~~Address:~~	~~———~~				
~~City:~~	~~———~~	~~State:~~	~~———~~	~~Zip:~~	~~———~~
Telephone:		~~Fax:~~	~~———~~		
Email Address:					

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

Name:		~~Title:~~	~~———~~		
~~Address:~~	~~———~~				
~~City:~~	~~———~~	~~State:~~	~~———~~	~~Zip:~~	~~———~~
Telephone:		~~Fax:~~	~~———~~		
Email Address:					

7. TSP 24x7 Control or Operations Center. As defined in the ERCOT Protocols, the 24x7 Control or Operations Center is responsible for operational communications and shall have sufficient authority to commit and bind the TSP.

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

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

Name:		~~Title:~~	~~———~~		
~~Address:~~	~~———~~				
~~City:~~	~~———~~	~~State:~~	~~———~~	~~Zip:~~	~~———~~
Telephone:		~~Fax:~~	~~———~~		
Email Address:					

PART II – ASSET REGISTRATION

1. Provide Generation Load Metering Point and TDSP Read Generation information as required on the ERCOT Generation Load Metering Point(s) & TDSP Read Generation Registration Form. The form is located at http://www.ercot.com/services/rq/tdsp/index.html. The completed form should be attached to, and submitted with, the TDSP Registration Application.

2. Provide status of registering MOU or EC:

☐ **Opt-In MOU or EC** – An EC or MOU that offers Customer Choice.

☐ **Non-Opt-In Entity (NOIE)** – An EC or MOU that does not offer Customer Choice.

PART III – ADDITIONAL REQUIRED INFORMATION

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

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

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

PART IV – SIGNATURE

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

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

Board Report

Date:	

ERCOT Nodal Protocols

Section 23

Form M: Independent Market Information System Registered Entity (IMRE) Application for Registration

~~June 1, 2023~~TBD

Board Report

Date Received: ______________________	

INDEPENDENT MARKET INFORMATION SYSTEM REGISTERED ENTITY (IMRE) APPLICATION FOR REGISTRATION

This application is for approval as an IMRE by the Electric Reliability Council of Texas Inc. (ERCOT) in accordance with the ERCOT Protocols. Information may be inserted electronically to expand the reply spaces as necessary. ERCOT will accept the completed, executed application via email to MPRegistration@ercot.com (.pdf version)~~ or via mail to Market Participant Registration, 8000 Metropolis Drive (Building E), Suite 100, Austin, Texas 78744~~. In addition to the application, ERCOT must receive an application fee in the amount of $500 via Electronic Funds Transfer (EFT) (wire or Automated Clearing House (ACH))~~check or wire transfer~~. All payments should reference the applicant's name and Data Universal Numbering System (DUNS) Number (DUNS #) in the remarks. If you need assistance filling out this form, or if you have any questions, please call (512) 248-3900.

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

PART I – ENTITY INFORMATION

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

[1]Defined in Section 2.1, Definitions.

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

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

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

Name:		**~~Title:~~**	~~———~~		
~~Address:~~	~~———~~				
~~City:~~	~~———~~	**~~State:~~**	~~———~~	**~~Zip:~~**	~~———~~
Telephone:		**~~Fax:~~**	~~———~~		

Email Address:	

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

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

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

4. Professional or Business Purpose for IMRE Registration: _____

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

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

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

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

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

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

PART II – ADDITIONAL REQUIRED INFORMATION

1. Officers. ERCOT will obtain the names of all individuals and/or entities listed with the Texas Secretary of State or otherwise designated as having binding authority for the Applicant. ERCOT will use this list of individuals to determine who can execute such documents as the Standard Form Market Participant Agreement (SFA), Amendment to the SFA, Digital Certificate Audit Attestation, etc. Alternatively, additional documentation (Articles of Incorporation, Board Resolutions, Delegation of Authority, Secretary's Certificate, etc.) can be provided to prove binding authority for the Applicant.
2. Affiliates and Other Registrations. Provide the name, legal structure, and relationship of each of the Applicant's affiliates, if applicable. See Section 2.1, Definitions, for the definition of "Affiliate." Please also provide the name and type of any other ERCOT Market Participant registrations held by the Applicant. *(Attach additional pages if necessary.)*

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

PART III – SIGNATURE

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

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

ERCOT Impact Analysis Report

NPRR Number	<u>1206</u>	NPRR Title	Revisions to QSE Operations and Termination Requirements, and Elimination of Providing Certain Market Participant Principal Information
Impact Analysis Date	October 25, 2023		
Estimated Cost/Budgetary Impact	None.		
Estimated Time Requirements	No project required. This Nodal Protocol Revision Request (NPRR) can take effect following Public Utility Commission of Texas (PUCT) approval.		
ERCOT Staffing Impacts (across all areas)	Ongoing Requirements: No impacts to ERCOT staffing.		
ERCOT Computer System Impacts	No impacts to ERCOT computer systems.		
ERCOT Business Function Impacts	No impacts to ERCOT business functions.		
Grid Operations & Practices Impacts	No impacts to ERCOT grid operations and practices.		

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

Comments
None.

Board Report

NPRR Number	1207	NPRR Title	Incidental Disclosure of Protected Information and ECEII During ERCOT Control Room Tours
Date of Decision	February 27, 2024		
Action	Recommended Approval		
Timeline	Normal		
Estimated Impacts	Cost/Budgetary: None Project Duration: Not applicable		
Proposed Effective Date	First of the month following Public Utility Commission of Texas (PUCT) approval		
Priority and Rank Assigned	Not applicable		
Nodal Protocol Sections Requiring Revision	1.3.5, Notice Before Permitted Disclosure 1.3.6, Exceptions		
Related Documents Requiring Revision/Related Revision Requests	None		
Revision Description	This Nodal Protocol Revision Request (NPRR) permits the incidental disclosure of Protected Information and ERCOT Critical Energy Infrastructure Information (ECEII) as part of a tour or overlook viewing of the ERCOT control room provided to eligible persons who, prior to accessing the control room, have signed nondisclosure agreements ("NDAs") and complied with screening and other requirements provided in a policy adopted by ERCOT security. The policy includes a prohibition on taking photographs and recordings of Protected Information and ECEII. This NPRR also exempts ERCOT from the requirement to provide notice of disclosure when ECEII or Protected Information is incidentally disclosed as part of a Control Room tour or overlook viewing, consistent with the conditions described above. This exception does not apply to a person who is a director, officer, employee, agent, representative, contractor, or consultant of a Market Participant that is registered with ERCOT as a Resource Entity, Qualified Scheduling Entity (QSE), Load Serving Entity (LSE), or Congestion Revenue Right (CRR) Account Holder.		

Board Report

Reason for Revision	☒ Strategic Plan Objective 1 – Be an industry leader for grid reliability and resilience ☐ Strategic Plan Objective 2 - Enhance the ERCOT region's economic competitiveness with respect to trends in wholesale power rates and retail electricity prices to consumers ☐ Strategic Plan Objective 3 - Advance ERCOT, Inc. as an independent leading industry expert and an employer of choice by fostering innovation, investing in our people, and emphasizing the importance of our mission ☐ General system and/ or process improvements ☐ Regulatory requirements ☐ ERCOT Board/PUCT Directive *(please select ONLY ONE – if more than one apply, please select the ONE that is most relevant)*
Justification of Reason for Revision and Market Impacts	From time to time, ERCOT executives and management provide tours or overlook viewings of the control room to persons such as members of Congress and the Texas Legislature, Federal Bureau of Investigation (FBI) agents and other law enforcement officers, researchers at National Labs, researchers at think tanks who work with ERCOT on cybersecurity and reliability projects, media, foreign delegations of persons representing grids and wholesale power markets from countries such as Japan and Australia, and employees of other North American grid operators. Persons on a control room tour or overlook viewing may briefly and incidentally view Protected Information and/or ECEII on the large control room screens or monitors. Examples of information that may appear on control room screens or monitors include the following: • Real-Time unit Resource status; • Resource Outage information; • Resource output; • Maps of the ERCOT System; • Generic Transmission Constraints (GTCs); and • Interconnection Reliability Opearting Limits (IROLs). This NPRR requires eligible tour participants to undergo background screening, sign NDAs, and refrain from taking photos and recordings in order to mitigate the risks associated with incidental disclosure of ECEII and Protected Information as part of a control room tour or

	overlook viewing. The tour exception does not apply to a director, officer, employee, agent, representative, contractor, or consultant of a Resource Entity, QSE, LSE, or CRR Account Holder due to competitive risks that may be associated with incidental disclosure of Protected Information to such persons. Given these protections, the incidental disclosure of ECEII and Protected Information as part of a control room tour or overlook viewing creates minimal risk, as tours visit or view the control room only briefly and tour participants remain at the back of the control room during their visit or in an overlook viewing area, enabling only limited visibility of information displayed on the monitors. (Tour participants may not closely inspect control room monitors.) The significant benefits of collaboration, education, and knowledge sharing with approved persons who participate in the tour or overlook viewing far outweigh the minimal risk associated with incidental disclosure of ECEII and Protected Information, given the protections that ERCOT has put in place regarding control room tours or viewings.
PRS Decision	On 12/15/23, PRS voted unanimously to recommend approval of NPRR1207 as submitted. All Market Segments participated in the vote. On 1/11/24, PRS voted unanimously to endorse and forward to TAC the 12/15/23 PRS Report and the 11/1/23 Impact Analysis for NPRR1207. All Market Segments participated in the vote.
Summary of PRS Discussion	On 12/15/23, participants reviewed NPRR1207. On 1/11/24, participants reviewed the 11/1/23 Impact Analysis.
TAC Decision	On 1/24/24, TAC voted unanimously to recommend approval of NPRR1207 as recommended by PRS in the 1/11/24 PRS Report. All Market Segments participated in the vote.
Summary of TAC Discussion	On 1/24/24, TAC there was no additional discussion beyond TAC review of the items below.
TAC Review/Justification of Recommendation	[X] Revision Request ties to Reason for Revision as explained in Justification [X] Impact Analysis reviewed and impacts are justified as explained in Justification [X] Opinions were reviewed and discussed [X] Comments were reviewed and discussed (if applicable)

	☐ Other: (explain)
Board Decision	On 2/27/24, the ERCOT Board voted unanimously to recommend approval of NPRR1207 as recommended by TAC in the 1/24/24 TAC Report.

Opinions	
Credit Review	ERCOT Credit Staff and the Credit Finance Sub Group (CFSG) have reviewed NPRR1207 and do not believe that it requires changes to credit monitoring activity or the calculation of liability.
Independent Market Monitor Opinion	IMM has no opinion on NPRR1207.
ERCOT Opinion	ERCOT supports approval of NPRR1207.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NPRR1207 and believes it would permit the incidental disclosure of Protected Information and ECEII as part of a tour or overlook viewing of the ERCOT control room provided to eligible persons who, prior to accessing the control room, have signed NDAs and complied with screening and other requirements provided in a policy adopted by ERCOT security, establishes a prohibition on taking photographs and recordings of Protected Information and ECEII, and exempts ERCOT from the requirement to provide notice of disclosure when ECEII or Protected Information is incidentally disclosed as part of a control room tour or overlook viewing, consistent with the conditions described above except for persons who are a director, officer, employee, agent, representative, contractor, or consultant of a Market Participant that is registered with ERCOT as a Resource Entity, QSE, LSE, or CRR Account Holder.

Sponsor	
Name	Doug Fohn and Holly Heinrich
E-mail Address	douglas.fohn@ercot.com / holly.heinrich@ercot.com
Company	ERCOT
Phone Number	512-275-7447 / 512-275-7436
Cell Number	
Market Segment	Not applicable

Board Report

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

Comments Recieved	
Comment Author	**Comment Summary**
None	

Market Rules Notes

None

Proposed Protocol Language Revision

1.3.5 Notice Before Permitted Disclosure

(1) Before making any disclosure under Section 1.3.6, Exceptions, the Receiving Party shall promptly notify the Disclosing Party in writing and, with the exception of information disclosed pursuant to paragraph (3) of Section 1.3.6, shall assert confidentiality and take reasonable steps to cooperate with the Disclosing Party in seeking to protect the Protected Information or ECEII from disclosure by confidentiality agreement, protective order, aggregation of information, or other reasonable measures. Notwithstanding the foregoing, ERCOT is not required to provide notice to the Disclosing Party of disclosures made under items (1)(b), ~~or~~ (1)(l), or (1)(n) of Section 1.3.6.

(2) If the Disclosing Party is not also the Creating Party, upon receipt of the notice required by paragraph (1) above, the Disclosing Party shall promptly notify the Creating Party, unless, after making reasonable efforts, the Disclosing Party is unable to identify the Creating Party.

1.3.6 Exceptions

(1) The Receiving Party or Creating Party may, without violating Section 1.3, Confidentiality, disclose Protected Information or ECEII:

(a) To governmental officials, Market Participants, the public, or others as required by any law, regulation, or order, or by these Protocols, but any Receiving Party or Creating Party must make reasonable efforts to restrict public access to the disclosed Protected Information or ECEII by protective order, by aggregating information, or otherwise if reasonably possible; or

(b) If ERCOT is the Receiving Party or Creating Party and disclosure to the PUCT, Reliability Monitor or IMM of the Protected Information or ECEII is required by ERCOT pursuant to applicable Protocol, law, regulation, or order; or

(c) For Protected Information, if the Disclosing Party has given its prior written consent to the disclosure, which consent may be given or withheld in Disclosing Party's sole discretion; or

(d) For Protected Information, if the Protected Information, before it is furnished to the Receiving Party, has been disclosed to the public through lawful means; or

(e) For Protected Information, if the Protected Information, after it is furnished to the Receiving Party, is disclosed to the public other than as a result of a breach by the Receiving Party of its obligations under Section 1.3; or

(f) If reasonably deemed by the disclosing Receiving Party to be required to be disclosed in connection with a dispute between the Receiving Party and the Disclosing Party, but the disclosing Receiving Party must make reasonable efforts to restrict public access to the disclosed Protected Information or ECEII by protective order, by aggregating information, or otherwise if reasonably possible; or

(g) To a TSP or DSP engaged in the ERCOT Transmission Grid or Distribution System planning and operating activities, provided that the TSP or DSP has executed a confidentiality agreement with ERCOT with requirements substantially similar to those in Section 1.3. ERCOT shall post on the ERCOT website a list of all TSPs and DSPs that have confidentiality agreements in effect with ERCOT; or

(h) For Protected Information, to a vendor or prospective vendor of goods and services to ERCOT or a TDSP, so long as such vendor or prospective vendor:

(i) Is not a Market Participant, except that ERCOT or the TDSP may disclose Protected Information to a vendor or prospective vendor that is also an Independent Market Information System Registered Entity (IMRE) to the extent appropriate for the vendor to carry out its responsibilities in such capacity or for the prospective vendor to engage in commercial discussions; and

(ii) Has executed a confidentiality agreement with requirements at least as restrictive as those in Section 1.3; or

(i) For ECEII, to a vendor or prospective vendor of goods and services, so long as such vendor or prospective vendor has executed a confidentiality agreement with requirements at least as restrictive as those in Section 1.3; or

(j) To the North American Electric Reliability Corporation (NERC) or the NERC Regional Entity if required for compliance with any applicable NERC or NERC

Regional Entity requirement, but any Receiving Party or Creating Party must make reasonable efforts to restrict public access to the disclosed Protected Information or ECEII as reasonably possible; or

(k) To ERCOT and its consultants, the IMM, the Reliability Monitor, and members of task forces and working groups of ERCOT, if engaged in performing analysis of abnormal system conditions, disturbances, unusual events, and abnormal system performance, or engaged in tasks involving ECEII for support of the ERCOT Transmission Grid. Notwithstanding the foregoing sentence, task forces and working groups may not receive Ancillary Service Offer prices or other competitively sensitive price or cost information before expiration of its status as Protected Information, and each member of a task force or working group shall execute a confidentiality agreement with requirements substantially similar to those in Section 1.3, prior to receiving any Protected Information or ECEII. Data to be disclosed under this exception to task forces and working groups must be limited to clearly defined periods surrounding the relevant conditions, events, or performance under review and must be limited in scope to information pertinent to the condition or events under review and may include the following:

(i) QSE Ancillary Service awards and deployments, in aggregate and by type of Resource;

(ii) Resource facility availability status, including the status of switching devices, auxiliary loads, and mechanical systems that had a material impact on Resource facility availability or an adverse impact on the transmission system operation;

(iii) Individual Resource information including Base Points, maximum/minimum generating capability, droop setting, real power output, and reactive output;

(iv) Resource protective device settings and status;

(v) Data from COPs;

(vi) Resource Outage schedule information; and

(vii) BSS test results and ERCOT's Black Start plan, including individual Black Start Resource start-up procedures, cranking paths, and individual TSP Black Start plans;

(l) To the CFTC if requested from ERCOT by the CFTC as part of an investigation or regulatory inquiry authorized pursuant to the Commodity Exchange Act and the CFTC's regulations or if required to be submitted to the CFTC pursuant to any other law, provided that ERCOT, as the Receiving Party or Creating Party, must timely submit a written request for confidential treatment in accordance with the CFTC's regulations or other applicable law;~~ or~~

(m) To a Governmental Cybersecurity Oversight Agency regarding a Cybersecurity Incident, if ERCOT is the Receiving Party, and disclosure of Protected Information is made to a Governmental Cybersecurity Oversight Agency or delegated entity for the purpose of ensuring the safety and/or security of the ERCOT System or ERCOT's ability to perform the functions of an independent organization under PURA; or

(n) Incidentally as part of a tour of the ERCOT control room provided to persons determined by ERCOT to be eligible to participate in the tour. Prior to accessing the ERCOT control room, such persons must sign a nondisclosure agreement required by ERCOT and comply with the screening and other requirements provided in a policy adopted by ERCOT security. The policy will include a prohibition against taking photographs or recordings of Protected Information or ECEII. This subsection does not apply to a person who is a director, officer, employee, agent, representative, contractor, or consultant of a Market Participant that is registered with ERCOT as one or more of the following registration types: Resource Entity, QSE, LSE, or CRR Account Holder.

(2) Protected Information may not be disclosed to other Market Participants prior to ten days following the Operating Day under review, except as permitted in paragraph (1)(n) above.

(3) ERCOT may disclose, and may authorize a Receiving Party or Creating Party to disclose, ECEII to the public or to any person under the provisions of this paragraph, except for ECEII otherwise protected from disclosure pursuant to law, regulation, or order.

(a) ERCOT may propose to disclose ECEII that is not otherwise protected from disclosure pursuant to law, regulation, or order. Any Receiving Party or Creating Party other than ERCOT may request ERCOT authorization to disclose such ECEII.

(i) ERCOT may propose to disclose ECEII that is not otherwise protected from disclosure pursuant to law, regulation, or order if it determines that the public benefit of the proposed disclosure of ECEII outweighs the potential harm resulting from the disclosure. ERCOT shall issue a Market Notice regarding ERCOT's intent to disclose the ECEII, subject to objection as further provided in paragraph (c) below.

(ii) A request by a Receiving Party or Creating Party other than ERCOT for authorization to disclose ECEII shall be submitted by e-mail to ERCOT's General Counsel. If the ECEII is not otherwise protected from disclosure pursuant to law, regulation, or order, and ERCOT determines that the public benefit of the proposed disclosure of ECEII outweighs the potential harm resulting from the disclosure, ERCOT shall issue a Market Notice authorizing the ECEII to be disclosed, subject to objection as further provided in paragraph (c) below. ERCOT shall make such a determination no later than five Business Days following the date it receives the request.

(b) The Market Notice issued pursuant to paragraph (a)(i) or (ii) above shall identify the ECEII to be disclosed; the party requesting the disclosure; the public benefit justifying the proposed disclosure; the date on which the information may be disclosed, which shall be no sooner than five Business Days following the date of the Market Notice; and, if the proposed disclosure is not to the public, the persons to whom ECEII would be disclosed. The authorization shall be effective unless a Market Participant submits an objection pursuant to paragraph (c) below.

(c) Any Market Participant may submit written objections to the proposed disclosure. Such objections shall be submitted by e-mail to ERCOT's General Counsel no later than the end of the fourth Business Day following the issuance of the Market Notice described in paragraph (b) above. Failure to object to the proposed allowance of ECEII disclosure pursuant to this paragraph shall constitute a waiver of any such objection for all purposes. ERCOT shall provide notice of the objection to the party requesting authorization to disclose ECEII no later than the end of the Business Day following receipt of the objection. The party requesting authorization to disclose ECEII shall not disclose the ECEII if it has been notified of any objection pursuant to this paragraph unless and until ERCOT issues a second Market Notice authorizing disclosure, as provided in paragraph (d) below.

(d) If one or more objections to disclosure is submitted pursuant to paragraph (c) above, ERCOT shall issue a second Market Notice describing each such objection and stating whether the objection affects ERCOT's determination as to the proposed disclosure of ECEII. If ERCOT determines that the ECEII should still be disclosed notwithstanding these objections, the second Market Notice shall establish the date on which the ECEII may be disclosed, which shall be no sooner than the fifth Business Day following the issuance of the second Market Notice. ERCOT's determination in the second Market Notice is a final decision that may be challenged at the PUCT without using the processes described in Section 20, Alternative Dispute Resolution Procedure. If ERCOT authorizes a non-public disclosure of ECEII, the party disclosing the ECEII shall require each recipient of ECEII to enter into a nondisclosure agreement that includes the restrictions against disclosure described in Section 1.3.2, ERCOT Critical Energy Infrastructure Information, as a condition for obtaining the ECEII.

(e) Notwithstanding anything in this Section, ERCOT may disclose ECEII to any federal, state or local government official without issuing a Market Notice if ERCOT determines that such disclosure is necessary to facilitate the government official's public duties and that the delay associated with providing the Notice otherwise required by this paragraph (3) would impair that government official's ability to take action to address a public emergency. As soon as practicable, but no later than 24 hours following the disclosure:

(i) ERCOT shall provide Notice to the Disclosing Party and all Market Participants materially impacted by the disclosure; and

(ii) ERCOT shall issue a Market Notice describing the disclosure, unless ERCOT determines that such a Notice could jeopardize public safety or welfare, in which case no Notice is required.

(iii) Each Disclosing Party, other than ERCOT, shall provide Notice to each Creating Party whose information has been disclosed pursuant to this paragraph (e).

(f) Notwithstanding anything in this Section, any Receiving Party or Creating Party other than ERCOT may disclose ECEII to any federal, state or local government official without requesting prior authorization from ERCOT if the Receiving Party or Creating Party determines that such disclosure is necessary to facilitate the government official's public duties and that the delay associated with requesting prior ERCOT authorization as otherwise required by this paragraph (3) would impair that government official's ability to take action to address a public emergency.

(i) The Receiving Party or Creating Party shall provide Notice to ERCOT and all Market Participants materially impacted by the disclosure as soon as practicable, but no later than 24 hours following the disclosure.

(ii) ERCOT shall issue a Market Notice describing the disclosure as soon as practicable, but no later than 24 hours following receipt of notice from the Receiving Party or Creating Party, unless ERCOT determines that such a Notice could jeopardize public safety or welfare, in which case no Notice is required.

ERCOT Impact Analysis Report

NPRR Number	1207	NPRR Title	Incidental Disclosure of Protected Information and ECEII During ERCOT Control Room Tours
Impact Analysis Date	November 1, 2023		
Estimated Cost/Budgetary Impact	None.		
Estimated Time Requirements	No project required. This Nodal Protocol Revision Request (NPRR) can take effect following Public Utility Commission of Texas (PUCT) approval.		
ERCOT Staffing Impacts (across all areas)	Ongoing Requirements: No impacts to ERCOT staffing.		
ERCOT Computer System Impacts	No impacts to ERCOT computer systems.		
ERCOT Business Function Impacts	ERCOT will update its business processes to implement this NPRR.		
Grid Operations & Practices Impacts	No impacts to ERCOT grid operations and practices.		

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

Comments
None.

Board Report

NPRR Number	1208	NPRR Title	Creation of Invoice Report
Date of Decision	February 27, 2024		
Action	Recommended Approval		
Timeline	Normal		
Estimated Impacts	Cost/Budgetary: Between $40K and $60K Project Duration: 4 to 6 months		
Proposed Effective Date	Upon system implementation		
Priority and Rank Assigned	Priority – 2024; Rank – 4090		
Nodal Protocol Sections Requiring Revision	9.20, ERCOT Invoice Report (new)		
Related Documents Requiring Revision/Related Revision Requests	None		
Revision Description	This Nodal Protocol Revision Request (NPRR) creates a new daily report, the ERCOT Invoice Report, which lists the ERCOT Invoices issued for the current day and day prior at a Counter-Party level.		
Reason for Revision	☐ Strategic Plan Objective 1 – Be an industry leader for grid reliability and resilience ☐ Strategic Plan Objective 2 - Enhance the ERCOT region's economic competitiveness with respect to trends in wholesale power rates and retail electricity prices to consumers ☐ Strategic Plan Objective 3 - Advance ERCOT, Inc. as an independent leading industry expert and an employer of choice by fostering innovation, investing in our people, and emphasizing the importance of our mission ☒ General system and/or process improvement(s) ☐ Regulatory requirements ☐ ERCOT Board and/or PUCT Directive		

Board Report

	(please select ONLY ONE – if more than one apply, please select the ONE that is most relevant)
Justification of Reason for Revision and Market Impacts	The Credit Finance Sub Group (CFSG) provided feedback to ERCOT that it is cumbersome for Counter-Parties to monitor the posting of Invoices that are posted at infrequent intervals (e.g. quarterly). ERCOT has observed this difficulty, noticing Qualified Scheduling Entities (QSEs) with a history of timely paying Settlement Invoices (which are posted daily), missing payment timelines for Wide Area Network (WAN) and Electric Reliability Organization (ERO) Invoices. This NPRR creates a daily report that lists the Invoices issued to all the QSEs and Congestion Revenue Right (CRR) Account Holders represented by the Counter-Party for the current day and the prior day. This report can be used by Counter-Parties to ensure they are aware of all Invoices posted, which helps assure timely payment. This also has the benefit of decreased administrative burden on ERCOT to manage late payments.
PRS Decision	On 12/15/23, PRS voted unanimously to recommend approval of NPRR1208 as submitted. All Market Segments participated in the vote. On 1/11/24, PRS voted unanimously to endorse and forward to TAC the 12/15/23 PRS Report and 1/9/24 Impact Analysis for NPRR1208 with a recommended priority of 2024 and rank of 4090. All Market Segments participated in the vote.
Summary of PRS Discussion	On 12/15/23, the sponsor provided an overview of NPRR1208. On 1/11/24, participants reviewed the 1/9/24 Impact Analysis and discussed the appropriate priority and rank for NPRR1208.
TAC Decision	On 1/24/24, TAC voted unanimously to recommend approval of NPRR1208 as recommended by PRS in the 1/11/24 PRS Report. All Market Segments participated in the vote.
Summary of TAC Discussion	On 1/24/24, there was no additional discussion beyond TAC review of the items below.
TAC Review/Justification of Recommendation	[X] Revision Request ties to Reason for Revision as explained in Justification [X] Impact Analysis reviewed and impacts are justified as explained in Justification [X] Opinions were reviewed and discussed [X] Comments were reviewed and discussed (if applicable)

Board Report

	☐ Other: (explain)
ERCOT Board Decision	On 2/27/24, the ERCOT Board voted unanimously to recommend approval of NPRR1208 as recommended by TAC in the 1/24/24 TAC Report.

Opinions	
Credit Review	ERCOT Credit Staff and the Credit Finance Sub Group (CFSG) have reviewed NPRR1208 and do not believe that it requires changes to credit monitoring activity or the calculation of liability.
Independent Market Monitor Opinion	IMM has no opinion on NPRR1208.
ERCOT Opinion	ERCOT supports approval of NPRR1208.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NPRR1208 and believes the market impact for NPRR1208 provides a consolidated view of Invoices which may reduce instances of late/missed payments by Market Participants and related collection activities at ERCOT.

Sponsor	
Name	Loretto Martin
E-mail Address	loretto.martin@nrg.com
Company	Reliant Energy
Phone Number	281-800-6244
Cell Number	
Market Segment	Independent Retail Electric Provider (IREP)

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

Comments Received	
Comment Author	**Comment Summary**

None	

Market Rules Notes

None

Proposed Protocol Language Revision

9.20 ERCOT Invoice Report

(1) ERCOT will post daily, on the Market Information System (MIS) Certified Area, a Counter-Party report that lists the following Invoices that were issued for the current day and prior day to the Qualified Scheduling Entity(s) (QSE(s)) and Congestion Revenue Right (CRR) Account Holder(s) represented by the Counter-Party:

(a) Settlement Invoice;

(b) CRR Auction Invoice;

(c) CRR Auction Revenue Distribution Invoice;

(d) CRR Balancing Account Invoice;

(e) Miscellaneous Invoice;

(f) Default Uplift Invoice;

(g) Securitization Uplift Charge Initial Invoice;

(h) Securitization Uplift Charge Reallocation Invoice;

(i) Securitization Default Charge Invoice;

(j) Electric Reliability Organization (ERO) Invoice;

(k) Wide Area Network (WAN) Invoice; and

(l) Weatherization Inspection Invoice.

ERCOT Impact Analysis Report

NPRR Number	**<u>1208</u>**	**NPRR Title**	**Creation of Invoice Report**
Impact Analysis Date	January 9, 2024		
Estimated Cost/Budgetary Impact	Between $40K and $60K		
Estimated Time Requirements	The timeline for implementing this Nodal Protocol Revision Request (NPRR) is dependent upon Public Utility Commission of Texas (PUCT) prioritization and approval. Estimated project duration: 4 to 6 months		
ERCOT Staffing Impacts (across all areas)	Implementation Labor: 100% ERCOT; 0% Vendor Ongoing Requirements: No impacts to ERCOT staffing.		
ERCOT Computer System Impacts	The following ERCOT systems would be impacted: • Data Management & Analytic Systems 91% • ERCOT Website and MIS Systems 5% • Channel Management Systems 4%		
ERCOT Business Function Impacts	No impacts to ERCOT business functions.		
Grid Operations & Practices Impacts	No impacts to ERCOT grid operations and practices.		

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

Comments
None.

Board Report

NPRR Number	1210	NPRR Title	Next Start Resource Test and Load-Carrying Test Frequency
Date of Decision	February 27, 2024		
Action	Recommended Approval		
Timeline	Normal		
Estimated Impacts	Cost/Budgetary: None Project Duration: No project required		
Proposed Effective Date	First of the month following Public Utility Commission of Texas (PUCT) approval		
Priority and Rank Assigned	Not applicable		
Nodal Protocol Sections Requiring Revision	8.1.1.2.1.5, System Black Start Capability Qualification and Testing		
Related Documents Requiring Revision/Related Revision Requests	None		
Revision Description	This Nodal Protocol Revision Request (NPRR) changes the frequency of the Next Start Resource Test and the Load-Carrying Test respectively from once every five years to once every four calendar years.		
Reason for Revision	☐ Strategic Plan Objective 1 – Be an industry leader for grid reliability and resilience ☐ Strategic Plan Objective 2 - Enhance the ERCOT region's economic competitiveness with respect to trends in wholesale power rates and retail electricity prices to consumers ☐ Strategic Plan Objective 3 - Advance ERCOT, Inc. as an independent leading industry expert and an employer of choice by fostering innovation, investing in our people, and emphasizing the importance of our mission ☐ General system and/or process improvement(s) ☒ Regulatory requirements		

	☐ ERCOT Board and/or PUCT Directive *(please select ONLY ONE – if more than one apply, please select the ONE that is most relevant)*
Justification of Reason for Revision and Market Impacts	North American Electric Reliability Corporation (NERC) Standard EOP-005-3, System Restoration from Blackstart Resources, R6, requires that a Black Start Resource be tested once every five years to verify that it can meet the real and reactive requirements of a cranking path and the dynamic capability to supply initial Loads. This requirement is met via the Next Start Resource Test outlined in paragraph (3)(d)(vii) of Section 8.1.1.2.1.5. It has become apparent that meeting the once-every-five-years testing requirement raises issues with respect to the specific deadline and can be difficult. For example, if a Next Start Resource Test is conducted on April 15, 2023 of the current year, depending on system conditions, it may be difficult for a contracted Black Start Resource to test by April 15, specifically, in 2028. Accordingly, ERCOT is proposing that the once-every-five-year testing cycle for the Next Start Resource Test be changed to once every four calendar years in order to consistently be within the five year NERC-required time frame and avoid issues related to the time of year in which the deadline falls. Once every four calendar years provides flexibility to test at any point within the calendar year that the test is due. To reduce complexity and the potential risk associated with managing different testing frequencies, the frequency of the Load-Carrying Test in paragraph (3)(c)(vi) of Section 8.1.1.2.1.5 is also changed to align with the frequency of the Next Start Resource Test.
PRS Decision	On 12/15/23, PRS voted unanimously to table NPRR1210 and refer the issue to ROS. All Market Segments participated in the vote. On 1/11/24, PRS voted unanimously to recommend approval of NPRR1210 as submitted. All Market Segments participated in the vote. On 2/8/24, PRS voted unanimously to endorse and forward to TAC the 1/11/24 PRS Report and the 11/15/23 Impact Analysis for NPRR1210. All Market Segments participated in the vote.
Summary of PRS Discussion	On 12/15/23, participants noted that the Black Start Working Group (BSWG) discussed a draft of NPRR1210 and had no concerns, but requested additional time for BSWG review now that the actual revision request is posted. On 1/11/24, participants reviewed the 1/8/24 ROS comments.

	On 2/8/24, participants reviewed the 11/15/23 Impact Analysis.
TAC Decision	On 2/14/24, TAC voted unanimously to recommend approval of NPRR1210 as recommended by PRS in the 2/8/24 PRS Report. All Market Segments participated in the vote.
Summary of TAC Discussion	On 2/14/24, there was no additional discussion beyond TAC review of the items below.
TAC Review/Justification of Recommendation	[X] Revision Request ties to Reason for Revision as explained in Justification [X] Impact Analysis reviewed and impacts are justified as explained in Justification [X] Opinions were reviewed and discussed [X] Comments were reviewed and discussed (if applicable) [ ] Other: (explain)
ERCOT Board Decision	On 2/27/24, the ERCOT Board voted unanimously to recommend approval of NPRR1210 as recommended by TAC in the 2/14/24 TAC Report.

Opinions	
Credit Review	ERCOT Credit Staff and the Credit Finance Sub Group (CFSG) have reviewed NPRR1210 and do not believe that it requires changes to credit monitoring activity or the calculation of liability.
Independent Market Monitor Opinion	The Independent Market Monitor (IMM) has no opinion on NPRR1210.
ERCOT Opinion	ERCOT supports approval of NPRR1210.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NPRR1210 and believes it has a positive market impact by providing flexibility and consistency within the NERC-required testing time frame, while reducing complexity and potential risks associated with managing different testing frequencies and issues related to the time of year in which a deadline may fall.

Sponsor	
Name	Alex Lee
E-mail Address	Alex.Lee@ercot.com

Board Report

Company	ERCOT
Phone Number	512-248-4287
Cell Number	512-709-9500
Market Segment	Not Applicable

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

Comments Received	
Comment Author	**Comment Summary**
ROS 010924	Endorsed NPRR1210 as submitted

Market Rules Notes

None

Proposed Protocol Language Revision

8.1.1.2.1.5 System Black Start Capability Qualification and Testing

(1) A Resource is qualified to be a Black Start Resource if it has met the following requirements:

(a) Verified control communication path performance;

(b) Verified primary and alternate voice circuits for receipt of instructions;

(c) Passed the "Basic Starting Test" as defined below;

(d) Passed the "Line-Energizing Test" as defined below;

(e) Passed the "Load-Carrying Test" as defined below;

(f) Passed the "Next Start Resource Test" as defined below;

(g) Provided an attestation, in the form required by ERCOT, of Black Start Service (BSS) Back-up Fuel that will support the Resource for a minimum of 72 hours at maximum output, except to the extent ERCOT has waived this requirement;

(h) Passed the "BSS Back-up Fuel Switching Test" as defined below, unless ERCOT has waived the BSS Back-up Fuel requirement;

(i) If not starting itself, has an ERCOT-approved firm standby power contract with deliverability under Blackout circumstances from a non-ERCOT Control Area that can be finalized upon selection as a Black Start Resource;

(j) If not starting itself, has an ERCOT approved agreement with the necessary TSPs for access to another power pool, for coordination of switching during a Blackout or Partial Blackout, for coordination of maintenance through the ERCOT Outage Scheduler for all non-redundant transmission startup feeds;

(k) If dependent upon non-ERCOT transmission resources, agreements providing this Transmission Service have been provided in the proposal; and

(l) Demonstrated to ERCOT's satisfaction that the Resource has successfully completed remediation to any weather-related limitation disclosed as part of the BSS bid.

(2) On successful demonstration of system BSS capability, ERCOT shall certify that the Black Start Resource is capable of providing system BSS capacity and shall provide a copy of the certificate to the Resource Entity of the Black Start Resource. Qualification shall be valid for the time frames set forth below. Except under extenuating circumstances, as reasonably determined by ERCOT, all qualification testing for the next year of BSS must be completed by June 1st of each year.

(3) ERCOT may limit the number of qualification retests allowed. Qualification retesting is required only for the aspect of system BSS capability for which the Black Start Resource failed. If a Black Start Resource under an existing Black Start Agreement does not successfully re-qualify within two months of failing a test described herein, ERCOT shall decertify the Black Start Resource for the remainder of the calendar year as described in Section 7, Black Start Decertification, of Section 22, Attachment D, Standard Form Black Start Agreement. The following tests are required for BSS qualification:

(a) The "Basic Starting Test" includes the following:

(i) The basic ability of the Black Start Resource to start itself, or start from a normally open interconnection to another provider not inside the ERCOT interconnection, without support from the ERCOT System;

(ii) Annual testing, either as a stand-alone test or part of the Line-Energizing and Load-Carrying Tests, and the test is performed during a one-week period agreed to in advance by the Black Start Resource and ERCOT and must not cause outage to ERCOT Customer Load or the availability of other Resources to the ERCOT market;

(iii) Confirmation of the dates of the test with the Black Start Resource by ERCOT;

(iv) Isolation of the Black Start Resource, including all auxiliary Loads, from the ERCOT System, except for the transmission that connects the Resource to a provider not inside the ERCOT interconnection if the startup power is supplied by a firm standby contract. Black Start Resources starting with the assistance of a provider not inside the ERCOT interconnection through a firm standby agreement will connect to provider not inside the ERCOT interconnection, start-up, carry internal Load, disconnect from the provider not inside the ERCOT interconnection if not supplied through a black-start capable Direct Current Tie (DC Tie), and continue equivalently to what is required of other Black Start Resources;

(v) The ability of the Black Start Resource to start without assistance from the ERCOT System, except for the transmission that connects the Resource to a provider not inside the ERCOT interconnection if the startup power is supplied by a firm standby contract;

(vi) The ability of the Black Start Resource to remain stable (in both frequency and voltage) while supplying only its own auxiliary Loads or Loads in the immediate area for at least 30 minutes;

(vii) The Black Start Resource must have verified that its Volts/Hz relay, over-excitation limiter, and under-excitation limiter are set properly and that no protection devices will trip the Black Start Resource within the required reactive range. The Resource Entity for the Black Start Resource shall provide ERCOT with data to verify these settings; and

(viii) Each Black Start Resource must pass a Basic Starting Test once each calendar year.

(b) The “Line-Energizing Test” must be conducted at a time agreed on by the Black Start Resource, TSP or Distribution Service Provider (DSP), and ERCOT and includes the following:

(i) Energizing transmission with the Black Start Resource when conditions permit as determined by the TSP or DSP but at least once every three years;

(ii) De-energizing sufficient transmission in such manner that when energized by the Black Start Resource it demonstrates the Black Start Resource’s ability to energize enough transmission to deliver to the Loads the Resource’s output that ERCOT’s restoration plan requires the Black Start Resource to supply. ERCOT shall be responsible for transmission connections and operations that are compatible with the capabilities of the Black Start Resource;

(iii) Conducting a Basic Starting Test;

(iv) Energizing transmission with the Black Start Resource of the previously de-energized transmission, while monitoring frequency and voltages at both ends of the line. Alternatively, if ERCOT agrees, the transmission line may be connected to the Black Start Resource before starting, allowing the Resource to energize the line as it comes up to speed;

(v) Stable operation of the Black Start Resource (in both frequency and voltage) while supplying only its auxiliary Loads or external Loads for at least 30 minutes;

(vi) This test may be performed together with the Basic Starting Test in one 30-minute interval; and

(vii) Each Black Start Resource must pass a Line-Energizing Test once every three years.

(c) The "Load-Carrying Test" shall utilize the Load agreed to between ERCOT, TSP and the Black Start Resource. Testing shall occur as conditions permit, at a time agreed on by the Black Start Resource, TSP or DSP, and ERCOT, and includes the following:

(i) Stable operation of the Black Start Resource (in both frequency and voltage) while supplying restoration power to Load that is not identified as auxiliary Load of the Resource and is allowed to be auxiliary Load of adjacent facilities;

(ii) Conducting a Basic Starting Test;

(iii) Conducting a Line-Energizing Test when required;

(iv) Under the direction of ERCOT or the TSP operator, the Black Start Resource shall demonstrate the Black Start Resource's capability to supply the required Load, while maintaining voltage and frequency for at least 30 minutes;

(v) This test may be performed together with the Basic Starting Test and Line-Energizing Test when required in one 30-minute interval; and

(vi) Qualification under the Load-Carrying Test is valid for ~~five~~ four calendar years.

(d) "Next Start Resource Test":

(i) The ability of a Black Start Resource to start up the next start unit's largest required motor while continuing to remain stable and control voltage and frequency shall be tested. This test shall be repeated when a new next start unit is selected;

(ii) To pass the test:

(A) The potential Black Start Resource must start the next start unit (as determined by ERCOT), or start the next start unit's largest required motor and satisfied the next start unit's minimum startup Load requirements; or

(B) The Resource Entity shall demonstrate to the satisfaction of ERCOT through simulation studies conducted by the Resource Entity or a qualified third party, that the potential Black Start Resource is capable of starting the next start unit's largest required motor while meeting the next start unit's minimum startup Load requirements.

(iii) Potential Black Start Resources may request from ERCOT the information detailed in paragraph (B) above of the next start unit prior to the satisfaction of this requirement. ERCOT shall request this information from the designated next start unit. Such data, if requested by ERCOT, shall be provided by the QSE or Resource Entity representing the next start unit to ERCOT within 30 days. Such information shall be considered Protected Information by the requesting Resource Entity;

(iv) If a physical test is performed, the test shall commence with a Basic Starting Test, followed by a Line-Energizing Test when required and a Load-Carrying Test as a stand-alone test or part of the Next Start Resource Test;

(v) If a physical test is performed, the Black Start Resource must remain stable (in both voltage and frequency) and controlling voltage for 30 minutes;

(vi) If a physical test is performed, this test may be performed together with the Basic Starting Test, Line-Energizing Test when required, and Load-Carrying Test in one 30-minute interval; and

(vii) Each Black Start Resource must pass the Next Start Resource Test once every ~~five~~ four calendar years.

(e) The "BSS Back-up Fuel Switching Test" shall:

(i) Demonstrate a Black Start Resource's ability to successfully switch to a BSS Back-up Fuel source;

(ii) Demonstrate the ability of the Black Start Resource to start itself, or start from a normally open interconnection to another provider not inside the ERCOT interconnection, without support from the ERCOT System and while operating on the BSS Back-up Fuel source. The Black Start Resource may start on its primary fuel source, if necessary, but must transition to the BSS Back-up Fuel source within the timeframe indicated in its proposal;

(iii) Demonstrate the ability of the Black Start Resource to remain stable (in both frequency and voltage) while operating on BSS Back-up Fuel source and supplying only its own auxiliary Loads or Loads in the immediate area for at least ten minutes; and

(iv) Demonstrate that there is a sufficient amount of BSS Back-up Fuel to satisfy the requirement in paragraph (10) of Section 3.14.2, Black Start.

(f) The BSS Back-up Fuel Switching Test will be conducted on odd numbered years and may, at ERCOT's discretion, also be:

(i) Performed as part of the Basic Starting Test while operating on BSS Back-up Fuel; or

(ii) As a stand-alone test.

(4) Each qualified Black Start Resource shall perform a Black Start Resource Availability Test quarterly unless the Black Start Resource has successfully started and operated at LSL or higher for at least four consecutive Settlement Intervals during the quarter. The Black Start Resource's cost to perform a Black Start Availability Test may be a component of the overall bid for BSS but ERCOT will not separately compensate QSEs representing Black Start Resources for such testing. ERCOT, at its sole discretion, may grant an exemption of the Black Start Resource Availability Test for QSEs whose Black Start Resources have responded as instructed by ERCOT during an EEA event.

(5) The Black Start Resource Availability Test shall be scheduled by ERCOT. Upon receipt of notification for a Black Start Resource Availability Test, the QSE representing the Black Start Resource shall send confirmation to ERCOT of its intent to comply with the test or submit a request to reschedule along with justification for the request.

(6) ERCOT shall provide the QSE representing the Black Start Resource two-hour notice in order to allow the QSE time to update its COP. The QSE representing the Black Start Resource shall show the Resource as "ONTEST" in its COP and through its Real-Time telemetry for the duration of the test. As part of the Black Start Resource Availability Test, the QSE representing the Black Start Resource shall start the Black Start Resource and operate it at or above its LSL for at least four consecutive Settlement Intervals. After completion of the Black Start Resource Availability Test the QSE will update its COP to reflect their current status.

(7) Upon completion of the Black Start Resource Availability Test, the QSE representing the Black Start Resource shall complete and file a Black Start Resource Availability Test report with ERCOT. If the Black Start Resource wants to use a successful start and normal operation to satisfy the quarterly reporting requirement, it must provide the necessary information for the start and normal operation on a Black Start Resource Availability Test report. The report form shall be provided by ERCOT.

(8) A Black Start Resource Availability Test is deemed to be successful if the Black Start Resource comes On-Line within the time specified in the Black Start Resource's Request for Proposal response submitted to ERCOT and operates at a minimum level as agreed to by ERCOT and the QSE representing the Black Start Resource for at least four consecutive Settlement Intervals.

(9) If the Black Start Resource fails to successfully start during the Black Start Resource Availability Test, the QSE representing the Black Start Resource shall immediately update its Availability Plan for that Black Start Resource showing zero availability. The QSE representing the Black Start Resource shall not receive the Hourly Standby Fee for BSS effective from the date of the failed Black Start Resource Availability Test. The QSE representing the Black Start Resource may schedule a second Black Start Resource Availability Test, subject to ERCOT approval, to be completed within ten Business Days of the date of the failed Black Start Resource Availability Test unless a later date is agreed to by ERCOT. The cost of the second Black Start Resource test will be borne solely by the QSE representing the Black Start Resource.

(10) If the Black Start Resource successfully passes the second Black Start Resource Availability Test, the QSE representing the Black Start Resource shall resume receipt of the Hourly Standby Fee beginning on the date of the successful Black Start Resource Availability Test.

(11) If the Black Start Resource fails a second Black Start Resource Availability Test within the quarter, it shall immediately be disqualified from providing BSS and shall receive no further compensation under the Black Start Service Agreement. In addition, ERCOT shall claw-back all Hourly Standby Fee payments made to the QSE representing the Black Start Resource since its last successful Black Start Resource Availability Test or its last successful start and operation under normal system conditions, whichever is later. The clawed-back Hourly Standby Fee payments shall be uplifted by ERCOT to Loads on a Load Ratio Share (LRS) basis. ERCOT may, at its sole discretion, consider allowing the Black Start Resource to perform an additional Black Start Resource Availability Test. ERCOT may also, at its sole discretion, seek to procure additional Black Start Resources to replace the disqualified Black Start Resource.

(12) A QSE representing the Black Start Resource shall update its Availability Plan for a Black Start Resource to show zero if the Black Start Resource fails to perform when ERCOT has issued a Dispatch Instruction to come On-Line any time other than for a Blackout. The Black Start Resource shall continue to be shown as unavailable until it successfully starts under normal operations or completes a successful Black Start Resource Availability Test.

(13) If the Black Start Resource fails to perform successfully during an actual Blackout and the Black Start Resource has been declared available, as defined in Section 22, Attachment D, ERCOT shall:

(a) Decertify the Black Start Resource for the remainder of the Black Start Agreement contract term; and

(b) Claw-back 100% of the Hourly Standby Fee paid to the QSE representing the Black Start Resource for all the Operating Days since its last successful Black Start Resource Availability Test or its last successful start and operation under normal system conditions, whichever is later.

ERCOT Impact Analysis Report

NPRR Number	1210	NPRR Title	Next Start Resource Test and Load-Carrying Test Frequency
Impact Analysis Date	November 15, 2023		
Estimated Cost/Budgetary Impact	None.		
Estimated Time Requirements	No project required. This Nodal Protocol Revision Request (NPRR) can take effect following Public Utility Commission of Texas (PUCT) approval.		
ERCOT Staffing Impacts (across all areas)	Ongoing Requirements: No impacts to ERCOT staffing.		
ERCOT Computer System Impacts	No impacts to ERCOT computer systems.		
ERCOT Business Function Impacts	ERCOT will update its business processes to implement this NPRR.		
Grid Operations & Practices Impacts	No impacts to ERCOT grid operations and practices.		

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

Comments
None.

Board Report

NPRR Number	1211	NPRR Title	Move OBD to Section 22 – Methodology for Setting Maximum Shadow Prices for Network and Power Balance Constraints
Date of Decision	February 27, 2024		
Action	Recommended Approval		
Timeline	Normal		
Estimated Impacts	Cost/Budgetary: Less than $5k (Operations & Maintenance (O&M)) Project Duration: Not applicable		
Proposed Effective Date	Upon system implementation		
Priority and Rank Assigned	Not applicable		
Nodal Protocol Sections Requiring Revision	4.5.1, DAM Clearing Process 6.4.9.2.2, SASM Clearing Process 6.5.7.1.11, Transmission Network and Power Balance Constraint Management Section 22, Attachment Q, Methodology for Setting Maximum Shadow Prices for Network and Power Balance Constraints (new)		
Related Documents Requiring Revision/Related Revision Requests	Methodology for Setting Maximum Shadow Prices for Network and Power Balance Constraints (Upon approval of this NPRR, this will be removed from the Other Binding Documents List.)		
Revision Description	This Nodal Protocol Revision Request (NPRR) incorporates the Other Binding Document "Methodology for Setting Maximum Shadow Prices for Network and Power Balance Constraints" into the Protocols.		
Reason for Revision	☐ Strategic Plan Objective 1 – Be an industry leader for grid reliability and resilience ☐ Strategic Plan Objective 2 - Enhance the ERCOT region's economic competitiveness with respect to trends in wholesale power rates and retail electricity prices to consumers ☐ Strategic Plan Objective 3 - Advance ERCOT, Inc. as an independent leading industry expert and an employer of choice		

	by fostering innovation, investing in our people, and emphasizing the importance of our mission ☒ General system and/or process improvement(s) ☐ Regulatory requirements ☐ ERCOT Board and/or PUCT Directive *(please select ONLY ONE – if more than one apply, please select the ONE that is most relevant)*
Justification of Reason for Revision and Market Impacts	This NPRR is published for transparency and to standardize the approval process for all binding language.
PRS Decision	On 12/15/23, PRS voted unanimously to recommend approval of NPRR1211 as submitted. All Market Segments participated in the vote. On 1/11/24, PRS voted unanimously to endorse and forward to TAC the 12/15/23 PRS Report and 11/20/23 Impact Analysis for NPRR1211. All Market Segments participated in the vote.
Summary of PRS Discussion	On 12/15/23, there was no discussion. On 1/11/24, participants reviewed the 11/20/23 Impact Analysis.
TAC Decision	On 1/24/24, TAC voted unanimously to recommend approval of NPRR1211 as recommended by PRS in the 1/11/24 PRS Report. All Market Segments participated in the vote.
Summary of TAC Discussion	On 1/24/24, there was no additional discussion beyond TAC review of the items below.
TAC Review/Justification of Recommendation	☒ Revision Request ties to Reason for Revision as explained in Justification ☒ Impact Analysis reviewed and impacts are justified as explained in Justification ☒ Opinions were reviewed and discussed ☒ Comments were reviewed and discussed (if applicable) ☐ Other: (explain)

Board Report

ERCOT Board Decision	On 2/27/24, the ERCOT Board voted unanimously to recommend approval of NPRR1211 as recommended by TAC in the 1/24/24 TAC Report.

Opinions	
Credit Review	ERCOT Credit Staff and the Credit Finance Sub Group (CFSG) have reviewed NPRR1211 and do not believe that it requires changes to credit monitoring activity or the calculation of liability.
Independent Market Monitor Opinion	The Independent Market Monitor (IMM) has no opinion on NPRR1211.
ERCOT Opinion	ERCOT supports approval of NPRR1211.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NPRR1211 and believes it has a positive market impact by standardizing the approval process for binding language.

Sponsor	
Name	Ann Boren
E-mail Address	Ann.Boren@ercot.com
Company	ERCOT
Phone Number	512-248-6465
Cell Number	
Market Segment	Not Applicable

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

Comments Received	
Comment Author	**Comment Summary**
None	

Board Report

Market Rules Notes

To improve transparency, existing Other Binding Document language for new Section 22, Attachment Q, is represented as blackline, with only proposed changes marked as redline.

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

- NPRR1186, Improvements Prior to the RTC+B Project for Better ESR State of Charge Awareness, Accounting, and Monitoring
  - Section 4.5.1
  - Section 6.4.9.2.2
- NPRR1188, Implement Nodal Dispatch and Energy Settlement for Controllable Load Resources
  - Section 4.5.1

Proposed Protocol Language Revision

4.5.1 DAM Clearing Process

Commented [BA1]: Please not NPRR1186 and NPRR1188 also propose revisions to this section.

(1) At 1000 in the Day-Ahead, ERCOT shall start the Day-Ahead Market (DAM) clearing process. If the processing of DAM bids and offers after 0900 is significantly delayed or impacted by a failure of ERCOT software or systems that directly impacts the DAM, ERCOT shall post a Notice as soon as practicable on the ERCOT website, in accordance with paragraph (1) of Section 4.1.2, Day-Ahead Process and Timing Deviations, extending the start time of the execution of the DAM clearing process by an amount of time at least as long as the duration of the processing delay plus ten minutes. In no event shall the extension exceed more than one hour from when the processing delay is resolved.

(2) ERCOT shall complete a Day-Ahead Simultaneous Feasibility Test (SFT). This test uses the Day-Ahead Updated Network Model topology and evaluates all Congestion Revenue Rights (CRRs) for feasibility to determine hourly oversold quantities.

(3) The purpose of the DAM is to economically and simultaneously clear offers and bids described in Section 4.4, Inputs into DAM and Other Trades.

(4) The DAM uses a multi-hour mixed integer programming algorithm to maximize bid-based revenues minus the offer-based costs over the Operating Day, subject to security and other constraints, and ERCOT Ancillary Service procurement requirements.

(a) The bid-based revenues include revenues from DAM Energy Bids and Point-to-Point (PTP) Obligation bids.

(b) The offer-based costs include costs from the Startup Offer, Minimum Energy Offer, and Energy Offer Curve of any Resource that submitted a Three-Part Supply Offer, DAM Energy-Only Offers and Ancillary Service Offers.

(c) Security constraints specified to prevent DAM solutions that would overload the elements of the ERCOT Transmission Grid include the following:

(i) Transmission constraints – transfer limits on energy flows through the ERCOT Transmission Grid, e.g., thermal or stability limits. These limits must be satisfied by the intact network and for certain specified contingencies. These constraints may represent:

(A) Thermal constraints – protect Transmission Facilities against thermal overload.

(B) Generic constraints – protect the ERCOT Transmission Grid against transient instability, dynamic stability or voltage collapse.

(C) Power flow constraints – the energy balance at required Electrical Buses in the ERCOT Transmission Grid must be maintained.

(ii) Resource constraints – the physical and security limits on Resources that submit Three-Part Supply Offers:

(A) Resource output constraints – the Low Sustained Limit (LSL) and High Sustained Limit (HSL) of each Resource; and

(B) Resource operational constraints – includes minimum run time, minimum down time, and configuration constraints.

(iii) Other constraints –

(A) Linked offers – the DAM may not select any one part of that Resource capacity to provide more than one Ancillary Service or to provide both energy and an Ancillary Service in the same Operating Hour. The DAM may, however, select part of that Resource capacity to provide one Ancillary Service and another part of that capacity to provide a different Ancillary Service or energy in the same Operating Hour, provided that linked Energy and Off-Line Non-Spinning Reserve (Non-Spin) Ancillary Service Offers are not awarded in the same Operating Hour.

(B) The sum of the awarded Ancillary Service capacities for each Resource must be within the Resource limits specified in the Current Operating Plan (COP) and Section 3.18, Resource Limits in Providing Ancillary Service, and the Resource Parameters as described in Section 3.7, Resource Parameters.

(C) Block Ancillary Service Offers for a Load Resource – blocks will not be cleared unless the entire quantity block can be awarded. Because block Ancillary Service Offers cannot set the Market

Clearing Price for Capacity (MCPC), a block Ancillary Service Offer may clear below the Ancillary Service Offer price for that block.

(D) Block DAM Energy Bids, DAM Energy-Only Offers, and PTP Obligation bids – blocks will not be cleared unless the entire time and/or quantity block can be awarded. Because quantity block bids and offers cannot set the Settlement Point Price, a quantity block bid or offer may clear in a manner inconsistent with the bid or offer price for that block.

(E) Combined Cycle Generation Resources – The DAM may commit a Combined Cycle Generation Resource in a time period that includes the last hour of the Operating Day only if that Combined Cycle Generation Resource can transition to a shutdown condition in the DAM Operating Day.

(d) Ancillary Service needs for each Ancillary Service include the needs specified in the Ancillary Service Plan that are not part of the Self-Arranged Ancillary Service Quantity and that must be met from available DAM Ancillary Service Offers while co-optimizing with DAM Energy Offers. ERCOT may not buy more of one Ancillary Service in place of the quantity of a different service. See Section 4.5.2, Ancillary Service Insufficiency, for what happens if insufficient Ancillary Service Offers are received in the DAM.

[NPRR1008 and NPRR1014: Replace applicable portions of paragraph (4) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1008; or upon system implementation for NPRR1014:]

(4) The DAM uses a multi-hour mixed integer programming algorithm to maximize bid-based revenues, including revenues based on Ancillary Service Demand Curves (ASDCs), minus the offer-based costs over the Operating Day, subject to security and other constraints.

(a) The bid-based revenues include revenues from ASDCs, DAM Energy Bids, bid portions of Energy Bid/Offer Curves, and Point-to-Point (PTP) Obligation bids.

(b) The offer-based costs include costs from the Startup Offer, Minimum Energy Offer, and Energy Offer Curve of any Resource that submitted a Three-Part Supply Offer, DAM Energy-Only Offers, offer portions of Energy Bid/Offer Curves, Ancillary Service Only Offers, and Ancillary Service Offers.

(c) Security constraints specified to prevent DAM solutions that would overload the elements of the ERCOT Transmission Grid include the following:

(i) Transmission constraints – transfer limits on energy flows through the ERCOT Transmission Grid, e.g., thermal or stability limits. These limits must be satisfied by the intact network and for certain specified contingencies. These constraints may represent:

(A) Thermal constraints – protect Transmission Facilities against thermal overload.

(B) Generic constraints – protect the ERCOT Transmission Grid against transient instability, dynamic stability or voltage collapse.

(C) Power flow constraints – the energy balance at required Electrical Buses in the ERCOT Transmission Grid must be maintained.

(ii) Resource constraints – the physical and security limits on Resources that submit Three-Part Supply Offers or Energy Bid/Offer Curves:

(A) Resource output constraints – the Low Sustained Limit (LSL) and High Sustained Limit (HSL) of each Resource; and

(B) Resource operational constraints – includes minimum run time, minimum down time, and configuration constraints.

(iii) Other constraints –

(A) Linked offers – the DAM may not select any one part of that Resource capacity to provide more than one Ancillary Service or to provide both energy and an Ancillary Service in the same Operating Hour. The DAM may, however, select part of that Resource capacity to provide one Ancillary Service and another part of that capacity to provide a different Ancillary Service or energy in the same Operating Hour, provided that linked Energy and Off-Line Non-Spinning Reserve (Non-Spin) Resource-Specific Ancillary Service Offers are not awarded in the same Operating Hour.

(B) The sum of the awarded Resource-Specific Ancillary Service Offer capacities for each Resource must be within the Resource limits specified in the Current Operating Plan (COP) and Section 3.18, Resource Limits in Providing Ancillary Service, and the Resource Parameters as described in Section 3.7, Resource Parameters.

(C) Block Resource-Specific Ancillary Service Offers for a Load Resource – blocks will not be cleared unless the entire quantity block can be awarded. Because block Resource-Specific Ancillary Service Offers cannot set the Market Clearing Price for Capacity (MCPC), a block Ancillary Service Offer may clear below the Ancillary Service Offer price for that block.

(D) Block DAM Energy Bids, DAM Energy-Only Offers, and PTP Obligation bids – blocks will not be cleared unless the entire time and/or quantity block can be awarded. Because quantity block bids and offers cannot set the Settlement Point Price, a quantity block bid or offer may clear in a manner inconsistent with the bid or offer price for that block.

(E) Combined Cycle Generation Resources – The DAM may commit a Combined Cycle Generation Resource in a time period that includes the last hour of the Operating Day only if that Combined Cycle Generation Resource can transition to a shutdown condition in the DAM Operating Day.

(F) Energy Storage Resources (ESRs) – The energy cleared for an ESR may be negative, indicating purchase of energy, or positive, indicating sale of energy.

(d) Ancillary Service needs will be reflected in ASDCs for each Ancillary Service. Self-Arranged Ancillary Service Quantities will first be used to meet the ASDCs, and the remaining Ancillary Service needs are met from Ancillary Service Offers, as long as the costs do not exceed the ASDC value. ERCOT may not buy more of one Ancillary Service in place of the quantity of a different service.

(5) ERCOT shall determine the appropriate Load distribution factors to allocate offers, bids, and source and sink of CRRs at a Load Zone across the energized power flow buses that are modeled with Load in that Load Zone. The non-Private Use Network Load distribution factors are based on historical State Estimator hourly distribution using a proxy day methodology representing anticipated weather conditions. The Private Use Network Load distribution factors are based on an estimated Load value considering historical net consumption at all Private Use Networks. If ERCOT decides, in its sole discretion, to change the Load distribution factors for reasons such as anticipated weather events or holidays, ERCOT shall select a State Estimator hourly distribution from a proxy day reasonably reflecting the anticipated Load in the Operating Day. ERCOT may also modify the Load distribution factors to account for predicted differences in network topology between the proxy day and Operating Day. ERCOT shall develop a methodology, subject to Technical Advisory Committee (TAC) approval, to describe the modification of the proxy day bus-load distribution for this purpose.

[NPRR1004: Replace paragraph (5) above with the following upon system implementation:]

(5) ERCOT shall determine the appropriate Load distribution factors to allocate offers, bids, and source and sink of PTP Obligations at a Load Zone across the energized power flow buses that are modeled with Load in that Load Zone. ERCOT shall derive DAM Load distribution factors with the set of Load distribution factors constructed in accordance with the ERCOT Load distribution factor methodology specified in paragraph (c) of Section 3.12, Load Forecasting. In the event the Load distribution factors are not available, the Load distribution factors for the most recent preceding Operating Day will be used.

(6) ERCOT shall allocate offers, bids, and source and sink of CRRs at a Hub using the distribution factors specified in the definition of that Hub in Section 3.5.2, Hub Definitions.

(7) A Resource that has a Three-Part Supply Offer cleared in the DAM may be eligible for Make-Whole Payment of the Startup Offer and Minimum Energy Offer submitted by the Qualified Scheduling Entity (QSE) representing the Resource under Section 4.6, DAM Settlement.

(8) The DAM Settlement is based on hourly MW awards and on Day-Ahead hourly Settlement Point Prices. All PTP Options settled in the DAM are settled based on the Day-Ahead Settlement Point Prices (DASPPs). ERCOT shall assign a Locational Marginal Price (LMP) to de-energized Electrical Buses for use in the calculation of the DASPPs by using heuristic rules applied in the following order:

(a) Use an appropriate LMP predetermined by ERCOT as applicable to a specific Electrical Bus; or if not so specified

(b) Use the following rules in order:

(i) Use average LMP for Electrical Buses within the same station having the same voltage level as the de-energized Electrical Bus, if any exist.

(ii) Use average LMP for all Electrical Buses within the same station, if any exist.

(iii) Use System Lambda.

(9) The Day-Ahead MCPC for each hour for each Ancillary Service is the Shadow Price for that Ancillary Service for the hour as determined by the DAM algorithm.

(10) Day-Ahead MCPCs shall not exceed the System-Wide Offer Cap (SWCAP). Ancillary Service Offers higher than corresponding Ancillary Service penalty factors, as defined in

Appendix 2, Day-Ahead Market Optimization Control Parameters, of ~~the Other Binding Document titled~~ Section 22, Attachment Q, "Methodology for Setting Maximum Shadow Prices for Network and Power Balance Constraints," will not be awarded.

[NPRR1080: Delete paragraph (10) above upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1008; or upon system implementation for NPRR1014; and renumber accordingly.]

(11) If the Day-Ahead MCPC cannot be calculated by ERCOT, the Day-Ahead MCPC for the particular Ancillary Service is equal to the Day-Ahead MCPC for that Ancillary Service in the same Settlement Interval of the preceding Operating Day.

[NPRR1008 and NPR1014: Delete paragraph (11) above upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1008; or upon system implementation for NPRR1014; and renumber accordingly.]

(12) If the DASPPs cannot be calculated by ERCOT, all CRRs shall be settled based on Real-Time prices. Settlements for all CRRs shall be reflected on the Real-Time Settlement Statement.

(13) Constraints can exist between the generator's Resource Connectivity Node and the Resource Node, in which case the awarded quantity of energy may be inconsistent with the clearing price when the constraint between the Resource Connectivity Node and the Resource Node is binding.

[NPRR1014: Replace paragraph (13) above with the following upon system implementation:]

(13) Constraints can exist between a Resource's Resource Connectivity Node and its Resource Node, in which case the awarded quantity of energy may be inconsistent with the clearing price when the constraint between the Resource Connectivity Node and the Resource Node is binding.

(14) PTP Obligation bids shall not be awarded where the DAM clearing price for the PTP Obligation is greater than the PTP Obligation bid price plus $0.01/MW per hour.

6.4.9.2.2 SASM Clearing Process

Commented [BA2]: Please note NPRR1186 also proposes revisions to this section.

(1) SASM procurement requirements are:

(a) ERCOT shall procure the additional quantity required of each Ancillary Service, less the quantity self-arranged, if applicable. ERCOT may not buy more of one Ancillary Service in place of the quantity of a different service.

(b) ERCOT shall select Ancillary Service Offers submitted by QSEs, such that:

(i) For each Ancillary Service being procured, other than Reg-Down, ERCOT shall select offers that minimize the overall offer-based cost of these Ancillary Services. For each of these Ancillary Services, if selection of the Resource offer exceeds ERCOT's required Ancillary Service quantity, then ERCOT shall select a portion of the Resource offer to meet the Ancillary Service quantity required. For Load Resources offering a block of capacity, ERCOT shall ignore the offer unless the entire block can be accepted.

(ii) For Reg-Down, ERCOT shall procure required quantities by selecting capacity in ascending order starting from the lowest-priced offer. ERCOT shall continue this selection process until the required quantity of Reg-Down is obtained. If selection of the Resource offer exceeds ERCOT's required Ancillary Service quantity, then ERCOT shall select a portion of the Resource offer to meet the Ancillary Service quantity required. For Load Resources offering a block of capacity, ERCOT shall ignore the offer unless the entire block can be accepted.

(iii) For each Ancillary Service Offer from an Off-Line Resource considered in a SASM, the offer will be awarded only if it can meet the start-up time of the Resource based on the current and the historical operational state of the Resource. If the start-up time cannot be met for the first hour of a block offer, then the whole block offer shall not be considered.

(c) If a QSE has submitted offers of the same Resource capacity for more than one Ancillary Service (sometimes called linked offers), ERCOT may not select any one part of that Resource capacity to provide more than one Ancillary Service in the same Operating Hour. ERCOT may, however, select part of that Resource capacity to provide one Ancillary Service and another part of that capacity to provide a different Ancillary Service in the same Operating Hour.

(d) The SASM MCPC for each hour for each service is the Shadow Price for the corresponding Ancillary Service constraint for the hour as determined by the SASM algorithm.

(e) SASM MCPCs for any Ancillary Service shall not exceed the SWCAP. Ancillary Service Offers higher than corresponding Ancillary Service penalty factors, as defined in Appendix 2, Day-Ahead Market Optimization Control Parameters, of the ~~Other Binding Document titled~~Section 22, Attachment Q, ~~"~~Methodology for

Setting Maximum Shadow Prices for Network and Power Balance Constraints,” will not be awarded.

[NPRR1010: Delete Section 6.4.9.2.2 above upon system implementation of the Real-Time Co-Optimization (RTC) project.]

6.5.7.1.11 Transmission Network and Power Balance Constraint Management

(1) ERCOT may not allow any constraint (contingency and limiting Transmission Element pair) identified by NSA to be activated in SCED until it has verified that the contingency definition in NSA associated with the constraint is accurate and appropriate given the current operating state of the ERCOT Transmission Grid. ERCOT shall continuously post to the MIS Secure Area all constraint contingencies in the NSA. ERCOT shall provide relevant constraint information, including, but not limited to, the contingency name as provided in the standard contingency list, whether or not the constraint is active in SCED, the overloaded Transmission Element name, the Rating of the overloaded Transmission Element including Generic Transmission Limits (GTLs) expressed in MW and MVA, and pre-contingency or post-contingency flows expressed in MW and MVA. For each Operating Day, ERCOT shall post to the MIS Secure Area within five days, a report listing all constraints with pre-contingency or post-contingency flows which exceeded the Rating of the overloaded Transmission Element for at least 15 minutes consecutively that were not activated in SCED and an explanation of why each constraint was not activated.

(2) Pursuant to Section 22, Attachment Q, Methodology for Setting Maximum Shadow Prices for Network and Power Balance Constraints, ERCOT shall establish a maximum Shadow Price for each network constraint as part of the definition of contingencies. The cost calculated by SCED to resolve an additional MW of congestion on the network constraint is limited to the maximum Shadow Price for the network constraint.

(3) Pursuant to Section 22, Attachment Q, ERCOT shall establish a maximum Shadow Price for the power balance constraint. The cost calculated by SCED to resolve either the addition or reduction of one MW of dispatched generation on the power balance constraint is limited to the maximum Shadow Price for the power balance constraint.

~~(4) ERCOT shall determine the methodology for setting maximum Shadow Prices for network constraints and for the power balance constraint. Following review and recommendation by the Technical Advisory Committee (TAC), the ERCOT Board shall review the recommendation and approve a final methodology.~~

~~(5) The process for setting the maximum Shadow Prices as described above shall require ERCOT to obtain ERCOT Board approval of the values assigned to these caps along with the effective date for application of the cap. Within two Business Days following~~

~~approval by the ERCOT Board, ERCOT shall post the Shadow Price caps and effective dates on the ERCOT website.~~

(4~~6~~) If ERCOT determines that rating(s) in the Network Operations Model or configuration of the Transmission Facilities are not correct, then the TSP will provide the appropriate data submittals to ERCOT to correct the problem upon notification by ERCOT.

[NPRR857: Replace paragraph (4~~6~~) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(4~~6~~) If ERCOT determines that rating(s) in the Network Operations Model or configuration of the Transmission Facilities are not correct, then the TSP or DCTO will provide the appropriate data submittals to ERCOT to correct the problem upon notification by ERCOT.

Board Report

ERCOT Nodal Protocols

Section 22

Attachment Q: Methodology for Setting Maximum Shadow Prices for Network and Power Balance Constraints

Date TBD

~~**PUCT Approved 3/31/22**~~

~~**Effective Date of 4/1/22**~~

~~**Version 15.0**~~

Board Report

~~Document Revisions~~

~~Date~~	~~Version~~	~~Description~~	~~Author(s)~~
~~07/21/2010~~	~~0.1~~	~~Initial draft~~	~~Bob Spangler/ Haso Peljto/Resmi Surendran~~
~~08/11/2010~~	~~0.11~~	~~Added Section 4.0 Power Balance Shadow Price Cap & Appendix, The SCED Optimization Objective Function and Constraints~~	~~Bob Spangler/ Haso Peljto/Resmi Surendran~~
~~08/18/2010~~	~~0.12~~	~~Added Transmission Constraint Shadow Price Cap 3.5~~	~~Bob Spangler~~
~~08/24/2010~~	~~0.13~~	~~Incorporate Resmi Surendran comments and revisions.~~	~~Bob Spangler/Resmi Surendran/Haso Peljto~~
~~09/21/2010~~	~~0.14~~	~~Incorporate Market Participant comments and revisions.~~	~~Bob Spangler/Resmi Surendran~~
~~09/22/2010~~	~~0.15~~	~~Incorporate WMS recommendation~~	~~Resmi Surendran~~
~~09/28/2010~~	~~0.2~~	~~Incorporate ERCOT updates & corrections~~	~~Hasso Peijto/ Resmi Surendan/ R Spangler~~
~~10/20/2010~~	~~0.21~~	~~Incorporate WMS recommendation~~	~~Resmi Surendran~~
~~11/16/2010~~	~~1.0~~	~~Updated to reflect TAC approval on November 4th 2010 and Board approval on November 16th 2010~~	~~Resmi Surendran~~
~~03/12/2010~~	~~1.14~~	~~Added section to address modification to Maximum Shadow Price for Valley import constraint~~	~~Resmi Surendran~~
~~05/03/2011~~	~~2.0~~	~~Revision submitted to the ERCOT Board for approval.~~	~~R Spangler~~
~~05/13/2011~~	~~2.0~~	~~Revision submitted to the ERCOT Board for approval.~~	~~Kristi Hobbs~~
~~05/18/2011~~	~~2.0~~	~~Updated to reflect Board approval on May 18, 2011.~~	~~Kristi Hobbs~~
~~8/29/2011~~	~~3.0~~	~~Updated to incorporate the 08/04/11 TAC recommendation for the calculation of Shadow Price Caps for non-competitive constraints that are deemed to be irresolvable in SCED.~~	~~R. Spangler~~
~~9/1/2011~~	~~3.0~~	~~Updated to reflect 09/01/11 TAC recommendation.~~	~~Kristi Hobbs~~
~~10/3/11~~	~~3.0~~	~~Comments submitted for TAC consideration.~~	~~Luminant~~
~~10/6/11~~	~~3.0~~	~~Updated to reflect clarifications offered at the 10/6/11 TAC.~~	~~Kristi Hobbs~~
~~10/11/11~~	~~3.0~~	~~Updated to reflect 10/11/11 TAC recommendation.~~	~~Kristi Hobbs~~
~~12/12/11~~	~~3.0~~	~~Board approved 10/11/11 TAC recommendation with 1/1/12 effective date.~~	~~Kristi Hobbs~~
~~3/1/12~~	~~4.0~~	~~TAC approved 030112 to include on OBD list.~~	~~Market Rules~~

Board Report

~~Date Approved~~	~~Version~~	~~Description~~	~~Author(s)~~	~~Approved By~~	~~Effective Date~~
~~7/17/12~~	~~5.0~~	• ~~6/20/12 Special TAC – voted on recommended PBPC~~ • ~~6/28/12 – TAC recommended approval~~ • ~~7/17/12 – ERCOT Board of Directors approval with an effective date of 8/1/12.~~	~~Kristi Hobbs~~	~~ERCOT Board~~	~~8/1/12~~
~~12/11/12~~	~~6.0~~	~~TAC recommended revisions to comport with PUCT changes to Substantive Rule 25.505 as well as other administrative clean up.~~ • ~~11/7/12 – WMS recommended approval~~ • ~~11/29/12 – TAC recommended approval~~ • ~~12/11/12 – ERCOT Board of Directors approval with effective date of 12/12/12.~~	~~Kristi Hobbs~~	~~ERCOT Board~~	~~12/12/12~~
~~5/14/13~~	~~7.0~~	~~TAC recommended revisions to reflect the 6/1/13 change of the high system-wide offer cap from $4,500 per MWh to $5,000 per MWh; and to remove non-competitiveness criteria from the methodology for setting Shadow Price caps for irresolvable transmission constraints.~~ • ~~4/12/13 – WMS recommended approval~~ • ~~5/2/13 – TAC recommended approval~~ • ~~5/14/13 – ERCOT Board of Directors approval with effective date of 6/1/13.~~	~~Market Rules~~	~~ERCOT Board~~	~~6/1/13~~
~~7/16/13~~	~~8.0~~	• ~~3/7/13 – TAC Tabled for WMS review.~~ • ~~5/2/13 – TAC recommended approval and requested an Impact Analysis.~~ • ~~6/6/13, TAC recommended approval.~~ • ~~7/16/13 – ERCOT Board of Directors approval with effective date of 7/17/13.~~ • ~~6/25/15 – Unboxed language in Section 3.6.2 due to effective date.~~	~~AEP~~	~~ERCOT Board~~	~~7/17/13~~

Board Report

~~Date Approved~~	~~Version~~	~~Description~~	~~Author(s)~~	~~Approved By~~	~~Effective Date~~
~~4/8/14~~	~~9.0~~	~~Section 4.3, The ERCOT Power Balance Penalty Curve, updated to reflect WMS approved Power Balance Penalty Curve.~~ • ~~3/5/14 – WMS recommended approval~~ • ~~3/27/14 – TAC recommended approval~~ • ~~4/8/14 – ERCOT Board of Directors approved with an effective date of 6/1/14. [Language grey boxed until effective date of 6/1/14]~~ • ~~6/1/14 – Unboxed language in Section 4.3 due to effective date.~~	~~ERCOT (Resmi Surendran)~~	~~ERCOT Board~~	~~6/1/14~~
~~2/14/17~~	~~10.0~~	~~Sections 3.5.1 and 4.3 are updated to reflect the current System-Wide Offer Cap and remove outdated material.~~	~~ERCOT (David Maggio)~~	~~ERCOT Board~~	~~2/15/17~~
~~6/12/18~~	~~11.0~~	~~Revisions proposed by OBDRR005, Change to the Generic Maximum Shadow Price for Base Case Transmission Constraints~~	~~ERCOT (David Maggio)~~	~~ERCOT Board~~	~~6/20/18~~
~~6/11/19~~	~~12.0~~	~~Revisions proposed by OBDRR013, Change to the Voltage Levels of Generic Transmission Shadow Prices Caps~~	~~ERCOT (David Maggio)~~	~~ERCOT Board~~	~~6/12/19~~
~~12/8/20~~	~~13.0~~	~~Revisions proposed by OBDRR020, RTC – Methodology for Setting Maximum Shadow Prices for Network and Power Balance Constraints~~	~~ERCOT (David Maggio)~~	~~ERCOT Board~~	~~12/10/20~~
~~6/28/21~~	~~14.0~~	~~Revisions proposed by OBDRR030, Related to NPRR1080, Limiting Ancillary Service Price to System-Wide Offer Cap~~	~~ERCOT and IMM (Kenan Ögelman / Carrie Bivens)~~	~~ERCOT Board~~	~~7/1/21~~
~~3/31/22~~	~~15.0~~	~~Revisions proposed by OBDRR037, Power Balance Penalty and Shadow Price Cap Updates to Align with PUCT Approved High System-Wide Offer Cap~~	~~ERCOT (David Maggio)~~	~~PUCT~~	~~4/1/22~~

Board Report

~~Revisions to this document shall be made according to the approval process as prescribed in Protocol Section 6.5.7.1.11, Transmission Network and Power Balance Constraint Management.~~

~~PROTOCOL DISCLAIMER~~

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

Board Report

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Board Report

1. PURPOSE

~~Protocol~~ Section 6.5.7.1.11, Transmission Network and Power Balance Constraint Management, requires the ~~ERCOT Board~~Public Utility Commission of Texas (PUCT) to approve ERCOT's methodology for establishing caps on the Shadow Prices for transmission constraints and the Power Balance constraint. Additionally, ~~the ERCOT Board~~PUCT must also approve the values (in $/MWh) for each of the Shadow Price caps.

The effect of the Shadow Price cap for transmission network constraints is to limit the cost calculated by the Security-Constrained Economic Dispatch (SCED) optimization to resolve an additional MW of congestion on a transmission network constraint to the designated maximum Shadow Price for that transmission network constraint. The effect of the Shadow Price cap for the Power Balance Constraint is to limit the cost calculated by the SCED optimization when the instantaneous amount of generation to be dispatched does not equal the instantaneous demand of the ERCOT system. In this case, the cost calculated by SCED to resolve either the addition or reduction of one MW of dispatched generation on the power balance constraint is limited to the maximum Shadow Price for the power balance constraint, which is also referred to as the Power Balance Penalty.

The maximum Shadow Prices for the transmission network constraints and the power balance constraint directly determine the Locational Marginal Prices (LMPs) for the ERCOT Real Time Market in the cases of constraint violations.

This Business Practice describes:

- the ~~ERCOT Board~~PUCT-~~-~~approved methodology that the ERCOT staff will use for determining the maximum system-wide Shadow Prices for transmission network constraints and for the power balance constraint, and
- the ~~ERCOT Board~~PUCT-~~-~~approved Shadow Price caps and their effective date.

2. BACKGROUND DISCUSSION

The term Shadow Price as used in a constrained optimization problem in economics, is usually defined as the change in the objective value of the optimal solution of the optimization problem obtained by changing each constraint, one-at-a-time, by one unit. In the SCED process the objective function to be minimized by the SCED optimization engine is the total system dispatch cost required to maintain the system power balance and to resolve congestion of the transmission network as specified in the transmission constraint input set. The term Shadow Price is used in the context of individual constraints, whether a transmission network constraints or power balance constraint. Consistent with the definition of the Shadow Price, in a minimization problem, such as the SCED, the Shadow Prices for the transmission constraints are different for each transmission constraint and they are positive $/MW amounts defined as increase of the system dispatch costs if a transmission line limit is decreased by one MW. The Shadow Price for the Power Balance constraint represents system costs for serving the last MW of load. The Power Balance Penalty can be either positive (if the system requires additional generation) or negative (if the system requires a reduction in generation). If a constraint is not binding, meaning the constraint has excess capability under the given system conditions, the Shadow Price of the constraint is $0.00/MWh. On the other hand, if the constraint is binding, meaning it is limiting because the system conditions are such that the constraint limit is exactly met by the SCED selected dispatch pattern, the constraint Shadow Price is a non-zero $/MW value and when the maximal Shadow Price (i.e. the Shadow Price cap) is reached the constraint will be violated without further increases in the constraint Shadow Price.

In the context of the SCED optimization, the Shadow Prices give rise to the application of a transmission penalty cost and a power balance penalty cost in the SCED objective function that results in an increase in the total system dispatch cost. On the other hand, the transmission network constraint Shadow Prices and the Power Balance Shadow Price directly determine the LMPs (in $/MWh) calculated in the SCED. The LMPs will be limited because of the Shadow Price cap amounts, expressed in $/MWh.

For the network transmission constraints, the Shadow Price Cap may vary for each constraint, may be a unique value applicable to all constraints, or may be values unique to subsets of the full constraint set. For the Power Balance constraint, the Shadow Price Cap may be a single value or a value given as a function of the amount of the power balance mismatch (instantaneous generation to be dispatch minus instantaneous demand) in MW.

[OBDRR020: Replace the paragraph above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

For the network transmission constraints, the Shadow Price Cap may vary for each constraint, may be a unique value applicable to all constraints, or may be values unique to subsets of the full constraint set. For the Power Balance constraint, the Shadow Price Cap is a single value.

3. ELEMENTS FOR METHODOLOGY FOR SETTING THE NETWORK TRANSMISSION SYSTEM-WIDE SHADOW PRICE CAPS

3.1 Congestion LMP Component

The LMPs at Electrical Buses are calculated as follows:

$$LMP_{EB} = \lambda - \sum_{line} SF_{EB}^{line} \cdot SP^{line}$$

Where:

LMP_{EB}	is LMP at Electrical Bus *EB*
λ	is system lambda (Shadow Price of power balance)
SF_{EB}^{line}	is Shift Factor for Electrical Bus *EB* for transmission *line*
SP^{line}	is Shadow Price for transmission *line.*

Note that the Shadow Prices for congested transmission lines are positive, otherwise they are equal zero. The Shift Factors for Electrical Buses on one side of transmission line are negative and for Electrical Buses on the other side of transmission line are positive.

The congestion component of Electrical Bus LMP is:

$$\Delta LMP_{EB}^{cong} = -\sum_{line} SF_{EB}^{line} \cdot SP^{line}$$

and it can be positive or negative depending on sign of Shift Factors. The congestion component of LMP represents a price incentive to generation units connected at that Electrical Bus to increase or decrease power output to manage network congestion. Note that only marginal units (i.e. units that are able to move, not those dispatched at min/max dispatch limits to resolve other constraints or to provide energy to the system) can participate in resolving network congestion and determining the system lambda for a particular iteration of SCED.

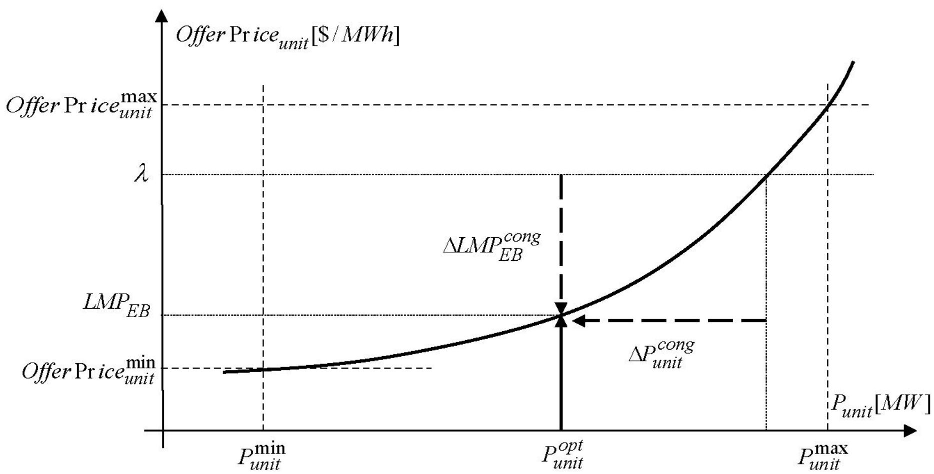
The optimal dispatch from both system (minimal congestion costs) and unit (maximal unit profit) prospective is determined by condition:

$$Offer\,\mathrm{Pr}\,ice_{unit}(P_{unit}^{opt}) = LMP_{EB}\,.$$

The generation unit response to pricing signal will result in line power flow reduction in amount:

$$\Delta P^{line} = SF_{EB}^{line} \cdot \Delta P_{unit}^{cong}$$

These relationships are illustrated at the following figure:



3.2 Network Congestion Efficiency

The following three elements of network congestion management determine the efficiency of generating unit participation (as defined above):

- Line power flow contribution ΔP^{line}
- LMP congestion component ΔLMP_{EB}^{cong}
- Unit power output adjustment ΔP_{unit}^{cong} .

The line power contribution is determined by its Shift Factor directly. It may be established that generating units with Shift Factors below specified threshold (10%) are not efficient in network congestion.

The LMP congestion component is main incentive controlling generating unit dispatch. It is determined by Shift Factors and Shadow Prices for transmission constraints:

$$\Delta LMP_{EB}^{cong} = \sum_{line} SF_{EB}^{line} \cdot SP^{line} .$$

Generating units with small Shift Factors (i.e. below Shift Factor threshold) will not be as effective in resolving constraints as will generators with higher shift factors on the constraint. If there is no efficient generating units then Shadow Price must be increased to get enough contribution from inefficient units. Therefore, high Shadow Prices indicate inefficient congestion management.

The maximal value of LMP congestion component $\Delta LMP_{\max}^{cong}$ directly limits the transmission congestion costs:

$$C_{\cos t}^{cong} = \sum_{unit} \Delta LMP_{\max}^{cong} \cdot P_{unit}^{opt} .$$

The efficiency of generating unit contribution can be determined by maximal value of LMP congestion component $\Delta LMP_{\max}^{cong}$ (say \$500/MWh). The maximal Shadow Price for transmission constraint can be established by Shift Factor efficiency threshold and maximal LMP congestion component as follows:

$$SP_{\max} = \Delta LMP_{\max}^{cong} / SF_{threshold}^{efficiency} .$$

The maximal unit power output adjustment $\Delta P_{\max}^{cong}$ will be determined by condition:

$$Offer\Pr ice_{unit}(P_{unit} - \Delta P_{\max}^{cong}) = LMP_{EB} = \lambda - SF_{threshold}^{efficency} \cdot SP_{\max}$$

3.3 Shift Factor Cutoff

Note: This Shift Factor cutoff is not related to above Shift Factor efficiency threshold used for determination of maximal Shadow Price.

Some generating units can be excluded from network congestion management by ignoring their contribution in line power flows. Note that this exclusion cannot be performed physically, i.e. all units will always contribute to line power flows according to their Shift Factors. Therefore, the Shift Factor cutoff introduces an additional approximation into line power flow modeling.

Since the effect of the Shift Factors below the cut off on the overload are ignored in the optimization, any Shift Factor cutoff will cause additional re-dispatch of the remaining generating units participating in the management of congestion on the constraint. I.e. Generation Resources with Shift Factor above cut off will have to be moved more to account for the increase in overload caused by increasing generation of an inexpensive Resource with positive Shift Factor below cut off and decreasing generation of an expensive Resource with negative Shift Factor below cut off.

The Shift Factor cutoff will cause mismatch between optimized line power flow and actual line power flow that will happen when dispatch Base Points are deployed. This mismatch can degrade the efficiency of congestion management.

The Shift Factor cutoff can reduce volume of Shift Factor data and filter out numerical errors in calculating Shift Factors. Currently the default value of Shift Factor cut off is 0.0001) and is implemented at the EMS to reduce the amount of data transferred to MMS. Any threshold above that level will cause a distortion of congestion management process.

3.4 Methodology Outline

The methodology for determination of maximal Shadow Prices for transmission constraints could be based on the following setting:

(a) Determine Shift Factor efficiency threshold $SF^{efficiency}_{threshold}$ (default x%)

(b) Determine maximal LMP congestion component $\Delta LMP^{cong}_{\max}$ (default \$y/MWh)

(c) Calculate maximal Shadow Price for transmission constraints:

$$SP_{\max} = \Delta LMP^{cong}_{\max} / SF^{efficiency}_{threshold}$$

(d) Determine Shift Factor cutoff threshold $SF^{cutoff}_{threshold}$ (default z%)

(e) Evaluate settings on variety of SCED save cases.

3.5 Generic Values for the Transmission Network System-Wide Shadow Price Caps in SCED

The Generic Transmission Shadow Price Caps noted below will be used in SCED unless ERCOT determines that a constraint is irresolvable by SCED. The methodology for determining and resolving an insecure state within SCED (i.e. SCED Irresolvable) is defined in Protocol Section 6.5.7.1.10, Network Security Analysis Processor and Security Violation Alarm, whereas the subsequent trigger condition for the determination of that constraint's Shadow Price Cap is described in Section 3.6, Methodology for Setting Transmission Shadow Price Caps for Irresolvable Constraints in SCED.

Generic Transmission Constraint Shadow Price Caps in SCED

- Base Case/Voltage Violation: $5,251/MW
- N-1 Constraint Violation
    - Greater than 200 kV: $4,500/MW
    - 100 kV to 200 kV: $3,500/MW
    - Less than 100 kV: $2,800/MW

3.5.1 Generic Transmission Constraint Shadow Price Cap in SCED Supporting Analysis

Figure 1 is a contour map that shows the relationship between the level of the constraint shadow price cap, the offer price difference of the marginal units deployed to resolve a constraint, and the shift factor difference of the marginal units deployed to resolve a constraint.[1]

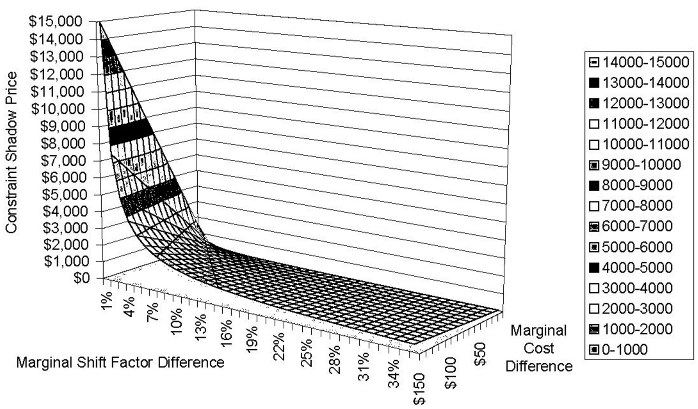


Figure 1

Figure 2 is a projection of Figure 1 onto the x-axis (*i.e.*, looking at it from the top). These two figures focus on constraint shadow price cap levels, and do not consider the interaction with the power balance constraint penalty factor, which is further discussed in association with Figure 4.

[1] A distributed load reference bus is assumed in this ~~document~~attachent, and all shift factor values refer to the flow on a constraint (either pre- or post-contingency) assuming an injection at the location in question and a withdrawal at the reference bus.

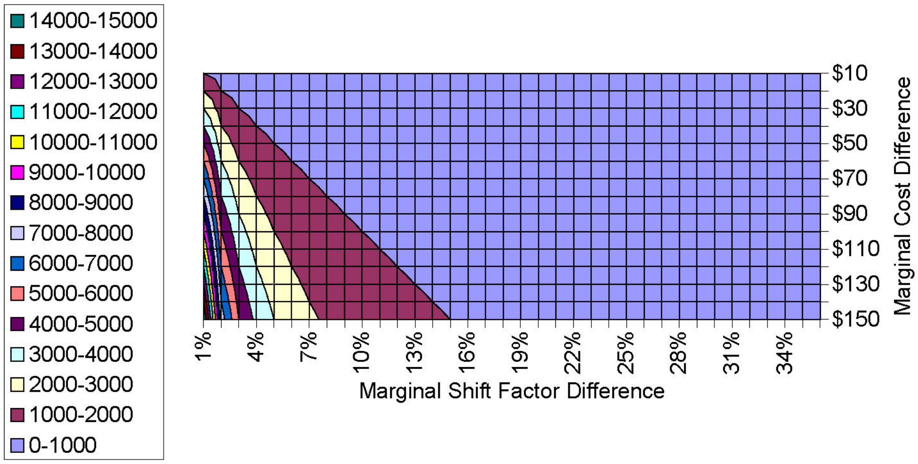


Figure 2

Figures 1 and 2 show that:

- For a constraint shadow price cap of $5,251/MW
  - Marginal units with an *offer price difference* of $52.51/MWh will be deployed to resolve a constraint when the *shift factor difference* of the marginal units is as low as 1%.
  - Marginal units with an *offer price difference* of $150/MWh will be deployed to resolve a constraint when the *shift factor difference* of the marginal units is as low as 2.9%.
- For a constraint shadow price cap of $4,500/MW
  - Marginal units with an *offer price difference* of $45/MWh will be deployed to resolve a constraint when the *shift factor difference* of the marginal units is as low as 1%.
  - Marginal units with an *offer price difference* of $150/MWh will be deployed to resolve a constraint when the *shift factor difference* of the marginal units is as low as 3.4%.
- For a constraint shadow price cap of $3,500/MW
  - Marginal units with an *offer price difference* of $35/MWh will be deployed to resolve a constraint when the *shift factor difference* of the marginal units is as low as 1%.

- Marginal units with an *offer price difference* of $150/MWh will be deployed to resolve a constraint when the *shift factor difference* of the marginal units is as low as 4.3%.
- For a constraint shadow price cap of $2,800/MW
  - Marginal units with an *offer price difference* of $28/MWh will be deployed to resolve a constraint when the *shift factor difference* of the marginal units is as low as 1%.
  - Marginal units with an *offer price difference* of $150/MWh will be deployed to resolve a constraint when the *shift factor difference* of the marginal units is as low as 5.35%.

Figure 3 shows the maximum offer price difference of the marginal units that will be deployed to resolve congestion with each of the proposed shadow price cap values as a function of the shift factor difference of the marginal units.

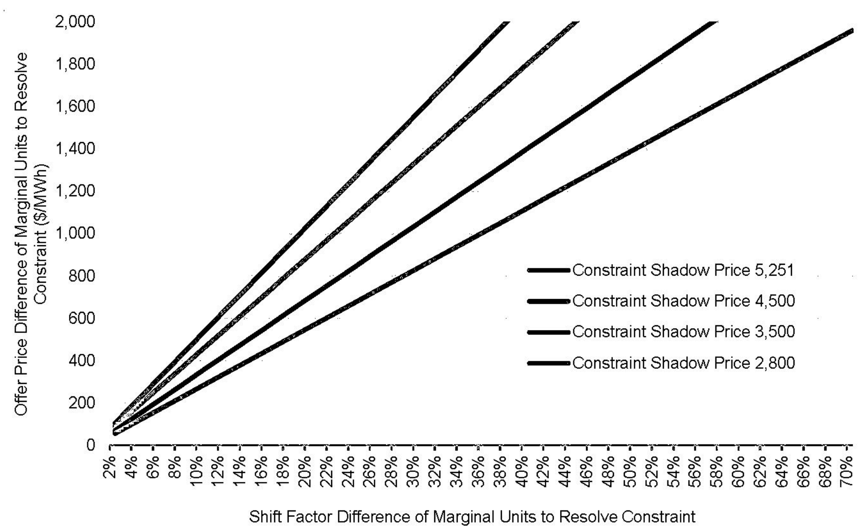


Figure 3

For example, with a shift factor difference of the marginal units of just 2%, the maximum offer price difference of the marginal units that will be deployed to resolve the constraint is $56, $70, $90 and $105.02/MWh for constraint shadow price cap values of $2,800, $3,500, $4,500 and $5,251/MW, respectively. Similarly, for with a shift factor difference of the marginal units of

60%, the maximum offer price difference of the marginal units that will be deployed to resolve the constraint is $1,680, $2,100, $2,700 and $3,150.60/MWh for constraint shadow price cap values of $2,800, $3,500, $4,500 and $5,251/MW, respectively.

In some circumstances these constraint shadow price cap values may preclude the deployment of an offer at the System-Wide Offer Cap (SWCAP). However, it is not possible in the nodal design to establish constraint shadow price caps at a level that will always accept an offer at SWCAP and still produce pricing outcomes that remain within reasonable bounds of subsection (g)(6) of P.U.C. SUBST. R. 25.505, Resource Adequacy in the Electric Reliability Council of Texas Power Region. For example, taking the case above where the shift factor difference of the marginal units is just 2%, a constraint shadow price cap of $250,000/MW would be required to deploy $5,000/MWh offers to resolve the congestion (assuming an offer price of zero for the marginal constrained-down unit). In this case, for nodes with a higher shift factor relative to the constraint (regardless of whether the nodes are generation or load nodes), the resulting LMP would be significantly higher than a $5,000/MWh SWCAP if the constraint was irresolvable. For example, a node with a shift factor of -50% would have an LMP with a congestion component of $125,000/MWh from just this one constraint, and even higher if multiple constraints are binding. In contrast, with a $5,251/MW shadow price cap, the congestion component of the LMP of the node with a shift factor of -50% would be $2,625.50/MW for just this one constraint.

The LMP at an individual node, hub or load zone can exceed the system-wide offer cap in some circumstances. This is most likely to occur when there are one or more irresolvable constraints on the system *and* when overall dispatchable supply on the system is tight. Relatively speaking, it is more likely that individual node prices will exceed the system-wide offer cap than hubs or load zones, but it is possible that hub or load zone prices could exceed the system-wide offer cap. It is not possible in the nodal system to assign constraint shadow price caps and power balance penalty factor values that achieve the desired reliability and efficiency objectives and ensure that all LMPs remain within the bounds of the system-wide offer caps under all circumstances.

Operationally once ERCOT reaches the shadow price cap, ERCOT may use the following method to manage congestion. Steps that may be taken by ERCOT operations to resolve congestion when the transmission constraint is violated in SCED after the Shadow Price reaches the shadow price cap include:

- Formulating a mitigation plan which may include
    - Transmission reconfiguration (switching)
    - Load rollover to adjacent feeders
    - Load shed plans

- Redistribution of ancillary services to increase the capacity available within a particular area.
- Commitment of additional units.
  - Re-dispatching generation through over-riding High Dispatch Limit (HDL) and Low Dispatch Limit (LDL) in accordance with paragraph (3)(g) of Protocol Section 6.5.7.1.10.

3.6 Methodology for Setting Transmission Shadow Price Caps for Irresolvable Constraints in SCED

ERCOT Operations is required to resolve security violations on the ERCOT Grid as described in Protocol Section 6, Adjustment Period and Real-Time Operations, and the associated Nodal Operating Guides and ERCOT will utilize the SCED application or direct actions on the transmission network and among Generation Resources, as needed, to resolve security violations. With regard to SCED operations, if a security violation on a constraint occurs, ERCOT will determine whether or not this constraint violation should be deemed to be irresolvable by online Generation Resource Dispatch by the SCED application. ERCOT will use the methodology described in this section to determine the Shadow Price Cap for a constraint that is deemed irresolvable pursuant to Section 3.6.1, Trigger for Modification of the Shadow Price Cap for a Constraint that is Consistently Irresolvable in SCED, below. For each of these constraints this Shadow Price Cap will be used by the SCED application in place of the generic cap specified by Section 3.5, Generic Values for the Transmission Network System-Wide Shadow Price Caps in SCED, until ERCOT deems the constraint resolvable by SCED. ERCOT shall provide the market 30 days notice before deeming the constraint resolvable by SCED. Upon deeming the constraint resolvable by SCED, the Shadow Price Cap for the constraint shall be determined pursuant to Section 3.5.

3.6.1 Trigger for Modification of the Shadow Price Cap for a Constraint that is Consistently Irresolvable in SCED

The methodology for determining and resolving an insecure state within SCED is defined in Protocol Section 6.5.7.1.10, Network Security Analysis Processor and Security Violation Alarm. ERCOT shall modify the Shadow Price Cap for a transmission network constraint that is consistently irresolvable by SCED if either of the following two conditions are true. Intervals with manual overrides performed as a result of SCED not resolving the congestion, shall be included:

A. A constraint violation is not resolved by the SCED dispatch or overridden for more than two consecutive hours on more than 4 consecutive Operating Days; or
B. A constraint violation is not resolved by the SCED dispatch for more than a total of 20 hours in a rolling thirty day period.

On the Operating Day during which ERCOT deems a network transmission constraint to have met the trigger conditions, ERCOT shall identify the following Generation Resources:

C. The Generation Resource with the lowest absolute value of the negative shift factor impact on the violated constraint (this resource is referred as Generation Resource C in the Shadow Price Cap calculation below); and,

D. The Generation Resource with the highest absolute value of the negative shift factor on the violated constraint (this resource is referred to as Generation Resource D in the designation of the net margin Settlement Point Price (SPP) described below).

When determining Generation Resources C and D above, ERCOT shall ignore all Generation Resources that have a shift factor with an absolute value of less than 0.02 impact on the irresolvable constraint.

3.6.2 Methodology for Setting the Constraint Shadow Price Cap for a Constraint that is Irresolvable in SCED

The Shadow Price Cap for a constraint that has met the trigger conditions described in Section 3.6.1, Trigger for Modification of the Shadow Price Cap for a Constraint that is Consistently Irresolvable in SCED, and the Shadow Price Cap for any constraint that has the same overloaded transmission element and direction as a constraint that has met the trigger conditions, will be determined as follows.
The Shadow Price Cap on the constraint that has met the trigger conditions described in Section 3.6.1, will be set to the minimum of E or F as follows:

E. The value of the Generic Shadow Price Cap as determined in Section 3.5, Generic Values for the Transmission Network System-Wide Shadow Price Caps in SCED, and

F. The Maximum of the either the largest value of the Mitigated Offer Cap for Generation Resource C, as determined above, divided by the absolute value of its shift factor impact on the constraint or $2000 per MW.

This calculation is performed one time in the Operating Day during which the trigger conditions described in Section 3.6.1 have been met and, subject to the value of the constraint net margin described below, this Shadow Price Cap will remain in effect for the shorter of the remainder of the calendar year or the remainder of the month in which the constraint is determined to be resolvable by SCED.

When the value of a constraint that has met the trigger conditions described in Section 3.6.1 accumulates a net margin, as determined in Section 3.6.3, The Constraint Net Margin Calculation for Constraints that Have Met the Trigger Conditions in Section 3.6.1, below, that exceeds $95,000 /MW at any time during the remainder of the calendar year following the determination that the constraint is irresolvable by SCED, the Shadow Price Cap for this, and for all constraints that have the same overloaded transmission element and direction as the constraint in the next Operating Day will be set to the minimum of either $2,000/MWh or G, below, for the remainder of the calendar year:

G. The Maximum of either the largest value of the Mitigated Offer Cap for Generation Resource C, as determined above, divided by the absolute value of its shift factor on the constraint or the currently effective Low System-Wide Offer Cap (LCAP) pursuant to subsection (g) of P.U.C. SUBST. R. 25.505, Resource Adequacy in the Electric Reliability Council of Texas Power Region.

When a constraint meets the trigger condition described in Section 3.6.1 and accumulates a net margin that exceeds $95,000/MW as described in Section 3.6.2, ERCOT shall:

1. As soon as practicable, but not more than ten (10) business days after the triggers are met, review transmission outages and recall outages that are contributing to overloading the constraint(s), if feasible.
2. As soon as practicable, but not more than thirty (30) days after the triggers are met, review and develop Remedial Action Plans (RAP) or Temporary Outage Action Plans (TOAP) to mitigate congestion on the affected constraint(s), if feasible. To the degree that a RAP or TOAP can be developed, ERCOT shall implement it through an Emergency Database Load, if necessary to avoid delay in addressing the congestion.
3. As soon as practicable, but not more than ninety (90) days after the triggers are met, review and develop or identify one or more Special Protection Systems or transmission proposal(s) to alleviate the risk of future congestion on the affected constraint(s), if feasible, so long as the proposed solution produces an overall reduction of congestion on the ERCOT system.
4. Perform a detailed review of the constraint(s) that is irresolvable by SCED, and in the next annual Regional Transmission Plan, identify projects that will mitigate the risk of future recurrence of the condition, if any.

Additionally, at the end of the calendar year, for all constraints that have a shadow price cap set in accordance with this section, ERCOT will:

- Again determine Generation Resource C and D, as described in item C and D above; and,
- Reset the Shadow Price Cap for each of the SCED irresolvable constraints to the minimum of E or F above for that constraint. These changes shall be become effective in January of the next year.
- Reset the Shadow Price Cap for each constraint determined to be resolvable by SCED to the appropriate generic value as defined in Section 3.5.

The IMM may initiate re-evaluation of the maximum Shadow Price of the constraint if it is identified that the constraint can be resolvable. This will reset the constraint net margin calculation.

3.6.3 The Constraint Net Margin Calculation for Constraints that Have Met the Trigger Conditions in Section 3.6.1

Each constraint that has met the trigger conditions in Section 3.6.1, Trigger for Modification of the Shadow Price Cap for a Constraint that is Consistently Irresolvable in SCED, will be assigned a unique net margin value calculated as follows:

1. The Settlement Point Price at the Resource Node for Generation Resource D (as determined for each SCED irresolvable constraint in Section 3.6.2, Methodology for Setting the Constraint Shadow Price Cap for a Constraint that is Irresolvable by SCED) is designated to be an irresolvable constraint net margin reference SPP. This SPP is unique to each SCED irresolvable constraint.
2. For these, ERCOT will calculate a constraint net margin in $/MW equal to the running sum of ¼ times the Maximum of either zero or that constraint's (net margin reference SPP – the POC) for all Real Time Settlement Intervals in the current calendar year during which the constraint is binding (i.e. the constraint net margin calculation starts with the first operating day in the current calendar year during which the constraint meets the trigger conditions described in Section 3.6.1).
3. The Proxy Operating Cost (POC) in $/MWh used in step 2 for each of these constraints equals 10 times the Fuel Index Price as defined in the Protocol Section 2, Definitions and Acronyms, for the Business Day previous to the current Operating Day.
4. All constraint net margin values for these constraints that will be carried to the next calendar year will be reset to zero at the start of the next calendar year and a new running sum will be calculated daily.

4. POWER BALANCE SHADOW PRICE CAP

4.1 The Power Balance Penalty

The Power Balance constraint is the balance between the ERCOT System Load and the amount of generation that is dispatched by SCED to meet that load. This Shadow Price for this constraint, also called System Lambda (λ), is the cost of providing one MWh of energy at the reference Electrical Bus. System Lambda, i.e. the Shadow Price for the Power Balance constraint, is equal to the change in the SCED objective function obtained by relaxing the Power Balance constraint by 1MW. The System Lambda is the energy component of Locational Marginal Price at each Settlement Point in ERCOT. The Power Balance Penalty sets the maximum limit for this Shadow Price, i.e. Power Balance Penalty is the maximum cost paid for one addition/less MW of generation to meet the ERCOT system load constraint. This section describes those factors that ERCOT considered in developing the amount of the Power Balance Penalty in $/MW versus the amount of the mismatch and provides the resulting Power Balance Penalty Curve proposed for ~~ERCOT Board~~PUCT approval.

The objective function for SCED is the sum of three components (1) the cost of dispatching generation (2) the penalty for violating Power Balance constraint (3) the penalty for violating network transmission constraints. SCED economically dispatches Generation Resources by minimizing this objective function within the generator physical limits and transmission limits. Since the Power Balance penalty is the maximum cost for meeting the Power Balance, SCED will re-dispatch generation to meet the Power Balance if the cost of re-dispatching the generation is less than cost of violating the Power Balance. When the cost of re-dispatching the Generation Resources becomes higher than the cost of violating the Power Balance constraint, SCED ceases the re-dispatch of the Generation Resources and the objective function is minimized with the Power Balance penalty determined by MW amount of the Power Balance constraint violation.

In the ERCOT design, SCED implements the Power Balance Penalty by a step function with up to 10 (Violation MW; Penalty $/MW) pairs. This curve determines the maximum System Lambda for a given amount of the Power Balance Constraint violation. The following section describes the factors that ERCOT considered in developing the amount of the Power Balance Penalty in $/MWh of violation and provides the resulting Power Balance Penalty Curve.

[OBDRR020: Replace Section 4.1 above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

The Power Balance constraint is the balance between the ERCOT System Load and the amount of generation that is dispatched by SCED to meet that load. This Shadow Price for this constraint, also called System Lambda (λ), is the cost of providing one MWh of energy at the reference Electrical Bus. System Lambda, i.e. the Shadow Price for the Power Balance constraint, is equal to the change in the SCED objective function obtained by relaxing the Power Balance constraint by 1MW. The System Lambda is the energy component of Locational Marginal Price at each Settlement Point in ERCOT. The Power Balance Penalty sets the maximum limit for this Shadow Price, i.e. Power Balance Penalty is the maximum cost paid for one addition/less MW of generation to meet the ERCOT system load constraint. This section describes those factors that ERCOT considered in developing the amount of the Power Balance Penalty in $/MW versus the amount of the mismatch and provides the resulting Power Balance Penalty Price proposed for ~~ERCOT Board~~PUCT approval.

The objective function for SCED is the sum of four components: (1) the cost of dispatching generation; (2) the cost of procuring Ancillary Services; (3) the penalty for violating Power Balance constraint; and (4) the penalty for violating network transmission constraints. SCED economically dispatches Generation Resources and procures Ancillary Services by minimizing this objective function within the generator physical limits and transmission limits. Since the Power Balance penalty is the maximum cost for meeting the Power Balance, SCED will re-dispatch generation to meet the Power Balance if the cost of re-dispatching the generation is

less than cost of violating the Power Balance. When the cost of re-dispatching the Generation Resources becomes higher than the cost of violating the Power Balance constraint, SCED ceases the re-dispatch of the Generation Resources and the objective function is minimized with the Power Balance penalty determined by MW amount of the Power Balance constraint violation. In the ERCOT design, SCED implements the under-generation Power Balance Penalty Price as a single value equal to the effective Value of Lost Load (VOLL) plus the effective Real-Time System-Wide Offer Cap (RTSWCAP) plus $0.01/MWh. This value determines the maximum System Lambda for a given amount of the Power Balance Constraint violation within the optimization. The SCED over-generation Power Balance Penalty Price is -$250/MWh.

4.2 Factors Considered in the Development of the Power Balance Penalty Curve

ERCOT considered a number of factors in the development of the Power Balance Penalty Curve as described below. The dominant factor in the ERCOT qualitative analysis relates to the use of Regulation Ancillary Service capacity in place of generation capacity provided by the market to resolve the SCED Power Balance constraint violation. ERCOT submits that the Power Balance Penalty Curve presented herein represents a reasonable balance between the loss of the Regulation Ancillary Service capacity used to achieve system power balance and the market value of the energy deployed from these Regulation Ancillary Service Generation Resources.

The factors considered by ERCOT in its qualitative analysis, include the following:

- The amount of regulation that can be sacrificed without affecting reliability,
- The PUCT defined System Wide Offer Cap (SWCAP),
- The expected percentage of intervals with SCED Up Ramp scarcity,
- The expected extent of Ancillary Service deployment by operators during intervals with capacity scarcity, and
- The transmission constraint penalty values.

The following discussion describes the details of these factors as they affect the Power Balance Penalty amounts.

Power Balance mismatch occurs whenever SCED is unable to find a dispatch at a cost lower than the Power Balance constraint Penalty. A Power Balance mismatch can occur under two conditions. One condition occurs when the amount of generation that is dispatched up to each resource's High Dispatch Limits is insufficient to meet the system load. This is referred to as an under generation and the System Lambda will be set by the under generation penalty. The opposite occurs when the amount of generation that is dispatched down to each resource's Low Dispatch Limits is greater than the system load. This is referred to as an over generation and the System

Lambda will be set by the over generation penalty. Both of these scenarios are unacceptable because, if left uncorrected by regulation, they result in the operation of the ERCOT system below (under generation) or above (over generation) the system frequency set point (nominally 60 Hertz). In the case of under generation, LFC will dispatch additional Regulation Service to correct the condition and restore system frequency to its set point (nominally 60 Hertz). On the other hand, in the case of over generation, LFC will dispatch reduced amounts of Regulation Service to correct the conditions and restore system frequency to its set point (nominally 60 Hertz). In other words, the Power Balance Penalty Curve acts as if it were an energy offer curve for a virtual Generation Resource injecting the amount of the Power Balance mismatch into the ERCOT system.

Since the actions that cause Regulation Ancillary Service capacity to be deployed to meet the Power Balance constraint reduces the amount of regulation capacity that can be used to maintain control of system frequency, the decision of the pricing of the power balance mismatch represents the value of the trade-off between the reduction in system reliability due to the use of the Regulation AS and the cost to the Load Serving Entities. The ERCOT system is particularly vulnerable to an inability to maintain system frequency because of the limited interchange capability of ERCOT with the Western and Eastern interconnects and, therefore, the larger the power balance mismatch, the larger the penalty amount.

In ERCOT, the PUCT has determined a maximum offer cap that is representative of supply side pricing associated with the concept of the value of lost load. By P.U.C. SUBST. R. 25.505, Resource Adequacy in the Electric Reliability Council of Texas Power Region, this amount is the High System-Wide Cap and ERCOT selected this amount to serve as the maximum value for the Power Balance Penalty.

Additionally, the Power Balance constraint can also be violated during operational scenarios characterized by generation resource ramp scarcity. SCED calculates dispatch limits (a High Dispatch Limit (HDL) and a Low Dispatch Limit (LDL)) for each resource that represent the amount of dispatch that can be achieved by a Generation Resource at the end of a 5 minute interval at the resource's specified ramp rate given current system conditions and the physical ability of the resource. The ramp rates used in this calculation are referred to as the SCED up Ramp Rate ("SURAMP") and the SCED Down Ramp Rate ("SDRAMP"). A ramp scarcity condition can occur when, for example during morning and evening system ramp intervals, the available capacity for increasing/ decreasing Base Points (the sum of HDL minus current generation/the sum of current generation – LDL) is less than the actual system demand based on the rate at which the system Load is increasing/decreasing. Since the HDL and LDL are calculated based on the physical ramp rate of the resources, they cannot be violated. The likelihood of violation of Power Balance during ramp scarcity increases with the reduction in the capacity available for SCED that in turn depends on the operational philosophies. If Ancillary Services are deployed to maintain enough capacity that can be ramped in each SCED interval then the likelihood of Power Balance violation will be less. On the other hand if Ancillary Services are only deployed to maintain frequency and maintain online capacity and not deployed to maintain enough ramp capacity then the likelihood of Power Balance violation will be more. Along with the violation of the Power Balance Constraint in the over and under generation discussed above, Regulation Ancillary Service will be co-opted in this scenario to compensate for the SCED available capacity shortfall due to these ramp limitations. This scenario is also included in the ERCOT analysis for pricing the Power Balance Penalty.

ERCOT also considered the fact that near scarcity, the Power Balance Constraint can become violated as the result of the network transmission constraints that are also binding/ violated at the same time. In this scenario LMPs will depend on the interaction of the Power Balance Penalty with the network transmission constraint Shadow Price caps (refer to the Appendix description of the SCED Energy LMP calculation to view this relationship). Under such condition the relative values of the network transmission constraint penalty and power balance penalty will determine whether resources with positive Shift Factor on the violated constraints will be moved up to meet Power Balance causing the network transmission constraint to become violated or will be moved down to resolve the network transmission constraint violation with a concomitant Power Balance violation.

Additionally, Protocols limit both the Energy Offer Curves ("EOCs") and the proxy EOC created in SCED to the SWCAP. SCED uses the EOC submitted by a QSE for its Generation Resources subject to the following. A proxy EOC is created in the SCED process if the QSE submitted Energy Offer Curve does not extend from LSL to HSL (in this case SCED extends the submitted EOC as described in Protocol Section 6.5.7.3, Security Constrained Economic Dispatch). A proxy EOC is also created for Generation Resources operating on an Output Schedule. In this case, the proxy EOC is designed to limit the dispatch of these resources from their Output Schedule amounts by pricing this dispatch at values equal to the System-Wide floor or cap. Since the Power Balance Penalty curve can be characterized as equivalent to a virtual EOC, the relative value of the Power Balance Penalty to the EOCs used by SCED will determine whether the energy will be deployed from the EOC or the Power Balance Penalty curve. If the Power Balance constraint is violated in step one of SCED, then the Power Balance Penalty will set the reference LMP and the submitted and proxy EOCs will then be mitigated at the max of that reference LMP or verifiable cost in the second step of SCED. Consequently, if the Power Balance Penalty Curve provides a gradual ramp to SWCAP then the prices will gradually ramp to the SWCAP instead experiencing a sudden jump to SWCAP.

[OBDRR020: Delete Section 4.2 above upon system implementation of the Real-Time Co-Optimization (RTC) project.]

4.3 The ERCOT Power Balance Penalty Curve

Based on the criteria described in Section 4.2, Factors Considered in the Development of the Power Balance Penalty Curve, above, the SCED under-generation Power Balance Penalty is shown in the table below. The SCED over-generation Power Balance Penalty curve will be set to System-Wide Offer Floor.

MW Violation	*Penalty Value ($/MWh)*
≤ 5	250
5 < to ≤ 10	300
10 < to ≤ 20	400
20 < to ≤ 30	500
30 < to ≤ 40	1,000
40 < to ≤ 50	2,250
50 < to ≤ 100	4,500
> 100	HCAP plus 1

The SCED under-generation Power Balance Penalty curve will be capped at LCAP plus $1 per MWh whenever the SWCAP is set to the LCAP.

SCED Over-generation Power Balance Penalty Curve

MW Violation	*Penalty Value ($/MWh)*
< 100,000	**-250**

[OBDRR020: Delete Section 4.3 above upon system implementation of the Real-Time Co-Optimization (RTC) project.]

APPENDIX 1: THE SCED OPTIMIZATION OBJECTIVE FUNCTION AND CONSTRAINTS

The SCED optimization objective function is as given by the following:

Minimize {Cost of dispatching generation
+ Penalty for violating Power Balance constraint
+ Penalty for violating transmission constraints}

which is:

Minimize {sum of (offer price * MW dispatched)
+ sum (Penalty * Power Balance violation MW amount)
+ sum (Penalty *Transmission constraint violation MW amount)}

The objective is subject to the following constraints:

- Power Balance Constraint
  sum (Base Point) + under gen slack – over gen slack = Generation To Be Dispatched
- Transmission Constraints
  sum(Shift Factor * Base Point) – violation slack $\leq$ limit
- Dispatch Limits
  LDL $\leq$ Base Point $\leq$ HDL

Based on the SCED dispatch the LMP at each Electrical Bus is calculated as

$$LMP_{bus,t} = SP_{demand,t} - \sum_{c} SF_{bus,c,t} \cdot SP_{c;t}$$

Where

$SP_{demand,t}$ = System Lambda or Power Balance Penalty (if a Power Balance violation exists) at time interval “t”

$SF_{bus,c,t}$ = Shift Factor impact of the bus “bus” on constraint “c” at time interval “t”

$SP_{c,t}$ = Shadow Price of constraint “c” at time interval “t” (capped at Max Shadow Price for this constraint).

During scarcity if a transmission constraint is violated then transmission constraint and Power Balance constraint will interact with each other to determine whether to move up or move down a resource with positive SF to the violated constraints if there are no other resources available.

(a) Cost of moving up the Resource = Shift Factor * Transmission Constraint Penalty + Offer cost
(b) Cost of moving down the Resource = Power Balance Penalty

The Resource will be moved down for resolving constraints if (a) > (b).
If (a) < (b) then the Resource will be moved up for meeting Power Balance.

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[OBDRR020: Delete Appendix 1 above upon system implementation of the Real-Time Co-Optimization (RTC) project and renumber accordingly.]

APPENDIX 2: DAY-AHEAD MARKET OPTIMIZATION CONTROL PARAMETERS

The purpose of the Day-Ahead Market (DAM) is to economically co-optimize energy and Ancillary Service by simultaneously clearing offers and bids submitted by the Market Participants to maximize social welfare while observing the transmission and generation physical constraints. The ERCOT DAM uses a multi-hour mixed integer programming algorithm to maximize bid-based revenues minus the offer-based costs over the Operating Day, subject to transmission security and other constraints as described in Protocol Section 4, Day-Ahead Operations. The bid-based revenues include revenues from DAM Energy Bids and Point-to-Point (PTP) Obligation Bids. The Offer-based costs include costs from the Startup Offer, Minimum Energy Offer, and Energy Offer Curve of Resources that submitted a Three-Part Supply Offer, as well as the DAM Energy-Only Offers, Congestion Revenue Right (CRR) offers, and Ancillary Service Offers. The DAM optimization's objective function includes components that represent the bid based revenues and offer based cost and, additionally, penalty cost values that are used to control certain non-economic aspects of the optimization as described below. These penalty values represent costs of constraint violations and they serve two purposes: rank constraints as relative violation priorities and limit the costs of constraint limitations. Based on paragraph (4)(c)(i) of Protocol Section 4.5.1, DAM Clearing Process, the transmission constraint limits needs to be satisfied in DAM and hence the transmission constraint penalty values are set to very high values to ensure that the constraints are not violated in DAM.

[OBDRR020: Replace the paragraph above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

The purpose of the Day-Ahead Market (DAM) is to economically co-optimize energy and Ancillary Service by simultaneously clearing offers and bids submitted by the Market Participants to maximize social welfare while observing the transmission and generation physical constraints. The ERCOT DAM uses a multi-hour mixed integer programming algorithm to maximize bid-based revenues minus the offer-based costs over the Operating Day, subject to transmission security and other constraints as described in Protocol Section 4, Day-Ahead Operations. The bid-based revenues include revenues from DAM Energy Bids and Point-to-Point (PTP) Obligation Bids. The Offer-based costs include costs from the Startup Offer, Minimum Energy Offer, and Energy Offer Curve of Resources that submitted a Three-Part Supply Offer, as well as the DAM Energy-Only Offers, Congestion Revenue Right (CRR) offers, and Ancillary Service Offers. The DAM optimization's objective function includes components that represent the bid based revenues and offer based cost and, additionally, penalty cost values that are used to control certain non-economic aspects of the optimization as described below. These penalty values represent costs of constraint violations and they serve two purposes: rank constraints as relative violation priorities and limit the costs of constraint limitations. The Protocols require transmission constraint limits to be satisfied in DAM and hence the transmission constraint penalty values are set to very high values to ensure that the constraints are not violated in DAM. The DAM optimization will also consider Ancillary Service Demand Curves for each Ancillary Service product.

The penalty factors used in the Day-Ahead optimization's objective function are configurable and can be set by an authorized ERCOT Operator. Table 2-1 lists the available optimization penalty cost parameters that are controllable by the ERCOT Operator. The values provided for each of these parameters have been determined by ERCOT based on the results of the DAM quality of solution analysis and various DAM stress tests performed by ERCOT and, following the TNMID, may only be changed with the concurrence of the responsible ERCOT Director.

[OBDRR020: Replace the paragraph above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

The penalty factors used in the DAM optimization's objective function are configurable and can be set by an authorized ERCOT Operator. Table 1-1 lists the available optimization penalty cost parameters that are controllable by the ERCOT Operator. The values provided for each of these parameters may only be changed with the concurrence of the responsible ERCOT Director.

TABLE 2 - 1

Penalty Function & Shadow Price Cap Cost Parameters	
Constraint	Penalty ($/MWh)
Over and Under - Generation Penalty Factors	
Over Generation	5,000,000.00
Under Generation	5,000,000.00
Ancillary Service Penalty Factors	
Regulation Down	SWCAP
Regulation Up	SWCAP
Responsive Reserve	SWCAP minus 0.01
Non-Spin Reserve	SWCAP minus 0.03
Network Transmission Penalty Factors	
Base case 1-10KV	350,000.00
Base case 10.1-20KV	450,000.00
Base case 20.1-30KV	550,000.00
Base case 30.1-50KV	650,000.00
Base case 50.1-100KV	750,000.00
Base case 100.1-120KV	850,000.00
Base case 120.1-150KV	950,000.00
Base case 150+KV	1,050,000.00
Contingency 1-10KV	300,000.00
Contingency 10.1-20KV	400,000.00
Contingency 20.1-30KV	500,000.00
Contingency 30.1-50KV	600,000.00
Contingency 50.1-100KV	700,000.00
Contingency 100.1-120KV	800,000.00
Contingency 120.1-150KV	900,000.00
Contingency 150+KV	1,000,000.00
Non-thermal (e.g. generic constraints)	1,000,000.00

[OBDRR020: Replace the Table 2-1 above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

TABLE 1 - 2

Penalty Function & Shadow Price Cap Cost Parameters	
Constraint	Penalty ($/MWh)
Over and Under - Generation Penalty Factors	
Over Generation	5,000,000.00

Under Generation	5,000,000.00
Network Transmission Penalty Factors	
Base case 1-10KV	350,000.00
Base case 10.1-20KV	450,000.00
Base case 20.1-30KV	550,000.00
Base case 30.1-50KV	650,000.00
Base case 50.1-100KV	750,000.00
Base case 100.1-120KV	850,000.00
Base case 120.1-150KV	950,000.00
Base case 150+KV	1,050,000.00
Contingency 1-10KV	300,000.00
Contingency 10.1-20KV	400,000.00
Contingency 20.1-30KV	500,000.00
Contingency 30.1-50KV	600,000.00
Contingency 50.1-100KV	700,000.00
Contingency 100.1-120KV	800,000.00
Contingency 120.1-150KV	900,000.00
Contingency 150+KV	1,000,000.00
Non-thermal (e.g. generic constraints)	1,000,000.00

Board Report

2.1 Over/Under – Generation Penalty Factors

In the ERCOT DAM an over/under energy supply condition (referred to here as over/under generation conditions) in an Operating Hour within the Operating Day can occur as a result of a strike of energy only block offers or the inherent lumpiness of Generation Resource strikes. The values of the Over/Under Generation Penalty Factors are chosen to allow the DAM clearing engine to select offers that result in the least amount of the over/under generation over the entire Operating Day and additionally, to enforce this constraint at the highest rank order relative to all other constraints. Additionally, the values of the Over/Under Generation Penalty Factors used in the DAM are considerably higher than the Power Balance Penalty Factor used in the SCED since DAM is a unit commitment problem and for it to clear reasonable offers and bids, the value of these penalty factors need to be high enough to reflect the start up and minimum generation cost of the committed resources. SCED, on the other hand, is an economic dispatch problem and hence for it to dispatch reasonable offers, the Power Balance Penalty Factor need only be in the order of the energy offer cost.

2.2 Ancillary Service Penalty Factors

The Ancillary Service penalty factors serve two purposes. The procured amount of an Ancillary Service can be lower than the difference between the amount of the required AS, as specified in the AS Plan, and the amount of the self-arranged AS. The value of the AS penalty factors are chosen to allow the selection of AS offers that result in the least amount of deficit considering the maximum AS penalty factors referenced in Appendix 2, Table 2-1 for each given AS over the Operating Day and to assign a priority to the AS constraints relative to the enforcement of the Power Balance and Network Transmission constraints. Additionally, the increasing penalty cost structure from Non-Spin AS to Regulation AS prioritizes the DAM AS procurement as first Regulation Services, then Responsive Reserve (RRS), and lastly Non-Spin. In other words multiple offers from the same resource will be considered in the rank order given. Notably however, the AS penalty factors are not used to set the Market Clearing Price for Capacity (MCPC) for each Ancillary Service. Instead, the infeasible AS requirement amounts are reduced to the feasible level and the DAM clearing is rerun so that the price of the last AS awarded MW sets the MCPC for each Ancillary Service. The AS penalty factors used in DAM are also used in the Supplemental Ancillary Service Market (SASM) engine.

[OBDRR020: Delete Section 2.2 above upon system implementation of the Real-Time Co-Optimization (RTC) project and renumber accordingly.]

2.3 Network Transmission Penalty Factors

The DAM Clearing Engine includes the Network Security Monitor (NSM) application and Network Constrained Unit Commitment (NCUC) application. These applications execute in a loop beginning with a NSM execution followed by a NCUC execution until a secure commitment pattern that maximizes the objective function is achieved (i.e. NSM begins with an estimated initial

unit commitment and uses, thereafter, the latest NCUC commitment). The value of the Network Transmission Penalty Factors for each specified voltage level are used in NCUC application to set the rank order for relaxing the base case constraints and the security constrained network transmission constraints by voltage level and to set the rank order for the enforcement of the Network Transmission Constraints relative to the Power Balance and AS requirements. The increasing value of the Network Transmission Penalty Factors for increasing voltage levels assures that base case and security constraint violations are relaxed progressively in the NSM and NCUC applications in order of voltage level, from lowest to highest. This assures that the DAM solution will honor network transmission constraints in the rank order from the 345 kV to the 69 kV voltage level. Additionally, these penalty factors are chosen such that, in each voltage range, the base case violations have a slightly higher penalty factor than the security constrained penalty factors. This assigns a higher priority in the NSM and NCUC to a network transmission base case violation compared to a network transmission security constrained violation. In other words, within the same voltage level, the security constraints are relaxed before the base case constraints.
Finally, the Non-Thermal (generic constraint) Penalty Factor assigns these constraints the same priority level in the optimization as the 345 kV security constraints making both less than the 345 kV base case constraints.

[OBDRR020: Replace the paragraph above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

The DAM Clearing Engine includes the Network Security Monitor (NSM) application and Network Constrained Unit Commitment (NCUC) application. These applications execute in a loop beginning with a NSM execution followed by a NCUC execution until a secure commitment pattern that maximizes the objective function is achieved (i.e. NSM begins with an estimated initial unit commitment and uses, thereafter, the latest NCUC commitment). The value of the Network Transmission Penalty Factors for each specified voltage level are used in NCUC application to set the rank order for relaxing the base case constraints and the security constrained network transmission constraints by voltage level and to set the rank order for the enforcement of the Network Transmission Constraints relative to the Power Balance constraint. The increasing value of the Network Transmission Penalty Factors for increasing voltage levels assures that base case and security constraint violations are relaxed progressively in the NSM and NCUC applications in order of voltage level, from lowest to highest. This assures that the DAM solution will honor network transmission constraints in the rank order from the 345 kV to the 69 kV voltage level. Additionally, these penalty factors are chosen such that, in each voltage range, the base case violations have a slightly higher penalty factor than the security constrained penalty factors. This assigns a higher priority in the NSM and NCUC to a network transmission base case violation compared to a network transmission security constrained violation. In other words, within the same voltage level, the security constraints are relaxed before the base case constraints. Finally, the Non-Thermal (generic constraint) Penalty Factor assigns these constraints the same priority level in the optimization as the 345 kV security constraints making both less than the 345 kV base case constraints.

The values of the Network Transmission Penalty Factors chosen to enforce the Network Transmission Constraints are considerably higher in DAM when compared to the SCED (Network

Transmission Shadow Price Caps) since the DAM is a unit commitment problem and for it to clear reasonable offers and bids, the Network Transmission Penalty Factors need to represent the higher costs associated with a unit start up and generation at minimum energy. The SCED is an economic dispatch problem and hence for it to dispatch reasonable offers; the penalties need only be in the order of energy offer cost.

ERCOT Impact Analysis Report

NPRR Number	**<u>1211</u>**	**NPRR Title**	**Move OBD to Section 22 – Methodology for Setting Maximum Shadow Prices for Network and Power Balance Constraints**
Impact Analysis Date	November 20, 2023		
Estimated Cost/Budgetary Impact	Less than $5k, which will be absorbed by the Operations & Maintenance (O&M) budgets of affected department.		
Estimated Time Requirements	No project required. This Nodal Protocol Revision Request (NPRR) can take effect within 3-5 days after Public Utility Commission of Texas (PUCT) approval		
ERCOT Staffing Impacts (across all areas)	Implementation Labor: 100% ERCOT; 0% Vendor Ongoing Requirements: No impacts to ERCOT staffing.		
ERCOT Computer System Impacts	The following ERCOT systems would be impacted: ERCOT Website and MIS Systems 67% Channel Management Systems 33%		
ERCOT Business Function Impacts	No impacts to ERCOT business functions.		
Grid Operations & Practices Impacts	No impacts to ERCOT grid operations and practices.		

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

Comments
None.

Board Report

NPRR Number	1213	**NPRR Title**	**Allow DGRs and DESRs on Circuits Subject to Load Shed to Provide ECRS and Clarify Language Regarding DGRs and DESRs Providing Non-Spin**
Date of Decision	February 27, 2024		
Action	Recommended Approval		
Timeline	Normal		
Estimated Impacts	Cost/Budgetary: Between $350K and $450K Project Duration: 8 to 12 months		
Proposed Effective Date	Upon system implementation; and upon system implementation of Nodal Protocol Revision Request (NPRR)1171, Requirements for DGRs and DESRs on Circuits Subject to Load Shedding		
Priority and Rank Assigned	Priority – 2024; Rank – 4050		
Nodal Protocol Sections Requiring Revision	3.8.6, Distribution Generation Resources (DGRs) and Distribution Energy Storage Resources (DESRs) 3.16, Standards for Determining Ancillary Service Quantities 4.4.7.1, Self-Arranged Ancillary Service Quantities 4.4.7.1.1, Negative Self-Arranged Ancillary Service Quantities 4.4.7.3, Ancillary Service Trades 4.4.7.3.1, Ancillary Service Trade Criteria		
Related Documents Requiring Revision/Related Revision Requests	None		
Revision Description	This NPRR amends requirements for Distribution Generation Resources (DGRs) and Distribution Energy Storage Resources (DESRs) that are seeking qualification to provide ERCOT Contingency Reserve Service (ECRS), as follows: • Paragraph (1)(c) of Section 3.8.6 allows for DGRs and DESRs on circuits subject to disconnection during Load shed events to provide ECRS; and • Section 3.16 recognizes that ERCOT will establish limits on ECRS, which may be provided by DGRs and DESRs on circuits subject to disconnection during Load shed events.		

	This NPRR also modifies requirements for Ancillary Service self-arrangement and Ancillary Service Trades for DGRs and DESRs on circuits subject to Load shed that provide Non-Spinning Reserve (Non-Spin).
Reason for Revision	[X] Strategic Plan Objective 1 – Be an industry leader for grid reliability and resilience [ ] Strategic Plan Objective 2 - Enhance the ERCOT region's economic competitiveness with respect to trends in wholesale power rates and retail electricity prices to consumers [ ] Strategic Plan Objective 3 - Advance ERCOT, Inc. as an independent leading industry expert and an employer of choice by fostering innovation, investing in our people, and emphasizing the importance of our mission [ ] General system and/or process improvement(s) [ ] Regulatory requirements [ ] ERCOT Board and/or PUCT Directive *(please select ONLY ONE – if more than one apply, please select the ONE that is most relevant)*
Justification of Reason for Revision and Market Impacts	The Public Utility Commission of Texas (PUCT) has asked ERCOT to review all Ancillary Services provided by DGRs and DESRs and review which may be provided by a Resource on a distribution circuit that may be subject to Under-Frequency Load Shed (UFLS), Under-Voltage Load Shed (UVLS), or Load shed during an Energy Emergency Alert (EEA) event. In response to the PUCT's request, NPRR1171 identified the Ancillary Services (Non-Spin Service and Regulation Down Service (Reg-Down)) that can be provided by DGRs and DESRs on circuits subject to Load shed. ERCOT indicated that ECRS would be considered following the implementation of ECRS and a reasonable window of time to gain experience with the new Ancillary Service. In order to support grid reliability and mitigate Real-Time operational issues, ERCOT launched ECRS in June 2023. ECRS complements and provides support to ERCOT's current suite of Ancillary Services: Regulation Up Service (Reg-Up), Reg-Down, Responsive Reserve (RRS) Service, and Non-Spin Service. Allowing more Resources to provide ECRS will support greater competition in the market to the overall benefit of consumers. As a matter of policy, access to ECRS will also incentivize greater deployment of resilient, dispatchable

	distributed resources that can support Texas' growing need for new generation capacity.
PRS Decision	On 12/15/23, PRS voted unanimously to recommend approval of NPRR1213 as submitted. All Market Segments participated in the vote. On 1/11/24, PRS voted unanimously to table NPRR1213. All Market Segments participated in the vote. On 2/8/24, PRS voted unanimously to endorse and forward to TAC the 1/11/24 PRS Report, as amended by the 2/7/24 ERCOT comments, and 2/6/24 Impact Analysis for NPRR1213 with a recommended priority of 2024 and rank of 4050. All Market Segments participated in the vote.
Summary of PRS Discussion	On 12/15/23, participants discussed a portion of ECRS would be eligible for participation in Ancillary Service provision, and that further discussion would be held prior to development of the 2025 Ancillary Services Methodology. On 1/11/24, participants noted ERCOT Staff request for additional time to prepare the Impact Analysis. On 2/8/24, participants reviewed the 2/7/24 ERCOT comments, the 2/6/24 Impact Analysis, the Reason for Revision, and the Justification of Reason for Revision and Market Impacts for NPRR1213. Participants discussed which Resource types were allowed to participate in the respective Ancillary Service self-arrangements and Ancillary Service Trades.
TAC Decision	On 2/14/24, TAC voted unanimously to recommend approval of NPRR1213, as recommended by PRS in the 2/8/24 PRS Report, and the 2/12/24 Revised Impact Analysis. All Market Segments participated in the vote.
Summary of TAC Discussion	On 2/14/24, there was no additional discussion beyond TAC review of the items below.
TAC Review/Justification of Recommendation	X Revision Request ties to Reason for Revision as explained in Justification X Impact Analysis reviewed and impacts are justified as explained in Justification X Opinions were reviewed and discussed X Comments were reviewed and discussed (if applicable)

	☐ Other: (explain)
ERCOT Board Decision	On 2/27/24, the ERCOT Board voted unanimously to recommend approval of NPRR1213 as recommended by TAC in the 2/14/24 TAC Report.

Opinions	
Credit Review	ERCOT Credit Staff and the Credit Finance Sub Group (CFSG) have reviewed NPRR1213 and do not believe that it requires changes to credit monitoring activity or the calculation of liability.
Independent Market Monitor Opinion	The Independent Market Monitor (IMM) has no opinion on NPRR1213.
ERCOT Opinion	ERCOT supports approval of NPRR1213.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NPRR1213 and believes it supplements NPRR1171 in identifying an additional Ancillary Service, namely ECRS, that can be provided by DGRs and DESRs on feeders subject to Load shedding.

Sponsor	
Name	Monica Batra-Shrader
E-mail Address	mbatra@enchantedrock.com
Company	Enchanted Rock
Phone Number	N/A
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Market Segment	Independent Retail Electric Provider (IREP)

Market Rules Staff Contact	
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Phone Number	512-225-7027

Comments Received	
Comment Author	**Comment Summary**

ERCOT 010424	Proposed to complete the Impact Analysis prior to the February 8, 2024 PRS meeting
ERCOT 020724	Clarified requirements that will apply to DGRs and DESRs on circuits subject to Load shed that provide ECRS; proposed edits to Ancillary Service self-arrangements and Ancillary Service Trades that would apply to DGRs and DESRs on circuits subject to Load shed that provide Non-Spin

Market Rules Notes

None

Proposed Protocol Language Revision

3.8.6 Distribution Generation Resources (DGRs) and Distribution Energy Storage Resources (DESRs)

(1) As a condition for the interconnection of a DGR or DESR, the affected Resource Entity, after consultation with the relevant Distribution Service Provider (DSP), shall provide documentation from the DSP to ERCOT stating that the interconnecting distribution circuit will not be disconnected as part of an Energy Emergency Alert (EEA) Level 3, an under-frequency Load shedding event, or an under-voltage Load shedding event, unless required for DSP local system maintenance or during a DSP local system emergency.

(a) If a DSP subsequently determines that any circuit to which a DGR or DESR is interconnected will need to be disconnected during these Load shedding events, or that a DGR or DESR will need to be moved to a circuit that will be disconnected during these Load shedding events:

(i) The DSP shall promptly notify the designated contact for the DGR or DESR;

(ii) The Resource Entity shall promptly notify ERCOT of this fact via the Resource Registration process; and

(iii) The DGR or DESR will immediately be disqualified from offering to provide any Ancillary Service.

(b) Upon receiving notification from the DSP that the DGR or DESR is no longer subject to disconnection during any of these Load shedding events, and that no known system limitations or changes have occurred that would inhibit the DGR or DESR from complying with Ancillary Service performance requirements, the Resource Entity for the DGR or DESR shall notify ERCOT of this fact via the Resource Registration process and will, at that time, be eligible to offer to provide Ancillary Services if the Resource is otherwise qualified to do so.

[NPRR1171: Replace paragraph (1) above with the following upon system implementation and renumber accordingly:]

(1) As a condition for the interconnection of a DGR or DESR, the affected Resource Entity, after consultation with the relevant Distribution Service Provider (DSP), shall submit an executed Section 23, Form R, Interconnection Circuit Designation for Distribution Generation Resources (DGRs) and Distribution Energy Storage Resources (DESRs).

(a) The DSP shall indicate that the interconnecting distribution circuit for the DGR or DESR is subject to Load shed if the DSP determines that the distribution circuit may be disconnected as part of an Energy Emergency Alert (EEA) Level 3 Load shedding event, an Under-Frequency Load Shed (UFLS) event, or an Under-Voltage Load Shed (UVLS) event.

(b) The DSP shall indicate that the interconnecting distribution circuit for the DGR or DESR is not subject to Load shed if the DSP determines that the distribution circuit will not be disconnected for any Load shed purpose during any of the events listed in paragraph (a) above. This condition may be met where:

(i) A DGR or DESR is connected to a distribution circuit which the DSP has excluded from Load shedding events, which may include, but is not limited to, a distribution circuit that interconnects only DGRs or DESRs; or

(ii) A DGR or DESR is connected to a distribution circuit where a recloser or other sectionalizing device excludes the DGR or DESR from Load shedding events on the distribution circuit.

(c) If the DSP has indicated that the interconnecting distribution circuit may be subject to Load shed, the DGR or DESR may qualify to provide only the following Ancillary Services, subject to the limits established by ERCOT pursuant to Section 3.16, Standards for Determining Ancillary Service Quantities:

(i) Non-Spinning Reserve (Non-Spin);

(ii) ERCOT Contingency Reserve Service (ECRS); and

(iii) Regulation Down Service (Reg-Down).

(d) If the DSP has indicated that the interconnecting distribution circuit is not subject to Load shed, then the DGR or DESR shall not be subject to the Ancillary Service qualification limitations described in paragraph (c) above.

(e) The DSP shall identify on Section 23, Form R, whether the DSP has identified any operational limitations for the DGR or DESR based on known system limitations and planning or operational studies, including studies performed in accordance with Planning Guide Section 5.4.2, Submission of Interconnection Agreement and TSP and/or DSP Studies and Technical Requirements. Temporary limitations, such as may occur during maintenance outage conditions, are not required to be reported on Section 23, Form R.

(2) If a DSP at any time after the interconnection of a DGR or DESR determines that any circuit to which the DGR or DESR is interconnected will be subject to Load shed during any of the Load shedding events listed in paragraph (1)(a) above, or that a DGR or DESR will need to be electrically relocated to a circuit that will be subject to Load shed during these Load shedding events:

(a) The DSP shall promptly notify ERCOT and the designated contact for the DGR or DESR;

(b) The Resource Entity for the DGR or DESR shall promptly submit an updated Section 23, Form R, to ERCOT and shall make a corresponding update to its Resource Registration data; and

(c) The Ancillary Service qualification limitations in paragraph (1)(c) above will apply to the DGR or DESR.

(3) If a DGR or DESR is interconnected to a circuit that is subject to Load shed and then either is relocated to a different circuit that is not subject to Load shed during any of the Load shed events listed in paragraph (1)(a) above or receives notification from the DSP that the DGR or DESR is no longer subject to Load shed during any of these events, the Resource Entity for the DGR or DESR shall submit an updated Section 23, Form R, to ERCOT and shall make a corresponding update to its Resource Registration data.

(2) For a proposed conversion of an existing Settlement Only Distribution Generator (SODG) to a DGR or DESR, the interconnecting DSP will evaluate the proposed conversion and will determine whether it is electrically and operationally feasible. If the interconnecting DSP determines that the conversion is not electrically or operationally feasible, the DSP may disallow the conversion.

[NPRR995 and NPRR1171: Replace applicable portions of paragraph (2) above with the following upon system implementation:]

(2) For a proposed conversion of an existing Settlement Only Distribution Generator (SODG) to a DGR or for a proposed conversion of an existing Settlement Only Distribution Energy Storage System (SODESS) to a DESR, the Resource Entity will follow the generation interconnection process outlined in Planning Guide Section 5, Generator Interconnection or Modification.

(3) The Resource Node for a DGR or DESR shall be fixed at a single Electrical Bus in the ERCOT Network Operations Model.

(a) If a DSP determines that a topology change has altered, or is expected to alter, the electrical path connecting the DGR or DESR to the ERCOT Transmission Grid for a period longer than 60 days:

(i) The DSP shall promptly notify the interconnecting Transmission Service Provider (TSP) and the designated contact for the DGR or DESR, and the interconnecting TSP shall notify ERCOT; and

(ii) The Resource Entity shall submit a change request to ERCOT via the Resource Registration process.

3.16 Standards for Determining Ancillary Service Quantities

(1) ERCOT shall comply with the requirements for determining Ancillary Service quantities as specified in these Protocols and the ERCOT Operating Guides.

(2) ERCOT shall, at least annually, determine with supporting data, the methodology for determining the quantity requirements for each Ancillary Service needed for reliability, including:

(a) The percentage or MW limit of ERCOT Contingency Reserve Service (ECRS) allowed from Load Resources providing ECRS;

(b) The maximum amount (MW) of Responsive Reserve (RRS) that can be provided by Resources capable of Fast Frequency Response (FFR);

[NPRR1128: Replace item (b) above with the following upon system implementation:]

(b) The maximum amount (MW) of Responsive Reserve (RRS) that can be provided by Resources capable of Fast Frequency Response (FFR) and specify the Operating Hours where prioritizing procurement of FFR up to the maximum FFR amount is beneficial in improving reliability;

(c) The maximum amount (MW) of Regulation Up Service (Reg-Up) that can be provided by Resources providing Fast Responding Regulation Up Service (FRRS-Up); and

(d) The maximum amount (MW) of Regulation Down Service (Reg-Down) that can be provided by Resources providing Fast Responding Regulation Down Service (FRRS-Down).

[NPRR1007: Delete items (c) and (d) above upon system implementation of the Real-Time Co-Optimization (RTC) project and renumber accordingly.]

(e) The minimum capacity required from Resources providing RRS using Primary Frequency Response shall not be less than 1,150 MW.

(3) The ERCOT Board shall review and approve ERCOT's methodology for determining the minimum Ancillary Service requirements, any minimum capacity required from Security-Constrained Economic Dispatch (SCED) dispatchable Resources to provide Non-Spinning Reserve (Non-Spin), the minimum capacity required from Resources providing Primary Frequency Response to provide RRS, the maximum amount of RRS that can be provided by Resources capable of FFR, and the maximum amount of Reg-Up and Reg-Down that can be provided by Resources providing FRRS-Up and FRRS-Down.

[NPRR1007, NPRR1128, NPRR1171, and NPRR1183: Replace applicable portions of paragraph (3) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1128, NPRR1171, or NPRR1183:]

(3) The ERCOT Board shall review and approve ERCOT's methodology for determining the minimum Ancillary Service requirements, any minimum capacity required from Security-Constrained Economic Dispatch (SCED) dispatchable Resources to provide Non-Spinning Reserve (Non-Spin), the maximum amount of Non-Spin that can be provided by Distribution Generation Resources (DGRs) and Distribution Energy Storage Resources (DESRs) that are interconnected to a distribution circuit that is subject to Load shed, the maximum amount of ECRS that can be provided by DGRs and DESRs that are interconnected to a distribution circuit that is subject to Load shed, the minimum capacity required from Resources providing Primary Frequency Response to provide RRS, the maximum amount of RRS that can be provided by Resources capable of FFR, and the Operating Hours where prioritizing procurement of FFR up to the maximum FFR amount is beneficial in improving reliability. ERCOT shall post on the ERCOT website the ERCOT Methodologies for Determining Minimum Ancillary Service Requirements approved by the ERCOT Board.

(4) If ERCOT determines a need for additional Ancillary Service Resources under these Protocols or the ERCOT Operating Guides, after an Ancillary Service Plan for a specified day has been posted, ERCOT shall inform the market by posting notice on the ERCOT website, of ERCOT's intent to procure additional Ancillary Service Resources under Section 6.4.9.2, Supplemental Ancillary Services Market. ERCOT shall post the reliability reason for the increase in service requirements.

[NPRR1007: Delete paragraph (4) above upon system implementation of the Real-Time Co-Optimization (RTC) project and renumber accordingly.]

(5) Monthly, ERCOT shall determine and post on the Market Information System (MIS) Secure Area a minimum capacity required from Resources providing RRS using Primary Frequency Response. The remaining capacity required for RRS may be supplied by all Resources qualified to provide RRS, provided that RRS from Load Resources on high-set under-frequency relays and Resources providing FFR shall be limited to 60% of the total ERCOT RRS requirement. ERCOT may increase the minimum capacity required from Resources providing RRS using Primary Frequency Response if it believes that the current posted quantity will have a negative impact on reliability or if it would require additional Regulation Service to be deployed.

[NPRR1128 and NPRR1183: Replace applicable portions of paragraph (5) above with the following upon system implementation:]

(5) Monthly, ERCOT shall determine and post on the ERCOT website a minimum capacity required from Resources providing RRS using Primary Frequency Response. The remaining capacity required for RRS may be supplied by all Resources qualified to provide RRS, provided that RRS from Load Resources on high-set under-frequency relays and Resources providing FFR shall be limited to 60% of the total ERCOT RRS requirement. ERCOT may increase the minimum capacity required from Resources providing RRS using Primary Frequency Response if it believes that the current posted quantity will have a negative impact on reliability or if it would require additional Regulation Service to be deployed. ERCOT may add more Operating Hours where prioritizing procurement of FFR up to the maximum FFR amount is beneficial in improving reliability if it believes that these additional hours are vulnerable to low system inertia. ERCOT will issue an operations notice when such a change is made.

(6) The amount of RRS that a Qualified Scheduling Entity (QSE) can self-arrange using a Load Resource excluding Controllable Load Resources and Resources providing FFR is limited to its Load Ratio Share (LRS) of the capacity allowed to be provided by Resources not providing RRS using Primary Frequency Response established in paragraph (5) above, provided that RRS from these Resources shall be limited to 60% of the total ERCOT RRS requirement.

(7) However, a QSE may offer more of the Load Resource above the percentage limit established by ERCOT for sale of RRS to other Market Participants. The total amount of RRS using the Load Resource procured by ERCOT is also limited to the capacity established in paragraph (5) above, up to the lesser of the 60% limit or the limit established by ERCOT in paragraph (5) above.

(8) Monthly, ERCOT shall determine and post on the MIS Secure Area a minimum capacity required from Resources providing ECRS. The amount of Load Resources excluding Controllable Load Resources that may or may not be on high-set under-frequency relays providing ECRS is limited to 50% of the total ERCOT ECRS requirement.

[NPRR1183: Replace paragraph (8) above with the following upon system implementation:]

(8) Monthly, ERCOT shall determine and post on the ERCOT website a minimum capacity required from Resources providing ECRS. The amount of Load Resources excluding Controllable Load Resources that may or may not be on high-set under-frequency relays providing ECRS is limited to 50% of the total ERCOT ECRS requirement.

(9) The amount of ECRS that a QSE can self-arrange using a Load Resource excluding Controllable Load Resources is limited to the lower of:

(a) 50% of its ECRS Ancillary Service Obligation; or

(b) A reduced percentage of its ECRS Ancillary Service Obligation based on the limit established by ERCOT in paragraph (8) above.

(10) A QSE may offer more of the Load Resource above the percentage limit established by ERCOT for sale of ECRS to other Market Participants. The total amount of ECRS using the Load Resource excluding Controllable Load Resources procured by ERCOT is also limited to the lesser of the 50% limit or the limit established by ERCOT in paragraph (9) above.

(11) The maximum MW amount of capacity from Resources providing FRRS-Up is limited to 65 MW. ERCOT may reduce this limit if it believes that this amount will have a negative impact on reliability or if this limit would require additional Regulation Service to be deployed.

(12) The maximum MW amount of capacity from Resources providing FRRS-Down is limited to 35 MW. ERCOT may reduce this limit if it believes that this amount will have a negative impact on reliability or if this limit would require additional Regulation Service to be deployed.

(13) Resources can only provide FRRS-Up or FRRS-Down if awarded Regulation Service in the Day-Ahead Market (DAM) for that particular Resource, up to the awarded quantity.

[NPRR1007: Delete paragraphs (11)-(13) above upon system implementation of the Real-Time Co-Optimization (RTC) project.]

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 100 MW of ERCOT Contingency Reserve Service (ECRS), 100 MW of Responsive Reserve (RRS), 25 MW of Regulation Up Service (Reg-Up), 25 MW of Regulation Down Service (Reg-Down), and 50 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 Services Market (SASM), as applicable, for $0/MWh.

[NPRR1091: Replace paragraph (1) above with the following upon system implementation:]

(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 Services Market (SASM), as applicable, for $0/MWh.

[NPRR1008: Replace paragraph (1) above with the following upon system implementation or upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(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, 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 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, 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 and Non-Spin, the QSE shall indicate the quantity of the service that is provided from Resources that are manually dispatched~~,~~ DGRs and DESRs on circuits subject to Load shed~~. and those~~, and Resources that are SCED-dispatchable not on circuits subject to Load shed.

(11) For self-arranged Non-Spin, the QSE shall indicate the quantity of the service that is provided from Resources that are manually dispatched, DGRs and DESRs on circuits subject to Load shed, and Resources that are SCED-dispatchable and not on circuits subject to Load shed.

4.4.7.1.1 Negative Self-Arranged Ancillary Service Quantities

(1) A QSE may submit a negative Self-Arranged Ancillary Service Quantity in the DAM. ERCOT shall procure all negative Self-Arranged Ancillary Service Quantities submitted by a QSE.

[NPRR1008: Replace paragraph (1) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(1) A QSE may submit a negative Self-Arranged Ancillary Service Quantity in the DAM. ERCOT shall procure all negative Self-Arranged Ancillary Service Quantities submitted by a QSE. Such negative Self-Arranged Ancillary Service Quantities will be considered by DAM to be equivalent to a bid to buy Ancillary Services at the highest price on each respective ASDC.

(2) Procurements of negative Self-Arranged Ancillary Service Quantities by ERCOT shall be settled in the same manner as Ancillary Service Obligations that are not self-arranged and according to the charges defined in Section 4.6.4.2, Charges for Ancillary Services Procurement in the DAM, and Section 6.7, Real-Time Settlement Calculations for the Ancillary Services.

(3) A QSE may not submit a negative Self-Arranged Ancillary Service Quantity in the DAM that is less than -500 MW per Ancillary Service. For negative self-arranged RRS~~ and ~~, ECRS, and Non-Spin, the QSE shall not specify FFR Resources, Controllable Load Resources,~~ and ~~ Load Resources controlled by high-set under-frequency relays, and DGRs and DESRs on circuits subject to Load shed. For compliance purposes, a QSE may not submit a negative Self-Arranged Ancillary Service Quantity in the DAM that is greater in magnitude than the absolute value of the net sales of its Ancillary Service Trades per Ancillary Service.

4.4.7.3 Ancillary Service Trades

(1) An Ancillary Service Trade is the information for a QSE-to-QSE transaction that transfers an obligation to provide Ancillary Service capacity between a buyer and a seller.

[NPRR1008: Replace paragraph (1) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(1) An Ancillary Service Trade is the information for a QSE-to-QSE transaction that transfers an obligation to provide Ancillary Service capacity or purchase Ancillary Services in the Real-Time Market (RTM) between a buyer and a seller.

(2) An Ancillary Service Trade that is reported to ERCOT by 1430 in the Day-Ahead changes the Ancillary Service Supply Responsibility of the buyer and seller in the DRUC process. An Ancillary Service Trade that is reported to ERCOT after 1430 in the Day-Ahead changes the Ancillary Service Supply Responsibility of the buyer and seller in any applicable HRUC process, the deadline for which is after the trade is submitted.

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

(2) An Ancillary Service Trade that is reported to ERCOT by 1430 in the Day-Ahead changes the Ancillary Service Position of the buyer and seller in the DRUC process. An Ancillary Service Trade that is reported to ERCOT after 1430 in the Day-Ahead changes the Ancillary Service Position of the buyer and seller in any applicable HRUC process, the deadline for which is after the trade is submitted.

(3) As soon as practicable, ERCOT shall notify each QSE through the Messaging System of any of its Ancillary Service Trades that are invalid Ancillary Service Trades. The QSE may correct and resubmit any invalid Ancillary Service Trade, but the reporting time of the trade is determined by when the validated Ancillary Service Trade was submitted and not when the original invalid Ancillary Service Trade was submitted.

~~(4) A QSE with an Ancillary Service Supply Responsibility for ECRS, originally designated to be provided by a Generation Resource, may transfer its responsibility via Ancillary Service Trade(s) to another QSE only if that QSE designates the ECRS will be provided by a Generation Resource.~~

~~***[NPRR1008: Replace paragraph (4) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***~~

~~(4) A QSE with an Ancillary Service Position for ECRS, originally designated to be provided by a Generation Resource, may transfer that portion of its Ancillary Service Position via Ancillary Service Trade(s) to another QSE only if that QSE designates the ECRS will be provided by a Generation Resource.~~

~~(5) A QSE with an Ancillary Service Supply Responsibility for ECRS, originally designated to be provided by a Load Resource providing ECRS triggered with or without under-frequency relays set at 59.70 Hz, may transfer its responsibility via Ancillary Service Trade(s) to another QSE only if that QSE designates the ECRS will be provided by either:~~

~~***[NPRR1008: Replace paragraph (5) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***~~

~~(5) A QSE with an Ancillary Service Position for ECRS, originally designated to be provided by a Load Resource providing ECRS triggered with or without under-frequency relays set at 59.70 Hz, may transfer that portion of its Ancillary Service Position via Ancillary Service Trade(s) to another QSE only if that QSE designates the ECRS will be provided by either:~~