
SYS_GEN_DISCFACTOR	none	*System-Wide Discount Factor* – The system-wide discount factor used to discount inputs used in the calculation of Real-Time Ancillary Services Imbalance payment or charge is calculated as the average of the currently approved Reserve Discount Factors (RDFs) applied to the temperatures from the current Season from the year prior.
UGEN $_{q, r, p}$	MWh	*Under Generation Volumes per QSE per Settlement Point per Resource*—The amount under-generated by the Generation Resource *r* represented by QSE *q* at Resource Node *p* for the 15-minute Settlement Interval.
UGENA $_{q, r, p}$	MWh	*Adjusted Under Generation Volumes per QSE per Settlement Point per Resource*—The amount under-generated by the Generation Resource *r* represented by QSE *q* at Resource Node *p* for the 15-minute Settlement Interval adjusted pursuant to paragraph (6) above.

Variable	Unit	Description
[NPRR987: Insert the variables "UPESR $_{q, r, p}$" and "UPESRA $_{q, r, p}$" below upon system implementation:]		
UPESR $_{q, r, p}$	MWh	*Under-Performance Volumes per QSE per Settlement Point per Resource*—The amount the ESR under-performed divided evenly among the modeled Generation and Controllable Load Resources *r* in the ESR, represented by QSE *q* at Resource Node *p*, for the 15-minute Settlement Interval.
UPESRA $_{q, r, p}$	MWh	*Adjusted Under-Performance Volumes per QSE per Settlement Point per Resource* — The amount the ESR under-performed divided evenly among the modeled Generation and Controllable Load Resources *r* in the ESR, represented by QSE *q* at Resource Node *p*, for the 15-minute Settlement Interval adjusted pursuant to paragraph (6) above.
r	none	A Generation or Load Resource.
y	none	A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.
q	none	A QSE.
p	none	A Resource Node Settlement Point.
[NPRR987: Insert the variable "g" below upon system implementation:]		
g	none	An ESR.

(8) The payment to each QSE for the Ancillary Service reserves associated with RUC Resources that have received a RUC Dispatch to provide Ancillary Services in which the 15-minute Settlement Interval is part of a RUC Buy-Back Hour based on the RUC opt out provision set forth in paragraph (14) of Section 5.5.2 for a given 15-minute Settlement Interval is calculated as follows:

$$\textbf{RTRUCRSVAMT}_{q} = \textbf{(-1) * (RTRUCRESP}_{q} \textbf{ * RTRSVPOR)}$$

$$\textbf{RTRDRUCRSVAMT}_{q} = \textbf{(-1) * (RTRUCRESP}_{q} \textbf{ * RTRDP)}$$

Where:

$$\text{RTRUCRESP}_{q} = \sum_{r} \text{RTRUCASA}_{q, r} * 1/4$$

The above variables are defined as follows:

Variable	Unit	Description
RTRUCRSVAMT $_{q}$	$	*Real-Time RUC Ancillary Service Reserve Amount*—The total payment |to QSE *q* for the Real-Time RUC Ancillary Service Reserve payment associated with ORDC for each 15-minute Settlement Interval.

Variable	Unit	Description
RTRDRUCRSVAMT $_q$	$	*Real-Time Reliability Deployment RUC Ancillary Service Reserve Amount*—The total payment |to QSE *q* for the Real-Time RUC Ancillary Service Reserve payment associated with reliability deployments for each 15-minute Settlement Interval.
RTRUCRESP $_q$	MWh	*Real-Time RUC Ancillary Service Supply Responsibility for the QSE*—The Real-Time Ancillary Service Supply Responsibility pursuant to the Ancillary Service awards for Reg-Up, RRS, and Non-Spin for all RUC Resources that have opted out per paragraph (14) of Section 5.5.2 for the QSE *q*, for the 15-minute Settlement Interval. ***[NPRR863: Replace the description above with the following upon system implementation:]*** *Real-Time RUC Ancillary Service Supply Responsibility for the QSE*—The Real-Time Ancillary Service Supply Responsibility pursuant to the Ancillary Service awards for Reg-Up, ECRS, RRS, and Non-Spin for all RUC Resources that have opted out per paragraph (14) of Section 5.5.2 for the QSE *q*, for the 15-minute Settlement Interval.
RTRUCASA $_{q,\,r}$	MW	*Real-Time RUC Ancillary Service Awards*—The Real-Time Ancillary Service award to the RUC Resource *r* for Reg-Up, RRS, and Non-Spin for the 15-minute Settlement Interval that falls within a RUC-Committed Hour for the QSE *q*. ***[NPRR863: Replace the description above with the following upon system implementation:]*** *Real-Time RUC Ancillary Service Awards*—The Real-Time Ancillary Service award to the RUC Resource *r* for Reg-Up, ECRS, RRS, and Non-Spin for the 15-minute Settlement Interval that falls within a RUC-Committed Hour for the QSE *q*.
RTRSVPOR	$/MWh	*Real-Time Reserve Price for On-Line Reserves*—The Real-Time Reserve Price for On-Line Reserves for the 15-minute Settlement Interval.
RTRDP	$/MWh	*Real-Time On-Line Reliability Deployment Price* —The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that is calculated from the Real-Time On-Line Reliability Deployment Price Adder.
q	none	A QSE.
r	none	A Generation Resource.

ERCOT Impact Analysis Report

NPRR Number	**1149**	**NPRR Title**	**Implementation of Systematic Ancillary Service Failed Quantity Charges**
Impact Analysis Date	September 20, 2022		
Estimated Cost/Budgetary Impact	Between $120k and $160k		
Estimated Time Requirements	The timeline for implementing this Nodal Protocol Revision Request (NPRR) is dependent upon Public Utility Commission of Texas (PUCT) prioritization and approval. Estimated project duration: 6 to 8 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: • Settlements & Billing Systems 71% • Market Operation Systems 22% • Data Management & Analytic Systems 7%		
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

NPRR Number	1151	NPRR Title	Protocol Revision Subcommittee Meeting Requirement
Date of Decision	February 28, 2023		
Action	Recommended Approval		
Timeline	Normal		
Proposed Effective Date	April 1, 2023		
Priority and Rank Assigned	Not applicable		
Nodal Protocol Sections Requiring Revision	21.3, Protocol Revision Subcommittee		
Related Documents Requiring Revision/Related Revision Requests	None		
Revision Description	This Nodal Protocol Revision Request (NPRR) eliminates the Protocol requirement to hold at least one Protocol Revision Subcommittee (PRS) meeting per month.		
Reason for Revision	☐ Addresses current operational issues. ☐ Meets Strategic goals (tied to the ERCOT Strategic Plan or directed by the ERCOT Board). ☒ Market efficiencies or enhancements ☐ Administrative ☐ Regulatory requirements ☐ Other: (explain) *(please select all that apply)*		
Business Case	As a measure to improve stakeholder process efficiency and as part of the 2022 TAC/TAC Subcommittee Structural and Procedural Review process, PRS discussed the possibility of removing the Protocol requirement for PRS to meet at least once per month. Currently PRS is the only subcommittee that is required per Protocols to meet monthly.		
PRS Decision	On 11/11/22, PRS voted unanimously to recommend approval of NPRR1151 as submitted. All Market Segments participated in the		

	vote. On 12/8/22, PRS voted unanimously to endorse and forward to TAC the 11/11/22 PRS Report and 11/22/22 Impact Analysis for NPRR1151. All Market Segments participated in the vote.
Summary of PRS Discussion	On 11/11/22, the sponsor provided an overview of NPRR1151. On 12/8/22, there was no discussion.
TAC Decision	On 1/24/23, TAC voted unanimously to recommend approval of NPRR1151 as recommended by PRS in the 12/8/22 PRS Report. All Market Segments participated in the vote.
Summary of TAC Discussion	On 1/24/23, TAC reviewed the ERCOT Opinion, ERCOT Market Impact Statement, and Independent Market Monitor (IMM) Opinion for NPRR1151.
ERCOT Board Decision	On 2/28/23, the ERCOT Board voted unanimously to recommend approval of NPRR1151 as recommended by TAC in the 1/24/23 TAC Report.

Opinions	
Credit Review	ERCOT Credit Staff and the Credit Work Group (Credit WG) have reviewed NPRR1151 and do not believe that it requires changes to credit monitoring activity or the calculation of liability.
Independent Market Monitor Opinion	IMM has no opinion on NPRR1151.
ERCOT Opinion	ERCOT supports approval of NPRR1151.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NPRR1151 and believes the market impact for NPRR1151 improves efficiency by providing the same meeting flexibility to PRS as other subcommittees and TAC.

Sponsor	
Name	Martha Henson
E-mail Address	Martha.henson@oncor.com
Company	Oncor Electric Delivery Company LLC
Phone Number	214-536-9004
Cell Number	
Market Segment	Investor Owned Utility (IOU)

Board Report

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

Comments Received	
Comment Author	**Comment Summary**
None	

Market Rules Notes

None

Proposed Protocol Language Revision

21.3 Protocol Revision Subcommittee

(1) The Protocol Revision Subcommittee (PRS) shall review and recommend action on formally submitted Nodal Protocol Revision Requests (NPRRs) and System Change Requests (SCRs) ("Revision Requests") provided that:

(a) PRS meetings are open to ERCOT, ERCOT Members, Market Participants, the Reliability Monitor, the North American Electric Reliability Corporation (NERC) Regional Entity, the Independent Market Monitor (IMM), and the Public Utility Commission of Texas (PUCT) Staff;

(b) Each Market Segment is allowed to participate; and

(c) Each Market Segment has equal voting power.

(2) Where additional expertise is needed, the PRS may refer a Revision Request to working groups or task forces that it creates or to existing Technical Advisory Committee (TAC) subcommittees, working groups or task forces for review and comment on the Revision Request. Suggested modifications—or alternative modifications if a consensus recommendation is not achieved by a non-voting working group or task force—to the Revision Request should be submitted by the chair or the chair's designee on behalf of the subcommittee, working group or task force as comments on the Revision Request for consideration by PRS. However, the PRS shall retain ultimate responsibility for the processing of all Revision Requests.

(3) ERCOT shall consult with the PRS chair to coordinate and establish the meeting schedule for the PRS. The PRS shall ~~meet at least once per month and shall~~ ensure that reasonable

advance notice of each meeting, including the meeting agenda, is posted on the ERCOT website.

ERCOT Impact Analysis Report

NPRR Number	1151	NPRR Title	Protocol Revision Subcommittee Meeting Requirement
Impact Analysis Date	November 22, 2022		
Estimated Cost/Budgetary Impact	None.		
Estimated Time Requirements	No project required. This Nodal Protocol Revision Request (NPRR) 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

NPRR Number	1153	NPRR Title	ERCOT Fee Schedule Changes
Date of Decision	February 28, 2023		
Action	Recommended Approval		
Timeline	Normal		
Proposed Effective Date	Phase 1 – April 1, 2023 Phase 2 – Upon system implementation		
Priority and Rank Assigned	Priority – 2023; Rank – 3790		
Nodal Protocol Sections Requiring Revision	9.16.2, User Fees ERCOT Fee Schedule Section 23, Form G, QSE Application and Service Filing for Registration Form Section 23, Form I, Resource Entity Application for Registration Section 23, Form J, Transmission and/or Distribution Service Provider Application for Registration		
Related Documents Requiring Revision/Related Revision Requests	None		
Revision Description	This Nodal Protocol Revision Request (NPRR) changes the ERCOT Fee Schedule by: 1) Adding two currently existing fees to the ERCOT Fee Schedule (public information request labor fees and ERCOT training fees); 2) Creating a registration fee of $500 for Resource Entities, Transmission or Distribution Service Providers (TDSPs), and Subordinate Qualified Scheduling Entities (Sub-QSEs); 3) Removing the current value of the ERCOT System Administration Fee; 4) Deleting the map sales fee; and 5) Restructuring three existing fees on the Fee Schedule (Generator Interconnection or Modification (GIM) fees, Full Interconnection Study (FIS) Application fees, and Wide Area Network (WAN) fees).		
Reason for Revision	☐ Addresses current operational issues. ☐ Meets Strategic goals (tied to the ERCOT Strategic Plan or directed by the ERCOT Board).		

Board Report

	☐ Market efficiencies or enhancements ☒ Administrative ☒ Regulatory requirements ☐ Other: (explain) *(please select all that apply)*
Business Case	This NPRR makes necessary changes to the ERCOT Fee Schedule which include adding existing fees that are not currently listed on the ERCOT Fee Schedule, deleting outdated fees, creating registration fees for a few Market Participant categories that currently do not pay the same registration fees charged to all other Market Participants, and restructuring certain fees to account for changes in costs or effort. This NPRR deletes the ERCOT System Administration fee because it is governed by subsection (e) of P.U.C. SUBST. R. 25.363, ERCOT Budget and Fees, and changes to the fee require Public Utility Commission of Texas (PUCT) approval as opposed to user fees which are approved through the ERCOT stakeholder process and the ERCOT Board of Directors. This NPRR also proposes changes to GIM fees and FIS Application fees to account for new categories of Resources that were not contemplated under the prior fee structure and increases in costs. Changes to the structure of the WAN fees are needed because the current structure caps the amount of charges from third-party vendors that ERCOT can recover. The WAN fee has not been changed in over a decade and third-party costs have increased over the years.
PRS Decision	On 11/11/22, PRS voted unanimously to table NPRR1153. All Market Segments participated in the vote. On 12/8/22, PRS voted unanimously to recommend approval of NPRR1153 as amended by the 11/2/22 ERCOT comments. All Market Segments participated in the vote. On 1/17/23, PRS voted unanimously to endorse and forward to TAC the 12/8/22 PRS Report as amended by the 12/12/22 ERCOT comments and 12/13/22 Revised Impact Analysis for NPRR1153 with a proposed effective date of April 1, 2023 for Phase 1 and upon system implementation for Phase 2 with a recommended priority of 2023 and rank of 3790. All Market Segments participated in the vote.
Summary of PRS Discussion	On 11/11/22, ERCOT Staff provided an overview of NPRR1153. Participants requested tabling to allow additional time to review.

	On 12/8/22, there was no discussion. On 1/17/23, participants reviewed the 12/12/22 ERCOT comments and 12/13/22 Revised Impact Analysis for NPRR1153.
TAC Decision	On 1/24/23, TAC voted unanimously to recommend approval of NPRR1153 as recommended by PRS in the 1/17/23 PRS Report. All Market Segments participated in the vote.
Summary of TAC Discussion	On 1/24/23, TAC reviewed the ERCOT Opinion, ERCOT Market Impact Statement, and Independent Market Monitor (IMM) Opinion for NPRR1153.
ERCOT Board Decision	On 2/28/23, the ERCOT Board voted unanimously to recommend approval of NPRR1153 as recommended by TAC in the 1/24/23 TAC Report.

Opinions	
Credit Review	ERCOT Credit Staff and the Market Credit Working Group (MCWG) have reviewed NPRR1153 and do not believe that it requires changes to credit monitoring activity or the calculation of liability.
Independent Market Monitor Opinion	IMM has no opinion on NPRR1153.
ERCOT Opinion	ERCOT supports approval of NPRR1153.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NPRR1153 and believes the market impact for NPRR1153 clarifies the ERCOT Fee Schedule by adding/restructuring the list of ERCOT-assessed fees, and removing fees from the ERCOT Fee Schedule which are governed by PUCT Substantive Rule.

Sponsor	
Name	Doug Fohn
E-mail Address	douglas.fohn@ercot.com
Company	ERCOT
Phone Number	512-275-7447
Cell Number	
Market Segment	Not applicable

Market Rules Staff Contact

Board Report

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

Comments Received	
Comment Author	**Comment Summary**
ERCOT 110222	Proposed an entry to the table inadvertently omitted from the original filing along with clarifying verbiage within Section 23, Forms
ERCOT 121222	Proposed administrative edits to align with the intent of NPRR1153.

Market Rules Notes

Please note the baseline language in the following Section(s) has been updated to reflect the incorporation of the following NPRR(s) into the Protocols:

- NPRR1127, Clarification of ERCOT Hotline Uses (incorporated 12/1/22)
  - Section 23, Form G

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

- NPRR1067, Market Entry Qualifications, Continued Participation Requirements, and Credit Risk Assessment
  - ERCOT Fee Schedule
- NPRR1158, Remove Sunset Date for Weatherization Inspection Fees
  - ERCOT Fee Schedule

Proposed Protocol Language Revision

9.16.2 User Fees

(1) The ERCOT Board approves user fees for products and services provided by ERCOT to a Market Participant or other Entity. Such user fees are approved in accordance with the ERCOT Board Policies and Procedures. User fees may include, but are not limited to, application fees, private Wide Area Network (WAN) costs, and interconnection study fees ~~and map sale fees~~.

(2) ERCOT shall post user fees approved by the ERCOT Board in the ERCOT Fee Schedule on the ERCOT website. ERCOT shall post the ERCOT Fee Schedule and effective date on the ERCOT website within two Business Days of change.

(3) A Market Participant or other Entity shall pay applicable user fees approved by the ERCOT Board.

ERCOT Fee Schedule[CP1]

Effective TBD~~August 1, 2022~~

The following is a schedule of ERCOT fees currently in effect. These fees are not refundable unless ERCOT Protocols provide otherwise.

Description	Nodal Protocol Reference	Calculation/Rate/Comment
~~ERCOT System Administration fee~~	~~9.16.1~~	~~$0.555 per MWh to fund ERCOT activities subject to Public Utility Commission of Texas (PUCT) oversight. This fee is charged to all Qualified Scheduling Entities (QSEs) based on Load represented.~~
Private Wide Area Network (WAN) fees	9.16.2	Actual costs of procuring, using, maintaining, and connecting to the third-~~-~~party communications networks and related hardware that provide ERCOT WAN communications~~. Initial equipment installation cost not to exceed $25,000, and monthly network management fee not to exceed $1,500~~. The portion of costs for ERCOT's work regarding an initial installation or reconfiguration of an existing installation will not exceed $7,000. The portion of the monthly network management fee for ERCOT's work will not exceed $450 per month.
ERCOT Load Resource registration and Generator~~ion~~ Interconnection or Modification fees ~~(Not Refundable)~~	NA	$500 for registration of a new Load Resource. If a Resource Entity seeks to increase the MW size of an existing Load Resource by more than 20% or change the Load Resource's registration between non-Controllable Load Resource and Controllable Load Resource, it will incur a registration fee of $500. The term "generator," as used in this fee schedule relating to interconnection fees and Full Interconnection Study (FIS) Application fees, includes Generation Resources, Energy Storage Resources (ESRs), and Settlement Only Generators (SOGs) but, as reflected below, Settlement-Only Distribution Generators (SODGs) will incur a different fee amount than Transmission connected SOGs. The following fee amounts apply for the registration of a new generator: $2,300 for SODGs; $8,000 for generators that are less than 10MW (other than SODGs); and $14,000 for generators that are 10MW or greater. If a Resource Entity for an existing SODG seeks to change its registration to a Distribution Generation Resource (DGR) it will incur a registration fee of $8,000. If a Resource Entity seeks to make a modification that is covered by paragraph (1)(c) of Planning Guide Section 5.2.1, Applicability, to an existing generator it will incur a registration fee in association with the modification request. If, at the time the modification is submitted, the cumulative MW amount of the modification and any other modifications that have been submitted for that generator within the

		last 12 months amount to less than 10MW, the registration fee will be $2,300. If, at the time the modification is submitted, the cumulative MW amount of the modification and any other modifications that have been submitted for that generator within the last 12 months amount to 10MW or greater, the registration fee will be $14,000. ~~Application to interconnect generation to the ERCOT System.~~ ~~$5,000 (less than or equal to 150MW)~~ ~~$7,000 (greater than 150MW)~~
Full Interconnection Study (FIS) Application fee ~~(Not Refundable)~~	NA	$3,000 for an FIS Application relating to a new generator. $2,700 for an FIS Application relating to modification of an existing generator. ~~$15 per MW – to support ERCOT system studies and coordination. Applicable MW amount per Planning Guide Section 5, Generator Interconnection or Modification.~~
~~Map Sale fees~~	~~NA~~	~~$20 - $40 per map request (by size)~~
Qualified Scheduling Entity (QSE) Application fee	9.16.2	$500 per Entity
Subordinate QSE (Sub-QSE) Application fee	9.16.2	$500 per Sub-QSE
Competitive Retailer (CR) Application fee	9.16.2	$500 per Entity
Congestion Revenue Right (CRR) Account Holder Application fee	9.16.2	$500 per Entity
Independent Market Information System Registered Entity (IMRE) fee	9.16.2	$500 per Entity
Resource Entity Application fee	9.16.2	$500 per Entity
Transmission and/or Distribution Service Providers (TDSPs)	9.16.2	$500 per Entity
Weatherization Inspection fees	NA	Resource Entities with Generation Resources or Energy Storage Resources (ESRs) and Transmission Service Providers (TSPs) shall pay fees to ERCOT for costs related to weatherization inspections conducted pursuant to 16 Texas Administrative Code (TAC) § 25.55 as provided below. TSPs shall pay an inspection fee of $3,000 for each of their substations or switching stations that are inspected.

		Each Resource Entity with Generation Resources or ESRs shall pay an inspection fee calculated as the Quarterly Generation Resource Inspection Costs * (Resource Entity MW Capacity/Aggregate MW Capacity). ERCOT will perform this calculation for each calendar quarter and gather the necessary MW capacity data for that quarter on one of the last 15 Business Days at the end of the quarter. Terms used in this formula are defined as follows: Quarterly Generation Resource Inspection Costs = the sum of outside services costs, ERCOT internal costs, and overhead costs related to weatherization inspections, less inspection fees that will be invoiced to TSPs for that quarter. Resource Entity MW Capacity = the total MW capacity associated with a Resource Entity with Generation Resources or ESRs. To calculate these amounts, ERCOT will query the Resource Integration and Ongoing Operations-Resource Services ("RIOO-RS") for a report that lists the total MW capacity (real power rating) for all generation assets associated with each Resource Entity. Aggregate MW Capacity = the total of all the Resource Entity MW Capacity amounts. To calculate this amount, ERCOT will query the RIOO-RS for a report that lists the total MW capacity (real power rating) for all Generation Resources and ESRs associated with all Resource Entities. ERCOT will issue Invoices in the first month following each calendar quarter to the Resource Entities and TSPs that owe inspection fees. Payment of the fee will be due within 30 days of the Invoice date and late payments will incur 18% annual interest. Entities that fail to pay their Invoice on time will be publicly reported in a filing with the PUCT. Further payment terms and instructions will be included on the Invoice.
[NPRR1107: Delete "Weatherization Inspection fees" above on July 31, 2023.]		
Voluminous Copy fee	NA	$0.15 per page in excess of 50 pages
Actual Costs associated with Information Requests	NA	ERCOT will provide an estimate to the requestor of any vendor or third-party costs ERCOT deems appropriate to fulfill the information request. If the requestor approves the cost estimate, the requestor must pay all such costs as instructed by ERCOT before the information will be delivered to the requestor.
ERCOT Labor Costs for Information Requests	NA	$15 per hour of ERCOT time. If ERCOT determines that a request will involve a substantial burden on ERCOT employee or contractor time to fulfill the request, ERCOT will provide an estimate to the requestor of the anticipated labor costs. If the requestor approves the cost estimate, the requestor must pay all

		such labor costs as instructed by ERCOT before the information will be delivered to the requestor.
ERCOT Training fees for courses that award Continuing Education Hours (CEHs)	NA	$25 per North American Electric Reliability Corporation (NERC) CEH. Examples of such trainings include, without limitation, the Operator Training Seminar and Black Start Training.
Cybersecurity Monitor fee for Non-ERCOT Utilities that participate in the Texas Cybersecurity Monitor Program	NA	The Cybersecurity Monitor fee amount varies from year to year. The current fee amount is posted on ERCOT's website here: https://www.ercot.com/services/programs/tcmp

ERCOT Nodal Protocols

Section 23

Form G: QSE Application and Service Filing for Registration Form

TBD~~February 1, 2022~~

QUALIFIED SCHEDULING ENTITY (QSE) APPLICATION AND SERVICE FILING FOR REGISTRATION

This application is for approval as a Qualified Scheduling Entity (QSE) by Electric Reliability Council of Texas Inc. (ERCOT) in accordance with the ERCOT Protocols. Information may be inserted electronically to expand the reply spaces as necessary. ERCOT will accept the completed, executed application via email to MPRegistration@ercot.com (.pdf version), via facsimile to (512) 225-7079, or via mail to Market Participant Registration, 8000 Metropolis Drive (Building E), Suite 100, Austin, Texas 78744. In addition to the application, ERCOT must receive an application fee in the amount of $500 ~~via check~~for each QSE or Sub-QSE registered. If you need assistance filling out this form, or if you have any questions, please call (512) 248-3900.

Board Report

This application must be signed by the Authorized Representative, Backup Authorized Representative or an Officer of the company listed herein, as appropriate. ERCOT may request additional information as reasonably necessary to support operations under the ERCOT Protocols.

PART I – ENTITY INFORMATION

Legal Name of the Applicant:	
Legal Address of the Applicant:	Street Address:
	City, State, Zip:
DUNS[1] Number:	

[1]Defined in Section 2.1, Definitions.

☐ **Check if Applying as an Emergency Response Service (ERS) Only QSE.**

1. Authorized Representative ("AR"). Defined in Section 2.1, Definitions.

Name:		**Title:**			
Address:					
City:		**State:**		**Zip:**	
Telephone:		**Fax:**			
Email Address:					

2. Backup AR. *(Optional)* This person may sign any form for which an AR's signature is required and will perform the functions of the AR as defined in the ERCOT Protocols in the event the AR is unavailable.

Name:		**Title:**			
Address:					
City:		**State:**		**Zip:**	
Telephone:		**Fax:**			
Email Address:					

3. Type of Legal Structure. (Please indicate only one.)

☐ Individual
☐ Partnership
☐ Municipally Owned Utility
☐ Electric Cooperative
☐ Limited Liability Company
☐ Corporation
☐ Other: _____

If Applicant is not an individual, provide the state in which the Applicant is organized, _____, and the date of organization: _____.

4. User Security Administrator (USA). As defined in Section 16.12, User Security Administrator and Digital Certificates, the USA is responsible for managing the Market Participant's access to ERCOT's computer systems through Digital Certificates.

Name:		**Title:**			
Address:					
City:		**State:**		**Zip:**	
Telephone:		**Fax:**			
Email Address:					

5. Backup USA. *(Optional)* This person may perform the functions of the USA as defined in the ERCOT Protocols in the event the USA is unavailable.

Name:		**Title:**			
Address:					
City:		**State:**		**Zip:**	
Telephone:		**Fax:**			
Email Address:					

6. Cybersecurity. This contact is responsible for communicating Cybersecurity Incidents.

Name:		**Title:**			
Address:					
City:		**State:**		**Zip:**	
Telephone:		**Fax:**			
Email Address:					

7. Control or Operations Center. As defined in item (1)(k) and (1)(l) of Section 16.2.1, Criteria for Qualification as a Qualified Scheduling Entity, the control or operations center is responsible for operational communications and shall have sufficient authority to commit and bind the QSE. For QSE Level 2, 3, and 4 the availability of the control or operations center is 24-hour, seven-day-per-week. For QSE Level 1 the availability of the control or operations center is during the hours of 0900 to 1700 Central Prevailing Time (CPT) on Business Days.

Desk Name:					
Address:					
City:		**State:**		**Zip:**	
Telephone:		**Fax:**			
Email Address:					

8. Compliance Contact. This person is responsible for compliance related issues.

Name:		**Title:**			
Address:					
City:		**State:**		**Zip:**	
Telephone:		**Fax:**			
Email Address:					

9. Proposed commencement date for service: _____

PART II – BANKING INFORMATION FOR FUNDS TRANSFERS

1. Banking Information. Applicant must be able to conduct Electronic Funds Transfers (EFTs) for the settlement of financial transactions with ERCOT.

Bank Name:	
Account Name:	
Account No.:	
ABA Number:	

2. Accounts Payable Contact (Settlement & Billing).

Name:		**Title:**			
Address:					
City:		**State:**		**Zip:**	
Telephone:		**Fax:**			
Email Address:					

Backup Accounts Payable Contact (Settlement & Billing). *(Optional)*

Name:		**Title:**			
Address:					
City:		**State:**		**Zip:**	
Telephone:		**Fax:**			
Email Address:					

PART III – DECLARATION OF SUBORDINATE QSEs

If the QSE intends to partition itself into subordinate QSEs (Sub-QSEs), please enter information for each Sub-QSE below. If a Sub-QSE will have a different Contact than the QSE, please provide that information in the spaces provided below. The Sub-QSE name must have a reference to the Legal Entity Name. For example: Legal Name of Market Participant (SQ1), Legal Name of Market Participant (SQ2), etc.

Sub-QSE One (SQ1)
Name: **Proposed commencement date for service:**
Contact information same? ☐ **Yes** ☐ **No (If no, complete the section below)**

Name:		**Title:**			
Address:					
City:		**State:**		**Zip:**	
Telephone:		**Fax:**			
Email Address:					

Sub-QSE Two (SQ2)
Name: Proposed commencement date for service:
Contact information same? ☐ Yes ☐ No (If no, complete the section below)

Name:			**Title:**		
Address:					
City:		**State:**		**Zip:**	
Telephone:		**Fax:**			
Email Address:					

Sub-QSE Three (SQ3)
Name: Proposed commencement date for service:
Contact information same? ☐ Yes ☐ No (If no, complete the section below)

Name:			**Title:**		
Address:					
City:		**State:**		**Zip:**	
Telephone:		**Fax:**			
Email Address:					

Sub-QSE Four (SQ4)
Name: Proposed commencement date for service:
Contact information same? ☐ Yes ☐ No (If no, complete the section below)

Name:			**Title:**		
Address:					
City:		**State:**		**Zip:**	
Telephone:		**Fax:**			
Email Address:					

PART IV – ADDITIONAL REQUIRED INFORMATION

1. Officers and Principals. Provide the name of all officers and the name and position of each Principal, as defined by Section 16.1.2, Principal of a Market Participant. In addition, ERCOT will obtain the names of all individuals and/or entities listed with the Texas Secretary of State as having binding authority for the Applicant. ERCOT will use this list of individuals to determine who can execute such documents as the Standard Form Market Participant Agreement (Section 22, Attachment A), Amendment to Standard Form Market Participant Agreement (Section 22, Attachment C), Digital Certificate Audit Attestation, etc. Alternatively, additional documentation (Articles of Incorporation, Board Resolutions, Delegation of Authority, Secretary's Certificate, etc.) can be provided to prove binding authority for the Applicant.

2. Affiliates and Other Registrations. Provide the name, legal structure, and relationship of each of the Applicant's affiliates, if applicable. See Section 2.1, Definitions, for the definition of "Affiliate." Please also provide the name and type of any other ERCOT Market Participant registrations held by the Applicant. *(Attach additional pages if necessary.)*

3. Disclosures. Provide the name of any Principal of the Applicant that is now, or was at any point in time, a Principal of any other Entity that is now, or was at any point in time, a registered ERCOT Market Participant, along with the name of the relevant ERCOT Market Participant and the dates during which the Principal of the Applicant was a Principal of the other Entity.

4. Counter-Party Credit Application. Complete the Counter-Party Credit Application, located at http://www.ercot.com/services/rq/credit, and submit as instructed in conjunction with this application, in accordance with Section 16.2, Registration and Qualification of Qualified Scheduling Entities.

Affiliate Name (or name used for other ERCOT registration)	**Type of Legal Structure** (partnership, limited liability company, corporation, etc.)	**Relationship** (parent, subsidiary, partner, affiliate, etc.)

5. Annual Certification Form to Meet ERCOT Additional Minimum Participation. Complete Section 22, Attachment J, Annual Certification Form to Meet ERCOT Additional Minimum Participation Requirements, and submit in conjunction with this application, pursuant to Section 16.16.3, Verification of Risk Management Framework.

PART V – SIGNATURE

I affirm that I have personal knowledge of the facts stated in this application and that I have the authority to submit this application form on behalf of the Applicant. I further affirm that all statements made and information provided in this application form are true, correct and complete, and that the Applicant will provide to ERCOT any changes in such information in a timely manner.

Signature of AR, Backup AR or Officer:	
Printed Name of AR, Backup AR or Officer:	
Date:	