

Board Report

MRAPSUFQ _{q, r}	MMBtu	<i>Must-Run Alternative Proxy Startup Fuel Quantity per QSE per Resource</i> —The proxy start up fuel quantity specified in the MRA Agreement for MRA <i>r</i> represented by QSE <i>q</i> . Where for a Combined Cycle Train, the Resource <i>r</i> is the Combined Cycle Train.
MRAH _{q, r}	Hour	<i>Must-Run Alternative Hours</i> —The number of hours during which MRA <i>r</i> represented by QSE <i>q</i> received a deployment instruction for each deployment event for the Operating Day. Where for a Combined Cycle Train, the Resource <i>r</i> is the Combined Cycle Train.
MRAFLAG _{q, r, h}	none	<i>Must-Run Alternative Flag</i> – An indicator to signify that an MRA <i>r</i> represented by QSE <i>q</i> followed the deployment instruction for the event for the hour <i>h</i> . An MRAFLAG value of 1 represents followed and a 0 represents did not follow the deployment. Where for a Combined Cycle Train, the Resource <i>r</i> is the Combined Cycle Train.
MRACEFA _{q, r}	\$/MMBtu	<i>Must-Run Alternative Contractual Estimated Fuel Adder</i> —The MRA Estimated Fuel Adder for the MRA <i>r</i> represented by QSE <i>q</i> as specified in the MRA Agreement. Where for a Combined Cycle Train, the Generation Resource <i>r</i> is the Combined Cycle Train.
<i>q</i>	none	A QSE.
<i>r</i>	none	An MRA.
<i>m</i>	none	An MRA Contracted Month under the MRA Agreement.
<i>h</i>	none	An MRA Contracted Hour under the MRA Agreement for the MRA Contracted Month.

- (43) The total of the deployment event payments for all MRAs represented by the QSE for a given MRA Contracted Hour is calculated as follows:

$$\text{MRADEAMTQSETOT}_q = \sum_r \text{MRADEAMT}_{q, r, h}$$

The above variables are defined as follows:

Variable	Unit	Definition
MRADEAMTQSETOT _q	\$	<i>Must-Run Alternative Deployment Event Amount per QSE by hour</i> —The total of the deployment event payments for all MRAs <i>r</i> , represented by the QSE <i>q</i> for the hour.
MRADEAMT _{q, r, h}	\$	<i>Must-Run Alternative Deployment Event Amount per QSE per Resource by hour</i> —The deployment event payment to QSE <i>q</i> for MRA <i>r</i> , for the hour. Where for a Combined Cycle Train, the Resource <i>r</i> is the Combined Cycle Train.
<i>q</i>	none	A QSE.
<i>r</i>	none	An MRA.
<i>h</i>	none	An MRA Contracted Hour under the MRA Agreement for the MRA Contracted Month.

- (54) The total of the deployment event payments for a given MRA Contracted Hour is calculated as follows:

$$\text{MRADEAMTTOT} = \sum_q \text{MRADEAMTQSETOT}_q$$

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The above variables are defined as follows:

Variable	Unit	Definition
MRADAMTTOT	\$	Must-Run Alternative Deployment Event Amount Total by hour—The total deployment event payment to all QSEs for all MRAs, for the hour.
MRADAMTQSETOT _q	\$	Must-Run Alternative Deployment Event Amount per QSE by hour—The total of the deployment event payments for all MRAs represented by the QSE <i>q</i> for the MRA Contracted Hour.
<i>q</i>	none	A QSE.

[NPRR885, NPRR1010, and NPRR1014: Insert applicable portions of Section 6.6.6.10 below upon system implementation for NPRR885 or NPRR1014; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010:]

6.6.6.10 MRA Variable Payment for Deployment

- (1) The variable payment to each QSE representing a Generation Resource MRA:

Outside of the MRA Contracted Hours, a Generation Resource MRA shall be treated in Settlements in the same manner as any Generation Resource registered with ERCOT

For MRA Contracted Hours with a deployment instruction:

$$\text{MRVAVMT}_{q,r,h} = (-1) * (\text{MRAGRCVP}_{q,r,h} - \text{MRARTREV}_{q,r,h})$$

For MRA Contracted Hours without a deployment instruction:

$$\text{MRVAVMT}_{q,r,h} = (-1) * (\text{Min}(\text{MRAGRCVP}_{q,r,h}, \text{MRARTREV}_{q,r,h}) - \text{MRARTREV}_{q,r,h})$$

Where,

$$\text{MRAGRCVP}_{q,r,h} = \sum_{i=1}^4 \text{Max} [\text{VPRICE}_{q,r}, (\text{FIP} + \text{MRACEFA}_{q,r}) * \text{MRAPHR}_{q,r}] * \text{Min}(\text{RTMG}_{q,r,p,i}, \text{MRACCAP}_{q,r,m} / 4)$$

$$\text{MRARTREV}_{q,r,h} = \sum_{i=1}^4 \text{Max} [0, (\text{RESREV}_{q,r,gsc,p,i} + (-1) * (\text{EMREAMT}_{q,r,p,i} + \text{VSSVARAMT}_{q,r,i} + \text{VSSEAMT}_{q,r,i}))]$$

- (2) The variable payment to each QSE representing an Energy Storage Resource (ESR) MRA:

- (a) ESR MRA will be compensated for energy consumed to re-charge the MRA capability after the hours of injection to the ERCOT system during an event deployment or an ERCOT-required Capacity Test based on the cost of the energy as metered by the meter recording load. The QSE will not be compensated for

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energy costs incurred during a re-test. An ESR shall only consume energy in hours that are not Contracted Hours, and it must be re-charged to a level sufficient to provide the contracted amount of MRA Service prior to the next start of a block of Contracted Hours. Additionally, the QSE shall use its best efforts to minimize the cost to re-charge and submit bid-to-buy curves taking into consideration estimates of future prices. The cost to re-charge shall be determined by starting with the least expensive consumed energy.

(b) Outside of the MRA Contracted Hours, an ESR MRA shall be treated in Settlements in the same manner as any ESR registered with ERCOT.

For MRA Contracted Hours with a deployment instruction:

$$\text{MRAVAMT}_{q,r,h} = (-1) * (\text{MRAESRCVP}_{q,r,h} - \text{MRARTREV}_{q,r,h})$$

For MRA Contracted Hours without a deployment instruction:

$$\text{MRAVAMT}_{q,r,h} = (-1) * (\text{Min}(\text{MRAESRCVP}_{q,r,h}, \text{MRARTREV}_{q,r,h}) - \text{MRARTREV}_{q,r,h})$$

Where,

$$\begin{aligned} \text{MRAESRCVP}_{q,r,h} &= \sum_{i=1}^4 \frac{\text{Max}[\text{VPRICE}_{q,r}, \text{ESRARCOST}_{q,r}] * \text{Min}(\text{RTMG}_{q,r,p}, \text{MRACCAP}_{q,r,m} / 4)}{4} \\ \text{MRARTREV}_{q,r,h} &= \sum_{i=1}^4 \frac{\text{Max}[0, (\text{RESREV}_{q,r,gsc,p,i} + (-1) * (\text{EMREAMT}_{q,r,p,i} + \text{VSSVARAMT}_{q,r,i} + \text{VSSEAMT}_{q,r,i}))]}{4} \end{aligned}$$

(32) The variable payment to each QSE representing an Other Generation MRA:

For MRA Contracted Hours with a deployment instruction:

$$\text{MRAVAMT}_{q,r,h} = (-1) * (\text{MRACVP}_{q,r,h} - \text{MRACRTREV}_{q,r,h})$$

For MRA Contracted Hours without a deployment instruction:

$$\text{MRAVAMT}_{q,r,h} = (-1) * (\text{Min}(\text{MRACVP}_{q,r,h}, \text{MRACRTREV}_{q,r,h}) - \text{MRACRTREV}_{q,r,h})$$

Where,

$$\text{MRACVP}_{q,r,h} = \sum_{i=1}^4 \frac{\text{Max}[\text{VPRICE}_{q,r}, (\text{FIP} + \text{MRACEFA}_{q,r}) * \text{MRAPHR}_{q,r}] * \text{RTVQ}_{q,r,i}}{4}$$

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$$MRACRTREV_{q, r, h} = \sum_{i=1}^4 (\text{Max}(0, \text{Min}(\text{RTVQ}_{q, r, i}, \text{MRACCAP}_{q, r, m} / 4) * \text{RTSPP}_{p, i}))$$

Where,

$$\text{RTVQ}_{q, r, i} = \text{MRAIPF}_{q, r, i} * \text{MRACCAP}_{q, r, m} / 4$$

(43) The variable payment to each QSE representing a Demand Response MRA:

For MRA Contracted Hours with a deployment instruction:

$$\text{MRAVAMT}_{q, r, h} = (-1) * \sum_{i=1}^4 \text{Max}[\text{VPRICE}_{q, r}, (\text{FIP} + \text{MRACEFA}_{q, r}) * \text{MRAPHR}_{q, r}] * \text{RTVQ}_{q, r, i}$$

Where,

$$\text{RTVQ}_{q, r, i} = \text{MRAIPF}_{q, r, i} * \text{MRACCAP}_{q, r, m} / 4$$

The above variables are defined as follows:

Variable	Unit	Definition
$\text{MRAVAMT}_{q, r, h}$	\$	<i>Must-Run Alternative Variable Amount per QSE per Resource by hour—The variable payment to QSE q for MRA r, for the hour h. Where for a Combined Cycle Train, the Resource r is the Combined Cycle Train.</i>
$\text{MRAGRCVP}_{q, r, h}$	\$	<i>Must-Run Alternative Generation Resource Calculated Variable Payment per QSE per Resource - The variable payment to QSE q for Generation Resource MRA r, for the hour h. Where for a Combined Cycle Train, the Resource r is the Combined Cycle Train.</i>
FIP	\$/MMBtu	<i>Fuel Index Price—The FIP for the Operating Day.</i>
$\text{MRARTREV}_{q, r, h}$	\$	<i>Must-Run Alternative Real-Time Revenues per QSE per Resource by hour—The revenues received in Real-Time for QSE q for MRA r, for the hour h. Where for a Combined Cycle Train, the Resource r is the Combined Cycle Train.</i>
$\text{MRAESRCVP}_{q, r, h}$	\$	<i>Must-Run Alternative Energy Storage Resource Calculated Variable Payment per QSE per Resource—The variable payment to QSE q for ESR MRA r, for the hour h.</i>
$\text{ESRARCOST}_{q, r}$	\$/MWh	<i>Must-Run Alternative Energy Storage Resource Average Recharge Cost per QSE per Resource—The average cost to recharge the ESR MRA r, for QSE q, during the period the ESR is charging to restore its capability to provide the contracted amount of MRA service.</i>
$\text{MRACCAP}_{q, r, m}$	MW	<i>Must-Run Alternative Contract Capacity per QSE per Resource—The capacity of MRA r represented by QSE q as specified in the MRA Agreement, for the month. Where for a Combined Cycle Train, the Resource r is the Combined Cycle Train.</i>
$\text{MRAIPF}_{q, r, i}$	none	<i>Must-Run Alternative Interval Performance Factor per QSE per Resource for the interval—The interval performance factor of the MRA r represented by QSE q, for the 15-minute Settlement Interval i.</i>

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MRACVP _{<i>q, r, h</i>}	\$	<i>Must-Run Alternative Calculated Variable Payment per QSE per Resource</i> - The variable payment to QSE <i>q</i> for an Other Generation MRA or Demand Response MRA <i>r</i> , for the hour <i>h</i> . Where for a Combined Cycle Train, the Resource <i>r</i> is the Combined Cycle Train.
VSSVARAMT _{<i>q, r, i</i>}	\$	<i>Voltage Support Service VAR Amount per QSE per Generation Resource</i> - The payment to QSE <i>q</i> for the VSS provided by Generation Resource MRA <i>r</i> , for the 15-minute Settlement Interval <i>i</i> . Where for a combined cycle resource, <i>r</i> is a Combined Cycle Train.
VSSEAMT _{<i>q, r, i</i>}	\$	<i>Voltage Support Service Energy Amount per QSE per Generation Resource</i> —The lost opportunity payment to QSE <i>q</i> for ERCOT-directed VSS from Generation Resource MRA <i>r</i> for the 15-minute Settlement Interval. Where for a combined cycle resource, <i>r</i> is a Combined Cycle Train.
RESREV _{<i>q, r, gsc, p, i</i>}	\$	<i>Resource Share Revenue Settlement Payment</i> —The Resource share of the total payment to the entire Facility with a net metering arrangement attributed to Generation Resource MRA <i>r</i> that is part of a generation site code <i>gsc</i> for the QSE <i>q</i> at Settlement Point <i>p</i> , for the 15-minute Settlement Interval <i>i</i> .
EMREAMT _{<i>q, r, p, i</i>}	\$	<i>Emergency Energy Amount per QSE per Settlement Point per unit per interval</i> —The payment to QSE <i>q</i> as additional compensation for the additional energy or Ancillary Services produced or consumed by Resource MRA <i>r</i> at Resource Node <i>p</i> in Real-Time during the Emergency Condition, for the 15-minute Settlement Interval <i>i</i> . Payment for emergency energy is made to the Combined Cycle Train.
VPRICE _{<i>q, r</i>}	\$/MWh	<i>Must-Run Alternative Variable Price per QSE per Resource</i> —The variable price for QSE <i>q</i> for MRA <i>r</i> , as specified in the MRA Agreement. Where for a Combined Cycle Train, the Resource <i>r</i> is the Combined Cycle Train.
MRAPHR _{<i>q, r</i>}	MMBtu/MWh	<i>Must-Run Alternative Proxy Heat Rate per QSE per Resource</i> - A proxy heat rate value for MRA <i>r</i> represented by QSE <i>q</i> , as specified in the MRA Agreement. Where for a Combined Cycle Train, the Resource <i>r</i> is the Combined Cycle Train.
MRACRTREV _{<i>q, r, h</i>}	\$	<i>Must-Run Alternative Calculated Real-Time Revenues per QSE per Resource</i> —The calculated variable revenue to QSE <i>q</i> for MRA <i>r</i> , for the hour.
RTVQ _{<i>q, r, i</i>}	MWh	<i>Real-Time Variable Quantity per QSE per Resource by Settlement Interval</i> — The Real-Time variable quantity for MRA <i>r</i> represented by QSE <i>q</i> , for the 15-minute Settlement Interval <i>i</i> .
RTMG _{<i>q, r, p, i</i>}	MWh	<i>Real-Time Metered Generation per QSE per Settlement Point per Generation Resource</i> —The metered generation of Resource <i>r</i> at Resource Node <i>p</i> represented by QSE <i>q</i> in Real-Time for the 15-minute Settlement Interval <i>i</i> . Where for a Combined Cycle Train, the Resource <i>r</i> is the Combined Cycle Train.
MRACEFA _{<i>q, r</i>}	\$/MMBtu	<i>Must-Run Alternative Contractual Estimated Fuel Adder</i> —The Estimated Fuel Adder that is contractually agreed upon in Section 22, Attachment N, Standard Form Must-Run Alternative Agreement. Where for a Combined Cycle Train, the Generation Resource <i>r</i> is the Combined Cycle Train.
RTSPP _{<i>p, i</i>}	\$/MWh	<i>Real-Time Settlement Point Price</i> —The Real-Time Settlement Point Price at the Settlement Point <i>p</i> for the 15-minute Settlement Interval <i>i</i> .
<i>q</i>	none	A QSE.
<i>r</i>	none	An MRA.

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m	none	An MRA Contracted Month.
h	none	An MRA Contracted Hour for the MRA Contracted Month.
i	none	A 15-minute Settlement Interval during the MRA Contracted Hours.
gsc	none	A generation site code.
p	none	A Resource Node Settlement Point.

(52) The total of the variable payments for all MRAs represented by the QSE for a given hour is calculated as follows:

$$MRAVAMTQSETOT_q = \sum_r MRAVAMT_{q,r,h}$$

The above variables are defined as follows:

Variable	Unit	Definition
$MRAVAMTQSETOT_q$	\$	<i>Must-Run Alternative Variable Amount Total per QSE by hour</i> —The total variable payment for all MRAs r , represented by the QSE q , for the hour.
$MRAVAMT_{q,r,h}$	\$	<i>Must-Run Alternative Variable Amount per QSE per Resource by hour</i> —The variable payment to QSE q representing MRA r for the hour h . Where for a Combined Cycle Train, the Resource r is the Combined Cycle Train.
q	none	A QSE.
r	none	An MRA.
h	none	An MRA Contracted Hour for the MRA Contracted Month.

(63) The total of the variable payments for a given MRA Contracted Hour is calculated as follows:

$$MRAVAMTTOT = \sum_q MRAVAMTQSETOT_q$$

The above variables are defined as follows:

Variable	Unit	Definition
$MRAVAMTTOT$	\$	<i>Must-Run Alternative Variable Amount Total by hour</i> —The total variable payments for the MRA Contracted Hour.
$MRAVAMTQSETOT_q$	\$	<i>Must-Run Alternative Variable Amount Total per QSE by hour</i> —The total variable payment for all MRAs, represented by the QSE q , for the MRA Contracted Hour.
q	none	A QSE.

ERCOT Impact Analysis Report

NPRR Number	<u>1256</u>	NPRR Title	Settlement of MRA of ESRs
Impact Analysis Date	October 14, 2024		
Estimated Cost/Budgetary Impact	Between \$25K and \$50K		
Estimated Time Requirements	<p>The timeline for implementing this Nodal Protocol Revision Request (NPRR) is dependent upon Public Utility Commission of Texas (PUCT) prioritization and approval; and upon system implementation of NPRR885, Must-Run Alternative (MRA) Details and Revisions Resulting from PUCT Project No. 46369, Rulemaking Relating to Reliability Must-Run Service.</p> <p>Estimated project duration: 3 to 5 months</p> <p>See Comments.</p>		
ERCOT Staffing Impacts (across all areas)	<p>Implementation Labor: 100% ERCOT; 0% Vendor</p> <p>Ongoing Requirements: No impacts to ERCOT staffing.</p>		
ERCOT Computer System Impacts	<p>The following ERCOT systems would be impacted:</p> <ul style="list-style-type: none">• Market Settlements 100%		
ERCOT Business Function Impacts	No impacts to ERCOT business functions.		
Grid Operations & Practices Impacts	No impacts to ERCOT grid operations and practices.		

Evaluation of Interim Solutions or Alternatives for a More Efficient Implementation

None offered.

Comments

NPRR1256 is dependent on NPRR885 and if they are implemented concurrently, a cost savings could be realized from project efficiencies.

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NPRR Number	<u>1268</u>	NPRR Title	RTC – Modification of Ancillary Service Demand Curves
Date of Decision	April 8, 2025		
Action	Recommended Approval		
Timeline	Urgent		
Estimated Impacts	Cost/Budgetary: None Project Duration: No project required		
Proposed Effective Date	Upon system implementation of PR447, Real-Time Co-Optimization (RTC)		
Priority and Rank Assigned	Not applicable		
Nodal Protocol Sections Requiring Revision	4.4.12, Determination of Ancillary Service Demand Curves for the Day-Ahead Market and Real-Time Market 4.5.1, DAM Clearing Process 6.5.7.3, Security Constrained Economic Dispatch Section 22 Attachment P, Methodology for Setting Maximum Shadow Prices for Network and Power Balance Constraints		
Related Documents Requiring Revision/Related Revision Requests	None		
Revision Description	This Nodal Protocol Revision Request (NPRR) defines a methodology for disaggregating the Operating Reserve Demand Curve (ORDC), creating “blended” Ancillary Service Demand Curves (ASDCs).		
Reason for Revision	<input type="checkbox"/> <u>Strategic Plan</u> Objective 1 – Be an industry leader for grid reliability and resilience <input type="checkbox"/> <u>Strategic Plan</u> Objective 2 - Enhance the ERCOT region's economic competitiveness with respect to trends in wholesale power rates and retail electricity prices to consumers <input type="checkbox"/> <u>Strategic Plan</u> 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		

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	<input checked="" type="checkbox"/> General system and/or process improvement(s) <input type="checkbox"/> Regulatory requirements <input type="checkbox"/> ERCOT Board/PUCT Directive <i>(please select ONLY ONE – if more than one apply, please select the ONE that is most relevant)</i>
Justification of Reason for Revision and Market Impacts	<p>Under RTC, the ASDCs reflect the penalty price for going short on Ancillary Services in Real-Time, where each Ancillary Service product has a corresponding ASDC. The Public Utility Commission of Texas (PUCT) determined that the ASDCs should reflect the pricing outcomes associated with the prevailing ORDC, and the ASDCs that followed from that directive are defined in RTC Key Principles (KP) 1.1(4) and 1.1(5). The Independent Market Monitor (IMM) has the following concerns with these ASDCs:</p> <ul style="list-style-type: none"> • Security-Constrained Economic Dispatch (SCED) cannot efficiently trade-off between Ancillary Service products, as pricing is strictly hierarchical; and • Non-Spinning Reserve (Non-Spin) tends to be underpriced during shortage conditions. <p>To address these concerns, the IMM has developed a new ORDC disaggregation approach, creating what we call “blended” ASDCs. These blended ASDCs will improve reliability and market performance by allowing SCED to make more efficient tradeoffs between energy and reserves under shortage conditions while maintaining sufficient price signals to promote resource adequacy.</p>
PRS Decision	<p>On 2/12/25, PRS voted unanimously to table NPRR1268. All Market Segments participated in the vote.</p> <p>On 3/12/25 PRS voted to grant NPRR1268 Urgent status; to recommend approval of NPRR1268 as amended by the 3/7/25 Hunt Energy Network comments; and to forward to TAC NPRR1268. There was one abstention from the Independent Generator (Vistra) Market Segment. All Market Segments participated in the vote.</p>
Summary of PRS Discussion	<p>On 2/12/25, the sponsor provided an overview of NPRR1268 and participants reviewed the 1/30/25 Hunt Energy Network comments and 2/5/25 IMM comments. Participants tabled NPRR1268 for continued discussions at upcoming Real-Time Co-optimization plus Batteries Task Force (RTCBTF) meetings, and the sponsor noted they plan to request Urgent status for NPRR1268 at the March PRS meeting to keep this NPRR on-track for PUCT approval ahead of</p>

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	<p>Real-Time Co-optimization plus Batteries (RTC+B) project market trials later this year.</p> <p>On 3/12/25, PRS reviewed the 2/19/25 ERCOT comments, 2/25/25 TCPA comments, and 3/7/25 Hunt Energy Network comments.</p>
TAC Decision	On 3/26/25, TAC voted unanimously to recommend approval of NPRR1268 as recommended by PRS in the 3/12/25 PRS Report as amended by the 3/19/25 IMM comments; and the 3/18/25 Impact Analysis. All Market Segments participated in the vote.
Summary of TAC Discussion	On 3/26/25, there was no additional discussion beyond TAC review of the items below.
TAC Review/Justification of Recommendation	<p><input checked="" type="checkbox"/> Revision Request ties to Reason for Revision as explained in Justification</p> <p><input checked="" type="checkbox"/> Impact Analysis reviewed and impacts are justified as explained in Justification</p> <p><input checked="" type="checkbox"/> Opinions were reviewed and discussed</p> <p><input checked="" type="checkbox"/> Comments were reviewed and discussed (if applicable)</p> <p><input type="checkbox"/> Other: (explain)</p>
ERCOT Board Decision	On 4/8/25, the ERCOT Board voted unanimously to recommend approval of NPRR1268 as recommended by TAC in the 3/26/25 TAC Report.

Opinions	
Credit Review	ERCOT Credit Staff and the Credit Finance Sub Group (CFSG) have reviewed NPRR1268 and do not believe that it requires changes to credit monitoring activity or the calculation of liability.
Independent Market Monitor Opinion	IMM supports approval of NPRR1268.
ERCOT Opinion	ERCOT supports approval of NPRR1268.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NPRR1268 and believes the market impact for NPRR1268, after extensive review with stakeholders at the RTCBTF, introduces “blended” ASDCs which will improve reliability and market performance by allowing SCED to make more efficient tradeoffs between energy and reserves under shortage conditions while maintaining sufficient price signals to promote Resource adequacy.

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Sponsor	
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Comments Received	
Comment Author	Comment Summary
Hunt Energy Network 013025	Proposed edits to use an unaltered ORDC to create the ASDCs instead of the Aggregated ORDC (AORDC)
IMM 020525	Corrected a typo within the redlines and provided meaning and rationale for the equation changes proposed by NPRR1268
ERCOT 021925	Proposed revisions based on RTCBTF discussions to strike the explicit "100-point" from the ASDC language and include language capping the Day-Ahead Marginal Clearing Prices for Capacity (MCPCs) at the effective the Value of Lost Load (VOLL)
TCPA 022525	Proposed revisions to include a price floor for DAM and RTM ASDCs
Hunt Energy Network 030725	Proposed clarifying edits to the 2/19/25 ERCOT comments to better describe the Aggregated Operating Reserve Demand Curve (AORDC)
IMM 031925	Proposed minor revisions to correct parameter names

Market Rules Notes

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

- NPRR1246, Energy Storage Resource Terminology Alignment for the Single-Model Era (incorporated 4/1/25)
 - Section 22, Attachment P

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

- NPRR1235, Dispatchable Reliability Reserve Service as a Stand-Alone Ancillary Service
 - Section 4.4.12
 - Section 4.5.1
- NPRR1269, RTC+B Three Parameters Policy Issues
 - Section 6.5.7.3

Proposed Protocol Language Revision

[NPRR1008, NPRR1216, and NPRR1245: Insert applicable portions of Section 4.4.12 below upon system implementation of NPRR1216; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1008 and NPRR1245:]

4.4.12 Determination of Ancillary Service Demand Curves for the Day-Ahead Market and Real-Time Market

- (1) This Section describes the process for determining ASDCs for Regulation Up Service (Reg-Up), Regulation Down Service (Reg-Down), Responsive Reserve (RRS), ERCOT Contingency Reserve Service (ECRS), and Non-Spinning Reserve (Non-Spin) for the Day-Ahead Market (DAM) and Real-Time Market (RTM). This section does not apply to ASDCs used in the Reliability Unit Commitment (RUC) process.
- (2) The Value of Lost Load (VOLL) is determined as described in Section 4.4.11, Day-Ahead and Real-Time System-Wide Offer Caps, and Section 4.4.11.1, Scarcity Pricing Mechanism.
- (3) The DAM shall use the same ASDCs as the RTM, as an initial condition. Specific to the DAM, the ASDCs will be adjusted, as needed, to account for negative Self-Arranged Ancillary Service Quantities.
- (43) For Reg-Down, the ASDC shall be a constant value equal to VOLL for the full range of the Ancillary Service Plan for Reg-Down.
- (54) To determine the individual ASDCs for Reg-Up, RRS, ECRS, and Non-Spin, an Aggregate ORDC (AORDC) will be created and then disaggregated into individual curves for the different Ancillary Services.
- (65) ERCOT shall develop the AORDC from historical data from the period of June 1, 2014 through August 31, 2025 as follows:

Commented [CP1]: Please note NPRR1235 also proposes revisions to this section.

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- (a) For all SCED intervals where the sum of RTOLCAP and RTOFFCAP is less than 10,000 MW, use the RTOLCAP and RTOFFCAP values to calculate historical reserve pricing outcomes, which are the following values used in the regression analysis described in (b) AORDC below as follows:

$$\text{AORDC} = (0.5 * (1 - \text{pnorm}(\text{RTOLCAP} - 3000, 0.5 * \mu, 0.707 * \sigma)) + 0.5 * (1 - \text{pnorm}(\text{RTOLCAP} + \text{RTOFFCAP} - 3000, \mu, \sigma))) * (\text{VOLL} - \min(\text{System Lambda}, 250))$$

The above variables are defined as follows:

Variable	Unit	Definition
RTOLCAP	MWh	<i>Real-Time On-Line Reserve Capacity</i> – The Real-Time reserve capacity of On-Line Resources available for the SCED intervals beginning June 1, 2014 through August 31, 2025
RTOFFCAP	MWh	<i>Real-Time Off-Line Reserve Capacity</i> – The Real-Time reserve capacity of Off-Line Resources available for the SCED intervals beginning June 1, 2014 through August 31, 2025.
μ	None	The mean value of the shifted LOLP distribution as published for Summer 2026
σ	None	The standard deviation of the shifted LOLP distribution as published for Summer 2026

- (b) Using the results of step (a) above, use regression methods to fit the following curve to the average reserve pricing outcomes for the various MW reserve levels:-

$$\text{AORDC} = (1 - \text{pnorm}(\text{reserve level} - 3000, \mu^*, \sigma^*)) * \text{VOLL}$$

The above variables are defined as follows:

Variable	Unit	Definition
μ^*	None	The mean value used for the calculation of the AORDC as <u>determined using the regression fit method described above.</u>
σ^*	None	The standard deviation used for the calculation of the AORDC as <u>determined using the regression fit method described above.</u>

- (c) Calculate points on the regression curve in 1 MW increments for any observed reserve level $\geq 3,000$ MW and price $> \$0.01/\text{MWh}$. These points form the AORDC.

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(76) ERCOT shall disaggregate the AORDC developed pursuant to paragraph (5) above into individual ASDCs for each Ancillary Service product as follows:

(a) Using the required percentage of Reg-Up, the maximum percentages of RRS and ECRS, and the minimum quantities of required Non-Spin and ECRS, the quantities of each Ancillary Service product procured until the Minimum Contingency Level (MCL) is satisfied are calculated as follows:

If, $RUPCT * RUREQ + ECRSPCTMAX * ECRSREQ + RRSPTMAX * RRSREQ + ECRSPCTMAX * ECRSREQ + NSMWMIN \leq MCL$:

$$RUMW = RUPCT * RUREQ$$

$$ECRSMW = ECRSPCTMAX * ECRSREQ$$

$$RRSMW = RRSPTMAX * RRSREQ$$

$$NSMW = MCL - RUMW - RRSMW - ECRSMW$$

Else, if $RUPCT * RUREQ + RRSPTMAX * RRSREQ + ECRSMWMIN + NSMWMIN > MCL$:

$$RUMW = RUPCT * RUREQ$$

$$ECRSMW = ECRSMWMIN$$

$$RRSMW = RRSPTMAX * RRSREQ - (RRSPTMAX * RRSREQ + RUPCT * RUREQ - (MCL - ECRSMWMIN - NSMWMIN))$$

$$NSMW = NSMWMIN$$

Otherwise, if $RUPCT * RUREQ + RRSPTMAX * RRSREQ + ECRSPCTMAX * ECRSREQ + NSMWMIN > MCL$:

$$RUMW = RUPCT * RUREQ$$

$$RRSMW = RRSPTMAX * RRSREQ - 0.5(RUPCT * RUREQ + RRSPTMAX * RRSREQ + ECRSPCTMAX * ECRSREQ - (MCL - NSMWMIN))$$

$$ECRSMW = ECRSPCTMAX * ECRSREQ - 0.5(RUPCT * RUREQ + RRSPTMAX * RRSREQ + ECRSPCTMAX * ECRSREQ - (MCL - NSMWMIN))$$

$$NSMW = NSMWMIN$$

The above variables are defined as follows:

<u>Variable</u>	<u>Unit</u>	<u>Definition</u>
<u>MCL</u>	<u>MW</u>	<u>Minimum Contingency Level – the minimum amount of reserves that ERCOT considers necessary to avoid a system-wide failure. -This value is set at 3,000 MW.</u>

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<u>RUREQ</u>	<u>MW</u>	Amount of Reg-Up capacity required to meet system reliability needs. Total capacity of Reg-Up in the Ancillary Service Plan
<u>RRSREQ</u>	<u>MW</u>	Amount of RRS capacity required to meet system reliability needs. Total capacity of RRS in the Ancillary Service Plan
<u>ECRSREQ</u>	<u>MW</u>	Amount of ECRS capacity required to meet system reliability needs. Total capacity of ECRS in the Ancillary Service Plan
<u>RUPCT</u>	<u>%</u>	Percentage of total Ancillary Service reserves allocated to Reg-Up. Fixed percentage of Reg-Up included in the MCL
<u>RRSPCTMAX</u>	<u>%</u>	Maximum RRS percentage at RRS-included in the MCL. max price.
<u>ECRSPCTMAX</u>	<u>%</u>	Maximum ECRS capacity percentage at ECRS max price. included in the MCL.
ECRS <u>MINMW</u> <u>MIN</u>	<u>MW</u>	Minimum ECRS capacity included in the MCL
<u>NSMWMIN</u>	<u>MW</u>	Minimum Non-Spin capacity at max price within the linear portion of the AORDC, regardless of requirement amount. included in the MCL.
<u>RUMW</u>	<u>MW</u>	Actual capacity allocated to Reg-Up within the linear portion of the AORDC. Capacity of Reg-Up included in the MCL
<u>RRSMW</u>	<u>MW</u>	Actual capacity allocated to RRS within the linear portion of the AORDC. Capacity of RRS included in the MCL.
<u>ECRSMW</u>	<u>MW</u>	Actual capacity allocated to ECRS within the linear portion of the AORDC. Capacity of ECRS included in the MCL
<u>NSMW</u>	<u>MW</u>	Actual capacity allocated to Non-Spin within the linear portion of the AORDC. Capacity of Non-Spin included in the MCL
<u>Fixed parameters are defined as follows:</u>		

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<u>Parameter</u>	<u>Unit</u>	<u>Current Value</u>
<u>RUPCT</u>	<u>%</u>	<u>90</u>
<u>RRSPCTMA</u> <u>X</u>	<u>%</u>	<u>90</u>
<u>ECRSPCTM</u> <u>AX</u>	<u>%</u>	<u>30</u>
<u>ECRS</u> MINM <u>WMIN</u>	<u>MW</u>	<u>40</u>
<u>NSMWMIN</u>	<u>MW</u>	<u>10</u>

Further, the quantities of each Ancillary Service product procured until the MCL is satisfied are priced as follows:

<u>Parameter</u>	<u>Unit</u>	<u>Current Value</u>
<u>Reg-Up Max</u> <u>Demand</u> <u>Price</u>	<u>\$/MWh</u>	<u>VOLL + 4,052</u>
<u>RRS Max</u> <u>Demand</u> <u>Price</u>	<u>\$/MWh</u>	<u>VOLL + 2,051</u>
<u>ECRS Max</u> <u>Demand</u> <u>Price</u>	<u>\$/MWh</u>	<u>VOLL + 50</u>
<u>Non-Spin</u> <u>Max Demand</u> <u>Price</u>	<u>\$/MWh</u>	<u>VOLL</u>

(b) Beyond the MCL, the nonlinear segments of the AORDC are disaggregated as follows:

- (i) First, extract evenly spaced 1 MW AORDC segments extending from the MCL to the minimum Reg-Up price. These segments form the nonlinear portion of the Reg-Up ASDC;
- (ii) Second, extract evenly spaced 1 MW AORDC segments extending from MCL to the minimum RRS price. These segments form the nonlinear portion of the RRS ASDC;

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(iii) Third, assign the remaining 1 MW segments of the AORDC to ECRS and Non-Spin alternately, until the requirements for both products have been met; and

(iv) Assign any remaining 1 MW segments of the AORDC priced above \$0.01/MWh to Non-Spin.

The minimum prices for Reg-Up and RRS are defined as follows:

<u>Parameter</u>	<u>Unit</u>	<u>Current Value</u>
<u>Reg-Up Min Price</u>	<u>\$/MWh</u>	<u>250</u>
<u>RRS Min Price</u>	<u>\$/MWh</u>	<u>100</u>

~~(a) — The ASDC for all Reg Up in the Ancillary Service Plan shall use the highest price portion of the AORDC;~~

~~(b) — The ASDC for all RRS in the Ancillary Service Plan shall use the highest price portion of the remaining AORDC after removing the portion of the AORDC that was used for the Reg Up ASDC;~~

~~(c) — The ASDC for all ECRS in the Ancillary Service Plan shall use the highest price portion of the remaining AORDC after removing the portions of the AORDC that were used for the Reg Up and RRS ASDCs;~~

~~(d) — The ASDC for Non-Spin shall use the remaining portion of the remaining AORDC after removing the portions of the AORDC that were used for the Reg Up, RRS, and ECRS ASDCs.~~

~~(87) Each ASDC will be represented by a 100-point linear approximation to the corresponding part of the AORDC. Fewer points may be used for cases where it would not result in decreased accuracy in representing the corresponding part of the AORDC.~~

~~(8) — The AORDC used in determining the individual ASDCs will be adjusted to reflect any updates to the value of VOLL, as described in Section 4.4.11, Day Ahead and Real Time System Wide Offer Caps, and Section 4.4.11.1, Scarcity Pricing Mechanism.~~

4.5.1 DAM Clearing Process

- (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

Commented [CP2]: Please note NPRR1235 also proposes revisions to this section.

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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 –

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- (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, NPRR1014, and NPRR1188: Replace applicable portions of paragraph (4) above with the following upon system implementation of the Real-Time Co-Optimization

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(RTC) project for NPRR1008; or upon system implementation for NPRR1014 or NPRR1188:)

- (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, Energy Bid Curves, 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 –

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- (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 that is not a Controllable Load Resource (CLR) – 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

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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:

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- (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. However, if an Ancillary Service price determined by the DAM algorithm exceeds the effective VOLL at the time of the DAM execution for any hour, that Day-Ahead MCPC will be capped at the effective VOLL.
- (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 Section 22, Attachment P, 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

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the clearing price when the constraint between the Resource Connectivity Node and the Resource Node is binding.

[NPRR1014 and NPRR1188: 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.

6.5.7.3 Security Constrained Economic Dispatch

Commented [CP3]: Please note NPRR1269 also proposes revisions to this section.

- (1) The SCED process is designed to simultaneously manage energy, the system power balance and network congestion through Resource Base Points and calculation of LMPs every five minutes. The SCED process uses a two-step methodology that applies mitigation prospectively to resolve Non-Competitive Constraints for the current Operating Hour. The SCED process evaluates Energy Offer Curves, Output Schedules and Real-Time Market (RTM) Energy Bids to determine Resource Dispatch Instructions by maximizing bid-based revenues minus offer-based costs, subject to power balance and network constraints. The SCED process uses the Resource Status provided by SCADA telemetry under Section 6.5.5.2, Operational Data Requirements, and validated by the Real-Time Sequence, instead of the Resource Status provided by the COP.
- (2) The SCED solution must monitor cumulative deployment of Regulation Services and ensure that Regulation Services deployment is minimized over time.
- (3) In the Generation To Be Dispatched (GTBD) determined by LFC, ERCOT shall subtract the sum of the telemetered net real power consumption from all CLRs available to SCED.
- (4) For use as SCED inputs, ERCOT shall use the available capacity of all committed Generation Resources by creating proxy Energy Offer Curves for certain Resources as follows:
 - (a) Non-IRRs and Dynamically Scheduled Resources (DSRs) without Energy Offer Curves
 - (i) ERCOT shall create a monotonically increasing proxy Energy Offer Curve as described below for:
 - (A) Each non-IRR for which its QSE has submitted an Output Schedule instead of an Energy Offer Curve; and
 - (B) Each DSR that has not submitted incremental and decremental Energy Offer Curves.

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MW	Price (per MWh)
HSL	SWCAP
Output Schedule MW plus 1 MW	SWCAP minus \$0.01
Output Schedule MW	-\$249.99
LSL	-\$250.00

(b) DSRs with Energy Offer Curves

- (i) For each DSR that has submitted incremental and decremental Energy Offer Curves, ERCOT shall create a monotonically increasing proxy Energy Offer Curve. That curve must consist of the incremental Energy Offer Curve that reflects the available capacity above the Resource's Output Schedule to its HSL and the decremental Energy Offer Curve that reflects the available capacity below the Resource's Output Schedule to the LSL. The curve must be created as described below:

MW	Price (per MWh)
Output Schedule MW plus 1 MW to HSL	Incremental Energy Offer Curve
LSL to Output Schedule MW	Decremental Energy Offer Curve

(c) Non-IRRs without full-range Energy Offer Curves

- (i) For each non-IRR for which its QSE has submitted an Energy Offer Curve that does not cover the full range of the Resource's available capacity, ERCOT shall create a proxy Energy Offer Curve that extends the submitted Energy Offer Curve to use the entire available capacity of the Resource above the highest point on the Energy Offer Curve to the Resource's HSL and the offer floor from the lowest point on the Energy Offer Curve to its LSL, using these points:

MW	Price (per MWh)
HSL (if more than highest MW in submitted Energy Offer Curve)	Price associated with highest MW in submitted Energy Offer Curve
Energy Offer Curve	Energy Offer Curve

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1 MW below lowest MW in Energy Offer Curve (if more than LSL)	-\$249.99
LSL (if less than lowest MW in Energy Offer Curve)	-\$250.00

(d) IRRs

- (i) For each IRR that has not submitted an Energy Offer Curve, ERCOT shall create a monotonically increasing proxy Energy Offer Curve as described below:

MW	Price (per MWh)
HSL	\$1,500
HSL minus 1 MW	-\$249.99
LSL	-\$250.00

- (ii) For each IRR for which its QSE has submitted an Energy Offer Curve that does not cover the full range of the IRR's available capacity, ERCOT shall create a monotonically increasing proxy Energy Offer Curve as described below:

MW	Price (per MWh)
HSL (if more than highest MW in submitted Energy Offer Curve)	Price associated with the highest MW in submitted Energy Offer Curve
Energy Offer Curve	Energy Offer Curve
1 MW below lowest MW in Energy Offer Curve (if more than LSL)	-\$249.99
LSL (if less than lowest MW in Energy Offer Curve)	-\$250.00

(e) RUC-committed Resources

- (i) For each RUC-committed Resource that has not submitted an Energy Offer Curve, ERCOT shall create a proxy Energy Offer Curve as described below:

MW	Price (per MWh)
HSL	\$250

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Zero	\$250
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- (ii) For each RUC-committed Resource that has submitted an Energy Offer Curve, ERCOT shall create a monotonically increasing proxy Energy Offer Curve as described below:

MW	Price (per MWh)
HSL (if more than highest MW in Energy Offer Curve)	Greater of \$250 or price associated with the highest MW in QSE submitted Energy Offer Curve
Energy Offer Curve	Greater of \$250 or the QSE submitted Energy Offer Curve
Zero	Greater of \$250 or the first price point of the QSE submitted Energy Offer Curve

- (iii) For each Combined Cycle Generation Resource that was RUC-committed from one On-Line configuration in order to transition to a different configuration with additional capacity, as instructed by ERCOT, that has not submitted an Energy Offer Curve for the RUC-committed configuration, ERCOT shall create a proxy Energy Offer Curve as described below:

MW	Price (per MWh)
HSL of RUC-committed configuration	\$250
Zero	\$250

- (iv) For each Combined Cycle Generation Resource that was RUC-committed from one On-Line configuration in order to transition to a different configuration with additional capacity, as instructed by ERCOT, that has submitted an Energy Offer Curve for the RUC-committed configuration, ERCOT shall create a monotonically increasing proxy Energy Offer Curve as described below:

MW	Price (per MWh)
HSL of RUC-committed configuration (if more than highest MW in Energy Offer Curve)	Greater of \$250 or price associated with the highest MW in QSE submitted Energy Offer Curve

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Energy Offer Curve for MW at and above HSL of QSE-committed configuration	Greater of \$250 or the QSE submitted Energy Offer Curve
HSL of QSE-committed configuration (if more than highest MW in Energy Offer Curve and price associated with highest MW in Energy Offer Curve is less than \$250)	\$250
HSL of QSE-committed configuration (if more than highest MW in Energy Offer Curve)	Price associated with the highest MW in QSE submitted Energy Offer Curve
Energy Offer Curve for MW at and below HSL of QSE-committed configuration	The QSE submitted Energy Offer Curve
1 MW below lowest MW in Energy Offer Curve (if more than LSL)	-\$249.99
LSL (if less than lowest MW in Energy Offer Curve)	-\$250.00

- (5) The Entity with decision making authority, as more fully described in Section 3.19.1, Constraint Competitiveness Test Definitions, over how a Resource or Split Generation Resource is offered or scheduled, shall be responsible for all offers associated with each Resource, including offers represented by a proxy Energy Offer Curve.
- (6) For a CLR whose QSE has submitted an RTM Energy Bid that does not cover the full range of the Resource's available Demand response capability, consistent with the CLR's telemetered quantities, ERCOT shall create a proxy energy bid as described below:

MW	Price (per MWh)
LPC to MPC minus maximum MW of RTM Energy Bid	Price associated with the lowest MW in submitted RTM Energy Bid curve
MPC minus maximum MW of RTM Energy Bid to MPC	RTM Energy Bid curve

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MPC	Right-most point (lowest price) on RTM Energy Bid curve
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- (7) ERCOT shall ensure that any RTM Energy Bid is monotonically non-increasing. The QSE representing the CLR shall be responsible for all RTM Energy Bids, including bids updated by ERCOT as described above.
- (8) If a CLR telemeters a status of OUTL, it is not considered as dispatchable capacity by SCED. A QSE may use this function to inform ERCOT of instances when the CLR is unable to follow SCED Dispatch Instructions. Under all telemetered statuses including OUTL, the remaining telemetry quantities submitted by the QSE shall represent the operating conditions of the CLR that can be verified by ERCOT. A QSE representing a CLR with a telemetered status of OUTL is still obligated to provide any applicable Ancillary Service Resource Responsibilities previously awarded to that CLR. This paragraph does not apply to ESRs.
- (9) Energy Offer Curves that were constructed in whole or in part with proxy Energy Offer Curves shall be so marked in all ERCOT postings or references to the energy offer.
- (10) The two-step SCED methodology referenced in paragraph (1) above is:
 - (a) The first step is to execute the SCED process to determine Reference LMPs. In this step, ERCOT executes SCED using the full Network Operations Model while only observing limits of Competitive Constraints. Energy Offer Curves for all On-Line Generation Resources and RTM Energy Bids from available CLRs, whether submitted by QSEs or created by ERCOT under this Section, are used in the SCED to determine "Reference LMPs."
 - (b) The second step is to execute the SCED process to produce Base Points, Shadow Prices, and LMPs, subject to security constraints (including Competitive and Non-Competitive Constraints) and other Resource constraints. The second step must:
 - (i) Use Energy Offer Curves for all On-Line Generation Resources, whether submitted by QSEs or created by ERCOT. Each Energy Offer Curve must be bounded at the lesser of the Reference LMP (from Step 1) or the appropriate Mitigated Offer Floor. In addition, each Energy Offer Curve subject to mitigation under the criteria described in Section 3.19.4, Security-Constrained Economic Dispatch Constraint Competitiveness Test, must be capped at the greater of the Reference LMP (from Step 1) at the Resource Node plus a variable not to exceed 0.01 multiplied by the value of the Resource's Mitigated Offer Cap (MOC) curve at the LSL or the appropriate MOC;
 - (ii) Use RTM Energy Bid curves for all available CLRs, whether submitted by QSEs or created by ERCOT. There is no mitigation of RTM Energy Bids. An RTM Energy Bid from a CLR represents the bid for energy distributed across all nodes in the Load Zone in which the CLR is located. For an ESR, an RTM Energy Bid represents a bid for energy at the ESR's Resource Node; and

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- (iii) Observe all Competitive and Non-Competitive Constraints.
- (c) ERCOT shall archive information and provide monthly summaries of security violations and any binding transmission constraints identified in Step 2 of the SCED process. The summary must describe the limiting element (or identified operator-entered constraint with operator's comments describing the reason and the Resource-specific impacts for any manual overrides). ERCOT shall provide the summary to Market Participants on the MIS Secure Area and to the Independent Market Monitor (IMM).
- (11) For each SCED process, in addition to the binding Base Points and LMPs, ERCOT shall calculate a non-binding projection of the Base Points and Resource Node LMPs, Real-Time Reliability Deployment Price Adders, Real-Time On-Line Reserve Price Adders, Real-Time Off-Line Reserve Price Adders, Hub LMPs and Load Zone LMPs at a frequency of every five minutes for at least 15 minutes into the future based on the same inputs to the SCED process as described in this Section, except that the Resource's HDL and LDL and the total generation requirement will be as estimated at future intervals. The Resource's HDL and LDL will be calculated for each interval of the projection based on the ramp rate capability over the study period. ERCOT shall estimate the projected total generation requirement by calculating a Load forecast for the study period. In lieu of the steps described in Section 6.5.7.3.1, Determination of Real-Time On-Line Reliability Deployment Price Adder, the non-binding projection of Real-Time Reliability Deployment Price Adders shall be estimated based on GTBD, reliability deployments MWs, and aggregated offers. The Energy Offer Curve from SCED Step 2, the virtual offers for Load Resources deployed and the power balance penalty curve will be compared against the updated GTBD to get an estimate of the System Lambda from paragraph (2)(m) of Section 6.5.7.3.1. ERCOT shall post the projected non-binding Base Points for each Resource for each interval study period on the MIS Certified Area and the projected non-binding LMPs for Resource Nodes, Real-Time Reliability Deployment Price Adders, Real-Time On-Line Reserve Price Adders, Real-Time Off-Line Reserve Price Adders, Hub LMPs and Load Zone LMPs on the ERCOT website pursuant to Section 6.3.2, Activities for Real-Time Operations.
- (12) For each SCED process, ERCOT shall calculate a Real-Time On-Line Reserve Price Adder and a Real-Time Off-Line Reserve Price Adder based on the On-Line and Off-Line available reserves in the ERCOT System and the Operating Reserve Demand Curve (ORDC). The Real-Time Off-Line available reserves shall be administratively set to zero when the SCED snapshot of the Physical Responsive Capability (PRC) is equal to or below the PRC MW at which Energy Emergency Alert (EEA) Level 1 is initiated. In addition, for each SCED process, ERCOT shall calculate a Real-Time On-Line Reliability Deployment Price Adder. The sum of the Real-Time Reliability Deployment Price Adder and the Real-Time On-Line Reserve Price Adder shall be averaged over the 15-minute Settlement Interval and added to the Real-Time LMPs to determine the Real-Time Settlement Point Prices. The price after the addition of the sum of the Real-Time On-Line Reliability Deployment Price Adder and the Real-Time On-Line Reserve Price Adder to LMPs approximates the pricing outcome of the impact to energy prices from reliability deployments and the Real-Time energy and Ancillary Service co-optimization since the Real-Time On-Line Reserve Price Adder captures the value of the opportunity

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cost of reserves based on the defined ORDC. An Ancillary Service imbalance Settlement shall be performed pursuant to Section 6.7.5, Real-Time Ancillary Service Imbalance Payment or Charge, to make Resources indifferent to the utilization of their capacity for energy or Ancillary Service reserves.

- (13) ERCOT shall determine the methodology for implementing the ORDC to calculate the Real-Time On-Line Reserve Price Adder and Real-Time Off-Line Reserve Price Adder. Following review by TAC, the ERCOT Board shall review the recommendation and approve a final methodology. Within two Business Days following approval by the ERCOT Board, ERCOT shall post the methodology on the ERCOT website.
- (14) At the end of each season, ERCOT shall determine the ORDC for the same season in the upcoming year, based on historic data using the ERCOT Board-approved methodology for implementing the ORDC. Annually, ERCOT shall verify that the ORDC is adequately representative of the loss of Load probability for varying levels of reserves. Twenty days after the end of the Season, ERCOT shall post the ORDC for the same season of the upcoming year on the ERCOT website.
- (15) ERCOT may override one or more of a CLR's parameters in SCED if ERCOT determines that the CLR's participation is having an adverse impact on the reliability of the ERCOT System.
- (16) The QSE representing an ESR, in order to charge the ESR, must submit RTM Energy Bids, and the ESR may withdraw energy from the ERCOT System only when dispatched by SCED to do so. An ESR may telemeter a status of OUTL only if the ESR is in Outage status.

[NPRR930, NPRR1000, NPRR1010, NPRR1014, NPRR1019, NPRR1188, and NPRR1204: Replace applicable portions of Section 6.5.7.3 above with the following upon system implementation for NPRR930, NPRR1000, NPRR1014, NPRR1019, or NPRR1188; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010 and NPRR1204:]

6.5.7.3 Security Constrained Economic Dispatch

- (1) The SCED process is designed to simultaneously manage energy, Ancillary Services, the system power balance and network congestion through Resource Base Points, Ancillary Service awards, and the calculation of LMPs and Real-Time MCPCs approximately every five minutes, or more frequently if necessary. The SCED process uses a two-step methodology that applies mitigation to offers for energy prospectively to resolve Non-Competitive Constraints for the current Operating Hour. The SCED process evaluates Energy Offer Curves, Energy Bid/Offer Curves, Ancillary Service Offers, Output Schedules, and Energy Bid Curves to determine Resource Dispatch Instructions and Ancillary Service awards by maximizing bid-based revenues minus offer-based costs, subject to power balance, Ancillary Service Demand Curves (ASDCs), and network constraints. The SCED process uses the Resource Status provided by SCADA telemetry under Section 6.5.5.2, Operational Data Requirements, and validated by the Real-Time Sequence, instead of the Resource Status provided by the COP. In addition, the SCED process accounts for each ESR's State of Charge

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(SOC) and SOC operating limits. This is to ensure that the SCED process will issue ESR Base Points and Ancillary Services that are feasible taking into account SCED duration requirements for energy and Ancillary Services and also that do not violate the ESR's Minimum State of Charge (MinSOC) and Maximum State of Charge (MaxSOC) limits.

- (2) The SCED solution must monitor cumulative deployment of Regulation Services and ensure that Regulation Services deployment is minimized over time.
- (3) In the Generation To Be Dispatched (GTBD) determined by LFC, ERCOT shall subtract the sum of the telemetered net real power consumption from all CLRs available to SCED.
- (4) For use as SCED inputs for determining energy dispatch and Ancillary Service awards, ERCOT shall use the available capacity of all committed Generation Resources by creating proxy Energy Offer Curves for certain Resources as follows:
 - (a) Non-IRRs without Energy Offer Curves
 - (i) ERCOT shall create a monotonically increasing proxy Energy Offer Curve as described below for:
 - (A) Each non-IRR for which its QSE has submitted an Output Schedule instead of an Energy Offer Curve.

MW	Price (per MWh)
HSL	RTSWCAP
Output Schedule MW plus 1 MW	RTSWCAP minus \$0.01
Output Schedule MW	-\$249.99
LSL	-\$250.00

- (b) Non-IRRs without full-range Energy Offer Curves
 - (i) For each non-IRR for which its QSE has submitted an Energy Offer Curve that does not cover the full range of the Resource's available capacity, ERCOT shall create a proxy Energy Offer Curve that extends the submitted Energy Offer Curve to use the entire available capacity of the Resource above the highest point on the Energy Offer Curve to the Resource's HSL and the offer floor from the lowest point on the Energy Offer Curve to its LSL, using these points:

MW	Price (per MWh)
HSL (if more than highest MW in submitted Energy Offer Curve)	Price associated with highest MW in

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	submitted Energy Offer Curve
Energy Offer Curve	Energy Offer Curve
1 MW below lowest MW in Energy Offer Curve (if more than LSL)	-\$249.99
LSL (if less than lowest MW in Energy Offer Curve)	-\$250.00

(c) IRRs

- (i) For each IRR that has not submitted an Energy Offer Curve, ERCOT shall create a monotonically increasing proxy Energy Offer Curve as described below:

MW	Price (per MWh)
HSL	\$1,500
HSL minus 1 MW	-\$249.99
LSL	-\$250.00

- (ii) For each IRR for which its QSE has submitted an Energy Offer Curve that does not cover the full range of the IRR's available capacity, ERCOT shall create a monotonically increasing proxy Energy Offer Curve as described below:

MW	Price (per MWh)
HSL (if more than highest MW in submitted Energy Offer Curve)	Price associated with the highest MW in submitted Energy Offer Curve
Energy Offer Curve	Energy Offer Curve
1 MW below lowest MW in Energy Offer Curve (if more than LSL)	-\$249.99
LSL (if less than lowest MW in Energy Offer Curve)	-\$250.00

(d) RUC-committed Resources

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- (i) For each RUC-committed Resource that has not submitted an Energy Offer Curve, ERCOT shall create a proxy Energy Offer Curve as described below:

MW	Price (per MWh)
HSL	\$250
Zero	\$250

- (ii) For each RUC-committed Resource that has submitted an Energy Offer Curve, ERCOT shall create a monotonically increasing proxy Energy Offer Curve as described below:

MW	Price (per MWh)
HSL (if more than highest MW in Energy Offer Curve)	Greater of \$250 or price associated with the highest MW in QSE submitted Energy Offer Curve
Energy Offer Curve	Greater of \$250 or the QSE submitted Energy Offer Curve
Zero	Greater of \$250 or the first price point of the QSE submitted Energy Offer Curve

- (iii) For each RUC-committed Resource during the time period stated in the Advance Action Notice (AAN) if any Resource received an Outage Schedule Adjustment, ERCOT shall create a proxy Energy Offer Curve as described below:

MW	Price (per MWh)
HSL	\$4,500 or the effective Value of Lost Load (VOLL), whichever is less.
Zero	\$4,500 or the effective VOLL, whichever is less.

- (iv) For each Combined Cycle Generation Resource that was RUC-committed from one On-Line configuration in order to transition to a

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different configuration with additional capacity, as instructed by ERCOT, that has not submitted an Energy Offer Curve for the RUC-committed configuration, ERCOT shall create a proxy Energy Offer Curve as described below:

MW	Price (per MWh)
HSL of RUC-committed configuration	\$250
Zero	\$250

- (v) For each Combined Cycle Generation Resource that was RUC-committed from one On-Line configuration in order to transition to a different configuration with additional capacity, as instructed by ERCOT, that has submitted an Energy Offer Curve for the RUC-committed configuration, ERCOT shall create a monotonically increasing proxy Energy Offer Curve as described below:

MW	Price (per MWh)
HSL of RUC-committed configuration (if more than highest MW in Energy Offer Curve)	Greater of \$250 or price associated with the highest MW in QSE submitted Energy Offer Curve
Energy Offer Curve for MW at and above HSL of QSE-committed configuration	Greater of \$250 or the QSE submitted Energy Offer Curve
HSL of QSE-committed configuration (if more than highest MW in Energy Offer Curve and price associated with highest MW in Energy Offer Curve is less than \$250)	\$250
HSL of QSE-committed configuration (if more than highest MW in Energy Offer Curve)	Price associated with the highest MW in QSE submitted Energy Offer Curve
Energy Offer Curve for MW at and below HSL of QSE-committed configuration	The QSE submitted Energy Offer Curve

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1 MW below lowest MW in Energy Offer Curve (if more than LSL)	-\$249.99
LSL (if less than lowest MW in Energy Offer Curve)	-\$250.00

- (vi) For each RUC-committed Switchable Generation Resource (SWGR) that is not part of a Combined Cycle Train already operating in ERCOT, that has not submitted an Energy Offer Curve, and that has a COP Resource Status of EMRSWGR for the instructed Operating Hour at the time of the RUC instruction, ERCOT shall create a proxy Energy Offer Curve as described below:

MW	Price (per MWh)
HSL	\$4,500 or the effective Value of Lost Load (VOLL), whichever is less
Zero	\$4,500 or the effective VOLL, whichever is less

- (vii) For each RUC-committed SWGR that is not part of a Combined Cycle Train already operating in ERCOT, that has submitted an Energy Offer Curve, and that has a COP Resource Status of EMRSWGR for the instructed Operating Hour at the time of the RUC instruction, ERCOT shall create a proxy Energy Offer Curve as described below:

MW	Price (per MWh)
HSL (if more than highest MW in Energy Offer Curve)	Greater of: \$4,500 or the effective VOLL, whichever is less; and the price associated with the highest MW in QSE-submitted Energy Offer Curve
Energy Offer Curve	Greater of: \$4,500 or the effective VOLL, whichever is less; and the QSE-submitted Energy Offer Curve

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Zero	Greater of: \$4,500 or the effective VOLL, whichever is less; and the first price point of the QSE-submitted Energy Offer Curve
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- (viii) For each Combined Cycle Train configuration that includes at least one SWGR that is operating in a non-ERCOT Control Area as part of a configuration with a COP Resource Status of EMRSWGR for the instructed Operating Hour at the time of a RUC instruction requiring the switching of the SWGR into the ERCOT Control Area, if the QSE for the Combined Cycle Train has not submitted an Energy Offer Curve for the RUC-committed configuration, ERCOT shall create a proxy Energy Offer Curve as described below:

MW	Price (per MWh)
HSL of RUC-committed configuration	\$4,500 or the effective VOLL, whichever is less
Zero	\$4,500 or the effective VOLL, whichever is less

- (ix) For each Combined Cycle Train configuration that includes at least one SWGR that is operating in a non-ERCOT Control Area as part of a configuration with a COP Resource Status of EMRSWGR for the instructed Operating Hour at the time of a RUC instruction requiring the switching of the SWGR into the ERCOT Control Area, if the QSE for the Combined Cycle Train has submitted an Energy Offer Curve for the RUC-committed configuration, ERCOT shall create a proxy Energy Offer Curve as described below:

MW	Price (per MWh)
HSL of RUC-committed configuration (if more than highest MW in Energy Offer Curve)	Greater of: \$4,500 or the effective VOLL, whichever is less; and the price associated with the highest MW in QSE-submitted Energy Offer Curve
Energy Offer Curve for MW at and above HSL of QSE-committed configuration	Greater of: \$4,500 or the effective VOLL, whichever is less; and the QSE-

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	submitted Energy Offer Curve
HSL of QSE-committed configuration (if more than highest MW in Energy Offer Curve and price associated with highest MW in Energy Offer Curve is less than \$4,500)	\$4,500 or the effective VOLL, whichever is less
HSL of QSE-committed configuration (if more than highest MW in Energy Offer Curve)	Price associated with the highest MW in QSE-submitted Energy Offer Curve
Energy Offer Curve for MW at and below HSL of QSE-committed configuration	The QSE-submitted Energy Offer Curve
1 MW below lowest MW in Energy Offer Curve (if more than LSL)	-\$249.99
LSL (if less than lowest MW in Energy Offer Curve)	-\$250.00

- (5) For use as SCED inputs for determining energy dispatch and Ancillary Service awards, ERCOT shall use the available Ancillary Service MW capacity of all Resources by creating a proxy Ancillary Service Offer for qualified Resources as follows:
- (a) The proxy Ancillary Service Offer shall be a linked Ancillary Service Offer across all Ancillary Service products for which a Resource is qualified to provide. For Generation Resources, the proxy Ancillary Service Offer MW shall be equal to the Resource's telemetered HSL. For ESRs, the proxy Ancillary Service Offer MW shall be equal to the difference between the Resource's telemetered HSL and LSL. For Load Resources, the proxy Ancillary Service Offer MW shall be equal to the Resource's telemetered Maximum Power Consumption (MPC).
 - (b) For Resources that are not RUC-committed, the price in the proxy Ancillary Service Offer shall be set to:
 - (i) For Reg-Up and RRS, the maximum of:
 - (A) The proxy Ancillary Service Offer price floor for Reg-Up or RRS, respectively;

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- (B) The Resource's highest submitted Ancillary Service Offer price for Reg-Up or RRS, respectively;
 - (C) The Resource's highest Ancillary Service Offer price for ECRS (submitted or proxy); or
 - (D) The Resource's highest Ancillary Service Offer price for Non-Spin (submitted or proxy).
- (ii) For ECRS, the maximum of:
 - (A) The proxy Ancillary Service Offer price floor for ECRS;
 - (B) The Resource's highest submitted Ancillary Service Offer price for ECRS; or
 - (C) The Resource's highest Ancillary Service Offer price for Non-Spin (submitted or proxy).
- (iii) For Non-Spin, the maximum of:
 - (A) The proxy Ancillary Service Offer price floor for Non-Spin; or
 - (B) The Resource's highest submitted Ancillary Service Offer price for Non-Spin.
- (iv) For Reg-Down, the maximum of:
 - (A) The proxy Ancillary Service Offer price floor for Reg-Down; or
 - (B) The Resource's highest submitted Ancillary Service Offer price for Reg-Down.
- (c) ERCOT systems shall be designed to allow for proxy Ancillary Service Offer price floors to differ when the same Ancillary Service product can be provided by either On-Line or Off-Line Resources, and/or an Ancillary Service product has sub-types.
- (d) Proxy Ancillary Service Offer price floors shall be approved by TAC and posted on the ERCOT website.
- (e) For RUC-committed Resources:
 - (i) If a RUC-committed Resource does not have an Ancillary Service Offer for an Ancillary Service product that the Resource is qualified to provide, ERCOT shall create an Ancillary Service Offer for that Ancillary Service product at a value of \$250/MWh for the full operating range of the Resource up to its telemetered HSL.
 - (ii) For each Ancillary Service product for which a RUC-committed Resource has an Ancillary Service Offer, the Ancillary Service Offer used by SCED for that Ancillary Service product across the full operating range of the Resource up to its telemetered HSL shall be the maximum of:

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- (A) The Resource's highest submitted Ancillary Service Offer price;
or
- (B) \$250/MWh.
- (6) For use as SCED inputs for determining energy Dispatch and Ancillary Service awards, ERCOT shall use the available capacity of all On-Line ESRs by creating proxy Energy Bid/Offer Curves for certain Resources as follows:
- (a) For each ESR for which its QSE has submitted an Energy Bid/Offer Curve that does not cover the full offer range (LSL to HSL) of the Resource's available capacity, ERCOT shall create a proxy Energy Bid/Offer Curve that extends the submitted Energy Bid/Offer Curve to use the entire available capacity of the Resource above the highest MW point on the Energy Bid/Offer Curve to the Resource's HSL and from the lowest MW point on the Energy Bid/Offer Curve to LSL, using these prices for the corresponding MW segments:

Scenario	MW Segment	Price (per MWh)
HSL MW and the highest MW point on the Energy Bid/Offer are both greater than or equal to zero, and, HSL is greater than the highest MW in submitted Energy Bid/Offer Curve	From highest MW point on submitted Energy Bid/Offer Curve to HSL MW	RTSWCAP
HSL MW is greater than or equal to zero, and, the highest MW point on the Energy Bid/Offer is less than zero	From highest MW point on submitted Energy Bid/Offer Curve to 0 MW From 0 MW to HSL	Price associated with the highest MW in submitted Energy Bid/Offer Curve RTSWCAP
HSL is less than zero and is also greater than the highest MW in submitted Energy Bid/Offer Curve	From highest MW point on submitted Energy Bid/Offer Curve to HSL MW	Price associated with the highest MW in submitted Energy Bid/Offer Curve
Energy Bid/Offer Curve		Energy Bid/Offer Curve
LSL MW and the lowest MW point on the Energy Bid/Offer Curve are both greater than or equal to zero, and,	From LSL to lowest MW point on submitted Energy Bid/Offer Curve	Price associated with the lowest MW in submitted Energy Bid/Offer Curve

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LSL is less than the lowest MW in submitted Energy Bid/Offer Curve		
LSL MW is less than zero, and, the lowest MW point on the Energy Bid/Offer Curve is greater than zero	From LSL to 0 MW From 0 MW to lowest MW point on submitted Energy Bid/Offer Curve	-\$250.00 Price associated with the lowest MW in submitted Energy Bid/Offer Curve
LSL and the lowest MW point on the Energy Bid/Offer Curve are both less than or equal to zero, and, LSL is less than the lowest MW point on the Energy Bid/Offer Curve	From LSL to lowest MW point on submitted Energy Bid/Offer Curve	-\$250.00

(b) At the time of SCED execution, if a valid Energy Bid/Offer Curve or Output Schedule does not exist for an ESR that has a status of On-Line, then ERCOT shall notify the QSE and create a proxy Energy Bid/Offer Curve priced at -\$250/MWh for the MW portion of the curve less than zero MW, and priced at the RTSWCAP for the MW portion of the curve greater than zero MW.

(c) At the time of SCED execution, if a QSE representing an ESR has submitted an Output Schedule instead of an Energy Bid/Offer Curve, ERCOT shall create a proxy Energy Bid/Offer Curve priced at -\$250/MWh for the MW portion of the curve from its LSL to the MW amount on the Output Schedule, and priced at the RTSWCAP for the MW portion of the curve from the MW amount on the Output Schedule to its HSL.

(7) The Entity with decision-making authority, as more fully described in Section 3.19.1, Constraint Competitiveness Test Definitions, over how a Resource or Split Generation Resource is offered or scheduled, shall be responsible for all offers associated with each Resource, including offers represented by a proxy Energy Offer Curve, proxy Energy Bid/Offer Curve, or proxy Ancillary Service Offer.

(8) For a CLR whose QSE has submitted an Energy Bid Curve that does not cover the full range of the Resource’s available Demand response capability, consistent with the CLR’s telemetered quantities, ERCOT shall create a proxy energy bid as described below:

MW	Price (per MWh)
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LPC to MPC minus maximum MW of Energy Bid Curve	Price associated with the lowest MW in submitted Energy Bid Curve
MPC minus maximum MW of Energy Bid Curve to MPC	Energy Bid Curve
MPC	Right-most point (lowest price) on Energy Bid Curve

- (9) For a CLR whose QSE has not submitted an Energy Bid Curve, consistent with the CLR's telemetered quantities, ERCOT shall create a proxy Energy Bid Curve as described below:

MW	Price (per MWh)
LPC to MPC	SWCAP

- (10) ERCOT shall ensure that any Energy Bid Curve is monotonically non-increasing. The QSE representing the CLR shall be responsible for all Energy Bid Curves, including Energy Bid Curves updated by ERCOT as described above.
- (11) A CLR may consume energy only when dispatched by SCED to do so. A CLR may telemeter a status of OUTL only if the Resource is Off-Line and unavailable with its energy consumption at zero. In instances when the CLR is unable to follow SCED Dispatch Instructions but still consumes energy, the CLR must submit a Resource Status of ONHOLD. Under all telemetered statuses, including OUTL, the remaining telemetry quantities submitted by the QSE shall represent the operating conditions of the CLR that can be verified by ERCOT. A QSE representing a CLR with a telemetered status of OUTL or ONHOLD is still obligated to provide any applicable Ancillary Services awarded to the Resource. This paragraph does not apply to ESRs.
- (12) Energy Offer Curves that were constructed in whole or in part with proxy Energy Offer Curves shall be so marked in all ERCOT postings or references to the energy offer.
- (13) SCED will enforce Resource-specific Ancillary Service constraints to ensure that Ancillary Service awards are aligned with a Resource's qualifications and telemetered Ancillary Service capabilities.
- (14) Energy Bid/Offer Curves that were constructed in whole or in part with proxy Energy Bid/Offer Curves shall be so marked in all ERCOT postings or references to the energy bid/offer.
- (15) The two-step SCED methodology referenced in paragraph (1) above is:
- (a) The first step is to execute the SCED process to determine Reference LMPs. In this step, ERCOT executes SCED using the full Network Operations Model while only observing limits of Competitive Constraints in addition to power

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balance and Ancillary Service constraints. Energy Offer Curves for all On-Line Generation Resources, Energy Bid/Offer Curves for all On-Line ESRs, and Energy Bid Curves from available CLRs, whether submitted by QSEs or created by ERCOT under this Section, are used in the SCED to determine “Reference LMPs.”

- (b) The second step is to execute the SCED process to produce Base Points, Ancillary Service awards, Shadow Prices, Real-Time MCPCs, and LMPs, subject to security constraints (including Competitive and Non-Competitive Constraints) and other Resource constraints. The second step must:
 - (i) Use Energy Offer Curves for all On-Line Generation Resources, whether submitted by QSEs or created by ERCOT. Each Energy Offer Curve must be bounded at the lesser of the Reference LMP (from Step 1) or the appropriate Mitigated Offer Floor. In addition, each Energy Offer Curve subject to mitigation under the criteria described in Section 3.19.4, Security-Constrained Economic Dispatch Constraint Competitiveness Test, must be capped at the greater of the Reference LMP (from Step 1) at the Resource Node plus a variable not to exceed 0.01 multiplied by the value of the Resource’s Mitigated Offer Cap (MOC) curve at the LSL or the appropriate MOC;
 - (ii) Use Energy Bid/Offer Curves for all On-Line ESRs, whether submitted by QSEs or created by ERCOT. Each Energy Bid/Offer Curve must be bounded at the lesser of the Reference LMP (from Step 1) or the appropriate Mitigated Offer Floor. The offer portion of each Energy Bid/Offer Curve subject to mitigation under the criteria described in Section 3.19.4, Security-Constrained Economic Dispatch Constraint Competitiveness Test, must be capped at the greater of the Reference LMP (from Step 1) at the Resource Node plus a variable not to exceed 0.01 multiplied by the value of the Resource’s MOC curve at the LSL or the appropriate MOC;
 - (iii) Use Energy Bid Curves for all available CLRs, whether submitted by QSEs or created by ERCOT. There is no mitigation of Energy Bid Curves. An Energy Bid Curve from an Aggregate Load Resource (ALR) represents the bid for energy distributed across all nodes in the Load Zone in which the ALR is located. For an ESR or a CLR that is not an ALR, an Energy Bid Curve represents a bid for energy at the applicable Resource Node;
 - (iv) Observe all Competitive and Non-Competitive Constraints; and
 - (v) Use Ancillary Service Offers to determine Ancillary Service awards.
- (c) ERCOT shall archive information and provide monthly summaries of security violations and any binding transmission constraints identified in Step 2 of the SCED process. The summary must describe the limiting element (or identified operator-entered constraint with operator’s comments describing the reason and the Resource-specific impacts for any manual overrides). ERCOT shall

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provide the summary to Market Participants on the MIS Secure Area and to the Independent Market Monitor (IMM).

- (d) The System Lambda used to determine LMPs and the Real-Time MCPCs from SCED Step 2 shall be capped at the effective VOLL.
- (16) For each SCED process, in addition to the binding Base Points, Ancillary Service awards, Real-Time MCPCs, and LMPs, ERCOT shall calculate a non-binding projection of the Base Points, Ancillary Service awards, MCPCs, Resource Node LMPs, Real-Time Reliability Deployment Price Adders, Hub LMPs, and Load Zone LMPs at a frequency of every five minutes for at least 15 minutes into the future based on the same inputs to the SCED process as described in this Section, except that the Resource's HDL and LDL and the total generation requirement will be as estimated at future intervals. The Resource's HDL and LDL will be calculated for each interval of the projection based on the ramp rate capability over the study period. ERCOT shall estimate the projected total generation requirement by calculating a Load forecast for the study period. In lieu of the steps described in Section 6.5.7.3.1, Determination of Real-Time Reliability Deployment Price Adders, the non-binding projection of Real-Time Reliability Deployment Price Adders shall be estimated based on GTBD, reliability deployments MWs, and aggregated offers. The Energy Offer Curve and Energy Bid/Offer Curves from SCED Step 2, the virtual offers for Load Resources deployed and the power balance penalty ~~pricecurve~~ will be compared against the updated GTBD to get an estimate of the System Lambda from paragraph (2)(m) of Section 6.5.7.3.1. ERCOT shall post the projected non-binding Base Points and Ancillary Service awards for each Resource for each interval study period on the MIS Certified Area and the projected non-binding LMPs for Resource Nodes, Real-Time MCPCs, Real-Time Reliability Deployment Price Adders, Hub LMPs and Load Zone LMPs on the ERCOT website pursuant to Section 6.3.2, Activities for Real-Time Operations.
- (17) ERCOT may override one or more of a CLR's parameters in SCED if ERCOT determines that the CLR's participation is having an adverse impact on the reliability of the ERCOT System.
- (18) The QSE representing an ESR may withdraw energy from the ERCOT System only when dispatched by SCED to do so. An ESR may telemeter a status of OUT only if the ESR is in Outage status.

ERCOT Nodal Protocols

Section 22

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

~~October 2, 2024~~TBD

1. Purpose

Section 6.5.7.1.11, Transmission Network and Power Balance Constraint Management, requires the 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, 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 (RTM) in the cases of constraint violations.

This Attachment describes:

- the 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 PUCT-approved Shadow Price caps and their effective date.

2. Background Discussion

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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

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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:

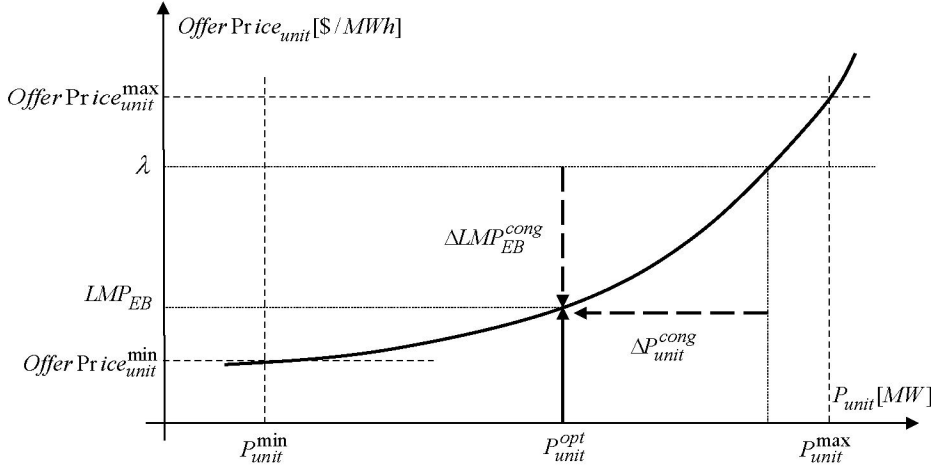
$$Offer Price_{unit}(P_{unit}^{opt}) = LMP_{EB}.$$

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:

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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}^{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 ΔLMP_{max}^{cong} directly limits the transmission congestion costs:

$$C_{cost}^{cong} = \sum_{unit} \Delta LMP_{max}^{cong_{unit}^{opt}}.$$

The efficiency of generating unit contribution can be determined by maximal value of LMP congestion component ΔLMP_{max}^{cong} (say \$500/MWh). The maximal Shadow Price for

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transmission constraint can be established by Shift Factor efficiency threshold and maximal LMP congestion component as follows:

$$SP_{max}^{congest_{threshold}^{efficiency}}$$

The maximal unit power output adjustment ΔP_{max}^{cong} will be determined by condition:

$$Offer Price_{unit}(P_{unit} - \Delta P_{max}^{congest_{threshold}^{efficiency}})$$

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.

[NPRR1246: Replace the paragraph above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

Some generating units (Generation Resources and Energy Storage Resources (ESRs)) 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.

[NPRR1246: Replace the paragraph above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

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 (Generation Resources and ESRs) participating in the management of congestion on the constraint. I.e. Generation Resources and ESRs with a Shift Factor above the cut off will have to be moved more to account for the increase in overload caused by

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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 Energy Management System (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 $SF_{threshold}^{efficiency}$ (default x%)
- (b) Determine maximal LMP congestion component ΔLMP_{max}^{cong} (default \$/MWh)
- (c) Calculate maximal Shadow Price for transmission constraints:
 $SP_{max}^{cong_{threshold}^{efficiency}}$
- (d) Determine Shift Factor cutoff threshold $SF_{threshold}^{cutoff}$ (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 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 (GTC) Shadow Price Caps in SCED

- Base Case/Voltage Violation: \$5,251/MW
- N-1 Constraint Violation
 - Greater than 200 kV: \$4,500/MW

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- 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

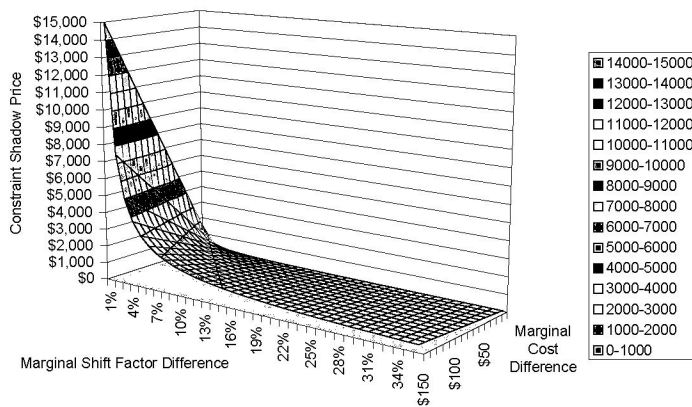


Figure 1

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 attachment, 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.

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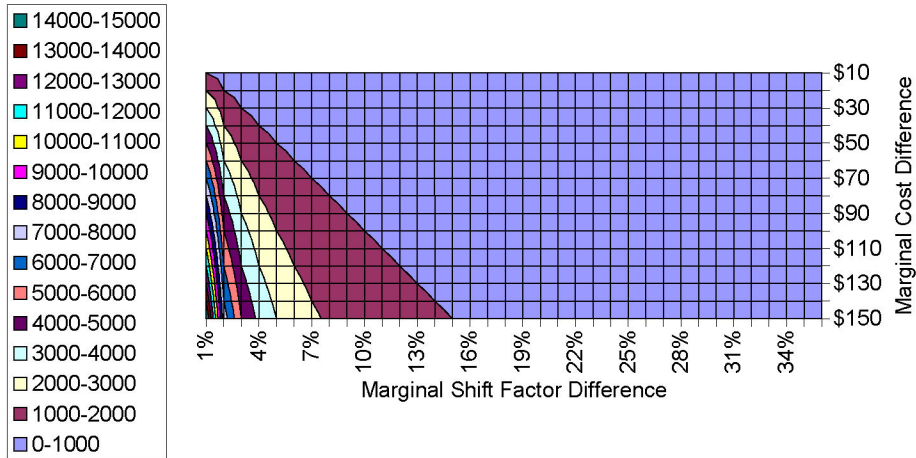


Figure 2

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%.

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- 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.

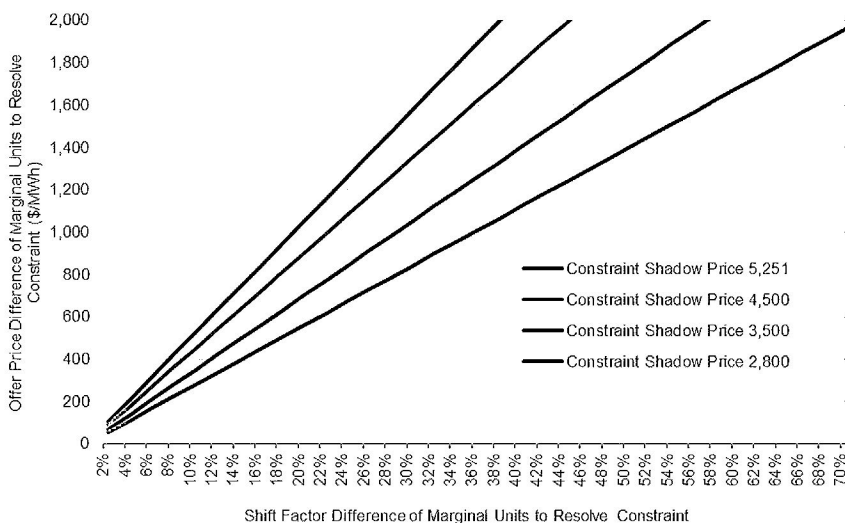


Figure 3

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.

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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 SWCAP 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 SWCAP than hubs or load zones, but it is possible that hub or load zone prices could exceed the SWCAP. 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 SWCAPs 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

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Section 6.5.7.1.10, Network Security Analysis Processor and Security Violation Alarm.

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 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.

[NPRR1246: Replace the paragraph above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

ERCOT Operations is required to resolve security violations on the ERCOT Grid as described in 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 and Energy Storage Resources (ESRs), 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 and ESR 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

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The methodology for determining and resolving an insecure state within SCED is defined in 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 described below).

[NPRR1246: Replace the paragraph above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

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 and/or ESRs:

- C. The Generation Resource or ESR with the lowest absolute value of the negative shift factor impact on the violated constraint (this resource is referred as Resource C in the Shadow Price Cap calculation below); and,
- D. The Generation Resource or ESR with the highest absolute value of the negative shift factor on the violated constraint (this resource is referred to as Resource D in the designation of the net margin Settlement Point Price 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.

[NPRR1246: Replace the paragraph above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

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When determining Resources C and D above, ERCOT shall ignore all Generation Resources and ESRs 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 (MOC) for Generation Resource C, as determined above, divided by the absolute value of its shift factor impact on the constraint or \$2000 per MW.

[NPRR1246: Replace paragraph (F) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

- F. The Maximum of the either the largest value of the Mitigated Offer Cap (MOC) for 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:

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- G. The Maximum of either the largest value of the MOC 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.

[NPRR1246: Replace paragraph (G) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

- G. The Maximum of either the largest value of the MOC for 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 (RAPs) or Temporary Outage Action Plans (TOAPs) 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,

[NPRR1246: Replace the paragraph above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

- Again determine Resource C and D, as described in item C and D above; and,

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- 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 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 Independent Market Monitor (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 Settlement Point Price. This Settlement Point Price is unique to each SCED irresolvable constraint.

[NPRR1246: Replace paragraph (1) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

1. The Settlement Point Price at the Resource Node for 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 Settlement Point Price. This Settlement Point Price 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 $\frac{1}{4}$ times the Maximum of either zero or that constraint's (net margin reference Settlement Point Price – 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 (FIP) as defined in 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.

3.7 Methodology for Setting Transmission Shadow Price Caps for an IROL in SCED

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Upon implementation of an Interconnection Reliability Operating Limit (IROL), the shadow price cap of an IROL shall be set by ERCOT to A, below. If ERCOT, in its sole discretion, determines that A, below, is insufficient for SCED to manage an IROL, ERCOT shall use B, below, to determine the shadow price cap:

- A. The value of the Generic Transmission Shadow Price Cap for Base Case constraints, as set in subsection 3.5, Generic Values for the Transmission Network System-Wide Shadow Price Caps in SCED, above; or
- B. ~~The power balance penalty price maximum price value on the Power Balance Penalty Curve~~ minus the mitigated offer floor for Resource H, as determined below, divided by Resource H's Shift Factor impact to the constraint.

ERCOT shall include the shadow price cap for each IROL in the associated Generic Transmission Constraint (GTC) Methodology posted pursuant to Section 3.10.7.6, Use of Generic Transmission Constraints and Generic Transmission Limits.

To determine Resource H, ERCOT shall identify all Generation Resources and Energy Storage Resource (ESRs) with positive Shift Factors not lower than 10% relative to the IROL and calculate the difference between the Seasonal net max sustainable rating ("seasonal High Sustained Limit (HSL)") and the Seasonal net min sustainable rating ("seasonal Low Sustained Limit (LSL)") for each Resource in effect at the time of the calculation. Starting with the Generation Resource or ESR with the highest positive Shift Factor, ERCOT will sum the differences between seasonal HSL and seasonal LSL until the sum is greater than or equal to the MW value that, if divided by 0.1 Hz, would equal the ERCOT System frequency bias ("bias MW value"). Resource H shall be the Generation Resource or ESR that results in this sum being greater than or equal to the bias MW value. If the sum of differences between the current seasonal HSL and seasonal LSL is not greater than or equal to the bias MW value, then Resource H will be the Generation Resource or ESR with the lowest positive shift factor not lower than 10%.

The shadow price cap and the Resource identified as Resource H for all applicable IROLs may be updated at any time based on ERCOT's review and shall be reviewed by ERCOT at least annually. Any updates to IROL shadow price caps will be communicated through a Market Notice at least 30 days prior to becoming effective.

When the shadow price cap for an IROL is determined based on the process in B, above, then the process outlined in Section 3.6, Methodology for Setting Transmission Shadow Price Caps for Irresolvable Constraints in SCED, does not apply to the IROL.

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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 LMP 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 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.

[JOBDRR020 and NPRR1246: 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 LMP at each Settlement Point in ERCOT. The Power Balance Penalty sets the maximum limit for this

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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 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 Energy Storage Resources (ESRs) and procures Ancillary Services by minimizing this objective function within the Resource 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 and ESRs becomes higher than the cost of violating the Power Balance constraint, SCED ceases the re-dispatch of the Generation Resources and ESRs 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 \$4,052~~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 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

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- 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 HDLs 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 LDLs 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, Load Frequency Control (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 Ancillary Service and the cost to the Load Serving Entities (LSEs). 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 HDL and a 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

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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 Qualified Scheduling Entity (QSE) for its Generation Resources subject to the following. A proxy EOC is created in the SCED process if the QSE submitted EOC does not extend from LSL to HSL (in this case SCED extends the submitted EOC as described in 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.

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[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.

<i>MW Violation</i>	<i>Penalty Value (\$/MWh)</i>
≤ 5	250
$5 < \text{to} \leq 10$	300
$10 < \text{to} \leq 20$	400
$20 < \text{to} \leq 30$	500
$30 < \text{to} \leq 40$	1,000
$40 < \text{to} \leq 50$	2,250
$50 < \text{to} \leq 100$	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

<i>MW Violation</i>	<i>Penalty Value (\$/MWh)</i>
$< 100,000$	-250

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

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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 Shift Factor to the violated constraints if there are no other resources available.

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- (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.

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

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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 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 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.

[JOBDRR020 and NPRR1246: 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 Resource 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 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

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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

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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

[JOBDRR020: 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

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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

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

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hence for it to dispatch reasonable offers, the Power Balance Penalty Factor need only be in the order of the energy offer cost.

[NPRR1246: Replace the paragraph above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

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 and Energy Storage (ESR) 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 Ancillary Service, as specified in the Ancillary Service Plan, and the amount of the self-arranged AS. The value of the Ancillary Service penalty factors are chosen to allow the selection of Ancillary Service offers that result in the least amount of deficit considering the maximum Ancillary Service penalty factors referenced in Appendix 2, Table 2-1 for each given Ancillary Service over the Operating Day and to assign a priority to the Ancillary Service constraints relative to the enforcement of the Power Balance and Network Transmission constraints. Additionally, the increasing penalty cost structure from Non-Spinning Reserve (Non-Spin) Ancillary Service to Regulation Ancillary Service prioritizes the DAM Ancillary Service 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 Ancillary Service penalty factors are not used to set the Market Clearing Price for Capacity (MCPC) for each Ancillary Service. Instead, the infeasible Ancillary Service requirement amounts are reduced to the feasible level and the DAM clearing is rerun so that the price of the last Ancillary Service awarded MW sets the MCPC for each Ancillary Service. The Ancillary Service penalty factors used in DAM are also used in the Supplemental Ancillary Services Market (SASM) engine.

[JOBDRR020: Delete Section 2.2 above upon system implementation of the Real-Time Co-Optimization (RTC) project and renumber accordingly.]

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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 Ancillary Service 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.

[JOBDRR020: 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

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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>1268</u>	NPRR Title	RTC – Modification of Ancillary Service Demand Curves
Impact Analysis Date	March 18, 2025		
Estimated Cost/Budgetary Impact	None.		
Estimated Time Requirements	No project required. This Nodal Protocol Revision Request (NPRR) can take effect upon implementation of PR447, Real-Time Co-Optimization (RTC). See Comments.		
ERCOT Staffing Impacts (across all areas)	Ongoing Requirements: No impacts to ERCOT staffing.		
ERCOT Computer System Impacts	No impacts to ERCOT computer systems.		
ERCOT Business Function Impacts	No impacts to ERCOT business functions.		
Grid Operations & Practices Impacts	No impacts to ERCOT grid operations and practices.		

Evaluation of Interim Solutions or Alternatives for a More Efficient Implementation

None offered.

Comments

There are no additional impacts to this NPRR beyond what was captured in PR447, Real-Time Co-optimization.

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NPRR Number	<u>1269</u>	NPRR Title	RTC+B Three Parameters Policy Issues
Date of Decision	April 8, 2025		
Action	Recommended Approval		
Timeline	Urgent		
Estimated Impacts	Cost/Budgetary: None Project Duration: No project required		
Proposed Effective Date	Upon system implementation of PR447, Real-Time Co-Optimization (RTC)		
Priority and Rank Assigned	Not applicable		
Nodal Protocol Sections Requiring Revision	4.4.12, Determination of Ancillary Service Demand Curves for the Day-Ahead Market and Real-Time Market 5.5.2, Reliability Unit Commitment (RUC) Process 6.5.7.3, Security Constrained Economic Dispatch		
Related Documents Requiring Revision/Related Revision Requests	None		
Revision Description	<p>This Nodal Protocol Revision Request (NPRR) determines and codifies a group of policy changes that were deferred from the original RTC-related Protocols developed in 2020.</p> <p>The three policy concepts below have been developed in coordination with the Real-Time Co-optimization plus Batteries Task Force (RTCBTF):</p> <ul style="list-style-type: none"> - Parameters for Ancillary Service proxy offers floors; - Scaling factor values for ramping; and - Ancillary Service Demand Curves (ASDCs) for use in Reliability Unit Commitment (RUC) studies. 		
Reason for Revision	<input type="checkbox"/> <u>Strategic Plan</u> Objective 1 – Be an industry leader for grid reliability and resilience <input type="checkbox"/> <u>Strategic Plan</u> Objective 2 - Enhance the ERCOT region's economic competitiveness with respect to trends in wholesale power rates and retail electricity prices to consumers		

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	<p><input type="checkbox"/> <u>Strategic Plan</u> 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</p> <p><input checked="" type="checkbox"/> General system and/or process improvement(s)</p> <p><input type="checkbox"/> Regulatory requirements</p> <p><input type="checkbox"/> ERCOT Board/PUCT Directive</p> <p><i>(please select ONLY ONE – if more than one apply, please select the ONE that is most relevant)</i></p>
Justification of Reason for Revision and Market Impacts	<p>The RTCBTF has reviewed the NPRR language and there was no opposition to moving this forward into the formal stakeholder process. However, some of the details are still under review at the RTCBTF and all other stakeholder feedback is welcome. The goal for this NPRR is to be recommended for approval at the March 2025 Protocol Revision Subcommittee (PRS) meeting, March 2025 Technical Advisory Committee (TAC) meeting and April 2025 ERCOT Board of Directors (ERCOT Board) meeting; to support the May 2025 market trial activities.</p>
PRS Decision	<p>On 2/12/25, PRS voted unanimously to table NPRR1269. All Market Segments participated in the vote.</p> <p>On 3/12/25, PRS voted to grant NPRR1269 Urgent status; to recommend approval of NPRR1269 as amended by the 3/4/25 TCPA comments; and to forward to TAC NPRR1269 and the 1/28/25 Impact Analysis. There were three opposing votes from the Consumer (Residential Consumer, City of Eastland, Occidental) Market Segment. All Market Segments participated in the vote.</p>
Summary of PRS Discussion	<p>On 2/12/25, the sponsor provided an overview of NPRR1269 and participants reviewed the 2/6/25 IMM comments. Participants tabled NPRR1269 for continued discussions at upcoming RTCBTF meetings, and the sponsor noted they plan to request Urgent status for NPRR1269 at the March PRS meeting to keep this NPRR on-track for PUCT approval ahead of RTC+B market trials later this year.</p> <p>On 3/12/25, participants reviewed the 3/3/25 ERCOT comments, 3/4/25 TCPA comments, 3/10/25 TIEC comments, and 3/11/25 IMM comments, along with a presentation from ERCOT. Participants discussed the appropriate levels and potential impact of ASDC floors within RUC, the Day-Ahead Market (DAM), and the Real-Time Market (RTM).</p>

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TAC Decision	On 3/26/25, TAC voted to recommend approval of NPRR1269 as recommended by PRS in the 3/12/25 PRS Report. There were seven opposing votes from the Consumer (6) (Residential Consumer, OPUC, CMC Steel, Lyondell Chemical, City of Eastland, City of Dallas) and Independent Retail Electric Provider (IREP) (APG&E) Market Segments and one abstention from the IREP (Demand Control 2) Market Segment. All Market Segments participated in the vote.
Summary of TAC Discussion	On 3/26/25, TAC reviewed the items below, along with a presentation from ERCOT Staff on the impact of proposed ASDC floors for the DAM and RTC. Participants discussed the potential impacts of NPRR1269 on the occurrence of RUCs under RTC. Opponents continued to express concerns with any floor above \$0 without observed market conditions under RTC justifying one.
Explanation of Opposing TAC Votes	<p>Consumer/Residential Consumer – Residential Consumers opposed NPRR1269 for reasons detailed in the 3/25/25 Joint Consumers comments.</p> <p>Consumer/OPUC – OPUC opposed NPRR1269 for reasons detailed in the 3/25/25 Joint Consumers comments.</p> <p>Consumer/City of Eastland – Explanation requested but not provided.</p> <p>Consumer/City of Dallas – City of Dallas voted against NPRR1269 for fundamental market design issues. NPRR1269 sets a floor for the proxy offer curve. The justification for the offer floor is the belief that this may reduce potential RUC in the future. Although RUC is an out-of-market solution and should be avoided if possible substituting an arbitrary offer floor is in itself an out-of-market solution. We are simply substituting administrative pricing for RUC commitment. Neither option is acceptable. The ERCOT “competitive” market has more administrative pricing and price adders than any competitive market we are aware of. RTC was intended to add efficiency, transparency and lower cost to the ERCOT market. At this point in time we do not know how Market Participants will offer into the new market, and to set offer floors before the market even opens is defeatist and anticompetitive.</p> <p>Consumer/CMC Steel – CMC Steel opposed NPRR1269 for reasons detailed in the 3/25/25 Joint Consumers comments.</p> <p>Consumer/Lyondell Chemical – Lyondell Chemical opposed NPRR1269 for reasons detailed in the 3/25/25 Joint Consumers comments.</p>

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	IREP/APG&E – APG&E opposed NPPR1269 for reasons detailed in the 3/25/25 Joint Consumers comments.
TAC Review/Justification of Recommendation	<input checked="" type="checkbox"/> Revision Request ties to Reason for Revision as explained in Justification <input checked="" type="checkbox"/> Impact Analysis reviewed and impacts are justified as explained in Justification <input checked="" type="checkbox"/> Opinions were reviewed and discussed <input checked="" type="checkbox"/> Comments were reviewed and discussed (if applicable) <input type="checkbox"/> Other: (explain)
ERCOT Board Decision	On 4/8/25, the ERCOT Board voted to recommend approval of NPPR1269 as recommended by TAC in the 3/26/25 TAC Report. There was one opposing vote.

Opinions	
Credit Review	ERCOT Credit Staff and the Credit Finance Sub Group (CFSG) have reviewed NPPR1269 and do not believe that it requires changes to credit monitoring activity or the calculation of liability.
Independent Market Monitor Opinion	IMM opposes NPPR1269.
ERCOT Opinion	ERCOT supports approval of NPPR1269.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NPPR1269 and believes the market impact for NPPR1269, after extensive review with stakeholders at the RTCBTF, codifies a group of policy changes that were deferred from the original RTC-related Protocols developed in 2020 to provide clarity ahead of the upcoming RTC market trials.

Sponsor	
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Company	ERCOT
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Market Segment	Not applicable

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Market Rules Staff Contact	
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Comments Received	
Comment Author	Comment Summary
IMM 020625	Opined that a proxy price for Ancillary Services at \$2,000 is arbitrary and excessively high relative to the cost to provide the service
ERCOT 030325	Proposed revisions replacing placeholder "X" values within the Protocol language and proposing that all ASDCs for RUC have a price floor such that no value on the curve for any Ancillary Service fall below \$15 per MW per hour
TCPA 030425	Proposed additional revisions to the 3/3/25 ERCOT comments to carry the proposed \$15 per MW per hour floor from RUC into the DAM and RTM as well
TIEC 031025	Proposed additional revisions to the 3/3/25 ERCOT comments lowering the proposed Ancillary Service proxy offer floor from \$2,000 per MW per hour to \$15 per MW per hour
IMM 031125	Responded to the 3/10/25 TCPA comments and provided supporting analysis of the impact of ASDC price floors in 2024
Joint Consumers 032525	Expressed concern that NPRR1269 proposes a fundamental, premature and arbitrary shift in RTC design before its implementation and proposed a compromise to modify the proposed floor price from \$15 to \$0 for monitoring throughout 2026
ERCOT 033125	Provided ERCOT's perspective on the concept of an ASDC floor in the DAM and RTM and the appropriate level for the Ancillary Service proxy offer floor; summarized results of the analysis of the impact of NPRR1269
Joint Consumers 040425	Reiterated opposition to the proposed \$15 floor price and encouraged the Board to recommend approval of NPRR1269 as amended by the 3/25/25 Joint Consumers comments

Market Rules Notes

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

- NPRR1235, Dispatchable Reliability Reserve Service as a Stand-Alone Ancillary Service
 - Section 4.4.12
 - Section 5.5.2
- NPRR1268, RTC – Modification of Ancillary Service Demand Curves
 - Section 4.4.12
 - Section 6.5.7.3

Proposed Protocol Language Revision

[NPRR1008, NPRR1216, and NPRR1245: Insert applicable portions of Section 4.4.12 below upon system implementation of NPRR1216; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1008 and NPRR1245:]

4.4.12 Determination of Ancillary Service Demand Curves for the Day-Ahead Market and Real-Time Market

Commented [CP1]: Please note NPRRs 1235 and 1268 also propose revisions to this section.

- (1) This Section describes the process for determining ASDCs for Regulation Up Service (Reg-Up), Regulation Down Service (Reg-Down), Responsive Reserve (RRS), ERCOT Contingency Reserve Service (ECRS), and Non-Spinning Reserve (Non-Spin) for the Day-Ahead Market (DAM) and Real-Time Market (RTM). This section does not apply to ASDCs used in the Reliability Unit Commitment (RUC) process.
- (2) The DAM shall use the same ASDCs as the RTM, as an initial condition. Specific to the DAM, the ASDCs will be adjusted, as needed, to account for negative Self-Arranged Ancillary Service Quantities.
- (3) For Reg-Down, the ASDC shall be a constant value equal to VOLL for the full range of the Ancillary Service Plan for Reg-Down.
- (4) To determine the individual ASDCs for Reg-Up, RRS, ECRS, and Non-Spin, an Aggregate ORDC (AORDC) will be created and then disaggregated into individual curves for the different Ancillary Services.
- (5) ERCOT shall develop the AORDC from historical data from the period of June 1, 2014 through August 31, 2025 as follows:
 - (a) For all SCED intervals where the sum of RTOLCAP and RTOFFCAP is less than 10,000 MW, use the RTOLCAP and RTOFFCAP values to calculate the AORDC as follows:

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$$AORDC = \left(0.5 * (1 - \text{pnorm}(RTOLCAP - 3000, 0.5 * \mu, 0.707 * \sigma)) + 0.5 * (1 - \text{pnorm}(RTOLCAP + RTOFFCAP - 3000, \mu, \sigma)) \right) * (VOLL - \min(\text{System Lambda}, 250))$$

The above variables are defined as follows:

Variable	Unit	Definition
RTOLCAP	MWh	<i>Real-Time On-Line Reserve Capacity</i> – The Real-Time reserve capacity of On-Line Resources available for the SCED intervals beginning June 1, 2014 through August 31, 2025
RTOFFCAP	MWh	<i>Real-Time Off-Line Reserve Capacity</i> – The Real-Time reserve capacity of Off-Line Resources available for the SCED intervals beginning June 1, 2014 through August 31, 2025.
μ	None	The mean value of the shifted LOLP distribution as published for Summer 2026
σ	None	The standard deviation of the shifted LOLP distribution as published for Summer 2026

- (b) Using the results of step (a) above, use regression methods to fit a curve to the average reserve pricing outcomes for the various MW reserve levels.
 - (c) Calculate points on the regression curve in 1 MW increments for any observed reserve level $\geq 3,000$ MW and price $> \$0.01/\text{MWh}$. These points form the AORDC.
- (6) ERCOT shall disaggregate the AORDC developed pursuant to paragraph (5) above into individual ASDCs for each Ancillary Service product as follows:
- (a) The ASDC for all Reg-Up in the Ancillary Service Plan shall use the highest price portion of the AORDC;
 - (b) The ASDC for all RRS in the Ancillary Service Plan shall use the highest price portion of the remaining AORDC after removing the portion of the AORDC that was used for the Reg-Up ASDC;
 - (c) The ASDC for all ECRS in the Ancillary Service Plan shall use the highest price portion of the remaining AORDC after removing the portions of the AORDC that were used for the Reg-Up and RRS ASDCs;
 - (d) The ASDC for Non-Spin shall use the remaining portion of the remaining AORDC after removing the portions of the AORDC that were used for the Reg-Up, RRS, and ECRS ASDCs.
- (7) Each ASDC will be represented by a 100-point linear approximation to the corresponding part of the AORDC. Fewer points may be used for cases where it

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would not result in decreased accuracy in representing the corresponding part of the AORDC.

- (8) All ASDCs will have a floor price, based on ERCOT's assessment of the need for a floor price on the ASDC for RUC, such that no values on the curve for any Ancillary Service fall below \$15 per MW per hour for the portion of the ASDC that corresponds to the Ancillary Service Plan.
- (98) The AORDC used in determining the individual ASDCs will be adjusted to reflect any updates to the value of VOLL, as described in Section 4.4.11, Day-Ahead and Real-Time System-Wide Offer Caps, and Section 4.4.11.1, Scarcity Pricing Mechanism.

5.5.2 Reliability Unit Commitment (RUC) Process

Commented [CP2]: Please note NPRR1235 also proposes revisions to this section.

- (1) The RUC process recommends commitment of Generation Resources, to match ERCOT's forecasted Load including Direct Current Tie (DC Tie) Schedules, subject to all transmission constraints and Resource performance characteristics. The RUC process takes into account Resources already committed in the Current Operating Plans (COPs), Resources already committed in previous RUCs, Off-Line Available Resources having a start-up time of one hour or less, and Resource capacity already committed to provide Ancillary Service. The formulation of the RUC objective function must employ penalty factors on violations of security constraints. The objective of the RUC process is to minimize costs based on the Resource costs described in paragraphs (5) through (9) below. For all hours of the RUC Study Period within the RUC process, Quick Start Generation Resources (QSGRs) with a COP Resource Status of OFFQS shall be considered as On-Line with Low Sustained Limit (LSL) at zero MW. QSGRs with a Resource Status of OFFQS shall only be committed by ERCOT through a RUC instruction in instances when a reliability issue would not otherwise be managed through Dispatch Instructions from Security-Constrained Economic Dispatch (SCED). For On-Line ESRs, the Hour Beginning Planned State of Charge (SOC) values provided in the COP for a given hour are discounted to ensure sufficient SOC is preserved to meet Ancillary Service Resource Responsibilities, as reflected in the COP. Any remaining SOC on the ESR will be considered available for energy dispatch by RUC while respecting the Minimum State of Charge (MinSOC) and Maximum State of Charge (MaxSOC) values provided in the COP.
- (2) The RUC process can recommend Resource decommitment. ERCOT may only decommit a Resource to resolve transmission constraints that are otherwise unresolvable. Qualifying Facilities (QFs) may be decommitted only after all other types of Resources have been assessed for decommitment. In addition, the HRUC process provides decision support to ERCOT regarding a Resource decommitment requested by a Qualified Scheduling Entity (QSE).
- (3) ERCOT shall review the RUC-recommended Resource commitments and the list of Off-Line Available Resources having a start-up time of one hour or less to assess feasibility and shall make any changes that it considers necessary, in its sole discretion. During the

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RUC process, ERCOT may also review and commit, through a RUC instruction, Combined Cycle Generation Resources that are currently planned to be On-Line but are capable of transitioning to a configuration with additional capacity. ERCOT may deselect Resources recommended in DRUC and in all HRUC processes if in ERCOT's sole discretion there is enough time to commit those Resources in the future HRUC processes, taking into account the Resources' start-up times, to meet ERCOT System reliability. After each RUC run, ERCOT shall post the amount of capacity deselected per hour in the RUC Study Period to the MIS Secure Area. A Generation Resource shown as On-Line and available for SCED dispatch for an hour in its COP prior to a DRUC or HRUC process execution, according to Section 5.3, ERCOT Security Sequence Responsibilities, will be considered self-committed for that hour. For purpose of Settlement, snapshot data will be used as specified in paragraph (2) of Section 5.3. ERCOT shall issue RUC instructions to each QSE specifying its Resources that have been committed as a result of the RUC process. ERCOT shall, within one day after making any changes to the RUC-recommended commitments, post to the MIS Secure Area any changes that ERCOT made to the RUC-recommended commitments with an explanation of the changes.

[NPRR1239: Replace paragraph (3) above with the following upon system implementation:]

- (3) ERCOT shall review the RUC-recommended Resource commitments and the list of Off-Line Available Resources having a start-up time of one hour or less to assess feasibility and shall make any changes that it considers necessary, in its sole discretion. During the RUC process, ERCOT may also review and commit, through a RUC instruction, Combined Cycle Generation Resources that are currently planned to be On-Line but are capable of transitioning to a configuration with additional capacity. ERCOT may deselect Resources recommended in DRUC and in all HRUC processes if in ERCOT's sole discretion there is enough time to commit those Resources in the future HRUC processes, taking into account the Resources' start-up times, to meet ERCOT System reliability. After each RUC run, ERCOT shall post the amount of capacity deselected per hour in the RUC Study Period to the ERCOT website. A Generation Resource shown as On-Line and available for SCED dispatch for an hour in its COP prior to a DRUC or HRUC process execution, according to Section 5.3, ERCOT Security Sequence Responsibilities, will be considered self-committed for that hour. For purpose of Settlement, snapshot data will be used as specified in paragraph (2) of Section 5.3. ERCOT shall issue RUC instructions to each QSE specifying its Resources that have been committed as a result of the RUC process. ERCOT shall, within one day after making any changes to the RUC-recommended commitments, post to the ERCOT website any changes that ERCOT made to the RUC-recommended commitments with an explanation of the changes.
- (4) A QSE shall notify the ERCOT Operator of any physical limitation that impacts its Resource's ability to start that is not reflected in the Resource's COP or the Resource's

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startup time, minimum On-Line time, or minimum Off-Line time. The following shall apply:

- (a) If a Resource receives a RUC Dispatch Instruction that it cannot meet due to a physical limitation described in paragraph (4) above, the QSE representing the Resource shall notify the ERCOT Operator of the inability to fully comply with the instruction and shall comply with the instruction to the best of the Resource's ability. If the QSE has provided the ERCOT Operator notice of that limitation at least seven days prior to the Operating Day in which the instruction occurs, the QSE shall be excused from complying with the portion of the RUC Dispatch Instruction that it could not meet due to the identified limitation.
 - (b) If a QSE provides notice pursuant to paragraph (a) above of a physical limitation that will delay the RUC-committed Resource's ability to reach its LSL in accordance with a RUC Dispatch Instruction, ERCOT shall extend the RUC Dispatch Instruction so that the Resource's minimum run time is respected. However, if the Resource will not be available in time to address the issue for which it received the RUC instruction, ERCOT may instead cancel the RUC Dispatch Instruction.
- (5) A QSE shall be excused from complying with any portion of a RUC Dispatch Instruction that it could not meet due to a physical limitation that was reflected, at the time of the RUC Dispatch Instruction, in the Resource's COP, startup time, minimum On-Line time, or minimum Off-Line time.
 - (6) To determine the projected energy output level of each Resource and to project potential congestion patterns for each hour of the RUC, ERCOT shall calculate proxy Energy Offer Curves based on the Mitigated Offer Caps (MOCs) for the type of Resource as specified in Section 4.4.9.4, Mitigated Offer Cap and Mitigated Offer Floor, for use in the RUC. Proxy Energy Offer Curves are calculated by multiplying the MOC by a constant selected by ERCOT from time to time that is no more than 0.10% and applying the cost for all Generation Resource output between High Sustained Limit (HSL) and LSL. The intent of this process is to minimize the effect of the proxy Energy Offer Curves on optimization.
 - (7) ERCOT shall use the RUC process to evaluate the need to commit Resources for which a QSE has submitted Three-Part Supply Offers and other available Off-Line Resources in addition to Resources that are planned to be On-Line during the RUC Study Period. All of the above commitment information must be as specified in the QSE's COP. For available Off-Line Resources with a cold start time of one hour or less that have not been removed from special consideration under paragraph (9) below pursuant to paragraph (4) of Section 8.1.2, Current Operating Plan (COP) Performance Requirements, the Startup Offers and Minimum-Energy Offer from a Resource's Three-Part Supply Offer shall not be used in the RUC process.
 - (8) ERCOT shall create Three-Part Supply Offers for all Resources that did not submit a Three-Part Supply Offer, but are specified as available but Off-Line, excluding Resources

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with a Resource Status of EMR, in a QSE's COP. For such Resources, excluding available Off-Line Resources with a cold start time of one hour or less that have not been removed from special consideration under paragraph (9) below pursuant to paragraph (4) of Section 8.1.2, ERCOT shall use in the RUC process 100% of any approved verifiable Startup Cost and verifiable minimum-energy cost or if verifiable costs have not been approved, the applicable Resource Category Generic Startup Offer Cost and the applicable Resource Category Generic Minimum-Energy Offer Cost as described specified in Section 4.4.9.2.3, Startup Offer and Minimum-Energy Offer Generic Caps, registered with ERCOT. Also, for Settlement purposes, ERCOT shall use any approved verifiable Startup Costs and verifiable minimum-energy cost for such Resources, or if verifiable costs have not been approved, the applicable Resource Category Generic Startup Offer Cost and Generic Minimum-Energy Offer Cost.

- (9) For all available Off-Line Resources having a cold start time of one hour or less and not removed from special consideration pursuant to paragraph (4) of Section 8.1.2, ERCOT shall scale any approved verifiable Startup Cost and verifiable minimum-energy cost or if verifiable costs have not been approved, the applicable Resource Category Generic Startup Offer Cost and the applicable Resource Category Generic Minimum-Energy Offer Cost as specified in Section 4.4.9.2.3 for use in the RUC process.

The above parameter is defined as follows:

Parameter	Unit	Current Value*
IHRLESSCOSTSCALING	Percentage	Maximum value of 100%
* The current value for the parameter(s) referenced in this table above will be recommended by the Technical Advisory Committee (TAC) and approved by the ERCOT Board and <u>approved by the Public Utility Commission of Texas (PUCT)</u> . ERCOT shall update parameter value(s) on the first day of the month following ERCOT Board <u>PUCT</u> approval unless otherwise directed by the ERCOT Board . ERCOT shall provide a Market Notice prior to implementation of a revised parameter value.		

- (10) The RUC process must treat all Resource capacity providing Ancillary Service as unavailable for the RUC Study Period, unless that treatment leads to infeasibility (i.e., that capacity is needed to resolve some local transmission problem that cannot be resolved by any other means). If an ERCOT Operator decides that the Ancillary Service capacity allocated to that Resource is infeasible based on ERCOT System conditions, then, ERCOT shall inform each affected QSE of the amount of its Resource capacity that does not qualify to provide Ancillary Service, and the projected hours for which this is the case. In that event, the affected QSE may, under Section 6.4.9.1.2, Replacement of Infeasible Ancillary Service Due to Transmission Constraints, either:
- (a) Substitute capacity from Resources represented by that QSE;
 - (b) Substitute capacity from other QSEs using Ancillary Service Trades; or
 - (c) Ask ERCOT to replace the capacity.
- (11) Factors included in the RUC process are:

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- (a) ERCOT System-wide hourly Load forecast allocated appropriately over Load buses;
 - (b) Transmission constraints – Transfer limits on energy flows through the electricity network;
 - (i) Thermal constraints – protect transmission facilities against thermal overload;
 - (ii) Generic constraints – protect the transmission system against transient instability, dynamic instability or voltage collapse;
 - (c) Planned transmission topology;
 - (d) Energy sufficiency constraints;
 - (e) Inputs from the COP, as appropriate;
 - (f) Inputs from Resource Parameters, including a list of Off-Line Available Resources having a start-up time of one hour or less, as appropriate;
 - (g) Each Generation Resource's Minimum-Energy Offer and Startup Offer, from its Three-Part Supply Offer;
 - (h) Any Generation Resource that is Off-Line and available but does not have a Three-Part Supply Offer;
 - (i) Forced Outage information; and
 - (j) Inputs from the eight-day look ahead planning tool, which may potentially keep a unit On-Line (or start a unit for the next day) so that a unit minimum duration between starts does not limit the availability of the unit (for security reasons).
- (12) The HRUC process and the DRUC process are as follows:
- (a) The HRUC process uses current Resource Status for the initial condition for the first hour of the RUC Study Period. All HRUC processes use the projected status of transmission breakers and switches starting with current status and updated for each remaining hour in the study as indicated in the COP for Resources and in the Outage Scheduler for transmission elements.
 - (b) The DRUC process uses the Day-Ahead forecast of total ERCOT Load including DC Tie Schedules for each hour of the Operating Day. The HRUC process uses the current hourly forecast of total ERCOT Load including DC Tie Schedules for each hour in the RUC Study Period.

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- (c) The DRUC process uses the Day-Ahead weather forecast for each hour of the Operating Day. The HRUC process uses the weather forecast information for each hour of the balance of the RUC Study Period.
- (13) A QSE that has one or more of its Resources RUC-committed to provide Ancillary Services must increase its Ancillary Service Supply Responsibility by the total amount of RUC-committed Ancillary Service quantities. The QSE may only use a RUC-committed Resource to meet its Ancillary Service Supply Responsibility during that Resource's RUC-Committed Interval if the Resource has been committed by the RUC process to provide Ancillary Service, or the Resource is a Combined Cycle Generation Resource that was RUC-committed to transition from one On-Line configuration to a different configuration with additional capacity. For cases in which the commitment was to provide Ancillary Service, the QSE shall indicate the exact amount and type of Ancillary Service for which it was committed as the Resource's Ancillary Service Resource Responsibility and Ancillary Services Schedule for the RUC-Committed Intervals for both telemetry and COP information provided to ERCOT. Upon deployment of the Ancillary Services, the QSE shall adjust its Ancillary Services Schedule to reflect the amounts requested in the deployment.
- (14) A QSE with a Resource that is not a Reliability Must-Run (RMR) Unit or has not received an Outage Schedule Adjustment (OSA) that has been committed in a DRUC or HRUC process may opt out of the RUC Settlement (or "buy back" the commitment) by setting the COP status of the RUC-committed Resource to ONOPTOUT for the first hour of a contiguous block of RUC-Committed Hours in the Opt Out Snapshot. All the configurations of the same Combined Cycle Train shall be treated as the same Resource for the purpose of creating the block of RUC-Committed Hours. A RUC-committed Combined Cycle Generation Resource may opt out of the RUC Settlement by setting the COP status of any Combined Cycle Generation Resource within the same Combined Cycle Train as the RUC-committed Resource to ONOPTOUT for the first hour of a contiguous block of RUC-Committed Hours in the Opt Out Snapshot. A Combined Cycle Generation Resource that is RUC-committed from one On-Line configuration in order to transition to a different configuration with additional capacity may opt out of the RUC Settlement following the same rule for RUC-committed Combined Cycle Generation Resources described above. A QSE that opts out of RUC Settlement forfeits RUC Settlement for the affected Resource for a given block of RUC Buy-Back Hours. A QSE that opts out of RUC Settlement treatment must make the Resource available to SCED for all RUC Buy-Back Hours. All hours in a contiguous block of RUC-Committed Hours that includes the RUC Buy-Back Hour shall be considered RUC Buy-Back Hours. If a contiguous block of RUC-Committed Hours spans more than one Operating Day and a QSE wishes to opt out of RUC Settlement for the RUC-Committed Hours in the second or subsequent Operating Day, the QSE must set its COP status to ONOPTOUT for the first hour of the first Operating Day in the Opt Out Snapshot of the first Operating Day.
- (15) ERCOT shall, as soon as practicable, post to the MIS Secure Area a report identifying those hours that were considered RUC Buy-Back Hours, along with the name of each RUC-committed Resource whose QSE opted out of RUC Settlement.

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[NPRR1239: Replace paragraph (15) above with the following upon system implementation:]

- (15) ERCOT shall, as soon as practicable, post to the ERCOT website a report identifying those hours that were considered RUC Buy-Back Hours, along with the name of each RUC-committed Resource whose QSE opted out of RUC Settlement.
- (16) A Resource that has a Three-Part Supply Offer cleared in the Day-Ahead Market (DAM) and subsequently receives a RUC commitment for the Operating Hour for which it was awarded will be treated as if the telemetered Resource Status was ONOPTOUT for purposes of Section 6.5.7.3, Security Constrained Economic Dispatch, and Section 6.5.7.3.1, Determination of Real-Time On-Line Reliability Deployment Price Adder.
- (17) A Resource that has self-committed for an Operating Hour after the RUC Snapshot was taken but before the RUC commitment has been communicated through an XML message for that RUC process and that Operating Hour is included in a block of RUC-committed hours for that RUC process will be treated as if the Resource Status was ONOPTOUT for purposes of Section 6.5.7.3, Section 6.5.7.3.1, Operating Reserve Demand Curve (ORDC) calculations, and RUC Settlement for the entire block of RUC-committed hours. A QSE that has a Resource that meets these conditions must make the Resource available to SCED for the entire block of RUC-committed hours. ERCOT will send the QSE a notification stating the Operating Day and block of hours for which this occurred.

[NPRR1009, NPRR1032, NPRR1204, NPRR1239, and NPRR1245: Replace applicable portions of Section 5.5.2 above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1009, NPRR1204, and NPRR1245; or upon system implementation for NPRR1032 or NPRR1239:]

5.5.2 Reliability Unit Commitment (RUC) Process

- (1) The RUC process recommends commitment of Generation Resources, to match ERCOT's forecasted Load including Direct Current Tie (DC Tie) Schedules and RUC Ancillary Service Demand Curves (ASDCs), subject to all transmission constraints and Resource performance characteristics. The RUC process takes into account Resources already committed in the Current Operating Plans (COPs), Resources already committed in previous RUCs, and Off-Line Available Resources having a start-up time of one hour or less. For On-Line Energy Storage Resources (ESRs), using RUC duration requirements for energy and Ancillary Services, RUC-projected dispatch for energy and Ancillary Service in one interval shall respect the ESR's minimum and maximum State of Charge (SOC) values from the COP, while incorporating any adjustments under paragraph (19)(d) below. In addition, using the Ancillary Service Deployment Factors and their respective deployment duration requirements, the SOC required to support these dispatch levels for energy and Ancillary Services will match as closely as possible the difference between the adjusted COP values of the next

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interval's Hour Beginning Planned SOC and the current interval's Hour Beginning Planned SOC. The formulation of the RUC objective function must employ penalty factors on violations of security constraints and violations of ESR COP Hour Beginning Planned SOC. The objective of the RUC process is to minimize costs based on the Resource costs described in paragraphs (11) through (15) below. ESR energy dispatch costs and Ancillary Service Offer costs are not included in the RUC objective function.

- (2) ERCOT shall create an ASDC for each Ancillary Service for use in RUC. As an initial condition, the ASDCs for each Ancillary Service for use in RUC shall be derived from substantively the same as the ASDCs as defined in Protocol Section 4.4.12, Determination of Ancillary Service Demand Curves for the Day-Ahead Market and the Real-Time Market. Specific to RUC, the ASDC for Non-Spin shall not extend beyond the Ancillary Service Plan for Non-Spin for the relevant Operating Hour. Additionally, all ASDCs for RUC will have a floor price such that no values on the curve for any Ancillary Service fall below \$15X per megawatt (MW) per hour. ERCOT shall post the ASDCs for RUC to the ERCOT website as soon as practicable after any change to the ASDCs following each execution of the RUC process.
- (3) ERCOT shall post the following Ancillary Service Deployment Factor data on the ERCOT website:
 - (a) Following each execution of RUC, ERCOT shall post the Ancillary Service Deployment Factors used by that RUC process for each hour in the RUC Study Period;
 - (b) No later than 0600 in the Day-Ahead for each Operating Day, ERCOT shall post the Ancillary Service Deployments Factors that are projected to be used in the RUC process for that Operating Day; and
 - (c) Following each month, ERCOT shall post the average, minimum, and maximum Ancillary Service Deployment Factors used in the RUC process by type of Ancillary Service and hour of the day for the month.
- (4) For all hours of the RUC Study Period within the RUC process, Quick Start Generation Resources (QSGRs) with a COP Resource Status of OFFQS shall be considered as On-Line with Low Sustained Limit (LSL) at zero MW. QSGRs with a Resource Status of OFFQS shall only be committed by ERCOT through a RUC instruction in instances when a reliability issue would not otherwise be managed through Dispatch Instructions from Security-Constrained Economic Dispatch (SCED).
- (5) In addition to On-Line qualified Generation Resources and Energy Storage Resources (ESRs), the RUC engine shall consider a COP Resource status of OFFQS for QSGRs that are qualified for ERCOT Contingency Reserve Service (ECRS), as being eligible to provide ECRS constrained by the Ancillary Service capability in the COP.
- (6) In addition to On-Line qualified Generation Resources and ESRs, the RUC engine shall consider a COP Resource Status of OFFQS for QSGRs that are qualified for Non-

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Spinning Reserve (Non-Spin), as being eligible to provide Non-Spin constrained by the Ancillary Service Capability in the COP. The RUC engine shall also consider a COP Resource Status of OFF (Off-Line but available for commitment in the DAM and RUC) for a Resource that is qualified for Non-Spin, as being eligible to provide Non-Spin constrained by the Ancillary Service capability in the COP.

- (7) In addition to On-Line qualified Generation Resources and ESRs, the RUC engine shall consider a COP Resource Status of ONL for Load Resources that are qualified for Ancillary Services, as being eligible to provide Ancillary Services constrained by the Ancillary Service Capability in the COP. The RUC engine will not consider any Load Resources for dispatch of energy.
- (8) The RUC process can recommend Resource decommitment. ERCOT may only decommit a Resource to resolve transmission constraints that are otherwise unresolvable. Qualifying Facilities (QFs) may be decommitted only after all other types of Resources have been assessed for decommitment. In addition, the HRUC process provides decision support to ERCOT regarding a Resource decommitment requested by a Qualified Scheduling Entity (QSE).
- (9) ERCOT shall review the RUC-recommended Resource commitments and the list of Off-Line Available Resources having a start-up time of one hour or less to assess feasibility and shall make any changes that it considers necessary, in its sole discretion. During the RUC process, ERCOT may also review and commit, through a RUC instruction, Combined Cycle Generation Resources that are currently planned to be On-Line but are capable of transitioning to a configuration with additional capacity. ERCOT may deselect Resources recommended in DRUC and in all HRUC processes if in ERCOT's sole discretion there is enough time to commit those Resources in the future HRUC processes, taking into account the Resources' start-up times, to meet ERCOT System reliability. After each RUC run, ERCOT shall post the amount of capacity deselected per hour in the RUC Study Period to the ERCOT website. A Generation Resource shown as On-Line and available for SCED dispatch for an hour in its COP prior to a DRUC or HRUC process execution, according to Section 5.3, ERCOT Security Sequence Responsibilities, will be considered self-committed for that hour. For purpose of Settlement, snapshot data will be used as specified in paragraph (2) of Section 5.3.
- (10) ERCOT shall issue RUC instructions to each QSE specifying its Resources that have been committed as a result of the RUC process. ERCOT shall, within one day after making any changes to the RUC-recommended commitments, post to the ERCOT website any changes that ERCOT made to the RUC-recommended commitments with an explanation of the changes.
- (11) ERCOT shall use the RUC process to evaluate the need to commit Resources for which a QSE has submitted Three-Part Supply Offers and other available Off-Line Resources in addition to Resources that are planned to be On-Line during the RUC Study Period. All of the above commitment information must be as specified in the QSE's COP. For available Off-Line Resources with a cold start time of one hour or less that have not

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been removed from special consideration under paragraph (17) below pursuant to paragraph (4) of Section 8.1.2, Current Operating Plan (COP) Performance Requirements, the Startup Offers and Minimum-Energy Offer from a Resource's Three-Part Supply Offer shall not be used in the RUC process.

- (12) ERCOT shall create Three-Part Supply Offers for all Resources that did not submit a Three-Part Supply Offer, but are specified as available but Off-Line, excluding Resources with a Resource Status of EMR, in a QSE's COP. For such Resources, excluding available Off-Line Resources with a cold start time of one hour or less that have not been removed from special consideration under paragraph (15) below pursuant to paragraph (4) of Section 8.1.2, ERCOT shall use in the RUC process 100% of any approved verifiable Startup Cost and verifiable minimum-energy cost or if verifiable costs have not been approved, the applicable Resource Category Generic Startup Offer Cost and the applicable Resource Category Generic Minimum-Energy Offer Cost as described specified in Section 4.4.9.2.3, Startup Offer and Minimum-Energy Offer Generic Caps, registered with ERCOT. Also, for Settlement purposes, ERCOT shall use any approved verifiable Startup Costs and verifiable minimum-energy cost for such Resources, or if verifiable costs have not been approved, the applicable Resource Category Generic Startup Offer Cost and Generic Minimum-Energy Offer Cost.
- (13) A QSE shall notify the ERCOT Operator of any physical limitation that impacts its Resource's ability to start that is not reflected in the Resource's COP or the Resource's startup time, minimum On-Line time, or minimum Off-Line time. The following shall apply:
 - (a) If a Resource receives a RUC Dispatch Instruction that it cannot meet due to a physical limitation described in paragraph (5) above, the QSE representing the Resource shall notify the ERCOT Operator of the inability to fully comply with the instruction and shall comply with the instruction to the best of the Resource's ability. If the QSE has provided the ERCOT Operator notice of that limitation at least seven days prior to the Operating Day in which the instruction occurs, the QSE shall be excused from complying with the portion of the RUC Dispatch Instruction that it could not meet due to the identified limitation.
 - (b) If a QSE provides notice pursuant to paragraph (a) above of a physical limitation that will delay the RUC-committed Resource's ability to reach its LSL in accordance with a RUC Dispatch Instruction, ERCOT shall extend the RUC Dispatch Instruction so that the Resource's minimum run time is respected. However, if the Resource will not be available in time to address the issue for which it received the RUC instruction, ERCOT may instead cancel the RUC Dispatch Instruction.
- (14) A QSE shall be excused from complying with any portion of a RUC Dispatch Instruction that it could not meet due to a physical limitation that was reflected, at the time of the RUC Dispatch Instruction, in the Resource's COP, startup time, minimum On-Line time, or minimum Off-Line time.

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- (15) To determine the projected energy output level of each Resource and to project potential congestion patterns for each hour of the RUC, ERCOT shall calculate proxy Energy Offer Curves based on the Mitigated Offer Caps (MOCs) for the type of Resource as specified in Section 4.4.9.4, Mitigated Offer Cap and Mitigated Offer Floor, for use in the RUC. Proxy Energy Offer Curves are calculated by multiplying the MOC by a constant selected by ERCOT from time to time that is no more than 0.10% and applying the cost for all Generation Resource output between High Sustained Limit (HSL) and LSL. The intent of this process is to minimize the effect of the proxy Energy Offer Curves on optimization. For ESRs, energy dispatch costs are not considered in determining projected energy output levels.
- (16) ERCOT shall calculate proxy Ancillary Service Offer Curves for use in RUC based on validated Ancillary Service Offers as specified in Section 4.4.7.2, Ancillary Service Offers. For all Resources that do not have a valid Ancillary Service Offer but are qualified to provide an Ancillary Service, ERCOT shall create an Ancillary Service Offer Curve for use in RUC as described in Section 6.5.7.3, Security Constrained Economic Dispatch. Proxy Ancillary Service Offer Curves for use in RUC are calculated by multiplying the Ancillary Service Offer by a constant selected by ERCOT from time to time that is no more than 0.1%, and are extended between the HSL and LSL. Notwithstanding the presence or absence of a proxy Ancillary Service Offer, Ancillary Service provision in RUC shall be limited by the Resource's Ancillary Service capabilities as reflected in the COP. For ESRs, Ancillary Service Offer costs are not considered in determining projected Ancillary Service awards.
- (17) For all available Off-Line Resources having a cold start time of one hour or less and not removed from special consideration pursuant to paragraph (4) of Section 8.1.2, ERCOT shall scale any approved verifiable Startup Cost and verifiable minimum-energy cost or if verifiable costs have not been approved, the applicable Resource Category Generic Startup Offer Cost and the applicable Resource Category Generic Minimum-Energy Offer Cost as specified in Section 4.4.9.2.3 for use in the RUC process.

The above parameter is defined as follows:

Parameter	Unit	Current Value*
IHRLESSCOSTSCALING	Percentage	Maximum value of 100%
* The current value for the parameter(s) referenced in this table above will be recommended by the Technical Advisory Committee (TAC) and approved by the ERCOT Board and <u>approved by the Public Utility Commission of Texas (PUCT)</u> . ERCOT shall update parameter value(s) on the first day of the month following ERCOT Board <u>PUCT</u> approval unless otherwise directed by the ERCOT Board . ERCOT shall provide a Market Notice prior to implementation of a revised parameter value.		

- (18) Factors included in the RUC process are:
- (a) ERCOT System-wide hourly Load forecast allocated appropriately over Load buses;

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- (b) ERCOT's Ancillary Service Plans in the form of ASDCs;
 - (c) Transmission constraints – Transfer limits on energy flows through the electricity network;
 - (i) Thermal constraints – protect transmission facilities against thermal overload;
 - (ii) Generic constraints – protect the transmission system against transient instability, dynamic instability or voltage collapse;
 - (d) Planned transmission topology;
 - (e) Energy sufficiency constraints, including RUC duration requirements for energy and Ancillary Services;
 - (f) Inputs from the COP, as appropriate;
 - (g) Inputs from Resource Parameters, including a list of Off-Line Available Resources having a start-up time of one hour or less, as appropriate;
 - (h) Each Generation Resource's Minimum-Energy Offer and Startup Offer, from its Three-Part Supply Offer;
 - (i) Any Generation Resource that is Off-Line and available but does not have a Three-Part Supply Offer;
 - (j) Forced Outage information;
 - (k) Inputs from the eight-day look ahead planning tool, which may potentially keep a unit On-Line (or start a unit for the next day) so that a unit minimum duration between starts does not limit the availability of the unit (for security reasons); and
 - (l) Ancillary Service Deployment Factors.
- (19) The HRUC process and the DRUC process are as follows:
- (a) The HRUC process uses current Resource Status for the initial condition for the first hour of the RUC Study Period. All HRUC processes use the projected status of transmission breakers and switches starting with current status and updated for each remaining hour in the study as indicated in the COP for Resources and in the Outage Scheduler for transmission elements.
 - (b) The DRUC process uses the current hourly forecast of total ERCOT Load including DC Tie Schedules up to the physical rating of the DC Tie for each hour of the Operating Day. The HRUC process uses the current hourly forecast

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of total ERCOT Load including DC Tie Schedules up to the physical rating of the DC Tie for each hour in the RUC Study Period.

- (c) The DRUC process uses the Day-Ahead weather forecast for each hour of the Operating Day. The HRUC process uses the weather forecast information for each hour of the balance of the RUC Study Period.
- (d) For the HRUC, DRUC, and Weekly Reliability Unit Commitment (WRUC) processes, a feasibility check on the COP submitted Hour Beginning Planned SOC will be performed. This check may adjust the Hour Beginning Planned SOC used in the RUC process. The feasibility check looks sequentially across all intervals in the RUC Study Period to validate whether a particular interval's COP Hour Beginning Planned SOC is achievable from the previous interval. If it is not feasible, then RUC will adjust the Hour Beginning Planned SOC to the closest achievable value.

- (20) A QSE with a Resource that is not a Reliability Must-Run (RMR) Unit or has not received an Outage Schedule Adjustment (OSA) that has been committed in a DRUC or HRUC process may opt out of the RUC Settlement (or "buy back" the commitment) by setting the COP status of the RUC-committed Resource to ONOPTOUT for the first hour of a contiguous block of RUC-Committed Hours in the Opt Out Snapshot. All the configurations of the same Combined Cycle Train shall be treated as the same Resource for the purpose of creating the block of RUC-Committed Hours. A RUC-committed Combined Cycle Generation Resource may opt out of the RUC Settlement by setting the COP status of any Combined Cycle Generation Resource within the same Combined Cycle Train as the RUC-committed Resource to ONOPTOUT for the first hour of a contiguous block of RUC-Committed Hours in the Opt Out Snapshot. A Combined Cycle Generation Resource that is RUC-committed from one On-Line configuration in order to transition to a different configuration with additional capacity may opt out of the RUC Settlement following the same rule for RUC-committed Combined Cycle Generation Resources described above. A QSE that opts out of RUC Settlement forfeits RUC Settlement for the affected Resource for a given block of RUC Buy-Back Hours. A QSE that opts out of RUC Settlement treatment must make the Resource available to SCED for all RUC Buy-Back Hours. All hours in a contiguous block of RUC-Committed Hours that includes the RUC Buy-Back Hour shall be considered RUC Buy-Back Hours. If a contiguous block of RUC-Committed Hours spans more than one Operating Day and a QSE wishes to opt out of RUC Settlement for the RUC-Committed Hours in the second or subsequent Operating Day, the QSE must set its COP status to ONOPTOUT for the first hour of that the first Operating Day in the Opt Out Snapshot of the first Operating Day.
- (21) ERCOT shall, as soon as practicable, post to the ERCOT website a report identifying those hours that were considered RUC Buy-Back Hours, along with the name of each RUC-committed Resource whose QSE opted out of RUC Settlement.
- (22) A Resource that has a Three-Part Supply Offer cleared in the Day-Ahead Market (DAM) and subsequently receives a RUC commitment for the Operating Hour for

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which it was awarded will be treated as if the Resource Status was ONOPTOUT for purposes of Section 6.5.7.3 and Section 6.5.7.3.1, Determination of Real-Time Reliability Deployment Price Adders.

- (23) A Resource that has self-committed for an Operating Hour after the RUC Snapshot was taken but before the RUC commitment has been communicated through an XML message for that RUC process and that Operating Hour is included in a block of RUC-committed hours for that RUC process will be treated as if the Resource Status was ONOPTOUT for purposes of Section 6.5.7.3, Section 6.5.7.3.1, and RUC Settlement for the entire block of RUC-committed hours. A QSE that has a Resource that meets these conditions must make the Resource available to SCED for the entire block of RUC-committed hours. ERCOT will send the QSE a notification stating the Operating Day and block of hours for which this occurred.

6.5.7.3 Security Constrained Economic Dispatch

Commented [CP3]: Please note NPRR1268 also proposes revisions to this section.

- (1) The SCED process is designed to simultaneously manage energy, the system power balance and network congestion through Resource Base Points and calculation of LMPs every five minutes. The SCED process uses a two-step methodology that applies mitigation prospectively to resolve Non-Competitive Constraints for the current Operating Hour. The SCED process evaluates Energy Offer Curves, Output Schedules and Real-Time Market (RTM) Energy Bids to determine Resource Dispatch Instructions by maximizing bid-based revenues minus offer-based costs, subject to power balance and network constraints. The SCED process uses the Resource Status provided by SCADA telemetry under Section 6.5.5.2, Operational Data Requirements, and validated by the Real-Time Sequence, instead of the Resource Status provided by the COP.
- (2) The SCED solution must monitor cumulative deployment of Regulation Services and ensure that Regulation Services deployment is minimized over time.
- (3) In the Generation To Be Dispatched (GTBD) determined by LFC, ERCOT shall subtract the sum of the telemetered net real power consumption from all CLRs available to SCED.
- (4) For use as SCED inputs, ERCOT shall use the available capacity of all committed Generation Resources by creating proxy Energy Offer Curves for certain Resources as follows:
 - (a) Non-IRRs and Dynamically Scheduled Resources (DSRs) without Energy Offer Curves
 - (i) ERCOT shall create a monotonically increasing proxy Energy Offer Curve as described below for:
 - (A) Each non-IRR for which its QSE has submitted an Output Schedule instead of an Energy Offer Curve; and

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- (B) Each DSR that has not submitted incremental and decremental Energy Offer Curves.

MW	Price (per MWh)
HSL	SWCAP
Output Schedule MW plus 1 MW	SWCAP minus \$0.01
Output Schedule MW	-\$249.99
LSL	-\$250.00

- (b) DSRs with Energy Offer Curves

- (i) For each DSR that has submitted incremental and decremental Energy Offer Curves, ERCOT shall create a monotonically increasing proxy Energy Offer Curve. That curve must consist of the incremental Energy Offer Curve that reflects the available capacity above the Resource's Output Schedule to its HSL and the decremental Energy Offer Curve that reflects the available capacity below the Resource's Output Schedule to the LSL. The curve must be created as described below:

MW	Price (per MWh)
Output Schedule MW plus 1 MW to HSL	Incremental Energy Offer Curve
LSL to Output Schedule MW	Decremental Energy Offer Curve

- (c) Non-IRRs without full-range Energy Offer Curves

- (i) For each non-IRR for which its QSE has submitted an Energy Offer Curve that does not cover the full range of the Resource's available capacity, ERCOT shall create a proxy Energy Offer Curve that extends the submitted Energy Offer Curve to use the entire available capacity of the Resource above the highest point on the Energy Offer Curve to the Resource's HSL and the offer floor from the lowest point on the Energy Offer Curve to its LSL, using these points:

MW	Price (per MWh)
HSL (if more than highest MW in submitted Energy Offer Curve)	Price associated with highest MW in submitted Energy Offer Curve
Energy Offer Curve	Energy Offer Curve
1 MW below lowest MW in Energy Offer Curve (if more than LSL)	-\$249.99
LSL (if less than lowest MW in Energy Offer Curve)	-\$250.00

- (d) IRRs

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- (i) For each IRR that has not submitted an Energy Offer Curve, ERCOT shall create a monotonically increasing proxy Energy Offer Curve as described below:

MW	Price (per MWh)
HSL	\$1,500
HSL minus 1 MW	-\$249.99
LSL	-\$250.00

- (ii) For each IRR for which its QSE has submitted an Energy Offer Curve that does not cover the full range of the IRR's available capacity, ERCOT shall create a monotonically increasing proxy Energy Offer Curve as described below:

MW	Price (per MWh)
HSL (if more than highest MW in submitted Energy Offer Curve)	Price associated with the highest MW in submitted Energy Offer Curve
Energy Offer Curve	Energy Offer Curve
1 MW below lowest MW in Energy Offer Curve (if more than LSL)	-\$249.99
LSL (if less than lowest MW in Energy Offer Curve)	-\$250.00

(e) RUC-committed Resources

- (i) For each RUC-committed Resource that has not submitted an Energy Offer Curve, ERCOT shall create a proxy Energy Offer Curve as described below:

MW	Price (per MWh)
HSL	\$250
Zero	\$250

- (ii) For each RUC-committed Resource that has submitted an Energy Offer Curve, ERCOT shall create a monotonically increasing proxy Energy Offer Curve as described below:

MW	Price (per MWh)
HSL (if more than highest MW in Energy Offer Curve)	Greater of \$250 or price associated with the highest MW in QSE submitted Energy Offer Curve
Energy Offer Curve	Greater of \$250 or the QSE submitted Energy Offer Curve

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Zero	Greater of \$250 or the first price point of the QSE submitted Energy Offer Curve
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- (iii) For each Combined Cycle Generation Resource that was RUC-committed from one On-Line configuration in order to transition to a different configuration with additional capacity, as instructed by ERCOT, that has not submitted an Energy Offer Curve for the RUC-committed configuration, ERCOT shall create a proxy Energy Offer Curve as described below:

MW	Price (per MWh)
HSL of RUC-committed configuration	\$250
Zero	\$250

- (iv) For each Combined Cycle Generation Resource that was RUC-committed from one On-Line configuration in order to transition to a different configuration with additional capacity, as instructed by ERCOT, that has submitted an Energy Offer Curve for the RUC-committed configuration, ERCOT shall create a monotonically increasing proxy Energy Offer Curve as described below:

MW	Price (per MWh)
HSL of RUC-committed configuration (if more than highest MW in Energy Offer Curve)	Greater of \$250 or price associated with the highest MW in QSE submitted Energy Offer Curve
Energy Offer Curve for MW at and above HSL of QSE-committed configuration	Greater of \$250 or the QSE submitted Energy Offer Curve
HSL of QSE-committed configuration (if more than highest MW in Energy Offer Curve and price associated with highest MW in Energy Offer Curve is less than \$250)	\$250
HSL of QSE-committed configuration (if more than highest MW in Energy Offer Curve)	Price associated with the highest MW in QSE submitted Energy Offer Curve
Energy Offer Curve for MW at and below HSL of QSE-committed configuration	The QSE submitted Energy Offer Curve
1 MW below lowest MW in Energy Offer Curve (if more than LSL)	-\$249.99
LSL (if less than lowest MW in Energy Offer Curve)	-\$250.00