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| NPRR Number | [1229](https://www.ercot.com/mktrules/issues/NPRR1229) | NPRR Title | Real-Time Constraint Management Plan Cost Recovery Payment |
| Date of Decision | July 31, 2025 |
| Action | Approved |
| Timeline  | Normal |
| Estimated Impacts | Cost/Budgetary: Between $100K and $200KProject Duration: 8 to 10 months |
| Effective Date | Upon system implementation for Section 9.5.3; August 1, 2025 for the remaining sections |
| Priority and Rank Assigned | Priority – 2028; Rank – 5100 |
| Nodal Protocol Sections Requiring Revision  | 4.4.9.3.3, Energy Offer Curve Cost Caps6.6.3.9, Real-Time Constraint Management Plan Cost Recovery Payment (new)6.6.3.10, Real-Time Constraint Management Plan Cost Recovery Charge (new)6.6.3.11, Miscellaneous Invoice for Cost Recovery Payments and Charges for a Real-Time Constraint Management Plan (new)9.5.3, Real-Time Market Settlement Charge Types |
| Related Documents Requiring Revision/Related Revision Requests | None |
| Revision Description | This Nodal Protocol Revision Request (NPRR) creates a process that compensates a Qualified Scheduling Entity (QSE) when a Constraint Management Plan (CMP) or ERCOT-directed switching instruction implemented by ERCOT causes the trip of a Generation Resource when it would not have occurred absent those conditions. |
| Reason for Revision |  [Strategic Plan](https://www.ercot.com/files/docs/2023/08/25/ERCOT-Strategic-Plan-2024-2028.pdf) Objective 1 – Be an industry leader for grid reliability and resilience [Strategic Plan](https://www.ercot.com/files/docs/2023/08/25/ERCOT-Strategic-Plan-2024-2028.pdf) Objective 2 - Enhance the ERCOT region’s economic competitiveness with respect to trends in wholesale power rates and retail electricity prices to consumers [Strategic Plan](https://www.ercot.com/files/docs/2023/08/25/ERCOT-Strategic-Plan-2024-2028.pdf) Objective 3 - Advance ERCOT, Inc. as an independent leading industry expert and an employer of choice by fostering innovation, investing in our people, and emphasizing the importance of our mission General system and/or process improvement(s) Regulatory requirements ERCOT Board/PUCT Directive*(please select ONLY ONE – if more than one apply, please select the ONE that is most relevant)* |
| Justification of Reason for Revision and Market Impacts | The changing Resource mix coupled with the dynamic of substantially increased load growth has put more strain on the ERCOT grid and the management of power flows. This is evidenced by a proliferation of Generic Transmission Constraints (GTCs) and CMPs, and the occasional use of ERCOT-directed switching instructions. Last summer, to support matching the available supply to demand, ERCOT implemented atypical transmission procedures or configurations to improve energy transfers across the system. Because of the enormous power transfer from south Texas to central and north Texas, ERCOT had to redispatch a vast number of Resources with very low Shift Factors and directed the switching of transmission equipment in an atypical configuration that placed a thermal Resource closer to risk of tripping to manage a post-contingency overload. A Resource should be compensated if the Resource is ultimately tripped Off-Line due to ERCOT actions taken in an effort to support reliability. A Resource that experiences a Forced Outage due to actions taken by ERCOT to benefit the remaining ERCOT System should be allowed to recover certain costs associated with that Forced Outage. The language and concepts added by this NPRR are borrowed from a similar mechanism with make-whole provisions (High Dispatch Limit (HDL) override payments, Outage Schedule Adjustment (OSA) make-whole payments, Reliability Unit Commitment (RUC) make-whole payments). In addition, there is consideration for Outage costs due to a Forced Outage resulting from an enacted CMP. The Settlement would be handled as a Settlement dispute initiated by the QSE. |
| PRS Decision | On 6/13/24, PRS voted unanimously to table NPRR1229 and refer the issue to ROS and WMS. All Market Segments participated in the vote.On 3/12/25, PRS voted to recommend approval of NPRR1229 as amended by the 3/6/25 WMS comments as revised by PRS. There were three opposing votes from the Consumer (Residential Consumer, City of Eastland, Occidental) Market Segment and one abstention from the Independent Power Marketer (IPM) (Tenaska) Market Segment. All Market Segments participated in the vote.On 4/9/25, PRS voted to endorse and forward to TAC the 3/12/25 PRS Report as amended by the 3/20/25 ERCOT comments and the 4/8/25 Impact Analysis for NPRR1229 with a recommended effective date of upon system implementation for Section 9.5.3 with a recommended priority of 2028 and rank of 5100 and the first of the month following Public Utility Commission of Texas (PUCT) approval for the remaining sections. There were two opposing votes from the Consumer (Residential Consumer, Occidental) Market Segment and one abstention from the Independent Generator (EDF Renewables) Market Segment. All Market Segments participated in the vote. |
| Summary of PRS Discussion | On 6/13/24, the sponsor provided an overview of NPRR1229, the 5/8/24 STEC comments, and the 6/12/24 STEC comments. Participants requested additional review of operational and Settlement components of NPRR1229 at ROS and WMS.On 3/12/25, participants reviewed the 3/6/25 WMS comments and proposed a desktop edit to correct a renumbered paragraph reference. Opponents in the Consumer Market Segment expressed concerns that NPRR1229, like NPRR1190, High Dispatch Limit Override Provision for Increased Load Serving Entity Costs, are inconsistent with the market design and create improper incentives.On 4/9/25, participants reviewed the 3/20/25 ERCOT comments. ERCOT Staff provided an overview of the near-term manual and longer-term automated implementation of NPRR1229. Participants requested the project work to automate NPRR1229 be prioritized far enough in the future to allow for a review of the size and frequency of any manual charges/payments made under NPRR1229 by stakeholders to determine if the automation is justified. |
| TAC Decision | On 4/23/25, TAC voted to recommend approval of NPRR1229 as recommended by PRS in the 4/9/25 PRS Report. There were eight opposing votes from the Consumer (6) (Residential Consumer, OPUC, Lyondell Chemical, CMC Steel, City of Eastland, City of Dallas) and Independent Retail Electric Provider (IREP) (2) (Rhythm Ops, Demand Control 2) Market Segments and one abstention from the IREP (APG&E) Market Segment. All Market Segments participated in the vote. |
| Summary of TAC Discussion | On 4/23/25, TAC reviewed the items below. Opponents reiterated concerns that NPRR1229 shifts and socializes costs to the entire market when the charges should be borne by the individual generators. Supporters noted the infrequency of the covered events existing requirements for reviewing Settlement disputes, and highlighted the assigned priority/rank will delay any associated project spending from NPRR1229 for several years. |
| Explanation of Opposing TAC Votes | **Consumer/Lyondell Chemical** – Lyondell Chemical opposed NPRR1229 for the same reasons it opposed NPRR1190, High Dispatch Limit Override Provision for Increased Load Serving Entity Costs. The explicit reasons for Lyondell Chemical's opposition are stated below, as adapted from Joint Consumer Comments Opposing NPRR1190, dated October 2, 2024, to which Lyondell Chemical was a party. A major reason the ERCOT market adopted nodal dispatch and pricing in PUCT Substantive Rule 25.501, "Wholesale Market Design for the Electric Reliability Council of Texas" was to avoid paying generation owners for power that was scheduled but not deliverable. Prior to the implementation of the rule, the ERCOT zonal market design operated under an approach that “all schedules must flow” and that Market Participants could be compensated with “OOME Down” payments for any portion of the scheduled power that was not deliverable. Ultimately, the PUCT deemed the OOME payment approach untenable in the long run and ordered ERCOT to institute nodal pricing instead, putting the risk of power delivery on Market Participants. This is known as the direct assignment of congestion costs, which is reflected in the Real-Time nodal pricing at a particular generator node or set of nodes. Through this rule, the PUCT instituted a policy that no Market Participant has an absolute right to flow power across the grid under all circumstances.The payments proposed under NPRR1229 will force consumers to subsidize Market Participants when grid conditions require curtailment. Over the past two decades, Market Participants have had ready access to alternative sources of power through purchases in the liquid commercial bilateral power market and have the capability to make arrangements in advance to handle a wide range of contingencies that might hinder the delivery of power from an owned or contracted Resource. These alternative arrangements assist both Resource adequacy in the long run and reliability in Real-Time. Just as other consumers would not pay for a generator if Security-Constrained Economic Dispatch (SCED) did not deploy a Resource at its full output, other power consumers should not have to subsidize Resources that are dispatched down by ERCOT by other means than SCED to maintain grid reliability. **Consumer/Residential Consumer** – Residential Consumer agrees with the comments of Lyondell Chemical above.**Consumer/OPUC** – OPUC agrees with the comments of Lyondell Chemical above.**Consumer/CMC Steel** – CMC Steel agrees with the comments of Lyondell Chemical above.**Consumer/City of Eastland** – City of Eastland agrees with the comments of Lyondell Chemical above.**Consumer/City of Dallas** – City of Dallas agrees with the comments of Lyondell Chemical above.**IREP/Rhythm Ops** – Rhythm Ops agrees with the comments of Lyondell Chemical above.**IREP/Demand Control 2** – Demand Control 2 agrees with the comments of Lyondell Chemical above. |
| TAC Review/Justification of Recommendation |  Revision Request ties to Reason for Revision as explained in Justification  Impact Analysis reviewed and impacts are justified as explained in Justification Opinions were reviewed and discussed Comments were reviewed and discussed (if applicable) Other: (explain) |
| ERCOT Board Decision | On 6/24/25, the ERCOT Board voted to recommend approval of NPRR1229 as recommended by TAC in the 4/23/25 TAC Report. There was one opposing vote. |
| PUCT Decision | On 7/31/25, the PUCT approved NPRR1229 and accompanying ERCOT Market Impact Statement as presented in Project No. 54445, Review of Protocols Adopted by the Independent Organization. |

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| **Opinions** |
| Credit Review | ERCOT Credit Staff and the Credit Finance Sub Group (CFSG) have reviewed NPRR1229 and do not believe that it requires changes to credit monitoring activity or the calculation of liability. |
| Independent Market Monitor Opinion | IMM has no opinion on NPRR1229. |
| ERCOT Opinion | ERCOT has no opinion on NPRR1229.  NPRR1229 is primarily focused on a cost allocation issue; and determines the entities responsible for bearing the costs due to Generation Resources tripping Off-Line if the trip is attributable to a CMP.  NPRR1229 does not impact reliability or market design outcomes. |
| ERCOT Market Impact Statement | ERCOT Staff has reviewed NPRR1229 and believes the market impact for NPRR1229 enables a QSE to submit a Settlement dispute seeking to recover costs attributable to a CMP under certain conditions that were previously not allowed. |

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| Sponsor |
| Name | Lucas Turner |
| E-mail Address | lucas@stec.org |
| Company | South Texas Electric Cooperative, Inc. (STEC) |
| Phone Number | 361-485-6200 |
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| Market Segment | Cooperative |

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| **Market Rules Staff Contact** |
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| **Phone Number** | 512-248-6464 |

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| **Comments Received** |
| Comment Author | **Comment Summary** |
| ERCOT 050724 | Provided an initial list of concerns with the as-submitted version of NPRR1229 for additional stakeholder discussion |
| STEC 050824 | Provided additional redlines to include Section 6.6.3.10 to address the charge needed to fund the proposed payment  |
| STEC 061224 | Provided additional redlines to the 5/8/24 STEC comments to implement a manual calculation for billing and provide additional clarity and efficiency |
| WMS 071124 | Requested PRS continue to table NPRR1229 for further review by the Wholesale Market Working Group (WMWG) |
| ROS 071124 | Requested PRS continue to table NPRR1229 |
| STEC 092024 | Proposed additional clarifying revisions to the 6/12/24 STEC comments based on stakeholder discussions at WMS and the WMWG |
| Residential Consumer 101624 | Requested NPRR1229 remain tabled until the ERCOT Board addresses NPRR1190 |
| STEC 110424 | Proposed additional clarifying revisions to the 9/20/24 STEC comments |
| STEC 010225 | Proposed additional clarifying revisions to the 11/4/24 STEC comments |
| ERCOT 012825 | Proposed additional clarifying revisions to the 1/2/25 STEC comments |
| ROS 020625 | Advised PRS that ROS determined the issues are financial in nature and ROS has no recommendation at this time |
| STEC 022625 | Proposed additional revisions to the 1/28/25 ERCOT comments adding a reporting threshold when the annual sum of demonstrable financial losses included exceeds $3.5 million |
| WMS 030625 | Endorsed NPRR1229 as amended by the 2/26/25 STEC comments as revised by WMS to lower the reporting threshold to $1.5 million |
| ERCOT 032025 | Provided additional redlines to add Real-Time Constraint Management Plan Cost Recovery Payments to the types of payments subject to Real-Time Energy Offer Curve Offer Curve Cost Caps (RTEOCOST) in Section 4.4.9.3.3 |

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| **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:

* NPRR1246, Energy Storage Resource Terminology Alignment for the Single-Model Era (incorporated 4/1/25)
	+ Section 4.4.9.3.3

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

* NPRR1214, Reliability Deployment Price Adder Fix to Provide Locational Price Signals, Reduce Uplift and Risk
	+ Section 9.5.3
* NPRR1235, Dispatchable Reliability Reserve Service as a Stand-Alone Ancillary Service
	+ Section 9.5.3

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| Proposed Protocol Language Revision |

4.4.9.3.3 Energy Offer Curve Cost Caps

(1) The following Energy Offer Curve Cost Caps must be used for the purpose of make-whole Settlements, Real-Time High Dispatch Limit Override Energy Payments, Real-Time Constraint Management Plan Cost Recovery Payments, and Voltage Support Service Payments:

(a) Nuclear = $15.00/MWh;

(b) Coal and Lignite = $18.00/MWh;

(c) Combined Cycle greater than 90 MW = 9 MMBtu/MWh \* ((Percentage of FIP \* FIP) + (Percentage of FOP \* FOP))/100, as specified in the Energy Offer Curve;

(d) Combined Cycle less than or equal to 90 MW = 10 MMBtu/MWh \* ((Percentage of FIP \* FIP) + (Percentage of FOP \* FOP))/100, as specified in the Energy Offer Curve;

(e) Gas - Steam Supercritical Boiler = 10.5 MMBtu/MWh \* ((Percentage of FIP \* FIP) + (Percentage of FOP \* FOP))/100, as specified in the Energy Offer Curve;

(f) Gas Steam Reheat Boiler = 11.5 MMBtu/MWh \* ((Percentage of FIP \* FIP) + (Percentage of FOP \* FOP))/100, as specified in the Energy Offer Curve;

(g) Gas Steam Non-reheat or boiler without air-preheater = 14.5 MMBtu/MWh \* ((Percentage of FIP \* FIP) + (Percentage of FOP \* FOP))/100, as specified in the Energy Offer Curve;

(h) Simple Cycle greater than 90 MW = 14 MMBtu/MWh \* ((Percentage of FIP \* FIP) + (Percentage of FOP \* FOP))/100, as specified in the Energy Offer Curve;

(i) Simple Cycle less than or equal to 90 MW = 15 MMBtu/MWh \* ((Percentage of FIP \* FIP) + (Percentage of FOP \* FOP))/100, as specified in the Energy Offer Curve;

(j) Reciprocating Engines = 16 MMBtu/MWh \* ((Percentage of FIP \* FIP) + (Percentage of FOP \* FOP))/100, as specified in the Energy Offer Curve;

(k) Hydro = $10.00/MWh;

(l) Other = SWCAP;

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| ***[NPRR1008: Replace item (l) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***(l) Other = DASWCAP or RTSWCAP; |

(m) RMR Resource = SWCAP;

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| ***[NPRR1008: Replace item (m) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***(m) RMR Resource = effective Value of Lost Load (VOLL); |

(n) Wind Generation Resources = $0.00/MWh; and

(o) PhotoVoltaic Generation Resource (PVGR) = $0.00/MWh.

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| ***[NPRR1246: Insert item (p) below upon system implementation of the Real-Time Co-Optimization (RTC) project:]***(p) Energy Storage Resource (ESR) = $0.00/MWh. |

(2) ERCOT shall produce an annual report each April that provides the amount of DAM and RUC Make-Whole Payments during the previous calendar year for Resources categorized as Other, per item (1)(l) above, as a percentage of the total amount of DAM and RUC Make-Whole Payments made during the previous calendar year. The report shall be based on final Settlements and include the total number of Resources classified as Other. ERCOT shall present this report annually to the appropriate Technical Advisory Committee (TAC) subcommittee. If there are no Make-Whole Payments for Resources categorized as Other for a given calendar year, then ERCOT will not be required to produce the annual report.

(3) Items in paragraphs (1)(c) and (d) above are determined by capacity of largest simple-cycle combustion turbine in the train selected.

(4) The FIP and FOP used to calculate the Energy Offer Curve Cap for Make-Whole Payment calculation purposes shall be the FIP or FOP for the Operating Day. In the event the Energy Offer Curve Cap for Make-Whole Payment calculation purposes must be calculated before the FIP or FOP is available for the particular Operating Day, the FIP and FOP for the most recent preceding Operating Day shall be used. Once the FIP and FOP are available for a particular Operating Day, those values shall be used in the calculations. If the percentage fuel mix is not specified or if no Energy Offer Curve exists, then the minimum of FIP or FOP shall be used.

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| ***[NPRR1216: Insert paragraph (5) below upon system implementation:]***(5) During an Emergency Offer Cap (ECAP) Effective Period, the SWCAP used for purposes of calculating the Energy Offer Curve Cost Caps shall be set to the maximum value of SWCAP that was effective for the Operating Day. |

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| ***[NPRR1216: Replace paragraph (5) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***(5) During an ECAP Effective Period, for purposes of calculating the Energy Offer Curve Cost Caps, the DASWCAP shall be set to the DASWCAP that was used to clear the DAM, and the VOLL shall be set to the maximum value VOLL that was effective for the Operating Day.  |

**6.6.3.9 Real-Time Constraint Management Plan Cost Recovery Payment**

(1) If a Generation Resource trips Off-Line from a transmission equipment operation that would have normally not tripped the unit Off-Line but for the activation of a Constraint Management Plan (CMP) or a Verbal Dispatch Instruction (VDI) issued by ERCOT which subjects a Generation Resource to N-1 contingency that could trip the Generation Resource Off-Line the QSE may be eligible for a Real-Time Constraint Management Plan Cost Recovery Payment, as calculated in paragraph (6) below, upon providing documented proof of the financial and repair cost. A Generation Resource impacted by the CMP or VDI shall not be eligible for a CMP cost recovery payment under any of the following two conditions:

(a) If the Resource Entity for this Generation Resource agreed with the CMP to subject the Generation Resource to the N-0 condition.

(b) If ERCOT must issue a VDI to open the Generation Resource’s breaker due to the Generation Resource improperly following ERCOT instructions without notifying ERCOT that the CMP or VDI would physically harm the Resource.

(2) To qualify for a Constraint Management Plan Cost Recovery Payment the following conditions must be met:

(a) The CMP or VDI must have financially impacted the Generation Resource that tripped Off-Line;

(b) The Generation Resource must have tripped Off-Line from a transmission equipment operation in an N-1 contingency following activation of a CMP directly impacting transmission equipment connected to the Generation Resource or an equivalent VDI issued by ERCOT to the Generation Resource or its Transmission Operator to operate equipment to produce the same effect; and

(c) The QSE must file a timely Settlement and billing dispute, including the following items:

(i) An attestation signed by an officer or executive with authority to bind the QSE;

(ii) The dollar amount and calculation of the demonstrable financial loss by Settlement Interval and the total repair cost for the CMP event, including:

(A) Demonstrable financial losses (excluding lost opportunity costs) while Resource is in an Outage caused by the CMP or equivalent VDI unit trip Off-Line and with a Resource Status of OUT, associated with one of the following:

(1) QSEs representing Generation Resources in their portfolio with a bilateral contract to sell energy at its Resource Node; or

(2) Incremental costs incurred by a QSE in the Real-Time Market (RTM) to serve its Load if the outage for the Resource is in the same QSE portfolio as the Load, and causes the QSE to be short energy compared to its Load for the intervals affected by the outage; or

(3) Variable cost components of DAM obligations; and

(B) Actual costs incurred to repair the plant equipment directly attributable to the Forced Outage caused by the CMP activation or equivalent VDI. The maximum amount recoverable shall be capped at $500,000 per event. Such costs include, but are not limited to:

(1) Costs associated with a Forced Outage if the result of the trip is due to the implementation of the CMP or equivalent VDI;

(2) Additional staff or contractor time as a result of the Forced Outage;

(3) Costs of equipment rental (including but not limited to cranes, manlifts, welding machines, etc.);

(4) Costs of facility rentals and other incidental incremental costs incurred by the Resource or its QSE created by the Forced Outage; and

(5) The cost of materials to be repaired that is a direct result of the Forced Outage.

(C) Costs covered under paragraphs (A) and (B) above do not include:

(1) Capital expenditures.

(iii) An explanation of the nature of the loss and how it was attributable to the CMP or equivalent VDI issued by ERCOT; and

(iv) Sufficient documentation to support the QSE’s calculation of the amount of the financial loss.

(3) If the total Settlement amount of demonstrable financial losses included within Constraint Management Plan Cost Recovery Payments, as defined in paragraph (2)(c)(ii)(A) above, exceeds $1.5 million in a calendar year, ERCOT will report to the Technical Advisory Committee (TAC) the causes of the payments and provide recommendations on how to reduce the costs based on the eligible demonstrable financial loss criteria in paragraph (2)(c)(ii)(A) above.

(4) The period used to calculate the Constraint Management Plan Cost Recovery Payment calculation will start at the Settlement Interval of initial trip and will conclude in the Settlement Interval at the soonest of:

(a) The Generation Resource is On-Line and available for Dispatch as per telemetry; or

(b) Ninety-six Operating Hours after the Resource trips Off-Line.

(5) ERCOT may request additional supporting documentation or explanation with respect to the submitted materials within 60 Business Days of receipt. Additional information requested by ERCOT must be provided by the QSE within 15 Business Days of ERCOT’s request. ERCOT will provide Notice of its acceptance or rejection of the claim for the Real-Time Constraint Management Plan Energy Payment within 15 Business Days of the updated submission, or request additional clarification as needed.

(6) The Startup costs available for the Generation Resource will be based on the Resource’s Category Startup Offer Generic Cap unless ERCOT has approved verifiable unit-specific Startup Costs for the Resource. If applicable, the calculated Verifiable Startup costs will be based on FIP or FOP fuel prices for the Operating Day when the Resource tripped Off-Line.

(7) The Constraint Management Plan Cost Recovery Payment shall be calculated for the period described in paragraph (4) above as follows:

CMPCRAMT *q, r, p, i* = (-1) \* (CMPFALA *q, r, p, i*  + CMPRALA *q, r, p, i*  + CMPSUPR*q, r, p, i*)

Where:

CMPFALA *q, r, p, i* = Min (CMPFAL *q, r, p, i ,* Max (0, (RTSPP *p, i*  – RTRSVPOR *i*  – RTRDP *i*  – RTEOCOST *q, r, p, i*) \* (1/4) \* CMPHSL *q, r, p, h* ))

And,

Where the repair costs are allocated equally over the intervals corresponding to the period determined in paragraph (4) above:

CMPRALA *q, r, p, i* = Min ($500,000*,* CMPRAL *q, r, p*) / Total number of intervals in CMP period

And,

Where on the first Operating Day of the period determined in paragraph (4) above, a cold startup cost is allocated evenly across the CMP event intervals. Subsequent Operating Days in the CMP event will not have startup cost allocations.

CMPSUPR *q, r, p, i*  = CMPSUCAP *q, r, p, cold*  / Total number of CMP period intervals in the first Operating Day of the CMP event

The above variables are defined as follows:

| **Variable** | **Unit** | **Definition** |
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| CMPCRAMT *q, r, p, i* | $ | *Constraint Management Plan Cost Recovery Amount* per QSE per Generation Resource—The payment to QSE *q* during eligible intervals of a Resource trip offline from an ERCOT-issued CMP unit trip or equivalent VDI for Resource *r*, at Settlement Point *p* for the 15-minute Settlement Interval *i*. Where, for a Combined Cycle Resource, *r* is a Combined Cycle Train. |
| CMPFALA *q, r, p, i* | $ | *Constraint Management Plan Financial Attested Losses Allowed per QSE per Generation Resource*— The payment for financial attested losses to QSE *q* for an ERCOT-issued CMP unit trip or equivalent VDI for Generation Resource *r,* at Settlement Point *p* for the 15-minute Settlement Interval *i*. Where, for a Combined Cycle Resource, *r* is a Combined Cycle Train. |
| CMPFAL *q, r, p, i* | $ | *Constraint Management Plan Demonstrable Financial Attested Losses* —The demonstrable financial loss to QSE *q* for Resource *r,* at Settlement Point *p* due to an ERCOT-issued CMP unit trip or equivalent VDI, as attested by the QSE, and in accordance with costs described in paragraph (2)(c)(ii)(A) above, for the 15-minute Settlement Interval *i*. Where, for a Combined Cycle Resource, *r* is a Combined Cycle Train. |
| CMPRALA *q, r, p, i* | $ | *Constraint Management Plan Repair Cost Attested Losses Allowed per QSE per Generation Resource —* The payment for repair costs attested losses to QSE *q* for an ERCOT-issued CMP unit trip or equivalent VDI for Generation Resource *r*, at Settlement Point *p* for the 15-minute Settlement Interval *i*. Where for a Combined Cycle Resource, *r* is a Combined Cycle Train. |
| CMPRAL *q, r, p* | $ | *Constraint Management Plan Repair Attested Losses*— The total Generation Resource repair cost due to trip off-Line of Resource following implementation of an ERCOT-issued CMP or equivalent VDI as attested by the QSE *q* and in accordance with costs described in paragraph (2)(c)(ii)(B) above. For a combined cycle Resource, *r* is a Combined Cycle Train. |
| CMPSUPR *q, r, p, i* | $/Start | *Startup Price per start*—The Settlement price for Resource *r* represented by QSE *q* for the cold start, for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train. |
| RTEOCOST *q, r, p, i* | $/MWh | *Real-Time Energy Offer Curve Cost Cap*—The Energy Offer Curve Cost Cap for Resource *r* represented by QSE *q*, for the Resource’s generation above the LSL for the Settlement Interval *i*. See Section 4.4.9.3.3, Energy Offer Curve Cost Caps. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. |
| CMPHSL *q, r, p, h* | MW | *Constraint Management Plan High Sustained Limit*— The High Sustained Limit (HSL) of Generation Resource *r* represented by QSE *q*, as submitted in the Current Operating Plan (COP), for the hour the Resource tripped off-line. Where for a Combined Cycle Resource, *r* is the Combined Cycle Generation Resource within the Combined Cycle Train that was online when the Resource tripped Off-Line. |
| RTSPP *p, i* | $/MWh | *Real-Time Settlement Point Price per Settlement Point*—The Real-Time Settlement Point Price at Settlement Point *p*, for the 15-minute Settlement Interval *i*. |
| RTRSVPOR *i* | $/MWh | *Real-Time Reserve Price for On-Line Reserves* - The Real-Time Reserve Price for On-Line Reserves for the 15-minute Settlement Interval *i*. |
| RTRDP *i* | $/MWh | *Real-Time On-Line Reliability Deployment Price* - The Real-Time price for the 15-minute Settlement Interval *i*, reflecting the impact of reliability deployments on energy prices that is calculated from the Real-Time On-Line Reliability Deployment Price Adder. |
| CMPSUCAP *q, r, p, s* | $/Start | *Constraint Management Plan Startup Cap*—The CMP cap is the Resource Category Startup Offer Generic Cap (RCGSC) unless ERCOT has approved verifiable unit-specific Startup Costs for that Resource, in which case the CMP startup cap will be verifiable unit-specific Startup Cost determined as described in Section 5.6.1. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train. |
| *q* | None | A QSE. |
| *r* | None | A Generation Resource. |
| *p* | None | A Resource Node Settlement Point. |
| *i* | None | A 15-minute Settlement Interval. |
| *h* | None | An Operating Hour. |
| *cold* | None | A cold start  |

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(8) The total compensation to each QSE for a trip Off-Line due to ERCOT CMP or equivalent VDI for the 15-minute Settlement Interval is calculated as follows:

**CMPCRAMTQSETOT *q, i* = CMPCRAMT *q, r, p, i***

The above variables are defined as follows:

| **Variable** | **Unit** | **Definition** |
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| CMPCRAMT *q, r, p, i* | $ | *Constraint Management Plan Cost Recovery Amount per QSE per Generation Resource*—The payment to QSE *q* during eligible hours of a Resource trip Off-Line from an ERCOT-issued CMP unit trip or equivalent VDI for Generation Resource *r* at Settlement Point *p* for the 15-minute Settlement Interval *i*. For a combined cycle Resource, *r* is a Combined Cycle Train. |
| CMPCRAMTQSETOT*q, i* | $ | *Constraint Management Plan Cost Recovery Amount QSE Total per QSE*—The total of the cost recovery payments to QSE *q* due to an ERCOT-issued CMP or equivalent VDI for the 15-minute Settlement Interval *i*. |
| *q* | none | A QSE. |
| *r* | none | A Generation Resource. |
| *p* | none | A Resource Node Settlement Point. |
| *i* | none | A 15-minute Settlement Interval. |

**6.6.3.10 Real-Time Constraint Management Plan Cost Recovery Charge**

(1) ERCOT shall allocate to QSEs on an LRS basis the total amount of the payment specified in Section 6.6.3.9, Real-Time Constraint Management Plan Cost Recovery Payment. The charge to each QSE for a given 15-minute Settlement Interval is calculated as follows:

**LACMPCRAMT *q, i*  = (-1) \* CMPCRAMTTOT *i* \* LRS *q, i***

Where:

CMPCRAMTTOT *i* =  CMPCRAMTQSETOT *q, i*

The above variables are defined as follows:

| **Variable** | **Unit** | **Definition** |
| --- | --- | --- |
| LACMPCRAMT *q, i* | $ | *Load-Allocated Constraint Management Plan Cost Recovery Amount per QSE*—The charge to QSE *q* for Constraint Management Plan Cost Recovery Payment as identified in Section 6.6.3.9, for the 15-minute Settlement Interval *i*. |
| CMPCRAMTTOT *i* | $ | *Constraint Management Plan Cost Recovery Amount total*—The total of payments to all QSEs Constraint Management Plan Cost Recovery Payments, for the 15-minute Settlement Interval *i*. |
| CMPCRAMTQSETOT *q, i* | $ | *Constraint Management Plan Cost Recovery Amount QSE total per QSE*—The total of the Constraint Management Plan Cost Recovery Payments to QSE *q* due to an ERCOT-issued CMP or equivalent VDI for the 15-minute Settlement Interval *i*. |
| LRS *q, i* | none | *The Load Ratio Share* calculated for QSE *q* for the 15-minute Settlement Interval *i*. See Section 6.6.2.2, QSE Load Ratio Share for a 15-Minute Settlement Interval. |
| *q* | none | A QSE. |
| *i* | none | A 15-minute Settlement Interval. |

**6.6.3.11 Miscellaneous Invoice for Cost Recovery Payments and Charges for a Real-Time Constraint Management Plan**

(1) Each approved dispute shall be settled as described in Section 9.14.2, Notice of Dispute.

(2) ERCOT shall issue a miscellaneous Invoice to the QSE representing the Resource that has received a Constraint Management Plan payment, as described in Section 6.6.3.9, Real-Time Constraint Management Plan Cost Recovery Payment.

(3) ERCOT shall issue a miscellaneous Invoice to the QSE representing Load based on the LRS as described in Section 6.6.3.10, Real-Time Constraint Management Plan Cost Recovery Charge.

(4) ERCOT shall issue a one-time miscellaneous Invoice encompassing all Operating Days in each approved dispute using the most recent available Settlement data at the time the Invoices were issued.

(5) ERCOT shall issue a Market Notice in conjunction with the issuance of miscellaneous Invoices for payments or charges for Real-Time Constraint Management Plan Settlement.

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| ***[NPRR1229: Delete Section 6.6.3.11 above upon system implementation.]*** |

***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](#_Toc109528011);

(g) Section [5.7.6, RUC Decommitment Charge](#_Toc109528014);

(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) or a Settlement Only Transmission Generator (SOTG);

(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) Section 6.6.14.2, Firm Fuel Supply Service Hourly Standby Fee Payment and Fuel Replacement Cost Recovery;

(jj) Section 6.6.14.3, Firm Fuel Supply Service Capacity Charge;

(kk) 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);

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

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

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

(oo) Paragraph (1)(e) of Section 6.7.1;

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

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

(rr) Paragraph (1)(c) of Section 6.7.2;

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

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

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

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

(ww) Paragraph (1)(e) of Section 6.7.2.1;

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

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

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

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

(bbb) Paragraph (1)(e) of Section 6.7.3;

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

(ddd) Paragraph (3) of Section 6.7.4;

(eee) Paragraph (4) of Section 6.7.4;

(fff) Paragraph (5) of Section 6.7.4;

(ggg) Paragraph (6) of Section 6.7.4;

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

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

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

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

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

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

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

(ooo) Section 9.16.1, ERCOT System Administration Fee.

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| ***[NPRR841, NPRR885, NPRR963, NPRR995, NPRR1012, NPRR1014, and NPRR1216: Replace applicable portions of paragraph (1) above with the following upon system implementation for NPRR841, NPRR885, NPRR963, NPRR995, NPRR1014, or NPRR1216 (Phase 2); 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](#_Toc109528011);(g) Section [5.7.6, RUC Decommitment Charge](#_Toc109528014);(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 6.6.3.9, Real-Time Constraint Management Plan Cost Recovery Payment;(q) Section 6.6.3.10, Real-Time Constraint Management Plan Cost Recovery Charge;(r) Section 6.6.4, Real-Time Congestion Payment or Charge for Self-Schedules;(s) Section 6.6.5.2, Set Point Deviation Charge for Over Generation; (t) Section 6.6.5.2.1, Set Point Deviation Charge for Under Generation; (u) Section 6.6.5.3, Controllable Load Resource Set Point Deviation Charge for Over Consumption; (v) Section 6.6.5.3.1, Controllable Load Resource Set Point Deviation Charge for Under Consumption;(w) Section 6.6.5.4, IRR Generation Resource Set Point Deviation Charge; (x) Section 6.6.5.4, Set Point Deviation Payment;(y) Section 6.6.5.5, Energy Storage Resource Set Point Deviation Charge for Over Performance; (z) Section 6.6.5.5.1, Energy Storage Resource Set Point Deviation Charge for Under Performance; (aa) Section 6.6.6.1, RMR Standby Payment;(bb) Section 6.6.6.2, RMR Payment for Energy;(cc) Section 6.6.6.3, RMR Adjustment Charge;(dd) Section 6.6.6.4, RMR Charge for Unexcused Misconduct;(ee) Section 6.6.6.5, RMR Service Charge;(ff) Section 6.6.6.6, Method for Reconciling RMR Actual Eligible Costs, RMR and MRA Contributed Capital Expenditures, and Miscellaneous RMR Incurred Expenses;(gg) Section 6.6.6.7, MRA Standby Payment;(hh) Section 6.6.6.8, MRA Contributed Capital Expenditures Payment;(ii) Section 6.6.6.9, MRA Payment for Deployment Event;(jj) Section 6.6.6.10, MRA Variable Payment for Deployment; (kk) Section 6.6.6.11, MRA Charge for Unexcused Misconduct;(ll) Section 6.6.6.12, MRA Service Charge;(mm) Paragraph (3) of Section 6.6.7.1, Voltage Support Service Payments;(nn) Paragraph (5) of Section 6.6.7.1;(oo) Section 6.6.7.2, Voltage Support Charge;(pp) Section 6.6.8.1, Black Start Hourly Standby Fee Payment;(qq) Section 6.6.8.2, Black Start Capacity Charge;(rr) Section 6.6.9.1, Payment for Emergency Operations Settlement;(ss) Section 6.6.9.2, Charge for Emergency Operations Settlement;(tt) Section 6.6.10, Real-Time Revenue Neutrality Allocation;(uu) Section 6.6.11.1, Emergency Response Service Capacity Payments; (vv) Section 6.6.11.2, Emergency Response Service Capacity Charge; (ww) Section 6.6.14.2, Firm Fuel Supply Service Hourly Standby Fee Payment and Fuel Replacement Cost Recovery;(xx) Section 6.6.14.3, Firm Fuel Supply Service Capacity Charge;(yy) Section 6.7.4, Real-Time Settlement for Updated Day-Ahead Market Ancillary Service Obligations;(zz) Section 6.7.5.2, Regulation Up Service Payments and Charges;(aaa) Section 6.7.5.3, Regulation Down Service Payments and Charges;(bbb) Section 6.7.5.4, Responsive Reserve Payments and Charges;(ccc) Section 6.7.5.5 , Non-Spinning Reserve Service Payments and Charges;(ddd) Section 6.7.5.6 , ERCOT Contingency Reserve Service Payments and Charges;(eee) Section 6.7.5.7 , Real-Time Derated Ancillary Service Capability Payment;(fff) Section 6.7.5.8 , Real-Time Derated Ancillary Service Capability Charge;(ggg) Section 6.7.6, Real-Time Ancillary Service Revenue Neutrality Allocation;(hhh) Section 6.8.2, Recovery of Operating Losses During an LCAP or ECAP Effective Period;(iii) Section 6.8.3, Charges for Operating Losses During an LCAP or ECAP Effective Period;(jjj) Section 7.9.2.1, Payments and Charges for PTP Obligations Settled in Real-Time; and(kkk) 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.