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OPEN MEETING COVER SHEET

MEMORANDUM AND PROPOSED ORDER

MEETING DATE:	December 16, 2021
DATE DELIVERED:	December 15, 2021
AGENDA ITEM NO.:	26
CAPTION:	Project No. 52307 – Review of Rules Adopted by the Independent Organization in Calendary Year 2021.
DESCRIPTION:	Memo and Proposed Order

Public Utility Commission of Texas

Memorandum

TO: Chairman Peter Lake
Commissioner Will McAdams
Commissioner Lori Cobos
Commissioner Jimmy Glotfelty

FROM: Rebecca Zerwas, Market Analysis

DATE: December 15, 2021

RE: December 16, 2021 Open Meeting – Item No. 26

Project No. 52307 – *Review of Rules Adopted by the Independent Organization in Calendar Year 2021 (Discussion and possible action)*

Senate Bill (SB) 2 (87th Legislature, Regular Session) requires both the Commission and the Electric Reliability Council of Texas (ERCOT) to establish processes for Commission approval of any rules or protocols adopted under authority delegated from the Commission to the independent organization. Commission Staff will utilize Project No. 52307, *Review of Rules Adopted by the Independent Organization in Calendar Year 2021*, to facilitate this review and approval. Staff continues to work with ERCOT on amendments to the revision request approval process in anticipation of Project No. 52301, *ERCOT Governance and Related Issues*, and a full implementation of SB2.

Since the Commission adopted an order approving the last set of ERCOT rules at the October 28, 2021 Open Meeting, the Technical Advisory Committee (TAC) and Board of Directors (Board) have each met and passed nineteen additional rules through the stakeholder process. These include ten Nodal Protocol Revision Requests (NPRRs), one Planning Guide Revision Request (PGRR), two Resource Registration Glossary Revision Requests (RRGRRs), four Nodal Operating Guide Revision Requests (NOGRRs) and two Other Binding Document Revision Requests (OBDRRs). These matters are now pending at the Commission prior to ERCOT implementation.

First, Staff requests consideration of two rules approved by TAC at its November 29, 2021 meeting:

- NOGRR231, *Remove ERCOT Regional Map*. Staff recommends approval to remove any confusion regarding the boundaries or definition of the ERCOT Region from the Nodal Operating Guide.
- RRGRR030, *Allow New Voltage Levels in Resource Registration Information*. Staff recommends approval to remove the hard coding of voltage levels for certain Resource Registration information to eliminate validation errors when data is submitted that uses a voltage level not on the list.

Included for your review are the TAC Report and ERCOT Impact Analysis. These documents are intended to provide a comprehensive overview describing the revisions, including ERCOT's market impact statement.

Next, Staff requests consideration of the following seventeen rules as approved by Board at its December 10, 2021 meeting:

- NPRR1077, *Extension of Self-Limiting Facility Concept to Settlement Only Generators (SOGs) and Telemetry Requirements for SOGs*. Staff recommends approval in support of the extension of the self-limiting facility to SOGs, including addressing requirements for facilities that are connected at distribution voltage, and the greater visibility of SOG performance provided to ERCOT operations and planning personnel.

- NPRR1091, *Changes to Address Market Impacts of Additional Non-Spin Procurement*. Staff recommends approval to address energy price suppression and liquidity issues created by recent changes to ancillary service procurement and deployments.

- NPRR1094, *Allow Under Frequency Relay Load to be Manually Shed During EEA3*. Staff recommends approval in support of the improved efficiency and reliability provided by removing restrictions on manually shedding under frequency relay load shed feeder-connected load during an EEA Level 3.

- NPRR1101, *Create Non-Spin Deployment Groups made up of Generation Resources Providing Off-Line Non-Spinning Reserve and Load Resources that are Not Controllable*

Load Resources Providing Non-Spinning Reserve. Staff recommends approval in support of the continued efforts to increase the procurement of ancillary services and deploy Non-Spin in a technology agnostic manner.

- NPRR1103, *Securitization – PURA Subchapter M Default Charges*. Staff recommends approval to establish at ERCOT processes for assessment and collection of default charges and default escrow as reflected in the Debt Obligation Order issued in PUCT Docket No. 52321, Subchapter M, of PURA.

- NPRR1104, *As-Built Definition of Real Time Liability Extrapolated (RTLE)*. Staff recommends approval in support of ERCOT's attempt to align the definition of RTLE with current credit system and risk assessments by including market activity for entities that have no load or generation but have real-time exposure.

- NPRR1105, *Option to Deploy Distribution Voltage Reduction Measures Prior to Energy Emergency Alert (EEA)*. Staff recommends approval to implement in the ERCOT Protocols the direction provided by the Commission and enhance grid operations by providing ERCOT the additional tool of voltage reduction measures before declaration of an EEA.

- NPRR1106, *Deployment of Emergency Response Service (ERS) Prior to Declaration of Energy Emergency Alert (EEA)*. Staff recommends approval to implement in the ERCOT Protocols the direction provided by the Commission and enhance ERCOT's operational tools to address potential reliability outcomes.

- NPRR1107, *Addition of Weatherization Inspection Fees to the ERCOT Fee Schedule and Clarification of Generation Interconnection Request Fees*. Staff recommends approval to recover costs relating to new regulatory requirements separately from the System Administration Fee and clarify that existing generation interconnection request fees apply to all generation interconnection projects.

- NPRR1109, *Process for Reinstating Decommissioned Generation Resources*. Staff recommends approval to balance the ability for generation resources that have been recently decommissioned and retired to return to service while granting ERCOT and the interconnecting utility the authority to require any studies, testing, metering, or upgrades deemed necessary, and address any operational concerns.

- NOGRR233, *Related to NPRR1094, Allow Under Frequency Relay Load to be Manually Shed During EEA3*. Staff recommends approval in support of the improved efficiency and reliability provided by NPRR1094.

- NOGRR236, *Related to NPRR1105, Option to Deploy Distribution Voltage Reduction Measures Prior to Energy Emergency Alert (EEA)*. Staff recommends approval in support of implementation in the ERCOT Nodal Operating Guide the direction provided by the Commission related to voltage reduction measures before declaration of an EEA.

- NOGRR237, *Related to NPRR1106, Deployment of Emergency Response Service (ERS) Prior to Declaration of Energy Emergency Alert (EEA)*. Staff recommends approval to implement in the ERCOT Nodal Operating Guide the direction provided by the Commission and enhance ERCOT's operational tools to address potential reliability outcomes as provided by NPRR 1106.

- OBDRR035, *Related to NPRR1101, Create Non-Spin Deployment Groups made up of Generation Resources Providing Off-Line Non-Spinning Reserve and Load Resources that are Not Controllable Load Resources Providing Non-Spinning Reserve*. Staff recommends approval in support of the continued efforts to increase the procurement of ancillary services and deploy Non-Spin in a technology agnostic manner.

- OBDRR036, *Related to NPRR1106, Deployment of Emergency Response Service (ERS) Prior to Declaration of Energy Emergency Alert (EEA)*. Staff recommends approval to implement the direction provided by the Commission and enhance ERCOT's operational tools to address potential reliability outcomes as provided by NPRR 1106.

- PGRR092, *Related to NPRR1077, Extension of Self-Limiting Facility Concept to Settlement Only Generators (SOGs) and Telemetry Requirements for SOGs*. Staff recommends approval in support of the extension of the self-limiting facility to SOGs consistent with NPRR1077.

- RRGRR029, *Related to NPRR1077, Extension of Self-Limiting Facility Concept to Settlement Only Generators (SOGs) and Telemetry Requirements for SOGs*. Staff recommends approval in support of the extension of the self-limiting facility to SOGs consistent with NPRR1077.

Included for your review are the Board Report and ERCOT Impact Analysis. These documents are intended to provide a comprehensive overview describing the revisions, including ERCOT's market impact statement.

Finally, ERCOT has requested approval of an Alignment NOGRR, NOGRR238, *Alignment Changes for December 17, 2021 Nodal Operating Guide – NPRR1094, NPRR1105, NPRR1106*. Alignment NOGRRs are not considered through the stakeholder process. Instead, an Alignment NOGRR allows ERCOT to make modifications to the Operating Guides for the purpose of maintaining duplicate language between the Protocols and the related sections of the Operating Guides.[1] ERCOT must post the Alignment NOGRR and distributed to Reliability and Operations Subcommittee (ROS) within five Business Days of ERCOT Board approval of the related NPRR.[2] NPRR1094, NPRR1105, and NPRR1106 were approved by the Board on December 10, 2021 and NOGRR238 was posted the same day. Therefore, Staff recommends approval of NOGRR238 consistent with the recommendations for NPRR1094, NPRR1105, and NPRR1106. The NOGRR is included for your review.

Please find attached a proposed order for your consideration consistent with Staff's recommendation in this memo.

[1] ERCOT Nodal Operating Guide, Section 1, Overview (May 1, 2021).
[2] *Id.*

PROJECT NO. 52307

REVIEW OF RULES ADOPTED BY THE INDEPENDENT ORGANIZATION IN CALENDAR YEAR 2021	§ § §	**PUBLIC UTILITY COMMISSION OF TEXAS**

PROPOSED ORDER APPROVING ERCOT REVISION REQUESTS

This Order addresses revisions to twenty Electric Reliability Council of Texas (ERCOT) rules. The Commission approves the revisions and the accompanying market impact statements.

The ERCOT Technical Advisory Committee approved Nodal Operating Guide Revision Request (NOGRR) 231, *Remove ERCOT Regional Map*; and Resource Registration Glossary Revision Request (RRGRR) 030, *Allow New Voltage Levels in Resource Registration Information*, at its meeting on November 29, 2021.

In addition, the ERCOT Board of Directors approved Nodal Protocol Revision Request (NPRR) 1077, *Extension of Self-Limiting Facility Concept to Settlement Only Generators (SOGs) and Telemetry Requirements for SOGs*; NPRR 1091, *Changes to Address Market Impacts of Additional Non-Spin Procurement*; NPRR 1094, *Allow Under Frequency Relay Load to be Manually Shed During EEA3*; NPRR 1101, *Create Non-Spin Deployment Groups made up of Generation Resources Providing Off-Line Non-Spinning Reserve and Load Resources that are Not Controllable Load Resources Providing Non-Spinning Reserve*; NPRR 1103, *Securitization – PURA Subchapter M Default Charges*; NPRR 1104, *As-Built Definition of Real Time Liability Extrapolated (RTLE)*; NPRR 1105, *Option to Deploy Distribution Voltage Reduction Measures Prior to Energy Emergency Alert (EEA)*; NPRR 1106, *Deployment of Emergency Response Service (ERS) Prior to Declaration of Energy Emergency Alert (EEA)*; NPRR 1107, *Addition of Weatherization Inspection Fees to the ERCOT Fee Schedule and Clarification of Generation Interconnection Request Fees*; NPRR 1109, *Process for Reinstating Decommissioned Generation Resources*; NOGRR 233, *Related to NPRR1094, Allow Under Frequency Relay Load to be Manually Shed During EEA3*; NOGRR 236, *Related to NPRR1105, Option to Deploy Distribution Voltage Reduction Measures Prior to Energy Emergency Alert (EEA)*; NOGRR 237, *Related to NPRR1106, Deployment of Emergency Response Service (ERS) Prior to Declaration of*

Energy Emergency Alert (EEA); Other Binding Documents Revision Request (OBDRR) 035, *Related to NPRR1101, Create Non-Spin Deployment Groups made up of Generation Resources Providing Off-Line Non-Spinning Reserve and Load Resources that are Not Controllable Load Resources Providing Non-Spinning Reserve*; OBDRR 036, *Related to NPRR1106, Deployment of Emergency Response Service (ERS) Prior to Declaration of Energy Emergency Alert (EEA)*; Planning Guide Revision Request (PGRR) 092, *Related to NPRR1077, Extension of Self-Limiting Facility Concept to Settlement Only Generators (SOGs) and Telemetry Requirements for SOGs*; and RRGRR 029, *Related to NPRR1077, Extension of Self-Limiting Facility Concept to Settlement Only Generators (SOGs) and Telemetry Requirements for SOGs*, at its meeting on December 10, 2021.

ERCOT is also seeking approval of an Alignment NOGRR. NOGRR 238, *Alignment Changes for December 17, 2021 Nodal Operating Guide – NPRR1094, NPRR1105, NPRR1106*. Alignment NOGRRs are not considered for approval through the stakeholder process.

Effective June 8, 2021, rules adopted by ERCOT under delegated authority from the Commission are subject to Commission oversight and review and do not take effect before receiving Commission approval.[1] Further, also effective June 8, ERCOT's process for adopting new protocols or revisions to existing protocols must require that new or revised protocols may not take effect until the Commission approves a market impact statement describing the new or revised protocols.[2]

Commission Staff filed a memorandum on December 15, 2021 related to these revisions in which it recommends that the Commission approve the revisions to the rules. Attached to Commission Staff's memorandum were supporting ERCOT documents, which constitute the market impact analysis.

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[1] PURA § 39.151(d); *see also*, *id.* § 39.151(g-1) ERCOT's protocols must be approved by the commission.

[2] PURA § 39.151(g-6).

The Commission finds that these revisions are necessary for the proper functioning of the ERCOT market as demonstrated by the supporting material and the Commission issues the following orders:

1. The Commission approves NOGRR 231 and accompanying market impact statement.
2. The Commission approves RRGRR 030 and accompanying market impact statement.
3. The Commission approves NPRR 1077 and accompanying market impact statement.
4. The Commission approves NPRR 1091 and accompanying market impact statement.
5. The Commission approves NPRR 1094 and accompanying market impact statement.
6. The Commission approves NPRR 1101 and accompanying market impact statement.
7. The Commission approves NPRR 1103 and accompanying market impact statement.
8. The Commission approves NPRR 1104 and accompanying market impact statement.
9. The Commission approves NPRR 1105 and accompanying market impact statement.
10. The Commission approves NPRR 1106 and accompanying market impact statement.
11. The Commission approves NPRR 1107 and accompanying market impact statement.
12. The Commission approves NPRR 1109 and accompanying market impact statement.
13. The Commission approves NOGRR 233 and accompanying market impact statement.
14. The Commission approves NOGRR 236 and accompanying market impact statement.
15. The Commission approves NOGRR 237 and accompanying market impact statement.
16. The Commission approves OBDRR 035 and accompanying market impact statement.
17. The Commission approves OBDRR 036 and accompanying market impact statement.
18. The Commission approves PGRR 092 and accompanying market impact statement.
19. The Commission approves RRGRR 029 and accompanying market impact statement.
20. The Commission approves NOGRR 238 and accompanying market impact statement.

Signed at Austin, Texas the ______ day of ____________ 2021.

PUBLIC UTILITY COMMISSION OF TEXAS

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PETER M. LAKE, CHAIRMAN

____

WILL MCADAMS, COMMISSIONER

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LORI COBOS, COMMISSIONER

____

JIMMY GLOTFELTY, COMMISSIONER

TAC Report

NOGRR Number	<u>231</u>	NOGRR Title	Remove ERCOT Regional Map
Date of Decision	November 29, 2021		
Action	Recommended Approval		
Timeline	Normal		
Proposed Effective Date	January 1, 2022		
Priority and Rank Assigned	Not applicable		
Nodal Operating Guide Sections Requiring Revision	1.1, Document Purpose		
Related Documents Requiring Revision/Related Revision Requests	None		
Revision Description	This Nodal Operating Guide Revision Request (NOGRR) removes the ERCOT Regional Map and corresponding reference from Section 1.1.		
Reason for Revision	☐ Addresses current operational issues. ☐ Meets Strategic goals (tied to the <u>ERCOT Strategic Plan</u> or directed by the ERCOT Board). ☐ Market efficiencies or enhancements ☒ Administrative ☐ Regulatory requirements ☐ Other: (explain) *(please select all that apply)*		
Business Case	The Nodal Operating Guide should not introduce confusion about the boundaries or definition of the ERCOT Region. Participants should refer to the Protocols and P.U.C. SUBST. R. 25.5, Definitions, for specific details about this definition.		
ROS Decision	On 9/2/21, ROS voted unanimously via roll call to table NOGRR231.		

	All Market Segments participated in the vote. On 10/7/21, ROS voted unanimously via roll call to recommend approval of NOGRR231 as amended by the 10/4/21 ERCOT comments. All Market Segments participated in the vote. On 11/4/21, ROS voted unanimously via roll call to endorse and forward to TAC the 10/7/21 ROS Report and the Impact Analysis for NOGRR231. All Market Segments participated in the vote.
Summary of ROS Discussion	On 9/2/21, participants reviewed NOGRR231 and requested additional specificity in labeling of the graphic to clarify areas with ERCOT transmission and generation facilities versus areas with Load being served by other Independent System Operators (ISOs). On 10/7/21, participants reviewed the 10/4/21 ERCOT comments and acknowledged the various map information available on the ERCOT website. On 11/4/21, there was no discussion.
TAC Decision	On 11/29/21, TAC voted unanimously via roll call to recommend approval of NOGRR231 as recommended by ROS in the 11/4/21 ROS Report. All Market Segments participated in the vote.
Summary of TAC Discussion	On 11/29/21, TAC reviewed the ERCOT Opinion and ERCOT Market Impact Statement for NOGRR231.
ERCOT Opinion	ERCOT supports approval of NOGRR231.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NOGRR231 and believes the market impact for NOGRR231 removes ambiguity regarding the boundaries and definition of the ERCOT Region as this information is in the Protocols and P.U.C. SUBST. R. 25.5.

Sponsor	
Name	Jimmy Hartmann
E-mail Address	Jimmy.Hartmann@ercot.com
Company	ERCOT
Phone Number	512-248-6986
Cell Number	512-694-4558
Market Segment	Not Applicable

TAC Report

Market Rules Staff Contact	
Name	Phillip Bracy
E-Mail Address	Phillip.Bracy@ercot.com
Phone Number	512-248-6917

Comments Received	
Comment Author	**Comment Summary**
ERCOT 100421	Proposed removal of the map graphic

Market Rules Notes

None

Proposed Guide Language Revision

1.1 Document Purpose

(1) These ERCOT Operating Guides supplement the Protocols. The Operating Guides provide more detail and establish additional operating requirements for those organizations and Entities operating in, or potentially impacting the reliability of the ERCOT Transmission Grid in the ERCOT Region.

(2) The title "Operating Guide" is not to be construed as presenting merely a recommendation. Organizations and Entities are obligated to comply with the Operating Guides. Specific practices described in the Operating Guides for the ERCOT Region are consistent with North American Electric Reliability Corporation (NERC) Reliability Standards and the Protocols.

ERCOT Impact Analysis Report

NOGRR Number	231	NOGRR Title	Update ERCOT Regional Map
Impact Analysis Date	August 17, 2021		
Estimated Cost/Budgetary Impact	None.		
Estimated Time Requirements	No project required. This Nodal Operating Guide Revision Request (NOGRR) can take effect upon Public Utility Commission of Texas (PUCT) approval.		
ERCOT Staffing Impacts (across all areas)	Ongoing Requirements: No impacts to ERCOT staffing.		
ERCOT Computer System Impacts	No impacts to ERCOT computer systems.		
ERCOT Business Function Impacts	No impacts to ERCOT business functions.		
Grid Operations & Practices Impacts	No impacts to ERCOT grid operations and practices.		

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

Comments
None.

TAC Report

RRGRR Number	**030**	**RRGRR Title**	**Allow New Voltage Levels in Resource Registration Information**
Date of Decision	November 29, 2021		
Action	Recommended Approval		
Timeline	Normal		
Proposed Effective Date	Upon system implementation		
Priority and Rank Assigned	Not applicable		
Resource Registration Glossary Sections Requiring Revision	Section 2 – Transformer Data (as applicable)		
Related Documents Requiring Revision/Related Revision Requests	None		
Revision Description	This Resource Registration Glossary Revision Request (RRGRR) removes the hard coding of voltage levels for certain Resource Registration information related to Transformer Data. This will allow Resources connected to other voltage levels to submit their Resource Registration data without receiving validation errors.		
Reason for Revision	[X] Addresses current operational issues. [ ] Meets Strategic goals (tied to the ERCOT Strategic Plan or directed by the ERCOT Board). [ ] Market efficiencies or enhancements [ ] Administrative [ ] Regulatory requirements [ ] Other: (explain) *(please select all that apply)*		
Business Case	This RRGRR will eliminate validation errors when Resource Registration data is submitted that uses a voltage level not in the list.		
ROS Decision	On 7/8/21, ROS unanimously voted via roll call to recommend approval of RRGRR030 as submitted. All Market Segments participated in the vote.		

TAC Report

	On 8/5/21, ROS unanimously voted via roll call to endorse and forward to TAC the 7/8/21 ROS Report and the Revised Impact Analysis for RRGRR030. All Market Segments participated in the vote.
Summary of ROS Discussion	On 7/8/21, ERCOT Staff provided an overview of RRGRR030. On 8/5/21, there was no discussion.
TAC Decision	On 8/27/21, TAC unanimously voted via roll call to table RRGRR030. All Market Segments participated in the vote. On 9/29/21, TAC unanimously voted via roll call to recommend approval of RRGRR030 as recommended by ROS in the 8/5/21 ROS Report as amended by the 9/7/21 ERCOT comments; and to bring the Revised Impact Analysis back to TAC. All Market Segments participated in the vote. On 11/29/21, TAC unanimously voted via roll call to endorse and forward to the ERCOT Board the 9/29/21 TAC Report and 7/27/21 Revised Impact Analysis for RRGRR030. All Market Segments participated in the vote.
Summary of TAC Discussion	On 8/27/21, participants acknowledged the desire to table RRGRR030 in anticipation of comments to be filed following the incorporation of RRGRR028, Transformer Impedance Clarifications, into the 9/1/21 Resource Registration Glossary. On 9/29/21, TAC reviewed the ERCOT Opinion and ERCOT Market Impact Statement for RRGRR030; and stated that the 9/7/21 ERCOT comments could have impacts to the current Impact Analysis. On 11/29/21, participants acknowledged that there were no updates required to the 7/27/21 Revised Impact Analysis, and reviewed the ERCOT Opinion and ERCOT Market Impact Statement for RRGRR030.
ERCOT Opinion	ERCOT supports approval of RRGRR030.
ERCOT Market Impact Statement	ERCOT Staff has reviewed RRGRR030 and believes that RRGRR030 increases efficiency by addressing issues with validation errors.

Sponsor	
Name	James Teixeira
E-mail Address	Jay.Teixeira@ercot.com
Company	ERCOT

TAC Report

Phone Number	512-248-6582
Cell Number	512-656-6734
Market Segment	Not applicable

Market Rules Staff Contact	
Name	Phillip Bracy
E-Mail Address	Phillip.Bracy@ercot.com
Phone Number	512-248-6917

Comments Received	
Comment Author	**Comment Summary**
ERCOT 090721	Updated to account for new baseline following the incorporation of RRGRR028 into the Resource Registration Glossary
ERCOT 102121	Stated that ERCOT Staff has reviewed and determined that there are no additional impacts or updates required to the 7/27/21 Revised Impact Analysis

Market Rules Notes

Please note that the baseline language in the following section has been updated to reflect the incorporation of the following RRGRR(s) into the Resource Registration Glossary:

- Section 2
  - RRGRR031 (incorporated 11/1/21)
- Section 2: Transformer Data (as applicable)
  - RRGRR028 (incorporated 9/1/21)

Proposed Guide Language Revision

SECTION 2: RESOURCE REGISTRATION GLOSSARY - Effective November 1, 2021																
Resource Registration Data	Wind	Solar Photovoltaic (PV)	[[RRGRR023 and RRGRR031: Insert applicable portions of column "Energy Storage System (ESS)" upon system implementation of NPRRs 1002, 1026, and	Conventional Generation (Gen)	Combined Cycle (CC)	Load Resources	Distributed Generation	Notes	Field Name	Definition / Detailed Description	Screening Study (SS) (R, C, O, A)	Full Interconnect Study (FIS) - Steady-State, Short Circuit, and Facility (R, C, O, A)	FIS - Stability Study (R, C, O, A)	Planning Model (R, C, O, A)	Full Registration (R, C, O, A)	
Transformer Data (as applicable)																
Transformer Data	X	X	X	X	X			List	Description of Change	Select: description of change from drop down list: Add, Change or Delete					C	
Transformer Data	X	X	X	X	X			enter all caps	Transformer Name	Transformer name must be 14 characters or less and contain no special characters other than an underscore "_".				R	R	
Transformer Data	X	X	X	X	X			enter all caps	ERCOT Station Name (Station Code or Station Mnemonic)	ERCOT Station Code/Mnemonic where the transformer is located.				R	R	
Transformer Data	X	X	X	X	X			Automatic	Transformer Code	Concatenated code				A	A	

										automatically provided						
Transformer Data	X	X	X	X	X			Y/N	Transformer Test Report Attached?	Is the Transformer test report attached to this Resource Registration? Submit the Transformer Test Report via the approved Resource Registration process.				R	R	
Transformer Data	X	X	X	X	X			Y/N	Is This Transformer In a Master-follower Current Balancing Configuration?	Select Y or N whether this transformer is part of a master - following configuration				R	R	
Transformer Data	X	X	X	X	X			enter all caps	Master Name (can Be Same As this transformer)	The registered name of the transformer designated as the master in a parallel transformer control system scheme.					C	
Transformer Data	X	X	X	X	X			enter all caps	Follower Name (can Be Same As this transformer)	The registered name of the transformer designated as the follower in a parallel transformer control system scheme.					C	
Transformer Data	X	X	X	X	X			Y/N	Generator Step up Transformer?	Select Y or N whether this		R	R	R	R	

										transformer is a generator step up transformer						
Transformer Data	X	X	X	X	X				Zero Sequence Data Winding Connect code (1-5)	Enter zero sequence data winding connect code 1 - 5 as noted below. Transformer Connection Codes: Two Winding Transformers (in order of Voltage highest first) 1 -- Wye-Wye Bank Both Neutrals Grounded 2 -- Wye - Delta Bank Grounded Wye 3 -- Delta - Wye Bank Grounded Wye 4 -- Delta - Delta Bank; Wye-Delta Bank Ungrounded Wye; Delta-Wye Bank Ungrounded Wye; Wye-Wye Bank Either Wye Grounded 5 -- Three Winding only (Test Reports needed for Code 5)		R	R	R	R	

Transformer Data	X	X	X	X	X			p.u.	Zero Sequence Grounding Resistance For An Impedance Grounded Transformer in P.u. (100 MVA Base)	Zero Sequence Grounding Resistance For An Impedance Grounded Generator in p.u. (100 MVA Base) and the nominal system voltage (eg. 69 kV, 138 kV, 345 kV)		R	R	R	R	
Transformer Data	X	X	X	X	X			p.u.	Zero Sequence Grounding Reactance For An Impedance Grounded Transformer In P.u. (100 MVA Base)	Zero Sequence Grounding Reactance For An Impedance Grounded Transformer In P.u. (100 MVA Base) and the nominal system voltage (eg. 69 kV, 138 kV, 345 kV)		R	R	R	R	
Transformer Data	X	X	X	X	X			p.u.	Zero Sequence Resistance In p.u. (100 MVA Base)	Zero Sequence Resistance In p.u. (100 MVA Base) and the nominal system voltage (eg. 69 kV, 138 kV, 345 kV)		R	R	R	R	
Transformer Data	X	X	X	X	X			p.u.	Zero Sequence Reactance In P.u. (100 MVA Base)	Zero Sequence Reactance In P.u. (100 MVA Base) and the nominal system voltage (eg. 69 kV, 138 kV, 345 kV)		R	R	R	R	
Transformer Data	X	X	X	X	X			p.u.	Positive Sequence Resistance (100 MVA Base)	Positive Sequence Resistance (100		R	R	R	R	

										MVA Base) and the nominal system voltage (eg. 69 kV, 138 kV, 345 kV)						
Transformer Data	X	X	X	X	X			p.u.	Positive Sequence Reactance (100 MVA Base)	Positive Sequence Reactance (100 MVA Base) and the nominal system voltage (eg. 69 kV, 138kV, 345 kV)		R	R	R	R	
Transformer Data	X	X	X	X	X			MVA	Normal Rating	The continuous MVA rating of the transformer, including substation terminal equipment in series with the transformer, at the applicable ambient temperature. The Transmission Element can operate at this rating indefinitely without damage, or violation of NESC clearances.		R	R	R	R	
Transformer Data	X	X	X	X	X			MVA	2-hr Emergency Rating	The two-hour MVA rating of the transformer, including substation terminal equipment in series with the		R	R	R	R	

										transformer, at the applicable ambient temperature. The Transmission Element can operate at this rating for two hours without violation of NESC clearances or equipment failure.						
Transformer Data	X	X	X	X	X			MVA	15-min Rating	The 15-minute MVA rating of the transformer, including substation terminal equipment in series with the transformer, at the applicable ambient temperature and with a step increase from a prior loading up to 90% of the Normal Rating. The transformer can operate at this rating for 15 minutes, assuming its pre-contingency loading up to 90% of the Normal Rating limit at the applicable ambient		R	R	R	R	

										temperature, without violation of NESC clearances or equipment failure. This rating takes advantage of the time delay associated with heating of the transformer following a sudden increase in current.						
Transformer Data	X	X	X	X	X			MVA	Relay loadability limit	Enter the rating in MVA that would cause the circuit to trip within 15 minutes of exceeding that value. If no overload trip relay exists, enter "99999"				R	R	
Transformer Data	X	X	X	X	X			enter all caps	Unit(s) Associated With This Transformer (Must be entered as SITECODE_UNITNAME)	Enter the Unit(s) Associated With This Transformer (name must match unit names provided on the unit info tab)					C	
Transformer Data	X	X	X	X	X			kV	High Side Voltage Level (no-Load)	Enter the voltage level of the high side for this transformer system nominal voltage (eg. 69 kV, 138 kV, 345 kV)				R	R	

Transformer Data	X	X	X	X	X			#	High Side PTI Bus Number	Enter the PTI bus number for the high side of this transformer				O	O	
Transformer Data	X	X	X	X	X			List	High Side Voltage Connection - Wye or Delta	Select whether this high side connection is a Wye or Delta connection		R	R	R	R	
Transformer Data	X	X	X	X	X			Device 1	High Side Voltage Connected Devices	Enter a device connected to the high side of this transformer					R	
Transformer Data	X	X	X	X	X			kV	High Side Manufactured Nominal Voltage	Enter the high side manufactured nominal voltage for this transformer		R	R	R	R	
Transformer Data	X	X	X	X	X			kV	Low Side Voltage level (no-Load)	Enter the voltage level of the low side for this transformer				R	R	
Transformer Data	X	X	X	X	X			#	Low Side PTI Bus Number	Enter the PTI bus number for the low side of this transformer				O	O	
Transformer Data	X	X	X	X	X			List	Low Side Voltage Connection - Wye or Delta	Select whether this low side connection is a Wye or Delta connection		R	R	R	R	
Transformer Data	X	X	X	X	X			Device 1	Low Side Voltage Connected Devices	Enter a device connected to the low side of this transformer					R	
Transformer Data	X	X	X	X	X			kV	Low Side Manufactured Nominal Voltage	Enter the low side manufactured nominal voltage for this transformer		R	R	R	R	

Transformer Data	X	X	X	X	X			Y/N	On-Load Voltage Regulation	Select Y or N whether this transformer will change tap settings automatically while online to control voltage.		R	R	R	R	
Transformer Data	X	X	X	X	X			Y/N	Does Transformer have an On-Load Tap Changer?	Select Y or N whether this transformer has an On-Load Tap changer		R	R	R	R	
Transformer Data	X	X	X	X	X			List	Location of On-Load Tap Changer - Primary (High) or Secondary (Low) side	If this transformer has an On-Load Tap changer, select whether it is on Primary (High) or Secondary (Low) side.		C	C	C	C	
Transformer Data	X	X	X	X	X			kV	Base kV of Regulated Side	Base kV of Regulated Side				C	C	
Transformer Data	X	X	X	X	X			kV	Target kV of Regulated Side	Target kV of Regulated Side				C	C	
Transformer Data	X	X	X	X	X			%	Acceptable Deviation of Target Voltage	Acceptable Deviation from Target Voltage before tap change, in percent (enter 1% as 0.01).				C	C	
Transformer Data	X	X	X	X	X				Comments	Enter any comments regarding this transformer data					O	
Transformer Data	X	X	X	X	X			Ohms/ Phase	DC Resistance of Winding 1	Using manufacturer's data, enter the DC				R	R	

										resistance of the Primary/high voltage winding (or for autotransformers, the series winding).						
Transformer Data	X	X	X	X	X			Ohms/ Phase	DC Resistance of Winding 2	Using manufacturer's data, enter the DC resistance of the Secondary/low voltage winding (or for autotransformers, the common winding). For physical three-winding transformers modeled as three 2-winding transformers, enter "99999"for each transformer row.				R	R	
Transformer Data	X	X	X	X	X			Y/N	GIC Blocking device on Winding 1	Answer Yes or No whether a Geomagnetic Induced Current blocking device exists on the Primary/high voltage winding (or for autotransformers, the series winding).				R	R	

Transformer Data	X	X	X	X	X			Y/N	GIC Blocking device on Winding 2	Answer Yes or No whether a Geomagnetic Induced Current blocking device exists on the Secondary/low voltage winding, (or for autotransformers, the common winding). For physical three-winding transformers modeled as three 2-winding transformers, select "N" for each transformer row.				R	R	
Transformer Data	X	X	X	X	X			List	Vector Group Identifier	Manufacturer-supplied alphanumeric identifier specifying vector group based on transformer winding connections and grounding. For physical three-winding transformers modeled as three 2-winding transformers, enter the same Vector Group Identifier for each transformer row.				R	R	

Transformer Data	X	X	X	X	X			List	Transformer Core Design Type	Manufacturer-supplied Transformer Core Design Type (Three Phase shell Form, Unknown, 3@Single Phase (separate cores), Three Phase 3-Legged Core Design, Three Phase 5-Legged Core Design, Three Phase 7-Legged Core Design). For physical three-winding transformers modeled as three 2-winding transformers, enter the same Transformer Core Design Type for each transformer row.				R	R	
Transformer Data	X	X	X	X	X			Number	K Factor	Value supplied by transformer manufacturer. If data is unavailable from the manufacturer, enter 0. For physical three-winding transformers modeled as three 2-winding				R	R	

										transformers, enter the same K Factor for each transformer row.						
Transformer Data	X	X	X	X	X			Ohms	Winding 1 Grounding DC Resistance	Enter the Primary/high voltage winding Grounding DC Resistance in Ohms for any grounding device, (for a solidly grounded winding, enter 0, enter "99999" for ungrounded).				R	R	
Transformer Data	X	X	X	X	X			Ohms	Winding 2 Grounding DC Resistance	Enter the Secondary/low voltage winding Grounding DC Resistance in Ohms for any grounding device, (for a solidly grounded winding, enter 0, enter "99999" for ungrounded). For physical three-winding transformers modeled as three 2-winding transformers, enter "99999" for each transformer row.				R	R	

Transformer Data	X	X	X	X	X			List	Transformer Model	Enter 0 except for a phase-shifting transformer, which should be entered as a 1. For physical three-winding transformers modeled as three 2-winding transformers, enter the same model for each transformer row.				R	R	
Transformer Data	X	X	X	X	X			mm/dd/yyyy	Effective Date:	Date this transformer was added, removed or updated in the model					R	
[RRGRR022, RRGRR023, and RRGRR028: Replace applicable portions of "Transformer Data (as applicable)" above with the following upon system implementation of NPRR973 for RRGRR022, upon system implementation of NPRRs 1002, 1026, and 1029 for RRGRR023, and upon system implementation for RRGRR028:]																
Transformer Data (as applicable)																
Transformer Data	X	X	X	X	X			List	Description of Change	Select: description of change from drop down list: Add, Change or Delete					C	
Transformer Data	X	X	X	X	X			enter all caps	Transformer Name	Transformer name must be 14 characters or less and contain no special characters other than an underscore "_".				R	R	
Transformer Data	X	X	X	X	X			enter all caps	ERCOT Station Name (Station Code or Station Mnemonic)	ERCOT Station Code/Mnemonic where the transformer is				R	R	

										located.						
Transformer Data	X	X	X	X	X			Automatic	Transformer Code	Concatenated code automatically provided				A	A	
Transformer Data	X	X	X	X	X			Y/N	Transformer Test Report Attached?	Is the Transformer test report attached to this Resource Registration? Submit the Transformer Test Report via the approved Resource Registration process. NOTE: Official transformer manufacturer test report (also known as Factory Acceptance Test or FAT, not to be confused with Transformer Commissioning Test Report) must be attached before energization.					R	
Transformer Data	X	X	X	X	X			enter all caps	Transformer Manufacturer	Name of the transformer manufacturer					R	
Transformer Data	X	X	X	X	X			Y/N	Is This Transformer In a Master-follower Current Balancing Configuration?	Select Y or N whether this transformer is part of a master -				R	R	

										following configuration						
Transformer Data	X	X	X	X	X			enter all caps	Master Name (can Be Same As this transformer)	The registered name of the transformer designated as the master in a parallel transformer control system scheme.					C	
Transformer Data	X	X	X	X	X			enter all caps	Follower Name (can Be Same As this transformer)	The registered name of the transformer designated as the follower in a parallel transformer control system scheme.					C	
Transformer Data	X	X	X	X	X			Y/N	Main Power Transformer (MPT)?	Select Y or N whether this transformer is a Main Power Transformer (MPT)		R	R	R	R	
Transformer Data	X	X	X	X	X				Zero Sequence Data Winding Connect code (1-5)	Enter zero sequence data winding connect code 1 - 5 as noted below. Transformer Connection Codes: Two Winding Transformers (in order of Voltage highest first) 1 -- Wye-Wye Bank Both		R	R	R	R	

										Neutrals Grounded 2 -- Wye - Delta Bank Grounded Wye 3 -- Delta - Wye Bank Grounded Wye 4 -- Delta - Delta Bank; Wye-Delta Bank Ungrounded Wye; Delta-Wye Bank Ungrounded Wye; Wye-Wye Bank Either Wye Grounded 5 -- Three Winding only						
Transformer Data	X	X	X	X	X			List	Winding location of neutral ground impedance	Select the Winding that the neutral ground impedance is connected to: Primary (high voltage side), Secondary (low voltage side), or Tertiary (tertiary voltage side if applicable).		R	R	R	R	
Transformer Data	X	X	X	X	X			p.u.	Zero Sequence Grounding Resistance For An Impedance Grounded Transformer in P.u. (100 MVA Base at nominal system voltage)	Zero Sequence Grounding Resistance For An Impedance Grounded Transformer in p.u. (100 MVA Base) and the nominal system voltage (eg. 69		R	R	R	R	

										kV, 138 kV, 345 kV)						
Transformer Data	X	X	X	X	X			p.u.	Zero Sequence Grounding Reactance For An Impedance Grounded Transformer In P.u. (100 MVA Base at nominal system voltage)	Zero Sequence Grounding Reactance For An Impedance Grounded Transformer In P.u. (100 MVA Base) and the nominal system voltage (eg. 69 kV, 138 kV, 345 kV)		R	R	R	R	
Transformer Data	X	X	X	X	X			Y/N	Zero Sequence Grounding (Neutral Grounding) Impedance Manufacturer Test Report Submitted	Has the zero sequence grounding (neutral grounding impedance) manufacturer test report been submitted to ERCOT? If not, please attach.					R	
Transformer Data	X	X	X	X	X			p.u.	Primary to Secondary Zero Sequence Resistance In p.u. (100 MVA Base at nominal system voltage)	Zero Sequence Resistance Primary-Secondary (resistive component of Z1Ns) In p.u. on 100 MVA Base and adjusted from Manufactured Nominal Voltage to the nominal system voltage (eg. 69 kV, 138 kV, 345 kV) base.		R	R	R	R	

Transformer Data	X	X	X	X	X			p.u.	Primary to Secondary Zero Sequence Reactance In p.u. (100 MVA Base at nominal system voltage)	Zero Sequence Reactance Primary-Secondary (reactive component of Z1Ns) In p.u. on 100 MVA Base and adjusted from Manufactured Nominal Voltage to the nominal system voltage (eg. 69 kV, 138 kV, 345 kV) base.		R	R	R	R		
Transformer Data	X	X	X	X	X			p.u.	Primary to Secondary Positive Sequence Resistance In p.u. (100 MVA Base at nominal system voltage)	Positive Sequence Resistance Primary-Secondary In p.u. on 100 MVA Base and adjusted from Manufactured Nominal Voltage to the nominal system voltage (eg. 69 kV, 138 kV, 345 kV) base.		R	R	R	R		
Transformer Data	X	X	X	X	X			p.u.	Primary to Secondary Positive Sequence Reactance In p.u. (100 MVA Base at nominal system voltage)	Positive Sequence Reactance Primary-Secondary In p.u. on 100 MVA Base and adjusted from Manufactured Nominal Voltage to the nominal system voltage (eg. 69 kV, 138		R	R	R	R		

										kV, 345 kV) base.						
Transformer Data	X	X	X	X	X			MVA	Primary Normal Rating	The continuous MVA rating of the primary winding of the transformer, including substation terminal equipment in series with the transformer, at the applicable ambient temperature. The Transmission Element can operate at this rating indefinitely without damage, or violation of NESC clearances.		R	R	R	R	
Transformer Data	X	X	X	X	X			MVA	Primary 2-hr Emergency Rating	The two-hour MVA rating of the primary winding of the transformer, including substation terminal equipment in series with the transformer, at the applicable ambient temperature. The Transmission Element can operate at this rating for two hours without		R	R	R	R	

										violation of NESC clearances or equipment failure.						
Transformer Data	X	X	X	X	X			MVA	Primary 15-min Rating	The 15-minute MVA rating of the primary winding of the transformer, including substation terminal equipment in series with the transformer, at the applicable ambient temperature and with a step increase from a prior loading up to 90% of the Normal Rating. The transformer can operate at this rating for 15 minutes, assuming its pre-contingency loading up to 90% of the Normal Rating limit at the applicable ambient temperature, without violation of NESC clearances or equipment failure. This rating takes advantage of the time delay associated with		R	R	R	R	

										heating of the transformer following a sudden increase in current.						
Transformer Data	X	X	X	X	X			MVA	Primary Relay loadability limit	Enter the rating in MVA that would cause the transformer to trip within 15 minutes of exceeding that value on the primary. If no overload trip relay exists, enter "99999"				R	R	
Transformer Data	X	X	X	X	X			enter all caps	Unit(s) Associated With This Transformer (Must be entered as SITECODE_UNITNAME)	Enter the Unit(s) Associated With This Transformer (name must match unit names provided on the unit info tab)					C	
Transformer Data	X	X	X	X	X			List	Primary Winding Voltage Connection - Wye or Delta	Select whether this primary winding connection is a Wye or Delta connection		R	R	R	R	
Transformer Data	X	X	X	X	X			Device 1	Primary Winding Voltage Connected Devices	Enter a device connected to the primary winding of this transformer					R	
Transformer Data	X	X	X	X	X			kV	Primary Winding Manufactured Nominal Voltage	Enter the primary winding manufactured nominal voltage for this transformer		R	R	R	R	

Transformer Data	X	X	X	X	X			kV	Secondary Winding Voltage level (no-Load)	Enter the voltage level of the secondary winding for this transformer				R	R	
Transformer Data	X	X	X	X	X			#	Secondary Winding PTI Bus Number	Enter the PTI bus number for the secondary winding of this transformer				O	O	
Transformer Data	X	X	X	X	X			List	Secondary Winding Voltage Connection - Wye or Delta	Select whether this secondary winding connection is a Wye or Delta connection		R	R	R	R	
Transformer Data	X	X	X	X	X			Device 1	Secondary Winding Voltage Connected Devices	Enter a device connected to the secondary winding of this transformer					R	
Transformer Data	X	X	X	X	X			kV	Secondary Winding Manufactured Nominal Voltage	Enter the secondary winding manufactured nominal voltage for this transformer		R	R	R	R	
Transformer Data	X	X	X	X	X			Y/N	On-Load Voltage Regulation	Select Y or N whether this transformer will change tap settings automatically while online to control voltage.		R	R	R	R	
Transformer Data	X	X	X	X	X			Y/N	Does Transformer have an On-Load Tap Changer?	Select Y or N whether this transformer has an On-Load Tap		R	R	R	R	

										changer						
Transformer Data	X	X	X	X	X			List	Location of On-Load Tap Changer - Primary (High) or Secondary (Low) side	If this transformer has an On-Load Tap changer, select whether it is on Primary (High) or Secondary (Low) side.		C	C	C	C	
Transformer Data	X	X	X	X	X			kV	Base kV of Regulated Side	Base kV of Regulated Side				C	C	
Transformer Data	X	X	X	X	X			kV	Target kV of Regulated Side	Target kV of Regulated Side				C	C	
Transformer Data	X	X	X	X	X			%	Acceptable Deviation of Target Voltage	Acceptable Deviation from Target Voltage before tap change, in percent (enter 1% as 0.01).				C	C	
Transformer Data	X	X	X	X	X				Comments	Enter any comments regarding this transformer data					O	
Transformer Data	X	X	X	X	X			Ohms/ Phase	DC Resistance of Winding 1	Using manufacturer's data, enter the DC resistance of the Primary/high voltage winding (or for autotransformers, the series winding).				R	R	
Transformer Data	X	X	X	X	X			Ohms/ Phase	DC Resistance of Winding 2	Using manufacturer's data, enter the DC resistance of the Secondary/low				R	R	

										voltage winding (or for autotransformers, the common winding). For physical three-winding transformers modeled as three 2-winding transformers, enter "99999"for each transformer row.						
Transformer Data	X	X	X	X	X			Y/N	GIC Blocking device on Winding 1	Answer Yes or No whether a Geomagnetic Induced Current blocking device exists on the Primary/high voltage winding (or for autotransformers, the series winding).				R	R	
Transformer Data	X	X	X	X	X			Y/N	GIC Blocking device on Winding 2	Answer Yes or No whether a Geomagnetic Induced Current blocking device exists on the Secondary/low voltage winding, (or for autotransformers, the common winding). For physical three-winding				R	R	

										transformers modeled as three 2-winding transformers, select "N" for each transformer row.						
Transformer Data	X	X	X	X	X			List	Vector Group Identifier	Manufacturer-supplied alphanumeric identifier specifying vector group based on transformer winding connections and grounding. For physical three-winding transformers modeled as three 2-winding transformers, enter the same Vector Group Identifier for each transformer row.				R	R	
Transformer Data	X	X	X	X	X			Number	K Factor	Value supplied by transformer manufacturer. If data is unavailable from the manufacturer, enter 0. For physical three-winding transformers modeled as three 2-winding transformers, enter the same K				R	R	

										Factor for each transformer row.						
Transformer Data	X	X	X	X	X			Ohms	Winding 1 Grounding DC Resistance	Enter the Primary/high voltage winding Grounding DC Resistance in Ohms for any grounding device, (for a solidly grounded winding, enter 0, enter "99999" for ungrounded).				R	R	
Transformer Data	X	X	X	X	X			Ohms	Winding 2 Grounding DC Resistance	Enter the Secondary/low voltage winding Grounding DC Resistance in Ohms for any grounding device, (for a solidly grounded winding, enter 0, enter "99999" for ungrounded). For physical three-winding transformers modeled as three 2-winding transformers, enter "99999" for each transformer row.				R	R	
Transformer Data	X	X	X	X	X			List	Transformer Model	Enter 0 except for a phase-shifting transformer, which should be entered as a 1. For				R	R	

										physical three-winding transformers modeled as three 2-winding transformers, enter the same model for each transformer row.						
Transformer Data	X	X	X	X	X			mm/dd/yyyy	Effective Date:	Date this transformer was added, removed or updated in the model					R	
Transformer Data	X	X	X	X	X			p.u.	Primary to Tertiary Zero Sequence Resistance In p.u. (100 MVA Base at nominal system voltage)	Zero Sequence Resistance Primary-Tertiary (resistive component of Z1No) In p.u. on 100 MVA Base and adjusted from Manufactured Nominal Voltage to the nominal system voltage (eg. 69 kV, 138 kV, 345 kV) base. (Applicable for three-winding transformers, code 5).		R	R	R	R	
Transformer Data	X	X	X	X	X			p.u.	Primary to Tertiary Zero Sequence Reactance In p.u. (100 MVA Base at nominal system voltage)	Zero Sequence Reactance Primary-Tertiary (reactive component of Z1No) In p.u. on 100 MVA Base and adjusted from		R	R	R	R	

										Manufactured Nominal Voltage to the nominal system voltage (eg. 69 kV, 138 kV, 345 kV) base. (Applicable for three-winding transformers, code 5).						
Transformer Data	X	X	X	X	X			p.u.	Primary to Tertiary Positive Sequence Resistance In p.u. (100 MVA Base at nominal system voltage)	Positive Sequence Resistance Primary-Tertiary In p.u. on 100 MVA Base and adjusted from Manufactured Nominal Voltage to the nominal system voltage (eg. 69 kV, 138 kV, 345 kV) base. (Applicable for three-winding transformers, code 5).		R	R	R	R	
Transformer Data	X	X	X	X	X			p.u.	Primary to Tertiary Positive Sequence Reactance In p.u. (100 MVA Base at nominal system voltage)	Positive Sequence Reactance Primary-Tertiary In p.u. on 100 MVA Base and adjusted from Manufactured Nominal Voltage to the nominal system voltage (eg. 69 kV, 138 kV, 345 kV) base.		R	R	R	R	

										(Applicable for three-winding transformers, code 5).						
Transformer Data	X	X	X	X	X			MVA	Tertiary Normal Rating	The continuous MVA rating of the tertiary windings of the transformer, including substation terminal equipment in series with the transformer, at the applicable ambient temperature. The Transmission Element can operate at this rating indefinitely without damage, or violation of NESC clearances.		R	R	R	R	
Transformer Data	X	X	X	X	X			MVA	Tertiary 2-hr Emergency Rating	The two-hour MVA rating of the tertiary windings of the transformer, including substation terminal equipment in series with the transformer, at the applicable ambient temperature. The Transmission Element can operate at this		R	R	R	R	

										rating for two hours without violation of NESC clearances or equipment failure.						
Transformer Data	X	X	X	X	X			MVA	Tertiary 15-min Rating	The 15-minute MVA rating of the tertiary windings of the transformer, including substation terminal equipment in series with the transformer, at the applicable ambient temperature and with a step increase from a prior loading up to 90% of the Normal Rating. The transformer can operate at this rating for 15 minutes, assuming its pre-contingency loading up to 90% of the Normal Rating limit at the applicable ambient temperature, without violation of NESC clearances or equipment failure. This rating takes advantage		R	R	R	R	

										of the time delay associated with heating of the transformer following a sudden increase in current.						
Transformer Data	X	X	X	X	X			MVA	Tertiary Relay loadability Limit	Enter the rating in MVA that would cause the transformer to trip within 15 minutes of exceeding that value on the tertiary. If no overload trip relay exists, enter "99999"				R	R	
Transformer Data	X	X	X	X	X			p.u.	Secondary to Tertiary Zero Sequence Resistance In p.u. (100 MVA Base at nominal system voltage)	Zero Sequence Resistance Secondary-Tertiary (resistive component of Z2No) In p.u. on 100 MVA Base and adjusted from Manufactured Nominal Voltage to the nominal system voltage (eg. 69 kV, 138 kV, 345 kV) base. (Applicable for three-winding transformers, code 5).		R	R	R	R	
Transformer Data	X	X	X	X	X			p.u.	Secondary to Tertiary Zero Sequence Reactance In p.u.	Zero Sequence Reactance Secondary-Tertiary (reactive		R	R	R	R	

									(100 MVA Base at nominal system voltage)	component of Z2No) In p.u. on 100 MVA Base and adjusted from Manufactured Nominal Voltage to the nominal system voltage (eg. 69 kV, 138 kV, 345 kV) base. (Applicable for three-winding transformers, code 5).						
Transformer Data	X	X	X	X	X			p.u.	Secondary to Tertiary Positive Sequence Resistance In p.u. (100 MVA Base at nominal system voltage)	Positive Sequence Resistance Secondary-Tertiary In p.u. on 100 MVA Base and adjusted from Manufactured Nominal Voltage to the nominal system voltage (eg. 69 kV, 138 kV, 345 kV) base. (Applicable for three-winding transformers, code 5).		R	R	R	R	
Transformer Data	X	X	X	X	X			p.u.	Secondary to Tertiary Positive Sequence Reactance In p.u. (100 MVA Base at nominal system voltage)	Positive Sequence Reactance Secondary-Tertiary In p.u. on 100 MVA Base and adjusted from Manufactured Nominal Voltage		R	R	R	R	

										to the nominal system voltage (eg. 69 kV, 138 kV, 345 kV) base. (Applicable for three-winding transformers, code 5).						
Transformer Data	X	X	X	X	X			MVA	Secondary Winding Normal Rating	The continuous MVA rating of the secondary winding of the transformer, including substation terminal equipment in series with the transformer, at the applicable ambient temperature. The Transmission Element can operate at this rating indefinitely without damage, or violation of NESC clearances.		R	R	R	R	
Transformer Data	X	X	X	X	X			MVA	Secondary 2-hr Emergency Rating	The two-hour MVA rating of the secondary winding of the transformer, including substation terminal equipment in series with the transformer, at the		R	R	R	R	

										applicable ambient temperature. The Transmission Element can operate at this rating for two hours without violation of NESC clearances or equipment failure.						
Transformer Data	X	X	X	X	X			MVA	Secondary 15-min Rating	The 15-minute MVA rating of the secondary windings of the transformer, including substation terminal equipment in series with the transformer, at the applicable ambient temperature and with a step increase from a prior loading up to 90% of the Normal Rating. The transformer can operate at this rating for 15 minutes, assuming its pre-contingency loading up to 90% of the Normal Rating limit at the applicable		R	R	R	R	

										ambient temperature, without violation of NESC clearances or equipment failure. This rating takes advantage of the time delay associated with heating of the transformer following a sudden increase in current.						
Transformer Data	X	X	X	X	X			MVA	Secondary Relay loadability Limit	Enter the rating in MVA that would cause the transformer to trip within 15 minutes of exceeding that value on the secondary. If no overload trip relay exists, enter "99999"				R	R	
Transformer Data	X	X	X	X	X			kV	Tertiary Winding Voltage level (no-Load)	Enter the voltage level of the tertiary winding for this transformer				R	R	
Transformer Data	X	X	X	X	X			#	Tertiary Winding PTI Bus Number	Enter the PTI bus number for the tertiary of this transformer (Required if tertiary exists, with or without external connections.)				R	R	
Transformer Data	X	X	X	X	X			List	Tertiary Winding Voltage Connection - Wye or Delta	Select whether this tertiary connection is a		R	R	R	R	

										Wye or Delta connection						
Transformer Data	X	X	X	X	X			Device 1	Tertiary Winding Voltage Connected Devices	Enter a device connected to the tertiary winding of this transformer					R	
Transformer Data	X	X	X	X	X			kV	Tertiary Winding Manufactured Nominal Voltage (applicable for transformers code 5)	Enter the tertiary manufactured nominal voltage for this transformer (Applicable for three-winding transformers, code 5).		R	R	R	R	

Revised ERCOT Impact Analysis Report

RRGRR Number	030	RRGRR Title	Allow New Voltage Levels in Resource Asset Information
Impact Analysis Date	July 27, 2021		
Estimated Cost/Budgetary Impact	Less than $5k, which will be absorbed by the Operations & Maintenance (O&M) budgets of affected department.		
Estimated Time Requirements	No project required. This Resource Registration Glossary Revision Request (RRGRR) can take effect within 3-5 months after Public Utility Commission of Texas (PUCT) approval. See comments		
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: • Resource Integration and Ongoing Operations (RIOO) 100%		
ERCOT Business Function Impacts	No impacts to ERCOT business functions.		
Grid Operations & Practices Impacts	No impacts to ERCOT grid operations and practices.		

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

Comments
If approved, ERCOT plans to implement the Resource Integration system changes as part of a future phase of PR106-01, RARF Replacement.

Board Report

NPRR Number	<u>1077</u>	**NPRR Title**	**Extension of Self-Limiting Facility Concept to Settlement Only Generators (SOGs) and Telemetry Requirements for SOGs**
Date of Decision	December 10, 2021		
Action	Recommended Approval		
Timeline	Normal		
Proposed Effective Date	Upon system implementation		
Priority and Rank Assigned	Priority – 2022; Rank – 3550		
Nodal Protocol Sections Requiring Revision	2.1, Definitions 2.2, Acronyms and Abbreviations 3.8.7, Self-Limiting Facility 6.3.2, Activities for Real-Time Operations 6.5.5.2, Operational Data Requirements 16.11.4.3.2, Real-Time Liability Estimate		
Related Documents Requiring Revision/Related Revision Requests	Planning Guide Revision Request (PGRR) 092, Related to NPRR1077, Extension of Self-Limiting Facility Concept to Settlement Only Generators (SOGs) and Telemetry Requirements for SOGs Resource Registration Glossary Revision Request (RRGRR) 029, Related to NPRR1077, Extension of Self-Limiting Facility Concept to Settlement Only Generators (SOGs) and Telemetry Requirements for SOGs		
Revision Description	This Nodal Protocol Revision Request (NPRR) expands the Self-Limiting Facility concept introduced in NPRR1026, BESTF-7 Self-Limiting Facilities, to include sites with one or more Settlement Only Generators (SOGs). This NPRR also introduces a number of additional revisions to fully address requirements for generators and Energy Storage Systems (ESSs) that are connected at distribution voltage. In order to ensure that SOGs in Self-Limiting Facilities abide by established MW Injection and MW Withdrawal limits, and in order to ensure that ERCOT operators and system planners have clear visibility into the performance of SOGs, this NPRR requires the Qualified Scheduling Entity (QSE) for any SOG to provide telemetry of the injection or withdrawal at the Point of Interconnection (POI) (for transmission-connected sites) or Point of Common Coupling		

	(POCC) (for distribution-connected sites) as well as telemetry of gross real power injection and withdrawal at the generator terminals and the status of each SOG's breaker. Self-Limiting Facilities that include SOGs would be subject to the same consequences as other Self-Limiting Facilities when the MW Injection or MW Withdrawal limit is exceeded.
Reason for Revision	[X] Addresses current operational issues. [ ] Meets Strategic goals (tied to the ERCOT Strategic Plan or directed by the ERCOT Board). [X] Market efficiencies or enhancements [ ] Administrative [ ] Regulatory requirements [ ] Other: (explain) *(please select all that apply)*
Business Case	Since NPRR1026 was submitted, a number of developers have indicated to ERCOT that extending the Self-Limiting Facility concept to include SOGs would benefit the development of their facilities, primarily by allowing co-located storage and solar to share a common inverter without counting the aggregate output of each source of generation, which could trigger a more extensive interconnection process. ERCOT sees no reason that Self-Limiting Facility concept should not be extended to SOGs. However, to ensure that Self-Limiting Facility sites with SOGs comply with their established MW Injection and MW Withdrawal limits, this NPRR proposes to require telemetry of the MW Injection and MW Withdrawal values at the POI or POCC. In addition to facilitating enforcement of Self-Limiting Facility limits, this net telemetry will provide greater visibility of SOG performance to ERCOT operations and planning personnel. However, to further support this visibility, this NPRR also requires SOGs to provide telemetry of gross real power output or withdrawal, as measured at the generator terminals. The requirement to provide these additional telemetered values will satisfy one part of Item Number 7 on the TAC Emergency Conditions List, which identifies a need to "[e]xpand registration and Real-Time data requirements for all types of resources beyond current modeling requirements (e.g., distribution-level resources) to enhance situational awareness for planning and operational purposes." The telemetry requirements in this NPRR are consistent with ERCOT's existing authority in Section 3.10.7.3, Modeling of Private Use Networks, to require QSEs to provide gross and net generator telemetry for Settlement Only Transmission Self-

	Generators, but this NPRR extends this requirement to all SOGs, so as to give ERCOT better visibility for planning and operations. ERCOT notes that NPRR866, Mapping Registered Distributed Generation and Load Resources to Transmission Loads in the Network Operations Model, was implemented to map Settlement Only Distribution Generators (SODG) to their Common Information Model (CIM) Loads to provide better visibility to ERCOT operations using the Load telemetry. ERCOT subsequently developed in-house tools in an effort to indirectly measure the output from these generators. However, during 2021 Winter Storm Uri, the indirect measurements from Loads were ineffective for determining SODG output during Load shed, which highlighted the operational need for telemetry.
Credit Work Group Review	ERCOT Credit Staff and the Credit Work Group (Credit WG) have reviewed NPRR1077 and do not believe that it requires changes to credit monitoring activity or the calculation of liability.
PRS Decision	On 6/10/21, PRS voted unanimously via roll call to table NPRR1077 and refer the issue to ROS and WMS. All Market Segments participated in the vote. On 10/14/21, PRS voted via roll call to recommend approval of NPRR1077 as amended by the 8/16/21 ERCOT comments. There were two abstentions from the Independent Generator (Broad Reach Power) and Independent Power Marketer (IPM) (Morgan Stanley) Market Segments. All Market Segments participated in the vote. On 11/10/21, PRS voted via roll call to endorse and forward to TAC the 10/14/21 PRS Report and Revised Impact Analysis for NPRR1077 with a recommended priority of 2022 and rank of 3550. There was one abstention from the Consumer (Occidental) Market Segment. All Market Segments participated in the vote.
Summary of PRS Discussion	On 6/10/21, participants reviewed NPRR1077 and the 6/10/21 ERCOT comments, noted that NPRR1077 was developed out of the Distribution Generation Resource (DGR) workshops, and requested further review at ROS and WMS to understand the implications of requirements for all SOGs to provide telemetry at the distribution level. On 10/14/21, participants reviewed the 8/16/21 ERCOT comments. On 11/10/21, participants reviewed the Revised Impact Analysis.
TAC Decision	On 11/29/21, TAC voted unanimously via roll call to recommend approval of NPRR1077 as recommended by PRS in the 11/10/21

	PRS Report as amended by the 11/22/21 ERCOT comments. All Market Segments participated in the vote.
Summary of TAC Discussion	On 11/29/21, TAC reviewed the ERCOT Opinion, ERCOT Market Impact Statement, the Business Case, and the 11/22/21 ERCOT comments for NPRR1077.
ERCOT Opinion	ERCOT supports approval of NPRR1077.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NPRR1077 and believes NPRR1077 will benefit the development of facilities by allowing co-located storage and solar to share a common inverter without counting the aggregate output of each source of generation, and that net telemetry will provide greater visibility of SOG performance to ERCOT operations and planning personnel.
Board Decision	On 12/10/21, the ERCOT Board recommended approval of NPRR1077 as recommended by TAC in the 11/29/21 TAC Report.

Sponsor	
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Comments Received	
Comment Author	**Comment Summary**
ROS 060421	Requested PRS continue to table NPRR1077 for review by the Operations Working Group (OWG)

ERCOT 061021	Introduced revisions to clarify that net output will now be included in the estimate of Real-Time Liability (RTL) for all SOGs since ERCOT will have telemetry of net output for all SOGs
WMS 071321	Requested PRS continue to table NPRR1077
ERCOT 081621	Offered additional clarifications
WMS 090321	Endorsed NPRR1077 as amended by the 8/16/21 ERCOT comments
ROS 090321	Endorsed NPRR1077 as amended by the 8/16/21 ERCOT comments
ERCOT 112221	Added the acronym "POCC" for Point of Common Coupling

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:

- NPRR995, RTF-6 Create Definition and Terms for Settlement Only Energy Storage (incorporated 9/1/21)
  - Section 6.3.2
  - Section 6.5.5.2
  - Section 16.11.4.3.2
- NPRR1093, Load Resource Participation in Non-Spinning Reserve (incorporated 11/1/21)
  - Section 6.5.5.2

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

- NPRR1067, Market Entry Qualifications, Continued Participation Requirements, and Credit Risk Assessment
  - Section 16.11.4.3.2

Proposed Protocol Language Revision

2.1 DEFINITIONS

[NPRR1026: Insert the following definition "MW Injection" upon system implementation:]

MW Injection

The instantaneous Megawatt (MW) energy injected into the ERCOT System as measured at the Point of Interconnection (POI) or Point of Common Coupling (POCC).

[NPRR1026: Insert the following definition "MW Withdrawal" upon system implementation:]

MW Withdrawal

The instantaneous Megawatt (MW) energy withdrawn from the ERCOT System as measured at the Point of Interconnection (POI) or Point of Common Coupling (POCC).

Point of Common Coupling (POCC)

Any point where a Distribution Service Provider's facilities are connected to the Facilities of a Customer or a Generation Entity.

[NPRR1026: Insert the following definition "Self-Limiting Facility" upon system implementation:]

Self-Limiting Facility

A modeled generation station that includes one or more Generation Resources, Energy Storage Resources (ESRs), and/or Settlement Only Generators (SOGs) with an established limit on the total MW Injection that is less than the total nameplate capacity of all registered generators or Energy Storage Systems (ESSs) within the Facility. A Facility with one or more ESRs may also have an established limit on the MW Withdrawal that is less than the total nameplate MW Withdrawal rating of all ESRs within the facility.

2.2 ACRONYMS AND ABBREVIATIONS

PCAP	Pre-Contingency Action Plan
PCRR	Pre-Assigned Congestion Revenue Right
PNM	Peaker Net Margin
POLR	Provider of Last Resort
POC	Peaking Operating Cost
POCC	Point of Common Coupling
POI	Point of Interconnection
POIB	Point of Interconnection Bus
POS	Power Operating System
PRC	Physical Responsive Capability
PRM	Planning Reserve Margin
PRR	Protocol Revision Request
PRS	Protocol Revision Subcommittee
PSS	Power System Stabilizer

PTB	Price-to-Beat
PTP	Point-to-Point
PUCT	Public Utility Commission of Texas
PURA	Public Utility Regulatory Act, Title II, Texas Utility Code
PURPA	Public Utility Regulatory Policy Act
PV	PhotoVoltaic
PVGR	PhotoVoltaic Generation Resource
PVGRPP	PhotoVoltaic Generation Resource Production Potential
PWG	Profiling Working Group

[NPRR1026: Insert Section 3.8.7 below upon system implementation:]

3.8.7 Self-Limiting Facility

(1) A Resource Entity or Interconnecting Entity (IE) for a Self-Limiting Facility may establish a MW Injection or MW Withdrawal limit by submitting an attestation in a form designated by ERCOT through the Resource Registration process. The Resource Entity or IE shall simultaneously provide a copy of the attestation to the interconnecting Transmission and/or Distribution Service Provider (TDSP). All registered generators or Energy Storage Systems (ESSs) within a Self-Limiting Facility shall be represented by a single Resource Entity and a single Qualified Scheduling Entity (QSE).

(2) A Self-Limiting Facility shall not inject or withdraw power in excess of its established MW Injection limit or its established MW Withdrawal limit.

(3) On a monthly basis, ERCOT will report to the Reliability Monitor and IMM any instance where a Self-Limiting Facility's actual MW Injections exceeded the MW Injection limit or where actual MW Withdrawals exceeded the MW Withdrawal limit established in the Resource Registration data for the Self-Limiting Facility, based on the telemetry of the injection and withdrawal values provided by the QSE for the registered generator or ESS in the Self-Limiting Facility, as described in Section 3.9.1, Current Operating Plan (COP) Criteria, and in Section 6.5.5.2, Operational Data Requirements, or based on the meter data at the Point of Interconnection (POI) or Point of Common Coupling (POCC) for the Self-Limiting Facility.

(4) If requested by ERCOT, the relevant QSE shall provide meter data to confirm whether the established limits for a Self-Limiting Facility were violated.

(5) If ERCOT determines that a Self-Limiting Facility connected at transmission voltage has exceeded either its MW Injection limit or its MW Withdrawal limit established in the Resource Registration data by more than the greater of 5 MW or 3% of the limit, the Self-Limiting Facility shall submit a new generation interconnection request based on the installed MW capacity of the individual Resource(s) and shall deregister as a Self-Limiting Facility at the completion of the generation interconnection process. The Self-Limiting Facility shall be subject to the established MW Injection limit and any

established MW Withdrawal limit until the generation interconnection process has been completed.

(6) A Distribution Service Provider (DSP) may limit injections and withdrawals from any Generation Resource, Settlement Only Generator (SOG), or ESR based on Resource Registration data and the interconnection agreement between the DSP and the IE or Resource Entity. In that case, the IE or Resource Entity shall submit the attestation required by paragraph (1) above, and shall be considered a Self-Limiting Facility.

(7) If ERCOT determines that a Self-Limiting Facility connected at distribution voltage has exceeded either its MW Injection limit or its MW Withdrawal limit established in the Resource Registration data, the Self-Limiting Facility shall submit a new generation interconnection request based on the installed MW capacity of the individual Resource(s) and shall be deregistered as a Self-Limiting Facility at the completion of the generation interconnection process. The Self-Limiting Facility shall be subject to any MW Injection or MW Withdrawal limit until the generation interconnection process has been completed.

(8) The interconnecting TDSP, at its sole discretion, may use relaying to ensure a Self-Limiting Facility does not inject or withdraw energy in excess of its MW Injection or MW Withdrawal limits in order to protect the TDSP's limiting element(s).

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 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	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 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

Operating Period	QSE Activities	ERCOT Activities
		Restart Real-Time Sequence on major change of Resource or Transmission Element Status Monitor ERCOT total system capacity providing Ancillary Services Validate COP information 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 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

Operating Period	QSE Activities	ERCOT Activities
		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 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 the Settlement Point Prices for each Settlement Point 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, NPRR917, NPRR995, NPRR1000, NPRR1006, NPRR1010: Replace applicable portions of paragraph (2) above with the following upon system implementation for

NPRR829, NPRR904, NPRR917, NPRR995, NPRR1000, or NPRR1006; 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	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 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.

6.5.5.2 Operational Data Requirements

(1) ERCOT shall use Operating Period data to monitor and control the reliability of the ERCOT Transmission Grid and shall use it in network analysis software to predict the short-term reliability of the ERCOT Transmission Grid. Each TSP, at its own expense, may obtain that Operating Period data from ERCOT or directly from QSEs.

(2) A QSE representing a Generation Resource connected to Transmission Facilities or distribution facilities shall provide the following Real-Time telemetry data to ERCOT for each Generation Resource. ERCOT shall make that data available, in accordance with ERCOT Protocols, NERC Reliability Standards, and Governmental Authority requirements, to requesting TSPs and DSPs operating within ERCOT. Such data must be provided to the requesting TSP or DSP at the requesting TSP's or DSP's expense, including:

(a) Net real power (in MW) as measured by installed power metering or as calculated in accordance with the Operating Guides based on metered gross real power and conversion constants determined by the Resource Entity and provided to ERCOT through the Resource Registration process. Net real power represents the actual generation of a Resource for all real power dispatch purposes, including use in Security-Constrained Economic Dispatch (SCED), determination of the High Ancillary Service Limit (HASL), High Dispatch Limit (HDL), Low Dispatch Limit (LDL) and Low Ancillary Service Limit (LASL), and is consistent with telemetered HSL, LSL and Non-Frequency Responsive Capacity (NFRC);

(b) Gross real power (in MW) as measured by installed power metering or as calculated in accordance with the Operating Guides based on metered real power, which may include Supervisory Control and Data Acquisition (SCADA) metering, and conversions constants determined by the Resource Entity and provided to ERCOT through the Resource Registration process;

(c) Gross Reactive Power (in Megavolt-Amperes reactive (MVAr));

(d) Net Reactive Power (in MVAr);

(e) Power to standby transformers serving plant auxiliary Load;

(f) Status of switching devices in the plant switchyard not monitored by the TSP or DSP affecting flows on the ERCOT Transmission Grid;

(g) Any data mutually agreed to by ERCOT and the QSE to adequately manage system reliability;

(h) Generation Resource breaker and switch status;

(i) HSL (Combined Cycle Generation Resources) shall:

(i) Submit the HSL of the current operating configuration; and

(ii) When providing RRS, update the HSL as needed, to be consistent with Resource performance limitations of RRS provision;

(j) NFRC currently available (unloaded) and included in the HSL of the Combined Cycle Generation Resource's current configuration;

(k) High Emergency Limit (HEL), under Section 6.5.9.2, Failure of the SCED Process;

(l) Low Emergency Limit (LEL), under Section 6.5.9.2;

(m) LSL;

(n) Configuration identification for Combined Cycle Generation Resources;

(o) Ancillary Service Schedule for each quantity of RRS and Non-Spin which is equal to the Ancillary Service Resource Responsibility minus the amount of Ancillary Service deployment;

(i) For On-line Non-Spin, Ancillary Service Schedule shall be set to zero;

(ii) For Off-Line Non-Spin and for On-Line Non-Spin using Off-Line power augmentation technology the Ancillary Service Schedule shall equal the Non-Spin obligation and then shall be set to zero within 20 minutes following Non-Spin deployment;

(p) Ancillary Service Resource Responsibility for each quantity of Regulation Up Service (Reg-Up), Regulation Down Service (Reg-Down), RRS and Non-Spin. The sum of Ancillary Service Resource Responsibility for all Resources in a QSE is equal to the Ancillary Service Supply Responsibility for that QSE;

(q) Reg-Up and Reg-Down participation factors represent how a QSE is planning to deploy the Ancillary Service energy on a percentage basis to specific qualified Resource(s). The Reg-Up and Reg-Down participation factors for a Resource providing Fast Responding Regulation Up Service (FRRS-Up) or Fast Responding Regulation Down Service (FRRS-Down) shall be zero; and

(r) The designated Master QSE of a Generation Resource that has been split to function as two or more Split Generation Resources shall provide Real-Time telemetry for items (a), (b), (c), (d), (e), (g), and (h) above, PSS and AVR status for the total Generation Resource in addition to the Split Generation Resource the Master QSE represents.

[NPRR863, NPRR1010, NPRR1014, and NPRR1029: Replace applicable portions of paragraph (2) above with the following upon system implementation for NPRR863, NPRR1014, or NPRR1029; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010:]

(2) A QSE representing a Generation Resource connected to Transmission Facilities or distribution facilities shall provide the following Real-Time telemetry data to ERCOT for each Generation Resource. ERCOT shall make that data available, in accordance with ERCOT Protocols, NERC Reliability Standards, and Governmental Authority requirements, to requesting TSPs and DSPs operating within ERCOT. Such data must

be provided to the requesting TSP or DSP at the requesting TSP's or DSP's expense, including:

(a) Net real power (in MW) as measured by installed power metering or as calculated in accordance with the Operating Guides based on metered gross real power and conversion constants determined by the Resource Entity and provided to ERCOT through the Resource Registration process. Net real power represents the actual generation of a Resource for all real power dispatch purposes, including use in Security-Constrained Economic Dispatch (SCED), High Dispatch Limit (HDL), and Low Dispatch Limit (LDL), and is consistent with telemetered HSL, LSL, and Frequency Responsive Capacity (FRC);

(b) Gross real power (in MW) as measured by installed power metering or as calculated in accordance with the Operating Guides based on metered real power, which may include Supervisory Control and Data Acquisition (SCADA) metering, and conversions constants determined by the Resource Entity and provided to ERCOT through the Resource Registration process;

(c) Gross Reactive Power (in Megavolt-Amperes reactive (MVAr));

(d) Net Reactive Power (in MVAr);

(e) Power to standby transformers serving plant auxiliary Load;

(f) Status of switching devices in the plant switchyard not monitored by the TSP or DSP affecting flows on the ERCOT Transmission Grid;

(g) Any data mutually agreed to by ERCOT and the QSE to adequately manage system reliability;

(h) Generation Resource breaker and switch status;

(i) HSL (Combined Cycle Generation Resources) shall:

    (i) Submit the HSL of the current operating configuration; and

    (ii) When providing ECRS, update the HSL as needed, to be consistent with Resource performance limitations of ECRS provision;

(j) For Resources with capacity that is not capable of providing Primary Frequency Response (PFR), the current FRC of the Resource;

(k) High Emergency Limit (HEL), under Section 6.5.9.2, Failure of the SCED Process;

(l) Low Emergency Limit (LEL), under Section 6.5.9.2;

(m) LSL;

(n) Configuration identification for Combined Cycle Generation Resources;

(o) For Resources with capacity that is not capable of providing PFR, the high and low limits in MW of the Resource's capacity that is frequency responsive;

(p) For RRS, including any sub-categories of RRS, the physical capability (in MW) of the Resource to provide RRS;

(q) For Ancillary Services other than RRS, a blended Normal Ramp Rate (in MW/min) that reflects the physical capability of the Resource to provide that specific type of Ancillary Service;

(r) Five-minute blended Normal Ramp Rates (up and down);

(s) The designated Master QSE of a Generation Resource that has been split to function as two or more Split Generation Resources shall provide Real-Time telemetry for items (a), (b), (c), (d), (e), (g), and (h) above, PSS and AVR status for the total Generation Resource in addition to the Split Generation Resource the Master QSE represents; and

(t) The telemetered MW of power augmentation capacity that is not On-Line for Resources that have power augmentation capacity included in HSL.

(3) For each Intermittent Renewable Resource (IRR), the QSE shall set the HSL equal to the current net output capability of the facility. The net output capability should consider the net real power of the IRR generation equipment, IRR generation equipment availability, weather conditions, and whether the IRR net output is being affected by compliance with a SCED Dispatch Instruction.

(4) For each Aggregate Generation Resource (AGR), the QSE shall telemeter the number of its generators online.

(5) A QSE representing a Load Resource connected to Transmission Facilities or distribution facilities shall provide the following Real-Time data to ERCOT for each Load Resource and ERCOT shall make the data available, in accordance with ERCOT Protocols, NERC standards and policies, and Governmental Authority requirements, to the Load Resource's host TSP or DSP at the TSP's or DSP's expense. The Load Resource's net real power consumption, Low Power Consumption (LPC) and Maximum Power Consumption (MPC) shall be telemetered to ERCOT using a positive (+) sign convention:

(a) Load Resource net real power consumption (in MW);

(b) Any data mutually agreed to by ERCOT and the QSE to adequately manage system reliability;

(c) Load Resource breaker status;

(d) LPC (in MW);

(e) MPC (in MW);

(f) Ancillary Service Schedule (in MW) for each quantity of RRS and Non-Spin, which is equal to the Ancillary Service Resource Responsibility minus the amount of Ancillary Service deployment;

(g) Ancillary Service Resource Responsibility (in MW) for each quantity of Reg-Up and Reg-Down for Controllable Load Resources, and RRS and Non-Spin for all Load Resources;

(h) The status of the high-set under-frequency relay, if required for qualification;

(i) For a Controllable Load Resource providing Non-Spin, the Scheduled Power Consumption that represents zero Ancillary Service deployments;

(j) For a single-site Controllable Load Resource with registered maximum Demand response capacity of ten MW or greater, net Reactive Power (in MVAr);

(k) Resource Status (Resource Status shall be ONRL if high-set under-frequency relay is active);

(l) Reg-Up and Reg-Down participation factor, which represents how a QSE is planning to deploy the Ancillary Service energy on a percentage basis to specific qualified Resource(s). The Reg-Up and Reg-Down participation factors for a Resource providing FRRS-Up or FRRS-Down shall be zero; and

(m) For a Controllable Load Resource providing Non-Spin, the "Scheduled Power Consumption Plus Two Hours," representing the QSE's forecast of the Controllable Load Resource's instantaneous power consumption for a point two hours in the future.

[NPRR863, NPRR1010, NPRR1029, and NPRR1093: Replace applicable portions of paragraph (5) above with the following upon system implementation for NPRR863, NPRR1029, or NPRR1093; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010:]

(5) A QSE representing a Load Resource connected to Transmission Facilities or distribution facilities shall provide the following Real-Time data to ERCOT for each Load Resource and ERCOT shall make the data available, in accordance with ERCOT Protocols, NERC standards and policies, and Governmental Authority requirements, to the Load Resource's host TSP or DSP at the TSP's or DSP's expense. The Load Resource's net real power consumption, Low Power Consumption (LPC) and

Maximum Power Consumption (MPC) shall be telemetered to ERCOT using a positive (+) sign convention:

(a) Load Resource net real power consumption (in MW);

(b) Any data mutually agreed to by ERCOT and the QSE to adequately manage system reliability;

(c) Load Resource breaker status, if applicable;

(d) LPC (in MW);

(e) MPC (in MW);

(f) The Load Resource's Ancillary Service self-provision (in MW) for RRS and/or ECRS provided via under-frequency relay;

(g) The status of the high-set under-frequency relay, if required for qualification. The under-frequency relay for a Load Resource providing Non-Spin shall be disabled and the status of that relay shall indicate it as disabled or unarmed;

(h) For a Controllable Load Resource providing Non-Spin, the Scheduled Power Consumption that represents zero Ancillary Service deployments;

(i) For a single-site Controllable Load Resource with registered maximum Demand response capacity of ten MW or greater, net Reactive Power (in MVAr);

(j) Resource Status;

(k) For a Controllable Load Resource providing Non-Spin, the "Scheduled Power Consumption Plus Two Hours," representing the QSE's forecast of the Controllable Load Resource's instantaneous power consumption for a point two hours in the future;

(l) For RRS, including any sub-categories of RRS, the current physical capability (in MW) of the Resource to provide RRS;

(m) For Ancillary Service products other than RRS, a blended Normal Ramp Rate (in MW/min) that reflects the current physical capability of the Resource's ability to provide a particular Ancillary Service product; and

(n) For a Controllable Load Resource, 5-minute blended Normal Ramp Rates (up and down).

[NPRR1014 and NPRR1029: Insert applicable portions of paragraph (6) below upon system implementation and renumber accordingly:]

(6) A QSE representing an ESR connected to Transmission Facilities or distribution facilities shall provide the following Real-Time telemetry data to ERCOT for each ESR. ERCOT shall make that data available, in accordance with ERCOT Protocols, NERC Reliability Standards, and Governmental Authority requirements, to requesting TSPs and DSPs operating within ERCOT. Such data must be provided to the requesting TSP or DSP at the requesting TSP's or DSP's expense, including:

(a) Net real power consumption or output (in MW) as measured by installed power metering or as calculated in accordance with the Operating Guides based on metered gross real power and conversion constants determined by the Resource Entity and provided to ERCOT through the Resource Registration process. Net real power represents the actual generation or consumption of an ESR for all real power dispatch purposes, including use in Security-Constrained Economic Dispatch (SCED), in determination of High Dispatch Limit (HDL), and Low Dispatch Limit (LDL) and is consistent with telemetered HSL, LSL and Frequency Responsive Capacity (FRC);

(b) Gross real power consumption or output (in MW) as measured by installed power metering or as calculated in accordance with the Operating Guides based on metered real power, which may include Supervisory Control and Data Acquisition (SCADA) metering, and conversion constants determined by the Resource Entity and provided to ERCOT through the Resource Registration process;

(c) Gross Reactive Power (in Megavolt-Amperes reactive (MVAr));

(d) Net Reactive Power (in MVAr);

(e) Power to standby transformers serving plant auxiliary Load;

(f) Status of switching devices in the plant switchyard not monitored by the TSP or DSP affecting flows on the ERCOT Transmission Grid;

(g) Any data mutually agreed to by ERCOT and the QSE to adequately manage system reliability;

(h) ESR breaker and switch status;

(i) HSL;

(j) High Emergency Limit (HEL), under Section 6.5.9.2, Failure of the SCED Process;

(k) Low Emergency Limit (LEL), under Section 6.5.9.2;

(l) LSL;

(m) For RRS, including any sub-category of RRS, the current physical capability (in MW) of the Resource to provide RRS;

(n) For Ancillary Services other than RRS, a blended ramp rate (in MW/min) that reflects the current physical capability of the Resource to provide that specific type of Ancillary Service; and

(o) Five-minute blended normal up and down ramp rates;

(6) A QSE with Resources used in SCED shall provide communications equipment to receive ERCOT-telemetered control deployments.

(7) A QSE providing any Regulation Service shall provide telemetry indicating the appropriate status of Resources providing Reg-Up or Reg-Down, including status indicating whether the Resource is temporarily blocked from receiving Reg-Up and/or Reg-Down deployments from the QSE. This temporary blocking will be indicated by the enabling of the Raise Block Status and/or Lower Block Status telemetry points.

(a) Raise Block Status and Lower Block Status are telemetry points used in transient unit conditions to communicate to ERCOT that a Resource's ability to adjust its output has been unexpectedly impaired.

(b) When one or both of the telemetry points are enabled for a Resource, ERCOT will cease using the regulation capacity assigned to that Resource for Ancillary Service deployment.

(c) This hiatus of deployment will not excuse the Resource's obligation to provide the Ancillary Services for which it has been committed.

[NPRR1010, NPRR1014, and NPRR1029: Replace applicable portions of paragraph (c) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010; or upon system implementation for NPRR1014 or NPRR1029:]

(c) This hiatus of deployment will not excuse the Resource's obligation to provide the Ancillary Services for which it has been awarded.

(d) These telemetry points shall only be utilized during unforeseen transient unit conditions such as plant equipment failures. Raise Block Status and Lower Block Status shall only be enabled until the Resource operator has time to update the Resource limits and Ancillary Service telemetry to reflect the problem.

(e) The Resource limits and Ancillary Service telemetry shall be updated as soon as practicable. Raise Block Status and Lower Block Status will then be disabled.

(8) Real-Time data for reliability purposes must be accurate to within three percent. This telemetry may be provided from relaying accuracy instrumentation transformers.

(9) Each QSE shall report the current configuration of combined-cycle Resources that it represents to ERCOT. The telemetered Resource Status for a Combined Cycle Generation Resource may only be assigned a Resource Status of OFFNS if no generation units within that Combined Cycle Generation Resource are On-Line.

[NPRR1010, NPRR1014, and NPRR1029: Replace applicable portions of paragraph (9) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010; or upon system implementation for NPRR1014 or NPRR1029:]

(9) Each QSE shall report the current configuration of combined-cycle Resources that it represents to ERCOT. The telemetered Resource Status for a Combined Cycle Generation Resource may only be assigned a Resource Status of OFF if no generation units within that Combined Cycle Generation Resource are On-Line.

(10) A QSE representing Combined Cycle Generation Resources shall provide ERCOT with the possible operating configurations for each power block with accompanying limits. Combined Cycle Train power augmentation methods may be included as part of one or more of the registered Combined Cycle Generation Resource configurations. Power augmentation methods may include:

(a) Combustion turbine inlet air cooling methods;

(b) Duct firing;

(c) Other ways of temporarily increasing the output of Combined Cycle Generation Resources; and

(d) For Qualifying Facilities (QFs), an LSL that represents the minimum energy available for Dispatch by SCED, in MW, from the Combined Cycle Generation Resource based on the minimum stable steam delivery to the thermal host plus a justifiable reliability margin that accounts for changes in ambient conditions.

(11) A QSE representing Generation Resources other than Combined Cycle Generation Resources may telemeter an NFRC value for their Generation Resource only if the QSE or Resource Entity associated with that Generation Resource has first requested and obtained ERCOT's approval of the Generation Resource's NFRC quantity.

[NPRR1010, NPRR1014, and NPRR1029: Replace applicable portions of paragraph (11) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010; or upon system implementation for NPRR1014 or NPRR1029:]

(11) A QSE representing a Generation Resource other than a Combined Cycle Generation Resource may provide FRC telemetry for the Generation Resource only if the QSE or Resource Entity associated with that Generation Resource has first requested and obtained ERCOT's approval.

(12) A QSE representing an Energy Storage Resource (ESR) shall provide the following Real-Time telemetry data to ERCOT for each ESR:

(a) Maximum Operating State of Charge, in MWh;

(b) Minimum Operating State of Charge, in MWh;

(c) State of Charge, in MWh;

(d) Maximum Operating Discharge Power Limit, in MW; and

(e) Maximum Operating Charge Power Limit, in MW.

(13) In accordance with ERCOT Protocols, NERC Reliability Standards, and Governmental Authority requirements, ERCOT shall make the data specified in paragraph (12) available to any requesting TSP or DSP at the requesting TSP's or DSP's expense.

(14) Except as provided in paragraph (15) below, a QSE representing a Settlement Only Generator (SOG) shall provide ERCOT the following Real-Time telemetry:

(a) Net real power injection at the Point of Interconnection (POI) or Point of Common Coupling (POCC) for each site with one or more SOGs;

(b) For any site with one or more ESSs that are registered as an SOG, net real power withdrawal at the POI or POCC;

(c) For each inverter at the site, gross real power output measured at the generator terminals for all SOGs that are located behind that inverter, separately aggregated by fuel type;

(d) For SOGs at the same site that are not located behind an inverter, gross real power output measured at the generator terminals for all SOGs, separately aggregated by fuel type;

(e) For any site with one or more ESSs registered as an SOG, for each inverter, gross real power withdrawal by all such ESSs that are located behind that inverter, as measured at the generator terminals; and

(f) Generator breaker status.

(15) A QSE is not required to provide telemetry for an SODG if:

(a) the site that includes the SODG has not exported more than 10 MWh in any calendar year, exclusive of any energy exported during any Settlement Interval in which an ERCOT-declared Energy Emergency Alert (EEA) is in effect;

(b) the QSE or Resource Entity for the SODG has submitted a written request to ERCOT seeking an exemption from the telemetry requirements under this paragraph; and

(c) ERCOT has provided the QSE or Resource Entity written confirmation that the SODG is exempt from providing telemetry under this paragraph.

(16) If ERCOT determines that a site that includes an SODG has exported more than 10 MWh in a given calendar year, it shall notify the SODG's QSE that the SODG is no longer eligible for the telemetry exemption. Within 90 days of receiving this notification, the QSE for the SODG shall comply with the telemetry requirements of paragraph (14) above.

[NPRR885: Insert paragraph (17) below upon system implementation:]

(17) A QSE representing a Must-Run Alternative (MRA) shall telemeter the MRA MW currently available (unloaded) and not included in the HSL.

[NPRR1029: Insert paragraph (18) below upon system implementation:]

(18) A QSE representing a DC-Coupled Resource shall provide the following Real-Time telemetry data in addition to that required for other Energy Storage Resources (ESRs):

(a) Gross AC MW production of the intermittent renewable generation component of the DC-Coupled Resource, which includes the portion of the intermittent renewable generation used to charge the Energy Storage System (ESS) and/or serve auxiliary Load on the DC side of the inverter; and

(b) Gross AC MW capability of the intermittent renewable generation component of the DC-Coupled Resource, based on Real-Time conditions.

[NPRR995: Insert paragraph (17) below upon system implementation:]

(17) A QSE representing a Settlement Only Energy Storage System (SOESS) that elects to include the net generation and/or net withdrawals of the SOESS in the estimate of Real-Time Liability (RTL) shall provide ERCOT Real-Time telemetry of the net generation and/or net withdrawals of the SOESS.

16.11.4.3.2 Real-Time Liability Estimate

(1) ERCOT shall estimate RTL for an Operating Day as the sum of estimates for the following RTM Settlement charges and payments:

(a) Section 6.6.3.1, Real-Time Energy Imbalance Payment or Charge at a Resource Node, using Real-Time Metered Generation (RTMG) as generation estimate;

(b) Section 6.6.3.2, Real-Time Energy Imbalance Payment or Charge at a Load Zone, using 14-day or seven-day-old LRS for Load estimate;

[NPRR829: Replace item (b) above with the following upon system implementation:]

(b) Section 6.6.3.2, Real-Time Energy Imbalance Payment or Charge at a Load Zone, using 14-day or seven-day-old LRS for Load estimate and Real-Time telemetry of net generation as the generation estimate;

(c) Section 6.6.3.3, Real-Time Energy Imbalance Payment or Charge at a Hub;

(d) Section 6.6.3.4, Real-Time Energy Payment for DC Tie Import;

(e) Section 6.6.3.6, Real-Time Energy Charge for DC Tie Export Represented by the QSE Under the Oklaunion Exemption;

[NPRR1054: Delete item (e) above upon system implementation and renumber accordingly.]

[NPRR917 and NPRR995: Insert applicable portions of item (f) below upon system implementation and renumber accordingly:]

(f) Section 6.6.3.9, Real-Time Payment or Charge for Energy from a Settlement Only Distribution Generator (SODG), Settlement Only Transmission Generator (SOTG), Settlement Only Distribution Energy Storage System (SODESS), or Settlement Only Transmission Energy Storage System (SOTESS), using the

Real-Time telemetry of net generation as the outflow estimate and the Real-Time Price for each SODG, SOTG, SODESS, or SOTESS site;

(f) Section 6.6.4, Real-Time Congestion Payment or Charge for Self-Schedules; and

[NPRR1013: Insert items (g)-(k) below upon system implementation of the Real-Time Co-Optimization (RTC) project and renumber accordingly:]   (g) Section 6.7.5.1, Regulation Up Payments and Charges;   (h) Section 6.7.5.2, Regulation Down Payments and Charges;   (i) Section 6.7.5.3, Responsive Reserve Payments and Charges;   (j) Section 6.7.5.4, Non-Spinning Reserve Payments and Charges; and   (k) Section 6.7.5.5, ERCOT Contingency Reserve Service Payments and Charges.

(g) Section 7.9.2.1, Payments and Charges for PTP Obligations Settled in Real-Time.

Revised ERCOT Impact Analysis Report

NPRR Number	**1077**	**NPRR Title**	**Extension of Self-Limiting Facility Concept to Settlement Only Generators (SOGs) and Telemetry Requirements for SOGs**
Impact Analysis Date		August 3, 2021	
Estimated Cost/Budgetary Impact		Between $100k and $160k Additional Cost to Implement in Passport: N/A	
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. Please see the Project Priority List (PPL) for additional information. Estimated project duration: 7 to 10 months in current systems Passport Schedule Risk Assessment: Potential Risk to Schedule	
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: • Resource Integration and Ongoing Operations (RIOO) 46% • Energy Management System (EMS) 43% • Grid Modeling Systems 11%	
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	**<u>1091</u>**	**NPRR Title**	**Changes to Address Market Impacts of Additional Non-Spin Procurement**
Date of Decision	December 10, 2021		
Action	Recommended Approval		
Timeline	Urgent – to ensure that the system changes necessary to implement Nodal Protocol Revision Request (NPRR) 1091 can be considered along with the system changes related to NPRR1093, Load Resource Participation in Non-Spinning Reserve, and NPRR1101, Create Non-Spin Deployment Groups made up of Generation Resources Providing Off-Line Non-Spinning Reserve and Load Resources that are Not Controllable Load Resources Providing Non-Spinning Reserve		
Proposed Effective Date	Upon system implementation		
Priority and Rank Assigned	Priority – 2022; Rank – 3195		
Nodal Protocol Sections Requiring Revision	4.4.7.1, Self-Arranged Ancillary Service Quantities 6.4.4.1, Energy Offer Curve for On-Line Non-Spinning Reserve Capacity 6.5.7.3.1, Determination of Real-Time On-Line Reliability Deployment Price Adder 6.5.7.6.2.3, Non-Spinning Reserve Service Deployment		
Related Documents Requiring Revision/Related Revision Requests	None		
Revision Description	This NPRR makes two changes to address the energy price suppression and liquidity issues created by ERCOT's urgent change to procure more Ancillary Service and deploying it early. Specifically, this NPRR: • Extends the treatment of must-take energy from Reliability Unit Commitments (RUCs) in pricing run to Off-Line Non-Spinning Reserve (Non-Spin), when it is manually deployed, by setting the Low Sustained Limit (LSL), Low Ancillary Service Limit (LASL), and Low Dispatch Limit (LDL) of Off-Line Non-Spin Resources to zero in the pricing run; and • Increases the amount of Responsive Reserve (RRS) and Non-Spin that an Entity can self-arrange above its obligation.		
Reason for Revision	☒ Addresses current operational issues.		

Board Report

	☐ Meets Strategic goals (tied to the ERCOT Strategic Plan or directed by the ERCOT Board). ☒ Market efficiencies or enhancements ☐ Administrative ☐ Regulatory requirements ☐ Other: (explain) *(please select all that apply)*
Business Case	The recent urgent change in procuring additional Ancillary Services (sometimes up to three times current value) and Other Binding Document Revision Request (OBDRR) 031, Change Non-Spinning Reserve Service Deployment, change to deploy it early, could cause significant amount of price-taker energy to be pumped into the system which in turn could cause price reversal. To mitigate the price reversal impacts of this action needed to maintain reliability, the Off-Line Non-Spin should have an offer floor and the must-take 0-LDL energy from the out-of-market action should be allowed to set price in the pricing run when Off-Line Non-Spin is manually deployed. Only Entities with Resources can offer Ancillary Services in the Day-Ahead Market (DAM). From bilateral trades done to hedge estimated obligation, Entities without Resources could have Ancillary Services in excess of their obligation because it is hard to exactly estimate the obligation. Since the amount of Non-Spin procured could change significantly between days now with the new change, increasing the flexibility to sell back extra hedges would increase liquidity in the market and help Entities procure/provide better hedges for these services without worrying about potential to forfeit additional quantities that they have procured.
Credit Work Group Review	ERCOT Credit Staff and the Credit Work Group (Credit WG) have reviewed NPRR1091 and do not believe that it requires changes to credit monitoring activity or the calculation of liability.
PRS Decision	On 9/16/21, PRS unanimously voted via roll call to table NPRR1091 and refer the issue to WMS. The Independent Retail Electric Provider (IREP) Market Segment did not participate in the vote. On 11/10/21, PRS voted via roll call to grant NPRR1091 Urgent status; to recommend approval of NPRR1091 as amended by the 11/8/21 WMS comments; and to forward to TAC NPRR1091. There was one abstention from the Consumer (Occidental Chemical) Market Segment. All Market Segments participated in the vote.

Board Report

Summary of PRS Discussion	On 9/16/21, the sponsor provided an overview of NPRR1091. Participants requested further discussion at WMS. On 11/10/21, participants reviewed the 11/8/21 WMS comments and 11/9/21 Shell comments.
TAC Decision	On 11/29/21, TAC unanimously voted via roll call to recommend approval of NPRR1091 as recommended by PRS in the 11/10/21 PRS Report with a recommended priority of 2022 and rank of 3195. All Market Segments participated in the vote.
Summary of TAC Discussion	On 11/29/21, TAC reviewed the Business Case, ERCOT Opinion, and ERCOT Market Impact Statement for NPRR1091.
ERCOT Opinion	ERCOT supports approval of NPRR1091.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NPRR1091 and believes the market impact for NPRR1091 addresses potential energy price suppression and liquidity issues related to recent changes in Non-Spin.
ERCOT Board Decision	On 12/10/21, the ERCOT Board recommended approval of NPRR1091 as recommended by TAC in the 11/29/21 TAC Report.

Sponsor	
Name	Resmi Surendran
E-mail Address	resmi.surendran@shell.com
Company	Shell Energy North America
Phone Number	346-234-0691
Cell Number	512-289-7131
Market Segment	Independent Power Marketer (IPM)

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

Comments Received	
Comment Author	**Comment Summary**

WMS 101221	Requested PRS continue to table NPRR1091 for further review by the Wholesale Market Working Group (WMWG)
WMS 110821	Proposed edits to Sections 6.4.4.1 and 6.5.7.6.2.3 to remove the proposed $75/MWh offer floor for Off-Line Non-Spin
Shell 110921	Endorsed the 11/8/21 WMS comments and requested PRS grant NPRR1091 Urgent status

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:

- NPRR1093, Load Resource Participation in Non-Spinning Reserve (incorporated 11/1/21)
  - Section 6.5.7.3.1
  - Section 6.5.7.6.2.3

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

- NPRR1101, Create Non-Spin Deployment Groups made up of Generation Resources Providing Off-Line Non-Spinning Reserve and Load Resources that are Not Controllable Load Resources Providing Non-Spinning Reserve
  - Section 6.5.7.6.2.3

Proposed Protocol Language Revision

4.4.7.1 Self-Arranged Ancillary Service Quantities

(1) For each Ancillary Service, a QSE may self-arrange all or a portion of the Ancillary Service Obligation allocated to it by ERCOT. QSEs may not self-arrange Regulation Service amounts that include Fast Responding Regulation Up Service (FRRS-Up) or Fast Responding Regulation Down Service (FRRS-Down) quantities. In addition, a QSE may self-arrange up to 150 MW of Responsive Reserve (RRS), 25 MW of Regulation Up Service (Reg-Up), 25 MW of Regulation Down Service (Reg-Down), and 300 MW of Non-Spinning Reserve (Non-Spin) in excess of its corresponding Ancillary Service Obligation, provided that the amount self-arranged from the QSE's Resources for a given Ancillary Service shall not exceed the amount of the QSE's Ancillary Services Obligation for that Ancillary Service. If a QSE elects to self-arrange Ancillary Service capacity, then ERCOT shall not pay the QSE for the Self-Arranged Ancillary Service Quantities for the portion that meets its Ancillary Service Obligation. Any Self-Arranged Ancillary Service Quantities in excess of a QSE's Ancillary Service Obligation will be considered to be offered in the DAM or Supplemental Ancillary Service Market (SASM), as applicable, for $0/MWh.

[NPRR863 and NPRR1008: Replace applicable portions of paragraph (1) above with the following upon system implementation or upon system implementation of the Real-Time Co-Optimization project, respectively:]

(1) For each Ancillary Service, a QSE may self-arrange all or a portion of the advisory Ancillary Service Obligation allocated to it by ERCOT, subject to the QSE's share of system-wide limits as established by Section 3.16, Standards for Determining Ancillary Service Quantities. If a QSE elects to self-arrange Ancillary Service capacity, then ERCOT shall not pay the QSE for the Self-Arranged Ancillary Service Quantities for the portion that meets its final Ancillary Service Obligation; ERCOT shall pay the QSE the respective Day-Ahead Ancillary Service price for any Self-Arranged Ancillary Service Quantities that exceed a QSE's final Ancillary Service Obligation.

(2) The QSE must indicate before 1000 in the Day-Ahead the Self-Arranged Ancillary Service Quantities, by service, so ERCOT can determine how much Ancillary Service capacity, by service, needs to be obtained through the DAM.

[NPRR1008: Replace paragraph (2) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(2) The QSE must indicate before 1000 in the Day-Ahead the Self-Arranged Ancillary Service Quantities, by service, so ERCOT can determine how much Ancillary Service capacity, by service, remains to be obtained based on DAM offers and associated Ancillary Service Demand Curves (ASDCs).

(3) At or after 1000 in the Day-Ahead, a QSE may not change its Self-Arranged Ancillary Service Quantities unless ERCOT opens a SASM.

[NPRR1008: Replace paragraph (3) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(3) At or after 1000 in the Day-Ahead, a QSE may not change its Self-Arranged Ancillary Service Quantities.

(4) Before 1430 in the Day-Ahead, all Self-Arranged Ancillary Service Quantities must be represented by physical capacity, either by Generation Resources or Load Resources, or backed by Ancillary Service Trades.

(5) The QSE may self-arrange Reg-Up, Reg-Down, RRS, and Non-Spin.

[NPRR863: Replace paragraph (5) above with the following upon system implementation:]

(5) The QSE may self-arrange Reg-Up, Reg-Down, ECRS, RRS, and Non-Spin.

(6) The QSE may self-arrange Ancillary Services from one or more Resources it represents and/or through an Ancillary Service Trade.

(7) The additional Self-Arranged Ancillary Service Quantity specified by the QSE in response to a SASM notice by ERCOT to obtain additional Ancillary Services in the Adjustment Period cannot be more than 100 MWs of RRS, 25 MWs of Reg-Up, 25 MWs of Reg-Down, and 100 MWs of Non-Spin greater than the additional Ancillary Service amount allocated by ERCOT to that QSE, as stated in the SASM notice, and cannot be changed once committed to ERCOT.

[NPRR863: Replace paragraph (7) above with the following upon system implementation:]

(7) The additional Self-Arranged Ancillary Service Quantity specified by the QSE in response to a SASM notice by ERCOT to obtain additional Ancillary Services in the Adjustment Period cannot be more than 100 MW of ECRS, 100 MW of RRS, 25 MW of Reg-Up, 25 MW of Reg-Down, and 50 MW of Non-Spin greater than the additional Ancillary Service amount allocated by ERCOT to that QSE, as stated in the SASM notice, and cannot be changed once committed to ERCOT.

(8) If a QSE does not self-arrange all of its Ancillary Service Obligation, ERCOT shall procure the remaining amount of that QSE's Ancillary Service Obligation.

[NPRR1008: Replace paragraphs (7) and (8) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project and renumber accordingly:]

(7) A QSE shall not submit Ancillary Services trades that result in the QSE's purchased quantities of Ancillary Services exceeding the QSE's Self-Arranged Ancillary Service Quantities.

(a) At 1430 in the Day-Ahead, ERCOT shall post a report on the MIS Certified Area to notify the QSE if there is an overage in the QSE's purchased quantities of Ancillary Services in violation of the above limitation.

(b) If the QSE has such an overage as of the end of the Adjustment Period, that QSE will be charged for any quantity that exceeds their Self-Arranged

Ancillary Service Quantities per Section 6.7.5.1, Real-Time Ancillary Service Imbalance Payment or Charge.

(9) For self-arranged RRS Service, the QSE shall indicate the quantity of the service that is provided from:

(a) Generation Resources;

(b) Controllable Load Resources; and

(c) Fast Frequency Response (FFR) Resources and/or Load Resources controlled by high-set under-frequency relays.

[NPRR863 and NPRR1015: Replace applicable portions of paragraph (9) above with the following upon system implementation:]

(9) For self-arranged RRS, the QSE shall indicate the quantity of the service that is provided from:

(a) Resources providing Primary Frequency Response;

(b) Load Resources controlled by high-set under-frequency relays; and

(c) Fast Frequency Response (FFR) Resources.

(10) For self-arranged ECRS, the QSE shall indicate the quantity of the service that is provided from Resources that are manually dispatched and those that are SCED-dispatchable.

6.4.4.1 Energy Offer Curve for On Line Non-Spinning Reserve Capacity

(1) The following applies to Generation Resources that a QSE assigns Non-Spinning Reserve (Non-Spin) Ancillary Service Resource Responsibility in its COP to meet the QSE's Ancillary Service Supply Responsibility for Non-Spin and applies to On Line Non-Spin assignments arising as the result of Day-Ahead Market (DAM) or Supplemental Ancillary Services Market (SASM) Ancillary Service awards, or Self-Arranged Ancillary Service Quantity.

(a) Prior to the end of the Adjustment Period for an Operating Hour during which a Generation Resource is assigned On Line Non-Spin Ancillary Service Resource Responsibility, the QSE shall ensure that a valid Output Schedule or Energy Offer Curve for the Operating Hour has been submitted and accepted by ERCOT. The

Energy Offer Curves submitted by the QSE for the capacity assigned to Non-Spin may not be offered at less than $75 per MWh.

(b) If the QSE also assigns Responsive Reserve (RRS) and/or Regulation Up Service (Reg-Up) to a Generation Resource that has been assigned Non-Spin, the QSE shall ensure that a valid Output Schedule or Energy Offer Curve for the Operating Hour has been submitted and accepted by ERCOT. The Energy Offer Curves submitted by the QSE for the capacity assigned to the sum of the RRS, Reg-Up, and Non-Spin Ancillary Service Resource Responsibilities, as well as any Non-Frequency Responsive Capacity (NFRC) that is above the Resource's High Ancillary Service Limit (HASL) and will not be utilized prior to deployment of a Resource's On-Line Non-Spin, may not be offered at less than $75 per MWh.

[NPRR1010: Delete Section 6.4.4.1 above upon system implementation of the Real-Time Co-Optimization (RTC) project.]

6.5.7.3.1 Determination of Real-Time On-Line Reliability Deployment Price Adder

(1) The following categories of reliability deployments are considered in the determination of the Real-Time On-Line Reliability Deployment Price Adder:

(a) RUC-committed Resources, except for those whose QSEs have opted out of RUC Settlement in accordance with paragraph (12) of Section 5.5.2, Reliability Unit Commitment (RUC) Process;

(b) RMR Resources that are On-Line, including capacity secured to prevent an Emergency Condition pursuant to paragraph (2) of Section 6.5.1.1, ERCOT Control Area Authority;

(c) Deployed Load Resources other than Controllable Load Resources;

(d) Deployed Emergency Response Service (ERS);

(e) Real-Time DC Tie imports during an EEA where the total adjustment shall not exceed 1,250 MW in a single interval;

(f) Real-Time DC Tie exports to address emergency conditions in the receiving electric grid;

(g) Energy delivered to ERCOT through registered Block Load Transfers (BLTs) during an EEA;

(h) Energy delivered from ERCOT to another power pool through registered BLTs during emergency conditions in the receiving electric grid;

(i) ERCOT-directed firm Load shed during EEA Level 3, as described in paragraph (3) of Section 6.5.9.4.2, EEA Levels; and

(j) ERCOT-directed deployment of Off-Line Non-Spin.

(2) The Real-Time On-Line Reliability Deployment Price Adder is an estimation of the impact to energy prices due to the above categories of reliability deployments. For intervals where there are reliability deployments as described in paragraph (1) above, after the two-step SCED process and also after the Real-Time On-Line Reserve Price Adder and Real-Time Off-Line Reserve Price Adder have been determined, the Real-Time On-Line Reliability Deployment Price Adder is determined as follows:

(a) For Off-Line Non-Spin Resources that are brought On-Line by ERCOT deployment instruction, RUC-committed Resources with a telemetered Resource Status of ONRUC and for RMR Resources that are On-Line, set the LSL, LASL, and LDL to zero.

(b) Notwithstanding item (a) above, for RUC-committed Combined Cycle Generation Resources with a telemetered Resource Status of ONRUC that were instructed by ERCOT to transition to a different configuration to provide additional capacity, set the LSL, LASL, and LDL equal to the minimum of their current value and the COP HSL of the QSE-committed configuration for the RUC hour at the snapshot time of the RUC instruction.

(c) For all other Generation Resources excluding ones with a telemetered status of ONRUC, ONTEST, STARTUP, SHUTDOWN, and also excluding RMR Resources that are On-Line and excluding Generation Resources with a telemetered output less than 95% of LSL:

(i) Set LDL to the greater of Aggregated Resource Output - (60 minutes * SCED Down Ramp Rate), or LASL; and

(ii) Set HDL to the lesser of Aggregated Resource Output + (60 minutes*SCED Up Ramp Rate), or HASL.

(d) For all Controllable Load Resources excluding ones with a telemetered status of OUTL:

(i) Set LDL to the greater of Aggregated Resource Output - (60 minutes * SCED Up Ramp Rate), or LASL; and

(ii) Set HDL to the lesser of Aggregated Resource Output + (60 minutes*SCED Down Ramp Rate), or HASL.

(e) Add the deployed MW from Load Resources other than Controllable Load Resources to GTBD linearly ramped over the ten-minute ramp period. The amount of deployed MW is calculated from the Resource telemetry and from applicable deployment instructions in Extensible Markup Language (XML) messages. ERCOT shall generate a linear bid curve defined by a price/quantity pair of $300/MWh for the first MW of Load Resources deployed and a price/quantity pair of $700/MWh for the last MW of Load Resources deployed in each SCED execution. After recall instruction, the amount of MW added to GTBD during the restoration period will be determined by validated telemetry. The TAC shall review the validity of the prices for the bid curve at least annually.

(f) Add the deployed MW from ERS to GTBD. The amount of deployed MW is determined from the XML messages and ERS contracted capacities for the ERS Time Periods when ERS is deployed. After recall, an approximation of the amount of un-restored ERS shall be used. After ERCOT recalls each group, GTBD shall be adjusted to reflect restoration on a linear curve over the assumed restoration period ("RHours").

The above parameter is defined as follows:

Parameter	Unit	Current Value*
RHours	Hours	4.5
* Changes to the current value of the parameter(s) referenced in this table above may be recommended by TAC and approved by the ERCOT Board. ERCOT shall update parameter values on the first day of the month following ERCOT Board approval unless otherwise directed by the ERCOT Board. ERCOT shall provide a Market Notice prior to implementation of a revised parameter value.		

(g) Add the MW from Real-Time DC Tie imports during an EEA to GTBD. The amount of MW is determined from the Dispatch Instruction and should continue over the duration of time specified by the ERCOT Operator.

(h) Subtract the MW from Real-Time DC Tie exports to address emergency conditions in the receiving electric grid from GTBD. The amount of MW is determined from the Dispatch Instruction and should continue over the duration of time specified by the receiving grid operator.

(i) Add the MW from energy delivered to ERCOT through registered BLTs during an EEA to GTBD. The amount of MW is determined from the Dispatch Instruction and should continue over the duration of time specified by the ERCOT Operator.

(j) Subtract the MW from energy delivered from ERCOT to another power pool through registered BLTs during emergency conditions in the receiving electric grid from GTBD. The amount of MW is determined from the Dispatch Instruction and should continue over the duration of time specified by the receiving grid operator.

(k) Perform a SCED with changes to the inputs in items (a) through (j) above, considering only Competitive Constraints and the non-mitigated Energy Offer Curves.

(l) Perform mitigation on the submitted Energy Offer Curves using the LMPs from the previous step as the reference LMP.

(m) Perform a SCED with the changes to the inputs in items (a) through (j) above, considering both Competitive and Non-Competitive Constraints and the mitigated Energy offer Curves.

(n) Determine the positive difference between the System Lambda from item (m) above and the System Lambda of the second step in the two-step SCED process described in paragraph (10)(b) of Section 6.5.7.3, Security Constrained Economic Dispatch.

(o) Determine the amount given by the Value of Lost Load (VOLL) minus the sum of the System Lambda of the second step in the two step SCED process described in paragraph (10)(b) of Section 6.5.7.3 and the Real-Time On-Line Reserve Price Adder.

(p) The Real-Time On-Line Reliability Deployment Price Adder is the minimum of items (n) and (o) above except when ERCOT is directing firm Load shed during EEA Level 3. When ERCOT is directing firm Load shed during EEA Level 3 to either maintain sufficient PRC or stabilize grid frequency, as described in paragraph (3) of Section 6.5.9.4.2, the Real-Time On-Line Reliability Deployment Price Adder is the VOLL minus the sum of the System Lambda of the second step in the two-step SCED process described in paragraph (10)(b) of Section 6.5.7.3 and the Real-Time On-Line Reserve Price Adder. Once ERCOT is no longer directing firm Load shed, as described above, the Real-Time On-Line Reliability Deployment Price Adder will again be set as the minimum of items (n) and (o) above.

[NPRR904, NPRR1006, NPRR1010, NPRR1014, and NPRR1093: Replace applicable portions of Section 6.5.7.3.1 above with the following upon system implementation for NPRR904, NPRR1006, NPRR1014, or NPRR1093; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010:]

6.5.7.3.1 Determination of Real-Time Reliability Deployment Price Adder

(1) The following categories of reliability deployments are considered in the determination of the Real-Time Reliability Deployment Price Adder for Energy, and the Real-Time Reliability Deployment Price Adders for Ancillary Services:

(a) RUC-committed Resources, except for those whose QSEs have opted out of RUC Settlement in accordance with paragraph (12) of Section 5.5.2, Reliability Unit Commitment (RUC) Process;

(b) RMR Resources that are On-Line, including capacity secured to prevent an Emergency Condition pursuant to paragraph (2) of Section 6.5.1.1, ERCOT Control Area Authority;

(c) Deployed Load Resources other than Controllable Load Resources;

(d) Deployed Emergency Response Service (ERS);

(e) ERCOT-directed DC Tie imports during an EEA or transmission emergency where the total adjustment shall not exceed 1,250 MW in a single interval;

(f) ERCOT-directed curtailment of DC Tie imports below the higher of DC Tie advisory import limit as of 0600 in the Day-Ahead or subsequent advisory import limit to address local transmission system limitations where the total adjustment shall not exceed 1,250 MW in a single interval;

(g) ERCOT-directed curtailment of DC Tie imports below the higher of DC Tie advisory import limit as of 0600 in the Day-Ahead or subsequent advisory import limit due to an emergency action by a neighboring system operator during an emergency that is accommodated by ERCOT where the total adjustment shall not exceed 1,250 MW in a single interval;

(h) ERCOT-directed DC Tie exports to address emergency conditions in the receiving electric grid where the total adjustment shall not exceed 1,250 MW in a single interval;

(i) ERCOT-directed curtailment of DC Tie exports below the DC Tie advisory export limit as of 0600 in the Day-Ahead or subsequent advisory export limit during EEA, a transmission emergency, or to address local transmission system limitations where the total adjustment shall not exceed 1,250 MW in a single interval;

(j) Energy delivered to ERCOT through registered Block Load Transfers (BLTs) during an EEA;

(k) Energy delivered from ERCOT to another power pool through registered BLTs during emergency conditions in the receiving electric grid;

(l) ERCOT-directed deployment of Transmission and/or Distribution Service Provider (TDSP) standard offer Load management programs; and

(m) ERCOT-directed deployment of Off-Line Non-Spin.

(2) The Real-Time Reliability Deployment Price Adder for Energy, and Real-Time Reliability Deployment Price Adders for Ancillary Services are estimations of the

impact to energy prices and Real-Time MCPCs due to the above categories of reliability deployments. For intervals where there are reliability deployments as described in paragraph (1) above, the Real-Time Reliability Deployment Price Adder for Energy and Real-Time Reliability Deployment Price Adders for Ancillary Services are determined as follows:

(a) For Off-Line Non-Spin Resources that are brought On-Line by ERCOT deployment instruction, RUC-committed Resources with a telemetered Resource Status of ONRUC and for RMR Resources that are On-Line:

(i) Set the LSL and LDL to zero;

(ii) Remove all Ancillary Service Offers; and

(iii) For the first step of SCED, administratively set the Energy Offer Curve for the Resource at a value equal to the power balance penalty price for all capacity between 0 MW and the HSL of the Resource.

(b) Notwithstanding item (a) above, for RUC-committed Combined Cycle Generation Resources with a telemetered Resource Status of ONRUC that were instructed by ERCOT to transition to a different configuration to provide additional capacity:

(i) Set the LSL and LDL equal to the minimum of their current value and the COP HSL of the QSE-committed configuration for the RUC hour at the snapshot time of the RUC instruction;

(ii) Set the maximum Ancillary Service capabilities of the Resource equal to the minimum of their current value and COP Ancillary Service capabilities of the QSE-committed configuration for the RUC hour at the snapshot time of the RUC instruction; and

(iii) For the first step of SCED, administratively set the Energy Offer Curve for the Resource at a value equal to the power balance penalty price for the additional capacity of the Resource, defined as the positive difference between the Resource's current telemetered HSL and the COP HSL of the QSE-committed configuration for the RUC hour at the snapshot time of the RUC instruction.

(c) For all other Generation Resources excluding ones with a telemetered status of ONRUC, ONTEST, STARTUP, SHUTDOWN, and also excluding RMR Resources that are On-Line and excluding Generation Resources with a telemetered output less than 95% of LSL:

(i) If the Generation Resource SCED Base Point is not at LDL, set LDL to the greater of Aggregated Resource Output - (60 minutes * Normal Ramp Rate down), or LSL; and

(ii) If the Generation Resource SCED Base Point is not at HDL, set HDL to the lesser of Aggregated Resource Output + (60 minutes * Normal Ramp Rate up), or HSL.

(d) For all On-Line ESRs:

(i) If the ESR SCED Base Point is not at LDL, set LDL to the greater of Aggregated Resource Output - (60 minutes * Normal Ramp Rate down), or LSL; and

(ii) If the ESR SCED Base Point is not at HDL, set HDL to the lesser of Aggregated Resource Output + (60 minutes * Normal Ramp Rate up), or HSL.

(e) For all Controllable Load Resources excluding ones with a telemetered status of OUTL:

(i) If the Controllable Load Resource SCED Base Point is not at LDL, set LDL to the greater of Aggregated Resource Output - (60 minutes * Normal Ramp Rate down), or LSL; and

(ii) If the Controllable Load Resource SCED Base Point is not at HDL, set HDL to the lesser of Aggregated Resource Output + (60 minutes * Normal Ramp Rate up), or HSL.

(f) Add the deployed MW from Load Resources that are not Controllable Load Resources and that are providing RRS to GTBD linearly ramped over the ten-minute ramp period and add the deployed MW from Load Resources that are not Controllable Load Resources providing Non-Spin to GTBD linearly ramped over the 30-minute ramp period. The amount of deployed MW is calculated from the Resource telemetry and from applicable deployment instructions in Extensible Markup Language (XML) messages. ERCOT shall generate a linear bid curve defined by a price/quantity pair of $300/MWh for the first MW of Load Resources deployed and a price/quantity pair of $700/MWh for the last MW of Load Resources deployed in each SCED execution. After recall instruction, the restoration period length and amount of MW added to GTBD during the restoration period will be determined by validated telemetry and the type of Ancillary Service deployed from the Resource. The TAC shall review the validity of the prices for the bid curve at least annually.