not reduce Primary Frequency Response on an individual Generation Resource, ESR, Settlement Only Generator (SOG), or SOTESS even during abnormal conditions without ERCOT's consent (conveyed by way of the Resource Entity's Qualified Scheduling Entity (QSE)) unless equipment damage is imminent. All Generation Resources, ESRs, SOTGs, SOTSGs, and SOTESSs that have capacity available to either increase output or decrease output in Real-Time must provide Primary Frequency Response, which may make use of that available capacity. Only Generation Resources or ESRs providing Responsive Reserve (RRS), Regulation Up (Reg-Up), Regulation Down (Reg-Down), ERCOT Contingency Reserve Service (ECRS), or Non-Spinning Reserve (Non-Spin) from On-Line Resources, as specified in Section 8.1.1, QSE Ancillary Service Performance Standards, shall be required to reserve capacity that may also be used to provide Primary Frequency Response.

[NPRR863, NPRR989, and NPRR1011: Insert applicable portions of paragraph (2) below upon system implementation for NPRR863 and NPRR989; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1011:]

(2) Generation Resources and ESRs that do not have an RRS or Regulation Service Ancillary Service award shall set their Governor Dead-Band no greater than ±0.036 Hz from nominal frequency of 60 Hz. A Generation Resource or ESR that widens its Governor Dead-Band greater than what is prescribed in Nodal Operating Guide Section 2.2.7, Turbine Speed Governors, must update its Resource Registration data with the new dead-band value.

(3) SOTGs, SOTSGs, and SOTESSs shall set their Governor Dead-Band no greater than ±0.036 Hz from nominal frequency of 60 Hz.

8.5.1.2 Reporting

(1) Each Resource Entity shall conduct applicable Governor tests on each of its Generation Resources as specified in the Operating Guides. The Resource Entity shall provide test results and other relevant information to ERCOT. ERCOT shall make these results available to the Transmission Service Providers (TSPs).

[NPRR963 and NPRR989: Replace applicable portions of paragraph (1) above with the following upon system implementation:]

(1) Each Resource Entity shall conduct applicable Governor tests on each of its Generation Resources and ESRs as specified in the Operating Guides. The Resource Entity shall provide test results and other relevant information to ERCOT. ERCOT shall make these results available to the Transmission Service Providers (TSPs).

(2) Generation Resource Governor modeling information required in the ERCOT planning criteria must be determined from actual Generation Resource testing described in the Operating Guides. Within 30 days of ERCOT's request, the results of the latest test performed must be supplied to ERCOT and the connected TSP.

[NPRR989: Replace paragraph (2) above with the following upon system implementation:]

(2) Generation Resource and ESR Governor modeling information required in the ERCOT planning criteria must be determined from actual Generation Resource or ESR testing described in the Operating Guides. Within 30 days of ERCOT's request, the results of the latest test performed must be supplied to ERCOT and the connected TSP.

(3) Each QSE shall inform ERCOT as soon as practical when notified by its On-Line Generation Resource, SOTG, SOTSG, or SOTESS of the Governor being out-of-service. The QSE shall supply related logs to ERCOT upon request.

[NPRR989: Replace paragraph (3) above with the following upon system implementation:]

(3) Each QSE shall inform ERCOT as soon as practical when notified by its On-Line Generation Resource, ESR, SOTG, SOTSG, or SOTESS of the Governor being out-of-service. The QSE shall supply related logs to ERCOT upon request.

(4) If a Generation Resource trips Off-Line during a disturbance, as defined by the North American Electric Reliability Corporation (NERC), while providing Primary Frequency Response, the QSE shall report the cause of the failure to ERCOT as soon as the cause has been identified.

[NPRR989: Replace paragraph (4) above with the following upon system implementation:]

(4) If a Generation Resource or ESR trips Off-Line during a disturbance, as defined by the North American Electric Reliability Corporation (NERC), while providing Primary Frequency Response, the QSE shall report the cause of the failure to ERCOT as soon as the cause has been identified.

8.5.2 Primary Frequency Response Measurements

(1) ERCOT, with the assistance of the appropriate Technical Advisory Committee (TAC) subcommittee, shall analyze the performance of Generation Resources, SOTGs, SOTSGs, SOTESSs, Resources capable of Fast Frequency Response (FFR), and Controllable Load Resources for all Frequency Measurable Events (FMEs) in accordance with the Operating Guides. In support of this analysis, ERCOT shall post the following:

[NPRR963 and NPRR989: Replace applicable portions of paragraph (1) above with the following upon system implementation:]

(1) ERCOT, with the assistance of the appropriate Technical Advisory Committee (TAC) subcommittee, shall analyze the performance of Generation Resources, ESRs, SOTGs, SOTSGs, SOTESSs, Resources capable of Fast Frequency Response (FFR), and Controllable Load Resources for all Frequency Measurable Events (FMEs) in accordance with the Operating Guides. In support of this analysis, ERCOT shall post the following:

(a) ERCOT shall post on the ERCOT website the occurrence of an FME within 14 calendar days of occurrence.

(b) ERCOT shall post on the Market Information System (MIS) Certified Area for Performance, Disturbance, Compliance Working Group (PDCWG) analysis, the Primary Frequency Response Unit Performance for each Generation Resource, SOTG, SOTSG, SOTESS, and Controllable Load Resource that is measured in the FME.

[NPRR963 and NPRR989: Replace applicable portions of paragraph (b) above with the following upon system implementation:]

(b) ERCOT shall post on the MIS Certified Area for Performance, Disturbance, Compliance Working Group (PDCWG) analysis, the Primary Frequency Response Unit Performance for each Generation Resource, ESR, SOTG, SOTSG, SOTESS, and Controllable Load Resource that is measured in the FME.

(c) ERCOT shall post on the ERCOT website a monthly report that displays the frequency response of the ERCOT System for a rolling average of the last six FMEs.

(d) ERCOT shall post on the ERCOT website an annual report that displays the minimum frequency response computation methodology of the ERCOT System.

(e) ERCOT shall post on the MIS Certified Area the Primary Frequency Response 12-month rolling average for each Generation Resource, SOTG, SOTSG, SOTESS, Resource capable of FFR, and Controllable Load Resource.

[NPRR963 and NPRR989: Replace applicable portions of paragraph (e) above with the following upon system implementation:]

(e) ERCOT shall post on the MIS Certified Area the Primary Frequency Response 12-month rolling average for each Generation Resource, ESR, SOTG, SOTSG, SOTESS, Resource capable of FFR, and Controllable Load Resource.

8.5.2.1 ERCOT Required Primary Frequency Response

(1) All Generation Resources, SOTGs, SOTSGs, SOTESS, Resources capable of FFR, and Controllable Load Resources shall provide Primary Frequency Response in accordance with the requirements established in the Operating Guides.

[NPRR963 and NPRR989: Replace applicable portions of paragraph (1) above with the following upon system implementation:]
(1) All Generation Resources, ESRs, SOTGs, SOTSGs, SOTESS, and Controllable Load Resources shall provide Primary Frequency Response in accordance with the requirements established in the Operating Guides.

(2) ERCOT shall evaluate, with the assistance of the appropriate TAC subcommittee, Primary Frequency Response during FMEs. The actual Generation Resource response must be compiled to determine if adequate Primary Frequency Response was provided.

[NPRR963 and NPRR989: Replace applicable portions of paragraph (2) above with the following upon system implementation:]
(2) ERCOT shall evaluate, with the assistance of the appropriate TAC subcommittee, Primary Frequency Response during FMEs. The actual Generation Resource or ESR response must be compiled to determine if adequate Primary Frequency Response was provided.

(3) ERCOT and the appropriate TAC subcommittee shall review each FME, verifying the accuracy of data. Data that is in question may be requested from the QSE for comparison or individual Generation Resource data may be retrieved from ERCOT's database.

[NPRR963 and NPRR989: Replace applicable portions of paragraph (3) above with the following upon system implementation:]
(3) ERCOT and the appropriate TAC subcommittee shall review each FME, verifying the accuracy of data. Data that is in question may be requested from the QSE for comparison or individual Resource data may be retrieved from ERCOT's database.

9.5.3 Real-Time Market Settlement Charge Types

(1) ERCOT shall provide, on each RTM Settlement Statement, the dollar amount for each RTM Settlement charge and payment. The RTM Settlement "Charge Types" are:

(a) Section 5.7.1, RUC Make-Whole Payment;

(b) Section 5.7.2, RUC Clawback Charge;

(c) Section 5.7.3, Payment When ERCOT Decommits a QSE-Committed Resource;

(d) Section 5.7.4.1, RUC Capacity-Short Charge;

(e) Section 5.7.4.2, RUC Make-Whole Uplift Charge;

(f) Section 5.7.5, RUC Clawback Payment;

(g) Section 5.7.6, RUC Decommitment Charge;

(h) Section 6.6.3.1, Real-Time Energy Imbalance Payment or Charge at a Resource Node;

(i) Section 6.6.3.2, Real-Time Energy Imbalance Payment or Charge at a Load Zone;

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

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

(l) Section 6.6.3.5, Real-Time Payment for a Block Load Transfer Point;

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

(n) Section 6.6.3.7, Real-Time High Dispatch Limit Override Energy Payment;

(o) Section 6.6.3.8, Real-Time High Dispatch Limit Override Energy Charge;

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

(q) Section 6.6.5.1.1.1, Base Point Deviation Charge for Over Generation;

(r) Section 6.6.5.1.1.2, Base Point Deviation Charge for Under Generation;

(s) Section 6.6.5.2, IRR Generation Resource Base Point Deviation Charge;

(t) Section 6.6.5.4, Base Point Deviation Payment;

(u) Section 6.6.6.1, RMR Standby Payment;

(v) Section 6.6.6.2, RMR Payment for Energy;

(w) Section 6.6.6.3, RMR Adjustment Charge;

(x) Section 6.6.6.4, RMR Charge for Unexcused Misconduct;

(y) Section 6.6.6.5, RMR Service Charge;

(z) Section 6.6.6.6, Method for Reconciling RMR Actual Eligible Costs, RMR and MRA Contributed Capital Expenditures, and Miscellaneous RMR Incurred Expenses;

(aa) Paragraph (2) of Section 6.6.7.1, Voltage Support Service Payments;

(bb) Paragraph (4) of Section 6.6.7.1;

(cc) Section 6.6.7.2, Voltage Support Charge;

(dd) Section 6.6.8.1, Black Start Hourly Standby Fee Payment;

(ee) Section 6.6.8.2, Black Start Capacity Charge;

(ff) Section 6.6.9.1, Payment for Emergency Power Increase Directed by ERCOT;

(gg) Section 6.6.9.2, Charge for Emergency Power Increases;

(hh) Section 6.6.10, Real-Time Revenue Neutrality Allocation;

(ii) Paragraph (1)(a) of Section 6.7.1, Payments for Ancillary Service Capacity Sold in a Supplemental Ancillary Services Market (SASM) or Reconfiguration Supplemental Ancillary Services Market (RSASM);

(jj) Paragraph (1)(b) of Section 6.7.1;

(kk) Paragraph (1)(c) of Section 6.7.1;

(ll) Paragraph (1)(d) of Section 6.7.1;

(mm) Paragraph (1)(a) of Section 6.7.2, Payments for Ancillary Service Capacity Assigned in Real-Time Operations;

(nn) Paragraph (1)(b) of Section 6.7.2;

(oo) Paragraph (1)(a) of Section 6.7.2.1, Charges for Infeasible Ancillary Service Capacity Due to Transmission Constraints;

(pp) Paragraph (1)(b) of Section 6.7.2.1;

(qq) Paragraph (1)(c) of Section 6.7.2.1;

(rr) Paragraph (1)(d) of Section 6.7.2.1;

(ss) Paragraph (1)(a) of Section 6.7.3, Charges for Ancillary Service Capacity Replaced Due to Failure to Provide;

(tt) Paragraph (1)(b) of Section 6.7.3;

(uu) Paragraph (1)(c) of Section 6.7.3;

(vv) Paragraph (1)(d) of Section 6.7.3;

(ww) Paragraph (2) of Section 6.7.4, Adjustments to Cost Allocations for Ancillary Services Procurement;

(xx) Paragraph (3) of Section 6.7.4;

(yy) Paragraph (4) of Section 6.7.4;

(zz) Paragraph (5) of Section 6.7.4;

(aaa) Paragraph (7) of Section 6.7.5, Real-Time Ancillary Service Imbalance Payment or Charge (Real-Time Ancillary Service Imbalance Amount);

(bbb) Paragraph (7) of Section 6.7.5, (Real-Time Reliability Deployment Ancillary Service Imbalance Amount);

(ccc) Paragraph (8) of Section 6.7.5, (Real-Time RUC Ancillary Service Reserve Amount);

(ddd) Paragraph (8) of Section 6.7.5, (Real-Time Reliability Deployment RUC Ancillary Service Reserve Amount);

(eee) Section 6.7.6, Real Time Ancillary Service Imbalance Revenue Neutrality Allocation (Load-Allocated Ancillary Service Imbalance Revenue Neutrality Amount);

(fff) Section 6.7.6, (Load-Allocated Reliability Deployment Ancillary Service Imbalance Revenue Neutrality Amount);

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

(hhh) Section 9.16.1, ERCOT System Administration Fee.

[NPRR841, NPRR863, NPRR885, NPRR917, NPRR963, NPRR1012, NPRR1014, and NPRR1054: Replace applicable portions of paragraph (1) above with the following upon system

implementation for NPRR841, NPRR863, NPRR885, NPRR963, NPRR1014, or NPRR1054; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1012:]

(1) ERCOT shall provide, on each RTM Settlement Statement, the dollar amount for each RTM Settlement charge and payment. The RTM Settlement "Charge Types" are:

(a) Section 5.7.1, RUC Make-Whole Payment;

(b) Section 5.7.2, RUC Clawback Charge;

(c) Section 5.7.3, Payment When ERCOT Decommits a QSE-Committed Resource;

(d) Section 5.7.4.1, RUC Capacity-Short Charge;

(e) Section 5.7.4.2, RUC Make-Whole Uplift Charge;

(f) Section 5.7.5, RUC Clawback Payment;

(g) Section 5.7.6, RUC Decommitment Charge;

(h) Section 6.6.3.1, Real-Time Energy Imbalance Payment or Charge at a Resource Node;

(i) Section 6.6.3.2, Real-Time Energy Imbalance Payment or Charge at a Load Zone;

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

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

(l) Section 6.6.3.5, Real-Time Payment for a Block Load Transfer Point;

(m) Section 6.6.3.6, Real-Time High Dispatch Limit Override Energy Payment;

(n) Section 6.6.3.7, Real-Time High Dispatch Limit Override Energy Charge;

(o) Section 6.6.3.8, Real-Time Payment or Charge for Energy from a Settlement Only Distribution Generator (SODG), Settlement Only Transmission Generator (SOTG), Settlement Only Distribution Energy Storage System (SODESS), or Settlement Only Transmission Energy Storage System (SOTESS);

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

(q) Section 6.6.5.2, Set Point Deviation Charge for Over Generation;

(r) Section 6.6.5.2.1, Set Point Deviation Charge for Under Generation;

(s) Section 6.6.5.3, Controllable Load Resource Set Point Deviation Charge for Over Consumption;

(t) Section 6.6.5.3.1, Controllable Load Resource Set Point Deviation Charge for Under Consumption;

(u) Section 6.6.5.4, IRR Generation Resource Set Point Deviation Charge;

(v) Section 6.6.5.4, Set Point Deviation Payment;

(w) Section 6.6.5.5, Energy Storage Resource Set Point Deviation Charge for Over Performance;

(x) Section 6.6.5.5.1, Energy Storage Resource Set Point Deviation Charge for Under Performance;

(y) Section 6.6.6.1, RMR Standby Payment;

(z) Section 6.6.6.2, RMR Payment for Energy;

(aa) Section 6.6.6.3, RMR Adjustment Charge;

(bb) Section 6.6.6.4, RMR Charge for Unexcused Misconduct;

(cc) Section 6.6.6.5, RMR Service Charge;

(dd) Section 6.6.6.6, Method for Reconciling RMR Actual Eligible Costs, RMR and MRA Contributed Capital Expenditures, and Miscellaneous RMR Incurred Expenses;

(ee) Section 6.6.6.7, MRA Standby Payment;

(ff) Section 6.6.6.8, MRA Contributed Capital Expenditures Payment;

(gg) Section 6.6.6.9, MRA Payment for Deployment Event;

(hh) Section 6.6.6.10, MRA Variable Payment for Deployment;

(ii) Section 6.6.6.11, MRA Charge for Unexcused Misconduct;

(jj) Section 6.6.6.12, MRA Service Charge;

(kk) Paragraph (3) of Section 6.6.7.1, Voltage Support Service Payments;

(ll) Paragraph (5) of Section 6.6.7.1;

(mm) Section 6.6.7.2, Voltage Support Charge;

(nn) Section 6.6.8.1, Black Start Hourly Standby Fee Payment;

(oo) Section 6.6.8.2, Black Start Capacity Charge;

(pp) Section 6.6.9.1, Payment for Emergency Operations Settlement;

(qq) Section 6.6.9.2, Charge for Emergency Operations Settlement;

(rr) Section 6.6.10, Real-Time Revenue Neutrality Allocation;

(ss) Section 6.6.11.1, Emergency Response Service Capacity Payments;

(tt) Section 6.6.11.2, Emergency Response Service Capacity Charge;

(uu) Section 6.7.4, Real-Time Settlement for Updated Day-Ahead Market Ancillary Service Obligations;

(vv) Section 6.7.5.2, Regulation Up Service Payments and Charges;

(ww) Section 6.7.5.3, Regulation Down Service Payments and Charges;

(xx) Section 6.7.5.4, Responsive Reserve Payments and Charges;

(yy) Section 6.7.5.5, Non-Spinning Reserve Service Payments and Charges;

(zz) Section 6.7.5.6, ERCOT Contingency Reserve Service Payments and Charges;

(aaa) Section 6.7.5.7, Real-Time Derated Ancillary Service Capability Payment;

(bbb) Section 6.7.5.8, Real-Time Derated Ancillary Service Capability Charge;

(ccc) Section 6.7.6, Real-Time Ancillary Service Revenue Neutrality Allocation;

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

(eee) Section 9.16.1, ERCOT System Administration Fee.

(2) In the event that ERCOT is unable to execute the Day-Ahead Market (DAM), ERCOT shall provide, on each RTM Settlement Statement, the dollar amount for the following RTM Congestion Revenue Right (CRR) Settlement charges and payments:

(a) Section 7.9.2.4, Payments for FGRs in Real-Time; and

(b) Section 7.9.2.5, Payments and Charges for PTP Obligations with Refund in Real-Time.

9.17.1 Billing Determinant Data Elements

(1) ERCOT shall calculate and provide to Market Participants on the ERCOT website the following data elements annually to be used by TSPs and DSPs as billing determinants

for transmission access service. This data must be provided by December 1 of each year. This calculation must be made under the requirements of P.U.C. SUBST. R. 25.192, Transmission Service Rates. ERCOT shall use the most recent aggregate data produced by the ERCOT Settlement system to perform these calculations.

(a) The 4-Coincident Peak (4-CP) for each DSP and External Load Serving Entity (ELSE), as applicable;

(b) The ERCOT average 4-CP;

(c) The average 4-CP for each DSP and ELSE, as applicable, coincident to the ERCOT average 4-CP.

(2) ERCOT average 4-CP is defined as the average of the coincidental MW peaks occurring during the months of June, July, August, and September.

(3) Coincidental MW peak is defined as the highest monthly Settlement Interval 15-minute MW peak for the entire ERCOT Transmission Grid as calculated per the following formula: The sum of all net energy produced by Generation Resources + Settlement Only Generators (SOGs) + Settlement Only Energy Storage Systems (SOESSs) + Block Load Transfers (BLTs) from ERCOT to another Control Area that have been registered for Settlement purposes + actual Direct Current Tie (DC Tie) imports - BLTs to ERCOT from another Control Area that are not reflected in a Non-Opt-In Entity's (NOIE's) Load - actual DC Tie exports - Wholesale Storage Load (WSL).

(4) Any difference between the coincidental MW peak (converted to MWh) and the ERCOT Settlement volumes, excluding DC Tie exports, BLTs to ERCOT from another Control Area that are not reflected in a NOIE's Load, and WSL, shall be allocated amongst all DSPs and ELSEs that are included in the ERCOT 4-CP Report on a pro rata basis as per the formula below:

$$\mathbf{LTDSP\_4CP}_{\ tdsp} = \mathbf{(PLTDSP4CPLRS}_{\ tdsp} \mathbf{\ *\ NLADJ) + PLTDSP4CP}_{\ tdsp}$$

The above variables are defined as follows:

Variable	Unit	Definition
LTDSP_4CP $_{tdsp}$	MWh	*Load by TDSP for 4-CP* - The load for each DSP and ELSE coincident to the coincidental MW peak adjusted for NLADJ
PLTDSP4CPLRS $_{tdsp}$	%	*Preliminary Load by TDSP for 4-CP Load Ratio Share* - The Load Ratio Share (LRS) for each DSP and ELSE coincident to the coincidental MW peak prior to adjusting for NLADJ
NLADJ	MWh	*Native Load Adjustment* - The difference between the coincidental MW peak (converted to MWh) and the ERCOT settlement volumes, excluding DC Tie exports, BLTs to ERCOT from another Control Area that are not reflected in a NOIE's Load, and WSL
PLTDSP4CP $_{tdsp}$	MWh	*Preliminary Load by TDSP for 4CP* - The Load for each DSP and ELSE coincident to the coincidental MW peak prior to adjusting for NLADJ
tdsp	None	A DSP or ELSE

9.19.1 Default Uplift Invoices

(1) ERCOT shall collect the total short-pay amount for all Settlement Invoices for a month, less the total payments expected from a payment plan, from Qualified Scheduling Entities (QSEs) and CRR Account Holders. ERCOT must pay the funds it collects from payments on Default Uplift Invoices to the Entities previously short-paid. ERCOT shall notify those Entities of the details of the payment.

(2) Each Counter-Party's share of the uplift is calculated using the best available Settlement data for each Operating Day in the month prior to the month in which the default occurred (the "reference month"), and is calculated as follows:

$$\mathbf{DURSCP}_{cp} = \mathbf{TSPA} * \mathbf{MMARS}_{cp}$$

Where:

$$\text{MMARS}_{cp} = \text{MMA}_{cp} / \text{MMATOT}$$

$$\begin{aligned}\text{MMA}_{cp} = \text{Max}\ \{ & \textstyle\sum_{mp} (\text{URTMG}_{mp} + \text{URTDCIMP}_{mp}),\\ & \textstyle\sum_{mp} (\text{URTAML}_{mp} + \text{UWSLTOT}_{mp}),\\ & \textstyle\sum_{mp} \text{URTQQES}_{mp},\\ & \textstyle\sum_{mp} \text{URTQQEP}_{mp},\\ & \textstyle\sum_{mp} \text{UDAES}_{mp},\\ & \textstyle\sum_{mp} \text{UDAEP}_{mp},\\ & \textstyle\sum_{mp} (\text{URTOBL}_{mp} + \text{URTOBLLO}_{mp}),\\ & \textstyle\sum_{mp} (\text{UDAOPT}_{mp} + \text{UDAOBL}_{mp} + \text{UOPTS}_{mp} + \text{UOBLS}_{mp}),\\ & \textstyle\sum_{mp} (\text{UOPTP}_{mp} + \text{UOBLP}_{mp})\}\end{aligned}$$

[NPRR917, NPRR1012, and NPRR1065: Replace applicable portions of the formula "MMA $_{cp}$" above with the following upon system implementation of NPRR917 for NPRR917 and NPRR1065; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1012:]

$$\begin{aligned}\text{MMA}_{cp} = \text{Max}\ \{ & \textstyle\sum_{mp} (\text{URTMG}_{mp} + \text{URTDCIMP}_{mp} + \text{USOGTOT}_{mp}),\\ & \textstyle\sum_{mp} (\text{URTAML}_{mp} + \text{UWSLTOT}_{mp} + \text{USOCLTOT}_{mp}),\\ & \textstyle\sum_{mp} \text{URTQQES}_{mp},\\ & \textstyle\sum_{mp} \text{URTQQEP}_{mp},\end{aligned}$$

$\sum_{mp}$ UDAES $_{mp}$, $\sum_{mp}$ UDAEP $_{mp}$, $\sum_{mp}$ (URTOBL $_{mp}$ + URTOBLLO $_{mp}$), $\sum_{mp}$ (UDAOPT $_{mp}$ + UDAOBL $_{mp}$ + UOPTS $_{mp}$ + UOBLS $_{mp}$), $\sum_{mp}$ (UOPTP $_{mp}$ + UOBLP $_{mp}$), $\sum_{mp}$ UDAASOAWD $_{mp}$}

MMATOT = $\sum_{cp}$ (MMA$_{cp}$)

Where:

URTMG $_{mp}$ = $\sum_{p,\ r,\ i}$ (RTMG $_{mp,\ p,\ r,\ i}$), excluding RTMG for RMR Resources and RTMG in Reliability Unit Commitment (RUC)-Committed Intervals for RUC-committed Resources

URTDCIMP $_{mp}$ = $\sum_{p,\ i}$ (RTDCIMP $_{mp,\ p,\ i}$) / 4

URTAML $_{mp}$ = max(0,$\sum_{p,\ i}$ (RTAML $_{mp,\ p,\ i}$))

URTQQES $_{mp}$ = $\sum_{p,\ i}$ (RTQQES $_{mp,\ p,\ i}$) / 4

URTQQEP $_{mp}$ = $\sum_{p,\ i}$ (RTQQEP $_{mp,\ p,\ i}$) / 4

UDAES $_{mp}$ = $\sum_{p,\ h}$ (DAES $_{mp,\ p,\ h}$)

UDAEP $_{mp}$ = $\sum_{p,\ h}$ (DAEP $_{mp,\ p,\ h}$)

URTOBL $_{mp}$ = $\sum_{(j,\ k),\ h}$ (RTOBL $_{mp,\ (j,\ k),\ h}$)

URTOBLLO $_{mp}$ = $\sum_{(j,\ k),\ h}$ (RTOBLLO $_{mp,\ (j,\ k),\ h}$)

UDAOPT $_{mp}$ = $\sum_{(j,\ k),\ h}$ (DAOPT $_{mp,\ (j,\ k),\ h}$)

UDAOBL $_{mp}$ = $\sum_{(j,\ k),\ h}$ (DAOBL $_{mp,\ (j,\ k),\ h}$)

UOPTS $_{mp}$ = $\sum_{(j,\ k),\ h}$ (OPTS $_{mp,\ (j,\ k),\ h}$)

UOBLS $_{mp}$ = $\sum_{(j,\ k),\ h}$ (OBLS $_{mp,\ (j,\ k),\ h}$)

UOPTP $_{mp}$ = $\sum_{(j,\ k),\ h}$ (OPTP $_{mp,\ j,\ h}$)

UOBLP $_{mp}$ = $\sum_{(j,\ k),\ h}$ (OBLP $_{mp,\ (j,\ k),\ h}$)

UWSLTOT $_{mp}$ = (-1) * $\sum_{r,\ b}$ (MEBL $_{mp,\ r,\ b}$)

[NPRR1012: Insert the formula "UDAASOAWD $_{mp}$" below upon system implementation of the Real-Time Co-Optimization (RTC) project:]

$$UDAASOAWD_{mp} = \sum_h (DARUOAWD_{mp,h} + DARDOAWD_{mp,h} + DARROAWD_{mp,h} + DANSOAWD_{mp,h} + DAECROAWD_{mp,h})$$

[NPRR917 and NPRR1065: Insert the formula "USOGTOT $_{mp}$" and "USOCLTOT $_{mp}$" below upon system implementation of NPRR917:]

$$USOGTOT_{mp} = \sum_{gsc} (MEBSOGNET_{mp,\, gsc}) + \sum_{p,\, i} (RTMGSOGZ_{mp,\, p,\, i})$$

$$USOCLTOT_{mp} = (-1) * \sum_{gsc,\, b} (WSOL_{mp,\, gsc,\, b})$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
$DURSCP_{cp}$	$	*Default Uplift Ratio Share per Counter-Party*—The Counter-Party's pro rata portion of the total short-pay amount for all Day-Ahead Market (DAM) and Real-Time Market (RTM) Invoices for a month.
TSPA	$	*Total Short Pay Amount*—The total short-pay amount calculated by ERCOT to be collected through the Default Uplift Invoice process.
$MMARS_{cp}$	None	*Maximum MWh Activity Ratio Share*—The Counter-Party's pro rata share of Maximum MWh Activity in the reference month.
MMA_{cp}	MWh	*Maximum MWh Activity*—The maximum MWh activity of all Market Participants represented by the Counter-Party in the DAM, RTM and CRR Auction in the reference month.
MMATOT	MWh	*Maximum MWh Activity Total*—The sum of all Counter-Party's Maximum MWh Activity in the reference month.
$RTMG_{mp,\, p,\, r,\, i}$	MWh	*Real-Time Metered Generation per Market Participant per Settlement Point per Resource*—The Real-Time energy produced by the Generation Resource *r* represented by Market Participant *mp*, at Resource Node *p*, for the 15-minute Settlement Interval *i*, where the Market Participant is a QSE.
$URTMG_{mp}$	MWh	*Uplift Real-Time Metered Generation per Market Participant*—The monthly sum of Real-Time energy produced by Generation Resources represented by Market Participant *mp*, excluding generation for RMR Resources and generation in RUC-Committed Intervals, where the Market Participant is a QSE assigned to the registered Counter-Party.
$RTDCIMP_{mp,\, p,\, i}$	MW	*Real-Time DC Import per QSE per Settlement Point*—The aggregated Direct Current Tie (DC Tie) Schedule submitted by Market Participant *mp,* as an importer into the ERCOT System through DC Tie *p*, for the 15-minute Settlement Interval *i*, where the Market Participant is a QSE.
$URTDCIMP_{mp}$	MW	*Uplift Real-Time DC Import per Market Participant*—The monthly sum of the aggregated DC Tie Schedule submitted by Market Participant *mp*, as an importer into the ERCOT System where the Market Participant is a QSE assigned to a registered Counter-Party.

Variable	Unit	Definition
RTAML $_{mp, p, i}$	MWh	*Real-Time Adjusted Metered Load per Market Participant per Settlement Point*—The sum of the Adjusted Metered Load (AML) at the Electrical Buses that are included in Settlement Point *p* represented by Market Participant *mp* for the 15-minute Settlement Interval *i*, where the Market Participant is a QSE.
URTAML $_{mp}$	MWh	*Uplift Real-Time Adjusted Metered Load per Market Participant*—The monthly sum of the AML represented by Market Participant *mp*, where the Market Participant is a QSE assigned to the registered Counter-Party.
RTQQES $_{mp, p, i}$	MW	*QSE-to-QSE Energy Sale per Market Participant per Settlement Point*—The amount of MW sold by Market Participant *mp* through Energy Trades at Settlement Point *p* for the 15-minute Settlement Interval *i*, where the Market Participant is a QSE.
URTQQES $_{mp}$	MWh	*Uplift QSE-to-QSE Energy Sale per Market Participant*—The monthly sum of MW sold by Market Participant *mp* through Energy Trades, where the Market Participant is a QSE assigned to the registered Counter-Party.
RTQQEP $_{mp, p, i}$	MW	*QSE-to-QSE Energy Purchase per Market Participant per Settlement Point*—The amount of MW bought by Market Participant *mp* through Energy Trades at Settlement Point *p* for the 15-minute Settlement Interval *i*, where the Market Participant is a QSE.
URTQQEP $_{mp}$	MWh	*Uplift QSE-to-QSE Energy Purchase per Market Participant*—The monthly sum of MW bought by Market Participant *mp* through Energy Trades, where the Market Participant is a QSE assigned to the registered Counter-Party.
DAES $_{mp, p, h}$	MW	*Day-Ahead Energy Sale per Market Participant per Settlement Point per hour*—The total amount of energy represented by Market Participant *mp*'s cleared Three-Part Supply Offers in the DAM and cleared DAM Energy-Only Offers at Settlement Point *p*, for the hour *h*, where the Market Participant is a QSE.
UDAES $_{mp}$	MWh	*Uplift Day-Ahead Energy Sale per Market Participant*—The monthly total of energy represented by Market Participant *mp*'s cleared Three-Part Supply Offers in the DAM and cleared DAM Energy-Only Offer Curves, where the Market Participant is a QSE assigned to the registered Counter-Party.
DAEP $_{mp, p, h}$	MW	*Day-Ahead Energy Purchase per Market Participant per Settlement Point per hour*—The total amount of energy represented by Market Participant *mp*'s cleared DAM Energy Bids at Settlement Point *p* for the hour *h*, where the Market Participant is a QSE.
UDAEP $_{mp}$	MWh	*Uplift Day-Ahead Energy Purchase per Market Participant*—The monthly total of energy represented by Market Participant *mp*'s cleared DAM Energy Bids, where the Market Participant is a QSE assigned to the registered Counter-Party.
RTOBL $_{mp, (j, k), h}$	MW	*Real-Time Obligation per Market Participant per source and sink pair per hour*—The number of Market Participant *mp*'s Point-to-Point (PTP) Obligations with the source *j* and the sink *k* settled in Real-Time for the hour *h*, and where the Market Participant is a QSE.
URTOBL $_{mp}$	MWh	*Uplift Real-Time Obligation per Market Participant*—The monthly total of Market Participant *mp*'s PTP Obligations settled in Real-Time, counting the quantity only once per source and sink pair, and where the Market Participant is a QSE assigned to the registered Counter-Party.
RTOBLLO $_{q, (j, k)}$	MW	*Real-Time Obligation with Links to an Option per QSE per pair of source and sink*—The total MW of the QSE's PTP Obligation with Links to an Option Bids cleared in the DAM and settled in Real-Time for the source *j* and the sink *k* for the hour.

Variable	Unit	Definition
URTOBLLO $_{q, (j, k)}$	MW	*Uplift Real-Time Obligation with Links to an Option per QSE per pair of source and sink*—The monthly total of Market Participant *mp*'s MW of PTP Obligation with Links to Options Bids cleared in the DAM and settled in Real-Time for the source *j* and the sink *k* for the hour, where the Market Participant is a QSE assigned to the registered Counter-Party.
DAOPT $_{mp, (j, k), h}$	MW	*Day-Ahead Option per Market Participant per source and sink pair per hour*—The number of Market Participant *mp*'s PTP Options with the source *j* and the sink *k* owned in the DAM for the hour *h*, and where the Market Participant is a CRR Account Holder.
UDAOPT $_{mp}$	MWh	*Uplift Day-Ahead Option per Market Participant*—The monthly total of Market Participant *mp*'s PTP Options owned in the DAM, counting the ownership quantity only once per source and sink pair, and where the Market Participant is a CRR Account Holder assigned to the registered Counter-Party.
DAOBL $_{mp, (j, k), h}$	MW	*Day-Ahead Obligation per Market Participant per source and sink pair per hour*—The number of Market Participant *mp*'s PTP Obligations with the source *j* and the sink *k* owned in the DAM for the hour *h*, and where the Market Participant is a CRR Account Holder.
UDAOBL $_{mp}$	MWh	*Uplift Day-Ahead Obligation per Market Participant*—The monthly total of Market Participant *mp*'s PTP Obligations owned in the DAM, counting the ownership quantity only once per source and sink pair, where the Market Participant is a CRR Account Holder assigned to the registered Counter-Party.
OPTS $_{mp, (j, k), a, h}$	MW	*PTP Option Sale per Market Participant per source and sink pair per CRR Auction per hour*—The MW quantity that represents the total of Market Participant *mp*'s PTP Option offers with the source *j* and the sink *k* awarded in CRR Auction *a*, for the hour *h*, where the Market Participant is a CRR Account Holder.
UOPTS $_{mp}$	MWh	*Uplift PTP Option Sale per Market Participant*—The MW quantity that represents the monthly total of Market Participant *mp*'s PTP Option offers awarded in CRR Auctions, counting the awarded quantity only once per source and sink pair, where the Market Participant is a CRR Account Holder assigned to the registered Counter-Party.
OBLS $_{mp, (j, k), a, h}$	MW	*PTP Obligation Sale per Market Participant per source and sink pair per CRR Auction per hour*—The MW quantity that represents the total of Market Participant *mp*'s PTP Obligation offers with the source *j* and the sink *k* awarded in CRR Auction *a*, for the hour *h*, where the Market Participant is a CRR Account Holder.
UOBLS $_{mp}$	MWh	*Uplift PTP Obligation Sale per Market Participant*—The MW quantity that represents the monthly total of Market Participant *mp*'s PTP Obligation offers awarded in CRR Auctions, counting the quantity only once per source and sink pair, where the Market Participant is a CRR Account Holder assigned to the registered Counter-Party.
OPTP $_{mp, (j, k), a, h}$	MW	*PTP Option Purchase per Market Participant per source and sink pair per CRR Auction per hour*—The MW quantity that represents the total of Market Participant *mp*'s PTP Option bids with the source *j* and the sink *k* awarded in CRR Auction *a*, for the hour *h*, where the Market Participant is a CRR Account Holder.
UOPTP $_{mp}$	MWh	*Uplift PTP Option Purchase per Market Participant*—The MW quantity that represents the monthly total of Market Participant *mp*'s PTP Option bids awarded in CRR Auctions, counting the quantity only once per source and sink pair, where the Market Participant is a CRR Account Holder assigned to the registered Counter-Party.

Variable	Unit	Definition
OBLP $_{mp, (j, k), a, h}$	MW	*PTP Obligation Purchase per Market Participant per source and sink pair per CRR Auction per hour*—The MW quantity that represents the total of Market Participant *mp*'s PTP Obligation bids with the source *j* and the sink *k* awarded in CRR Auction *a*, for the hour *h*, where the Market Participant is a CRR Account Holder.
UOBLP $_{mp}$	MWh	*Uplift PTP Obligation Purchase per Market Participant*—The MW quantity that represents the monthly total of Market Participant *mp*'s PTP Obligation bids awarded in CRR Auctions, counting the quantity only once per source and sink pair, where the Market Participant is a CRR Account Holder assigned to the registered Counter-Party.
UWSLTOT $_{mp}$	MWh	*Uplift Metered Energy for Wholesale Storage Load at bus per Market Participant*—The monthly sum of Market Participant *mp*'s Wholesale Storage Load (WSL) energy metered by the Settlement Meter which measures WSL.
MEBL $_{mp, r, b}$	MWh	*Metered Energy for Wholesale Storage Load at bus*—The WSL energy metered by the Settlement Meter which measures WSL for the 15-minute Settlement Interval represented as a negative value, for the Market Participant *mp*, Resource *r*, at bus *b*.

[NPRR1012: Insert the variables below upon system implementation of the Real-Time Co-Optimization (RTC) project:]

UDAASOAWD $_{mp}$	MWh	*Uplift Day-Ahead Ancillary Service Only Award per Market Participant*—The monthly total of Market Participant *mp's* Ancillary Service Only Offers awarded in DAM, where the Market Participant is a QSE assigned to the registered Counter-Party.
DARUOAWD $_{mp, h}$	MW	*Day-Ahead Reg-Up Only Award per Market Participant*— The Reg-Up Only capacity quantity awarded in the DAM to the Market Participant *mp* for the hour *h*.
DARDOAWD $_{mp, h}$	MW	*Day-Ahead Reg-Down Only Award per Market Participant*— The Reg-Down Only capacity quantity awarded in the DAM to the Market Participant *mp* for the hour *h*.
DARROAWD $_{mp, h}$	MW	*Day-Ahead Responsive Reserve Only Award per Market Participant*—The Responsive Reserve (RRS) Only capacity quantity awarded in the DAM to the Market Participant *mp* for the hour *h*.
DANSOAWD $_{mp, h}$	MW	*Day-Ahead Non-Spin Only Award per Market Participant*— The Non-Spin Only capacity quantity awarded in the DAM to the Market Participant *mp* for the hour *h*.
DAECROAWD $_{mp, h}$	MW	*Day-Ahead ERCOT Contingency Reserve Service Only Award per Market Participant*— The ERCOT Contingency Reserve Service (ECRS) Only capacity quantity awarded in the DAM to the Market Participant *mp* for the hour *h*.

Variable	Unit	Definition
[NPRR917, NPRR1052, and NPRR1065: Insert the variables "USOGTOT $_{mp}$", "USOCLTOT $_{mp}$", " RTMGSOGZ $_{mp, p, i}$", "MEBSOGNET $_{mp, gsc}$" and "WSOL $_{mp, gsc, b}$" below upon system implementation of NPRR917:]		
USOGTOT $_{mp}$	MWh	*Uplift Real- Time Settlement Only Generator Site per Market Participant*—The monthly sum of Real-Time energy produced by SODGs, SOTGs, SODESSs, or SOTESSs represented by Market Participant *mp*, where the Market Participant is a QSE assigned to the registered Counter-Party.
USOCLTOT $_{mp}$	MWh	*Uplift Real-Time Settlement Only Charging Load per Market Participant*—The monthly sum of Real-Time charging Load that is WSL by Settlement Only Distribution Energy Storage Systems (SODESSs) and Settlement Only Transmission Energy Storage Systems (SOTESSs) represented by Market Participant *mp*, where the Market Participant is a QSE assigned to the registered Counter-Party.
RTMGSOGZ $_{mp, p, i}$	MWh	*Real-Time Metered Generation from Settlement Only Generators Zonal per QSE per Settlement Point*— The total Real-Time energy produced by Settlement Only Transmission Self-Generators (SOTSGs) for the Market Participant *mp* in Load Zone Settlement Point *p*, for the 15-minute Settlement Interval. MWh quantities for Energy Storage System (ESS), Settlement Only Distribution Generators (SODGs), and Settlement Only Transmission Generators (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 opted out of nodal pricing pursuant to Section 6.6.3.9, Real-Time Payment or Charge for Energy from a Settlement Only Distribution Generator (SODG), Settlement Only Transmission Generator (SOTG), SODESS, or SOTESS, will also be included in this value.
MEBSOGNET $_{q, gsc}$	MWh	*Net Metered energy at gsc for an SODG, SOTG, SODESS, or SOTESS Site* —The net sum for all Settlement Meters for SODG, SOTG, SODESS, or SOTESS site *gsc* represented by QSE *q* for the 15-minute Settlement Interval. A positive value indicates an injection of power to the ERCOT System.
WSOL $_{mp, gsc, b}$	MWh	*WSL for an SODESS or SOTESS Site* - The WSL as measured for an for SODESS or SOTESS site *gsc* at Electrical Bus *b*, represented by the Market Participant *mp,* represented as a negative value, for the 15-minute Settlement Interval.
cp	none	A registered Counter-Party.
mp	none	A Market Participant with MWh activity in the reference month that is a currently-registered QSE or CRR Account Holder or that voluntarily terminated its QSE or CRR Account Holder registration.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.
a	none	A CRR Auction.
p	none	A Settlement Point.
i	none	A 15-minute Settlement Interval.
h	none	The hour that includes the Settlement Interval i.

Variable	Unit	Definition
r	none	A Resource.

[NPRR917: Insert the variables "gsc" and "b" below upon system implementation:]

gsc	none	A generation site code.
b	none	An Electrical Bus.

(3) The uplifted short-paid amount will be allocated to the Market Participants (QSEs or CRR Account Holders) assigned to a registered Counter-Party based on the pro-rata share of MWhs that the QSE or CRR Account Holder contributed to its Counter-Party's maximum MWh activity ratio share.

(4) Any uplifted short-paid amount greater than $2,500,000 must be scheduled so that no amount greater than $2,500,000 is charged on each set of Default Uplift Invoices until ERCOT uplifts the total short-paid amount. ERCOT must issue Default Uplift Invoices at least 30 days apart from each other.

(5) ERCOT shall issue Default Uplift Invoices no earlier than 90 days following a short-pay of a Settlement Invoice on the date specified in the Settlement Calendar. The Invoice Recipient is responsible for accessing the Invoice on the MIS Certified Area once posted by ERCOT.

(6) Each Default Uplift Invoice must contain:

(a) The Invoice Recipient's name;

(b) The ERCOT identifier (Settlement identification number issued by ERCOT);

(c) Net Amount Due or Payable – the aggregate summary of all charges owed by a Default Uplift Invoice Recipient;

(d) Run Date – the date on which ERCOT created and published the Default Uplift Invoice;

(e) Invoice Reference Number – a unique number generated by the ERCOT applications for payment tracking purposes;

(f) Default Uplift Invoice Reference – an identification code used to reference the amount uplifted;

(g) Payment Date and Time – the date and time that Default Uplift Invoice amounts must be paid;

(h) Remittance Information Details – details including the account number, bank name, and electronic transfer instructions of the ERCOT account to which any amounts owed by the Invoice Recipient are to be paid or of the Invoice Recipient's account from which ERCOT may draw payments due; and

(i) Overdue Terms – the terms that would apply if the Market Participant makes a late payment.

(7) Each Invoice Recipient shall pay any net debit shown on the Default Uplift Invoice on the payment due date whether or not there is any Settlement and billing dispute regarding the amount of the debit.

10.1 Overview

(1) This Section specifies the responsibilities and requirements for meter data, certification of Metering Facilities, meter standards, approved meter types and the process for auditing, testing, and maintenance of Metering Facilities to be used in the ERCOT Region.

(2) Transmission Service Providers (TSPs) and Distribution Service Providers (DSPs) are the only Entities authorized to provide Settlement Meter data to ERCOT. ERCOT shall maintain a Meter Data Acquisition System (MDAS) to collect generation and consumption energy data for Settlement purposes under these Protocols. The MDAS must receive Customer Load meter data from TSPs and DSPs and must collect data from all ERCOT-Polled Settlement (EPS) Meters.

(3) All Service Delivery Points, excluding EPS, Settlement Only Distribution Generator (SODG), Settlement Only Distribution Energy Storage System (SODESS), or Non-Opt-In Entity (NOIE) metering points, that meet the requirements of P.U.C. SUBST. R. 25.311, Competitive Metering Services, are eligible for competitive meter ownership pursuant to such Public Utility Commission of Texas (PUCT) Substantive Rule. All competitively owned meters shall meet all the applicable metering requirements of these Protocols and the Retail Market Guide Section 10, Competitive Metering.

10.2.2 TSP and DSP Metered Entities

(1) Each Transmission Service Provider (TSP) and Distribution Service Provider (DSP) is responsible for supplying ERCOT with meter data associated with:

(a) All Loads using the ERCOT System;

(b) Any Settlement Only Distribution Generator (SODG); a DSP may make some or all such meters ERCOT-Polled Settlement (EPS) compliant and may request that ERCOT poll the meters. Notwithstanding the foregoing sentence, meter data is not required from:

(i) Generation owned by a Non-Opt-In Entity (NOIE) and used for the NOIE's self-use (not serving Customer Load);

(ii) Distributed Renewable Generation (DRG) with a design capacity less than 50 kW interconnected to a DSP where the owner chooses not to have the out-flow measured in accordance with P.U.C. SUBST. R. 25.213, Metering for Distributed Renewable Generation; and

(iii) Distributed Generation (DG) interconnected to a DSP behind a registered NOIE boundary metering point, not registered as a Generation Resource and with an installed capacity below the DG registration threshold, as determined in Section 16.5, Registration of a Resource Entity, and posted on the ERCOT website.

(c) NOIE or External Load Serving Entity (ELSE) points of delivery where metering points are radial Loads and are uni-directionally metered and NOIE points of delivery that have bi-directional flows that are solely the result of generation interconnected to a Transmission and/or Distribution Service Provider (TDSP) owned Distribution System behind a NOIE point of delivery metering point. A TSP or DSP has the option of making some or all such meters EPS compliant and to request that ERCOT poll the meters; and

(d) Generation participating in a current Emergency Response Service (ERS) Contract Period, where such generation only exports energy to the ERCOT System during an ERS deployment or ERS test.

(2) Each TSP and DSP is responsible for the following:

(a) Compliance with the procedures and standards in this Section, the Settlement Metering Operating Guide (SMOG) and the Operating Guides;

(b) Installation, control, and maintenance of the Settlement Metering Facilities, as more fully described in this Section and the SMOG, which includes meters, recorders, instrument transformers, wiring, and miscellaneous equipment required to measure electrical energy;

(c) Costs incurred in the installation and maintenance of these Metering Facilities and communications except for incremental costs incurred for functions not required for the Settlement of the Load or Generation Resource, Settlement Only Generator (SOG), or Load Resource. These incremental costs shall be borne by the Entities requesting the service pursuant to the TSP or DSP tariffs; and

(d) Installation, maintenance, data collection, and related communications, telemetry for the Metering Facilities, and related services necessary to meet the mandatory Interval Data Recorder (IDR) requirements detailed in this Section, Section 18, Load Profiling, and the SMOG.

10.2.3 ERCOT-Polled Settlement Meters

(1) ERCOT shall poll Metering Facilities that meet any one of the following criteria:

(a) Generation connected directly to the ERCOT Transmission Grid, unless the generation is participating in a current ERS Contract Period and the generation only exports energy to the ERCOT Transmission Grid during equipment testing, an ERS deployment, or an ERS test;

(b) Auxiliary meters used for generation netting by ERCOT;

(c) Generation delivering 10 MW or more to the ERCOT System, unless the generation is participating in a current ERS Contract Period and the generation only exports energy to the ERCOT System during equipment testing, an ERS deployment, or an ERS test;

(d) Generation participating in any Ancillary Service market;

(e) NOIE points connected bi-directionally to the ERCOT System, unless the bi-directional energy flows are the sole result of generation interconnected to a TDSP owned Distribution System behind a NOIE point of delivery metering point;

(f) Direct Current Ties (DC Ties);

(g) Metering required to determine the WSL or Non-WSL Settlement Only Charging Load associated to a SODESS or SOTESS;

(h) Metering required to determine WSL associated with an Energy Storage Resource (ESR); and

(i) Metering required to determine the Non-WSL ESR Charging Load.

(2) Additionally, ERCOT shall poll any SODG or NOIE metering point at the request of such Entity, provided the Metering Facility meets all requirements and approvals associated with EPS metering requirements of this Section and the SMOG. Load Resources of 10 MW or more on the ERCOT System, may, at their option have an EPS Meter.

10.2.3.1 Entity EPS Responsibilities

(1) The following defines the responsibilities of Entities regarding EPS metering:

(a) EPS Meters must be polled directly by ERCOT, which shall then convert the raw data to Settlement Quality Meter Data in accordance with this Section, Section 11, Data Acquisition and Aggregation, and the SMOG.

(b) A TSP or DSP shall have EPS Metering Facilities installed and maintained under the supervision of a TSP or DSP "EPS Meter Inspector," which is defined as an employee or agent of the TSP or DSP who has received EPS training from

ERCOT, and is described further herein. This requirement does not apply to Resource Entity-owned Metering Facilities used to measure, calculate, or telemeter ESR, SODESS, or SOTESS auxiliary Load pursuant to Section 10.2.4, Resource Entity Calculation and Telemetry of ESR Auxiliary Load Values.

(c) Each TSP and DSP shall install, control, and maintain the meters, recorders, instrument transformers, wiring, communications, and other miscellaneous equipment required to measure electrical energy, as described in this Section and SMOG, except for Resource Entity-owned equipment used to measure, calculate, or telemeter an auxiliary Load value for an ESR, SODESS, or SOTESS pursuant to Section 10.2.4.

(d) Each TSP and DSP shall install and maintain a Back-up Meter(s) at each EPS Meter location for Resources, auxiliary netting, and bi-directional meter points. A "Back-up Meter" is defined as a redundant revenue quality EPS Meter connected at the same metering point as the primary EPS Meter and meeting the requirements defined in the SMOG.

(e) Costs incurred in the installation and maintenance of EPS metered Facilities and communications will be the responsibility of the TSP or DSP except for incremental costs incurred for functions not required for the energy settlement as required by these Protocols. These incremental costs shall be borne by the Entities requesting the service, as per the TSP's or DSP's tariffs.

(f) Specific operating practices for EPS Metering Facilities are included in the SMOG.

10.2.4 Resource Entity Calculation and Telemetry of ESR, SODESS, or SOTESS Auxiliary Load Values

(1) When the Resource Entity certifies, the interconnecting TDSP confirms by approving the metering design, and, based on the information provided by the TDSP as part of the EPS Design Proposal, ERCOT agrees that metering of an ESR's WSL separate from the ESR's, SODESS's, or SOTESS's auxiliary Load is not feasible based on the ESR's, SODESS's, or SOTESS's physical design, the Resource Entity for that ESR, SODESS, or SOTESS shall be permitted to calculate the auxiliary Load using measurements from its own internal sensors and telemeter a Real-Time aggregated value for that Load to the TDSP's EPS Meter. The Resource Entity may telemeter a zero Load value only when the ESR, SODESS, or SOTESS is discharging more than the calculated auxiliary Load. The methodology by which the auxiliary Load is calculated is subject to ERCOT approval.

(2) An officer of the Resource Entity shall annually attest to the methodology and validity of the auxiliary Load calculation, as further described in the SMOG. The Resource Entity shall include with its annual attestation the findings of an independent audit performed by a registered Texas Professional Engineer confirming the auxiliary Load calculation does not understate the Load value. The audit shall be based on laboratory testing that reflects the anticipated field conditions of the same model of sensor as that used by the Resource

Entity or validation using measurements by other devices over the past year, as further described in the SMOG. The audit shall evaluate the impact of any degradation in accuracy of the sensors over time.

(3) If the Resource Entity is unable to provide the attestation and audit findings meeting the requirements of paragraph (2) above, it shall either reconfigure the Resource Entity's site and resubmit its meter design within 30 days to allow for separately metering the WSL or forfeit WSL treatment.

(4) ERCOT may conduct an audit of the Resource Entity's processes, equipment, and calculation of the auxiliary Load.

(5) The TSP or DSP shall assign all costs required for separately metering the auxiliary Load for WSL treatment to the EPS Meter to the Resource Entity.

10.2.4.1 Responsibilities for Resource Entity Calculation and Telemetry of ESR, SODESS, or SOTESS Auxiliary Load Values

(1) For each site at which a Resource Entity telemeters its auxiliary Load value, as permitted by Section 10.2.4, Resource Entity Calculation and Telemetry of ESR Auxiliary Load Values:

(a) The Resource Entity shall:

(i) Provide supporting information on the equipment, configuration, drawings and processes used to calculate the telemetry signal, including supporting information on the calculation of the telemetry signal for inclusion in the EPS Design Proposal.

(ii) Provide documentation of the auxiliary Load calculation methodology as defined in this Section and the SMOG.

(iii) Install, control, and maintain the sensors, instrumentation, wiring, communications, and other equipment required to calculate and provide the telemetry signal.

(iv) Provide and update contact information for a person designated for communication regarding the auxiliary Load supporting information and data.

(v) Act in accordance with any TDSP requirements concerning EPS Meters and Metering Facilities in the Protocols and SMOG that pertain to the following issues:

(A) Calculation of Load values and data estimation issues;

(B) The provision of notice to ERCOT regarding any outage or any other issue affecting the accuracy of the Load calculation or the availability of the telemetry of the Load value; and

(C) The implementation of any proposed change to the calculation or equipment, as documented in the EPS Design Proposal; and

(vi) Provide any information requested by ERCOT or the TDSP with respect to the measurement, calculation, and/or telemetry of the auxiliary Load value.

(b) The interconnecting TDSP shall:

(i) Use an EPS Meter to calculate 15 minute energy values from the Resource Real-Time telemetry signal for the auxiliary Load and store the data in the EPS Meter for retrieval by the ERCOT Meter Data Acquisition System (MDAS); and

(ii) Include an auxiliary Load metering point on the EPS Design Proposal that represents the calculation of the telemetry signal.

(c) ERCOT shall:

(i) Review the Resource-provided data on the calculation of the telemetry signal submitted as part of the EPS Design Proposal to ensure compliance with defined rules in this Section and the SMOG; and

(ii) Request assistance and information from the Resource-designated contact for items related to the telemetry.

10.3.2.3 Generation Netting for ERCOT-Polled Settlement Meters

(1) Generation Resources and netted Loads, including construction and maintenance Load that is netted with existing generation auxiliaries, must be metered at their POIs to the ERCOT Transmission Grid. Interval Data Recorders (IDRs) must be used to determine generator output or Load usage. In the intervals where the generation output exceeds the Load, the net must be settled as generation. In the intervals where the Load exceeds the generation output, the net must be settled as Load, and carry any applicable Load shared charges and credits.

[NPRR917: Replace paragraph (1) above with the following upon system implementation:]

(1) Generation Resources or Settlement Only Generators (SOGs) and netted Loads, including construction and maintenance Load that is netted with existing generation auxiliaries, must be metered at their POIs to the ERCOT Transmission Grid or Service Delivery Point. Interval Data Recorders (IDRs) must be used to determine net generator output or Load usage. In the intervals where the generation output exceeds the Load, the net must be

settled as generation. In the intervals where the Load exceeds the generation output, the net must be settled as Load and carry any applicable Load shared charges and credits.

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

(a) Single POI or Service Delivery Point with delivered and received metering data channels;

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

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

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

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

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

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

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

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

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

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

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

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

[NPRR945: Insert paragraph (7) below upon system implementation:]

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

10.9.1 ERCOT-Polled Settlement Meters

(1) The TSP or DSP for ERCOT-Polled Settlement (EPS) Meters shall ensure that the EPS Metering Facilities comply with this Section and the Settlement Metering Operating Guide (SMOG). This requirement does not apply to Resource Entity-owned Metering

Facilities used to measure, calculate, or telemeter Energy Storage Resource (ESR), SODESS, or SOTESS auxiliary Load pursuant to Section 10.2.4, Resource Entity Calculation and Telemetry of ESR Auxiliary Load Values.

(2) IDRs used for settlement of EPS Metering Facilities shall:

(a) Capture energy consumption and/or production in increments consistent with ERCOT defined Settlement Interval;

(b) Be able to capture energy in increments of five minutes (excluding memory allocation) for new and replacement IDRs used for settlement;

(c) Provide interval data for daily polling on a schedule that supports ERCOT's requirements (typically a daily cycle);

(d) Be capable of having data retrieved via telemetry by Meter Data Acquisition System (MDAS);

(e) Have battery or other energy-storage back-up to maintain time during power outages;

(f) Have remote time synchronization capability compatible with the MDAS;

(g) Maintain meter clocks on a time reference standard that enables ERCOT MDAS to maintain the IDR data on Central Prevailing Time (CPT). The meter clock shall be synchronized to within +/- 1% of the Settlement Interval when compared with the National Institute of Standards and Technology (NIST) Atomic Clock. ERCOT shall perform the time synchronization for meters at the time of the interrogation if the meter is outside tolerance; and,

(h) Divide each hour into Settlement Intervals ending as follows:

XX:15:00
XX:30:00
XX:45:00
XX:00:00

11.1.6 ERCOT Polled Settlement Meter Netting

(1) As allowed by Section 10, Metering, of these Protocols, ERCOT will perform the approved netting schemes, which sum the meters at a given Generation Resource site.

[NPRR1002: Replace paragraph (1) above with the following upon system implementation:]

(1) As allowed by Section 10, Metering, of these Protocols, ERCOT will perform the approved netting schemes, which sum the meters at a given Generation Resource, or Energy Storage Resource (ESR) site.

(2) Both Load consumption and Generation Resource production meters will be combined together to obtain a total amount of Load or Resource.

[NPRR1002: Replace paragraph (2) above with the following upon system implementation:]

(2) Both Load consumption and generation production meters will be combined together to obtain a total amount of Load or generation.

(3) For a Generation Resource site with Wholesale Storage Load (WSL):

[NPRR1002: Replace paragraph (3) above with the following upon system implementation:]

(3) For an ESR site:

(a) WSL is measured by the corresponding EPS Meter, except that when a Resource Entity for an Energy Storage Resource (ESR) communicates its auxiliary Load value to the EPS Meter, WSL is calculated by subtracting the auxiliary Load from the total Load measured by the corresponding EPS meter. If the calculated auxiliary Load is greater than the total Load, WSL shall be zero.

(b) For WSL that is metered behind the POI metering point, the WSL will be added back into the POI metering point to determine the net flows for the POI metering point.

(c) For WSL that is separately metered at the POI, the WSL will not be included in the determination of whether the generation site is net generation or net Load for the purpose of Settlement.

(4) For an ESR that has separately metered its charging Load, but elects not to receive WSL treatment, the Non-WSL ESR Charging Load for the 15-minute interval shall be determined using the metered ESR charging Load.

(5) For an ESR that has not separately metered its charging Load, or has forfeited WSL treatment pursuant to paragraph (3) of Section 10.2.4, Resource Entity Calculation and Telemetry of ESR Auxiliary Load Values, the Non-WSL ESR Charging Load for the 15-minute interval shall be equal to the total metered ESR Load minus auxiliary Load, where auxiliary Load is calculated as the greater of the following:

(a) The lesser of the total metered ESR Load or X MWh, where X is calculated as 15% of the ESR's nameplate capacity multiplied by 0.25; or

(b) 15% of the total metered ESR Load for the 15-minute interval.

(6) For an SODESS or SOTESS that has been approved for WSL treatment and has a single POI or Service Delivery Point:

(a) For withdrawals from the ERCOT System consisting of only WSL or WSL in combination with auxiliary Load:

(i) WSL is measured by the corresponding EPS Meter, except when a Resource Entity communicates its auxiliary Load value to the EPS Meter, WSL is calculated by subtracting the auxiliary Load from the total Load measured by the corresponding EPS meter. If the calculated auxiliary Load is greater than the total Load, WSL shall be set to zero.

(ii) For measured or calculated WSL that is behind the POI or Service Delivery Point, the WSL will be added back into the POI or Service Delivery Point metering point to determine the net flows for the POI or Service Delivery Point metering point.

(b) For withdrawals from the ERCOT System that include Load other than WSL Load or auxiliary Load:

(i) The charging Load is measured by the corresponding EPS Meter, except that when the Resource Entity communicates its auxiliary Load value to the EPS Meter, the charging Load is calculated by subtracting the auxiliary Load from the total SODESS or SOTESS Load measured by the corresponding EPS meter. If the calculated auxiliary Load is greater than the total SODESS or SOTESS Load, the charging load shall be set to zero.

(ii) Where injections are exclusively the result of generation from an SODESS or SOTESS, the WSL quantity shall be determined through the use of a generation accumulator, which is calculated as the accumulated output measured at the POI or Service Delivery Point minus the accumulated charging Load receiving WSL treatment. The charging load that is less than or equal to the generation accumulator will be settled as WSL for each 15-minute interval.

(iii) Where injections are the result of a combination of SODESS or SOTESS and non-SODESS or non-SOTESS generation, the output channel of the EPS meter that measures charging Load is required to be used for Settlement. For these sites, the WSL quantity shall be determined through the use of a generation accumulator, which is calculated as the lesser of (i) the accumulated SODESS or SOTESS output or (ii) the accumulated output measured at the POI or Service Delivery Point minus the accumulated charging load receiving WSL treatment. The charging load that is less than or equal to the generation accumulator will be settled as WSL for each 15-minute interval.

(iv) For measured or calculated charging Load that is behind the POI or Service Delivery Point, the charging Load will be added back into the POI or Service Delivery Point metering point to determine the net flows for the POI or Service Delivery Point metering point.

(7) For an SODESS or SOTESS that either has not elected or has not been approved for WSL treatment and has a single POI or Service Delivery Point:

(a) For withdrawals from the ERCOT System consisting of only charging Load or charging Load in combination with auxiliary Load, the Non-WSL Settlement Only Charging Load for the 15-minute Settlement Interval shall be determined as follows:

(i) The metered charging Load that would otherwise be eligible for WSL; or

(ii) The total metered SODESS or SOTESS Load minus auxiliary Load, where auxiliary Load is calculated as the greater of the following:

(A) The lesser of the total metered Load or X MWh, where X is calculated as 15% of the nameplate capacity of the ESS multiplied by 0.25; or

(B) 15% of the total SODESS or SOTESS metered Load.

(b) For withdrawals from the ERCOT System that include Load other than Non-WSL Settlement Only Charging Load or auxiliary Load, the Non-WSL Settlement Only Charging Load for the 15-minute settlement interval shall be determined as follows:

(i) Where injections are exclusively the result of generation from an SODESS or SOTESS, the Non-WSL Settlement Only Charging Load quantity shall be determined through the use of a generation accumulator, which is calculated as the accumulated output measured at the POI or Service Delivery Point minus the metered or calculated charging load determined in option (A) or (B) below:

(A) Where the charging Load is separately metered, the accumulated metered charging Load that would otherwise be eligible for WSL; or

(B) Where the charging Load is not separately metered, the accumulated total metered SODESS or SOTESS Load minus auxiliary Load, where auxiliary Load is calculated as the greater of the following:

(1) The lesser of the total SODESS or SOTESS metered Load or X MWh, where X is calculated as 15% of the nameplate capacity of the SODESS or SOTESS multiplied by 0.25; or

(2) 15% of the total SODESS or SOTESS metered Load.

(ii) Where injections are the result of a combination of generation from SODESS or SOTESS and other generating facilities, the output channel of the EPS meter that measures charging Load is required to be used for Settlement. For these sites, the Non-WSL Settlement Only Charging Load quantity shall be determined through the use of a generation accumulator, which is calculated as the lesser of (a) the accumulated SODESS or SOTESS output or (b) the accumulated output measured at the POI or Service Delivery Point minus:

(A) Where the charging Load is separately metered, the accumulated metered charging Load that would otherwise be eligible for WSL; or

(B) Where the charging Load is not separately metered, the accumulated total metered SODESS or SOTESS Load minus auxiliary Load, where auxiliary Load is calculated as the greater of the following:

(1) The lesser of the total metered Load or X MWh, where X is calculated as 15% of the nameplate capacity of the SODESS or SOTESS multiplied by 0.25; or

(2) 15% of the total SODESS or SOTESS metered Load.

(iii) For each 15-minute interval, the metered or calculated charging load that is less than or equal to the generation accumulator will be settled as Non-WSL Settlement Only Charging Load.

16.5 Registration of a Resource Entity

(1) A Resource Entity owns or controls a Generation Resource, Settlement Only Generator (SOG), Settlement Only Energy Storage System (SOESS), or Load Resource connected to the ERCOT System. Each Resource Entity operating in the ERCOT Region must register with ERCOT. To become registered as a Resource Entity, an Entity must execute a Standard Form Market Participant Agreement (using the form in Section 22, Attachment A, Standard Form Market Participant Agreement), designate Resource Entity Authorized Representatives, contacts, and a User Security Administrator (USA) (per the Application for Registration as a Resource Entity), and demonstrate to ERCOT's reasonable satisfaction that it is capable of performing the functions of a Resource Entity under these Protocols. The Resource Entity shall provide Resource Registration data pursuant to Planning Guide Section 6.8.2, Resource Registration Process, for each Generation Resource, SOG, SOESS, or Load Resource through ERCOT registration, except for Distributed Generation (DG) with an installed capacity equal to or lower than the DG registration threshold that has chosen not to register with ERCOT. A Resource Entity may submit a proposal to register the aggregation of generators, with the exception

of Intermittent Renewable Resources (IRRs) pursuant to paragraph (12) of Section 3.10.7.2, Modeling of Resources and Transmission Loads, as an Aggregate Generation Resource (AGR) which ERCOT may grant at its sole discretion.

[NPRR1002 and NPRR1052: Replace applicable portions of paragraph (1) above with the following upon system implementation for NPRR1002; or upon system implementation of NPRR917 for NPRR1052:]

(1) A Resource Entity owns or controls a Generation Resource, Energy Storage Resource (ESR), Settlement Only Generator (SOG), Settlement Only Energy Storage System (SOESS), or Load Resource connected to the ERCOT System. Each Resource Entity operating in the ERCOT Region must register with ERCOT. To become registered as a Resource Entity, an Entity must execute a Standard Form Market Participant Agreement (using the form in Section 22, Attachment A, Standard Form Market Participant Agreement), designate Resource Entity Authorized Representatives, contacts, and a User Security Administrator (USA) (per the Application for Registration as a Resource Entity), and demonstrate to ERCOT's reasonable satisfaction that it is capable of performing the functions of a Resource Entity under these Protocols. The Resource Entity shall provide Resource Registration data pursuant to Planning Guide Section 6.8.2, Resource Registration Process, for each Resource, SOG, or SOESS through ERCOT registration, except for Distributed Generation (DG) with an installed capacity equal to or lower than the DG registration threshold that has chosen not to register with ERCOT. A Resource Entity may submit a proposal to register the aggregation of generators, with the exception of Intermittent Renewable Resources (IRRs) pursuant to paragraph (12) of Section 3.10.7.2, Modeling of Resources and Transmission Loads, as an Aggregate Generation Resource (AGR) which ERCOT may grant at its sole discretion. If a Resource Entity intends to register one or more Energy Storage Systems (ESSs) and one or more non-ESS generators as SOGs at the same site, the Resource Entity must provide an affidavit attesting to the amount of ESS and non-ESS capacity at the site as a condition for registration.

(2) Prior to commissioning, Resources Entities will regularly update the data necessary for modeling. These updates will reflect the best available information at the time submitted.

(3) Once ERCOT has received a new or amended Standard Generation Interconnection Agreement (SGIA) or a letter from a duly authorized official from the Municipally Owned Utility (MOU) or Electric Cooperative (EC) and has determined that the proposed Generation Resource, SOG, or SOESS meets the requirements of Planning Guide Section 6.9, Addition of Proposed Generation to the Planning Models, ERCOT shall review the description of the proposed Generation Resource, SOG, or SOESS in Exhibit "C" (or similar exhibit) to the SGIA and the data submitted pursuant to Planning Guide Section 6.8.2 to assess whether the Generation Resource, SOG, or SOESS, as proposed, would violate any operational standards established in the Protocols, Planning Guide, Nodal Operating Guides, and Other Binding Documents. ERCOT must provide its determination to the Transmission Service Provider (TSP) and the owner of the proposed Generation Resource, SOG, or SOESS within 90 days of the date the Generation

Resource, SOG, or SOESS meets the conditions for review. Notwithstanding the foregoing, this determination shall not preclude ERCOT from subsequently determining that the Generation Resource, SOG, or SOESS violates any operational standards established in the Protocols, Planning Guide, Nodal Operating Guides, and Other Binding Documents or from taking any appropriate action based on that determination.

[NPRR1002: Replace paragraph (3) above with the following upon system implementation:]

(3) Once ERCOT has received a new or amended Standard Generation Interconnection Agreement (SGIA) or a letter from a duly authorized official from the Municipally Owned Utility (MOU) or Electric Cooperative (EC) and has determined that the proposed Generation Resource, ESR, SOG, or SOESS meets the requirements of Planning Guide Section 6.9, Addition of Proposed Generation to the Planning Models, ERCOT shall review the description of the proposed Generation Resource, ESR, SOG, or SOESS in Exhibit "C" (or similar exhibit) to the SGIA and the data submitted pursuant to Planning Guide Section 6.8.2, to assess whether the Generation Resource, ESR, SOG, or SOESS, as proposed, would violate any operational standards established in the Protocols, Planning Guide, Nodal Operating Guides, and Other Binding Documents. ERCOT must provide its determination to the Transmission Service Provider (TSP) and the owner of the proposed Generation Resource, ESR, SOG, or SOESS within 90 days of the date the Generation Resource, ESR, SOG, or SOESS meets the conditions for review. Notwithstanding the foregoing, this determination shall not preclude ERCOT from subsequently determining that the Generation Resource, ESR, SOG, or SOESS violates any operational standards established in the Protocols, Planning Guide, Nodal Operating Guides, and Other Binding Documents or from taking any appropriate action based on that determination.

(4) An Interconnecting Entity (IE) shall not proceed to Initial Synchronization of a Generation Resource, Settlement Only Transmission Generator (SOTG), Settlement Only Transmission Self-Generator (SOTSG), or Settlement Only Transmission Energy Storage System (SOTESS) in the event of any of the following conditions:

(a) Pursuant to paragraph (3) above, ERCOT has reasonably determined that the Generation Resource, SOTG, SOTSG, or SOTESS may violate operational standards established in the Protocols, Planning Guide, Nodal Operating Guides, and Other Binding Documents, and the Resource Entity has not yet demonstrated to ERCOT's satisfaction that the Generation Resource, SOTG, SOTSG, or SOTESS can comply with these standards;

(b) The requirements of Planning Guide Section 5.9, Quarterly Stability Assessment, have not been completed for the Generation Resource, SOTG, SOTSG, or SOTESS; or

(c) Any required Subsynchronous Resonance (SSR) studies, SSR Mitigation Plan, SSR Protection, and SSR monitoring if required, have not been completed and approved by ERCOT.

[NPRR1002 and NPRR1016: Replace applicable portions of paragraph (4) above with the following upon system implementation:]

(4) An Interconnecting Entity (IE) shall not proceed to Initial Synchronization of a Generation Resource, ESR, Settlement Only Transmission Generator (SOTG),Settlement Only Transmission Self-Generator (SOTSG), or Settlement Only Transmission Energy Storage System (SOTESS) in the event of any of the following conditions:

(a) Pursuant to paragraph (3) above, ERCOT has reasonably determined that the Generation Resource, ESR, SOTG, SOTSG, or SOTESS may violate operational standards established in the Protocols, Planning Guide, Nodal Operating Guides, and Other Binding Documents, and the Resource Entity has not yet demonstrated to ERCOT's satisfaction that the Generation Resource, ESR, SOTG, SOTSG, or SOTESS can comply with these standards;

(b) The requirements of Planning Guide Section 5.9, Quarterly Stability Assessment, if applicable, have not been completed for the Generation Resource, ESR, SOTG, SOTSG, or SOTESS; or

(c) Any required Subsynchronous Resonance (SSR) studies, SSR Mitigation Plan, SSR Protection, and SSR monitoring if required, have not been completed and approved by ERCOT.

(5) DG with an installed capacity greater than one MW, the DG registration threshold, which exports energy into a Distribution System, must register with ERCOT.

(6) A Resource Entity representing an Energy Storage Resource (ESR) shall register the ESR as both a Generation Resource and a Controllable Load Resource.

[NPRR1002: Replace paragraph (6) above with the following upon system implementation:]

(6) A Resource Entity representing an ESR shall register the ESR as an ESR. ERCOT systems, including the Energy and Market Management System (EMMS) and Settlement system, shall continue to treat the ESR as both a Generation Resource and a Controllable Load Resource until such time as all ERCOT systems are capable of treating an ESR as a single Resource.

16.5.1.2 Waiver for Federal Hydroelectric Facilities

(1) ERCOT may grant a waiver to any federally owned hydroelectric Generation Resource, SOG, SOESS, or Load Resource within the ERCOT System from fulfilling the requirements in Section 16.5, Registration of a Resource Entity, as they pertain to the submission of a Resource Entity application and the execution of a Standard Form Market Participant Agreement (Section 22, Attachment A, Standard Form Market Participant Agreement). ERCOT may grant such waiver after the federally owned hydroelectric Resource Entity provides ERCOT with the following:

(a) All information necessary to meet the Resource Entity registration requirements as provided in this Section;

(b) The designation of a QSE for each Generation Resource, SOG, SOESS, or Load Resource that it owns or controls; and

(c) Assignment of each Generation Resource's, SOG's, SOESS's, or Load Resource's Electric Service Identifier (ESI ID) to a Load Serving Entity (LSE) serving any Load or net Load, if the Generation Resource, SOG, SOESS, or Load Resource is net metered and will be connected to the ERCOT System. Such Load, if retail Load, is subject to all applicable rules and procedures, including rules concerning disconnection and Provider of Last Resort (POLR) service, applicable to other retail points of delivery.

16.11.4.3.2 Real-Time Liability Estimate

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

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

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

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

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

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

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

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

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

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

(f) Section 6.6.3.9, Real-Time Payment or Charge for Energy from a Settlement Only Distribution Generator (SODG), Settlement Only Transmission Generator (SOTG), Settlement Only Distribution Energy Storage System (SODESS), or Settlement Only Transmission Energy Storage System (SOTESS), using the Real-Time telemetry, if provided, of net generation as the outflow estimate and the Real-Time Price for each SODG, SOTG, SODESS, or SOTESS site;

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

[NPRR1013: Insert items (g)-(k) below upon system implementation of the Real-Time Co-Optimization (RTC) project and renumber accordingly:]

(g) Section 6.7.5.1, Regulation Up Payments and Charges;

(h) Section 6.7.5.2, Regulation Down Payments and Charges;

(i) Section 6.7.5.3, Responsive Reserve Payments and Charges;

(j) Section 6.7.5.4, Non-Spinning Reserve Payments and Charges; and

(k) Section 6.7.5.5, ERCOT Contingency Reserve Service Payments and Charges.

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

Section 22

Attachment L: Declaration of Private Use Network Net Generation Capacity Availability

TBD

Declaration of Private Use Network Net Generation Capacity Availability

A Private Use Network is an electric network connected to the ERCOT Transmission Grid that contains load that is not directly metered by ERCOT (i.e., load that is typically netted with internal generation). A Resource Entity that represents a Generation Resource, a Settlement Only Generator (SOG), or a Settlement Only Energy Storage System (SOESS) in a Private Use Network shall use this form to provide ERCOT with information required by ERCOT Protocol Section 10.3.2.4, Reporting of Net Generation Capacity. This form must be submitted to ERCOT by February 1 of each year. ERCOT shall treat this information as Protected Information in accordance with paragraph (1)(x) of Section 1.3.1.1, Items Considered Protected Information.

Please fill out this form electronically, print and sign. The form can be sent to ERCOT via email to MPRegistration@ercot.com (.pdf), via facsimile to (512) 225-7079, or via mail to ERCOT, Attention: Market Participant Registration, 7620 Metro Center Drive, Austin, Texas 78744.

Date of Notice: ________________

Resource Entity: ______________________ DUNS Number: _________________

Facility Name: _________________

In the table below, enter the incremental forecasted changes in net generation capacity (in Megawatts) available to the ERCOT Transmission Grid for May 31 of the previous calendar year to May 31 of the current calendar year, and year-on-year changes as of May 31 for the next 10 subsequent years. The capacity forecasts should account for changes in both process loads and self-generation capability. Example: If the capacity change is -75 MW from May 31 of the previous calendar year to May 31 of the current year, enter -75 MW in line 1. If the capacity change is 100 MW from May 31 of the current calendar year to May 31 of the next calendar year, enter 100 MW in line 2. DO NOT enter cumulative annual changes. (For this example, do not enter 25 MW in line 2).

Line#	Annual Forecast Periods	Expected Change in Net Generation Capacity Available to the ERCOT Grid, MW
1	May 31 of previous calendar year to May 31 of current calendar year	
2	May 31 of current calendar year to May 31 of forecast year 1	
3	May 31 of forecast year 1 to May 31 of forecast year 2	
4	May 31 of forecast year 2 to May 31 of forecast year 3	
5	May 31 of forecast year 3 to May 31 of forecast year 4	
6	May 31 of forecast year 4 to May 31 of forecast year 5	
7	May 31 of forecast year 5 to May 31 of forecast year 6	
8	May 31 of forecast year 6 to May 31 of forecast year 7	
9	May 31 of forecast year 7 to May 31 of forecast year 8	
10	May 31 of forecast year 8 to May 31 of forecast year 9	
11	May 31 of forecast year 9 to May 31 of forecast year 10	

Describe any future load expansions, equipment shutdowns, or new self-generation associated with the capacity changes reported above.

By signing below, I certify that I am authorized to execute and submit this Notice on behalf of the above Resource Entity, and that the data and statements contained herein are true and correct to the best of my knowledge.

Signature of Authorized Signatory: ________________________________

Name: ________________________________

Title: ________________________________

Phone: ________________

Date: ________________

ERCOT Nodal Protocols

Section 23

Form I: Resource Entity Application for Registration

TBD

RESOURCE ENTITY
APPLICATION FOR REGISTRATION

This application is for approval as a Resource Entity by the Electric Reliability Council of Texas Inc. (ERCOT) in accordance with the ERCOT Protocols. Information may be inserted electronically to expand the reply spaces as necessary. The completed, executed application will be accepted by ERCOT via email to MPRegistration@ercot.com (.pdf version), via facsimile to (512) 225-7079, or via mail to Market Participant Registration, 7620 Metro Center Drive, Austin, Texas 78744. If you need assistance filling out this form, or if you have any questions, please call (512) 248-3900.

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

PART I – ENTITY INFORMATION

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

[1]Defined in Section 2.1, Definitions.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

8. Proposed commencement date for service: ______.

PART II – ADDITIONAL REQUIRED INFORMATION

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

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

3. Qualified Scheduling Entity (QSE) Acknowledgment. Provide all information requested in Attachment A and have the document executed by both parties. Resource Entities representing Generation Resources or Load Resources shall designate a QSE qualified to represent the Resources. Resource Entities with Settlement Only Generators (SOGs) or Settlement Only Energy Storage Systems (SOESSs) shall designate any qualified QSE.

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

PART III – SIGNATURE

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

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

Attachment A – QSE Acknowledgment

Acknowledgment by Designated QSE for Scheduling and Settlement Responsibilities with ERCOT

The Applicant below has named the QSE listed below as its designated QSE to represent the Applicant for scheduling and Settlement transactions with ERCOT.

The Applicant's designated QSE, listed below, hereby acknowledges that it does represent the Applicant and that it shall be responsible for the Applicant's scheduling and Settlement transactions with ERCOT pursuant to the ERCOT Protocols.

The requested effective date for such representation is: _____**

or

Establish partnership at the earliest possible date ☐

Acknowledgment by **QSE**:

Signature of Authorized Representative ("AR") for QSE:	
Printed Name of AR:	
Email Address of AR:	
Date:	
Name of Designated QSE:	
DUNS of Designated QSE:	

Acknowledgment by **Applicant**:

Signature of AR for MP:	
Printed Name of AR:	
Email Address of AR:	
Date:	
Name of MP:	
DUNS No. of MP:	

** *Actual effective date will depend on time needed to implement the relationship in ERCOT systems once ERCOT has received all necessary information (a minimum of three Business Days), and may be later than the requested effective date. ERCOT will notify the parties of the actual effective date.*

Revised ERCOT Impact Analysis Report

NPRR Number	**995**	**NPRR Title**	**RTF-6 Create Definition and Terms for Settlement Only Storage**
Impact Analysis Date	July 27, 2021		
Estimated Cost/Budgetary Impact	Between $800k and $1.2M Additional Cost to Implement in Passport: TBD		
Estimated Time Requirements	The timeline for implementing this Nodal Protocol Revision Request (NPRR) is dependent upon Public Utility Commission of Texas (PUCT) prioritization and approval. Please see the Project Priority List (PPL) for additional information. Estimated project duration: 20 to 30 months in current systems Passport Schedule Risk Assessment: Significant Risk to Passport Schedule		
ERCOT Staffing Impacts (across all areas)	Implementation Labor: 96% ERCOT; 4% Vendor Ongoing Requirements: No impacts to ERCOT staffing.		
ERCOT Computer System Impacts	The following ERCOT systems would be impacted: • Resource Integration 44% • Market Settlements (S&B) 38% • Market Management Systems (MMS) 9% • Data and Information Products (DAIP) 4% • Energy Management System (EMS) 2% • Network Model Management System (NMMS) 1% • CRM & Registration System (REG) 1% • Integration 1%		
ERCOT Business Function Impacts	No impacts to ERCOT business functions.		
Grid Operations & Practices Impacts	No impacts to ERCOT grid operations and practices.		

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

Comments
None.

Board Report

NPRR Number	1005	NPRR Title	Clarify Definition of Point of Interconnection (POI) and Add Definition Point of Interconnection Bus (POIB)
Date of Decision		August 10, 2021	
Action		Recommended Approval	
Timeline		Normal	
Proposed Effective Date		Upon system implementation	
Priority and Rank Assigned		Not Applicable	
Nodal Protocol Sections Requiring Revision		2.1, Definitions 2.2, Acronyms and Abbreviations 3.2.6.2.2, Total Capacity Estimate 3.10.3.1, Process for Managing Changes in Updated Network Operations Model for Resource Retirements or Point of Interconnection Changes 3.10.7.2, Modeling of Resources and Transmission Loads 3.10.7.3, Modeling of Private Use Networks 3.10.7.5.2, Continuous Telemetry of the Real-Time Measurements of Bus Load, Voltages, Tap Position, and Flows 3.15, Voltage Support 3.15.1, ERCOT Responsibilities Related to Voltage Support 3.15.2, DSP Responsibilities Related to Voltage Support 6.5.7.7, Voltage Support Service 10.3.2.3, Generation Netting for ERCOT-Polled Settlement Meters Section 23, Form K: Wide Area Network (WAN) Agreement	
Related Documents Requiring Revision/Related Revision Requests		Nodal Operating Guide Revision Request (NOGRR) 210, Related to NPRR1005, Clarify Definition of Point of Interconnection (POI) and Add Definition Point of Interconnection Bus (POIB) Resource Registration Glossary Revision Request (RRGRR) 025, Related to NPRR1005, Clarify Definition of Point of Interconnection (POI) and Add Definition Point of Interconnection Bus (POIB)	
Revision Description		This Nodal Protocol Revision Request (NPRR) proposes the following revisions: • Revises the definition of Point of Interconnection (POI) to refer to any physical location where a Generation Entity's Facilities connect to a Transmission Service Provider's (TSP's) Facilities, and removes references to Load interconnections, since the only relevant Load connection points are those	

	associated with the Generation Entity's generators, which are included in the term "Generation Entity's Facilities." • Introduces the term "Point of Interconnection Bus (POIB)" to refer to the Electrical Bus in the substation that is closest to the Generation Resource's POI, or any electrically equivalent Electrical Bus in that substation, for each TSP-owned substation to which the Generation Resource interconnects. • Changes POI to POIB throughout the Protocols in appropriate cases based on the above clarifications. • Removes the reference to POI in Section 2.1 in the definition of Aggregate Generation Resource because having a common Generator Step-Up (GSU) transformer would aggregate output before the POI, and the generators' separate outputs do not have separate POIs. • Clarifies Section 10.3.2.3 to specify that, at a given Generation Resource Facility, generation and associated Load must either be physically metered at each POI or Service Delivery Point, or loss-compensated to the applicable POI in accordance with Section 10.3.2.2, Loss Compensation of EPS Meter Data. • Unboxes NPRR917, Nodal Pricing for Settlement Only Distribution Generators (SODGs) and Settlement Only Transmission Generators (SOTGs), greyboxed language in Section 10.3.2.3, as there is no system implementation required for this language. Removes POI from Section 23, Form K because it is used there incorrectly.
Reason for Revision	[X] Addresses current operational issues. [ ] Meets Strategic goals (tied to the ERCOT Strategic Plan or directed by the ERCOT Board). [X] Market efficiencies or enhancements [ ] Administrative [ ] Regulatory requirements [ ] Other: (explain) *(please select all that apply)*
Business Case	The current definition of the term POI requires that a POI must be at a substation (at a specified voltage level) but also that this substation must be reflected in the Standard Generation Interconnection Agreement (SGIA). This is problematic not only because many

	Generation Resources that are either older or Non-Opt-In Entity (NOIE)-owned do not have an SGIA, but also because the SGIA in Section 1.14 defines the POI to be the point where ownership changes from the generator to the TSP, and in many cases, the POI designated in the SGIA is at some location other than the substation. In these cases, it is not clear what point should be considered the POI under the definition of that term. In many cases where the term POI is used in the Protocols, the meaning is material to the application of the provision. For example, in paragraph (1) of Section 10.3.2.2, POI must be understood to refer to the point of ownership change, and not necessarily the TSP's substation, because the provision applies only when "the EPS Meter is not located at the [POI]" and would therefore have no meaning if the POI was always understood to be at the substation where the EPS Meter is located. In other cases, such as with the Voltage Support Service (VSS) requirements in Section 3.15 and Section 6.5.7.7, POI must be understood to refer to a TSP-owned substation because the TSP metering equipment used to monitor voltage is always located at the substation, and not necessarily at the point of ownership change defined in the SGIA. Given these differing uses of the term POI, ERCOT has concluded that two terms are necessary—one to refer to the point of ownership change, consistent with the definition in the SGIA, and one to refer to the substation downstream of the point of ownership change, or more precisely, to one or more buses in that substation (given that electrical differences may exist at different buses in the same substation, and that, for all instances in the Protocols where POI should be understood to refer to the downstream substation, bus-level measurements appear to be appropriate). For the sake of consistency with the SGIA, ERCOT proposes to modify the existing term POI to conform with the SGIA's conception of the POI as the point of ownership change. At the same time, ERCOT proposes to remove the reference to the SGIA in that definition, since NOIE generators and certain older generators may not have an SGIA. For the purpose of existing POI references that may be reasonably understood to refer to some point in the TSP's substation downstream of that point of ownership change, ERCOT is proposing a new term POIB.
Credit Work Group Review	ERCOT Credit Staff and the Credit Work Group (Credit WG) have reviewed NPRR1005 and do not believe that it requires changes to credit monitoring activity or the calculation of liability.

Board Report

PRS Decision	On 6/11/20, PRS voted unanimously via roll call to table NPRR1005. All Market Segments participated in the vote. On 5/13/21, PRS voted unanimously via roll call to recommend approval of NPRR1005 as amended by the 4/7/21 Longhorn Power comments as revised by PRS. All Market Segments participated in the vote. On 6/10/21, PRS voted unanimously via roll call to endorse and forward to TAC the 5/13/21 PRS Report and Impact Analysis for NPRR1005. All Market Segments participated in the vote.
Summary of PRS Discussion	On 6/11/20, participants discussed further refinements to definitions, and requested additional time to review potential impacts of definition changes to pending interconnections. On 5/13/21, participants reviewed the 4/7/21 Longhorn Power comments and offered additional clarifying language. On 6/10/21, there was no discussion.
TAC Decision	On 6/23/21, TAC voted unanimously via roll call to recommend approval of NPRR1005 as recommended by PRS in the 6/10/21 PRS Report. All Market Segments participated in the vote.
Summary of TAC Discussion	On 6/23/21, there was no discussion.
ERCOT Opinion	ERCOT supports approval of NPRR1005.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NPRR1005 and believes the market impact for NPRR1005 provides one or more of the following benefits: transparency, efficiency, and/or reliability; and/or aligns with current market rules.
Board Decision	On 8/10/21, the ERCOT Board voted to recommend approval of NPRR1005 as recommended by TAC in the 6/23/21 TAC Report.

Sponsor	
Name	Donald Tucker and Jay Teixeira
E-mail Address	Donald.Tucker@ercot.com / Jay.Teixeira@ercot.com
Company	ERCOT

Board Report

Phone Number	512-248-3913 / 512-248-6582
Market Segment	Not Applicable

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

Comments Received	
Comment Author	**Comment Summary**
ERCOT 020421	Accommodated baseline Protocol language updates and provided additional clarification to paragraph (1) of Section 10.3.2.3
TIEC 031021	Added a new description of a standard transmission-level Private Use Network interconnection in paragraph (2) of Section 10.3.2.3
CenterPoint Energy 033021	Offered clarifications to the POIB definition
Longhorn Power 040721	Offered clarifications to the undefined term "common buswork" in paragraph (2)(b) of Section 10.3.2.3

Market Rules Notes

Please note the baseline Protocol language in the following sections has been updated to reflect the incorporation of the following NPRRs into the Protocols:

- NPRR945, Net Metering Requirements (incorporated 1/1/21)
  - Section 10.3.2.3
- NPRR973, Add Definitions for Generator Step-Up and Main Power Transformer (incorporated 9/1/20)
  - Section 3.10.7.2
- NPRR979, Incorporate State Estimator Standards and Telemetry Standards into Protocols (incorporated 7/1/21)
  - Section 3.10.7.5.2
- NPRR980, Accounting for NSO Forced Outages and GINR Inactive Projects in the Report on the Capacity, Demand and Reserves in the ERCOT Region (incorporated 3/1/20)
  - Section 3.2.6.2.2

- NPRR989, BESTF-1 Energy Storage Resource Technical Requirements (incorporated 7/1/20)
  - Section 3.15
  - Section 3.15.1
  - Section 6.5.7.7
- NPRR1003, Elimination of References to Resource Asset Registration Form (incorporated 9/1/20)
  - Section 3.2.6.2.2
- NPRR1016, Clarify Requirements for Distribution Generation Resources (DGRs) and Distribution Energy Storage Resources (DESRs) (incorporated 9/1/20)
  - Section 3.10.7.2
  - Section 3.15
  - Section 6.5.7.7
- NPRR1020, Allow Some Integrated Energy Storage Designs to Calculate Internal Loads (unboxed 3/15/21)
  - Section 10.3.2.3
- NPRR1026, BESTF-7 Self-Limiting Facilities (incorporated 1/1/21)
  - Section 3.15
- NPRR1038, BESTF-8 Limited Exemption from Reactive Power Requirements for Certain Energy Storage Resources (incorporated 11/1/20)
  - Section 3.15
- NPRR1042, Planned Capacity Adjustment in the Report on Capacity, Demand and Reserves in the ERCOT Region (incorporated 1/1/21)
  - Section 3.2.6.2.2
- NPRR1047, Consolidate Greybox re NPRR973 and NPRR1016 (incorporated 1/1/21)
  - Section 3.10.7.2
- NPRR1049, Management of DC Tie Load Zone Modifications (incorporated 3/1/21)
  - Section 3.10.3.1
- NPRR1050, 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 (incorporated 3/1/21)
  - Section 3.2.6.2.2

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

- NPRR995, RTF-6 Create Definition and Terms for Settlement Only Energy Storage
  - Section 3.10.7.2
  - Section 10.3.2.3

Proposed Protocol Language Revision

2.1 DEFINITIONS

Point of Interconnection (POI)

Any physical location where a Generation Entity's Facilities electrically connect to the Transmission Service Provider's (TSP's) Facilities.

Point of Interconnection Bus (POIB)

For a Generation Resource connecting to the ERCOT Transmission System through a Transmission Service Provider (TSP) substation, the Electrical Bus at that TSP substation that is electrically closest to the Generation Resource's Point of Interconnection (POI), or any electrically equivalent Electrical Bus in that substation.

For a Generation Resource connecting to the ERCOT Transmission System through a non-TSP substation, the Electrical Bus at that non-TSP substation that is electrically closest to the Generation Resource's POI, or any electrically equivalent Electrical Bus in that substation.

Resource Attribute

Specific qualities associated with various Resources (i.e., specific aspects of a Resource or the services the Resource is qualified to provide).

Aggregate Generation Resource (AGR)

A Generation Resource that is an aggregation of generators, with the exception of Intermittent Renewable Resources (IRRs) pursuant to paragraph (12) of Section 3.10.7.2, Modeling of Resources and Transmission Loads, each of which is less than 20 MW in output, which share identical operational characteristics and are located behind the same Generator Step-Up (GSU) transformer (with a high-side voltage greater than 60 kV).

[NPRR973: Replace the definition "Aggregate Generation Resource (AGR)" above with the following upon system implementation of PR106:]

Aggregate Generation Resource (AGR)

A Generation Resource that is an aggregation of generators, with the exception of Intermittent Renewable Resources (IRRs) pursuant to paragraph (12) of Section 3.10.7.2, Modeling of Resources and Transmission Loads, each of which is less than 20 MW in output, which share identical operational characteristics and are located behind the same Main Power Transformer (MPT).

Voltage Set Point

The voltage that a Generation Resource is required to maintain at its Point of Interconnection Bus (POIB) and that is initially communicated via the Voltage Profile but may be modified by a Real-Time instruction from ERCOT, the interconnecting Transmission Service Provider (TSP), or that TSP's agent.

[NPRR989: Replace the above definition "Voltage Set Point" with the following upon system implementation:]

Voltage Set Point

The voltage that a Generation Resource or Energy Storage Resource (ESR) is required to maintain at its Point of Interconnection Bus (POIB) and that is initially communicated via the Voltage Profile but may be modified by a Real-Time instruction from ERCOT, the interconnecting Transmission Service Provider (TSP), or that TSP's agent.

2.2 ACRONYMS AND ABBREVIATIONS

POIB **Point of Interconnection Bus**

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**
$\text{TOTCAP}_{s,i}$	MW	*Total Capacity*—Estimated total capacity available during the Peak Load Season *s* for the year *i*.
$\text{INSTCAP}_{s,i}$	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.

Variable	Unit	Definition
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.
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.

Variable	Unit	Definition
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.
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.

Variable	Unit	Definition
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.
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 Bus (POIB). 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.

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

(1) Following the permanent change in Point of Interconnection Bus (POIB) 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.

3.10.7.2 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, 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, 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, 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 behind the same main power transformer 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 POIB; 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.

3.10.7.3 Modeling of Private Use Networks

(1) ERCOT shall create and use network models describing Private Use Networks according to the following:

(a) A Generation Entity with a Resource located within a Private Use Network shall provide data to ERCOT, for use in the Network Operations Model, for each of its individual generating unit(s) located within the Private Use Network in accordance with Section 3.3.2.1, Information to Be Provided to ERCOT, if it meets any one of the following criteria:

(i) Contains a generator greater than ten MW and is registered with the PUCT according to P.U.C. SUBST. R. 25.109, Registration of Power Generation Companies and Self-Generators, as a power generation company; or

(ii) Is part of a Private Use Network which contains more than one connection to the ERCOT Transmission Grid; or

(iii) Contains generation registered to provide Ancillary Services.

(b) A Generation Entity with an SOTSG shall provide to ERCOT annually, or more often upon change, the following information for ERCOT's use in the Network Operations Model, for each of its individual generating unit(s) located within the Private Use Network:

(i) Equipment owner(s);

(ii) Equipment operator(s);

(iii) TSP substation name connecting the Private Use Network to the ERCOT System;

(iv) At the request of ERCOT, a description of Transmission Elements within the Private Use Network that may be connected through breakers or switches;

(v) Net energy delivery metering, as required by ERCOT, to and from the Private Use Network and the ERCOT System at the POIB;

(vi) For each individual generator located within the Private Use Network, the gross capacity in MW and its reactive capability curve;

(vii) Maximum and minimum reasonability limits of the Load located within the Private Use Network;

(viii) Outage schedule for each generation unit located within the Private Use Network, updated as changes occur from the annually submitted information; and

(ix) Other interconnection data as required by ERCOT.

(c) Energy delivered to ERCOT from an SOTSG shall be settled in accordance with Section 6.6.3.2, Real-Time Energy Imbalance Payment or Charge at a Load Zone.

(d) ERCOT shall ensure the Network Operations Model properly models the physical effect of the loss of generators and Transmission Elements on the ERCOT Transmission Grid equipment loading, voltage, and stability.

(e) ERCOT may require the owner or operator of a Private Use Network to provide information to ERCOT and the TSP on Transmission Facilities located within the Private Use Network for use in the Network Operations Model if the information is required to adequately model and determine the security of the ERCOT Transmission Grid, including data to perform loop flow analysis of Private Use Networks.

(f) ERCOT shall review submittals of modeling data from owners or operators of Private Use Networks assure that it will result in correct analysis of ERCOT Transmission Grid security.

3.10.7.5.2 Continuous Telemetry of the Real-Time Measurements of Bus Load, Voltages, Tap Position, and Flows

(1) Each TSP and QSE shall provide telemetry of voltages, flows, and Loads on any modeled Transmission Element it owns or its Resource Entity owns, respectively, to the extent such may be required to estimate all transmission Load withdrawals and generation injections to and from the ERCOT Transmission Grid using the State Estimator and as needed to meet the State Estimator requirements set forth in Section 3.10.9, State Estimator Requirements, with consideration given to the economic implications of inaccurate LMP results versus the cost to remedy.

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

(1) Each TSP, DCTO, and QSE shall provide telemetry of voltages, flows, and Loads on any modeled Transmission Element it owns or its Resource Entity owns, respectively, to the extent such may be required to estimate all transmission Load withdrawals and generation injections to and from the ERCOT Transmission Grid using the State Estimator and as needed to meet the State Estimator requirements set forth in Section 3.10.9, State Estimator Requirements, with consideration given to the economic implications of inaccurate LMP results versus the cost to remedy.

(2) Each QSE that represents a Split Generation Resource, with metering according to Section 3.8, Special Considerations for Split Generation Meters, Combined Cycle Generation Resources, Quick Start Generation Resources, Hydro Generation Resources, and Energy Storage Resources, shall provide ERCOT with telemetry of the actual equivalent generator injection of its Split Generation Resource and the Master QSE shall provide telemetry in accordance with Section 6.5.5.2, Operational Data Requirements, on a total Generation Resource basis. ERCOT shall calculate the sum of each QSE's telemetry on a Split Generation Resource and compare the sum to the telemetry for the total Generation Resource. ERCOT shall notify each QSE representing a Split Generation Resource of any errors in telemetry detected by the State Estimator.

(3) Each TSP and QSE shall provide telemetered measurements at a periodicity of ten seconds on modeled Transmission Elements it owns or its Resource Entity owns, respectively, to ensure State Estimator observability of any monitored voltage and power flow between their associated transmission breakers to the extent such can be shown to be needed to meet the State Estimator requirements set forth in Section 3.10.9. On monitored non-Load substations, ERCOT may request additional telemetry in accordance with Section 3.10.7.5.10, ERCOT Requests for Redundant Telemetry.

[NPRR857: Replace paragraph (3) above with the following upon system implementation:]

(3) Each TSP, DCTO, and QSE shall provide telemetered measurements at a periodicity of ten seconds on modeled Transmission Elements it owns or its Resource Entity owns, respectively, to ensure State Estimator observability of any monitored voltage and power flow between their associated transmission breakers to the extent such can be shown to be needed to meet the State Estimator requirements set forth in Section 3.10.9. On monitored non-Load substations, ERCOT may request additional telemetry in accordance with Section 3.10.7.5.10, ERCOT Requests for Redundant Telemetry.

(4) The accuracy of the State Estimator is critical to successful market operations. For this reason it is a critical objective for ERCOT to maintain reasonable and accurate results of the State Estimator. ERCOT shall use all reasonable efforts to achieve that objective, including the provision of legitimate constraints used in calculating LMPs.

(5) Each TSP, QSE and ERCOT shall develop a continuously operated program to maintain telemetry of all Transmission Element measurements to provide accurate State Estimator results as outlined in Section 3.10.9. For any location where there is a connection of multiple, measured, Transmission Elements, ERCOT shall have an automated process to detect and notify ERCOT System operators if the residual sum of all telemetered measurements is more than:

(a) 5% of the largest line Normal Rating at the State Estimator Bus; or

(b) Five MW, whichever is greater.

If a location chronically fails this test, ERCOT shall notify the applicable TSP or QSE and suggest actions that the TSP or QSE could take to correct the failure. Within 30 days, the TSP or QSE shall take the actions necessary to correct the failure or provide ERCOT with a detailed plan with a projected time frame to correct the failure. ERCOT shall post a notice on the MIS Secure Area of any State Estimator Buses not meeting the State Estimator requirements set forth in Section 3.10.9, including a list of all measurements and the residual errors on a monthly basis.

[NPRR857: Replace paragraph (5) above with the following upon system implementation:]

(5) Each TSP, DCTO, QSE, and ERCOT shall develop a continuously operated program to maintain telemetry of all Transmission Element measurements to provide accurate State Estimator results as outlined in Section 3.10.9. For any location where there is a connection of multiple, measured, Transmission Elements, ERCOT shall have an automated process to detect and notify ERCOT System operators if the residual sum of all telemetered measurements is more than:

(a) 5% of the largest line Normal Rating at the State Estimator Bus; or

(b) Five MW, whichever is greater.

If a location chronically fails this test, ERCOT shall notify the applicable TSP, DCTO, or QSE and suggest actions that the TSP, DCTO, or QSE could take to correct the failure. Within 30 days, the TSP, DCTO, or QSE shall take the actions necessary to correct the failure or provide ERCOT with a detailed plan with a projected time frame to correct the failure. ERCOT shall post a notice on the MIS Secure Area of any State Estimator Buses not meeting the State Estimator requirements set forth in Section 3.10.9, including a list of all measurements and the residual errors on a monthly basis.

(6) ERCOT shall implement a study mode version of the State Estimator with special tools designed for troubleshooting and tuning purposes that can be used independently of any other ERCOT process that is dependent on the Real-Time State Estimator. ERCOT shall implement a process to recognize inaccurate State Estimator results and shall create and implement alternative Real-Time LMP calculation processes for use when inaccurate results are detected. ERCOT must be guided in this by Section 3.10.9.

(7) ERCOT shall establish a system to provide overload and over/under limit alarming on all Transmission Elements monitored as constraints in the LMP models.

(8) Each TSP shall designate which telemetered measurement of the POIB voltage shall be utilized to determine compliance with Voltage Set Point instructions, and then update the designation as necessary in the Network Operations Model by submitting a NOMCR. Each TSP shall telemeter this POI kV bus measurement to ERCOT. If the TSP cannot provide a kV bus measurement at the POI, the TSP may propose an alternate location subject to ERCOT approval.

3.15 Voltage Support

(1) ERCOT, in coordination with the Transmission Service Providers (TSPs), shall establish and update, as necessary, the ERCOT System Voltage Profile and shall post it on the Market Information System (MIS) Secure Area. ERCOT, the interconnecting TSP, or that TSP's agent, may modify the Voltage Set Point described in the Voltage Profile based on current system conditions.

(2) All Generation Resources (including self-serve generating units) that have a gross generating unit rating greater than 20 MVA or those units connected at the same Point of Interconnection Bus (POIB) that have gross generating unit ratings aggregating to greater than 20 MVA, that supply power to the ERCOT Transmission Grid, shall provide Voltage Support Service (VSS).

[NPRR989 and NPRR1016: Replace applicable portions of paragraph (2) above with the following upon system implementation:]

(2) All Generation Resources (including self-serve generating units) and Energy Storage Resources (ESRs) that are connected to Transmission Facilities and that have a gross unit rating greater than 20 MVA or those units connected at the same Point of Interconnection Bus (POIB) that have gross unit ratings aggregating to greater than 20 MVA, that supply power to the ERCOT Transmission Grid, shall provide Voltage Support Service (VSS).

(3) Except as reasonably necessary to ensure reliability or operational efficiency, TSPs should utilize available static reactive devices prior to requesting a Voltage Set Point change from a Generation Resource.

[NPRR989: Replace paragraph (3) above with the following upon system implementation:]

(3) Except as reasonably necessary to ensure reliability or operational efficiency, TSPs should utilize available static reactive devices prior to requesting a Voltage Set Point change from a Generation Resource or ESR.

(4) Each Generation Resource required to provide VSS shall comply with the following Reactive Power requirements in Real-Time operations when issued a Voltage Set Point by a TSP or ERCOT:

(a) An over-excited (lagging or producing) power factor capability of 0.95 or less determined at the generating unit's maximum net power to be supplied to the ERCOT Transmission Grid and for any Voltage Set Point from 0.95 per unit to 1.04 per unit, as measured at the POIB;

(b) An under-excited (leading or absorbing) power factor capability of 0.95 or less, determined at the generating unit's maximum net power to be supplied to the ERCOT Transmission Grid and for any Voltage Set Point from 1.0 per unit to 1.05 per unit, as measured at the POIB;

(c) For any Voltage Set Point outside of the voltage ranges described in paragraphs (a) and (b) above, the Generation Resource shall supply or absorb the maximum amount of Reactive Power available within its inherent capability and the capability of any VAr-capable devices as necessary to achieve the Voltage Set Point;

(d) When a Generation Resource required to provide VSS is issued a new Voltage Set Point, that Generation Resource shall make adjustments in response to the new Voltage Set Point, regardless of whether the current voltage is within the tolerances identified in paragraph (4) of Nodal Operating Guide Section 2.7.3.5, Resource Entity Responsibilities and Generation Resource Requirements;

(e) Reactive Power capability shall be available at all MW output levels and may be met through a combination of the Generation Resource's Unit Reactive Limit (URL), which is the generating unit's dynamic leading and lagging operating capability, and/or dynamic VAr-capable devices. This Reactive Power profile is depicted graphically as a rectangle. For Intermittent Renewable Resources (IRRs), the Reactive Power requirements shall be available at all MW output levels at or above 10% of the IRR's nameplate capacity. When an IRR is operating below 10% of its nameplate capacity and is unable to support voltage at the POIB, ERCOT, the interconnecting TSP, or that TSP's agent may require an IRR to disconnect from the ERCOT System for purposes of maintaining reliability;

[NPRR989, NPRR1038, and NPRR1026: Replace applicable portions of paragraph (4) above with the following upon system implementation of NPRR989 for NPRR989 and NPRR1038; or upon system implementation for NPRR1026:]

(4) Each Generation Resource and ESR required to provide VSS shall comply with the following Reactive Power requirements in Real-Time operations when issued a Voltage Set Point by a TSP or ERCOT:

(a) An over-excited (lagging or producing) power factor capability of 0.95 or less determined at the unit's maximum net power to be supplied to the ERCOT Transmission Grid and for any Voltage Set Point from 0.95 per unit to 1.04 per unit, as measured at the POIB;

(b) An under-excited (leading or absorbing) power factor capability of 0.95 or less, determined at the unit's maximum net power to be supplied to the ERCOT Transmission Grid and for any Voltage Set Point from 1.0 per unit to 1.05 per unit, as measured at the POIB;

(c) For any Voltage Set Point outside of the voltage ranges described in paragraphs (a) and (b) above, the Generation Resource or ESR shall supply or absorb the maximum amount of Reactive Power available within its inherent capability and the capability of any VAr-capable devices as necessary to achieve the Voltage Set Point;

(d) When a Generation Resource or an ESR required to provide VSS is issued a new Voltage Set Point, that Generation Resource or ESR shall make adjustments in response to the new Voltage Set Point, regardless of whether the current voltage is within the tolerances identified in paragraph (4) of Nodal Operating Guide Section 2.7.3.5, Resource Entity Responsibilities and Generation Resource and Energy Storage Resource Requirements;

(e) For Generation Resources, the Reactive Power capability shall be available at all MW output levels and may be met through a combination of the Generation Resource's Corrected Unit Reactive Limit (CURL), which is the generating unit's dynamic leading and lagging operating capability, and/or dynamic VAr-capable devices. This Reactive Power profile is depicted graphically as a rectangle. For Intermittent Renewable Resources (IRRs), the Reactive Power requirements shall be available at all MW output levels at or above 10% of the IRR's nameplate capacity. When an IRR is operating below 10% of its nameplate capacity and is unable to support voltage at the POIB, ERCOT, the interconnecting TSP, or that TSP's agent may require an IRR to disconnect from the ERCOT System for purposes of maintaining reliability. For ESRs, the Reactive Power capability shall be available at all MW levels, when charging or discharging, and may be met through a combination of the ESR's CURL, and/or dynamic VAr-capable devices. For any ESR that achieved Initial Synchronization before December 16, 2019, the requirement to have Reactive Power capability when charging does not apply if the Resource Entity for the ESR has submitted a notarized attestation to ERCOT stating that, since the date of Initial Synchronization, the ESR has been unable to comply with this requirement without physical or software changes/modifications, and ERCOT has provided written confirmation of the exemption to the Resource Entity. The exemption shall apply only to the extent of the ESR's inability to comply with the requirement when the ESR is charging.

(f) For any Generation Resource or Energy Storage Resource (ESR) that is part of a Self-Limiting Facility, the capabilities described in paragraphs (a) and (b) above shall be determined based on the Self-Limiting Facility's established MW Injection limit and, if applicable, established MW Withdrawal limit.

(5) As part of the technical Resource testing requirements prior to the Resource Commissioning Date, all Generation Resources must conduct an engineering study, and demonstrate through performance testing, the ability to comply with the Reactive Power capability requirements in paragraph (4), (7), (8), or (9) of this Section, as applicable. Any study and testing results must be accepted by ERCOT prior to the Resource Commissioning Date.

[NPRR989: Replace paragraph (5) above with the following upon system implementation:]

(5) As part of the technical Resource testing requirements prior to the Resource Commissioning Date, all Generation Resources and ESRs must conduct an engineering study, and demonstrate through performance testing, the ability to comply with the Reactive Power capability requirements in paragraph (4), (7), (8), or (9) of this Section, as applicable. Any study and testing results must be accepted by ERCOT prior to the Resource Commissioning Date.

(6) Except for a Generation Resource subject to Planning Guide Section 5.1.1, Applicability, a Generation Resource that has already been commissioned is not required to submit a new reactive study or conduct commissioning-related reactive testing, as described in paragraph (5) above.

[NPRR989: Replace paragraph (6) above with the following upon system implementation:]

(6) Except for a Generation Resource or an ESR subject to Planning Guide Section 5.1.1, Applicability, a Generation Resource or an ESR that has already been commissioned is not required to submit a new reactive study or conduct commissioning-related reactive testing, as described in paragraph (5) above.

(7) Wind-powered Generation Resources (WGRs) that commenced operation on or after February 17, 2004, and have a signed Standard Generation Interconnection Agreement (SGIA) on or before December 1, 2009 ("Existing Non-Exempt WGRs"), must be capable of producing a defined quantity of Reactive Power to maintain a set point in the Voltage Profile established by ERCOT in accordance with the Reactive Power requirements established in paragraph (4) above, except in the circumstances described in paragraph (a) below.

(a) Existing Non-Exempt WGRs whose current design does not allow them to meet the Reactive Power requirements established in paragraph (4) above must conduct an engineering study using the Summer/Fall 2010 on-peak/off-peak Voltage Profiles, or conduct performance testing to determine their actual Reactive Power capability. Any study or testing results must be accepted by ERCOT. The Reactive Power requirements applicable to these Existing Non-Exempt WGRs will be the greater of: the leading and lagging Reactive Power capabilities established by the Existing Non-Exempt WGR's engineering study or testing results; or Reactive Power proportional to the real power output of the Existing Non-Exempt WGR (this Reactive Power profile is depicted graphically as a triangle) sufficient to provide an over-excited (lagging) power factor capability of 0.95 or less and an under-excited (leading) power factor capability of 0.95 or less, both determined at the WGR's set point in the Voltage Profile established by ERCOT, and both measured at the POIB.

(i) Existing Non-Exempt WGRs shall submit the engineering study results or testing results to ERCOT no later than five Business Days after its completion.

(ii) Existing Non-Exempt WGRs shall update any and all Resource Registration data regarding their Reactive Power capability documented by the engineering study results or testing results.

(iii) If the Existing Non-Exempt WGR's engineering study results or testing results indicate that the WGR is not able to provide Reactive Power capability that meets the triangle profile described in paragraph (a) above, then the Existing Non-Exempt WGR will take steps necessary to meet that Reactive Power requirement depicted graphically as a triangle by a date mutually agreed upon by the Existing Non-Exempt WGR and ERCOT. The Existing Non-Exempt WGR may meet the Reactive Power requirement through a combination of the WGR's URL and/or automatically switchable static VAr-capable devices and/or dynamic VAr-capable devices. No later than five Business Days after completion of the steps to meet that Reactive Power requirement, the Existing Non-Exempt WGR will update any and all Resource Registration data regarding its Reactive Power and provide written notice to ERCOT that it has completed the steps necessary to meet its Reactive Power requirement.

(iv) For purposes of measuring future compliance with Reactive Power requirements for Existing Non-Exempt WGRs, results from performance testing or the Summer/Fall 2010 on-peak/off-peak Voltage Profiles utilized in the Existing Non-Exempt WGR's engineering study shall be the basis for measuring compliance, even if the Voltage Profiles provided to the Existing Non-Exempt WGR are revised for other purposes.

(b) Existing Non-Exempt WGRs whose current design allows them to meet the Reactive Power requirements established in paragraph (4) above (depicted graphically as a rectangle) shall continue to comply with that requirement. ERCOT, with cause, may request that these Existing Non-Exempt WGRs provide further evidence, including an engineering study, or performance testing, to confirm accuracy of Resource Registration data supporting their Reactive Power capability.

(8) Qualified Renewable Generation Resources (as described in Section 14, State of Texas Renewable Energy Credit Trading Program) in operation before February 17, 2004, required to provide VSS and all other Generation Resources required to provide VSS that were in operation prior to September 1, 1999, whose current design does not allow them to meet the Reactive Power requirements established in paragraph (4) above, will be required to maintain a Reactive Power requirement as defined by the Generation Resource's URL that was submitted to ERCOT and established per the criteria in the ERCOT Operating Guides.

(9) New generating units connected before May 17, 2005, whose owners demonstrate to ERCOT's satisfaction that design and/or equipment procurement decisions were made prior to February 17, 2004, based upon previous standards, whose design does not allow them to meet the Reactive Power requirements established in paragraph (4) above, will be required to maintain a Reactive Power requirement as defined by the Generation Resource's URL that was submitted to ERCOT and established per the criteria in the Operating Guides.

(10) For purposes of meeting the Reactive Power requirements in paragraphs (4) through (9) above, multiple generation units including IRRs shall, at a Generation Entity's option, be treated as a single Generation Resource if the units are connected to the same transmission bus.

[NPRR989: Replace paragraph (10) above with the following upon system implementation:]

(10) For purposes of meeting the Reactive Power requirements in paragraphs (4) through (9) above, multiple units including IRRs shall, at a Resource Entity's option, be treated as a single Resource if the units are connected to the same transmission bus.

(11) Generation Entities may submit to ERCOT specific proposals to meet the Reactive Power requirements established in paragraph (4) above by employing a combination of the URL and added VAr capability, provided that the added VAr capability shall be automatically switchable static and/or dynamic VAr devices. A Generation Resource and TSP may enter into an agreement in which the proposed static VAr devices can be switchable using Supervisory Control and Data Acquisition (SCADA). ERCOT may, at its sole discretion, either approve or deny a specific proposal, provided that in either case, ERCOT shall provide the submitter an explanation of its decision.

[NPRR989: Replace paragraph (11) above with the following upon system implementation:]

(11) Resource Entities may submit to ERCOT specific proposals to meet the Reactive Power requirements established in paragraph (4) above by employing a combination of the CURL and added VAr capability, provided that the added VAr capability shall be automatically switchable static and/or dynamic VAr devices. A Resource Entity and TSP may enter into an agreement in which the proposed static VAr devices can be switchable using Supervisory Control and Data Acquisition (SCADA). ERCOT may, at

its sole discretion, either approve or deny a specific proposal, provided that in either case, ERCOT shall provide the submitter an explanation of its decision.

(12) A Generation Resource and TSP may enter into an agreement in which the Generation Resource compensates the TSP to provide VSS to meet the Reactive Power requirements of paragraph (4) above in part or in whole. The TSP shall certify to ERCOT that the agreement complies with the Reactive Power requirements of paragraph (4).

[NPRR989: Replace paragraph (12) above with the following upon system implementation:]

(12) A Resource Entity and TSP may enter into an agreement in which the Generation Resource or ESR compensates the TSP to provide VSS to meet the Reactive Power requirements of paragraph (4) above in part or in whole. The TSP shall certify to ERCOT that the agreement complies with the Reactive Power requirements of paragraph (4).

(13) Unless specifically approved by ERCOT, no unit equipment replacement or modification at a Generation Resource shall reduce the capability of the unit below the Reactive Power requirements that applied prior to the replacement or modification.

[NPRR989: Replace paragraph (13) above with the following upon system implementation:]

(13) Unless specifically approved by ERCOT, no unit equipment replacement or modification at a Generation Resource or ESR shall reduce the capability of the unit below the Reactive Power requirements that applied prior to the replacement or modification.

(14) Generation Resources shall not reduce high reactive loading on individual units during abnormal conditions without the consent of ERCOT unless equipment damage is imminent.

[NPRR989: Replace paragraph (14) above with the following upon system implementation:]

(14) Generation Resources or ESRs shall not reduce high reactive loading on individual units during abnormal conditions without the consent of ERCOT unless equipment damage is imminent.

(15) All WGRs must provide a Real-Time SCADA point that communicates to ERCOT the number of wind turbines that are available for real power and/or Reactive Power injection into the ERCOT Transmission Grid. WGRs must also provide two other Real-Time SCADA points that communicate to ERCOT the following:

[NPRR989: Replace paragraph (15) above with the following upon system implementation:]

(15) All WGRs must provide a Real-Time SCADA point that communicates to ERCOT the number of wind turbines that are available for real power and Reactive Power injection into the ERCOT Transmission Grid. WGRs must also provide two other Real-Time SCADA points that communicate to ERCOT the following:

(a) The number of wind turbines that are not able to communicate and whose status is unknown; and

(b) The number of wind turbines out of service and not available for operation.

(16) All PhotoVoltaic Generation Resources (PVGRs) must provide a Real-Time SCADA point that communicates to ERCOT the capacity of PhotoVoltaic (PV) equipment that is available for real power and/or Reactive Power injection into the ERCOT Transmission Grid. PVGRs must also provide two other Real-Time SCADA points that communicate to ERCOT the following:

[NPRR989: Replace paragraph (16) above with the following upon system implementation:]

(16) All PhotoVoltaic Generation Resources (PVGRs) must provide a Real-Time SCADA point that communicates to ERCOT the capacity of PhotoVoltaic (PV) equipment that is available for real power and Reactive Power injection into the ERCOT Transmission Grid. PVGRs must also provide two other Real-Time SCADA points that communicate to ERCOT the following:

(a) The capacity of PV equipment that is not able to communicate and whose status is unknown; and

(b) The capacity of PV equipment that is out of service and not available for operation.

[NPRR1029: Insert paragraph (17) below upon system implementation and renumber accordingly:]

(17) Each DC-Coupled Resource must provide a Real-Time SCADA point that communicates to ERCOT the capacity of the intermittent renewable generation component of the Resource that is available for real power and/or Reactive Power injection into the ERCOT System. Each DC-Coupled Resource must also provide Real-Time SCADA points that communicate to ERCOT the following:

(a) The capacity of any PV generation equipment that is not able to communicate and whose status is unknown;

(b) The capacity of any PV generation equipment that is out of service and not available for operation;

(c) The number of any wind turbines that are not able to communicate and whose status is unknown; and

(d) The number of any wind turbines out of service and not available for operation.

(17) For the purpose of complying with the Reactive Power requirements under this Section 3.15, Reactive Power losses that occur on privately-owned transmission lines behind the POIB may be compensated by automatically switchable static VAr-capable devices.

3.15.1 ERCOT Responsibilities Related to Voltage Support

(1) ERCOT, in coordination with the TSPs, shall establish, and update as necessary, a Voltage Profile at the POIB for each Generation Resource required to provide VSS to maintain system voltages within established limits.

[NPRR989: Replace paragraph (1) above with the following upon system implementation:]

(1) ERCOT, in coordination with the TSPs, shall establish, and update as necessary, a Voltage Profile at the POIB for each Generation Resource and ESRs required to provide VSS to maintain system voltages within established limits.

(2) ERCOT shall communicate to the Qualified Scheduling Entity (QSE) and TSPs the desired voltage at the POIB by providing Voltage Profiles.

[NPRR989: Replace paragraph (2) above with the following upon system implementation:]

(2) ERCOT shall communicate to the Qualified Scheduling Entity (QSE) and TSPs the desired voltage at the POIB by providing Voltage Profiles.

(3) ERCOT, in coordination with TSPs, shall deploy static Reactive Power Resources as required to continuously maintain dynamic reactive reserves from QSEs, both leading and lagging, adequate to meet ERCOT System requirements.

(4) For any Market Participant's failure to meet the Reactive Power voltage control requirements of these Protocols, ERCOT shall notify the Market Participant in writing of such failure and, upon a request from the Market Participant, explain whether and why the failure must be corrected.

(5) ERCOT shall notify all affected TSPs of any alternative requirements it approves.

(6) Annually, ERCOT shall review Distribution Service Provider (DSP) power factors using the actual summer Load and power factor information included in the annual Load data

request to assess whether DSPs comply with the requirements of this subsection. At times selected by ERCOT, ERCOT shall require manual power factor measurement at substations and points of interconnection for Load that do not have power factor metering. ERCOT shall try to provide DSPs sufficient notice to perform the manual measurements. ERCOT may not request more than four measurements per calendar year for each DSP substation or points of interconnection for Load where power factor measurements are not available.

(7) If actual conditions indicate probable non-compliance of TSPs and DSPs with the requirements to provide voltage support, ERCOT shall require power factor measurements at the time of its choice while providing sufficient notice to perform the measurements.

(8) ERCOT shall investigate claims of TSP and DSP alleged non-compliance with Voltage Support requirements. The ERCOT investigator shall advise ERCOT and TSP planning and operating staffs of the results of such investigations.

3.15.2 DSP Responsibilities Related to Voltage Support

(1) Each DSP and Resource Entity within a Private Use Network shall meet the requirements specified in this subsection, or at their option, may meet alternative requirements specifically approved by ERCOT. Such alternative requirements may include requirements for aggregated groups of Facilities.

(a) Sufficient static Reactive Power capability shall be installed by a DSP or a Resource Entity within a Private Use Network not subject to a DSP tariff in substations and on the distribution voltage system to maintain at least a 0.97 lagging power factor for the maximum net active power measured in aggregate on the distribution voltage system. In those cases where a Private Use Network's power factor is established and governed by a DSP tariff, a Resource Entity within a Private Use Network shall ensure that the Private Use Network meets the requirements as defined and measured in the applicable tariff.

(b) DSP substations whose annual peak Load has exceeded ten MW shall have and maintain Watt/VAr metering sufficient to monitor compliance; otherwise, DSPs are not required to install additional metering to determine compliance.

(c) All DSPs shall report any changes in their estimated net impact on ERCOT as part of the annual Load data assessment.

(d) As part of the annual Load data assessment, all Resource Entities owning Generation Resources shall provide an annual estimate of the highest potential affiliated MW and MVAr Load (including any Load netted with the generation output) and the highest potential MW and MVAr generation that could be experienced at the POIB, based on the current configuration (and the projected configuration if the configuration is going to change during the year) of the Generation Resource and any affiliated Loads.

6.5.7.7 Voltage Support Service

(1) ERCOT shall coordinate with TSPs the creation and maintenance of Voltage Profiles as described in Section 3.15, Voltage Support.

(2) ERCOT shall instruct the interconnecting TSP, or the TSP's agent, to make Voltage Set Point adjustments, as necessary, within the Generation Resource's Unit Reactive Limit (URL) provided to ERCOT. The interconnecting TSP, or the TSP's agent, shall instruct any QSE or Resource Entity representing a Generation Resource to make the Voltage Set Point adjustments instructed by ERCOT, or as the TSP determines to be necessary. If ERCOT determines that a Generation Resource should be instructed to provide additional MVAr beyond its URL or that a Generation Resource's real power output should be decreased to allow the Generation Resource to provide additional Reactive Power beyond the URL, ERCOT shall issue a Resource-specific Dispatch Instruction requiring any change in Reactive Power and/or real power output, except that ERCOT may not require a Generation Resource to exceed its excitation limits.

[NPRR989: Replace paragraph (2) above with the following upon system implementation:]

(2) ERCOT shall instruct the interconnecting TSP, or the TSP's agent, to make Voltage Set Point adjustments, as necessary, within the Generation Resource's or ESR's Corrected Unit Reactive Limit (CURL) provided to ERCOT. The interconnecting TSP, or the TSP's agent, shall instruct any QSE or Resource Entity representing a Generation Resource or ESR to make the Voltage Set Point adjustments instructed by ERCOT, or as the TSP determines to be necessary. If ERCOT determines that a Generation Resource or ESR should be instructed to provide additional MVAr beyond its URL or that a Generation Resource's or ESR's real power output should be decreased to allow the Generation Resource or ESR to provide additional Reactive Power beyond the URL, ERCOT shall issue a Resource-specific Dispatch Instruction requiring any change in Reactive Power and/or real power output, except that ERCOT may not require a Generation Resource or ESR to exceed its operational limits.

(3) ERCOT and TSPs shall develop procedures for the operation of transmission-controlled reactive Resources in order to minimize the dependence on generation-supplied reactive Resources. For Generation Resources required to provide Voltage Support Service (VSS), GSU transformer tap settings must be managed to maximize the use of the ERCOT System for all Market Participants while maintaining adequate reliability.

[NPRR989: Replace paragraph (3) above with the following upon system implementation:]

(3) ERCOT and TSPs shall develop procedures for the operation of transmission-controlled reactive equipment in order to minimize the dependence on Reactive Power supplied by Generation Resources and ESRs. For Generation Resources and ESRs required to provide Voltage Support Service (VSS), GSU transformer tap settings must

be managed to maximize the use of the ERCOT System for all Market Participants while maintaining adequate reliability.

(4) Each TSP, under ERCOT's direction, is responsible for monitoring and ensuring that all Generation Resources required to provide VSS have their dynamic reactive capability deployed in approximate proportion to their respective capability requirements.

[NPRR989: Replace paragraph (4) above with the following upon system implementation:]

(4) Each TSP, under ERCOT's direction, is responsible for monitoring and ensuring that all Generation Resources and ESRs required to provide VSS have their dynamic reactive capability deployed in approximate proportion to their respective capability requirements.

(5) Each Generation Resource required to provide VSS shall follow its Voltage Set Point as directed by ERCOT, the interconnecting TSP, or the TSP's agent, within the operating Reactive Power capability of the Generation Resource.

[NPRR989: Replace paragraph (5) above with the following upon system implementation:]

(5) Each Generation Resource and ESR required to provide VSS shall follow its Voltage Set Point as directed by ERCOT, the interconnecting TSP, or the TSP's agent, within the operating Reactive Power capability of the Generation Resource or ESR.

(6) Each interconnecting TSP, or the TSP's agent, shall telemeter via ICCP the Real-Time Voltage Set Point to ERCOT at the Point of Interconnection Bus (POIB) for each Generation Resource interconnected to the TSP's system. Each interconnecting TSP, or the TSP's agent shall modify the telemetered Voltage Set Point to match any verbal Voltage Set Point instructions as soon as practicable. ERCOT shall telemeter the Real-Time desired Voltage Set Point and the TSP-designated POIB kV measurement via ICCP to each QSE representing a Generation Resource. Each QSE representing a Generation Resource shall provide in Real-Time the desired Voltage Set Point and the associated POIB kV measurement provided by ERCOT to the Resource Entity for that Generation Resource.

[NPRR989 and NPRR1016: Replace applicable portions of paragraph (6) above with the following upon system implementation:]

(6) Each interconnecting TSP, or the TSP's agent, shall telemeter via ICCP the Real-Time Voltage Set Point to ERCOT at the Point of Interconnection Bus (POIB) for each Generation Resource and ESRs interconnected to the TSP's system required to provide

VSS. Each interconnecting TSP, or the TSP's agent shall modify the telemetered Voltage Set Point to match any verbal Voltage Set Point instructions as soon as practicable. ERCOT shall telemeter the Real-Time desired Voltage Set Point and the TSP-designated POIB kV measurement via ICCP to each QSE representing a Generation Resource or an ESR. Each QSE representing a Generation Resource or an ESR shall provide in Real-Time the desired Voltage Set Point and the associated POIB kV measurement provided by ERCOT to the Resource Entity for that Generation Resource or ESR.

10.3.2.3 Generation Netting for ERCOT-Polled Settlement Meters

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

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

(a) Single POI or Service Delivery Point ;

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

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

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

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

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

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

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

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

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

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

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

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

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

[NPRR945: Insert paragraph (7) below upon system implementation:]

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

ERCOT Nodal Protocols

Section 23

Form K: Wide Area Network (WAN) Agreement

TBD

ERCOT Private Wide Area Network (WAN) Agreement

This Private WAN Agreement ("Agreement") is made and entered into on this day of , ("Effective Date") by and between Electric Reliability Council of Texas, Inc. (ERCOT), a Texas non-profit corporation having an office at 7620 Metro Center Drive, Austin, Texas 78744-1654 and the undersigned entity ("Participant") (collectively, "the Parties"), having an office at the address listed below.

1. Scope

1.1 This Agreement sets forth the terms, conditions and prices under which ERCOT agrees to allow Participant to interconnect Participant's data transfer system with ERCOT's data network and facilities for the sole purpose of transferring data between ERCOT and Participant. This Agreement also sets forth the terms and conditions to maintain operational security of the ERCOT WAN for the secure transfer of data between ERCOT and Participant.

1.2 Participant represents and warrants that Participant is a Market Participant as defined by the ERCOT Protocols and has executed (or will timely execute prior to participation as a Market Participant) all agreements required of Participant by the ERCOT Protocols (Protocols Agreement(s)). This Agreement shall terminate immediately and automatically upon the termination of all Participant's Protocols Agreement(s). "ERCOT Protocols" shall mean the document adopted by ERCOT, including any attachments or exhibits referenced in that document, as amended from time to time that contains the scheduling, operating, planning, reliability, and settlement (including customer registration) policies, rules, guidelines, procedures, standards, and criteria of ERCOT.

1.3 Except to the extent provided otherwise in this Agreement, the terms and conditions of the Protocols Agreement(s) signed between Participant and ERCOT shall apply and be incorporated by reference into this Agreement. In the event of a conflict between this Agreement and the Protocols Agreement(s), this Agreement shall control with respect to the subject matter of this Agreement.

2. Term of Agreement

2.1 The initial term of this Agreement shall commence on the Effective Date and expire 12 months thereafter. The term of this Agreement shall automatically renew for a successive 12-month period on each anniversary date of the Effective Date, unless either party delivers to the other party written notice to terminate as provided herein.

2.2 If Participant wishes to terminate this Agreement, it shall notify ERCOT in writing of its desire to terminate. Termination shall be effective no sooner than 60 days following receipt of such written notice by ERCOT.

2.3 In addition to any other remedies ERCOT may have at law or in equity, ERCOT may terminate this Agreement for material breach in accordance with the default provisions set forth in the Protocols Agreement(s).

2.4 ERCOT may also terminate this Agreement upon 60 days' written notice to Participant if ERCOT amends the form of this standard form agreement. In such event, ERCOT shall provide Participant the opportunity to execute a new standard form agreement regarding the subject matter of this Agreement.

2.5 In the event of any termination of this Agreement, Participant shall reimburse ERCOT for ERCOT's expenses incurred hereunder prior to notice of termination. If this Agreement has been terminated except as proved under Section 2.4 above, ERCOT may remove from Participant's premises any equipment for which ERCOT has not received payment and Participant shall reimburse ERCOT for the cost of such removal.

3. Interconnection with and use of ERCOT WAN

3.1 Participant shall interconnect its facilities with ERCOT in a manner consistent with and defined by ERCOT. ERCOT shall define and demarcate the location of interconnection with the ERCOT WAN.

3.2 ERCOT shall provide, in accordance with its reasonable discretion and control, the design, engineering, procurement, and installation of the equipment and facilities necessary to interconnect Participant's Facilities to the ERCOT WAN. Participant shall reimburse ERCOT for ERCOT's expenses incurred in design, engineering, procurement, and installation of such equipment and facilities for each such new installation. The reimbursed costs for each new installation shall not exceed the fees designated in the ERCOT Fee Schedule. Only ERCOT-authorized personnel shall conduct network problem diagnosis and administrative functions, including, but not limited to, provisioning, monitoring, and auditing the ERCOT WAN. Participant will reimburse ERCOT's cost of performing or acquiring such services per month per installation during the initial term hereof and any subsequent renewal terms. The monthly cost per installation shall not exceed the fees designated in the ERCOT Fee Schedule. Participant will also reimburse ERCOT's cost of providing or acquiring data transport service to Participant, which cost will vary according to Participant's location.

3.3 With respect to access to the ERCOT WAN, Participant will comply with ERCOT's security and safety procedures and requirements, including, but not limited to, access restrictions, sign in, and identification requirements. Participant will also comply with all ERCOT policies and procedures regarding use of the ERCOT WAN (as such policies and procedures may be amended from time to time), including, but not limited to, the document entitled "Communicating with ERCOT," the document entitled "QSE Qualification Testing," the ERCOT Operating Guides and ERCOT Protocols.

3.4 Participant shall consistently maintain the security of its computer systems (including the interconnection with the ERCOT WAN, support equipment, systems, tools, and/or data required under this Agreement) in accordance with industry standards for computer system security.

3.5 Participant shall maintain operational security of the ERCOT WAN for the uninterrupted transfer of data between ERCOT and Participant. Participant agrees that the integrity of the data provided through the WAN is essential, and will take all steps and responsibility for ensuring the integrity of such data. Such steps shall include, at a minimum, ensuring the prevention of any remote electronic connections by unauthorized persons or organizations through Participant's network to the ERCOT WAN connection point. Particularly, Participant's systems must deny any connectivity with Participant's internet access point to unauthorized persons or organizations.

3.6 If ERCOT determines, within its reasonable discretion, that Participant is not in compliance with this Agreement or ERCOT's security procedures and requirements, ERCOT may prohibit Participant from transferring data using the WAN.

3.7 Where one Party's information resides on the other Party's computer system, the Party in control of the computer system shall take, or cause the custodian of the computer system to take commercially reasonable measures to prevent unauthorized access to such information by others who have access to that computer system. Each Party agrees that it, its employees, agents and representatives who have access to its computer systems at its facilities will not use the WAN and/or the interconnection with the ERCOT WAN to obtain or to attempt to obtain unauthorized access to information of the other Party or information of a third party that may reside on the other Party's computer system.

4. Network Maintenance and Management

4.1 As part of the WAN Application, Participant has provided ERCOT contact information for network maintenance and management. Participant may change such contact information by submitting a Notice of Change of Information (NCI) (Section 23, Form E) to ERCOT, and referring specifically to this Agreement.

4.2 Participant will not use any service provided under this Agreement in a manner that impairs the quality of service to other WAN users. Participant shall cooperate with ERCOT in the testing of interconnection to the WAN and in the prevention or correction of disruption or loss of service over the WAN.

4.3 ERCOT agrees to provide Participant reasonable written notice of changes in the information necessary for the transmission and routing of data using ERCOT's facilities or networks, as well as other changes that affect the interoperability of those respective facilities and networks.

4.4 Participant agrees to notify the ERCOT Help Desk immediately of any intrusion or virus event within its network or systems connected to the ERCOT WAN so that ERCOT can take steps to ensure the integrity of the rest of the WAN.

5. Compensation

5.1 Participant agrees to reimburse ERCOT for ERCOT's expenses incurred in the design, engineering, procurement, and installation of equipment and facilities hereunder. Participant further agrees to pay ERCOT for any additional services rendered by ERCOT under this Agreement; to the extent such expenses and chargers are assessed pursuant to Section 3.2 above.

5.2 ERCOT will remit a bill to Participant to reflect the charges required and permitted pursuant to Section 3.2 above under this Agreement, any applicable taxes, and other costs or charges that are the responsibility of Participant, but were incurred by ERCOT. Payment is due within 30 days of receipt of the bill.

5.3 Payments shall be made either through bank draft or wire transfer, as agreed upon by the parties. Interest shall accrue on any past due amount at the lesser of: (a) 18% per annum; or (b) the maximum rate permitted by applicable law. If Participant fails to make payment within 30 days of receipt of the bill, ERCOT may, at its option, terminate this Agreement.

6. Liability

6.1 EXCEPT TO THE EXTENT REQUIRED BY STATE OR FEDERAL LAW, ERCOT MAKES NO REPRESENTATIONS OR WARRANTIES, EXPRESS OR IMPLIED, INCLUDING BUT NOT LIMITED TO ANY WARRANTY AS TO MERCHANT ABILITY OR FITNESS FOR INTENDED OR PARTICULAR PURPOSE WITH RESPECT TO EQUIPMENT OR SERVICES PROVIDED HEREUNDER. ADDITIONALLY, ERCOT MAKES NO WARRANTIES, EXPRESS OR IMPLIED, CONCERNING PARTICIPANT'S (OR ANY THIRD PARTY'S) RIGHTS WITH RESPECT TO INTELLECTUAL PROPERTY OR THIRD PARTY CONTRACT RIGHTS, INCLUDING WHETHER SUCH RIGHTS WILL BE VIOLATED BY PARTICIPANT'S INTERCONNECTION WITH ERCOT'S WAN OR PARTICIPANT'S USE OF THE OTHER EQUIPMENT OR FACILITIES FURNISHED UNDER THIS AGREEMENT.

6.2 Each Party understands and acknowledges that third parties might obtain unauthorized remote access to the other Party's computer systems, and further, that there exists the possibility that such third parties may attempt unauthorized access to the computer systems or information thereon, that computer viruses may be transmitted, and that damage might result to a Party's computer systems or data thereon, or that the confidentiality of a Party's information may thereby be breached. ACCORDINGLY, EACH PARTY SHALL BE SOLELY AND EXCLUSIVELY RESPONSIBLE FOR SAFEGUARDING ITS OWN COMPUTER SYSTEMS AND INFORMATION THEREON FROM SUCH UNAUTHORIZED ACCESS OR DAMAGE OCCURRING THROUGH THE INTERCONNECTION WITH ERCOT UNDER THIS AGREEMENT AND FOR THE ACTIONS OF ITS EMPLOYEES, AGENTS, AND REPRESENTATIVES WHO USE ITS COMPUTER SYSTEMS.

7. Notices

Except as provided herein for operational communications, all notices required to be given under this Agreement shall be in writing, and shall be deemed delivered three days after being deposited in the U.S. mail, first class postage prepaid, registered (or certified) mail, return receipt requested, addressed to the other Party at the address specified in this Agreement or shall be deemed delivered on the day of receipt if sent in another manner requiring a signed receipt, such as courier delivery or Federal Express delivery. ERCOT may change its address for such notices by delivering to Participant a written notice referring specifically to this Agreement. Participant may change its address for such notices by submitting an NCI (Section 23, Form E) to ERCOT and referring specifically to this Agreement.

8. Entire Agreement and Amendments

8.1 This Agreement constitutes the entire agreement between the Parties concerning the subject matter hereof and supersedes any prior agreements, representations, statements, negotiations, understandings, proposals or undertakings, oral or written, with respect to the subject matter expressly set forth herein.

8.2 Neither Party will be bound by an amendment, modification or additional term unless it is reduced to writing and signed by an authorized representative of the Party sought to be bound.

Each person whose signature appears below represents and warrants that he or she has authority to bind the Party on whose behalf he or she has executed this Agreement.

Executed and Agreed:

Electric Reliability Council of Texas, Inc.: Signature: ______________________________ Date: ______________________________ Printed Name: ________________________ Title: ______________________________ 7620 Metro Center Drive Austin, Texas 78744-1654	Participant: Signature: ______________________________ Date: Printed Name: Title: Address: City, State, Zip: Type of Organization: Organized Under the Laws of:

(512) 225-7000	

ERCOT Impact Analysis Report

NPRR Number	**1005**	**NPRR Title**	**Clarify Definition of Point of Interconnection (POI) and Add Definition Point of Interconnection Bus (POIB)**
Impact Analysis Date	February 26, 2020		
Estimated Cost/Budgetary Impact	Less than $5k, which will be absorbed by the Operations & Maintenance (O&M) budgets of affected department.		
Estimated Time Requirements	No project required; however, ERCOT plans to combine required changes with other projects for increased efficiency. Estimated duration: 1-2 months		
ERCOT Staffing Impacts (across all areas)	Implementation Labor: 100% ERCOT; 0% Vendor Ongoing Requirements: No impacts to ERCOT staffing.		
ERCOT Computer System Impacts	The following ERCOT systems would be impacted: • Resource Integration 100%		
ERCOT Business Function Impacts	No impacts to ERCOT business functions.		
Grid Operations & Practices Impacts	No impacts to ERCOT grid operations and practices.		

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

Comments
None.

Board Report

NPRR Number	1063	NPRR Title	Dynamic Rating Transparency
Date of Decision		August 10, 2021	
Action		Recommended Approval	
Timeline		Normal	
Proposed Effective Date		Upon system implementation	
Priority and Rank Assigned		Priority – 2021; Rank – 3330	
Nodal Protocol Sections Requiring Revision		3.10.8.4, ERCOT Responsibilities Related to Dynamic Ratings	
Related Documents Requiring Revision/Related Revision Requests		None	
Revision Description		This Nodal Protocol Revision Request (NPRR) requires ERCOT to post information related to Dynamic Rating approvals to the Market Information System (MIS) Secure Area.	
Reason for Revision		☐ Addresses current operational issues. ☐ Meets Strategic goals (tied to the ERCOT Strategic Plan or directed by the ERCOT Board). ☒ Market efficiencies or enhancements ☐ Administrative ☐ Regulatory requirements ☐ Other: (explain) *(please select all that apply)*	
Business Case		Dynamic Rating changes can have a significant impact on congestion costs. Posting the proposed information will increase transparency of these changes and thereby improve Market Participants' ability to assess and hedge risk.	
Credit Work Group		ERCOT Credit Staff and the Credit Work Group (Credit WG) have	

Review	reviewed NPRR1063 and do not believe that it requires changes to credit monitoring activity or the calculation of liability.
PRS Decision	On 2/11/21, PRS voted via roll call to table NPRR1063 and refer the issue to ROS and WMS. There were two abstentions from the Independent Generator (Luminant, Calpine) Market Segment. All Market Segments participated in the vote. On 5/13/21, PRS voted unanimously via roll call to recommend approval of NPRR1063 as amended by the 4/21/21 DC Energy comments. All Market Segments participated in the vote. On 6/10/21, PRS voted unanimously via roll call to endorse and forward to TAC the 5/13/21 PRS Report and Impact Analysis for NPRR1063 with a recommended priority of 2021 and rank of 3330. All Market Segments participated in the vote.
Summary of PRS Discussion	On 2/11/21, participants requested additional time to examine more cost effective methods of delivering dynamic rating transparency. On 5/13/21, participants referenced the 5/4/21 ROS comments and 5/7/21 WMS comments. On 6/10/21, participants reviewed the Impact Analysis and the priority and rank for NPRR1063. It was noted that the information in NPRR1063 qualifies as ERCOT Critical Energy Infrastructure Information (ECEII) as stated in the 6/8/21 ERCOT comments.
TAC Decision	On 6/23/21, TAC voted unanimously via roll call to recommend approval of NPRR1063 as recommended by PRS in the 6/10/21 PRS Report. All Market Segments participated in the vote.
Summary of TAC Discussion	On 6/23/21, there was no discussion.
ERCOT Opinion	ERCOT supports approval of NPRR1063.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NPRR1063 and believes the market impact for NPRR1063 provides one or more of the following benefits: transparency, efficiency, and/or reliability; and/or aligns with current market rules.
Board Decision	On 8/10/21, the ERCOT Board voted to recommend approval of NPRR1063 as recommended by TAC in the 6/23/21 TAC Report.

Sponsor

Board Report

Name	Seth Cochran
E-mail Address	cochran@dc-energy.com
Company	DC Energy Texas
Phone Number	512-971-8767
Cell Number	
Market Segment	Independent Power Marketer (IPM)

Market Rules Staff Contact	
Name	Jordan Troublefield
E-Mail Address	Jordan.Troublefield@ercot.com
Phone Number	512-248-6521

Comments Received	
Comment Author	**Comment Summary**
ROS 030521	Requested PRS continue to table NPRR1063
WMS 030921	Requested PRS continue to table NPRR1063 for further review by the Congestion Management Working Group (CMWG)
DC Energy Texas 042121	Aligned NPRR1063 language in support of ERCOT's Dynamic Ratings sample report as provided at the April 1, 2021 ROS meeting
ROS 050421	Endorsed NPRR1063 as amended by the 4/21/21 DC Energy Texas comments
WMS 050721	Endorsed NPRR1063 as amended by the 4/21/21 DC Energy Texas comments
ERCOT 060821	Provided notice that NPRR1063 contains ECEII that would only be available on the MIS Secure Area to users with ECEII-eligible Digital Certificates

Market Rules Notes

None

Proposed Protocol Language Revision

3.10.8.4 ERCOT Responsibilities Related to Dynamic Ratings

(1) ERCOT shall provide a system to accept and implement Dynamic Ratings or temperatures to be applied to rating tables for each hour in the Day-Ahead and in the Operating Hour. ERCOT shall also:

(a) Provide software and processes that allow secure access for TSPs and Market Participants and that maintains a log of data provided and the actions of the TSP and ERCOT, to implement the Dynamic Ratings as described above;

(b) Use Dynamic Ratings for alarming, compliance with ERCOT and NERC requirements, and SCED purposes in both Real-Time operations and operational planning;

(c) Approve or reject the new Dynamic Rating request within 24 hours of receipt;

(d) Post Dynamic Ratings approved by ERCOT for each planned production load of the Network Operations Model on the MIS Secure Area. The posting will include the Transmission Element name, approved thermal rating limits, and the planned effective date; and

(e) Implement the approved Dynamic Rating automatically within 24 hours of approval.

(2) ERCOT shall provide a system to implement Dynamic Ratings and to obtain monthly expected ambient air temperatures to be applied to rating tables for the CRR Network Models. Temperatures applied to the rating tables shall be determined using the same method as described in item (3)(f) of Section 7.5.5.4, Simultaneous Feasibility Test. Transmission Elements that have Dynamic Ratings implemented in the Network Operations Model must have Dynamic Ratings in the CRR Network Models.

(3) ERCOT shall identify additional Transmission Elements that have a high probability of providing significant added economic efficiency to the ERCOT market through Dynamic Rating and request such Dynamic Ratings from the associated TSP. ERCOT shall post annually the list of the Transmission Elements and identify if the TSP has agreed to provide the rating on the MIS Secure Area.

Revised ERCOT Impact Analysis Report

NPRR Number	1063	NPRR Title	Dynamic Rating Transparency
Impact Analysis Date	July 28, 2021		
Estimated Cost/Budgetary Impact	Between \$15k and \$25k Additional Cost to Implement in Passport: N/A		
Estimated Time Requirements	The timeline for implementing this Nodal Protocol Revision Request (NPRR) is dependent upon Public Utility Commission of Texas (PUCT) prioritization and approval. Please see the Project Priority List (PPL) for additional information. Estimated project duration: 3 to 4 months in current systems Passport Schedule Risk Assessment: No Risk to Schedule		
ERCOT Staffing Impacts (across all areas)	Implementation Labor: 100% ERCOT; 0% Vendor Ongoing Requirements: No impacts to ERCOT staffing.		
ERCOT Computer System Impacts	The following ERCOT systems would be impacted: • ERCOT Website and MIS Systems 100%		
ERCOT Business Function Impacts	ERCOT will update its business processes to implement this NPRR.		
Grid Operations & Practices Impacts	No impacts to ERCOT grid operations and practices.		

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

Comments
None.

Board Report

NPRR Number	<u>1073</u>	**NPRR Title**	**Market Entry/Participation by Principals of Counter-Parties with Financial Obligations**
Date of Decision	August 10, 2021		
Action	Recommended Approval		
Timeline	Urgent – Urgent status is necessary to put the language into effect as soon as possible after the default allocation related to Winter Storm Uri		
Proposed Effective Date	Upon staffing completion		
Priority and Rank Assigned	Not applicable		
Nodal Protocol Sections Requiring Revision	16.1.2, Principal of a Market Participant (new) 16.2.1, Criteria for Qualification as a Qualified Scheduling Entity 16.2.1.1, QSE Background Check Process (new) 16.2.1.1, Data Agent-Only Qualified Scheduling Entities 16.2.2, QSE Application Process 16.2.2.2, Incomplete Applications 16.2.2.3, ERCOT Approval or Rejection of Qualified Scheduling Entity Application 16.2.3.2, Maintaining and Updating QSE Information 16.8.1, Criteria for Qualification as a CRR Account Holder 16.8.1.1, CRR Account Holder Background Check Process (new) 16.8.2, CRR Account Holder Application Process 16.8.2.2, Incomplete Applications 16.8.2.3, ERCOT Approval or Rejection of CRR Account Holder Application 16.8.3.1, Maintaining and Updating CRR Account Holder Information Section 23 Form A: Congestion Revenue Right (CRR) Account Holder Application for Registration Section 23 Form G: QSE Application and Service for Registration Form ERCOT Fee Schedule		
Related Documents Requiring Revision/Related Revision Requests	None		
Revision Description	This Nodal Protocol Revision Request (NPRR) modifies ERCOT's market entry qualification and continued participation requirements for ERCOT Counter-Parties i.e., Qualified Scheduling Entities		

	(QSEs) and Congestion Revenue Right (CRR) Account Holders, and modifies application forms for QSEs and CRR Account Holders. This NPRR makes the following modifications to Section 16, Registration and Qualification of Market Participants: (1) Defines Principals of a Market Participant; and (2) Provides that a QSE/CRR Account Holder applicant or existing QSE/CRR Account Holder must be able to demonstrate to ERCOT's reasonable satisfaction that its Principals were/are not Principals of a terminated Market Participant with money remaining owed to ERCOT. This NPRR also modifies the QSE/CRR Account Holder applicant form to require disclosure of the Principals of the QSE/CRR Account Holder applicant.
Reason for Revision	[X] Addresses current operational issues. [ ] Meets Strategic goals (tied to the ERCOT Strategic Plan or directed by the ERCOT Board). [X] Market efficiencies or enhancements [ ] Administrative [ ] Regulatory requirements [ ] Other: (explain) *(please select all that apply)*
Business Case	Currently, ERCOT has limited authority to prevent a person that had decision-making authority over a terminated Market Participant with an unpaid financial obligation to ERCOT from re-entering the ERCOT market by forming a new Entity. A concern has been expressed that Market Participants who are responsible for a Default Uplift Ratio Share due to the impacts of Winter Storm Uri could attempt to avoid responsibility for that financial obligation by leaving the ERCOT market, only to have the persons with decision-making authority over such Market Participants later rejoin the ERCOT market as a new legal Entity. To address this concern, this NPRR strengthens ERCOT's market entry and continued participation requirements for ERCOT Counter-Parties by clarifying that the Principal(s) of ERCOT Counter-Parties will not be permitted to circumvent payment obligations to ERCOT, including any accrued obligations to pay Default Uplift Ratio Shares,

	by terminating an existing Market Participant with a payment obligation and then later joining the ERCOT market under a new legal Entity.
Credit Work Group Review	See 4/21/21 and 7/21/21 Credit WG comments
PRS Decision	On 4/15/21, PRS voted unanimously via roll call to grant NPRR1073 Urgent status; to recommend approval of NPRR1073 as amended by the 4/14/21 DC Energy comments; and to forward to TAC NPRR1073. All Market Segments participated in the vote.
Summary of PRS Discussion	On 4/15/21, the sponsor provided an overview of NPRR1073, the nature of the request for Urgent status, and reviewed recent comments. ERCOT Staff noted intent to submit additional comments to account for possible outcomes related to Market Participants with a terminated Standard Form Market Participant Agreement that are not currently contemplated in the NPRR.
TAC Decision	On 4/28/21, TAC voted unanimously via roll call to table NPRR1073. All Market Segments participated in the vote. On 5/26/21, TAC voted unanimously via roll call to table NPRR1073 until the July 28, 2021 TAC meeting, and to refer the issue to WMS. All Market Segments participated in the vote. On 7/28/21, TAC voted via roll call to recommend approval of NPRR1073 as recommended by PRS in the 4/15/21 PRS Report as amended by the 7/6/21 Luminant comments; and the Revised Impact Analysis. There was one abstention from the Independent Power Marketer (IPM) (Shell) Market Segment. All Market Segments participated in the vote.
Summary of TAC Discussion	On 4/28/21, participants reviewed the staffing impacts associated with NPRR1073, noted the potential for further refinement of language, and requested tabling of NPRR1073. On 5/26/21, participants reviewed recent comments to NPRR1073. ERCOT Staff provided additional details regarding the proposed implementation plan and addressed questions posed by Market Participants about how the provisions outlined would apply in various scenarios. Participants also discussed the 120-day "look-back" concept outlined in the 5/25/21 ERCOT comments in addition to the questions proposed by the 5/25/21 Shell comments, and considered potential implications if NPRR1073 were to remain tabled for additional discussion. On 7/28/21, participants reviewed the 7/6/21 Luminant comments, and discussed the budgetary impact associated with additional

	staffing. Participants noted the desire for further discussion of a specific appeals process for Entities deemed to be Principals; and that it be considered via a separate NPRR.
ERCOT Opinion	ERCOT supports approval of NPRR1073.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NPRR1073 and believes the market impact for NPRR1073 provides one or more of the following benefits: transparency, efficiency, and/or reliability; and/or aligns with current market rules.
Board Decision	On 8/10/21, the ERCOT Board recommended approval of NPRR1073 as recommended by TAC in the 7/28/21 TAC Report.

Sponsor	
Name	Clayton Greer
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Company	Morgan Stanley Capital Group, Inc.
Phone Number	512-497-2986
Cell Number	
Market Segment	IPM

Market Rules Staff Contact	
Name	Phillip Bracy
E-Mail Address	Phillip.Bracy@ercot.com
Phone Number	512-865-0064

Comments Received	
Comment Author	**Comment Summary**
DC Energy 041221	Expressed support for NPRR1073; and proposed giving ERCOT discretion to determine that an individual or Entity is a Principal, adding a minimum two Business Days to satisfy a determination of Unreasonable Credit Risk, and limiting default disclosure in the CRR Account Holder and QSE applications to only material, uncured financial defaults in ERCOT or other energy markets