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PROJECT NO. 24055

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PROTOCOL REVISION INFORMATIONAL FILINGS BY THE ELECTRIC RELIABILTY COUNCIL OF TEXAS	§ § § §	**PUBLIC UTILITY COMMISSION OF TEXAS**

ERCOT'S NOTICE OF NODAL PROTOCOL REVISIONS (MARCH 1, 2021)

Electric Reliability Council of Texas, Inc. (ERCOT) respectfully informs the Public Utility Commission of Texas (Commission) of revisions to the ERCOT Nodal Protocols.

Summary of Revisions

In accordance with the process set forth in Section 21 of the ERCOT Protocols, ERCOT adopted Nodal Protocol Revision Requests (NPRRs) 994, 1044, 1049, 1050, 1053, 1068 (effective March 1, 2021); 1024, 1034, 1040, 1051 (effective upon system implementation); 1048 (effective upon system implementation of NPRR978); 1052 (effective upon system implementation of NPRR917); and 1054 (effective March 1, 2021 for Sections 4.2.1.2, 4.4.4, and 4.4.4.2; and upon system implementation for all remaining language). These NPRRs were developed in the ERCOT committee process, and approved by the ERCOT Board of Directors (ERCOT Board) on February 9, 2021. These NPRRs are described below.

NPRR	Description	ERCOT Nodal Protocol Sections Modified
994	**Clarify Generator Interconnection Neutral Project Classification Revision.** This NPRR clarifies which transmission improvement projects associated with the interconnection of new Generation Resources should be classified as "neutral" projects, including new substations. This NPRR also provides clarity in regards to which Generation Resource interconnection Transmission Facilities are considered when determining if ERCOT should perform an economic analysis	Section 3, Subsections 3.11.4.3 and 3.11.6 (Attachment A)

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	pursuant to paragraph (2) of Section 3.11.6, Generation Interconnection Process.	
1024 **(effective upon system implementation)**	**Determination of Significance with Respect to Price Corrections.** This NPRR gives ERCOT the authority to consider significance in determining whether to perform a price correction for the Day-Ahead Market (DAM) or Real-Time Market (RTM). Specifically, this NPRR introduces metrics for determining when ERCOT will perform a price correction or request ERCOT Board approval for a price correction.	Section 4, Subsection 4.5.3 (Attachment B) Section 6, Subsection 6.3 (Attachment C)
1034 **(effective upon system implementation)**	**Frequency-Based Limits on DC Tie Imports or Exports.** This NPRR creates new Section 4.4.4.4, Frequency-Based Limits on DC Tie Imports or Exports, to allow ERCOT to establish import or export limits on Direct Current Ties (DC Ties) to avoid the risk of any unacceptable frequency deviation that may be identified in the event of an unexpected loss of one or more DC Ties when importing or exporting. Revisions to Section 4.4.4, DC Tie Schedules, would allow ERCOT to curtail DC Tie Schedules on a DC Tie on a last-in-first-out basis when necessary to address this risk. The last-in-first-out curtailment methodology is consistent with current practice documented in the Operating Procedure Manual – DC Tie Desk. ERCOT would be required to post on the ERCOT website the operating conditions and associated limits that it would expect to use.	Section 4, Subsections 4.4.4 and 4.4.4.4 (Attachment B)
1040 **(effective upon**	**Compliance Metrics for Ancillary Service Supply Responsibility.** This NPRR establishes	Section 8, Subsections 8.1.1.3 and 8.1.1.4.1

system implementation)	compliance metrics for Ancillary Service Supply Responsibility.	(Attachment D)
1044	**Enhancement of SSR Mitigation Requirement.** This NPRR requires Generation Resources and Energy Storage Resources (ESRs) to develop and implement Subsynchronous Resonance (SSR) Mitigation plans to address SSR vulnerabilities in the event of six or fewer concurrent transmission Outages, instead of the current threshold of four or fewer Outages. Generation Resources and ESRs that satisfied Planning Guide Section 6.9, Addition of Proposed Generation to the Planning Models, before September 1, 2020 would be allowed to elect SSR monitoring to address SSR vulnerabilities in the event of five or six concurrent transmission Outages.	Section 3, Subsection 3.22.1.2 (Attachment A)
1048 **(effective upon system implementation of NPRR978)**	**Clarification on NPRR978 Short-Term Adequacy Reports.** This NPRR changes certain reports required by Section 3.2.3, System Adequacy Reports, from being aggregated "by Load Zone" to being aggregated "by Forecast Zone." "Forecast Zones," which have the same boundaries as the 2003 ERCOT Congestion Management Zones (CMZs), consist of North, South, West, and Houston.	Section 3, Subsection 3.2.3 (Attachment A)
1049	**Management of DC Tie Load Zone Modifications.** This NPRR removes the requirement to obtain ERCOT Board approval to add, delete, or change a DC Tie Load Zone. This NPRR also removes the 48-month waiting period before such actions can go into effect. Further, this	Section 3, Subsections 3.4.2 and 3.10.3.1 (Attachment A)

	NPRR aligns the timeline for deleting DC Tie Load Zones with the timeline for removing Resource Nodes associated with a retiring Generation Resource.	
1050	**Change to the Summer Commercial Operations Date Deadline for Including Planned Generation Capacity in Reports on the Capacity, Demand and Reserves in the ERCOT Region.** This NPRR changes the summer projected Commercial Operations Date deadline from the start of the summer Peak Load Season to July 1. Also, to be consistent with establishing a specific Commercial Operations Date deadline for the summer Peak Load Season, this NPRR adds the date of the start of the winter Peak Load Season.	Section 3, Subsection 3.2.6.2.2 (Attachment A)
1051 **(effective upon system implementation)**	**Removal of the Price Floor Applied to Day-Ahead Settlement Point Prices.** This NPRR removes the administrative price floor of -$251/MWh from all Day-Ahead Settlement Point Prices (DASPPs).	Section 4, Subsection 4.6.1 (Attachment B)
1052 **(effective upon system implementation of NPRR917)**	**Load Zone Pricing for Settlement Only Storage Prior to NPRR995 Implementation.** This NPRR ensures that Energy Storage Systems (ESSs) that are registered with ERCOT as Settlement Only Generators (SOGs) will continue to have their injections and withdrawals settled at Load Zone pricing until nodal pricing for injections and withdrawals is approved and implemented.	Section 6, Subsections 6.6.3.2 and 6.6.3.9 (Attachment C) Section 9, Subsection 9.19.1 (Attachment E) Section 16, Subsection 16.5 (Attachment F)

1053	**BESTF-9 Exemption from Ancillary Service Supply Compliance Requirements for Energy Storage Resources Affected by EEA Level 3 Charging Suspensions.** This NPRR establishes an exemption from Ancillary Service supply compliance requirements for any Qualified Scheduling Entity (QSE) representing an ESR whose ability to charge is restricted during an Energy Emergency Alert (EEA) Level 3 event. The NPRR clarifies that the compliance exemption does not impact the QSE's financial responsibility due to the Ancillary Service insufficiency. Upon implementation of the Real-Time Co-optimization (RTC) Project, these provisions will no longer be necessary, and the language inserted by this NPRR will be removed.	Section 8, Subsection 8.1.1.3 (Attachment D)
1054 **(effective March 1, 2021 for Sections 4.2.1.2, 4.4.4, and 4.4.4.2; upon system implementation for all remaining language)**	**Removal of Oklaunion Exemption Language.** This NPRR removes all references to Oklaunion Exemption from the ERCOT Protocols and adjusts the affected sections' remaining language accordingly.	Section 2, Subsection 2.1 (Attachment G) Section 4, Subsections 4.2.1.2, 4.4.4, and 4.4.4.2 (Attachment B) Section 5, Subsection 5.7.4.1.1 (Attachment H) Section 6, Subsections 6.6.2.1, 6.6.2.3, 6.6.2.6, 6.6.2.8, 6.6.3.5, 6.6.3.6 (delete), and 6.6.10 (Attachment C) Section 7, Subsection 7.5.7

		and 7.9.3.5 (Attachment I) Section 9, Subsection 9.5.3 (Attachment E) Section 11, Subsection 11.4.6.1 (Attachment J) Section 16, Subsection 16.11.4.3.2 (Attachment F)
1068	**Administrative Changes for March 1, 2021 Nodal Protocols - Remove "ROSC" from NCI Form.** This Administrative NPRR removes the "Resource Outage Submittal Contact (ROSC)" from the Notice of Change of Information (NCI) Form. The ROSC identified a contact for a Resource Entity that was to be used as a single point of contact for the entry of Outages. However, ERCOT utilizes the 24x7 contact for use in the Outage Scheduler, and the ROSC no longer serves a purpose for ERCOT.	Section 23, Form E (Attachment K)
	Administrative Changes. Non-substantive administrative changes were made such as spelling corrections, formatting, and correcting Section numbering and references.	Section 3, Subsections 3.2.3, 3.8.8, 3.10.7.2, 3.14.1.7, 3.14.2, and 3.14.4.1 (Attachment A) Section 4, Subsections 4.3, 4.4.9.4.2, 4.4.10, and 4.6.3 (Attachment B)

The changes to the Nodal Protocol language as revised by the above NPRRs are shown in Attachments A through K in redline format.

The ERCOT Nodal Protocols, including these revisions, may be accessed on ERCOT's website at http://www.ercot.com/mktrules/nprotocols/index.html.

Respectfully submitted,

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COUNCIL OF TEXAS, INC.

LIST OF ATTACHMENTS

ERCOT Nodal Protocols

Section 3: Management Activities for the ERCOT System

March~~February~~ 1, 2021

3 MANAGEMENT ACTIVITIES FOR THE ERCOT SYSTEM

3.2 Analysis of Resource Adequacy

3.2.3 Short-Term System Adequacy Reports

(1) ERCOT shall generate and post short-term adequacy reports on the ERCOT website. ERCOT shall update these reports hourly following updates to the Seven-Day Load Forecast, except where noted otherwise. The short-term adequacy reports will provide:

(a) For Generation Resources, the available On-Line Resource capacity for each hour, using the COP for the first seven days and considering Resources with a COP Resource Status listed in paragraph (5)(b)(i) of Section 3.9.1, Current Operating Plan (COP) Criteria;

(b) ERCOT shall post a total system-wide capacity of Resource Outages as reflected in the Outage Scheduler that are accepted or approved. The Resource Outage capacity amount shall be based from each Resource's current Seasonal High Sustained Limit (HSL) and posted each hour for the top of each Operating Hour for the next 168 hours. This posted information will exclude specific Resource information and Outages related to Mothballed or Decommissioned Generation Resources, and will be aggregated on a system-wide basis in three categories:

(i) IRRs with an Outage Scheduler nature of work other than "New Equipment Energization";

(ii) Other Resources with an Outage Scheduler nature of work other than "New Equipment Energization"; and

(iii) Resources with an Outage Scheduler nature of work "New Equipment Energization";

(c) For Load Resources, the available capacity for each hour using the COP for the first seven days and considering Resources with a COP Resource Status of ONRGL, ONCLR, or ONRL;

(d) Forecast Demand for each hour described in Section 3.2.2, Demand Forecasts;

(e) For Generation Resources, the available Off-Line Resource capacity that can be started for each hour, using the COP for the first seven days and considering Resources with a COP Resource Status of OFF or OFFNS and temporal constraints; and

(f) Following each Hourly Reliability Unit Commitment (HRUC), the available On-Line capacity from Generation Resources, based on Real-Time telemetry, for which the COP Resource Status is OFF, OUT, or EMR for all hours within the

HRUC Study Period. The available On-Line capacity will consider those Resources with a Real-Time Resource Status listed in paragraph (5)(b)(i) of Section 3.9.1 excluding SHUTDOWN.

[NPRR962, NPRR974, NPRR978, NPRR1007, ~~and~~ NPRR1029, and NPRR1048: Replace applicable portions of Section 3.2.3 above with the following upon system implementation for NPRR962, NPRR974, ~~NPRR978,~~ or NPRR1029; upon system implementation of NPRR978 for NPRR978 and NPRR1048; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007:]

3.2.3 Short-Term System Adequacy Reports

(1) ERCOT shall generate and post short-term adequacy reports on the ERCOT website. ERCOT shall update these reports hourly following updates to the Seven-Day Load Forecast, except where noted otherwise. The short-term adequacy reports will provide:

(a) For Generation Resources, the available On-Line Resource capacity for each hour, aggregated by ~~Load~~Forecast Zone, using the COP for the first seven days and considering Resources with a COP Resource Status listed in paragraph (5)(b)(i) of Section 3.9.1, Current Operating Plan (COP) Criteria;

(b) The total system-wide capacity of Resource Outages as reflected in the Outage Scheduler that are accepted or approved. The Resource Outage capacity amount shall be based from each Resource's current Seasonal High Sustained Limit (HSL) and posted each hour for the top of each Operating Hour for the next 168 hours. This posted information will exclude specific Resource information and Outages related to Mothballed or Decommissioned Generation Resources, and will be aggregated on a ~~Load~~Forecast Zone basis in three categories:

(i) IRRs and the intermittent renewable generation component of each DC-Coupled Resource with an Outage Scheduler nature of work other than "New Equipment Energization";

(ii) Other Resources with an Outage Scheduler nature of work other than "New Equipment Energization"; and

(iii) Resources with an Outage Scheduler nature of work "New Equipment Energization";

(c) For Load Resources, the available capacity for each hour aggregated by ~~Load~~Forecast Zone, using the COP for the first seven days and considering Resources with a COP Resource Status of ONL;

(d) The total capability of Resources available to provide the following Ancillary Service combinations, using COPs submitted by QSEs for the first seven days and capped by the COP limits for individual Resources. A Resource's capability shall only be included in the sums below if the Resource Status allows the Resource to provide at least one of the Ancillary Services within the sum:

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

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

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

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

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

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

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

(viii) Capacity to provide Reg-Down;

(e) Forecast Demand for each hour described in Section 3.2.2, Demand Forecasts;

(f) For Generation Resources, the available Off-Line Resource capacity that can be started for each hour, aggregated by ~~Load~~Forecast Zone, using the COP for the first seven days and considering Resources with a COP Resource Status of OFF and temporal constraints; and

(g) Following each Hourly Reliability Unit Commitment (HRUC), the available On-Line capacity from Generation Resources, aggregated by ~~Load~~Forecast Zone, based on Real-Time telemetry, for which the COP Resource Status is OFF, OUT, or EMR for all hours within the HRUC Study Period. The available On-Line capacity will consider those Resources with a Real-Time Resource Status listed in paragraph (5)(b)(i) of Section 3.9.1 excluding SHUTDOWN.

(h) For each Direct Current Tie (DC Tie), the sum of any ERCOT-approved DC Tie Schedules for each 15-minute interval for the first seven days. The sum shall be displayed as an absolute value and classified as a net import or net export.

(i) The available capacity for each hour for the next seven days. For day one, and for day two following the execution of the Day-Ahead Reliability Unit Commitment (DRUC) on day one, the available capacity will be the sum of the values calculated in paragraphs (a) and (f~~e~~) above, except that for IRRs the forecasted output will be used instead of COP values, and DC Tie Exports will be subtracted. For the remaining hours of the seven days, the available capacity will be calculated as the sum of the Seasonal HSLs for non-IRR Generation Resources including seasonal Private Use Network capacity and the forecasted output for IRRs minus the total capacity of accepted or approved Resource Outages.

(j) The available capacity for reserves for each hour, which will be the available capacity calculated in paragraph (~~h~~i) above minus the forecasted Demand for that hour.

3.2.6 ERCOT Planning Reserve Margin

3.2.6.2 ERCOT Planning Reserve Margin Calculation Methodology

3.2.6.2.2 Total Capacity Estimate

(1) The total capacity estimate shall be determined based on the following equation:

$$\mathbf{TOTCAP}_{s,i} = \mathbf{INSTCAP}_{s,i} + \mathbf{PUNCAP}_{s,i} + \mathbf{WINDCAP}_{s,i,r} + \mathbf{HYDROCAP}_{s,i} + \mathbf{SOLARCAP}_{s,i} + \mathbf{RMRCAP}_{s,i} + \mathbf{DCTIECAP}_{s} + \mathbf{PLANDCTIECAP}_{s} + \mathbf{SWITCHCAP}_{s,i} + \mathbf{MOTHCAP}_{s,i} + \mathbf{PLANNON}_{s,i} + \mathbf{PLANIRR}_{s,i,r} - \mathbf{LTOUTAGE}_{s,i} - \mathbf{UNSWITCH}_{s,i} - \mathbf{RETCAP}_{s,i}$$

The above variables are defined as follows:

Variable	Unit	Definition
TOTCAP $_{s,i}$	MW	*Total Capacity*—Estimated total capacity available during the Peak Load Season *s* for the year *i*.
INSTCAP $_{s,i}$	MW	*Seasonal Net Max Sustainable Rating*—The Seasonal net max sustainable rating for the Peak Load Season *s* as reported in the approved Resource Registration process for each operating Generation Resource for the year *i* excluding WGRs, hydro Generation Resource capacity, solar unit capacity, Resources operating under RMR Agreements, and Generation Resources capable of "switching" from the ERCOT Region to a non-ERCOT Region.

Variable	Unit	Definition
PUNCAP $_{s, i}$	MW	*Private Use Network Capacity*—The forecasted generation capacity available to the ERCOT Transmission Grid, net of self-serve load, from Generation Resources and Settlement Only Generators (SOGs) in Private Use Networks for Peak Load Season *s* and year *i*. The capacity forecasts are developed as follows. First, a base capacity forecast, determined from Settlement data, is calculated as the average net generation capacity available to the ERCOT Transmission Grid during the 20 highest system-wide peak Load hours for each preceding three-year period for Peak Load Season *s* and year *i*. The base capacity forecast is then adjusted by adding the aggregated incremental forecasted annual changes in net generation capacity as of the start of the summer Peak Load Season *s* for forecast year *i* reported for Private Use Networks pursuant to Section 10.3.2.4, Reporting of Net Generation Capacity. This calculation is limited to Generation Resources and SOGs in Private Use Networks (1) with a Resource Commissioning Date that occurs no later than the start of the most current Peak Load Season used for the calculation, and (2) that have not been permanently retired by the start of the most current Peak Load Season used for the calculation.
WINDPEAKPCT $_{s, r}$	%	*Seasonal Peak Average Wind Capacity as a Percent of Installed Capacity*—The average WGR capacity available for the summer and winter Peak Load Seasons *s* and region *r*, divided by the installed capacity for region *r*, expressed as a percentage. The Seasonal Peak Average, derived from Settlement data, is first calculated as the average capacity during the 20 highest system-wide peak Load hours for a given year's summer and winter Peak Load Seasons. The final value is the weighted average of the previous ten eligible years of Seasonal Peak Average values where each year is weighted by its installed capacity. Eligible years include 2009 through the most recent year for which COP data is available for the summer and winter Peak Load Seasons. If the number of eligible years is less than ten, the average shall be based on the number of eligible years available. This calculation is limited to WGRs (1) with a Resource Commissioning Date that occurs no later than the start of the most current Peak Load Season used for the calculation, and (2) that have not been permanently retired by the start of the most current Peak Load Season used for the calculation.
WINDCAP $_{s, i, r}$	MW	*Existing WGR Capacity*—The capacity available for all existing WGRs for the summer and winter Peak Load Seasons *s*, year *i*, and region *r*, multiplied by WINDPEAKPCT for summer and winter Peak Load Seasons *s* and region *r*.
HYDROCAP $_{s, i}$	MW	*Hydro Unit Capacity*—The average hydro Generation Resource capacity available, as determined from the COP, during the highest 20 peak Load hours for each preceding three-year period for Peak Load Season *s* and year *i*. This calculation is limited to hydro Generation Resources (1) with a Resource Commissioning Date that occurs no later than the start of the most current Peak Load Season used for the calculation, and (2) that have not been permanently retired by the start of the most current Peak Load Season used for the calculation.
SOLARPEAKPCT $_{s}$	%	*Seasonal Peak Average Solar Capacity as a Percent of Installed Capacity*—The average PVGR capacity available for the summer and winter Peak Load Seasons *s*, divided by the installed capacity, expressed as a percentage. The Seasonal Peak Average, derived from Settlement data, is first calculated as the average capacity during the 20 highest system-wide peak Load hours for a given year's summer and winter Peak Load Seasons. The final value is the weighted average of the previous three years of Seasonal Peak Average values where each year is weighted by its installed capacity. This calculation is limited to PVGRs (1) with a Resource Commissioning Date that occurs no later than the start of the most current Peak Load Season used for the calculation, and (2) that have not been permanently retired by the start of the most current Peak Load Season used for the calculation.

Variable	Unit	Definition
SOLARCAP $_{s,i}$	MW	*Existing PVGR Capacity*—The capacity available for all existing PVGRs for the summer and winter Peak Load Season *s* and year *i*, multiplied by SOLARPEAKPCT for summer and winter Peak Load Seasons *s*
RMRCAP $_{s,i}$	MW	*Seasonal Net Max Sustainable Rating for Generation Resource providing RMR Service*—The Seasonal net max sustainable rating for the Peak Load Season *s* as reported in the approved Resource Registration process for each Generation Resource providing RMR Service for the year *i* until the approved exit strategy for the RMR Resource is expected to be completed.
DCTIEPEAKPCT $_{s}$	%	*Seasonal Peak Average Capacity for existing DC Tie Resources as a Percent of Installed DC Tie Capacity*—The average net emergency DC Tie imports for the summer and winter Peak Load Seasons *s*, divided by the total installed DC Tie capacity for Peak Load Seasons *s*, expressed as a percentage. The average net emergency DC Tie imports is calculated for the SCED intervals during which ERCOT declared an Energy Emergency Alert (EEA). This calculation is limited to the most recent single summer and winter Peak Load Seasons in which an EEA was declared. The total installed DC Tie capacity is the capacity amount at the start of the Peak Load Seasons used for calculating the net DC Tie imports.
DCTIECAP $_{s}$	MW	*Expected Existing DC Tie Capacity Available under Emergency Conditions*—DCTIEPEAKPCT $_{s}$ multiplied by the installed DC Tie capacity available for the summer and winter Peak Load Seasons *s*, adjusted for any known capacity transfer limitations.
PLANDCTIECAP $_{s}$	MW	*Expected Planned DC Tie Capacity Available under Emergency Conditions*—DCTIEPEAKPCT $_{s}$ multiplied by the maximum peak import capacity of planned DC Tie projects included in the most recent Steady State Working Group (SSWG) base cases, for the summer and winter Peak Load Seasons *s*. The import capacity may be adjusted to reflect known capacity transfer limitations indicated by transmission studies.
SWITCHCAP $_{s,i}$	MW	*Seasonal Net Max Sustainable Rating for Switchable Generation Resource*—The Seasonal net max sustainable rating for the Peak Load Season *s* as reported in the approved Resource Registration process for each Generation Resource for the year *i* that can electrically connect (i.e., "switch") from the ERCOT Region to another power region.
MOTHCAP $_{s,i}$	MW	*Seasonal Net Max Sustainable Rating for Mothballed Generation Resource*—The Seasonal net max sustainable rating for the Peak Load Season *s* as reported in the approved Resource Registration process for each Mothballed Generation Resource for the year *i* based on the lead time and probability information furnished by the owners of Mothballed Generation Resources pursuant to Section 3.14.1.9, Generation Resource Status Updates. If the value furnished by the owner of a Mothballed Generation Resource pursuant to Section 3.14.1.9 is greater than or equal to 50%, then use the Seasonal net max sustainable rating for the Peak Load Season *s* as reported in the approved Resource registration process for the Mothballed Generation Resource for the year *i*. If the value furnished by the owner of a Mothballed Generation Resource pursuant to Section 3.14.1.9 is less than 50%, then exclude that Resource from the Total Capacity Estimate.

Variable	Unit	Definition
PLANNON $_{s,i}$	MW	*New, non-IRR Generating Capacity*—The amount of new, non-IRR generating capacity available by July 1 and December 1 for the summer and winter Peak Load Seasons *s*, respectively, and year *i* that: (a) has a Texas Commission on Environmental Quality (TCEQ)-approved air permit, (b) has a federal Greenhouse Gas permit, if required, (c) has obtained water rights, contracts or groundwater supplies sufficient for the generation of electricity at the Resource, and (d) has a signed Standard Generation Interconnect Agreement (SGIA), or a public, financially-binding agreement between the Resource owner and TSP under which generation interconnection facilities would be constructed; or for a Municipally Owned Utility (MOU) or Electric Cooperative (EC), a public commitment letter to construct a new Resource. New, non-IRR generating capacity is excluded if the Generation Interconnection or Change Request (GINR) project status in the online Resource Integration and Ongoing Operations (RIOO) interconnection services system is set to "Cancelled" or "Inactive" or if the Resource was previously mothballed or retired and does not have an owner that intends to operate it. For the purposes of this section, ownership of a mothballed or retired Resource for which a new generation interconnection is sought can only be satisfied by proof of site control as described in paragraph (1)(a), (b), or (d) of Planning Guide Section 5.4.9, Proof of Site Control.
PLANIRR $_{s,i,r}$	MW	*New IRR Capacity*—For new WGRs, the capacity available by July 1 and December 1 for the summer and winter Peak Load Seasons *s*, respectively, year *i*, and region *r*, multiplied by WINDPEAKPCT for summer and winter Load Season *s* and region *r*. For new PVGRs, the capacity available for the summer and winter Peak Load Seasons *s* and year *i*, multiplied by SOLARPEAKPCT for summer and winter Load Seasons *s*. New IRRs must have an SGIA or other public, financially binding agreement between the Resource owner and TSP under which generation interconnection facilities would be constructed or, for a MOU or EC, a public commitment letter to construct a new IRR. New IRR capacity is excluded if the GINR project status in the online RIOO interconnection services system is set to "Cancelled," or "Inactive."
LTOUTAGE $_{s,i}$	MW	*Forced Outage Capacity Reported in a Notification of Suspension of Operations*—For non-IRRs whose operation has been suspended due to a Forced Outage as reported in a Notification of Suspension of Operations (NSO), the sum of Seasonal net max sustainable ratings for Peak Load Seasons *s* for year *i*, as reported in the NSO forms. For IRRs, use the PLANIRR $_{s,i,r}$ calculated for each IRR.
UNSWITCH $_{s,i}$	MW	*Capacity of Unavailable Switchable Generation Resource*—The amount of capacity reported by the owners of a switchable Generation Resource that will be unavailable to ERCOT during the Peak Load Season *s* and year *i* pursuant to paragraph (2) of Section 16.5.4, Maintaining and Updating Resource Entity Information.
RETCAP $_{s,i}$	MW	*Capacity Pending Retirement*—The amount of capacity in Peak Load Season *s* of year *i* that is pending retirement based on information submitted on an NSO form (Section 22, Attachment E, Notification of Suspension of Operations) pursuant to Section 3.14.1.11, Budgeting Eligible Costs, but is under review by ERCOT pursuant to Section 3.14.1.2, ERCOT Evaluation Process, that has not otherwise been considered in any of the above defined categories. For Generation Resources and SOGs within Private Use Networks, the retired capacity amount is the peak average capacity contribution included in PUNCAP. For reporting of individual Generation Resources and SOGs in the Report on the Capacity, Demand and Reserves in the ERCOT Region, only the summer net max sustainable rating included in the NSO shall be disclosed.

Variable	Unit	Definition
i	None	Year.
s	None	Summer and winter Peak Load Seasons for year *i*.
r	None	Coastal, Panhandle, and Other wind regions. WGRs are classified into regions based on the county that contains their Point of Interconnection (POI). The Coastal region is defined as the following counties: Aransas, Brazoria, Calhoun, Cameron, Kenedy, Kleberg, Matagorda, Nueces, Refugio, San Patricio, and Willacy. The Panhandle region is defined as the following counties: Armstrong, Bailey, Briscoe, Carson, Castro, Childress, Cochran, Collingsworth, Crosby, Dallam, Deaf Smith, Dickens, Donley, Floyd, Gray, Hale, Hall, Hansford, Hartley, Hemphill, Hockley, Hutchinson, Lamb, Lipscomb, Lubbock, Moore, Motley, Ochiltree, Oldham, Parmer, Potter, Randall, Roberts, Sherman, Swisher, and Wheeler. The Other region consists of all other counties in the ERCOT Region.

3.4 Load Zones

3.4.2 Load Zone Modifications

(1) Competitive Load Zones and NOIE Load Zones may be added, deleted, or changed, only when approved by the ERCOT Board, with the exception of paragraph (1)(c) of Section 3.4.3, NOIE Load Zones. Approved additions, deletions, or changes go into effect 48 months after the end of the month in which the addition, deletion, or change was approved, with the exception of paragraph (3) below. DC Tie Load Zones are not subject to these requirements.

(2) The addition of Load that is new to the ERCOT System to an existing Load Zone does not constitute a change to a Load Zone under this section. This provision includes the transfer of existing Load from a non-ERCOT Control Area into a Load Zone in the ERCOT System. Adding Load that is new to the ERCOT System to an existing Load Zone does not require ERCOT Board approval, and no notice period is required prior to adding such Load to an existing Load Zone.

(3) A NOIE that was included in the establishment of an automatic pre-assigned NOIE Load Zone under paragraph (1)(c) of Section 3.4.3 may elect to be assigned to an appropriate Competitive Load Zone after giving notice of termination of its power supply arrangement if a request to be assigned to a Competitive Load Zone was given to ERCOT at least 90 days prior to the start of the Pre-Assigned Congestion Revenue Right (PCRR) nomination window for the effective year of the Load Zone change. The move to a Competitive Load Zone requires ERCOT Board approval and shall be effective no sooner than the first day of the PCRR Nomination Year.

3.8 Special Considerations for Split Generation Meters, Combined Cycle Generation Resources, Quick Start Generation Resources, Hydro Generation Resources, Limited Duration Resources, and Energy Storage Resources

[NPRR1026: Insert Section 3.8.8 below upon system implementation:]

3.8.8 Self-Limiting Facility

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

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

(3) On a monthly basis, ERCOT will report to the Reliability Monitor and IMM any instance where a Self-Limiting Facility's actual MW Injections exceeded the MW Injection limit or where actual MW Withdrawals exceeded the MW Withdrawal limit established in the Resource Registration data for the Self-Limiting Facility, as described in Section 3.9.1, Current Operating Plan (COP) Criteria.

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

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

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

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

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

3.10 Network Operations Modeling and Telemetry

3.10.3 CRR Network Model

3.10.3.1 Process for Managing Network Operations Model Updates~~Changes in Updated Network Operations Model~~ for ~~Resource Retirements or~~ Point of Interconnection Changes, Resource Retirements and Deletion of DC Tie Load Zones

(1) Following the permanent change in Point of Interconnection (POI) of all Resources associated with a Resource Node, ERCOT shall retain the associated Settlement Point in the Network Operations Model at its existing location or an electrically similar location until all outstanding CRRs associated with that Settlement Point have expired. Following the retirement of all Resources associated with a Resource Node, ERCOT shall move the Resource Node to a proxy Electrical Bus. The proxy Electrical Bus will be selected by finding the nearest energized Electrical Bus at the same voltage level with the least impedance equipment between the retired Resource Node and the proxy Electrical Bus. For purposes of the CRR Auction model for calendar periods that are prior to the expiration date of all CRRs associated with the Settlement Point, the Settlement Point will continue to be available as a sink or source for CRR Auction transaction submittals. For calendar months that are beyond the expiration date of all CRRs associated with the Settlement Point, the Settlement Point will not be available for transaction submittals in the associated CRR Auctions. The Settlement Point will be removed from the Network Operations Model once all associated CRRs have expired.

(2) When a Direct Current Tie (DC Tie) is to be permanently removed from service, ERCOT will delete the associated DC Tie Load Zone from the Network Operations Model after all outstanding CRRs associated with that DC Tie Load Zone have expired. The DC Tie Load Zone will continue to be available as a sink or source Settlement Point for transaction submittals in CRR Auctions for calendar periods that are prior to the

scheduled deletion date of the DC Tie Load Zone; however, the DC Tie Load Zone will no longer be an available Settlement Point for transaction submittals in CRR Auctions for calendar periods that are after the scheduled deletion date of the DC Tie Load Zone.

3.10.7 ERCOT System Modeling Requirements

3.10.7.2 Modeling of Resources and Transmission Loads

(1) Each Resource Entity shall provide ERCOT and its interconnecting TSP with information describing each of its Generation Resources, SOGs, and Load Resources connected to the transmission system. All Resources greater than ten MW, Generation Resources less than ten MW but providing Ancillary Service, Settlement Only Transmission Generators (SOTGs), Settlement Only Transmission Self-Generators (SOTSGs), Split Generation Resources where the physical generator being split is greater than ten MW, Private Use Networks containing Resources greater than ten MW, Wind-powered Generation Resources (WGRs), PhotoVoltaic Generation Resources (PVGRs) or Aggregated Generation Resources (AGRs) with an aggregate interconnection to the ERCOT System greater than ten MW, ~~Direct Current Tie (~~DC Tie~~)~~ Resources, and the non-TSP owned step-up transformers greater than ten MVA, must be modeled to provide equivalent generation injections to the ERCOT Transmission Grid. ERCOT shall coordinate the modeling of Generation Resources, Private Use Networks, DC Tie Resources and Load Resources with their owners to ensure consistency between TSP models and ERCOT models.

[NPRR973: Replace paragraph (1) above with the following upon system implementation of PR106:]

(1) Each Resource Entity shall provide ERCOT and its interconnecting TSP with information describing each of its Generation Resources, SOGs, and Load Resources connected to the transmission system. All Resources greater than ten MW, Generation Resources less than ten MW but providing Ancillary Service, Settlement Only Transmission Generators (SOTGs), Settlement Only Transmission Self-Generators (SOTSGs), Split Generation Resources where the physical generator being split is greater than ten MW, Private Use Networks containing Resources greater than ten MW, Wind-powered Generation Resources (WGRs), PhotoVoltaic Generation Resources (PVGRs) or Aggregated Generation Resources (AGRs) with an aggregate interconnection to the ERCOT System greater than ten MW, Direct Current Tie (DC Tie) Resources, and the non-TSP owned MPTs greater than ten MVA, must be modeled to provide equivalent generation injections to the ERCOT Transmission Grid. ERCOT shall coordinate the modeling of Generation Resources, Private Use Networks, DC Tie Resources and Load Resources with their owners to ensure consistency between TSP models and ERCOT models.

[NPRR1016: Replace paragraph (1) above with the following upon system implementation:]

(1) Each Resource Entity shall provide ERCOT and its interconnecting TSP with information describing each of its Generation Resources, SOGs, and Load Resources connected to the ERCOT System. All Transmission Generation Resources (TGRs), Settlement Only Transmission Generators (SOTGs), Settlement Only Transmission Self-Generators (SOTSGs), and the non-TSP MPTs greater than ten MVA, must be modeled to provide equivalent generation injections to the ERCOT Transmission Grid. ERCOT shall coordinate the modeling of Generation Resources, Private Use Networks, and Load Resources with their owners to ensure consistency between TSP models and ERCOT models.

(2) Each Resource Entity representing either a Load Resource or an Aggregate Load Resource (ALR) shall provide ERCOT and, as applicable, its interconnecting DSP and TSP, with information describing each such Resource as specified in Section 3.7.1.2, Load Resource Parameters, and any additional information and telemetry as required by ERCOT, in accordance with the timelines set forth in Section 3.10.1, Time Line for Network Operations Model Changes. ERCOT shall coordinate the modeling of ALRs with Resource Entities. ERCOT shall coordinate with representatives of the Resource Entity to map Load Resources to their appropriate Load in the Network Operations Model.

[NPRR1016: Insert paragraph (3) below upon system implementation and renumber accordingly:]

(3) Each Resource Entity representing a Distribution Generation Resource (DGR) or Distribution Energy Storage Resource (DESR) that is registered with ERCOT pursuant to Section 16.5, Registration of a Resource Entity, shall provide ERCOT, its interconnecting DSP, and the TSP that interconnects the DSP to the transmission system with information describing each of its DGR or DESR facilities, and additional information and telemetry as required by ERCOT and the interconnecting DSP. ERCOT shall coordinate with representatives of the Resource Entity to represent the registered DGR or DESR facilities at their appropriate Electrical Bus in the Network Operations Model.

(3) Each Resource Entity representing a Distributed Generation (DG) facility that is registered with ERCOT pursuant to paragraph (5) of Section 16.5, Registration of a Resource Entity, shall provide ERCOT, its interconnecting DSP, and the TSP that interconnects the DSP to the transmission system with information describing each of its registered DG facilities, and additional information and telemetry as required by ERCOT. ERCOT shall coordinate with representatives of the Resource Entity to map registered DG facilities to their appropriate Load in the Network Operations Model.

[NPRR1016: Replace paragraph (3) above with the following upon system implementation:]

(3) Each Resource Entity representing a Settlement Only Distribution Generator (SODG) facility that is registered with ERCOT pursuant to paragraph (5) of Section 16.5 shall provide ERCOT, its interconnecting DSP, and the TSP that interconnects the DSP to the transmission system with information describing each of its SODG facilities, and additional information and telemetry as required by ERCOT. ERCOT shall coordinate with representatives of the Resource Entity to map registered SODG facilities to their appropriate Load in the Network Operations Model.

(4) Each Resource Entity representing a Split Generation Resource shall provide information to ERCOT and TSPs describing an individual Split Generation Resource for its share of the generation facility to be represented in the Network Operations Model in accordance with Section 3.8, Special Considerations for Split Generation Meters, Combined Cycle Generation Resources, Quick Start Generation Resources, Hydro Generation Resources, Limited Duration Resources, and Energy Storage Resources. The Split Generation Resource must be modeled as connected to the ERCOT Transmission Grid on the low side of the generation facility main power transformer.

[NPRR973 and NPRR1016: Replace applicable portions of paragraph (4) above with the following upon system implementation of PR106 or upon system implementation, respectively:]

(4) Each Resource Entity representing a Split Generation Resource shall provide information to ERCOT and TSPs describing an individual Split Generation Resource for its share of the generation facility to be represented in the Network Operations Model in accordance with Section 3.8, Special Considerations for Split Generation Meters, Combined Cycle Generation Resources, Quick Start Generation Resources, Hydro Generation Resources, Limited Duration Resources, and Energy Storage Resources, Distribution Generation Resources, and Distribution Energy Storage Resources. The Split Generation Resource must be modeled as connected to the ERCOT Transmission Grid on the low side of the generation facility MPT.

(5) ERCOT shall create a DC Tie Resource to represent an equivalent generation injection to represent the flow into the ERCOT Transmission Grid from operation of DC Ties. The actual injection flow on the DC Tie from telemetry provided by the facility owner(s) is the DC Tie Resource output.

(6) TSPs shall provide ERCOT with information describing all transmission Load connections on the ERCOT Transmission Grid. Individual Load connections may be combined, at the discretion of ERCOT, with other Load connections on the same transmission line to represent a Model Load to facilitate state estimation of Loads that do not telemeter Load measurements. ERCOT shall define "Model Loads", which may be

one or more combined Loads, for use in its Network Operations Model. A Model Load cannot be used to represent Load connections that are in different Load Zones.

[NPRR857: Replace paragraph (6) above with the following upon system implementation:]

(6) Each TSP and DCTO shall provide ERCOT with information describing all transmission Load connections on the ERCOT Transmission Grid. Individual Load connections may be combined, at the discretion of ERCOT, with other Load connections on the same transmission line to represent a Model Load to facilitate state estimation of Loads that do not telemeter Load measurements. ERCOT shall define "Model Loads", which may be one or more combined Loads, for use in its Network Operations Model. A Model Load cannot be used to represent Load connections that are in different Load Zones.

(7) ERCOT may require TSPs to provide additional Load telemetry to provide adequate modeling of the transmission system in accordance with Section 3.10.7.5, Telemetry Standards. When the TSP does not own the station for which additional Load telemetry is being requested, the TSP shall request that the owner make the telemetry available. The TSP shall notify ERCOT if the owner does not comply with the request.

[NPRR857: Replace paragraph (7) above with the following upon system implementation:]

(7) ERCOT may require TSPs and DCTOs to provide additional Load telemetry to provide adequate modeling of the transmission system in accordance with Section 3.10.7.5, Telemetry Standards. When the TSP or DCTO does not own the station for which additional Load telemetry is being requested, the TSP shall request that the owner make the telemetry available. The TSP or DCTO shall notify ERCOT if the owner does not comply with the request.

(8) ERCOT shall create a DC Tie Load to represent an equivalent Load withdrawal to represent the flow from the ERCOT Transmission Grid from operation of DC Ties. The actual withdrawal flow on the DC Tie from telemetry provided by the facility owner(s) is the DC Tie Load output.

(9) Each TSP shall also provide information to ERCOT describing automatic Load transfer (rollover) plans and the events that trigger which Loads are switched to other Transmission Elements on detection of Outage of a primary Transmission Element. ERCOT shall accommodate Load rollover plans in the Network Operations Model

(10) Loads associated with a Generation Resource in a common switchyard as defined in Section 10.3.2.3, Generation Netting for ERCOT-Polled Settlement Meters, and served through a transformer owned by the Resource Entity is treated as an auxiliary Load and must be netted first against any generation meeting the requirements under Section 10.3.2.3.

(11) For purposes of Day-Ahead Market (DAM) Ancillary Services clearing, transmission Outages will be presumed not to affect the availability of any Load Resource for which an offer is submitted. In the event that ERCOT contacts a TSP and confirms that load will not remain connected during a transmission Outage, ERCOT will temporarily override the energization status of the load in DAM to properly reflect the status during the Outage.

[NPRR1016: Replace paragraph (11) above with the following upon system implementation:]

(11) If the Day-Ahead Market (DAM) determines, in the processing of Outages, that a Load Resource, DGR, or DESR is de-energized in the ERCOT Network Operations Model, the de-energized Resource will be eligible to receive Ancillary Service awards in the DAM, but will not be eligible to receive energy awards in the DAM.

(12) A Resource Entity may aggregate Intermittent Renewable Resource (IRR) generation equipment together to form an IRR (WGR or PVGR) if the generation equipment is connected to the same Electrical Bus at the POI and is the same model and size, and the aggregation does not reduce ERCOT's ability to model pre- and post-contingency conditions. A Resource Entity may also aggregate IRR generation equipment that is not the same model and size together with an existing IRR only if:

(a) The mix of IRR generation equipment models and sizes causes no degradation in the dynamic performance of the IRR represented by the parameters modeled by ERCOT in operational studies and the aggregation of IRR generation equipment does not limit ERCOT's ability to model the ERCOT Transmission Grid and the relevant contingencies required for monitoring pre- and post-contingency system limits and conditions;

(b) The mix of IRR generation equipment is included in the Resource Registration data submitted for the WGR;

(c) All relevant IRR generation equipment data requested by ERCOT is provided;

(d) With the addition of dissimilar IRR generation equipment, the existing IRR shall continue to meet the applicable Protocol performance requirements, including but not limited to Primary Frequency Response, dynamic capability and Reactive Power capability, at the POI; and

(e) Either:

(i) No more than the lower of 5% or ten MW aggregate capacity is of IRR generation equipment that is not the same model or size from the other equipment within the existing IRR; or

(ii) The wind turbines that are not the same model or size meet the following criteria:

(A) The IRR generation equipment has similar dynamic characteristics to the existing IRR generation equipment, as determined by ERCOT in its sole discretion;

(B) The MW capability difference of each generator is no more than 10% of each generator's maximum MW rating; and

(C) For WGRs, the manufacturer's power curves for the wind turbines have a correlation of 0.95 or greater with the other wind turbines within the existing WGR over wind speeds of 0 to 18 m/s.

3.11 Transmission Planning

3.11.4 Regional Planning Group Project Review Process

3.11.4.3 Categorization of Proposed Transmission Projects

(1) ERCOT classifies all proposed transmission projects into one of four categories (or Tiers). Each Tier is defined so that projects with a similar cost and impact on reliability and the ERCOT market are grouped into the same Tier. For Tier classification, the total estimated cost of the project shall be used which includes costs borne by another party.

(a) A project shall be classified as Tier 1 if the estimated capital cost is greater than or equal to $100,000,000, unless the project is considered to be a neutral project pursuant to paragraph (f) below.

(b) A project shall be classified as Tier 2 if the estimated capital cost is less than $100,000,000 and a Certificate of Convenience and Necessity (CCN) is required, unless the project is considered to be a neutral project pursuant to paragraph (f) below.

(c) A project shall be classified as Tier 3 if any of the following are true:

(i) The estimated capital cost is less than $100,000,000 and greater than or equal to $25,000,000 and a CCN is not required, unless the project is considered to be a neutral project pursuant to paragraph (f) below; or

(ii) The estimated capital cost is less than $25,000,000, a CCN is not required, and the project includes 345 kV circuit reconductor of more than one mile, additional 345/138 kV autotransformer capacity, or a new 345 kV substation, unless the project is considered to be a neutral project pursuant to paragraph (f) below.

(d) A project with an estimated capital cost greater than or equal to $25,000,000 that is proposed for the purpose of replacing aged infrastructure or storm hardening shall be processed as a Tier 3 project and shall be reclassified as a Tier 4, neutral project upon ERCOT's determination that any concerns, questions or objections raised during the comment process have been resolved satisfactorily.

(e) A project shall be classified as Tier 4 if it does not meet the requirements to be classified as Tier 1, 2, or 3 or if it is considered a neutral project pursuant to paragraph (f) below.

(f) A project shall be considered a neutral project if it consists entirely of:

(i) The addition of or upgrades to radial transmission circuits;

(ii) The addition of equipment that does not affect the transfer capability of a circuit;

(iii) Repair and replacement-in-kind projects;

(iv) ~~Projects that are associated with the direct interconnection of new generation~~Transmission Facilities needed to connect a new Generation Resource, Energy Storage Resource (ESR), or Settlement Only Generator (SOG) to a new or existing substation on the existing ERCOT Transmission Grid, including the substation;

(v) The addition of static reactive devices;

(vi) A project to serve a new Load, unless such project would create a new transmission circuit connection between two stations (other than looping an existing circuit into the new Load-serving station);

(vii) Replacement of failed equipment, even if it results in a ratings and/or impedance change; or

(viii) Equipment upgrades resulting in only ratings changes.

(2) ERCOT may use its reasonable judgment to increase the level of review of a proposed project (e.g., from Tier 3 to Tier 2) from that which would be strictly indicated by these criteria, based on stakeholder comments, ERCOT analysis or the system impacts of the project.

(a) A project with an estimated capital cost greater than or equal to $50,000,000 that requires a CCN shall be reclassified and processed as a Tier 1 project upon request by a Market Participant during the comment period per Planning Guide Section 3.1.5, Regional Planning Group Comment Process.

(3) Any project that would be built by an Entity that is exempt (e.g., a Municipally Owned Utility (MOU)) from getting a CCN for transmission projects but would require a CCN if

it were to be built by a regulated Entity will be treated as if the project would require a CCN for the purpose of defining the Tier of the project.

(4) If during the course of ERCOT's independent review of a project, the project scope changes, ERCOT may reclassify the project into the appropriate Tier.

3.11.6 Generation Interconnection Process

(1) The generation interconnection process facilitates the interconnection of new generation units in the ERCOT Region by assessing the transmission upgrades necessary for new generating units to operate reliably. The process to study interconnecting new generation or modifying an existing generation interconnection to the ERCOT Transmission Grid is covered in the Planning Guide. The generation interconnection study process primarily addresses the direct connection of generation Facilities to the ERCOT Transmission Grid and directly-related projects. Projects that are identified through this process and are regional in nature may be reviewed through the RPG Project Review process upon recommendation by the TSP or ERCOT, subject to the confidentiality provisions in Section 1.3, Confidentiality.

(2) ERCOT shall perform an independent economic analysis of the Transmission Facilities needed to connect a new Generation Resource, ESR, or SOG to a new or existing substation on the existing ERCOT Transmission Grid, including the substation,~~transmission projects~~ that are identified through this process that are expected to cost more than $25,000,000. This economic analysis is performed only for informational purposes; as such, no ERCOT endorsement will be provided. The results of the economic analysis shall be included in the interconnection study posting.

(3) Additional upgrades to the ERCOT Transmission Grid that might be cost-effective as a result of new or modified generation may be initiated by any stakeholder through the RPG Project Review procedure described in Section 3.11.4, Regional Planning Group Project Review Process, at the appropriate time, subject to the confidentiality provisions of the generation interconnection procedure.

3.14 Contracts for Reliability Resources and Emergency Response Service Resources

3.14.1 Reliability Must Run

3.14.1.7 RMR or MRA Contract Termination

(1) This section applies only to RMR exit strategies corresponding to specific RMR or MRA Agreements that have not been terminated.

(2) Once a suitable RMR or MRA exit strategy has been developed as defined in Section 3.14.1.4, Exit Strategy from an RMR Agreement, and the strategy has been approved by the ERCOT Board and the affected TSP(s), the TSP(s) responsible for the Transmission Facilities upgrades, when requested by ERCOT, shall submit to ERCOT:

(a) A preliminary construction outage schedule necessary to complete the Transmission Facilities upgrades. Submissions, changes, approvals, rejections, and withdrawals regarding the preliminary construction outage schedule shall be processed through the ERCOT Outage Scheduler on the ERCOT MIS. Such construction outage schedule shall be updated monthly; or

(b) A Certificate of Convenience and Necessity (CCN) application timeline for projects requiring such PUCT certification. Once a CCN has been granted by the PUCT, the TSP(s) shall be required to meet the requirements in item (a) above.

(3) ERCOT shall review and approve or reject each construction outage schedule as provided in accordance with procedures developed by ERCOT in compliance with Section 3.1, Outage Coordination.

(4) The TSP(s) responsible for the Transmission Facilities upgrades that are part of an RMR or MRA exit strategy shall provide to ERCOT a project status and an estimated project completion date within five Business Days of ERCOT's request.

(5) If ERCOT determines that a mutually agreeable preliminary construction outage schedule can be accommodated during the fall, winter, or spring, ERCOT and the TSP shall collaborate to determine if the 90 day termination notice for the RMR and/or MRA can be issued as soon after the summer load Season of the preceding year as possible and publish a Market Notice of these terminations. ERCOT and the TSP may give consideration to the risk of the decision to terminate the RMR and/or MRA Agreement and any options, such as RAPs and/or Mitigation Plans that could be used to mitigate transmission construction delays.

3.14.2 Black Start

(1) Each Generation Resource providing BSS must meet the requirements specified in North American Electric Reliability Corporation (NERC) Reliability Standards and the Operating Guides.

(2) Each Generation Resource providing BSS must meet technical requirements specified in Section 8.1.1, QSE Ancillary Service Performance Standards, and Section 8.1.1.1, Ancillary Service Qualification and Testing.

(3) Bids for BSS are due on or before February 15th of each two--year period. Bids must be evaluated based on evaluation criteria attached as an appendix to the request for bids and contracted by December 31st for the following two--year period. ERCOT shall ensure BSSs are arranged, provided, and deployed as necessary to reenergize the ERCOT System following a Blackout or Partial Blackout.

(a) Resources shall disclose any weather-related limitations that could affect the Resource's ability to provide BSS using the form provided in Section 22, Attachment M, Generation Resource Disclosure Regarding Bids for Black Start Service, as part of a bid to provide BSS.

(b) When a Resource is selected to provide BSS, the Black Start Resource shall be required to complete all applicable testing requirements as specified in Section 8.1.1.2.1.5, System Black Start Capability Qualification and Testing.

(c) ERCOT shall provide a list of all prospective Black Start Resources that responded to the Request for Proposal for BSS to the impacted TSPs no later than seven days after the date on which bids for BSS are due. Any feedback from affected TSPs shall be limited to the identification of transmission constraints that may adversely impact the ability of the Black Start Resource to energize the Next Start Resource and shall be due to ERCOT by March 1st of that year. ERCOT shall share the feedback with the QSE representing the prospective Black Start Resource as soon as practicable. The QSE representing the Black Start Resource shall have the option to provide a response to any feedback provided by an affected TSP.

(4) ERCOT may schedule unannounced Black Start testing, to verify that BSS is operable as specified in Section 8.1.1.2.1.5, System Black Start Capability Qualification and Testing.

(5) QSEs representing Generation Resources contracting for BSSs shall participate in training and restoration drills coordinated by ERCOT.

(6) ERCOT shall periodically determine and review the location and number of Black Start Resources required, as well as any special transmission or voice communication needs required. ERCOT and providers of this service shall meet the requirements as specified in the Operating Guides and in NERC Reliability Standards.

(7) A Resource Entity representing a Black Start Resource may request that an alternate Generation Resource which is connected to the same black start primary and secondary cranking path as the original Black Start Resource be substituted in place of the original Black Start Resource during the two year term of an executed Standard Form Black Start Agreement (Section 22, Attachment D, Standard Form Black Start Agreement) if the alternate Generation Resource meets testing and verification under established qualification criteria to ensure BSS.

(a) ERCOT, in its sole discretion, may reject a Resource Entity's request for an alternate Generation Resource and will provide the Resource Entity an explanation of such rejection.

(b) If ERCOT accepts the alternative Generation Resource as the substituted Black Start Resource, such acceptance shall not affect the original terms, conditions and obligations of the Resource Entity under the Standard Form Black Start Agreement. The Resource Entity shall submit to ERCOT an Amendment to

Standard Form Black Start Agreement (Section 22, Attachment I, Amendment to Standard Form Black Start Agreement) after qualification criteria has been met.

(8) For the purpose of the Black Start Hourly Standby Fee as described in Section 6.6.8.1, Black Start Hourly Standby Fee, the Black Start Service Availability Reduction Factor shall be determined by using the availability for the original Black Start Resource and any substituted Black Start Resource(s), as appropriate for the rolling 4380 hour period of the evaluation.

(9) Each Generation Resource selected to provide BSS shall be prepared and able to provide BSS at any time as may be required by ERCOT, subject only to the limitations described in ERCOT Protocols or the Black Start Agreement.

(10) A Resource Entity that submits a bid or is contracted to provide BSS or serve as an alternate to provide BSS with a Switchable Generation Resource (SWGR):

(a) Shall not nominate the SWGR to satisfy supply adequacy or capacity planning requirements in any Control Area other than the ERCOT Region during the term of the BSS contract;

(b) Shall submit a report to ERCOT in compliance with paragraph (2) of Section 16.5.4, Maintaining and Updating Resource Entity Information, indicating that the SWGR does not have any contractual requirement in a non-ERCOT Control Area during the term of the BSS contract; and

(c) Shall take any further action requested by ERCOT to ensure that ERCOT will be classified as the "Primary Party" for the SWGR under any agreement between ERCOT and another Control Area Operator during the term of the BSS contract.

(11) If a Resource Entity with a SWGR is contracted to provide BSS or designated as an alternate to provide BSS, the Resource Entity shall have its Black Start plan procedures approved by ERCOT. In the event of a partial Blackout or Blackout of the ERCOT System, the Resource Entity with a SWGR shall immediately:

(a) Effectuate its Black Start plan procedures to be available to provide BSS; and

(b) Provide BSS as directed by ERCOT or the local Transmission Operator (TO).

[NPRR885 and NPRR1007: Insert applicable portions of Sections 3.14.4 and 3.14.4.1 below upon system implementation for NPRR885; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007:]

3.14.4 Must-Run Alternative Service

3.14.4.1 Overview and Description of MRAs

(1) Subject to approval by the ERCOT Board, ERCOT may procure Must-Run Alternative (MRA) Service as an alternative to contracting with an RMR Unit if ERCOT determines that the MRA Agreement(s) will, in whole or in part, address the reliability need identified in the RMR study in a more cost-effective manner.

(2) ERCOT will issue a request for proposal (RFP) to solicit offers from QSEs to provide MRA Service.

(a) A QSE may submit an offer in response to the RFP or enter into an MRA Agreement only if it meets all registration and qualification criteria in Section 16.2, Registration and Qualification of Qualified Scheduling Entities.

(b) QSEs whose offers for MRA Service are accepted will be paid according to their offers, subject to the terms of the RFP, MRA Agreement and ERCOT Protocols. A clearing price mechanism shall not be used for awarding offers for MRA Service.

(c) A QSE may submit more than one offer for MRA Service in response to a single RFP. A QSE may not submit the same MRA or MRA Sites in more than one of its offers. ERCOT may award multiple offers to a QSE, so long as the MRA or MRA Sites in an awarded offer are not included in any other awarded offer. A QSE may condition ERCOT's acceptance of an offer for a Demand Response MRA on ERCOT's acceptance of an offer for a co-located Other Generation MRA offer.

(d) Demand Response MRAs and Other Generation MRAs, including MRA Sites within aggregated MRAs, that are situated in NOIE service territories, are eligible to provide MRA Service. Any QSE other than the NOIE QSE wishing to represent such MRAs must obtain written authorization allowing the representation from the NOIE in which the MRA is located. This authorization must be signed by an individual with authority to bind the NOIE and must be submitted to ERCOT prior to the submission of an offer in response to the MRA.

(3) An MRA may be connected at either transmission or distribution voltage.

(4) An MRA offer is ineligible to the extent it offers capacity that was included as a Resource in ERCOT's RMR analysis or in the Load forecasts from the Steady State Working Group (SSWG) base cases used as the basis for the RMR analysis, as provided for in paragraph (3)(a) of Section 3.14.1.2, ERCOT Evaluation Process.

(5) Each MRA must provide at least five MW of capacity.

(6) Eligible MRA resources may include:

(a) A proposed Generation Resource that was not included in the reliability need evaluation pursuant to paragraph (3)(a) of Section 3.14.1.2.

(i) Proposed Generation Resources must adhere to all interconnection requirements, including the requirements of Planning Guide Section 5, Generation Resource Interconnection or Change Request.

(ii) If the proposed Generation Resource is an Intermittent Renewable Resource (IRR), the QSE shall provide capacity values based on the Resource's projected peak average capacity contribution during the MRA Contracted Hours.

(b) Proposed capacity additions to existing Generation Resources, if the additional capacity was not included in the reliability need evaluation pursuant to paragraph (3)(a) of Section 3.14.1.2.

(i) Prior to providing MRA Service, the Resource Entity will be required to modify its Resource Registration information and complete necessary Generator interconnection requirements with respect to this additional capacity.

(ii) If the capacity is being added to an IRR, the QSE shall provide capacity values based on the Resource's projected peak average capacity contribution during the hours identified during the MRA Contracted Hours.

(c) A proposed or existing generator registered, or proposed to be registered, with ERCOT as a Settlement Only Generator (SOG) or as Distributed Generation (DG). If the generator is an intermittent renewable generator, the QSE, when responding to an RFP for MRA Service, shall provide capacity values based on the MRA's projected peak average capacity contribution during the hours identified in the MRA Contracted Hours.

(d) Proposed or existing Demand response assets, which may include Load Resources and ERS Loads.

(7) An MRA must be able to provide power injection or Demand response to the ERCOT System at ERCOT's discretion during the MRA Contracted Hours.

(a) QSE offers in response to an RFP for MRA Service must fully describe all of the MRA's temporal constraints.

(b) For a Demand Response MRA, QSE offers in response to an RFP for MRA Service must include a statement as to whether the offered capacity is a Weather–Sensitive MRA.

(8) The QSE representing an MRA must be capable of receiving both VDI and XML instructions.

(9) ERCOT will periodically validate an MRA's telemetry using 15-minute interval meter data.

(10) An MRA for which the MRA or every MRA Site, is metered with either an Advanced Meter or an ERCOT-Polled Settlement (EPS) Meter must be available for qualification testing no later than 10 days prior to the first day of the contracted MRA Service. Other MRAs must be available for qualification testing no later than 45 days prior to the first day of the contracted MRA Service.

(11) All MRA Sites within an MRA must be of the same type (i.e., all Generation Resource MRA, Other Generation MRA, or Demand Response MRA).

(12) A QSE representing an MRA shall submit to ERCOT and continuously update an Availability Plan for each MRA Contracted Hour for the current Operating Day and the next six Operating Days.

(13) A QSE representing an MRA or MRA Site may not submit DAM Offers, provide an Ancillary Service or carry an ERS responsibility on behalf of any MRA or MRA Site during the MRA Contracted Hours. Demand Response MRAs may not participate in TDSP standard offer programs during any MRA Contracted Hours.

(14) A Combined Cycle Train serving as an MRA must be configured as a single Combined Cycle Generation Resource.

(15) QSEs representing MRAs shall submit offers using an MRA offer sheet as provided by ERCOT.

(16) QSEs must submit the following information for each MRA offer:

(a) The capacity, months and hours offered;

(b) For an aggregated MRA, the offered capacity allocated to each MRA Site for all months and hours offered;

(c) The Resource ID, ESI ID and or unique meter ID associated with the MRA, or in the case of an aggregated MRA, a list of the Resource IDs, ESI IDs and/or unique meter IDs of the offered MRA Sites;

(d) The MRA Standby Price, represented in dollars per MW per hour;

(e) Required capital expenditure, if any, if the MRA offer is awarded;

(f) The MRA Event Deployment Price, in dollars per deployment event, or proxy fuel consumption rate;

(g) The ramp period or startup time of the MRA or aggregated MRA;

(h) The MRA Variable Price, in dollars per MW per hour, and/or proxy heat rate;

(i) The target availability of the MRA or aggregated MRA; and

(j) Any additional information required by ERCOT within the RFP.

(17) Demand Response MRAs shall not be deployed more than once per Operating Day.

(18) Except for a Forced Outage, any Outage of an MRA must be approved by ERCOT.

(19) For any MRA that is registered with ERCOT as a Resource, the QSE representing the MRA must be the same as the QSE representing the Resource.

3.22 Subsynchronous Resonance

3.22.1 Subsynchronous Resonance Vulnerability Assessment

3.22.1.2 Generation Resource or Energy Storage Resource Interconnection Assessment

(1) In the security screening study for a Generation Resource Interconnection or Change Request, ERCOT will perform a topology-check and determine if the Generation Resource or Energy Storage Resource (ESR) will become radial to a series capacitor(s) in the event of ~~less~~fewer than 14 concurrent transmission Outages.

(2) If ERCOT identifies that a Generation Resource or ESR will become radial to a series capacitor(s) in the event of ~~less~~fewer than 14 concurrent transmission Outages, the interconnecting TSP shall perform an SSR study including frequency scan assessment and/or detailed SSR assessment for the Interconnecting Entity (IE) in accordance with Section 3.22.2, Subsynchronous Resonance Vulnerability Assessment Criteria, to determine SSR vulnerability. The SSR study shall determine which system configurations create vulnerability to SSR. Alternatively, if the IE can demonstrate to ERCOT's and the interconnecting TSP's satisfaction that the Generation Resource or ESR is not vulnerable to SSR, then the interconnecting TSP is not required to perform the SSR study. If an SSR study is conducted, the interconnecting TSP shall submit it to ERCOT upon completion and shall include any SSR Mitigation ~~P~~plan developed by the IE that has been reviewed by the TSP.

(3) If the SSR study performed in accordance with paragraph (2) above indicates that the Generation Resource or ESR is vulnerable to SSR in the event of ~~four~~six or ~~less~~fewer

concurrent transmission Outages, the IE shall develop an SSR Mitigation ~~P~~plan, provide it to the interconnecting TSP for review and inclusion in the TSP's SSR study report to be approved by ERCOT, and implement the SSR Mitigation prior to Initial Synchronization.

(a) If the SSR study performed in accordance with paragraph (2) above indicates that the Generation Resource or ESR is vulnerable to SSR in the event of four concurrent transmission Outages, the IE may install SSR Protection in lieu of SSR Mitigation, as required by paragraph (3) above, if:

(i) The Generation Resource or ESR satisfied Planning Guide Section 6.9, Addition of Proposed Generation to the Planning Models, between August 12, 2013 and March 20, 2015;

(ii) The SSR Protection is approved by ERCOT; and

(iii) The Generation Resource or ESR installs the ERCOT-approved SSR Protection prior to Initial Synchronization.

(b) For any Generation Resource or ESR that satisfied Planning Guide Section 6.9 before September 1, 2020, if the SSR study performed in accordance with paragraph (2) above indicates that the Generation Resource or ESR is vulnerable to SSR in the event of five or six concurrent transmission Outages, the IE may elect not to develop or implement an SSR Mitigation plan, in which case ERCOT shall implement SSR monitoring in accordance with Section 3.22.3, Subsynchronous Resonance Monitoring. The IE shall provide ERCOT written Notice of any such election before the Generation Resource or ESR achieves Initial Synchronization, and the Generation Resource or ESR shall not be permitted to proceed to Initial Synchronization until ERCOT has implemented SSR monitoring.

~~(4) If the SSR study performed in accordance with paragraph (2) above indicates that the Generation Resource is vulnerable to SSR in the event of five or six concurrent transmission Outages, ERCOT shall implement SSR monitoring in accordance with Section 3.22.3, Subsynchronous Resonance Monitoring, within 45 days after ERCOT's approval of the SSR study report conditionally if all monitored elements are in the Energy Management System (EMS), or if the monitored elements are not in the EMS, 45 days after the elements are in the EMS.~~

(4~~5~~) ERCOT shall respond with its comments or approval of an SSR study report, which should include any required SSR Mitigation ~~P~~plan, within 30 days of receipt. ERCOT comments should be addressed as soon as practicable by the TSP, and any action taken in response to ERCOT's comments on an SSR study report shall be subject to further ERCOT review and approval. Upon approval of the SSR study report, ERCOT shall notify the interconnecting TSP, and the interconnecting TSP shall provide the approved SSR study report to the IE.

ERCOT Nodal Protocols

Section 4: Day-Ahead Operations

March~~February~~ 1, 2021

4 DAY-AHEAD OPERATIONS

4.2 ERCOT Activities in the Day-Ahead

4.2.1 Ancillary Service Plan and Ancillary Service Obligation

4.2.1.2 Ancillary Service Obligation Assignment and Notice

(1) ERCOT shall assign part of the Ancillary Service Plan quantity, by service, by hour, to each Qualified Scheduling Entity (QSE) based on its Load Serving Entity (LSE) Load Ratio Shares (LRSs) (including the shares for Direct Current Tie (DC Tie) exports~~ not eligible for the Oklaunion Exemption~~) aggregated by hour to the QSE level. If the resultant QSE-level share is negative, the QSE's share will be set to zero and all other QSE shares will be adjusted on a pro rata basis such that the sum of all shares is equal to one. The resulting Ancillary Service quantity for each QSE, by service, by hour, is called its Ancillary Service Obligation. ERCOT shall base the QSE Ancillary Service allocation on the QSE to LSE relationships for the operating date and on the hourly LSE LRSs from the Real-Time Market (RTM) data used for Initial Settlement for the same hour and day of the week, for the most recent day for which Initial Settlement data is available, multiplied by the quantity of that service required in the Day-Ahead Ancillary Service Plan. The Ancillary Service Obligation defined shall be adjusted based on the most current real time settlement and resettlement data for the Operating Day for which the Ancillary Service was procured.

(2) By 0600 of the Day-Ahead, ERCOT shall notify each QSE of its Ancillary Service Obligation for each service and for each hour of the Operating Day.

(3) By 0600 of the Day-Ahead, ERCOT shall post on the Market Information System (MIS) Certified Area each QSE's LRS used for the Ancillary Service Obligation calculation.

[NPRR1008: Replace Section 4.2.1.2 above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

4.2.1.2 Ancillary Service Obligation Assignment and Notice

(1) ERCOT shall assign part of the Ancillary Service Plan quantity, or total Ancillary Service procurement quantity, if different, by service, by hour, to each Qualified Scheduling Entity (QSE) based on its Load Serving Entity (LSE) Load Ratio Shares (LRSs) (including the shares for Direct Current Tie (DC Tie) exports~~ not eligible for the Oklaunion Exemption~~) aggregated by hour to the QSE level. If the resultant QSE-level share is negative, the QSE's share will be set to zero and all other QSE shares will be adjusted on a pro rata basis such that the sum of all shares is equal to one. The resulting Ancillary Service quantity for each QSE, by service, by hour, is called its

Ancillary Service Obligation. ERCOT shall base the QSE Ancillary Service allocation on the QSE to LSE relationships for the operating date and on the hourly LSE LRSs from the Real-Time Market (RTM) data used for Initial Settlement for the same hour and day of the week, for the most recent day for which Initial Settlement data is available, multiplied by the quantity of that service required in the Day-Ahead Ancillary Service Plan. The Ancillary Service Obligation defined shall be adjusted based on the most current real time settlement and resettlement data for the Operating Day for which the Ancillary Service was procured.

(2) By 0600 of the Day-Ahead, ERCOT shall notify each QSE of its advisory Ancillary Service Obligation for each service and for each hour of the Operating Day, based on the Ancillary Service Plan, as well as that QSE's proportional limit for any Self-Arranged Ancillary Services as set forth in Section 3.16, Standards for Determining Ancillary Service Quantities.

(3) By 0600 of the Day-Ahead, ERCOT shall post on the Market Information System (MIS) Certified Area each QSE's LRS used for both the advisory and final Ancillary Service Obligation calculations.

(4) The minimum Ancillary Service Obligation quantity will be 0.1 MW and will apply to both advisory and final values.

(5) After DAM has published, ERCOT shall notify each QSE of its final Ancillary Service Obligation based on the total DAM Ancillary Service procurement quantity, comprised of DAM Ancillary Service awards and Self-Arranged Ancillary Service Quantities for each service and for each hour of the Operating Day.

4.3 QSE Activities and Responsibilities in the Day-Ahead

(1) During the Day-Ahead, a Qualified Scheduling Entity (QSE):

(a) Must submit its Current Operating Plan (COP) and update its COP as required in Section 3.9, Current Operating Plan (COP); and

(b) May submit Three-Part Supply Offers, Day-Ahead Market (DAM) Energy-Only Offers, DAM Energy Bids, Energy Trades, Self-Schedules, Capacity Trades, Direct Current Tie (~~Direct-Current~~ Tie) Schedules, Ancillary Service Offers, Ancillary Service Trades, Self-Arranged Ancillary Service Quantities, and Point-to-Point (PTP) Obligation bids as specified in this Section.

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

(b) May submit Three-Part Supply Offers, Day-Ahead Market (DAM) Energy-Only Offers, DAM Energy Bids, Energy Bid/Offer Curves, Energy Trades, Self-Schedules, Capacity Trades, Direct Current Tie (DC Tie) Schedules, Resource-Specific Ancillary Service Offers, DAM Ancillary Service Only Offers, Ancillary Service Trades, Self-Arranged Ancillary Service Quantities, and Point-to-Point (PTP) Obligation bids as specified in this Section.

(2) By 0600 in the Day-Ahead, each QSE representing Reliability Must-Run (RMR) Units or Black Start Resources shall submit its Availability Plan to ERCOT indicating availability of RMR Units and Black Start Resources for the Operating Day and any other information that ERCOT may need to evaluate use of the units as set forth in the applicable Agreements and this Section.

4.4 Inputs into DAM and Other Trades

4.4.4 DC Tie Schedules

(1) All schedules between the ERCOT Control Area and a non-ERCOT Control Area(s) over Direct Current Tie(s) (DC Ties(s)), must be implemented under these Protocols, any applicable North American Electric Reliability Corporation (NERC) Reliability Standards, North American Energy Standards Board (NAESB) Practice Standards, and operating agreements between ERCOT and the Comision Federal de Electricidad (CFE).

[NPRR857: Replace paragraph (1) above with the following upon system implementation:]

(1) All Direct Current Tie (DC Tie) Schedules between the ERCOT Control Area and a non-ERCOT Control Area(s) must be implemented in accordance with these Protocols, any applicable North American Electric Reliability Corporation (NERC) Reliability Standards, North American Energy Standards Board (NAESB) Practice Standards, and operating agreements between ERCOT and the appropriate operating authority for the non-ERCOT Control Area.

(2) A DC Tie Schedule for hours in the Operating Day corresponding to an Electronic Tag (e-Tag) that is reported to ERCOT before 1430 in the Day-Ahead creates a capacity supply for the equivalent Resource or an obligation for the equivalent Load of the DC Tie in the DRUC process. DC Tie Schedules corresponding to e-Tags approved after 1430 in the Day-Ahead for the Operating Day create a capacity supply or obligation in any applicable HRUC processes. DC Tie Schedules corresponding to e-Tags approved after the Reliability Unit Commitment (RUC) snapshot are considered in the Adjustment Period snapshot in accordance with the market timeline.

(3) A QSE that is an importer into ERCOT through a DC Tie in a Settlement Interval under an approved e-Tag must be treated as a Resource at that DC Tie Settlement Point for that Settlement Interval.

(4) A QSE that is an exporter from ERCOT through a DC Tie in a Settlement Interval under an approved e-Tag must be treated as a Load at the DC Tie Settlement Point for that Settlement Interval and is responsible for allocated Transmission Losses, Unaccounted for Energy (UFE), System Administration Fee, and any other applicable ERCOT fees. ~~This applies to all exports across the DC Ties except those that qualify for the Oklaunion Exemption.~~

(5) ERCOT shall approve any e-Tag that does not exceed the available physical capacity of the DC Tie and any limits supplied the non-ERCOT Control Area for the time period for which the e-Tag is requested unless a DC Tie Curtailment Notice is in effect for the particular DC Tie for which the e-Tag request is made. While a DC Tie Curtailment Notice is in effect, ERCOT will deny any additional e-Tag requests that would exacerbate the transmission security violations that led to that DC Tie Curtailment Notice. Notwithstanding the foregoing, ERCOT shall deny or curtail any e-Tag over any of the DC Ties if necessary to avoid causing any Entity in the ERCOT Region that is not a "public utility" as defined in the Federal Power Act (FPA), including ERCOT, to become such a public utility. If ERCOT determines that it is necessary to deny or curtail e-Tags in order to prevent any Entity from becoming a "public utility," it shall provide notice of that determination by posting an operations message to the ERCOT website and issuing a Market Notice.

[NPRR999: Replace paragraph (5) above with the following upon project implementation of the Intra-Hour Variability (iCAT) Tool:]

(5) ERCOT shall approve any e-Tag that does not exceed the available physical capacity of the DC Tie, system ramping capability, and any limits supplied by the non-ERCOT Control Area for the time period for which the e-Tag is requested unless a DC Tie Curtailment Notice is in effect for the particular DC Tie for which the e-Tag request is made; otherwise, ERCOT shall deny the e-Tag. While a DC Tie Curtailment Notice is in effect, ERCOT will deny any additional e-Tag requests that would exacerbate the transmission security violations that led to that DC Tie Curtailment Notice. Notwithstanding the foregoing, ERCOT shall deny or curtail any e-Tag over any of the DC Ties if necessary to avoid causing any Entity in the ERCOT Region that is not a "public utility" as defined in the Federal Power Act (FPA), including ERCOT, to become such a public utility. If ERCOT determines that it is necessary to deny or curtail e-Tags in order to prevent any Entity from becoming a "public utility," it shall provide notice of that determination by posting an operations message to the ERCOT website and issuing a Market Notice.

(6) ERCOT shall perform schedule confirmation with the applicable non-ERCOT Control Area(s) and shall coordinate the approval process for the e-Tags for the ERCOT Control Area. An e-Tag for a schedule across a DC Tie is considered approved if:

(a) All Control Areas and Transmission Service Providers (TSPs) with approval rights approve the e-Tag (active approval); or

[NPRR857: Replace paragraph (a) above with the following upon system implementation:]

(a) All Control Areas and Direct Current Tie Operators (DCTOs) with approval rights approve the e-Tag (active approval); or

(b) No Entity with approval rights over the e-Tag has denied it, and the approval time window has ended (passive approval).

(7) Using the DC Tie Schedule information corresponding to e-Tags submitted by QSEs, ERCOT shall update and maintain a Current Operating Plan (COP) for each DC Tie for which the aggregated DC Tie Schedules for that tie show a net export out of ERCOT for the applicable interval. When the net energy schedule for a DC Tie indicates an export, ERCOT shall treat the DC Tie as an Off-Line Resource and set the High Sustained Limit (HSL) and Low Sustained Limit (LSL) for that DC Tie Resource to zero. ERCOT shall monitor the associated Resource Status telemetry during the Operating Period. When the net energy schedule for a DC Tie shows a net import, the Resource HSL, High Ancillary Service Limit (HASL) and LSL must be set appropriately, considering the resulting net import.

[NPRR1008: Replace paragraph (7) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(7) Using the DC Tie Schedule information corresponding to e-Tags submitted by QSEs, ERCOT shall update and maintain a Current Operating Plan (COP) for each DC Tie for which the aggregated DC Tie Schedules for that tie show a net export out of ERCOT for the applicable interval. When the net energy schedule for a DC Tie indicates an export, ERCOT shall treat the DC Tie as an Off-Line Resource and set the High Sustained Limit (HSL) and Low Sustained Limit (LSL) for that DC Tie Resource to zero. ERCOT shall monitor the associated Resource Status telemetry during the Operating Period. When the net energy schedule for a DC Tie shows a net import, the Resource HSL and LSL must be set appropriately, considering the resulting net import.

(8) A QSE exporting from ERCOT and/or importing to ERCOT through a DC Tie shall:

(a) Secure and maintain an e-Tag service to submit e-Tags and monitor e-Tag status according to NERC requirements;

(b) Submit e-Tags for all proposed transactions; and

(c) Implement backup procedures in case of e-Tag service failure.

(9) ERCOT shall post a notice to the MIS Certified Area when a confirmed e-Tag is downloaded, cancelled, or curtailed by ERCOT's systems.

(10) ERCOT shall use the DC Tie e-Tag MW amounts for Settlement. The DC Tie operator shall communicate deratings of the DC Ties to ERCOT and other affected regions and all parties shall agree to any adjusted or curtailed e-Tag amounts.

[NPRR857: Replace paragraph (10) above with the following upon system implementation:]

(10) ERCOT shall use the DC Tie e-Tag MW amounts for Settlement. The DCTO shall communicate deratings of the DC Ties to ERCOT and other affected regions and all parties shall agree to any adjusted or curtailed e-Tag amounts.

(11) DC Tie Load is considered as Load for daily and hourly reliability studies, and settled as Adjusted Metered Load (AML). DC Tie Load is curtailed prior to other Load on the ERCOT System as described below, and during Energy Emergency Alert (EEA) events as set forth in Section 6.5.9.4.2, EEA Levels.

(12) DC Tie Load shall neither be curtailed by ERCOT during the Adjustment Period, nor for more than one hour at a time, except for the purpose of maintaining reliability, or as indicated in paragraphs (13), (14), (15), and (16) below.

(13) If a system operator in a non-ERCOT Control Area requests curtailment of a DC Tie Schedule due to an actual or anticipated emergency in its Control Area, ERCOT may curtail the DC Tie Schedule. If the DC Tie Schedule is curtailed, ERCOT shall post a DC Tie Curtailment Notice to the ERCOT website as soon as practicable.

(14) If a DC Tie experiences an Outage, ERCOT may curtail DC Tie Schedules that are, or that are expected to be, affected by the Outage based on system conditions and expected restoration time of the Outage. ERCOT shall ~~post a~~ post a DC Tie Curtailment Notice to the ERCOT website as soon as practicable. Updated DC Tie limits shall be posted as required in paragraph (1) of Section 3.10.7.7, DC Tie Limits.

(15) If market-based congestion management techniques embedded in Security-Constrained Economic Dispatch (SCED) as specified in these Protocols will not be adequate to resolve one or more transmission security violations that would be fully or partially resolved by the curtailment of DC Tie Load and, in ERCOT's judgment, no approved Constraint Management Plan (CMP) is adequate to resolve those violations, ERCOT may instruct Resources to change output and, if still necessary, curtail DC Tie Load to maintain reliability and shall post a DC Tie Curtailment Notice to the ERCOT website as soon as practicable. The quantity of DC Tie Load to be curtailed shall be the minimum

required to resolve the constraint(s) after the other remediation actions described above have been taken.

(16) ERCOT may curtail DC Tie Schedules as necessary to ensure that any Entity in the ERCOT Region that is not a "public utility" as defined in the FPA, including ERCOT, does not become such a public utility.

[NPRR1034: Insert paragraph (17) below upon system implementation and renumber accordingly:]

(17) ERCOT may curtail DC Tie Schedules on a DC Tie on a last-in-first-out basis when ERCOT determines that one or more DC Tie Schedules on that DC Tie would exceed a limit established pursuant to paragraph (1) of Section 4.4.4.4, Frequency-Based Limits on DC Tie Imports or Exports.

(17) Market Participants shall not engage in DC Tie export transactions that are reasonably expected to be uneconomic in consideration of all costs and revenues associated with the transaction, excluding Congestion Revenue Right (CRR) Auction Revenue Distribution (CARD) and CRR Balancing Account (CRRBA) allocations.

[NPRR1030: Delete paragraph (17) above upon system implementation.]

~~4.4.4.2 Oklaunion Exemption~~

~~(1) ERCOT shall record DC Tie Schedules that qualify for the Oklaunion Exemption to support the billing of applicable TSP tariffs.~~

~~(2) A QSE requesting the Oklaunion Exemption shall:~~

~~(a) Apply to ERCOT for the exemption;~~

~~(b) Set up a separate QSE (or sub-QSE) solely to schedule DC Tie exports under the exemption;~~

~~(c) Designate a non-exempt QSE for settlement of surplus exports; and~~

~~(d) Secure the Resources for a DC Tie Schedule by a DC Tie Schedule from each QSE representing part or all the Oklaunion Resource.~~

~~(3) Prior to Real-Time Market (RTM) final Settlement, ERCOT shall verify for each Settlement Interval that the sum of the "exempted" exports under the Oklaunion Exemption is not more than the total output from the Oklaunion Resource.~~

~~(4) If an adjustment is necessary, the QSE's exempt Load that is greater than the sum of its respective Real-Time metered generation for the virtual generators that are eligible for the exemption will be transferred from the exempt QSE to the designated non-exempt QSE.~~

[NPRR999: Insert Section 4.4.4.2~~3~~ below upon project implementation of the Intra-Hour Variability (iCAT) Tool:]

4.4.4.2~~3~~ Management of DC Tie Schedules due to Ramp Limitations

(1) If system conditions near or in Real-Time show insufficient ramp capability to meet the sum of all DC Ties' scheduled ramp, taking into account the full ramping capability of all available Resources and preserving sufficient Physical Responsive Capability (PRC) to avoid EEA Level 1, and ERCOT determines that sufficient time exists, ERCOT may request that one or more e-Tags be resubmitted with an adjusted ramp duration that would conform with the system's ramp capability. If ERCOT determines that insufficient time exists to request resubmission of e-Tags, or that an insufficient number of e-Tags have been resubmitted to conform with the system's ramp capability, ERCOT shall curtail DC Tie Schedules on a last-in-first-out basis as necessary to conform with the system's ramp capability and shall deny any additional e-Tags that cannot be accommodated within that ramp capability during the impacted intervals.

[NPRR1034: Insert Section 4.4.4.3 below upon system implementation:]

4.4.4.3 Frequency-Based Limits on DC Tie Imports or Exports

(1) ERCOT may establish import or export limits applicable to any DC Tie to mitigate the risk of significant frequency deviation due to the unexpected loss of that DC Tie. ERCOT shall identify the operating conditions and limits it would expect to use in a posting to the ERCOT website.

4.4.9 Energy Offers and Bids

4.4.9.4 Mitigated Offer Cap and Mitigated Offer Floor

4.4.9.4.2 Mitigated Offer Floor

(1) Energy Offer Curves may be subject to mitigation in the Real-Time Market (RTM) under Section 6.5.7.3, Security Constrained Economic Dispatch, using a Mitigated Offer Floor. The Mitigated Offer Floor is:

Resource Category	Mitigated Offer Floor
Nuclear and Hydro	-$250/MWh
Coal and Lignite	-$20/MWh
Combined Cycle	-$20/MWh
Gas/Oil Steam and Combustion Turbine	-$20/MWh
Qualifying Facility (QF)	-$50/MWh
Wind	-$100/MWh
PhotoVoltaic (PV)	-$50/MWh
Other	-$50/MWh

[NPRR1014: Replace paragraph (1) above with the following upon system implementation:]

(1) Energy Offer Curves and Energy Bid/Offer Curves may be subject to mitigation in the Real-Time Market (RTM) under Section 6.5.7.3, Security Constrained Economic Dispatch, using a Mitigated Offer Floor. The Mitigated Offer Floor is:

Resource Category	Mitigated Offer Floor
Nuclear and Hydro	-$250/MWh
Coal and Lignite	-$20/MWh
Combined Cycle	-$20/MWh
Gas/Oil Steam and Combustion Turbine	-$20/MWh
Qualifying Facility (QF)	-$50/MWh
Wind	-$100/MWh

PhotoVoltaic (PV)	-$50/MWh
Energy Storage Resource (ESR)	-$250/MWh
Other	-$50/MWh

4.4.10 Credit Requirement for DAM Bids and Offers

(1) Each QSE's ability to bid and offer in the DAM is subject to credit exposure from the QSE's bids and offers being within the credit limit for DAM participation established for the entire Counter-Party of which the QSE is part, as specified in item (1) of Section 16.11.4.6.2, Credit Requirements for DAM Participation, and taking into account the credit exposure of accepted DAM bid and offers of the Counter-Party's other QSEs.

(2) DAM bids and offers of all QSEs of the Counter-Party are accepted in the order submitted while ensuring that the credit exposure from accepted bids and offers do not exceed the Counter-Party's credit limit for DAM participation.

(3) ERCOT shall reject the QSE's individual bids and offers whose credit exposure, as calculated in item (6) below, exceeds the Counter-Party's credit limit for DAM participation as described in items (1) and (2) above, and shall notify the QSE through the MIS Certified Area as soon as practicable.

(4) The QSE may revise and resubmit such rejected bids and offers described in item (3) above, provided that the resubmitted bids and offers are valid and within the Counter-Party's credit limit for DAM participation adjusted for all accepted DAM bids and offers of the Counter-Party's QSE's limit and that such resubmission occurs prior to 1000 of the Operating Day.

(5) The DAM shall use the Counter-Party's credit limit for DAM participation provided and adjusted for accepted bids and offers for DAM transactions cleared, until a new credit limit for DAM participation is available.

(6) ERCOT shall calculate credit exposure for bids and offers in the DAM as follows:

(a) For a DAM Energy Bid, the credit exposure shall be calculated as the quantity of the bid multiplied by a bid exposure price that is calculated as follows:

(i) If the price of the DAM Energy Bid is less than or equal to zero, the bid exposure price for that quantity will equal zero.

(ii) If the price of the DAM Energy Bid is greater than zero, the bid exposure price for that quantity will equal the greater of zero or the sum of (A) and (B):

(A) The lesser of:

(1) The d^{th} percentile of the Day-Ahead Settlement Point Price (DASPP) for the hour over the previous 30 days; and

(2) The bid price.

(B) The value *e1* multiplied by (bid price minus (A)) when the bid price is greater than (A).

(1) The value *e1* is computed as the $ep1^{th}$ percentile of Ratio1 for the 30 days prior to the Operating Day, where Ratio1 is calculated daily as follows:

$$\text{Ratio1} = \text{Min}[1, \text{Max}[0, (\sum_{h=1,24} (Q_{\text{cleared Bids}} * P_{DAM} - Q_{\text{cleared Offers}} * P_{DAM})) / (\sum_{h=1,24} Q_{\text{cleared Bids}} * P_{DAM})]]$$

except Ratio1 = 1 when $\sum_{h=1,24} Q_{\text{cleared Bids}} * P_{DAM} = 0$

(2) ERCOT may adjust *e1* by changing the quantity of bids or offers to the values reported by the Counter-Party in paragraph (8) below or based on information available to ERCOT.

(iii) For DAM Energy Bids of curve quantity type, the credit exposure shall be the credit exposure, as calculated above, at the price and MW quantity of the bid curve that produces the maximum credit exposure for the DAM Energy Bid.

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

(a) For a DAM Energy Bid or for each MW portion of the bid portion of an Energy Bid/Offer Curve, the credit exposure shall be calculated as the quantity of the bid multiplied by a bid exposure price that is calculated as follows:

(i) If the price of the DAM Energy Bid or the price on the bid portion of an Energy Bid/Offer Curve is less than or equal to zero, the bid exposure price for that quantity will equal zero.

(ii) If the price of the DAM Energy Bid or the price on the bid portion of an Energy Bid/Offer Curve is greater than zero, the bid exposure price for that quantity will equal the greater of zero or the sum of (A) and (B):

(A) The lesser of:

(1) The d^{th} percentile of the Day-Ahead Settlement Point Price (DASPP) for the hour over the previous 30 days; and

(2) The bid price.

(B) The value *e1* multiplied by (bid price minus (A)) when the bid price is greater than (A).

(1) The value *e1* is computed as the $ep1^{th}$ percentile of Ratio1 for the 30 days prior to the Operating Day, where Ratio1 is calculated daily as follows:

$$Ratio1 = Min[1, Max[0, (\sum_{h=1,24} (Q_{cleared\ Bids} * P_{DAM} - Q_{cleared\ Offers} * P_{DAM}))/ (\sum_{h=1,24} Q_{cleared\ Bids} * P_{DAM})]]$$

except Ratio1 = 1 when $\sum_{h=1,24} Q_{cleared\ Bids} * P_{DAM} = 0$

(2) ERCOT may adjust *e1* by changing the quantity of bids or offers to the values reported by the Counter-Party in paragraph (8) below or based on information available to ERCOT.

(iii) For DAM Energy Bids or bid portions of Energy Bid/Offer Curves of curve quantity type, the credit exposure shall be the credit exposure, as calculated above, at the price and MW quantity of the bid curve that produces the maximum credit exposure for the DAM Energy Bid or bid portions of Energy Bid/Offer Curves.

(b) For each MW portion of a DAM Energy-Only Offer:

(i) That has an offer price that is less than or equal to the a^{th} percentile of the DASPP for the hour over the previous 30 days, the sum of (A) and (B) shall apply.

(A) Credit exposure will be:

(1) Reduced (when the b^{th} percentile Settlement Point Price for the hour is positive). The reduction shall be the quantity of the offer multiplied by the b^{th} percentile of the DASPP for the hour over the previous 30 days multiplied by the value *e2*.

(a) The value *e2* is computed as the $ep2^{th}$ percentile of Ratio2 for the 30 days prior to the Operating Day, where Ratio2 is calculated daily as follows:

$$Ratio2 = 1 - Max[0, (\sum_{h=1,24} (Q_{cleared\ Offers} - Q_{cleared\text{-}Bids}))/(\sum_{h=1,24} (Q_{cleared\ Offers}))]$$

except $Ratio2 = 0$ when $\sum_{h=1,24} Q_{cleared\ Offers} = 0$

(b) ERCOT may adjust the value of *e2* by changing the quantity of bids or offers to the values reported by the Counter-Party in paragraph (7) below or based on information available to ERCOT; or

(2) Increased (when the b^{th} percentile Settlement Point Price for the hour is negative). The increase shall be the quantity of the offer multiplied by the b^{th} percentile of the DASPP for the hour over the previous 30 days.

(B) Credit exposure will be increased by the product of the quantity of the offer multiplied by the dp^{th} percentile of any positive hourly difference of Real-Time Settlement Point Price and DASPP over the previous 30 days for the hour multiplied by *e3*.

(ii) That has an offer price that is greater than the a^{th} percentile of the DASPP for the hour over the previous 30 days, credit exposure will be increased by the product of the quantity of the offer multiplied by the dp^{th} percentile of any positive hourly difference of Real-Time Settlement Point Price and DASPP over the previous 30 days for the hour multiplied by *e3*.

(iii) ERCOT may, in its sole discretion, use a percentile other than the dp^{th} percentile of any positive hourly difference of Real-Time Settlement Point Price and DASPP over the previous 30 days of the hour in determining credit exposure per this paragraph (6)(b) in evaluating DAM Energy-Only Offers.

(c) For each MW portion of the Energy Offer Curve of a Three-Part Supply Offer:

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

(c) For each MW portion of the Energy Offer Curve of a Three-Part Supply Offer or for each MW portion of the offer portion of an Energy Bid/Offer Curve:

(i) That has an offer price that is less than or equal to the y^{th} percentile of the DASPP for the hour over the previous 30 days, credit exposure will be reduced (when the z^{th} percentile Settlement Point Price is positive) or increased (when the z^{th} percentile Settlement Point Price is negative) by the quantity of the offer multiplied by the z^{th} percentile of the DASPP for the hour over the previous 30 days.

(ii) That has an offer price that is greater than the y^{th} percentile of the DASPP for the hour over the previous 30 days, the credit exposure will be zero.

(iii) For a Combined Cycle Generation Resource with Three-Part Supply Offers for multiple generator configurations, the reduction in credit exposure will be the maximum credit exposure reduction created by the individual Three-Part Supply Offers' Offer Curves (when the z^{th} percentile Settlement Point Price is positive). If the Three-Part Supply Offer causes a credit increase (when the z^{th} percentile Settlement Point Price is negative), the increase in credit exposure will be the maximum credit exposure increase created by the individual Three-Part Supply Offers.

(d) For PTP Obligation Bids:

(i) That have a bid price greater than zero, the sum of the quantity of the bid multiplied by the bid price, plus the u^{th} percentile of the hourly positive price difference between the source Real-Time Settlement Point Price minus the sink Real-Time Settlement Point Price over the previous 30 days multiplied by the quantity of the bid.

(ii) That have a bid price less than or equal to zero, the u^{th} percentile of the hourly positive price difference between the source Real-Time Settlement Point Price minus the sink Real-Time Settlement Point Price over the previous 30 days multiplied by the quantity of the bid.

(iii) Each tenth of a MW quantity (0.1 MW) of an expiring CRR for a Counter-Party can provide credit reduction for only one-tenth of a MW (0.1 MW) of a PTP Obligation bid for that Counter-Party.

(A) The QSE must submit the PTP Obligation bid at the same source and sink pair for the same hour, for the same operating date where the QSE submitting the PTP Obligation bid is represented by the same Counter-Party as the CRR Account Holder that is the owner of record for an expiring CRR, or group of CRRs.

(B) A portion or all of the PTP Obligation bid quantity must be less than or equal to the total of the quantity of all expiring CRRs at the specified source and sink pair and delivery period, less all valid previously submitted PTP Obligation bids at the specified source and sink pair and delivery period.

(iv) For qualified PTP Obligation bids with a bid price greater than zero, ERCOT shall reduce the credit exposure in paragraph (6)(d)(i) above as follows:

Credit Reduction = Reduction Factor * min[PTP bid quantity, remaining expiring CRR MWs] * bid price.

The Reduction Factor is *bd*%. The factor can be adjusted up or down at ERCOT's sole discretion with at least two Bank Business Days' notice. ERCOT may adjust this factor up with less notice, if needed. The expiring CRR may be PTP Options and/or PTP Obligations. If a QSE later cancels the PTP Obligation bid then the amount of exposure credited back to the Counter-Party will be treated as though this PTP Obligation bid was previously offset by expiring CRRs if a matching CRR source and sink pair exists up to the maximum expiring CRR quantity. If a QSE updates the PTP Obligation bid then it will be treated as a cancel followed by a new submission for purposes of credit exposure calculation. Outcome of this calculation is dependent of the sequence of submittals for updates and cancels.

(e) For PTP Obligation bids with Links to an Option with a bid price greater than zero:

Credit Reduction = (1- Reduction Factor *bd*) * (bid quantity * bid price)

(f) For Ancillary Service Obligations not self-arranged, the product of the quantity of Ancillary Service Obligation not self-arranged multiplied by the t^{th} percentile of the hourly MCPC for that Ancillary Service over the previous 30 days for that hour. For negative Self-Arranged Ancillary Service Quantities, the absolute value of the product of the quantity of the negative Self-Arranged Ancillary Service Quantity times the t^{th} percentile of the hourly MCPC for that Ancillary Service over the previous 30 days for that hour.

[NPRR1008 and NPRR1014: Insert applicable portions of paragraph (g) below upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1008; or upon system implementation for NPRR1014; and renumber accordingly:]

(g) For Ancillary Service Only Offers, credit exposure will be increased by the sum of the quantity of the Ancillary Service Only Offer multiplied by the dp^{th} percentile of the positive hourly difference for that Ancillary Service between RTMCPC and DAMCPC for that Ancillary Service over the previous 30 days for the Operating Hour of the Ancillary Service Only Offer.

(g) Values *e1*, *e2*, or *e3*, which are applicable to items (a) and (b) above, under conditions described below, will be determined and applied at ERCOT's sole discretion. Within the application parameters identified below, ERCOT shall establish values for *e1*, *e2*, and *e3* and provide notice to an affected Counter-Party of any changes to *e1*, *e2*, or *e3* before 0900 generally two Bank Business Days prior to the normally scheduled DAM 1000 by a minimum of two of these methods: written, electronic, posting to the MIS Certified Area or telephonic. However, ERCOT may adjust any DAM credit parameter immediately if, in its sole discretion, ERCOT determines that the parameter(s) set for a Counter-Party do not adequately match the financial risk created by that Counter-Party's activities in the market. ERCOT shall review the values for *e1*, *e2*, or *e3* for each Counter-Party no less than once every two weeks. ERCOT shall provide written or electronic notice to the Counter-Party of the basis for ERCOT's assessment, or change of assessment, of the exposure adjustment variable established for the Counter-Party and the impact of the adjustment.

(i) The value of each exposure adjustment *e1*, *e2*, and *e3* is a value between zero and one, rounded to the nearest hundredth decimal place, set by ERCOT by Counter-Party. The values ERCOT establishes for *e1*, *e2*, and *e3* for a Counter-Party shall be applied equally to the portfolio of all QSEs represented by such Counter-Party.

(h) ERCOT must re-examine DAM credit parameters immediately if Counter-Party exceeds 90% of its Available Credit Limit (ACL) available to DAM.

(7) A Counter-Party may request more favorable parameters from ERCOT by agreeing to all of the conditions below:

(a) The Counter-Party shall notify ERCOT of any expected changes to Ratio1 or Ratio2, due to change in activity, as described below, and the likely duration of such change as soon as practicable, but no later than two Business Days in advance of the change:

(i) If Ratio1 as defined in paragraph (6)(a)(ii)(B) above is likely to be greater than the Counter-Party's currently assigned value of *e1* for particular day(s), then the estimated daily values of Ratio1 specifying the day(s) along with the daily DAM Energy Bid, Energy-Only Offer, and Three-Part Supply Offer quantity assumptions used to arrive at those values; and

(ii) If Ratio2 as defined in paragraph (6)(b)(i)(A)(1) above is likely to be lower than the Counter-Party's currently assigned value of *e2* for particular day(s), then the estimated daily values of Ratio2 specifying the day(s) along with the daily DAM Energy Bid, Energy-Only Offer, and Three-Part Supply Offer quantity assumption used to arrive at those values.

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

(a) The Counter-Party shall notify ERCOT of any expected changes to Ratio1 or Ratio2, due to change in activity, as described below, and the likely duration of such change as soon as practicable, but no later than two Business Days in advance of the change:

(i) If Ratio1 as defined in paragraph (6)(a)(ii)(B) above is likely to be greater than the Counter-Party's currently assigned value of *e1* for particular day(s), then the estimated daily values of Ratio1 specifying the day(s) along with the daily DAM Energy Bid, Energy-Only Offer, Energy Bid/Offer Curves, and Three-Part Supply Offer quantity assumptions used to arrive at those values; and

(ii) If Ratio2 as defined in paragraph (6)(b)(i)(A)(1) above is likely to be lower than the Counter-Party's currently assigned value of *e2* for particular day(s), then the estimated daily values of Ratio2 specifying the day(s) along with the daily DAM Energy Bid, Energy-Only Offer, Energy Bid/Offer Curves, and Three-Part Supply Offer quantity assumption used to arrive at those values.

(b) ERCOT, in its sole discretion, will determine the adequacy of the disclosures made in item (a) above and may require additional information as needed to evaluate whether a Counter- Party is eligible for favorable treatment.

(c) ERCOT may change the requirements for providing information, as described in item (a) above, to ensure that reasonable information is obtained from Counter-Parties.

(d) ERCOT may, but is not required, to use information provided by a Counter-Party to re-evaluate DAM credit parameters and may take other information into consideration as needed.

(e) If ERCOT determines that information provided to ERCOT is erroneous or that ERCOT has not been notified of required changes, ERCOT may set all parameters for the Counter-Party to the default values with a possible adder on the e1 variable, at ERCOT's sole discretion, for a period of not less than seven days and until ERCOT is satisfied that the Counter-Party has and will comply with the conditions set forth in this Section. In no case shall the adder result in an e1 value greater than one.

(8) Beginning no later than 0800 and ending at 0945 each Business Day, ERCOT shall post to the MIS Certified Area, approximately every 15 minutes, each active Counter-Party's remaining Available Credit Limit (ACL) for that day's DAM and the time at which the report was run.

(9) After the DAM results are posted, ERCOT shall post once each Business Day on the MIS Certified Area each active Counter-Party's calculated aggregate DAM credit exposure and its aggregate DAM credit exposure per transaction type, to the extent available, as it pertains to the most recent DAM Operating Day. The transaction types are:

(a) DAM Energy Bids;

(b) DAM Energy Only Offers;

(c) PTP Obligation Bids;

(d) Three-Part Supply Offers; and

(e) Ancillary Services.

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

(e) Ancillary Services related to Self-Arranged Ancillary Service Quantities;

(f) Ancillary Service Only Offers;

(g) Energy Bid/Offer Curves.

(10) The parameters in this Section are defined as follows:

(a) The default values of the parameters are:

Parameter	**Unit**	**Current Value***
d	percentile	85
ep1	percentile	95
a	percentile	50
b	percentile	45
dp	percentile	90
ep2	percentile	0
e3	value	1
y	percentile	45
z	percentile	50
u	percentile	90
bd	%	90
t	percentile	50
* The current value for the parameters referenced in this table above will be recommended by TAC and approved by the ERCOT Board. ERCOT shall update parameter values on the first day of the month following ERCOT Board		

Parameter	Unit	Current Value*
approval unless otherwise directed by the ERCOT Board. ERCOT shall provide a Market Notice prior to implementation of a revised parameter value.		

(b) The values of the parameters for Entities that meet the requirements in paragraph (7) above for more favorable treatment are:

Parameter	Unit	Current Value
d	percentile	85
ep1	percentile	75
a	percentile	50
b	percentile	45
dp	percentile	90
ep2	percentile	25
e3	value	1
y	percentile	45
z	percentile	50
u	percentile	90
t	percentile	50
* The current value for the parameters referenced in this table above will be recommended by TAC and approved by the ERCOT Board. ERCOT shall update parameter values on the first day of the month following ERCOT Board approval unless otherwise directed by the ERCOT Board. ERCOT shall provide a Market Notice prior to implementation of a revised parameter value.		

4.5 DAM Execution and Results

4.5.3 Communicating DAM Results

(1) As soon as practicable, but no later than 1330 in the Day-Ahead, ERCOT shall notify the parties to each cleared DAM transaction (e.g., the buyer and the seller) of the results of the DAM as follows:

(a) Awarded Ancillary Service Offers, specifying Resource, MW, Ancillary Service type, and price, for each hour of the awarded offer;

(b) Awarded energy offers from Three-Part Supply Offers and from DAM Energy-Only Offers, specifying Resource (except for DAM Energy-Only Offers), MWh, Settlement Point, and Settlement Point Price, for each hour of the awarded offer;

(c) Awarded DAM Energy Bids, specifying MWh, Settlement Point, and Settlement Point Price for each hour of the awarded bid; and

(d) Awarded PTP Obligation Bids, number of PTP Obligations in MW, source and sink Settlement Points, and price for each Settlement Interval of the awarded bid.

[NPRR1008 and NPRR1014: Replace applicable portions of paragraph (1) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1008; or upon system implementation for NPRR1014:]

(1) As soon as practicable, but no later than 1330 in the Day-Ahead, ERCOT shall notify the parties to each cleared DAM transaction (e.g., the buyer and the seller) of the results of the DAM as follows:

(a) Awarded Resource-Specific Ancillary Service Offers, specifying Resource, MW, Ancillary Service type, and price, for each hour of the awarded offer;

(b) Awarded Ancillary Service Only Offers, specifying MW, Ancillary Service type, and price, for each hour of the awarded offer;

(c) Awarded energy offers from Three-Part Supply Offers and from DAM Energy-Only Offers, specifying Resource (except for DAM Energy-Only Offers), MWh, Settlement Point, and Settlement Point Price, for each hour of the awarded offer;

(d) Awarded DAM Energy Bids, specifying MWh, Settlement Point, and Settlement Point Price for each hour of the awarded bid;

(e) Awarded Energy Bid/Offer Curves, specifying Resource, MWh, Settlement Point, and Settlement Point Price, for each hour of the awarded bid/offer; and

(f) Awarded PTP Obligation Bids, number of PTP Obligations in MW, source and sink Settlement Points, and price for each Settlement Interval of the awarded bid.

(2) As soon as practicable, but no later than 1330, ERCOT shall post on the ERCOT website the hourly:

(a) Day-Ahead MCPC for each type of Ancillary Service for each hour of the Operating Day;

(b) DASPPs for each Settlement Point for each hour of the Operating Day;

(c) Day-Ahead hourly LMPs for each Electrical Bus for each hour of the Operating Day;

(d) Shadow Prices for every binding constraint for each hour of the Operating Day;

(e) Quantity of total Ancillary Service Offers received in the DAM, in MW by Ancillary Service type for each hour of the Operating Day;

(f) Energy bought in the DAM consisting of the following:

(i) The total quantity of awarded DAM Energy Bids (in MWh) bought in the DAM at each Settlement Point for each hour of the Operating Day; and

(ii) The total quantity of awarded PTP Obligation Bids (in MWh) cleared in the DAM that sink at each Settlement Point for each hour of the Operating Day.

(g) Energy sold in the DAM consisting of the following:

(i) The total quantity of awarded DAM Energy Offers (in MWh), from Three-Part Supply Offers and DAM Energy Only Offers, bought in the DAM at each Settlement Point for each hour of the Operating Day; and

(ii) The total quantity of awarded PTP Obligation Bids (in MWh) cleared in the DAM that source at each Settlement Point for each hour of the Operating Day.

(h) Aggregated Ancillary Service Offer Curve of all Ancillary Service Offers for each type of Ancillary Service for each hour of the Operating Day;

(i) Electrically Similar Settlement Points used during the DAM clearing process; and

(j) Settlement Points that were de-energized in the base case; and

(k) System Lambda.

[NPRR1008 and NPRR1014: Replace applicable portions of paragraph (2) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1008; or upon system implementation for NPRR1014:]

(2) As soon as practicable, but no later than 1330, ERCOT shall post on the ERCOT website the hourly:

(a) Day-Ahead MCPC for each type of Ancillary Service for each hour of the Operating Day;

(b) DASPPs for each Settlement Point for each hour of the Operating Day;

(c) Day-Ahead hourly LMPs for each Electrical Bus for each hour of the Operating Day;

(d) Shadow Prices for every binding constraint for each hour of the Operating Day;

(e) Energy bought in the DAM consisting of the following:

(i) The total quantity of awarded DAM Energy Bids (in MWh) bought in the DAM at each Settlement Point for each hour of the Operating Day;

(ii) The total quantity of awarded PTP Obligation Bids (in MWh) cleared in the DAM that sink at each Settlement Point for each hour of the Operating Day; and

(iii) The total absolute value quantity of awards to bid portions of Energy Bid/Offer Curves (in MWh) cleared in the DAM at each Settlement Point for each hour of the Operating Day.

(f) Energy sold in the DAM consisting of the following:

(i) The total quantity of awarded DAM Energy Offers (in MWh), from Three-Part Supply Offers and DAM Energy Only Offers, bought in the DAM at each Settlement Point for each hour of the Operating Day;

(ii) The total quantity of awarded PTP Obligation Bids (in MWh) cleared in the DAM that source at each Settlement Point for each hour of the Operating Day; and

(iii) The total quantity of awards to offer portions of Energy Bid/Offer Curves (in MWh) cleared in the DAM at each Settlement Point for each hour of the Operating Day.

(g) Aggregated Ancillary Service Offer Curve of all Ancillary Service Offers (including both Resource-Specific Ancillary Service Offers and Ancillary Service Only Offers) for each type of Ancillary Service for each hour of the Operating Day;

(h) Electrically Similar Settlement Points used during the DAM clearing process; ~~and~~

(i) Settlement Points that were de-energized in the base case;

(j) System Lambda; and

(k) Ancillary Services sold in the DAM consisting of the total quantity of awarded Resource-Specific Ancillary Service Offers and Ancillary Service Only Offers, for each Ancillary Service for each hour of the Operating Day.

(3) ERCOT shall monitor Day-Ahead MCPCs and Day-Ahead hourly LMPs for errors and if there are conditions that cause the price to be questionable, ERCOT shall notify all Market Participants that the DAM prices are under investigation as soon as practicable.

(4) ERCOT shall correct prices when: (i) a market solution is determined to be invalid or (ii) invalid prices are identified in an otherwise valid market solution, unless accurate prices cannot be determined. The following are some reasons that may cause these conditions.

[NPRR1024: Replace paragraph (4) above with the following upon system implementation:]

(4) ERCOT shall correct prices for an Operating Day when a market solution is determined to be invalid or invalid prices are identified in an otherwise valid market solution, accurate prices can be determined, and the impact of the price correction is significant. The following are some reasons that may cause an invalid market solution or invalid prices in a valid market solution.

(a) Data Input error: Missing, incomplete, or incorrect versions of one or more data elements input to the DAM application may result in an invalid market solution and/or prices.

(b) Software error: Pricing errors may occur due to software implementation errors in DAM pre-processing, DAM clearing process, and/or DAM post processing.

(c) Inconsistency with these Protocols or the Public Utility Commission of Texas (PUCT) Substantive Rules: Pricing errors may occur when specific circumstances result in prices that are in conflict with such Protocol language or the PUCT Substantive Rules.

[NPRR1024: Insert paragraph (5) below upon system implementation and renumber accordingly:]

(5) For purposes of a price correction performed prior to 1000 on the second Business Day after the Operating Day, the impact of a price correction is considered significant, as that term is used in paragraph (4) above, for the Operating Day when:

(a) The absolute value change to any single DAM Settlement Point Price at a Resource Node or Day-Ahead MCPC is greater than $0.05/MWh;

(b) The price correction would require ERCOT to change more than ten DAM Settlement Point Prices and Day-Ahead MCPCs; or

(c) The absolute value change to any DAM Settlement Point Price at a Load Zone or Hub is greater than $0.02/MWh.

(5) All DAM LMPs, MCPCs, and Settlement Point Prices are final at 1000 of the second Business Day after the Operating Day.

(a) However, after DAM LMPs, MCPCs, and Settlement Point Prices are final, if ERCOT determines that prices are in need of correction and seeks ERCOT Board review of such prices, it shall notify Market Participants and describe the need for such correction as soon as practicable but no later than 30 days after the Operating Day. Failure to notify Market Participants within this timeline precludes the ERCOT Board from reviewing such prices. However, nothing in this section shall be understood to limit or otherwise inhibit any of the following:

(i) ERCOT's duty to inform the PUCT of potential or actual violations of the ERCOT Protocols or PUCT Rules and its right to request that the PUCT authorize correction of any prices that may have been affected by such potential or actual violations;

(ii) The PUCT's authority to order price corrections when permitted to do so under other law; or

(iii) ERCOT's authority to grant relief to a Market Participant pursuant to the timelines specified in Section 20, Alternative Dispute Resolution Procedure.

(b) The ERCOT Board may review and change DAM LMPs, MCPCs, or Settlement Point Prices if ERCOT gave timely notice to Market Participants and the ERCOT Board finds that such prices are significantly affected by an error.

(c) In review of DAM LMPs, MCPCs, or Settlement Point Prices, the ERCOT Board may rely on the same reasons identified in paragraph (4) above to find that the prices are significantly affected by an error.

[NPRR1024: Replace paragraph (5) above with the following upon system implementation:]

(6) All DAM LMPs, MCPCs, and Settlement Point Prices are final at 1000 of the second Business Day after the Operating Day.

(a) However, after DAM LMPs, MCPCs, and Settlement Point Prices are final, if ERCOT determines that prices qualify for a correction pursuant to paragraph (4) above and that ERCOT will seek ERCOT Board review of such prices, it shall notify Market Participants and describe the need for such correction as soon as practicable but no later than 30 days after the Operating Day. Failure to notify Market Participants within this timeline precludes the ERCOT Board from reviewing such prices. However, nothing in this section shall be understood to limit or otherwise inhibit any of the following:

(i) ERCOT's duty to inform the PUCT of potential or actual violations of the ERCOT Protocols or PUCT Rules and its right to request that the PUCT authorize correction of any prices that may have been affected by such potential or actual violations;

(ii) The PUCT's authority to order price corrections when permitted to do so under other law; or

(iii) ERCOT's authority to grant relief to a Market Participant pursuant to the timelines specified in Section 20, Alternative Dispute Resolution Procedure.

(b) Before seeking ERCOT Board review of prices, ERCOT will determine if the impact of the price correction is significant, as that term is used in paragraph (4) above, by calculating the potential changes to the DAM Settlement Statement(s) of any Counter-Party on the given Operating Day. ERCOT shall seek ERCOT Board review of prices if the change in DAM Settlement Statements(s) would result in the absolute value impact to any single Counter-Party, based on the sum of all original DAM Settlement Statement amounts of Market Participants assigned to the Counter-Party, to be greater than:

(i) 2% and also greater than $20,000; or

(ii) 20% and also greater than $2,000.

(c) The ERCOT Board may review and change DAM LMPs, MCPCs, or Settlement Point Prices if ERCOT gave timely notice to Market Participants and the ERCOT Board finds that such prices should be corrected for an Operating Day.

(d) In review of DAM LMPs, MCPCs, or Settlement Point Prices, the ERCOT Board may rely on the same reasons identified in paragraph (4) above to find that the prices should be corrected for an Operating Day.

(6) As soon as practicable, but no later than 1330, ERCOT shall make available the Day-Ahead Shift Factors for binding constraints in the DAM and post to the Market Information System (MIS) Secure Area.

4.6 DAM Settlement

4.6.1 Day-Ahead Settlement Point Prices

(1) The Day-Ahead Settlement Point Price (DASPP) calculations are described in this Section for Resource Nodes, Load Zones, Hubs, and logical Resource Nodes. For all

DASPPs, there shall be an administrative price floor of -$251/MWh.

[NPRR1051: Replace paragraph (1) above with the following upon system implementation:]

(1) The Day-Ahead Settlement Point Price (DASPP) calculations are described in this Section for Resource Nodes, Load Zones, Hubs, and logical Resource Nodes.

4.6.3 Settlement for PTP Obligations Bought in DAM

(1) ERCOT shall pay or charge a QSE for a cleared PTP Obligation bid the difference in the DAM Settlement Point Prices between the sink Settlement Point and the source Settlement Point. The charge or payment to each QSE for a given Operating Hour of its cleared PTP Obligation bids with each pair of source and sink Settlement Points is calculated as follows:

$$\text{DARTOBLAMT}_{q,\,(j,\,k)} = \text{DAOBLPR}_{(j,\,k)} * \text{RTOBL}_{q,\,(j,\,k)}$$

Where:

$$\text{DAOBLPR}_{(j,\,k)} = \text{DASPP}_{k} - \text{DASPP}_{j}$$

The above variables are defined as follows:

Variable	Unit	Definition
$\text{DARTOBLAMT}_{q,\,(j,\,k)}$	$	*Day-Ahead Real-Time Obligation Amount per QSE per pair of source and sink*—The charge or payment to QSE q for a PTP Obligation bid cleared in the DAM with the source j and the sink k, for the hour.
$\text{DAOBLPR}_{(j,\,k)}$	$/MWh	*Day-Ahead Obligation Price per pair of source and sink*—The DAM clearing price of a PTP Obligation bid with the source j and the sink k, for the hour.
DASPP_{j}	$/MWh	*Day-Ahead Settlement Point Price at source*—The DAM Settlement Point Price at the source Settlement Point j for the hour.
DASPP_{k}	$/MWh	*Day-Ahead Settlement Point Price at sink*—The DAM Settlement Point Price at the sink Settlement Point k for the hour.
$\text{RTOBL}_{q,\,(j,\,k)}$	MW	*Real-Time Obligation per QSE per pair of source and sink*—The total MW of QSE q's PTP Obligation bids cleared in the DAM and settled in Real-Time for the source j and the sink k, for the hour.
q	none	A QSE.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.

(2) The net total charge or payment to the QSE for the hour of all its cleared PTP Obligation bids is calculated as follows:

$$\text{DARTOBLAMTQSETOT}_{q} = \sum_{j}\sum_{k} \text{DARTOBLAMT}_{q, (j, k)}$$

The above variables are defined as follows:

Variable	Unit	Definition
$\text{DARTOBLAMTQSETOT}_{q}$	$	*Day-Ahead Real-Time Obligation Amount QSE Total per QSE*—The net total charge or payment to QSE *q* for all its PTP Obligation bids cleared in the DAM for the hour.
$\text{DARTOBLAMT}_{q, (j, k)}$	$	*Day-Ahead Real-Time Obligation Amount per QSE per pair of source and sink*—The charge or payment to QSE *q* for a PTP Obligation bids cleared in the DAM with the source *j* and the sink *k*, for the hour.
q	none	A QSE.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.

(3) ERCOT shall charge a QSE for a cleared PTP Obligation bid with Links to an Option the positive difference in the DASPP between the sink Settlement Point and the source Settlement Point. The charge to each QSE for a given Operating Hour of its cleared PTP Obligation bid with Links to an Option with each pair of source and sink Settlement Points is calculated as follows:

$$\text{DARTOBLLOAMT}_{q, (j, k)} = \text{Max}\,(0, \text{DAOBLPR}_{(j, k)}) * \text{RTOBLLO}_{q, (j, k)}$$

Where:

$$\text{RTOBLLO}_{q, (j, k)} = \sum_{crrid} \text{OBLLOCRR}_{q, (j, k), crrid, crrofferid}$$

The above variables are defined as follows:

Variable	Unit	Definition
$\text{DARTOBLLOAMT}_{q, (j, k)}$	$	*Day-Ahead Real-Time Obligation with Links to an Option Amount per QSE per pair of source and sink*—The charge to QSE *q* for a PTP Obligation bid with Links to an Option cleared in the DAM with the source *j* and the sink *k*, for the hour.
$\text{DAOBLPR}_{(j, k)}$	$/MWh	*Day-Ahead Obligation Price per pair of source and sink*—The DAM clearing price of a PTP Obligation bid with the source *j* and the sink *k*, for the hour.
$\text{RTOBLLO}_{q, (j, k)}$	MW	*Real-Time PTP Obligation with Links to an Option per QSE per pair of source and sink*—The total MW of QSE *q*'s PTP Obligation bids with Links to an Option cleared in the DAM and settled in Real-Time for the source *j* and the sink *k*, for the hour.
$\text{OBLLOCRR}_{q, (j, k), crrid, crrofferid}$	MW	*PTP Obligation with Links to an Option per QSE per pair of source and sink, CRRID and CRR Offer ID of the linked Option*—The total MW of QSE *q*'s PTP Obligation bids with Links to an Option cleared in the DAM for the source *j* and the sink *k*, for the hour and CRRID and CRROFFERID of the linked PTP Option.
crrid	none	A Congestion Revenue Right (CRR) Option identification code.
crrofferid	none	A CRR Offer identification code.
q	none	A QSE.

Variable	Unit	Definition
j	none	A source Settlement Point.
k	none	A sink Settlement Point.

(4) The net total charge to the QSE for the hour of all its cleared PTP Obligation bids with Links to an Option is calculated as follows:

$$\text{DARTOBLLOAMTQSETOT}_{q} = \sum_{j} \sum_{k} \text{DARTOBLLOAMT}_{q,\,(j,\,k)}$$

The above variables are defined as follows:

Variable	Unit	Definition
DARTOBLLOAMTQSETOT $_{q}$	$	*Day-Ahead Real-Time Obligation with Links to an Option Amount QSE Total per QSE*—The net total charge to QSE q for all its PTP Obligation bids with Links to an Option cleared in the DAM for the hour.
DARTOBLLOAMT $_{q,\,(j,\,k)}$	$	*Day-Ahead Real-Time Obligation with Links to Option Amount per QSE per pair of source and sink*—The charge to QSE q for a PTP Obligation bid with Links to an Option cleared in the DAM with the source j and the sink k, for the hour.
q	none	A QSE.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.

ERCOT Nodal Protocols

Section 6: Adjustment Period and Real-Time Operations

March~~January~~ 1, 2021

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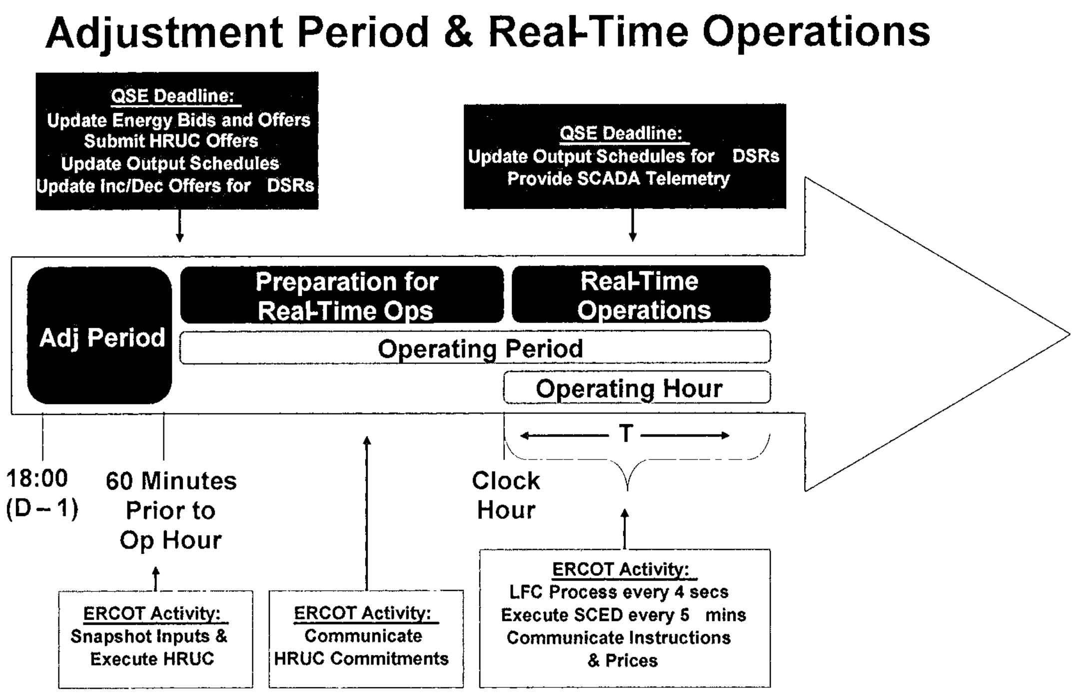
6 ADJUSTMENT PERIOD AND REAL-TIME OPERATIONS

6.3 Adjustment Period and Real-Time Operations Timeline

(1) The figure below highlights the major activities that occur in the Adjustment Period and Real-Time operations:



(2) Activities for the Adjustment Period begin at 1800 in the Day-Ahead and end one full hour before the start of the Operating Hour. The figure above is intended to be only a general guide and not controlling language, and any conflict between this figure and another section of the Protocols is controlled by the other section.

(3) ERCOT shall monitor Real-Time Locational Marginal Prices (LMPs), Supplemental Ancillary Services Market (SASM) Market Clearing Prices for Capacity (MCPCs), and Real-Time Settlement Point Prices, including Real-Time prices for energy metered, Real-Time On-Line Reliability Deployment Price Adders, Real-Time On-Line Reliability Deployment Prices, Real-Time Off-Line Reserve Price Adders, Real-Time On-Line Reserve Price Adders, Real-Time Reserve Prices for On-Line Reserves and Real-Time Reserve Prices for Off-Line Reserves, for errors and if there are conditions that cause the price to be questionable, ERCOT shall notify all Market Participants that the Real-Time LMPs, SASM MCPCs, and Real-Time Settlement Point Prices are under investigation as soon as practicable.

(4) ERCOT shall correct prices when: (i) a market solution is determined to be invalid, (ii) invalid prices are identified in an otherwise valid market solution, (iii) the Base Points received by Market Participants are inconsistent with the Base Points of a valid market solution, unless accurate prices cannot be determined, or (iv) the Security-Constrained

Economic Dispatch (SCED) process experiences a failure as described in Section 6.5.9.2, Failure of the SCED Process. The following are some reasons that may cause these conditions.

(a) Data Input error: Missing, incomplete, stale, or incorrect versions of one or more data elements input to the market applications may result in an invalid market solution and/or prices.

(b) Data Output error: These include: (i) incorrect or incomplete data transfer, (ii) price recalculation error in post-processing, and (iii) Base Points inconsistent with prices due to the Emergency Base Point flag remaining activated even when the SCED solution is valid.

(c) Hardware/Software error: These include unpredicted hardware or software failures, planned market system or database outages, planned application or database upgrades, software implementation errors, and failure of the market run to complete.

(d) Inconsistency with the Protocols or Public Utility Commission of Texas (PUCT) Substantive Rules: Pricing errors may occur when specific circumstances result in prices that are in conflict with such Protocol language or the PUCT Substantive Rules.

(5) If it is determined that any Real-Time Settlement Point Prices, Settlement Point LMPs, Electrical Bus LMPs, Real-Time prices for energy metered, Real-Time On-Line Reliability Deployment Price Adders, Real-Time On-Line Reliability Deployment Prices, Real-Time On-Line Reserve Price Adders, Real-Time Off-Line Reserve Price Adders, Real-Time Reserve Prices for On-Line Reserves, Real-Time Reserve Prices for Off-Line Reserves, and/or constraint Shadow Prices are erroneous, ERCOT shall correct the prices before the prices are considered final in paragraph (6) below. Specifically:

(a) If it is determined that correcting the Real-Time Settlement Point Prices will not affect the Base Points that were received by Qualified Scheduling Entities (QSEs), then ERCOT shall correct the prices before the prices are considered final in paragraph (6) below.

(b) If it is determined that correcting the Real-Time Settlement Point Prices will affect the Base Points that were received by QSEs, then ERCOT shall correct the prices before the prices are considered final and settle the SCED executions as failed in accordance with Section 6.5.9.2.

(c) If the Base Points received by QSEs are inconsistent with the Real-Time Settlement Point Prices reduced by the sum of the Real-Time On-Line Reliability Deployment Prices and the Real-Time Reserve Prices for On-Line Reserves averaged over the 15-minute Settlement Interval, then ERCOT shall consider those Base Points as due to manual override from the ERCOT Operator and settle the relevant Settlement Interval(s) in accordance with Section 6.6.9, Emergency Operations Settlement.

(6) All Real-Time LMPs, Real-Time Settlement Point Prices, Real-Time prices for energy metered, Real-Time On-Line Reliability Deployment Price Adders, Real-Time On-Line Reliability Deployment Prices, Real-Time Reserve Prices for On-Line Reserves, Real-Time Reserve Prices for Off-Line Reserves, Real-Time On-Line Reserve Price Adders, Real-Time Off-Line Reserve Price Adders and SASM MCPCs are final at 1600 of the second Business Day after the Operating Day.

(a) However, after Real-Time LMPs, Real Time Settlement Point Prices, Real-Time prices for energy metered, Real-Time On-Line Reliability Deployment Price Adders, Real-Time On- Line Reliability Deployment Prices, Real-Time Reserve Prices for On-Line Reserves, Real-Time Reserve Prices for Off-Line Reserves, Real-Time On-Line Reserve Price Adders, Real-Time Off-Line Reserve Price Adders and SASM MCPCs are final, if ERCOT determines that prices are in need of correction and seeks ERCOT Board review of such prices, it shall notify Market Participants and describe the need for such correction as soon as practicable but no later than 30 days after the Operating Day. Failure to notify Market Participants within this timeline precludes the ERCOT Board from reviewing such prices. However, nothing in this section shall be understood to limit or otherwise inhibit any of the following:

(i) ERCOT's duty to inform the PUCT of potential or actual violations of the ERCOT Protocols or PUCT Rules and its right to request that the PUCT authorize correction of any prices that may have been affected by such potential or actual violations;

(ii) The PUCT's authority to order price corrections when permitted to do so under other law; or

(iii) ERCOT's authority to grant relief to a Market Participant pursuant to the timelines specified in Section 20, Alternative Dispute Resolution Procedure.

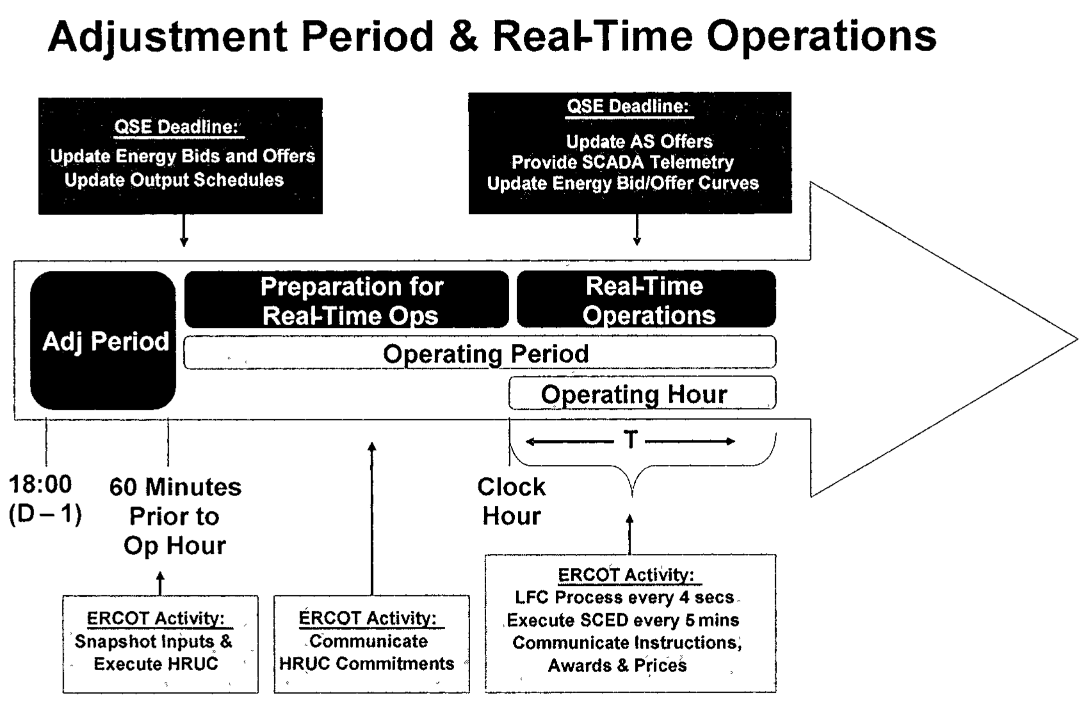
(b) The ERCOT Board may review and change Real-Time LMPs, Real-Time Settlement Point Prices, Real-Time prices for energy metered, Real-Time On-Line Reliability Deployment Price Adders, Real-Time On-Line Reliability Deployment Prices, Real-Time Reserve Prices for On-Line Reserves, Real-Time Reserve Prices for Off-Line Reserves, Real-Time On-Line Reserve Price Adders, Real-Time Off-Line Reserve Price Adders and SASM MCPCs if ERCOT gave timely notice to Market Participants and the ERCOT Board finds that such prices are significantly affected by an error.

(c) In review of Real-Time LMPs, Real Time Settlement Point Prices, Real-Time prices for energy metered, Real-Time On-Line Reliability Deployment Price Adders, Real-Time On-Line Reliability Deployment Prices, Real-Time Reserve Prices for On-Line Reserves, Real-Time Reserve Prices for Off-Line Reserves, Real-Time On-Line Reserve Price Adders, Real-Time Off-Line Reserve Price Adders and SASM MCPCs, the ERCOT Board may rely on the same reasons identified in paragraph (4) above to find that the prices are significantly affected by an error.

[NPRR1000, NPRR1010, ~~and~~ NPRR1014, and NPRR1024: Replace applicable portions of Section 6.3 above with the following upon system implementation for NPRR1000, ~~or~~ NPRR1014, or NPRR1024; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010:]

6.3 Adjustment Period and Real-Time Operations Timeline

(1) The figure below highlights the major activities that occur in the Adjustment Period and Real-Time operations:



(2) Activities for the Adjustment Period begin at 1800 in the Day-Ahead and end one full hour before the start of the Operating Hour. The figure above is intended to be only a general guide and not controlling language, and any conflict between this figure and another section of the Protocols is controlled by the other section.

(3) ERCOT shall monitor Real-Time Locational Marginal Prices (LMPs), Real-Time Market Clearing Prices for Capacity (MCPCs), and Real-Time Settlement Point Prices, including Real-Time prices for energy metered, Real-Time Reliability Deployment Price Adders for Energy, and Real-Time Reliability Deployment Price Adders for Ancillary Service, for errors and if there are conditions that cause the price to be questionable, as soon as practicable, ERCOT shall notify all Market Participants that

the Real-Time LMPs, Real-Time MCPCs, and Real-Time Settlement Point Prices are under investigation.

(4) ERCOT shall correct prices for an Operating Day when accurate prices can be determined, the impact of the price correction is determined to be significant, and one of the following conditions has been met: ~~(i)~~ a market solution is determined to be invalid, ~~(ii)~~ invalid prices are identified in an otherwise valid market solution, ~~(iii)~~ the Base Points or Ancillary Service awards received by Market Participants are inconsistent with the Base Points or Ancillary Service awards of a valid market solution, ~~unless accurate prices cannot be determined,~~ or ~~(iv)~~ the Security-Constrained Economic Dispatch (SCED) process experiences a failure as described in Section 6.5.9.2, Failure of the SCED Process. The following are some reasons that may cause these conditions.

(a) Data Input error: Missing, incomplete, stale, or incorrect versions of one or more data elements input to the market applications may result in an invalid market solution and/or prices.

(b) Data Output error: These include: ~~(i)~~ incorrect or incomplete data transfer, ~~(ii)~~ price recalculation error in post-processing, and ~~(iii)~~ Base Points inconsistent with prices due to the Emergency Base Point flag remaining activated even when the SCED solution is valid.

(c) Hardware/Software error: These include unpredicted hardware or software failures, planned market system or database outages, planned application or database upgrades, software implementation errors, and failure of the market run to complete.

(d) Inconsistency with the Protocols or Public Utility Commission of Texas (PUCT) Substantive Rules: Pricing errors may occur when specific circumstances result in prices that are in conflict with such Protocol language or the PUCT Substantive Rules.

(5) For purposes of a price correction performed prior to 1600 on the second Business Day after the Operating Day, the impact of a price correction shall be considered significant, as that term is used in paragraph (4) above, for the Operating Day when:

(a) The absolute value change to any single Real-Time Settlement Point Price at a Resource Node is greater than $0.05/MWh;

(b) The price correction would require ERCOT to change more than 50 Real-Time Settlement Point Prices;

(c) The absolute value change to any Real-Time Settlement Point Price at a Load Zone or Hub is greater than $0.02/MWh;

(d) The estimated absolute total dollar impact for changes to Real-Time prices for energy metered is greater than $500; or

(e) The absolute total dollar impact for changes to SASM MCPCs is greater than $500.

(6~~5~~) If it is determined that any Real-Time Settlement Point Prices, Settlement Point LMPs, Electrical Bus LMPs, Real-Time prices for energy metered, Real-Time Reliability Deployment Price Adders for Energy, Real-Time MCPCs, Real-Time Reliability Deployment Price Adders for Ancillary Service, and/or constraint Shadow Prices are erroneous, ERCOT shall correct the prices before the prices are considered final in paragraph (7~~6~~) below. Specifically:

(a) If it is determined that correcting the Real-Time Settlement Point Prices will not affect the Base Points, and correcting Real-Time MCPCs will not affect Ancillary Service awards, then ERCOT shall correct the prices before the prices are considered final in paragraph (7~~6~~) below.

(b) If it is determined that correcting the Real-Time Settlement Point Prices will affect the Base Points, or correcting Real-Time MCPCs will affect Ancillary Service awards, then ERCOT shall correct the prices before the prices are considered final and settle the SCED executions as failed in accordance with Section 6.5.9.2.

(c) For Settlement purposes, if the Base Points are inconsistent with the Real-Time Settlement Point Prices, reduced by the Real-Time Reliability Deployment Price Adder for Energy, or Ancillary Service awards are inconsistent with the Real-Time MCPCs, reduced by the Real-Time Reliability Deployment Price Adder for Ancillary Service, averaged over the 15-minute Settlement Interval, then ERCOT shall consider the relevant Settlement Interval(s) in accordance with Section 6.6.9, Emergency Operations Settlement.

(7~~6~~) All Real-Time LMPs, Real-Time Settlement Point Prices, Real-Time prices for energy metered, Real-Time Reliability Deployment Price Adders for Energy, Real-Time MCPCs, and Real-Time Reliability Deployment Price Adders for Ancillary Service are final at 1600 of the second Business Day after the Operating Day.

(a) However, after Real-Time LMPs, Real-Time Settlement Point Prices, Real-Time prices for energy metered, Real-Time Reliability Deployment Price Adders for Energy, Real-Time MCPCs, and Real-Time Reliability Deployment Price Adders for Ancillary Service are final, if ERCOT determines that prices qualify for a price correction pursuant to paragraph (4) above~~are in need of correction~~ and that ERCOT will seek~~s~~ ERCOT Board review of such prices, it shall notify Market Participants and describe the need for such correction as soon as practicable but no later than 30 days after the Operating Day. Failure to notify Market Participants within this timeline precludes the ERCOT Board from reviewing such prices. However, nothing in this section shall be understood to limit or otherwise inhibit any of the following:

(i) ERCOT's duty to inform the PUCT of potential or actual violations of the ERCOT Protocols or PUCT Rules and its right to request that the PUCT authorize correction of any prices that may have been affected by such potential or actual violations;

(ii) The PUCT's authority to order price corrections when permitted to do so under other law; or

(iii) ERCOT's authority to grant relief to a Market Participant pursuant to the timelines specified in Section 20, Alternative Dispute Resolution Procedure.

(b) Before seeking ERCOT Board review of prices, ERCOT will determine if the impact of the price correction is significant, as that term is used in paragraph (4) above, by calculating the potential changes to the RTM Settlement Statement(s) of any Counter-Party on a given Operating Day. ERCOT shall seek ERCOT Board review of prices if the change in RTM Settlement Statement(s) would result in the absolute value impact to any single Counter-Party, based on the sum of all original RTM Settlement Statement amounts of Market Participants assigned to the Counter-Party, to be greater than:

(i) 2% and also greater than $20,000; or

(ii) 20% and also greater than $2,000.

(c~~b~~) The ERCOT Board may review and change Real-Time LMPs, Real-Time Settlement Point Prices, Real-Time prices for energy metered, Real-Time Reliability Deployment Price Adders for Energy, Real-Time MCPCs, and Real-Time Reliability Deployment Price Adders for Ancillary Service if ERCOT gave timely notice to Market Participants and the ERCOT Board finds that such prices ~~are significantly affected by an error~~should be corrected for an Operating Day.

(d~~c~~) In review of Real-Time LMPs, Real-Time Settlement Point Prices, Real-Time prices for energy metered, Real-Time Reliability Deployment Price Adders for Energy, Real-Time MCPCs, and Real-Time Reliability Deployment Price Adders for Ancillary Service, the ERCOT Board may rely on the same reasons identified in paragraph (4) above to find that the prices ~~are significantly affected by an error~~should be corrected for an Operating Day.

6.5 Real-Time Energy Operations

6.5.9 Emergency Operations

6.5.9.4 Energy Emergency Alert

(1) At times it may be necessary to reduce ERCOT System Demand because of a temporary decrease in available electricity supply. To provide orderly, predetermined procedures for curtailing Demand during such emergencies, ERCOT shall initiate and coordinate the implementation of the EEA following the steps set forth below in Section 6.5.9.4.2, EEA Levels.

(2) The goal of the EEA is to provide for maximum possible continuity of service while maintaining the integrity of the ERCOT System to reduce the chance of cascading Outages.

(3) ERCOT's operating procedures must meet the following goals:

(a) Use of market processes to the fullest extent practicable without jeopardizing the reliability of the ERCOT System;

(b) Use of RRS, other Ancillary Services, and Emergency Response Service (ERS) to the extent permitted by ERCOT System conditions;

[NPRR863: Replace item (b) above with the following upon system implementation:]

(b) Use of RRS, ECRS, other Ancillary Services, and Emergency Response Service (ERS) to the extent permitted by ERCOT System conditions;

(c) Maximum use of ERCOT System capability;

(d) Maintenance of station service for nuclear-powered Generation Resources;

(e) Securing startup power for Generation Resources;

(f) Operation of Generation Resources during loss of communication with ERCOT;

(g) Restoration of service to Loads in the manner defined in the Operating Guides; and

(h) Management of Interconnection Reliability Operating Limits (IROLs) shall not change.

(4) ERCOT is responsible for coordinating with QSEs, TSPs, and DSPs to monitor ERCOT System conditions, initiating the EEA levels, notifying all QSEs, and coordinating the implementation of the EEA levels while maintaining transmission security limits.

[NPRR857: Replace paragraph (4) above with the following upon system implementation:]

(4) ERCOT is responsible for coordinating with QSEs, DCTOs, TSPs, and DSPs to monitor ERCOT System conditions, initiating the EEA levels, notifying all QSEs, and coordinating the implementation of the EEA levels while maintaining transmission security limits.

(5) ERCOT, at management's discretion, may at any time issue an ERCOT-wide appeal through the public news media for voluntary energy conservation.

(6) During the EEA, ERCOT has the authority to obtain energy from non-ERCOT Control Areas using the DC Ties or by using ~~Block Load Transfers (~~BLTs~~)~~ to move load to non-ERCOT Control Areas. ERCOT maintains the authority to curtail energy schedules flowing into or out of the ERCOT System across the DC Ties in accordance with NERC scheduling guidelines.

(7) Some of the EEA steps are not applicable if transmission security violations exist. There may be insufficient time to implement all EEA levels in sequence, however, to the extent practicable, ERCOT shall use Ancillary Services that QSEs have made available in the market to maintain or restore reliability.

[NPRR1010: Replace paragraph (7) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(7) Some of the EEA steps are not applicable if transmission security violations exist. There may be insufficient time to implement all EEA levels in sequence, however, to the extent practicable, ERCOT shall use Ancillary Service capabilities of Resources in the market to maintain or restore reliability.

(8) ERCOT may immediately implement EEA Level 3 any time the clock-minute average system frequency falls below 59.91 Hz for 20 consecutive minutes and shall immediately implement EEA Level 3 any time the steady-state frequency is below 59.5 Hz for any duration.

(9) Percentages for EEA Level 3 Load shedding will be based on the previous year's TSP peak Loads, as reported to ERCOT, and must be reviewed by ERCOT and modified annually as required.

(10) During EEA Level 2 or 3, for those constraints that meet the criteria identified in paragraph (5)(a) of Section 6.5.9.3.2, Advisory, ERCOT may control the post-

contingency flow to within the 15-Minute Rating in SCED. After PRC is restored to at least 3,000 MW or the Emergency Condition has ended, whichever is later, and ERCOT has determined that system conditions have improved such that the chance of re-entering into an EEA Level 2 or 3 is low, ERCOT shall restore control to the post-contingency flow to within the Emergency Rating for these constraints that utilized the 15-Minute Rating in SCED.

(11) During EEA Level 2 or 3, for those constraints that meet the criteria identified in paragraph (5)(b) of Section 6.5.9.3.2, ERCOT shall continue to enforce constraints associated with double-circuit contingencies throughout an EEA if the double-circuit failures are determined to be at high risk of occurring, due to system conditions. For all other double-circuit contingencies identified in paragraph (5)(b) of Section 6.5.9.3.2, ERCOT will enforce only the associated single-circuit contingencies during EEA Level 2 or 3. ERCOT shall resume enforcing such constraints as a double-circuit contingency after PRC is restored to at least 3,000 MW or the Emergency Condition has ended, whichever is later, and ERCOT has determined that system conditions have improved such that the chance of re-entering into an EEA Level 2 or 3 is low. For constraints related to stability limits that are not IROLs, ERCOT may elect not to enforce double-circuit contingencies during EEA Level 3 only.

6.5.9.5 Block Load Transfers between ERCOT and Non-ERCOT Control Areas

(1) BLTs are procedures that transfer Loads normally located in the ERCOT Control Area to a non-ERCOT Control Area. Similarly, when a non-ERCOT Control Area experiences certain transmission contingencies or short-supply conditions, ERCOT may agree to the implementation of BLT procedures that transfer Loads normally located in a non-ERCOT Control Area to the ERCOT Control Area. BLTs are restricted to the following conditions:

(a) All modeled BLTs shall be implemented only with approval from ERCOT, unless a governmental order is issued requiring the use of the BLT.

(i) BLTs shall be registered with ERCOT. Such registration shall be subject to ERCOT approval.

(ii) For all BLTs, the TSP in the ERCOT Control Area responsible for implementing the BLT shall coordinate with ERCOT in the implementation and execution of BLTs to ensure the reliability of the ERCOT System is not jeopardized and to ensure sufficient generation capacity is available prior to serving additional Load.

(b) BLTs that are comprised of looped systems may be tied to the non-ERCOT Control Area's electrical system(s) through multiple interconnection points at the same time. Transfers of looped configurations are permitted only if all interconnection points are registered and netted under a single Electric Service Identifier (ESI ID) and represented by a singled TSP or DSP or netted behind the Non-Opt-In Entity (NOIE) metering points.

(c) BLTs of Load to the ERCOT Control Area are:

(i) Treated as non-competitive wholesale Load in the Load Zone containing the ERCOT breaker or switch that initiated the BLT;

(ii) Registered in accordance with Section 6.5.9.5.1, Registration and Posting of BLT Points, by the TSP in the ERCOT Control Area responsible for implementing the BLT;

(iii) Responsible for Unaccounted For Energy (UFE) allocations and Transmission Losses consistent with similarly situated NOIE metering points; and

(iv) Permitted only if the BLT will not jeopardize the reliability of the ERCOT System. Under an Emergency Notice, BLTs that have been implemented may be curtailed or terminated by ERCOT to maintain the reliability of the ERCOT System.

(d) BLTs of Load from the ERCOT Control Area are:

(i) Treated as generation and Load in the ERCOT Settlement system unless the Load is in a NOIE territory and the NOIE has opted for the Load transfer to be treated as a NOIE Load reduction by not submitting a Settlement Block Load Transfer Registration Form. BLTs may only be instructed with the permission of the affected non-ERCOT Control Area. Under an emergency condition in a non-ERCOT Control Area, BLTs that have been implemented may be curtailed or terminated by the non-ERCOT Control Area to maintain the reliability of the non-ERCOT system;

(ii) Registered in accordance with Section 6.5.9.5.1 by the TSP in the ERCOT Control Area responsible for implementing the BLT; and

(iii) Permitted only if the BLT will not jeopardize the reliability of the ERCOT System.

(e) BLTs specifically exclude transfers of Load between ERCOT and non-ERCOT Control Areas that occur behind a retail Settlement Meter.

(f) BLTs may be used in the restoration of service to Customers if the transfers will not jeopardize the reliability of the ERCOT System.

(g) For any BLT established in a Transmission and/or Distribution Service Provider (TDSP) area that is open to Customer Choice, the TDSP must register the BLT metering point for Settlement. For any BLT established in a NOIE territory, the NOIE may either register the BLT for Settlement or may forgo registration and have the Load transfer settled as a Load increase or reduction. As a condition for Settlement, a BLT must be registered using the Settlement Block Load Transfer

Registration Form found on the ERCOT website, and each BLT metering point must use revenue quality, 15-minute Interval Data Recorder (IDR) Meters. ERCOT may impose additional metering requirements it considers necessary to ensure ERCOT System reliability and integrity.

(h) SCADA telemetry on switching devices at BLT points that are deemed necessary by ERCOT to be modeled in the Network Operations Model must be provided by the TSP registering the BLT.

6.6 Settlement Calculations for the Real-Time Energy Operations

6.6.1 Real-Time Settlement Point Prices

6.6.1.3 Real-Time Settlement Point Price for a Hub

(1) The Real-Time Settlement Point Price at a Hub is determined according to the methodology included in the definition of that Hub in Section 3.5.2, Hub Definitions.

6.6.2 Load Ratio Share

6.6.2.1 ERCOT Total Adjusted Metered Load for a 15-Minute Settlement Interval

(1) ERCOT total Adjusted Metered Load (AML) (excluding the DC Tie export associated with the Qualified Scheduling Entities (QSEs) under the "Oklaunion Exemption") for a 15-minute Settlement Interval is calculated as follows:

[NPRR1054: Replace paragraph (1) above with the following upon system implementation:]

(1) ERCOT total Adjusted Metered Load (AML) for a 15-minute Settlement Interval is calculated as follows:

$$\textbf{RTAMLTOT} = \sum_{q} (\max(0, \sum_{p} \textbf{RTAML}_{q,p}))$$

The above variables are defined as follows:

Variable	Unit	Description
RTAMLTOT	MWh	*Real-Time Adjusted Metered Load Total*—The total AML in ERCOT, for the 15-minute Settlement Interval.
RTAML $_{q,p}$	MWh	*Real-Time Adjusted Metered Load per Qualified Scheduling Entity (QSE) per Settlement Point*—The sum of the AML at the Electrical Buses that are included in Settlement Point p, represented by QSE q, for the 15-minute Settlement Interval.
q	none	A QSE. The summation is over all of the QSEs with metered readings in that interval.
p	none	A Settlement Point. The summation is over all of the Settlement Points.

6.6.2.3 ERCOT Total Adjusted Metered Load for an Operating Hour

(1) ERCOT total AML (excluding the DC Tie export associated with the QSEs under the Oklaunion Exemption) for an Operating Hour is calculated as follows:

[NPRR1054: Replace paragraph (1) above with the following upon system implementation:]

(1) ERCOT total AML for an Operating Hour is calculated as follows:

$$\textbf{HRTAMLTOT} = \sum_{q} (\max(0, \sum_{i=1}^{4} \sum_{p} \textbf{RTAML}_{q,p}))$$

The above variables are defined as follows:

Variable	Unit	Description
HRTAMLTOT	MWh	*Real-Time Adjusted Metered Load Total*—The total AML in ERCOT, for the Operating Hour.
RTAML $_{q,p}$	MWh	*Real-Time Adjusted Metered Load per QSE per Settlement Point*—The sum of the AML at the Electrical Buses that are included in Settlement Point p, represented by QSE q, for the 15-minute Settlement Interval.
q	none	A QSE. The summation is over all of the QSEs with metered readings in that interval.
p	none	A Settlement Point. The summation is over all of the Settlement Points.
i	none	A 15-minute Settlement Interval in the Operating Hour. The summation is over all of the Settlement Intervals of the Operating Hour.

[NPRR1030 and NPRR1054: Insert applicable portions of Section 6.6.2.6 below upon system implementation:]

6.6.2.6 QSE DC Tie Export Load Ratio Share for a Month

(1) Each QSE's DC Tie Export DCMLRS for a calendar month is calculated as follows:

$$\textbf{DCMLRS}_{q} = \max(0, \sum_{i} \sum_{p} \textbf{RTAMLDC}_{q,p,i}) / \textbf{MRTAMLTOT}$$

The above variables are defined as follows:

Variable	Unit	Description
DCMLRS $_{q}$	none	*DC Tie Export Monthly Load Ratio Share per QSE*—The ratio share calculated for QSE q with DC Tie Exports ~~(excluding Oklaunion)~~ for the calendar month.
RTAMLDC $_{q,p,i}$	MWh	*Real-Time Adjusted Metered Load for DC Ties per Settlement Point per QSE*—The sum of the DC Tie AML at the Electrical Buses that are included in Settlement Point p, represented by QSE q, for the 15-minute Settlement Interval i.
MRTAMLTOT	MWh	*Monthly Real-Time Adjusted Metered Load Total*—The total AML in ERCOT, for the calendar month.

q	none	A QSE.
p	none	A Settlement Point.
i	none	A 15-minute Settlement Interval.

[NPRR1030 and NPRR1054: Insert applicable portions of Section 6.6.2.8 below upon system implementation:]

6.6.2.8 QSE DC Tie Export Load Ratio Share by Congestion Management Zone for a Month

(1) Each QSE's DC Tie Export DCMLRSZ by CMZ for a calendar month is calculated as follows:

$$\mathbf{DCMLRSZ}_{q,\,z} = \mathbf{max(0,} \sum_{i} \sum_{p} \mathbf{RTAMLDC}_{q,\,p,\,i}\mathbf{)\ /\ MRTAMLLZTOT}_{z}$$

The above variables are defined as follows:

Variable	Unit	Description
DCMLRSZ $_{q,\,z}$	none	*DC Tie Exports Monthly Load Ratio Share Zonal per QSE*—The ratio share calculated for QSE *q* with DC Tie exports ~~(excluding Oklaunion)~~ by CMZ *z* for the calendar month.
RTAMLDC $_{q,\,p,\,i}$	MWh	*Real-Time Adjusted Metered Load for DC Ties per Settlement Point per QSE*—The sum of the DC Tie AML at the Electrical Buses that are included in Settlement Point *p*, represented by QSE *q*, for the 15-minute Settlement Interval *i*.
MRTAMLLZTOT $_{z}$	MWh	*Monthly Real-Time Adjusted Metered Load - Load Zone Total*—The total AML in CMZ z, for the calendar month.
q	none	A QSE.
p	none	A Settlement Point in the 2003 ERCOT CMZ.
i	none	A 15-minute Settlement Interval.
z	none	A 2003 ERCOT CMZ.

6.6.3 Real-Time Energy Charges and Payments

6.6.3.2 Real-Time Energy Imbalance Payment or Charge at a Load Zone

(1) The payment or charge to each QSE for Energy Imbalance Service is calculated based on the Real-Time Settlement Point Price for the following amounts at a particular Load Zone Settlement Point:

(a) The amount of its Self-Schedules with sink specified at the Settlement Point; plus

(b) The amount of its DAM Energy Bids cleared in the DAM at the Settlement Point; plus

(c) The amount of its Energy Trades at the Settlement Point where the QSE is the buyer; minus

(d) The amount of its Self-Schedules with source specified at the Settlement Point; minus

(e) The amount of its energy offers cleared in the DAM at the Settlement Point; minus

(f) The amount of its Energy Trades at the Settlement Point where the QSE is the seller; minus

(g) Its AML at the Settlement Point; plus

[NPRR986 and NPRR1043: Replace item (g) above with the following upon system implementation of NPRR986:]

(g) Its AML at the Settlement Point excluding Non-WSL ESR Charging Load; plus

(h) The aggregated generation of its Settlement Only Generators (SOGs) in the Load Zone.

[NPRR917 and NPRR1052: Replace item (h) above with the following upon system implementation of NPRR917:]

(h) The aggregated generation of its Settlement Only Transmission Self-Generators (SOTSGs) at the Settlement Point. SOTSG sites will be represented as a single unit in the ERCOT Settlement system.

(i) The aggregated generation of its Settlement Only Distribution Generators (SODGs) and Settlement Only Transmission Generators (SOTGs) that have elected to retain Load Zone pricing in accordance with Section 6.6.3.9, Real-Time Payment or Charge for Energy from a Settlement Only Distribution Generator (SODG) or a Settlement Only Transmission Generator (SOTG). SODG and SOTG sites will be represented as a single unit in the ERCOT Settlement system.

(j) The aggregated generation of its Energy Storage System (ESS) SODGs and SOTGs at sites where the ESS capacity constitutes more than 50% of the total SODG or SOTG nameplate capacity, as confirmed by an affidavit submitted by the Resource Entity for the site. SODG and SOTG sites will be represented as a single unit in the ERCOT Settlement system.

(2) The payment or charge to each QSE for Energy Imbalance Service at a Load Zone for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTEIAMT}_{q,p} = (-1) * \{[\mathbf{RTSPP}_{p} * [(\mathbf{SSSK}_{q,p} * 1/4) + (\mathbf{DAEP}_{q,p} * 1/4) + (\mathbf{RTQQEP}_{q,p} * 1/4) - (\mathbf{SSSR}_{q,p} * 1/4) - (\mathbf{DAES}_{q,p} * 1/4) - (\mathbf{RTQQES}_{q,p} * 1/4)]] + [\mathbf{RTSPPEW}_{p} * (\mathbf{RTMGNM}_{q,p} - \mathbf{RTAML}_{q,p})]\}$$

[NPRR917 and NPRR986: Replace applicable portions of the formula "RTEIAMT $_{q,p}$" above with the following upon system implementation:]

$$\mathbf{RTEIAMT}_{q,p} = (-1) * \{[\mathbf{RTSPP}_{p} * [(\mathbf{SSSK}_{q,p} * 1/4) + (\mathbf{DAEP}_{q,p} * 1/4) + (\mathbf{RTQQEP}_{q,p} * 1/4) - (\mathbf{SSSR}_{q,p} * 1/4) - (\mathbf{DAES}_{q,p} * 1/4) - (\mathbf{RTQQES}_{q,p} * 1/4)]] + [\mathbf{RTSPPEW}_{p} * (\mathbf{RTMGSOGZ}_{q,p} - (\mathbf{RTAML}_{q,p} - \mathbf{RTAMLESRNW}_{q,p}))]\}$$

And

$$\mathbf{LZIMBAL}_{q,p} = (\mathbf{SSSK}_{q,p} * 1/4) + (\mathbf{DAEP}_{q,p} * 1/4) + (\mathbf{RTQQEP}_{q,p} * 1/4) - (\mathbf{SSSR}_{q,p} * 1/4) - (\mathbf{DAES}_{q,p} * 1/4) - (\mathbf{RTQQES}_{q,p} * 1/4) - \mathbf{RTAML}_{q,p} + \mathbf{RTMGNM}_{q,p}$$

[NPRR917 and NPRR986: Replace applicable portions of the formula "LZIMBAL $_{q,p}$" above with the following upon system implementation:]

$$\mathbf{LZIMBAL}_{q,p} = (\mathbf{SSSK}_{q,p} * 1/4) + (\mathbf{DAEP}_{q,p} * 1/4) + (\mathbf{RTQQEP}_{q,p} * 1/4) - (\mathbf{SSSR}_{q,p} * 1/4) - (\mathbf{DAES}_{q,p} * 1/4) - (\mathbf{RTQQES}_{q,p} * 1/4) - (\mathbf{RTAML}_{q,p} - \mathbf{RTAMLESRNW}_{q,p}) + \mathbf{RTMGSOGZ}_{q,p}$$

The above variables are defined as follows:

Variable	Unit	Description
RTEIAMT $_{q,p}$	$	*Real-Time Energy Imbalance Amount per QSE per Settlement Point*—The payment or charge to QSE *q* for Real-Time Energy Imbalance Service at Settlement Point *p*, for the 15-minute Settlement Interval.
RTSPP $_{p}$	$/MWh	*Real-Time Settlement Point Price per Settlement Point*—The Real-Time Settlement Point Price at Settlement Point *p*, for the 15-minute Settlement Interval.
LZIMBAL $_{q,p}$	MWh	*Load Zone Energy Imbalance per QSE per Settlement Point*—The Load Zone volumetric imbalance for QSE *q* for Real-Time Energy Imbalance Service at Settlement Point *p*, for the 15-minute Settlement Interval.
RTSPPEW $_{p}$	$/MWh	*Real-Time Settlement Point Price Energy-Weighted*—The Real-Time Settlement Point Price at the Settlement Point *p*, for the 15-minute Settlement Interval that is

Variable	Unit	Description
		weighted by the State Estimated Load for the Load Zone of each SCED interval within the 15-minute Settlement Interval.
RTAML $_{q, p}$	MWh	*Real-Time Adjusted Metered Load per QSE per Settlement Point*—The sum of the AML at the Electrical Buses that are included in Settlement Point *p* represented by QSE *q* for the 15-minute Settlement Interval.

[NPRR986 and NPRR1043: Insert the variable "RTAMLESRNW $_{q, p}$" below upon system implementation of NPRR986:]

RTAMLESRNW $_{q, p}$	MWh	*Real-Time Adjusted Metered Load for ESR Non-WSL per QSE per Settlement Point*—The sum of the AML for the Non-WSL ESR Charging Load at the Electrical Buses that are included in Settlement Point *p* represented by QSE *q* for the 15-minute Settlement Interval, represented as a positive value.

SSSK $_{q, p}$	MW	*Self-Schedule with Sink at Settlement Point per QSE per Settlement Point*—The QSE *q*'s Self-Schedule with sink at Settlement Point *p*, for the 15-minute Settlement Interval.
DAEP $_{q, p}$	MW	*Day-Ahead Energy Purchase per QSE per Settlement Point*—The QSE *q*'s DAM Energy Bids at Settlement Point *p* cleared in the DAM, for the hour that includes the 15-minute Settlement Interval.
RTQQEP $_{q, p}$	MW	*Real-Time QSE-to-QSE Energy Purchase per QSE per Settlement Point*—The amount of MW bought by QSE *q* through Energy Trades at Settlement Point *p*, for the 15-minute Settlement Interval.
SSSR $_{q, p}$	MW	*Self-Schedule with Source at Settlement Point per QSE per Settlement Point*—The QSE *q*'s Self-Schedule with source at Settlement Point *p*, for the 15-minute Settlement Interval.
DAES $_{q, p}$	MW	*Day-Ahead Energy Sale per QSE per Settlement Point*—The QSE *q*'s energy offers at Settlement Point *p* cleared in the DAM, for the hour that includes the 15-minute Settlement Interval.
RTQQES $_{q, p}$	MW	*Real-Time QSE-to-QSE Energy Sale per QSE per Settlement Point*—The amount of MW sold by QSE *q* through Energy Trades at Settlement Point *p*, for the 15-minute Settlement Interval.
RTMGNM $_{q, p}$	MWh	*Real-Time Metered Generation from Settlement Only Generators per QSE per Settlement Point*—The total Real-Time energy produced by SOGs represented by QSE *q* in Load Zone Settlement Point *p*, for the 15-minute Settlement Interval.

[NPRR917 and NPRR1052: Replace the variable "RTMGNM $_{q, p}$" above with the following upon system implementation of NPRR917:]

RTMGSOGZ $_{q, p}$	MWh	*Real-Time Metered Generation from Settlement Only Generators Zonal per QSE per Settlement Point*—The total Real-Time energy produced by SOTSGs represented by QSE *q* in Load Zone Settlement Point *p*, for the 15-minute Settlement Interval. MWh quantities for ESS SODGs and SOTGs at sites where the ESS capacity constitutes more than 50% of the total SOG nameplate capacity will be included in this value. MWh quantities for SODGs and SOTGs that have opted out of nodal pricing pursuant to Section 6.6.3.9 will also be included in this value.

q	none	A QSE.
p	none	A Load Zone Settlement Point.

(3) The total net payments and charges to each QSE for Energy Imbalance Service at all Load Zones for the 15-minute Settlement Interval is calculated as follows:

$$\textbf{RTEIAMTQSETOT}_{q} = \sum_{p} \textbf{RTEIAMT}_{q,\,p}$$

The above variables are defined as follows:

Variable	Unit	Definition
RTEIAMTQSETOT $_{q}$	$	*Real-Time Energy Imbalance Amount QSE Total per QSE*—The total net payments and charges to QSE *q* for Real-Time Energy Imbalance Service at all Load Zone Settlement Points for the 15-minute Settlement Interval.
RTEIAMT $_{q,\,p}$	$	*Real-Time Energy Imbalance Amount per QSE per Settlement Point*—The charge to QSE *q* for Real-Time Energy Imbalance Service at Settlement Point *p*, for the 15-minute Settlement Interval.
q	none	A QSE.
p	none	A Load Zone Settlement Point.

6.6.3.4 Real-Time Energy Payment for DC Tie Import

(1) The payment to each QSE for energy imported into the ERCOT System through each DC Tie is calculated based on the Real-Time Settlement Point Price at the DC Tie Settlement Point. The payment for a given 15-minute Settlement Interval is calculated as follows:

$$\textbf{RTDCIMPAMT}_{q,\,p} = \textbf{(-1) * RTSPP}_{p} \textbf{ * (RTDCIMP}_{q,\,p} \textbf{ * ¼)}$$

The above variables are defined as follows:

Variable	Unit	Description
RTDCIMPAMT $_{q,\,p}$	$	*Real-Time DC Import Amount per QSE per Settlement Point*—The payment to QSE *q* for DC Tie import through DC Tie *p*, for the 15-minute Settlement Interval.
RTSPP $_{p}$	$/MWh	*Real-Time Settlement Point Price per Settlement Point*—The Real-Time Settlement Point Price at Settlement Point *p*, for the 15-minute Settlement Interval.
RTDCIMP $_{q,\,p}$	MW	*Real-Time DC Import per QSE per Settlement Point*—The aggregated DC Tie Schedule submitted by QSE *q* as an importer into the ERCOT System through DC Tie *p*, for the 15-minute Settlement Interval. ***[NPRR1032: Replace the description above with the following upon system implementation:]*** *Real-Time DC Import per QSE per Settlement Point*—The aggregated final, approved DC Tie Schedule submitted by QSE *q* as an importer into the ERCOT System through DC Tie *p*, for the 15-minute Settlement Interval.
q	none	A QSE.
p	none	A DC Tie Settlement Point.

(2) ERCOT shall pay each QSE for energy imported into the ERCOT System during a declared Emergency Condition through each DC Tie in response to an ERCOT Dispatch

Instruction. The payment for a given 15-minute Settlement Interval is calculated as follows:

$$\textbf{RTEDCIMPAMT}_{q,p} = (-1) * \textbf{Max}\ \{\textbf{RTSPP}_{p}, (\textbf{VEEPDCTP}_{q,p} * \textbf{CAEDCT})\} * (\textbf{RTEDCIMP}_{q,p} * 1/4)$$

The above variables are defined as follows:

Variable	Unit	Description
RTEDCIMPAMT $_{q,p}$	$	*Real-Time Emergency DC Import Amount per QSE per Settlement Point*—The payment to QSE q for emergency DC Tie import through DC Tie p, for the 15-minute Settlement Interval.
RTSPP $_{p}$	$/MWh	*Real-Time Settlement Point Price per Settlement Point*—The Real-Time Settlement Point Price at Settlement Point p, for the 15-minute Settlement Interval.
FIP	$/MMBtu	*Fuel Index Price*—As defined in Section 2, Definitions and Acronyms.
RTEDCIMP $_{q,p}$	MW	*Real-Time Emergency DC Import per QSE per Settlement Point*—The aggregated DC Tie Schedule for emergency energy imported by QSE q into the ERCOT System during Emergency Conditions through DC Tie p, for the 15-minute Settlement Interval.
VEEPDCTP $_{q,p}$	$/MWh	*Verified Emergency Energy Price at DC Tie Point*—The ERCOT verified cost for the energy imported by QSE q into the ERCOT System during declared Emergency Condition through a DC Tie p as instructed by a Dispatch Instruction.
CAEDCT	#	*Cost Adder for Emergency DC Tie Import*—A multiplier of 1.10.
q	none	A QSE.
p	none	A DC Tie Settlement Point.

(3) The total of the payments to each QSE for all energy imported into the ERCOT System through DC Ties for the 15-minute Settlement Interval is calculated as follows:

$$\textbf{RTDCIMPAMTQSETOT}_{q,p} = \sum_{p} (\textbf{RTDCIMPAMT}_{q,p} + \textbf{RTEDCIMPAMT}_{q,p})$$

The above variables are defined as follows:

Variable	Unit	Definition
RTDCIMPAMTQSETOT $_{q,p}$	$	*Real-Time DC Import Amount QSE Total per QSE*—The total of the payments to QSE q for energy imported into the ERCOT System through DC Ties p, for the 15-minute Settlement Interval.
RTDCIMPAMT $_{q,p}$	$	*Real-Time DC Import Amount per QSE per Settlement Point*—The payment to QSE q for DC Tie import through DC Tie p, for the 15-minute Settlement Interval.
RTEDCIMPAMT $_{q,p}$	$	*Real-Time Emergency DC Import Amount per QSE per Settlement Point*—The payment to QSE q for emergency DC Tie import through DC Tie p, for the 15-minute Settlement Interval.
q	none	A QSE.
p	none	A DC Tie Settlement Point.

6.6.3.5 Real-Time Payment for a Block Load Transfer Point

(1) ERCOT shall pay each QSE for the energy delivered to an ERCOT Load through a Block Load Transfer (BLT) Point that is registered for Settlement when that Load is moved from the ERCOT Control Area to a non-ERCOT Control Area. The payment for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{BLTRAMT}_{q,\,bltp,\,p} = (-1) * \mathbf{MAX}\ \{\mathbf{RTSPPEW}_{p}, (\mathbf{VEEPBLTP}_{q,\,bltp}) * \mathbf{CABLT}\} * \mathbf{BLTR}_{q,\,p,\,bltp}$$

The above variables are defined as follows:

Variable	Unit	Definition
BLTRAMT $_{q,\,bltp,\,p}$	$	*Block Load Transfer Resource Amount per QSE per Settlement Point per BLT Point*—The payment to QSE q for the BLT Resource that delivers energy to Load Zone p through BLT Point $bltp$, for the 15-minute Settlement Interval.
RTSPPEW $_{p}$	$/MWh	*Real-Time Settlement Point Price per Settlement Point Energy-Weighted*—The Real-Time Settlement Point Price at Settlement Point p, for the 15-minute Settlement Interval, that is weighted by the state estimated Load of the Load Zone of each SCED interval within the 15-minute Settlement Internal.
VEEPBLTP $_{q,\,bltp}$	$/MWh	*Verified Emergency Energy Price at BLT Point*—The ERCOT verified cost for the energy delivered to an ERCOT Load through BLT Point *bltp*.
CABLT	none	*Cost Adder for Block Load Transfer*—A multiplier of 1.10.
BLTR $_{q,\,p,\,bltp}$	MWh	*Block Load Transfer Resource per QSE per Settlement Point per BLT Point*—The energy delivered to an ERCOT Load in Load Zone p through BLT Point *bltp* represented by QSE q, for the 15-minute Settlement Interval.
q	none	A QSE.
p	none	A Load Zone Settlement Point.
bltp	none	A BLT Point.

(2) The total of the payments to each QSE for all energy delivered to ERCOT Loads through BLT Points for the 15-minute Settlement Interval is calculated as follows:

$$\mathbf{BLTRAMTQSETOT}_{q} = \sum_{p} \sum_{bltp} \mathbf{BLTRAMT}_{q,\,bltp,\,p}$$

The above variables are defined as follows:

Variable	Unit	Definition
BLTRAMTQSETOT $_{q}$	$	*Block Load Transfer Resource Amount QSE Total per QSE*—The total of the payments to QSE q for energy delivered into the ERCOT System through BLT Points for the 15-minute Settlement Interval.
BLTRAMT $_{q,\,bltp,\,p}$	$	*Block Load Transfer Resource Amount per QSE per Settlement Point per BLT Point*—The payment to QSE q for the BLT Resource at BLT Point *bltp*, which delivers energy to Load Zone p, for the 15-minute Settlement Interval.
q	none	A QSE.

p	none	A Load Zone Settlement Point.
bltp	none	A BLT Point.

(3) For the purpose of Settlement, ERCOT shall treat the energy associated with the Presidio Exception like energy delivered to an ERCOT Load through a BLT Point that is moved from the ERCOT Control Area to a non-ERCOT Control Area, by allowing for compensation of verified costs associated with the energy. After receipt and verification of the invoiced cost associated with the Presidio Exception, ERCOT shall compensate for the energy associated with the Presidio Exception using the monthly verified cost multiplied by the Cost Adder for Block Load Transfer defined in paragraph (1) above. ERCOT shall uplift the cost to QSEs representing Load using the monthly LRS per QSE as defined in Section 7.5.7, Method for Distributing CRR Auction Revenues. Costs associated with the Presidio Exception must be submitted to ERCOT within 90 days of the last day of the month that the costs were incurred.

[NPRR1030: Replace paragraph (3) above with the following upon system implementation:]

(3) For the purpose of Settlement, ERCOT shall treat the energy associated with the Presidio Exception like energy delivered to an ERCOT Load through a BLT Point that is moved from the ERCOT Control Area to a non-ERCOT Control Area, by allowing for compensation of verified costs associated with the energy. After receipt and verification of the invoiced cost associated with the Presidio Exception, ERCOT shall compensate for the energy associated with the Presidio Exception using the monthly verified cost multiplied by the Cost Adder for Block Load Transfer defined in paragraph (1) above. ERCOT shall uplift the cost to QSEs representing Load using the same methodology as defined in Section 7.5.7, Method for Distributing CRR Auction Revenues. Costs associated with the Presidio Exception must be submitted to ERCOT within 90 days of the last day of the month that the costs were incurred.

(a) The monthly payment to be calculated as follows:

$$\textbf{MBLTAMT}_{q,p} = \quad \textbf{(-1) * VMEBLTP}_{q,p} \textbf{ * CABLT}$$

The above variables are defined as follows:

Variable	Unit	Definition
MBLTAMT $_{q,p}$	$	*Monthly Block Load Transfer Amount per QSE per Settlement Point*—The payment to QSE *q* for the delivered energy to Load Zone *p* for the month.
VMEBLTP $_{q,p}$	$/MWh	*Verified Monthly Energy Cost*—The ERCOT verified monthly cost for the energy delivered to an ERCOT Load as determined by an invoice submitted to ERCOT.
CABLT	none	*Cost Adder for Block Load Transfer*—A multiplier of 1.10.
q	none	A QSE.
p	none	A Load Zone Settlement Point.

(b) The total of the payments to each QSE for all energy delivered to ERCOT Loads through BLT Points for the 15-minute Settlement Interval is calculated as follows:

$$\mathbf{MBLTAMTQSETOT}_{q} = \sum_{p} \mathbf{MBLTAMT}_{q,p}$$

The above variables are defined as follows:

Variable	Unit	Definition
MBLTAMTQSETOT $_{q}$	$	*Monthly Block Load Transfer Amount QSE Total per QSE*—The total of the payments to QSE q for energy delivered into the ERCOT System for the month.
MBLTAMT $_{q,p}$	$	*Monthly Block Load Transfer Amount per QSE per Settlement Point*—The payment to QSE q for the delivered energy to Load Zone p for the month.
q	none	A QSE.
p	none	A Load Zone Settlement Point.

(c) ERCOT shall calculate each QSE's monthly BLT charge as follows:

$$\mathbf{LAMBLTAMT}_{q} = (-1) * \mathbf{MLRS}_{q} * \mathbf{MBLTAMTTOT}$$

$$\mathbf{MBLTAMTTOT} = \sum_{q} \mathbf{MBLTAMTQSETOT}_{q}$$

The above variables are defined as follows:

Variable	Unit	Description
MLRS $_{q}$	none	*Monthly Load Ratio Share per QSE*—The LRS calculated for QSE q for the peak-Load 15-minute Settlement Interval in the month. See Section 6.6.2.2, QSE Load Ratio Share for a 15-Minute Settlement Interval.
MBLTAMTQSETOT $_{q}$	$	*Monthly Block Load Transfer Amount QSE Total per QSE*—The total of the payments to QSE q for energy delivered into the ERCOT System for the month.
LAMBLTAMT $_{q}$	$	*Load-Allocated Monthly BLT Amount per QSE*—Monthly BLT charge for QSE q.
MBLTAMTTOT	$	*Monthly BLT Amount ERCOT wide Total*—The total monthly BLT charge for all QSEs.
q	none	A QSE.

[NPRR1030 and NPRR1054: Replace applicable portions of paragraph (c) above with the following upon system implementation:]

(c) ERCOT shall calculate each QSE's monthly BLT charge as follows:

$$\mathbf{LAMBLTAMT}_{q} = (-1) * (\mathbf{MBLTDC}_{q} + \mathbf{MBLTNDC}_{q})$$

Where:

$$\text{MBLTNDC}_q = \text{MLRS}_q * (\text{MBLTAMTTOT} - \sum_q \text{MBLTDC}_q)$$

$$\text{MBLTDC}_q = \text{DCMLRS}_q * \text{MBLTAMTTOT}$$

$$\text{MBLTAMTTOT} = \sum_q \text{MBLTAMTQSETOT}_q$$

The above variables are defined as follows:

Variable	Unit	Description
LAMBLTAMT $_q$	$	*Load-Allocated Monthly BLT Amount per QSE*—Sum of the monthly BLT charges for Loads and DC Tie exports for QSE *q*.
DCMLRS $_q$	none	*DC Tie Export Monthly Load Ratio Share per QSE*—The ratio share calculated for QSE *q* with DC Tie Exports ~~(excluding Oklaunion)~~ for the calendar month.
MLRS $_q$	none	*Monthly Load Ratio Share per QSE*—The ratio share of Loads excluding DC Tie Exports for QSE *q*, for the peak Load 15-minute Settlement Interval.
MBLTAMTQSETOT $_q$	$	*Monthly Block Load Transfer Amount QSE Total per QSE*—The total of the payments to QSE *q* for energy delivered into the ERCOT System for the month.
MBLTDC $_q$	$	*Monthly BLT Amount for DC Tie Exports per QSE*—Monthly BLT amount for DC Tie exports~~, excluding Oklaunion,~~ for QSE *q*.
MBLTNDC $_q$	$	*Monthly BLT Amount for Non-DC Tie Loads per QSE*—Monthly BLT amount for Loads (excluding DC Tie exports) for QSE *q*.
MBLTAMTTOT	$	*Monthly BLT Amount ERCOT wide Total*—The total monthly BLT payment for all QSEs.
q	none	A QSE.

6.6.3.6 Real-Time Energy Charge for DC Tie Export Represented by the QSE Under the Oklaunion Exemption

(1) The charge to a QSE that is exporting energy from the ERCOT System under the "Oklaunion Exemption" through a DC Tie associated with the exemption is calculated based on the Real-Time Settlement Point Price at the DC Tie Settlement Point. This charge for a given 15-minute Settlement Interval is calculated as follows:

$$\textbf{RTDCEXPAMT}_{q,p} = \textbf{RTSPP}_p * (\textbf{RTDCEXP}_{q,p} * 1/4)$$

The above variables are defined as follows:

Variable	Unit	Definition
RTDCEXPAMT $_{q,p}$	$	*Real-Time DC Export Amount per QSE per Settlement Point*—The charge to QSE *q* for the DC Tie exports through DC Tie *p*, for the 15-minute Settlement Interval.
RTSPP $_p$	$/MWh	*Real-Time Settlement Point Price per Settlement Point*—The Real-Time Settlement Point Price at Settlement Point *p*, for the 15-minute Settlement Interval.
RTDCEXP $_{q,p}$	MW	*Real-Time DC Export per QSE per Settlement Point*—The aggregated DC Tie Schedule through DC Tie *p* submitted by QSE *q* that is under the "Oklaunion

		Exemption" as an exporter from the ERCOT area, for the 15-minute Settlement Interval.
q	none	A QSE.
p	none	A DC Tie Settlement Point.

(2) The total of the charges to each QSE for all energy exported from the ERCOT System through DC Ties for the 15-minute Settlement Interval is calculated as follows:

$$\textbf{RTDCEXPAMTQSETOT}_{q} = \sum_{p} \textbf{RTDCEXPAMT}_{q,p}$$

The above variables are defined as follows:

Variable	Unit	Definition
RTDCEXPAMTQSETOT $_{q}$	$	*Real-Time DC Export Amount QSE Total per QSE*—The total of the charges to QSE *q* for energy exported from the ERCOT System through DC Ties for the 15-minute Settlement Interval.
RTDCEXPAMT $_{q,p}$	$	*Real-Time DC Export Amount per QSE per Settlement Point*—The charge to QSE *q* for the DC Tie exports through DC Tie *p*, for the 15-minute Settlement Interval.
q	none	A QSE.
p	none	A DC Tie Settlement Point.

[NPRR1054: Delete Section 6.6.3.6 above upon system implementation and renumber accordingly.]

[NPRR917, ~~and~~ NPRR1010, and NPRR1052: Insert applicable portions of Section 6.6.3.9 below upon system implementation of NPRR917 for NPRR917 and NPRR1052; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010:]

6.6.3.9 Real-Time Payment or Charge for Energy from a Settlement Only Distribution Generator (SODG) or a Settlement Only Transmission Generator (SOTG)

(1) ~~Except for a SODG or SOTG that has opted out of nodal pricing as described in paragraph (5) below, t~~The payment or charge to each QSE for energy from an SODG or an SOTG shall be based on an identified nodal energy price, RTESOGPR, as described in this subsection, with the following exceptions:~~.~~

(a) An SODG or SOTG that has opted out of nodal pricing as described in paragraph (5) below; or

(b) Any site with one or more ESS SODGs or SOTGs where the ESS capacity constitutes more than 50% of the site's total SOG nameplate capacity.

(2) For an SODG, the price used as the basis for the 15-minute Real-Time price calculation is the time-weighted price at the Electrical Bus associated with this mapped Load in the Network Operations Model. For an SOTG, the price used as the basis for the 15-minute Real-Time price calculation is the time-weighted price at the Electrical Bus as determined by ERCOT in review of the meter location of the SOTG in the Network Operations Model. The outflow of energy into the grid as measured by each Settlement Meter for the 15-minute Settlement Interval shall be priced at the nodal energy price (RTESOGPR, as defined in paragraph (3) below), and the inflow of energy is treated as Load and shall be settled accordingly at the zonal energy price (the Load Zone Settlement Point Price). SODG and SOTG sites will be represented as a single unit in the ERCOT Settlement system.

(3) For an SODG or an SOTG, the total payment or charge for each 15-minute Settlement Interval shall be calculated as follows:

$$\mathbf{RTESOGSAMT}_{q,\,gsc} = (-1) * [\sum_{b} (\mathbf{RTESOGPR}_{b} * \mathbf{OFSOG}_{q,\,gsc,\,b})]$$

Where the price for the SOTG or SODG is determined as follows:

$$\mathbf{RTESOGPR}_{b} = \mathbf{Max}\ [-\$251, \sum_{y} ((\mathbf{SDWF}_{y} * \mathbf{RTLMP}_{b,\,y}) + \mathbf{RTRDP})]$$

Where:

$$\text{RTRDP} = \sum_{y} (\text{SDWF}_{y} * \text{RTRDPA}_{y})$$

$$\text{SDWF}_{y} = \text{TLMP}_{y} / \sum_{y} \text{TLMP}_{y}$$

The above variables are defined as follows:

Variable	Unit	Description
$\text{RTESOGSAMT}_{q,\,gsc}$	$	*Real-Time Energy for SODG and SOTG Site Amount* —The total payment or charge to QSE *q* for SODG or SOTG site *gsc* for the 15-minute Settlement Interval.
RTESOGPR_{b}	$/MWh	*Real-Time Price for the Energy Metered for each SODG or SOTG Site* —The Real-Time price at Electrical Bus *b* for the Settlement Meter for the SODG or SOTG site for the 15-minute Settlement Interval.
$\text{OFSOG}_{q,\,gsc,\,b}$	MWh	*Outflow as Measured for an SODG or SOTG Site* —The outflow as measured by the Settlement Meter(s) at Electrical Bus *b* for SODG or SOTG site *gsc* represented by QSE *q*.
RTRDP	$/MWh	*Real-Time Reliability Deployment Price for Energy*—The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that is calculated from the Real-Time Reliability Deployment Price Adder for Energy.

$RTRDPA_{y}$	\$/MWh	*Real-Time Reliability Deployment Price Adder for Energy*—The Real-Time price adder that captures the impact of reliability deployments on energy prices for the SCED interval *y*.
$SDWF_{y}$	None	*SCED Duration Weighting Factor per interval*—The weight used in the SODG or SOTG price calculation for the portion of the SCED interval *y* within the Settlement Interval.
$RTLMP_{b,y}$	\$/MWh	*Real-Time Locational Marginal Price at bus per interval*—The Real-Time LMP at Electrical Bus *b*, for the SCED interval *y*.
$TLMP_{y}$	second	*Duration of SCED interval per interval*—The duration of the SCED interval *y* within the Settlement Interval.
gsc	none	A generation site code.
b	none	An Electrical Bus.
y	None	A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.

(4) The total net payments and charges to each QSE for energy from SODGs and SOTGs for the 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTESOGAMTQSETOT}_{q} = \sum_{gsc} \mathbf{RTESOGSAMT}_{q,\,gsc}$$

The above variables are defined as follows:

Variable	Unit	Definition
$RTESOGAMTQSETOT_{q}$	\$	*Real-Time Energy Payment or Charge per QSE for Energy from SODGs and SOTGs* —The payment or charge to QSE *q* for Real-Time energy from SODGs and SOTGs, for the 15-minute Settlement Interval.
$RTESOGSAMT_{q,\,gsc}$	\$	*Real-Time Energy for SODG and SOTG Site Amount* —The total payment or charge to QSE *q* for an SODG or SOTG site *gsc* for the 15-minute Settlement Interval.
q	none	A QSE.
gsc	none	A generation site code.

(5) Notwithstanding anything else in this Section except paragraphs (6) and (7) below, a Resource Entity may opt out of nodal pricing and continue Load Zone Settlement for any SODG or SOTG if, by January 1, 2019, the SODG or SOTG was operational or was subject to a Power Purchase or Tolling Agreement (PPA) or Transmission and/or Distribution Service Provider (TDSP) interconnection agreement, or had an executed agreement with a developer. By December 31, 2019, the Resource Entity must submit a properly completed Section 23, Form N, Pricing Election for Settlement Only Distribution Generators and Settlement Only Transmission Generators. Any SODG or SOTG relying on a PPA or TDSP interconnection agreement or agreement with a developer must also have achieved Initial Synchronization for the full Resource capacity before June 1, 2020 to be eligible to opt out of nodal pricing. A Resource Entity must provide ERCOT documented proof of any PPA, TDSP interconnection agreement, or developer agreement that it relies on as a basis for any election under this paragraph. This election is valid through the earlier of December 31, 2029 or the date on which the

election is revoked pursuant to paragraph (8) of this Section. On January 1, 2030, all SODGs and SOTGs will be subject to nodal pricing.

(6) For any SODG or SOTG for which the applicable Resource Entity has elected to opt out of nodal pricing, ERCOT shall settle the output of the SODG or SOTG using the Load Zone Settlement Point Price for the duration of the opt-out period so long as the SODG or SOTG is not physically modified for any purpose, including to increase the capacity of the unit or change the fuel type of the unit, except as necessary for routine maintenance or repairs to address normal wear and tear.

(7) If at any time ERCOT determines that the SODG or SOTG fails to meet the opt-out conditions in paragraph (6) above, ERCOT shall settle the output of the SODG or SOTG at the applicable nodal price as soon as practicable after providing written notice to the affected Resource Entity.

(8) A Resource Entity that has opted out of nodal pricing for one or more SODGs or SOTGs pursuant to paragraph (5) of this Section may withdraw that election and begin receiving applicable nodal pricing for one or more such generators by submitting a properly completed election form (Section 23, Form N). An election of nodal pricing is irrevocable. ERCOT will effectuate the transition of an SODG or SOTG to nodal pricing in ERCOT Settlement systems as soon as practicable.

6.6.4 Real-Time Congestion Payment or Charge for Self-Schedules

(1) The congestion payment or charge to each QSE submitting a Self-Schedule calculated based on the difference in Real-Time Settlement Point Prices at the specified sink and the source of the Self-Schedule multiplied by the amount of the Self-Schedule. The congestion charge to each QSE for each of its Self-Schedule for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTCCAMT}_{q,s} = (\mathbf{RTSPP}_{sink,s} - \mathbf{RTSPP}_{source,s}) * (\mathbf{SSQ}_{q,s} * 1/4)$$

The above variables are defined as follows:

Variable	Unit	Description
RTCCAMT $_{q,s}$	\$	*Real-Time Congestion Cost Amount per QSE per Self-Schedule*—The congestion charge to QSE q for its Self-Schedule s, for the 15-minute Settlement Interval.
RTSPP $_{sink,s}$	\$/MWh	*Real-Time Settlement Point Price at the Sink of Self-Schedule*—The Real-Time Settlement Point Price at the sink of the Self-Schedule s, for the 15-minute Settlement Interval.
RTSPP $_{source,s}$	\$/MWh	*Real-Time Settlement Point Price at the Source of Self-Schedule*—The Real-Time Settlement Point Price at the source of the Self-Schedule s, for the 15-minute Settlement Interval.
SSQ $_{q,s}$	MW	*Self-Schedule Quantity per Self-Schedule*—The QSE q's Self Schedule MW quantity for Self-Schedule s, for the 15-minute Settlement Interval.
q	none	A QSE.

s	none	A Self-Schedule.
sink	none	Sink Settlement Point
source	none	Source Settlement Point

(2) The total net congestion payments and charges to each QSE for all its Self-Schedules for the 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTCCAMTQSETOT}_{\,q} = \sum_{s} \mathbf{RTCCAMT}_{\,q,\,s}$$

The above variables are defined as follows:

Variable	Unit	Definition
RTCCAMTQSETOT $_q$	\$	*Real-Time Congestion Cost Amount QSE Total per QSE*—The total net congestion payments and charges to QSE *q* for its Self-Schedules for the 15-minute Settlement Interval.
RTCCAMT $_{q,\,s}$	\$	*Real-Time Congestion Cost Amount per QSE per Self-Schedule*—The congestion payment or charge to QSE *q* for its Self-Schedule *s*, for the 15-minute Settlement Interval.
q	none	A QSE.
s	none	A Self-Schedule.

6.6.7 Voltage Support Settlement

6.6.7.1 Voltage Support Service Payments

(1) All other Generation Resources shall be eligible for compensation for Reactive Power production in accordance with Section 6.5.7.7, Voltage Support Service, only if ERCOT issues a Dispatch Instruction that results in the following unit operation:

(a) When ERCOT instructs the Generation Resource to exceed its Unit Reactive Limit (URL) and the Generation Resource provides additional Reactive Power, then ERCOT shall pay for the additional Reactive Power provided at a price that recognizes the avoided cost of reactive support Resources on the transmission network.

(b) Any real power reduction directed by ERCOT through VDIs to provide for additional reactive capability for voltage support must be compensated as a lost opportunity payment

(2) The payment for a given 15-minute Settlement Interval to each QSE representing a Generation Resource that operates in accordance with an ERCOT Dispatch Instruction is calculated as follows:

Depending on the Dispatch Instruction, payment for Volt-Amperes reactive (VAr):

If VSSVARLAG $_{q,\,r} > 0$

$$\mathbf{VSSVARAMT}_{q,r} = \mathbf{(-1) * VSSVARPR * VSSVARLAG}_{q,r}$$

If VSSVARLEAD $_{q,r}$ > 0

$$\mathbf{VSSVARAMT}_{q,r} = \mathbf{(-1) * VSSVARPR * VSSVARLEAD}_{q,r}$$

Where:

$$\text{VSSVARLAG}_{q,r} = \text{Max}\left[0, \text{Min}\left(\tfrac{1}{4} * \text{VSSVARIOL}_{q,r}, \text{RTVAR}_{q,r}\right) - \left(\tfrac{1}{4} * \text{URLLAG}_{q,r}\right)\right]$$

$$\text{VSSVARLEAD}_{q,r} = \text{Max}\left\{0, \left[\left(\tfrac{1}{4} * \text{URLLEAD}_{q,r}\right) - \text{Max}\left(\left(\tfrac{1}{4} * \text{VSSVARIOL}_{q,r}\right), \text{RTVAR}_{q,r}\right)\right]\right\}$$

$$\text{URLLAG}_{q,r} = 0.32868 * \text{HSL}_{q,r}$$

$$\text{URLLEAD}_{q,r} = (-1) * 0.32868 * \text{HSL}_{q,r}$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
VSSVARAMT $_{q,r}$	$	*Voltage Support Service VAr Amount per QSE per Generation Resource* - The payment to QSE *q* for the VSS provided by Generation Resource *r*, for the 15-minute Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Train.
VSSVARPR	$/MVArh	*Voltage Support Service VAr Price* - The price for instructed MVAr beyond a Generation Resource's URL currently is $2.65/MVArh (based on $50.00/installed kVAr).
VSSVARLAG $_{q,r}$	MVArh	*Voltage Support Service VAr Lagging per QSE per Generation Resource* - The instructed portion of the Reactive Power above the Generation Resource's lagging URL for Generation Resource *r* represented by QSE *q*, for the 15-minute Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Train.
VSSVARLEAD $_{q,r}$	MVArh	*Voltage Support Service VAr Leading per QSE per Generation Resource* - The instructed portion of the Reactive Power below the Generation Resource's leading URL for Generation Resource *r* represented by QSE *q*, for the 15-minute Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Train.
VSSVARIOL $_{q,r}$	MVAr	*Voltage Support Service VAr Instructed Output Level per QSE per Generation Resource*—The instructed Reactive Power output level of Generation Resource *r* represented by QSE *q*, lagging Reactive Power if positive and leading Reactive Power if negative, for the 15-minute Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Train.
RTVAR $_{q,r}$	MVArh	*Real-Time VAr per QSE per Resource*—The netted Reactive Energy measured for Generation Resource *r* represented by QSE *q*, for the 15-minute Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Train.

Variable	Unit	Definition
URLLAG $_{q,r}$	MVAr	*Unit Reactive Limit Lagging per QSE per Resource*—The URL for lagging Reactive Power of the Generation Resource *r* represented by QSE *q* as determined in accordance with these Protocols. Its value is positive. Where for a combined cycle resource, *r* is a Combined Cycle Train.
URLLEAD $_{q,r}$	MVAr	*Unit Reactive Limit Leading per QSE per Resource*—The URL for leading Reactive Power of the Generation Resource *r* represented by QSE *q* as determined in accordance with these Protocols. Its value is negative. Where for a combined cycle resource, *r* is a Combined Cycle Train.
HSL $_{q,r}$	MW	*High Sustained Limit*—The HSL of a Generation Resource as defined in Section 2, Definitions, for the hour that includes the Settlement Interval *i*. Where for a combined cycle resource, *r* is a Combined Cycle Generation Resource.
q	none	A QSE.
r	none	A Generation Resource.

(3) The total additional compensation to each QSE for voltage support service for the 15-minute Settlement Interval is calculated as follows:

$$\mathbf{VSSVARAMTQSETOT_q} = \sum_{r} \mathbf{VSSVARAMT}_{q,r}$$

Variable	Unit	Definition
VSSVARAMT $_{q,r}$	$	*Voltage Support Service VAr Amount per QSE per Generation Resource*—The payment to QSE *q* for the VSS provided by Generation Resource *r*, for the 15-minute Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Train.
VSSVARAMTQSETOT $_{q}$	$	*Voltage Support VAr Amount QSE total per QSE*—The total of the payments to QSE *q* as compensation for VSS by this QSE for the 15-minute settlement interval.
q	none	A QSE.
r	none	A Generation Resource.

(4) The lost opportunity payment, if applicable:

$$\mathbf{VSSEAMT}_{q,r} = \mathbf{(-1) * Max\ (0, RTSPP_p * Max\ (0, (HSL_{q,r} * 1/4 - RTMG_{q,r})) - (RTICHSL_{q,r} - RTVSSAIEC_{q,r} * (RTMG_{q,r} - LSL_{q,r} * 1/4)))}$$

Where:

$$\mathrm{RTICHSL}_{q,r} = \mathrm{RTHSLAIEC}_{q,r} * (1/4 * \mathrm{HSL}_{q,r} - 1/4 * \mathrm{LSL}_{q,r})$$

The above variables are defined as follows:

Variable	Unit	Definition
VSSEAMT $_{q,r}$	$	*Voltage Support Service Energy Amount per QSE per Generation Resource*—The lost opportunity payment to QSE *q* for ERCOT-directed VSS from Generation Resource r for the 15-minute Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Train.
RTMG $_{q,r}$	MWh	*Real-Time Metered Generation per QSE per Resource*—The Real-Time metered generation of Generation Resource *r* represented by QSE *q*, for the 15-minute Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Train.
RTSPP $_{p}$	$/MWh	*Real-Time Settlement Point Price*—The Real-Time Settlement Point Price at the Resource Node for the 15-minute Settlement Interval.
RTVSSAIEC $_{q,r}$	$/MWh	*Real-Time Average Incremental Energy Cost per QSE per Resource*—The average incremental cost to operate (not subject to cost cap) the Generation Resource *r* represented by QSE *q* from its LSL to its metered MW output, for the 15-minute Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Generation Resource.
RTICHSL $_{q,r}$	$	*Real-Time Incremental Cost Corresponding with HSL per QSE per Resource*—The incremental cost to operate (not subject to cost cap) Generation Resource *r* represented by QSE *q* from its LSL to its HSL, for the 15-minute Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Generation Resource.
RTHSLAIEC $_{q,r}$	$/MWh	*Real-Time Average Incremental Energy Cost for the entire Energy Offer Curve through the HSL per QSE per Resource*—The average incremental cost to operate (not subject to cost cap) the Generation Resource *r* represented by QSE *q* from its LSL to its HSL, for the 15-minute Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Generation Resource.
HSL $_{q,r}$	MW	*High Sustained Limit Generation per QSE per Settlement Point per Resource*—The HSL of Generation Resource *r* represented by QSE *q* at Resource Node p for the hour that includes the 15-minute Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Generation Resource.
LSL $_{q,r}$	MW	*Low Sustained Limit Generation per QSE per Settlement Point per Resource*—The LSL of Generation Resource *r* represented by QSE *q* at Resource Node p for the hour that includes the 15-minute Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Generation Resource.
q	none	A QSE.
r	none	A Generation Resource.
p	none	A Resource Node Settlement Point.

(5) The total of the payments to each QSE for ERCOT-directed power reduction to provide VSS for a given 15-minute Settlement Interval is calculated as follows:

$$\textbf{VSSEAMTQSETOT}_{q} = \sum_{r} \textbf{VSSEAMT}_{q,r}$$

The above variables are defined as follows:

Variable	Unit	Definition
VSSEAMTQSETOT $_{q}$	$	*Voltage Support Service Lost Opportunity Amount QSE Total per QSE*—The total of the lost opportunity payments to QSE q for providing VSS for providing ERCOT-directed VSS for the 15-minute Settlement Interval.
VSSEAMT $_{q,\ r}$	$	*Voltage Support Service Energy Amount per QSE per Settlement Point per Generation Resource*—The lost opportunity payment to QSE q for ERCOT-directed VSS from Generation Resource r for the 15-minute Settlement Interval for the 15-minute Settlement Interval. Where for a combined cycle resource, r is a Combined Cycle Train.
q	none	A QSE.
r	none	A Generation Resource.

[NPRR971 and NPRR1014: Replace applicable portions of Section 6.6.7.1 above with the following upon system implementation:]

6.6.7.1 Voltage Support Service Payments

(1) All other Generation Resources or ESRs shall be eligible for compensation for Reactive Power production in accordance with Section 6.5.7.7, Voltage Support Service, only if ERCOT issues a Dispatch Instruction that results in the following unit operation:

(a) When ERCOT instructs the Generation Resource or ESR to exceed its Unit Reactive Limit (URL) and the Generation Resource or ESR provides additional Reactive Power, then ERCOT shall pay for the additional Reactive Power provided at a price that recognizes the avoided cost of reactive support Resources on the transmission network.

(b) Any real power reduction directed by ERCOT through VDIs to provide for additional reactive capability for voltage support must be compensated as a lost opportunity payment

(2) The payment for a given 15-minute Settlement Interval to each QSE representing a Generation Resource or ESR that operates in accordance with an ERCOT Dispatch Instruction is calculated as follows:

Depending on the Dispatch Instruction, payment for Volt-Amperes reactive (VAr):

If VSSVARLAG $_{q,\ r} > 0$

$$\textbf{VSSVARAMT}_{q,\ r} = \textbf{(-1) * VSSVARPR * VSSVARLAG}_{q,\ r}$$

If VSSVARLEAD $_{q,\ r} > 0$

$$\textbf{VSSVARAMT}_{q,\ r} = \textbf{(-1) * VSSVARPR * VSSVARLEAD}_{q,\ r}$$

Where:

$VSSVARLAG_{q,r}$ = Max [0, Min (¼ * $VSSVARIOL_{q,r}$, $RTVAR_{q,r}$) – (¼ * $URLLAG_{q,r}$)]

$VSSVARLEAD_{q,r}$ = Max {0, [(¼ * $URLLEAD_{q,r}$) – Max ((¼ * $VSSVARIOL_{q,r}$), $RTVAR_{q,r}$)]}

And:

If an ESR has a net withdrawal for the Settlement Interval, then:

$URLLAG_{q,r}$ = 0.32868 * ABS($LSL_{q,r}$)

$URLLEAD_{q,r}$ = (-1) * 0.32868 * ABS($LSL_{q,r}$)

Otherwise:

$URLLAG_{q,r}$ = 0.32868 * $HSL_{q,r}$

$URLLEAD_{q,r}$ = (-1) * 0.32868 * $HSL_{q,r}$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
$VSSVARAMT_{q,r}$	$	*Voltage Support Service VAr Amount per QSE per Resource* - The payment to QSE *q* for the VSS provided by Resource *r*, for the 15-minute Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Train.
VSSVARPR	$/MVArh	*Voltage Support Service VAr Price* - The price for instructed MVAr beyond a Resource's URL currently is $2.65/MVArh (based on $50.00/installed kVAr).
$VSSVARLAG_{q,r}$	MVArh	*Voltage Support Service VAr Lagging per QSE per Resource* - The instructed portion of the Reactive Power above the Generation Resource's lagging URL for Resource *r* represented by QSE *q*, for the 15-minute Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Train.
$VSSVARLEAD_{q,r}$	MVArh	*Voltage Support Service VAr Leading per QSE per Resource* - The instructed portion of the Reactive Power below the Resource's leading URL for Resource *r* represented by QSE *q*, for the 15-minute Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Train.
$VSSVARIOL_{q,r}$	MVAr	*Voltage Support Service VAr Instructed Output Level per QSE per Resource*—The instructed Reactive Power output level of Resource *r* represented by QSE *q*, lagging Reactive Power if positive and leading Reactive Power if negative, for the 15-minute Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Train.

RTVAR $_{q,\,r}$	MVArh	*Real-Time VAr per QSE per Resource*—The netted Reactive Energy measured for Resource *r* represented by QSE *q*, for the 15-minute Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Train.
URLLAG $_{q,\,r}$	MVAr	*Unit Reactive Limit Lagging per QSE per Resource*—The URL for lagging Reactive Power of the Resource *r* represented by QSE *q* as determined in accordance with these Protocols. Its value is positive. Where for a combined cycle resource, *r* is a Combined Cycle Train.
URLLEAD $_{q,\,r}$	MVAr	*Unit Reactive Limit Leading per QSE per Resource*—The URL for leading Reactive Power of the Resource *r* represented by QSE *q* as determined in accordance with these Protocols. Its value is negative. Where for a combined cycle resource, *r* is a Combined Cycle Train.
HSL $_{q,\,r}$	MW	*High Sustained Limit*—The HSL of Resource *r* represented by QSE *q* as defined in Section 2, Definitions, for the hour that includes the Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Generation Resource.
LSL $_{q,\,r}$	MW	*Low Sustained Limit*—The LSL for Resource *r* represented by QSE *q*, as defined in Section 2, Definitions, for the hour that includes the Settlement Interval.
q	none	A QSE.
r	none	A Generation Resource or Energy Storage Resource.

(3) The total additional compensation to each QSE for voltage support service for the 15-minute Settlement Interval is calculated as follows:

$$\textbf{VSSVARAMTQSETOT}_{\mathbf{q}} = \sum_{r} \textbf{VSSVARAMT}_{q,r}$$

Variable	Unit	Definition
VSSVARAMT $_{q,\,r}$	$	*Voltage Support Service VAr Amount per QSE per Resource*—The payment to QSE *q* for the VSS provided by Resource *r*, for the 15-minute Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Train.
VSSVARAMTQSETOT $_{q}$	$	*Voltage Support VAr Amount QSE total per QSE*—The total of the payments to QSE *q* as compensation for VSS by this QSE for the 15-minute settlement interval.
q	None	A QSE.
r	None	A Generation Resource or Energy Storage Resource.

(4) The lost opportunity payment, if applicable:

If an ESR has a net withdrawal for the Settlement Interval, then:

$$\textbf{VSSEAMT}_{q,\,r} = \textbf{(-1) * Max (0, RTSPP}_{p}\textbf{) * Max (0, (ABS(LSL}_{q,\,r}\textbf{ * ¼ - NETVSSA}_{q,\,r}\textbf{)))}$$

Otherwise: