# REVISIONS

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1. **Glossary**

**Aggregate Price Node (APNode)**

A collection of Price Nodes (PNodes) whose prices are averaged with a defined weighting component to determine an aggregate price.

**Asset Owner**

An owner of any combination of: (1) registered physical assets (Resource, load, Import Interchange Transaction, Export Interchange Transaction, Through Interchange Transaction), (2) Transmission Congestion Rights or (3) any combination of financial assets (Virtual Energy Offer, Virtual Energy Bid, Financial Schedules) within the SPP Balancing Authority Area.

**Auction Clearing Price (ACP)**

The prices generated at each source and sink Settlement Location in each round of the Annual TCR Auction and Monthly TCR Auction based upon the TCR Offers and Bids submitted.

**Auction Revenue Right (ARR)**

A financial right, awarded during the annual ARR allocation process and/or incremental ARR allocation process, that entitles the holder to a share of the auction revenues generated in the applicable Transmission Congestion Rights (TCR) auction(s) and/or entitles the holder to self-covert the ARRs into TCRs.

**ARR Nomination Cap**

The maximum total amount of ARRs that an Eligible Entity may nominate in each month and season in the annual ARR allocation process and the monthly incremental ARR allocation process.

**Balancing Authority**

As defined in the SPP Tariff.

**Balancing Authority Area**

As defined in the SPP Tariff.
Bid

A commitment to pay a specific maximum price for a quantity of Energy or TCRs such as a Demand Bid, Virtual Energy Bid an Export Interchange Transaction Bid and/or a TCR Bid.

Block Controllable Load

A registered, measurable load that is capable of being reduced prior to the start of an Operating Hour for the entire Operating Hour at the instruction of the SPP operator and subsequently increased at the instruction of the SPP operator at the end of the Operating Hour in order to provide a one hour dispatchable quantity in the form of a Block Demand Response Resource. A Block Controllable Load must be associated with a Block Demand Response Resource.

Block Demand Response Resource

A controllable load, including controllable load of an aggregator of retail customers, that is not a Dispatchable Resource that can reduce the withdrawal of Energy from the transmission grid when directed by SPP.

Central Prevailing Time (CPT)

Clock time for the season of a year, i.e. Central Standard Time and Central Daylight Time.

Commercial Model


Commitment Status

A parameter submitted as part of a Resource Offer that specifies the option under which the Resource is to be committed.

Commit Time

The time specified by SPP in a commit order at which a Resource with a commit status of “Market” or “Reliability” that was committed by SPP in the DA Market or any Reliability Unit Commitment process should be synchronized and at or above Minimum Economic Capacity Operating Limit.
**Common Bus**

A single bus to which two or more Resources that are owned by the same Asset Owner are connected in an electrically equivalent manner where such Resources may be treated as interchangeable for certain compliance monitoring purposes.

**Contingency Reserve**

Resource capacity held in reserve for Resource contingencies which is the sum of Spinning Reserve and Supplemental Reserve.

**Contingency Reserve Deployment Instruction**

An instruction issued by SPP to Resources cleared for Contingency Reserve in the Real-Time Balancing Market to deploy a specific MW quantity of Contingency Reserve as communicated as a component of the Setpoint Instructions.

**Contingency Reserve Deployment Period**

The time period specified in the SPP Criteria following the issuance of a reserve sharing event within which a Resource has to deploy Contingency Reserve.

**Contingency Reserve Ramp Rate**

A single MW/minute value that is used to determine Resource maximum Spinning Reserve quantities or on-line Supplemental Reserve quantities.

**Control Status**

A parameter communicated electronically to SPP by a Market Participant at any time during an Operating Hour indicating a Resource’s ability to follow Setpoint Instructions.

**Current Operating Plan**

SPP’s internal hourly Resource commitment schedule for the Operating Day resulting from the various Day-Ahead Market and Day-Ahead Reliability Unit Commitment processes and updated, as required, during the Intra-Day RUC process that is used as input into the Real-Time Balancing Market.

**DA Market Commitment Period**

The contiguous period of time between a Resource’s DA Market Commit Time and DA Market De-Commit Time.
Day-Ahead

The time period starting at 0001 and ending at 2400 on the day prior to the Operating Day.

Day-Ahead Market (DA Market)

The financially binding market for Energy and Operating Reserve that is conducted on the day prior to the Operating Day.

Day-Ahead Reliability Unit Commitment (Day-Ahead RUC)

The process performed by SPP following the close of the DA Market and prior to the Operating day to assess resource and operating reserve adequacy for the Operating Day, commit and/or de-commit Resources as necessary, and communicate commitment or de-commitment of Resources to the appropriate Market Participants as necessary.

De-Commit Time

The time specified by SPP in a de-commit order at which a Resource with a Commitment Status of “Market” or “Reliability” that was committed by SPP in the DA Market or any Reliability Unit Commitment process should begin de-synchronization procedures.

Demand Bid

A proposal by a Market Participant associated with a physical load to purchase a fixed or price sensitive-amount of Energy at a specified location and period of time in the Day-Ahead Market.

Demand Curve

A series of quantity/price points used to set Operating Reserve Market Clearing Prices when there is a supply shortage of Operating Reserve and to set LMPs when there is shortage of capacity to meet Energy requirements.

Demand Response Load

A registered load identified in the registration of a Dispatchable Demand Response Resource or a Block Demand Response Resource.

Demand Response Resource

A Dispatchable Demand Response Resource or a Block Demand Response Resource.
Designated Resource

As defined in the SPP Tariff.

Desired Dispatch

A MW value calculated from a Resource’s RTBM Energy Offer Curve that represents the point at which the Resource’s incremental Energy offer is equal to the Resource’s RTBM LMP.

Dispatchable Controllable Load

A registered, measurable load that is capable of being reduced at the instruction of the SPP operator and subsequently increased at the instruction of the SPP operator in order to provide a 5-minute dispatchable quantity in the form of a Dispatchable Demand Response Resource. A Dispatchable Controllable Load must be associated with a Dispatchable Demand Response Resource.

Dispatch Status

A parameter submitted as part of a Resource Offer that specifies the option under which the Resource is to be dispatched once the Resource has been committed and becomes a Synchronized Resource.

Dispatchable Resource

A Resource for which an Energy Offer Curve has been submitted and that is available for dispatch by SPP on a Dispatch Interval basis.

Dispatchable Demand Response Resource

A controllable load, including behind-the-meter generation, that is a Dispatchable Resource that can reduce the withdrawal of Energy from the transmission grid when directed by SPP.

Dispatch Interval

The period of time for which SPP issues Dispatch Instructions for Energy and clears Operating Reserve in the Real-Time Balancing Market. The Dispatch Interval is currently 5 minutes.

Dispatch Instruction (DI)

The communicated Resource target energy MW output level at the end of the Dispatch Interval.
Electrical Node (ENode)

A physical node represented in the Network Model where electrical equipment and components are connected.

Eligible Entity

A Transmission Customer or Market Participant that is eligible to nominate ARRs during the annual allocation process.

Emergency

As defined as Emergency Condition in the SPP Tariff.

Energy

An amount of electricity that is Bid or Offered, produced, purchased, consumed, sold or transmitted over a period of time, which is measured or calculated in megawatt hours (MWh).

Energy and Operating Reserve Markets

The Day-Ahead Market and Real-Time Balancing Market.

Energy Management System (EMS)

The software system used by SPP for the real-time acquisition of operating data and operations.

Energy Offer Curve

A set of price/quantity pairs that represents the offer to provide Energy from a Resource.

Export Interchange Transaction

A Market Participant schedule for exporting Energy out of the SPP Balancing Authority Area.

Export Interchange Transaction Bid

A proposal by a Market Participant to purchase a fixed or price-sensitive amount of Energy in the Day-Ahead Market or a fixed amount of Energy in the Real-Time Balancing Market for delivery outside of the SPP Balancing Authority Area at a specified External Interface and period of time.
**External Contingency Reserve**

The sum of External Spinning Reserve and External Supplemental Reserve.

**External Interface**

A Settlement Location representing a physical interconnection point(s) between the SPP Balancing Authority Area and an External Balancing Authority Area.

**External Reserve Zone Obligation Transfer Schedule**

A schedule from a Balancing Authority external to the SPP Balancing Authority into a Reserve Zone supported by firm transmission service to the SPP border that allows a Market Participant to reduce its Operating Reserve obligation in that Reserve Zone.

**External Spinning Reserve**

Spinning Reserve contracted by a Market Participant that is being supplied from an external BA to a Reserve Zone within the SPP BA for the purposes of meeting the Market Participant’s Spinning Reserve obligation within the Reserve Zone.

**External Supplemental Reserve**

Supplemental Reserve contracted by a Market Participant that is being supplied from an external BA to a Reserve Zone within the SPP BA for the purposes of meeting the Market Participant’s Supplemental Reserve obligation within the Reserve Zone.

**Financial Schedule**

A financial arrangement between two Market Participants: (1) designating the buyer, seller, MW amount and Settlement Location for Energy transactions or (2) designating the buyer, seller, obligation percentage and Reserve Zone for Operating Reserve obligation transfer transactions.

**Firm Point-to-Point ARR Nomination Cap (“FPTP ARR Nomination Cap”)**

The maximum total amount of FPTP Candidate ARRs that an Eligible Entity may nominate in each month and season in the annual ARR allocation process and/or the monthly incremental ARR allocation process.
Firm Point-to-Point Candidate ARR (“FPTP Candidate ARR”)

All or portion of the MW quantity of a confirmed Firm Point-To-Point Transmission Service Reservation (TSR), verified prior to the start of the annual ARR allocation process, that the holder of the TSR can nominate for conversion into an ARR in the annual ARR allocation process.

Firm Point-to-Point Incremental Candidate ARR (“FPTP Incremental Candidate ARR”)

All or portion of the MW quantity of a confirmed Firm Point-To-Point Transmission Service Reservation (TSR), verified following the completion of the annual TCR auction process but prior to the start of the subsequent annual ARR allocation process, that the holder of the TSR can nominate for conversion into an ARR in the incremental ARR allocation process.

Firm Point-to-Point Transmission Service

As defined in the SPP Tariff.

GFA Firm Point-to-Point ARR Nomination Cap (“GFA FPTP ARR Nomination Cap”)

The maximum total amount of GFA FPTP Candidate ARRs and GFA FPTP Incremental Candidate ARRs that an Eligible Entity may nominate in each month and season in the annual ARR allocation process and/or the incremental ARR allocation process.

GFA Firm Point-to-Point Candidate ARR (“GFA FPTP Candidate ARR”)

All or a portion of the MW quantity of the transmission service component of a Grandfathered Agreement (GFA) providing service equivalent to Firm Point-to-Point Transmission Service, as defined in the SPP Tariff, verified prior to the start of the annual ARR allocation process, that the applicable Eligible Entity can nominate for conversion into an ARR in the annual ARR allocation process.

GFA Firm Point-to-Point Incremental Candidate ARR (“GFA FPTP Incremental Candidate ARR”)

All or a portion of the MW quantity of the transmission service component of a Grandfathered Agreement (GFA) providing service equivalent to Firm Point-to-Point Transmission Service, as defined in the SPP Tariff, verified following the completion of the annual TCR auction process but prior to the start of the subsequent annual ARR allocation process, that the applicable Eligible Entity can nominate for conversion into an ARR in the incremental ARR allocation process.
GFA NITS ARR Nomination Cap

The maximum total amount of GFA NITS Candidate ARRs that an Eligible Entity may nominate in each month and season in the annual ARR allocation process and the monthly Incremental ARR allocation process.

GFA NITS Candidate ARR

All or a portion of the MW quantity of the transmission service component of a Grandfathered Agreement (GFA) providing service equivalent to Network Integration Transmission Service, as defined in the SPP Tariff, verified prior to the start of the annual ARR allocation process, that the applicable Eligible Entity can nominate for conversion into an ARR in the annual ARR allocation process.

GFA NITS Incremental Candidate ARR

All or a portion of the MW quantity of the transmission service component of a Grandfathered Agreement (GFA) providing service equivalent to Network Integration Transmission Service, as defined in the SPP Tariff, verified following the completion of the annual TCR auction process but prior to the start of the subsequent annual ARR allocation process, that the applicable Eligible Entity can nominate for conversion into an ARR in the annual ARR allocation process.

Grandfathered Agreement (GFA)

As defined as Grandfathered Agreements or Transactions in the SPP Tariff.

Hub

A Settlement Location consisting of an aggregation of Price Nodes developed for financial and trading purposes.

Import Interchange Transaction

A Market Participant schedule for importing Energy into the SPP Balancing Authority Area.

Import Interchange Transaction Offer

A proposal by a Market Participant to purchase a fixed or price-sensitive amount of Energy in the Day-Ahead Market or a fixed amount of Energy in the Real-Time Balancing Market for delivery into the SPP Balancing Authority Area at a specified External Interface and period of time.
Interchange Transaction

Any Energy transaction that is crossing the boundary of the SPP Balancing Authority Area and requires checkout with one or more external Balancing Authority Areas. This includes any Import Interchange Transaction, Export Interchange Transaction and/or Through Interchange Transaction.

Intra-Day Reliability Unit Commitment (Intra-Day RUC)

The process performed by SPP following the completion of the DA RUC and throughout the Operating day to assess Resource and Operating Reserve adequacy for the Operating Day, commit and/or de-commit Resources as necessary, and communicate commitment or de-commitment of Resources to the appropriate Market Participants as necessary.

Jointly Owned Resource

A Resource that is owned by more than one Asset Owner.

Locational Marginal Price (LMP)

The market clearing price for Energy at a given Price Node which is equivalent to the marginal cost of serving demand at the Price Node while meeting SPP Operating Reserve requirements.

Loss Pool

A collection of Settlement Locations that is dynamically determined for each Asset Owner based on that Asset Owner’s transactional activity that is used for the purposes of determining that Asset Owner’s allocation of over collected loss revenues.

Manual Dispatch Instruction

A dispatch instruction created outside of the normal RTBM SCED Dispatch Instruction solution to address a system reliability condition that could not be resolved by the RTBM SCED.

Market Clearing Price (MCP)

The price used for settlements of an Operating Reserve product in each Reserve Zone. A separate price is calculated for Regulation-Up, Regulation-Down, Spinning Reserve and Supplemental Reserve.

Market Participant

As defined in the SPP Tariff.
Maximum Daily Energy

The maximum amount of Energy, in MWh, that is available to be produced in an Operating Day from a particular Resource.

Maximum Daily Starts

The maximum number of times a Resource can be started within a rolling 24-hour period.

Maximum Economic Capacity Operating Limit

The maximum MW level at which a Resource may operate under normal system conditions.

Maximum Emergency Capacity Operating Limit

The maximum MW level at which a Resource other than a Block Demand Response Resource may operate under Emergency system conditions.

Maximum Emergency Capacity Run Time

The maximum length of time a Resource can operate above its Maximum Economic Capacity Operating Limit up to its Maximum Emergency Capacity Operating Limit.

Maximum Quick-Start Response Limit

The maximum amount of Supplemental Reserve that can be provided by a Quick-Start Resource from an off-line state.

Maximum Regulation Capability

A Resource’s Maximum Regulation Capability is equal to that Resource’s Regulation Ramp Rate multiplied by the Regulation Response Time.

Maximum Regulation Capacity Operating Limit

The maximum MW level at which a Regulation Qualified Resource, a Regulation-Up Qualified Resource or a Regulation-Down Qualified Resource may operate while providing Regulation Deployment.

Maximum Run Time

The maximum length of time a Resource can run from the time the Resource is synchronized to the time the Resource is off-line.
**Maximum Weekly Starts**

The maximum number of times a Resource can be started within a rolling seven-day period.

**Megawatt (MW)**

A measurement unit of the instantaneous demand for energy.

**Meter Data Submittal Location**

One or more Meter Settlement Locations for which meter data is submitted to SPP by the Meter Agent for settlement purposes.

**Meter Settlement Location**

The effective point at which a Market Participant’s registered load and Resources interchange energy with the Real-Time Balancing Market.

**Metering Parties**

All parties, identified in a transmission service agreement, that have a vested interest in the accuracy of the meter data.

**Mid-Term Load Forecast**

A Settlement Area Load forecast developed by SPP on a rolling hourly basis for the next seven days for input into Reliability Unit Commitment.

**Minimum Down Time**

The minimum length of time required following desynchronization that a Resource must remain off-line prior to a subsequent synchronization.

**Minimum Economic Capacity Operating Limit**

The minimum MW level at which a Resource may operate under normal system conditions.

**Minimum Emergency Capacity Operating Limit**

The minimum MW level at which a Resource other than a Block Demand Response Resource may operate under Emergency system conditions.
Minimum Emergency Capacity Run Time

The maximum length of time a Resource can operate below its Minimum Economic Capacity Operating Limit down to its Minimum Emergency Capacity Operating Limit.

Minimum Regulation Capacity Operating Limit

The minimum MW level at which a Regulation Qualified Resource, a Regulation-Up Qualified Resource or a Regulation-Down Qualified Resource may operate while providing Regulation Deployment.

Minimum Run Time

The minimum length of time a Resource must run from the time the Resource is put online to the time the Resource is shut down.

Min-To-Off Profile

The output versus time profile for a Resource to de-synchronize from the grid starting from the Resource’s Minimum Economic Capacity Operating Limit.

Multi-Day Reliability Assessment

The process performed prior to the Operating Day to assess resource adequacy for the Operating Day, commit Resources with long Start-Up Times that cannot be considered as part of the DA Market or Day-Ahead RUC, and communicate commitment of such Resources as necessary.

Net Actual Interchange

The algebraic sum of all metered interchange over all interconnections between two physically adjacent Balancing Authority Areas.

Net Scheduled Interchange

The algebraic sum of all Interchange Transactions between Balancing Authorities for a given period or instant in time.

Network Integration Transmission Service (NITS)

As defined in the SPP Tariff.
Network Model

A representation of the transmission, generation, and load elements of the interconnected SPP Transmission System and the transmission systems of other regions in the Eastern Interconnection.

NITS ARR Nomination Cap

The maximum total amount of NITS Candidate ARRs and NITS Incremental Candidate ARRs that an Eligible Entity may nominate in each month and season in the annual ARR allocation process and/or the monthly incremental ARR allocation process.

NITS Candidate ARR

The MW quantity associated with firm NITS, that is verified prior to the start of the annual ARR allocation process, that the holder of the NITS can nominate for conversion into an ARR, subject to the NITS ARR Nomination Cap, in the annual ARR allocation process.

NITS Incremental Candidate ARR

The MW quantity associated with firm NITS, that is verified following the completion of the annual TCR auction process but prior to the start of the subsequent annual ARR allocation process, that the holder of the NITS can nominate for conversion into an ARR, subject to the NITS ARR Nomination Cap, in the incremental ARR allocation process.

Node

A specific ENode for which a settlement price is calculated.

No-Load Offer

The compensation request in a Resource Offer, in dollars, by a Market Participant representing the hourly fee for operating a synchronized Resource at zero (0) MW output. For a generating unit, No-Load Offers are generally representative of the fuel expense required to maintain synchronous speed at zero (0) MW output (i.e. the resource is operating under a “no load” condition). For a Dispatchable Demand Response Resource or Block Demand Response Resource, No-Load Offers are generally representative of a combination of the fuel expense required to maintain synchronous speed at zero (0) MW output for behind the meter generation (i.e. the resource is operating under a “no load” condition) and/or ongoing hourly costs associated with manufacturing process changes associated with a reduction in load consumption.
Offer
A commitment to sell a quantity of Energy at a specific minimum price such as a Resource Offer, a Virtual Energy Offer and/or an Import Interchange Transaction Offer.

Off-Peak
As defined under Schedule 1 of the SPP Tariff.

On-Peak
As defined under Schedule 1 of the SPP Tariff.

Operating Day
A daily period beginning at midnight.

Operating Hour
A 60-minute period of time during the Operating Day corresponding to a clock hour typically expressed as hour-ending.

Operating Reserve
Resource capacity held in reserve for Resource contingencies and NERC control performance compliance which includes the following products: Regulation-Up, Regulation-Down, Spinning Reserve and Supplemental Reserve.

Operating Tolerance
The MW range of actual Resource output above and below the Resource’s average Setpoint Instruction over the Dispatch Interval where the Resource will not be subject to charges associated with Uninstructed Resource Deviation.

Portal
Internet interface between SPP and its Members.

Post-Operating Day
The time period starting with the day immediately following the Operating Day.

Power Transfer Distribution Factor (PTDF)
The percentage of power transfer flowing through a facility or set of facilities (flowgate) for a particular transfer when there are no contingencies
Pre-Day-Ahead

The time period starting six days prior to Day-Ahead and ending midnight on the day prior to Day-Ahead.

Price Node (PNode)

A single node in the Commercial Model that has a one-to-one relationship to an ENode where Locational Marginal Prices are calculated.

Quick-Start Resource

A Resource that can be started, synchronized and inject Energy within ten minutes of SPP notification.

Ramp-Rate-Down

A curve specifying MW/minute ramp rates applicable between Resource operating ranges that is used to dispatch Resources in the down direction.

Ramp-Rate-Up

A curve specifying MW/minute ramp rates applicable between Resource operating ranges that is used to dispatch Resources in the up direction.

Real-Time

The continuous time period during which the RTBM is operated.

Real-Time Balancing Market (RTBM)

The market operated by SPP continuously in real-time to balance the system through deployment of Energy and to clear Regulation-Up, Regulation-Down, Spinning Reserve and Supplemental Reserve.

Reference Bus

The location on the SPP Transmission System relative to which all mathematical quantities, including shift factors and penalty factors relating to physical operation, will be calculated.

Regulation Deployment

The utilization of Regulation-Up and Regulation-Down through Automatic Generation Control (AGC) equipment to automatically and continuously adjust Resource output to balance the SPP Balancing Authority Area in accordance with NERC control performance criteria.
Regulation-Down

Resource capacity that is available for the purpose of providing Regulation Deployment between zero Regulation Deployment and the down direction.

Regulation-Down Offer

The price at which a Regulation Qualified Resource or a Regulation-Down Qualified Resource has agreed to sell Regulation-Down in dollars per MW.

Regulation-Down Qualified Resource

A Resource that has met the requirements to be eligible to submit Regulation-Down Offers into the Energy and Operating Reserve Markets but has not met the requirements to be eligible to submit Regulation-Up Offers into the Energy and Operating Reserve Markets.

Regulation-Only Resource

A Regulation-Up Qualified Resource, Regulation-Down Qualified Resource or a Regulation Qualified Resource that cannot be cleared or dispatched for Energy or cleared for Contingency Reserve.

Regulation Qualified Resource

A Resource that has met the requirements to be eligible to submit Regulation-Up Offers and Regulation-Down Offers into the Energy and Operating Reserve Markets.

Regulation-Up Qualified Resource

A Resource that has met the requirements to be eligible to submit Regulation-Up Offers into the Energy and Operating Reserve Markets but has not met the requirements to be eligible to submit Regulation-Down Offers into the Energy and Operating Reserve Markets.

Regulation Ramp Rate

A single MW/minute value that is used to determine Resource maximum Regulation-Up and/or Regulation-Down quantities.

Regulation Response Time

The maximum amount of time allowed for a Resource to move its output from zero Regulation Deployment to the full amount of Regulation-Up cleared or to move from zero Regulation Deployment to the full amount of Regulation-Down cleared.
Regulation-Up

Resource capacity held in reserve for the purpose of providing Regulation Deployment between zero Regulation Deployment and the up direction.

Regulation-Up Offer

The price at which a Regulation Qualified Resource or a Regulation-Up Qualified Resource has agreed to sell Regulation-Up in dollars per MW.

Reserved Capacity

The reservation MW between a specified source and sink associated with SPP Transmission Service.

Reserve Sharing Event

A request for assistance to deploy Contingency Reserve by any signatory to the Reserve Sharing Group Agreement following the sudden loss of a Resource.

Reserve Shutdown

An SPP approved Resource shutdown that is requested by a Market Participant for the purposes of making the Resource unavailable for SPP commitment and dispatch due to reasons other than to perform maintenance or to repair equipment.

Reserve Zone

A zone containing a specific group of Price Nodes for which a minimum and maximum Operating Reserve requirement is established.

Resident Load

As defined in the SPP Tariff.

Resource

An asset that is located internal to the SPP Balancing Authority Area or that is Pseudo-Tied into the SPP Balancing Authority Area that injects Energy into the transmission grid, or which reduces the withdrawal of Energy from the transmission grid.

Resource Offer

For a Resource, the combination of its Start-Up Offer, No-Load Offer, Energy Offer Curve, Regulation-Up Offer, Regulation-Down Offer, Spinning Reserve Offer and Supplemental Reserve Offer.
**Resource-to-Load Distribution Factor**

The simulated impact of incremental power output from a specific Resource (“source”) on the loading of a specific flowgate based on delivery to a representation of the locational weighting of all loads within all Settlement Locations (“sink”).

**Reliability Unit Commitment (RUC)**

The process performed by SPP to assess resource and operating reserve adequacy for the Operating Day, commit and/or de-commit resource as necessary, and communicate commitment or de-commitment of Resources to the appropriate Market Participants as necessary.

**RUC Commitment Period**

The contiguous period of time between a Resource’s RUC Commit Time and RUC De-Commit Time.

**Scarcity Price**

The MCP price levels determined by Demand Curves when there is insufficient Operating Reserve available to meet the Operating Reserve requirement.

**Security Constrained Economic Dispatch (SCED)**

An algorithm capable of clearing, dispatching, and pricing Energy and Operating Reserve on a co-optimized basis that minimizes overall cost while enforcing multiple security constraints.

**Security Constrained Unit Commitment (SCUC)**

An algorithm capable of committing Resources to supply Energy and/or Operating Reserve on a co-optimized basis that minimizes capacity costs while enforcing multiple security constraints.

**Setpoint Instruction**

The real-time desired MW output signal calculated for a specific Resource by SPP’s control system on a specified periodicity that is equal to the current Dispatch Instruction plus the Regulation Deployment instruction (which may be positive or negative) plus an adjustment to the Dispatch Instruction for Energy to account for Contingency Reserve Deployment Instructions. The Setpoint Instruction represents the desired output level of
the Resource and assumes that the Resource can attain this output instantaneously (i.e. infinite ramp rate).

Settlement Area
A geographic area within the SPP Balancing Authority Area for which transmission interval metering can account for the net area Load within the geographic area.

Settlement Determinant Report
A daily report of interval input, intermediate calculation and settlement result data with full Settlement Location and transactional detail which is generated for each Asset Owner and Operating Day settled, either on an Initial, Final or Resettlement basis. Separate reports are available for 1) 5-minute data and 2) hourly and daily data.

Settlement Invoice
A weekly summary of the SPP Integrated Marketplace net daily charges and credits by Asset Owner and Operating Day which is generated for each Market Participant and contains data for all of the Operating Days settled, either on an Initial, Final or Resettlement basis, during the invoice period. For each Operating Day only the net amounts (current total less previously invoiced - if a Final or Resettlement) contribute to the invoice amounts.

Settlement Location
A location defined for the purpose of commercial operations and settlement. A Settlement Location is the location of finest granularity for calculation of Day-Ahead Market and Real-Time Balancing Market settlements.

Settlement Statement
A daily summary of the SPP Integrated Marketplace total daily charges and credits by charge type and Operating Day which is generated for each Asset Owner and contains data for all of the Operating Days settled, either on an Initial, Final or Resettlement basis, on a single settlement execution day. For each Operating Day the current, previous and net amounts are included on the statement.

Shadow Price
A price for a commodity that measures the marginal value of this commodity, that is, the rate at which system costs could be decreased or increased by slightly increasing or decreasing, respectively, the amount of the commodity being made available. For
example, the shadow price associated with a transmission constraint is equal to the change in total system production cost produced through re-dispatching the system when incrementally relaxing that transmission line limit.

Short-Term Load Forecast

A Settlement Area Load forecast developed by SPP on a rolling 5-minute basis for the next 120 Dispatch Intervals for input into the Real-Time Balancing Market.

Spinning Reserve

The portion of Contingency Reserve consisting of Resources synchronized to the system and fully available to serve load within the Contingency Reserve Deployment Period following a contingency event.

Spinning Reserve Offer

The price at which a Spin Qualified Resource has agreed to sell Spinning Reserve in dollars per MW.

Spin Qualified Resource

A Resource that has met the requirements to be eligible to submit Spinning Reserve Offers into the Energy and Operating Reserve Markets.

SPP Holidays


SPP Integrated Marketplace


SPP Region

As defined in the SPP Tariff.
Start-Up Offer

The compensation required by a Market Participant for bringing an off-line Resource on-line or for reducing consumption of a Dispatchable Demand Response Resource or Block Demand Response Resource. Start-Up Offers are generally representative of the out of pocket cost that a Market Participant incurs in starting up a generating unit from an off-line state through Minimum Economic Capacity Operating Limit. For Dispatchable Demand Response Resources and Block Demand Response Resources, Start-Up Offers are generally representative of a combination of out-of-pocket costs that a Market Participant incurs in starting up a behind-the-meter generating unit and/or out-of-pocket costs associated with preparing for manufacturing process changes in preparation for reducing load consumption.

State Estimator

The computer software used to estimate the properties of the electric system based on a sample of system measurements based on current system conditions.

Start-Up Time

The time required to start a Resource and reach the Minimum Economic Capacity Operating Limit following receipt of a start-up order from SPP.

Stored Energy Resource

A device which replenishes the supply of its energy source (water, compressed air, battery or flywheel) through withdrawal of Energy from the system.

Supplemental Qualified Resource

A Resource that has met the requirements to be eligible to submit Supplemental Reserve Offers into the Energy and Operating Reserve Markets.

Supplemental Reserve

The portion of Operating Reserve consisting of on-line Resources and/or off-line Resources capable of being synchronized to the system that is fully available to serve load within the Contingency Reserve Deployment Period following a contingency event.

Supplemental Reserve Offer

The price at which a Supplemental Qualified Resource has agreed to sell Supplemental Reserve in dollars per MW.
Sync-To-Min Profile

The output versus time profile for a Resource’s output to reach Minimum Economic Capacity Operating Limit following synchronization to the grid.

Synchronized Resource

A Resource that is electrically connected to the grid as evidenced by the closing of the Resource circuit breaker.

Through Interchange Transaction

A Market Participant schedule submitted between two External Interfaces for use in the DA Market or RTBM for moving Energy through the SPP Balancing Authority Area.

Transmission Congestion Right (TCR)

A financial right that entitles the holder to a share of the congestion revenue collected in the Day-Ahead Market.

Transmission Congestion Rights Markets

The Auction Revenue Rights annual and monthly allocation processes and the annual and monthly Transmission Congestion Rights auctions.

Turn-Around Ramp Rate Factor

A percentage factor between 0% and 100% applied to a Resources Ramp-Rate-Up or Ramp-Rate-Down that applies only in the next Dispatch Interval when the Resource is issued a Dispatch Instruction that is in the opposite direction of the previous Dispatch Instruction.

Uninstructed Resource Deviation (URD)

The average MW amount of actual Resource output in a Dispatch Interval above or below the Resource’s average Setpoint Instruction in the Dispatch Interval.

Variable Energy Resource

A Resource powered solely by wind, solar energy, run-of-river hydro or other unpredictable fuel source that is beyond the control of the resource operator.

Virtual Energy Bid
A proposal by a Market Participant to purchase Energy at a specified price, Settlement Location and period of time in the Day-Ahead Market that is not associated with a physical Load.

**Virtual Energy Offer**

A proposal by a Market Participant to sell Energy at a specified price, Settlement Location and period of time in the Day-Ahead Market that is not associated with a physical Resource.
2. Introduction

SPP Market Protocols complement the Governing Documents, as defined in Exhibit 2-1, through documentation of detailed procedures that implement their provisions. Exhibit 2-1 shows how the Market Protocols interact with the Governing Documents and business practices related to the transmission markets.

Exhibit 2-1: Document Relationships

RTWG – Regional Tariff Working Group
BOD – SPP Board of Directors
TWG – Transmission Working Group
MWG – Market Working Group

MOPC – Market and Operations Policy Committee
ORWG - Operating Reliability Working Group
BPWG – Business Practices Working Group
SUG – Settlement Users Group
2.1 Purpose

The Market Protocols developed by SPP provide background information, guidelines, business rules, and processes for the operation and administration of the SPP Integrated Marketplace and the Reliability Unit Commitment processes, including market settlements, billing, and accounting requirements.
3. **SPP Integrated Marketplace Overview**

As a Regional Transmission Organization, SPP is mandated by the Federal Energy Regulatory Commission to ensure reliable supplies of power, adequate transmission infrastructure, and competitive wholesale prices of electricity. In order to ensure reliable operations and competitive wholesale electricity prices, SPP operates and administers Energy and Operating Reserve Markets and Transmission Congestion Rights Markets. The SPP Integrated Marketplace does not supersede any Market Participants’ obligations with respect to any other capacity or ancillary service obligations. The responsibilities in regards to capacity adequacy, reserves, and other reliability-based concerns do not change as a result of this market.

3.1 **Energy and Operating Reserve Markets**

The Energy and Operating Reserve Markets processes include mandatory Market Participant participation in:

- a price-based Day-Ahead Market (DA Market) with Transmission Congestion Rights providing the hedge against transmission congestion costs in the DA Market,
- a price-based Real-Time Balancing Market (RTBM) and
- all Reliability Unit Commitment (RUC) processes.

The DA Market provides Market Participants with the ability to submit offers to sell Energy, Regulation-Up, Regulation-Down, Spinning Reserve and Supplemental Reserve and/or to submit bids to purchase Energy. The RTBM provides Market Participants with the ability to submit offers to sell Energy, Regulation-Up, Regulation-Down, Spinning Reserve and Supplemental Reserve. Energy and Operating Reserve Markets operations will “simultaneously” or “jointly” optimize Resource Offers for Energy and Operating Reserve in the Security Constrained Unit Commitment (SCUC) and Security Constrained Economic Dispatch (SCED) algorithms. The objective function of joint optimization will be the minimization of the total production costs in the DA Market and the RTBM for energy and operating reserve products to meet the requirements. Procurement of Operating Reserve (Regulation-Up, Regulation Down, Spinning Reserve, and Supplemental Reserve) will not be decoupled from the procurement of Energy from Resources capable of providing both Energy and Operating Reserve. Resources selected to provide Operating Reserve will receive opportunity cost payments when appropriate which are included in the Market Clearing Prices for each product. The simultaneous optimization logic considers various permutations of unit commitment, and the joint dispatch of Energy and Operating Reserve, arriving to a solution that results in the least overall production cost subject
to reliability constraints. The simultaneous optimization logic also allows product substitution of Operating Reserve if economically efficient, i.e., the logic utilizes a higher quality product offer to fill a lower quality product demand if and when such selection would reduce the overall production cost compared to if each product were cleared separately.

The RUC processes are reliability based and are needed to ensure that the physical unit commitment produced from the DA Market is sufficient to meet SPP projected capacity needs during the Operating Day. Exhibit 3-1 provides an overview of the key Energy and Operating Reserve Market functions.

**Exhibit 3-1: Overview of Key Energy and Operating Reserve Market Functions**

Key features of the Day-Ahead Market include:

1. Financially binding market in which all cleared supply and demand is settled with a minimum mandatory offer requirement for physical Resources that are not on a planned or forced outage or Reserve Shutdown that is equal to a Market Participant’s expected daily peak Resident Load plus its estimated Operating Reserve obligation;

2. Financial Schedules for Energy and Operating Reserve accommodate internal physical bilateral transactions by removing their impact from the DA Market settlement;
(3) Physical supply offers, virtual supply offers, physical demand bids and virtual demand
bids are accommodated;

(4) DA Market clearing is performed for Energy, Regulation-Up, Regulation-Down,
Spinning Reserve and Supplemental Reserve on a least cost, co-optimized basis and
accounts for each Resource’s marginal system losses, congestion, and Energy cost to
minimize the overall production cost;

(5) All physical supply cleared for Operating Reserve products cleared are paid at the
applicable Reserve Zone Market Clearing Price for the Operating Reserve product;

(6) All Energy supply cleared is paid at the Settlement Location DA Market Locational
Marginal Price and all Energy demand cleared is charged at the Settlement Location
DA Market Locational Marginal Price producing an over collection due to congestion
(congestion revenues) and marginal losses (marginal loss revenues);

(7) TCR holders are paid (or charged) for the TCR MW at the difference between the DA
Market Marginal Congestion Component at the TCR sink and the DA Market Marginal
Congestion Component at the TCR source using the congestion revenues;

(8) Losses are settled financially through the LMP settlement process. Any over collection
of marginal loss revenues are credited to Asset Owners with net Energy withdrawals in
proportion to the amount of marginal loss revenue collected from that Asset Owner;

(9) SPP committed Resources are assured recovery of their Start-Up Offer, No-Load Offer
and actual incremental Energy costs as defined in the Energy Offer Curve subject to
certain eligibility criteria; and

(10) Operating Reserve procurement costs are allocated and collected on a Reserve Zone
basis.

Key features of the RUC processes and Real-Time Balancing Market include:

(1) For the RUC, it is mandatory that Market Participants submit offers for all of their
Resources that are not on a planned, forced or otherwise approved outage;

(2) Financial Schedules for Energy and Operating Reserve accommodate internal physical
bilateral transactions by removing their impact from the RTBM settlement (Financial
Schedules to not have any impact on the RUC processes);

(3) The RTBM operates on a 5-minute basis and calculates Dispatch Instructions for
Energy and clears Regulation-Up, Regulation-Down, Spinning Reserve and
Supplemental Reserve on a least cost, co-optimized basis and accounts for each Resource’s marginal system losses, congestion, and Energy cost to minimize the overall production cost;

(4) Cleared Operating Reserve product settlement is performed on a 5-minute basis. Charges and credits are calculated as the difference between the RTBM Operating Reserve MW cleared and the DA Market Operating Reserve MW cleared amount multiplied by the applicable Reserve Zone Operating Reserve Market Clearing Price;

(5) Resource settlement is performed on a 5-minute basis. Energy charges and credits are calculated as the difference between the Resource actual output and the Resource DA Market cleared MW amount multiplied by the Settlement Location RTBM Locational Marginal Price;

(6) Load settlement is performed on a 5-minute basis. Energy charges and credits are calculated as the difference between the load actual consumption and the load DA Market cleared MW amount multiplied by the Settlement Location RTBM Locational Marginal Price;

(7) Import, Export and Through Interchange Transaction settlement is performed on a 5-minute basis. Charges and credits are calculated as the difference between the real-time scheduled MW amount and the DA Market cleared MW amount multiplied by the RTBM Locational Marginal Price of the appropriate External Interface Settlement Location;

(8) Losses are settled financially through the LMP settlement process. Any over collection or under collection of marginal loss revenues are credited/charged to Asset Owners with net Energy withdrawals in proportion to the amount of marginal loss revenue collected from that Asset Owner.

(9) SPP committed Resources are assured recovery of their Start-Up Offer, No-Load Offer and actual incremental Energy costs as defined in the Energy Offer Curve subject to certain eligibility criteria;

(10) Charges are imposed on Market Participants for failure to deploy Energy, regulation and Contingency Reserve as instructed; and

(11) Operating Reserve procurement costs, net of penalty revenues received for regulation and Contingency Reserve deployment failure, are collected from Market Participants on a real-time load ratio share basis.
Exhibit 3-2 provides a timeline-based illustration of the sequencing and interaction of the key Energy and Operating Reserve Market functions for a representative Operating Day (1/31).

**Exhibit 3-2: Energy and Operating Reserve Markets Processes Timeline**

3.2 Transmission Congestion Rights Markets

The structure of the TCR Markets includes annual nomination and allocation of Auction Revenue Rights (ARRs) to Eligible Entities followed by annual and monthly TCR Auctions. Eligible Entities include Transmission Customers with firm SPP transmission service and entities with firm non-SPP transmission service (commonly referred to as a “grandfathered agreement or GFA”) into, out of, within or through the SPP Region that have identified such service during the annual ARR verification process. Entities with firm non-SPP transmission service (GFA) must agree between the parties as to which party is eligible to nominate ARRs. Additionally, Eligible Entities may request NITS, GFA NITS, FPTP and/or GFA FPTP Incremental Candidate ARRs for firm transmission service confirmed following completion of the annual TCR auction.
Key features of the annual ARR allocation process include:

(1) Eligible Entities nominate candidate ARRs separately for On-Peak and Off-Peak periods each month and season of the annual period in a three-round process;

(2) Nominated candidate ARRs are awarded up to the amount that is simultaneously feasible;

(3) Awarded ARRs are of the obligation type which means that the awarded ARR could result in a payment or charge to the ARR holder;

(4) 100% of the SPP transmission system capability is available for allocation;

(5) Holders of ARRs receive positive or negative revenue resulting from the annual and monthly TCR auctions, including those ARRs that were self converted to TCRs. Positive auction revenue results when the sink Auction Clearing Price (ACP) is greater than the source ACP for a given ARR. Negative revenue results when the sink ACP is less than the source ACP, in other words, a counterflow ARR.

(a) For the annual TCR auction, the amount of ARRs eligible to receive auction revenues is equal to the greater of self-converted TCRs or the amount of ARRs awarded multiplied by the following percentages: June – 100%; July through August, 90%; and Fall, Winter, Spring – 60%.

(b) For the monthly TCR auction for the months of July through September, the amount of ARRs eligible to receive auction revenues is equal to the amount of ARRs awarded in the incremental ARR allocation process plus: the lesser of (i) 10% of the annual ARR award or (ii) the difference between the annual ARR award and the amount of self-converted TCRs in the annual TCR auction;

(c) For the monthly TCR auction for the months of October through May, the amount of ARRs eligible to receive auction revenues is equal to the amount of ARRs awarded in the incremental ARR allocation process plus: the lesser of (i) 40% of the annual ARR award or (ii) the difference between the annual ARR award and the amount of self-converted TCRs in the annual TCR auction.

Key features of the annual TCR auction include:

(1) Any Market Participant that meets the applicable credit requirements may submit TCR Bids to purchase (for which the entity is the owner of record) separately for On-Peak and Off-Peak periods in the annual TCR auction for each month in the annual period;
(2) TCRs are of the obligation type which means that the awarded TCR could result in a payment or charge to the TCR holder in the DA Market settlement;

(3) The annual TCR auction is a single process for the month of June that makes 100% of the available SPP transmission system capability available, is a single round process for the months of July, August and September that makes 90% of the available SPP transmission system capability available and is a single round process for the Fall, Winter and Spring seasons that makes 60% of the available SPP transmission system capability available;

(4) Market Participants who have TCR bids cleared in the annual TCR auction will be charged (or get paid in the case of a counter-flow TCR) based on the amount of TCR MWs cleared and the annual TCR auction clearing prices associated with the source and sink of the offered TCR; and

(5) Market Participants holding ARRs may self-convert their ARRs into TCRs for the applicable period subject to simultaneous feasibility.

Key features of the monthly incremental ARR allocation include:

(1) Eligible Entities must submit a request to SPP specifying the NITS Incremental Candidate ARRs, GFA NITS Incremental Candidate ARRs, FPTP Incremental Candidate ARRs and/or GFA FPTP Incremental Candidate ARRs desired that are associated with the confirmed firm transmission service and the request must be submitted ten days prior to the start of the applicable monthly TCR auction process to be eligible to participate in the upcoming monthly TCR auction;

(2) SPP verifies the request and performs a monthly incremental ARR allocation process beginning five days prior to the applicable monthly TCR auction process.

   (a) Eligible Entities may nominate candidate ARRs from their verified NITS Incremental Candidate ARRs not to exceed the difference between their NITS ARR Nomination Cap and the ARRs awarded from nominated NITS Candidate ARRs in the annual ARR allocation process;

   (b) Eligible Entities may nominate candidate ARRs from their verified FPTP Incremental Candidate ARRs not to exceed the difference between their FPTP ARR Nomination Cap and the ARRs awarded from nominated FPTP Candidate ARRs in the annual ARR allocation process;

   (c) Eligible Entities may nominate candidate ARRs from their verified GFA NITS Incremental Candidate ARRs not to exceed the difference between their GFA
NITS ARR Nomination Cap and the ARRs awarded from nominated GFA NITS Candidate ARRs in the annual ARR allocation process;

(d) Eligible Entities may nominate candidate ARRs from their verified GFA FPTP Incremental Candidate ARRs not to exceed the difference between their GFA FPTP ARR Nomination Cap and the ARRs awarded from nominated GFA FPTP Candidate ARRs in the annual ARR allocation process;

(e) Nominated candidate ARRs are awarded up to the amount that is simultaneously feasible;

(f) All TCRs previously awarded in the Annual TCR Auction Process and all remaining ARRs not accounted for in the Annual TCR Auction Process for the applicable month are modeled as fixed injections at the specified sources and fixed withdrawals at the specified sinks prior to assessing nominated incremental candidate ARR feasibility.

(3) Awarded incremental ARRs are of the obligation type which means that the awarded incremental ARR could result in a payment or charge to the ARR holder; and

(4) 100% of the SPP transmission system capability is available for allocation.

Key features of the monthly ARR auction include:

(1) The monthly TCR auction process allows any Market Participants that have met the applicable credit requirements to submit TCR Bids to purchase additional TCRs or TCR Offers to sell currently held TCRs in a single-round process for the months of July, August and September and in a two-round process for the months of October through May;

(2) 100% of the SPP transmission system capability is made available; and

(3) Market Participants may self-convert their remaining ARRs (including ARRs remaining from the annual TCR auction process and ARRs awarded in the incremental ARR allocation process) into TCRs for the applicable period subject to simultaneous feasibility.

Exhibit 3-3 provides an overview of the TCR Markets structure.
Exhibit 3-3: Overview of TCR Markets Structure

The TCR Markets are operated in parallel with the timeline depicted in Exhibit 3-2 to ensure the Market Participants are able to obtain TCRs prior to DA Market operation. A representative timeline for the TCR Market processes is shown in Exhibit 3-4.
The Energy and Operating Reserve Markets processes are described in detail in Section 4 and the TCR Markets processes are described in detail in Section 5.
4. Energy and Operating Reserve Markets Processes

Energy and Operating Reserve Markets processes consist of activities beginning six days prior to the DA Market (Pre-Day-Ahead), activities the day prior to the Operating Day (Day-Ahead), activities during the Operating Day (Operating Day) and activities following the end of the Operating Day (Post Operating Day). All time referenced throughout this Section 4 is Central Prevailing Time (CPT). A detailed description of the activities in each of these four periods and key market design elements for the Energy and Operating Reserve Markets functions depicted in Exhibit 3-1 are provided in the following subsections.

4.1 SPP System Requirements

Prior to and in parallel with the Energy and Operating Reserve Markets processes, SPP performs several related activities as follows.

4.1.1 Reserve Zone Establishment

SPP establishes Reserve Zones to ensure the deliverability of cleared Operating Reserve throughout the SPP Balancing Authority Area. Reserve Zones are established on a semiannual basis as follows.

(1) SPP identifies the need for Reserve Zones within the SPP BAA through Reserve Zone studies that identify constrained areas within the SPP BAA which may require a minimum amount of Operating Reserve procurement or may be limited to a maximum amount of Operating Reserve procurement to ensure system-wide procurement of Operating Reserve is deliverable when deployed.

(2) Reserve Zones may be added or reconfigured between semiannual updates to address significant changes in system conditions that would cause adverse reliability impacts absent the Reserve Zone addition or reconfiguration.

(3) Each Reserve Zone is defined through identification of the Pnodes that are contained within that Reserve Zone.

4.1.2 Forecasting

4.1.2.1 Short Term and Mid-Term Load Forecasting

SPP develops Short-Term Load Forecasts and Mid-Term Load Forecasts for each Settlement Area. The Short-Term Load Forecast produces values on a rolling 5-minute basis for input into the RTBM. The Mid-Term Load Forecast produces hourly values for the next hour through
seven (7) days and is used in all of the RUC processes. Load forecasts are derived through a combination of conforming load and non-conforming load forecasts for each Settlement Area as described under Sections 4.1.2.1.1 and 4.1.2.1.2. The Settlement Area short-term and mid-term forecasts are then summed up to SPP Balancing Authority Area short-term and mid-term forecasts. These forecasts include an estimate of losses that must be removed, as described under Section 4.1.2.1.3, prior to execution of the Market applications in order for the dispatch to reflect losses appropriately under the marginal losses approach. Once the estimated losses have been removed, both the Mid-Term Load Forecast and the Short-Term Load Forecast is distributed to the Pnode level for modeling purposes for use in the RUC and RTBM processes respectively as described under Section 4.1.2.1.7. The DA Market relies on bid-in demand so these load forecasts are not used in that process.

4.1.2.1.1 Conforming Load

Conforming load is load that changes in a reasonably predictable, uniform ratio that is environmentally driven (i.e. changes in temperature as) as opposed to process driven (i.e. large industrial or irrigation processes). SPP uses a load forecasting tool to produce the mid-term and short-term load forecasts for conforming load within each Settlement Area. The load forecasting tool use historical actual conforming load values as well as temperature, wind speed, dew point and any other environmental variables determined necessary to accurately forecast the conforming load within each Settlement Area.

4.1.2.1.2 Non-conforming Load

Non-conforming load is that load that is more process driven and not as dependent on the temperature or weather. It may not have a predictable pattern that can be forecasted through the load forecasting tool. Market Participants with Non-Conforming Load are required to submit hourly load forecasts of Non-Conforming Load consumption to SPP by 1100 hours Day-Ahead for the Operating Day and for six days following the Operating Day. Market Participants must update their forecasts of Non-Conforming Load on a 5-minute rolling 10-minute ahead basis. The submitted non-conforming load will be added to the conforming load forecasts to create the total Settlement Area forecast. Estimates of Non-Conforming Load must be subtracted from the submitted actual load total of a Settlement Area in order for SPP to develop the actual conforming load values referenced under Section 4.1.2.1.1.
4.1.2.1.3 Losses

Both the short-term and the mid-term load forecasts for each Settlement Area are originally calculated including an estimate of losses. To allow for the correct dispatch using a marginal losses approach, the losses estimates from the original forecasts must be removed before distributing the forecast load to the loads at the individual Pnodes.

For the RTBM, SPP determines the average system loss percentage by dividing the solved losses of each Settlement Area in the last interval solution by the total load plus losses of each Settlement Area in the last interval solution. SPP then multiplies the short-term load forecast of the Settlement Area by \((1 – \text{average system loss percentage})\) prior to summing them up to the SPP BA Short-Term Load Forecast.

For each RUC execution, SPP multiplies \((1 – \text{average system loss percentage})\) by the mid-term load forecast of the Settlement Area prior to summing them up to the SPP BA Mid-Term Load Forecast for use in RUC. The average system loss percentage in this case is the historical average system loss percentage of the Settlement Area at the historical load level that most closely matches the Settlement Area mid-term load forecast.

4.1.2.1.4 Stored Energy Resource Load

Stored Energy Resources replenish the supply of their energy source (water, compressed air, battery or flywheel) through withdrawal of Energy from the system. During these times, these Resources will appear as load if only one Settlement Location is used for settlement of Energy. Therefore, loads associated with Stored Energy Resources are required to register as a separate load Settlement Location and will also be required to submit a consumption forecast as a non-conforming load which will then be incorporated into the final mid-term and short-term load forecasts of their Settlement Area. SPP models will include a separate pseudo-load asset that will represent this load. The load asset is switched on-line in the Network Model when consumption occurs.

4.1.2.1.5 Demand Response Adjustments

In developing the Short-Term Load Forecast, SPP will perform a gross-up adjustment in real-time for deployed Demand Response Resources (DRR) in order to continue to forecast the total load to be served by the RTBM. SPP will gross-up the Settlement Area actual real-time load received via SCADA by adding the real-time DRR output to the Settlement Area actual load.
where the DRR resides. The DRR output, in this case, is the estimated DRR output as calculated pursuant to Section 4.2.2.5.

### 4.1.2.1.6 Reserve Zone Load

Using the Pnode load forecasts developed under Section 4.1.2.1.7, SPP sums up the load forecasts at each Pnode in a Reserve Zone to determine the amount of load within the Reserve Zone for input into the study models used to establish the daily Reserve Zone minimum and maximum Operating Reserve requirements. Additionally, SPP will calculate each Market Participants forecast load within each Reserve Zone and SPP will then use this Market Participant load forecast to estimate each Market Participants Operating Reserve obligation within each Reserve Zone.

### 4.1.2.1.7 Load Distribution

SPP uses historical hourly load consumption patterns at each Pnode within each Settlement Area, as determined by the State Estimator from a reference day, to allocate the Settlement Area Mid-term Load Forecast down to the Pnode level within each Settlement Area for all RUC processes. The reference day used for each Settlement Area will be determined by SPP Operations Staff who are also responsible for load forecasting. By default the reference day will be the same day of the week seven (7) days prior but SPP has the discretion to choose a different reference day if more appropriate due to holidays, dramatic weather pattern changes or other factors as appropriate.

For the DA Market, bid-in demand at each Settlement Location will be distributed using the same weighting used for the RUC process.

For the RTBM, the Short-term Load Forecast will be distributed to each Pnode weighted by the load at each Pnode from the latest State Estimator solution.

### 4.1.2.2 Wind-Power Generation Resource Output Forecasts

SPP produces and updates an hourly Mid-Term Wind Forecast (MTWF) that provides a rolling 48-hour hourly forecast of wind production potential from each Wind-powered Generation Resource (WGR). This process uses a combination of physical and statistical models. SPP will produce an hourly Expected Wind Output Forecast (EWOF) for each WGR using a physical modeling technique that incorporates the relationships of the WGRs to wind speed, topography, atmospheric conditions, actual WGR output, and other variables that influence WGR production. SPP also produces and updates an hourly SPP Total Wind Power Forecast (TWPF) providing a
probability distribution of the hourly production potential from all wind-power in SPP for each of the next 48 hours.

The WGR Production Potential (WGRPP) is an hourly probability of exceedance forecast of energy production for each WGR. SPP shall use the probabilistic TWPF and select the forecast that the actual total SPP WGR production is expected to exceed 50% of the time (50% probability of exceedance forecast). To produce the WGRPP, SPP will allocate the TWPF 50% probability of exceedance forecast to each WGR based on the EWOF of each WGR. The updated WGRPP forecasts for each hour for each WGR are used as input into each RUC process.

SPP produces the WGRPP forecasts using the information provided by WGR owners including WGR availability, meteorological information, and Supervisory Control and Data Acquisition (SCADA) as described in the SPP Criteria. In addition to the Availability and Actual Output data required of all generation Resources, each Market Participant that owns a WGR shall install and telemeter to SPP the site-specific meteorological information that SPP determines is necessary to produce the MTWF and TWPF. SPP shall establish procedures specifying the accuracy requirements of WGR meteorological information telemetry.

4.1.3 Operating Reserve Requirements

SPP calculates the amount of Operating Reserve required for the Operating Day, on both a system-wide basis and a Reserve Zone basis, to comply with the reliability requirements specified in the SPP Criteria. SPP calculates the hourly Regulation-Up, Regulation-Down and Contingency Reserve requirements on an SPP BAA basis and calculates minimum and maximum Operating Reserve requirements for each Reserve Zone.

(1) SPP BAA Contingency Reserve requirements are set consistent with SPP Criteria and may vary on an hourly basis.

(2) SPP BAA Regulation-Up and Regulation-Down requirements are set to ensure compliance with NERC control performance requirements and are based upon a percentage of forecasted load, adjusted up or down to account for resource output variability, and may vary on an hourly basis.

(3) The SPP BAA requirements and minimum and maximum Reserve Zone requirements are calculated and posted no later than 7:00 AM Day-Ahead. At this time, SPP will also communicate each Market Participant’s estimated Operating Reserve obligations in each Reserve Zone using the BAA Mid-Term Load Forecast and the Market Participant load forecasts developed by SPP under Section 4.1.2.1.6.
(4) These Operating Reserve requirements are used by SPP as inputs into the DA Market and RTBM clearing and RUC processes.

(a) SPP may increase Operating Reserve requirements for use in RTBM clearing and RUC processes above the requirements used in the DA Market clearing, including changes to Reserve Zone minimums and maximums, as required to meet increases in reliability requirements caused by changes in system conditions.

(5) Reserve Zone minimum and maximum Operating Reserve requirements are determined through reserve zone studies prior to the DA Market. Reserve zone studies are performed as described under Section 4.1.3.1.

4.1.3.1 Reserve Zone Requirements

Reserve Zone studies are performed on a daily basis to determine each Reserve Zone’s minimum and maximum Operating Reserve requirements. A base case is produced using RTBM Resource Offer data to produce a Resource commitment and dispatch with all applicable transmission constraints activated. Using this base case, Reserve Zone studies are performed as follows.

4.1.3.1.1 Minimum Operating Reserve Requirements

Using this base case commitment and dispatch, the loss of the largest Resource is simulated for each Reserve Zone and the unused import capability is assessed based on normal operating limits. Operating Reserve being supplied to a Reserve Zone from outside of the SPP BA as described under Sections 4.2.2.7.1 and 4.2.2.7.2 is included in this evaluation;

(1) Power Transfer Distribution Factor (PTDF) interface flowgates for the import/export study will use appropriate ratings that do not reflect additional protection for transmission contingencies.

(2) If unused import capability equals or exceeds the largest Resource MW, then Reserve Zone minimum is equal to zero.

(3) If unused import capability is less than the largest Resource MW, then the Reserve Zone minimum Operating Reserve requirement is equal to the lesser of: 1) the difference between the largest Resource MW and unused import capability; or 2) the difference between the Reserve Zone load and import capability. The minimum requirement for each Operating Reserve product is determined as follows:
(a) The minimum Regulation-Up Requirement is equal to 25% of the product the SPP BAA Regulation-Up requirement and the ratio of the sum of the Maximum Regulation Capability of Resources within the Reserve Zone to the sum of the Maximum Regulation Capability of all Regulation Qualified Resources and Regulation-Up Qualified Resources;

(b) The minimum Regulation-Down Requirement is equal to 25% of the product the SPP BAA Regulation-Down requirement and the ratio of the sum of the Maximum Regulation Capability of Resources within the Reserve Zone to the sum of the Maximum Regulation Capability of all Regulation Qualified Resources and Regulation-Down Qualified Resources;

(c) The minimum Contingency Reserve requirement for a Reserve Zone is equal to the minimum Operating Reserve requirement of the Reserve Zone less the Regulation-Up requirement of the Reserve Zone but not less than zero (0) MW;

(d) The minimum Spinning Reserve Requirement for a specific Reserve Zone is equal to 25% of the product of the minimum Contingency Reserve requirement for that Reserve Zone and the ratio of the SPP BAA Spinning Reserve requirement to the SPP BAA Contingency Reserve requirement; and

(e) The minimum Supplemental Reserve requirement for a specific Reserve Zone is equal to the minimum Contingency Reserve Requirement for the Reserve Zone less the minimum Spinning Reserve Requirement for the Reserve Zone.

4.1.3.1.2 Maximum Operating Reserve Requirements

Using the base case commitment and dispatch, simulate the loss of the largest Resource in one Reserve Zone and assess the export capability in remaining Reserve Zones based on normal operating limits. Contingency Reserve being supplied to a Reserve Zone from outside of the SPP BA as described under Sections 4.2.2.7.1 and 4.2.2.7.2 is included in this evaluation.

(1) Aggregate and proxy PTDF flowgates for the import/export study will use appropriate ratings that do not reflect additional protection for transmission contingencies.

(2) The Reserve Zone maximum is equal to the unused Reserve Zone export capability. The maximum Regulation-Up, Regulation- Down, Spinning Reserve and Supplemental Reserve requirement is equal to Reserve Zone obligation for these products multiplied by the ratio of the Reserve Zone maximum Operating Reserve requirement and the Reserve Zone Operating Reserve obligation.
4.1.4 Violation Relaxation Limits

The DA Market, RUC processes and RTBM SCED enforce a number of operating constraints in developing the co-optimized market solution. In certain situations, attempting to enforce all constraints may result in a solution that is not feasible at a Shadow Price less than an appropriately priced Violation Relaxation Limit. In such cases, SPP must apply Violation Relaxation Limits (VRLs) in SCED.

There are five categories of constraints and associated VRLs: (1) Resource Capacity Constraints; (2) Resource Ramp Constraint; (3) Global Power Balance Constraint; (4) Operating Constraint (which include Pnode, Manual, Watch List, flowgate and Real-Time Contingency Analysis (RTCA) Constraints) and (5) Spinning Reserve requirement constraint. A higher VRL value is an indication of the relative priority for enforcing the constraint type. For example, the VRL value assigned to a ramp rate limit exceeds that assigned to a flowgate limit indicating that the flowgate constraint should be relaxed before the ramp rate constraint. If the VRL with the lowest value will not allow SCED to balance the market's energy obligations, a higher VRL will be applied. In the case of the Operating Constraint VRLs, the values limit the cost of the dispatch needed to balance system injections and withdrawals by capping the Shadow Price depending upon the level of the violation. Similarly, the Spinning Reserve Constraint VRL limits the costs of redispatch need to meet the Spinning Reserve requirement by capping the Spinning Reserve Shadow Price. Exhibit 4-1 provides a summary of the current VRL values by constraint type.
<table>
<thead>
<tr>
<th>Constraint Type</th>
<th>Description</th>
<th>VRL [$/MW]</th>
</tr>
</thead>
<tbody>
<tr>
<td>(1) Resource Capacity</td>
<td>The minimum and maximum MW dispatchable output of a resource as indicated in a Resource Offer.</td>
<td>100,000</td>
</tr>
<tr>
<td>(2) Global Power Balance</td>
<td>Energy needed to balance resources and load.</td>
<td>50,000</td>
</tr>
<tr>
<td>(3) Resource Ramp</td>
<td>The ramp capability of a resource as indicated in the resource plan.</td>
<td>5,000</td>
</tr>
<tr>
<td>(4) Operating Constraint</td>
<td>A MW limit that can be imposed on SPP related to MW flow across a market node, a manually-identified transmission constraint, a Watch List transmission constraint, a flowgate constraint, or a transmission constraint identified by SPP’s real-time contingency analysis.</td>
<td>$500 when the loading is greater than 100% and less than or equal to 101% at each network constraint. $750 when the loading is greater than 101% and less than or equal to 102% at each network constraint. $1,000 when the loading is greater than 102% and less than or equal to 103% at each network constraint. $1,250 when the loading is greater than 103% and less than or equal to 104% at each network constraint. $1,500 when the loading is greater than 104% at each network constraint.</td>
</tr>
<tr>
<td>(5) Spinning Reserve Constraint</td>
<td>A MW value representing the Spinning Reserve requirement</td>
<td>$200</td>
</tr>
</tbody>
</table>
VRLs and associated values are intended to achieve the following objectives: (1) Mitigate the occurrence of price excursions or other extreme prices; (2) Remove the portion of a loading violation attributed to market flow on a flowgate within 30 minutes of the start of a VRL violation; (3) Mitigate the regulation burden placed on the Resources providing regulation services; (4) Limit contribution to CPS violations; and (5) Minimize the need for Manual Dispatch Instructions.

4.1.4.1 Impact of VRLs on LMPs and MCPs

The applicable VRLs impact the calculation of LMPs in the following manner:

1. When a Resource Capacity, Global Power Balance, Resource Ramp, or Operating Constraint is reached but not exceeded, it is referred to as “binding.” In this state, VRLs are not applicable and LMPs are calculated through the normal SCED solution;

2. When an Operating Constraint is exceeded and can’t be resolved at a Shadow Price less than or equal to the applicable Operating Constraint VRL, the constraint is relaxed so that SCED can solve (i.e. the limit is increased by the amount of the violation). The VRL values applied by SCED in this case act as a cap on the Shadow Price on the applicable Operating Constraint and do have a direct impact on the resulting LMPs. LMPs are determined by the relaxed SCED solution;

   a. For example, assume Flowgate A has a 100 MW limit and SCED is re-dispatching to correct a limit violation. The SCED Shadow Price on Flowgate A reaches $1500/MW at which point the SCED calculated flow on Flowgate A is 107 MW. At this point, SCED will stop trying to re-dispatch to meet the 100 MW limit, the limit is then increased (“relaxed”) to 107 MW, and SCED concludes its solution using the new limit. The Shadow Price on Flowgate A is calculated based on this new 107 MW limit and will be approximately equal to $1500/MW. LMPs are calculated using the marginal resources of this relaxed SCED solution.

   b. Further to the example in (a) above and assuming that the recalculated Shadow Price is equal to $1495/MW, applying the equations for calculation of LMP as described under Section 4.5.4 (LMP = MEC + MCC + MLC) for Node X:

   Assume: MEC = $20/MWh
   Shift Factor for Node X on Flowgate A is 5%
   MLC = 0
MCC = Shadow Price * Shift Factor

Then: Node X LMP = $20/MWh + ($1495/MWh * .05) = $94.75/MWh.

(3) When a Resource Ramp Constraint for Energy in the up direction is exceeded and can’t be resolved and there is no capacity shortage causing Scarcity Pricing to be initiated as described under Section 4.1.5, LMPs are set equal to the highest Resource Offer for Energy as specified in the Energy Offer Curve that cleared in the DA Market or that was dispatched in the RTBM and MCPs are set by reducing the Operating Reserve requirement to match available Operating Reserve. Under capacity shortage conditions, LMPs and MCPs are set by the Operating Reserve Demand Curve as described under Section 4.1.5; and

(4) When a Resource Ramp Constraint for Energy in the down direction is exceeded and can’t be resolved and there is no excess generation condition causing Scarcity Pricing to be initiated as described under Section 4.1.5, LMPs are set equal to the lowest Resource Offer for Energy as specified in the Energy Offer Curve that cleared in the DA Market or that was dispatched in the RTBM and MCPs are set based upon the submitted Resource Offers. Under excess generation conditions, LMPs and MCPs are set by the Regulation-Down Demand Curve as described under Section 4.1.5.

(5) When a Spinning Constraint is exceeded and can’t be resolved at a Shadow Price less than or equal to the Spinning Reserve Constraint VRL, the constraint is relaxed so that SCED can solve (i.e. the Spinning Reserve requirement is reduced by the amount of the violation). The VRL values applied by SCED in this case act as a cap on the Shadow Price of the Spinning Reserve constraint and do have a direct impact on the calculation of the Spinning Reserve MCPs. LMPs and MCPs are determined by the relaxed SCED solution.

4.1.4.2 Determination of VRLs

Each year by November 1, VRLs and their associated values shall be reviewed and approved by the MOPC based on recommendations received from ORWG and MWG. Any changes to the VRLs or associated values must be approved for filing by the Board of Directors and approved by FERC prior to their implementation. The most recent FERC approved VRLs and their associated values shall be posted on the SPP OASIS website.

SPP shall post the following information on the SPP OASIS website on at least a monthly basis within 15 days of the last day of the month:
(1) The number of times that VRL values were applied by SCED during the month, and associated detail regarding the VRL type and value for each incident;

(2) The value of each LMP in excess of the safety net offer cap or below zero (0) during the month;

(3) The number and duration of each incident where a VRL was employed with respect to the same flowgate for two or more consecutive intervals;

(4) If SPP was unable to achieve the market flow relief required by the IDC, the constraint that was violated, the deployment interval(s) during which the violation occurred, the MW amount of the violation, and the Min and Max LMP during the violation period;

(5) The assessment of regulation requirement from application of a VRL;

(6) The number of CPS violations coincident with the application of a VRL;

(7) The number and magnitude of Manual Dispatch Instructions issued coincident with the application of a VRL.

4.1.4.3 VRL Reporting

By August 1st each year, SPP will provide analysis as well as a set of proposed VRLs and associated values to the ORWG and MWG. ORWG and MWG will then recommend a set of proposed VRLs and associated values to the MOPC.

4.1.4.3.1 Quarterly Reporting

SPP shall report the following information to the ORWG and the MWG on a quarterly basis in the month following the end of the quarter:

(1) A summary report and supporting detailed data identifying:

   (a) Number of times, each month, the application of VRL was required to provide a market solution;

   (b) VRL type and value;

   (c) Amount of the limiting condition;

   (d) Amount exceeding the limit;

   (e) Resulting shadow prices for each incident;
(f) Number and duration of each incident where a VRL was employed with respect to the same flowgate for six or more consecutive intervals;

(g) Number and magnitude of Manual dispatch instructions issued coincident with the application of a VRL; and

(h) An assessment of how effective the VRLs have been at achieving the stated objectives.

(2) An assessment of how effective the VRLs have been at achieving the stated objectives.

4.1.4.3.2 Annual Reporting

Each year by August 1st, SPP shall produce a report with supporting documentation that will analyze the effectiveness of VRLs and associated values on reliability and prices. The report shall include a sensitivity analysis of the existing VRL and associated values and examine impacts of raising or lowering the associated values. If changes are warranted, SPP shall recommend changes to the ORWG and the MWG for consideration.

4.1.5 Scarcity Pricing

SPP uses Demand Curves to set Market Clearing Prices in both the DA Market and RTBM during times of capacity shortages ("Scarcity Pricing"), either on a Reserve Zone basis or system-wide basis. Capacity shortages do not include shortages of Operating Reserve relating to insufficient ramping capability and Scarcity Pricing triggered under this situation may be mitigated through the use of ramp sharing as described below under Section 4.1.5.1. There are three sets of Demand Curves that apply on a system-wide basis and a Reserve Zone basis: (1) Operating Reserve; (2) Regulation-Up; and (3) Regulation-Down. The Scarcity Pricing levels associated with each of these Demand Curves are as follows:

(1) Operating Reserve – The sum of the Safety-Net Energy Offer Cap and the Contingency Reserve Offer Cap as specified under Section 8.2.5;

(2) Regulation-Up – The sum of the Regulation Offer Cap and the Contingency Reserve Offer Cap as specified under Section 8.2.5; and

(3) Regulation-Down - The sum of the Regulation Offer Cap and the Contingency Reserve Offer Cap as specified under Section 8.2.5.

If there is insufficient capacity to meet Energy requirements either on a Reserve Zone basis or system-wide basis, LMPs are set as follows:
(1) If there is a complete shortage of Operating Reserve within a Reserve Zone and there is insufficient capacity to meet Energy requirements within that Reserve Zone, all LMPs within that Reserve Zone are set to the highest LMP calculated in that Reserve Zone prior to realization of the complete shortage of Operating Reserve within the Reserve Zone.

(2) If there is a complete shortage of Operating Reserve on a system-wide basis and there is insufficient capacity to meet Energy requirements, all LMPs are set to the highest LMP calculated prior to realization of the complete shortage of Operating Reserve.

Capacity is required by Energy, Regulation-Up, Spinning Reserve and Supplemental Reserve and Operating Reserve product pricing rules (“price cascading”) require that the Regulation-Up MCP be greater than or equal to Spinning Reserve MCP and that the Spinning Reserve MCP be greater than or equal to the Supplemental Reserve MCP. Therefore, any shortage in capacity to meet Energy, Regulation-Up and Contingency Reserve requirements will be reflected in the pricing of all of these products.

For example, if we assume that there is a 50 MW shortage of Supplemental Reserve, the Supplemental Reserve MCP would be set to $1100/MW and the Spinning Reserve MCP, Regulation-Up MCP and the Energy LMP would also reflect the impacts of this $1100/MW price. The Energy LMP is increased by the Operating Reserve shortage price of $1100/MW because this price would be included in the LMP through the Shadow Price calculation (i.e. an increase in demand of 1 MW would cause a corresponding increase in Operating Reserve shortage since capacity is already short).

The system-wide and Reserve Zone Regulation-Up and Regulation-Down Demand Curve prices are designed to reflect pricing signals that are commensurate with a shortage in Regulation-Up or Regulation-Down capability, not shortages in capacity (i.e. there may be sufficient capacity available to meet the Regulation-Up requirement but there is simply not enough Regulation Qualified Resources and Regulation-Up Qualified Resources available). A shortage of Regulation-Up capability will invoke Regulation-Up Scarcity Pricing. A shortage of Regulation-Down capability will invoke Regulation-Down Scarcity Pricing. In these cases, Energy LMPs will not be impacted since there is no shortage of capacity, only Regulation-Up capability or Regulation-Down capability. However, LMPs will reflect negative Scarcity Prices as set by the Regulation-Down Demand Curve due to a shortage of Regulation-Down capability that is caused by an excess generation emergency situation as described under Sections 4.3.1.2.2 and 4.4.2.2.2.
### 4.1.5.1 Ramp Sharing

To ensure that ramping deficiencies across Hours in the DA Market or Dispatch Intervals in the RTBM do not initiate unjustified Scarcity Pricing (i.e. Scarcity Pricing should only be initiated when there is a capacity shortage) ramp sharing may be applied when needed to clear sufficient amounts of Energy, Regulation-Up and Spinning Reserve to meet the requirements. This is accomplished through the use of tuning parameters within the SCED model that will allow sharing of ramp ranging from no sharing of ramp to 100% sharing of ramp between Energy and Regulation-Up and/or Energy and Spinning Reserve. SPP will update these tuning parameters from time to time based upon historical system performance. For example, if SPP institutes 50% ramp sharing between Energy and Spinning Reserve, 1.5 times the ramp rate submitted in the Resource Offer will be made available to clear Energy and Spinning Reserve on all Resources which may result in Spinning Reserve being cleared that is not 100% deployable. SPP will not implement ramp sharing in the RTBM that will result in the inability to meet applicable NERC reliability standards and control performance requirements.

### 4.1.5.2 Demand Curve Interaction with VRLs

During capacity shortage conditions, both LMPs and MCPs are impacted by prices set by Demand Curves. Additionally, LMPs may also be impacted by VRLs as described under Section 4.1.4. Exhibit 4-2 below shows the impacts to LMPs and MCPs under varying system conditions caused by the applicable of VRLs and Demand Curves.
### Exhibit 4-2: VRL and Demand Curve Interaction

<table>
<thead>
<tr>
<th></th>
<th>Non-Binding Operating Constraint VRL</th>
<th>Binding Operating Constraint VRL</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td><strong>LMP Impact</strong></td>
<td><strong>LMP Impact</strong></td>
</tr>
<tr>
<td>No Capacity Shortage</td>
<td>Set economically by Resource Offers.</td>
<td>LMPs calculated by relaxing the Transmission Constraint associated with the Operating Constraint VRL.</td>
</tr>
<tr>
<td></td>
<td><strong>MCP Impact</strong></td>
<td><strong>MCP Impact</strong></td>
</tr>
<tr>
<td></td>
<td>Set economically by Resource Offers.</td>
<td>Set economically by Resource Offers. Not impacted by Operating Constraint VRL.</td>
</tr>
<tr>
<td>Operating Reserve Capacity Shortage</td>
<td>Max LMP equal to LMP set economically by Resource Offers plus Operating Reserve Demand Curve price.</td>
<td>LMPs calculated by relaxing the Transmission Constraint associated with the Operating Constraint VRL. Operating Demand Curve price included in LMP calculation.</td>
</tr>
<tr>
<td></td>
<td><strong>MCP Impact</strong></td>
<td><strong>MCP Impact</strong></td>
</tr>
<tr>
<td></td>
<td>MCP set at Operating Reserve Demand Curve price.</td>
<td>MCP set at Operating Reserve Demand Curve price.</td>
</tr>
</tbody>
</table>
4.1.6 Outage Scheduling and Reporting

SPP is responsible for approving the scheduling of maintenance on all transmission facilities making up the Transmission System and for coordinating with Resource Asset Owners, as appropriate, to schedule maintenance on generation facilities.

The roles and responsibilities of SPP and Market Participants regarding submittal of requested transmission and generation outages through the outage scheduler tool, evaluation and approval of requests and reporting of generator forced outages through the outage scheduler tool is described in the SPP Criteria. Additionally, as described under Section 4.2.2.2.1, an outage must be recorded using the outage scheduler tool in order to select an “Outage” Commitment Status.

4.1.7 Joint Operating Agreements – Seams Coordination

Joint Operating Agreements (JOAs) are arrangements between SPP and adjacent Balancing Authorities that enable one BA on an hourly basis to request the other to re-dispatch to relieve, or make available, additional transmission flowgate capacity for use by the requesting BA. There are hours when it may be more economical for a bordering BA to make additional flowgate capacity available than it is for that BA to re-dispatch its own Resources. This capability is available in the DA Market, RUC processes and RTBM. The cost incurred to re-dispatch is paid for by the BA that utilized the additional capacity. For both the DA Market and RTBM, the costs incurred are calculated in accordance with the formula in the JOA. Any funds received or paid by SPP for seams coordination are distributed or collected through the Revenue Neutrality Uplift charge type as described under Section 4.5.12.

4.2 Pre-Day-Ahead Activities

SPP and Market Participant activities during Pre-Day-Ahead begin seven (7) days prior to the Operating Day with Market Participant Offer and Bid submittal and end with the Multi-Day Reliability Assessment process that considers Resources with long lead times for potential commitment for use in both the DA Market and RTBM. Exhibit 4-3 provides a representative overall timeline of Pre-Day-Ahead activities.
A description of each of the functions identified in the Pre Day-Ahead timeline, other than the SPP Mid-Term Load Forecast process which is described under Section 4.1.2, is provided in the following subsections.

### 4.2.1 Must-Offer Requirement

For the Day-Ahead Market, RUC and RTBM, Resource Offers must include: (i) a Start-Up Offer, a No-Load Offer and an Energy Offer Curve for Resources qualified to provide Energy, (ii) a Regulation-Up Offer for Regulation-Up Qualified Resources and Regulation-Qualified Resources, (iii) a Regulation-Down Offer for Regulation-Down Qualified Resources and Regulation Qualified Resources, (iv) a Spinning Reserve Offer for Spin Qualified Resources and (v) a Supplemental Reserve Offer for Supplemental Qualified Resources.

#### 4.2.1.1 Day-Ahead Market

Each Market Participant must offer sufficient Resources to the Day-Ahead Market to cover their load plus Operating Reserve obligation to the extent the Resources are available (e.g. not on forced outage, planned outage or Reserve Shutdown).
(1) A Market Participant’s load for purposes of this section shall be equal to that Market Participant’s expected daily peak Resident Load.

(2) A Market Participant’s daily Operating Reserve obligation shall be equal to the sum of that Market Participant’s maximum daily Regulation-Up, Regulation-Down and Contingency Reserve obligation as calculated by SPP as described in Section 4.1.3(3).

4.2.1.2 RUC and RTBM

For the RUC and RTBM, Market Participants must submit Resource Offers for all Resources to the extent these Resources are available (e.g. not on forced outage, planned outage, or Reserve Shutdown). Market Participants must include in their Resource Offers the full amount of physical capacity available as reflected in the Resource’s submitted Maximum Economic Capacity Operating Limit and Maximum Emergency Capacity Operating Limit.

4.2.2 Offer Submittal

Beginning seven days prior to the Operating Day, Market Participants may begin to submit Offers for use in the DA Market and Offers for use in the RTBM. DA Market Offers may be updated up to 1100 hours Day-Ahead and RTBM Offers may be updated 30 minutes prior to each Operating Hour. The following business rules apply to Offer submittal:

(1) Offers submitted for use in the DA Market are submitted independent from the Offers submitted for use in the RTBM;

(2) Market Participants have the option of specifying that the Offers submitted for use in the DA Market also apply in the RTBM;

(3) Submitted Resource Offers roll forward hour to hour until changed within each respective market (DA Market and RTBM);

(4) Offers may be submitted that vary for each hour of the Operating Day except Offer parameters relating to unit commitment, as identified under Section 4.2.2.1, for which a single value is submitted that rolls forward in each hour until updated;

(5) Offers submitted for use in the RTBM are also used in the RUC processes;

(6) Resource Offers may only be submitted at Resource Settlement Locations, Import Interchange Transaction Offers may only be submitted at External Interface Settlement Locations; Virtual Energy Offers may be submitted at any Settlement Location, including a Hub;
(7) Resource Offers for Regulation-Up may only be submitted for Regulation Qualified Resources and Regulation-Up Qualified Resources. Resource Offers for Regulation-Down may only be submitted for Regulation Qualified Resources and Regulation-Down Qualified Resources. Resource Offers for Spinning Reserve may only be submitted for Spin Qualified Resources. Resource Offers for Supplemental Reserve may be submitted for either a Spin Qualified Resource or a Supplemental Qualified Resource. Resource qualifications are verified by SPP as part of the registration process as follows;

(a) A Regulation Qualified Resource, Regulation-Up Qualified Resource or Regulation-Down Qualified Resource must pass a specific regulation test as described under Section 6.1.11.3 that verifies:

(i) The Resource has the necessary equipment installed to be able to respond to Automatic Generation Control on a 4-second basis, including telemetering that can be scanned and updated on a 2-second basis; and

(ii) The Resource is capable of deploying 100% of cleared Regulation-Up or cleared Regulation-Down within the Regulation Response Time for a continuous duration of 60 minutes.

(b) A Spin Qualified Resource must:

(i) Self-Certify as described under Section 6.1.11.1 that the Resource is capable of deploying 100% of cleared Spinning Reserve or cleared Supplemental Reserve within the Contingency Reserve Deployment Period for a continuous duration of 60 minutes; and

(ii) Provide telemetered output data that can be scanned every 10 seconds.

(c) A Supplemental Qualified Resource must:

(i) Self-certify as described under Section 6.1.11.2 that the Resource is capable of deploying 100% of cleared Supplemental Reserve from an off-line state within the Contingency Reserve Deployment Period for a continuous duration of 60 minutes.

(ii) Provide telemetered output data that can be scanned every 10 seconds.

(8) Resource Offers consisting of Energy Offer Curve, Regulation-Up Offer, Regulation-Down Offer, Spinning Reserve Offer and Supplemental Reserve Offer are limited by the offer caps and floors specified under Section 8.2.5.
4.2.2.1 Resource Offer Parameters

The following Resource Offer parameters must be submitted to constitute a valid offer for use in either the DA Market or RTBM:

1. Resource Name (as specified during Market Registration and cannot be changed as part of Resource Offer submittal);
2. Resource Type (as specified during Market Registration and cannot be changed as part of Resource Offer submittal). See Section 4.2.2.5 for specific modeling rules for certain Resource Types;
3. Start-Up Offer ($/Start, Hot, Intermediate and Cold – Unit Commitment);  
4. No-Load Offer ($/Hour);  
5. Energy Offer Curve (MW, $/MWh, up to 10 price/quantity pairs, slope or block option, monotonically non-decreasing):
   a. The price of all MWhs below the first pricing point MWh is equal to the first pricing point price. The price of all MWhs above the last pricing point MWh is equal to the last pricing point price.
   b. Under the slope option, the set of price points that are submitted are used as the beginning and ending values for calculating a linear slope for each set of beginning and ending values. Therefore, each MW between the two price points has a different price due to the interpolation of the submitted price points. Under the block option, each MW between the two MW points is offered at the price of the larger MW point. Exhibit 4-4 illustrates Energy Offer Curves developed from submitted price/MWh pairs for both the slope and block options.

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1 For Asset Owners that have registered a JOU under the Combined Resource Option (see Section 6.1.7.2), this value must be submitted by the specified Asset Owner and represents the value for the entire Physical JOU Resource)
(6) Regulation-Up Offer ($/MW);
(7) Regulation-Down Offer ($/MW);
(8) Spinning Reserve Offer ($/MW);
(9) Supplemental Reserve Offer ($/MW);
(10) Sync-To-Min Profile (hours:minutes, MW – Operations Information);
(11) Min-To-Off Profile (hours:minutes, MW – Operations Information);
(12) Start-Up Time (hours:minutes, Hot, Intermediate, Cold – Unit Commitment);^1
(13) Hot to Intermediate Time (hours:minutes – Unit Commitment);^1
(14) Hot to Cold Time (hours:minutes – Unit Commitment);^1
(15) Maximum Daily Starts – rolling 24-hour (Unit Commitment);^1
(16) Maximum Weekly Starts – rolling 7-day (Unit Commitment);^1
(17) Maximum Daily Energy (MWh – Unit Commitment);^1
(18) Minimum Run Time (hours:minutes – Unit Commitment);^1
(19) Maximum Run Time (hours:minutes – Unit Commitment);^1
(20) Minimum Down Time (hours:minutes – Unit Commitment);^1
(21) Minimum Emergency Capacity Operating Limit (MW);
(22) Minimum Emergency Capacity Run Time (hours:minutes – Operations Information);
(23) Minimum Economic Capacity Operating Limit (MW);
(24) Minimum Regulation Capacity Operating Limit (MW);
(25) Maximum Regulation Capacity Operating Limit (MW);
(26) Maximum Economic Capacity Operating Limit (MW);
(27) Maximum Emergency Capacity Operating Limit (MW);
(28) Maximum Emergency Capacity Run Time (hours:minutes – Operations Information);
(29) Maximum Quick-Start Response Limit (MW, this represents the maximum amount of Supplemental Reserve that may be supplied by an off-line Quick-Start Resource)\(^1\);
(30) Ramp-Rate-Up (curve, MW/Minute - for use when the Resource is dispatched in the up direction). Ramp-Rate-Up submittal for use in the RTBM is through a segmented profile as follows. Each profile will require at least one (1) segment and may have up to \(n\) segments where \(n\) will be defined by SPP, initially set to ten (10);
   (a) Breakpoint Limit 1– Resource MW output at which segment 1 Ramp-Rate-Up will apply. If the actual measured MW during deployment is less than the Breakpoint Limit 1, the Ramp-Rate-Up in Block 1 will apply back to the actual measured MW.
   (b) Block 1 Ramp Rate Up – Rate at which Resource can change output upward in MW/min at output levels greater than or equal to Breakpoint Limit 1.
   (c) Block 1 Ramp Rate Emergency – Rate at which Resource can change output upward in MW/min at output levels greater than or equal to Breakpoint Limit 1 during an Emergency.
   (d) Breakpoint Limit \(n\)– Resource MW output at which Ramp-Rate-Up changes from previous segment values to segment \(n\) values.
   (e) Block \(n\) Ramp-Rate-Up - Rate at which Resource can change output upward in MW/min at output levels greater than or equal to the Breakpoint Limit \(n\).
   (f) Block \(n\) Ramp-Rate-Up Emergency – Rate at which Resource can change output upward in MW/min at output levels greater than the Breakpoint Limit 1 and less than Breakpoint Limit 2 during an Emergency.

(31) Ramp-Rate-Down (curve, MW/Minute - for use when the Resource is dispatched in the Down direction). Ramp-Rate-Down submittal for use in the RTBM is through a segmented profile as follows. Each profile will require at least one (1) segment and may have up to \(n\) segments where \(n\) will be defined by SPP, initially set to ten (10);
   (a) Breakpoint Limit 1– Resource MW output at which segment 1 Ramp-Rate-Down will apply. If the actual measured MW during deployment is less than the Breakpoint Limit 1, the Ramp-Rate-Down in Block 1 will apply back to the actual measured MW.
(b) Block 1 Ramp Rate Down – Rate at which Resource can change output downward in MW/min at output levels greater than or equal to Breakpoint Limit 1.

(c) Block 1 Ramp-Rate-Down Emergency – Rate at which Resource can change output downward in MW/min at output levels greater than or equal to Breakpoint Limit 1 during an Emergency.

(d) Breakpoint Limit \( n \) – Resource MW output at which Ramp-Rate-Down changes from previous segment values to segment \( n \) values.

(e) Block \( n \) Ramp-Rate-Down - Rate at which Resource can change output downward in MW/min at output levels greater than or equal to the Breakpoint Limit \( n \).

(f) Block \( n \) Ramp-Rate-Down Emergency – Rate at which Resource can change output downward in MW/min at output levels greater than the Breakpoint Limit 1 and less than Breakpoint Limit 2 during an Emergency.

(32) Turn-Around Ramp Rate Factor (a percentage between 0% and 100%). This factor is used to adjust a Resource’s Ramp-Rate-Up or Ramp-Rate-Down in a Dispatch Interval for which the Resource’s Dispatch Instruction has changed direction. For example, if in the last Dispatch Interval the Resource’s Dispatch Instruction was in the up direction and in the current Dispatch Interval its Dispatch Instruction is in the down direction, this factor is applied to the Resource’s Ramp-Rate-Down prior to the calculation of the actual Dispatch Instruction in that Dispatch Interval. A submittal of 0% creates a Ramp-Rate-Up or Ramp-Rate-Down of 0 MW/Min and a submittal of 100% indicates no change to the Resource’s Ramp-Rate-Up or Ramp-Rate-Down;

(33) Regulation Ramp Rate (single value, MW/Minute);

(34) Contingency Reserve Ramp Rate (single value, MW/Minute);

(35) Resource Status (see Section 4.2.2.2); and

(36) JOU Ownership Share (See Section 4.2.2.5.4).

### 4.2.2.2 Resource Status

In addition to the Resource Offer parameters specified under Section 4.2.2.1, Market Participants must also specify a Resource Commitment Status and a Resource Dispatch Status as part of the Resource Offer. The Commitment Status selection indicates to SPP how the Resource should be considered for unit commitment and may be specified separately for use in either the DA Market,
RTBM or both unless otherwise noted below. For Resources opting for the JOU modeling described under Section 4.2.2.5.4, this value must be submitted by the Market Participant specified during market registration and represents the Commitment Status for the entire Physical JOU Resource. The Dispatch Status selection is submitted for each product and indicates to SPP how the Resource may be dispatched once it is committed. The Dispatch Status may be specified for use in either the DA Market, RTBM or both unless otherwise noted below. Valid Commitment Status and Dispatch Status selections are:

**4.2.2.2.1 Commitment Status**

1. **Market** – The Resource is available for SPP economic commitment if it is off-line;
2. **Self** – The Market Participant is committing the Resource and SPP should include it as committed in either the DA Market and/or RUC as specified;
3. **Reliability** – The Resource is off-line and is only available for commitment by SPP if there is an anticipated Emergency condition;
4. **Outage** – The Resource is unavailable due to a planned, forced, maintenance or other approved outage and the outage must be documented using the outage scheduler tool described in the SPP Criteria for this selection to be valid.

**4.2.2.2.2 Dispatch Status**

There is a Dispatch Status for each product (Energy, Regulation-Up, Regulation-Down, Spinning Reserve and Supplemental Reserve as follows:

1. **Energy**
   a. **Market** – The Resource is available for SPP economic dispatch if committed;
   b. **VER** – Only available in RTBM and if Resource is registered as Variable Energy Resource. Resource is considered dispatchable but the dispatchable range will be determined dynamically by Ramp-Rate-Down, the actual SCADA and any submitted VER Output Profile. If Ramp-Rate-Up and Ramp-Rate-Down are both 0, SPP will set Dispatch Instruction equal to actual Resource output in each 5-minute interval or per a submitted VER Output Profile (if submitted as described under Section 4.2.2.5.5). If Ramp-Rate-Up and Ramp-Rate-Down are not 0, the Maximum Economic Capacity Operating Limit and Maximum Emergency Capacity Operating Limit will be equal to the actual SCADA or the submitted
VER Output Profile. The Minimum Economic Capacity Operating Limit and Minimum Emergency Capacity Operating Limit will be as submitted in the Resource Offer;

(c) Not Qualified – The Resource is not qualified to provide Energy. This status is only valid for a Stored Energy Resource or an External Resource that is not available for Energy dispatch.

(2) Operating Reserve (separate status for each product)

(a) Market – The Resource is available to clear the Operating Reserve product based on submitted Operating Reserve Offers;

(b) Fixed - Market Participant is fixing the Operating Reserve product clearing at the specified MW level. The minimum level is 100 KW (0.1 MW);

(i) SPP may clear the Operating Reserve product above the fixed MW based on submitted Operating Reserve Offers and may only clear below the fixed MW amount during an Emergency condition.

(ii) The fixed Operating Reserve MW will be rejected if the fixed MW violates any of the Resource Offer parameters.

(c) Not Qualified – The Market Participant may specify that a Resource is no longer qualified to supply Regulation-Up, Regulation-Down, Spinning Reserve or Supplemental Reserve. The Not Qualified designation can only be used for a Regulation Qualified Resource, Regulation-Up Qualified Resource, Regulation-Down Qualified Resource, Spin Qualified Resource or Supplemental Qualified Resource that can no longer provide the specified product because of physical restrictions.

4.2.2.3 Resource Limit Validation

Resource limits submitted as part of the Resource Offer must pass the following validation rules. Otherwise, the Resource Offer will be rejected.

(1) A Resource’s Minimum Economic Capacity Operating Limit must be greater than or equal to the Resource’s Minimum Emergency Capacity Operating Limit;

(2) A Resource’s Minimum Regulation Capacity Operating Limit must be greater than or equal to the Resource’s Minimum Economic Capacity Operating Limit;
(3) A Resource’s Maximum Regulation Capacity Operating Limit must be greater than or equal to the Resource’s Minimum Regulation Capacity Operating Limit;

(4) A Resource’s Maximum Economic Capacity Operating Limit must be greater than or equal to the Resource’s Maximum Regulation Capacity Operating Limit; and

(5) A Resource’s Maximum Emergency Capacity Operating Limit must be greater than or equal to the Resource’s Maximum Economic Capacity Operating Limit.

Exhibit 4-5 shows typical valid limit relationships.

**Exhibit 4-5: Resource Limit Relationships**
4.2.2.4 Resource Commitment Parameter Relationships

When developing the Resource Offer parameters relating to Resource commitment, Market Participants should assume the relationships shown in Exhibit 4-6.

Exhibit 4-6: Resource Commitment Parameter Relationships

4.2.2.5 Resource Modeling

The Offer parameters specified under Sections 4.2.2.1 and 4.2.2.2 may be submitted for all Resource types with the understanding that some parameters may be optional for certain types of Resources. Special Resource modeling rules for such Resources are described for specific Resource types as follows:

4.2.2.5.1 Dispatchable Demand Response Resource

The following special modeling rules apply to a DDR Resource.
(1) A DDR Resource is a special type of Resource created to model demand reduction associated with controllable load and/or a behind-the-meter generator that is dispatchable on a 5-minute basis;

(2) A DDR Resource is modeled in the Commercial Model the same as any other Resource with a defined Settlement Location and associated PNode;

(3) A DDR Resource is also included in the SPP Network Model as a generator;

(4) A DDR Resource must also have a corresponding Demand Response Load (DRL) identified with identical PNode representation as the DDR Resource;

(5) The Demand Response Load for a DDR Resource must have telemetering installed;

(6) The Market Participant must submit the real-time value of the Demand Response Load to SPP via SCADA on a 10-second basis;

(7) A DDR Resource may select one of two options for reporting of the actual DDR Resource output: Submitted Resource Production Option or the Calculated Resource Production Option.

(a) **Submitted Resource Production Option** - For DDR Resources that are utilizing strictly behind-the-meter Generation to provide the response or DDR Resources where the retail provider is offering the Resource under an agreed upon Retail Tariff provision that includes near real-time measurement and verification terms, the amount of the response provided may be sent directly to SPP via ICCP and will represent the real-time resource production.

   (i) The Market Participant must determine the real-time resource production and submit the value to SPP via SCADA on a 10-second basis.

   (ii) After-the-fact integrated meter values will be submitted directly by the Meter Agent for the DDR Resource.

(b) **Calculated Resource Production Option** - SPP will calculate the real-time resource output for operational dispatch and actual Resource output for settlements.

   (i) A baseline hourly load profile must be submitted for the DRL prior to the hour for which the DDR Resource has been committed that represents the forecast consumption for the hour assuming no load reduction.
(ii) At the start of the Operating Hour for which a DDR Resource is committed, SPP will take a snapshot of the demand MW consumption of the Demand Response Load.

(iii) The Real-Time Resource output for operational dispatch in the Dispatch Interval will be calculated as the difference between 1) the Minimum of (Hourly Load Profile of the DRL, Snapshot of the DRL SCADA interval prior to Deployment) and 2) the Real-Time SCADA value for the DRL.

(iv) The actual Resource output for use in settlements in the Dispatch Interval will be calculated as the difference between 1) the Minimum of (Hourly Load Profile of the DRL, Snapshot of the DRL SCADA interval prior to Deployment) and 2) the actual metered value for the DRL. The actual metered value for the DRL in the Dispatch Interval is either directly submitted by the Meter Agent if 5-minute metering is available or, is calculated by SPP based upon the hourly metered value submitted and the profiling method described under Section 4.5.9.

Exhibit 4-7 shows how a DDR Resource’s Real-Time output for operational dispatch would be calculated within an Operating Hour using the Calculated Resource Production Option.

**Exhibit 4-7: Calculated DDR Output**

<table>
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<tr>
<th>Interval</th>
<th>Net Telemetered Value of DRL (1)</th>
<th>Hourly Load Profile (2)</th>
<th>Telemetered Value prior to Deployment (3)</th>
<th>DDR Resource Production (4) = Min(2,3) – (1)</th>
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4.2.2.5.2 Block Demand Response Resource

The following special modeling rules apply to a BDR Resource.

1. A BDR Resource is a special type of Resource created to model demand reduction that is not dispatchable on a 5-minute basis but can be committed and dispatched in hourly blocks;

2. A BDR Resource is modeled in the Commercial Model the same as any other Resource with a defined Settlement Location and associated PNode or APNode;

3. A BDR Resource is not included in the SPP Network Model as a Resource;

4. A BDR Resource must also have a corresponding Demand Response Load (DRL) identified with identical PNode or APNode representation as the BDR Resource;

5. The DRL must have telemetering installed and have the real-time Load consumption at the DRL sent to SPP SCADA via ICCP on a 10-second scan rate;

6. All BDR Resources will use the Calculated Resource Production Option to determine the amount of Real-Time Resource Production and Actual Resource Production. Therefore, the following information requirements apply:

   a. An hourly load profile must be submitted for the DRL prior to the hour for which the BDR Resource has been committed that represents the forecast DRL consumption for the hour assuming no load reduction;

   b. The interval prior to the first interval for which a BDR Resource is committed and deployed, SPP will take a snapshot of the demand MW consumption of the DRL;

   c. The Real-Time Resource output for operational dispatch in the Dispatch Interval will be calculated as the difference between 1) the Minimum of (Hourly Load Profile of the DRL, Snapshot of the DRL SCADA interval prior to Deployment) and 2) the Real-Time SCADA value for the DRL.

   d. The actual Resource output for use in settlements in the Dispatch Interval will be calculated as the difference between 1) the Minimum of (Hourly Load Profile of the DRL, Snapshot of the DRL SCADA interval prior to Deployment) and 2) the actual metered value for the DRL. The actual metered value for the DRL in the Dispatch Interval is either directly submitted by the Meter Agent if 5-minute metering is available or, is calculated by SPP based upon the hourly metered value submitted and the profiling method described under Section 4.5.9.
(7) There are also operational differences that apply to BDR Resources as follows:

(a) A BDR Resource will only use two operating limits: Minimum Economic Capacity Operating Limit and Maximum Economic Capacity Operating Limit. The Minimum Economic Capacity Operating Limit represents the MW amount of demand reduction associated with the first price block identified in the Energy Offer Curve. The Maximum Economic Capacity Limit will represent the maximum amount of demand reduction that can be achieved.

(b) In the RTBM, if the BDR Resource is committed and dispatched in the DA Market or RUC, the BDR Resource Minimum Economic Capacity Operating Limit will be increased to match the dispatched amount and either Spinning Reserve or Supplemental Reserve will be allowed to clear above minimum output if the BDR Resource is a Spin Qualified Resource. Spinning Reserve clearing will be based upon submitted Ramp-Rate Up curve for the BDR Resource, the submitted Spinning Reserve Offer, the Supplemental Reserve Offer and the BDR Resource’s Maximum Economic Capacity Operating Limit.

(c) Other than the restriction on submittal of operating limits as stated in (a) above, a BDR Resource may submit Offers that include any of the Offer parameters listed under Sections 4.2.2.1 and 4.2.2.2.

4.2.2.5.3 Combined Cycle Resource

Combined Cycle modeling will be accommodated as follows for Resources registered as a Combined Cycle Resource. Market Participants that jointly own a Combined Cycle Resource that desire to use the Jointly Owned Unit modeling options described under Section 4.2.2.5.4 must register as a Jointly Owned Unit and cannot register the Resource as a Combined Cycle Resource.

(1) Market Participants will have to select from one of the three following options regarding submitting Resource Offers for their registered Combined Cycle Resources which will need to be declared during asset registration as described under Section 6.1.8:

(a) A Resource Offer may be submitted for a single aggregate Combined Cycle Resource, where the aggregate will represent a Market Participant selected operating configuration of combustion turbines (CT) and steam turbines (ST) (i.e. a 1CT x 1ST, 2CT x 1ST, 3CT x 1ST, etc). Under this option, the Combined
Cycle Resource will be committed, dispatched and settled the same as any other Resource; or

(b) A Resource Offer may be submitted for each Combined Cycle Resource combustion turbine and/or steam turbine and each component will be committed and dispatched independently and settled the same as any other single Resource; or

(c) A Resource Offer may be submitted for each pseudo Combined Cycle Resource, where each pseudo Combined Cycle Resource will represent the combination of one combustion turbine and a portion of the steam turbine. Under this option, each pseudo Combined Cycle Resource must be capable of being committed and dispatched independently the same as any other Resource and each pseudo Combined Cycle Resource will be settled the same as any other Resource.

4.2.2.5.4 Jointly Owned Unit

Jointly Owned Unit (JOU) owners may elect to model their individual ownership shares as separate Resources using either the Individual Resource Option or the Combined Resource Option as specified during market registration as described under Section 6.1.7. Otherwise, the Resource is modeled like any other single Resource with an associated single Asset Owner. Each Asset Owner may submit Resource offers for their JOU ownership (“JOU Share Resource”) the same as any other Resource subject to the following Resource Offer validation rules and exceptions.

(1) As part of market registration, the designated Asset Owner must submit the following offer parameters representing the ownership and physical characteristics of the entire JOU (“Physical JOU Resource”):

(a) JOU maximum physical capacity operating limit;
(b) JOU minimum physical capacity operating limit;
(c) maximum physical 10-minute response from an off-line state (if a Quick-Start Resource); and
(d) Ownership Percent Share by Asset Owner (Default value. May be updated as part of DA Market and RTBM Offer. Only required if registered under Combined Resource Option).
(2) The following Offer parameters as submitted by each Asset Owner for its JOU Share Resource must meet the following criteria in order to be accepted as valid offers, otherwise, all Offers related to the Physical JOU Resource will be rejected as invalid;

   (a) The sum of the Maximum Emergency Capacity Operating Limits of each JOU Share Resource associated with the Physical JOU Resource must be less than or equal to the Physical JOU Resource maximum physical capacity operating limit;

   (b) The sum of the Minimum Emergency Capacity Operating Limits of each JOU Share Resource associated with the Physical JOU Resource must be greater than or equal to the Physical JOU Resource minimum physical capacity operating limit; and

   (c) The sum of the Maximum Quick Start Response Limits of each JOU Share Resource associated with the Physical JOU Resource must be less than or equal to the Physical JOU Resource maximum physical 10-minute response from an off-line state.

(3) Commitment of individual JOU Share Resources that have registered under the Individual Resource Option will be evaluated by SCUC based on the individually submitted Offers for each JOU Share Resource;

(4) Commitment of JOU Share Resources that have registered under the Combined Resource option will be evaluated by SCUC based on a combination of the individually submitted Offers for each JOU Share Resource and the commitment related Offer parameters submitted by the designated Asset Owner that apply to the entire Physical JOU Resource (see Section 4.2.2.1 for identified commitment parameters) given the additional constraint that if one of the JOU Resources is committed, all JOU Share Resources associated with the Physical JOU Resource must be committed. This rule also applies to clearing of Supplemental Reserve from off-line Quick-Start Resources. Prior to evaluation by SCUC, each JOU Share Resource associated with the Physical JOU Resource is assigned the following unit commitment parameters as submitted by the designated Asset Owner:

   (a) The Start-Up Offer of each Asset Owner’s JOU Share Resource associated with the Physical JOU Resource is calculated by multiplying the Start-Up Offer submitted for the Physical JOU Resource by that Asset Owner’s JOU Ownership Share and this value will be used for make-whole-payment calculation purposes;
(b) The No-Load Offer of each Asset Owner’s JOU Share Resource associated with the Physical JOU Resource is calculated by multiplying the No-Load Offer submitted for the Physical JOU Resource by that Asset Owner’s JOU Ownership Share and this value will be used for make-whole-payment calculation purposes;

(c) The Start-Up Time of each Asset Owner’s JOU Share Resource associated with the Physical JOU Resource is set equal to the Start-Up Time submitted for the Physical JOU Resource;

(d) The Hot to Intermediate Time of each Asset Owner’s JOU Share Resource associated with the Physical JOU Resource is set equal to the Hot to Intermediate Time submitted for the Physical JOU Resource;

(e) The Hot to Cold Time of each Asset Owner’s JOU Share Resource associated with the Physical JOU Resource is set equal to the Hot to Cold Time submitted for the Physical JOU Resource;

(f) The Maximum Daily Starts of each Asset Owner’s JOU Share Resource associated with the Physical JOU Resource is set equal to the Maximum Daily Starts submitted for the Physical JOU Resource;

(g) The Maximum Weekly Starts of each Asset Owner’s JOU Share Resource associated with the Physical JOU Resource is set equal to the Maximum Weekly Starts submitted for the Physical JOU Resource;

(h) The Maximum Daily Energy of each Asset Owner’s JOU Share Resource associated with the Physical JOU Resource is calculated by multiplying the Maximum Daily Energy submitted for the Physical JOU Resource by that Asset Owner’s JOU Ownership Share;

(i) The Minimum Run Time of each Asset Owner’s JOU Share Resource associated with the Physical JOU Resource is set equal to the Minimum Run Time submitted for the Physical JOU Resource;

(j) The Minimum Down Time of each Asset Owner’s JOU Share Resource associated with the Physical JOU Resource is set equal to the Minimum Down Time submitted for the Physical JOU Resource;

(k) The Maximum Run Time of each Asset Owner’s JOU Share Resource associated with the Physical JOU Resource is set equal to the Maximum Run Time submitted for the Physical JOU Resource;
(l) The Maximum Quick-Start Response Limit of each Asset Owner’s JOU Share Resource associated with the Physical JOU Resource is calculated by multiplying the Maximum Quick-Start Response Limit submitted for the Physical JOU Resource by that Asset Owner’s JOU Ownership Share; and

(m) The Commitment Status of each Asset Owner’s JOU Share Resource associated with the Physical JOU Resource is set equal to the Commitment Status submitted for the Physical JOU Resource.

(5) If committed, each JOU Share Resource will be considered separately for the purposes of dispatch, Operating Reserve clearing and settlement and the Physical JOU Resource will receive an aggregate Setpoint Instruction for the purposes of Energy and Operating Reserve deployment;

(a) If a JOU Share Resource is committed by SPP in the DA Market, that JOU Share Resource is cleared for Energy based on the submitted Energy Offer Curve and Ramp Rate and is cleared for Operating Reserve based on the submitted Operating Reserve Offers and Ramp Rate;

(b) Each JOU Share Resource committed by SPP in the DA Market is eligible to receive a DA Market make-whole payment under the same eligibility rules as any other Resource as described under Section 4.5.8.12;

(c) In the RTBM, each JOU Share Resource is dispatched for Energy based on the submitted Energy Offer Curve, Ramp-Rate-Up and Ramp-Rate-Down and is cleared for Operating Reserve based on the submitted Operating Reserve Offers, Ramp-Rate-Up and Ramp-Rate-Down. SPP sends an independent Dispatch Instruction and cleared amounts of Operating Reserve to each individual JOU Share Resource Asset Owner and a combined Dispatch Instruction and total cleared amounts of Operating Reserve to the Physical JOU Resource operating owner for information purposes. SPP then creates a Physical JOU Resource Setpoint Instruction and the Physical JOU Resource operating owner uses this combined Setpoint Instruction for Energy and Operating Reserve deployment purposes. SPP also calculates Setpoint Instructions and communicates these instructions to each individual JOU Share Resource Asset Owner for information and compliance purposes.

(i) If a JOU Share Resource is committed by SPP in any RUC process, that individual JOU Share Resource is eligible to receive a RUC make-whole
payment under the same eligibility rules as any other Resource as described under Section 4.5.9.8.

(ii) Each JOU Share Resource will be subject to charges associated with Uninstructed Resource Deviation that exceeds the JOU Share Resource Operating Tolerance as described under Sections 4.5.9.8 and 4.5.9.10, Regulation deployment failure charges as described under Section 4.5.9.15 and Contingency Reserve deployment failure charges as described under Section 4.5.9.17, under the same eligibility rules as any other Resource.

(6) The Meter Agent(s) assigned to the Physical JOU Resource must account for all physical Energy produced and properly reflect this Energy in each individual JOU Share Resource meter data submittal.

4.2.2.5.5 Variable Energy Resource Output Profiles

Variable Energy Resources have the option to submit an output profile to be followed during the Real-Time Balancing Market. An output profile may be submitted prior to the Operating Hour for each Dispatch Interval in the Operating Hour and updated at any time during the hour via ICCP. The RTBM SCED will set the Dispatch Instruction equal to the profile value for the Dispatch Interval. If an output profile is not submitted prior to the Operating Hour and the Resource has selected the “VER” Dispatch Status, the Resource will be dispatched according to the options specified under Section 4.2.2.2.2.

4.2.2.6 Virtual Energy Offers

Virtual Energy Offers are supported in the DA Market only. Virtual Energy Offers are purely financial, only apply to Energy and are not associated with a physical Resource asset. The following rules apply to Virtual Energy Offer submittal.

(1) A Virtual Energy Offer can be submitted by a Market Participant at any Settlement Location;

(2) A Market Participant may submit a single Virtual Energy Offer for each Asset Owner at any Settlement Location for a particular Hour in the form of a Virtual Energy Offer Curve (MW, $/MWh, up to ten (10) price/quantity pairs, slope or block option) with the highest MW quantity submitted in the Virtual Energy Offer Curve representing the maximum MW amount that can be cleared;
(3) Each Virtual Energy Offer must specify a start and stop Hour within the applicable Operating Day;

(4) Virtual Energy Offers are subject to a transaction fee as described under Section 4.5.8.20.

### 4.2.2.7 Import Interchange Transaction Offers

Market Participants may submit offers to sell Energy coming from outside of the SPP Balancing Authority Area for use in the DA Market and/or RTBM using their existing network or point-to-point service or spot market transmission service. The following rules apply to Import Interchange Transaction Offer submittal.

(1) The MW amount of Import Interchange Transactions will be limited on a Dispatch Interval basis by the amount of SPP system ramping capability available. Market Participants must use the SPP ramp reservation system as described under Section 4.2.5 to ensure there is sufficient ramp to accommodate their transaction;

(2) Import Interchange Transaction Offers will be submitted via NERC E-tag and Real-Time Operations Scheduling System (RTOSS) as described under the SPP OATT Business Practices. Additional fields will be available through E-tagging to identify transaction type and to submit price-based information as necessary;

(3) Three types of Import Interchange Transaction Offers will be supported: Fixed, Dispatchable and Up-To-Transmission Usage Charge or ‘Up-to-TUC”.

   (a) A Fixed Offer is a specified MW that will be cleared regardless of the price at the External Interface Settlement Location (Source GCA specified on NERC E-tag). If the Fixed Import Interchange Transaction is submitted for use in the DA Market, it will be cleared in the DA Market and automatically roll forward as a fixed schedule for use in RUC and the RTBM. If specified for use in the RTBM only, the Fixed Import Interchange Transaction will be considered a fixed schedule for the RUC processes and RTBM.

   (b) A Dispatchable Offer specifies both a MW amount and a minimum $/MWh price that the Market Participant must be paid if the transaction clears the DA Market. Dispatchable Offers are only available for use in the DA Market. If the transaction clears the DA Market, it automatically rolls forward as a fixed schedule for use in RUC and the RTBM. Any adjustment to the schedule will be settled as a deviation from the DA Market.
(c) An Up-To-TUC Offer specifies both a MW amount and the maximum amount of congestion cost and marginal loss cost, in \$/MWh, between the specified NERC E-tag Source and Sink Settlement Location the Market Participant is willing to pay if the transaction clears the DA Market. Up-To-TUC Offers are only available for use in the DA Market. If the transaction clears the DA Market, it automatically rolls forward as a fixed schedule for use in the RUC and RTBM. Any adjustment to the schedule will be settled as a deviation from the DA Market.

4.2.2.7.1 External Contingency Reserve

A Market Participant may reduce its Contingency Reserve obligation within a Reserve Zone through submittal of an External Reserve Zone Obligation Transfer Schedule relating to a contract for External Contingency Reserve supply subject to the following requirements:

(1) The Market Participant must initially notify SPP seven (7) business days prior to the applicable Operating Day of its intent to supply a portion of its Contingency Reserve obligation from external sources and identify the applicable Reserve Zone(s);

(2) Transmission service from the external party to the SPP border must be consistent with supplying External Contingency Reserve into the Reserve Zone(s) identified;

(3) Submittal of an External Reserve Zone Obligation Transfer Schedule reduces the amount of Contingency Reserve procured from the DA Market and RTBM and reduces the Market Participant’s Contingency Reserve obligation within the applicable Reserve Zone as calculated under Section 4.5.8.10 for Spinning Reserve and Section 4.5.8.11 for Supplemental Reserve. Market Participants must submit their External Reserve Zone Obligation Transfer Schedules no later than 8:00 AM Day-Ahead and must specify the following information:

   (a) Asset Owner Buyer

   (b) Sink Reserve Zone;

   (c) Contingency Reserve Product; and

   (d) MW Amount.

(4) External Reserve Zone Obligation Transfer Schedules in excess of the Market Participants Contingency Reserve obligation in the applicable Reserve Zone is not eligible to receive payment.

4.2.2.7.2 External Regulation
A Market Participant may meet all or a portion of its Regulation-Up and Regulation-Down obligation within a Reserve Zone through External Regulation subject to the following requirements:

(1) If the source BA is supplying the External Regulation from three physical resources or less, the External Regulation must be modeled as a Pseudo-Tie Resource inside the SPP BAA. The Pseudo-Tie Resource may only be used to represent Regulation-Up and/or Regulation Down being sourced from one of the maximum of three physical Resources at any one time. Otherwise, the External Regulation must be represented as a Dynamic Schedule and the market accounting will be performed consistent with the treatment of External Contingency Reserve described under Section 4.2.2.7.1; and

(2) Firm transmission service from the external party to the SPP border must be obtained identifying a sink location consistent with supplying Regulation-Up and Regulation Down to load within the Reserve Zone(s) identified.

4.2.3 Bid Submittal

Beginning seven (7) days prior to the Operating Day, Market Participants are expected to begin submitting Demand Bids and Virtual Energy Bids for the purchase of Energy in the DA Market and/or Export Interchange Transaction Bids for the purchase of Energy in the DA Market or RTBM. The following business rules apply to Bid submittal:

(1) Bid submittal other than for a fixed Export Interchange Transaction Bid does not apply to any of the RUC processes or the RTBM;

(2) Submitted Bids do not roll forward hour to hour;

(3) Demand Bids may only be submitted at Load Settlement Locations, Export Interchange Transaction Bids may only be submitted at External Interface Settlement Locations; Virtual Energy Bids may be submitted at any Settlement Location, including a Hub;

(4) Bid submittal for use in the DA Market is voluntary.

4.2.3.1 Demand Bids

Only Market Participants with registered load assets may submit Demand Bids for use in the DA Market. Demand Bids are associated with physical load assets. The following rules apply to Demand Bid submittal:
(1) A Market Participant can only submit Demand Bids for the registered load Settlement Location of the Asset Owner(s);

(2) Two types of Demand Bids will be supported: Fixed and Price Sensitive;

   (a) A Fixed Demand Bid is a specified MW that will be cleared in the DA Market regardless of the price at the Load Settlement Location based on the start and stop time submitted for the applicable Operating Day.

   (b) A Price Sensitive Demand Bid is specified as a Demand Bid Curve (MW, $/MWh, up to 10 price/quantity pairs, slope or block option) that will clear only if the price at the Load Settlement Location is less than or equal to the specified curve price within the specified start and stop time submitted for the applicable Operating Day with the highest MW quantity submitted in the Demand Bid Curve representing the maximum MW amount that can be cleared.

4.2.3.2 Virtual Energy Bids

Virtual Energy Bids are supported in the DA Market only. Virtual Energy Bids are purely financial in nature, only apply to Energy and are not associated with a physical Load asset. The following rules apply to Virtual Energy Bid submittal.

(1) A Virtual Energy Bid can be submitted at any Settlement Location;

(2) A Market Participant may submit a single Virtual Energy Bid for each Asset Owner at any Settlement Location for a particular Hour in the form of a Virtual Energy Bid Curve (MW, $/MWh, up to 10 price/quantity pairs, slope or block option) with the highest MW quantity submitted in the Virtual Energy Bid Curve representing the maximum MW amount that can be cleared;

(3) Each Virtual Energy Bid must specify a start and stop Hour within the applicable Operating Day;

(4) Virtual Energy Bids are subject to a transaction fee as described under Section 4.5.8.20.

4.2.3.3 Export Interchange Transaction Bids

Market Participants may submit bids to purchase Energy from the DA Market for sale outside of the SPP Balancing Authority Area. A Market Participant must reserve transmission service prior to submittal of the Bid in accordance with the procedures specified in the SPP OATT Business Practices. The following rules apply to Export Interchange Transaction Bid submittal.
(1) The MW amount of Export Interchange Transactions will be limited on a Dispatch Interval basis by the amount of SPP system ramping capability available. Market Participants must use the SPP ramp reservation system as described under Section 4.2.5 to ensure there is sufficient ramp to accommodate their transaction;

(2) Export Interchange Transaction Bids will be submitted via NERC E-tag and RTOSS. Additional fields will be available through E-tagging to submit price-based information as necessary;

(3) Three types of Export Interchange Transaction Bids will be supported: Fixed, Dispatchable and Up-To-TUC;

(a) A Fixed Bid is a specified MW that will be cleared regardless of the price at the External Interface Settlement Location (Sink LCA specified on NERC E-tag). If the Fixed Export Interchange Transaction is submitted for use in the DA Market, it will be cleared in the DA Market and automatically roll forward as a fixed schedule for use in RUC and the RTBM. If specified for use in the RTBM only, the Fixed Export Interchange Transaction will be considered a fixed schedule for the RUC processes and RTBM.

(b) A Dispatchable Bid specifies both a MW amount and a maximum $/MWh price that the Market Participant is willing to pay if the transaction clears the DA Market. Dispatchable Bids are only available for use in the DA Market. If the transaction clears the DA Market, it automatically rolls forward as a Fixed schedule for use in RUC and the RTBM. Any adjustment to the schedule will be settled as a deviation from the DA Market.

(c) An Up-To-TUC Bid specifies both a MW amount and the maximum amount of congestion cost and marginal loss cost, in $/MWh, between the specified NERC E-tag Source and Sink Settlement Location the Market Participant is willing to pay if the transaction clears the DA Market. Up-To-TUC Bids are only available for use in the DA Market. If the transaction clears the DA Market, it automatically rolls forward as a Fixed schedule for use in the RUC and RTBM. Any adjustment to the schedule will be settled as a deviation from the DA Market.

(4) Export Interchange Transaction Bids are eligible to supply Supplemental Reserve subject to meeting the follow eligibility requirements:

(a) The Export Interchange Transaction Bid must be fixed and submitted for use in the DA Market;
(b) The Export Interchange Transaction must be fully recallable within a 10-minute period for the amount of Supplemental Reserve specified;

(c) All Supplemental Reserve supplied by an Export Interchange Transaction will be used to reduce the Market Participant’s Supplemental Reserve obligation within the applicable Reserve Zone;

(d) Supplemental Reserve supplied by an Export Interchange Transaction in excess of the Market Participant’s Supplemental Reserve obligation within the applicable Reserve Zone will not be eligible for payment; and

(e) Provision of Supplemental Reserve from an Export Interchange Transaction is limited to export transactions associated to DC tie-lines.

4.2.4 Through Interchange Transactions

Energy scheduled through the SPP Balancing Authority Area will be settled in the DA Market, RTBM or both. A Market Participant must reserve transmission service prior to submittal of the schedule in accordance with the procedures specified in the SPP OATT Business Practices in an amount sufficient to cover the request.

(1) Through Interchange Transactions will be submitted via NERC E-tag and RTOSS;

(2) Two types of Through Interchange Transactions will be supported: Fixed and Up-To-TUC;

(a) A Fixed Through Interchange Transaction is a specified MW that will be cleared regardless of the price at either of the External Interface Settlement Locations (Source GCA and Sink LCA specified on E-Tag). If submitted for use in the DA Market, a Fixed Through Interchange Transaction will automatically roll forward as a Fixed schedule for use in RUC and the RTBM. If submitted for use in the RTBM, the Fixed Through Interchange Transaction will clear in the RTBM and will be considered a fixed schedule for use in any RUC Processes.

(b) An Up-To-TUC Through Interchange Transaction specifies both a MW amount and the maximum amount of congestion cost and marginal loss cost, in $/MWh, between the specified E-Tag Source GCA and Sink LCA Settlement Location the Market Participant is willing to pay if the transaction clears the DA Market. Up-To-TUC Through Interchange Transactions are only available for use in the DA Market. If the transaction clears the DA Market, it automatically rolls forward as
4.2.5   **Ramp Reservation Requirements**

SPP uses a ramp reservation system to limit schedule changes to an amount equal to or less than the available ramp capability. The ramp reservation system allows SPP to ensure that sufficient ramp is available before the schedules created under Sections 4.2.2.7 and 4.2.3.3 are approved. SPP determines a limit for the net amount of schedule change into or out of the SPP BA for any 10 minute period based on projected available ramping capability and updates these limits on an ongoing basis. SPP will not approve schedules that violate this limit.

Market Participants may optionally submit requests to reserve ramping capability. A ramp reservation can be made to “hold” ramp room while Market Participants complete their scheduling responsibilities. Ramp reservations are then associated on the NERC Tag when the Market Participant submits the schedule. The ramp reservation is validated against the submitted NERC Tag to ensure the energy profile and path matches. If a Market Participant does not submit a specific request, the ramp reservation system will automatically generate a ramp reservation when the schedule is submitted, if there is sufficient ramp capability available. The follow business rules apply to submittal and approval of ramp reservation requests:

1. There are two time periods during which Market Participants can submit requests to reserve ramping capability:
   a. Up to 1100 hours on the day prior to the Operating Day in order to reserve ramping capability for import or export transactions that clear in the DA Market. Any unused reserved ramping capability is made available for use in import and/or export scheduling in the RTBM for the Operating Day.
   b. Beginning at 1100 hours on the day prior to the Operating Day, ramp reservation requests may be submitted for import and/or export scheduling in the RTBM for the Operating Day, up to 30 minutes prior to the Operating Hour.

2. Market Participant ramp reservation requests are evaluated and granted on a first come, first served basis;

3. Market Participants may be required to shift their schedule requests in order to get their ramp reservation requests approved. If the Market Participant shifts their schedule up to one hour in either direction, they are not required to purchase additional transmission;
(4) If a Market Participant chooses to fix their ramp violation by extending the duration of the transaction, they do not have to purchase additional transmission if the total MWh capacity of the transmission request is not exceeded;

(5) Market Participants may submit one or more schedules associated with one or more approved ramp reservations, such that the sum of the submitted schedule MWhs do not exceed the MWhs of approved ramp on that path. Any approved ramp reservations for a path in excess of the associated schedules is released for use in the RUC processes and RTBM;

(6) SPP updates available ramping capability on a five (5) minute basis.

4.2.6 Multi-Day Reliability Assessment

The Multi-Day Reliability Assessment identifies Resources which must be given start-up orders well in advance of an Operating Day. Each day, SPP performs a Multi-Day Reliability Assessment for at least three days prior to the Operating Day, to assess capacity adequacy for each Operating Day. The purpose of the Multi-Day Reliability Assessment is to evaluate the need to issue start-up instructions for Resources that cannot be committed in the DA RUC process because of a long lead time (“Long-Lead-Time Resource”).

The Multi-Day Reliability Assessment consists of four steps: (1) process inputs; (2) perform resource adequacy assessment; (3) evaluate results; and (4) issue commitment orders.

4.2.6.1 Multi-Day Reliability Assessment Inputs

Inputs to the Multi-Day Reliability Assessment process will consist of:

(1) RTBM Resource Offers;

(2) Estimated Fixed Export Interchange Transaction Bids;

(3) Estimated Fixed Import Interchange Transaction Offers;

(4) Estimated SPP Operating Reserve requirements (system-wide and Reserve Zone min and max) based on historical requirements;

(5) SPP Mid-Term Load Forecast (MTLF) as described under Section 4.1.2.1;

(6) Wind Resource output forecast as described under Section 4.1.2.2;

(7) Transmission System topology with approved Transmission System outages; and

(8) Resource outages.
4.2.6.2 Multi-Day Reliability Assessment Analysis

Using the inputs described above, SPP performs a capacity adequacy analysis for the upcoming Operating Day as follows:

1. SPP calculates an SPP system requirement for each hour of the Operating Day as the sum of (a) Mid-Term Load Forecast, (b) Fixed Interchange Transaction Bids, (c) Regulation-Up requirement and (d) the Contingency Reserve requirement in each hour reduced by the Wind Resource output forecast;

2. SPP then calculates available Resource capacity in each hour as the sum of (a) Maximum Emergency Capacity Operating Limit for Resources other than Long-Lead-Time Resources that are not on an approved SPP outage as submitted as part of the Resource Offer and (b) Fixed Import Interchange Transaction Offers;

3. For each hour of the Operating Day, SPP then compares the values calculated under (1) above and (2) above. If in any hour of the Operating Day, the values calculated under (1) above exceed the values calculated under (2) above, SPP will commit available Long-Lead-Time Resources on an economic basis to eliminate the deficiency as follows:

   a. For each available Long-Lead Time Resource, SPP calculates a commitment cost in dollars that is equal to:

      i. The sum of 1) the Resources Start-Up Offer, 2) the Resource’s No-Load Offer multiplied by the greater of the Resource’s Minimum Run Time (in Hours) or the number of hours the Resource would be committed ignoring the Minimum Run Time, and 3) the Resources average cost to operate at Minimum Economic Capacity Operating Limit, as calculated from the Resource’s Energy Offer Curve, multiplied by the greater of the Resource’s Minimum Run Time (in Hours) or the number of hours the Resource would be committed ignoring the Minimum Run Time.

      ii. SPP then creates a merit order list starting with the least cost Resource bases upon the commitment cost calculated in (i) above. SPP then selects Resources for commitment in merit order until sufficient capacity is committed to relieve the anticipated capacity shortage with the objective of minimizing the total capacity committed to meet the anticipated shortage at the lowest overall commitment cost.
(4) In additional to the analysis in (3) above, SPP may also commit Long-Lead-Time Resources to address Transmission System related reliability problems. SPP will select such Resources for commitment using the methodology described in (3) above except that the merit order list of available Resources will be limited to specific Resources that are in the needed geographic location.

4.2.6.3 Multi-Day Reliability Assessment Results

SPP staff communicates these start-up orders to the affected Market Participants. At the time of this notification, the submitted Offers become binding and the selected Resource(s) Offers are included in the DA Market with a Commitment Status similar to Self-commit. Unlike Self-Committed Resources, however, the Multi-day Reliability Assessment committed Resources will be eligible for DA Market make-whole payment guarantees as described under Section 4.5.8.12.

4.3 Day-Ahead Activities

Day-Ahead activities begin 24 hours prior to the Operating Day and consist of the DA Market and Day-Ahead RUC processes. Exhibit 4-8 provides a representative overall timeline of Day-Ahead activities. The times specified in the timeline are the times associated with normal operating conditions. SPP may delay these times to account for unforeseen circumstances and, under such circumstances, SPP will notify Market Participants of any such timing delays.

Exhibit 4-8: Day-Ahead Activities Timeline
A detailed description of the DA Market and Day-Ahead RUC processes is provided in the following subsections.

### 4.3.1 Day-Ahead Market

The DA Market process begins with the submittal of new Offers and Bids, or updates to the Offers and Bids submitted in Pre-Day-Ahead, for use in the DA Market clearing. Energy clearing is based upon the Offers and Bids submitted. Operating Reserve clearing is based upon the Offers submitted to meet the SPP Operating Reserve requirement. Market Participants must submit final Offers and Bids no later than 1100 hours Day-Ahead.

Immediately following the close of the DA Market at 1100 hours Day-Ahead, SPP begins the process of clearing the DA Market and completes the process by 1600 hours. DA Market operations consist of three steps: (1) process DA Market inputs; (2) DA Market execution and (3) DA Market results. Each of these steps is described in the following subsections.

#### 4.3.1.1 DA Market Inputs

Inputs to the DA Market algorithm consist of:

1. **DA Market Offers and Bids as submitted by Market Participants prior to 1100 hours Day-Ahead;**
   - For Demand Bids, Virtual Energy Bids and/or Virtual Energy Offers submitted at a Load Settlement Location that contains more than one PNode, SPP distributes the Bid MW down to the associated PNodes using weighting factors for modeling purposes as described under Section 4.1.2.1.7.
   - For Virtual Energy Bids and/or Virtual Energy Offers submitted at a Hub Settlement Location and Interchange Transactions submitted at an External Interface, SPP uses a common set of weighting factors to distribute the Bid and/or Offer MWs down to PNodes included in the Hub or External Interface for modeling purposes. These weighting factors are determined by SPP at the time the Hub or External Interface is created and are not dependent upon historical injections/withdrawals.

2. **Resource Offers for long lead time Resources selected by SPP for commitment during the Operating Day during the Multi-Day Reliability Assessment process;**

3. **Through Interchange Transactions as submitted by Market Participants prior to 1100 hours Day-Ahead;**
(4) SPP Operating Reserve requirements (system-wide and Reserve Zone min and max);

(5) SPP Transmission System topology consistent with Network Model in place for current Operating Day, including adjustments to RCF firm flow entitlements if applicable;

(6) Transmission System outages; and

(7) Resource outages.

4.3.1.2 DA Market Execution

SPP clears the Day-Ahead Market for each hour of the upcoming Operating Day based on the inputs described above. A simultaneous co-optimization methodology, utilizing the SCUC and SCED algorithms is employed to simultaneously perform the following tasks:

(1) Commit offered Resources, Import Interchange Transaction Offers and Virtual Energy Offers using the SCUC algorithm to meet the Demand Bids, Virtual Energy Bids, Export Interchange Transactions Bids and Operating Reserve requirements at least cost throughout the projected upcoming Operating Day while respecting Resource operating constraints and transmission constraints;

   (a) The DA Market SCUC algorithm will initially consider commitment of Resources with a Commit Status of Market and Self, including Resources committed in the Multi-Day Reliability Assessment process, only including capacity up to the Resources’ Maximum Economic Capacity Operating Limit (or Maximum Regulation Capacity Operating Limit if selected for Regulation-Up) and down to the Resources Minimum Economic Capacity Operating Limit (or Minimum Regulation Capacity Operating Limit if selected for Regulation-Down).

   (i) If this capacity is not sufficient to meet the fixed Demand Bids and fixed Export Interchange Transaction Bids plus Operating Reserve requirements, the DA Market SCUC algorithm will, in priority order: (1) curtail non-firm fixed Export Interchange Transaction Bids (2) incorporate capacity up to the Resources’ Maximum Emergency Capacity Operating Limit; and (3) include commitment of Resources’ with a Commit Status of Reliability.

   (ii) If there is a capacity surplus calculated as the sum of Self-Committed capacity at minimum output, fixed Import Interchange Transaction Offers and the Regulation-Down requirement that is in excess of the sum of
Fixed Demand Bids and fixed Export Interchange Transaction Bids, the DA Market SCUC algorithm will, in priority order (1) curtail non-firm fixed Import Interchange Transaction Offers and (2) incorporate capacity down to the Resources’ Minimum Emergency Capacity Operating Limit for Resources not selected for Regulation-Down and (3) incorporate capacity down to the Resources’ Minimum Emergency Capacity Operating Limit for Resources selected for Regulation-Down.  

(2) Using the commitment results from the SCUC, clear Resource Offers and Import Interchange Transaction Offers to meet Demand Bids, Virtual Energy Bids, Export Interchange Transaction Bids and Operating Reserve requirements at minimum cost for each hour of the upcoming Operating Day using the SCED algorithm while respecting Resource operating constraints and transmission constraints.  

(a) The SCED algorithm includes marginal loss sensitivity factors which approximate the change in marginal system losses for a change in Energy dispatch. Inclusion of these factors further optimizes the Energy dispatch and reduces overall production costs.  

(b) In certain situations, enforcing constraints may result in a solution that is not feasible at a Shadow Price less than an appropriately priced VRL. In such cases, SPP must apply Violation Relaxation Limits (VRLs) in SCED as described under Section 4.1.4.  

(c) To ensure rational pricing of cleared Operating Reserve products, the SCED algorithm will include product substitution logic as follows:  

(i) Any Regulation-Up Offers remaining once the Regulation-Up Requirement is satisfied may be used to meet Contingency Reserve requirements if Regulation-Up Offer is more economic or is required to meet the overall Operating Reserve requirement;  

(ii) Any Spinning Reserve Offers remaining once the Spinning Reserve Requirement is satisfied may be used to meet Supplemental Reserve requirements if Spinning Reserve Offer is more economic or is required to meet the overall Operating Reserve requirement;  

(iii) The product substitution logic ensures that the MCP for Regulation-Up is always greater than or equal to the Spinning Reserve MCP and that the
Spinning Reserve MCP is always greater than or equal to the Supplemental Reserve MCP.

(d) To ensure that Market Participants are indifferent as to whether they are cleared for Energy or Operating Reserve, the co-optimization logic will provide through the Shadow Price calculation Market Clearing Prices for Operating Reserve that include any lost opportunity costs incurred as a result of Operating Reserve clearing.

4.3.1.2.1 Clearing During Capacity Shortage

(1) If there is an Operating Reserve shortage in any hour, Scarcity Pricing will be invoked as described under Section 4.1.5;

(2) If there is a shortage of capacity to meet the fixed Demand Bids and fixed firm Export Interchange Transactions in any hour, the SCED algorithm will reduce the fixed Demand Bids and fixed firm Export Interchange Transactions on a pro-rata reduction basis based on the fixed MW amounts to match the available capacity and Scarcity Pricing will be invoked as described under Section 4.1.5;

(3) Ramp sharing is applied to ensure that short-term ramping deficiencies from hour to hour do not initiate unjustified Scarcity Pricing (i.e. Scarcity Pricing should only be initiated when there is a capacity shortage) as described under Section 4.1.5.1;

(4) If there is a transmission constraint that cannot be relieved due to a shortage of capacity in any hour, the SCED algorithm will clear the bid-in demands on a pro-rata basis based upon the impact on relieving the constraint;

4.3.1.2.2 Clearing During Excess Generation Conditions

(1) If the sum of Minimum Emergency Capacity Operating Limits on self-committed Resources plus the Regulation-Down requirement is in excess of the cleared bid-in demands in any hour, the SCED algorithm will reduce Resources on a pro-rata reduction basis such that the resulting sum of minimum limits matches the bid-in demand.

(a) LMPs will be set by the Offers prices associated with Energy down to the Minimum Emergency Capacity Operating Limit to the extent that the Regulation-Down requirement can be maintained. If the actions under 4.3.1.2 (1)(a)(ii) above create a Regulation-Down shortage during any Hour either on a system-wide basis or Reserve Zone basis, the MCPs for Regulation-Down will reflect Scarcity
Prices and LMPs will reflect negative Scarcity Prices as described under Section 4.1.5.

4.3.1.3 DA Market Results

No later than 1600 hours Day-Ahead, SPP electronically communicates the DA Market results for each hour of the Operating Day to Market Participants. The following results are communicated to each Market Participant that relates only to that Market Participant:

   (a) Cleared Offers for Energy associated with Resource Offers also represent a physical Resource commitment schedule that forms the basis for the Current Operating Plan for the upcoming Operating Day.
   (b) Resources committed by SPP in the DA Market that incur one or more start-up costs within the Operating Day as a result of the SPP DA Market commitment are guaranteed to receive revenues that are at least equal to the Resource Offer costs for the associated cleared amount of Energy, Regulation-Up, Regulation-Down Spinning Reserve and/or Supplemental Reserve.

2. Cleared Virtual Energy Offers, in MW;

3. Cleared Import Interchange Transaction Offers, in MW;

4. Cleared Demand Bids, in MW;

5. Cleared Virtual Energy Bids, in MW;

6. Cleared Export Interchange Transaction Bids, in MW;

7. Cleared Through Interchange Transactions, in MW.

The following results are communicated to all Market Participants:

1. Locational Marginal Prices (LMPs) for each Settlement Location, the Marginal Energy Component (MEC) of LMP, the Marginal Congestion Component (MCC) of LMP for each Settlement Location and the Marginal Losses Component (MLC) of LMP for each Settlement Location;

2. Market Clearing Prices for Regulation-Up, Regulation-Down, Spinning Reserve and Supplemental Reserve for each Reserve Zone.
4.3.2  Day-Ahead Reliability Unit Commitment

At 1700 hours or one hour following the posting of the DA Market results, whichever is later, SPP begins the Day-Ahead RUC process to assess capacity adequacy during the Operating Day. No later than 2000 hours or three hours following the start of the DA RUC process, whichever is later, SPP communicates new or modified Resource commitment schedules to affected Market Participants and updates the Current Operating Plan.

The Day-Ahead RUC consists of four steps: (1) process RUC inputs; (2) execute RUC algorithm; (3) evaluate RUC results; and (4) issue commitment/de-commitment orders and update Current Operating Plan.

4.3.2.1  Day-Ahead RUC Inputs

Inputs to the RUC algorithm consist of:

1. RTBM Resource Offers, including Resources with a Self-Commit status submitted between 1600 hours and 1700 hours Day-Ahead;
2. Confirmed cleared Export Interchange Transaction Bids from the DA Market;
3. Confirmed cleared Import Interchange Transaction Offers from the DA Market;
4. Confirmed cleared Through Interchange Transactions from the DA Market;
5. Confirmed Export Interchange Transactions specified for use in the RTBM only;
6. Confirmed Import Interchange Transactions specified for use in the RTBM only;
7. Confirmed Through Interchange Transactions specified for use in the RTBM only;
8. SPP Operating Reserve requirements (system-wide and Reserve Zone min and max);
9. SPP Mid-Term Load Forecast (MTLF) as described under Section 4.1.2.1;
10. SPP Transmission System topology consistent with Network Model in place for the Operating Day, including adjustments to RCF firm flow entitlements if applicable;
11. Resource commitment schedules from the DA Market unless SPP Operators are informed of a Resource outage;
12. Commitment schedules for long lead time Resources selected in the Multi-Day Reliability Assessment process unless SPP Operators are informed of a Resource outage;
13. Wind Resource MWh output forecast as described under Section 4.1.2.2;
(14) Transmission System outages; and
(15) Resource outages.

4.3.2.2 Day-Ahead RUC Execution

Using the inputs described above, SPP performs a capacity adequacy analysis for the upcoming Operating Day using the SCUC algorithm.

(1) The objective of the SCUC is to commit Resources to meet the SPP Mid-Term Load Forecast and Operating Reserve requirements over the Operating Day such that commitment costs are minimized while adhering to transmission system security constraints and the resource operating parameter constraints submitted as part of the RTBM Offers;

(2) Commitment costs are defined as Start-Up Offer, No-Load Offer and incremental cost to operate at minimum output as defined in the submitted Energy Offer Curve. Incremental Energy costs above minimum output and Operating Reserve Offers are not considered by the RUC SCUC in making commitment decisions;

(3) The SCUC algorithm will initially consider commitment of Resources with a Commit Status of Market or Self only including capacity up to the Resources’ Maximum Economic Capacity Operating Limit (or Maximum Regulation Capacity Operating Limit if selected for Regulation-Up) and down to the Resources Minimum Economic Capacity Operating Limit (or Minimum Regulation Capacity Operating Limit if selected for Regulation-Down).

(a) If this capacity, either on a system-wide basis or Reserve Zone basis, is not sufficient to meet the SPP Mid-Term Load Forecast plus Operating Reserve requirements, the SCUC algorithm will, in priority order: (1) curtail non-firm Export Interchange Transactions; (2) increase capacity up to the Resources’ Maximum Emergency Capacity Operating Limit; and (3) include commitment of Resources’ with a Commit Status of Reliability.

(b) Either on a system-wide basis or Reserve Zone basis, if the sum of Self-Committed capacity at minimum output, fixed Import Interchange Transaction Offers and the Regulation-Down requirement is in excess of the sum of the SPP Mid-Term Load Forecast and fixed Export Interchange Transactions, the RUC SCUC algorithm will, in priority order: (1) curtail non-firm fixed Import Interchange Transactions; (2) reduce Resource capacity down to the Resources’
Minimum Emergency Capacity Operating Limit for Resources not selected for Regulation-Down; (3) de-commit Resources that were committed in the DA Market with a Commit Status of Market; and (4) de-commit Self-Committed Resources.

(i) If there is a transmission constraint within a Reserve Zone occurring simultaneously with a Reserve Zone excess capacity event, SCUC may commit additional Resources and/or de-commit Resources to relieve the constraints provided that any commitment changes do not aggravate the excess capacity situation.

Any curtailment of schedules, use of Reliability Status Resources or use of Emergency operating limits by the RUC algorithms will only be advisory information to the SPP RUC Operators. Day-Ahead RUC and Intra-Day RUC Operators will determine which of these options should be acted on and when as described in the Day-Ahead and Intra-Day RUC Results sections.

4.3.2.3 Day-Ahead RUC Results

No later than 2000 hours Day-Ahead, SPP electronically communicates the Day-Ahead RUC results for each hour of the Operating Day to Market Participants which consist of the following:

(1) Resource commitment schedules for Resources submitting a Commit Status of “Market” or “Reliability” as part of the RTBM Resource Offer indicating which hours the Resource is scheduled to operate for the Operating Day. This schedule does not become effective until the Market Participant is issued a start-up order by SPP. SPP then updates the Current Operating Plan;

   (a) Resources committed by SPP in the Day-Ahead RUC that incur one or more start-up costs within the Operating Day as a result of the Day-Ahead RUC commitment are guaranteed to receive revenues that are at least equal to the Resource Offer costs for the associated cleared amount of Energy, Regulation, Spinning Reserve and/or Supplemental Reserve over the commitment period, subject to eligibility criteria, as described in Section 4.5.9.8.

(2) Resource de-commitment schedules for Resources submitting a Commit Status of “Market” or “Reliability” as part of the RTBM Resource Offer, or a DA Market Commit Status or “Market” as part of the DA Market Resource Offer, indicating the hour the Resource is scheduled to be de-committed. This schedule does not become effective until
the Market Participant is issued a shut-down order by SPP. SPP then updates the Current Operating Plan;

(a) This de-commitment schedule may include de-commitment of Resources that were committed by SPP in the DA Market with a DA Market Commit Status of “Market” to alleviate anticipated excess supply conditions as described under Section 4.3.2.2(3)(b). This schedule does not become effective until the Market Participant is issued a shut-down order by SPP. To the extent that a shut-down order is issued to a Resource that was committed by SPP in the DA Market, that Resource is eligible for compensation under Section 4.5.9.9. SPP then updates the Current Operating Plan.

(3) Each Market Participant is notified regarding its Resources that are expected to be dispatched to Maximum Emergency Capacity Operating Limits. This notification is for information purposes only and will not become effective until confirmed by SPP prior to the affected Operating Hour. Market Participants will be notified at least ten (10) minutes prior to the beginning of the Operating Hour but not more than 30 minutes prior to the beginning of the Operating Hour that the Maximum Emergency Capacity Operating Limit will be used;

(4) Each Market Participant is notified regarding its Resources that are expected to be dispatched to Minimum Emergency Capacity Operating Limit. This notification is for information purposes only and will not become effective until confirmed by SPP prior to the affected Operating Hour. Market Participants will be notified at least ten (10) minutes prior to the beginning of the Operating Hour but not more than 30 minutes prior to the beginning of the Operating Hour that the Minimum Emergency Capacity Operating Limit will be used;

(5) Notification that a fixed Interchange Transaction is expected to be curtailed due to excess or shortage conditions.

4.3.2.3.1 Managing Regulation Control Status Prior to Operating Hour

All on-line Regulation Qualified Resources, Regulation-Up Qualified Resources and Regulation-Down Qualified Resources are expected to be on “Regulating” Control Status thus making such Resources eligible to be cleared for Regulation-Up and/or Regulation-Down during the Operating Hour. However, SPP may not select certain qualified Resources to be eligible for regulation clearing during an Operating Hour if:
(a) during times of expected capacity shortages as described in (3) above, a Resource’s Maximum Regulation Capacity Operating Limit is less than its Maximum Economic Capacity Operating Limits;

(b) during times of expected excess generation conditions as described under (4) above, a Resource’s Minimum Regulation Capacity Operating Limits is greater than its Minimum Economic Capacity Operating Limit; or

(c) a Market Participant requests that its qualified Resource operate under “Non-Regulating” status for economic reasons and SPP approves the request after determining that sufficient qualified Resources are remaining to meet the Regulation-Up and Regulation-Down requirements during the affected Operating Hour.

If the conditions under (a), (b) or (c) above apply, SPP will notify Market Participants electronically or by other means at least 30 minutes prior to the start of each Operating Hour that the Market Participant’s affected on-line Regulation-Qualified Resources, Regulation-Up Qualified Resources and/or Regulation-Down Qualified Resources are not eligible to clear regulation within the Operating Hour. Following this notification, Market Participants must ensure that their Resource Control Status for the affected Resource(s) is set to “Non-Regulating” or “Manual.” The Resource shall remain in this status until the affected Market Participant is otherwise notified by SPP or the affected Market Participant requests a change to “Regulating” status and SPP approves the request.

4.4 Operating Day Activities

Operating Day activities begin at 2000 hours Day-Ahead and consist of the Intra-Day RUC processes and RTBM. Exhibit 4-9 provides a representative overall timeline of Operating Day activities.
A detailed description of the Intra-Day RUC and RTBM processes is provided in the following subsections.

### 4.4.1 Intra-Day Reliability Unit Commitment

Following completion of the Day-Ahead RUC process, SPP continually evaluates the need for an Intra-Day RUC for the remainder of the Day-Ahead period and the Operating Day and performs additional Intra-Day RUCs at least every four hours. Consistent with the Day-Ahead RUC, these additional Intra-Day RUCs assess capacity adequacy during the Operating Day.

The Intra-Day RUC consists of four steps: (1) process RUC inputs; (2) execute RUC algorithm; (3) evaluate RUC results; and (4) issue commitment/de-commitment orders and update Current Operating Plan.
4.4.1.1 Intra-Day RUC Inputs

Inputs to the RUC algorithm consist of:

1. RTBM Resource Offers;
2. Confirmed Export Interchange Transactions;
3. Confirmed Import Interchange Transactions;
4. Confirmed Through Interchange Transactions;
5. SPP Operating Reserve requirements (system-wide and Reserve Zone min and max);
6. SPP Mid-Term Load Forecast as described under Section 4.1.2.1;
7. SPP Transmission System topology consistent with Network Model in place for the Operating Day, including adjustments to RCF firm flow entitlements if applicable;
8. Resource commitment and de-commitment schedules from the Day-Ahead RUC or previous Intra-Day RUCs;
9. Resources providing Regulation-Up and Regulation-Down from the Day-Ahead RUC or previous Intra-Day RUCs;
10. Wind Resource output forecast as described under Section 4.1.2.2;
11. Transmission System outages; and

4.4.1.2 Intra-Day RUC Execution

Using the inputs described above, SPP performs a capacity adequacy analysis for the upcoming Operating Day and throughout the Operating Day using a SCUC algorithm.

1. The objective of the SCUC is to commit Resources to meet the SPP Mid-Term Load Forecast and Operating Reserve requirements over the Operating Day such that commitment costs are minimized while adhering to transmission system security constraints and the resource operating parameter constraints submitted as part of the RTBM Offers;

2. Commitment costs are defined as Start-Up Offer, No-Load Offer and incremental cost to operate at minimum output as defined on the submitted Energy Offer Curve. Incremental
Energy costs above minimum output and Operating Reserve Offers are not considered by the RUC SCUC in making commitment decisions;

(3) The SCUC algorithm will initially consider commitment of Resources with a Commit Status of Market or Self only including capacity up to the Resources’ Maximum Economic Capacity Operating Limit (or Maximum Regulation Capacity Operating Limit if selected for Regulation-Up) and down to the Resources Minimum Economic Capacity Operating Limit (or Minimum Regulation Capacity Operating Limit if selected for Regulation-Down).

(a) If this capacity, either on a system-wide basis or Reserve Zone basis, is not sufficient to meet the SPP Mid-Term Load Forecast plus Operating Reserve requirements, the RUC SCUC algorithm will, in priority order: (1) curtail non-firm Export Interchange Transactions; (2) increase capacity up to the Resources’ Maximum Emergency Capacity Operating Limit; and (3) include commitment of Resources’ with a Commit Status of Reliability.

(b) Either on a system-wide basis or Reserve Zone basis, if the sum of Self-Committed capacity at minimum output, fixed Import Interchange Transactions and the Regulation-Down requirement is in excess of the sum of the SPP Mid-Term Load Forecast and fixed Export Interchange Transactions, the SCUC algorithm will, in priority order: (1) curtail non-firm fixed Import Interchange Transactions; (2) reduce capacity down to the Resources’ Minimum Emergency Capacity Operating Limit for Resources not selected for Regulation-Down; (3) de-commit Resources that were committed in the DA Market with a Commit Status of Market; and (4) de-commit Self-Committed Resources that were committed following the Day-Ahead RUC process.

(i) If there is a transmission constraint within a Reserve Zone occurring simultaneously with a Reserve Zone excess capacity event, RUC may commit additional Resources to relieve the constraints provided that the additional commitment does not aggravate the excess capacity situation.

4.4.1.3 Intra-Day RUC Results

SPP electronically communicates the RUC results for each hour of the Operating Day to Market Participants as soon as practical following completion of each Intra-Day RUC execution. These results consist of the following:
(1) Resource commitment schedules for Resources submitting a Commit Status of “Market” or “Reliability” as part of the RTBM Resource Offer indicating which hours the Resource is scheduled to operate for the Operating Day. This schedule does not become binding until the Market Participant is issued a start-up order by SPP. SPP then updates the Current Operating Plan;

   (a) Resources committed by SPP in the Intra-Day RUC that incur one or more start-up costs within the Operating Day as a result of the Intra-Day RUC commitment are guaranteed to receive revenues that are at least equal to the Resource Offer costs for the associated cleared amount of Energy, Regulation, Spinning Reserve and/or Supplemental Reserve over the commitment period, subject to eligibility criteria, as described in Section 4.5.9.8.

(2) Resource de-commitment schedules for Resources submitting a Commit Status of “Market” or “Reliability” as part of the RTBM Resource Offer, or a DA Market Commit Status or “Market” as part of the DA Market Resource Offer, indicating the hour the Resource is scheduled to be de-committed. This schedule does not become effective until the Market Participant is issued a shut-down order by SPP. SPP then updates the Current Operating Plan;

   (a) This de-commitment schedule may include de-commitment of Resources that were committed by SPP in the DA Market with a DA Market Commit Status of “Market” to alleviate anticipated excess supply conditions as described under Section 4.4.1.2(3)(b). This schedule does not become effective until the Market Participant is issued a shut-down order by SPP. To the extent that a shut-down order is issued to a Resource that was committed by SPP in the DA Market, that Resource is eligible for compensation under Section 4.5.9.9. SPP then updates the Current Operating Plan.

(3) Each Market Participant is notified regarding its Resources that are expected to be dispatched to its Maximum Emergency Capacity Operating Limit. This notification is for information purposes only and will not become effective until confirmed by SPP prior to the affected Operating Hour. Market Participants will be notified at least ten (10) minutes prior to the beginning of the Operating Hour but not more than 30 minutes prior to the beginning of the Operating Hour that the Maximum Emergency Capacity Operating Limit will be used;
(4) Each Market Participant is notified regarding its Resources that are expected to be dispatched down to its Minimum Emergency Capacity Operating Limit. This notification is for information purposes only and will not become effective until confirmed by SPP prior to the affected Operating Hour. Market Participants will be notified at least ten (10) minutes prior to the beginning of the Operating Hour but not more than 30 minutes prior to the beginning of the Operating Hour that the Minimum Emergency Capacity Operating Limit will be used;

(5) Notification that a fixed Interchange Transaction is expected to be curtailed due to excess or shortage conditions.

4.4.1.3.1 Managing Regulation Control Status Prior to Operating Hour

All on-line Regulation Qualified Resources, Regulation-Up Qualified Resources and Regulation-Down Qualified Resources are expected to be on “Regulating” Control Status thus making such Resources eligible to be cleared for Regulation-Up and/or Regulation-Down during the Operating Hour. However, SPP may not select certain qualified Resources to be eligible for regulation clearing during an Operating Hour if:

(a) during times of expected capacity shortages as described in (3) above, a Resource’s Maximum Regulation Capacity Operating Limit is less than its Maximum Economic Capacity Operating Limits;

(b) during times of expected excess generation conditions as described under (4) above, a Resource’s Minimum Regulation Capacity Operating Limits is greater than its Minimum Economic Capacity Operating Limit; or

(c) a Market Participant requests that its qualified Resource operate under “Non-Regulating” status for economic reasons and SPP approves the request after determining that sufficient qualified Resources are remaining to meet the Regulation-Up and Regulation-Down requirements during the affected Operating Hour.

If the conditions under (a), (b) or (c) above apply, SPP will notify Market Participants electronically or by other means at least 30 minutes prior to the start of each Operating Hour that the Market Participant’s affected on-line Regulation-Qualified Resources, Regulation-Up Qualified Resources and/or Regulation-Down Qualified Resources are not eligible to clear regulation within the Operating Hour. Following this notification, Market Participants must ensure that their Resource Control Status for the affected Resource(s) is set to “Non-Regulating” or “Manual.” The Resource shall remain in this status until the affected Market Participant is
otherwise notified by SPP or the affected Market Participant requests a change to “Regulating” status and SPP approves the request.

4.4.2 Real-Time Balancing Market

SPP operates the RTBM on a continuous 5-minute basis. SPP clears the RTBM by determining the security-constrained dispatch that is the least costly means of balancing generation and load (supply/demand) while meeting Operating Reserve requirements within the SPP Balancing Authority Area based on actual conditions, forecasted conditions, and submitted Offers. The RTBM uses the same Network Model that is used in the DA Market, with all RTBM network configurations and constraints as determined from the most recent State Estimator results.

RTBM operations consist of three steps: (1) Process RTBM inputs; (2) Execute RTBM and (3) Post RTBM results. Each of these steps is described in the following subsections.

4.4.2.1 RTBM Inputs

Inputs into the RTBM algorithm consist of data provided prior to each Operating Hour and data provided within each Operating Hour.

4.4.2.1.1 Pre-Operating Hour Inputs:

(1) RTBM Resource Offers;

(2) Approved and tagged Export Interchange Transactions, Import Interchange Transactions and Through Interchange Transactions;

   (a) Interchange Transactions submitted at an External Interface, SPP uses a common set of weighting factors to distribute the MWs down to PNodes included in the External Interface for modeling purposes. These weighting factors are determined by SPP at the time the External Interface is created and are not dependent upon historical injections/withdrawals.

(3) SPP Operating Reserve requirements (system-wide and Reserve Zone min and max);

(4) Resources selected to provide Regulation-Up or Regulation-Down from the most recent RUC process. This set of Resources will remain on regulation control for the Operating Hour and will be used by SCED to clear Regulation-Up and/or Regulation-Down on a 5-minute basis to meet the regulation requirements;

(5) Resource commitment from the Current Operating Plan;
(a) The Current Operating Plan includes Resource commitments and Resource de-commitments from the Multi-Day Reliability Assessment process, DA Market, Day-Ahead RUC and Intra-Day RUC.

(6) Use of Maximum Emergency Capacity Operating Limits on Resources identified in the Day-Ahead RUC or Intra-Day RUC; and

(7) Use of Minimum Emergency Capacity Operating Limits on Resources identified in the Day-Ahead RUC or Intra-Day RUC.

4.4.2.1.2 In-Operating Hour Inputs:

(1) Latest State Estimator solution for:
   (a) distribution of load forecast throughout the Network Model;
   (b) latest transmission topology for the Network Model; and
   (c) backup initial energy injection of Resources if SCADA not available.

(2) Actual Resource output from latest SCADA snapshot to determine initial energy injection of Resources and Generator outages;

(3) Active transmission constraints including RCFs with firm flow entitlement adjustments if applicable;

(4) Intra-Hour adjustments to Interchange Transactions due to curtailments or initiation of a Reserve Sharing Event involving external Balancing Authorities;

(5) Intra-Hour adjustments to Resource Offer parameters;
   (a) Market Participants are required to keep their Resource Offer operating parameters up-to-date during the Operating Day. In the event of a required change in a Resource Offer operating parameter due to physical Resource changes during an Operating Hour, the Market Participant is responsible for notifying SPP of required changes, and SPP will make the required modification for the current Operating Hour. Market Participant shall remain responsible for accurately reflecting Resource operating parameters in their Resource Offer submissions for subsequent hours.

(6) SPP Short-Term Load Forecast (STLF) as described under Section 4.1.2.1;
   (a) SPP distributes the STLF down to the associated PNodes using weighting factors for modeling purposes as described under Section 4.1.2.1.7
(7) Wind Resource output forecast as described under Section 4.1.2.2.

4.4.2.2 RTBM Execution

SPP executes the RTBM every 5-minutes for the next Dispatch Interval based on the inputs described above.

(1) A simultaneous co-optimization methodology utilizing a SCED algorithm is employed to calculate Resource Dispatch Instructions and clear Regulation-Up, Regulation Down, Spinning Reserve and/or Supplemental Reserve to meet the SPP Short-Term Load Forecast and Operating Reserve requirements at minimum costs based upon submitted Offers while respecting Resource operating constraints and transmission constraints;

(2) The SCED algorithm includes marginal loss sensitivity factors which approximate the change in marginal system losses for a change in Energy dispatch. Inclusion of these factors further optimizes the Energy dispatch and reduces overall production costs;

(3) In certain situations, enforcing constraints may result in a solution that is not feasible at a Shadow Price less than an appropriately priced VRL. In such cases, SPP must apply Violation Relaxation Limits (VRLs) in SCED as described under Section 4.1.4;

(4) To ensure rational pricing of cleared Operating Reserve products, the SCED algorithm will include product substitution logic as follows:

(a) Any Regulation-Up Offers remaining once the Regulation-Up Requirement is satisfied may be used to meet Contingency Reserve requirements if Regulation-Up Offer is more economic or is needed to meet the overall Operating Reserve requirement;

(b) Any Spinning Reserve Offers remaining once the Spinning Reserve Requirement is satisfied may be used to meet the Supplemental Reserve requirements if the Spinning Reserve Offer is more economic or is needed to meet the overall Operating Reserve requirement.

The product substitution logic ensures that the MCP for Regulation-Up is always greater than or equal to the Spinning Reserve MCP and that the Spinning Reserve MCP is always greater than or equal to the Supplemental Reserve MCP.

(5) To ensure that Market Participants are indifferent as to whether they are cleared for Energy or Operating Reserve, the co-optimization logic will provide through the Shadow
Price calculation Market Clearing Prices for Operating Reserve that include any lost opportunity costs incurred as a result of Operating Reserve clearing;

(6) Additionally, SPP executes a look-ahead SCED prior to the RTBM SCED process. The look-ahead SCED will perform at least these two functions: (1) anticipate the need to adjust Dispatch Instructions for the current Dispatch Interval to prepare to meet forecasted changes in the load several Dispatch Intervals into the future and (2) determine commitment of Quick-Start Resources within the Operating Hour. The look-ahead period is at least two Dispatch Intervals, one of which is the next Dispatch Interval following the current Dispatch Interval.

4.4.2.2.1 Emergency Operations – Capacity Shortage

(1) If there is an actual Operating Reserve shortage during any Dispatch Interval, either on a system-wide or a Reserve Zone basis, the system-wide or Reserve Zone Scarcity Prices will be invoked as described under Section 4.1.5.

(2) If there is a shortage of available capacity to meet Energy requirements either on a system-wide or Reserve Zone basis, SPP will begin load shedding procedures and all LMPs will be set as described under Section 4.1.5.

(3) Ramp sharing is applied to ensure that short-term ramping deficiencies within an Operating Hour do not initiate unjustified Scarcity Pricing (i.e. Scarcity Pricing should only be initiated when there is a capacity shortage) as described under Section 4.1.5.1.

4.4.2.2.2 Emergency Operations – Excess Generation

(1) SPP operators may take the following actions within the Operating Hour to address excess generation conditions on either a system-wide or Reserve Zone basis, that were not alleviated through actions taken prior to the Operating Hour:

(a) Notify any remaining Resources not cleared for Regulation-Down that do not have a Dispatch Status of Fixed that were not notified prior to the Operating Hour that those Resources will be dispatched down to their Minimum Emergency Capacity Operating Limits;

(b) De-commit any remaining Resources that were Self-Committed following the Day-Ahead RUC process;

(c) Curtail any remaining fixed Import Interchange Schedules that were submitted and approved following the Day-Ahead RUC process;
(d) Reduce Resources with a Dispatch Status of Fixed and Variable Energy Resources pro-rata down to Minimum Emergency Capacity Operating Limits;

(e) Curtail any remaining fixed Import Interchange Schedules pro-rata;

(f) Reduce Resources with cleared Regulation-Down economically, as needed, down to Minimum Emergency Capacity Operating Limit;

(g) Coordinate with Generation Operators, SPP BA Operator and SPP Reliability Coordinator to de-commit generation to meet power balance.

(2) If actions taken under (1) above are not sufficient to relieve the excess generation condition in any Dispatch Interval either on a system-wide basis or Reserve Zone basis, LMPs will be set by the Offers prices associated with Energy down to the Minimum Emergency Capacity Operating Limit or zero, whichever is less, to the extent that the Regulation-Down requirement can be maintained. If the actions under (9) above create a Regulation-Down shortage during any Dispatch Interval either on a system-wide basis or Reserve Zone basis, the MCPs for Regulation-Down will reflect Scarcity Prices and LMPs will reflect negative Scarcity Prices as described under Section 4.1.5;

(3) In parallel with the actions under (1) above, if there is a transmission constraint within a Reserve Zone occurring simultaneously with a Reserve Zone excess capacity event, SPP operators may take the following additional actions:

(a) Identify and communicate with owners of Resources with greater than a 5% Generation Shift Factor (“GSF”) on the constraint and fixed Import Interchange Transactions with greater than a 3% transfer distribution factor on constraint;

(b) Issue TLR to curtail any Interchange Transactions that may be contributing to the loading;

(c) Commit Quick Start Resources in the constrained area if they can be re-dispatched with other Resources in constrained area to relieve constraint without contributing to the excess capacity situation.

4.4.2.3 RTBM Results

Following execution of the RTBM SCED, the following results are communicated to Market Participants prior to the start of the applicable Dispatch Interval. The following results are communicated to each Market Participant that relates only to that Market Participant:
(1) Resource Dispatch Instructions. The Dispatch Instruction is a MW output target for the end of the applicable Dispatch Interval;

(2) Cleared Regulation-Up, Regulation-Down, Spinning Reserve and Supplemental Reserve MW by Resource.

These values are used by the Energy Management System (EMS) for Regulation Deployment and by the Reserve Sharing System (RSS) for Contingency Reserve Deployment.

The following results are communicated to all Market Participants and are used for settlement purposes (i.e. prices used for settlement are “ex-ante”);

(1) Locational Marginal Prices (LMPs) for each Settlement Location, the Marginal Congestion Component (MCC) of LMP for each Settlement Location and the Marginal Losses Component (MLC) of LMP for each Settlement Location; and

(2) Market Clearing Prices for Regulation-Up, Regulation-Down, Spinning Reserve and Supplemental Reserve for each Reserve Zone.

4.4.2.4 Out-of-Merit Energy (OOME) Dispatch

SPP may issue reliability directives via a Manual Dispatch Instruction to any on-line Resource to resolve Emergency conditions (referred to in the system as OOME, or out-of-merit energy). A Resource will receive Setpoint Instructions that include a Manual Dispatch Instruction for the duration of the reliability directive. SPP will issue Manual Dispatch Instructions at the MW level the Resource is expected to produce until such time as the constraint can be resolved by SCED through the RTBM. SPP will make every effort to define and activate the appropriate constraints in RTBM SCED within one hour of the manual reconfiguration.

When an OOME event occurs, SPP takes the following actions:

(a) Notifications are immediately issued for all future intervals for which a SCED Dispatch Instruction has already been calculated and included in the Resource Setpoint Instruction;

(b) Setpoint Instructions for future intervals not yet dispatched will include the Manual Dispatch Instruction instead of the SCED Dispatch Instruction for the same interval;

(c) SPP notifies the Market Participant when the OOME event had ended;

(d) Asset Owners are compensated for OOME events in accordance with Section 4.5.9.9.
4.4.3 Energy and Operating Reserve Deployment

SPP deploys Energy, Regulation-Up, Regulation-Down, Spinning Reserve and on-line Supplemental Reserve simultaneously through the issuance of Setpoint Instructions to each Resource on a 4-second basis. Deployment of Supplemental Reserve from off-line Quick-Start Resources is accomplished through SPP issuance of a start-up order following a Contingency Reserve event. The Setpoint Instruction is the sum of:

1. The Resource MW Dispatch Instruction for the current Dispatch Interval either as developed by SCED under Section 4.4.2.3 or by Manual Dispatch Instruction as described under Section 4.4.2.4;
2. Regulation-Up Deployment Instruction;
3. Regulation-Down Deployment Instruction;
4. Spinning Reserve Deployment Instruction; and
5. On-line Supplemental Reserve Deployment Instruction.

Resource Setpoint Instructions represent the total amount of desired deployment (i.e. the Setpoint Instruction does not include a ramped signal, but a stepped signal). However, for information purposes, SPP will also provide a ramped Setpoint Instruction.

4.4.3.1 Regulation Deployment

Regulation Deployment is limited to Resources that have cleared Regulation-Up and/or Regulation-Down with a Control Status of “Regulating”. Regulation-Up and/or Regulation-Down is deployed on specific Resources through Setpoint Instructions via the AGC system on a pro-rata basis based upon Regulation-Up and/or Regulation-Down cleared MW, adjusted as needed to ensure deliverability. No Regulation Deployment will occur on Resources that have not cleared Regulation-Up and/or Regulation-down even if their Control Statuses are set to “Regulating”.

Market Participants providing Regulation-Up and/or Regulation-Down service during the Operating Hour have an obligation to report to SPP when their Resources are no longer capable of providing the service due to physical problems with the associated Resources through submission of the applicable Resource Control Status via ICCP as described under Exhibit 4-10. If the problem persists into the next Operating Hour, that Market Participant must update its Resource Offer by submitting a Regulation-Up and Regulation-Down Dispatch Status as “Not-Qualified”. If a Market Participant fails to follow this procedure and SPP observes that a
particular Resource is failing to provide the Regulation-Up or Regulation-Down service for 3 or more consecutive Dispatch Intervals, SPP will change the Resource’s regulation Dispatch Status to “Not-Qualified” and will contact the Market Participant to ascertain the nature of the problem. If the physical limitation is expected to be corrected within that Operating Hour, SPP will return the Resource’s Dispatch Status to “Market” or “Fixed”, as applicable when notified by the Market Participant. If the Market Participant fails to notify SPP within that Operating Hour and then fails to submit an updated Resource Offer indicating a Regulation-Up and/or Regulation Down Dispatch Status of “Not-Qualified”, SPP will disqualify that Resource as a Regulation Qualified Resource, Regulation-Up Qualified Resource or Regulation-Down Qualified Resource and that Resource must pass a re-test as described under Section 6.1.11.3 in order to be re-certified. Exhibit 4-10 shows the all of the available Resource Control Statuses in the AGC system.

Exhibit 4-10: AGC System Control Status

<table>
<thead>
<tr>
<th>Resource Control Status</th>
<th>Market Systems Impact</th>
</tr>
</thead>
<tbody>
<tr>
<td>Off-Line</td>
<td>Off-Line and not available to the RTBM.</td>
</tr>
<tr>
<td>Non-Regulating</td>
<td>On-line, not capable of providing Regulation-Up or Regulation-Down service, capable of providing online Contingency Reserve deployment and capable of following Dispatch Instructions.</td>
</tr>
<tr>
<td>Regulating</td>
<td>On-line, capable of providing Regulation-Up and/or Regulation-Down deployment, on-line Contingency Reserve deployment and following Dispatch Instructions.</td>
</tr>
<tr>
<td>Manual</td>
<td>On-line, not capable of following Setpoint Instruction. Setpoint Instruction is an echo of the latest SCADA output or State Estimator solution output if SCADA is not available.</td>
</tr>
</tbody>
</table>

4.4.3.2 Contingency Reserve Deployment

Contingency Reserve procured in the RTBM will be deployed through a Contingency Reserve Deployment Instruction, via both Inter-Control Center Communications Protocol (ICCP) and Extensible Markup Language (XML) instruction, following a system event, normally following the sudden loss of a Resource. The following rules apply to the deployment of Contingency Reserve for both internal SPP BA contingencies and for providing assistance to a Reserve
Sharing Group member. Scheduling procedures for provision of assistance to/from Resource Sharing Group members are described under Section 4.4.3.3:

1. Contingency Reserve is deployed on Resources with cleared Contingency Reserve and Export Interchange Transactions providing Supplemental Reserve in the Dispatch Interval immediately following the system event;

2. Spinning Reserve and on-line Supplemental Reserve is deployed ahead of off-line Supplemental Reserve;

3. If the amount of Spinning Reserve and on-line Supplemental Reserve cleared is greater than or equal to the Contingency Reserve amount required in response to a contingency, no off-line Supplemental Reserve is deployed;

4. Spinning Reserve and on-line Supplemental Reserve is deployed in proportion to the amount of Spinning Reserve and on-line Supplemental Reserve cleared on each Resource, adjusted as needed to ensure deliverability;

5. Supplemental Reserve from off-line Quick-Start Resources is deployed on Resources in merit order based on economics of Start-Up Offer, No-Load Offer, Energy Offer Curves and Minimum Run Time, adjusted as needed to ensure deliverability. For the purposes of deploying Supplemental Reserve supplied from Export Interchange Transactions, as described under Section 4.2.3.3, the merit order cost will be equal to zero.

4.4.3.3 Reserve Sharing Group Scheduling Procedures

NERC Reliability Standards and applicable SPP Criteria will continue to dictate Contingency Reserve deployment between Reserve Sharing Group (RSG) members. Whereas SPP administers the reserve sharing program, the energy schedules implemented through the reserve sharing Contingency Reserve deployment, as created automatically by the Reserve Sharing System (RSS) are settled through the RTBM as either a fixed export schedule at the applicable External Interface Settlement Location LMP (SPP BA is providing assistance to a RSG member) or a fixed import schedule (SPP BA is receiving assistance from an RSG member) at the applicable External Interface Settlement Location LMP. Any additional compensation over and above the External Interface Settlement Location LMP as specified in the contractual arrangements between RSG members is also settled as part of the RTBM.

Deployment of Contingency Reserve by the SPP BA to provide assistance to an RSG member shall be in accordance with the deployment procedures specified under Section 4.4.3.2.
4.4.3.4 Contingency Reserve Recovery

Following an Operating Reserve contingency, the SPP Balancing Authority will restore its Contingency Reserve to its pre-disturbance Contingency Reserve requirement by the end of the Assistance Period, which is defined in the SPP Criteria. During the Assistance Period, the Real-Time Balancing Market will clear Contingency Reserve up to the pre-disturbance Contingency Reserve requirement or to the level of available capacity, whichever is less, and Scarcity Pricing will not apply.

4.4.4 Energy and Operating Reserve Deployment Failure

Market Participants that fail to comply with Setpoint Instructions during Dispatch Intervals that do not include any Contingency Reserve deployment will incur a portion of RUC Make-Whole Payment Amount costs unless specifically exempted per Section 4.4.4.1A and may also incur Regulation Deployment failure charges. During any Dispatch Interval that includes a Contingency Reserve deployment, Uninstructed Resource Deviation does not apply on a Resource that is deployed for Contingency Reserve. However, Resources that are deployed for Contingency Reserve may be subject to Contingency Reserve deployment failure charges if these Resources fail to deploy the instructed amount of Contingency Reserve. Uninstructed Resource Deviation, Regulation Deployment failure charges and Contingency Reserve deployment failure charges are described in the following subsections.

4.4.4.1 Uninstructed Resource Deviation

The following rules apply to the calculation of Uninstructed Resource Deviation (URD).

(1) URD is the difference between a Resource’s average ramped MW Setpoint Instruction over a Dispatch Interval and the Resources actual average MW output over the Dispatch Interval. The Resources of a single Asset Owner with Resources at a Common Bus will be aggregated and treated as a single Resource. In such case, the Resources’ combined average ramped MW Setpoint Instruction and the Resources’ combined actual average MW output at the Common Bus will be used for URD calculation purposes for the Dispatch Interval;

(2) A Resource’s URD is allocated a portion of the RUC Make-Whole Payment costs in any Dispatch Interval where Resource’s URD is outside of its Operating Tolerance unless that Resource has been exempted from URD under Section 4.4.4.1.1.
(a) A generating unit Resource’s Operating Tolerance in each Dispatch Interval is equal to the Resource’s Maximum Emergency Capacity Operating Limit multiplied by 5%, subject to a minimum of 5 MW and a maximum of 20 MW.

(b) A Dispatchable Demand Response Resource’s Operating Tolerance in each Dispatch Interval is equal to the resource’s Maximum Emergency Capacity Operating Limit multiplied by 5%, subject to a minimum of 5 MW and a maximum of 20 MW.

(c) A Block Demand Response Resource’s Operating Tolerance in each Dispatch Interval is equal to the resource’s Maximum Economic Capacity Operating Limit multiplied by 5%, subject to a minimum of 5 MW and a maximum of 20 MW.

(d) The Common Bus Operating Tolerance for each Asset Owner registered at a Common Bus is equal to the sum of that Asset Owner’s Resources’ Maximum Emergency Capacity Operating Limits for Resources that are on-line multiplied by 5%, subject to a minimum of 5 MW and a maximum of 20 MW.

(e) If the absolute value of a Resource’s URD is greater than the Resource’s Operating Tolerance in any Dispatch Interval, the Resource URD / 12 is included in the hourly allocation of RUC Make-Whole Payment cost allocation. The hourly URD amount is calculated as the sum of Dispatch Interval URD for the hour. See Section 4.5.9.10 for calculation details. Additionally, if that Resource was eligible to receive a RUC Make-Whole Payment, the payment may be reduced. See Section 4.5.9.8 for calculation details.

### 4.4.1.1 URD Exemptions

A Resource’s URD in a Dispatch Interval shall be considered equal to zero (0) under the following situations:

1. The Resource is deployed for Contingency Reserve;
2. The Resource trips or is derated after receiving Dispatch Instructions;
3. There is missing or bad Resource SCADA data in the Dispatch Interval;
4. During a system Emergency if the URD is above the Resource’s Setpoint Instruction in a shortage condition or if the URD is below the Resource’s Setpoint Instruction during an excess generation condition;
(5) If a Dispatch Instruction is issued to a Resource beyond the reported capabilities due to the application of a VRL;

(6) If the Resource is part of a Common Bus and the URD calculated at the Common Bus is less than the Operating Tolerance calculated at the Common Bus;

(7) SPP may set Uninstructed Resource Deviation to zero (0) to the extent a Market Participant can demonstrate such deviation was caused solely by events or conditions beyond its control, and without the fault or negligence of the Market Participant. The Market Participant must provide SPP with adequate documentation through the invoice dispute process in order for the Market Participant to be eligible to avoid such Uninstructed Resource Deviation. SPP shall determine through the dispute process whether such Uninstructed Resource Deviation should be waived.

4.4.4.2 Regulation Deployment Failure Charges

In any Dispatch Interval, if the URD of a Resource with cleared Regulation-Up, Regulation-Down or both is outside of the Resource’s Operating Tolerance, that Market Participant will incur a Regulation Deployment failure charge. The Regulation Deployment failure charge is described under Section 4.5.9.12.

4.4.4.3 Contingency Reserve Deployment Failure Charges

An Asset Owner receiving a Contingency Reserve Deployment Instruction must pass one of the following four tests in order to be in full compliance with the instruction. Each of these tests is performed either at the individual Resource level or at a Common Bus level if the Asset Owner’s Resource receiving the Contingency Reserve Deployment Instruction is registered at a Common Bus. A Resource that fails all four tests will receive a Contingency Reserve deployment failure charge as described under Section 4.5.9.16. The four tests are described as follows:

(1) **Test 1**: Test 1 compares the Resource expected output or Common Bus expected output at the end of the Contingency Reserve Deployment Period to the Resource actual output or Common Bus actual output as measured at the end of the Contingency Reserve Deployment Period.

   (a) The expected output for Resources deployed for Spinning Reserve or on-line Supplemental Reserve is equal to the Resource’s instantaneous ramped Setpoint Instruction at the end of the Contingency Reserve Deployment Period.
(b) The expected output for Resources deployed for off-line Supplemental Reserve is equal to the amount of Supplemental Reserve deployed.

(c) The Common Bus expected output for an Asset Owner is equal to the sum of the expected outputs described under i. and ii. above for all of the Asset Owner’s Resources at the Common Bus.

(d) The Common Bus actual output is equal to the sum of actual outputs of all the Asset Owner’s Resources at the Common Bus.

Exhibit 4-11 provides an illustration of Test 1 showing Spinning Reserve deployment for a Resource or Common Bus that has passed Test 1 because the actual output at the end of the Contingency Reserve Deployment Period is greater than or equal to the expected output (Resource A Ramped Setpoint) resulting in a Shortfall Quantity that is equal to zero. An actual output that is less than the expected output would constitute a failure of Test 1 resulting in a Shortfall Quantity equal to the difference between the expected output and the actual output.

**Exhibit 4-11: Contingency Reserve Deployment Compliance Measurement – Test 1**

(2) **Test 2:** Test 2 also compares the Resource expected output or Common Bus expected output at the end of the Contingency Reserve Deployment Period to the Resource actual output or Common Bus actual output as measured at the end of the Contingency Reserve Deployment Period.
(a) The expected output for Resources deployed for Spinning Reserve or on-line Supplemental Reserve is equal to the Resource’s instantaneous stepped Setpoint Instruction at the end of the Contingency Reserve Deployment Period.

(b) The expected output for Resources deployed for off-line Supplemental Reserve is equal to the amount of Supplemental Reserve deployed.

(c) The Common Bus expected output for an Asset Owner is equal to the sum of the expected outputs described under i. and ii. above for all of the Asset Owner’s Resources at the Common Bus.

(d) The Common Bus actual output is equal to the sum of actual outputs of all the Asset Owner’s Resources at the Common Bus.

Exhibit 4-12 provides an illustration of Test 2 showing Spinning Reserve deployment for a Resource or Common Bus that has passed Test 2 because the actual output at the end of the Contingency Reserve Deployment Period is greater than or equal to the expected output (Resource A Stepped Setpoint) resulting in a Shortfall Quantity that is equal to zero. An actual output that is less than the expected output would constitute a failure of Test 2 resulting in a Shortfall Quantity equal to the difference between the expected output and the actual output.

**Exhibit 4-12: Contingency Reserve Deployment Compliance Measurement – Test 2**
(3) **Test 3:** Test 3 compares the change in Resource expected output or Common Bus expected output between the beginning and the end of the Contingency Reserve Deployment Period to the change in Resource actual output or Common Bus actual output between the beginning and the end of the Contingency Reserve Deployment Period.

(a) The change in expected output for Resources deployed for Spinning Reserve or on-line Supplemental Reserve is equal to the difference between the Resource’s instantaneous ramped Setpoint Instruction at the end of the Contingency Reserve Deployment Period and the Resource’s instantaneous ramped Setpoint Instruction at the beginning of the Contingency Reserve Deployment Period.

(b) The change in expected output for Resources deployed for off-line Supplemental Reserve is equal to the amount of Supplemental Reserve deployed.

(c) The change in Common Bus expected output is equal to the difference between: (i) the sum of the expected outputs described under (a) and (b) above at the end of the Contingency Reserve Deployment Period for all of the Asset Owner’s Resources at the Common Bus.; and (ii) the sum of the expected outputs described under (a) and (b) above at the beginning of the Contingency Reserve Deployment Period for all of the Asset Owner’s Resources at the Common Bus.

(d) The change in Common Bus actual output is equal to the difference between: (i) the sum of all actual outputs at the end of the Contingency Reserve Deployment Period for all of the Asset Owner’s Resources at the Common Bus; and (ii) the sum of all actual outputs at the beginning of the Contingency Reserve Deployment Period for all of the Asset Owner’s Resources at the Common Bus.

Exhibit 4-13 provides an illustration of Test 3 showing Spinning Reserve deployment for a Resource or Common Bus that has passed Test 3 because the change in actual output is greater than or equal to the change in expected output (as measured using Resource A Ramped Setpoint) over the Contingency Reserve Deployment Period resulting in a Shortfall Quantity that is equal to zero. A change in actual output that is less than the change in expected output would constitute a failure of Test 3 resulting in a Shortfall Quantity equal to the difference between the change in expected output and the change in actual output.
(4) **Test 4:** Test 4 also compares the change in Resource expected output or Common Bus expected output between the beginning and the end of the Contingency Reserve Deployment Period to the change in Resource actual output or Common Bus actual output between the beginning and the end of the Contingency Reserve Deployment Period except that the expected output is calculated using the stepped Setpoint Instruction.

(a) The change in expected output for Resources deployed for Spinning Reserve or on-line Supplemental Reserve is equal to the difference between the Resource’s instantaneous stepped Setpoint Instruction at the end of the Contingency Reserve Deployment Period and the Resource’s instantaneous stepped Setpoint Instruction at the beginning of the Contingency Reserve Deployment Period.

(b) The change in expected output for Resources deployed for off-line Supplemental Reserve is equal to the amount of Supplemental Reserve deployed.

(c) The change in Common Bus expected output is equal to the difference between: (i) the sum of the expected outputs described under (a) and (b) above at the end of the Contingency Reserve Deployment Period for all of the Asset Owner’s Resources at the Common Bus; and (ii) the sum of the expected outputs described
under (a) and (b) above at the beginning of the Contingency Reserve Deployment Period for all of the Asset Owner’s Resources at the Common Bus.

(d) The change in Common Bus actual output is equal to the difference between: (i) the sum of all actual outputs at the end of the Contingency Reserve Deployment Period for all of the Asset Owner’s Resources at the Common Bus; and (ii) the sum of all actual outputs at the beginning of the Contingency Reserve Deployment Period for all of the Asset Owner’s Resources at the Common Bus.

Exhibit 4-14 provides an illustration of Test 4 showing Spinning Reserve deployment for a Resource or Common Bus that has passed Test 4 because the change in actual output is greater than or equal to the change in expected output (as measured using Resource A Stepped Setpoint) over the Contingency Reserve Deployment Period resulting in a Shortfall Quantity that is equal to zero. A change in actual output that is less than the change in expected output would constitute a failure of Test 4 resulting in a Shortfall Quantity equal to the difference between the change in expected output and the change in actual output.

**Exhibit 4-14: Contingency Reserve Deployment Compliance Measurement – Test 4**

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![Diagram showing Test 4](image-url)
4.4.5 Inadvertent Management

SPP shall maintain inadvertent accounts and administer inadvertent payback for the SPP Balancing Authority Area. In doing so, SPP shall adhere to the following principles:

1. Inadvertent payback shall be administered in accordance with NERC criteria, applicable Joint Operating Agreements, and Good Utility Practice;

2. Inadvertent payback decisions shall be made without regard to possible profits or losses resulting from changes in energy costs over time.

4.4.5.1 Inadvertent Payback Reporting

The SPP BA will report its Inadvertent Interchange balance with the applicable interconnection. SPP reporting will be consistent with the requirements and timelines for Balancing Authorities outlined in NERC Reliability Standard BAL-006-0.

The SPP BA will manage and pay back its net Inadvertent Interchange balance following NAESB WEQBPS-005-000 Inadvertent Interchange payback. Inadvertent payback will be initiated based on an objective and publicly available process that is triggered on balances exceeding statistical norms. Inadvertent payback will be done during periods and in amounts such that payback will not burden others or interfere with time corrections. Financial gain will not factor into the decision to payback or recover inadvertent interchange.

4.5 Post Operating Day and Settlement Activities

Post Operating Day activities begin on the day immediately following the Operating Day. SPP issues initial settlement statements for each Operating Day on the 7th day following the Operating Day and final settlement statements on the 47th day following the Operating Day. Settlement statements will be configurable by Market Participants to show hourly net amounts or to show that Market Participant’s hourly and sub-hourly billing quantities at each Settlement Location to be paid or credited resulting from the DA Market and RTBM settlements. All charge types and billing determinants defined under Sections 4.5.8, 4.5.9, 4.5.10, 4.5.11, and 4.5.12 are available on the Settlement Statement and Settlement Determinant Report unless specifically excluded as identified in the table definitions under each charge type. Settlement Invoices are issued on weekly basis.

Metering standards associated with submittal of actual load and Resource Energy quantities are specified in Appendix C and settlement data reporting processes are specified in Appendix D to
these Market Protocols. Detailed explanations of all DA Market and RTBM charges types, along with example calculations, are contained within Appendix F to these Market Protocols.

Exhibit 4-15 provides a representative overall timeline of Post Operating Day activities.

**Exhibit 4-15: Post Operating Day Activities Timeline**

A description of the DA Market and RTBM settlements is provided in the following subsections.

### 4.5.1 Settlement Sign Conventions

Settlement statements use negative signs to reflect payments to Market Participants and positive signs to reflect charges to Market Participants. Throughout the settlement calculations, multiplication by (-1) is used to attain the proper sign convention. The following sign conventions are applied for settlement calculations:

1. Cleared Resource MWh and Virtual Energy Offer MWh in the DA Market is negative value;
2. Cleared load MWh and Virtual Energy Bid MWh in the DA Market is a positive value;
3. Import Interchange Transaction MWh is a negative value;
4. Export Interchange Transaction MWh is a positive value;
5. Dispatch Instruction MW is a positive value;
6. Setpoint Instruction, Dispatch Instruction, Regulation-Up Deployment instructions and Regulation-Down Deployment instructions are positive value;
4.5.2 Commercial Model

The Commercial Model describes the financial market relationships of the Market Participants and the Asset Owners (AOs), and the commercial relationships among the elements of the Network Model. The hierarchy of relationships along with their descriptions is as follows.

1. Node Level
2. Pricing Node Level (PNode) Level
   a. Aggregate Pricing Node Level (APNode) Level
3. Settlement Locations
4. Asset Owner Level
5. Market Participant Level

4.5.2.1 Nodes

Nodes represent Electrical Nodes (ENodes) within the Network Model where LMPs are calculated. ENodes represent the physical connection points in the Transmission System
Network Model. ENodes include all locations in the Network Model where electrical equipment components (e.g. generators, loads, transmission lines, and transformers) connect but LMPs are calculated at only a subset of ENodes (i.e. Nodes).

4.5.2.2 Pricing Nodes

Pricing Nodes (PNodes) provide the linkage between the Network Model and the Commercial Model and are the finest level of granularity in the Commercial Model and have a one-to-one relationship with a Node. PNodes are defined for all locations where energy is injected and/or withdrawn from the Transmissions System, as well as other commercially significant buses.

4.5.2.2.1 Aggregated Pricing Nodes

The Aggregated Pricing Node (APNode) represents an aggregation of two or more PNodes using weighting factors. For each APNode, the relationship of PNodes to APNodes determines how Energy at the APNode level is allocated at the PNode/ENode level and/or how prices at the PNode level are weighted at the APNode level. This nodal relationship is maintained in SPP’s registration system. However, weighting factors may vary based on projected or historical injection/withdrawal values at each PNode for the applicable market process.

4.5.2.3 Settlement Locations

Settlement Locations represent the next hierarchical level in the Commercial Model and have a relationship to a single PNode or APNode. Energy supply and demand is financially settled at the Settlement Locations based on the appropriate PNode or APNode LMP and Settlement Location energy injection or withdrawal level. There are four (4) types of Settlement Locations: Resource, Load, Hub and Interface.

4.5.2.4 Asset Owners

The Asset Owner is the next higher hierarchical level in the Commercial Model and typically, but not necessarily, represents a company. A company may choose to be registered as more than one Asset Owner. Within the Commercial Model, Asset Owners can own any combination of generation, Load, ARR and/or TCR assets within the SPP Region. All Asset Owners must each be represented by a Market Participant. SPP calculates charges and produces market settlements statements for each Asset Owner. Each Settlement statement provides the billing determinants for each transaction, along with the Asset Owner’s total financial obligation resulting from its transactions.
4.5.2.5 Market Participants

The Market Participant is the highest hierarchical level in the Commercial Model and is the entity in the Commercial Model that is financially obligated to SPP for market settlements. A single Market Participant represents one or more Asset Owners. A single Market Participant may authorize other entities to act on its behalf. The Market Participant remains financially responsible for market settlements.

Exhibit 4-16 provides an illustration of potential relationships within the Commercial Model.

**Exhibit 4-16: Example of Commercial Model Relationships**

Legend:
- AO = Asset Owner
- MP = Market Participant
- G = Generator
- L = Load
- D = Demand Response
In addition to these defined financial relationships, the Commercial Model is also used to define and represent Loss Pools, Common Buses, Reserve Zones, Meter Data Submittal Locations, Meter Settlement Locations and Demand Response Load. These relationships are defined under Section 6, Market Registration.

4.5.3 Financial Schedules and External Reserve Zone Obligation Transfer Schedules

4.5.3.1 Financial Schedules

Market Participants may create Financial Schedules for Energy and Operating Reserve obligation by registering and confirming the parameters of the agreement between buyer and seller such as the Schedule ID, Settlement Location, Reserve Zone, maximum allowable hourly quantity, market product, submitting party, auto-confirmation option and the effective & termination dates. Once this “header” information is validated and entered into the system by SPP, hourly quantities submitted reference the Schedule ID in order to be associated with all the parameters required for settlement calculations. In the event that either party no longer consents to participate in the Financial Schedule or if SPP staff encounter recurring settlement dispute activity related to its usage the “header” information may be ended in advance of the original termination date effectively preventing further submittal of hourly quantities.

Market Participants may submit Financial Schedule quantities for Energy and Operating Reserve obligation up to four (4) days following the applicable Operating Day for the Initial settlement. New submittals and revisions to previously submitted values may be submitted up to 44 days following the applicable Operating Day to be included in the Final settlement. The submittal timeline is subject to acceleration around holidays (see Section 4.5.14). Auto-confirmation applies to only the first submittal per Operating Day and must occur prior to the cutoff for the Initial settlement. Submittals 1) for agreements not using the auto-confirmation option, 2) beyond the cutoff date for the Initial settlement or 3) which update previous submittals must all be explicitly confirmed by the submitting party and counterparty. Submittals not confirmed by both parties will not be included in any settlement execution.

Transactions related to Financial Schedules for Energy must specify the Settlement Location, the MW amount, the buyer, the seller and which market it applies to (DA Market or RTBM). The seller receives an increase in load obligation equal to the specified MW amount and the buyer receives a reduction in load obligation equal to the specified MW amount (the equivalent of a Resource settlement) at the specified Settlement Location.
Transactions related to Financial Schedules for Operating Reserve obligation must specify the buyer, the seller, the Operating Reserve product, the MW obligation transfer and the Reserve Zone within which the obligation transfer applies. The seller receives an increase in Operating Reserve obligation equal to the specified MW and the buyer receives a corresponding decrease in Operating Reserve obligation within the specified Reserve Zone.

4.5.3.2 External Reserve Zone Obligation Transfer Schedules

Market Participants may submit External Reserve Zone Obligation Transfer Schedules for Operating Reserve as described under Section 4.2.2.7.1. The buyer receives a corresponding decrease in Operating Reserve obligation in the sink Reserve Zone up to but not beyond the buyer’s obligation.

4.5.4 Calculation of LMPs, LMP Components and MCPs

SPP uses a co-optimized SCED model to compute Locational Marginal Prices (LMPs) for Energy at PNodes. The LMPs are then mapped to Settlement Locations in the commercial model. The SCED model also computes Market Clearing Prices (MCPs) for Regulation-Up Regulation-Down, Spinning Reserve and Supplemental Reserve on a Reserve Zone basis. For the DA Market, LMPs and MCPs are calculated on an hourly basis. For the RTBM, LMPs and MCPs are calculated for each 5-minute Dispatch Interval. Inputs to SCED for the DA Market are as described under Section 4.3.1.1 and inputs to SCED for the RTBM are as described under Section 4.4.2.1. The following subsections further describe how LMPs, LMP Components and MCPs are calculated.

4.5.4.1 LMP Calculations and LMP Components

The LMP at a PNode is the cost of delivering an additional MW of energy at that specific PNode, while satisfying all operational constraints. The LMP at any PNode is the sum of three components; the marginal costs of Energy (Marginal Energy Component or MEC), the marginal cost of losses (Marginal Loss Component or MLC), and the marginal cost of congestion (Marginal Congestion Component or MCC).

LMP Components at PNode $i$ are calculated based upon the following formulas:

$$\text{LMP}_i = \text{MEC} + \text{MLC}_i + \text{MCC}_i$$

Where:

(1) MEC is the component of LMP, representing the marginal cost of Energy;
(2) MLC
i
is the component of LMP
i
representing the marginal cost of losses at PNode
i
relative to the Reference Bus;

(3) MCC
i
is the component of LMP
i
representing the marginal cost of congestion at ENode
i
relative to the Reference Bus; and

(4) The Reference Bus represents the network Distributed Load Bus.

4.5.4.1.1 Marginal Losses Component Calculation

The MLC
i
at each Pnode
i
is defined by the following equations:

\[ MLC_i = -\text{MLSF}_i \times \text{MEC} \]

\[ \text{MLSF}_i = \frac{\partial (\text{SPP Losses})}{\partial P_i} \]

Where:

(1) SPP Losses = SPP transmission system losses;

(2) MLSF
i
= Marginal Loss Sensitivity Factor at PNode
i
;

(3) MEC is the component of LMP
i
representing the marginal cost of Energy;

(4) \( P_i \) = Net injection at PNode
i
.

The MLSF
i
is a linearized estimate of the change in SPP transmission losses that will result from a 1 MW injection at PNode
i
coupled with a corresponding withdrawal at the Reference Bus to maintain global power balance (the withdrawal at the Reference Bus will generally be higher or lower than 1 MW since there will be a change in losses). Marginal loss sensitivity factors are dependent on topology, node injections and node withdrawals, and are only considered constant within a small deviation from a fixed operating point.

4.5.4.1.2 Marginal Congestion Component Calculation

The MCC
i
at each PNode
i
is defined by the following equations:

\[ MCC_i = - \left( \sum_{k=1}^{K} \text{Sens}_{ik} \times \text{SP}_k \right) \]

\[ \text{Sens}_{ik} = \frac{\partial \text{Flow}_k}{\partial P_i} \]

Where:

(1) \( K \) is the number of transmission constraints;
(2) Sens\(_{ik}\) is the linearized estimate of the change in the constraint k flow resulting from an incremental energy injection at PNode \(i\) coupled with an incremental energy withdrawal at the Reference Bus;

(3) Flow\(_k\) = Calculated flow for constraint \(k\);

(4) SP\(_k\) = is the Shadow Price of constraint \(k\);

(5) \(P_i\) = Net injection at PNode \(i\).

4.5.4.1.3 Marginal Energy Component Calculation

The MEC is defined as the computed LMP at the Reference Bus. By definition, MCC and MLC components are zero at the Reference Bus.

4.5.4.2 MCP Calculations

The MCP represents the cost of supplying an increment of operating reserve, taking into account lost opportunity cost and is composed of the marginal Operating Reserve costs and marginal costs associated with Operating Reserve scarcity. The DA Market and RTBM MCPs for Regulation-Up, Spinning Reserve and Supplemental Reserve at a Reserve Zone for Resources with cleared Regulation-Up, Spinning Reserve and/or Supplemental Reserve at that Reserve Zone are equal to the summation of the applicable Shadow Prices associated with each Operating Reserve constraint. This type of MCP formulation is referred to as “price-cascading”.

(1) There are three sets of constraints: (i) an Operating Reserve constraint which is set equal to the sum of the Contingency Reserve requirement and the Regulation-Up requirement; (ii) a Regulation-Up plus Spinning Reserve constraint which is set equal to the sum of the Regulation-Up requirement and the Spinning Reserve requirement; and (iii) a Regulation-Up constraint which is set equal to the Regulation-Up requirement. These constraints apply on both a system-wide basis and a Reserve Zone basis. For example, on a system-wide basis and assuming no binding Reserve Zone limits:

(a) The Regulation-Up MCP is equal to sum of the Shadow Prices for the Regulation-Up constraint, Regulation-Up plus Spinning Reserve constraint and the Operating Reserve constraint;

(b) The Spinning Reserve MCP is equal to the sum of the Shadow Prices for the Regulation-Up plus Spinning Reserve constraint and the Operating Reserve constraint; and
(c) The Supplemental Reserve MCP is equal to the Shadow Price of the Operating Reserve constraint.

(2) During times of Operating Reserve scarcity, LMPs and MCPs will be impacted by Scarcity Prices as described under Section 4.1.5;

(3) The MCP formulations allow for the substitution of higher quality reserve products for lower quality reserve products to meet the Operating Reserve requirements to the extent that there is excess higher quality Operating Reserve available and these excess amounts provide a more economic solution. Allowing for this substitution in combination with the “price-cascading” rules described in (1) above ensures that the clearing for Operating Reserve produces Regulation-Up MCPs that are greater than or equal to Spinning Reserve MCPs and Spinning Reserve MCPs that are greater than or equal to Supplemental Reserve MCPs;

(a) Due to the physical characteristics of Regulation-Only Resources, the Regulation-Up cleared on Regulation-Only Resources is ineligible to substitute for Spinning Reserve and Supplemental Reserve. Therefore, Regulation-Only Resource Regulation-Up MCPs can be less than Spinning Reserve and/or Supplemental Reserve MCPs.

(b) Regulation-Down is not eligible to substitute for Spinning Reserve and Supplemental Reserve. Therefore, Resource Regulation-Down MCPs can be less than Spinning Reserve and/or Supplemental Reserve MCPs.

(4) The MCPs for the various Operating Reserve products as determined by the market clearing process will be sufficient to cover the Offer costs of each Resource as well as the opportunity costs incurred to allocate a portion of the Resource capacity to the supply of the corresponding Operating Reserve product in lieu of another product. The recovery of both offered cost and opportunity costs via Market Clearing Prices is inherent in the co-optimized SCED formulations, thus the separate calculation of opportunity costs is unnecessary.

4.5.5 Settlement Location LMPs and LMP Components

For Settlement Locations that are associated with more than one PNode, the following calculations are performed to calculate the Settlement Location LMPs and the associated LMP Components. The LMPs for Settlement Locations associated with a single PNode are those LMPs directly calculated by the DA Market software as described under Section 4.3.1.3 and the
RTBM software as described under Section 4.4.2.3. All nodal LMPs are subject to the price correction procedures described under Section 7.

4.5.5.1 Calculation of LMP at a Hub Settlement Location

SPP calculates an LMP for each Hub based on the LMPs for the set of PNodes that comprise the Hub. These Hub LMPs are the weighted average of the LMPs at the PNodes that comprise the Hub. The weighting factors are pre-determined and remain fixed as described under Section 4.3.1.1. These weighting factors are applied for calculating a LMP, MCP and MLC at a Hub for both the DA Market and RTBM.

The LMP for Hub $j$ is:

$$LMP_{Hub_j} = \sum_k (W_k \times LMP_k)$$

The MCC for Hub $j$ is:

$$MCCHub_j = \sum_k (W_k \times MCC_k)$$

The MLC for Hub $j$ is:

$$MLCHub_j = \sum_k (W_k \times MLC_k)$$

Where:

1. $W_k$ is the weighting factor for Pnode $k$ which is part of Hub $j$. The sum of the weighting factors for all Pnodes $k$ must sum to 1.0;

2. $LMP_k$ is the LMP for Pnode $k$ which is part of Hub $j$;

3. $MCC_k$ is the Marginal Congestion Component of the LMP for Pnode $k$ which is part of Hub $j$;

4. $MLC_k$ is the Marginal Losses Component of the LMP for Pnode $k$ which is part of Hub $j$. 
4.5.5.2 Calculation of LMP at a Load APNode Settlement Location

SPP calculates an LMP for each APNode Load Settlement Location based on the LMPs for the set of PNodes that comprise the APNode Load Settlement Location. These Load Settlement Location LMPs are the weighted average of the LMPs at the PNodes that comprise the Load Settlement Location. For both the DA Market and RTBM, the weighting factors are those described under Section 4.1.2.1.7 for each respective market. These weighting factors are applied for calculating the LMP, MCP and MLC for the APNode Load Settlement Location.

The LMP for APNode \(_j\) is:

\[
\text{LMP}_{\text{APNode}_j} = \sum_k (W_k \times \text{LMP}_k)
\]

The MCC for APNode \(_j\) is:

\[
\text{MCC}_{\text{APNode}_j} = \sum_k (W_k \times \text{MCC}_k)
\]

The MLC for APNode \(_j\) is:

\[
\text{MLC}_{\text{APNode}_j} = \sum_k (W_k \times \text{MLC}_k)
\]

Where:

1. \(W_k\) is the weighting factor for Pnode \(k\) which is part of APNode \(j\). The sum of the weighting factors for all Pnodes \(k\) must sum to 1.0;
2. \(\text{LMP}_k\) is the LMP for Pnode \(k\) which is part of APNode \(j\);
3. \(\text{MCC}_k\) is the Marginal Congestion Component of the LMP for Pnode \(k\) which is part of APNode \(j\);
4. \(\text{MLC}_k\) is the Marginal Losses Components of the LMP for Pnode \(k\) which is part of APNode \(j\).
4.5.5.3 Calculation of LMP at an External Interface Settlement Location

SPP calculates an LMP for each External Interface based on the LMPs for the set of PNodes that comprise the External Interface. These External Interface LMPs are the weighted average of the LMPs at the PNodes that comprise the External Interface. The weighting factors are predetermined and remain fixed as described under Section 4.3.1.1. These weighting factors are applied for calculating a LMP, MCP and MLC at an External Interface for both the DA Market and RTBM.

The LMP for External Interface \( j \) is:

\[
LMPEI_{j} = \sum_{k} (W_{k} \times LMP_{k})
\]

The MCC for External Interface \( j \) is:

\[
MCCEI_{j} = \sum_{k} (W_{k} \times MCC_{k})
\]

The MLC for External Interface \( j \) is:

\[
MLCEI_{j} = \sum_{k} (W_{k} \times MLC_{k})
\]

Where:

1. \( W_{k} \) is the weighting factor for Pnode \( k \) which is part of External Interface \( j \). The sum of the weighting factors for all Pnodes \( k \) must sum to 1.0;

2. \( LMP_{k} \) is the LMP for Pnode \( k \) which is part of External Interface \( j \);

3. \( MCC_{k} \) is the Marginal Congestion Components of the LMP for Pnode \( k \) which is part of External Interface \( j \);

4. \( MLC_{k} \) is the LMP for Pnode \( k \) which is part of External Interface \( j \).

4.5.6 Precision and Rounding

Exhibit 4-17 documents the input data precision assumptions and the rounding assumptions related to calculated values for each intermediate bill determinant and all charge types. The Unit
column corresponds to the Unit column included in the variable description tables included with each charge type. The rounding assumptions in Exhibit 4-17 under the Calculated Data are applied to all variable names that begin with a ‘#’.

**Exhibit 4-17: Input Data Precision and Rounding Assumptions**

<table>
<thead>
<tr>
<th>Input Data</th>
<th>Calculated Data</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Maximum Allowable Precision</strong></td>
<td><strong>Precision</strong></td>
</tr>
<tr>
<td>Unit</td>
<td>Precision</td>
</tr>
<tr>
<td>$/MW or $/MWh</td>
<td>.0001</td>
</tr>
<tr>
<td>MWh</td>
<td>.001</td>
</tr>
<tr>
<td>MW</td>
<td>.001</td>
</tr>
<tr>
<td>Factor</td>
<td>.0001</td>
</tr>
<tr>
<td>$</td>
<td>.01 (for cost data)</td>
</tr>
</tbody>
</table>

**4.5.7 FERC Electric Quarterly Reporting**

In order to assist Market Participants in meeting their FERC Electric Quarterly Reporting (EQR) obligations, SPP has provided the required billing determinants under each applicable charge type. These charge types along with the EQR transaction type for the billing determinant provided are summarized in the Exhibit 4-18 below.
## Exhibit 4-18: FERC EQR Reporting Billing Determinants

<table>
<thead>
<tr>
<th>Charge Type</th>
<th>EQR Transaction Type</th>
<th>EQR Reporting Interval</th>
</tr>
</thead>
<tbody>
<tr>
<td>Day-Ahead Asset Energy</td>
<td>DA Market Energy Sale from Resource net of Financial Schedule</td>
<td>Hour</td>
</tr>
<tr>
<td></td>
<td>Price for DA Market Energy Sale from Resource net of Financial Schedule</td>
<td>Hour</td>
</tr>
<tr>
<td>Day-Ahead Non-Asset Energy</td>
<td>DA Market Energy Sale from Export Transaction net of Financial Schedule</td>
<td>Hour</td>
</tr>
<tr>
<td></td>
<td>Price for DA Market Energy Sale from Export Transaction net of Financial Schedule</td>
<td>Hour</td>
</tr>
<tr>
<td>Day-Ahead Regulation-Up</td>
<td>DA Market Regulation-Up Sale by Resource by Hour</td>
<td>Hour</td>
</tr>
<tr>
<td></td>
<td>Price for DA Market Regulation-Up Sale by Resource by Hour</td>
<td>Hour</td>
</tr>
<tr>
<td>Day-Ahead Regulation-Down</td>
<td>DA Market Regulation-Down Sale by Resource by Hour</td>
<td>Hour</td>
</tr>
<tr>
<td></td>
<td>Price for DA Market Regulation-Down Sale by Resource by Hour</td>
<td>Hour</td>
</tr>
<tr>
<td>Day-Ahead Spinning Reserve</td>
<td>DA Market Spinning Reserve Sale by Resource</td>
<td>Hour</td>
</tr>
<tr>
<td></td>
<td>Prices for DA Market Spinning Reserve Sale by Resource</td>
<td>Hour</td>
</tr>
<tr>
<td>Day-Ahead Supplemental Reserve</td>
<td>DA Market Supplemental Reserve Sale by Resource</td>
<td>Hour</td>
</tr>
<tr>
<td></td>
<td>Prices for DA Market Supplemental Reserve Sale by Resource</td>
<td>Hour</td>
</tr>
<tr>
<td>Day-Ahead Make-Whole Payment</td>
<td>DA Market Make-Whole-Payment $ by Resource</td>
<td>DA Make-Whole-Payment Eligibility Period</td>
</tr>
<tr>
<td>Real-Time Asset Energy</td>
<td>RTBM net Energy transaction from Resource Settlement Location net of Financial Schedule, by Settlement Location</td>
<td>Dispatch Interval</td>
</tr>
<tr>
<td></td>
<td>Price for RTBM net Energy transaction from Resource Settlement Location net of Financial Schedule, by Settlement Location</td>
<td>Dispatch Interval</td>
</tr>
<tr>
<td>Charge Type</td>
<td>EQR Transaction Type</td>
<td>EQR Reporting Interval</td>
</tr>
<tr>
<td>--------------------------------------</td>
<td>--------------------------------------------------------------------------------------</td>
<td>----------------------------------------</td>
</tr>
<tr>
<td>Real-Time Non-Asset Energy</td>
<td>RTBM net Energy Sale net of Financial Schedule from External Interface Settlement Location, by Settlement Location</td>
<td>Dispatch Interval</td>
</tr>
<tr>
<td></td>
<td>Price for RTBM net Energy Sale net of Financial Schedule from External Interface Settlement Location, by Settlement Location</td>
<td>Dispatch Interval</td>
</tr>
<tr>
<td>Real-Time Regulation-Up</td>
<td>RTBM net Regulation-Up transaction by Resource</td>
<td>Dispatch Interval</td>
</tr>
<tr>
<td></td>
<td>Price for RTBM net Regulation-Up transaction by Resource</td>
<td>Dispatch Interval</td>
</tr>
<tr>
<td>Real-Time Regulation-Down</td>
<td>RTBM net Regulation-Down transaction by Resource</td>
<td>Dispatch Interval</td>
</tr>
<tr>
<td></td>
<td>Price for RTBM net Regulation-Down transaction by Resource</td>
<td>Dispatch Interval</td>
</tr>
<tr>
<td>Real-Time Spinning Reserve</td>
<td>RTBM net Spinning Reserve transaction by Resource</td>
<td>Dispatch Interval</td>
</tr>
<tr>
<td></td>
<td>Price for RTBM net Spinning Reserve transaction by Resource</td>
<td>Dispatch Interval</td>
</tr>
<tr>
<td>Real-Time Supplemental Reserve</td>
<td>RTBM net Supplemental Reserve transaction by Resource</td>
<td>Dispatch Interval</td>
</tr>
<tr>
<td></td>
<td>Price for RTBM net Supplemental Reserve transaction by Resource</td>
<td>Dispatch Interval</td>
</tr>
<tr>
<td>RUC Make-Whole Payment</td>
<td>RUC Make-Whole-Payment $ by Resource</td>
<td>RUC Make-Whole-Payment Eligibility Period</td>
</tr>
<tr>
<td>Real-Time Out-of-Merit</td>
<td>RTBM Out-of-Merit Energy and Operating Reserve $ by Resource</td>
<td>Dispatch Interval</td>
</tr>
<tr>
<td>Real-Time Regulation Deployment</td>
<td>RTBM Regulation Deployment Adjustment $ by Resource</td>
<td>Dispatch Interval</td>
</tr>
</tbody>
</table>
4.5.8 Day-Ahead Market Settlement

Settlement calculations for Energy and Operating Reserve in the DA Market are performed on an hourly basis for each Operating Day and are based upon the results of the DA Market clearing for that Operating Day.

1. Each Market Participant with cleared Offers is paid for each Settlement Location:
   - For the amount of physical Energy sold, net of Financial Schedules for Energy, at the associated LMP (see Sections 4.5.8.1 and 4.5.8.2);
   - For the amount of virtual Energy sold at the associated LMP (see Sections 4.5.8.3 and 4.5.8.20);
   - For the amount of Regulation-Up sold at the associated Regulation-Up MCP (see Section 4.5.8.4);
   - For the amount of Regulation-Down sold at the associated Regulation-Down MCP (see Section 4.5.8.5);
   - For the amount of Spinning Reserve sold at the associated Spinning Reserve MCP (see Section 4.5.8.6); and
   - For the amount of Supplemental Reserve sold at the associated Supplemental Reserve MCP (see Section 4.5.8.7).

2. Each Market Participant with cleared Bids is charged for each Settlement Location:
   - For the amount of physical Energy purchased, net of Financial Schedules for Energy, at the associated LMP (see Sections 4.5.8.1 and 4.5.8.2); and
   - For the amount of virtual Energy purchased at the associated LMP (see Sections 4.5.8.3 and 4.5.8.20).

3. Charges to Market Participants for Operating Reserve procured in the DA Market are calculated on a Reserve Zone basis by multiplying the Reserve Zone Operating Reserve procurement rate by each Asset Owner’s DA Market Operating Reserve Reserve Zone Obligation. See Sections 4.5.8.8, 4.5.8.9, 4.5.8.10, and 4.5.8.11 for additional details;
   - The procurement rate within a Reserve Zone for each Operating Reserve product is equal to the DA Market Operating Reserve product procurement costs to meet the Reserve Zone DA Market Operating Reserve product obligation divided by the DA Market Reserve Zone Operating Reserve obligation.
(b) For Reserve Zones where Operating Reserve procured is more than the entire obligation in the zone, the DA Market Operating Reserve procurement cost is equal to the clearing price for DA Market Operating Reserve for that zone, multiplied by the zone obligation. For Reserve Zones where Operating Reserve procured is less than the entire obligation in the zone, the DA Market Operating Reserve procurement cost is the weighted average of (1) the clearing price for DA Market Operating Reserve for that zone and (2) the average clearing price for the DA Market Operating Reserve procured and imported from other zones, multiplied by the zone obligation.

(4) Market Participants of SPP committed Resources in the DA Market will also receive a make whole payment if the total revenues received for Energy and Operating Reserve sales in the DA Market settlement are less than the Resource’s Offer costs associated with those sales. Make-Whole payments are calculated on a commitment period basis and are collected on a daily basis from Asset Owners based upon their pro-rata share of the sum of all Bids cleared in the Operating Day. See Sections 4.5.8.12, and 4.5.8.13 for additional details;

(5) Settlements related to congestion management are also performed as part of the Day-Ahead Market settlement as follows;

   (a) Holders of TCRs are paid (or charged) for the amount of TCRs held between a particular source and sink at the difference between the sink MCC and the source MCC. See Section 4.5.8.14 for additional details.

   (b) To the extent that there are insufficient congestion revenues collected in an Operating Day to fully fund TCR holders, TCR holders are charged a pro-rata uplift amount to cover the under collection based upon each TCR holder’s net charges or credits for the Operating Day. If there is excess congestion revenues collected in an Operating Day, the excess is carried for use at the end of the month. See Section 4.5.8.15 for additional details.

   (c) At the end of each month, if there are excess congestion revenues available, these revenues are used to reimburse TCR holders that received an uplift charge for Operating Days during that month. Each TCR holder is reimbursed a pro-rata share of the uplift charges paid based upon the level of uplift charges paid until they are fully reimbursed or the excess congestion revenues are depleted. To the extent that there are excess congestion revenues remaining after fully reimbursing
TCR holders, this excess is carried forward for use at the end of the year. See Section 4.5.8.16 for additional details.

(d) At the end of each year, if there are excess congestion revenues available, these revenues are used to reimburse TCR holders that received an uplift charge for Operating Days during that year that were not fully reimbursed. Each TCR holder is reimbursed a pro-rata share of the remaining uplift charges paid based upon the level of remaining uplift charges paid until they are fully reimbursed or the excess congestion revenues are depleted. See Section 4.5.8.17 for additional details.

(e) To the extent that there are excess congestion revenues remaining at the end of the year after fully reimbursing TCR holders, this excess is distributed back to ARR holders pro-rata based upon their annual ARR Nomination Caps. See Section 4.5.8.18 for additional details.

(6) Settlement associated with revenue over collection due to the impact of marginal losses on the DA Market LMPs is also performed as part of the Day-Ahead Market settlement as follows. See Section 4.5.8.19 for calculation details.

(a) For each Asset Owner, a proxy loss charge contribution amount is developed for each Settlement Location with a net withdrawal that is equal to the positive difference between the MLC at the net withdrawal Settlement Location and the weighted average MLC of all net injections assumed to be serving the net withdrawal, multiplied by that Asset Owner’s share of the net withdrawal, where that share is calculated excluding cleared Virtual Bids and cleared Virtual Offers.

(i) The net injections assumed to be serving the net withdrawal are the net injections at the Settlement Locations included in that Asset Owner’s Loss Pool. The Asset Owner’s Loss Pool is defined dynamically and includes all Settlement Locations at which that Asset Owner has transactional activity (Financial Schedules, Resource output, load consumption, Interchange Transactions), but excludes virtual transactions. To the extent that the net injections in the Asset Owner’s Loss Pool are not sufficient to serve the net withdrawals in the Asset Owner’s Loss Pool, net injections from an injection exchange are included to make up the difference. To the extent that the net injections in the Asset Owner’s Loss Pool are greater than the net withdrawals in
the Asset Owner’s Loss Pool, the excess is added to the injection exchange.

(ii) The injection exchange is comprised of quantities from Loss Pools in which injection exceeds withdrawal. A weighted average of the MLC at the source of these quantities establishes a reference for the component of the loss charge contributions at Settlement Locations with net withdrawal met from outside the Asset Owner’s Loss Pool.

(b) Each Asset Owner’s credit (all Asset Owner net withdrawals at each Settlement Location participate) for over collected losses is then equal a pro-rata share of the total marginal losses over collection as calculated from the proxy loss charge contribution calculated in (a) above.

The following subsections describe the DA Market settlement charge types. For each charge type, the calculation is performed at the hourly level for each Asset Owner at each Settlement Location. In addition to the hourly values, daily values will be accessible on the Settlement Statement for all charge types.

4.5.8.1 Day-Ahead Asset Energy Amount

(1) A DA Market credit or charge for net physical Energy activity associated with load and Resources, adjusted for Financial Schedules for Energy, is calculated at each Settlement Location for each Asset Owner for each Hour. The net amount is calculated as follows:

$$\#DaEnergyHrlyAmt_{a,s,h} = DaLmpHrlyPrc_{s,h} \times (DaClrdHrlyQty_{a,s,h} - \sum_{t} DaEnFinHrlyQty_{a,s,h,t})$$

(2) For each Asset Owner, a daily amount is calculated at each Settlement Location. The net daily amount is calculated as follows:

$$DaEnergyDlyAmt_{a,s,d} = \sum_{h} DaEnergyHrlyAmt_{a,s,h}$$

(3) For each Asset Owner associated with Market Participant $m$, a daily amount is calculated. The net daily amount is calculated as follows:
\[ \text{DaEnergyAoAmt}_{a, m, d} = \sum_s \text{DaEnergyDlyAmt}_{a, s, d} \]

(4) For each Market Participant, a daily amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The net amount is calculated as follows:

\[ \text{DaEnergyMpAmt}_{m, d} = \sum_a \text{DaEnergyAoAmt}_{a, m, d} \]

(5) For FERC Electric Quarterly Reporting ("EQR") purposes, SPP calculates hourly sales volume and prices associated with this Charge Type for each Asset Owner as follows:

(a) \[ \text{EqrDaAssetEnergyHrlyQty}_{a, s, h} = (-1) \times \min(0, \text{DaClrdHrlyQty}_{a, s, h} - \sum_t \text{DaEnFinHrlyQty}_{a, s, h, t}) \]

(b) IF \( \text{EqrDaAssetEnergyHrlyQty}_{a, s, h} > 0 \) THEN
\[ \text{EqrDaAssetEnergyHrlyPrc}_{a, s, h} = \text{DaLmpHrlyPrc}_{s, h} \]
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>DaEnergyHrlyAmt ( a,s,h )</td>
<td>$ \text{$/h}</td>
<td>Hour</td>
<td>Day-Ahead Asset Energy Amount per AO per Settlement Location per Hour - The DA Market amount to AO ( a ) for net cleared Resource’s and load, net of Financial Schedules for Energy, at Settlement Location ( s ) for the Hour.</td>
</tr>
<tr>
<td>DaLmpHrlyPre ( s,h )</td>
<td>$/\text{MWh}</td>
<td>Hour</td>
<td>Day-Ahead LMP - The DA Market LMP at Settlement Location ( s ) for the Hour.</td>
</tr>
<tr>
<td>DaClrdHrlyQty ( a,s,h )</td>
<td>MWh</td>
<td>Hour</td>
<td>Day-Ahead Cleared Energy Quantity per AO per Settlement Location per Hour - The total net quantity of Energy represented by AO ( a )’s DA Market cleared Resource Offers and Demand Bids in the DA Market at Settlement Location ( s ) for the Hour.</td>
</tr>
<tr>
<td>DaEnFinHrlyQty ( a,s,h,t )</td>
<td>MWh</td>
<td>Hour</td>
<td>Day-Ahead Asset Energy Financial Schedule per AO per Transaction per Settlement Location per Hour - The quantity specified by the buyer AO and seller AO in a DA Market Financial Schedule for Energy at Asset Settlement Location ( s ), for each transaction ( t ), for the Hour. The buyer AO quantity is a positive value and the seller AO quantity is a negative value.</td>
</tr>
<tr>
<td>DaEnergyDlyAmt ( a,s,d )</td>
<td>$ \text{$/d}</td>
<td>Operating Day</td>
<td>Day-Ahead Asset Energy Amount per AO per Settlement Location per Operating Day - The DA Market amount to AO ( a ) for net cleared offers and bids, net of Financial Schedules for Energy, at Settlement Location ( s ) for the Operating Day.</td>
</tr>
<tr>
<td>DaEnergyAoAmt ( a,m,d )</td>
<td>$ \text{$/d}</td>
<td>Operating Day</td>
<td>Day-Ahead Asset Energy Amount per AO per Operating Day - The DA Market amount to AO ( a ) associated with Market Participant ( m ) for net cleared offers and bids, net of Financial Schedules for Energy for the Operating Day.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>----------</td>
<td>------</td>
<td>---------------------</td>
<td>------------</td>
</tr>
<tr>
<td>EqrDaAssetEnergyHrlyQtyas,h</td>
<td>MWh</td>
<td>Hour</td>
<td>Day-Ahead Electric Quarterly Reporting Asset Energy Sales per AO per Settlement Location per Hour – AO ( a ) ’s DA Market Energy sales at Resource Settlement Location ( s ), net of Financial Schedules, in Hour ( h ) for use by AO ( a ) in reporting such sales to FERC in accordance with FERC EQR requirements.</td>
</tr>
<tr>
<td>EqrDaAssetEnergyHrlyPrcas,h</td>
<td>$/MWh</td>
<td>Hour</td>
<td>Day-Ahead Electric Quarterly Reporting Asset Energy Sales Prices per AO per Settlement Location per Hour – AO ( a ) ’s DA Market Energy sales price at Resource Settlement Location ( s ), net of Financial Schedules, in Hour ( h ) for use by AO ( a ) in reporting such sales to FERC in accordance with FERC EQR requirements.</td>
</tr>
<tr>
<td>( a )</td>
<td>none</td>
<td>none</td>
<td>An Asset Owner.</td>
</tr>
<tr>
<td>( s )</td>
<td>none</td>
<td>none</td>
<td>A Settlement Location.</td>
</tr>
<tr>
<td>( t )</td>
<td>none</td>
<td>none</td>
<td>A single tagged Interchange Transaction, a single virtual energy transaction, a single Financial Schedule, a single contracted Operating Reserve transaction, a single TCR instrument, a single ARR award or a single Reserve Sharing Event transaction.</td>
</tr>
<tr>
<td>( h )</td>
<td>none</td>
<td>none</td>
<td>An Hour.</td>
</tr>
<tr>
<td>( d )</td>
<td>none</td>
<td>none</td>
<td>An Operating Day.</td>
</tr>
<tr>
<td>( m )</td>
<td>none</td>
<td>none</td>
<td>A Market Participant.</td>
</tr>
</tbody>
</table>
4.5.8.2  Day-Ahead Non-Asset Energy Amount

(1) A DA Market credit or charge for net physical Energy activity associated Interchange Transactions, adjusted for Financial Schedules for Energy, is calculated at each Settlement Location for each Asset Owner for each Hour. The net amount is calculated as follows:

\[
\text{DaNEnergyHrlyAmt}_{a,s,h} = \text{DaLmpHrlyPrc}_{s,h} \times \left( \sum_i \sum_t \left( \frac{\text{DaImpExp5minQty}_{a,i,t}}{12} \right) - \sum_t \text{DaNEEnFinHrlyQty}_{a,s,h,t} \right)
\]

(2) For each Asset Owner, a daily amount is calculated at each Settlement Location. The net daily amount is calculated as follows:

\[
\text{DaNEnergyDlyAmt}_{a,s,d} = \sum_h \text{DaNEnergyHrlyAmt}_{a,s,h}
\]

(3) For each Asset Owner associated with Market Participant \(m\), a daily amount is calculated. The net daily amount is calculated as follows:

\[
\text{DaNEnergyAoAmt}_{a,m,d} = \sum_s \text{DaNEnergyDlyAmt}_{a,s,d}
\]

(4) For each Market Participant, a daily amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The net daily amount is calculated as follows:

\[
\text{DaNEnergyMpAmt}_{m,d} = \sum_a \text{DaNEnergyAoAmt}_{a,m,d}
\]

(5) For FERC Electric Quarterly Reporting (“EQR”) purposes, SPP calculates hourly sales volume and prices associated with this Charge Type for each Asset Owner as follows:

(a) \[
\text{EqrDaNAssetEnergyHrlyQty}_{a,s,h} = -1 \times \min \left[ 0, \left( \sum_i \sum_t \left( \frac{\text{DaImpExp5minQty}_{a,i,t}}{12} \right) \right) \right]
\]
(b) IF EqrDaNAssetEnergyHrlyQty_{a, s, h} > 0
THEN
EqrDaNAssetEnergyHrlyPrc_{a, s, h} = DaLmpHrlyPrc_{s, h}
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>DaNEnergyHrlyAmt&lt;sub&gt;a, s, h&lt;/sub&gt;</td>
<td>$</td>
<td>Hour</td>
<td>Day-Ahead Non-Asset Energy Amount per AO per Settlement Location per Hour - The DA Market amount to AO &lt;em&gt;a&lt;/em&gt; for net cleared Interchange Transactions, net of Financial Schedules for Energy, at Settlement Location &lt;em&gt;s&lt;/em&gt; for the Hour.</td>
</tr>
<tr>
<td>DaLmpHrlyPre&lt;sub&gt;s, h&lt;/sub&gt;</td>
<td>$/MWh</td>
<td>Hour</td>
<td>Day-Ahead LMP - The DA Market LMP at Settlement Location &lt;em&gt;s&lt;/em&gt; for the Hour.</td>
</tr>
<tr>
<td>DaNEnergyAoAmt&lt;sub&gt;a, m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Non-Asset Energy Amount per AO per Operating Day - The DA Market amount to AO &lt;em&gt;a&lt;/em&gt; for net cleared offers and bids, net of Financial Schedules for Energy for the Operating Day.</td>
</tr>
<tr>
<td>DaNEnergyAoAmt&lt;sub&gt;a, m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Non-Asset Energy Amount per AO per Operating Day - The DA Market amount to AO &lt;em&gt;a&lt;/em&gt; associated with Market Participant &lt;em&gt;m&lt;/em&gt; for net cleared offers and bids, net of Financial Schedules for Energy for the Operating Day.</td>
</tr>
<tr>
<td>DaNEnergyDlyAmt&lt;sub&gt;a, s, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Non-Asset Energy Amount per AO per Settlement Location per Operating Day - The DA Market amount to AO &lt;em&gt;a&lt;/em&gt; for net cleared offers and bids, net of Financial Schedules for Energy, at Settlement Location &lt;em&gt;s&lt;/em&gt; for the Operating Day.</td>
</tr>
<tr>
<td>DaNEnergyDlyAmt&lt;sub&gt;a, s, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Non-Asset Energy Amount per AO per Settlement Location per Operating Day - The DA Market amount to AO &lt;em&gt;a&lt;/em&gt; for net cleared offers and bids, net of Financial Schedules for Energy for the Operating Day.</td>
</tr>
<tr>
<td>DaNEnergyDlyAmt&lt;sub&gt;a, s, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Non-Asset Energy Amount per AO per Operating Day - The DA Market amount to AO &lt;em&gt;a&lt;/em&gt; associated with Market Participant &lt;em&gt;m&lt;/em&gt; for net cleared offers and bids, net of Financial Schedules for Energy for the Operating Day.</td>
</tr>
<tr>
<td>DaNEnergyDlyAmt&lt;sub&gt;a, s, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Non-Asset Energy Amount per AO per Operating Day - The DA Market amount to AO &lt;em&gt;a&lt;/em&gt; associated with Market Participant &lt;em&gt;m&lt;/em&gt; for net cleared offers and bids, net of Financial Schedules for Energy for the Operating Day.</td>
</tr>
<tr>
<td>DaNEnergyDlyAmt&lt;sub&gt;a, s, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Non-Asset Energy Amount per AO per Operating Day - The DA Market amount to AO &lt;em&gt;a&lt;/em&gt; associated with Market Participant &lt;em&gt;m&lt;/em&gt; for net cleared offers and bids, net of Financial Schedules for Energy for the Operating Day.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>----------------------------------------------</td>
<td>-------</td>
<td>---------------------</td>
<td>--------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>DaNEnergyMpAmt&lt;sub&gt;m,d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Non-Asset Energy Amount per Market Participant per Operating Day - The DA Market amount to Market Participant &lt;i&gt;m&lt;/i&gt; for net cleared offers and bids, net of Financial Schedules for Energy for the Operating Day.</td>
</tr>
<tr>
<td>EqrDaNAAssetEnergyHrlyQty&lt;sub&gt;a,s,h&lt;/sub&gt;</td>
<td>MWh</td>
<td>Hour</td>
<td>Day-Ahead Electric Quarterly Reporting Non-Asset Energy Sales per AO per Settlement Location per Hour – AO &lt;i&gt;a&lt;/i&gt;’s Energy sales at External Interface Settlement Location &lt;i&gt;s&lt;/i&gt;, net of Financial Schedules, in Hour &lt;i&gt;h&lt;/i&gt; for use by AO &lt;i&gt;a&lt;/i&gt; in reporting such sales to FERC in accordance with FERC EQR requirements.</td>
</tr>
<tr>
<td>EqrDaNAAssetEnergyHrlyPrc&lt;sub&gt;a,s,h&lt;/sub&gt;</td>
<td>$/MWh</td>
<td>Hour</td>
<td>Day-Ahead Electric Quarterly Reporting Non-Asset Energy Sales Prices per AO per Settlement Location per Hour – AO &lt;i&gt;a&lt;/i&gt;’s DA Market Energy sales price at External Interface Settlement Location &lt;i&gt;s&lt;/i&gt;, net of Financial Schedules, in Hour &lt;i&gt;h&lt;/i&gt; for use by AO &lt;i&gt;a&lt;/i&gt; in reporting such sales to FERC in accordance with FERC EQR requirements.</td>
</tr>
<tr>
<td>&lt;i&gt;a&lt;/i&gt;</td>
<td>none</td>
<td>none</td>
<td>An Asset Owner.</td>
</tr>
<tr>
<td>&lt;i&gt;s&lt;/i&gt;</td>
<td>none</td>
<td>none</td>
<td>A Settlement Location.</td>
</tr>
<tr>
<td>&lt;i&gt;t&lt;/i&gt;</td>
<td>none</td>
<td>none</td>
<td>A single tagged Interchange Transaction, a single virtual energy transaction, a single Financial Schedule, a single contracted Operating Reserve transaction, a single TCR instrument, a single ARR award or a single Reserve Sharing Event transaction.</td>
</tr>
<tr>
<td>&lt;i&gt;h&lt;/i&gt;</td>
<td>none</td>
<td>none</td>
<td>An Hour.</td>
</tr>
<tr>
<td>&lt;i&gt;d&lt;/i&gt;</td>
<td>none</td>
<td>none</td>
<td>An Operating Day.</td>
</tr>
<tr>
<td>&lt;i&gt;m&lt;/i&gt;</td>
<td>none</td>
<td>none</td>
<td>A Market Participant.</td>
</tr>
</tbody>
</table>
4.5.8.3 Day-Ahead Virtual Energy Amount

(1) A DA Market credit or charge for net virtual Energy activity will be calculated at each Settlement Location for each Asset Owner for each hour. The net amount is calculated as follows:

\[
#\text{DaVEnergyHrlyAmt}_{a,s,h} = \text{DaLmpHrlyPrc}_{s,h} \times \sum_t \text{DaClrdVHrlyQty}_{a,s,h,t}
\]

(2) For each Asset Owner, a daily amount is calculated at each Settlement Location. The net daily amount is calculated as follows:

\[
\text{DaVEnergyDlyAmt}_{a,s,d} = \sum_h \text{DaVEnergyHrlyAmt}_{a,s,h}
\]

(3) For each Asset Owner associated with Market Participant \( m \), a daily amount is calculated. The net daily amount is calculated as follows:

\[
\text{DaVEnergyAoAmt}_{a,m,d} = \sum_s \text{DaVEnergyDlyAmt}_{a,s,d}
\]

(4) For each Market Participant, a daily amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The net daily amount is calculated as follows:

\[
\text{DaVEnergyMpAmt}_{m,d} = \sum_a \text{DaVEnergyAoAmt}_{a,m,d}
\]
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>DaVEnergyHrlyAmt (_{a, s, h})</td>
<td>$</td>
<td>Hour</td>
<td>Day-Ahead Virtual Energy Amount per AO per Settlement Location per Hour - The DA Market amount to AO (a) for net cleared Virtual Energy Offers and Virtual Energy Bids at Settlement Location (s) for the Hour.</td>
</tr>
<tr>
<td>DaLmpHrlyPre (_{s, h})</td>
<td>$/MWh</td>
<td>Hour</td>
<td>Day-Ahead LMP – The value described under Section 4.5.8.1.</td>
</tr>
<tr>
<td>DaClrdVHrlyQty (_{a, s, h, t})</td>
<td>MWh</td>
<td>Hour</td>
<td>Day-Ahead Cleared Virtual Energy Quantity per AO per Transaction per Settlement Location per Hour - The virtual energy quantity represented by AO (a)’s cleared Virtual Energy Offers and Virtual Demand Bids in the DA Market at Settlement Location (s) for each transaction (t) for the Hour.</td>
</tr>
<tr>
<td>DaVEnergyDlyAmt (_{a, s, d})</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Virtual Energy Amount per AO per Settlement Location per Operating Day - The DA Market amount to AO (a) for net cleared virtual offers and bids, net of Financial Schedules for Energy, at Settlement Location (s) for the Operating Day.</td>
</tr>
<tr>
<td>DaVEnergyAoAmt (_{a, m, d})</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Virtual Energy Amount per AO per Operating Day - The DA Market amount to AO (a) associated with Market Participant (m) for net cleared virtual offers and bids, net of Financial Schedules for Energy for the Operating Day.</td>
</tr>
<tr>
<td>DaVEnergyMpAmt (_{m, d})</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Virtual Energy Amount per Market Participant per Operating Day - The DA Market amount to Market Participant (m) for net cleared virtual offers and bids, net of Financial Schedules for Energy for the Operating Day.</td>
</tr>
</tbody>
</table>

\(a\) none none An Asset Owner.
\(h\) none none An Hour.
\(s\) none none A Settlement Location.
<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>$t$</td>
<td>none</td>
<td>none</td>
<td>A single tagged Interchange Transaction, a single virtual energy transaction, a single Financial Schedule, a single contracted Operating Reserve transaction, a single TCR instrument, a single ARR award or a single Reserve Sharing Event transaction.</td>
</tr>
<tr>
<td>$d$</td>
<td>none</td>
<td>none</td>
<td>An Operating Day.</td>
</tr>
<tr>
<td>$m$</td>
<td>none</td>
<td>none</td>
<td>A Market Participant.</td>
</tr>
</tbody>
</table>
4.5.8.4 Day-Ahead Regulation-Up Amount

(1) A DA Market credit or charge\(^2\) for cleared Regulation-Up will be calculated at each Settlement Location for each Asset Owner for each hour. The amount will be calculated as follows:

\[ \#\text{DaRegUpHrlyAmt}_{a,s,h} = (\text{DaRegUpMcpHrlyPrc}_{z,s,h} \times \text{DaRegUpHrlyQty}_{a,s,h}) \times (-1) \]

(2) For each Asset Owner, a daily amount is calculated at each Settlement Location. The daily amount is calculated as follows:

\[ \text{DaRegUpDlyAmt}_{a,s,d} = \sum_{h} \text{DaRegUpHrlyAmt}_{a,s,h} \]

(3) For each Asset Owner associated with Market Participant \(m\), a daily amount is calculated. The daily amount is calculated as follows:

\[ \text{DaRegUpAoAmt}_{a,m,d} = \sum_{s} \text{DaRegUpDlyAmt}_{a,s,d} \]

(4) For each Market Participant, a daily amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The daily amount is calculated as follows:

\[ \text{DaRegUpMpAmt}_{m,d} = \sum_{a} \text{DaRegUpAoAmt}_{a,m,d} \]

(5) For FERC Electric Quarterly Reporting (“EQR”) purposes, SPP calculates hourly sales volume and prices associated with this Charge Type for each Asset Owner as follows:

(a) \[ \text{EqrDaRegUpHrlyQty}_{a,s,h} = \text{DaRegUpHrlyQty}_{a,s,h} \]

(b) \[ \text{EqrDaRegUpHrlyPrc}_{a,s,h} = \text{DaRegUpMcpHrlyPrc}_{z,s,h} \]

\(^2\) Note that this charge type will almost always produce a credit. The charge is included here for the rare occasion when a charge may be produced as a result of a data error and/or a resettlement.
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>DaRegUpHrlyAmt (a, s, h)</td>
<td>$</td>
<td>Hour</td>
<td>Day-Ahead Regulation-Up Amount per AO per Resource Settlement Location per Hour - The DA Market amount to AO (a) for cleared Regulation-Up Offers at Resource Settlement Location (s) for the Hour.</td>
</tr>
<tr>
<td>DaRegUpMcpHrlyPre (z, s, h)</td>
<td>$/MW</td>
<td>Hour</td>
<td>Day-Ahead MCP for Regulation-Up - The DA Market MCP for Regulation-Up for the Reserve Zone that includes Resource Settlement Location (s) for the Hour.</td>
</tr>
<tr>
<td>DaRegUpHrlyQty (a, s, h)</td>
<td>MW</td>
<td>Hour</td>
<td>Day-Ahead Cleared Regulation-Up Quantity per AO per Settlement Location per Hour - The total quantity of Regulation-Up MW represented by AO (a)’s cleared Regulation-Up Offers in the DA Market at Resource Settlement Location (s) for the Hour.</td>
</tr>
<tr>
<td>DaRegUpDlyAmt (a, s, d)</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Regulation-Up Amount per AO per Settlement Location per Operating Day - The DA Market amount to AO (a) for cleared Regulation-Up Offers at Settlement Location (s) for the Operating Day.</td>
</tr>
<tr>
<td>DaRegUpAoAmt (a, m, d)</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Regulation-Up Amount per AO per Operating Day - The DA Market amount to AO (a) associated with Market Participant (m) for cleared Regulation-Up Offers for the Operating Day.</td>
</tr>
<tr>
<td>DaRegUpMpAmt (m, d)</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Regulation-Up Amount per MP per Operating Day - The DA Market amount to Market Participant (m) for cleared Regulation-Up Offers for the Operating Day.</td>
</tr>
<tr>
<td>EqrDaRegUpHrlyQty (a, s, h)</td>
<td>MWh</td>
<td>Hour</td>
<td>Day-Ahead Electric Quarterly Reporting Regulation-Up Sales per AO per Settlement Location per Hour – AO (a)’s DA Market Regulation-Up sales at External Interface Settlement Location (s) in Hour (h) for use by AO (a) in reporting such sales to FERC in accordance with FERC EQR requirements.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>---------------------------</td>
<td>--------</td>
<td>---------------------</td>
<td>-------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>EqrDaRegUpHrlyPre(a, s, h)</td>
<td>S/MWh</td>
<td>Hour</td>
<td>Day-Ahead Electric Quarterly Reporting Regulation-Up Sales Prices per AO per Settlement Location per Hour – AO a’s DA Market Regulation-Up sales price at External Interface Settlement Location s in Hour h for use by AO a in reporting such sales to FERC in accordance with FERC EQR requirements.</td>
</tr>
<tr>
<td>a</td>
<td>none</td>
<td>none</td>
<td>An Asset Owner.</td>
</tr>
<tr>
<td>s</td>
<td>none</td>
<td>none</td>
<td>A Resource Settlement Location.</td>
</tr>
<tr>
<td>h</td>
<td>none</td>
<td>none</td>
<td>An Hour.</td>
</tr>
<tr>
<td>z</td>
<td>none</td>
<td>none</td>
<td>A Reserve Zone.</td>
</tr>
<tr>
<td>d</td>
<td>none</td>
<td>none</td>
<td>An Operating Day.</td>
</tr>
<tr>
<td>m</td>
<td>none</td>
<td>none</td>
<td>A Market Participant.</td>
</tr>
</tbody>
</table>
4.5.8.5  Day-Ahead Regulation-Down Amount

(1) A DA Market credit or charge\(^3\) for cleared Regulation-Down will be calculated at each Settlement Location for each Asset Owner for each hour. The amount will be calculated as follows:

\[ #\text{DaRegDnHrlyAmt}_{a, s, h} = (\text{DaRegDnMcpHrlyPrc}_{z, s, h} \times \text{DaRegDnHrlyQty}_{a, s, h}) \times (-1) \]

(2) For each Asset Owner, a daily amount is calculated at each Settlement Location. The daily amount is calculated as follows:

\[ \text{DaRegDnDlyAmt}_{a, s, d} = \sum_h \text{DaRegDnHrlyAmt}_{a, s, h} \]

(3) For each Asset Owner associated with Market Participant \(m\), a daily amount is calculated. The daily amount is calculated as follows:

\[ \text{DaRegDnAoAmt}_{a, m, d} = \sum_s \text{DaRegDnDlyAmt}_{a, s, d} \]

(4) For each Market Participant, a daily amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The daily amount is calculated as follows:

\[ \text{DaRegDnMpData}_{m, d} = \sum_a \text{DaRegDnAoAmt}_{a, m, d} \]

(5) For FERC Electric Quarterly Reporting (“EQR”) purposes, SPP calculates hourly sales volume and prices associated with this Charge Type for each Asset Owner as follows:

(a) \[ Eqr\text{DaRegDnHrlyQty}_{a, s, h} = \text{DaRegDnHrlyQty}_{a, s, h} \]

(b) \[ Eqr\text{DaRegDnHrlyPrc}_{a, s, h} = \text{DaRegDnMcpHrlyPrc}_{z, s, h} \]

\(^3\) Note that this charge type will almost always produce a credit. The charge is included here for the rare occasion when a charge may be produced as a result of a data error and/or a resettlement.
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>DaRegDnHrlyAmt (_{a, s, h})</td>
<td>$</td>
<td>Hour</td>
<td>Day-Ahead Regulation-Down Amount per AO per Resource Settlement Location per Hour - The DA Market amount to AO (a) for cleared Regulation-Down Offers at Resource Settlement Location (s) for the Hour.</td>
</tr>
<tr>
<td>DaRegDnMcpHrlyPre (_{z, s, h})</td>
<td>S/MW</td>
<td>Hour</td>
<td>Day-Ahead MCP for Regulation-Down - The DA Market MCP for Regulation-Down for the Reserve Zone that includes Resource Settlement Location (s) for the hour.</td>
</tr>
<tr>
<td>DaRegDnHrlyQty (_{a, s, h})</td>
<td>MW</td>
<td>Hour</td>
<td>Day-Ahead Cleared Regulation-Down Quantity per AO per Settlement Location per Hour - The total quantity of Regulation-Down MW represented by AO (a)’s cleared Regulation-Down Offers in the DA Market at Resource Settlement Location (s), for the Hour.</td>
</tr>
<tr>
<td>DaRegDnDlyAmt (_{a, s, d})</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Regulation-Down Amount per AO per Settlement Location per Operating Day - The DA Market amount to AO (a) for cleared Regulation-Down Offers at Settlement Location (s) for the Operating Day.</td>
</tr>
<tr>
<td>DaRegDnAoAmt (_{a, m, d})</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Regulation-Down Amount per AO per Operating Day - The DA Market amount to AO (a) associated with Market Participant (m) for cleared Regulation-Down Offers for the Operating Day.</td>
</tr>
<tr>
<td>DaRegDnMpAmt (_{m, d})</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Regulation-Down Amount per MP per Operating Day - The DA Market amount to Market Participant (m) for cleared Regulation-Down Offers for the Operating Day.</td>
</tr>
<tr>
<td>EqrDaRegDnHrlyQty (_{a, s, h})</td>
<td>MWh</td>
<td>Hour</td>
<td>Day-Ahead Electric Quarterly Reporting Regulation-Down Sales per AO per Settlement Location per Hour – AO (a)’s DA Market Regulation-Down sales at External Interface Settlement Location (s) in Hour (h) for use by AO (a) in reporting such sales to FERC in accordance with FERC EQR requirements.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>--------------------------</td>
<td>--------</td>
<td>---------------------</td>
<td>-------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td><strong>EqrDaRegDnHrlyPrc</strong></td>
<td>S/MWh</td>
<td>Hour</td>
<td><strong>Day-Ahead Electric Quarterly Reporting Regulation-Down Sales Prices per AO per Settlement Location per Hour</strong> – AO a’s DA Market Regulation-Down sales price at External Interface Settlement Location s in Hour h for use by AO a in reporting such sales to FERC in accordance with FERC EQR requirements.</td>
</tr>
<tr>
<td>a</td>
<td>none</td>
<td>none</td>
<td>An Asset Owner.</td>
</tr>
<tr>
<td>s</td>
<td>none</td>
<td>none</td>
<td>A Resource Settlement Location.</td>
</tr>
<tr>
<td>h</td>
<td>none</td>
<td>none</td>
<td>An Hour.</td>
</tr>
<tr>
<td>z</td>
<td>none</td>
<td>none</td>
<td>A Reserve Zone.</td>
</tr>
<tr>
<td>d</td>
<td>none</td>
<td>none</td>
<td>An Operating Day.</td>
</tr>
<tr>
<td>m</td>
<td>none</td>
<td>none</td>
<td>A Market Participant.</td>
</tr>
</tbody>
</table>
4.5.8.6  Day-Ahead Spinning Reserve Amount

(1) A DA Market credit or charge for cleared Spinning Reserve will be calculated at each Settlement Location for each Asset Owner for each hour. The amount will be calculated as follows:

\[ \#\text{DaSpinHrlyAmt}_{a,s,h} = (\text{DaSpinMcpHrlyPrc}_{x,s,h} \times \text{DaSpinHrlyQty}_{a,s,h}) \times (-1) \]

(2) For each Asset Owner, a daily amount is calculated at each Settlement Location. The daily amount is calculated as follows:

\[ \text{DaSpinDlyAmt}_{a,s,d} = \sum_h \text{DaSpinHrlyAmt}_{a,s,h} \]

(3) For each Asset Owner associated with Market Participant \(m\), a daily amount is calculated. The amount is calculated as follows:

\[ \text{DaSpinAoAmt}_{a,m,d} = \sum_s \text{DaSpinDlyAmt}_{a,s,d} \]

(4) For each Market Participant, a daily amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The daily amount is calculated as follows:

\[ \text{DaSpinMpAmt}_{m,d} = \sum_a \text{DaSpinAoAmt}_{a,m,d} \]

(5) For FERC Electric Quarterly Reporting (“EQR”) purposes, SPP calculates hourly sales volume and prices associated with this Charge Type for each Asset Owner as follows:

(a) \[ \text{EqrDaSpinHrlyQty}_{a,s,h} = \text{DaSpinHrlyQty}_{a,s,h} \]

(b) \[ \text{EqrDaSpinHrlyPrc}_{a,s,h} = \text{DaSpinMcpHrlyPrc}_{x,s,h} \]

\[ ^4 \text{ Note that this charge type will almost always produce a credit. The charge is included here for the rare occasion when a charge may be produced as a result of a data error and/or a resettlement.} \]
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>DaSpinHrlyAmt (a, s, h)</td>
<td>$</td>
<td>Hour</td>
<td>Day-Ahead Spinning Reserve Amount per AO per Resource Settlement Location per Hour - The DA Market amount to AO (a) for cleared Spinning Reserve offers at Resource Settlement Location (s) for the Hour.</td>
</tr>
<tr>
<td>DaSpinMcpHrlyPrc (z, s, h)</td>
<td>$/MW</td>
<td>Hour</td>
<td>Day-Ahead MCP for Spinning Reserve - The DA Market MCP for Spinning Reserve for the Reserve Zone that includes Resource Settlement Location (s) for the hour.</td>
</tr>
<tr>
<td>DaSpinHrlyQty (a, s, h)</td>
<td>MW</td>
<td>Hour</td>
<td>Day-Ahead Cleared Spinning Reserve Quantity per AO per Settlement Location per Hour - The total quantity of Spinning Reserve MW represented by AO (a)’s cleared Spinning Reserve Offers in the DA Market at Resource Settlement Location (s), for the Hour.</td>
</tr>
<tr>
<td>DaSpinDlyAmt (a, s, d)</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Spinning Reserve Amount per AO per Settlement Location per Operating Day - The DA Market amount to AO (a) for cleared Spinning Reserve Offers at Settlement Location (s), for the Operating Day.</td>
</tr>
<tr>
<td>DaSpinAoAmt (a, m, d)</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Spinning Reserve Amount per AO per Operating Day - The DA Market amount to AO (a) associated with Market Participant (m) for cleared Spinning Reserve Offers for the Operating Day.</td>
</tr>
<tr>
<td>DaSpinMpAmt (m, d)</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Spinning Reserve Amount per MP per Operating Day - The DA Market amount to Market Participant (m) for cleared Spinning Reserve Offers for the Operating Day.</td>
</tr>
<tr>
<td>EqrDaSpinHrlyQty (a, s, h)</td>
<td>MWh</td>
<td>Hour</td>
<td>Day-Ahead Electric Quarterly Reporting Spinning Reserve Sales per AO per Settlement Location per Hour – AO (a)’s DA Market Spinning Reserve sales at External Interface Settlement Location (s) in Hour (h) for use by AO (a) in reporting such sales to FERC in accordance with FERC EQR requirements.</td>
</tr>
<tr>
<td>EqrDaSpinHrlyPrc (a, s, h)</td>
<td>$/MWh</td>
<td>Hour</td>
<td>Day-Ahead Electric Quarterly Reporting Spinning Reserve Sales Prices per AO per Settlement Location per Hour – AO (a)’s DA Market Spinning Reserve sales price at External Interface Settlement Location (s) in Hour (h) for use by AO (a) in reporting such sales to FERC in accordance with FERC EQR requirements.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>----------</td>
<td>------</td>
<td>---------------------</td>
<td>---------------------------------</td>
</tr>
<tr>
<td>$a$</td>
<td>none</td>
<td>none</td>
<td>An Asset Owner.</td>
</tr>
<tr>
<td>$s$</td>
<td>none</td>
<td>none</td>
<td>A Resource Settlement Location.</td>
</tr>
<tr>
<td>$h$</td>
<td>none</td>
<td>none</td>
<td>An Hour.</td>
</tr>
<tr>
<td>$z$</td>
<td>none</td>
<td>none</td>
<td>A Reserve Zone.</td>
</tr>
<tr>
<td>$d$</td>
<td>none</td>
<td>none</td>
<td>An Operating Day.</td>
</tr>
<tr>
<td>$m$</td>
<td>none</td>
<td>none</td>
<td>A Market Participant</td>
</tr>
</tbody>
</table>
4.5.8.7 Day-Ahead Supplemental Reserve Amount

(1) A DA Market credit or charge for cleared Supplemental Reserve will be calculated at each Settlement Location for each Asset Owner for each hour. The amount will be calculated as follows:

\[ #\text{DaSuppHrlyAmt}_{a,s,h} = (\text{DaSuppMcpHrlyPrc}_{z,s,h} \times \text{DaSuppHrlyQty}_{a,s,h}) \times (-1) \]

(2) For each Asset Owner, a daily amount is calculated at each Settlement Location. The net daily amount is calculated as follows:

\[ \text{DaSuppDlyAmt}_{a,s,d} = \sum_{h} \text{DaSuppHrlyAmt}_{a,s,h} \]

(3) For each Asset Owner associated with Market Participant \( m \), a daily amount is calculated. The daily amount is calculated as follows:

\[ \text{DaSuppAoAmt}_{a,m,d} = \sum_{s} \text{DaSuppDlyAmt}_{a,s,d} \]

(4) For each Market Participant, a daily amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The daily amount is calculated as follows:

\[ \text{DaSuppMpAmt}_{m,d} = \sum_{a} \text{DaSuppAoAmt}_{a,m,d} \]

(5) For FERC Electric Quarterly Reporting (“EQR”) purposes, SPP calculates hourly sales volume and prices associated with this Charge Type for each Asset Owner as follows:

(a) \[ \text{EqrDaSuppHrlyQty}_{a,s,h} = \text{DaSuppHrlyQty}_{a,s,h} \]

(b) \[ \text{EqrDaSuppHrlyPrc}_{a,s,h} = \text{DaSuppMcpHrlyPrc}_{z,s,h} \]

\[ \text{Note that this charge type will almost always produce a credit. The charge is included here for the rare occasion when a charge may be produced as a result of a data error and/or a resettlement.} \]
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>DaSuppHrlyAmt&lt;sub&gt;a,s,h&lt;/sub&gt;</td>
<td>$</td>
<td>Hour</td>
<td>Day-Ahead Supplemental Reserve Amount per AO per Resource Settlement Location per Hour - The DA Market amount to AO a for cleared Supplemental Reserve offers at Resource Settlement Location s for the Hour.</td>
</tr>
<tr>
<td>DaSuppMcpHrlyPre&lt;sub&gt;z,s,h&lt;/sub&gt;</td>
<td>$/MW</td>
<td>Hour</td>
<td>Day-Ahead MCP for Supplemental Reserve - The DA Market MCP for Supplemental Reserve for the Reserve Zone that includes Resource Settlement Location s for the Hour.</td>
</tr>
<tr>
<td>DaSuppHrlyQty&lt;sub&gt;a,s,h&lt;/sub&gt;</td>
<td>MW</td>
<td>Hour</td>
<td>Day-Ahead Cleared Supplemental Reserve Quantity per AO per Settlement Location per Hour - The total quantity of Supplemental Reserve represented by AO a’s cleared Supplemental Reserve Offers in the DA Market at Resource Settlement Location s, for the Hour.</td>
</tr>
<tr>
<td>DaSuppDlyAmt&lt;sub&gt;a,s,d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Supplemental Reserve Amount per AO per Settlement Location per Operating Day - The DA Market amount to AO a for cleared Supplemental Reserve Offers at Settlement Location s for the Operating Day.</td>
</tr>
<tr>
<td>DaSuppAoAmt&lt;sub&gt;a,m,d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Supplemental Reserve Amount per AO per Operating Day - The DA Market amount to AO a associated with Market Participant m for cleared Supplemental Reserve Offers for the Operating Day.</td>
</tr>
<tr>
<td>DaSuppMpAmt&lt;sub&gt;m,d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Supplemental Reserve Amount per MP per Operating Day - The DA Market amount to Market Participant m for cleared Supplemental Reserve Offers for the Operating Day.</td>
</tr>
<tr>
<td>EqrDaSuppHrlyQty&lt;sub&gt;a,s,h&lt;/sub&gt;</td>
<td>MWh</td>
<td>Hour</td>
<td>Day-Ahead Electric Quarterly Reporting Supplemental Reserve Sales per AO per Settlement Location per Hour – AO a’s DA Market Supplemental Reserve sales at External Interface Settlement Location s in Hour h for use by AO a in reporting such sales to FERC in accordance with FERC EQR requirements.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>-------------------</td>
<td>------</td>
<td>---------------------</td>
<td>--------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>EqrDaSuppHrlyPre</td>
<td>$/MWh</td>
<td>Hour</td>
<td>Day-Ahead Electric Quarterly Reporting Supplemental Reserve Sales Prices per AO per Settlement Location per Hour – AO a’s DA Market Supplemental Reserve sales price at External Interface Settlement Location s in Hour h for use by AO a in reporting such sales to FERC in accordance with FERC EQR requirements.</td>
</tr>
<tr>
<td>a</td>
<td>none</td>
<td>none</td>
<td>An Asset Owner.</td>
</tr>
<tr>
<td>s</td>
<td>none</td>
<td>none</td>
<td>A Resource Settlement Location.</td>
</tr>
<tr>
<td>h</td>
<td>none</td>
<td>none</td>
<td>An Hour.</td>
</tr>
<tr>
<td>z</td>
<td>none</td>
<td>none</td>
<td>A Reserve Zone.</td>
</tr>
<tr>
<td>d</td>
<td>none</td>
<td>none</td>
<td>An Operating Day.</td>
</tr>
<tr>
<td>m</td>
<td>none</td>
<td>none</td>
<td>A Market Participant.</td>
</tr>
</tbody>
</table>
4.5.8.8 Day-Ahead Regulation-Up Distribution Amount

(1) A DA Market charge or credit\textsuperscript{6} will be calculated for each Asset Owner for each hour for each Reserve Zone. The Asset Owner amount within each Reserve Zone will be equal to the net Reserve Zone procurement rate for Regulation-Up multiplied by the Asset Owners Regulation-Up obligation within the Reserve Zone. For the purpose of allocating DA Market Regulation-Up procurement costs, all Non-Binding Reserve Zones will be combined into a single Non-Binding Reserve Zone. The amount to each Asset Owner is calculated as follows:

\[
\#\text{DaRegUpDistHrlyAmt}_{a, z, h} = \text{DaRegUpDistHrlyRate}_{z, h} \times \text{DaRegUpAoObligHrlyQty}_{a, z, h}
\]

Where,

(a) IF \(\text{DaRegUpObligRznHrlyQty}_{z, h} > 0\)

THEN

\[
\#\text{DaRegUpDistHrlyRate}_{z, h} = \frac{\text{DaRegUpRznHrlyCost}_{z, h}}{\text{DaRegUpObligRznHrlyQty}_{z, h}}
\]

ELSE

\[
\text{DaRegUpDistHrlyRate}_{z, h} = 0
\]

(a.1) \(\text{DaRegUpObligRznHrlyQty}_{z, h} = \sum_{a} \text{DaRegUpAoObligHrlyQty}_{a, z, h}\)

(a.2) \(\#\text{DaRegUpRznHrlyCost}_{z, h} = \text{Min} (\text{DaRegUpRznHrlyQty}_{z, h}, \text{DaRegUpObligRznHrlyQty}_{z, h}) \times \text{DaRegUpMcpHrlyPrc}_{z, h}\)

\textsuperscript{6} Note that this charge type will almost always produce a charge. The credit is included here for the rare occasion when a credit may be produced as a result of a data error and/or a resettlement.
\[ + \max \left( 0, \left( \text{DaRegUpObligRznHrlyQty}_{z, h} - \text{DaRegUpRznHrlyQty}_{z, h} \right) \right) \]

* \text{DaRegUpSpxHrlyRate}_h

(a.2.1) IF \[ \sum_z \max \left( 0, \text{DaRegUpRznHrlyQty}_{z, h} - \text{DaRegUpObligRznHrlyQty}_{z, h} \right) > 0 \]

THEN

\[ \#\text{DaRegUpSpxHrlyRate}_h = \frac{\sum_z \left( \max \left( 0, \text{DaRegUpRznHrlyQty}_{z, h} - \text{DaRegUpObligRznHrlyQty}_{z, h} \right) \times \text{DaRegUpMcpHrlyPrc}_{z, h} \right)}{\sum_z \max \left( 0, \text{DaRegUpRznHrlyQty}_{z, h} - \text{DaRegUpObligRznHrlyQty}_{z, h} \right)} \]

ELSE

\[ \text{DaRegUpSpxHrlyRate}_h = 0 \]

(a.2.2) \[ \text{DaRegUpRznHrlyQty}_{z, h} = \sum_a \sum_s \text{DaRegUpHrlyQty}_{a, s, z, h} \]

(b) \[ \#\text{DaRegUpAoObligHrlyQty}_{a, z, h} = (\text{DaRegUpInterAoObligHrlyQty}_{a, z, h} \times \text{DaRegUpObligRatio}_h) - \sum_t \text{RegUpFinHrlyQty}_{a, z, h, t} \]

(b.1) \[ \text{DaRegUpInterAoObligHrlyQty}_{a, z, h} = \]

\[ \max \left( 0, \text{DaRegUpIniAoObligHrlyQty}_{a, z, h} - \sum_t \text{ContrRegUpHrlyQty}_{a, z, h, t} \right) \]
(b.2) \[ \text{DaRegUpIniAoObligHrlyQty}_{a, z, h} = \]
\[
( \text{DaRegUpSppHrlyQty}_h + \text{ContrRegUpSppHrlyQty}_h ) \]
\[
\times \left( \sum_s \text{RtRegUpRznLoadHrlyQty}_{a, s, z, h} / \text{RtLoadSppHrlyQty}_h \right) \]

(b.2.1) \[ \text{ContrRegUpSppHrlyQty}_h = \sum_a \sum_z \sum_t \text{ContrRegUpHrlyQty}_{a, z, h, t} \]

(b.2.2) \[ \text{RtLoadSppHrlyQty}_h = \sum_a \sum_s \sum_z \text{RtRegUpRznLoadHrlyQty}_{a, s, z, h} \]

(b.2.3) \[ \text{DaRegUpSppHrlyQty}_h = \sum_a \sum_s \sum_z \text{DaRegUpHrlyQty}_{a, s, z, h} \]

(b.3) \[ \text{DaRegUpObligRatio}_h = \frac{\text{DaRegUpSppHrlyQty}_h}{\text{DaRegUpInterObligSppHrlyQty}_h} \]

(b.3.1) \[ \text{DaRegUpInterObligSppHrlyQty}_h = \sum_a \sum_z \text{DaRegUpInterAoObligHrlyQty}_{a, z, h} \]

(b.4) \[ \#\text{RtRegUpRznLoadHrlyQty}_{a, s, z, h} = \left[ \text{Max} \left( 0, \sum_i \text{RtBillMtr5minQty}_{a, s, i} \right) \right. \]
\[ + \left. \text{Max} \left( 0, \sum_i \sum_t \text{RtImpExp5minQty}_{a, s, i, t} \times (1 - \text{RsgCrdFlgt}) \right) \right] \]
\[ \times \text{PctSlinRznRegUpHrlyFct}_{a, s, z, h} / 12 \]
(c) \[ \#\text{DaRegUpSIObligHrlyQty}_{a, s, z, h} = (\text{DaRegUpSppHrlyQty}_{h} + \text{ContrRegUpSppHrlyQty}_{h}) \times \left( \frac{\text{RtRegUpRznLoadHrlyQty}_{a, s, z, h}}{\text{RtLoadSppHrlyQty}_{h}} \right) \]

(2) For each Asset Owner, a daily amount is calculated at each Reserve Zone. The daily amount is calculated as follows:

\[ \text{DaRegUpDistDlyAmt}_{a, z, d} = \sum_{h} \text{DaRegUpDistHrlyAmt}_{a, z, h} \]

(3) For each Asset Owner associated with Market Participant \( m \), a daily amount is calculated. The daily amount is calculated as follows:

\[ \text{DaRegUpDistAoAmt}_{a, m, d} = \sum_{z} \text{DaRegUpDistDlyAmt}_{a, z, d} \]

(4) For each Market Participant, a daily amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The daily amount is calculated as follows:

\[ \text{DaRegUpDistMpAmt}_{m, d} = \sum_{a} \text{DaRegUpDistAoAmt}_{a, m, d} \]
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>DaRegUpDistHrlyAmt&lt;sub&gt;a, z, h&lt;/sub&gt;</td>
<td>$</td>
<td>Hour</td>
<td>Day-Ahead Regulation-Up Distribution Amount per AO per Reserve Zone per Hour - The amount to AO ( a ) for AO ( a )'s share of DA Market Regulation-Up procurement costs in Reserve Zone ( z ) in Hour ( h ).</td>
</tr>
<tr>
<td>DaRegUpDistHrlyRate&lt;sub&gt;z, h&lt;/sub&gt;</td>
<td>$/MW</td>
<td>Hour</td>
<td>Day-Ahead Regulation-Up Distribution Hourly Rate per Reserve Zone per Hour – The rate applied to AO ( a )'s Regulation-Up obligation within Reserve Zone ( z ) in Hour ( h ).</td>
</tr>
<tr>
<td>ContrRegUpHrlyQty&lt;sub&gt;a, z, h, t&lt;/sub&gt;</td>
<td>MW</td>
<td>Hour</td>
<td>Contracted Regulation-Up per AO per Reserve Zone per Transaction per Hour – AO ( a )'s contracted Regulation-Up transaction ( t ) being supplied to Reserve Zone ( z ) from external to the SPP BA to meet AO ( a )'s Regulation-Up obligation. Contracted Regulation-Up being supplied to AO ( a ) is a positive value.</td>
</tr>
<tr>
<td>DaRegUpRznHrlyCost&lt;sub&gt;z, h&lt;/sub&gt;</td>
<td>$</td>
<td>Hour</td>
<td>Day-Ahead Regulation-Up Reserve Zone Cost per Reserve Zone per Hour – The total DA Market Regulation-Up procurement cost for Reserve Zone ( z ) in Hour ( h ).</td>
</tr>
<tr>
<td>DaRegUpHrlyQty&lt;sub&gt;a, s, z, h&lt;/sub&gt;</td>
<td>MW</td>
<td>Hour</td>
<td>Day-Ahead Regulation-Up Hourly Quantity per Asset Owner per Settlement Location per Reserve Zone per Hour – The value described under Section 4.5.8.4 in Reserve Zone ( z ).</td>
</tr>
<tr>
<td>DaRegUpAoObligHrlyQty&lt;sub&gt;a, z, h&lt;/sub&gt;</td>
<td>MW</td>
<td>Hour</td>
<td>Day-Ahead Regulation-Up Asset Owner Obligation Quantity per Reserve Zone per Hour – Asset Owner ( a )'s DA Market Regulation-Up obligation in Reserve Zone ( z ) for Hour ( h ).</td>
</tr>
<tr>
<td>DaRegUpRznHrlyQty&lt;sub&gt;z, h&lt;/sub&gt;</td>
<td>MW</td>
<td>Hour</td>
<td>Day-Ahead Regulation-Up Hourly Quantity per Reserve Zone per Hour – The total amount of cleared Regulation-Up in Reserve Zone ( z ) for Hour ( h ).</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>----------</td>
<td>------</td>
<td>---------------------</td>
<td>------------</td>
</tr>
<tr>
<td>DaRegUpObligRznHrlyQty&lt;sub&gt;z, h&lt;/sub&gt;</td>
<td>MW</td>
<td>Hour</td>
<td>Day-Ahead Regulation-Up Obligation per Reserve Zone per Hour – Reserve Zone z’s DA Market Regulation-Up obligation for Hour h.</td>
</tr>
<tr>
<td>ContrRegUpSppHrlyQty&lt;sub&gt;h&lt;/sub&gt;</td>
<td>MW</td>
<td>Hour</td>
<td>ContrRegUpHrlyQty&lt;sub&gt;a, z, h, t&lt;/sub&gt; for Hour h.</td>
</tr>
<tr>
<td>RtLoadSppHrlyQty&lt;sub&gt;h&lt;/sub&gt;</td>
<td>MW</td>
<td>Hour</td>
<td>Real-Time SPP Load per Hour – SPP total actual load and Export Interchange Transactions in Hour h.</td>
</tr>
<tr>
<td>DaRegUpSppHrlyQty&lt;sub&gt;h&lt;/sub&gt;</td>
<td>MW</td>
<td>Hour</td>
<td>Total SPP Day-Ahead Regulation-Up Hourly Quantity per Hour – The total amount of Regulation-Up cleared in the DA Market for Hour h.</td>
</tr>
<tr>
<td>DaRegUpInterObligSppHrlyQty&lt;sub&gt;h&lt;/sub&gt;</td>
<td>MW</td>
<td>Hour</td>
<td>Day-Ahead SPP Regulation-Up Interim Obligation Quantity per AO per Reserve Zone per Hour – The total of all Asset Owner’s DA Market Regulation-Up interim obligation over all Reserve Zones for Hour h.</td>
</tr>
<tr>
<td>DaRegUpInterAoObligHrlyQty&lt;sub&gt;a, z, h&lt;/sub&gt;</td>
<td>MW</td>
<td>Hour</td>
<td>Day-Ahead Regulation-Up Interim Asset Owner Obligation Quantity per AO per Reserve Zone per Hour – Asset Owner a’s DA Market Regulation-Up interim obligation that includes treatment of ContrRegUpHrlyQty&lt;sub&gt;a, z, h, t&lt;/sub&gt; but does not include allocation of excess ContrRegUpHrlyQty&lt;sub&gt;a, z, h, t&lt;/sub&gt; in Reserve Zone z for Hour h.</td>
</tr>
<tr>
<td>DaRegUpIniAoObligHrlyQty&lt;sub&gt;a, z, h&lt;/sub&gt;</td>
<td>MW</td>
<td>Hour</td>
<td>Day-Ahead Regulation-Up Initial Asset Owner Obligation Quantity per AO per Reserve Zone per Hour – Asset Owner a’s DA Market Regulation-Up initial obligation that does not include treatment of ContrRegUpHrlyQty&lt;sub&gt;a, z, h, t&lt;/sub&gt; in Reserve Zone z for Hour h.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>------------------------------------</td>
<td>---------------</td>
<td>---------------------</td>
<td>-------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>DaRegUpObligRatio&lt;sub&gt;_h&lt;/sub&gt;</td>
<td>none</td>
<td>Hour</td>
<td>Day-Ahead Regulation-Up Asset Owner Obligation Ratio per Hour – The percentage applied to Asset Owner a’s DaRegUpInterAoObligHrlyQty&lt;sub&gt;_a, z, h&lt;/sub&gt; to account for allocation of any excess ContrRegUpHrlyQty&lt;sub&gt;_a, z, h, t&lt;/sub&gt; in Reserve Zone z in Hour h.</td>
</tr>
<tr>
<td>DaRegUpSL-obligHrlyQty&lt;sub&gt;_a, s, z, h&lt;/sub&gt;</td>
<td>MW</td>
<td>Hour</td>
<td>Day-Ahead Regulation-Up Obligation Quantity per AO per Settlement Location per Hour - Asset Owner a’s DA Market Regulation-Up initial obligation that does not include treatment of ContrRegUpHrlyQty&lt;sub&gt;_a, z, h, t&lt;/sub&gt; at Settlement Location s in Reserve Zone z for Hour h. Note that this value is provided for information purposes only and is not used in any of the cost allocation calculations.</td>
</tr>
<tr>
<td>DaRegUpMcpHrlyPrc&lt;sub&gt;_z, h&lt;/sub&gt;</td>
<td>$/MW</td>
<td>Hour</td>
<td>Day-Ahead MCP for Regulation-Up per Reserve Zone – The value described under Section 4.5.8.4 for Reserve Zone z.</td>
</tr>
<tr>
<td>DaRegUpSpxHrlyRate&lt;sub&gt;_h&lt;/sub&gt;</td>
<td>$/MW</td>
<td>Hour</td>
<td>Day-Ahead Regulation-Up SPP Exchange Rate per Hour – The rate applied to calculate the portion of DA Market Reserve Zone procurement costs associated with Reserve Zones that must purchase cleared Regulation-Up from other Reserve Zones in order to meet the Reserve Zone Regulation-Up obligation.</td>
</tr>
<tr>
<td>RtRegUpRznLoadHrlyQty&lt;sub&gt;_a, s, z, h&lt;/sub&gt;</td>
<td>MWh</td>
<td>Hour</td>
<td>Real-Time Reserve Zone Load per AO per Settlement Location in Reserve Zone z for Hour h – Asset Owner a’s actual load and Export Interchange Transactions at Settlement Location s in Reserve Zone z for Hour h for use in Regulation-Up cost allocation.</td>
</tr>
<tr>
<td>RtBillMtr5minQty&lt;sub&gt;_a, s, i&lt;/sub&gt;</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Billing Meter Quantity per AO per Settlement Location per Dispatch Interval - The value described under Section 4.5.9.1 for Reserve Zone z.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>----------</td>
<td>------</td>
<td>---------------------</td>
<td>------------</td>
</tr>
<tr>
<td>PctSlinRznRegUpHrlyFct&lt;sub&gt;a, s, z, h&lt;/sub&gt;</td>
<td>%</td>
<td>Hour</td>
<td>Percent Settlement Location in Reserve Zone per AO per Settlement Location per Reserve Zone per Hour – The percentage factor of AO a’s load at Settlement Location s that is contained within Reserve Zone z for use in Regulation-Up cost allocation.</td>
</tr>
<tr>
<td>RtImpExp5minQty&lt;sub&gt;a, s, i, t&lt;/sub&gt;</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Interchange Transaction Quantity per AO per Settlement Location per Dispatch Interval per Transaction – The value described under Section 4.5.9.2 for Reserve Zone z.</td>
</tr>
<tr>
<td>RsgCrdFlg&lt;sub&gt;r&lt;/sub&gt;</td>
<td>none</td>
<td>none</td>
<td>Reserve Sharing Group Contingency Reserve Deployment Flag per Event – A flag indicating that an import or export is a result of a schedule created by a Reserve Sharing Event. Normally, this flag is equal to zero. It is set equal to one for a Reserve Sharing Event.</td>
</tr>
<tr>
<td>RegUpFinHrlyQty&lt;sub&gt;a, z, h, t&lt;/sub&gt;</td>
<td>MW</td>
<td>Hour</td>
<td>Financial Schedule for Regulation-Up per AO per Settlement Location per Transaction per Hour - The MW amount specified by the buyer AO and seller AO in a RTBM Financial Schedule transaction t for Regulation-Up at Reserve Zone z for the Hour. The buyer AO MW amount is a positive value and the seller AO MW amount is a negative value.</td>
</tr>
<tr>
<td>DaRegUpDistDlyAmt&lt;sub&gt;a, z, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Regulation-Up Distribution Amount per AO per Reserve Zone per Operating Day - AO a’s share of DA Market Regulation-Up procurement costs for Reserve Zone z in Operating Day d.</td>
</tr>
<tr>
<td>DaRegUpDistAoAmt&lt;sub&gt;a, m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Regulation-Up Distribution Amount per AO per Operating Day - AO a’s for total DA Market Regulation-Up procurement costs associated with Market Participant m in Operating Day d.</td>
</tr>
<tr>
<td>DaRegUpDistMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Regulation-Up Distribution Amount per MP per Operating Day - MP m’s share of total DA Market Regulation-Up procurement costs for in Operating Day d.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>----------</td>
<td>------</td>
<td>---------------------</td>
<td>------------</td>
</tr>
<tr>
<td>(a)</td>
<td>none</td>
<td>none</td>
<td>An Asset Owner.</td>
</tr>
<tr>
<td>(s)</td>
<td>none</td>
<td>none</td>
<td>A Settlement Location.</td>
</tr>
<tr>
<td>(h)</td>
<td>none</td>
<td>none</td>
<td>An Hour.</td>
</tr>
<tr>
<td>(z)</td>
<td>none</td>
<td>none</td>
<td>A Reserve Zone.</td>
</tr>
<tr>
<td>(i)</td>
<td>none</td>
<td>none</td>
<td>A Dispatch Interval.</td>
</tr>
<tr>
<td>(t)</td>
<td>none</td>
<td>none</td>
<td>A single tagged Interchange Transaction, a single virtual energy transaction, a single Financial Schedule, a single contracted Operating Reserve transaction, a single TCR instrument, a single ARR award or a single Reserve Sharing Event transaction.</td>
</tr>
<tr>
<td>(d)</td>
<td>none</td>
<td>none</td>
<td>An Operating Day.</td>
</tr>
<tr>
<td>(m)</td>
<td>none</td>
<td>none</td>
<td>A Market Participant.</td>
</tr>
</tbody>
</table>
4.5.8.9 Day-Ahead Regulation-Down Distribution Amount

(1) A DA Market charge or credit\(^7\) will be calculated for each Asset Owner for each hour for each Reserve Zone. The Asset Owner amount within each Reserve Zone will be equal to the net Reserve Zone procurement rate for Regulation-Down multiplied by the Asset Owners Regulation-Down obligation within the Reserve Zone. For the purpose of allocating DA Market Regulation-Down procurement costs, all Non-Binding Reserve Zones will be combined into a single Non-Binding Reserve Zone. The amount to each Asset Owner is calculated as follows:

\[
\#\text{DaRegDnDistHrlyAmt}_{a, \alpha, h} = \text{DaRegDnDistHrlyRate}_{\alpha, h} \times \text{DaRegDnAoObligHrlyQty}_{a, \alpha, h}
\]

Where,

(a) IF \(\text{DaRegDnObligRznHrlyQty}_{\alpha, h} > 0\)

THEN

\[
\#\text{DaRegDnDistHrlyRate}_{\alpha, h} = \frac{\text{DaRegDnRznHrlyCost}_{\alpha, h}}{\text{DaRegDnObligRznHrlyQty}_{\alpha, h}}
\]

ELSE

\[
\text{DaRegDnDistHrlyRate}_{\alpha, h} = 0
\]

(a.1) \(\text{DaRegDnObligRznHrlyQty}_{\alpha, h} = \sum_a \text{DaRegDnAoObligHrlyQty}_{a, \alpha, h}\)

(a.2) \(\#\text{DaRegDnRznHrlyCost}_{\alpha, h} = \min(\text{DaRegDnRznHrlyQty}_{\alpha, h}, \text{DaRegDnObligRznHrlyQty}_{\alpha, h}) \times \text{DaRegDnMcpHrlyPrec}_{\alpha, h}\)

\(^7\) Note that this charge type will almost always produce a charge. The credit is included here for the rare occasion when a credit may be produced as a result of a data error and/or a resettlement.
+ \text{Max} \left( 0, \left( \text{DaRegDnObligRznHrlyQty}_{z, h} - \text{DaRegDnRznHrlyQty}_{z, h} \right) \right) \\
* \text{DaRegDnSpxHrlyRate}_{h} \\

(a.2.1) \text{IF} \sum_{z} \text{Max} \left( 0, \text{DaRegDnRznHrlyQty}_{z, h} - \text{DaRegDnObligRznHrlyQty}_{z, h} \right) > 0 \\
\text{THEN} \\

\#\text{DaRegDnSpxHrlyRate}_{h} = \\
\sum_{z} \left( \text{Max} \left( 0, \text{DaRegDnRznHrlyQty}_{z, h} - \text{DaRegDnObligRznHrlyQty}_{z, h} \right) \right) \\
* \text{DaRegDnMcpHrlyPrc}_{z, h} ) \\
/ \sum_{z} \text{Max} \left( 0, \text{DaRegDnRznHrlyQty}_{z, h} - \text{DaRegDnObligRznHrlyQty}_{z, h} \right) \\

\text{ELSE} \\
\text{DaRegDnSpxHrlyRate}_{h} = 0 \\

(a.2.2) \text{DaRegDnRznHrlyQty}_{z, h} = \sum_{a} \sum_{s} \text{DaRegDnHrlyQty}_{a, s, z, h} \\
(b) \#\text{DaRegDnAoObligHrlyQty}_{a, z, h} = ( \text{DaRegDnInterAoObligHrlyQty}_{a, z, h} \\
* \text{DaRegDnObligRatio}_{h} ) - \sum_{t} \text{RegDnFinHrlyQty}_{a, z, h, t} \\
(b.1) \text{DaRegDnInterAoObligHrlyQty}_{a, z, h} = \\
\text{Max} \left( 0, \text{DaRegDnIniAoObligHrlyQty}_{a, z, h} - \sum_{t} \text{ContrRegDnHrlyQty}_{a, z, h, t} \right)
(b.2) \[ \text{DaRegDnIniAoObligHrlyQty}_{a, z, h} = \]
\[ (\text{DaRegDnSppHrlyQty}_h + \text{ContrRegDnSppHrlyQty}_h) \]
\[ \times (\sum_s \text{RtRegDnRznLoadHrlyQty}_{a, s, z, h} / \text{RtLoadSppHrlyQty}_h) \]

(b.2.1) \[ \text{ContrRegDnSppHrlyQty}_h = \sum_a \sum_z \sum_t \text{ContrRegDnHrlyQty}_{a, z, h, t} \]

(b.2.2) \[ \text{DaRegDnSppHrlyQty}_h = \sum_a \sum_s \sum_z \text{DaRegDnHrlyQty}_{a, s, z, h} \]

(b.3) \[ \text{DaRegDnObligRatio}_h = \frac{\text{DaRegDnSppHrlyQty}_h}{\text{DaRegDnInterObligSppHrlyQty}_h} \]

(b.3.1) \[ \text{DaRegDnInterObligSppHrlyQty}_h = \sum_a \sum_z \text{DaRegDnInterAoObligHrlyQty}_{a, z, h} \]

(b.4) \[ \#\text{RtRegDnRznLoadHrlyQty}_{a, s, z, h} = [\max(0, \sum_i \text{RtBillMtr5minQty}_{a, s, i}) \]
\[ + \max(0, \sum_i \sum_t \text{RtImpExp5minQty}_{a, s, i, t} \times (1 - \text{RsgCrdFlg}_{t})) ] \]
\[ \times \text{PctSlinRznRegDnHrlyFct}_{a, s, z, h} / 12 \]

(c) \[ \#\text{DaRegDnSloObligHrlyQty}_{a, s, z, h} = \]
\[ (\text{DaRegDnSppHrlyQty}_h + \text{ContrRegDnSppHrlyQty}_h) \]
\[ \times (\text{RtRegDnRznLoadHrlyQty}_{a, s, z, h} / \text{RtLoadSppHrlyQty}_h) \]
(2) For each Asset Owner, a daily amount is calculated at each Reserve Zone. The daily amount is calculated as follows:

$$\text{DaRegDnDistDlyAmt}_{a, z, d} = \sum_h \text{DaRegDnDistHrlyAmt}_{a, z, h}$$

(3) For each Asset Owner associated with Market Participant $m$, a daily amount is calculated. The daily amount is calculated as follows:

$$\text{DaRegDnDistAoAmt}_{a, m, d} = \sum_z \text{DaRegDnDistDlyAmt}_{a, z, d}$$

(4) For each Market Participant, a daily amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The daily amount is calculated as follows:

$$\text{DaRegDnDistMpAmt}_{m, d} = \sum_a \text{DaRegDnDistAoAmt}_{a, m, d}$$
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>DaRegDnDistHrlyAmt</strong>&lt;sub&gt;a, z, h&lt;/sub&gt;</td>
<td>$</td>
<td>Hour</td>
<td><em>Day-Ahead Regulation-Down Distribution Amount per AO per Reserve Zone per Hour</em> - The amount to AO a for AO a’s share of DA Market Regulation-Down procurement costs in Reserve Zone z in Hour h.</td>
</tr>
<tr>
<td><strong>DaRegDnDistHrlyRate</strong>&lt;sub&gt;z, h&lt;/sub&gt;</td>
<td>$/MW</td>
<td>Hour</td>
<td><em>Day-Ahead Regulation-Down Distribution Hourly Rate per Reserve Zone per Hour</em> – The rate applied to AO a’s Regulation-Down obligation within Reserve Zone z in Hour h.</td>
</tr>
<tr>
<td><strong>ContrRegDnHrlyQty</strong>&lt;sub&gt;a, z, h, t&lt;/sub&gt;</td>
<td>MW</td>
<td>Hour</td>
<td><em>Contracted Regulation-Down per AO per Reserve Zone per Transaction per Hour</em> – AO a’s contracted Regulation-Down transaction t being supplied to Reserve Zone z from outside of the SPP BA to meet AO a’s Regulation-Down obligation. Contracted Regulation-Down being supplied to AO a is a positive value.</td>
</tr>
<tr>
<td><strong>DaRegDnRznHrlyCost</strong>&lt;sub&gt;z, h&lt;/sub&gt;</td>
<td>$</td>
<td>Hour</td>
<td><em>Day-Ahead Regulation-Down Reserve Zone Cost per Reserve Zone per Hour</em> – The total DA Market Regulation-Down procurement cost for Reserve Zone z in Hour h.</td>
</tr>
<tr>
<td><strong>DaRegDnHrlyQty</strong>&lt;sub&gt;a, s, z, h&lt;/sub&gt;</td>
<td>MW</td>
<td>Hour</td>
<td><em>Day-Ahead Regulation-Down Hourly Quantity per Asset Owner per Settlement Location per Reserve Zone per Hour</em> – The value described under Section 4.5.8.5 in Reserve Zone z.</td>
</tr>
<tr>
<td><strong>DaRegDnAoObligHrlyQty</strong>&lt;sub&gt;a, z, h&lt;/sub&gt;</td>
<td>MW</td>
<td>Hour</td>
<td><em>Day-Ahead Regulation-Down Asset Owner Obligation Quantity per Reserve Zone per Hour</em> – Asset Owner a’s DA Market Regulation-Down obligation in Reserve Zone z for Hour h.</td>
</tr>
<tr>
<td><strong>DaRegDnRznHrlyQty</strong>&lt;sub&gt;z, h&lt;/sub&gt;</td>
<td>MW</td>
<td>Hour</td>
<td><em>Day-Ahead Regulation-Down Hourly Quantity per Reserve Zone per Hour</em> – The total amount of cleared Regulation-Down in Reserve Zone z for Hour h.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>----------</td>
<td>------</td>
<td>---------------------</td>
<td>------------</td>
</tr>
<tr>
<td>DaRegDnObligRznHrlyQty_{z, h}</td>
<td>MW</td>
<td>Hour</td>
<td>Day-Ahead Regulation-Down Obligation per Reserve Zone per Hour – Reserve Zone z’s DA Market Regulation-Down obligation for Hour h.</td>
</tr>
<tr>
<td>ContrRegDnSppHrlyQty_{h}</td>
<td>MW</td>
<td>Hour</td>
<td>Contracted Regulation-Down per Hour – The total of all ContrRegDnHrlyQty_{a, z, h, t} for Hour h.</td>
</tr>
<tr>
<td>RtLoadSppHrlyQty_{h}</td>
<td>MW</td>
<td>Hour</td>
<td>Real-Time SPP Load per Hour – The value described under Section 4.5.8.8.</td>
</tr>
<tr>
<td>DaRegDnSppHrlyQty_{h}</td>
<td>MW</td>
<td>Hour</td>
<td>Total SPP Day-Ahead Regulation-Down Hourly Quantity per Hour – The total amount of Regulation-Down cleared in the DA Market for Hour h.</td>
</tr>
<tr>
<td>DaRegDnInterObligSppHrlyQty_{h}</td>
<td>MW</td>
<td>Hour</td>
<td>Day-Ahead SPP Regulation-Down Interim Obligation Quantity per AO per Reserve Zone per Hour – The total of all Asset Owner’s DA Market Regulation-Down interim obligation over all Reserve Zones for Hour h.</td>
</tr>
<tr>
<td>DaRegDnInterAoObligHrlyQty_{a, z, h}</td>
<td>MW</td>
<td>Hour</td>
<td>Day-Ahead Regulation-Down Interim Asset Owner Obligation Quantity per AO per Reserve Zone per Hour – Asset Owner a’s DA Market Regulation-Down interim obligation that includes treatment of ContrRegDnHrlyQty_{a, z, h, t} but does not include allocation of excess ContrRegDnHrlyQty_{a, z, h, t} in Reserve Zone z for Hour h.</td>
</tr>
<tr>
<td>DaRegDnIniAoObligHrlyQty_{a, z, h}</td>
<td>MW</td>
<td>Hour</td>
<td>Day-Ahead Regulation-Down Initial Asset Owner Obligation Quantity per AO per Reserve Zone per Hour – Asset Owner a’s DA Market Regulation-Down initial obligation that does not include treatment of ContrRegDnHrlyQty_{a, z, h, t} in Reserve Zone z for Hour h.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>-----------------------------------------------</td>
<td>----------</td>
<td>---------------------</td>
<td>----------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>DaRegDnObligRatio$_{h}$</td>
<td>none</td>
<td>Hour</td>
<td>Day-Ahead Regulation-Down Asset Owner Obligation Ratio per Hour – The percentage applied to Asset Owner a’s</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>DaRegDnInterAoObligHrlyQty$<em>{a,z,h}$ to account for allocation of any excess ContrRegDnHrlyQty$</em>{a,z,h,t}$ in Reserve Zone z in Hour h.</td>
</tr>
<tr>
<td>DaRegDnSIObligHrlyQty$_{a,s,z,h}$</td>
<td>MW</td>
<td>Hour</td>
<td>Day-Ahead Regulation-Down Obligation Quantity per AO per Settlement Location per Hour - Asset Owner a’s DA Market Regulation-Down initial obligation that does not include treatment of ContrRegDnHrlyQty$_{a,z,h,t}$ at Settlement Location s in Reserve Zone z for Hour h. Note that this value is provided for information purposes only and is not used in any of the cost allocation calculations.</td>
</tr>
<tr>
<td>DaRegDnMcpHrlyPrc$_{z,h}$</td>
<td>$/MW</td>
<td>Hour</td>
<td>Day-Ahead MCP for Regulation-Down per Reserve Zone – The value described under Section 4.5.8.5 for Reserve Zone z.</td>
</tr>
<tr>
<td>DaRegDnSpxHrlyRate$_{h}$</td>
<td>$/MW</td>
<td>Hour</td>
<td>Day-Ahead Regulation-Down SPP Exchange Rate per Hour – The rate applied to calculate the portion of DA Market Reserve Zone procurement costs associated with Reserve Zones that must purchase cleared Regulation-Down from other Reserve Zones in order to meet the Reserve Zone Regulation-Down obligation.</td>
</tr>
<tr>
<td>RtRegDnRznLoadHrlyQty$_{a,s,z,h}$</td>
<td>MWh</td>
<td>Hour</td>
<td>Real-Time Reserve Zone Load per AO per Settlement Location in Reserve Zone z for Hour h – Asset Owner a’s actual load and Export Interchange Transactions at Settlement Location s in Reserve Zone z for Hour h for use in Regulation-Down cost allocation.</td>
</tr>
<tr>
<td>RtBillMtr5minQty$_{a,s,i}$</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Billing Meter Quantity per AO per Settlement Location per Dispatch Interval - The value described under Section 4.5.9.1 for Reserve Zone z.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>--------------------------</td>
<td>------</td>
<td>---------------------</td>
<td>-------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>PctSlinRznRegDnHrlyFct&lt;sub&gt;a, s, z, h&lt;/sub&gt;</td>
<td>%</td>
<td>Hour</td>
<td>The percentage factor of AO a’s load at Settlement Location s that is contained within Reserve Zone z for use in Regulation-Down cost allocation.</td>
</tr>
<tr>
<td>RtImpExp5minQty&lt;sub&gt;a, s, i, t&lt;/sub&gt;</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>The value described under Section 4.5.9.2 for Reserve Zone.</td>
</tr>
<tr>
<td>RsgCrdFlg&lt;sub&gt;r&lt;/sub&gt;</td>
<td>none</td>
<td>none</td>
<td>Reserve Sharing Group Contingency Reserve Deployment Flag per Event – The value described under Section 4.5.8.8.</td>
</tr>
<tr>
<td>RegDnFinHrlyQty&lt;sub&gt;a, z, h, t&lt;/sub&gt;</td>
<td>MW</td>
<td>Hour</td>
<td>The MW amount specified by the buyer AO and seller AO in a RTBM Financial Schedule transaction t for Regulation-Down at Reserve Zone z for the Hour. The buyer AO MW amount is a positive value and the seller AO MW amount is a negative value.</td>
</tr>
<tr>
<td>DaRegDnDistDlyAmt&lt;sub&gt;a, z, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>AO a’s share of DA Market Regulation-Down procurement costs for Reserve Zone z in Operating Day d.</td>
</tr>
<tr>
<td>DaRegDnDistAoAmt&lt;sub&gt;a, m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>AO a’s for total DA Market Regulation-Down procurement costs associated with Market Participant m in Operating Day d.</td>
</tr>
<tr>
<td>DaRegDnDistMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>MP m’s share of total DA Market Regulation-Down procurement costs for in Operating Day d.</td>
</tr>
<tr>
<td>a</td>
<td>none</td>
<td>none</td>
<td>An Asset Owner.</td>
</tr>
<tr>
<td>s</td>
<td>none</td>
<td>none</td>
<td>A Settlement Location.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>----------</td>
<td>-------</td>
<td>---------------------</td>
<td>------------</td>
</tr>
<tr>
<td>$h$</td>
<td>none</td>
<td>none</td>
<td>An Hour.</td>
</tr>
<tr>
<td>$z$</td>
<td>none</td>
<td>none</td>
<td>A Reserve Zone.</td>
</tr>
<tr>
<td>$i$</td>
<td>none</td>
<td>none</td>
<td>A Dispatch Interval.</td>
</tr>
<tr>
<td>$t$</td>
<td>none</td>
<td>none</td>
<td>A single tagged Interchange Transaction, a single virtual energy transaction, a single Financial Schedule, a single contracted Operating Reserve transaction, a single TCR instrument, a single ARR award or a single Reserve Sharing Event transaction.</td>
</tr>
<tr>
<td>$d$</td>
<td>none</td>
<td>none</td>
<td>An Operating Day.</td>
</tr>
<tr>
<td>$m$</td>
<td>none</td>
<td>none</td>
<td>A Market Participant.</td>
</tr>
</tbody>
</table>
4.5.8.10 Day-Ahead Spinning Reserve Distribution Amount

(1) A DA Market charge or credit\(^8\) will be calculated for each Asset Owner for each hour for each Reserve Zone. The Asset Owner amount within each Reserve Zone will be equal to the net Reserve Zone procurement rate for Spinning Reserve multiplied by the Asset Owners Spinning Reserve obligation within the Reserve Zone. For the purpose of allocating DA Market Spinning Reserve procurement costs, all Non-Binding Reserve Zones will be combined into a single Non-Binding Reserve Zone. The amount to each Asset Owner is calculated as follows:

\[
#\text{DaSpinDistHrlyAmt}_{a,z,h} = \text{DaSpinDistHrlyRate}_{z,h} \times \text{DaSpinAoObligHrlyQty}_{a,z,h}
\]

Where,

(a) IF \(\text{DaSpinObligRznHrlyQty}_{z,h} > 0\)

THEN

\[
#\text{DaSpinDistHrlyRate}_{z,h} = \frac{\text{DaSpinRznHrlyCost}_{z,h}}{\text{DaSpinObligRznHrlyQty}_{z,h}}
\]

ELSE

\[
\text{DaSpinDistHrlyRate}_{z,h} = 0
\]

(a.1) \(\text{DaSpinObligRznHrlyQty}_{z,h} = \sum_{a} \text{DaSpinAoObligHrlyQty}_{a,z,h}\)

(a.2) \(\text{DaSpinRznHrlyCost}_{z,h} = \min (\text{DaSpinRznHrlyQty}_{z,h}, \text{DaSpinObligRznHrlyQty}_{z,h}) \times \text{DaSpinMcpHrlyPrc}_{z,h} + \max (0, (\text{DaSpinObligRznHrlyQty}_{z,h} - \text{DaSpinRznHrlyQty}_{z,h}))\)

---

\(^8\) Note that this charge type will almost always produce a charge. The credit is included here for the rare occasion when a credit may be produced as a result of a data error and/or a resettle.
(a.2.1) IF $\sum_z \text{Max} \left(0, \text{DaSpinRznHrlyQty}_{z, h} - \text{DaSpinObligRznHrlyQty}_{z, h}\right) > 0$

THEN

$\text{#DaSpinSpxHrlyRate}_h = \sum_z \frac{(\text{Max} \left(0, \text{DaSpinRznHrlyQty}_{z, h} - \text{DaSpinObligRznHrlyQty}_{z, h}\right) \times \text{DaSpinMcpHrlyPrc}_{z, h})}{\sum_z \text{Max} \left(0, \text{DaSpinRznHrlyQty}_{z, h} - \text{DaSpinObligRznHrlyQty}_{z, h}\right)}$

ELSE

$\text{DaSpinSpxHrlyRate}_h = 0$

(a.2.2) $\text{DaSpinRznHrlyQty}_{z, h} = \sum_a \sum_s \text{DaSpinHrlyQty}_{a, s, z, h}$

(b) $\text{#DaSpinAoObligHrlyQty}_{a, z, h} = (\text{DaSpinInterAoObligHrlyQty}_{a, z, h}) - \sum_t \text{SpinFinHrlyQty}_{a, z, h, t}$

* $\text{DaSpinObligRatio}_h$ - $\sum_t \text{SpinFinHrlyQty}_{a, z, h, t}$

(b.1) $\text{DaSpinInterAoObligHrlyQty}_{a, z, h} =$

$\text{Max} \left(0, \text{DaSpinIniAoObligHrlyQty}_{a, z, h} - \sum_t \text{ContrSpinHrlyQty}_{a, z, h, t}\right)$
(b.2)  \( \text{DaSpinIniAoObligHrlyQty}_{a,z,h} = \) 
\[
( \text{DaSpinSppHrlyQty}_{h} \, + \, \text{ContrSpinSppHrlyQty}_{h} )
\]
* (\( \sum_{s} \text{RtSpinRznLoadHrlyQty}_{a,s,z,h} \, / \, \text{RtLoadSppHrlyQty}_{h} \))

(b.2.1)  \( \text{ContrSpinSppHrlyQty}_{h} = \sum_{a} \sum_{z} \sum_{t} \text{ContrSpinHrlyQty}_{a,z,h,t} \)

(b.2.2)  \( \text{DaSpinSppHrlyQty}_{h} = \sum_{a} \sum_{s} \sum_{z} \text{DaSpinHrlyQty}_{a,s,z,h} \)

(b.3)  \( \text{DaSpinObligRatio}_{h} = \text{DaSpinSppHrlyQty}_{h} \)
\[ \text{DaSpinInterObligSppHrlyQty}_{h} \]

(b.3.1) \( \text{DaSpinInterObligSppHrlyQty}_{h} = \sum_{a} \sum_{z} \text{DaSpinInterAoObligHrlyQty}_{a,z,h} \)

(b.4)  \# \text{RtSpinRznLoadHrlyQty}_{a,s,z,h} = [ \text{Max} \, ( \, 0, \, \sum_{i} \text{RtBillMtr5minQty}_{a,s,i} \) 
\[ + \text{Max} \, ( \, 0, \, \sum_{i} \sum_{t} \text{RtImpExp5minQty}_{a,s,i,t \, \ast \, (1 - \text{RsgCrdFlgt})} \) ] \]
\[ \ast \, \text{PctSlinRznSpinHrlyFct}_{a,s,z,h} \, / \, 12 \]

(c)  \# \text{DaSpinSlObligHrlyQty}_{a,s,z,h} = 
\[
( \text{DaSpinSppHrlyQty}_{h} \, + \, \text{ContrSpinSppHrlyQty}_{h} )
\]
\[ \ast \, (\text{RtSpinRznLoadHrlyQty}_{a,s,z,h} \, / \, \text{RtLoadSppHrlyQty}_{h} ) \]
(2) For each Asset Owner, a daily amount is calculated at each Reserve Zone. The daily amount is calculated as follows:

\[ \text{DaSpinDistDlyAmt}_{a, z, d} = \sum_{h} \text{DaSpinDistHrlyAmt}_{a, z, h} \]

(3) For each Asset Owner associated with Market Participant \( m \), a daily amount is calculated. The daily amount is calculated as follows:

\[ \text{DaSpinDistAoAmt}_{a, m, d} = \sum_{z} \text{DaSpinDistDlyAmt}_{a, z, d} \]

(4) For each Market Participant, a daily amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The daily amount is calculated as follows:

\[ \text{DaSpinDistMpAmt}_{m, d} = \sum_{a} \text{DaSpinDistAoAmt}_{a, m, d} \]
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>DaSpinDistHrlyAmt&lt;sub&gt;a, z, h&lt;/sub&gt;</td>
<td>$</td>
<td>Hour</td>
<td>Day-Ahead Spinning Reserve Distribution Amount per AO per Reserve Zone per Hour - The amount to AO a for AO a’s share of DA Market Spinning Reserve procurement costs in Reserve Zone z in Hour h.</td>
</tr>
<tr>
<td>DaSpinDistHrlyRate&lt;sub&gt;z, h&lt;/sub&gt;</td>
<td>$/MW</td>
<td>Hour</td>
<td>Day-Ahead Spinning Reserve Distribution Hourly Rate per Reserve Zone per Hour – The rate applied to AO a’s Spinning Reserve obligation within Reserve Zone z in Hour h.</td>
</tr>
<tr>
<td>ContrSpinHrlyQty&lt;sub&gt;a, z, h, t&lt;/sub&gt;</td>
<td>MW</td>
<td>Hour</td>
<td>Contracted Spinning Reserve per AO per Reserve Zone per Transaction per Hour – AO a’s contracted Spinning Reserve transaction t being supplied to Reserve Zone z from outside of the SPP BA to meet AO a’s Spinning Reserve obligation. Contracted Spinning Reserve being supplied to AO a is a positive value.</td>
</tr>
<tr>
<td>DaSpinRznHrlyCost&lt;sub&gt;z, h&lt;/sub&gt;</td>
<td>$</td>
<td>Hour</td>
<td>Day-Ahead Reserve Zone Cost per Reserve Zone Spinning Reserve per Hour – The total DA Market Spinning Reserve procurement cost for Reserve Zone z in Hour h.</td>
</tr>
<tr>
<td>DaSpinHrlyQty&lt;sub&gt;a, s, z, h&lt;/sub&gt;</td>
<td>MW</td>
<td>Hour</td>
<td>Day-Ahead Spinning Reserve Hourly Quantity per Asset Owner per Settlement Location per Reserve Zone per Hour – The value described under Section 4.5.8.6 in Reserve Zone z.</td>
</tr>
<tr>
<td>DaSpinAoObligHrlyQty&lt;sub&gt;a, z, h&lt;/sub&gt;</td>
<td>MW</td>
<td>Hour</td>
<td>Day-Ahead Spinning Reserve Asset Owner Obligation Quantity per Reserve Zone per Hour – Asset Owner a’s DA Market Spinning Reserve obligation in Reserve Zone z for Hour h.</td>
</tr>
<tr>
<td>DaSpinRznHrlyQty&lt;sub&gt;z, h&lt;/sub&gt;</td>
<td>MW</td>
<td>Hour</td>
<td>Day-Ahead Spinning Reserve Hourly Quantity per Reserve Zone per Hour – The total amount of cleared Spinning Reserve in Reserve Zone z for Hour h.</td>
</tr>
<tr>
<td>DaSpinObligRznHrlyQty&lt;sub&gt;z, h&lt;/sub&gt;</td>
<td>MW</td>
<td>Hour</td>
<td>Day-Ahead Spinning Reserve Obligation per Reserve Zone per Hour – Reserve Zone z’s DA Market Spinning Reserve obligation for Hour h.</td>
</tr>
<tr>
<td>ContrSpinSppHrlyQty&lt;sub&gt;h&lt;/sub&gt;</td>
<td>MW</td>
<td>Hour</td>
<td>Contracted Spinning Reserve per Hour – The total of all ContrSpinHrlyQty&lt;sub&gt;a, z, h, t&lt;/sub&gt; for Hour h.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>----------</td>
<td>------</td>
<td>---------------------</td>
<td>------------</td>
</tr>
<tr>
<td>RtLoadSppHrlyQty&lt;sub&gt;<em>h</em>&lt;/sub&gt;</td>
<td>MW</td>
<td>Hour</td>
<td>Real-Time SPP Load per Hour – The value described under Section 4.5.8.8.</td>
</tr>
<tr>
<td>DaSpinSppHrlyQty&lt;sub&gt;<em>h</em>&lt;/sub&gt;</td>
<td>MW</td>
<td>Hour</td>
<td>Total SPP Day-Ahead Spinning Reserve Hourly Quantity per Hour – The total amount of Spinning Reserve cleared in the DA Market for Hour ( h ).</td>
</tr>
<tr>
<td>DaSpinInterObligSppHrlyQty&lt;sub&gt;<em>h</em>&lt;/sub&gt;</td>
<td>MW</td>
<td>Hour</td>
<td>Day-Ahead SPP Spinning Reserve Interim Obligation Quantity per AO per Reserve Zone per Hour – The total of all Asset Owner’s DA Market Spinning Reserve interim obligation over all Reserve Zones for Hour ( h ).</td>
</tr>
<tr>
<td>DaSpinInterAoObligHrlyQty&lt;sub&gt;<em>a, z, h</em>&lt;/sub&gt;</td>
<td>MW</td>
<td>Hour</td>
<td>Day-Ahead Spinning Reserve Interim Asset Owner Obligation Quantity per AO per Reserve Zone per Hour – Asset Owner ( a )’s DA Market Spinning Reserve interim obligation that includes treatment of ( \text{ContrSpinHrlyQty}<em>{a, z, h, t} ) but does not include allocation of excess ( \text{ContrSpinHrlyQty}</em>{a, z, h, t} ) in Reserve Zone ( z ) for Hour ( h ).</td>
</tr>
<tr>
<td>DaSpinIniAoObligHrlyQty&lt;sub&gt;<em>a, z, h</em>&lt;/sub&gt;</td>
<td>MW</td>
<td>Hour</td>
<td>Day-Ahead Spinning Reserve Initial Asset Owner Obligation Quantity per AO per Reserve Zone per Hour – Asset Owner ( a )’s DA Market Spinning Reserve initial obligation that does not include treatment of ( \text{ContrSpinHrlyQty}_{a, z, h, t} ) in Reserve Zone ( z ) for Hour ( h ).</td>
</tr>
<tr>
<td>DaSpinObligRatio&lt;sub&gt;<em>h</em>&lt;/sub&gt;</td>
<td>none</td>
<td>Hour</td>
<td>Day-Ahead Spinning Reserve Asset Owner Obligation Ratio per Hour – The percentage applied to Asset Owner ( a )’s ( \text{DaSpinInterAoObligHrlyQty}<em>{a, z, h} ) to account for allocation of any excess ( \text{ContrSpinHrlyQty}</em>{a, z, h, t} ) in Reserve Zone ( z ) in Hour ( h ).</td>
</tr>
<tr>
<td>DaSpinSlObligHrlyQty&lt;sub&gt;<em>a, s, z, h</em>&lt;/sub&gt;</td>
<td>MW</td>
<td>Hour</td>
<td>Day-Ahead Spinning Reserve Obligation Quantity per AO per Settlement Location per Hour - Asset Owner ( a )’s DA Market Spinning Reserve initial obligation that does not include treatment of ( \text{ContrSpinHrlyQty}_{a, z, h, t} ) at Settlement Location ( s ) in Reserve Zone ( z ) for Hour ( h ). Note that this value is provided for information purposes only and is not used in any of the cost allocation calculations.</td>
</tr>
</tbody>
</table>
### Market Protocols for SPP Integrated Marketplace

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>DaSpinMcpHrlyPre (_{z,h})</td>
<td>$/MW</td>
<td>Hour</td>
<td>Day-Ahead MCP for Spinning Reserve per Reserve Zone – The value described under Section 4.5.8.6 for Reserve Zone (_z).</td>
</tr>
<tr>
<td>DaSpinSpxHrlyRate (_h)</td>
<td>$/MW</td>
<td>Hour</td>
<td>Day-Ahead Spinning Reserve SPP Exchange Rate per Hour – The rate applied to calculate the portion of DA Market Reserve Zone procurement costs associated with Reserve Zones that must purchase cleared Spinning Reserve from other Reserve Zones in order to meet the Reserve Zone Spinning Reserve obligation.</td>
</tr>
<tr>
<td>RtSpinRznLoadHrlyQty (_{a,s,z,h})</td>
<td>MWh</td>
<td>Hour</td>
<td>Real-Time Reserve Zone Load per AO per Settlement Location in Reserve Zone (_z) for Hour (_h) – Asset Owner (_a)'s actual load and Export Interchange Transactions at Settlement Location (_s) in Reserve Zone (_z) for Hour (_h) for use in Spinning Reserve cost allocation.</td>
</tr>
<tr>
<td>RtBillMtr5minQty (_{a,s,i})</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Billing Meter Quantity per AO per Settlement Location per Dispatch Interval - The value described under Section 4.5.9.1 for Reserve Zone (_z).</td>
</tr>
<tr>
<td>PetSlinRznSpinHrlyFct (_{a,s,z,h})</td>
<td>%</td>
<td>Hour</td>
<td>Percent Settlement Location in Reserve Zone per AO per Settlement Location per Reserve Zone per Hour – The percentage factor of AO (_a)'s load at Settlement Location (_s) that is contained within Reserve Zone (_z) for use in Spinning Reserve cost allocation.</td>
</tr>
<tr>
<td>RtImpExp5minQty (_{a,s,i,t})</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Interchange Transaction Quantity per AO per Settlement Location per Dispatch Interval per Transaction – The value described under Section 4.5.9.2 for Reserve Zone (_z).</td>
</tr>
<tr>
<td>RsgCrdFlg (_t)</td>
<td>none</td>
<td>none</td>
<td>Reserve Sharing Group Contingency Reserve Deployment Flag per Event – The value described under Section 4.5.8.8.</td>
</tr>
<tr>
<td>SpinFinHrlyQty (_{a,z,h,t})</td>
<td>MW</td>
<td>Hour</td>
<td>Financial Schedule for Spinning Reserve per AO per Settlement Location per Transaction per Hour – The MW amount specified by the buyer AO and seller AO in a RTBM Financial Schedule transaction (_t) for Spinning Reserve at Reserve Zone (_z) for the Hour. The buyer AO MW amount is a positive value and the seller AO MW amount is a negative value.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>-----------------------------</td>
<td>------</td>
<td>---------------------</td>
<td>-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>DaSpinDistDlyAmt&lt;sub&gt;a,z,d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Spinning Reserve Distribution Amount per AO per Reserve Zone per Operating Day - AO a’s share of DA Market Spinning Reserve procurement costs for Reserve Zone z in Operating Day d.</td>
</tr>
<tr>
<td>DaSpinDistAoAmt&lt;sub&gt;a,m,d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Spinning Reserve Distribution Amount per AO per Operating Day - AO a’s share of total DA Market Spinning Reserve procurement costs associated with Market Participant m in Operating Day d.</td>
</tr>
<tr>
<td>DaSpinDistMpAmt&lt;sub&gt;m,d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Spinning Reserve Distribution Amount per MP per Operating Day - MP m’s share of total DA Market Spinning Reserve procurement costs for in Operating Day d.</td>
</tr>
<tr>
<td>a</td>
<td>none</td>
<td>none</td>
<td>An Asset Owner.</td>
</tr>
<tr>
<td>s</td>
<td>none</td>
<td>none</td>
<td>A Settlement Location.</td>
</tr>
<tr>
<td>h</td>
<td>none</td>
<td>none</td>
<td>An Hour.</td>
</tr>
<tr>
<td>z</td>
<td>none</td>
<td>none</td>
<td>A Reserve Zone.</td>
</tr>
<tr>
<td>i</td>
<td>none</td>
<td>none</td>
<td>A Dispatch Interval.</td>
</tr>
<tr>
<td>t</td>
<td>none</td>
<td>none</td>
<td>A single tagged Interchange Transaction, a single virtual energy transaction, a single Financial Schedule, a single contracted Operating Reserve transaction, a single TCR instrument, a single ARR award or a single Reserve Sharing Event transaction.</td>
</tr>
<tr>
<td>d</td>
<td>none</td>
<td>none</td>
<td>An Operating Day.</td>
</tr>
<tr>
<td>m</td>
<td>none</td>
<td>none</td>
<td>A Market Participant.</td>
</tr>
</tbody>
</table>
4.5.8.11 Day-Ahead Supplemental Reserve Distribution Amount

(1) A DA Market charge or credit\(^9\) will be calculated for each Asset Owner for each hour for each Reserve Zone. The Asset Owner amount within each Reserve Zone will be equal to the net Reserve Zone procurement rate for Supplemental Reserve multiplied by the Asset Owners Supplemental Reserve obligation within the Reserve Zone. For the purpose of allocating DA Market Supplemental Reserve procurement costs, all Non-Binding Reserve Zones will be combined into a single Non-Binding Reserve Zone. The amount to each Asset Owner is calculated as follows:

\[
#\text{DaSuppDistHrlyAmt}_{a,z,h} = \text{DaSuppDistHrlyRate}_{z,h} \times \text{DaSuppAoObligHrlyQty}_{a,z,h}
\]

Where,

(a) IF \(\text{DaSuppObligRznHrlyQty}_{z,h} > 0\) THEN

\[
#\text{DaSuppDistHrlyRate}_{z,h} = \frac{\text{DaSuppRznHrlyCost}_{z,h}}{\text{DaSuppObligRznHrlyQty}_{z,h}}
\]

ELSE

\[
\text{DaSuppDistHrlyRate}_{z,h} = 0
\]

(a.1) \(\text{DaSuppObligRznHrlyQty}_{z,h} = \sum_a \text{DaSuppAoObligHrlyQty}_{a,z,h}\)

(a.2) \(\#\text{DaSuppRznHrlyCost}_{z,h} =\)

\[
\text{Min} \left( \text{DaSuppRznHrlyQty}_{z,h}, \text{DaSuppObligRznHrlyQty}_{z,h} \right) \times \text{DaSuppMcpHrlyPrc}_{z,h}
\]

\[+ \text{Max} \left( 0, \left( \text{DaSuppObligRznHrlyQty}_{z,h} - \text{DaSuppRznHrlyQty}_{z,h} \right) \right) \]

\(^9\) Note that this charge type will almost always produce a charge. The credit is included here for the rare occasion when a credit may be produced as a result of a data error and/or a resettlement.
* DaSuppSpxHrlyRateₜ

(a.2.1) IF \( \sum \max(0, \text{DaSuppRznHrlyQty}_{z, h} - \text{DaSuppObligRznHrlyQty}_{z, h}) > 0 \)

THEN

\#DaSuppSpxHrlyRateₜ =

\[ \frac{\sum \max(0, \text{DaSuppRznHrlyQty}_{z, h} - \text{DaSuppObligRznHrlyQty}_{z, h}) \times \text{DaSuppMcpHrlyPrc}_{z, h}}{\sum \max(0, \text{DaSuppRznHrlyQty}_{z, h} - \text{DaSuppObligRznHrlyQty}_{z, h})} \]

ELSE

\[ \text{DaSuppSpxHrlyRate}_t = 0 \]

(a.2.2) \[ \text{DaSuppRznHrlyQty}_{z, h} = \sum_a \sum_s \text{DaSuppHrlyQty}_{a, s, z, h} \]

(b) \[ \#\text{DaSuppAoObligHrlyQty}_{a, z, h} = (\text{DaSuppInterAoObligHrlyQty}_{a, z, h} - \sum_t \text{SuppFinHrlyQty}_{a, z, h, t}) \]

(b.1) \[ \text{DaSuppInterAoObligHrlyQty}_{a, z, h} = \]

\[ \max(0, \text{DaSuppIniAoObligHrlyQty}_{a, z, h} - \sum_t \text{ContrSuppHrlyQty}_{a, z, h, t}) \]
(b.2) \[ \text{DaSuppIniAoObligHrlyQty}_{a,z,h} = \]

( \text{DaSuppSppHrlyQty}_h + \text{ContrSuppSppHrlyQty}_h )

* ( \( \sum_s \text{RtSuppRznLoadHrlyQty}_{a,s,z,h} / \text{RtLoadSppHrlyQty}_h \) )

(b.2.1) \[ \text{ContrSuppSppHrlyQty}_h = \sum_a \sum_z \sum_t \text{ContrSuppHrlyQty}_{a,z,h,t} \]

(b.2.2) \[ \text{DaSuppSppHrlyQty}_h = \sum_a \sum_s \sum_z \text{DaSuppHrlyQty}_{a,s,z,h} \]

(b.3) \[ \text{DaSuppObligRatio}_h = \frac{\text{DaSuppSppHrlyQty}_h}{\text{DaSuppInterObligSppHrlyQty}_h} \]

(b.3.1) \[ \text{DaSuppInterObligSppHrlyQty}_h = \sum_a \sum_z \text{DaSuppInterAoObligHrlyQty}_{a,z,h} \]

(b.4) \[ \# \text{RtSuppRznLoadHrlyQty}_{a,s,z,h} = [ \text{Max} (0, \sum_i \text{RtBillMtr5minQty}_{a,s,i}) \]

+ \text{Max} (0, \sum_i \sum_t \text{RtImpExp5minQty}_{a,s,i,t} \times (1 - \text{RsgCrdFlg}_t)) ]

* \( \text{PctSlinRznSuppHrlyFct}_{a,s,z,h} / 12 \)

(c) \[ \# \text{DaSuppSlObligHrlyQty}_{a,s,z,h} = \]

( \text{DaSuppSppHrlyQty}_h + \text{ContrSuppSppHrlyQty}_h )

* ( \( \text{RtSuppRznLoadHrlyQty}_{a,s,z,h} / \text{RtLoadSppHrlyQty}_h \) )
(2) For each Asset Owner, a daily amount is calculated at each Reserve Zone. The daily amount is calculated as follows:

\[ \text{DaSuppDistDlyAmt}_{a, z, d} = \sum_h \text{DaSuppDistHrlyAmt}_{a, z, h} \]

(3) For each Asset Owner associated with Market Participant \( m \), a daily amount is calculated. The daily amount is calculated as follows:

\[ \text{DaSuppDistAoAmt}_{a, m, d} = \sum_z \text{DaSuppDistDlyAmt}_{a, z, d} \]

(4) For each Market Participant, a daily amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The daily amount is calculated as follows:

\[ \text{DaSuppDistMpAmt}_{m, d} = \sum_a \text{DaSuppDistAoAmt}_{a, m, d} \]
The above variables are defined as follows:

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<thead>
<tr>
<th>Variable</th>
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<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>DaSuppDistHrlyAmt (a, z, h)</td>
<td>$</td>
<td>Hour</td>
<td>Day-Ahead Supplemental Reserve Distribution Amount per AO per Reserve Zone per Hour - The amount to AO (a) for AO (a)’s share of DA Market Supplemental Reserve procurement costs in Reserve Zone (z) in Hour (h).</td>
</tr>
<tr>
<td>DaSuppDistHrlyRate (z, h)</td>
<td>$/MW</td>
<td>Hour</td>
<td>Day-Ahead Supplemental Reserve Distribution Hourly Rate per Reserve Zone per Hour – The rate applied to AO (a)’s Supplemental Reserve obligation within Reserve Zone (z) in Hour (h).</td>
</tr>
<tr>
<td>ContrSuppHrlyQty (a, z, h, t)</td>
<td>MW</td>
<td>Hour</td>
<td>Contracted Supplemental Reserve per AO per Reserve Zone per Transaction per Hour – AO (a)’s contracted Supplemental Reserve transaction (t) being supplied to Reserve Zone (z) from outside of the SPP BA to meet AO (a)’s Supplemental Reserve obligation. Contracted Supplemental Reserve being supplied to AO (a) is a positive value.</td>
</tr>
<tr>
<td>DaSuppRznHrlyCost (z, h)</td>
<td>$</td>
<td>Hour</td>
<td>Day-Ahead Reserve Zone Supplemental Reserve Cost per Reserve Zone per Hour – The total DA Market Supplemental Reserve procurement cost for Reserve Zone (z) in Hour (h).</td>
</tr>
<tr>
<td>DaSuppHrlyQty (a, s, z, h)</td>
<td>MW</td>
<td>Hour</td>
<td>Day-Ahead Supplemental Reserve Hourly Quantity per Asset Owner per Settlement Location per Reserve Zone per Hour – The value described under Section 4.5.8.7 in Reserve Zone (z).</td>
</tr>
<tr>
<td>DaSuppAoObligHrlyQty (a, z, h)</td>
<td>MW</td>
<td>Hour</td>
<td>Day-Ahead Supplemental Reserve Asset Owner Obligation Quantity per Reserve Zone per Hour – Asset Owner (a)’s DA Market Supplemental Reserve obligation in Reserve Zone (z) for Hour (h).</td>
</tr>
<tr>
<td>DaSuppRznHrlyQty (z, h)</td>
<td>MW</td>
<td>Hour</td>
<td>Day-Ahead Supplemental Reserve Hourly Quantity per Reserve Zone per Hour – The total amount of cleared Supplemental Reserve in Reserve Zone (z) for Hour (h).</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>----------</td>
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<td>---------------------</td>
<td>------------</td>
</tr>
<tr>
<td>DaSuppObligRznHrlyQty (_{z,h})</td>
<td>MW</td>
<td>Hour</td>
<td>Day-Ahead Supplemental Reserve Obligation per Reserve Zone per Hour – Reserve Zone (z)’s DA Market Supplemental Reserve obligation for Hour (h).</td>
</tr>
<tr>
<td>ContrSuppSppHrlyQty (_h)</td>
<td>MW</td>
<td>Hour</td>
<td>Contracted Supplemental Reserve per Hour – The total of all ContrSuppHrlyQty (_{a,z,h,t}) for Hour (h).</td>
</tr>
<tr>
<td>RtLoadSppHrlyQty (_h)</td>
<td>MW</td>
<td>Hour</td>
<td>Real-Time SPP Load per Hour – The value described under Section 4.5.8.8.</td>
</tr>
<tr>
<td>DaSuppSppHrlyQty (_h)</td>
<td>MW</td>
<td>Hour</td>
<td>Total SPP Day-Ahead Supplemental Reserve Hourly Quantity per Hour – The total amount of Supplemental Reserve cleared in the DA Market for Hour (h).</td>
</tr>
<tr>
<td>DaSuppInterObligSppHrlyQty (_h)</td>
<td>MW</td>
<td>Hour</td>
<td>Day-Ahead SPP Supplemental Reserve Interim Obligation Quantity per AO per Reserve Zone per Hour – The total of all Asset Owner’s DA Market Supplemental Reserve interim obligation over all Reserve Zones for Hour (h).</td>
</tr>
<tr>
<td>DaSuppInterAoObligHrlyQty (_{a,z,h})</td>
<td>MW</td>
<td>Hour</td>
<td>Day-Ahead Supplemental Reserve Interim Asset Owner Obligation Quantity per AO per Reserve Zone per Hour – Asset Owner (a)’s DA Market Supplemental Reserve interim obligation that includes treatment of ContrSuppHrlyQty (<em>{a,z,h,t}) but does not include allocation of excess ContrSuppHrlyQty (</em>{a,z,h,t}) in Reserve Zone (z) for Hour (h).</td>
</tr>
<tr>
<td>DaSuppIniAoObligHrlyQty (_{a,z,h})</td>
<td>MW</td>
<td>Hour</td>
<td>Day-Ahead Supplemental Reserve Initial Asset Owner Obligation Quantity per AO per Reserve Zone per Hour – Asset Owner (a)’s DA Market Supplemental Reserve initial obligation that does not include treatment of ContrSuppHrlyQty (_{a,z,h,t}) in Reserve Zone (z) for Hour (h).</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
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</tr>
<tr>
<td>DaSuppObligRatio&lt;sub&gt;_h&lt;/sub&gt;</td>
<td>none</td>
<td>Hour</td>
<td>Day-Ahead Supplemental Reserve Asset Owner Obligation Ratio per Hour – The percentage applied to Asset Owner a’s Day-Ahead Supplemental Reserve Obligation Quantity per AO in Reserve Zone z in Hour h.</td>
</tr>
<tr>
<td>DaSuppSlObligHrlyQty&lt;sub&gt;<em>&lt;sub&gt;a, s, z, h&lt;/sub&gt;</em>&lt;/sub&gt;</td>
<td>MW</td>
<td>Hour</td>
<td>Day-Ahead Supplemental Reserve Obligation Quantity per AO per Settlement Location per Hour - Asset Owner a’s DA Market Supplemental Reserve initial obligation that does not include treatment of ContrSuppHrlyQty&lt;sub&gt;<em>&lt;sub&gt;a, z, h, t&lt;/sub&gt;</em>&lt;/sub&gt; at Settlement Location s in Reserve Zone z for Hour h. Note that this value is provided for information purposes only and is not used in any of the cost allocation calculations.</td>
</tr>
<tr>
<td>DaSuppMcpHrlyPrc&lt;sub&gt;<em>&lt;sub&gt;z, h&lt;/sub&gt;</em>&lt;/sub&gt;</td>
<td>$/MW</td>
<td>Hour</td>
<td>Day-Ahead MCP for Supplemental Reserve per Reserve Zone – The value described under Section 4.5.8.7 for Reserve Zone z.</td>
</tr>
<tr>
<td>DaSuppSpxHrlyRate&lt;sub&gt;_h&lt;/sub&gt;</td>
<td>$/MW</td>
<td>Hour</td>
<td>Day-Ahead Supplemental Reserve SPP Exchange Rate per Hour – The rate applied to calculate the portion of DA Market Reserve Zone procurement costs associated with Reserve Zones that must purchase cleared Supplemental Reserve from other Reserve Zones in order to meet the Reserve Zone Supplemental Reserve obligation.</td>
</tr>
<tr>
<td>RtSuppRznLoadHrlyQty&lt;sub&gt;<em>&lt;sub&gt;a, s, z, h&lt;/sub&gt;</em>&lt;/sub&gt;</td>
<td>MWh</td>
<td>Hour</td>
<td>Real-Time Reserve Zone Load per AO per Settlement Location in Reserve Zone z for Hour h – Asset Owner a’s actual load and Export Interchange Transactions at Settlement Location s in Reserve Zone z for Hour h for use in Supplemental Reserve cost allocation.</td>
</tr>
<tr>
<td>RtBillMtr5minQty&lt;sub&gt;<em>&lt;sub&gt;a, s, i&lt;/sub&gt;</em>&lt;/sub&gt;</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Billing Meter Quantity per AO per Settlement Location per Dispatch Interval - The value described under Section 4.5.9.1 for Reserve Zone z.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
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</tr>
<tr>
<td>PetSlinRznSuppHrlyFct&lt;sub&gt;a&lt;/sub&gt;,&lt;sub&gt;s&lt;/sub&gt;,&lt;sub&gt;z&lt;/sub&gt;,&lt;sub&gt;h&lt;/sub&gt;</td>
<td>%</td>
<td>Hour</td>
<td>Percent Settlement Location in Reserve Zone per AO per Settlement Location per Reserve Zone per Hour – The percentage factor of AO a’s load at Settlement Location s that is contained within Reserve Zone z for use in Supplemental Reserve cost allocation.</td>
</tr>
<tr>
<td>RtImpExp5minQty&lt;sub&gt;a&lt;/sub&gt;,&lt;sub&gt;s&lt;/sub&gt;,&lt;sub&gt;i&lt;/sub&gt;,&lt;sub&gt;t&lt;/sub&gt;</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Interchange Transaction Quantity per AO per Settlement Location per Dispatch Interval per Transaction – The value described under Section 4.5.9.2 for Reserve Zone z.</td>
</tr>
<tr>
<td>RsgCrdFlg&lt;sub&gt;r&lt;/sub&gt;</td>
<td>none</td>
<td>none</td>
<td>Reserve Sharing Group Contingency Reserve Deployment Flag per Event – The value described under Section 4.5.8.8.</td>
</tr>
<tr>
<td>SuppFinHrlyQty&lt;sub&gt;a&lt;/sub&gt;,&lt;sub&gt;z&lt;/sub&gt;,&lt;sub&gt;h&lt;/sub&gt;,&lt;sub&gt;t&lt;/sub&gt;</td>
<td>MW</td>
<td>Hour</td>
<td>Real-Time Financial Schedule for Supplemental Reserve per AO per Settlement Location per Transaction per Hour - The MW amount specified by the buyer AO and seller AO in a RTBM Financial Schedule transaction t for Supplemental Reserve at Reserve Zone z for the Hour. The buyer AO MW amount is a positive value and the seller AO MW amount is a negative value.</td>
</tr>
<tr>
<td>DaSuppDistDlyAmt&lt;sub&gt;a&lt;/sub&gt;,&lt;sub&gt;z&lt;/sub&gt;,&lt;sub&gt;d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Supplemental Reserve Distribution Amount per AO per Reserve Zone per Operating Day - AO a’s share of DA Market Supplemental Reserve procurement costs for Reserve Zone z in Operating Day d.</td>
</tr>
<tr>
<td>DaSuppDistAoAmt&lt;sub&gt;a&lt;/sub&gt;,&lt;sub&gt;m&lt;/sub&gt;,&lt;sub&gt;d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Supplemental Reserve Distribution Amount per AO per Operating Day - AO a’s for total DA Market Supplemental Reserve procurement costs associated with Market Participant m in Operating Day d.</td>
</tr>
<tr>
<td>DaSuppDistMpAmt&lt;sub&gt;m&lt;/sub&gt;,&lt;sub&gt;d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Supplemental Reserve Distribution Amount per MP per Operating Day - MP m’s share of total DA Market Supplemental Reserve procurement costs for in Operating Day d.</td>
</tr>
<tr>
<td>a</td>
<td>none</td>
<td>none</td>
<td>An Asset Owner.</td>
</tr>
<tr>
<td>s</td>
<td>none</td>
<td>none</td>
<td>A Settlement Location.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>----------</td>
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<td>------------</td>
</tr>
<tr>
<td>$h$</td>
<td>none</td>
<td>none</td>
<td>An Hour.</td>
</tr>
<tr>
<td>$z$</td>
<td>none</td>
<td>none</td>
<td>A Reserve Zone.</td>
</tr>
<tr>
<td>$i$</td>
<td>none</td>
<td>none</td>
<td>A Dispatch Interval.</td>
</tr>
<tr>
<td>$t$</td>
<td>none</td>
<td>none</td>
<td>A single tagged Interchange Transaction, a single virtual energy transaction, a single Financial Schedule, a single contracted Operating Reserve transaction, a single TCR instrument, a single ARR award or a single Reserve Sharing Event transaction.</td>
</tr>
<tr>
<td>$d$</td>
<td>none</td>
<td>none</td>
<td>An Operating Day.</td>
</tr>
<tr>
<td>$m$</td>
<td>none</td>
<td>none</td>
<td>A Market Participant.</td>
</tr>
</tbody>
</table>
4.5.8.12 Day-Ahead Make-Whole-Payment Amount

(1) The Day-Ahead Make-Whole-Payment Amount is a credit or charge\(^{10}\) to a Resource Asset Owner and is calculated for each Resource with an associated DA Market Commitment Period. A payment is made to the Resource Asset Owner when the sum of the Resource’s DA Market Start-Up Offer costs, No-Load Offer costs, Energy Offer Curve and Operating Reserve Offer costs associated with cleared DA Market amounts for Energy and Operating Reserve is greater than the Energy and Operating Reserve DA Market revenues received for that Resource over the Resource’s DA Market Make-Whole-Payment Eligibility Period.

(2) A Resource’s DA Market Make-Whole-Payment Eligibility Period is equal to a Resource’s DA Market Commitment Period except as defined below:

(a) For Resources with an associated DA Market Commitment Period that begins in one Operating Day and ends in the next Operating Day, two DA Market Make-Whole-Payment Eligibility Periods are created. The first period begins in the first Operating Day in the hour that the DA Market Commitment Period begins and ends in the last hour of the first Operating Day. The second period begins in the first hour of the next Operating Day and ends in the last hour of the DA Market Commitment Period.

(3) The following cost recovery eligible rules apply to each DA Market Make-Whole-Payment Eligibility Period. Offer costs are calculated using the DA Market Offer prices in effect at the time the commitment decision was made except under the situation described under Section (b).a.i below.

(a) There may be more than one DA Market Make-Whole Payment Eligibility Period for a Resource in a single Operating Day for which a credit or charge is calculated. A single DA Market Make-Whole Payment Eligibility Period is contained within a single Operating Day.

(b) A Resource’s DA Market Start-Up Offer costs are not eligible for recovery in the following DA Market Make-Whole Payment Eligibility Periods:

a. Any DA Market Make-Whole Payment Eligibility Period that is adjacent to the end of a RUC Make-Whole Payment Eligibility Period except as described in (i) below;

\(^{10}\) Note that this charge type will almost always produce a credit. The charge is included here for the rare occasion when a charge may be produced as a result of a data error and/or a resettlement.
i. As described under Section 4.5.9.8(3)h, to the extent that the full amount of the RTBM Start-Up Offer is not accounted for in the adjacent RUC Make-Whole Payment Eligibility Period, any remaining RTBM Start-Up Offer costs are carried forward for recovery in the adjacent Day-Ahead Make-Whole Payment Eligibility Period.

b. Any DA Market Make-Whole Payment Eligibility Period resulting from a DA Market Commitment Period that contains a DA Market Self-Commit Hour; and

c. Any DA Make-Whole Payment Eligibility Period for which a Resource is a Synchronized Resource prior to this commitment period at a time one hour prior to that Resource’s DA Market Commit Time less the Resource’s Sync-To-Min Profile.

(c) For each DA Market Make-Whole Payment Eligibility Period within an Operating Day, a Resource’s DA Market Start-Up Offer is divided by the lesser of (1) the Resource’s Minimum Run Time rounded down to the nearest hour or (2) 24 Hours, and that portion of the Start-Up Offer is included as a cost in each hour of the DA Market Make-Whole Payment Eligibility Period until the sum of these hourly costs are equal to the DA Market Start-Up Offer or until the end of the DA Market Make-Whole Payment Eligibility Period, whichever occurs first.

(d) To the extent that the full amount of the DA Market Start-Up Offer is not accounted for in the last DA Market Make-Whole Payment Eligibility Period in the Operating Day, any remaining DA Market Start-Up Offer costs are carried forward for recovery in the first DA Market Make-Whole Payment Eligibility Period of the following Operating Day. For example, consider a Resource that is committed starting at 10:00 PM in Operating Day 1 that has a Minimum Run Time of 10 hours and a Start-Up Offer of $10,000. The DA Market Commitment Period is from 10:00 PM in Operating Day 1 through 8:00 AM of Operating Day 2. For DA Market Make-Whole Payment calculation purposes, the DA Market Commitment Period is split into two separate DA Market Make-Whole Payment Eligibility Periods as described in (2).b above. The first DA Market Make-Whole Payment Eligibility Period will include $1000/hour of Start-Up Offer costs ($10,000 / 10 Hours) in hours 23 and 24. The second DA Market Make-Whole Payment Eligibility Period will include $1000/hour of Start-Up Offer costs in hours 1 through 8.
(4) The amount to each Asset Owner (AO) for each eligible Resource Settlement Location for each hour in a given DA Market Make-Whole Payment Eligibility Period is calculated as follows:

\[
\#DaMwpCpAmt_{a,s,c} = \max(0, \sum_{h} (DaMwpCostHrlyAmt_{a,h,s,c} + DaMwpRevHrlyAmt_{a,h,s,c}) ) \times (-1)
\]

(a) \(DaMwpCostHrlyAmt_{a,h,s,c} =\)

\[DaStartUpEligHrlyFlg_{h,s,c} \times DaStartUpHrlyAmt_{a,h,s,c} + DaClrdComStatHrlyFlg_{a,s,c} \]

* [ \(DaRucRmndrStartUpHrlyAmt_{a,s,h,c} + DaNoLoadHrlyAmt_{a,h,s,c} + DaIncrEnHrlyAmt_{a,h,s,c} + DaRegUpAvailHrlyAmt_{a,h,s,c} + DaRegDnAvailHrlyAmt_{a,h,s,c} + DaSpinAvailHrlyAmt_{a,h,s,c} + DaSuppAvailHrlyAmt_{a,h,s,c} \) ]

Where,

\[
\#DaIncrEnHrlyAmt_{a,h,s,c} = \frac{\int_{0}^{\text{ABS(DaClrdHrlyQty}_{a,h,s)}} \text{DA Market Energy Offer Curve} \text{ d}t}{\text{DA Market Energy Offer Curve}}
\]

(b) \(DaMwpRevHrlyAmt_{a,h,s,c} = DaClrdComStatHrlyFlg_{a,h,s,c} \)

* [ \(DaLmpHrlyPrc_{s,h} \times DaClrdHrlyQty_{a,s,h} \) ]

\[+ DaRegUpHrlyAmt_{a,h,s} + DaRegDnHrlyAmt_{a,h,s} + DaSpinHrlyAmt_{a,h,s} + DaSuppHrlyAmt_{a,h,s} \]
(5) For each Asset Owner, a daily amount is calculated at each Settlement Location. The daily amount is calculated as follows:

\[ \text{DaMwpDlyAmt}_{a,s,d} = \sum_c \text{DaMwpCpAmt}_{a,s,c} \]

(6) For each Asset Owner associated with Market Participant \( m \), a daily amount is calculated. The daily amount is calculated as follows:

\[ \text{DaMwpAoAmt}_{a,m,d} = \sum_s \text{DaMwpDlyAmt}_{a,s,d} \]

(7) For each Market Participant, a daily amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The daily amount is calculated as follows:

\[ \text{DaMwpMpAmt}_{m,d} = \sum_a \text{DaMwpAoAmt}_{a,m,d} \]

(8) For FERC Electric Quarterly Reporting (EQR) purposes, SPP calculates DA Market Make-Whole Payment $ per DA Market Make-Whole-Payment Eligibility Period for each Asset Owner as follows:

(a) \( \text{EqrDaMwpHrlyPrc}_{a,s,c} = (-1) \times \text{DaMwpCpAmt}_{a,s,c} \)

(b) \( \text{IF } \text{EqrDaMwpHrlyPrc}_{a,s,c} > 0 \) \( \text{THEN} \)

\[ \text{EqrDaMwpHrlyQty}_{a,s,c} = 1 \]
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>DaMwpCpAmt&lt;sub&gt;a, s, c&lt;/sub&gt;</td>
<td>$</td>
<td>Eligibility Period</td>
<td>Day-Ahead Make-Whole-Payment Amount per AO per Settlement Location per DA Market Make-Whole-Payment Eligibility Period - The DA Market make-whole amount to AO a for DA Market Make-Whole-Payment Eligibility Period c at Resource Settlement Location s.</td>
</tr>
<tr>
<td>DaStartUpHrlyAmt&lt;sub&gt;a, h, s, c&lt;/sub&gt;</td>
<td>$</td>
<td>Hour</td>
<td>Day-Ahead Start-Up Cost Amount per AO per Settlement Location per Hour Per DA Market Make-Whole-Payment Eligibility Period - The DA Market Start-Up Offer associated with AO a’s eligible Resource at Settlement Location s for DA Market Make-Whole-Payment Eligibility Period c that is included in each Hour h of the DA Market Make-Whole-Payment Eligibility Period. This value is calculated by dividing DaStartUpAmt&lt;sub&gt;a, s, c&lt;/sub&gt; by the lesser of the Resource’s DaMinRunTime&lt;sub&gt;a, h, s, c&lt;/sub&gt; or 24. These hourly values are carried forward into the following Operating Day, if needed, to ensure recovery of any remaining DaStartUpAmt&lt;sub&gt;a, s, c&lt;/sub&gt;.</td>
</tr>
<tr>
<td>DaStartUpAmt&lt;sub&gt;a, s, c&lt;/sub&gt; (Not Available on Settlement Statement)</td>
<td>$</td>
<td>Eligibility Period</td>
<td>Day-Ahead Start-Up Cost Amount per AO per Settlement Location per DA Market Make-Whole-Payment Eligibility Period - The DA Market Start-Up Offer associated with AO a’s eligible Resource at Settlement Location s for DA Market Make-Whole-Payment Eligibility Period c.</td>
</tr>
<tr>
<td>DaStartUpEligHrlyFlg&lt;sub&gt;h, s, c&lt;/sub&gt;</td>
<td>None</td>
<td>Hour</td>
<td>Day-Ahead Start-Up Recovery Eligibility Flag per Resource Settlement Location per DA Market Make-Whole-Payment Eligibility Period – This flag is set equal to 1 in each hour of a DA Market Make-Whole-Payment Eligibility Period where the Resource is eligible to recover start-up costs, or 0 in each hour of the DA Market Make-Whole-Payment Eligibility Period where the Resource is not eligible to recover start-up costs.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
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</tr>
<tr>
<td>DaClrdComStatHrlyFlg&lt;sub&gt;<em>h, s, c</em>&lt;/sub&gt;</td>
<td>None</td>
<td>Hour</td>
<td>Day-Ahead Commitment Status Hourly Flag per Resource Settlement Location per DA Market Make-Whole-Payment Eligibility Period – This flag is set equal to 1 for each hour of a DA Market Make-Whole-Payment Eligibility Period in which its Commitment Status was “Market” or “Reliability, or 0 if its Commitment Status was “Self”.</td>
</tr>
<tr>
<td>DaRucRmndrStartUpHrlyAmt&lt;sub&gt;<em>a, s, h, c</em>&lt;/sub&gt;</td>
<td>$</td>
<td>Hour</td>
<td>Day-Ahead RUC Remaining Start-Up Offer Amount per Hour per DA Market Make-Whole Payment Eligibility Period - the amount of Start-Up Offer recovery remaining associated with an adjacent RUC Make-Whole Payment Eligibility Period.</td>
</tr>
<tr>
<td>DaMinRunTime&lt;sub&gt;<em>a, h, s, c</em>&lt;/sub&gt;</td>
<td>Time</td>
<td>Hour</td>
<td>Day-Ahead Minimum Run Time per AO per Settlement Location Per Hour – The Minimum Run Time associated with AO a’s eligible Resource at Settlement Location s for DA Market Make-Whole-Payment Eligibility Period c as submitted as part of the DA Market Offer.</td>
</tr>
<tr>
<td>DaMwpCostHrlyAmt&lt;sub&gt;<em>a, h, s, c</em>&lt;/sub&gt;</td>
<td>$</td>
<td>Hour</td>
<td>Day-Ahead Make-Whole Payment Cost Amount per AO per Settlement Location per Hour in the DA Market Make-Whole-Payment Eligibility Period - The hourly cost associated with AO a’s eligible Resource at Settlement Location s for Hour h in DA Market Make-Whole-Payment Eligibility Period c.</td>
</tr>
<tr>
<td>DaMwpRevHrlyAmt&lt;sub&gt;<em>a, h, s, c</em>&lt;/sub&gt;</td>
<td>$</td>
<td>Hour</td>
<td>Day-Ahead Make-Whole Payment Revenue Amount per AO per Settlement Location per Hour in the DA Market Make-Whole-Payment Eligibility Period – The hourly revenue associated with AO a’s eligible Resource at Settlement Location s for Hour h in DA Market Make-Whole-Payment Eligibility Period c.</td>
</tr>
<tr>
<td>DaNoLoadHrlyAmt&lt;sub&gt;<em>a, h, s, c</em>&lt;/sub&gt;</td>
<td>$</td>
<td>Hour</td>
<td>Day-Ahead No-Load Cost Amount per AO per Settlement Location per Hour per DA Market Make-Whole-Payment Eligibility Period - The No-Load Offer, in dollars, associated with AO a’s eligible Resource at Settlement Location s for Hour h in DA Market Make-Whole-Payment Eligibility Period c.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>------------------------</td>
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<td>-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>DaIncrEnHrlyAmt (_a, h, s, c)</td>
<td>$</td>
<td>Hour</td>
<td><em>Day-Ahead Incremental Energy Cost Amount per AO per Settlement Location per Hour in the DA Market Make-Whole-Payment Eligibility Period</em> - The average incremental energy offer cost, in dollars, associated with AO (a)’s eligible Resource at Settlement Location (s) for Hour (h) in DA Market Make-Whole-Payment Eligibility Period (c) at an output level equal to (DaClrdHrlyQty\ (_a, s, h)).</td>
</tr>
<tr>
<td>DaRegUpAvailHrlyAmt (_a, h, s, c)</td>
<td>$</td>
<td>Hour</td>
<td><em>Day-Ahead Regulation-Up Offer Cost Amount per AO per Settlement Location per Hour per DA Market Make-Whole-Payment Eligibility Period</em> - The Regulation-Up Offer cost, in dollars, associated with AO (a)’s eligible Resource at Settlement Location (s) for Hour (h) in DA Market Make-Whole-Payment Eligibility Period (c). The Resource’s Regulation-Up Offer cost in the Hour is equal to the Resources (DaRegUpHrlyQty\ (_a, s, h)) multiplied by the Resource’s Regulation-Up Offer, in $/MW.</td>
</tr>
<tr>
<td>DaRegDnAvailHrlyAmt (_a, h, s, c)</td>
<td>$</td>
<td>Hour</td>
<td><em>Day-Ahead Regulation-Down Offer Cost Amount per AO per Settlement Location per Hour per DA Market Make-Whole-Payment Eligibility Period</em> - The Regulation-Down Offer cost, in dollars, associated with AO (a)’s eligible Resource at Settlement Location (s) for Hour (h) in DA Market Make-Whole-Payment Eligibility Period (c). The Resource’s Regulation-Down Offer cost in the Hour is equal to the Resources (DaRegDnHrlyQty\ (_a, s, h)), multiplied by the Resource’s Regulation-Down Offer, in $/MW.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>---------------------------</td>
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<td>-----------------------------------------------------------------------------</td>
</tr>
<tr>
<td>DaSpinAvailHrlyAmt (a, h, s, c)</td>
<td>$</td>
<td>Hour</td>
<td>Day-Ahead Spin Offer Cost Amount per AO per Settlement Location per Hour per DA Market Make-Whole-Payment Eligibility Period - The Spinning Reserve Offer cost, in dollars, associated with AO (a)’s eligible Resource at Settlement Location (s) for Hour (h) in DA Market Make-Whole-Payment Eligibility Period (c). The Resource’s Spinning Reserve Offer cost in the Hour is equal to the Resources (\text{DaSpinHrlyQty}_{a,s,h}) multiplied by the Resource’s Spinning Reserve Offer, in $/MW.</td>
</tr>
<tr>
<td>DaSuppAvailHrlyAmt (a, h, s, c)</td>
<td>$</td>
<td>Hour</td>
<td>Day-Ahead Supplemental Offer Cost Amount per AO per Settlement Location per Hour per DA Market Make-Whole-Payment Eligibility Period - The Supplemental Reserve Offer cost, in dollars, associated with AO (a)’s eligible Resource at Settlement Location (s) for Hour (h) in DA Market Make-Whole-Payment Eligibility Period (c). The Resource’s Supplemental Reserve Offer cost in the Hour is equal to the Resources (\text{DaSuppHrlyQty}_{a,s,h}) multiplied by the Resource’s Supplemental Reserve Offer, in $/MW.</td>
</tr>
<tr>
<td>DaLmpHrlyPrce (s, h)</td>
<td>$/MW h</td>
<td>Hour</td>
<td>Day-Ahead LMP - The DA Market LMP at Resource Settlement Location (s) for Hour (h).</td>
</tr>
<tr>
<td>DaClrHrlyQty (a, s, h)</td>
<td>MWh</td>
<td>Hour</td>
<td>Day-Ahead Cleared Energy Quantity per AO per Resource Settlement Location per Hour – The value described under Section 4.5.8.1 for AO (a)’s eligible Resource Settlement Location (s).</td>
</tr>
<tr>
<td>DaRegUpHrlyAmt (a, h, s)</td>
<td>$</td>
<td>Hour</td>
<td>Day-Ahead Regulation-Up Amount per AO per Settlement Location per Hour – The (\text{DaRegUpHrlyAmt}_{a,s,h}) calculated under Section 4.5.8.4 associated with AO (a)’s eligible Resource at Settlement Location (s) for Hour (h).</td>
</tr>
<tr>
<td>DaRegDnHrlyAmt (a, h, s)</td>
<td>$</td>
<td>Hour</td>
<td>Day-Ahead Regulation-Down Amount per AO per Settlement Location per Hour– The (\text{DaRegDnHrlyAmt}_{a,s,h}) calculated under Section 4.5.8.5 associated with AO (a)’s eligible Resource at Settlement Location (s) for Hour (h).</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>--------------------------</td>
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<td>---------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>DaSpinHrlyAmt&lt;sub&gt;a, h, s&lt;/sub&gt;</td>
<td>$</td>
<td>Hour</td>
<td>Day-Ahead Spinning Reserve Amount per AO per Settlement Location per Hour—The DaSpinHrlyAmt&lt;sub&gt;a, s, h&lt;/sub&gt; calculated under Section 4.5.8.6 associated with AO a’s eligible Resource at Settlement Location s for Hour h.</td>
</tr>
<tr>
<td>DaSuppHrlyAmt&lt;sub&gt;a, h, s&lt;/sub&gt;</td>
<td>$</td>
<td>Hour</td>
<td>Day-Ahead Supplemental Reserve Amount per AO per Settlement Location per Hour — The DaSuppHrlyAmt&lt;sub&gt;a, s, h&lt;/sub&gt; calculated under Section 4.5.8.7 associated with AO a’s eligible Resource at Settlement Location s for Hour h.</td>
</tr>
<tr>
<td>DaMwpDlyAmt&lt;sub&gt;a, s, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Make-Whole-Payment Amount per AO per Settlement Location per Operating Day - The DA Market make-whole amount to AO a for Operating Day d at Resource Settlement Location s.</td>
</tr>
<tr>
<td>DaMwpAoAmt&lt;sub&gt;a, m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Make-Whole-Payment Amount per AO per Operating Day - The DA Market make-whole amount to AO a associated with Market Participant m for Operating Day d.</td>
</tr>
<tr>
<td>DaMwpMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Make-Whole-Payment Amount per MP per Operating Day - The DA Market make-whole amount to Market Participant m for Operating Day d.</td>
</tr>
<tr>
<td>EqrDaMwpHrlyPrc&lt;sub&gt;a, s, c&lt;/sub&gt;</td>
<td>$</td>
<td>Eligibility Period</td>
<td>Day-Ahead Electric Quarterly Reporting Make-Whole-Payment Amount per AO per Settlement Location per DA Market Make-Whole-Payment Eligibility Period - The DA Market make-whole amount to AO a for DA Market Make-Whole-Payment Eligibility Period c at Resource Settlement Location s for use by AO a in reporting such make-whole-payments to FERC in accordance with FERC EQR requirements..</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>----------</td>
<td>------</td>
<td>---------------------</td>
<td>------------</td>
</tr>
<tr>
<td>EqrDaMwpHrlyQty&lt;sub&gt;a, s, c&lt;/sub&gt;</td>
<td>$</td>
<td>Eligibility Period</td>
<td>Day-Ahead Electric Quarterly Reporting Make-Whole-Payment Quantity per AO per Settlement Location per DA Market Make-Whole-Payment Eligibility Period – This value is set equal to 1 if &lt;span&gt;EqrDaMwpHrlyPrc&lt;sub&gt;a, s, c&lt;/sub&gt; &gt; 0&lt;/span&gt; for use by AO &lt;span&gt;a&lt;/span&gt; in reporting such make-whole-payments to FERC in accordance with FERC EQR requirements.</td>
</tr>
<tr>
<td>a</td>
<td>none</td>
<td>none</td>
<td>An Asset Owner.</td>
</tr>
<tr>
<td>h</td>
<td>none</td>
<td>none</td>
<td>An Hour in a DA Market Make-Whole-Payment Eligibility Period.</td>
</tr>
<tr>
<td>s</td>
<td>none</td>
<td>none</td>
<td>A Resource Settlement Location.</td>
</tr>
<tr>
<td>c</td>
<td>none</td>
<td>none</td>
<td>A DA Market Make-Whole-Payment Eligibility Period.</td>
</tr>
<tr>
<td>d</td>
<td>none</td>
<td>none</td>
<td>An Operating Day.</td>
</tr>
<tr>
<td>m</td>
<td>none</td>
<td>none</td>
<td>A Market Participant.</td>
</tr>
</tbody>
</table>
4.5.8.13 Day-Ahead Make-Whole-Payment Distribution Amount

(1) The Day-Ahead Make-Whole-Payment Distribution Amount is an hourly charge or credit\(^{11}\) based on a daily distribution rate to Asset Owners with net cleared Energy withdrawals at a Settlement Location in the DA Market. Total daily charges to Asset Owners are equal to the total Day-Ahead Make-Whole-Payment Amount for the Operating Day. The hourly amount to each Asset Owner at each Settlement Location is calculated as follows:

\[
#DaMwpDistHrlyAmt_{a,s,h} = DaMwpSppDistRate_d \times DaMwpDistHrlyQty_{a,s,h}
\]

Where,

(a) \(DaMwpDistHrlyQty_{a,s,h} = \text{Max} \left( 0, DaClrdHrlyQty_{a,s,h} \right)

+ \sum_t DaClrdVHrlyQty_{a,s,h,t} + \sum_i \sum_t DaImpExp5minQty_{a,s,i,t} / 12 \)

(b) \(\#DaMwpSppDistRate_d = \left( \frac{DaMwpSppAmt_d}{DaMwpSppDistQty_d} \right) \times (-1)\)

(a.1) \(DaMwpSppAmt_d = \sum_m DaMwpMpAmt_{m,d}\)

(a.2) \(DaMwpSppDistQty_d = \sum_a \sum_s \sum_h DaMwpDistHrlyQty_{a,s,h}\)

(2) For each Asset Owner, a daily amount is calculated at each Settlement Location. The daily amount is calculated as follows:

\[
DaMwpDistDlyAmt_{a,s,d} = \sum_h DaMwpDistHrlyAmt_{a,s,h}
\]

(3) For each Asset Owner associated with Market Participant \(m\), a daily amount is calculated. The daily amount is calculated as follows:

\(^{11}\) Note that this charge type will almost always produce a charge. The credit is included here for the rare occasion when a credit may be produced as a result of a data error and/or a resettlement.
\[ \text{DaMwpDistAoAmt}_{a, m, d} = \sum_s \text{DaMwpDistDlyAmt}_{a, s, d} \]

(4) For each Market Participant, a daily amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The daily amount is calculated as follows:

\[ \text{DaMwpDistMpAmt}_{m, d} = \sum_a \text{DaMwpDistAoAmt}_{a, m, d} \]
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>DaMwpDistHrlyAmt (_{a, s, h})</td>
<td>$/h</td>
<td>Hour</td>
<td>Day-Ahead Make-Whole-Payment Distribution Amount per AO per Hour per Settlement Location - The amount to AO (a) for Hour (h) and Settlement Location (s) for recovery of the DaMwpSppAmt (_d) for Operating Day (d).</td>
</tr>
<tr>
<td>DaMwpSppDistRate (_d)</td>
<td>$/MWh</td>
<td>Operating Day</td>
<td>Day-Ahead SPP Make-Whole Payment Distribution Rate per Operating Day – The rate applied to each AO’s total withdrawal volume in each Hour (h) at Settlement Location (s) in Operating Day (d).</td>
</tr>
<tr>
<td>DaMwpDistHrlyQty (_{a, s, h})</td>
<td>MWh/(h)</td>
<td>Hour</td>
<td>Day-Ahead Make-Whole Payment Distribution Volume per Asset Owner per Settlement Location per Hour – The withdrawal volume associated with AO (a) at Settlement Location (s) for the Hour.</td>
</tr>
<tr>
<td>DaMwpSppAmt (_d)</td>
<td>$/\(d)</td>
<td>Operating Day</td>
<td>Day-Ahead SPP Make-Whole Payment Amount per Operating Day – The total of all DaMwpAmt (_{a, c, s}) in Operating Day (d).</td>
</tr>
<tr>
<td>DaMwpSppDistQty (_d)</td>
<td>MWh/\(d)</td>
<td>Operating Day</td>
<td>Day-Ahead SPP Make-Whole Payment Distribution Volume per Operating Day – The sum across all hours and Settlement Locations of all AO withdrawal volumes in Operating Day (d).</td>
</tr>
<tr>
<td>DaClrdHrlyQty (_{a, s, h})</td>
<td>MWh/(h)</td>
<td>Hour</td>
<td>Day-Ahead Cleared Energy Quantity per AO per Settlement Location per Hour in the DA Market – The value described under Section 4.5.8.1.</td>
</tr>
<tr>
<td>DaClrdVHrlyQty (_{a, s, h, t})</td>
<td>MWh/(h)</td>
<td>Hour</td>
<td>Day-Ahead Cleared Virtual Energy Quantity per AO per Transaction per Settlement Location per Hour in the DA Market – The value described under Section 4.5.8.3.</td>
</tr>
<tr>
<td>DaImpExp5minQty (_{a, s, i, t})</td>
<td>MWh/(d)</td>
<td>Dispatch Interval</td>
<td>Day-Ahead Interchange Transaction Quantity per AO per Transaction per Settlement Location per Dispatch Interval – The value described under Section 4.5.8.2.</td>
</tr>
<tr>
<td>DaMwpMpAmt (_{m, d})</td>
<td>$/\(d)</td>
<td>Operating Day</td>
<td>Day-Ahead Make-Whole-Payment Amount per MP per Operating Day - The value calculated under Section 4.5.8.8.</td>
</tr>
<tr>
<td>DaMwpDistDlyAmt (_{a, s, d})</td>
<td>$/\(d)</td>
<td>Operating Day</td>
<td>Day-Ahead Make-Whole-Payment Distribution Amount per AO per Settlement Location per Operating Day - The DA Market amount to AO (a) for Operating Day (d) at Resource Settlement Location (s) for recovery of the DaMwpSppAmt (_d).</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>------------------</td>
<td>------</td>
<td>---------------------</td>
<td>-----------------------------------------------------------------------------</td>
</tr>
<tr>
<td>DaMwpDistAoAmt</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Make-Whole-Payment Distribution Amount per AO per Operating Day - The DA Market amount to AO $a$ associated with Market Participant $m$ for Operating Day $d$ for recovery of the DaMwpSppAmt $d$.</td>
</tr>
<tr>
<td>DaMwpDistMpAmt</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Make-Whole-Payment Distribution Amount per MP per Operating Day - The DA Market amount to Market Participant $m$ for Operating Day $d$ for recovery of the DaMwpSppAmt $d$.</td>
</tr>
<tr>
<td>$h$</td>
<td>none</td>
<td>none</td>
<td>An Hour in a DA Market Make-Whole-Payment Eligibility Period.</td>
</tr>
<tr>
<td>$d$</td>
<td>none</td>
<td>none</td>
<td>An Operating Day.</td>
</tr>
<tr>
<td>$a$</td>
<td>none</td>
<td>none</td>
<td>An Asset Owner.</td>
</tr>
<tr>
<td>$c$</td>
<td>none</td>
<td>none</td>
<td>A DA Market Make-Whole-Payment Eligibility Period.</td>
</tr>
<tr>
<td>$s$</td>
<td>none</td>
<td>none</td>
<td>A Settlement Location.</td>
</tr>
<tr>
<td>$t$</td>
<td>none</td>
<td>none</td>
<td>A single tagged Interchange Transaction, a single virtual energy transaction, a single Financial Schedule, a single contracted Operating Reserve transaction, a single TCR instrument, a single ARR award or a single Reserve Sharing Event transaction.</td>
</tr>
<tr>
<td>$m$</td>
<td>none</td>
<td>none</td>
<td>A Market Participant</td>
</tr>
</tbody>
</table>
4.5.8.14 Transmission Congestion Rights Funding Amount

(1) The Transmission Congestion Rights Funding Amount can be either a credit or charge to an Asset Owner and is calculated for each TCR instrument held by the Asset Owner. TCR instruments will be fully funded in each hour. The amount to each Asset Owner (AO) for each TCR instrument for a given hour of the Operating Day is calculated as follows:

\[
\text{TcrFundHrlyAmt}_{a, h} = \sum_t (\text{TcrHrlyQty}_{a, h, t} \times (\text{DaMccHrlyPrc}_{\text{source}, h} - \text{DaMccHrlyPrc}_{\text{sink}, h}))
\]

(2) For each Asset Owner associated with Market Participant \( m \), a daily amount is calculated. The daily amount is calculated as follows:

\[
\text{TcrFundAoAmt}_{a, m, d} = \sum_h \text{TcrFundHrlyAmt}_{a, h}
\]

(3) For each Market Participant, a daily amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The daily amount is calculated as follows:

\[
\text{TcrFundMpAmt}_{m, d} = \sum_a \text{TcrFundAoAmt}_{a, m, d}
\]
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>TcrFundHrlyAmt&lt;sub&gt;a, h&lt;/sub&gt;</td>
<td>$</td>
<td>Hour</td>
<td>Transmission Congestion Rights Hourly Funding Amount per AO per Hour - The net amount to AO a for all AO a’s TCR instruments for the Hour.</td>
</tr>
<tr>
<td>TcrHrlyQty&lt;sub&gt;a, h, t&lt;/sub&gt;</td>
<td>$/MWh</td>
<td>Hour</td>
<td>Transmission Congestion Right Quantity - The MW quantity specified in TCR instrument t, for AO a for the Hour.</td>
</tr>
<tr>
<td>DaMccHrlyPre&lt;sub&gt;sink, h&lt;/sub&gt;</td>
<td>$/MWh</td>
<td>Hour</td>
<td>Day-Ahead Marginal Congestion Component of Day-Ahead LMP at the Sink per Hour – The Marginal Congestion Component of the Day-Ahead LMP at the Settlement Location of the sink point specified in TCR instrument t for Hour h.</td>
</tr>
<tr>
<td>DaMccHrlyPre&lt;sub&gt;source, h&lt;/sub&gt;</td>
<td>$/MWh</td>
<td>Hour</td>
<td>Day-Ahead Marginal Congestion Component of Day-Ahead LMP at the Source per Hour – The Marginal Congestion Component of the Day-Ahead LMP at the Settlement Location of the source point specified in TCR instrument t for Hour h.</td>
</tr>
<tr>
<td>TcrFundAoAmt&lt;sub&gt;a, m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Transmission Congestion Rights Funding Amount per AO per Operating Day- - The net amount to AO a associated with Market Participant m for all AO a’s TCR instruments for the Operating Day.</td>
</tr>
<tr>
<td>TcrFundMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Transmission Congestion Rights Hourly Funding Amount per MP per Operating Day- The net amount to MP m for all MP m’s TCR instruments for the Operating Day.</td>
</tr>
<tr>
<td>source</td>
<td>none</td>
<td>none</td>
<td>The Settlement Location identified as the source point in TCR instrument t.</td>
</tr>
<tr>
<td>sink</td>
<td>none</td>
<td>none</td>
<td>The Settlement Location identified as the sink point in TCR instrument t.</td>
</tr>
<tr>
<td>a</td>
<td>none</td>
<td>none</td>
<td>An Asset Owner.</td>
</tr>
<tr>
<td>t</td>
<td>none</td>
<td>none</td>
<td>A single tagged Interchange Transaction, a single virtual energy transaction, a single Financial Schedule, a single contracted Operating Reserve transaction, a single TCR instrument, a single ARR award or a single Reserve Sharing Event transaction.</td>
</tr>
<tr>
<td>h</td>
<td>none</td>
<td>none</td>
<td>An Hour.</td>
</tr>
<tr>
<td>d</td>
<td>none</td>
<td>none</td>
<td>An Operating Day.</td>
</tr>
<tr>
<td>m</td>
<td>none</td>
<td>none</td>
<td>A Market Participant.</td>
</tr>
</tbody>
</table>
4.5.8.15 Transmission Congestion Rights Daily Uplift Amount

(1) A DA Market charge or credit\(^{12}\) will be calculated for each Asset Owner holding TCRs for each Operating Day to the extent that congestion revenues collected over the Operating Day are not sufficient to fund the net of the total charges and credits calculated under Section 4.5.8.14 over the Operating Day. The amount is calculated as follows:

\[
#\text{TcrUpliftDlyAmt}_{a,d} = 
\text{ShortFallDlyAmt}_d \times \left[ \frac{#\text{TcrUpliftRatioAoDlyAmt}_{a,d}}{#\text{TcrUpliftRatioSppDlyAmt}_d} \right]
\]

Where,

(a) \( #\text{TcrUpliftRatioAoDlyAmt}_{a,d} = \)

\[
\sum_h \sum_t \text{ABS} \left( (\text{TcrHrlyQty}_{a,h,t} \times (\text{DaMccHrlyPrc}_{\text{source},h} - \text{DaMccHrlyPrc}_{\text{sink},h})) \right)
\]

(b) \( #\text{TcrUpliftRatioSppDlyAmt}_d = \)

\[
\sum_a \sum_h \sum_t \text{ABS} \left( (\text{TcrHrlyQty}_{a,h,t} \times (\text{DaMccHrlyPrc}_{\text{source},h} - \text{DaMccHrlyPrc}_{\text{sink},h})) \right)
\]

(c) \( #\text{ShortFallDlyAmt}_d = \)

\[
(-1) \times \text{MIN} \left\{ \sum_a \sum_s \sum_h \left[ \text{DaMccHrlyPrc}_{s,h} \times (\text{DaClrdHrlyQty}_{a,s,h} \right. \right.
\]

\[
+ \sum_i \sum_t \left. \left( \frac{\text{DaImpExp5minQty}_{a,s,i,t}}{12} \right) + \sum_t \text{DaClrdVHrlyQty}_{a,s,h,t} \right) \right\}
\]

\[
+ \sum_a \sum_h \text{TcrFundHrlyAmt}_{a,h}
\]

\(^{12}\) Note that this charge type will almost always produce a charge. The credit is included here for the rare occasion when a credit may be produced as a result of a data error and/or a resettlement.
(2) For each Market Participant, a daily amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The daily amount is calculated as follows:

\[ \text{TcrUpliftDlyMpAmt}_{m,d} = \sum_{a} \text{TcrUpliftDlyAmt}_{a,d} \]
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>TcrUpliftDlyAmt&lt;sub&gt;a, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Transmission Congestion Rights Daily Uplift Amount per AO - AO a’s share of the ShortFallDlyAmt&lt;sub&gt;d&lt;/sub&gt; in Operating Day d.</td>
</tr>
<tr>
<td>TcrUpliftRatioAoDlyAmt&lt;sub&gt;a, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Transmission Congestion Rights Uplift Ratio per Asset Owner per Operating Day – The total of the absolute value of Asset Owner a’s hourly TCR instrument economic value for Operating Day d.</td>
</tr>
<tr>
<td>TcrUpliftRatioSppDlyAmt&lt;sub&gt;d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>SPP Transmission Congestion Rights Uplift Ratio per Operating Day – The total of TcrUpliftRatioAoDlyAmt&lt;sub&gt;a, d&lt;/sub&gt; for Operating Day d.</td>
</tr>
<tr>
<td>ShortFallDlyAmt&lt;sub&gt;d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Transmission Congestion Rights Daily Shortfall Amount – The shortfall in congestion revenues that would be required to fully fund TCRs in Operating Day d.</td>
</tr>
<tr>
<td>DaMccHrlyPre&lt;sub&gt;s, h&lt;/sub&gt;</td>
<td>$/MWh</td>
<td>Hour</td>
<td>Day-Ahead Marginal Congestion Component of Day-Ahead LMP – The Marginal Congestion Component of the Day-Ahead LMP at Settlement Location s for Hour h.</td>
</tr>
<tr>
<td>DaClrdHrlyQty&lt;sub&gt;a, s, h&lt;/sub&gt;</td>
<td>MWh</td>
<td>Hour</td>
<td>Day-Ahead Cleared Energy Quantity per AO per Settlement Location per Hour in the DA Market – The value described under Section 4.5.8.1.</td>
</tr>
<tr>
<td>DaClrdVHrlyQty&lt;sub&gt;a, s, h, t&lt;/sub&gt;</td>
<td>MWh</td>
<td>Hour</td>
<td>Day-Ahead Cleared Virtual Energy Quantity per AO per Settlement Location per Hour in the DA Market – The value described under Section 4.5.8.3.</td>
</tr>
<tr>
<td>DaImpExp5minQty&lt;sub&gt;a, s, i, t&lt;/sub&gt;</td>
<td>MWh</td>
<td>Dispatch Interval</td>
<td>Day-Ahead Interchange Transaction Quantity per AO per Settlement Location per Dispatch Interval – The value described under Section 4.5.9.2.</td>
</tr>
<tr>
<td>TcrHrlyQty&lt;sub&gt;a, h, t&lt;/sub&gt;</td>
<td>MWh</td>
<td>Hour</td>
<td>Transmission Congestion Right Quantity - The value described under Section 4.5.8.14.</td>
</tr>
<tr>
<td>TcrFundHrlyAmt&lt;sub&gt;a, h&lt;/sub&gt;</td>
<td>$</td>
<td>Hour</td>
<td>Transmission Congestion Rights Hourly Funding Amount per AO per Hour - The value calculated under Section 4.5.8.14.</td>
</tr>
<tr>
<td>TcrUpliftDlyMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Transmission Congestion Rights Daily Uplift Amount per MP per Operating Day - MP m’s share of the ShortFallDlyAmt&lt;sub&gt;d&lt;/sub&gt; in Operating Day d.</td>
</tr>
<tr>
<td>a</td>
<td>none</td>
<td>none</td>
<td>An Asset Owner.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>----------</td>
<td>------</td>
<td>---------------------</td>
<td>------------</td>
</tr>
<tr>
<td>$h$</td>
<td>none</td>
<td>none</td>
<td>An Hour.</td>
</tr>
<tr>
<td>$s$</td>
<td>none</td>
<td>none</td>
<td>A Settlement Location.</td>
</tr>
<tr>
<td>$i$</td>
<td>none</td>
<td>none</td>
<td>A Dispatch Interval.</td>
</tr>
<tr>
<td>$t$</td>
<td>none</td>
<td>none</td>
<td>A single tagged Interchange Transaction, a single virtual energy transaction, a single Financial Schedule, a single contracted Operating Reserve transaction, a single TCR instrument, a single ARR award or a single Reserve Sharing Event transaction.</td>
</tr>
<tr>
<td>$d$</td>
<td>none</td>
<td>none</td>
<td>An Operating Day.</td>
</tr>
<tr>
<td>$m$</td>
<td>none</td>
<td>none</td>
<td>A Market Participant.</td>
</tr>
</tbody>
</table>
4.5.8.16 Transmission Congestion Rights Monthly Payback Amount

(1) A DA Market monthly credit or charge\(^{13}\) will be calculated for each Asset Owner receiving a charge under Section 4.5.8.15 in any Operating Day of the month in order to ensure full funding of TCRs to the extent possible. The amount is calculated as follows:

\[
#\text{TcrPaybackMnthlyAmt}_{a,mn} = (-1) \times \min \{ \text{TcrUpliftAoMnthlyAmt}_{a,mn}, \left[ \text{ECFMnthlyAmt}_{mn} \times \text{TcrUpliftAoMnthlyAmt}_{a,mn} / \text{TcrUpliftSppMnthlyAmt}_{mn} \right] \}
\]

Where,

(a) \( \text{TcrUpliftAoMnthlyAmt}_{a,mn} = \sum_d \text{TcrUpliftDlyAmt}_{a,d} \)

(b) \( \text{TcrUpliftSppMnthlyAmt}_{mn} = \sum_a \sum_d \text{TcrUpliftDlyAmt}_{a,d} \)

(c) \( \# \text{ECFMnthlyAmt}_{mn} = \sum_d \text{ECFDlyAmt}_d \)

(c.1) \( \text{ECFDlyAmt}_d = \max \{ 0, \sum_a \sum_s \sum_h \text{DaMccHrlyPrce}_{s,h} \times ( \text{DaClrHrlyQty}_{a,s,h} + ( \text{DaImpExp5minQty}_{a,s,i,t} / 12 ) + \text{DaClrVHrlyQty}_{a,s,h,t} ) \}
\]

\( + \sum_a \sum_h \text{TcrFundHrlyAmt}_{a,h} \} \)

\(^{13}\) Note that this charge type will almost always produce a credit. The charge is included here for the rare occasion when a charge may be produced as a result of a data error and/or a resettlement.
(2) For each Market Participant, a monthly amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The monthly amount is calculated as follows:

\[ TcrPaybackMnthlyMpAmt_{m, mn} = \sum_a TcrPaybackMnthlyAmt_{a, mn} \]
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>TcrPaybackMnthlyAmt(_{a, mn})</td>
<td>$</td>
<td>Month</td>
<td>Transmission Congestion Rights Monthly Payback Amount per AO - AO (a)'s share of the ECFMnthlyAmt(_{mn}) in month (mn).</td>
</tr>
<tr>
<td>TcrUpliftAoMnthlyAmt(_{a, mn})</td>
<td>$</td>
<td>Month</td>
<td>Transmission Congestion Rights Monthly Uplift Amount per AO – The sum of TcrUpliftDlyAmt(_{a, d}) for AO (a) for Month (mn).</td>
</tr>
<tr>
<td>TcrUpliftSppMnthlyAmt(_{mn})</td>
<td>$</td>
<td>Month</td>
<td>Transmission Congestion Rights Monthly Uplift Amount – The sum of TcrUpliftAoMnthlyAmt(_{a, mn}) for all AOs for Month (mn).</td>
</tr>
<tr>
<td>ECFMnthlyAmt(_{mn})</td>
<td>$</td>
<td>Month</td>
<td>Excess Congestion Fund Monthly Amount – The sum of ECFDlyAmt(_d) in month (mn).</td>
</tr>
<tr>
<td>ECFDlyAmt(_d)</td>
<td>$</td>
<td>Operating Day</td>
<td>Excess Congestion Fund Daily Amount – The excess in congestion revenues over that required to fully fund TCRs in Operating Day (d).</td>
</tr>
<tr>
<td>DaMccHrlyPre(_{s, h})</td>
<td>$/MWh</td>
<td>Hour</td>
<td>Day-Ahead Marginal Congestion Component of Day-Ahead LMP – The Marginal Congestion Component of the Day-Ahead LMP at Settlement Location (s) for Hour (h).</td>
</tr>
<tr>
<td>DaClrdHrlyQty(_{a, s, h})</td>
<td>MWh</td>
<td>Hour</td>
<td>Day-Ahead Cleared Energy Quantity per AO per Settlement Location per Hour in the DA Market – The value described under Section 4.5.8.1.</td>
</tr>
<tr>
<td>DaClrdVHrlyQty(_{a, s, h, t})</td>
<td>MWh</td>
<td>Hour</td>
<td>Day-Ahead Cleared Virtual Energy Quantity per AO per Settlement Location per Hour in the DA Market – The value described under Section 4.5.8.3.</td>
</tr>
<tr>
<td>DaImpExp5minQty(_{a, s, h, t})</td>
<td>MWh</td>
<td>Dispatch Interval</td>
<td>Day-Ahead Interchange Transaction Quantity per AO per Settlement Location per Dispatch Interval – The value described under Section 4.5.9.2.</td>
</tr>
<tr>
<td>TcrFundHrlyAmt(_{a, h})</td>
<td>$</td>
<td>Hour</td>
<td>Transmission Congestion Rights Hourly Funding Amount per AO per Hour - The value calculated under Section 4.5.8.14.</td>
</tr>
<tr>
<td>TcrUpliftDlyAmt(_{a, d})</td>
<td>$</td>
<td>Operating Day</td>
<td>Transmission Congestion Rights Daily Uplift Amount per AO - The value calculated under Section 4.5.8.15.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>----------------------------------</td>
<td>------</td>
<td>---------------------</td>
<td>----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>$TcrPaybackMnthlyMpAmtn_{m,mn}$</td>
<td>$</td>
<td>Month</td>
<td>Transmission Congestion Rights Monthly Payback Amount per MP per Month - MP a’s share of the $ECFMnthlyAmtn_{mn}$ in month $mn$.</td>
</tr>
<tr>
<td>$a$</td>
<td>none</td>
<td>none</td>
<td>An Asset Owner.</td>
</tr>
<tr>
<td>$h$</td>
<td>none</td>
<td>none</td>
<td>An Hour.</td>
</tr>
<tr>
<td>$s$</td>
<td>none</td>
<td>none</td>
<td>A Settlement Location.</td>
</tr>
<tr>
<td>$i$</td>
<td>none</td>
<td>none</td>
<td>A Dispatch Interval.</td>
</tr>
<tr>
<td>$t$</td>
<td>none</td>
<td>none</td>
<td>A single tagged Interchange Transaction, a single virtual energy transaction, a single Financial Schedule, a single contracted Operating Reserve transaction, a single TCR instrument, a single ARR award or a single Reserve Sharing Event transaction.</td>
</tr>
<tr>
<td>$d$</td>
<td>none</td>
<td>none</td>
<td>An Operating Day.</td>
</tr>
<tr>
<td>$mn$</td>
<td>none</td>
<td>none</td>
<td>A month.</td>
</tr>
<tr>
<td>$m$</td>
<td>none</td>
<td>none</td>
<td>A Market Participant.</td>
</tr>
</tbody>
</table>
4.5.8.17 Transmission Congestion Rights Annual Payback Amount

(1) A DA Market annual credit or charge\(^{14}\) will be calculated for each Asset Owner receiving credits under Section 4.5.8.16 that were not sufficient to cover charges received under Section 4.5.8.15 over the year in order to ensure full funding of TCRs to the extent possible. The amount is calculated as follows:

\[
\text{TcrPaybackYrlyAmt}_{a, yr} = (-1) \times \min \{ \text{TcrNetUpliftAoYrlyAmt}_{a, yr}, \text{ECFYrlyAmt}_{yr} \} \times \frac{\text{TcrNetUpliftAoYrlyAmt}_{a, yr}}{\text{TcrNetUpliftSppYrlyAmt}_{yr}}
\]

Where,

(a) \( \text{TcrNetUpliftAoYrlyAmt}_{a, yr} = \)

\[
\sum_{d} \text{TcrUpliftDlyAmt}_{a, d} + \sum_{m,n} \text{TcrPaybackMnthlyAmt}_{a, m,n}
\]

(b) \( \text{TcrNetUpliftSppYrlyAmt}_{yr} = \)

\[
\sum_{a} \left\{ \sum_{d} \text{TcrUpliftDlyAmt}_{a, d} + \sum_{m,n} \text{TcrPaybackMnthlyAmt}_{a, m,n} \right\}
\]

(c) \( \text{ECFYrlyAmt}_{yr} = \sum_{m,n} \text{ECFMnthlyAmt}_{m,n} + \sum_{m,n} \sum_{a} \text{TcrPaybackMnthlyAmt}_{a, m,n} \)

(2) For each Market Participant, an annual amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The annual amount is calculated as follows:

\[
\text{TcrPaybackYrlyMpAmt}_{m, yr} = \sum_{a} \text{TcrPaybackYrlyAmt}_{a, yr}
\]

\(^{14}\) Note that this charge type will almost always produce a credit. The charge is included here for the rare occasion when a charge may be produced as a result of a data error and/or a resettlement.
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>TcrPaybackYrlyAmt (_{a, yr})</td>
<td>$</td>
<td>Year</td>
<td>Transmission Congestion Rights Annual Payback Amount per AO - AO a’s share of the ECFYrlyAmt (_{mn}) in year yr limited to the amount required to fully fund AO a’s TCRs.</td>
</tr>
<tr>
<td>TcrNetUpliftAoYrlyAmt (_{a, yr})</td>
<td>$</td>
<td>Year</td>
<td>Transmission Congestion Rights Net Uplift Amount per AO per Year – AO a’s remaining uplift amount to be paid in year yr.</td>
</tr>
<tr>
<td>TcrNetUpliftSppYrlyAmt (_{yr})</td>
<td>$</td>
<td>Year</td>
<td>Transmission Congestion Rights Net Uplift Amount per Year – The total of all AO’s remaining uplift amounts to be paid in year yr.</td>
</tr>
<tr>
<td>TcrPaybackMnthlyAmt (_{a, mn})</td>
<td>$</td>
<td>Month</td>
<td>Transmission Congestion Rights Monthly Payback Amount per AO - The value described under Section 4.5.8.16.</td>
</tr>
<tr>
<td>ECFYrlyAmt (_{yr})</td>
<td>$</td>
<td>Year</td>
<td>Excess Congestion Fund Yearly Amount – The sum of ECFMnthlyAmt (_{mn}) in year yr, net of payback from the month-end process.</td>
</tr>
<tr>
<td>ECFMnthlyAmt (_{mn})</td>
<td>$</td>
<td>Month</td>
<td>Excess Congestion Fund Monthly Amount – The value described under Section 4.5.8.16.</td>
</tr>
<tr>
<td>TcrUpliftDlyAmt (_{a, d})</td>
<td>MWh</td>
<td>Operating Day</td>
<td>Transmission Congestion Rights Daily Uplift Amount per AO - The value calculated under Section 4.5.8.15.</td>
</tr>
<tr>
<td>TcrPaybackYrlyMpAmt (_{m, yr})</td>
<td>$</td>
<td>Year</td>
<td>Transmission Congestion Rights Monthly Payback Amount per MP per Year - MP a’s share of the ECFYrlyAmt (_{yr}) in year yr.</td>
</tr>
</tbody>
</table>

\(a\) none none An Asset Owner.
\(d\) none none An Operating Day.
\(mn\) none none A month.
\(yr\) none none A year.
\(m\) none none A Market Participant.
4.5.8.18 Transmission Congestion Rights Annual Closeout Amount

(1) A DA Market annual credit or charge\(^{15}\) will be calculated for each Asset Owner Transmission Customer with ARR Nomination Caps established under Section (4) to the extent that there are any funds remaining once all credits are paid under Section 4.5.8.17. The amount is calculated as follows:

\[
\#TcrCloseoutYrlyAmt_{a, yr} = (-1) \times [ ECFYrlyAmt_{yr} + TcrPaybackSppYrlyAmt_{yr} ] \\
\times ArrNominationCapAoYrlyQty_{a, yr} \\
/ ArrNominationCapSppYrlyQty_{yr}
\]

(a) \(TcrPaybackSppYrlyAmt_{yr} = \sum_{a} TcrPaybackYrlyAmt_{a, yr}\)

(b) \(ArrNominationCapAoYrlyQty_{a, yr} = \sum_{d} ArrNominationCapQty_{a, d}\)

(c) \(ArrNominationCapSppYrlyQty_{yr} = \sum_{a} \sum_{d} ArrNominationCapQty_{a, d}\)

(2) For each Market Participant, an annual amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The annual amount is calculated as follows:

\[
TcrCloseoutYrlyMpAmt_{m, yr} = \sum_{a} TcrCloseoutYrlyAmt_{a, yr}
\]

\(^{15}\) Note that this charge type will almost always produce a credit. The charge is included here for the rare occasion when a charge may be produced as a result of a data error and/or a resettlement.
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>TcrCloseoutYrlyAmt&lt;sub&gt;a, yr&lt;/sub&gt;</td>
<td>$</td>
<td>Year</td>
<td>Transmission Congestion Rights Annual Payback Amount per AO - AO a’s share of any remaining ECFYrlyAmt&lt;sub&gt;mn&lt;/sub&gt; in year yr.</td>
</tr>
<tr>
<td>TcrPaybackYrlyAmt&lt;sub&gt;a, yr&lt;/sub&gt;</td>
<td>$</td>
<td>Year</td>
<td>Transmission Congestion Rights Annual Payback Amount per AO - The value calculated under Section 4.5.8.17.</td>
</tr>
<tr>
<td>TcrPaybackSppYrlyAmt&lt;sub&gt;yr&lt;/sub&gt;</td>
<td>$</td>
<td>Year</td>
<td>Transmission Congestion Rights Payback Total per Year - The SPP total of the values calculated under Section 4.5.8.17 for year yr.</td>
</tr>
<tr>
<td>ArrNominationCapAoYrlyQty&lt;sub&gt;a, yr&lt;/sub&gt;</td>
<td>MW</td>
<td>Year</td>
<td>ARR Nomination Cap per AO per Year – The sum of the values described under Section 4.5.10.3 for AO a for year yr.</td>
</tr>
<tr>
<td>ArrNominationCapSppYrlyQty&lt;sub&gt;yr&lt;/sub&gt;</td>
<td>MW</td>
<td>Year</td>
<td>ARR Nomination Cap Total per Year – The SPP total of the values described under Section 4.5.10.3 for year yr.</td>
</tr>
<tr>
<td>ECFYrlyAmt&lt;sub&gt;yr&lt;/sub&gt;</td>
<td>$</td>
<td>Year</td>
<td>Excess Congestion Fund Yearly Amount – The sum of ECFMthlyAmt&lt;sub&gt;mn&lt;/sub&gt; in year yr.</td>
</tr>
<tr>
<td>ArrNominationCapQty&lt;sub&gt;a, d&lt;/sub&gt;</td>
<td>MW</td>
<td>Operating Day</td>
<td>ARR Nomination Cap per AO per Operating Day – The value described under Section 4.5.10.3.</td>
</tr>
<tr>
<td>TcrCloseoutYrlyMpAmt&lt;sub&gt;m, yr&lt;/sub&gt;</td>
<td>$</td>
<td>Year</td>
<td>Transmission Congestion Rights Annual Payback Amount per MP per Year - MP a’s share of the ECFYrlyAmt&lt;sub&gt;yr&lt;/sub&gt; in year yr.</td>
</tr>
</tbody>
</table>

### Variables

- **a**: An Asset Owner.
- **d**: An Operating Day.
- **yr**: A year.
- **m**: A Market Participant.
4.5.8.19 Day-Ahead Over-Collected Losses Distribution Amount

(1) The Marginal Losses Component of the DA Market LMP that results from the economic market solution which considers the cost of marginal losses, congestion costs and incremental Energy costs creates an over collection related to payment for losses ("DA Market Over-Collected Losses") that must be refunded. A DA Market credit or charge\textsuperscript{16} is calculated for each hour at each Settlement Location for which an Asset Owner has a DA Market Energy withdrawal that contributed positively to the over collection. Each Asset Owner’s contribution to the DA Market Over-Collected Losses is calculated based upon a Loss Pool that is dynamically defined by the Asset Owner’s transactional activity. A loss rebate factor is calculated for each Asset Owner and withdrawal Settlement Location as the difference between the Marginal Loss Component at a withdrawal Settlement Location in the Asset Owner’s Loss Pool and the injection weighted average Marginal Loss Component for the Asset Owner’s Loss Pool, multiplied by the Asset Owner’s share of the net withdrawal (calculated excluding cleared Virtual Bids and cleared Virtual Offers) at that Settlement Location. The injection weighted average MLC for the Asset Owner’s Loss Pool is calculated assuming that injection in the Loss Pool first serves withdrawal in the Loss Pool and then goes to meet the withdrawal in Loss Pools which do not have sufficient injections to meet all withdrawals. The loss rebate factor (positive value only, negative values are ignored) is a measure of the Asset Owner’s payment for losses on a marginal basis at each Settlement Location. The loss rebate factors are then normalized to allocate a pro-rata portion of the total over collection in the hour to Asset Owners by Settlement Location. The amount is calculated as follows:

\[
\#\text{DaOclDistHrlyAmt}_{a, s, lp, h} = \text{DaNormLossRbtHrlyFct}_{a, s, lp, h} \times \text{DaOclHrlyAmt}_{h} \times (-1)
\]

Where,

\[
\text{DaOclHrlyAmt}_{h} = \sum_{a} \sum_{s} \sum_{lp} (\text{DaLmpHrlyPrc}_{s, h} - \text{DaMccHrlyPrc}_{s, h}) \times \left( \text{DaClrdHrlyQty}_{a, s, lp, h} + \sum_{t} \text{DaClrdVHrlyQty}_{a, s, lp, h, t} \right)
\]

\textsuperscript{16} Note that this charge type will almost always produce a credit. The charge is included here for the rare occasion when a charge may be produced as a result of a data error and/or a resettlement.
\[ + \sum_i \sum_l \text{DaImpExp5minQty}_{a, s, lp, i, l} / 12 \]

(b) IF \( \text{DaLossRbtSppHrlyFct}_{h} = 0 \) THEN

\( \text{DaNormLossRbtHrlyFct}_{a, s, lp, h} = 0 \)

ELSE

\( \#\text{DaNormLossRbtHrlyFct}_{a, s, lp, h} = \) \[
\text{Max}(0, \text{DaLossRbtHrlyFct}_{a, s, lp, h}) / \text{DaLossRbtSppHrlyFct}_{h}
\]

(b.1) \( \text{DaLossRbtSppHrlyFct}_{h} = \sum_a \sum_i \sum_l \text{Max}(0, \text{DaLossRbtHrlyFct}_{a, s, lp, h}) \)

(c) \( \#\text{DaLossRbtHrlyFct}_{a, s, lp, h} = [ \text{DaLpIntSupplyHrlyFct}_{lp, h} \]

* ( \( \text{DaMlcHrlyPrc}_{s, h} - \text{DaLpIwaMlcHrlyPrc}_{lp, h} \) )

+ (1 – \( \text{DaLpIntSupplyHrlyFct}_{lp, h} \) )

* ( \( \text{DaMlcHrlyPrc}_{s, h} - \text{DaSppIwaMlcHrlyPrc}_{h} \) ) \]

* \( \text{DaLpNetWdrHrlyQty}_{a, s, lp, h} \)

(c.1) IF \( \text{DaAoNetWdrSppHrlyQty}_{s, h} = 0 \) THEN

\( \text{DaLpNetWdrHrlyQty}_{a, s, lp, h} = 0 \)

ELSE

\( \text{DaLpNetWdrHrlyQty}_{a, s, lp, h} = \text{DaSlNetWdrHrlyQty}_{s, h} \)

* \( \{ \text{DaAoNetWdrHrlyQty}_{a, s, lp, h} / \text{DaAoNetWdrSppHrlyQty}_{s, h} \} \)
(c.2) \( \text{DaAoNetWdrSppHrlyQty}_{s,h} = \sum_{lp} \sum_{a} \text{DaAoNetWdrHrlyQty}_{a,s,lp,h} \)

(c.3) \( \text{DaAoNetWdrHrlyQty}_{a,s,lp,h} = \)

\[
\text{Max} \left( 0, \left( \text{DaClrdHrlyQty}_{a,s,lp,h} - \sum_{t} \text{DaEnFinHrlyQty}_{a,s,lp,h,t} \right) - \sum_{t} \text{DaNEnFinHrlyQty}_{a,s,lp,h,t} + \sum_{i} \sum_{t} \left( \text{DaImpExp5minQty}_{a,s,lp,i,t} / 12 \right) \right) \]

(c.4) \( \text{DaSlNetWdrHrlyQty}_{s,h} = \)

\[
\text{Max} \left( 0, \sum_{a} \sum_{lp} \left( \text{DaClrdHrlyQty}_{a,s,lp,h} + \sum_{t} \text{DaClrdVHrlyQty}_{a,s,lp,h,t} \right) + \sum_{i} \sum_{t} \left( \text{DaImpExp5minQty}_{a,s,lp,i,t} / 12 \right) \right) \]

(d) IF \( \sum_{s} \text{DaLpNetWdrHrlyQty}_{a,s,lp,h} = 0 \)

THEN

\( \text{DaLpNetSupplyHrlyFct}_{lp,h} = 0 \)

ELSE

\( \text{DaLpNetSupplyHrlyFct}_{lp,h} = \)

\[
\text{Min} \left[ 1, \sum_{s} \text{DaLpNetInjHrlyQty}_{a,s,lp,h} / \sum_{s} \text{DaLpNetWdrHrlyQty}_{a,s,lp,h} \right] \]

(d.1) IF \( \text{DaAoNetInjSppHrlyQty}_{s,h} = 0 \)
THEN

\[ \text{DaLpNetInjHrlyQty}_{a, s, lp, h} = 0 \]

ELSE

\[ \text{DaLpNetInjHrlyQty}_{a, s, lp, h} = \text{DaSlNetInjHrlyQty}_{s, h} \]

\[ * \{ \text{DaAoNetInjHrlyQty}_{a, s, lp, h} / \text{DaAoNetInjSppHrlyQty}_{s, h} \} \]

(d.2) \[ \text{DaAoNetInjSppHrlyQty}_{s, h} = \sum_{lp} \sum_{a} \text{DaAoNetInjHrlyQty}_{a, s, lp, h} \]

(d.3) \[ \text{DaAoNetInjHrlyQty}_{a, s, lp, h} = \]

\[ (-1) * \text{Min}(0, (\text{DaClrdHrlyQty}_{a, s, lp, h} - \sum_{t} \text{DaEnFinHrlyQty}_{a, s, lp, h, t} \]

\[ - \sum_{i} \text{DaNEnFinHrlyQty}_{a, s, lp, h, t} \]

\[ + \sum_{i} \sum_{t} (\text{DaImpExp5minQty}_{a, s, lp, i, t} / 12) ) ) \]

(d.4) \[ \text{DaSlNetInjHrlyQty}_{s, h} = \]

\[ \{ \text{Min}(0, \sum_{lp} \sum_{a} \text{DaClrdHrlyQty}_{a, s, lp, h} + \sum_{t} \text{DaClrdVHrlyQty}_{a, s, lp, h, t} \]

\[ + \sum_{i} \sum_{t} (\text{DaImpExp5minQty}_{a, s, lp, i, t} / 12) ) ) \} * (-1) \]

(e) \[ \text{IF} \sum_{s} \text{DaLpNetInjHrlyQty}_{a, s, lp, h} = 0 \]

THEN

\[ \text{DaLpExtSupplyHrlyFct}_{lp, h} = 0 \]
ELSE

\[ \text{DaLpExtSupplyHrlyFct}_{lp, h} = \]

\[ \text{Max} \left[ 0, \left( 1 - \left( \sum_s \text{DaLpNetWdrHrlyQty}_{a, s, lp, h} \right) \right) / \left( \sum_s \text{DaLpNetInjHrlyQty}_{a, s, lp, h} \right) \right] \]

(f) \quad \text{IF} \quad \sum_s \text{DaLpNetInjHrlyQty}_{a, s, lp, h} = 0 \quad \text{THEN}

\[ \text{DaLpIwaMlcHrlyPrc}_{lp, h} = 0 \]

ELSE

\[ \text{DaLpIwaMlcHrlyPrc}_{lp, h} = \]

\[ \sum_s \text{DaLpNetInjHrlyQty}_{a, s, lp, h} \times \text{DaMlcHrlyPrc}_{s, h} / \sum_s \text{DaLpNetInjHrlyQty}_{a, s, lp, h} \]

(g) \quad \text{DaSppIwaMlcHrlyPrc}_{h} = \sum_{lp} \sum_a \left[ \text{DaLpExtSupplyHrlyFct}_{a, lp, h} \times \left( \sum_s \left( \text{DaLpNetInjHrlyQty}_{a, s, lp, h} \times \text{DaMlcHrlyPrc}_{s, h} \right) \right) \right] / \sum_{lp} \sum_a \left[ \text{DaLpExtSupplyHrlyFct}_{a, lp, h} \times \sum_s \text{DaLpNetInjHrlyQty}_{a, s, lp, h} \right] \]
(2) For each Asset Owner, a daily amount is calculated at each Settlement Location. The daily amount is calculated as follows:

\[
DaOclDistDlyAmt_{a,s,lp,d} = \sum_h DaOclDistHrlyAmt_{a,s,lp,h}
\]

(3) For each Asset Owner associated with Market Participant \( m \), a daily amount is calculated. The daily amount is calculated as follows:

\[
DaOclDistAoAmt_{a,m,d} = \sum_s \sum_{lp} DaOclDistDlyAmt_{a,s,lp,d}
\]

(4) For each Market Participant, a daily amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The daily amount is calculated as follows:

\[
DaOclDistMpAmt_{m,d} = \sum_a DaOclDistAoAmt_{a,m,d}
\]
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>DaOclDistHrlyAmt_{a, s, lp, h}</td>
<td>$</td>
<td>Hour</td>
<td>Day-Ahead Over Collected Losses Distribution Amount per AO per Settlement Location per Loss Pool per Hour - The amount to AO $a$ for AO $a$’s share of total over collection due to marginal losses at Settlement Location $s$ in Loss Pool $lp$ for the Hour.</td>
</tr>
<tr>
<td>DaNormLossRbtHrlyFct_{a, s, lp, h}</td>
<td>none</td>
<td>Hour</td>
<td>Day-Ahead Normalized Loss Rebate Factor per AO per Settlement Location per Loss Pool per Hour – AO $a$’s percentage rebate of the DaOclHrlyAmt_{h} at Settlement Location $s$ in Loss Pool $lp$ for the Hour.</td>
</tr>
<tr>
<td>DaLossRbtHrlyFct_{a, s, lp, h}</td>
<td>$</td>
<td>Hour</td>
<td>Day-Ahead Loss Rebate Factor per AO per Settlement Location per Loss Pool per Hour – AO $a$’s amount of marginal loss dollars collected at Settlement Location $s$ in Loss Pool $lp$ for the Hour.</td>
</tr>
<tr>
<td>DaLossRbtSppHrlyFct_{h}</td>
<td>$</td>
<td>Hour</td>
<td>Day-Ahead Loss Rebate Factor per Hour – The SPP total of DaLossRbtHrlyFct_{a, s, lp, h} for the Hour.</td>
</tr>
<tr>
<td>DaAoNetWdrSppHrlyQty_{s, h}</td>
<td>MW</td>
<td>Hour</td>
<td>Day-Ahead Net Withdrawal Quantity per Hour – The SPP total of DaAoNetWdrHrlyQty_{a, s, lp, h} for the Hour.</td>
</tr>
<tr>
<td>DaAoNetInjSppHrlyQty_{s, h}</td>
<td>MW</td>
<td>Hour</td>
<td>Day-Ahead Net Injection Quantity per Hour – The SPP total of DaAoNetInjHrlyQty_{a, s, lp, h} for the Hour.</td>
</tr>
<tr>
<td>DaOclHrlyAmt_{h}</td>
<td>$</td>
<td>Hour</td>
<td>Day-Ahead Over Collected Losses Amount per Hour – The amount of over collection in the DA Market due to marginal losses for the Hour.</td>
</tr>
<tr>
<td>DaLpIntSupplyHrlyFct_{lp, h}</td>
<td>none</td>
<td>Hour</td>
<td>Day-Ahead Loss Pool Internal Supply Factor per Loss Pool per Hour – A ratio indicating the percentage of Loss Pool $lp$’s net withdrawals that are being served by net injections inside of Loss Pool $lp$.</td>
</tr>
<tr>
<td>DaLpExtSupplyHrlyFct_{lp, h}</td>
<td>none</td>
<td>Hour</td>
<td>Day-Ahead Loss Pool External Supply Factor per Loss Pool per Hour – A ratio indicating the percentage of Loss Pool $lp$’s net injections that are in excess of Loss Pool $lp$’s net withdrawals.</td>
</tr>
<tr>
<td>DaLpIwaMlcHrlyPrc_{lp, h}</td>
<td>$/MWh</td>
<td>Hour</td>
<td>Day-Ahead Loss Pool Injection Weighted Average Marginal Loss Component per Loss Pool per Hour - The weighted average DaMlcHrlyPrc_{s, h} for all injections in loss pool $lp$ in Hour $h$.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>----------</td>
<td>------------</td>
<td>---------------------</td>
<td>------------</td>
</tr>
<tr>
<td>DaSppIwaMlcHrlyPrc&lt;sub&gt;h&lt;/sub&gt;</td>
<td>S/MWh</td>
<td>Hour</td>
<td>Day-Ahead SPP Injection Weighted Average Marginal Loss Component per Hour - The weighted average DaMlcHrlyPrc&lt;sub&gt;s, h&lt;/sub&gt; for all loss pool injections in excess of loss pool withdrawals in Hour &lt;i&gt;h&lt;/i&gt;.</td>
</tr>
<tr>
<td>DaLpNetInjHrlyQty&lt;sub&gt;a, s, lp, h&lt;/sub&gt;</td>
<td>MWh</td>
<td>Hour</td>
<td>Day-Ahead Net Injection Quantity per Settlement Location per Loss Pool per Hour – Asset Owner a’s net injection quantity at Settlement Location s in Loss pool lp in Hour &lt;i&gt;h&lt;/i&gt;.</td>
</tr>
<tr>
<td>DaAoNetInjHrlyQty&lt;sub&gt;a, s, lp, h&lt;/sub&gt;</td>
<td>MWh</td>
<td>Hour</td>
<td>Day-Ahead Net Injection Quantity per AO per Settlement Location per Loss Pool per Hour – Asset Owner a’s total injection quantity at Settlement Location s in Loss pool lp in Hour &lt;i&gt;h&lt;/i&gt;.</td>
</tr>
<tr>
<td>DaSlNetInjHrlyQty&lt;sub&gt;s, h&lt;/sub&gt;</td>
<td>MWh</td>
<td>Hour</td>
<td>Day-Ahead Net Injection Quantity per Settlement Location per Hour – Settlement Location s’s net injection quantity in Hour &lt;i&gt;h&lt;/i&gt;.</td>
</tr>
<tr>
<td>DaLpNetWdrHrlyQty&lt;sub&gt;a, s, lp, h&lt;/sub&gt;</td>
<td>MWh</td>
<td>Hour</td>
<td>Day-Ahead Net Withdrawal Quantity per Settlement Location per Loss Pool per Hour – Asset Owner a’s net withdrawal at Settlement Location s in Loss pool lp in Hour &lt;i&gt;h&lt;/i&gt;.</td>
</tr>
<tr>
<td>DaSlNetWdrHrlyQty&lt;sub&gt;s, h&lt;/sub&gt;</td>
<td>MWh</td>
<td>Hour</td>
<td>Day-Ahead Net Withdrawal Quantity per Settlement Location per Hour – Settlement Location s’s net withdrawal quantity for Hour &lt;i&gt;h&lt;/i&gt;.</td>
</tr>
<tr>
<td>DaAoNetWdrHrlyQty&lt;sub&gt;a, s, lp, h&lt;/sub&gt;</td>
<td>MWh</td>
<td>Hour</td>
<td>Day-Ahead Net Withdrawal Quantity per AO per Settlement Location per Loss Pool per Hour – Asset Owner a’s total withdrawal quantity at Settlement Location s in Loss Pool lp for Hour &lt;i&gt;h&lt;/i&gt;.</td>
</tr>
<tr>
<td>DaLmpHrlyPrc&lt;sub&gt;s, h&lt;/sub&gt;</td>
<td>S/MWh</td>
<td>Hour</td>
<td>Day-Ahead LMP – The value described under Section 4.5.8.1 at Settlement Location s for Hour &lt;i&gt;h&lt;/i&gt;.</td>
</tr>
<tr>
<td>DaMccHrlyPrc&lt;sub&gt;s, h&lt;/sub&gt;</td>
<td>SMWh</td>
<td>Hour</td>
<td>Day-Ahead Marginal Congestion Component of Day-Ahead LMP – The value described under Section 4.5.8.15 at Settlement Location s for Hour &lt;i&gt;h&lt;/i&gt;.</td>
</tr>
<tr>
<td>DaMlcHrlyPrc&lt;sub&gt;s, h&lt;/sub&gt;</td>
<td>SMWh</td>
<td>Hour</td>
<td>Day-Ahead Marginal Losses Component of Day-Ahead LMP – The Marginal Losses Component of the Day-Ahead LMP at Settlement Location s for Hour &lt;i&gt;h&lt;/i&gt;.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>----------</td>
<td>------</td>
<td>---------------------</td>
<td>------------</td>
</tr>
<tr>
<td>DaClrdHrlyQty (_{a,s,lp,h})</td>
<td>MWh</td>
<td>Dispatch Interval</td>
<td>Day-Ahead Cleared Energy Quantity per AO per Settlement Location per Loss Pool per Hour in the DA Market – The value described under Section 4.5.8.1 for AO (_a) at Settlement Location (_s) in Loss Pool (_lp) for Hour (_h).</td>
</tr>
<tr>
<td>DaClrdVHrlyQty (_{a,s,lp,h,t})</td>
<td>MWh</td>
<td>Dispatch Interval</td>
<td>Day-Ahead Cleared Virtual Energy Quantity per AO per Settlement Location per Transaction per Loss Pool per Hour in the DA Market – The value described under Section 4.5.8.3 for AO (_a) at Settlement Location (_s) in Loss Pool (_lp) for transaction (_t) for Hour (_h).</td>
</tr>
<tr>
<td>DaImpExp5minQty (_{a,s,lp,i,t})</td>
<td>MWh</td>
<td>Dispatch Interval</td>
<td>Day-Ahead Interchange Transaction Quantity per AO per Settlement Location per Transaction per Loss Pool per Dispatch Interval – The value described under Section 4.5.8.2 for AO (_a) at Settlement Location (_s) in Loss Pool (_lp) for transaction (_t) for Dispatch Interval (_i).</td>
</tr>
<tr>
<td>DaOclDistDlyAmt (_{a,s,lp,d})</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Over Collected Losses Distribution Amount per AO per Settlement Location per Loss Pool per Operating Day – The amount to AO (_a) for AO (_a)’s share of total over collection due to marginal losses at Settlement Location (_s) in Loss Pool (_lp) for the Operating Day.</td>
</tr>
<tr>
<td>DaOclDistAoAmt (_{a,m,d})</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Over Collected Losses Distribution Amount per AO per Operating Day – The amount to AO (_a) associated with Market Participant (_m) for AO (_a)’s share of total over collection due to marginal losses for the Operating Day.</td>
</tr>
<tr>
<td>DaOclDistMpAmt (_{m,d})</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Over Collected Losses Distribution Amount per MP per Operating Day – The amount to MP (_m) for MP (_m)’s share of total over collection due to marginal losses for the Operating Day.</td>
</tr>
</tbody>
</table>

\(a\) none none An Asset Owner.

\(s\) none none A Settlement Location.

\(h\) none none An Hour.

\(i\) none none A Dispatch Interval.
<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>$t$</td>
<td>none</td>
<td>none</td>
<td>A single tagged Interchange Transaction, a single virtual energy transaction, a single Financial Schedule, a single contracted Operating Reserve transaction, a single TCR instrument, a single ARR award or a single Reserve Sharing Event transaction.</td>
</tr>
<tr>
<td>$d$</td>
<td>none</td>
<td>none</td>
<td>An Operating Day.</td>
</tr>
<tr>
<td>$lp$</td>
<td>none</td>
<td>none</td>
<td>A Loss Pool.</td>
</tr>
<tr>
<td>$m$</td>
<td>none</td>
<td>none</td>
<td>A Market Participant.</td>
</tr>
</tbody>
</table>
4.5.8.20  Day-Ahead Virtual Energy Transaction Fee Amount

(1) A DA Market credit\(^{17}\) or charge for each submitted Virtual Energy Offer and Virtual Energy Bid will be calculated for each Asset Owner for each Operating Day. Charges collected by SPP under this charge type are used by SPP to reduce the SPP budgeted expenses used to calculate the rate specified under Schedule 1-A of the SPP Tariff. The amount is calculated as follows:

\[
#\text{DaVTxnFeeAoAmt}_{a, m, d} = \text{DaVTxnDlyCnt}_{a, d} \times \text{DaVTxnFeeDlyRate}_{d}
\]

(2) For each Market Participant, a daily amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The net daily charge or credit is calculated as follows:

\[
\text{DaVTxnFeeMpAmt}_{m, d} = \sum_{a} \text{DaVTxnFeeAoAmt}_{a, m, d}
\]

\(^{17}\) Note that this charge type will almost always produce a charge. The credit is included here for the rare occasion when a credit may be produced as a result of a data error and/or a resettlement.
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>DaVTxnFeeAoAmt_{a, m, d}</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Virtual Energy Transaction Fee Amount per AO per Operating Day - The DA Market amount to AO a associated with Market Participant m for total amount of submitted Virtual Energy Offers and Virtual Energy Bids in Operating Day d.</td>
</tr>
<tr>
<td>DaVTxnDlyCnt_{a, d}</td>
<td>none</td>
<td>Operating Day</td>
<td>Day-Ahead Virtual Energy Transaction Daily Count per AO per Operating Day - The total number of AO a’s submitted Virtual Energy Offers and Virtual Energy Bids in Operating Day d.</td>
</tr>
<tr>
<td>DaVTxnFeeDlyRate_{d}</td>
<td>$/Transaction</td>
<td>Operating Day</td>
<td>Day-Ahead Virtual Energy Transaction Fee Rate per Operating Day - The daily rate applied to DaVTxnDlyCnt_{a, d} in Operating Day d as specified in the SPP Tariff.</td>
</tr>
<tr>
<td>DaVTxnFeeMpAmt_{m, d}</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Virtual Energy Transaction Fee Amount per MP per Operating Day - The DA Market amount to MP m for total amount of submitted Virtual Energy Offers and Virtual Energy Bids in Operating Day d submitted by all AOs associated with Market Participant m.</td>
</tr>
</tbody>
</table>

<p>| | | | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>a</td>
<td>none</td>
<td>none</td>
<td>An Asset Owner.</td>
</tr>
<tr>
<td>d</td>
<td>none</td>
<td>none</td>
<td>An Operating Day.</td>
</tr>
<tr>
<td>m</td>
<td>none</td>
<td>none</td>
<td>A Market Participant.</td>
</tr>
</tbody>
</table>
4.5.9 **Real-Time Balancing Market Settlement**

Settlement calculations for the Real-Time Balancing Market are performed on a Dispatch Interval basis for each Operating Day and are based upon the difference between the results of the RTBM process and the DA Market clearing for that Operating Day. To calculate RTBM actual Energy in a Dispatch Interval for Asset Owners that have not directly submitted 5-minute interval meter data, SPP allocates the submitted hourly meter data for Resources and loads into 5-minute values using 5-minute telemetered or State Estimator profiles for the corresponding hour. The profiling of the hourly meter data maintains the shape of the 5-minute telemetered or State Estimator values even if there are both positive and negative values contained within the 12 intervals. All Dispatch Interval values are expressed in MW, not MWh. Exhibit 4-19 shows an example of how the profiling will work for a Resource that submits an actual hourly meter amount of -80 MWh.

**Exhibit 4-19: Meter Profiling Example**

<table>
<thead>
<tr>
<th>Interval</th>
<th>(1) State Estimator MW</th>
<th>(2) Absolute Value of Column (1)</th>
<th>(3) Normalize Column (2) [Col (2) MW / Total Col (2) MW]</th>
<th>(4) Profiled Hourly Meter (-80 – (-66.25)) * 12 * Col (3) + Col (1)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>10</td>
<td>10</td>
<td>0.012</td>
<td>8</td>
</tr>
<tr>
<td>2</td>
<td>5</td>
<td>5</td>
<td>0.006</td>
<td>4</td>
</tr>
<tr>
<td>3</td>
<td>0</td>
<td>0</td>
<td>0.000</td>
<td>0</td>
</tr>
<tr>
<td>4</td>
<td>-50</td>
<td>50</td>
<td>0.061</td>
<td>-60</td>
</tr>
<tr>
<td>5</td>
<td>-60</td>
<td>60</td>
<td>0.073</td>
<td>-72</td>
</tr>
<tr>
<td>6</td>
<td>-70</td>
<td>70</td>
<td>0.085</td>
<td>-84</td>
</tr>
<tr>
<td>7</td>
<td>-80</td>
<td>80</td>
<td>0.097</td>
<td>-96</td>
</tr>
<tr>
<td>8</td>
<td>-90</td>
<td>90</td>
<td>0.109</td>
<td>-108</td>
</tr>
<tr>
<td>9</td>
<td>-100</td>
<td>100</td>
<td>0.121</td>
<td>-120</td>
</tr>
<tr>
<td>10</td>
<td>-110</td>
<td>110</td>
<td>0.133</td>
<td>-132</td>
</tr>
<tr>
<td>11</td>
<td>-120</td>
<td>120</td>
<td>0.145</td>
<td>-144</td>
</tr>
<tr>
<td>12</td>
<td>-130</td>
<td>130</td>
<td>0.158</td>
<td>-156</td>
</tr>
<tr>
<td></td>
<td>-66.25 MWh</td>
<td>825 (total)</td>
<td>1.000</td>
<td>-80 MWh (Meter) (submitted)</td>
</tr>
</tbody>
</table>

RTBM results are presented on an hourly basis but Market Participants and Asset Owners have access to the 5 minute data for verification purposes.
(1) Each Market Participant with actual Resource output is charged or paid for each Settlement Location for the difference between the amount of actual RTBM physical Energy sold and the amount of physical Energy sold in the DA Market, net of Financial Schedules for Energy, at the associated RTBM LMP (see Section 4.5.9.1);

(2) Each Market Participant with Import Interchange Transactions or Through Interchange Transactions (Resource Node) is charged or paid for each Settlement Location for the difference between the amount of actual RTBM physical import Energy scheduled and the amount of physical Energy sold in the DA Market, net of Financial Schedules for Energy, at the associated RTBM LMP (see Section 4.5.9.2);

(3) Each Market Participant with virtual Energy purchased in the DA Market is paid for the amount of virtual Energy purchased in the DA Market at the associated RTBM LMP (see Section 4.5.9.3);

(4) Each Market Participant with cleared Operating Reserve Offers is charged or paid for each Settlement Location:

   (a) For the difference between the amount of Regulation-Up sold in the RTBM and the amount of Regulation-Up sold in the DA Market at the associated RTBM Regulation-Up MCP (see Section 4.5.9.4);

   (b) For the difference between the amount of Regulation-Down sold in the RTBM and the amount of Regulation-Up sold in the DA Market at the associated RTBM Regulation-Down MCP (see Section 4.5.9.5);

   (c) For the difference between the amount of Spinning Reserve sold in the RTBM and the amount of Regulation-Up sold in the DA Market at the associated RTBM Spinning Reserve MCP (see Section 4.5.9.6); and

   (d) For the difference between the amount of Supplemental Reserve sold in the RTBM and the amount of Regulation-Up sold in the DA Market at the associated RTBM Supplemental Reserve MCP (see Section 4.5.9.7).

(5) Each Market Participant with actual load consumption is charged or paid for each Settlement Location for the difference between the amount of actual physical load purchased and the amount of physical Energy purchased in the DA Market, net of Financial Schedules for Energy, at the associated RTBM LMP (see Section 4.5.9.1);

(6) Each Market Participant with Export Interchange Transactions or Through Interchange Transactions (Load Node) is charged or paid for each Settlement Location for the
difference between the amount of actual physical export Energy scheduled and the amount of physical export Energy purchased in the DA Market, net of Financial Schedules for Energy, at the associated RTBM LMP (see Section 4.5.9.2);

(7) Market Participants with SPP committed Resources in any of the RUC processes that were not committed in the DA Market may receive a make whole-payment if the total revenues received for Energy and Operating Reserve sales in the RTBM settlement are less than the Resource’s Offer costs. See Section 4.5.9.8 for calculation details. Certain costs are not eligible for recovery as follows:

(a) If the Resource operates outside of its Operating Tolerance in a Dispatch Interval, costs associated with Energy provided in excess of the Resource’s Desired Dispatch are not eligible for recovery in that Dispatch Interval;

(b) If Resource is in “Manual” Control Status in a Dispatch Interval, costs associated with Energy provided in excess of the Resource’s Desired Dispatch are not eligible for recovery in that Dispatch Interval; and

(c) If the Resource increases its minimum limits in a Dispatch Interval above the minimum limits used by SPP to make the commitment decision by more than the Resource’s Operating Tolerance, costs associated with Energy provided in excess of the Resource’s Desired Dispatch are not eligible for recovery in that Dispatch Interval.

(8) Make-Whole payments for SPP committed Resources as described in (7) above are collected on a daily basis from Market Participants based upon their pro-rata share of the sum of following quantities for the Operating Day as described in detail under Section 4.5.9.10:

(a) The absolute value of the net Settlement Location deviations from DA Market cleared amounts for load, virtual transactions and interchange transactions;

(b) The positive difference between RTBM Resource minimum limits and DA Market Resource minimum limits, subject to exclusion if certain criteria are met;

(c) The positive difference between the DA Market Resource maximum limits and the RTBM Resource maximum limits, subject to exclusion if certain criteria are met;

(d) A Resource’s DA Market cleared amount if that Resource is off-line in the RTBM, subject to exclusion if certain criteria are met;
(e) The absolute value of the difference between a Resource’s actual output and the Resource’s Desired Dispatch quantity if Resource is in “Manual” Control Status;

(f) The actual Resource output for Resources that self-committed following the close of the DA Market, subject to exclusion if certain criteria are met;

(g) A Resource’s Desired Dispatch quantity for Resources that were committed following the close of the DA Market if that Resource is off-line in the RTBM, subject to exclusion if certain criteria are met; and

(h) The absolute value of a Resource’s Uninstructed Resource Deviation if that Resource operated outside of its Operating Tolerance, subject to exclusion if certain criteria are met.

(9) In addition, Resources may receive a make-whole payment related to a Manual Dispatch Instruction as described under Section 4.5.9.9, subject to certain eligibility requirements, as follows:

(a) If the Resource is issued a Manual Dispatch Instruction by SPP in any hour that creates Out Of Merit Energy (OOME) in excess of the Resource’s Dispatch Instruction and the Resource Offer costs associated with the OOME are greater than the Energy revenue received for the OOME, the Resource will receive the difference between the Energy Offer Curve costs associated with the OOME and the OOME Energy revenue;

(b) If the Manual Dispatch Instruction is for Energy in the down direction and the RTBM LMP is greater than the DA Market LMP, the Asset Owner will receive a credit for the difference multiplied by the OOME MW. The OOME MW is calculated as Max (0, the difference between the Resource’s DA Market cleared Energy MW and actual Resource output); and

(c) If during the Manual Dispatch Instruction, the RTBM cleared amount of an Operating Reserve product is less than the DA Market cleared amount of the corresponding Operating Reserve product and the RTBM MCP is greater than the DA Market MCP, the Asset Owner will receive a credit for the difference multiplied by the OOMOR MW. The OOMOR MW is calculated as Max (0, the difference between the Resource’s DA Market cleared Operating Reserve MW and the Resource’s RTBM cleared Operating Reserve MW).
Make-whole payments associated with OOME are collected as part of revenue neutrality uplift as described under Section 4.5.12.

(10) Charges for failure to deploy Regulation-Up or Regulation-Down and charges for failure to deploy the specified amount of cleared Spinning Reserve or Supplemental Reserve are collected from Market Participants as part of the RTBM settlement as described under Sections 4.5.9.15 and 4.5.9.17 are distributed to Market Participants on a load ratio share basis as described under Sections 4.5.9.16 and 4.5.9.18;

(11) Charges to Market Participants for RTBM Operating Reserve procurement costs are collected on a Real-Time load ratio share basis as described under Sections 4.5.9.11, 4.5.9.12, 4.5.9.13 and 4.5.9.14;

(12) Resources providing Regulation-Up and/or Regulation-Down deployment will receive a credit or charge associated with the regulation deployment energy as described under Section 4.5.9.19 such that Resources maintain Energy margins that are equal to the Energy margins that would have been attained absent the regulation deployment;

(a) For Regulation-Up, a credit is calculated if the cost rate of the Regulation-Up Energy is greater than the associated LMP and a charge is calculated if the associated LMP is greater than the Regulation-Up Energy cost rate;\(^\text{18}\)

(b) For Regulation-Down, a credit is calculated if the associated LMP is greater than the cost rate of the Regulation-Down Energy and a charge is calculated if the cost rate of the Regulation-Down Energy is greater than the associated LMP.\(^\text{19}\)

(13) Settlement associated with revenue mismatch due to the impact of marginal losses on the RTBM LMPs is also performed as part of the RTBM settlement as follows. See Section 4.5.9.20 for calculation details;

(a) For each Asset Owner, a proxy loss charge contribution amount is developed for each Settlement Location with a net RTBM withdrawal (RTBM actual – DA Market cleared amount) that is equal to the positive difference between the MLC at the net withdrawal Settlement Location and the weighted average MLC of all net injections (RTBM actual – DA Market cleared amount) assumed to be serving the net withdrawal, multiplied by that Asset Owner’s share of the net withdrawal,

\(\text{18}\) A charge is calculated here because this difference (opportunity cost) has already been included in the Regulation-Up MCP.

\(\text{19}\) A charge is calculated here because this difference has already been included in the Regulation-Down MCP.
where that share is calculated excluding cleared Virtual Bids and cleared Virtual Offers;

(i) The net injections assumed to be serving the net withdrawal are the net injections at the Settlement Locations included in that Asset Owner’s Loss Pool. The Asset Owner’s Loss Pool is defined dynamically and includes all Settlement Locations at which that Asset Owner has transactional activity (Financial Schedules, Resource output, load consumption, Interchange Transactions), but excludes virtual transactions. To the extent that the net injections in the Asset Owner’s Loss Pool are not sufficient to serve the net withdrawals in the Asset Owner’s Loss Pool, net injections from an injection exchange are included to make up the difference. To the extent that the net injections in the Asset Owner’s Loss Pool are greater than the net withdrawals in the Asset Owner’s Loss Pool, the excess is added to the injection exchange;

(ii) The injection exchange is comprised of quantities from Loss Pools in which injection exceeds withdrawal. A weighted average of the MLC at the source of these quantities establishes a reference for the component of the loss charge contributions at Settlement Locations with net withdrawal met from outside the Asset Owner’s Loss Pool.

(b) Each Asset Owner’s credit or charge (all Asset Owner net withdrawals at Settlement Location participate) associated with RTBM over collected losses (which may be either an over collection or under collection) is then equal a pro-rata share of the total marginal losses over collection or under collection as calculated from the proxy loss charge contribution calculated in (a) above.

(14) Settlement (charges or credits) associated with services provided under Joint Operating Agreements are described under Section 4.5.9.21. These Charges or credits are collected or distributed as part of revenue neutrality uplift as described under Section 4.5.12;

(15) Settlement (charges or credits) associated with Contingency Reserve deployment involving Reserve Sharing Group members is accounted for as described under Section 4.5.9.22. These charges or credits are collected or distributed on a load ratio share as described under Section 4.5.9.23.

The following subsections describe the RTBM settlement charge types in more detail. For each charge type, the initial calculation is performed either at the Dispatch Interval level or hourly
level for each Asset Owner at each Settlement Location. In addition to the Dispatch Interval and hourly values, hourly and daily values will be accessible on the Settlement Statement for all charge types.

4.5.9.1 Real-Time Asset Energy Amount

(1) The Real-Time Asset Energy Amount can be either a credit to an Asset Owner or a charge to an Asset Owner and is calculated on a net basis at each Settlement Location for:

(a) the difference between actual metered supply MWh amounts in a Dispatch Interval and cleared Resource Offers in the DA Market;

(b) the difference between actual metered demand MWh amounts in a Dispatch Interval and all cleared Demand Bids in the DA Market; and

(c) Real-Time Financial Schedules for Energy in a Dispatch Interval.

The net amount to each Asset Owner (AO) for each Settlement Location in a Dispatch Interval is calculated as follows:

\[
#\text{RtEnergy5minAmt}_{a,s,i} = \text{RtLmp5minPre}_{s,i} \times \left[ (\text{RtBillMtr5minQty}_{a,s,i} - \text{DaClrdHrlyQty}_{a,s,h}) - \sum_t \text{RtEnFinHrlyQty}_{a,s,t,h} \right] / 12
\]

Where,

(a) The 5-minute billable meter determinant at the Settlement Location level is the sum of the 5-minute billable meter determinants at the Meter Data Submittal Location level as shown in the formula below. Most Settlement Locations will be comprised of only one Meter Data Submittal Location, but in certain cases a single Settlement Location will represent multiple Meter Data Submittal Locations, each of which is in a separate Settlement Area. Since the calibration function must be performed within Settlement Area boundaries, it is done before summing the data to the Settlement Location level. The 5-minute determinants are expressed in terms of levelized MW at both the Settlement Location and Meter Data Submittal Location level.
(b) The 5-minute billable meter determinant at the Meter Data Submittal Location level is the sum of the 5-minute adjusted meter determinant and the 5-minute calibration meter determinants at the Meter Data Submittal Location level as shown in the formula below. Both 5-minute determinants are expressed in terms of levelized MW.

\[ \text{RtBillMtr5minQty}_{a,s,i} = \sum_{ml} \text{RtMlBillMtr5minQty}_{a,ml,i} \]

(c) For Resource and load assets, the 5-minute adjusted meter determinant is a hierarchal selection among 1) 5-minute submitted actual meter reading, 2) profiled hourly submitted actual meter reading and 3) default 5-minute state estimator value. Registration will determine whether 5-minute or hourly meter submittals are permitted – it will not allow both for any given period. Under the Marginal Loss approach, it is assumed that meter submissions, with the exception of those with a “top-down load” relationship to the Settlement Area – generally those for which a top-down calculation is used – are net of transmission losses. Losses will be backed out of load submittals for the “top-down load”. For Demand Response Resources, the hierarchy is the same for submitted data, but instead of defaulting to the State Estimator data, the Resource output is calculated as the difference between a) the minimum of i) the hourly baseline load submitted for the Demand Response Load and ii) the State Estimator snapshot for the Demand Response Load for the 5 minute interval immediately preceding the first dispatch interval (i = -1) and b) the Adjusted Meter Quantity for the DRL for each 5 minute interval. Registration will determine whether meter submittals are permitted or if the Demand Response resource must rely solely on the calculated resource output. For loads in which a Demand Response resource is imbedded within a Settlement Location, the response is added to the load meter data “grossing-up” the MW to avoid double counting of the response. In cases where load is calculated via a “top-down load” method (usually for the top-down load entity in the Settlement Area), gross-up is not necessary if the response is included with other generation from which interchange, metered load and losses
are netted to achieve the submitted load. 5-minute adjusted meter, state estimator, SCADA and gross-up determinants are expressed in terms of levelized MW and both hourly and 5-minute submitted actual determinants are in terms of MWh. The formula for the 5-minute adjusted meter determinant is shown below.

IF EXISTS { RtActMtr5minQty a, ml, i } THEN

\[
#RtAdjMtr5minQty a, ml, i =
\]

\[
RtActMtr5minQty a, ml, i * 12 + RtLoadGrossUp5minQty a, ml, i
\]

- {IF TOPDOWNLOAD(ml) THEN RtSELoss5minQty sa, i , ELSE 0 }

ELSE

IF EXISTS { RtActMtrHrlyQty a, ml, h } THEN

\[
#RtAdjMtr5minQty a, ml, i = RtSE5minQty a, ml, i
\]

+ { ( RtActMtrHrlyQty a, ml, h - \sum_{i} \text{RtSE5minQty } a, ml, i / 12) 

* [ \text{ABS} ( \text{RtSE5minQty } a, ml, i ) / \sum_{i} \text{ABS} ( \text{RtSE5minQty } a, ml, i ) ] * 12 }

+ RtLoadGrossUp5minQty a, ml, i

- { IF TOPDOWNLOAD(ml) THEN RtSELoss5minQty sa, i , ELSE 0 }

ELSE

IF { DRR } THEN

\[
#RtAdjMtr5minQty a, ml, i =
\]

\[
[ ( \text{MIN} ( \text{RtBaseLineHrlyQty } a, ml(drl), h , \text{RtSE5minQty } a, ml(drl), i = -1 ) 

- RtAdjMtr5minQty a, ml(drl), i ] ) * (-1)
\]

ELSE
\[ \#RtAdjMtr5minQty_{a, ml, i} = \]
\[ RtSE5minQty_{a, ml, i} + RtLoadGrossUp5minQty_{a, ml, i} \]

(d) The 5-minute load gross-up determinant is the inverse of the 5-minute adjusted meter determinant for the Demand Response resource which is behind the meter of the load. The 5-minute load gross-up determinant is expressed in terms of levelized MW. The formula for the 5-minute load gross-up determinant is shown below.

\[ \sum_{ml(drr)} \right( \frac{RtAdjMtr5minQty_{a, ml(drr), i}}{-1} \) * (-1) \]

(e) The 5-minute calibration meter determinant is the hourly quantity, profiled by State Estimator data into 5-minute intervals as shown in the formula below. The 5-minute calibration meter determinant is expressed in terms of levelized MW. The formula for the 5-minute calibration meter determinant is shown below.

\[ \#RtCalMtr5minQty_{a, ml, i} = RtSE5minQty_{a, ml, i} \]

\[ + \left\{ \left( RtCalMtrHrlyQty_{a, ml, h} - \sum_{i} \frac{RtSE5minQty_{a, ml, i}}{12} \right) \right\} \]

\[ * \left[ \frac{ABS(RtSE5minQty_{a, ml, i})}{\sum_{i} \ ABS(RtSE5minQty_{a, ml, i})} \right] * 12 \}

(f) The hourly calibration meter determinant is the weighted distribution of Settlement Area residual among load in the Settlement Area. The hourly calibration meter determinant is expressed in terms of levelized MW. The formula for the hourly calibration meter determinant is shown below.

\[ \#RtCalMtrHrlyQty_{a, ml, h} = RtResMtrHrlyQty_{sa, h} \]

\[ * \left[ \frac{MAX \left( RtAdjMtrHrlyQty_{a, ml, h}, 0 \right)}{12} \right] \]
The hourly adjusted meter determinant is the sum of the 5-minute adjusted meter determinant divided by 12. The hourly adjusted meter determinant is expressed in terms of levelized MW. The formula for the hourly adjusted meter determinant is shown below.

\[
\text{RtAdjMtrHrlyQty}_{a, ml, h} = \sum_{i} \frac{\text{RtAdjMtr5minQty}_{a, ml, i}}{12}
\]

The hourly residual load determinant is the net difference between generation & load, interchange and losses per Settlement Area. Hourly Net Actual Interchange is derived as the sum of the hourly metering submitted for aggregate ties between interconnected Settlement Areas. Missing tie values are assumed to be 0. The hourly residual determinant is expressed in terms of levelized MW. The formula for the hourly residual load determinant is shown below.

\[
\text{RtResMtrHrlyQty}_{sa, h} = \left( \sum_{ml} \text{RtAdjMtrHrlyQty}_{a, ml, h} + \text{RtSaNetActIchngHrlyQty}_{sa, h} + \sum_{i} \frac{\text{RtSELoss5minQty}_{sa, i}}{12} \right) \times (-1)
\]

(2) For each Asset Owner, an hourly amount is calculated at each Settlement Location. The amount is calculated as follows:

\[
\text{RtEnergyHrlyAmt}_{a, s, h} = \sum_{i} \text{RtEnergy5minAmt}_{a, s, i}
\]

(3) For each Asset Owner, a daily amount is calculated at each Settlement Location. The amount is calculated as follows:

\[
\text{RtEnergyDlyAmt}_{a, s, d} = \sum_{h} \text{RtEnergyHrlyAmt}_{a, s, h}
\]

(4) For each Asset Owner associated with Market Participant \( m \), a daily amount is calculated. The daily amount is calculated as follows:
\( \text{RtEnergyAoAmt}_{a,m,d} = \sum_{s} \text{RtEnergyDlyAmt}_{a,s,d} \)

(5) For each Market Participant, a daily amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The daily amount is calculated as follows:

\( \text{RtEnergyMpAmt}_{m,d} = \sum_{a} \text{RtEnergyAoAmt}_{a,m,d} \)

(6) For FERC Electric Quarterly Reporting (EQR) purposes, SPP calculates net hourly sales volume in excess of DA Market amounts and associated prices and calculates net hourly purchases when Real-Time sales volume less than DA Market sales volume and associated prices that are associated with this Charge Type for each Asset Owner as follows:

(a) \( \text{EqrRtAssetEnergy5minQty}_{a,s,i} = \)

\[
\text{Max} \left( 0, -1 \times \left[ (\text{RtBillMtr5minQty}_{a,s,i} - \text{DaClrdHrlyQty}_{a,s,h}) - \sum_{t} \text{RtEnFinHrlyQty}_{a,s,t,h} \right] / 12 \right)
\]

+ \{ \text{IF} \ EqrDaAssetEnergyHrlyQty_{a,s,h} > 0 \text{ THEN} \]

\[
\text{Min} \left( 0, -1 \times \left[ (\text{RtBillMtr5minQty}_{a,s,i} - \text{DaClrdHrlyQty}_{a,s,h}) - \sum_{t} \text{RtEnFinHrlyQty}_{a,s,t,h} \right] / 12 \right) \}
\]

(b) IF \( \text{EqrRtAssetEnergy5minQty}_{a,s,i} < > 0 \)

THEN

\( \text{EqrRtAssetEnergy5minPrc}_{a,s,i} = \text{RtLmp5minPrc}_{s,i} \)
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>( \text{RtEnergy5minAmt}_{a,s,i} )</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time Energy Amount per AO per Settlement Location per Dispatch Interval - The amount to AO ( a ) for deviations between Real-Time actual Energy amounts and net cleared energy offers and bids at Settlement Location ( s ) for the Dispatch Interval.</td>
</tr>
<tr>
<td>( \text{RtLmp5minPrc}_{s,i} )</td>
<td>$/MW</td>
<td>Dispatch Interval</td>
<td>Real-Time LMP - The RTBM LMP at Settlement Location ( s ) for Dispatch Interval ( i ).</td>
</tr>
<tr>
<td>( \text{DaClrdHrlyQty}_{a,s,h} )</td>
<td>MWh</td>
<td>Hour</td>
<td>Day-Ahead Cleared Energy Quantity per AO per Settlement Location per Hour in the DA Market – The value described under Section 4.5.8.1.</td>
</tr>
<tr>
<td>( \text{RtBillMtr5minQty}_{a,s,i} )</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Billing Meter Quantity per AO per Settlement Location per Dispatch Interval - The Dispatch Interval metered quantities for AO ( a ) Resources and load at Settlement Location ( s ) in Dispatch Interval ( i ) used by SPP for settlement purposes.</td>
</tr>
<tr>
<td>( \text{RtActMtr5minQty}_{a,ml,i} )</td>
<td>MWh</td>
<td>Dispatch Interval</td>
<td>Real-Time Actual Meter Quantity per AO per Meter Data Submittal Location per Dispatch Interval - The Dispatch Interval metered quantity, in MWh, for AO ( a )'s Resources and load directly submitted by the Market Participant.</td>
</tr>
<tr>
<td>( \text{RtActMtrHrlyQty}_{a,ml,h} )</td>
<td>MWh</td>
<td>Hour</td>
<td>Real-Time Actual Meter Quantity per AO per Meter Data Submittal Location per Hour - The hourly metered quantity, in MWh, for AO ( a )'s Resources and load directly submitted by the Market Participant.</td>
</tr>
<tr>
<td>( \text{RtMlBillMtr5minQty}_{a,ml,i} )</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Billing Meter Quantity per AO per Meter Data Submittal Location per Dispatch Interval - The Dispatch Interval ( \text{RtAdjMtr5minQty}_{a,ml,i} ) quantities adjusted to account for calibration Energy for AO ( a ) load at Meter Data ( ml ) in Dispatch Interval ( i ).</td>
</tr>
<tr>
<td>( \text{RtCalMtr5minQty}_{a,ml,i} )</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Calibration Meter Quantity per AO per Meter Data Submittal Location per Dispatch Interval - The Dispatch Interval calibration quantities calculated by SPP for AO ( a ) at load at Meter Data.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>-----------------------------------------------</td>
<td>--------------</td>
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<td>---------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>RtCalMtrHrlyQty&lt;sub&gt;a, ml, h&lt;/sub&gt;</td>
<td>MWh</td>
<td>Hour</td>
<td>Real-Time Calibration Meter Quantity per AO per Meter Settlement Location per Hour - The Dispatch Interval calibration energy quantities calculated by SPP for AO &lt;i&gt;a&lt;/i&gt; at load at Meter Data Submittal Location &lt;i&gt;ml&lt;/i&gt; in Hour &lt;i&gt;h&lt;/i&gt;.</td>
</tr>
<tr>
<td>RtLoadGrossUp5minQty&lt;sub&gt;a, ml, i&lt;/sub&gt;</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Load Gross Up per AO per Meter Settlement Location per Dispatch Interval - The Dispatch Interval load gross up associated with a Demand Response Reserve for AO &lt;i&gt;a&lt;/i&gt; at load Meter Data Submittal Location &lt;i&gt;ml&lt;/i&gt; in Dispatch Interval &lt;i&gt;i&lt;/i&gt;.</td>
</tr>
<tr>
<td>RtSE5minQty&lt;sub&gt;a, ml, i&lt;/sub&gt;</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time State Estimator Quantity per AO per Meter Data Submittal Location per Dispatch Interval - The Dispatch Interval State Estimator value for AO &lt;i&gt;a&lt;/i&gt; at Meter Data Submittal Location &lt;i&gt;ml&lt;/i&gt; in Dispatch Interval &lt;i&gt;i&lt;/i&gt;.</td>
</tr>
<tr>
<td>RtBaseLineHrlyQty&lt;sub&gt;a, ml(drl), h&lt;/sub&gt;</td>
<td>MWh</td>
<td>Hour</td>
<td>Real-Time Base Line Load Quantity per AO per Demand Response Load Meter Data Submittal Location per Hour – The estimated consumption value associated with AO &lt;i&gt;a&lt;/i&gt;’s Demand Response Load as submitted prior to Operating Hour &lt;i&gt;h&lt;/i&gt;.</td>
</tr>
<tr>
<td>RtSELoss5minQty&lt;sub&gt;sa, i&lt;/sub&gt;</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time State Estimator Losses per AO per Settlement Area per Dispatch Interval - The Dispatch Interval State Estimator total losses value for Settlement Area &lt;i&gt;sa&lt;/i&gt; in Dispatch Interval &lt;i&gt;i&lt;/i&gt;.</td>
</tr>
<tr>
<td>RtResMtrHrlyQty&lt;sub&gt;sa, h&lt;/sub&gt;</td>
<td>MWh</td>
<td>Hour</td>
<td>Real-Time Residual Load per Settlement Area per Hour - The hourly Residual Load for Settlement Area &lt;i&gt;sa&lt;/i&gt; in Hour &lt;i&gt;h&lt;/i&gt;.</td>
</tr>
<tr>
<td>RtSaNetActIchngHrlyQty&lt;sub&gt;sa, h&lt;/sub&gt;</td>
<td>MWh</td>
<td>Hour</td>
<td>Real-Time Net Actual Interchange per Settlement Area per Hour - The sum of hourly actual interchange values submitted for Settlement Area &lt;i&gt;sa&lt;/i&gt; in Hour &lt;i&gt;h&lt;/i&gt;.</td>
</tr>
<tr>
<td>RtAdjMtr5minQty&lt;sub&gt;a, ml, i&lt;/sub&gt;</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Adjusted Actual Meter Quantity per AO per Meter Data Submittal Location per Dispatch Interval - The Dispatch Interval metered quantity, in MW, for AO &lt;i&gt;a&lt;/i&gt;’s Resources and load calculated by SPP to account for load adjustments related to Demand Response</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>----------</td>
<td>------</td>
<td>---------------------</td>
<td>------------</td>
</tr>
<tr>
<td>RtAdjMtrHrlyQty_{a,m,h}</td>
<td>MWh</td>
<td>Hour</td>
<td>Real-Time Adjusted Actual Meter Quantity per AO per Meter Data Submittal Location per Hour - The hourly metered quantity, in MWh, for AO a’s Resources and load calculated by SPP to account for load adjustments related to Demand Response Resources and to calculate a default value if RtActMtrHrlyQty_{a,m,h} or RtActMtr5minQty_{a,m,i} is not submitted.</td>
</tr>
<tr>
<td>RtEnFinHrlyQty_{a,s,t,h}</td>
<td>MWh</td>
<td>Hour</td>
<td>Real-Time Asset Financial Schedule for Energy per AO per Settlement Location per Transaction per Hour - The amount specified by the buyer AO and seller AO in a RTBM Financial Schedule for Energy at Asset Settlement Location s, for transaction t, for the Hour. The buyer AO amount is a positive value and the seller AO amount is a negative value.</td>
</tr>
<tr>
<td>RtEnergyHrlyAmt_{a,s,h}</td>
<td>$</td>
<td>Hour</td>
<td>Real-Time Energy Amount per AO per Settlement Location per Hour - The amount to AO a for deviations between Real-Time actual Energy amounts and net cleared energy offers and bids at Settlement Location s for the Hour.</td>
</tr>
<tr>
<td>RtEnergyDlyAmt_{a,s,d}</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Energy Amount per AO per Settlement Location per Operating Day - The amount to AO a for deviations between Real-Time actual Energy amounts and net cleared energy offers and bids at Settlement Location s for the Operating Day.</td>
</tr>
<tr>
<td>RtEnergyAoAmt_{a,m,d}</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Energy Amount per AO per Operating Day - The amount to AO a associated with Market Participant m for deviations between Real-Time actual Energy amounts and net cleared energy offers and bids for the Operating Day.</td>
</tr>
<tr>
<td>RtEnergyMpAmt_{m,d}</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Energy Amount per MP per Operating Day - The amount to MP m for deviations between Real-Time actual Energy amounts and net cleared energy offers and bids for the Operating Day.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>----------</td>
<td>------</td>
<td>---------------------</td>
<td>------------</td>
</tr>
<tr>
<td>EqrRtAssetEnergy5minQty (_{a, s, i})</td>
<td>MWh</td>
<td>Dispatch Interval</td>
<td>Real-Time Electric Quarterly Reporting net Asset Energy Transactions per AO per Settlement Location per Dispatch Interval—AO (a)’s RTBM Energy sale at Resource Settlement Location (s) in excess of the amount cleared Day-Ahead, net of Financial Schedules, in Dispatch Interval (i) or AO (a)’s RTBM Energy purchase at Resource Settlement Location (s) created when the actual Real-Time output is less than the amount cleared Day-Ahead, net of Financial Schedules, in Dispatch Interval (i), for use by AO (a) in reporting such sales/purchases to FERC in accordance with FERC EQR requirements.</td>
</tr>
<tr>
<td>EqrRtAssetEnergy5minPre (_{a, s, i})</td>
<td>$/MWh</td>
<td>Dispatch Interval</td>
<td>Real-Time Electric Quarterly Reporting net Asset Energy Transactions Prices per AO per Settlement Location per Hour – AO (a)’s prices associated with non-zero EqrRtAssetEnergy5minQty (_{a, s, i}) quantities in Dispatch Interval (i) for use by AO (a) in reporting such sales to FERC in accordance with FERC EQR requirements.</td>
</tr>
<tr>
<td>(a)</td>
<td>none</td>
<td>none</td>
<td>An Asset Owner.</td>
</tr>
<tr>
<td>(h)</td>
<td>none</td>
<td>none</td>
<td>An Hour.</td>
</tr>
<tr>
<td>(i)</td>
<td>none</td>
<td>none</td>
<td>A Dispatch Interval.</td>
</tr>
<tr>
<td>(s)</td>
<td>none</td>
<td>none</td>
<td>A Settlement Location.</td>
</tr>
<tr>
<td>(t)</td>
<td>none</td>
<td>none</td>
<td>A single tagged Interchange Transaction, a single virtual energy transaction, a single Financial Schedule, a single contracted Operating Reserve transaction, a single TCR instrument, a single ARR award or a single Reserve Sharing Event transaction.</td>
</tr>
<tr>
<td>ml(drr)</td>
<td>none</td>
<td>none</td>
<td>A Demand Response Resource Meter Data Submittal Location.</td>
</tr>
<tr>
<td>ml(drl)</td>
<td>none</td>
<td>none</td>
<td>A Demand Response Load Meter Data Submittal Location.</td>
</tr>
<tr>
<td>sa</td>
<td>none</td>
<td>none</td>
<td>A Settlement Area.</td>
</tr>
<tr>
<td>ml</td>
<td>none</td>
<td>none</td>
<td>A Meter Data Submittal Location.</td>
</tr>
<tr>
<td>(d)</td>
<td>none</td>
<td>none</td>
<td>An Operating Day.</td>
</tr>
<tr>
<td>(m)</td>
<td>none</td>
<td>none</td>
<td>A Market Participant.</td>
</tr>
</tbody>
</table>
4.5.9.2 Real-Time Non-Asset Energy Amount

(1) The Real-Time Non-Asset Energy Amount can be either a credit to an Asset Owner or a charge to an Asset Owner and is calculated on a net basis at each Settlement Location for:

(a) The difference between actual scheduled Import Interchange Transactions in a Dispatch Interval and cleared Import Interchange Transactions in the DA Market;

(b) The difference between actual scheduled Export Interchange Transactions in a Dispatch Interval and cleared Export Interchange Transactions in the DA Market;

(c) The difference between actual scheduled Through Interchange Transactions in a Dispatch Interval and cleared Through Interchange Transactions in the DA Market;

and

(d) Real-Time Financial Schedules for Energy in a Dispatch Interval.

The net amount to each Asset Owner (AO) for each Settlement Location in a Dispatch Interval is calculated as follows:

\[
\#RtNEnergy5minAmt_{a,s,i} = \text{RtLmp5minPrc}_{s,i} \times \left[ \sum_t \text{RtImpExp5minQty}_{a,s,i,t} - \sum_t \text{DaImpExp5minQty}_{a,s,i,t} - \sum_t \text{RtNEnFinHrlyQty}_{a,s,h,t} \right] / 12
\]

(2) For each Asset Owner, an hourly amount is calculated at each Settlement Location. The amount is calculated as follows:

\[
\text{RtNEnergyHrlyAmt}_{a,s,h} = \sum_i \text{RtNEnergy5minAmt}_{a,s,i}
\]

(3) For each Asset Owner, a daily amount is calculated at each Settlement Location. The amount is calculated as follows:

\[
\text{RtNEnergyDlyAmt}_{a,s,d} = \sum_h \text{RtNEnergyHrlyAmt}_{a,s,h}
\]
(4) For each Asset Owner associated with Market Participant \( m \), a daily amount is calculated. The daily amount is calculated as follows:

\[
RtNEnergyAoAmt_{a, m, d} = \sum_s RtNEnergyDlyAmt_{a, s, d}
\]

(5) For each Market Participant, a daily amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The daily amount is calculated as follows:

\[
RtNEnergyMpAmt_{m, d} = \sum_a RtNEnergyAoAmt_{a, m, d}
\]

(6) For FERC Electric Quarterly Reporting (EQR) purposes, SPP calculates net hourly sales volume in excess of DA Market amounts and associated prices and calculates net hourly purchases when Real-Time sales volume less than DA Market sales volume and associated prices that are associated with this Charge Type for each Asset Owner as follows:

(a) \( EqrRtNAssetEnergy5minQty_{a, s, i} = \)

\[
\text{Max} \left( 0, -1 \times \left[ \sum_t \text{RtImpExp5minQty}_{a, s, i, t} - \sum_t \text{DaImpExp5minQty}_{a, s, i, t} \right] / 12 \right)
\]

\[
+ \left\{ \begin{array}{l}
\text{IF } EqrDaNAssetEnergyHrlyQty_{a, s, h} > 0 \text{ THEN} \\
\text{Min} \left( 0, -1 \times \left[ \sum_t \text{RtImpExp5minQty}_{a, s, i, t} - \sum_t \text{DaImpExp5minQty}_{a, s, i, t} \right] - \sum_t \text{RtNEnFinHrlyQty}_{a, s, h, t} \right] / 12 \end{array} \right\}
\]

(b) \( \text{IF } EqrRtNAssetEnergy5minQty_{a, s, i} < 0 \text{ THEN} \)

\[
EqrRtNAssetEnergy5minPrc_{a, s, i} = \text{RtLmp5minPrc}_{s, i}
\]
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>RtNEnergy5minAmt (_{a,s,i})</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time Non-Asset Energy Amount per AO per Settlement Location per Dispatch Interval - The amount to AO (_a) for deviations between RTBM scheduled Interchange Transaction quantities and DA Market cleared Interchange Transactions, net of Financial Schedules at Settlement Location (_s) for the Dispatch Interval.</td>
</tr>
<tr>
<td>RtLmp5minPrc (_{s,i})</td>
<td>$/MW</td>
<td>Dispatch Interval</td>
<td>Real-Time LMP - The RTBM LMP at Settlement Location (_s) for Dispatch Interval (_i).</td>
</tr>
<tr>
<td>DaImpExp5minQty (_{a,s,i,t})</td>
<td>MWh</td>
<td>Dispatch Interval</td>
<td>Day-Ahead Interchange Transaction Quantity per AO per Settlement Location per Dispatch Interval – The value described under Section 4.5.8.2.</td>
</tr>
<tr>
<td>RtNEnFinHrlyQty (_{a,s,h,t})</td>
<td>MWh</td>
<td>Hour</td>
<td>Real-Time Non-Asset Financial Schedule for Energy per AO per Settlement Location per Transaction per Hour - The quantity specified by the buyer AO and seller AO in a RTBM Financial Schedule for Energy at Non-Asset Settlement Location (_s), for transaction (_t), for the Hour. The buyer AO amount is a positive value and the seller AO amount is a negative value.</td>
</tr>
<tr>
<td>RtImpExp5minQty (_{a,s,i,t})</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Interchange Transaction Quantity per AO per Settlement Location per Dispatch Interval - The total net quantity of energy represented by AO (_a)’s actual Interchange Transactions in the RTBM at Settlement Location (_s), for each tagged transaction (_t), for the Hour. The Dispatch Interval value of the transaction will be equal to the scheduled MW within the scheduled start-time and stop-time of the transaction. Transaction ramping will be ignored.</td>
</tr>
<tr>
<td>RtNEnergyHrlyAmt (_{a,s,h})</td>
<td>$</td>
<td>Hour</td>
<td>Real-Time Non-Asset Energy Amount per AO per Settlement Location per Hour - The amount to AO (_a) for deviations between RTBM scheduled Interchange Transaction quantities and DA Market cleared Interchange Transactions, net of Financial Schedules at Settlement Location (_s) for the Hour.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>----------</td>
<td>------</td>
<td>---------------------</td>
<td>------------</td>
</tr>
<tr>
<td>RtNEnergyDlyAmt (a, s, d)</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Non-Asset Energy Amount per AO per Settlement Location per Operating Day - The amount to AO (a) for deviations between RTBM scheduled Interchange Transaction quantities and DA Market cleared Interchange Transactions, net of Financial Schedules at Settlement Location (s) for the Operating Day.</td>
</tr>
<tr>
<td>RtNEnergyAoAmt (a, m, d)</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Non-Asset Energy Amount per AO per Operating Day - The amount to AO (a) for deviations between RTBM scheduled Interchange Transaction quantities and DA Market cleared Interchange Transactions, net of Financial Schedules for the Operating Day.</td>
</tr>
<tr>
<td>RtNEnergyMpAmt (m, d)</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Non-Asset Energy Amount per MP per Operating Day - The amount to MP (m) for deviations between RTBM scheduled Interchange Transaction quantities and DA Market cleared Interchange Transactions, net of Financial Schedules for the Operating Day.</td>
</tr>
<tr>
<td>EqrRtNAmtEnergy5minQty (a, s, i)</td>
<td>MWh</td>
<td>Dispatch Interval</td>
<td>Real-Time Electric Quarterly Reporting net Non-Asset Energy Transactions per AO per Settlement Location per Dispatch Interval – AO (a)’s RTBM Energy sale at External Interface Settlement Location (s) in excess of the amount cleared Day-Ahead, net of Financial Schedules, in Dispatch Interval (i) or AO (a)’s RTBM Energy purchase at External Interface Settlement Location (s) created when the actual Real-Time schedule is less than the amount cleared Day-Ahead, net of Financial Schedules, in Dispatch Interval (i), for use by AO (a) in reporting such sales/purchases to FERC in accordance with FERC EQR requirements.</td>
</tr>
<tr>
<td>EqrRtNAmtEnergy5minPrc (a, s, i)</td>
<td>$/MWh</td>
<td>Dispatch Interval</td>
<td>Real-Time Electric Quarterly Reporting net Non-Asset Energy Transactions Prices per AO per Settlement Location per Hour – AO (a)’s prices associated with non-zero (EqrRtNAmtEnergy5minQty a, s, i) quantities in Dispatch Interval (i) for use by AO (a) in reporting such sales to FERC in accordance with FERC EQR requirements.</td>
</tr>
</tbody>
</table>

\(a\) none none An Asset Owner.  
\(h\) none none An Hour.
<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>$i$</td>
<td>none</td>
<td>none</td>
<td>A Dispatch Interval.</td>
</tr>
<tr>
<td>$s$</td>
<td>none</td>
<td>none</td>
<td>A Settlement Location.</td>
</tr>
<tr>
<td>$t$</td>
<td>none</td>
<td>none</td>
<td>A single tagged Interchange Transaction, a single virtual energy transaction, a single Financial Schedule, a single contracted Operating Reserve transaction, a single TCR instrument, a single ARR award or a single Reserve Sharing Event transaction.</td>
</tr>
<tr>
<td>$d$</td>
<td>none</td>
<td>none</td>
<td>An Operating Day.</td>
</tr>
<tr>
<td>$m$</td>
<td>none</td>
<td>none</td>
<td>A Market Participant.</td>
</tr>
</tbody>
</table>
4.5.9.3 Real-Time Virtual Energy Amount

(a) The Real-Time Virtual Energy Amount can be either a credit to charge to an Asset Owner and is calculated on an Asset Owner net virtual transaction basis at each Settlement Location for all cleared Virtual Energy Offers and all cleared Virtual Energy Bids in the DA Market. Cleared Virtual Energy Offers and cleared Virtual Energy Bids in the DA Market create deviations in the RTBM that are equal to the negative of the cleared DA Market amounts. The net amount to each Asset Owner (AO) for each Settlement Location for a Dispatch Interval is calculated as follows:

\[
\text{#RtVEnergy5minAmt}_{a, s, i} = (\text{RtLmp5minPrc}_{s, i} \times (\sum_{t} \text{DaClrdVHrlyQty}_{a, s, h, t} /12 )) \times (-1)
\]

(b) For each Asset Owner, an hourly amount is calculated at each Settlement Location. The amount is calculated as follows:

\[
\text{RtVEnergyHrlyAmt}_{a, s, h} = \sum_{i} \text{RtVEnergy5minAmt}_{a, s, i}
\]

(c) For each Asset Owner, a daily amount is calculated at each Settlement Location. The amount is calculated as follows:

\[
\text{RtVEnergyDlyAmt}_{a, s, d} = \sum_{h} \text{RtVEnergyHrlyAmt}_{a, s, h}
\]

(d) For each Asset Owner associated with Market Participant \( m \), a daily amount is calculated. The daily amount is calculated as follows:

\[
\text{RtVEnergyAoAmt}_{a, m, d} = \sum_{s} \text{RtVEnergyDlyAmt}_{a, s, d}
\]

(e) For each Market Participant, a daily amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The daily amount is calculated as follows:

\[
\text{RtVEnergyMpAmt}_{m, d} = \sum_{a} \text{RtVEnergyAoAmt}_{a, m, d}
\]
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>$RtVEnergySminAmt_{a,s,i}$</td>
<td>$$/Hour</td>
<td>Hour</td>
<td><em>Real-Time Virtual Energy Amount per AO per Settlement Location per Dispatch Interval</em> - The amount to AO $a$ for DA Market cleared Virtual Energy Offers and Virtual Energy Bids at Settlement Location $s$ for each transaction for the Dispatch Interval.</td>
</tr>
<tr>
<td>$RtLmpSminPrc_{s,i}$</td>
<td>$$/MWh</td>
<td>Hour</td>
<td><em>Real-Time LMP</em> - The value defined under Section 4.5.9.1 at Settlement Location $s$ for Dispatch Interval $i$.</td>
</tr>
<tr>
<td>$DaClrdVHrlyQty_{a,s,h,t}$</td>
<td>MWh</td>
<td>Hour</td>
<td><em>Day-Ahead Cleared Virtual Energy Quantity per AO per Settlement Location per Hour in the DA Market</em> – The value described under Section 4.5.8.3.</td>
</tr>
<tr>
<td>$RtVEnergyHrlyAmt_{a,s,h}$</td>
<td>$$/Hour</td>
<td>Hour</td>
<td><em>Real-Time Virtual Energy Amount per AO per Settlement Location per Hour</em> - The amount to AO $a$ for DA Market cleared Virtual Energy Offers and Virtual Energy Bids at Settlement Location $s$ for the Hour.</td>
</tr>
<tr>
<td>$RtVEnergyDlyAmt_{a,s,d}$</td>
<td>$$/Operating Day</td>
<td>Operating Day</td>
<td><em>Real-Time Virtual Energy Amount per AO per Settlement Location per Operating Day</em> - The amount to AO $a$ for DA Market cleared Virtual Energy Offers and Virtual Energy Bids at Settlement Location $s$ for the Operating Day.</td>
</tr>
<tr>
<td>$RtVEnergyAoAmt_{a,m,d}$</td>
<td>$$/Operating Day</td>
<td>Operating Day</td>
<td><em>Real-Time Virtual Energy Amount per AO per Operating Day</em> - The amount to AO $a$ associated with Market Participant $m$ for DA Market cleared Virtual Energy Offers and Virtual Energy Bids for the Operating Day.</td>
</tr>
<tr>
<td>$RtVEnergyMpAmt_{m,d}$</td>
<td>$$/Operating Day</td>
<td>Operating Day</td>
<td><em>Real-Time Virtual Energy Amount per MP per Operating Day</em> - The amount to MP $m$ for DA Market cleared Virtual Energy Offers and Virtual Energy Bids for the Operating Day.</td>
</tr>
</tbody>
</table>

$a$ none none An Asset Owner.
$s$ none none A Settlement Location.
$h$ none none An Hour.
$i$ none none A Dispatch Interval.
<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>$t$</td>
<td>none</td>
<td>none</td>
<td>A single tagged Interchange Transaction, a single virtual energy transaction, a single Financial Schedule, a single contracted Operating Reserve transaction, a single TCR instrument, a single ARR award or a single Reserve Sharing Event transaction.</td>
</tr>
<tr>
<td>$d$</td>
<td>none</td>
<td>none</td>
<td>An Operating Day.</td>
</tr>
<tr>
<td>$m$</td>
<td>none</td>
<td>none</td>
<td>A Market Participant.</td>
</tr>
</tbody>
</table>
4.5.9.4 Real-Time Regulation-Up Amount

(1) A RTBM charge or credit for deviations between cleared RTBM Regulation-Up and cleared DA Market Regulation-Up will be calculated at each Settlement Location for each Asset Owner for each Dispatch Interval. The amount will be calculated as follows:

\[ \#RtRegUp5minAmt_{a,s,i} = (RtRegUpMcp5minPrc_{z,s,i} \times (RtRegUp5minQty_{a,s,i} - DaRegUpHrlyQty_{a,s,h}) / 12) \times (-1) \]

(2) For each Asset Owner, an hourly amount is calculated at each Settlement Location. The amount is calculated as follows:

\[ RtRegUpHrlyAmt_{a,s,h} = \sum_{i} RtRegUp5minAmt_{a,s,i} \]

(3) For each Asset Owner, a daily amount is calculated at each Settlement Location. The amount is calculated as follows:

\[ RtRegUpDlyAmt_{a,s,d} = \sum_{h} RtRegUpHrlyAmt_{a,s,h} \]

(4) For each Asset Owner associated with Market Participant \( m \), a daily amount is calculated. The daily amount is calculated as follows:

\[ RtRegUpAoAmt_{a,m,d} = \sum_{s} RtRegUpDlyAmt_{a,s,d} \]

(5) For each Market Participant, a daily amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The daily amount is calculated as follows:

\[ RtRegUpMpAmt_{m,d} = \sum_{a} RtRegUpAoAmt_{a,m,d} \]

(6) For FERC Electric Quarterly Reporting (EQR) purposes, SPP calculates net hourly sales volume in excess of DA Market amounts and associated prices and calculates net hourly purchases when Real-Time sales volume less than DA Market sales volume and associated prices that are associated with this Charge Type for each Asset Owner as follows:
(a) \[ \text{EqrRtRegUp5minQty}_{a,s,i} = \]
\[ \text{Max} \left( 0, \frac{(\text{RtRegUp5minQty}_{a,s,i} - \text{DaRegUpHrlyQty}_{a,s,h})}{12} \right) \]
\[ + \]
\[ \text{IF EqrDaRegUpHrlyQty}_{a,s,h} > 0 \text{ THEN} \]
\[ \text{Min} \left( 0, \frac{(\text{RtRegUp5minQty}_{a,s,i} - \text{DaRegUpHrlyQty}_{a,s,h})}{12} \right) \}

(b) IF EqrRtRegUp5minQty \_ {a,s,i} \_ <> 0

THEN

\[ \text{EqrRtRegUp5minPrc}_{a,s,i} = \text{RtRegUpMcp5minPrc}_{z,s,i} \]
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>RtRegUp5minAmt&lt;sub&gt;a, s, i&lt;/sub&gt;</td>
<td>$</td>
<td>Dispatch Interval</td>
<td><em>Real-Time Regulation-Up Amount per AO per Resource Settlement Location per Dispatch Interval</em> - The amount to AO a for deviations between cleared RTBM and DA Market Regulation-Up Offers at Resource Settlement Location s for the Dispatch Interval.</td>
</tr>
<tr>
<td>RtRegUpMcp5minPre&lt;sub&gt;z, s, i&lt;/sub&gt;</td>
<td>$/MW</td>
<td>Dispatch Interval</td>
<td><em>Real-Time MCP for Regulation-Up per Reserve Zone</em> - The RTBM MCP for Regulation-Up for the Reserve Zone that includes Resource Settlement Location s for Dispatch Interval i.</td>
</tr>
<tr>
<td>RtRegUp5minQty&lt;sub&gt;a, s, i&lt;/sub&gt;</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td><em>Real-Time Cleared Regulation-Up Quantity per AO per Settlement Location per Dispatch Interval</em> - The total amount of Regulation-Up MW represented by AO a’s cleared Regulation-Up Offers in the RTBM at Resource Settlement Location s, for Dispatch Interval i.</td>
</tr>
<tr>
<td>RtRegUpHrlyAmt&lt;sub&gt;a, s, h&lt;/sub&gt;</td>
<td>$</td>
<td>Hour</td>
<td><em>Real-Time Regulation-Up Amount per AO per Settlement Location per Hour</em> - The amount to AO a for deviations between cleared RTBM and DA Market Regulation-Up Offers at Resource Settlement Location s for the Hour.</td>
</tr>
<tr>
<td>RtRegUpDlyAmt&lt;sub&gt;a, s, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td><em>Real-Time Regulation-Up Amount per AO per Settlement Location per Operating Day</em> - The amount to AO a for deviations between cleared RTBM and DA Market Regulation-Up Offers at Resource Settlement Location s for the Operating Day.</td>
</tr>
<tr>
<td>RtRegUpAoAmt&lt;sub&gt;a, m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td><em>Real-Time Regulation-Up Amount per AO per Operating Day</em> - The amount to AO a associated with Market Participant m for deviations between cleared RTBM and DA Market Regulation-Up Offers for the Operating Day.</td>
</tr>
<tr>
<td>RtRegUpMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td><em>Real-Time Regulation-Up Amount per MP per Operating Day</em> - The amount to MP m for deviations between cleared RTBM and DA Market Regulation-Up Offers for the Operating Day.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>--------------------------</td>
<td>--------</td>
<td>---------------------</td>
<td>------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>EqrRtRegUp5minQty (a, s, i)</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Electric Quarterly Reporting net Regulation-Up Transactions per AO per Settlement Location per Dispatch Interval— AO a’s RTBM Regulation-Up sale at Resource Settlement Location s in excess of the amount cleared Day-Ahead in Dispatch Interval i or AO a’s RTBM Regulation-Up purchase at Resource Settlement Location s created when the cleared Real-Time Regulation-Up is less than the amount cleared Day-Ahead in Dispatch Interval i, for use by AO a in reporting such sales/purchases to FERC in accordance with FERC EQR requirements.</td>
</tr>
<tr>
<td>EqrRtRegUp5minPrc (a, s, i)</td>
<td>S/MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Electric Quarterly Reporting net Regulation Up Transactions Prices per AO per Settlement Location per Hour – AO a’s prices associated with non-zero EqrRtRegUp5minQty (a, s, i) quantities in Dispatch Interval i for use by AO a in reporting such sales to FERC in accordance with FERC EQR requirements.</td>
</tr>
</tbody>
</table>

\(a\) none none An Asset Owner.

\(s\) none none A Resource Settlement Location.

\(h\) none none An Hour.

\(i\) none none A Dispatch Interval.

\(d\) none none An Operating Day.

\(z\) none none A Reserve Zone.

\(m\) none none A Market Participant.
4.5.9.5  Real-Time Regulation-Down Amount

(1) A RTBM charge or credit for deviations between cleared RTBM Regulation-Down and cleared DA Market Regulation-Down will be calculated at each Settlement Location for each Asset Owner for each Dispatch Interval. The amount will be calculated as follows:

\[
#RtRegDn5minAmt_{a, s, i} = (RtRegDnMcp5minPrc_{z, s, i} \times (RtRegDn5minQty_{a, s, i} - DaRegDnHrlyQty_{a, s, h}) / 12) \times (-1)
\]

(2) For each Asset Owner, an hourly amount is calculated at each Settlement Location. The amount is calculated as follows:

\[
RtRegDnHrlyAmt_{a, s, h} = \sum_i RtRegDn5minAmt_{a, s, i}
\]

(3) For each Asset Owner, a daily amount is calculated at each Settlement Location. The amount is calculated as follows:

\[
RtRegDnDlyAmt_{a, s, d} = \sum_h RtRegDnHrlyAmt_{a, s, h}
\]

(4) For each Asset Owner associated with Market Participant \(m\), a daily amount is calculated. The daily amount is calculated as follows:

\[
RtRegDnAoAmt_{a, m, d} = \sum_s RtRegDnDlyAmt_{a, s, d}
\]

(5) For each Market Participant, a daily amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The daily amount is calculated as follows:

\[
RtRegDnMpAmt_{m, d} = \sum_a RtRegDnAoAmt_{a, m, d}
\]

(6) For FERC Electric Quarterly Reporting (EQR) purposes, SPP calculates net hourly sales volume in excess of DA Market amounts and associated prices and calculates net hourly purchases when Real-Time sales volume less than DA Market sales volume and associated prices that are associated with this Charge Type for each Asset Owner as follows:
(a) \( \text{EqrRtRegDn5minQty}_{a,s,i} = \)

\[
\text{Max} \left( 0, \left( \text{RtRegDn5minQty}_{a,s,i} - \text{DaRegDnHrlyQty}_{a,s,h} \right) / 12 \right)
\]

\[
+ \{ \text{IF} \ \text{EqrDaRegDnHrlyQty}_{a,s,h} > 0 \ \text{THEN} \]

\[
\text{Min} \left( 0, \left( \text{RtRegDn5minQty}_{a,s,i} - \text{DaRegDnHrlyQty}_{a,s,h} \right) / 12 \right) \}
\]

(b) \( \text{IF} \ \text{EqrRtRegDn5minQty}_{a,s,i} <> 0 \)

\( \text{THEN} \)

\[
\text{EqrRtRegDn5minPrc}_{a,s,i} = \text{RtRegDnMcp5minPrc}_{z,s,i}
\]
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>( \text{RtRegDn5minAmt}_{a,s,i} )</td>
<td>( $/\text{Dispatch Interval} )</td>
<td>( \text{Settlement Location per Dispatch Interval} )</td>
<td>( \text{Real-Time Regulation-Down Amount per AO per Resource Settlement Location per Dispatch Interval} ) - The amount to AO ( a ) for deviations between cleared RTBM and DA Market Regulation-Down Offers at Resource Settlement Location ( s ) for the Dispatch Interval.</td>
</tr>
<tr>
<td>( \text{RtRegDnMcp5minPre}_{z,s,i} )</td>
<td>( $/\text{MW} )</td>
<td>( \text{Dispatch Interval} )</td>
<td>( \text{Real-Time MCP for Regulation-Down per Reserve Zone} ) - The RTBM MCP for Regulation-Down for the Reserve Zone that includes Resource Settlement Location ( s ) for Dispatch Interval ( i ).</td>
</tr>
<tr>
<td>( \text{RtRegDn5minQty}_{a,s,i} )</td>
<td>( \text{MW} )</td>
<td>( \text{Dispatch Interval} )</td>
<td>( \text{Real-Time Cleared Regulation-Down Quantity per AO per Settlement Location per Dispatch Interval} ) - The total amount of Regulation-Down represented by AO ( a )'s cleared Regulation-Down Offers in the RTBM at Resource Settlement Location ( s ), for Dispatch Interval ( i ).</td>
</tr>
<tr>
<td>( \text{RtRegDnHrlyAmt}_{a,s,h} )</td>
<td>( $/\text{Hour} )</td>
<td>( \text{Hour} )</td>
<td>( \text{Real-Time Regulation-Down Amount per AO per Settlement Location per Hour} ) - The amount to AO ( a ) for deviations between cleared RTBM and DA Market Regulation-Down Offers at Resource Settlement Location ( s ) for the Hour.</td>
</tr>
<tr>
<td>( \text{RtRegDnDlyAmt}_{a,s,d} )</td>
<td>( $/\text{Operating Day} )</td>
<td>( \text{Operating Day} )</td>
<td>( \text{Real-Time Regulation-Down Amount per AO per Settlement Location per Operating Day} ) - The amount to AO ( a ) for deviations between cleared RTBM and DA Market Regulation-Down Offers at Resource Settlement Location ( s ) for the Operating Day.</td>
</tr>
<tr>
<td>( \text{RtRegDnAoAmt}_{a,m,d} )</td>
<td>( $/\text{Operating Day} )</td>
<td>( \text{Operating Day} )</td>
<td>( \text{Real-Time Regulation-Down Amount per AO per Operating Day} ) - The amount to AO ( a ) associated with Market Participant ( m ) for deviations between cleared RTBM and DA Market Regulation-Down Offers for the Operating Day.</td>
</tr>
<tr>
<td>( \text{RtRegDnMpAmt}_{m,d} )</td>
<td>( $/\text{Operating Day} )</td>
<td>( \text{Operating Day} )</td>
<td>( \text{Real-Time Regulation-Down Amount per MP per Operating Day} ) - The amount to MP ( m ) for deviations between cleared RTBM and DA Market Regulation-Down Offers for the Operating Day.</td>
</tr>
</tbody>
</table>
### Table: Real-Time Electric Quarterly Reporting net Regulation-Down Transactions per AO per Settlement Location per Dispatch Interval

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>EqrRtRegDn5minQty (_a, s, i)</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td><em>Real-Time Electric Quarterly Reporting net Regulation-Down Transactions per AO per Settlement Location per Dispatch Interval</em> – AO (a)’s RTBM Regulation-Down sale at Resource Settlement Location (s) in excess of the amount cleared Day-Ahead in Dispatch Interval (i) or AO (a)’s RTBM Regulation-Down purchase at Resource Settlement Location (s) created when the cleared Real-Time Regulation-Down is less than the amount cleared Day-Ahead in Dispatch Interval (i), for use by AO (a) in reporting such sales/purchases to FERC in accordance with FERC EQR requirements.</td>
</tr>
<tr>
<td>EqrRtRegDn5minPrc (_a, s, i)</td>
<td>$/MW</td>
<td>Dispatch Interval</td>
<td><em>Real-Time Electric Quarterly Reporting net Regulation-Down Transactions Prices per AO per Settlement Location per Hour</em> – AO (a)’s prices associated with non-zero (EqrRtRegDn5minQty_{a, s, i}), quantities in Dispatch Interval (i) for use by AO (a) in reporting such sales to FERC in accordance with FERC EQR requirements.</td>
</tr>
</tbody>
</table>

\(a\) none none An Asset Owner.  
\(s\) none none A Resource Settlement Location.  
\(h\) none none An Hour.  
\(i\) none none A Dispatch Interval.  
\(d\) none none An Operating Day.  
\(z\) none none A Reserve Zone.  
\(m\) none none A Market Participant.
4.5.9.6 Real-Time Spinning Reserve Amount

(1) A RTBM charge or credit for deviations between cleared RTBM Spinning Reserve and cleared DA Market Spinning Reserve will be calculated at each Settlement Location for each Asset Owner for each Dispatch Interval. The amount will be calculated as follows:

\[
#\text{RtSpin5minAmt}_{a,s,i} = (\text{RtSpinMcp5minPrc}_{z,s,i} \times (\text{RtSpin5minQty}_{a,s,i} - \text{DaSpinHrlyQty}_{a,s,h}) / 12) \times (-1)
\]

(2) For each Asset Owner, an hourly amount is calculated at each Settlement Location. The amount is calculated as follows:

\[
\text{RtSpinHrlyAmt}_{a,s,h} = \sum_i \text{RtSpin5minAmt}_{a,s,i}
\]

(3) For each Asset Owner, a daily amount is calculated at each Settlement Location. The amount is calculated as follows:

\[
\text{RtSpinDlyAmt}_{a,s,d} = \sum_h \text{RtSpinHrlyAmt}_{a,s,h}
\]

(4) For each Asset Owner associated with Market Participant \(m\), a daily amount is calculated. The daily amount is calculated as follows:

\[
\text{RtSpinAoAmt}_{a,m,d} = \sum_s \text{RtSpinDlyAmt}_{a,s,d}
\]

(5) For each Market Participant, a daily amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The daily amount is calculated as follows:

\[
\text{RtSpinMpAmt}_{m,d} = \sum_a \text{RtSpinAoAmt}_{a,m,d}
\]

(6) For FERC Electric Quarterly Reporting (EQR) purposes, SPP calculates net hourly sales volume in excess of DA Market amounts and associated prices and calculates net hourly purchases when Real-Time sales volume less than DA Market sales volume and associated prices that are associated with this Charge Type for each Asset Owner as follows:
(a) \( EqrRtSpin5minQty_{a,s,i} = \)

\[
\text{Max} \left( 0, \frac{(RtSpin5\text{minQty}_{a,s,i} - DaSpin\text{hrlyQty}_{a,s,h})}{12} \right) + \\
\{ \text{IF} \ EqrDaSpin\text{hrlyQty}_{a,s,h} > 0 \text{ THEN} \\
\text{Min} \left( 0, \frac{(RtSpin5\text{minQty}_{a,s,i} - DaSpin\text{hrlyQty}_{a,s,h})}{12} \right) \}
\]

(b) \( \text{IF} \ EqrRtSpin5\text{minQty}_{a,s,I} <> 0 \)

\( \text{THEN} \)

\( EqrRtSpin5\text{minPrc}_{a,s,i} = RtSpin\text{Mcp5minPrc}_{z,s,i} \)
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>RtSpin5minAmt_{a, s, i}</td>
<td>$</td>
<td>Dispatch Interval</td>
<td><strong>Real-Time Spinning Reserve Amount per AO per Resource Settlement Location per Dispatch Interval</strong> - The amount to AO $a$ for deviations between cleared RTBM and DA Market Spinning Reserve Offers at Resource Settlement Location $s$ for the Dispatch Interval.</td>
</tr>
<tr>
<td>RtSpinMcp5minPrc_{z, s, i}</td>
<td>$/MWh</td>
<td>Dispatch Interval</td>
<td><strong>Real-Time MCP for Spinning Reserve</strong> - The RTBM MCP for Spinning Reserve for the Reserve Zone that includes Resource Settlement Location $s$ for Dispatch Interval $i$.</td>
</tr>
<tr>
<td>RtSpin5minQty_{a, s, i}</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td><strong>Real-Time Cleared Spinning Reserve Quantity per AO per Settlement Location per Dispatch Interval</strong> - The total amount of Spinning Reserve represented by AO $a$’s cleared Spinning Reserve Offers in the RTBM at Resource Settlement Location $s$, for Dispatch Interval $i$.</td>
</tr>
<tr>
<td>RtSpinHrlyAmt_{a, s, h}</td>
<td>$</td>
<td>Hour</td>
<td><strong>Real-Time Spinning Reserve Amount per AO per Settlement Location per Hour</strong> - The amount to AO $a$ for deviations between cleared RTBM and DA Market Spinning Reserve Offers at Resource Settlement Location $s$ for the Hour.</td>
</tr>
<tr>
<td>RtSpinDlyAmt_{a, s, d}</td>
<td>$</td>
<td>Operating Day</td>
<td><strong>Real-Time Spinning Reserve Amount per AO per Settlement Location per Operating Day</strong> - The amount to AO $a$ for deviations between cleared RTBM and DA Market Spinning Reserve Offers at Resource Settlement Location $s$ for the Operating Day.</td>
</tr>
<tr>
<td>RtSpinAoAmt_{a, m, d}</td>
<td>$</td>
<td>Operating Day</td>
<td><strong>Real-Time Spinning Reserve Amount per AO per Operating Day</strong> - The amount to AO $a$ associated with Market Participant $m$ for deviations between cleared RTBM and DA Market Spinning Reserve Offers for the Operating Day.</td>
</tr>
<tr>
<td>RtSpinMpAmt_{m, d}</td>
<td>$</td>
<td>Operating Day</td>
<td><strong>Real-Time Spinning Reserve Amount per MP per Operating Day</strong> - The amount to MP $m$ for deviations between cleared RTBM and DA Market Spinning Reserve Offers for the Operating Day.</td>
</tr>
</tbody>
</table>
### EqrRtSpin5minQty \(_{a,s,i}\)

**Unit:** MW  
**Settlement Interval:** Dispatch Interval  
**Definition:** Real-Time Electric Quarterly Reporting net Spinning Reserve Transactions per AO per Settlement Location per Dispatch Interval—AO \(a\)'s RTBM Spinning Reserve sale at Resource Settlement Location \(s\) in excess of the amount cleared Day-Ahead in Dispatch Interval \(i\) or AO \(a\)'s RTBM Spinning Reserve purchase at Resource Settlement Location \(s\) created when the cleared Real-Time Spinning Reserve is less than the amount cleared Day-Ahead in Dispatch Interval \(i\), for use by AO \(a\) in reporting such sales/purchases to FERC in accordance with FERC EQR requirements.

### EqrRtSpin5minPrc \(_{a,s,i}\)

**Unit:** S/MW  
**Settlement Interval:** Dispatch Interval  
**Definition:** Real-Time Electric Quarterly Reporting net Spinning Reserve Transactions Prices per AO per Settlement Location per Hour—AO \(a\)'s prices associated with non-zero EqrRtSpin5minQty \(_{a,s,i}\) quantities in Dispatch Interval \(i\) for use by AO \(a\) in reporting such sales to FERC in accordance with FERC EQR requirements.

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>EqrRtSpin5minQty (_{a,s,i})</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Electric Quarterly Reporting net Spinning Reserve Transactions per AO per Settlement Location per Dispatch Interval—AO (a)'s RTBM Spinning Reserve sale at Resource Settlement Location (s) in excess of the amount cleared Day-Ahead in Dispatch Interval (i) or AO (a)'s RTBM Spinning Reserve purchase at Resource Settlement Location (s) created when the cleared Real-Time Spinning Reserve is less than the amount cleared Day-Ahead in Dispatch Interval (i), for use by AO (a) in reporting such sales/purchases to FERC in accordance with FERC EQR requirements.</td>
</tr>
<tr>
<td>EqrRtSpin5minPrc (_{a,s,i})</td>
<td>S/MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Electric Quarterly Reporting net Spinning Reserve Transactions Prices per AO per Settlement Location per Hour—AO (a)'s prices associated with non-zero EqrRtSpin5minQty (_{a,s,i}) quantities in Dispatch Interval (i) for use by AO (a) in reporting such sales to FERC in accordance with FERC EQR requirements.</td>
</tr>
<tr>
<td>(a)</td>
<td>none</td>
<td>none</td>
<td>An Asset Owner.</td>
</tr>
<tr>
<td>(s)</td>
<td>none</td>
<td>none</td>
<td>A Resource Settlement Location.</td>
</tr>
<tr>
<td>(h)</td>
<td>none</td>
<td>none</td>
<td>An Hour.</td>
</tr>
<tr>
<td>(i)</td>
<td>none</td>
<td>none</td>
<td>A Dispatch Interval.</td>
</tr>
<tr>
<td>(d)</td>
<td>none</td>
<td>none</td>
<td>An Operating Day.</td>
</tr>
<tr>
<td>(z)</td>
<td>none</td>
<td>none</td>
<td>A Reserve Zone.</td>
</tr>
<tr>
<td>(m)</td>
<td>none</td>
<td>none</td>
<td>A Market Participant.</td>
</tr>
</tbody>
</table>
4.5.9.7 Real-Time Supplemental Reserve Amount

(1) A RTBM charge or credit for deviations between cleared RTBM Supplemental Reserve and cleared DA Market Supplemental Reserve will be calculated at each Settlement Location for each Asset Owner for each Dispatch Interval. The amount will be calculated as follows:

\[
\text{#RtSupp5minAmt}_{a,s,i} = (\text{RtSuppMcp5minPrc}_{a,s,i} \times (\text{RtSupp5minQty}_{a,s,i} - \text{DaSuppHrlyQty}_{a,s,h}) / 12 ) \times (-1)
\]

(2) For each Asset Owner, an hourly amount is calculated at each Settlement Location. The amount is calculated as follows:

\[
\text{RtSuppHrlyAmt}_{a,s,h} = \sum_{i} \text{RtSupp5minAmt}_{a,s,i}
\]

(3) For each Asset Owner, a daily amount is calculated at each Settlement Location. The amount is calculated as follows:

\[
\text{RtSuppDlyAmt}_{a,s,d} = \sum_{h} \text{RtSuppHrlyAmt}_{a,s,h}
\]

(4) For each Asset Owner associated with Market Participant \( m \), a daily amount is calculated. The daily amount is calculated as follows:

\[
\text{RtSuppAoAmt}_{a,m,d} = \sum_{s} \text{RtSuppDlyAmt}_{a,s,d}
\]

(5) For each Market Participant, a daily amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The daily amount is calculated as follows:

\[
\text{RtSuppMpAmt}_{m,d} = \sum_{a} \text{RtSuppAoAmt}_{a,m,d}
\]
(6) For FERC Electric Quarterly Reporting (EQR) purposes, SPP calculates net hourly sales volume in excess of DA Market amounts and associated prices and calculates net hourly purchases when Real-Time sales volume less than DA Market sales volume and associated prices that are associated with this Charge Type for each Asset Owner as follows:

(a) \[ EqrRtSupp5minQty_{a,s,i} = \]
\[ \text{Max} \left( 0, \left( \text{RtSupp5minQty}_{a,s,i} - \text{DaSuppHrlyQty}_{a,s,h} \right) / 12 \right) \]
\[ + \]
\[ \{ \text{IF } EqrDaSuppHrlyQty_{a,s,h} > 0 \text{ THEN} \]
\[ \text{Min} \left( 0, \left( \text{RtSupp5minQty}_{a,s,i} - \text{DaSuppHrlyQty}_{a,s,h} \right) / 12 \right) \} \]

(b) \[ \text{IF } EqrRtSupp5minQty_{a,s,i} < 0 \]
\[ \text{THEN} \]
\[ EqrRtSupp5minPrc_{a,s,i} = \text{RtSuppMcp5minPrc}_{a,s,i} \]
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>RtSupp5minAmt&lt;sub&gt;a, s, i&lt;/sub&gt;</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time Supplemental Reserve Amount per AO per Resource Settlement Location per Dispatch Interval - The amount to AO &lt;i&gt;a&lt;/i&gt; for deviations between cleared RTBM and DA Market Supplemental Reserve Offers at Resource Settlement Location &lt;i&gt;s&lt;/i&gt; for the Dispatch Interval.</td>
</tr>
<tr>
<td>RtSuppMcp5minPre&lt;sub&gt;z, s, i&lt;/sub&gt;</td>
<td>$/MWh</td>
<td>Dispatch Interval</td>
<td>Real-Time MCP for Supplemental Reserve - The RTBM MCP for Supplemental Reserve for the Reserve Zone that includes Resource Settlement Location &lt;i&gt;s&lt;/i&gt; for Dispatch Interval &lt;i&gt;i&lt;/i&gt;.</td>
</tr>
<tr>
<td>RtSupp5minQty&lt;sub&gt;a, s, i&lt;/sub&gt;</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Cleared Supplemental Reserve Quantity per AO per Settlement Location per Dispatch Interval - The total amount of Supplemental Reserve represented by AO &lt;i&gt;a&lt;/i&gt;’s cleared Supplemental Reserve Offers in the RTBM at Resource Settlement Location &lt;i&gt;s&lt;/i&gt;, for Dispatch Interval &lt;i&gt;i&lt;/i&gt;.</td>
</tr>
<tr>
<td>RtSuppHrlyAmt&lt;sub&gt;a, s, h&lt;/sub&gt;</td>
<td>$</td>
<td>Hour</td>
<td>Real-Time Supplemental Reserve Amount per AO per Settlement Location per Hour - The amount to AO &lt;i&gt;a&lt;/i&gt; for deviations between cleared RTBM and DA Market Supplemental Reserve Offers at Resource Settlement Location &lt;i&gt;s&lt;/i&gt; for the Hour.</td>
</tr>
<tr>
<td>RtSuppDlyAmt&lt;sub&gt;a, s, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Supplemental Reserve Amount per AO per Settlement Location per Operating Day - The amount to AO &lt;i&gt;a&lt;/i&gt; for deviations between cleared RTBM and DA Market Supplemental Reserve Offers at Resource Settlement Location &lt;i&gt;s&lt;/i&gt; for the Operating Day.</td>
</tr>
<tr>
<td>RtSuppAoAmt&lt;sub&gt;a, m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Supplemental Reserve Amount per AO per Operating Day - The amount to AO &lt;i&gt;a&lt;/i&gt; associated with Market Participant &lt;i&gt;m&lt;/i&gt; for deviations between cleared RTBM and DA Market Supplemental Reserve Offers for the Operating Day.</td>
</tr>
<tr>
<td>RtSuppMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Supplemental Reserve Amount per MP per Operating Day - The amount to MP &lt;i&gt;m&lt;/i&gt; for deviations between cleared RTBM and DA Market Supplemental Reserve Offers for the Operating Day.</td>
</tr>
</tbody>
</table>
### Variable: EqrRtSupp5minQty \(_{a,s,i}\)  
- **Unit:** MW  
- **Settlement Interval:** Dispatch Interval  
- **Definition:** Real-Time Electric Quarterly Reporting net Supplemental Reserve Transactions per AO per Settlement Location per Dispatch Interval—AO \(a\)'s RTBM Supplemental Reserve sale at Resource Settlement Location \(s\) in excess of the amount cleared Day-Ahead in Dispatch Interval \(i\) or AO \(a\)'s RTBM Supplemental Reserve purchase at Resource Settlement Location \(s\) created when the cleared Real-Time Supplemental Reserve is less than the amount cleared Day-Ahead in Dispatch Interval \(i\), for use by AO \(a\) in reporting such sales/purchases to FERC in accordance with FERC EQR requirements.

### Variable: EqrRtSupp5minPrc \(_{a,s,i}\)  
- **Unit:** $/MW  
- **Settlement Interval:** Dispatch Interval  
- **Definition:** Real-Time Electric Quarterly Reporting net Supplemental Reserve Transactions Prices per AO per Settlement Location per Hour—AO \(a\)'s prices associated with non-zero \(EqrRtSupp5minQty\) \(_{a,s,i}\) quantities in Dispatch Interval \(i\) for use by AO \(a\) in reporting such sales to FERC in accordance with FERC EQR requirements.

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>(EqrRtSupp5minQty) (_{a,s,i})</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Electric Quarterly Reporting net Supplemental Reserve Transactions per AO per Settlement Location per Dispatch Interval—AO (a)'s RTBM Supplemental Reserve sale at Resource Settlement Location (s) in excess of the amount cleared Day-Ahead in Dispatch Interval (i) or AO (a)'s RTBM Supplemental Reserve purchase at Resource Settlement Location (s) created when the cleared Real-Time Supplemental Reserve is less than the amount cleared Day-Ahead in Dispatch Interval (i), for use by AO (a) in reporting such sales/purchases to FERC in accordance with FERC EQR requirements.</td>
</tr>
<tr>
<td>(EqrRtSupp5minPrc) (_{a,s,i})</td>
<td>$/MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Electric Quarterly Reporting net Supplemental Reserve Transactions Prices per AO per Settlement Location per Hour—AO (a)'s prices associated with non-zero (EqrRtSupp5minQty) (_{a,s,i}) quantities in Dispatch Interval (i) for use by AO (a) in reporting such sales to FERC in accordance with FERC EQR requirements.</td>
</tr>
</tbody>
</table>

\(a\): An Asset Owner.  
\(s\): A Resource Settlement Location.  
\(h\): An Hour.  
\(i\): A Dispatch Interval.  
\(d\): An Operating Day.  
\(z\): A Reserve Zone.  
\(m\): A Market Participant.
4.5.9.8 RUC Make-Whole-Payment Amount

(1) The RUC Make-Whole-Payment Amount is a credit or charge to a Resource Asset Owner and is calculated for each Resource with a RUC Commitment Period. A payment is made to the Resource Asset Owner when the sum of the Resource’s eligible RTBM Start-Up Offer costs, No-Load Offer costs, Energy Offer Curve and Operating Reserve Offer costs associated with actual MWh amounts for Energy and cleared RTBM Operating Reserve is greater than the Energy and Operating Reserve RTBM revenues received for that Resource over the Resource’s RUC Make-Whole-Payment Eligibility Period.

(2) A Resource’s RUC Make-Whole-Payment Eligibility Period is equal to the Resource’s RUC Commitment Period except as described below:

(a) As shown in Exhibit 4-20, for Resources with a RUC Commitment Period that begins in one Operating Day and ends in the next Operating Day, two RUC Make-Whole-Payment Eligibility Periods are created. The first period begins in the first Operating Day in the Dispatch Interval associated with the Resource’s RUC Commit Time and ends at the last Dispatch Interval of the first Operating Day. The second period begins in the first Dispatch Interval of the next Operating Day and ends in the Dispatch Interval associated with the Resource’s RUC De-Commit Time.

Note that this charge type will almost always produce a credit. The charge is included here for the rare occasion when a charge may be produced as a result of a data error and/or a resettlement.
Exhibit 4-20: RUC Make-Whole Payment Eligibility Period – Multiple Operating Days

(3) The following cost recovery eligible rules apply to each RUC Make-Whole-Payment Eligibility Period. Offer costs are calculated using the RTBM Offer prices in effect at the time the commitment decision was made.

(a) If SPP cancels a start-up order prior to the start of the associated RUC Make-Whole-Payment Eligibility Period and the Resource is not a Synchronized Resource, the Asset Owner will receive reimbursement for a time-based pro-rata share of the Resource’s RTBM Start-Up Offer. Asset Owners may request additional compensation through submittal of actual cost documentation to the SPP. SPP will review the submitted documentation and confirm that the submitted information is sufficient to document actual costs and that all or a portion of the actual costs are eligible for recovery.

(b) In order to receive Start-Up Offer recovery within a RUC Make-Whole-Payment Eligibility Period, the Resource must be a Synchronized Resource for at least one Dispatch Interval in the RUC Make-Whole Payment Eligibility Period.

(c) In order to receive recovery of No-Load Offer costs in any Dispatch Interval in the RUC Make-Whole Payment Eligibility Period, the Resource must be a Synchronized Resource in that Dispatch Interval.

(d) There may be more than one RUC Make-Whole Payment Eligibility Period for a Resource in a single Operating Day for which a credit or charge is calculated. A single RUC Make-Whole Payment Eligibility Period is contained within a single Operating Day.
(e) A Resource’s RTBM Start-Up Offer costs are not eligible for recovery in the following RUC Make-Whole Payment Eligibility Periods:

(i) Any RUC Make-Whole Payment Eligibility Period that is adjacent to the end of a DA Market Make-Whole Payment Eligibility Period;

(ii) Any RUC Make-Whole Payment Eligibility Period for which a Resource is a Synchronized Resource prior to this commitment period at a time one hour prior to that Resource’s RUC Commit Time less the Resource’s Sync-To-Min Profile; and

(iii) Any RUC Make-Whole Payment Eligibility Period resulting from a RUC Commitment Period that contains an hour for which the Resource Commitment Status is Self-Commit.

(f) For each RUC Make-Whole Payment Eligibility Period within an Operating Day, a Resource’s RTBM Start-Up Offer is divided by the lesser of (1) the Resource’s Minimum Run Time multiplied by 12 rounded down to the nearest whole interval or (2) 24 Hours multiplied by 12, and that portion of the Start-Up Offer is included as a cost in each interval of the RUC Make-Whole Payment Eligibility Period until the sum of these interval costs are equal to the RTBM Start-Up Offer or until the end of the RUC Make-Whole Payment Eligibility Period, whichever occurs first.

(g) To the extent that the full amount of the RTBM Start-Up Offer is not accounted for in the last RUC Make-Whole Payment Eligibility Period in the Operating Day, any remaining RTBM Start-Up Offer costs are carried forward for recovery in the first RUC Make-Whole Payment Eligibility Period of the following Operating Day provided that the Resource has not been committed in the DA Market in any hour of the first RUC Make-Whole Payment Eligibility Period as described in (h) below. For example, consider a Resource that is committed starting at 10:00 PM in Operating Day 1 that has a Minimum Run Time of 10 hours and a Start-Up Offer of $12,000. The RUC Commitment Period is from 10:00 PM in Operating Day 1 through 8:00 AM of Operating Day 2. For RUC Make-Whole Payment calculation purposes, the RUC Commitment Period is split into two separate RUC Make-Whole Payment Eligibility Periods as described in (2).a above. The first RUC Make-Whole Payment Eligibility Period will include $100/interval of Start-Up Offer costs ($12,000 / 120 intervals) in hour 23 and 24 intervals. The second RUC Make-Whole Payment Eligibility Period will include $100/interval of Start-Up Offer costs in hours 1 through 8 intervals.
(h) If the Resource has been committed in the DA Market in a period adjacent to and following a RUC Make-Whole Payment Eligibility Period to the extent that the full amount of the RTBM Start-Up Offer is not accounted for in the RUC Make-Whole Payment Eligibility Period, any remaining RTBM Start-Up Offer costs are carried forward for recovery in the Day-Ahead Make-Whole Payment Eligibility Period.

(4) The amount to each Asset Owner (AO) for each eligible Resource Settlement Location for a given RUC Make-Whole Payment Eligibility Period is calculated as follows:

\[
#\text{RtMwpCpAmt}_{a,s,c} = (\text{CncldStartAmt}_{a,s,c} + \max(0, ( (\text{CncldStartRatio}_{a,s,c} = 0, \text{THEN} 1, \text{ELSE} 0) \times \sum_i ((\text{RtStartUpElig5minFlg}_{a,s,i,c} \times \text{RtStartUp5minAmt}_{a,s,i,c} + \text{RtRucComStat5minFlg}_{a,s,i,c} \times \text{RtMwpCost5minAmt}_{a,s,i,c} + \text{RtMwpRev5minAmt}_{a,s,i,c} + \text{RtOom5minAmt}_{a,s,i} + \text{RtRegAdj5minAmt}_{a,s,i} - \text{RtURDAdj5minAmt}_{a,s,i,c} - \text{RtStatusAdj5minAmt}_{a,s,i,c} - \text{RtLimitAdj5minAmt}_{a,s,i,c}) \times (-1)\\>

Where,

(a) \#\text{RtMwpCost5minAmt}_{a,s,i,c} = \text{RtRucComStat5minFlg}_{a,s,i,c} \times (\text{RtIncrEn5minAmt}_{a,s,i} + \max(0, (\text{RtNoLoad5minAmt}_{a,s,i,c} - \text{IF}(\text{DaClrdHrlyQty}_{a,s,h} < 0, \text{THEN} \text{DaNoLoadHrlyAmt}_{a,s,h,c}, \text{ELSE} 0) \times (\text{RtMinEn5minAmt}_{a,s,i,c} + \text{RtRegUpAvail5minAmt}_{a,s,i,c} + \text{RtRegDnAvail5minAmt}_{a,s,i,c}) \times (-1)\\)
\[ + \text{RtSpinAvail5minAmt}_{a,s,i} + \text{RtSuppAvail5minAmt}_{a,s,i} / 12 \]

(a.1) \(\text{IF ABS (DaClrdHrlyQty}_{a,s,h} \geq \text{ABS (RtBillMtr5minQty}_{a,s,i})}\)

\[\text{THEN} \]

\[\text{RtIncrEn5minAmt}_{a,s,i} = 0\]

\[\text{ELSE IF}\]

\[\text{ControlStatus5minFlg}_{a,s,i} = \text{“Regulating”}\]

\[\#\text{RtIncrEn5minAmt}_{a,s,i} = \int_{x}^{y} \text{RTBM As Dispatched Energy Offer Curve}\]

\[\text{Where:}\]

\[X = \text{Max (ABS (DaClrdHrlyQty}_{a,s,h}, \text{RtComMinRegCapOL5minQty}_{a,s,i})}\]

\[Y = \text{ABS (RtBillMtr5minQty}_{a,s,i})\]

\[\text{ELSE IF}\]

\[\text{ControlStatus5minFlg}_{a,s,i} <> \text{“Regulating”}\]

\[\#\text{RtIncrEn5minAmt}_{a,s,i} = \int_{x}^{y} \text{RTBM As Dispatched Energy Offer Curve}\]

\[\text{Where:}\]

\[X = \text{Max (ABS (DaClrdHrlyQty}_{a,s,h}, \text{RtComMinEconCapOL5minQty}_{a,s,i})}\]

\[Y = \text{ABS (RtBillMtr5minQty}_{a,s,i})\]
(a.2) IF ABS (DaClrdHrlyQty_{a,s,h}) > 0

THEN

RtMinEn5minAmt_{a,s,i,c} = 0

ELSE IF

ControlStatus5minFlg_{a,s,i} = “Regulating”

# RtMinEn5minAmt_{a,s,i,c} =

\[ \text{RtComMinRegCapOL5minQty}_{a,s,i} \int_{0}^{\text{RTBM}} \text{As Committed Energy Offer Curve} \]

ELSE IF

ControlStatus5minFlg_{a,s,i} <> “Regulating”

# RtMinEn5minAmt_{a,s,i,c} =

\[ \text{RtComMinEconCapOL5minQty}_{a,s,i} \int_{0}^{\text{RTBM}} \text{As Committed Energy Offer Curve} \]

(a.3) RtRegUpAvail5minAmt_{a,s,i,c} =

Max ( 0, [ RtRegUp5minQty_{a,s,i} - DaRegUpHrlyQty_{a,s,h} ] )

* RtRegUpOffer_{a,s,i,c}

(a.4) RtRegDnAvail5minAmt_{a,s,i,c} =

Max ( 0, [ RtRegDn5minQty_{a,s,i} - DaRegDnHrlyQty_{a,s,h} ] )
* \( RtRegDnOffer_{a,s,i,c} \)

(a.5) \[
RtSpinAvail5minAmt_{a,s,i,c} = \max(0, [RtSpin5minQty_{a,s,i} - DaSpinHrlyQty_{a,s,h}] )
\]

* \( RtSpinOffer_{a,s,i,c} \)

(a.6) \[
RtSuppAvail5minAmt_{a,s,i,c} = \max(0, [RtSupp5minQty_{a,s,i} - DaSuppHrlyQty_{a,s,h}] )
\]

* \( RtSuppOffer_{a,s,i,c} \)

(b) \[
\#RtMwpRev5minAmt_{a,s,i,c} = \]

\[
RtRucComStat5minFlg_{a,s,i,c} \times \left( \frac{\text{Min}(0, [RtBillMtr5minQty_{a,s,i} - DaClrdHrlyQty_{a,s,h}] )}{12} \right) + RtRegUpRev5minAmt_{a,s,i,c} + RtRegDnRev5minAmt_{a,s,i,c} + RtSpinRev5minAmt_{a,s,i,c} + RtSuppRev5minAmt_{a,s,i,c}
\]

(b.1) \[
RtRegUpRev5minAmt_{a,s,i,c} = \]

\[
(-1) \times RtRucComStat5minFlg_{a,s,i,c} \times \left( \frac{\text{Max}(0, [RtRegUp5minQty_{a,s,i} - DaRegUpHrlyQty_{a,s,h}] )}{12} \right)
\]

(b.2) \[
RtRegDnRev5minAmt_{a,s,i,c} = \]

\[
(-1) \times RtRucComStat5minFlg_{a,s,i,c}
\]
(b.3) \( \text{RtSpinRev5minAmt}_{a, s, i, c} = \)

\( (-1) \times \text{RtRucComStat5minFlg}_{a, s, i, c} \)

*( Max ( 0, [ \text{RtSpin5minQty}_{a, s, i} - \text{DaSpinHrlyQty}_{a, s, h} ] )

* \( \text{RtSpinMcp5minPrc}_{a, s, i} \) ) / 12

(b.4) \( \text{RtSuppRev5minAmt}_{a, s, i, c} = \)

\( (-1) \times \text{RtRucComStat5minFlg}_{a, s, i, c} \)

*( Max ( 0, [ \text{RtSupp5minQty}_{a, s, i} - \text{DaSuppHrlyQty}_{a, s, h} ] )

* \( \text{RtSuppMcp5minPrc}_{a, s, i} \) ) / 12

(c) \( \#\text{CncldStartAmt}_{a, s, c} = \)

\[ \sum_{i} \left( \text{RtStartUp5minAmt}_{a, s, i, c} \times \text{RtStartUpElig5minFlg}_{a, s, i, c} \right) \]

* \( \text{CncldStartRatio}_{a, s, c} \)

\( \text{CncldStartRatio}_{a, s, c} = \left( \frac{\text{ElapsedTime}_{a, s, c}}{\text{StartUpTime}_{a, s, c}} \right) \)

(d) In any Dispatch Interval in which the Resource has operated outside of its Operating Tolerance and that Resource has not been exempted from URD per Section 4.4.4.1, any incremental Energy costs associated with actual Energy output above the Resource’s Desired Dispatch is not eligible for recovery. The URD adjustment is calculated as follows:
IF ABS (URD5minQty\(_{a,s,i}\)) > ResOpTol5minQty\(_{a,s,i}\) AND

(XmptDev5minFlg\(_{a,s,i}\) = 0)

THEN

\[\#RtURDAdj5minAmt\(_{a,s,i,c}\) = RtRucComStat5minFlg\(_{a,s,i,c}\)\]

* Max ( 0, (RtIncrEn5minAmt\(_{a,s,i}\) – RtDesiredEn5minAmt\(_{a,s,i}\) ) / 12)

ELSE

RtURDAdj5minAmt\(_{a,s,i,c}\) = 0

(d.1) URD5minQty\(_{a,s,i}\) =

\[\text{RtBillMtr5minQty}_{a,s,i} * (-1) - \text{RtAvgSetPoint5minQty}_{a,s,i}\]

(d.2) ResOpTol5minQty\(_{a,s,i}\) =

\[\text{Min (URDMaxTol5minQty}_{a,s,i}, \text{Max (URDMinTol5minQty}_{a,s,i}, \text{URDTol5minPct}_{a,s,i} * \text{RtDispMaxEmerCapOL5minQty}_{a,s,i})\)\]

(d.3) IF RtDesiredEn5minQty\(_{a,s,i}\) < ABS (DaClrdHrlyQty\(_{a,s,h}\)) THEN

\[\#RtDesiredEn5minAmt_{a,s,i} = \text{RtIncrEn5minAmt}_{a,s,i}\]

ELSE IF

ControlStatus5minFlg\(_{a,s,i}\) = “Regulating”

\[\#RtDesiredEn5minAmt_{a,s,i} = \int \text{RTBM As Dispatched Energy Offer Curve}\]

Where:
\[ X = \text{Max} \left( \text{ABS} \left( \text{DaCldHrlyQty}_{a,s,h} , \text{RtComMinRegCapOL5minQty}_{a,s,i} \right) \right) \]

\[ Y = \text{RtDesiredEn5minQty}_{a,s,i} \]

ELSE IF

\[ \text{ControlStatus5minFlg}_{a,s,i} < > \text{“Regulating”} \]

\[ \#\text{RtDesiredEn5minAmt}_{a,s,i} = \int_{x}^{y} \text{RTBM As DispatchedEnergyOfferCurve} \]

Where:

\[ X = \text{Max} \left( \text{ABS} \left( \text{DaCldHrlyQty}_{a,s,h} , \text{RtComMinEconCapOL5minQty}_{a,s,i} \right) \right) \]

\[ Y = \text{RtDesiredEn5minQty}_{a,s,i} \]

(e) In any Dispatch Interval in which a Resource is in “Manual” status, any incremental Energy costs associated with actual Energy output above the Resource’s Desired Dispatch is not eligible for recovery. The status change adjustment is calculated as follows:

IF ControlStatus5minFlg \(a,s,i\) = “Manual”

AND ABS \(\text{URD5minQty}_{a,s,i}\) <= \(\text{ResOpTol5minQty}_{a,s,i}\)

THEN

\[ \#\text{RtStatusAdj5minAmt}_{a,s,i,c} = \text{RtRucComStat5minFlg}_{a,s,i,c} \times \text{Max} \left( 0, \left( \text{RtIncrEn5minAmt}_{a,s,i} - \text{RtDesiredEn5minAmt}_{a,s,i} \right) / 12 \right) \]

ELSE

\[ \text{RtStatusAdj5minAmt}_{a,s,i,c} = 0 \]
(f) In any Dispatch Interval in which a Resource has increased its Minimum Economic Capacity Operating Limit (or its Minimum Regulation Capacity Operating Limit if the Resource has cleared for Regulation-Up or Regulation-Down) above the Resource’s minimum limits used by SPP in the commitment decision or the minimum limits used to move from one configuration to another in the case of a Combined Cycle Resource, the Resource is not in “Manual” status and the increase in minimum limit is greater than the Resource’s Operating Tolerance, any incremental Energy costs associated with actual Energy output above the Resource’s Desired Dispatch is not eligible for recovery. The limit change adjustment is calculated as follows:

\[
\text{IF} \quad \text{ControlStatus5minFlg}_{a,s,i} \neq \text{“Regulating” AND ControlStatus5minFlg}_{a,s,i} \neq \text{“Manual” AND ( RtDispMinEconCapOL5minQty}_{a,s,i} - \text{RtComMinEconCapOL5minQty}_{a,s,i}) > \text{ResOpTol5minQty}_{a,s,i} \quad \text{AND ABS (URD5minQty}_{a,s,i}) \leq \text{ResOpTol5minQty}_{a,s,i} \quad \text{THEN}
\]

\[
\#\text{RtLimitAdj5minAmt}_{a,s,i,c} = \text{RtRucComStat5minFlg}_{a,s,i,c} \times \max(0, \frac{(\text{RtIncrEn5minAmt}_{a,s,i} - \text{RtDesiredEn5minAmt}_{a,s,i})}{12})
\]

ELSE IF

\[
\text{ControlStatus5minFlg}_{a,s,i} = \text{“Regulating” AND ( RtDispMinRegCapOL5minQty}_{a,s,i} - \text{RtComMinRegCapOL5minQty}_{a,s,i}) > \text{ResOpTol5minQty}_{a,s,i} \quad \text{AND ABS (URD5minQty}_{a,s,i}) \leq \text{ResOpTol5minQty}_{a,s,i} \quad \text{THEN}
\]
#RtLimitAdj5minAmt_{a,s,i,c} = RtRucComStat5minFlg_{a,s,i,c} * Max ( 0, (RtIncrEn5minAmt_{a,s,i} - RtDesiredEn5minAmt_{a,s,i}) / 12 \\
ELSE \\
RtLimitAdj5minAmt_{a,s,i,c} = 0 \\

(5) For each Asset Owner, a daily amount is calculated at each Settlement Location. The daily amount is calculated as follows:

\[ RtMwpDlyAmt_{a,s,d} = \sum_{c} RtMwpCpAmt_{a,s,c} \]

(6) For each Asset Owner associated with Market Participant \( m \), a daily amount is calculated. The daily amount is calculated as follows:

\[ RtMwpAoAmt_{a,m,d} = \sum_{s} RtMwpDlyAmt_{a,s,d} \]

(7) For each Market Participant, a daily amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The daily amount is calculated as follows:

\[ RtMwpMpAmt_{m,d} = \sum_{a} RtMwpAoAmt_{a,m,d} \]

(8) For FERC Electric Quarterly Reporting ("EQR") purposes, SPP calculates RUC Make-Whole Payment $ per RUC Make-Whole-Payment Eligibility Period for each Asset Owner as follows:

\( a \)
\[ EqrRtMwp5minPrc_{a,s,c} = (-1) * RtMwpCpAmt_{a,s,c} \]

\( b \)
\[ IF EqrRtMwp5minPrc_{a,s,c} > 0 \]
\[ THEN \]
\[ EqrRtMwp5minQty_{a,s,c} = 1 \]
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>RtMwpCpAmt ( a, s, c )</td>
<td>$</td>
<td>Eligibility Period</td>
<td>RUC Make-Whole-Payment Amount per AO per Settlement Location per RUC Make-Whole-Payment Eligibility Period - The amount to AO ( a ) for RUC Make-Whole-Payment Eligibility Period ( c ) at Resource Settlement Location ( s ).</td>
</tr>
<tr>
<td>DaClrdHrlyQty ( a, s, h )</td>
<td>MWh</td>
<td>Hour</td>
<td>Day-Ahead Cleared Energy Quantity per AO per Settlement Location per Hour - The value described under Section 4.5.8.1 for AO ( a )’s combined cycle resource at Settlement Location ( s ) for the Hour.</td>
</tr>
<tr>
<td>RtStartUp5minAmt ( a, s, i, c )</td>
<td>$</td>
<td>Eligibility Period</td>
<td>Real-Time Start-Up Cost Amount per AO per Settlement Location per Dispatch Interval per RUC Make-Whole-Payment Eligibility Period - The RTBM Start-Up Offer associated with AO ( a )’s eligible Resource at Settlement Location ( s ) for RUC Make-Whole-Payment Eligibility Period ( c ) in Dispatch Interval ( i ). This value is calculated by dividing ( \text{RtStartUpAmt}<em>{a, s, c} ) by the lesser of the Resource’s ( \text{(RtMinRunTime}</em>{a, i, s, c} \times 12) ) or ( (24 \times 12) ). These interval values are carried forward into the following Operating Day, if needed, to ensure recovery of any remaining ( \text{RtStartUpAmt}_{a, s, c} ).</td>
</tr>
<tr>
<td>RtStartUpAmt ( a, s, c )</td>
<td>$</td>
<td>Eligibility Period</td>
<td>Real-Time Start-Up Cost Amount per AO per Settlement Location per RUC Make-Whole-Payment Eligibility Period - The RTBM Start-Up Offer used in the commitment decision, associated with AO ( a )’s eligible Resource at Settlement Location ( s ) for RUC Make-Whole-Payment Eligibility Period ( c ).</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>----------</td>
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</tr>
<tr>
<td>RtStartUpElig5minFlg&lt;sub&gt; a,s,i,c &lt;/sub&gt;</td>
<td>None</td>
<td>Dispatch Interval</td>
<td><strong>RUC Start-Up Recovery Eligibility Flag per AO per Resource Settlement Location per Dispatch Interval per RUC Make-Whole-Payment Eligibility Period</strong> – This flag is set equal to 1 in each Dispatch Interval of a RUC Make-Whole-Payment Eligibility Period where the Resource is eligible to recover start-up costs, or 0 where the Resource is not eligible to recover start-up costs.</td>
</tr>
<tr>
<td>RtRucComStat5minFlg&lt;sub&gt; a,s,i,c &lt;/sub&gt;</td>
<td>None</td>
<td>Dispatch Interval</td>
<td><strong>RUC Commitment Status Flag per AO per Resource Settlement Location per Dispatch Interval in RUC Make-Whole-Payment Eligibility Period</strong> – This flag is set equal to 1 for each Dispatch Interval of a RUC Make-Whole-Payment Eligibility Period in which a Resource’s Commitment Status was “Market” or “Reliability”, or 0 if its Commitment Status was “Self”.</td>
</tr>
<tr>
<td>CncldStartRatio&lt;sub&gt; a,s,c &lt;/sub&gt;</td>
<td>None</td>
<td></td>
<td><strong>Canceled Start Ratio per Resource Settlement Location in RUC Make-Whole-Payment Eligibility Period</strong> – The ratio of ElapsedTime&lt;sub&gt;a,s,c&lt;/sub&gt; to StartUpTime&lt;sub&gt;a,s,c&lt;/sub&gt; as calculated for each Dispatch Interval in RUC Make-Whole-Payment Eligibility Period c.</td>
</tr>
<tr>
<td>RtMinRunTime&lt;sub&gt; a,i,s,c &lt;/sub&gt;</td>
<td>Time</td>
<td>Hour</td>
<td><strong>Real-Time Minimum Run Time per AO per Settlement Location Per Dispatch Interval per RUC Make-Whole-Payment Eligibility Period</strong> – The Minimum Run Time used in the commitment decision, associated with AO a’s eligible Resource at Settlement Location s for RUC Make-Whole-Payment Eligibility Period c as submitted as part of the RTBM Market Offer.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>------------------------</td>
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<td>-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>RtNoLoad5minAmt (a, i, s, c)</td>
<td>$</td>
<td>Hour</td>
<td>Real-Time No-Load Cost Amount per AO per Settlement Location per Dispatch Interval in the RUC Make-Whole-Payment Eligibility Period - The No-Load Offer used in the commitment decision, in dollars, associated with AO (a)’s eligible Resource at Settlement Location (s) for Dispatch Interval (i) in RUC Make-Whole-Payment Eligibility Period (c).</td>
</tr>
<tr>
<td>RtMwpCost5minAmt (a, s, i, c)</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>RUC Make-Whole-Payment Cost per AO per Settlement Location per Dispatch Interval in the RUC Make-Whole-Payment Eligibility Period – The total Energy and Operating Reserve cost at actual Resource output, in dollars, associated with AO (a)’s eligible Resource at Settlement Location (s) for Dispatch Interval (i) in RUC Make-Whole-Payment Eligibility Period (c).</td>
</tr>
<tr>
<td>RtMwpRev5minAmt (a, s, i, c)</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>RUC Make-Whole-Payment Revenue per AO per Settlement Location per Dispatch Interval in the RUC Make-Whole-Payment Eligibility Period – The total Energy and Operating Reserve revenue at actual Resource output, in dollars, associated with AO (a)’s eligible Resource at Settlement Location (s) for Dispatch Interval (i) in RUC Make-Whole-Payment Eligibility Period (c).</td>
</tr>
<tr>
<td>CncldStartAmt (a, s, c)</td>
<td>$</td>
<td>Eligibility Period</td>
<td>Real-Time Cancelled Start Amount per AO per Settlement Location per for the RUC Make-Whole-Payment Eligibility Period – The Start-Up Offer cost reimbursement for an SPP cancelled start-up, in dollars, associated with AO (a)’s eligible Resource at Settlement Location (s) for RUC Make-Whole-Payment Eligibility Period (c).</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>------------------------</td>
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<td>-------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>ElapsedTime(_{a,s,c})</td>
<td>$</td>
<td>Eligibility Period</td>
<td><em>Elapsed Time per AO per Settlement Location per for the RUC Make-Whole-Payment Eligibility Period</em> – The elapsed time, in minutes, between the start of a Resource’s (StartUpTime(_{a,s,c})* and the time SPP cancelled the start-up, in dollars, associated with AO (a)’s eligible Resource at Settlement Location (s) for RUC Make-Whole-Payment Eligibility Period (c).</td>
</tr>
<tr>
<td>StartUpTime(_{a,s,c})</td>
<td>$</td>
<td>Eligibility Period</td>
<td><em>Start-up Time per AO per Settlement Location for the RUC Make-Whole-Payment Eligibility Period</em> – The Start-Up Time, in minutes, used in the commitment decision associated with AO (a)’s eligible Resource at Settlement Location (s) for RUC Make-Whole-Payment Eligibility Period (c) as specified in the RTBM Offer submitted prior to the RUC Make-Whole-Payment Eligibility Period.</td>
</tr>
<tr>
<td>RtURDAj5minAmt(_{a,s,i,c})</td>
<td>$</td>
<td>Dispatch Interval</td>
<td><em>URD Adjustment per AO per Settlement Location per Dispatch Interval in the RUC Make-Whole-Payment Eligibility Period</em> – The reduction in RUC Make-Whole Payment Amount associated with AO (a)’s eligible Resource at Settlement Location (s) for Dispatch Interval (i) in RUC Make-Whole-Payment Eligibility Period (c) when the Resource’s (URD5\text{min}Qty(<em>{a,s,i}) is outside of the Resource’s (ResOpTol5\text{min}Qty(</em>{a,s,i}).</td>
</tr>
<tr>
<td>URD5minQty(_{a,s,i})</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td><em>Uninstructed Resource Deviation per AO per Settlement Location per Dispatch Interval</em> – The Uninstructed Resource Deviation associated with AO (a)’s Resource at Settlement Location (s) in Dispatch Interval (i).</td>
</tr>
<tr>
<td>ResOpTol5minQty(_{a,s,i})</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td><em>Resource Operating Tolerance per AO per Settlement Location per Dispatch Interval</em> – The Resource Operating Tolerance associated with AO (a)’s Resource at Settlement Location (s) in Dispatch Interval (i).</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>----------</td>
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</tr>
<tr>
<td>URDMaxTol5minQty_{a,s,i}</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Uninstructed Resource Deviation Maximum Tolerance per AO per Settlement Location per Dispatch Interval – The maximum value of ResOpTol5minQty_{a,s,i} that is currently set at 20 MW.</td>
</tr>
<tr>
<td>URDMinTol5minQty_{a,s,i}</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Uninstructed Resource Deviation Minimum Tolerance per AO per Settlement Location per Dispatch Interval – The minimum value of ResOpTol5minQty_{a,s,i} that is currently set at 5 MW.</td>
</tr>
<tr>
<td>URDTol5minPct_{a,s,i}</td>
<td>Percent</td>
<td>Dispatch Interval</td>
<td>Uninstructed Resource Deviation Tolerance Percentage per AO per Settlement Location per Dispatch Interval – The percentage used to calculate the value of ResOpTol5minQty_{a,s,i} that is currently set at 5%.</td>
</tr>
<tr>
<td>RtAvgSetPoint5minQty_{a,s,i}</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Average Setpoint Instruction MW per AO per Settlement Location per Dispatch Interval – The average Setpoint Instruction over Dispatch Interval (i) for AO (a)'s Resource at Settlement Location (s).</td>
</tr>
<tr>
<td>XmptDev5minFlg_{a,s,i}</td>
<td>none</td>
<td>Dispatch Interval</td>
<td>URD Exemption Flag per AO per Resource Settlement Location per Dispatch Interval – A flag associated with AO (a)'s eligible Resource at Settlement Location (s) indicating that a Resource that has operated outside of its Operating Tolerance is or is not exempt from any associated penalty charges in Dispatch Interval (i). If the flag is equal to zero, the Resource is not exempt. Otherwise, the flag will be set to a positive integer number which will indicate the reason of the exemption as specified under Section 4.4.4.1.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>-----------------------------------------------</td>
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<td>---------------------</td>
<td>-------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>RtStatusAdj5minAmt  (a, s, i, c)</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Resource Status Change Adjustment per AO per Settlement Location per Dispatch Interval in the RUC Make-Whole-Payment Eligibility Period – The reduction in RUC Make-Whole Payment Amount associated with AO (a)’s eligible Resource at Settlement Location (s) for Dispatch Interval (i) in RUC Make-Whole-Payment Eligibility Period (c) when the Resource’s Control Status is set to “Manual”.</td>
</tr>
<tr>
<td>ControlStatus5minFlg  (a, s, i)</td>
<td>None</td>
<td>Dispatch Interval</td>
<td>Control Status per AO per Settlement Location per Dispatch Interval – A Resource status indicator associated with AO (a)’s eligible Resource at Settlement Location (s) for Dispatch Interval (i) as set by SPP operators that indicates the current dispatchable status of the Resource.</td>
</tr>
<tr>
<td>RtDispMaxEmerCapOL5minQty  (a, s, i)</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Maximum Emergency Capacity Operating Limit Quantity per AO per Settlement Location per Dispatch Interval – The Maximum Emergency Capacity Operating Limit associated with AO (a)’s eligible Resource at Settlement Location (s) for Dispatch Interval (i).</td>
</tr>
<tr>
<td>RtDispMinEconCapOL5minQty  (a, s, i)</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Minimum Economic Capacity Operating Limit Quantity per AO per Settlement Location per Dispatch Interval – The Minimum Economic Capacity Operating Limit associated with AO (a)’s eligible Resource at Settlement Location (s) for Dispatch Interval (i).</td>
</tr>
<tr>
<td>RtDispMinRegCapOL5minQty  (a, s, i)</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Minimum Regulation Capacity Operating Limit Quantity per AO per Settlement Location per Dispatch Interval – The Minimum Regulation Capacity Operating Limit associated with AO (a)’s eligible Resource at Settlement Location (s) for Dispatch Interval (i).</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>----------</td>
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</tr>
<tr>
<td>RtLimitAdj5minAmt&lt;sub&gt;a, s, i, c&lt;/sub&gt;</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Resource Limit Change Adjustment per AO per Settlement Location per Dispatch Interval in the RUC Make-Whole-Payment Eligibility Period – The reduction in RUC Make-Whole Payment Amount associated with AO a’s eligible Resource at Settlement Location s for Dispatch Interval i in RUC Make-Whole-Payment Eligibility Period c for a Real-Time increase in minimum limit.</td>
</tr>
<tr>
<td>RtComMinEconCapOL5minQty&lt;sub&gt;a, s, i&lt;/sub&gt;</td>
<td>MW</td>
<td>Eligibility Period</td>
<td>Real-Time Minimum Economic Capacity Operating Limit Quantity per AO per Settlement Location – The Minimum Economic Capacity Operating Limit associated with AO a’s eligible Resource at Settlement Location s for Dispatch Interval i as submitted in an RTBM Offer prior to the RUC Make-Whole-Payment Eligibility Period that was used in making the initial Resource commitment decision.</td>
</tr>
<tr>
<td>RtComMinRegCapOL5minQty&lt;sub&gt;a, s, i&lt;/sub&gt;</td>
<td>MW</td>
<td>Eligibility Period</td>
<td>Real-Time Minimum Regulation Capacity Operating Limit Quantity per AO per Settlement Location – The Minimum Regulation Capacity Operating Limit associated with AO a’s eligible Resource at Settlement Location s for Dispatch Interval i as submitted in an RTBM Offer prior to the RUC Make-Whole-Payment Eligibility Period that was used in making the initial Resource commitment decision.</td>
</tr>
<tr>
<td>RtIncrEn5minAmt&lt;sub&gt;a, s, i&lt;/sub&gt;</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time Incremental Energy Cost Amount per AO per Settlement Location per Dispatch Interval - The average incremental energy offer cost, in dollars, associated with AO a’s eligible Resource at Settlement Location s for Dispatch Interval i at an output level equal to RtBillMtr5minQty&lt;sub&gt;a, s, i&lt;/sub&gt;.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>----------</td>
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<td>------------</td>
</tr>
<tr>
<td>$RtMinEn5minAmt_{a,s,i,c}$</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time Energy Cost at Minimum Limit per AO per Settlement Location per Dispatch Interval in the RUC Make-Whole-Payment Eligibility Period - The average incremental energy offer cost at the applicable minimum limit associated with AO a’s eligible Resource at Settlement Location s for Dispatch Interval i in RUC Make-Whole-Payment Eligibility Period c</td>
</tr>
<tr>
<td>$RtDesiredEn5minAmt_{a,s,i}$</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time Energy Cost at Desired Dispatch Quantity per AO per Settlement Location per Dispatch Interval - The average incremental energy offer cost at $RtDesiredEn5minQty_{a,s,i}$ associated with AO a’s eligible Resource at Settlement Location s for Dispatch Interval i.</td>
</tr>
<tr>
<td>$RtDesiredEn5minQty_{a,s,i}$</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Desired Dispatch Quantity per AO per Settlement Location per Dispatch Interval – The Desired Dispatch MW for AO a’s eligible Resource for Dispatch Interval i at $RtLmp5minPrc_{s,i}$ as calculated from the Resource’s As Dispatched Energy Offer Curve using $RtComMinEconCapOL5minQty_{a,s,i}$ or $RtComMinRegCapOL5minQty_{a,s,i}$ as an output floor, as applicable.</td>
</tr>
<tr>
<td>$RtOom5minAmt_{a,s,i}$</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time Out-Of-Merit Make-Whole-Payment Amount per AO per Settlement Location per Dispatch Interval - The value calculated under Section 4.5.9.9.</td>
</tr>
<tr>
<td>$RtRegAdj5minAmt_{a,s,i}$</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time Regulation Deployment Adjustment Amount per AO per Resource Settlement Location per Dispatch Interval - The value calculated under Section 4.5.9.19.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>---------------------------</td>
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<td>-------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>RtRegUpOffer (_{a,s,i,c}) (Not Available on Settlement Statement)</td>
<td>$/MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Regulation-Up Offer per AO per Resource Settlement Location per Dispatch Interval in RUC Make-Whole-Payment Eligibility Period – The Regulation-Up Offer associated with AO (a)'s Resource Settlement Location (s) at the time the commitment decision was made for RUC Make-Whole-Payment Eligibility Period (c) in Dispatch Interval (i).</td>
</tr>
<tr>
<td>RtRegDnOffer (_{a,s,i,c}) (Not Available on Settlement Statement)</td>
<td>$/MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Regulation-Down Offer per AO per Resource Settlement Location per Dispatch Interval in RUC Make-Whole-Payment Eligibility Period – The Regulation-Down Offer associated with AO (a)'s Resource Settlement Location (s) at the time the commitment decision was made for RUC Make-Whole-Payment Eligibility Period (c) in Dispatch Interval (i).</td>
</tr>
<tr>
<td>RtSpinOffer (_{a,s,i,c}) (Not Available on Settlement Statement)</td>
<td>$/MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Spinning Reserve Offer per AO per Resource Settlement Location per Dispatch Interval in RUC Make-Whole-Payment Eligibility Period – The Spinning Reserve Offer associated with AO (a)'s Resource Settlement Location (s) at the time the commitment decision was made for RUC Make-Whole-Payment Eligibility Period (c) in Dispatch Interval (i).</td>
</tr>
<tr>
<td>RtSuppOffer (_{a,s,i,c}) (Not Available on Settlement Statement)</td>
<td>$/MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Supplemental Reserve Offer per AO per Resource Settlement Location per Dispatch Interval in RUC Make-Whole-Payment Eligibility Period – The Supplemental Reserve Offer associated with AO (a)'s Resource Settlement Location (s) at the time the commitment decision was made for RUC Make-Whole-Payment Eligibility Period (c) in Dispatch Interval (i).</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>----------</td>
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</tr>
<tr>
<td>RtRegUpAvail5minAmt&lt;sub&gt;a,s,i,c&lt;/sub&gt;</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time Regulation-Up Offer Cost Amount per AO per Settlement Location per Dispatch Interval in the RUC Make-Whole-Payment Eligibility Period - The Regulation-Up Offer cost, in dollars, associated with AO a’s eligible Resource at Settlement Location s for Dispatch Interval i in RUC Make-Whole-Payment Eligibility Period c.</td>
</tr>
<tr>
<td>RtRegDnAvail5minAmt&lt;sub&gt;a,s,i,c&lt;/sub&gt;</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time Regulation-Down Offer Cost Amount per AO per Settlement Location per Dispatch Interval in the RUC Make-Whole-Payment Eligibility Period - The Regulation-Down Offer cost, in dollars, associated with AO a’s eligible Resource at Settlement Location s for Dispatch Interval i in DA Market Commitment Period c.</td>
</tr>
<tr>
<td>RtSpinAvail5minAmt&lt;sub&gt;a,s,i,c&lt;/sub&gt;</td>
<td>c</td>
<td>Dispatch Interval</td>
<td>Real-Time Spin Offer Cost Amount per AO per Settlement Location per Dispatch Interval in RUC Make-Whole-Payment Eligibility Period - The Spinning Reserve Offer cost, in dollars, associated with AO a’s eligible Resource at Settlement Location s for Dispatch Interval i in RUC Make-Whole-Payment Eligibility Period c.</td>
</tr>
<tr>
<td>RtSuppAvail5minAmt&lt;sub&gt;a,s,i,c&lt;/sub&gt;</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time Supplemental Offer Cost Amount per AO per Settlement Location per Dispatch Interval in RUC Make-Whole-Payment Eligibility Period - The Supplemental Reserve Offer cost, in dollars, associated with AO a’s eligible Resource at Settlement Location s for Dispatch Interval i in RUC Make-Whole-Payment Eligibility Period c.</td>
</tr>
<tr>
<td>RtLmp5minPrc&lt;sub&gt;s,i&lt;/sub&gt;</td>
<td>$/MWh</td>
<td>Dispatch Interval</td>
<td>Real-Time LMP - The value defined under Section 4.5.9.1 at Settlement Location s for Dispatch Interval i.</td>
</tr>
<tr>
<td>RtBillMtr5minQty&lt;sub&gt;a,s,i&lt;/sub&gt;</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Actual Meter Quantity per AO per Location per Dispatch Interval - The value defined under Section 4.5.9.1 for Dispatch Interval i.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
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</tr>
<tr>
<td>RtRegUpRev5minAmt&lt;sub&gt;a, s, i, c&lt;/sub&gt;</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time Regulation-Up Revenue Amount per AO per Settlement Location per Dispatch Interval in RUC Make-Whole-Payment Eligibility Period – The Real-Time incremental Regulation-Up revenue associated with AO a’s eligible Resource at Settlement Location s for Dispatch Interval i in RUC Make-Whole-Payment Eligibility Period c.</td>
</tr>
<tr>
<td>RtRegDnRev5minAmt&lt;sub&gt;a, s, i, c&lt;/sub&gt;</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time Regulation-Down Revenue Amount per AO per Settlement Location per Dispatch Interval in RUC Make-Whole-Payment Eligibility Period – The Real-Time incremental Regulation-Down revenue associated with AO a’s eligible Resource at Settlement Location s for Dispatch Interval i in RUC Make-Whole-Payment Eligibility Period c.</td>
</tr>
<tr>
<td>RtSpinRev5minAmt&lt;sub&gt;a, s, i, c&lt;/sub&gt;</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time Spinning Reserve Revenue Amount per AO per Settlement Location per Dispatch Interval in RUC Make-Whole-Payment Eligibility Period – The Real-Time incremental Spinning Reserve associated with AO a’s eligible Resource at Settlement Location s for Dispatch Interval i in RUC Make-Whole-Payment Eligibility Period c.</td>
</tr>
<tr>
<td>RtSuppRev5minAmt&lt;sub&gt;a, s, i, c&lt;/sub&gt;</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time Supplemental Reserve Revenue Amount per AO per Settlement Location per Dispatch Interval in RUC Make-Whole-Payment Eligibility Period – The Real-Time incremental Supplemental Reserve revenue associated with AO a’s eligible Resource at Settlement Location s for Dispatch Interval i in RUC Make-Whole-Payment Eligibility Period c.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
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</tr>
<tr>
<td>RtMwpDlyAmt&lt;sub&gt;a, s, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>RUC Make-Whole-Payment Amount per AO per Settlement Location per Operating Day - The RUC Make-whole amount to AO &lt;i&gt;a&lt;/i&gt; for Operating Day &lt;i&gt;d&lt;/i&gt; at Resource Settlement Location &lt;i&gt;s&lt;/i&gt;.</td>
</tr>
<tr>
<td>RtMwpAoAmt&lt;sub&gt;a, m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>RUC Make-Whole-Payment Amount per AO per Operating Day - The RUC Make-whole amount to AO &lt;i&gt;a&lt;/i&gt; associated with Market Participant &lt;i&gt;m&lt;/i&gt; for Operating Day &lt;i&gt;d&lt;/i&gt;.</td>
</tr>
<tr>
<td>RtMwpMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>RUC Make-Whole-Payment Amount per MP per Operating Day - The RUC Make-whole amount to Market Participant &lt;i&gt;m&lt;/i&gt; for Operating Day &lt;i&gt;d&lt;/i&gt;.</td>
</tr>
<tr>
<td>EqrRtMwp5minPrc&lt;sub&gt;a, s, c&lt;/sub&gt;</td>
<td>$</td>
<td>Eligibility Period</td>
<td>RUC Electric Quarterly Reporting Make-Whole-Payment Amount per AO per Settlement Location per RUC Make-Whole-Payment Eligibility Period - The RUC make-whole amount to AO &lt;i&gt;a&lt;/i&gt; for RUC Make-Whole-Payment Eligibility Period &lt;i&gt;c&lt;/i&gt; at Resource Settlement Location &lt;i&gt;s&lt;/i&gt; for use by AO &lt;i&gt;a&lt;/i&gt; in reporting such make-whole-payments to FERC in accordance with FERC EQR requirements.</td>
</tr>
<tr>
<td>EqrRtMwp5minQty&lt;sub&gt;a, s, c&lt;/sub&gt;</td>
<td>$</td>
<td>Eligibility Period</td>
<td>RUC Electric Quarterly Reporting Make-Whole-Payment Quantity per AO per Settlement Location per RUC Make-Whole-Payment Eligibility Period – This value is set equal to 1 if EqrRtMwp5minPrc&lt;sub&gt;a, s, c&lt;/sub&gt; &gt; 0 for use by AO &lt;i&gt;a&lt;/i&gt; in reporting such make-whole-payments to FERC in accordance with FERC EQR requirements.</td>
</tr>
</tbody>
</table>

<i>a</i> none none An Asset Owner.

<i>i</i> none none A Dispatch Interval.

<i>h</i> none none An Hour.

<i>d</i> An Operating Day.

<i>s</i> none none A Settlement Location.
<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>$c$</td>
<td>none</td>
<td>none</td>
<td>A RUC Make-Whole-Payment Eligibility Period.</td>
</tr>
<tr>
<td>$m$</td>
<td>none</td>
<td>none</td>
<td>A Market Participant.</td>
</tr>
</tbody>
</table>
4.5.9.9 Real-Time Out-Of-Merit Amount

(1) A RTBM credit or charge\(^{21}\) will be made to each Market Participant with a Resource that receives a SPP Manual Dispatch Instruction that creates a cost to the Asset Owner or that adversely impacts the Asset Owner’s DA Market position and/or if a Market Participant must buy back its DA Market position for any Operating Reserve product at a RTBM MCP that is greater than that product’s DA Market MCP. The amount will be calculated on a Dispatch Interval basis under the following conditions:

(a) If the Manual Dispatch Instruction is for Energy in the up direction and the Energy Offer Curve cost associated with the Out-Of-Merit-Energy (OOME) MW is greater than the RTBM LMP, the Asset Owner will receive a credit for the difference. The OOME MW is calculated as Max (0, or the difference between the actual Resource output and the Resource’s Desired Dispatch);

(b) If the Manual Dispatch Instruction is for Energy in the down direction, including a Resource de-commitment and the RTBM LMP is greater than the DA Market LMP, the Asset Owner will receive a credit for the difference multiplied by the OOME MW. The OOME MW is calculated as Max (0, or the difference between the Resource’s DA Market cleared Energy MW and the actual Resource output); and/or

(c) If the RTBM cleared amount of an Operating Reserve product is less than the DA Market cleared amount of the corresponding Operating Reserve product and the RTBM MCP is greater than the DA Market MCP, the Asset Owner will receive a credit for the difference multiplied by the OOMOR MW. The OOMOR MW is calculated as Max (0, or the difference between the Resource’s DA Market cleared Operating Reserve MW and the Resource’s RTBM cleared Operating Reserve MW).

To the extent that additional costs are incurred as a direct result of a Manual Dispatch Instruction through the compensation mechanisms described above, Market Participants may request additional compensation through submittal of actual cost documentation to SPP. SPP will

\(^{21}\) Note that this charge type will almost always produce a credit. The charge is included here for the rare occasion when a charge may be produced as a result of a data error and/or a resettlement.
review the submitted documentation and confirm that the submitted information is sufficient to
document actual costs and that all or a portion of the actual costs are eligible for recovery.

The amount to each Asset Owner (AO) for each eligible Resource Settlement Location for each
Dispatch Interval is calculated as follows:

\[
\#RtOom5minAmt_{a,s,i} = RtOom5minFlg_{a,s,i} * (RtOomeIncr5minAmt_{a,s,i} + RtOomeDecr5minAmt_{a,s,i} + RtOomor5minAmt_{a,s,i}) * (-1)
\]

Where,

(a) \(RtOomeIncr5minAmt_{a,s,i} = \)

\[
\text{Max} (0, RtIncrEn5minAmt_{a,s,i} - RtDesiredEn5minAmt_{a,s,i} + \text{Min} (0, RtBillMtr5minQty_{a,s,i} + RtDesiredEn5minQty_{a,s,i}) * \text{Max}(0, RtLmp5minPrc_{s,i} )) / 12
\]

(b) \(RtOomeDecr5minAmt_{a,s,i} = \)

\[
\text{Max} (0, RtBillMtr5minQty_{a,s,i} - DaClrdHrlyQty_{a,s,h} ) * \text{Max}(0, RtLmp5minPrc_{s,i} - DaLmpHrlyPrc_{s,h} ) / 12
\]

(c) \(RtOomor5minAmt_{a,s,i} = \)

\[
\text{Max} (0, DaRegUpHrlQty_{a,s,h} - RtRegUp5minQty_{a,s,i}) * \text{Max} (0, RtRegUpMcp5minPrc_{s,i} - DaRegUpMcpHrlyPrc_{s,h} ) ) + \text{Max} (0, DaRegDnHrlyQty_{a,s,h} - RtRegDn5minQty_{a,s,i}) * \text{Max} (0, RtRegDnMcp5minPrc_{s,i} - DaRegDnMcpHrlyPrc_{s,h} ) ) + \text{Max} (0, DaSpinHrlyQty_{a,s,h} - RtSpin5minQty_{a,s,i})
\]
\[
* \text{Max} \left( 0, \text{RtSpinMcp5minPrc}_{s,i} - \text{DaSpinMcpHrlyPrc}_{s,h} \right) \\
+ \left( \text{Max} \left( 0, \text{DaSuppHrlyQty}_{a,s,h} - \text{RtSupp5minQty}_{a,s,i} \right) \\
* \text{Max} \left( 0, \text{RtSuppMcp5minPrc}_{s,i} - \text{DaSuppMcpHrlyPrc}_{s,h} \right) \right) / 12
\]

(2) For each Asset Owner, an hourly amount is calculated at each Settlement Location. The hourly amount is calculated as follows:

\[
\text{RtOomHrlyAmt}_{a,s,h} = \sum_{i} \text{RtOom5minAmt}_{a,s,i}
\]

(3) For each Asset Owner, a daily amount is calculated at each Settlement Location. The daily credit amount is calculated as follows:

\[
\text{RtOomDlyAmt}_{a,s,d} = \sum_{h} \text{RtOomHrlyAmt}_{a,s,h}
\]

(4) For each Asset Owner associated with Market Participant \(m\), a daily amount is calculated. The daily amount is calculated as follows:

\[
\text{RtOomAoAmt}_{a,m,d} = \sum_{s} \text{RtOomDlyAmt}_{a,s,d}
\]

(5) For each Market Participant, a daily amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The daily amount is calculated as follows:

\[
\text{RtOomMpAmt}_{m,d} = \sum_{a} \text{RtOomAoAmt}_{a,m,d}
\]

(6) For FERC Electric Quarterly Reporting (“EQR”) purposes, SPP calculates Real-Time Out-of-Merit Energy and Operating Reserve $ per Dispatch Interval for each Asset Owner as follows:

(a) \( \text{EqrRtOom5minPrc}_{a,s,i} = (-1) \times \text{RtOom5minAmt}_{a,s,i} \)

(b) \( \text{IF} \text{EqrRtOom5minPrc}_{a,s,i} > 0 \)

THEN

\( \text{EqrRtOom5minQty}_{a,s,i} = 1 \)
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>RtOom5minAmt(_{a,s,i})</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time Out-Of-Merit Make-Whole-Payment Amount per AO per Settlement Location per Dispatch Interval - The amount to AO (a) for eligible Resource Settlement Location (s) in Dispatch Interval (i) for Out-Of-Merit Energy and Operating Reserve resulting from an SPP Manual Dispatch Instruction.</td>
</tr>
<tr>
<td>RtOomeIncr5minAmt(_{a,s,i})</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time Out-Of-Merit Incremental Energy Make-Whole-Payment Amount per AO per Settlement Location per Dispatch Interval - The portion of AO (a)'s RtOom5minAmt(_{a,s,i}) amount for eligible Resource Settlement Location (s) in Dispatch Interval (i) for Out-Of-Merit Energy resulting from an SPP manual Dispatch Instruction in the up direction.</td>
</tr>
<tr>
<td>RtOomeDecr5minAmt(_{a,s,i})</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time Out-Of-Merit Decremental Energy Make-Whole-Payment Amount per AO per Settlement Location per Dispatch Interval - The portion of AO (a)'s RtOom5minAmt(_{a,s,i}) amount for eligible Resource Settlement Location (s) in Dispatch Interval (i) for Out-Of-Merit Energy resulting from an SPP manual Dispatch Instruction in the down direction.</td>
</tr>
<tr>
<td>RtOom5minFlg(_{a,s,i})</td>
<td>None</td>
<td>Dispatch Interval</td>
<td>Real-Time Out-of-Merit Flag per AO per Settlement Location per Dispatch Interval – A flag that is set equal to 1 when SPP issues a Manual Dispatch Instruction or whenever there is a price correction event as described under Section 7, otherwise, this flag is set equal to zero.</td>
</tr>
<tr>
<td>RtOomor5minAmt(_{a,s,i})</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time Out-Of-Merit Operating Reserve Make-Whole-Payment Amount per AO per Settlement Location per Dispatch Interval - The portion of AO (a)'s RtOome5minAmt(_{a,s,i}) attributable to buying back a DA Market Operating Reserve position in the RTBM at a RTBM MCP that is greater than the corresponding DA Market MCP. This should not be a normal occurrence but could happen as a result of price corrections as described under Section 7.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>-------------------------------</td>
<td>------------</td>
<td>---------------------</td>
<td>-------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td><code>RtDesiredEn5minQty_{a,s,i}</code></td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Desired Dispatch Quantity per AO per Settlement Location per Dispatch Interval – The value described under Section 4.5.9.8.</td>
</tr>
<tr>
<td><code>RtIncrEn5minAmt_{a,s,i}</code></td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time Out-Of-Merit Energy Incremental Energy Cost Amount per AO per Settlement Location per Dispatch Interval – The value described under Section 4.5.9.8.</td>
</tr>
<tr>
<td><code>RtDesiredEn5minAmt_{a,s,i}</code></td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time Energy Cost at Desired Dispatch Amount per AO per Settlement Location per Dispatch Interval - The value described under Section 4.5.9.8.</td>
</tr>
<tr>
<td><code>RtBillMtr5minQty_{a,s,i}</code></td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Actual Meter Quantity per AO per Location per Dispatch Interval - The value defined under Section 4.5.9.1 for Dispatch Interval i.</td>
</tr>
<tr>
<td><code>RtLmp5minPrc_{s,i}</code></td>
<td>$/MW</td>
<td>Dispatch Interval</td>
<td>Real-Time LMP - The value defined under Section 4.5.9.1 at Settlement Location s for Dispatch Interval i.</td>
</tr>
<tr>
<td><code>DaClrdHrlyQty_{a,s,h}</code></td>
<td>MWh</td>
<td>Hour</td>
<td>Day-Ahead Cleared Energy Quantity per AO per Settlement Location per Hour in the DA Market – The value described under Section 4.5.8.1.</td>
</tr>
<tr>
<td><code>DaRegUpHrlyQty_{a,s,h}</code></td>
<td>MW</td>
<td>Hour</td>
<td>Day-Ahead Regulation-Up Quantity per AO per Settlement Location per Hour in the DA Market– The value described under Section 4.5.8.4.</td>
</tr>
<tr>
<td><code>DaRegDnHrlyQty_{a,s,h}</code></td>
<td>MW</td>
<td>Hour</td>
<td>Day-Ahead Regulation-Down Quantity per AO per Settlement Location per Hour in the DA Market– The value described under Section 4.5.8.5.</td>
</tr>
<tr>
<td><code>DaSpinHrlyQty_{a,s,h}</code></td>
<td>MW</td>
<td>Hour</td>
<td>Day-Ahead Spinning Reserve Quantity per AO per Settlement Location per Hour in the DA Market– The value described under Section 4.5.8.6.</td>
</tr>
<tr>
<td><code>DaSuppHrlyQty_{a,s,h}</code></td>
<td>MW</td>
<td>Hour</td>
<td>Day-Ahead Spinning Reserve Quantity per AO per Settlement Location per Hour in the DA Market– The value described under Section 4.5.8.7.</td>
</tr>
<tr>
<td><code>RtRegUp5minQty_{a,s,i}</code></td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Regulation-Up Quantity per AO per Settlement Location per Dispatch Interval in the RTBM– The value described under Section 4.5.9.4.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>--------------------------</td>
<td>---------</td>
<td>---------------------</td>
<td>-------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>RtRegDn5minQty&lt;sub&gt;a,s,i&lt;/sub&gt;</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td><strong>Real-Time Regulation-Down Quantity per AO per Settlement Location per Dispatch Interval in the RTBM</strong>—The value described under Section 4.5.9.5.</td>
</tr>
<tr>
<td>RtSpin5minQty&lt;sub&gt;a,s,i&lt;/sub&gt;</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td><strong>Real-Time Spinning Reserve Quantity per AO per Settlement Location per Dispatch Interval in the RTBM</strong>—The value described under Section 4.5.9.6.</td>
</tr>
<tr>
<td>RtSupp5minQty&lt;sub&gt;a,s,i&lt;/sub&gt;</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td><strong>Real-Time Supplemental Reserve Quantity per AO per Settlement Location per Dispatch Interval in the RTBM</strong>—The value described under Section 4.5.9.7.</td>
</tr>
<tr>
<td>DaRegUpMcpHrlyPrc&lt;sub&gt;x,h&lt;/sub&gt;</td>
<td>$/MW</td>
<td>Hour</td>
<td><strong>Day-Ahead Regulation-Up Market Clearing Price per Settlement Location per Hour in the DA Market</strong>—The value described under Section 4.5.8.4.</td>
</tr>
<tr>
<td>DaRegDnMcpHrlyPrc&lt;sub&gt;x,h&lt;/sub&gt;</td>
<td>$/MW</td>
<td>Hour</td>
<td><strong>Day-Ahead Regulation-Down Market Clearing Price per Settlement Location per Hour in the DA Market</strong>—The value described under Section 4.5.8.5.</td>
</tr>
<tr>
<td>DaSpinMcpHrlyPrc&lt;sub&gt;x,h&lt;/sub&gt;</td>
<td>$/MW</td>
<td>Hour</td>
<td><strong>Day-Ahead Spinning Reserve Market Clearing Price per Settlement Location per Hour in the DA Market</strong>—The value described under Section 4.5.8.6.</td>
</tr>
<tr>
<td>DaSuppMcpHrlyPrc&lt;sub&gt;x,h&lt;/sub&gt;</td>
<td>$/MW</td>
<td>Hour</td>
<td><strong>Day-Ahead Spinning Reserve Market Clearing Price per Settlement Location per Hour in the DA Market</strong>—The value described under Section 4.5.8.7.</td>
</tr>
<tr>
<td>RtRegUpMcp5minPrc&lt;sub&gt;x,i&lt;/sub&gt;</td>
<td>$/MW</td>
<td>Dispatch Interval</td>
<td><strong>Real-Time Regulation-Up Market Clearing Price per Settlement Location per Dispatch Interval in the RTBM</strong>—The value described under Section 4.5.9.4.</td>
</tr>
<tr>
<td>RtRegDnMcp5minPrc&lt;sub&gt;x,i&lt;/sub&gt;</td>
<td>$/MW</td>
<td>Dispatch Interval</td>
<td><strong>Real-Time Regulation-Down Market Clearing Price per Settlement Location per Dispatch Interval in the RTBM</strong>—The value described under Section 4.5.9.5.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>------------------------</td>
<td>------------</td>
<td>---------------------</td>
<td>---------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>RtSpinMcp5minPrc&lt;sub&gt;s, i&lt;/sub&gt;</td>
<td>$/MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Spinning Reserve Market Clearing Price per Settlement Location per Dispatch Interval in the RTBM—The value described under Section 4.5.9.6.</td>
</tr>
<tr>
<td>RtSuppMcp5minPrc&lt;sub&gt;s, i&lt;/sub&gt;</td>
<td>$/MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Supplemental Reserve Market Clearing Price per Settlement Location per Dispatch Interval in the RTBM—The value described under Section 4.5.9.7.</td>
</tr>
<tr>
<td>RtOomHrlyAmt&lt;sub&gt;a, s, h&lt;/sub&gt;</td>
<td>$</td>
<td>Hour</td>
<td>Real-Time Out-Of-Merit Make-Whole-Payment Amount per AO per Settlement Location per Hour - The amount to AO &lt;i&gt;a&lt;/i&gt; for eligible Resource Settlement Location &lt;i&gt;s&lt;/i&gt; in Hour &lt;i&gt;h&lt;/i&gt; for Out-Of-Merit Energy and Operating Reserve resulting from an SPP Manual Dispatch Instruction.</td>
</tr>
<tr>
<td>RtOomDlyAmt&lt;sub&gt;a, s, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Out-Of-Merit Make-Whole-Payment Amount per AO per Settlement Location per Operating Day - The amount to AO &lt;i&gt;a&lt;/i&gt; for eligible Resource Settlement Location &lt;i&gt;s&lt;/i&gt; in Operating Day &lt;i&gt;d&lt;/i&gt; for Out-Of-Merit Energy and Operating Reserve resulting from an SPP Manual Dispatch Instruction.</td>
</tr>
<tr>
<td>RtOomAoAmt&lt;sub&gt;a, m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Out-Of-Merit Make-Whole-Payment Amount per AO per Operating Day - The amount to AO &lt;i&gt;a&lt;/i&gt; associated with Market Participant &lt;i&gt;m&lt;/i&gt; in Operating Day &lt;i&gt;d&lt;/i&gt; for Out-Of-Merit Energy and Operating Reserve resulting from an SPP Manual Dispatch Instruction.</td>
</tr>
<tr>
<td>RtOomMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Out-Of-Merit Make-Whole-Payment Amount per MP per Operating Day - The amount to MP &lt;i&gt;m&lt;/i&gt; in Operating Day &lt;i&gt;d&lt;/i&gt; for Out-Of-Merit Energy and Operating Reserve resulting from an SPP Manual Dispatch Instruction.</td>
</tr>
<tr>
<td>EqrRtOom5minPrc&lt;sub&gt;a, s, i&lt;/sub&gt;</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time Electric Quarterly Reporting Out-of-Merit Make-Whole-Payment Amount per AO per Settlement Location per Dispatch Interval - The Out-of-Merit make-whole amount to AO &lt;i&gt;a&lt;/i&gt; for Dispatch Interval &lt;i&gt;i&lt;/i&gt; at Resource Settlement Location &lt;i&gt;s&lt;/i&gt; for use by AO &lt;i&gt;a&lt;/i&gt; in reporting such make-whole-payments to FERC in accordance with FERC EQR requirements.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>-------------------</td>
<td>------</td>
<td>---------------------</td>
<td>-------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>$EqrRtOom5minQty_{a, s, i}$</td>
<td>$$</td>
<td>Dispatch Interval</td>
<td><em>Real-Time Electric Quarterly Reporting Out-of-Merit Make-Whole-Payment Quantity per AO per Settlement Location per Dispatch Interval</em> – This value is set equal to 1 if $EqrRtOom5minPrc_{a, s, i} &gt; 0$ for use by AO $a$ in reporting such make-whole-payments to FERC in accordance with FERC EQR requirements.</td>
</tr>
<tr>
<td>$a$</td>
<td>none</td>
<td>none</td>
<td>An Asset Owner.</td>
</tr>
<tr>
<td>$s$</td>
<td>none</td>
<td>none</td>
<td>A Settlement Location.</td>
</tr>
<tr>
<td>$i$</td>
<td>none</td>
<td>none</td>
<td>A Dispatch Interval.</td>
</tr>
<tr>
<td>$h$</td>
<td>none</td>
<td>none</td>
<td>An Hour.</td>
</tr>
<tr>
<td>$d$</td>
<td>none</td>
<td>none</td>
<td>An Operating Day.</td>
</tr>
<tr>
<td>$m$</td>
<td>none</td>
<td>none</td>
<td>A Market Participant.</td>
</tr>
</tbody>
</table>
4.5.9.10  RUC Make-Whole-Payment Distribution Amount

(1) A RTBM charge or credit\(^\text{22}\) will be calculated at each Settlement Location for each Asset Owner for each hour in order to fund the payments made under Section 4.5.9.8. The amount will be determined by multiplying the Asset Owner deviations by a daily RTBM MWP rate. The hourly amount is calculated as follows:

\[
#\text{RtMwpDistHrlyAmt}_{a,s,h} = \text{RtMwpSppDistRate}_{d} \times \text{RtDevHrlyQty}_{a,s,h}
\]

Where,

\[\text{RtDevHrlyQty}_{a,s,h} = \text{RtNetSlDevHrlyQty}_{a,s,h} + \text{RtMinLimitDevHrlyQty}_{a,s,h} + \text{RtMaxLimitDevHrlyQty}_{a,s,h} + \text{RtOutageDevHrlyQty}_{a,s,h} + \text{RtStatusDevHrlyQty}_{a,s,h} + \text{RtRucScDevHrlyQty}_{a,s,h} + \text{RtRucCommitDevHrlyQty}_{a,s,h} + \text{RtURDDevHrlyQty}_{a,s,h}\]

\[(a.1)\] An Asset Owner’s Settlement Location deviation is calculated as the Absolute Value of the sum of (1) (RTBM actual load MWh - DA Market cleared load MWh), (2) (RTBM actual Export Interchange Transactions – DA Market cleared Export Interchange Transactions), (3) (RTBM actual Import Interchange Transactions – DA Market cleared Import Interchange Transactions), (4) (RTBM actual Through Interchange Transactions (sink only) – DA Market cleared Through Interchange Transactions (sink only)), (5) DA Market cleared Virtual Energy Bids * (-1), and (6) DA Market cleared Virtual Energy Offers * (-1). An Asset Owner’s Settlement Location deviation is calculated as follows.

\[
\text{RtNetSlDevHrlyQty}_{a,s,h} = \text{ABS} \sum_i \text{RtNetSlDev5minQty}_{a,s,i}
\]

\(^{22}\) Note that this charge type will almost always produce a charge. The credit is included here for the rare occasion when a credit may be produced as a result of a data error and/or a resettlement.
\[ \#\text{RtNetSldDev5minQty}_{a,s,i} = \]

\[
\{ \max(0, \text{RtBillMtr5minQty}_{a,s,i}) - \max(0, \text{DaClrdHrlyQty}_{a,s,h}) + \sum t \max(0, \text{RtImpExp5minQty}_{a,s,i,t,dir}) - \sum t \max(0, \text{DaImpExp5minQty}_{a,s,i,t,dir}) + [ \text{IF \text{DIR} <> “THROUGH”, THEN} \sum t \min(0, \text{RtImpExp5minQty}_{a,s,i,t,dir}) - \sum t \min(0, \text{DaImpExp5minQty}_{a,s,i,t,dir}), \text{ELSE} 0 ] \}
\]

\[ \times (1 - \text{RsgCrdFlg}_{r}) - \sum t \text{DaClrdVHrlyQty}_{a,s,h,t} / 12 \]

**a.2** For a Resource with DA Market cleared MW in an hour, if the Resource’s Minimum Economic Capacity Operating Limit (or Minimum Regulation Capacity Operating Limit if cleared for Regulation-Up or Regulation-Down) in the RTBM is (1) greater than the comparable limits used to clear the Resource in the DA Market by more than the Resource Operating Tolerance; (2) is greater than its DA Market cleared MW; and (3) the Resource’s Setpoint Instruction in any Dispatch Interval within the Hour is equal to the Resource’s applicable minimum limit, the difference between the Resource’s applicable minimum limit and its DA Market cleared MW is included as a deviation. In the case where the Resource has cleared Regulation-Up or Regulation Down in the RTBM and has not cleared Regulation-Up or Regulation Down in the DA Market, the deviation is the lesser of the (1) the difference between the Resource’s RTBM regulation minimum limit and its DA Market cleared MW or (2) the difference between the Resource’s RTBM regulation minimum limit and the its DA Market regulation minimum limit.
\[
RtMinLimitDevHrlyQty_{a,s,h} = \sum_i RtMinLimitDev5minQty_{a,s,i}
\]

Where,

IF \(\text{SetPointMinHrlyFlg}_{a,s,h} = \text{“1”} \) AND \(\text{DaClrdHrlyQty}_{a,s,h} < 0\) AND \(\text{RtRucComStat5minFlg}_{a,s,i,c} <> \text{“1”}\) AND \(\text{RtRucComStat5minFlg}_{a,s,i,c} <> \text{“0”}\)

THEN

** Regulation is not cleared in RTBM **

IF \(\text{ControlStatus5minFlg}_{a,s,i} <> \text{“Regulating”}\) AND

\(\text{(RtDispMinEconCapOL5minQty}_{a,s,i} - \text{DaComMinEconCapOLHrlyQty}_{a,s,h})\) > \(\text{ResOpTol5minQty}_{a,s,i}\)

THEN

\(#\text{RtMinLimitDev5minQty}_{a,s,i} = \max\left(\text{RtDispMinEconCapOL5minQty}_{a,s,i} + \text{DaClrdHrlyQty}_{a,s,h}, 0\right) / 12\)

ELSE IF

** Regulation is cleared in both DA Market and RTBM **

IF \(\text{ControlStatus5minFlg}_{a,s,i} = \text{“Regulating”}\) AND

\(\text{DaRegUpHrlyQty}_{a,s,h} + \text{DaRegDnHrlyQty}_{a,s,h} > 0\) AND

\(\text{(RtDispMinRegCapOL5minQty}_{a,s,i} - \text{DaComMinRegCapOLHrlyQty}_{a,s,h})\) > \(\text{ResOpTol5minQty}_{a,s,i}\)

THEN
#RtMinLimitDev5minQty\_{a,s,i} = \text{Max} \{ (\text{RtDispMinRegCapOL5minQty\_{a,s,i} + \text{DaClrdHrlyQty\_{a,s,h}}) , 0 \} / 12 \}

ELSE IF

** Regulation is cleared in RTBM and not cleared in DA Market **

IF ControlStatus5minFlg\_{a,s,i} = \text{``Regulating'' AND} \\
DaRegUpHrlyQty\_{a,s,h} + DaRegDnHrlyQty\_{a,s,h} = 0 \text{ AND} \\
(\text{RtDispMinRegCapOL5minQty\_{a,s,i} - \text{DaComMinRegCapOLHrlyQty\_{a,s,h}}}) > \text{ResOpTol5minQty\_{a,s,i}}

THEN

#RtMinLimitDev5minQty\_{a,s,i} = \text{Max} \{ \text{RtDispMinRegCapOL5minQty\_{a,s,i}} \}

\text{Max} \{ \text{ABS ( DaClrdHrlyQty\_{a,s,h} ) , DaComMinRegCapOLHrlyQty\_{a,s,h} } , 0 \} / 12

ELSE

RtMinLimitDev5minQty\_{a,s,i} = 0

(a.3) For a Resource with DA Market cleared MW in an hour, if the Resource’s Maximum Economic Capacity Operating Limit (or Maximum Regulation Capacity Operating Limit if cleared for Regulation-Up or Regulation-Down) in the RTBM is (1) less than the comparable limits used to clear the Resource in the DA Market by more than the Resource Operating Tolerance; (2) is less than its DA Market cleared MW; and (3) the Resource’s Setpoint Instruction in any Dispatch Interval within the Hour is equal to the Resource’s applicable maximum limit, the difference between the Resource’s DA Market cleared MW and its applicable maximum limit is included as a deviation. In the case where the Resource has cleared Regulation-Up or Regulation Down in the RTBM and has not cleared Regulation-Up or Regulation Down in the DA Market, the deviation is the lesser of the (1) the difference between the Resource’s DA Market cleared MW and its RTBM regulation maximum limit or (2) the difference between the
Resource’s DA Market regulation minimum limit and its RTBM regulation minimum limit.

\[ \text{RtMaxLimitDevHrlyQty}_{a,s,h} = \sum_{i} \text{RtMaxLimitDev5minQty}_{a,s,i} \]

Where,

IF SetPointMaxHrlyFlg\(_{a,s,h} = \text{“1” AND DaClrdHrlyQty}_{a,s,h} < 0 \)

THEN

**Regulation is not cleared in RTBM**

IF ControlStatus5minFlg\(_{a,s,i} \neq \text{“Regulating” AND} \)

( DaComMaxEconCapOLHrlyQty\(_{a,s,h} - \text{RtDispMaxEconCapOL5minQty}_{a,s,i} \) ) > ResOpTol5minQty\(_{a,s,i} \)

THEN

#RtMaxLimitDev5minQty\(_{a,s,i} = \)

Max [ (ABS ( DaClrdHrlyQty\(_{a,s,h} \) ) - \text{RtDispMaxEconCapOL5minQty}_{a,s,i} ), 0 ] / 12

ELSE IF

**Regulation is cleared in both DA Market and RTBM**

IF ControlStatus5minFlg\(_{a,s,i} = \text{“Regulating” AND} \)

DaRegUpHrlyQty\(_{a,s,h} + \text{DaRegDnHrlyQty}_{a,s,h} > 0 \) AND

( DaComMaxRegCapOLHrlyQty\(_{a,s,h} - \text{RtDispMaxRegCapOL5minQty}_{a,s,i} \) ) > ResOpTol5minQty\(_{a,s,i} \)

THEN

#RtMaxLimitDev5minQty\(_{a,s,i} = \)
Max \[ (\text{ABS}(\text{DaClrdHrlyQty}_{a,s,h}) - \text{RtDispMaxRegCapOL5minQty}_{a,s,i}) \leq 0 \] / 12

ELSE IF

** Regulation is cleared in RTBM and not cleared in DA Market **

IF ControlStatus5minFlg_{a,s,i} = “Regulating” AND

\text{DaRegUpHrlyQty}_{a,s,h} + \text{DaRegDnHrlyQty}_{a,s,h} = 0 \text{ AND}

( \text{DaComMaxRegCapOLHrlyQty}_{a,s,h} - \text{RtDispMaxRegCapOL5minQty}_{a,s,i} ) > \text{ResOpTol5minQty}_{a,s,i}

THEN

#\text{RtMaxLimitDev5minQty}_{a,s,i} =

\text{Max} \{ \text{Min} [ \text{ABS}(\text{DaClrdHrlyQty}_{a,s,h}), \text{DaComMaxRegCapOLHrlyQty}_{a,s,h}] - \text{RtDispMaxRegCapOL5minQty}_{a,s,i}, 0 \} / 12

ELSE

\text{RtMaxLimitDev5minQty}_{a,s,i} = 0

(a.4) For Resources with DA Market cleared MW in an hour, if the Resource is off-line in the RTBM and it has not been de-committed by SPP the Resource DA Market cleared MW is included as a deviation. An Asset Owner’s outage deviation is calculated as follows.

\text{RtOutageDevHrlyQty}_{a,s,h} = \sum_i \text{RtOutageDev5minQty}_{a,s,i}

IF \text{DaClrdHrlyQty}_{a,s,h} < 0 \text{ AND}

\text{RtBillMtr5minQty}_{a,s,i} \geq 0 \text{ AND}

\text{ResDeCommit5minFlg}_{a,s,i} <> “1”
THEN

\[ \#RtOutageDev5minQty_{a,s,i} = \frac{\text{ABS} \left( \text{DaClrdHrlyQty}_{a,s,h} \right)}{12} \]

ELSE

\[ \text{RtOutageDev5minQty}_{a,s,i} = 0 \]

(a.5) For Resources with DA Market cleared MW in an hour, for each Dispatch Interval the Resource is in “Manual” status, a deviation is calculated that is equal to one-twelfth of the difference between the Resource actual output and the Resource’s Desired Dispatch. An Asset Owner’s status change deviation is calculated as follows.

\[ \text{RtStatusDevHrlyQty}_{a,s,h} = \sum_{i} \text{RtStatusDev5minQty}_{a,s,i} \]

IF ControlStatus5minFlg_{a,s,i} = “Manual” AND

\[ \text{DaClrdHrlyQty}_{a,s,h} < 0 \]

THEN

\[ \#RtStatusDev5minQty_{a,s,i} = \frac{\text{ABS} \left( \text{RtBillMtr5minQty}_{a,s,i} + \text{RtDesiredEn5minQty}_{a,s,i} \right)}{12} \]

ELSE

\[ \text{RtStatusDev5minQty}_{a,s,i} = 0 \]

(a.6) For Resources that Self-Committed following the Day-Ahead Market and the Resource’s Setpoint Instruction in any Dispatch Interval within the Hour is equal to the Resource’s applicable minimum limit, a deviation is included in an amount equal to the Resource actual output or, in the case of a Combined Cycle Resource, a deviation is included in an amount equal to the difference between the Resource actual output and the Resource DA Market cleared amount. Resources that were offered into the DA Market for SPP commitment and not committed in the DA Market and then Self-Committed prior to the Day-Ahead RUC are exempted from this calculation. An Asset Owner’s Self-Commit deviation is calculated as follows.
\[
RtRucScDevHrlyQty_{a,s,h} = \sum_i RtRucScDev5minQty_{a,s,i}
\]

IF \( RtRucComStat5minFlg_{a,s,i,c} = "0" \) AND
SetPointMinHrlyFlg_{a,s,h} = "1"
THEN

\[
#RtRucScDev5minQty_{a,s,i} =
\]

\[
\text{ABS} \left( \text{Min} \left( RtBillMtr5minQty_{a,s,i} - DaClrdHrlyQty_{a,s,h}, 0 \right) / 12 \right)
\]
ELSE

\[
RtRucScDev5minQty_{a,s,i} = 0
\]

(a.7) For Resources that are either Self-Committed or committed by SPP following the DA Market and that are off-line in the RTBM and have not been de-committed by SPP, the greater of the Minimum Economic Capacity Operating Limit at the time of commitment or the Resource’s Desired Dispatch will be included as a deviation. An Asset Owner’s RTBM commitment outage deviation is calculated as follows.

\[
RtRucCommitDevHrlyQty_{a,s,h} = \sum_i RtRucCommitDev5minQty_{a,s,i}
\]

IF \( \text{[ RtRucComStat5minFlg}_{a,s,i,c} = "0" \) OR
RtRucComStat5minFlg_{a,s,i,c} = "1" \) AND

\[
\sum_i RtBillMtr5minQty_{a,s,i} >= 0 AND
\]
ResDeCommit5minFlg_{a,s,i} \not= 1
THEN

\[
#RtRucCommitDev5minQty_{a,s,i} = \text{RtDesiredEn5minQty}_{a,s,i} / 12
\]
In any Dispatch Interval in which a Resource operates outside of its Operating Tolerance and the Resource has not been exempted from URD per Section 4.4.4.1, one-twelth of the Absolute Value of the Resource’s Uninstructed Resource Deviation is included as a deviation. An Asset Owner’s URD deviation is calculated as follows.

$$RtURDDevHrlyQty_{a,s,h} = \sum_i RtURDDev5minQty_{a,s,i}$$

IF \( \text{ABS} (URD5minQty_{a,s,i}) > \text{ResOpTol5minQty}_{a,s,i} \) AND \( \text{XmptDev5minFlg}_{a,s,i} = 0 \) THEN

$$#RtURDDev5minQty_{a,s,i} = \frac{\text{ABS} (URD5minQty_{a,s,i})}{12}$$

ELSE

$$RtURDDev5minQty_{a,s,i} = 0$$

(b) \( #RtMwpSppDistRate_{d} = \)

$$\left( \frac{RtMwpSppDlyAmt_{d}}{RtDevSppDlyQty_{d}} \right) \times (-1)$$

(b.1) \( RtMwpSppDlyAmt_{d} = \sum_m RtMwpMpAmt_{m,d} \)

(b.2) \( RtDevSppDlyQty_{d} = \sum_a \sum_s \sum_h RtDevHrlyQty_{a,s,h} \)
(2) For each Asset Owner, a daily amount is calculated at each Settlement Location. The daily amount is calculated as follows:

\[ \text{RtMwpDistDlyAmt}_{a, s, d} = \sum_h \text{RtMwpDistHrlyAmt}_{a, s, h} \]

(3) For each Asset Owner associated with Market Participant \( m \), a daily amount is calculated. The daily amount is calculated as follows:

\[ \text{RtMwpDistAoAmt}_{a, m, d} = \sum_s \text{RtMwpDistDlyAmt}_{a, s, d} \]

(4) For each Market Participant, a daily amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The daily amount is calculated as follows:

\[ \text{RtMwpDistMpAmt}_{m, d} = \sum_a \text{RtMwpDistAoAmt}_{a, m, d} \]
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>( RtMwpDistHrlyAmt_{a,s,h} )</td>
<td>$</td>
<td>Hour</td>
<td>( RUC ) Make-Whole-Payment Distribution Amount per AO per Hour per Settlement Location - The amount to AO ( a ) for Hour ( h ) and Settlement Location ( s ) for recovery of the total amount paid under Section 4.5.9.8 for Operating Day ( d ).</td>
</tr>
<tr>
<td>( RtDevHrlyQty_{a,s,h} )</td>
<td>MWh</td>
<td>Hour</td>
<td>Real-Time Deviation Quantity per AO per Hour per Settlement Location – The total deviation MWh for AO ( a ) at Settlement Location ( s ) for Hour ( h ).</td>
</tr>
<tr>
<td>( RtMwpSppDistRate_{d} )</td>
<td>$/MWh</td>
<td>Operating Day</td>
<td>( RUC ) Make-Whole Payment SPP Distribution Rate per Operating Day – The rate applied to AO ( a )’s ( RtDevHrlyQty_{a,s,h} ) in each Hour ( h ) at Settlement Location ( s ) in Operating Day ( d ).</td>
</tr>
<tr>
<td>( RtMwpMpAmt_{m,d} )</td>
<td>$</td>
<td>Operating Day</td>
<td>( RUC ) Make-Whole-Payment Amount per MP per Operating Day - The value calculated under Section 4.5.9.8 for Operating Day ( d ).</td>
</tr>
<tr>
<td>( RtMwpSppDlyAmt_{d} )</td>
<td>$</td>
<td>Operating Day</td>
<td>( RUC ) Make-Whole-Payment Amount per Operating Day - The SPP total of the values calculated under Section 4.5.9.8 for Operating Day ( d ).</td>
</tr>
<tr>
<td>( RtDevSppDlyQty_{d} )</td>
<td>MWh</td>
<td>Operating Day</td>
<td>Real-Time Deviation Quantity per Operating Day - The SPP total deviation MWh for all AOs for Operating Day ( d ).</td>
</tr>
<tr>
<td>( RtNetSlDevHrlyQty_{a,s,i} )</td>
<td>MWh</td>
<td>Dispatch Interval</td>
<td>Real-Time Net Settlement Location Deviation per AO per Dispatch Interval per Settlement Location – AO ( a )’s portion of ( RtNetSlDevHrlyQty_{a,s,i} ) related to net of Real-Time load deviations from Day-Ahead amount, Real-Time Interchange Transaction deviations from Day-Ahead amounts and virtual transactions at Settlement Location ( s ) in Dispatch Interval ( i ).</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>--------------------------------</td>
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</tr>
<tr>
<td>RtNetSlDevHrlyQty (_{a, s, h})</td>
<td>MWh</td>
<td>Hour</td>
<td>Real-Time Net Settlement Location Deviation per AO per Hour per Settlement Location – AO (a)’s portion of RtDevHrlyQty (_{a, s, h}) related to net of Real-Time load deviations from Day-Ahead amount, Real-Time Interchange Transaction deviations from Day-Ahead amounts and virtual transactions at Settlement Location (s) in Hour (h).</td>
</tr>
<tr>
<td>RtBillMtr5minQty (_{a, s, i})</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Billing Meter Quantity per AO per Settlement Location per Dispatch Interval - The quantity described under Section 4.5.9.1.</td>
</tr>
<tr>
<td>DaClrdHrlyQty (_{a, s, h})</td>
<td>MWh</td>
<td>Hour</td>
<td>Day-Ahead Cleared Energy Quantity per AO per Settlement Location per Hour in the DA Market – The quantity described under Section 4.5.8.1.</td>
</tr>
<tr>
<td>RtImpExp5minQty (_{a, s, i, t, dir})</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Interchange Transaction Quantity per AO per Settlement Location per Dispatch Interval - The quantity described under Section 4.5.9.2 as identified by direction (dir).</td>
</tr>
<tr>
<td>RsgCrdFlg(_r)</td>
<td>none</td>
<td>none</td>
<td>Reserve Sharing Group Contingency Reserve Deployment Flag per Event – The value described under Section 4.5.8.8.</td>
</tr>
<tr>
<td>DaImpExp5minQty (_{a, s, i, t, dir})</td>
<td>MWh</td>
<td>Dispatch Interval</td>
<td>Day-Ahead Interchange Transaction Quantity per AO per Settlement Location per Dispatch Interval - The quantity described under Section 4.5.8.2 as identified by direction (dir).</td>
</tr>
<tr>
<td>DaClrdVHrlyQt(<em>y</em>{a, s, h, t})</td>
<td>MWh</td>
<td>Hour</td>
<td>Day-Ahead Cleared Virtual Energy Quantity per AO per Settlement Location per Transaction per Hour in the DA Market – The quantity described under Section 4.5.8.3.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
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<td>---------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>RtMinLimitDev5minQty (<em>a,s,i</em>)</td>
<td>MWh</td>
<td>Dispatch Interval</td>
<td>Real-Time Minimum Limit Deviation per AO per Dispatch Interval per Settlement Location – AO (a)'s portion of (\text{RtDevHrlyQty}<em>{a,s,h}) associated with Resources with cleared Day-Ahead amounts that increase their Real- (\text{RtMinLimit}</em>{a,s,h}) above their (\text{DaMinLimit}_{a,s,h}) at Resource Settlement Location (s) in Hour (h).</td>
</tr>
<tr>
<td>RtMinLimitDevHrlyQty (<em>a,s,h</em>)</td>
<td>MWh</td>
<td>Hour</td>
<td>Real-Time Minimum Limit Deviation per AO per Hour per Settlement Location – The sum of AO (a)'s (\text{RtMinLimitDev5minQty}_{a,s,i}) at Resource Settlement Location (s) in Hour (h).</td>
</tr>
<tr>
<td>RtMaxLimitDev5minQty (<em>a,s,i</em>)</td>
<td>MWh</td>
<td>Dispatch Interval</td>
<td>Real-Time Maximum Limit Deviation per AO per Dispatch Interval per Settlement Location – AO (a)'s portion of (\text{RtDevHrlyQty}<em>{a,s,h}) associated with Resources with cleared Day-Ahead amounts that reduce their Real- (\text{RtMaxLimit}</em>{a,s,h}) below their (\text{DaMaxLimit}_{a,s,h}) at Resource Settlement Location (s) in Hour (h).</td>
</tr>
<tr>
<td>RtMaxLimitDevHrlyQty (<em>a,s,h</em>)</td>
<td>MWh</td>
<td>Hour</td>
<td>Real-Time Maximum Limit Deviation per AO per Hour per Settlement Location – The sum of AO (a)'s (\text{RtMaxLimitDev5minQty}_{a,s,i}) at Resource Settlement Location (s) in Hour (h).</td>
</tr>
<tr>
<td>RtOutageDev5minQty (<em>a,s,i</em>)</td>
<td>MWh</td>
<td>Dispatch Interval</td>
<td>Real-Time Outage Deviation per AO per Dispatch Interval per Settlement Location – AO (a)'s portion of (\text{RtDevHrlyQty}_{a,s,h}) associated with Resources with cleared Day-Ahead amounts that are off-line in Real-Time and have not be de-committed by SPP at Resource Settlement Location (s) in Dispatch Interval (i).</td>
</tr>
<tr>
<td>RtOutageDevHrlyQty (<em>a,s,h</em>)</td>
<td>MWh</td>
<td>Hour</td>
<td>Real-Time Outage Deviation per AO per Hour per Settlement Location – The sum of AO (a)'s (\text{RtOutageDev5minQty}_{a,s,i}) at Resource Settlement Location (s) in Hour (h).</td>
</tr>
<tr>
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<td>Definition</td>
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<td>------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>( \text{RtStatusDev5minQty} \ a, s, i )</td>
<td>MWh</td>
<td>Dispatch Interval</td>
<td>\textit{Real-Time Resource Status Change Deviation per AO per Settlement Location per Dispatch Interval} – AO ( a )'s \textit{portion} ( \text{of \ RtDevHrlyQty} \ a, s, h ) associated with Resources for which the Control Status is set to “Manual” at Settlement Location ( s ) for Dispatch Interval ( i ).</td>
</tr>
<tr>
<td>( \text{RtStatusDevHrlyQty} \ a, s, h )</td>
<td>MWh</td>
<td>Dispatch Interval</td>
<td>\textit{Real-Time Status Deviation per AO per Hour per Settlement Location} – The sum of AO ( a )'s ( \text{RtStatusDev5minQty} \ a, s, i ) at Resource Settlement Location ( s ) in Hour ( h ).</td>
</tr>
<tr>
<td>( \text{ControlStatus5minFlg} \ a, s, i )</td>
<td>none</td>
<td>Dispatch Interval</td>
<td>\textit{Control Status per AO per Settlement Location per Dispatch Interval} – The value described under Section 4.5.9.8.</td>
</tr>
<tr>
<td>( \text{RtRucScDev5minQty} \ a, s, i )</td>
<td>MWh</td>
<td>Dispatch Interval</td>
<td>\textit{Real-Time RUC Self-Commit Deviation per AO per Settlement Location per Dispatch Interval} – AO ( a )'s \textit{portion} ( \text{of \ RtDevHrlyQty} \ a, s, h ) associated with Resources that have Self-Committed following completion of the Day-Ahead RUC process at Settlement Location ( s ) for Dispatch Interval ( i ).</td>
</tr>
<tr>
<td>( \text{RtRucScDevHrlyQty} \ a, s, h )</td>
<td>MWh</td>
<td>Hour</td>
<td>\textit{Real-Time RUC Self-Commit Deviation per AO per Settlement Location per Hour} – The summation of AO ( a )'s ( \text{RtRucScDev5minQty} \ a, s, i ) for Hour ( h ).</td>
</tr>
<tr>
<td>( \text{RtRucCommitDev5minQty} \ a, s, i )</td>
<td>MWh</td>
<td>Dispatch Interval</td>
<td>\textit{Real-Time RUC Commit Deviation per AO per Settlement Location per Dispatch Interval} – AO ( a )'s \textit{portion} ( \text{of \ RtDevHrlyQty} \ a, s, h ) associated with Resources that were committed in the Day-Ahead RUC process and fail to come on line at Settlement Location ( s ) for Dispatch Interval ( i ).</td>
</tr>
<tr>
<td>( \text{RtRucCommitDevHrlyQty} \ a, s, h )</td>
<td>MWh</td>
<td>Dispatch Interval</td>
<td>\textit{Real-Time RUC Commit Deviation per AO per Settlement Location per Hour} – The summation of AO ( a )'s ( \text{RtRucCommitDev5minQty} \ a, s, i ) for Hour ( h ).</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
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<td>---------------------------------------------------------------------------</td>
</tr>
<tr>
<td>RtURDDev5minQty (_{a,s,i})</td>
<td>MWh</td>
<td>Dispatch Interval</td>
<td><strong>Real-Time URD Deviation per AO per Settlement Location per Dispatch Interval</strong> – AO a’s portion of RtDevHrlyQty (<em>{a,s,h}) associated with Resources that have operated outside of their ResOpTol (</em>{a,s,i}) at Settlement Location s for Dispatch Interval i.</td>
</tr>
<tr>
<td>RtURDDevHrlyQty (_{a,s,h})</td>
<td>MWh</td>
<td>Hour</td>
<td><strong>Real-Time URD Deviation per AO per Hour per Settlement Location</strong> – The sum of AO a’s RtURDDev5minQty (_{a,s,i}) at Resource Settlement Location s in Hour h.</td>
</tr>
<tr>
<td>URD5minQty (_{a,s,i})</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td><strong>Uninstructed Resource Deviation per AO per Settlement Location per Dispatch Interval</strong> – The value calculated as described under Section 4.5.9.8.</td>
</tr>
<tr>
<td>XmptDev5minFlg (_{a,s,i})</td>
<td>none</td>
<td>Dispatch Interval</td>
<td><strong>Failure-to-Follow Dispatch Exemption Flag per AO per Resource Settlement Location per Dispatch Interval</strong> – The value described under Section 4.5.9.8.</td>
</tr>
<tr>
<td>RtDesiredEn5minQty (_{a,s,i})</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td><strong>Real-Time Desired Dispatch Quantity per AO per Settlement Location per Dispatch Interval</strong> – The value described under Section 4.5.9.8.</td>
</tr>
<tr>
<td>RtDispMinEconCapOL5minQty (_{a,s,i})</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td><strong>Real-Time Minimum Economic Capacity Operating Limit Quantity per AO per Settlement Location per Dispatch Interval</strong> – The value described under Section 4.5.9.8 for Dispatch Interval i.</td>
</tr>
<tr>
<td>RtDispMinRegCapOL5minQty (_{a,s,i})</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td><strong>Real-Time Minimum Regulation Capacity Operating Limit Quantity per AO per Settlement Location per Dispatch Interval</strong> – The value described under Section 4.5.9.8 for Dispatch Interval i.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
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</tr>
<tr>
<td>DaComMinEconCapOLHrlyQty_{a, s, h}</td>
<td>MW</td>
<td>Hour</td>
<td>Day-Ahead Minimum Economic Capacity Operating Limit Quantity per AO per Settlement Location per Hour – The Minimum Economic Capacity Operating Limit associated with AO a’s eligible Resource at Settlement Location s for Hour h as submitted in the DA Market Offer used in the DA Market commitment decision.</td>
</tr>
<tr>
<td>DaComMinRegCapOLHrlyQty_{a, s, h}</td>
<td>MW</td>
<td>Hour</td>
<td>Day-Ahead Minimum Regulation Capacity Operating Limit Quantity per AO per Settlement Location per Hour – The Minimum Regulation Capacity Operating Limit associated with AO a’s eligible Resource at Settlement Location s for Hour h as submitted in the DA Market Offer used in the DA Market commitment decision.</td>
</tr>
<tr>
<td>RtDispMaxEconCapOL5minQty_{a, s, i}</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Maximum Economic Capacity Operating Limit Quantity per AO per Settlement Location per Dispatch Interval – The Maximum Economic Capacity Operating Limit associated with AO a’s eligible Resource at Settlement Location s for Dispatch Interval i.</td>
</tr>
<tr>
<td>RtDispMaxRegCapOL5minQty_{a, s, i}</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Maximum Regulation Capacity Operating Limit Quantity per AO per Settlement Location per Dispatch Interval – The Maximum Regulation Capacity Operating Limit associated with AO a’s eligible Resource at Settlement Location s for Dispatch Interval i.</td>
</tr>
<tr>
<td>DaComMaxEconCapOLHrlyQty_{a, s, h}</td>
<td>MW</td>
<td>Hour</td>
<td>Day-Ahead Maximum Economic Capacity Operating Limit Quantity per AO per Settlement Location per Hour – The Maximum Economic Capacity Operating Limit associated with AO a’s eligible Resource at Settlement Location s for Hour h as submitted in the DA Market Offer used in the DA Market commitment decision.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
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<td>-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>DaComMaxRegCapOLHrlyQty&lt;sub&gt;a, s, h&lt;/sub&gt;</td>
<td>MW</td>
<td>Hour</td>
<td>Day-Ahead Maximum Regulation Capacity Operating Limit Quantity per AO per Settlement Location per Hour – The Maximum Regulation Capacity Operating Limit associated with AO a’s eligible Resource at Settlement Location s for Hour h as submitted in the DA Market Offer used in the DA Market commitment decision.</td>
</tr>
<tr>
<td>ResOpTol5minQty&lt;sub&gt;a, s, i&lt;/sub&gt;</td>
<td>MWh</td>
<td>Dispatch Interval</td>
<td>Resource Operating Tolerance per AO per Settlement Location per Hour – The value calculated as described under Section 4.5.9.8.</td>
</tr>
<tr>
<td>ResDeCommit5minFlg&lt;sub&gt;a, s, i&lt;/sub&gt;</td>
<td>none</td>
<td>Dispatch Interval</td>
<td>Resource De-Commitment Flag per AO per Dispatch Interval per Settlement Location – A flag set by SPP indicating that AO a’s Resource has been de-committed by SPP at Resource Settlement Location s in Dispatch Interval i.</td>
</tr>
<tr>
<td>RtRucComStat5minFlg&lt;sub&gt;a, s, i, c&lt;/sub&gt;</td>
<td>none</td>
<td>Dispatch Interval</td>
<td>RUC Commitment Status Flag per AO per Resource Settlement Location per Dispatch Interval – The value described under Section 4.5.9.8.</td>
</tr>
<tr>
<td>SetPointMinHrlyFlg&lt;sub&gt;a, s, h&lt;/sub&gt;</td>
<td>none</td>
<td>Hour</td>
<td>Setpoint Minimum Flag per AO per Hour per Settlement Location – A flag associated with AO a’s Resource that is set equal to “1” if the Resource receives a Setpoint Instruction that is equal to the Resource’s applicable minimum limit at any time in Hour h.</td>
</tr>
<tr>
<td>SetPointMaxHrlyFlg&lt;sub&gt;a, s, h&lt;/sub&gt;</td>
<td>none</td>
<td>Hour</td>
<td>Setpoint Maximum Flag per AO per Hour per Settlement Location – A flag associated with AO a’s Resource that is set equal to “1” if the Resource receives a Setpoint Instruction that is equal to the Resource’s applicable maximum limit at any time in Hour h.</td>
</tr>
<tr>
<td>DaRegUpHrlyQty&lt;sub&gt;a, s, h&lt;/sub&gt;</td>
<td>MW</td>
<td>Hour</td>
<td>Day-Ahead Regulation-Up Quantity per AO per Settlement Location per Hour – The value described under Section 4.5.8.4.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
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</tr>
<tr>
<td>DaRegDnHrlyQty (_{a,s,h})</td>
<td>MW</td>
<td>Hour</td>
<td>Day-Ahead Regulation-Down Quantity per AO per Settlement Location per Hour – The value described under Section 4.5.8.5.</td>
</tr>
<tr>
<td>RtMwpDistDlyAmt (_{a,s,d})</td>
<td>$</td>
<td>Operating Day</td>
<td>RUC Make-Whole-Payment Distribution Amount per AO per Settlement Location per Operating Day - The amount to AO (a) at Settlement Location (s) for recovery of the total amount paid under Section 4.5.9.8 for Operating Day (d).</td>
</tr>
<tr>
<td>RtMwpDistAoAmt (_{a,m,d})</td>
<td>$</td>
<td>Operating Day</td>
<td>RUC Make-Whole-Payment Distribution Amount per AO per Operating Day - The amount to AO (a) associated with Market Participant (m) for recovery of the total amounts paid under Section 4.5.9.8 for Operating Day (d).</td>
</tr>
<tr>
<td>RtMwpDistMpAmt (_{m,d})</td>
<td>$</td>
<td>Operating Day</td>
<td>RUC Make-Whole-Payment Distribution Amount per MP per Operating Day - The amount to MP (m) for recovery of the total amounts paid under Section 4.5.9.8 for Operating Day (d).</td>
</tr>
<tr>
<td>(i)</td>
<td>none</td>
<td>none</td>
<td>An Dispatch Interval</td>
</tr>
<tr>
<td>(h)</td>
<td>none</td>
<td>none</td>
<td>An Hour.</td>
</tr>
<tr>
<td>(d)</td>
<td>none</td>
<td>none</td>
<td>An Operating Day.</td>
</tr>
<tr>
<td>(a)</td>
<td>none</td>
<td>none</td>
<td>An Asset Owner.</td>
</tr>
<tr>
<td>(c)</td>
<td>none</td>
<td>none</td>
<td>A RUC Make-Whole-Payment Eligibility Period.</td>
</tr>
<tr>
<td>(s)</td>
<td>none</td>
<td>None</td>
<td>A Settlement Location.</td>
</tr>
<tr>
<td>(t)</td>
<td>none</td>
<td>none</td>
<td>A single tagged Interchange Transaction, a single virtual energy transaction, a single Financial Schedule, a single contracted Operating Reserve transaction, a single TCR instrument, a single ARR award or a single Reserve Sharing Event transaction.</td>
</tr>
<tr>
<td>(dir)</td>
<td>none</td>
<td>none</td>
<td>Direction (Import, Export or Through).</td>
</tr>
<tr>
<td>(m)</td>
<td>none</td>
<td>none</td>
<td>A Market Participant.</td>
</tr>
</tbody>
</table>
4.5.9.11 Real-Time Regulation-Up Distribution Amount

(1) A RTBM charge or credit will be calculated for each Asset Owner for each hour. The Asset Owner amount will be equal to the Asset Owner’s real-time load ratio share of the net RTBM Regulation-Up procurement costs. The amount to each Asset Owner is calculated as follows:

\[
#\text{RtRegUpDistHrlyAmt}_{a, s, h} = \frac{Rt\text{RegUpSppHrlyAmt}_h \times Rt\text{LoadRatioShareHrlyFct}_{a, s, h} \times (-1)}{Rt\text{LoadSppHrlyQty}_h}
\]

Where,

(a) \(Rt\text{RegUpSppHrlyAmt}_h = \sum_a \sum_s Rt\text{RegUpHrlyAmt}_{a, s, h}\)

(b) \(#\text{RtLoadRatioShareHrlyFct}_{a, s, h} = \left[ \left[ \text{Max} \left( 0, \sum_i \text{RtBillMtr5minQty}_{a, s, i} \right) \right] + \left[ \text{Max} \left( 0, \sum_i \sum_t \text{RtImpExp5minQty}_{a, s, i, t} \right) \times (1 - \text{RsgCrdFlg}_{t}) \right] / 12 \left] / R\text{tLoadSppHrlyQty}_h \right]\)

(2) For each Asset Owner, a daily amount is calculated at each Settlement Location. The daily amount is calculated as follows:

\[
Rt\text{RegUpDistDlyAmt}_{a, s, d} = \sum_h Rt\text{RegUpDistHrlyAmt}_{a, s, h}
\]

(3) For each Asset Owner associated with Market Participant \(m\), a daily amount is calculated. The daily amount is calculated as follows:

\[
Rt\text{RegUpDistAoAmt}_{a, m, d} = \sum_s Rt\text{RegUpDistDlyAmt}_{a, s, d}
\]

(4) For each Market Participant, a daily amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The daily amount is calculated as follows:

\[
Rt\text{RegUpDistMpAmt}_{m, d} = \sum_a Rt\text{RegUpDistAoAmt}_{a, m, d}
\]
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>RtRegUpDistHrlyAmt(_{a,s,h})</td>
<td>$</td>
<td>Hour</td>
<td>Real-Time Regulation-Up Distribution Amount per AO per Settlement Location per Hour - The amount to AO (a) for AO (a)'s share of the total of (\text{RtRegUpHrlyAmt}_{a,s,h}) in Hour (h).</td>
</tr>
<tr>
<td>RtLoadRatioShareHrlyFct(_{a,s,h})</td>
<td>Ratio</td>
<td>Hour</td>
<td>Real-Time Load Ratio Share Factor per AO per Settlement Location per Hour – AO (a)'s percentage share of total SPP actual real-time load plus Export Interchange Transactions at Settlement Location (s) in Hour (h).</td>
</tr>
<tr>
<td>RtRegUpHrlyAmt(_{a,s,h})</td>
<td>$</td>
<td>Hour</td>
<td>Real-Time Regulation-Up Amount per AO per Settlement Location per Hour – The value calculated under Section 4.5.9.4.</td>
</tr>
<tr>
<td>RtRegUpSppHrlyAmt(_{h})</td>
<td>$</td>
<td>Hour</td>
<td>Real-Time Regulation-Up Amount per Hour – The SPP total amount of the values calculated under Section 4.5.9.4 in Hour (h).</td>
</tr>
<tr>
<td>RtBillMtr5minQty(_{a,s,i})</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Billing Meter Quantity per AO per Settlement Location per Dispatch Interval - The value described under Section 4.5.9.1.</td>
</tr>
<tr>
<td>RtImpExp5minQty(_{a,s,i,t})</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Interchange Transaction Quantity per AO per Settlement Location per Dispatch Interval per Transaction – The value described under Section 4.5.9.2.</td>
</tr>
<tr>
<td>RtLoadSppHrlyQty(_{h})</td>
<td>MWh</td>
<td>Hour</td>
<td>Real-Time SPP Load per Hour – SPP total actual load and Export Interchange Transactions in Hour (h) as calculated under Section 4.5.8.8.</td>
</tr>
<tr>
<td>RsgCrdFlg(_{r})</td>
<td>none</td>
<td>none</td>
<td>Reserve Sharing Group Contingency Reserve Deployment Flag per Event – The value described under Section 4.5.8.8.</td>
</tr>
<tr>
<td>RtRegUpDistDlyAmt(_{a,s,d})</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Regulation-Up Distribution Amount per AO Operating Day. The amount to AO (a) for total net Regulation-Up procurement costs in Operating Day (d).</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>---------------------------</td>
<td>------</td>
<td>---------------------</td>
<td>-----------------------------------------------------------------------------</td>
</tr>
<tr>
<td>RtRegUpDistAoAmt&lt;sub&gt;a, m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Regulation-Up Distribution Amount per AO per Operating Day The amount to AO a associated with Market Participant m for total net Regulation-Up procurement costs in Operating Day d.</td>
</tr>
<tr>
<td>RtRegUpDistMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Regulation-Up Distribution Amount per MP per Operating Day The amount to MP m for total net Regulation-Up procurement costs in Operating Day d.</td>
</tr>
<tr>
<td>a</td>
<td>none</td>
<td>none</td>
<td>An Asset Owner.</td>
</tr>
<tr>
<td>s</td>
<td>none</td>
<td>none</td>
<td>A Settlement Location.</td>
</tr>
<tr>
<td>h</td>
<td>none</td>
<td>none</td>
<td>An Hour.</td>
</tr>
<tr>
<td>i</td>
<td>none</td>
<td>none</td>
<td>A Dispatch Interval.</td>
</tr>
<tr>
<td>t</td>
<td>none</td>
<td>none</td>
<td>A single tagged Interchange Transaction, a single virtual energy transaction, a single Financial Schedule, a single contracted Operating Reserve transaction, a single TCR instrument, a single ARR award or a single Reserve Sharing Event transaction.</td>
</tr>
<tr>
<td>d</td>
<td>none</td>
<td>none</td>
<td>An Operating Day.</td>
</tr>
<tr>
<td>m</td>
<td>none</td>
<td>none</td>
<td>A Market Participant.</td>
</tr>
</tbody>
</table>
4.5.9.12  Real-Time Regulation-Down Distribution Amount

(1) A RTBM charge or credit will be calculated for each Asset Owner for each hour. The Asset Owner amount will be equal to the Asset Owner’s real-time load ratio share of the net RTBM Regulation-Down procurement costs. The amount to each Asset Owner is calculated as follows:

\[ \text{#RtRegDnDistHrlyAmt}_{a,s,h} = \text{RtRegDnSppHrlyAmt}_{h} \times \text{RtLoadRatioShareHrlyFct}_{a,s,h} \times (-1) \]

Where,

\[ \text{RtRegDnSppHrlyAmt}_{h} = \sum_{a} \sum_{s} \text{RtRegDnHrlyAmt}_{a,s,h} \]

(2) For each Asset Owner, a daily amount is calculated at each Settlement Location. The daily amount is calculated as follows:

\[ \text{RtRegDnDistDlyAmt}_{a,s,d} = \sum_{h} \text{RtRegDnDistHrlyAmt}_{a,s,h} \]

(3) For each Asset Owner associated with Market Participant \( m \), a daily amount is calculated. The daily amount is calculated as follows:

\[ \text{RtRegDnDistAoAmt}_{a,m,d} = \sum_{s} \text{RtRegDnDistDlyAmt}_{a,s,d} \]

(4) For each Market Participant, a daily amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The daily amount is calculated as follows:

\[ \text{RtRegDnDistMpAmt}_{m,d} = \sum_{a} \text{RtRegDnDistAoAmt}_{a,m,d} \]
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>$RtRegDnDistHrlyAmt_{a, s, h}$</td>
<td>$\mathsf{S}$</td>
<td>Hour</td>
<td><strong>Real-Time Regulation-Down Distribution Amount per AO per Settlement Location per Hour</strong> - The amount to AO $a$ for AO $a$’s share of the total of $RtRegDnHrlyAmt_{a, s, h}$ in Hour $h$.</td>
</tr>
<tr>
<td>$RtLoadRatioShareHrlyFct_{a, s, h}$</td>
<td>Ratio</td>
<td>Hour</td>
<td><strong>Real-Time Load Ratio Share Factor per AO per Settlement Location per Hour</strong> - The value calculated under Section 4.5.9.11.</td>
</tr>
<tr>
<td>$RtRegDnHrlyAmt_{a, s, h}$</td>
<td>$\mathsf{S}$</td>
<td>Hour</td>
<td><strong>Real-Time Regulation-Down Amount per AO per Settlement Location per Hour</strong> - The value calculated under Section 4.5.9.5.</td>
</tr>
<tr>
<td>$RtRegDnSppHrlyAmt_{h}$</td>
<td>$\mathsf{S}$</td>
<td>Hour</td>
<td><strong>Real-Time Regulation-Down Amount per Hour</strong> – The SPP total amount of the values calculated under Section 4.5.9.5 in Hour $h$.</td>
</tr>
<tr>
<td>$RtRegDnDistDlyAmt_{a, s, d}$</td>
<td>$\mathsf{S}$</td>
<td>Operating Day</td>
<td><strong>Real-Time Regulation-Down Distribution Amount per AO per Operating Day</strong> The amount to AO $a$ for total net Regulation-Down procurement costs in Operating Day $d$.</td>
</tr>
<tr>
<td>$RtRegDnDistAoAmt_{a, m, d}$</td>
<td>$\mathsf{S}$</td>
<td>Operating Day</td>
<td><strong>Real-Time Regulation-Down Distribution Amount per AO per Operating Day</strong> The amount to AO $a$ associated with Market Participant $m$ for total net Regulation-Down procurement costs in Operating Day $d$.</td>
</tr>
<tr>
<td>$RtRegDnDistMpAmt_{m, d}$</td>
<td>$\mathsf{S}$</td>
<td>Operating Day</td>
<td><strong>Real-Time Regulation-Down Distribution Amount per MP per Operating Day</strong> The amount to MP $m$ for total net Regulation-Down procurement costs in Operating Day $d$.</td>
</tr>
</tbody>
</table>

$a$ none none An Asset Owner.

$s$ none none A Settlement Location.

$h$ none none An Hour.

$d$ none none An Operating Day.

$m$ none none A Market Participant.
4.5.9.13 Real-Time Spinning Reserve Distribution Amount

(1) A RTBM charge or credit will be calculated for each Asset Owner for each hour. The Asset Owner amount will be equal to the Asset Owner’s real-time load ratio share of the net RTBM Spinning Reserve procurement costs. The amount to each Asset Owner is calculated as follows:

\[
\text{#RtSpinDistHrlyAmt}_{a, s, h} = \text{RtSpinSppHrlyAmt}_h \times \text{RtLoadRatioShareHrlyFct}_{a, s, h} \times (-1)
\]

Where,

\[
\text{RtSpinSppHrlyAmt}_h = \sum_{a} \sum_{s} \text{RtSpinHrlyAmt}_{a, s, h}
\]

(2) For each Asset Owner, a daily amount is calculated at each Settlement Location. The daily amount is calculated as follows:

\[
\text{RtSpinDistDlyAmt}_{a, s, d} = \sum_{h} \text{RtSpinDistHrlyAmt}_{a, s, h}
\]

(3) For each Asset Owner associated with Market Participant \(m\), a daily amount is calculated. The daily amount is calculated as follows:

\[
\text{RtSpinDistAoAmt}_{a, m, d} = \sum_{s} \text{RtSpinDistDlyAmt}_{a, s, d}
\]

(4) For each Market Participant, a daily amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The daily amount is calculated as follows:

\[
\text{RtSpinDistMpAmt}_{m, d} = \sum_{a} \text{RtSpinDistAoAmt}_{a, m, d}
\]
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>RtSpinDistHrlyAmt&lt;sub&gt;a, s, h&lt;/sub&gt;</td>
<td>$</td>
<td>Hour</td>
<td><strong>Real-Time Spinning Reserve Distribution Amount per AO per Settlement Location per Hour</strong> - The amount to AO a for AO a’s share of the total of RtSpinHrlyAmt&lt;sub&gt;a, s, h&lt;/sub&gt; in Hour h.</td>
</tr>
<tr>
<td>RtLoadRatioShareHrlyFct&lt;sub&gt;a, s, h&lt;/sub&gt;</td>
<td>Ratio</td>
<td>Hour</td>
<td><strong>Real-Time Load Ratio Share Factor per AO per Settlement Location per Hour</strong> – The value calculated under Section 4.5.9.11.</td>
</tr>
<tr>
<td>RtSpinHrlyAmt&lt;sub&gt;a, s, h&lt;/sub&gt;</td>
<td>$</td>
<td>Hour</td>
<td><strong>Real-Time Spinning Reserve Amount per AO per Settlement Location per Hour</strong> – The value calculated under Section 4.5.9.6.</td>
</tr>
<tr>
<td>RtSpinSppHrlyAmt&lt;sub&gt;h&lt;/sub&gt;</td>
<td>$</td>
<td>Hour</td>
<td><strong>Real-Time Spinning Reserve Amount per Hour</strong> – The SPP total amount of the values calculated under Section 4.5.9.6 in Hour h.</td>
</tr>
<tr>
<td>RtSpinDistDlyAmt&lt;sub&gt;a, s, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td><strong>Real-Time Spinning Reserve Distribution Amount per AO per Operating Day</strong> The amount to AO a for total net Spinning Reserve procurement costs in Operating Day d.</td>
</tr>
<tr>
<td>RtSpinDistAoAmt&lt;sub&gt;a, m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td><strong>Real-Time Spinning Reserve Distribution Amount per AO per Operating Day</strong> The amount to AO a associated with Market Participant m for total net Spinning Reserve procurement costs in Operating Day d.</td>
</tr>
<tr>
<td>RtSpinDistMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td><strong>Real-Time Spinning Reserve Distribution Amount per MP per Operating Day</strong> The amount to MP m for total net Spinning Reserve procurement costs in Operating Day d.</td>
</tr>
</tbody>
</table>

<sub>a</sub> none none An Asset Owner.
<sub>s</sub> none none A Settlement Location.
<sub:h</sub> none none An Hour.
<sub>d</sub> none none An Operating Day.
<sub>m</sub> none none A Market Participant.
4.5.9.14 Real-Time Supplemental Reserve Distribution Amount

(1) A RTBM charge or credit will be calculated for each Asset Owner for each hour. The Asset Owner amount will be equal to the Asset Owner’s real-time load ratio share of the net RTBM Supplemental Reserve procurement costs. The amount to each Asset Owner is calculated as follows:

\[
#\text{RtSuppDistHrlyAmt}_{a, s, h} = \text{RtSuppSppHrlyAmt}_h \times \text{RtLoadRatioShareHrlyFct}_{a, s, h} \times (-1)
\]

Where,

\[
\text{RtSuppSppHrlyAmt}_h = \sum_a \sum_s \text{RtSuppHrlyAmt}_{a, s, h}
\]

(2) For each Asset Owner, a daily amount is calculated at each Settlement Location. The daily amount is calculated as follows:

\[
\text{RtSuppDistDlyAmt}_{a, s, d} = \sum_h \text{RtSuppDistHrlyAmt}_{a, s, h}
\]

(3) For each Asset Owner associated with Market Participant \(m\), a daily amount is calculated. The daily amount is calculated as follows:

\[
\text{RtSuppDistAoAmt}_{a, m, d} = \sum_s \text{RtSuppDistDlyAmt}_{a, s, d}
\]

(4) For each Market Participant, a daily amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The daily amount is calculated as follows:

\[
\text{RtSuppDistMpAmt}_{m, d} = \sum_a \text{RtSuppDistAoAmt}_{a, m, d}
\]
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>RtSuppDistHrlyAmtₐ,ₛ,ₕ</td>
<td>$</td>
<td>Hour</td>
<td>Real-Time Supplemental Reserve Distribution Amount per AO per Settlement Location per Hour - The amount to AO ₐ for AO ₐ’s share of the total of (\text{RtSuppHrlyAmt}_ₐ,ₛ,ₕ) in Hour ₕ.</td>
</tr>
<tr>
<td>RtLoadRatioShareHrlyFctₐ,ₛ,ₕ</td>
<td>Ratio</td>
<td>Hour</td>
<td>Real-Time Load Ratio Share Factor per AO per Settlement Location per Hour – The value calculated under Section 4.5.9.11.</td>
</tr>
<tr>
<td>RtSuppHrlyAmtₐ,ₛ,ₕ</td>
<td>$</td>
<td>Hour</td>
<td>Real-Time Supplemental Reserve Amount per AO per Settlement Location per Hour – The value calculated under Section 4.5.9.7.</td>
</tr>
<tr>
<td>RtSuppSppHrlyAmtₐ</td>
<td>$</td>
<td>Hour</td>
<td>Real-Time Supplemental Reserve Amount per Hour – The SPP total amount of the values calculated under Section 4.5.9.7 in Hour ₕ.</td>
</tr>
<tr>
<td>RtSuppDistDlyAmtₐ,ₛ,ₜ</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Supplemental Reserve Distribution Amount per AO per Operating Day The amount to AO ₐ for total net Supplemental Reserve procurement costs in Operating Day ₜ.</td>
</tr>
<tr>
<td>RtSuppDistAoAmtₐ,ₘ,ₜ</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Supplemental Reserve Distribution Amount per AO per Operating Day The amount to AO ₐ associated with Market Participant ₘ for total net Supplemental Reserve procurement costs in Operating Day ₜ.</td>
</tr>
<tr>
<td>RtSuppDistMpAmtₘ,ₜ</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Supplemental Reserve Distribution Amount per MP per Operating Day The amount to MP ₘ for total net Supplemental Reserve procurement costs in Operating Day ₜ.</td>
</tr>
</tbody>
</table>

ₐ: An Asset Owner.  
ₛ: A Settlement Location.  
ₕ: An Hour.  
ₜ: An Operating Day.  
ₘ: A Market Participant.
4.5.9.15 Real-Time Regulation Non-Performance Amount

(1) A RTBM charge or credit\(^{23}\) will be calculated at each Resource Settlement Location for each Asset Owner for each Dispatch Interval when a Resource with cleared RTBM Regulation-Up, Regulation-Down or both operates outside of its Operating Tolerance. The amount will be determined as one-twelfth of the sum of:

(a) the greater of: (i) zero; or (ii) DA Market cleared Regulation-Up MW multiplied by DA Market Regulation-Up MCP plus (RTBM cleared Regulation-Up MW – DA Market cleared Regulation-Up MW) multiplied by RTBM Regulation-Up MCP; and

(b) the greater of: (i) zero; or (ii) DA Market cleared Regulation-Down MW multiplied by DA Market Regulation-Down MCP plus (RTBM cleared Regulation-Down MW – DA Market cleared Regulation-Down MW) multiplied by RTBM Regulation-Down MCP.

The amount to each applicable Asset Owner is calculated as follows.

\[
\text{IF } \text{ABS} (\text{URD5minQty}_{a,s,i}) > \text{ResOpTol5minQty}_{a,s,i} \quad \text{AND} \\
(\text{RtRegUp5minQty}_{a,s,i} + \text{RtRegDn5minQty}_{a,s,i}) > 0 \quad \text{AND} \\
(\text{XmptDev5minFlg}_{a,s,i} = 0) \\
\text{THEN} \\
\text{RtRegNonPerf5minAmt}_{a,s,i} = \\
\text{Max} (0, (\text{DaRegUpHrlyQty}_{a,s,h} \times \text{DaRegUpMcpHrlyPrc}_{z,s,h} \\
+ (\text{RtRegUp5minQty}_{a,s,i} - \text{DaRegUpHrlyQty}_{a,s,h}) \\
\times \text{RtRegUpMcp5minPrc}_{z,s,i}) / 12 \\
+ (\text{DaRegDnHrlyQty}_{a,s,h} \times \text{DaRegDnMcpHrlyPrc}_{z,s,h} \\
+ (\text{RtRegDn5minQty}_{a,s,i} - \text{DaRegDnHrlyQty}_{a,s,h}) \\
\text{\footnotesize 23 Note that this charge type will almost always produce a charge. The credit is included here for the rare occasion when a credit may be produced as a result of a data error and/or a resettlement.}
\[ * \frac{\text{RtRegDnMcp5minPrc}_{z,s,i}}{12} \]

ELSE

\[ \text{RtRegNonPerf5minAmt}_{a,s,i} = 0 \]

(2) For each Asset Owner, an hourly amount is calculated at each Settlement Location. The amount is calculated as follows:

\[ \text{RtRegNonPerfHrlyAmt}_{a,s,h} = \sum_i \text{RtRegNonPerf5minAmt}_{a,s,i} \]

(3) For each Asset Owner, a daily amount is calculated at each Settlement Location. The amount is calculated as follows:

\[ \text{RtRegNonPerfDlyAmt}_{a,s,d} = \sum_h \text{RtRegNonPerfHrlyAmt}_{a,s,h} \]

(4) For each Asset Owner associated with Market Participant \( m \), a daily amount is calculated. The daily amount is calculated as follows:

\[ \text{RtRegNonPerfAoAmt}_{a,m,d} = \sum_s \text{RtRegNonPerfDlyAmt}_{a,s,d} \]

(5) For each Market Participant, a daily amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The daily amount is calculated as follows:

\[ \text{RtRegNonPerfMpAmt}_{m,d} = \sum_a \text{RtRegNonPerfAoAmt}_{a,m,d} \]
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>RtRegNonPerf5minAmt (_{a,s,i})</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time Regulation Non-Performance Amount per AO per Resource Settlement Location per Dispatch Interval - The amount to AO (a) for failure to provide regulation deployment at Resource Settlement Location (s) for the Dispatch Interval.</td>
</tr>
<tr>
<td>RtRegUpMcp5minPre (_{z,s,i})</td>
<td>$/MW</td>
<td>Dispatch Interval</td>
<td>Real-Time MCP for Regulation-Up per Settlement Location per Dispatch Interval per Reserve Zone - The value described under Section 4.5.9.4.</td>
</tr>
<tr>
<td>RtRegDnMcp5minPre (_{z,s,i})</td>
<td>$/MW</td>
<td>Dispatch Interval</td>
<td>Real-Time MCP for Regulation-Down per Settlement Location per Dispatch Interval per Reserve Zone - The value described under Section 4.5.9.5.</td>
</tr>
<tr>
<td>XmptDev5minFlg (_{a,s,i})</td>
<td>none</td>
<td>Dispatch Interval</td>
<td>Failure-to-Follow Dispatch Exemption Flag per AO per Resource Settlement Location per Dispatch Interval – The value described under Section 4.5.9.8.</td>
</tr>
<tr>
<td>RtRegUp5minQty (_{a,s,i})</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Cleared Regulation-Up Quantity per AO per Settlement Location per Dispatch Interval - The value described under Section 4.5.9.4.</td>
</tr>
<tr>
<td>RtRegDn5minQty (_{a,s,i})</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Cleared Regulation-Down Quantity per AO per Settlement Location per Dispatch Interval - The value described under Section 4.5.9.5.</td>
</tr>
<tr>
<td>DaRegUpHrlyQty (_{a,s,h})</td>
<td>MW</td>
<td>Hour</td>
<td>Day-Ahead Cleared Regulation-Up Quantity per AO per Settlement Location per Hour - The value described under Section 4.5.8.4.</td>
</tr>
<tr>
<td>DaRegDnHrlyQty (_{a,s,h})</td>
<td>MW</td>
<td>Hour</td>
<td>Day-Ahead Cleared Regulation-Down Quantity per AO per Settlement Location per Hour - The value described under Section 4.5.8.5.</td>
</tr>
<tr>
<td>DaRegUpMcpHrlyPre (_{z,s,h})</td>
<td>$/MW</td>
<td>Hour</td>
<td>Day-Ahead MCP for Regulation-Up per Settlement Location per Dispatch Interval per Reserve Zone - The value described under Section 4.5.8.4.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>-------------------------------</td>
<td>--------</td>
<td>--------------------</td>
<td>-----------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>DaRegDnMcpHrlyPre\textsubscript{z,s,h}</td>
<td>$/MW</td>
<td>Hour</td>
<td>Day-Ahead MCP for Regulation-Up per Settlement Location per Dispatch Interval per Reserve Zone - The value described under Section 4.5.8.5.</td>
</tr>
<tr>
<td>RtRegNonPerfHrlyAmt\textsubscript{a,s,h}</td>
<td>$</td>
<td>Hour</td>
<td>Real-Time Regulation Non-Performance Amount per AO per Settlement Location per Hour - The amount to AO \textsubscript{a} for failure to provide regulation deployment at Resource Settlement Location \textsubscript{s} for the Hour.</td>
</tr>
<tr>
<td>RtRegNonPerfDlyAmt\textsubscript{a,s,d}</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Regulation-Non-Performance Amount per AO per Settlement Location per Operating Day - The amount to AO \textsubscript{a} for failure to provide regulation deployment at Resource Settlement Location \textsubscript{s} for the Operating Day.</td>
</tr>
<tr>
<td>RtRegNonPerfAoAmt\textsubscript{a,m,d}</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Regulation Non-Performance Amount per AO per Operating Day - The amount to AO \textsubscript{a} associated with Market Participant \textsubscript{m} for failure to provide regulation deployment for the Operating Day.</td>
</tr>
<tr>
<td>RtRegNonPerfMpAmt\textsubscript{m,d}</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Regulation-Non-Performance Amount per MP per Operating Day - The amount to MP \textsubscript{m} for failure to provide regulation deployment for the Operating Day.</td>
</tr>
</tbody>
</table>

\text{a} none none An Asset Owner.
\text{s} none none A Resource Settlement Location.
\text{h} none none An Hour.
\text{i} none none A Dispatch Interval.
\text{d} none none An Operating Day.
\text{m} none none A Market Participant.
4.5.9.16 Real-Time Regulation Non-Performance Distribution Amount

(1) A RTBM charge or credit will be calculated for each Asset Owner for each hour. The Asset Owner amount will be equal to the Asset Owner’s real-time load ratio share of the Real-Time Regulation Non-Performance Amount. The amount to each Asset Owner is calculated as follows:

\[
\#RtRegNonPerfDistHrlyAmt_{a,s,h} = \frac{RtRegNonPerfSppHrlyAmt_h}{RtLoadRatioShareHrlyFct_{a,s,h}} \times (-1)
\]

Where,

\[
RtRegNonPerfSppHrlyAmt_h = \sum_a \sum_s RtRegNonPerfHrlyAmt_{a,s,h}
\]

(2) For each Asset Owner, a daily amount is calculated at each Settlement Location. The daily amount is calculated as follows:

\[
RtRegNonPerfDistDlyAmt_{a,s,d} = \sum_h RtRegNonPerfDistHrlyAmt_{a,s,h}
\]

(3) For each Asset Owner associated with Market Participant \(m\), a daily amount is calculated. The daily amount is calculated as follows:

\[
RtRegNonPerfDistAoAmt_{a,m,d} = \sum_s RtRegNonPerfDistDlyAmt_{a,s,d}
\]

(4) For each Market Participant, a daily amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The daily amount is calculated as follows:

\[
RtRegNonPerfDistMpAmt_{m,d} = \sum_a RtRegNonPerfDistAoAmt_{a,m,d}
\]
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>RtRegNonPerfDistHrlyAmt(_{a, s, h})</td>
<td>$</td>
<td>Hour</td>
<td>Real-Time Regulation Non-Performance Distribution Amount per AO per Settlement Location per Hour - The amount to AO (a) for AO (a)’s share of the total of RtRegNonPerfHrlyAmt(_{a, s, h}) in Hour (h).</td>
</tr>
<tr>
<td>RtLoadRatioShareHrlyFct(_{a, s, h})</td>
<td>Ratio</td>
<td>Hour</td>
<td>Real-Time Load Ratio Share Factor per AO per Settlement Location per Hour – The value calculated under Section 4.5.9.11.</td>
</tr>
<tr>
<td>RtRegNonPerfHrlyAmt(_{a, s, h})</td>
<td>$</td>
<td>Hour</td>
<td>Real-Time Regulation Non-Performance Amount per AO per Resource Settlement Location per Hour – The value calculated under Section 4.5.9.15.</td>
</tr>
<tr>
<td>RtRegNonPerfSppHrlyAmt(_h)</td>
<td>$</td>
<td>Hour</td>
<td>Real-Time Regulation Non-Performance Amount per Hour – The SPP total of the values calculated under Section 4.5.9.15 in Hour (h).</td>
</tr>
<tr>
<td>RtRegNonPerfDistDlyAmt(_{a, s, d})</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Regulation Non-Performance Distribution Amount per AO per Operating Day The amount to AO (a) for total Regulation Non-Performance charges in Operating Day (d).</td>
</tr>
<tr>
<td>RtRegNonPerfDistAoAmt(_{a, m, d})</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Regulation Non-Performance Distribution Amount per AO per Operating Day The amount to AO (a) associated with Market Participant (m) for total Regulation Non-Performance charges in Operating Day (d).</td>
</tr>
<tr>
<td>RtRegNonPerfDistMpAmt(_m, d)</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Regulation Non-Performance Distribution Amount per MP per Operating Day The amount to MP (m) for total Regulation Non-Performance charges in Operating Day (d).</td>
</tr>
<tr>
<td>(a)</td>
<td>none</td>
<td>none</td>
<td>An Asset Owner.</td>
</tr>
<tr>
<td>(s)</td>
<td>none</td>
<td>none</td>
<td>A Settlement Location.</td>
</tr>
<tr>
<td>(h)</td>
<td>none</td>
<td>none</td>
<td>An Hour.</td>
</tr>
<tr>
<td>(d)</td>
<td>none</td>
<td>none</td>
<td>An Operating Day.</td>
</tr>
<tr>
<td>(m)</td>
<td>none</td>
<td>none</td>
<td>A Market Participant.</td>
</tr>
</tbody>
</table>
4.5.9.17  Real-Time Contingency Reserve Deployment Failure Amount

(1) A RTBM charge or credit\(^{24}\) will be assessed at each Resource Settlement Location or Common Bus for each Asset Owner following deployment of Contingency Reserve if the amount of Contingency Reserve specified in the Contingency Reserve Deployment Instruction fails to be provided. Failure to provide the specified amount of Contingency Reserve is determined through a series four (4) tests as described in Section 4.4.4.3. The tests are performed either at the individual Resource level or, at the Common Bus level if the Resource receiving the Contingency Reserve Deployment Instruction is registered at a Common Bus. An Asset Owner must fail all four tests in order to receive a penalty for deployment failure. The penalty amount will be determined by multiplying the RTBM LMP (Absolute Value) for the Dispatch Interval in which the Contingency Reserve Deployment Period ends by the minimum of all Shortfall Quantity Amounts calculated from each of the four tests.

The amount to each applicable Asset Owner is calculated as follows.

\[
\text{IF CommonBusFlg}_{a,cb,s,i} = "1”
\]

THEN

\[
#RtCRDeplFailAmt_{a,s,i} = \text{RtCRCBShortfallQty}_{a,cb,i} \times \text{ABS (RtLmp5minPrc}_{s,i})
\]

ELSE

\[
#RtCRDeplFailAmt_{a,s,i} = \text{RtCRSLShortfallQty}_{a,s,i} \times \text{ABS (RtLmp5minPrc}_{s,i})
\]

Where,

(a) \text{RtCRSLShortfallQty}_{a,s,i} =

\[
\text{Min (Test1SLShortfallQty}_{a,s,i}, \text{Test2SLShortFallQty}_{a,s,i}, \text{Test3SLShortfallQty}_{a,s,i}, \text{Test4SLShortFallQty}_{a,s,i})
\]

\(^{24}\)Note that this charge type will almost always produce a charge. The credit is included here for the rare occasion when a credit may be produced as a result of a data error and/or a resettlement.
(b) \( \text{RtCRCBShortfallQty}_{a, cb, i} = \)
\[
\text{Min} \left( \text{Test1CBShortfallQty}_{a, cb, i}, \text{Test2CBShortfallQty}_{a, cb, i}, \text{Test3CBShortfallQty}_{a, cb, i}, \text{Test4CBShortfallQty}_{a, cb, i} \right)
\]

(c) \( \text{Test1SLShortfallQty}_{a, s, i} = \)
\[
\text{Max} \left( 0, \text{RtEndTelemtr5minQty}_{a, s, i} + \text{RtEndInstRampSP5minQty}_{a, s, i} \right)
\]

(d) \( \text{Test1CBShortfallQty}_{a, cb, i} = \)
\[
\text{Max} \left( 0, \sum_{s} \text{RtEndTelemtr5minQty}_{a, s, i} + \sum_{s} \text{RtEndInstRampSP5minQty}_{a, s, i} \right)
\]

(e) \( \text{Test2SLShortfallQty}_{a, s, i} = \)
\[
\text{Max} \left( 0, \text{RtEndTelemtr5minQty}_{a, s, i} + \text{RtEndInstStepSP5minQty}_{a, s, i} \right)
\]

(f) \( \text{Test2CBShortfallQty}_{a, cb, i} = \)
\[
\text{Max} \left( 0, \sum_{s} \text{RtEndTelemtr5minQty}_{a, s, i} + \sum_{s} \text{RtEndInstStepSP5minQty}_{a, s, i} \right)
\]

(g) \( \text{Test3SLShortfallQty}_{a, s, i} = \text{Max} \left( 0, \{ \text{RtEndTelemtr5minQty}_{a, s, i} - \text{RtBeginTelemtr5minQty}_{a, s, i} \} \right. \)
\[
\left. + \{ \text{RtEndInstRampSP5minQty}_{a, s, i} - \text{RtBeginInstRampSP5minQty}_{a, s, i} \} \right)
\]

(h) \( \text{Test3CBShortfallQty}_{a, cb, i} = \text{Max} \left( 0, \sum_{s} \text{RtEndTelemtr5minQty}_{a, s, i} \right. \)
\[
\left. - \sum_{s} \text{RtBeginTelemtr5minQty}_{a, s, i} \right)
\]
\[
+ \left\{ \sum_{s} \text{RtEndInstRampSP5minQty}_{a, s, i} \right\} - \left. \sum_{s} \text{RtBeginInstRampSP5minQty}_{a, s, i} \right\}
\]

(i) \hspace{1cm} \text{Test4SLShortfallQty}_{a, s, i} = \max \left( 0, \left\{ \sum_{s} \text{RtEndTelemtr5minQty}_{a, s, i} \right\} - \text{RtBeginTelemtr5minQty}_{a, s, i} \right) + \left\{ \sum_{s} \text{RtEndInstStepSP5minQty}_{a, s, i} \right\} - \left. \sum_{s} \text{RtBeginInstStepSP5minQty}_{a, s, i} \right\}

(j) \hspace{1cm} \text{Test4CBShortfallQty}_{a, cb, i} = \max \left( 0, \left\{ \sum_{s} \text{RtEndTelemtr5minQty}_{a, s, i} \right\} - \left. \sum_{s} \text{RtBeginTelemtr5minQty}_{a, s, i} \right\}
\]

+ \left\{ \sum_{s} \text{RtEndInstStepSP5minQty}_{a, s, i} \right\}

\]

(2) For each Asset Owner, an hourly amount at each Settlement Location is calculated. The amount is calculated as follows:

\[
\text{RtCRDeplFailHrlyAmt}_{a, s, h} = \sum_{i} \text{RtCRDeplFailAmt}_{a, s, i}
\]

(3) For each Asset Owner, a daily amount at each Settlement Location is calculated. The amount is calculated as follows:
\[ \text{RtCRDeplFailDlyAmt}_{a, s, d} = \sum_{h} \text{RtCRDeplFailHrlyAmt}_{a, s, h} \]

(4) For each Asset Owner associated with Market Participant \( m \), a daily amount is calculated. The daily amount is calculated as follows:\[ \text{RtCRDeplFailAoAmt}_{a, m, d} = \sum_{s} \text{RtCRDeplFailDlyAmt}_{a, s, d} \]

(5) For each Market Participant, a daily amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The daily amount is calculated as follows:\[ \text{RtCRDeplFailMpAmt}_{m, d} = \sum_{a} \text{RtCRDeplFailAoAmt}_{a, m, d} \]
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>RtCRDeplFailAmt (_{a, s, i})</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time Contingency Reserve Deployment Failure Amount per AO per Settlement Location per Dispatch Interval – The amount to AO (a) for failure to provide Contingency Reserve deployment at Resource Settlement Location (s) or Common Bus location (cb) for the Dispatch Interval.</td>
</tr>
<tr>
<td>RtCRCBShortfallQty (_{a, cb, i})</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Contingency Reserve Shortfall Quantity per AO per Common Bus per Dispatch Interval – AO (a)’s MW amount of Contingency Reserve that failed to deploy at Common Bus location (cb) for the Dispatch Interval.</td>
</tr>
<tr>
<td>RtCRSLShortfallQty (_{a, s, i})</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Contingency Reserve Shortfall Quantity per AO per Settlement Location per Dispatch Interval – AO (a)’s MW amount of Contingency Reserve that failed to deploy at Settlement Location (s) for the Dispatch Interval.</td>
</tr>
<tr>
<td>Test1SLShortfallQty (_{a, s, i})</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Contingency Reserve Deployment Test 1 Shortfall Quantity per AO per Settlement Location per Dispatch Interval – AO (a)’s MW amount of Contingency Reserve that failed to deploy at Settlement Location (s) or Common Bus location (cb) for the Dispatch Interval under Test 1 described under Section 4.4.4.3.</td>
</tr>
<tr>
<td>Test1CBShortfallQty (_{a, cb, i})</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Contingency Reserve Deployment Test 1 Shortfall Quantity per AO per Common Bus per Dispatch Interval – AO (a)’s MW amount of Contingency Reserve that failed to deploy at Common Bus (cb) for the Dispatch Interval under Test 1 described under Section 4.4.4.3.</td>
</tr>
<tr>
<td>Test2SLShortfallQty (_{a, s, i})</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Contingency Reserve Deployment Test 2 Shortfall Quantity per AO per Settlement Location per Dispatch Interval – AO (a)’s MW amount of Contingency Reserve that failed to deploy at Settlement Location (s) or Common Bus location (cb) for the Dispatch Interval under Test 2 described under Section 4.4.4.3.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>--------------------------------</td>
<td>------</td>
<td>---------------------</td>
<td>-------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>Test2CBShortfallQty(_a, cb, i)</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td><strong>Real-Time Contingency Reserve Deployment Test 2 Shortfall Quantity per AO per Common Bus per Dispatch Interval</strong> – AO a’s MW amount of Contingency Reserve that failed to deploy at Common Bus cb for the Dispatch Interval under Test 2 described under Section 4.4.4.3.</td>
</tr>
<tr>
<td>Test3SLShortfallQty(_a, s, i)</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td><strong>Real-Time Contingency Reserve Deployment Test 3 Shortfall Quantity per AO per Settlement Location per Dispatch Interval</strong> – AO a’s MW amount of Contingency Reserve that failed to deploy at Settlement Location s or Common Bus location cb for the Dispatch Interval under Test 3 described under Section 4.4.4.3.</td>
</tr>
<tr>
<td>Test3CBShortfallQty(_a, cb, i)</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td><strong>Real-Time Contingency Reserve Deployment Test 3 Shortfall Quantity per AO per Common Bus per Dispatch Interval</strong> – AO a’s MW amount of Contingency Reserve that failed to deploy at Common Bus cb for the Dispatch Interval under Test 3 described under Section 4.4.4.3.</td>
</tr>
<tr>
<td>Test4SLShortfallQty(_a, s, i)</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td><strong>Real-Time Contingency Reserve Deployment Test 4 Shortfall Quantity per AO per Settlement Location per Dispatch Interval</strong> – AO a’s MW amount of Contingency Reserve that failed to deploy at Settlement Location s or Common Bus location cb for the Dispatch Interval under Test 4 described under Section 4.4.4.3.</td>
</tr>
<tr>
<td>Test4CBShortfallQty(_a, cb, i)</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td><strong>Real-Time Contingency Reserve Deployment Test 4 Shortfall Quantity per AO per Common Bus per Dispatch Interval</strong> – AO a’s MW amount of Contingency Reserve that failed to deploy at Common Bus cb for the Dispatch Interval under Test 4 described under Section 4.4.4.3.</td>
</tr>
<tr>
<td>RtLmp5minPrc(_s, i)</td>
<td>S/MW</td>
<td>Dispatch Interval</td>
<td><strong>Real-Time LMP</strong> - The value defined under Section 4.5.9.1 at the Settlement Location s for Dispatch Interval i that is associated with the Resource receiving the Contingency Reserve Deployment Instruction.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>----------</td>
<td>------</td>
<td>---------------------</td>
<td>------------</td>
</tr>
<tr>
<td>( \text{RtBeginTelemtr5minQty}_{a,s,i} )</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Telemetered Quantity per AO per Settlement Location per Dispatch Interval – AO a’s Resource telemetered (SCADA) MW output as measured at the beginning of the Contingency Reserve Deployment Period.</td>
</tr>
<tr>
<td>( \text{RtEndTelemtr5minQty}_{a,s,i} )</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Telemetered Quantity per AO per Settlement Location per Dispatch Interval – AO a’s Resource telemetered (SCADA) MW output as measured at the end of the Contingency Reserve Deployment Period.</td>
</tr>
<tr>
<td>( \text{RtBeginInstRampSP5minQty}_{a,s,i} )</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Instantaneous Ramped Setpoint Quantity per AO per Settlement Location per Dispatch Interval – AO a’s Resource ramped Setpoint Instruction at the beginning of the Contingency Reserve Deployment Period.</td>
</tr>
<tr>
<td>( \text{RtEndInstRampSP5minQty}_{a,s,i} )</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Instantaneous Ramped Setpoint Quantity per AO per Settlement Location per Dispatch Interval – AO a’s Resource ramped Setpoint Instruction at the end of the Contingency Reserve Deployment Period.</td>
</tr>
<tr>
<td>( \text{RtBeginInstStepSP5minQty}_{a,s,i} )</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Instantaneous Stepped Setpoint Quantity per AO per Settlement Location per Dispatch Interval – AO a’s Resource stepped Setpoint Instruction at the beginning of the Contingency Reserve Deployment Period.</td>
</tr>
<tr>
<td>( \text{RtEndInstStepSP5minQty}_{a,s,i} )</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Instantaneous Stepped Setpoint Quantity per AO per Settlement Location per Dispatch Interval – AO a’s Resource stepped Setpoint Instruction at the end of the Contingency Reserve Deployment Period.</td>
</tr>
<tr>
<td>( \text{CommonBusFlg}_{a,cb,s,i} )</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Common Bus Flag per AO per Settlement Location per Common Bus per Dispatch Interval – A Flag that is set equal to 1 in Dispatch Interval ( i ) at any one of AO a’s Resource Settlement Locations ( s ) that is registered at Common Bus ( cb ).</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>----------</td>
<td>------</td>
<td>---------------------</td>
<td>------------</td>
</tr>
<tr>
<td>RtCRDeplFailHrlyAmt (_{a, s, h})</td>
<td>$</td>
<td>Hour</td>
<td><strong>Real-Time Contingency Reserve Deployment Failure Amount per AO per Settlement Location per Hour</strong> – The amount to AO (a) for failure to provide Contingency Reserve deployment at Settlement Location (s) for the Hour.</td>
</tr>
<tr>
<td>RtCRDeplFailDlyAmt (_{a, s, d})</td>
<td>$</td>
<td>Operating Day</td>
<td><strong>Real-Time Contingency Reserve Deployment Failure Amount per AO per Settlement Location per Operating Day</strong> – The amount to AO (a) associated with Market Participant (m) for failure to provide Contingency Reserve deployment as Settlement Location (s) for the Operating Day.</td>
</tr>
<tr>
<td>RtCRDeplFailAoAmt (_{a, m, d})</td>
<td>$</td>
<td>Operating Day</td>
<td><strong>Real-Time Contingency Reserve Deployment Failure Amount per AO per Operating Day</strong> – The amount to AO (a) associated with Market Participant (m) for failure to provide Contingency Reserve deployment for the Operating Day.</td>
</tr>
<tr>
<td>RtCRDeplFailMpAmt (_{m, d})</td>
<td>$</td>
<td>Operating Day</td>
<td><strong>Real-Time Spinning Reserve Deployment Failure Amount per MP per Operating Day</strong> – The amount to MP (m) for failure to provide Contingency Reserve deployment for the Operating Day.</td>
</tr>
</tbody>
</table>

\(a\) none none An Asset Owner.

\(s\) none none A Resource Settlement Location.

\(cb\) none none A Common Bus.

\(h\) none none An Hour.

\(i\) none none A Dispatch Interval.

\(d\) none none An Operating Day.

\(m\) none none A Market Participant.
4.5.9.18 Real-Time Contingency Reserve Deployment Failure Distribution Amount

(1) A RTBM charge or credit will be calculated for each Asset Owner for each hour. The Asset Owner amount will be equal to the Asset Owner’s real-time load ratio share of the Real-Time Contingency Reserve Deployment Failure Amount. The amount to each Asset Owner is calculated as follows:

\[
\# \text{RtCRDeplFailDistHrlyAmt}_{a, s, h} = \text{RtCRDeplFailSppHrlyAmt}_{h} \times \text{RtLoadRatioShareHrlyFct}_{a, s, h} \times (-1)
\]

Where,

\[
\text{RtCRDeplFailSppHrlyAmt}_{h} = \sum_{a} \sum_{s} \text{RtCRDeplFailHrlyAmt}_{a, s, h}
\]

(2) For each Asset Owner, a daily amount is calculated at each Settlement Location. The daily amount is calculated as follows:

\[
\text{RtCRDeplFailDistDlyAmt}_{a, s, d} = \sum_{h} \text{RtCRDeplFailDistHrlyAmt}_{a, s, h}
\]

(3) For each Asset Owner associated with Market Participant \(m\), a daily amount is calculated. The daily amount is calculated as follows:

\[
\text{RtCRDeplFailDistAoAmt}_{a, m, d} = \sum_{s} \text{RtCRDeplFailDistDlyAmt}_{a, s, d}
\]

(4) For each Market Participant, a daily amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The daily amount is calculated as follows:

\[
\text{RtCRDeplFailDistMpAmt}_{m, d} = \sum_{a} \text{RtCRDeplFailDistAoAmt}_{a, m, d}
\]
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>RtCRDeplFailDistHrlyAmt&lt;sub&gt;a, s, h&lt;/sub&gt;</td>
<td>$</td>
<td>Hour</td>
<td>Real-Time Contingency Reserve Deployment Failure Distribution Amount per AO per Settlement Location per Hour - The amount to AO &lt;i&gt;a&lt;/i&gt; for AO &lt;i&gt;a&lt;/i&gt;’s share of the total of RtCRDeplFailHrlyAmt&lt;sub&gt;a, s, h&lt;/sub&gt; in Hour &lt;i&gt;h&lt;/i&gt;.</td>
</tr>
<tr>
<td>RtLoadRatioShareHrlyFct&lt;sub&gt;a, s, h&lt;/sub&gt;</td>
<td>Ratio</td>
<td>Hour</td>
<td>Real-Time Load Ratio Share Factor per AO per Settlement Location per Hour – The value calculated under Section 4.5.9.11.</td>
</tr>
<tr>
<td>RtCrDeplFailHrlyAmt&lt;sub&gt;a, s, h&lt;/sub&gt;</td>
<td>$</td>
<td>Hour</td>
<td>Real-Time Contingency Reserve Deployment Failure Amount per AO per Hour – The value calculated under Section 4.5.9.17.</td>
</tr>
<tr>
<td>RtCRDeplFailSppHrlyAmt&lt;sub&gt;h&lt;/sub&gt;</td>
<td>$</td>
<td>Hour</td>
<td>Real-Time Contingency Reserve Deployment Failure Amount per Hour – The DPP total of the values calculated under Section 4.5.9.17 in Hour &lt;i&gt;h&lt;/i&gt;.</td>
</tr>
<tr>
<td>RtCRDeplFailDistDlyAmt&lt;sub&gt;a, s, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Contingency Reserve Deployment Failure Distribution Amount per AO per Reserve Zone per Operating Day The amount to AO &lt;i&gt;a&lt;/i&gt; for total Contingency Reserve deployment failure charges in Operating Day &lt;i&gt;d&lt;/i&gt;.</td>
</tr>
<tr>
<td>RtCRDeplFailDistAoAmt&lt;sub&gt;a, m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Contingency Reserve Deployment Failure Distribution Amount per AO per Operating Day The amount to AO &lt;i&gt;a&lt;/i&gt; associated with Market Participant &lt;i&gt;m&lt;/i&gt; for total Contingency Reserve deployment failure charges in Operating Day &lt;i&gt;d&lt;/i&gt;.</td>
</tr>
<tr>
<td>RtCRDeplFailDistMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Contingency Reserve Deployment Failure Distribution Amount per MP per Operating Day The amount to MP &lt;i&gt;m&lt;/i&gt; for total Contingency Reserve deployment failure charges in Operating Day &lt;i&gt;d&lt;/i&gt;.</td>
</tr>
</tbody>
</table>

<i>a</i>  none  none  An Asset Owner.
<i>s</i>  none  none  A Settlement Location.
<i>h</i>  none  none  An Hour.
<i>d</i>  none  none  An Operating Day.
<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>$m$</td>
<td>none</td>
<td>none</td>
<td>A Market Participant.</td>
</tr>
</tbody>
</table>
4.5.9.19 Real-Time Regulation Deployment Adjustment Amount

(1) A RTBM charge or credit will be calculated at each Resource Settlement Location for each Asset Owner for each Dispatch Interval when a Resource with cleared RTBM Regulation-Up or Regulation-Down is deployed. The amount will be determined as one-twelfth of the sum of:

(a) For Regulation-Up deployment, the amount is equal to the difference between (1) actual Regulation-Up deployment MW multiplied by RTBM LMP, and (2) Energy Offer Curve cost of actual Regulation-Up deployment MW;

(i) The actual Regulation-Up deployment MW is calculated as the difference between the lesser of (1) (Dispatch Instruction + average Regulation-Up deployment) or (2) Absolute Value of actual Resource output, and the Resource’s average Dispatch Instruction for Energy. If the Absolute Value of the Resource’s actual output is less than or equal to the Resource’s average Dispatch Instruction for Energy, then the actual Regulation-Up deployment MW is equal to zero.

(b) For Regulation-Down deployment, the amount is equal to the difference between (1) Energy Offer Curve cost of actual Regulation-Down deployment MW, and (2) actual Regulation-Down deployment MW multiplied by RTBM LMP;

(i) The actual Regulation-Down deployment MW is calculated as the difference between the Resource’s average Dispatch Instruction for Energy and the greater of (1) (average Dispatch Instruction - average Regulation-Down deployment) or (2) Absolute Value of actual Resource output. If the Absolute Value of the Resource’s actual output is greater than or equal to the Resource’s average Dispatch Instruction for Energy, then the actual Regulation-Down deployment MW is equal to zero.

The amount to each applicable Asset Owner is calculated as follows.

IF ControlStatus5minFlg_{a,s,i} = “Regulating”

THEN

RtRegAdj5minAmt_{a,s,i} = RtRegUpAdj5minAmt_{a,s,i} + RtRegDnAdj5minAmt_{a,s,i}

ELSE
RtRegAdj5minAmt_{a,s,i} = 0

Where,

(a) \#RtRegUpAdj5minAmt_{a,s,i} = RtRegUpDepl5minQty_{a,s,i} \\
* (RtLmp5minPrc_{s,i} - RtRegUpDepl5minCostRate_{a,s,i}) / 12

(a.1) RtRegUpDepl5minQty_{a,s,i} = \\
Max (RtAvgDispatch5minQty_{a,s,i}, \\
Min ( RtBillMtr5minQty_{a,s,i} * (-1), ( RtAvgDispatch5minQty_{a,s,i} \\
+ RtAvgRegUpSp5minQty_{a,s,i} ))) \\
- RtAvgDispatch5minQty_{a,s,i}

(b) \#RtRegDnAdj5minAmt_{a,s,i} = RtRegDnDepl5minQty_{a,s,i} \\
* (RtRegDnDepl5minCostRate_{a,s,i} - RtLmp5minPrc_{s,i}) / 12

(b.1) RtRegDnDepl5minQty_{a,s,i} = RtAvgDispatch5minQty_{a,s,i} \\
- Min (RtAvgDispatch5minQty_{a,s,i}, \\
Max ( RtBillMtr5minQty_{a,s,i} * (-1), ( RtAvgDispatch5minQty_{a,s,i} \\
- RtAvgRegDnSp5minQty_{a,s,i} )))

(2) For each Asset Owner, an hourly amount is calculated at each Settlement Location. The amount is calculated as follows:

\[ \text{RtRegAdjHrlyAmt}_{a,s,h} = \sum_{i} \text{RtRegAdj5minAmt}_{a,s,i} \]

(3) For each Asset Owner, a daily amount is calculated at each Settlement Location. The credit amount is calculated as follows:
\[ \text{RtRegAdjDlyAmt}_{a,s,d} = \sum_h \text{RtRegAdjHrlyAmt}_{a,s,h} \]

(4) For each Asset Owner associated with Market Participant \( m \), a daily amount is calculated. The daily amount is calculated as follows:

\[ \text{RtRegAdjAoAmt}_{a,m,d} = \sum_s \text{RtRegAdjDlyAmt}_{a,s,d} \]

(5) For each Market Participant, a daily amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The daily amount is calculated as follows:

\[ \text{RtRegAdjMpAmt}_{m,d} = \sum_a \text{RtRegAdjAoAmt}_{a,m,d} \]

(6) For FERC Electric Quarterly Reporting ("EQR") purposes, SPP calculates Real-Time Regulation Deployment Adjustment $ per Dispatch Interval for each Asset Owner as follows:

(a) \( \text{EqrRtRegAdj5minPrc}_{a,s,i} = (-1) \times \text{RtRegAdj5minAmt}_{a,s,i} \)

(b) IF \( \text{EqrRtRegAdj5minPrc}_{a,s,i} <> 0 \) THEN

\[ \text{EqrRtRegAdj5minQty}_{a,s,i} = 1 \]
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>RtRegAdj5minAmt_{a,s,i}</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time Regulation Deployment Adjustment Amount per AO per Resource Settlement Location per Dispatch Interval - The amount to AO ( a ) for Energy associated with Regulation deployment at Resource Settlement Location ( s ) for the Dispatch Interval.</td>
</tr>
<tr>
<td>RtBillMtr5minQty_{a,s,i}</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Billing Meter Quantity per AO per Settlement Location per Dispatch Interval - The value described under Section 4.5.9.1.</td>
</tr>
<tr>
<td>RtLmp5minPrc_{s,i}</td>
<td>$/MW</td>
<td>Dispatch Interval</td>
<td>Real-Time LMP - The value defined under Section 4.5.9.1 at Settlement Location ( s ) for Dispatch Interval ( i ).</td>
</tr>
<tr>
<td>RtRegUpAdj5minAmt_{a,s,i}</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time Regulation-Up Deployment Adjustment Amount per AO per Resource Settlement Location per Dispatch Interval - The amount to AO ( a ) for Energy associated with Regulation-Up deployment at Resource Settlement Location ( s ) for the Dispatch Interval.</td>
</tr>
<tr>
<td>RtRegUpDepl5minQty_{a,s,i}</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Regulation-Up Deployment MW per AO per Settlement Location per Dispatch Interval – The integrated MW of Regulation-Up Deployment associated with AO ( a )’s Resource at Settlement Location ( s ) in Dispatch Interval ( i ).</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>----------</td>
<td>------</td>
<td>---------------------</td>
<td>------------</td>
</tr>
</tbody>
</table>
| RtRegUpDepl5minCostRate<sub>a, s, i</sub> | $/MW | Dispatch Interval | **Real-Time Regulation-Up Deployment Cost Rate per AO per Settlement Location per Dispatch Interval** – The cost, in $/MW, associated with RtRegUpDepl5minQty<sub>a, s, i</sub> for AO a’s Resource at Settlement Location s in Dispatch Interval i. The cost is calculated as \[
\int_{\text{Start}}^{\text{Stop}} \frac{\text{RTBM As Dispatched Energy Offer Curve}}{(\text{RtRegUpDepl5minQty<sub>a, s, i</sub>})},
\]
where \[
\text{Stop} = \min (\text{RtAvgSetpoint5minQty<sub>a, s, i</sub>, RtBillMtr5minQty<sub>a, s, i</sub>}),
\]
\[
\text{Start} = (\text{Stop} - \text{RtRegUpDepl5minQty<sub>a, s, i</sub>})
\] |
<p>| RtRegDnAdj5minAmt&lt;sub&gt;a, s, i&lt;/sub&gt; | $ | Dispatch Interval | <strong>Real-Time Regulation-Down Deployment Adjustment Amount per AO per Resource Settlement Location per Dispatch Interval</strong> - The amount to AO a for Energy associated with Regulation-Down deployment at Resource Settlement Location s for the Dispatch Interval. |
| RtRegDnDepl5minQty&lt;sub&gt;a, s, i&lt;/sub&gt; | MW | Dispatch Interval | <strong>Real-Time Regulation-Down Deployment MW per AO per Settlement Location per Dispatch Interval</strong> – The integrated MW of Regulation-Down Deployment associated with AO a’s Resource at Settlement Location s in Dispatch Interval i. |</p>
<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
</table>
| RtRegDnDepl5minCostRate_{a, s, i} | $/MW       | Dispatch Interval   | Real-Time Regulation-Down Deployment Cost Rate per AO per Settlement Location per Dispatch Interval – The cost, in $/MW, associated with RtRegDnDepl5minQty_{a, s, i} for AO a’s Resource at Settlement Location s in Dispatch Interval i. The cost is calculated as \[
\int_{\text{Start}}^{\text{Stop}} \frac{\text{RTBM As Dispatched Energy Offer Curve}}{\text{(RtRegDnDepl5minQty}_{a, s, i})},
\]
where
Start = \(\text{Max ( RtAvgSetpoint5minQty}_{a, s, i}, (-1)\text{RtBillMtr5minQty}_{a, s, i})\)
Stop = \(\text{(Start} + \text{RtRegDnDepl5minQty}_{a, s, i})\) |
<p>| RtAvgDispatch5minQty_{a, s, i}   | MW         | Dispatch Interval   | Real-Time Average Dispatch Instruction MW per AO per Settlement Location per Dispatch Interval – The average Dispatch Instruction as calculated as the average of the Dispatch Instruction in current Dispatch Interval i and the Dispatch Instruction for the previous Dispatch Interval i for AO a’s Resource at Settlement Location s in Dispatch Interval i. |
| RtAvgRegUpSp5minQty_{a, s, i}    | MW         | Dispatch Interval   | Real-Time Average Regulation-Up Setpoint Instruction MW per AO per Settlement Location per Dispatch Interval – The average of the portion of the Resource Setpoint Instruction associated with Regulation-Up deployment as calculated using the Resource’s applicable ramp rate used by the RTBM SCED to calculate the Dispatch Instruction for Energy and the amount of RTBM cleared Regulation-Up for AO a’s Resource at Settlement Location s in Dispatch Interval i. |</p>
<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>RtAvgRegDnSp5minQty&lt;sub&gt;a, s, i&lt;/sub&gt;</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td><strong>Real-Time Average Regulation-Down Setpoint Instruction MW per AO per Settlement Location per Dispatch Interval</strong> – The average of the portion of the Resource Setpoint Instruction associated with Regulation-Down deployment as calculated using the Resource’s applicable ramp rate used by the RTBM SCED to calculate the Dispatch Instruction for Energy and the amount of RTBM cleared Regulation-Down for AO a’s Resource at Settlement Location s in Dispatch Interval i.</td>
</tr>
<tr>
<td>ControlStatus5minFlg&lt;sub&gt;a, s, i&lt;/sub&gt;</td>
<td>None</td>
<td></td>
<td><strong>Control Status per AO per Settlement Location per Dispatch Interval</strong> – The value described under Section 4.5.9.8.</td>
</tr>
<tr>
<td>RtRegAdjHrlyAmt&lt;sub&gt;a, s, h&lt;/sub&gt;</td>
<td>$</td>
<td>Dispatch Interval</td>
<td><strong>Real-Time Regulation Deployment Adjustment Amount per AO per Resource Settlement Location per Hour</strong> - The amount to AO a for Energy associated with Regulation deployment at Resource Settlement Location s for the Hour.</td>
</tr>
<tr>
<td>RtRegAdjDlyAmt&lt;sub&gt;a, s, d&lt;/sub&gt;</td>
<td>$</td>
<td>Dispatch Interval</td>
<td><strong>Real-Time Regulation Deployment Adjustment Amount per AO per Resource Settlement Location per Operating Day</strong> - The amount to AO a for Energy associated with Regulation deployment at Resource Settlement Location s for the Operating Day.</td>
</tr>
<tr>
<td>RtRegAdjAoAmt&lt;sub&gt;a, m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Dispatch Interval</td>
<td><strong>Real-Time Regulation Deployment Adjustment Amount per AO per Operating Day</strong> - The amount to AO a associated with Market Participant m for Energy associated with Regulation deployment for the Operating Day.</td>
</tr>
<tr>
<td>RtRegAdjMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Dispatch Interval</td>
<td><strong>Real-Time Regulation Deployment Adjustment Amount per MP per Operating Day</strong> - The amount to MP m for Energy associated with Regulation deployment for the Operating Day.</td>
</tr>
<tr>
<td>EqrRtRegAdj5minPrc&lt;sub&gt;a, s, i&lt;/sub&gt;</td>
<td>$</td>
<td>Dispatch Interval</td>
<td><strong>Real-Time Electric Quarterly Reporting Regulation Deployment Adjustment Amount per AO per Settlement Location per Dispatch Interval</strong> - The Regulation Deployment Adjustment charge/credit to AO a for Dispatch Interval i at Resource Settlement Location s for use by AO a in reporting such charges/credits to FERC in accordance with FERC EQR requirements.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>----------------------------------</td>
<td>------</td>
<td>---------------------</td>
<td>---------------------------------------------------------------------------</td>
</tr>
<tr>
<td>$EqrRtRegAdj5minQty_{a,s,c}$</td>
<td>$$</td>
<td>Dispatch Interval</td>
<td>Real-Time Electric Quarterly Reporting Regulation Deployment Adjustment Quantity per AO per Settlement Location per Dispatch Interval – This value is set equal to 1 if $EqrRtRegAdj5minPrc_{a,s,c} &gt; 0$ for use by AO $a$ in reporting such make-whole-payments to FERC in accordance with FERC EQR requirements.</td>
</tr>
<tr>
<td>$a$</td>
<td>none</td>
<td>none</td>
<td>An Asset Owner.</td>
</tr>
<tr>
<td>$s$</td>
<td>none</td>
<td>none</td>
<td>A Resource Settlement Location.</td>
</tr>
<tr>
<td>$h$</td>
<td>none</td>
<td>none</td>
<td>An Hour.</td>
</tr>
<tr>
<td>$i$</td>
<td>none</td>
<td>none</td>
<td>A Dispatch Interval.</td>
</tr>
<tr>
<td>$d$</td>
<td>none</td>
<td>none</td>
<td>An Operating Day.</td>
</tr>
<tr>
<td>$m$</td>
<td>none</td>
<td>none</td>
<td>A Market Participant.</td>
</tr>
</tbody>
</table>
4.5.9.20 Real-Time Over-Collected Losses Distribution Amount

(1) The Marginal Losses Component of the RTBM LMP that results from the economic market solution which considers the cost of marginal losses, congestion costs and incremental Energy costs creates an over collection (or under collection as a result of the Real-Time deviation accounting) related to payment for losses (“RTBM Over-Collected Losses”) that must be accounted for. A RTBM credit or charge is calculated for each hour at each Settlement Location for which an Asset Owner has a net RTBM Energy withdrawal that contributed positively to the over collection or under collection. Each Asset Owner’s contribution to the RTBM Over-Collected Losses is calculated based upon a Loss Pool that is dynamically defined by the Asset Owner’s transactional activity. A loss rebate factor is calculated for each Asset Owner and withdrawal Settlement Location as the difference between the Marginal Loss Component at a withdrawal Settlement Location in the Asset Owner’s Loss Pool and the injection weighted average Marginal Loss Component for the Asset Owner’s Loss Pool, multiplied by that Asset Owner’s share of the net withdrawal (calculated excluding cleared DA Market Virtual Bids and cleared DA Market Virtual Offers) at that Settlement Location. The injection weighted average MLC for the Asset Owner’s Loss Pool is calculated assuming that injection in the Loss Pool first serves withdrawal in the Loss Pool and then goes to meet the withdrawal in Loss Pools which do not have sufficient injection to meet all withdrawal. The loss rebate factor (positive value only, negative values are ignored) is a measure of the payment for losses on a marginal basis at each Settlement Location. The loss rebate factors are then normalized to allocate a pro-rata portion of the total over collection or under collection in the hour to Asset Owners by Settlement Location. The amount is calculated as follows:

\[
#\text{RtOclDistHrlyAmt}_{a, s, lp, h} = \text{RtNormLossRbtHrlyFct}_{a, s, lp, h} \times \text{RtIncrOclHrlyAmt}_{h} \times (-1)
\]

Where,

\[
(a) \quad \text{RtIncrOclHrlyAmt}_{h} = \sum_{i} \text{RtIncrOcl5minAmt}_{i}
\]

\[
(a.1) \quad #\text{RtIncrOcl5minAmt}_{i} =
\]
\[
\sum_a \sum_s \sum_{lp} \left( \text{RtLmp5minPrc}_{s, i} - \text{RtMcc5minPrc}_{s, i} \right) \\
\times \left( \left( \text{RtBillMtr5minQty}_{a, s, lp, i} - \text{DaCldrHrlyQty}_{a, s, lp, h} \right) \\
- \sum_t \text{DaCldrVHrlyQty}_{a, s, lp, h, t} \\
+ \sum_i \text{RtImpExp5minQty}_{a, s, lp, i, t} - \sum_t \text{DaImpExp5minQty}_{a, s, lp, i, t} \right) / 12 \\
+ \text{RtNetInadvertentSpp5minAmt}_i \\
\]

(b) IF \( \text{RtLossRbtSppHrlyFct}_h = 0 \)

THEN

\( \text{RtNormLossRbtHrlyFct}_{a, s, lp, h} = 0 \)

ELSE

\[ \#\text{RtNormLossRbtHrlyFct}_{a, s, lp, h} = \]

\[ \text{Max} \left( 0, \text{RtLossRbtHrlyFct}_{a, s, lp, h} \right) / \text{RtLossRbtSppHrlyFct}_h \]

(b.1) \( \text{RtLossRbtSppHrlyFct}_h = \sum_a \sum_s \sum_{lp} \text{Max} \left( 0, \text{RtLossRbtHrlyFct}_{a, s, lp, h} \right) \)

(c) \( \text{RtLossRbtHrlyFct}_{a, s, lp, h} = \sum_i \text{Max} \left( 0, \text{RtLossRbt5minFct}_{a, s, lp, i} \right) \)

(c.1) \[ \#\text{RtLossRbt5minFct}_{a, s, lp, i} = \{ \left[ \text{RtLpIntSupply5minFct}_{lp, i} \\
\times \left( \text{RtMlc5minPrc}_{s, i} - \text{RtLpIwaMlc5minPrc}_{lp, i} \right) \\
+ \left( 1 - \text{RtLpIntSupply5minFct}_{lp, i} \right) \right] \times \left( \text{RtMlcHrlyPrc}_{s, i} - \text{RtSppIwaMlc5minPrc}_{i} \right) \} \]
* $\text{RtLpNetWdr5minQty}_{a, s, lp, i}$

(c.2) IF $\text{RtAoNetWdrSpp5minQty}_{s, i} = 0$

THEN

$\text{RtLpNetWdr5minQty}_{a, s, lp, i} = 0$

ELSE

$\text{RtLpNetWdr5minQty}_{a, s, lp, i} = \text{RtSlNetWdr5minQty}_{s, i}$

* $(\text{RtAoNetWdr5minQty}_{a, s, lp, i} / \text{RtAoNetWdrSpp5minQty}_{s, i})$

(c.3) $\text{RtAoNetWdrSpp5minQty}_{s, i} = \sum_{lp} \sum_{a} \text{RtAoNetWdr5minQty}_{a, s, lp, i}$

(c.4) $\text{RtAoNetWdr5minQty}_{a, s, lp, i} = \text{Max} \left( 0, ( \text{RtBillMtr5minQty}_{a, s, lp, i} - \text{DaClrdHrlyQty}_{a, s, lp, h} - \sum_{t} \text{RtEnFinHrlyQty}_{a, s, lp, h, t} - \sum_{t} \text{RtNEnFinHrlyQty}_{a, s, lp, h, t} + \sum_{t} \text{RtImpExp5minQty}_{a, s, lp, i, t} \times (1 - \text{RsgCrdFlgt}_{r}) \right) / 12$

(c.5) $\text{RtSlNetWdr5minQty}_{s, i} = \text{Max} \left( 0, \sum_{lp} \sum_{a} ( \text{RtBillMtr5minQty}_{a, s, lp, i} - \text{DaClrdHrlyQty}_{a, s, lp, h} - \sum_{t} \text{DaClrdVHrlyQty}_{a, s, lp, h, t} \right)$
+ \sum_t \text{RtImpExp5minQty}_{a,s,lp,i,t} \cdot (1 - \text{RsgCrdFlg}_t)

- \sum_t \text{DaImpExp5minQty}_{a,s,lp,i,t}) / 12

(d) IF \sum_s \text{RtLpNetWdr5minQty}_{a,s,lp,i} = 0

THEN

\text{RtLpIntSupply5minFct}_{lp,i} = 0

ELSE

\text{RtLpIntSupply5minFct}_{lp,i} =

\text{Min} \left[ 1, \sum_s \text{RtLpNetInj5minQty}_{a,s,lp,i} / \sum_s \text{RtLpNetWdr5minQty}_{a,s,lp,i} \right]

(d.1) IF \text{RtAoNetInjSpp5minQty}_{s,i} = 0

THEN

\text{RtLpNetInj5minQty}_{a,s,lp,i} = 0

ELSE

\text{RtLpNetInj5minQty}_{a,s,lp,i} = \text{RtSlNetInj5minQty}_{s,i} \cdot \frac{\text{RtAoNetInj5minQty}_{a,s,lp,i}}{\text{RtAoNetInjSpp5minQty}_{s,i}}

(d.2) \text{RtAoNetInjSpp5minQty}_{s,i} = \sum_{lp} \sum_a \text{RtAoNetInj5minQty}_{a,s,lp,i}

(d.3) \text{RtAoNetInj5minQty}_{a,s,lp,i} =

(-1) \cdot \text{Min} \left( 0, \frac{\text{RtBillMtr5minQty}_{a,s,lp,i} - \text{DaClrdHrlyQty}_{a,s,lp,h}}{2} \right)
Market Protocols for SPP Integrated Marketplace

(d.4) \[ \text{RtSlNetInj5minQty} \, s, i = (-1) \]

\[ \times \{ \min \left( 0, \sum_{lp} \sum_{a} \left[ \text{RtBillMtr5minQty} \, a, s, lp, i - \text{DaClrdHrlyQty} \, a, s, lp, h \right] \right) \} / 12 \]

+ \sum_{i} \text{DaImpExp5minQty} \, a, s, lp, i, t \times (1 - \text{RsgCrdFlg}_{i})

- \sum_{i} \text{DaImpExp5minQty} \, a, s, lp, i, t \}} / 12

(e) \[ \text{IF} \sum_{i} \text{RtLpNetInj5minQty} \, a, s, lp, i = 0 \]

THEN

\[ \text{RtLpExtSupply5minFct} \, lp, i = 0 \]

ELSE

\[ \text{RtLpExtSupply5minFct} \, lp, i = \]

Max \left| 0, (1 - \left( \sum_{s} \text{RtLpNetWdr5minQty} \, a, s, lp, i \right) \right|
(f) \[ \text{IF } \sum \text{RtLpNetInj5minQty}_{a,s,lp,i} = 0 \text{ THEN} \]
\[ \text{RtLpIwaMlc5minPrc}_{lp,i} = 0 \text{ ELSE} \]
\[ \text{RtLpIwaMlc5minPrc}_{lp,i} = \frac{\sum [\text{RtLpNetInj5minQty}_{a,s,lp,i} \cdot \text{RtMlc5minPrc}_{s,i}]}{\sum \text{RtLpNetInj5minQty}_{a,s,lp,i}} \]

(g) \[ \text{RtSppIwaMlc5minPrc}_{i} = \sum \sum [\text{RtLpExtSupply5minFct}_{lp,i} \cdot \sum (\text{RtLpNetInj5minQty}_{a,s,lp,i} \cdot \text{RtMlc5minPrc}_{s,i})] \]
\[ / \sum \sum [\text{RtLpExtSupply5minFct}_{lp,i} \cdot \sum \text{RtLpNetInj5minQty}_{a,s,lp,i}] \]

(2) For each Asset Owner, a daily amount is calculated at each Settlement Location. The daily amount is calculated as follows:

\[ \text{RtOclDistDlyAmt}_{a,s,lp,d} = \sum \text{RtOclDistHrlyAmt}_{a,s,lp,h} \]

(3) For each Asset Owner associated with Market Participant \( m \), a daily amount is calculated. The daily amount is calculated as follows:
\[ \text{RtOclDistAoAmt}_{a,m,d} = \sum_{s} \sum_{lp} \text{RtOclDistDlyAmt}_{a,s,lp,d} \]

(4) For each Market Participant, a daily amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The daily amount is calculated as follows:

\[ \text{RtOclDistMpAmt}_{m,d} = \sum_{a} \text{RtOclDistAoAmt}_{a,m,d} \]
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>RtOclDistHrlyAmt (a, s, lp, h)</td>
<td>$</td>
<td>Hour</td>
<td>Real-Time Over Collected Losses Distribution Amount per AO per Settlement Location in Loss Pool (lp) per Hour - The amount to AO (a) for AO (a)'s share of total over/under collection due to marginal losses at Settlement Location (s) in Loss Pool (lp) for the Hour.</td>
</tr>
<tr>
<td>RtNormLossRbtHrlyFct (a, s, lp, h)</td>
<td>none</td>
<td>Hour</td>
<td>Real-Time Normalized Loss Rebate Factor per AO per Settlement Location per Loss Pool per Hour – AO (a)'s percentage rebate of the (RtOclHrlyAmt) (a) at Settlement Location (s) in Loss Pool (lp) for the Hour.</td>
</tr>
<tr>
<td>RtLossRbtHrlyFct (a, s, lp, h)</td>
<td>$</td>
<td>Hour</td>
<td>Real-Time Loss Rebate Factor per AO per Settlement Location per Loss Pool per Hour – The sum of AO (a)'s (RtLossRbt5minFct) (a, s, lp, i) at Settlement Location (s) in Loss Pool (lp) for the Hour.</td>
</tr>
<tr>
<td>RtLossRbt5minFct (a, s, lp, i)</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time Loss Rebate Factor per AO per Settlement Location per Loss Pool per Dispatch Interval – AO (a)'s amount of marginal loss dollars calculated at Settlement Location (s) in Loss Pool (lp) for the Dispatch Interval.</td>
</tr>
<tr>
<td>RtLossRbtSppHrlyFct (h)</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time Loss Rebate Factor per Hour – The SPP total of (RtLossRbtHrlyFct) (a, s, lp, h) for the Hour.</td>
</tr>
<tr>
<td>RtAoNetWdrSpp5minQty (s, i)</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Net Withdrawal Quantity per Dispatch Interval – The SPP total of (RtAoNetWdr5minQty) (a, s, lp, i) for the Dispatch Interval.</td>
</tr>
<tr>
<td>RtAoNetInjSpp5minQty (s, i)</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Net Injection Quantity per Dispatch Interval – The SPP total of (RtAoNetInj5minQty) (a, s, lp, i) for the Dispatch Interval.</td>
</tr>
<tr>
<td>RtincrOclHrlyAmt (h)</td>
<td>$</td>
<td>Hour</td>
<td>Real-Time Incremental Over Collected Losses Amount per Hour – The sum of (RtincrOcl5minAmt) (j) for the Hour.</td>
</tr>
<tr>
<td>RtincrOcl5minAmt (i)</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time Incremental Over Collected Losses Amount per Dispatch Interval – The amount of over/under collection in the RTBM due to marginal losses for the Dispatch Interval.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>----------</td>
<td>------------</td>
<td>---------------------</td>
<td>----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>RtLpIntSupply5minFct(_{lp,i})</td>
<td>none</td>
<td>Dispatch Interval</td>
<td>Real-Time Loss Pool Internal Supply Factor per Loss Pool per Dispatch Interval – A ratio indicating the percentage of Loss Pool (lp)’s net withdrawals that are being served by net injections inside of Loss Pool (lp) in Dispatch Interval (i).</td>
</tr>
<tr>
<td>RtLpExtSupply5minFct(_{lp,i})</td>
<td>none</td>
<td>Dispatch Interval</td>
<td>Real-Time Loss Pool External Supply Factor per Loss Pool per Dispatch Interval – A ratio indicating the percentage of Loss Pool (lp)’s net injections that are in excess of Loss Pool (lp)’s net withdrawals in Dispatch Interval (i).</td>
</tr>
<tr>
<td>RtLpIwaMlc5minPrc(_{lp,i})</td>
<td>$/MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Loss Pool Injection Weighted Average Marginal Loss Component per Loss Pool per Dispatch Interval - The weighted average (\text{RtMlc5minPrc}_{s,i}) for all injections in loss pool (lp) in Dispatch Interval (i).</td>
</tr>
<tr>
<td>RtSppIwaMlc5minPrc(_{i})</td>
<td>$/MW</td>
<td>Dispatch Interval</td>
<td>Real-Time SPP Injection Weighted Average Marginal Loss Component per Dispatch Interval - The weighted average of (\text{RtMlc5minPrc}_{s,i}) for all loss pool injections in excess of loss pool withdrawals in Dispatch Interval (i).</td>
</tr>
<tr>
<td>RtLpNetInj5minQty(_{a,s,lp,i})</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Net Injection Quantity per Settlement Location per Loss Pool per Dispatch Interval – Asset Owner (a)’s net injection quantity at Settlement Location (s) in Loss pool (lp) in Dispatch Interval (i).</td>
</tr>
<tr>
<td>RtAoNetInj5minQty(_{a,s,lp,i})</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Net Injection Quantity per AO Settlement Location per Loss Pool per Dispatch Interval – Asset Owner (a)’s total injection quantity at Settlement Location (s) in Loss pool (lp) in Dispatch Interval (i).</td>
</tr>
<tr>
<td>RtSlNetInj5minQty(_{s,i})</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Net Injection Quantity per Settlement Location per Dispatch Interval – Settlement Location (s)’s net injection quantity in Dispatch Interval (i).</td>
</tr>
<tr>
<td>RtLpNetWdr5minQty(_{a,s,lp,i})</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Net Withdrawal Quantity per Settlement Location per Loss Pool per Dispatch Interval – Asset Owner (a)’s net withdrawal quantity at Settlement Location (s) in Loss pool (lp) in Dispatch Interval (i).</td>
</tr>
</tbody>
</table>

---
<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>RtAoNetWdr5minQty&lt;sub&gt;a, s, lp, i&lt;/sub&gt;</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td><em>Real-Time Net Withdrawal Quantity per AO per Settlement Location per Dispatch Interval</em> – AO a’s total withdrawal quantity at Settlement Location s in Loss pool lp in Dispatch Interval h.</td>
</tr>
<tr>
<td>RtSlNetWdr5minQty&lt;sub&gt;s, i&lt;/sub&gt;</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td><em>Real-Time Net Withdrawal Quantity per Settlement Location per Dispatch Interval</em> – Settlement Location s’s net withdrawal quantity in Dispatch Interval i.</td>
</tr>
<tr>
<td>RtLmp5minPre&lt;sub&gt;s, i&lt;/sub&gt;</td>
<td>$/MWh</td>
<td>Dispatch Interval</td>
<td><em>Real-Time LMP</em> – The value described under Section 4.5.9.1 at Settlement Location s in Loss Pool lp for Dispatch Interval i.</td>
</tr>
<tr>
<td>RtMcc5minPre&lt;sub&gt;s, i&lt;/sub&gt;</td>
<td>$/MWh</td>
<td>Dispatch Interval</td>
<td><em>Real-Time Marginal Congestion Component of Real-Time LMP</em> – The Marginal Congestion Component of Real-Time LMP at Settlement Location s in Loss Pool lp for Dispatch Interval i.</td>
</tr>
<tr>
<td>RtMlc5minPre&lt;sub&gt;s, i&lt;/sub&gt;</td>
<td>$/MWh</td>
<td>Dispatch Interval</td>
<td><em>Real-Time Marginal Losses Component of Real-Time LMP</em> – The Marginal Losses Component of the Real-Time LMP at Settlement Location s in Loss Pool lp for Dispatch Interval i.</td>
</tr>
<tr>
<td>RtEnFinHrlyQty&lt;sub&gt;a, s, lp, t, h&lt;/sub&gt;</td>
<td>MWh</td>
<td>Hour</td>
<td><em>Real-Time Asset Financial Schedule for Energy per AO per Settlement Location per Transaction per Loss pool per Hour</em> - The value described under Section 4.5.9.1 for Loss Pool lp.</td>
</tr>
<tr>
<td>RtNEEnFinHrlyQty&lt;sub&gt;a, s, lp, t, h&lt;/sub&gt;</td>
<td>MWh</td>
<td>Hour</td>
<td><em>Real-Time Non-Asset Financial Schedule for Energy per AO per Settlement Location per Transaction per Loss pool per Hour</em> - The value described under Section 4.5.9.2 for Loss Pool lp.</td>
</tr>
<tr>
<td>DaClrdHrlyQty&lt;sub&gt;a, s, lp, h&lt;/sub&gt;</td>
<td>MWh</td>
<td>Dispatch Interval</td>
<td><em>Day-Ahead Cleared Energy Quantity per AO per Settlement Location per Loss Pool per Hour in the DA Market</em> – The value described under Section 4.5.8.1 for AO a at Settlement Location s in Loss Pool lp for Hour h.</td>
</tr>
<tr>
<td>DaClrdVHrlyQty&lt;sub&gt;a, s, lp, h, t&lt;/sub&gt;</td>
<td>MWh</td>
<td>Dispatch Interval</td>
<td><em>Day-Ahead Cleared Virtual Energy Quantity per AO per Settlement Location per Transaction per Loss Pool per Hour in the DA Market</em> – The value described under Section 4.5.8.3 for AO a at Settlement Location s in Loss Pool lp for transaction t for Hour h.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>----------</td>
<td>------</td>
<td>---------------------</td>
<td>------------</td>
</tr>
<tr>
<td>DaImpExp5minQty&lt;sub&gt;a, s, lp, i, t&lt;/sub&gt;</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Day-Ahead Interchange Transaction Quantity per AO per Settlement Location per Transaction per Loss Pool per Dispatch Interval – The value described under Section 4.5.8.2 for AO a at Settlement Location s in Loss Pool lp for transaction t for Dispatch Interval i.</td>
</tr>
<tr>
<td>RtImpExp5minQty&lt;sub&gt;a, s, lp, i, t&lt;/sub&gt;</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Interchange Transaction Quantity per AO per Settlement Location per Transaction per Loss Pool per Dispatch Interval – The value described under Section 4.5.9.2 for AO a at Settlement Location s in Loss Pool lp for transaction t for Dispatch Interval i.</td>
</tr>
<tr>
<td>RsgCrdFlg&lt;sub&gt;t&lt;/sub&gt;</td>
<td>none</td>
<td>none</td>
<td>Reserve Sharing Group Contingency Reserve Deployment Flag per Event – The value described under Section 4.5.8.8.</td>
</tr>
<tr>
<td>RtBillMtr5minQty&lt;sub&gt;a, s, lp, i&lt;/sub&gt;</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Billing Meter Quantity per AO per Settlement Location per Loss Pool per Dispatch Interval - The value described under Section 4.5.9.1 for AO a at Settlement Location s in Loss Pool lp for Dispatch Interval i.</td>
</tr>
<tr>
<td>RtNetInadvertentSpp5minAmt&lt;sub&gt;i&lt;/sub&gt;</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time SPP Net Inadvertent Energy Amount per Dispatch Interval – The value calculated under Section 4.5.12.</td>
</tr>
<tr>
<td>RtOclDistDlyAmt&lt;sub&gt;a, s, lp, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Over Collected Losses Distribution Amount per AO per Settlement Location per Loss Pool Operating Day - The amount to AO a for AO a’s share of total over/under collection due to marginal losses at Settlement Location s in Loss Pool lp for the Operating Day.</td>
</tr>
<tr>
<td>RtOclDistAoAmt&lt;sub&gt;a, m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Over Collected Losses Distribution Amount per AO per Operating Day- The amount to AO a associated with Market Participant m for AO a’s share of total over/under collection due to marginal losses for the Operating Day.</td>
</tr>
<tr>
<td>RtOclDistMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Over Collected Losses Distribution Amount per MP per Operating Day- The amount to MP m for MP m’s share of total over/under collection due to marginal losses for the Operating Day.</td>
</tr>
<tr>
<td>a</td>
<td>none</td>
<td>none</td>
<td>An Asset Owner.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>----------</td>
<td>-------</td>
<td>---------------------</td>
<td>-----------------------------------------------------------------------------</td>
</tr>
<tr>
<td>s</td>
<td>none</td>
<td>none</td>
<td>A Settlement Location.</td>
</tr>
<tr>
<td>h</td>
<td>none</td>
<td>none</td>
<td>An Hour.</td>
</tr>
<tr>
<td>i</td>
<td>none</td>
<td>none</td>
<td>A Dispatch Interval.</td>
</tr>
<tr>
<td>t</td>
<td>none</td>
<td>none</td>
<td>A single tagged Interchange Transaction, a single virtual energy transaction, a single Financial Schedule, a single contracted Operating Reserve transaction, a single TCR instrument, a single ARR award or a single Reserve Sharing Event transaction.</td>
</tr>
<tr>
<td>d</td>
<td>none</td>
<td>none</td>
<td>An Operating Day.</td>
</tr>
<tr>
<td>lp</td>
<td>none</td>
<td>none</td>
<td>A Loss Pool.</td>
</tr>
<tr>
<td>m</td>
<td>none</td>
<td>none</td>
<td>A Market Participant.</td>
</tr>
</tbody>
</table>
4.5.9.21 Real-Time Joint Operating Agreement Amount

(1) A RTBM credit or charge for RTBM congestion management coordination between SPP and JOA counterparties will be calculated for each Asset Owner counterparty as specified in the applicable JOA and distributed/collected from Market Participants through the RNU charge type as described under Section 4.5.12. Charges and credits for this activity will be represented under the following charge type:

#RtJoaHrlyAmt_{a,h,f} = JOA Calculated Charge or Credit
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>$R_{tJo}A_{h,l}m_{a,h,f}$</td>
<td>$$</td>
<td>Hour</td>
<td><em>Real-Time Joint Operating Agreement Amount per Asset Owner per Hour</em> - The RTBM amount to SPP from the JOA counterparty AO or from SPP to the JOA counterparty AO for the calculated JOA congestion management coordination amount in Hour $h$. Note use of the Asset Owner subscript for the counterparty does not require that counterparty to become a Market Participant or be represented by a Market Participant. This is only required in this case to effectuate an automated billing mechanism.</td>
</tr>
<tr>
<td>$a$</td>
<td>none</td>
<td>none</td>
<td>An Asset Owner.</td>
</tr>
<tr>
<td>$h$</td>
<td>none</td>
<td>none</td>
<td>An Hour.</td>
</tr>
<tr>
<td>$f$</td>
<td>none</td>
<td>none</td>
<td>A flowgate identified in the applicable JOA.</td>
</tr>
</tbody>
</table>
4.5.9.22 Real-Time Reserve Sharing Group Amount

(1) A RTBM credit or charge for requested assistance provided between Reserve Sharing Group following a Resource contingency will be calculated for each Asset Owner counterparty as specified in the Reserve Sharing Agreement. Charges and credits for this activity will be represented under the following charge type:

#RtRsg5minAmt_{a,i,t} = RSG Agreement Calculated Charge or Credit

\[ \text{RtRsgHrlyAmt}_{a,h} = \sum_{i} \sum_{t} (\text{RtRsg5minAmt}_{a,i,t}) \]

(2) For each Asset Owner, a daily amount is calculated. The daily amount is calculated as follows:

\[ \text{RtRsgDlyAmt}_{a,d} = \sum_{h} \text{RtRsgHrlyAmt}_{a,h} \]
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>RtRsg5minAmt&lt;sub&gt;a, i, t&lt;/sub&gt;</td>
<td>$</td>
<td>Hour</td>
<td>Real-Time Reserve Sharing Group Agreement Amount per Asset Owner per Dispatch Interval per Reserve Sharing Event Transaction - The RTBM amount to SPP from the RSG counterparty AO for assistance provided by SPP or the RTBM amount from SPP to the RSG counterparty AO for assistance provided by the RSG counterparty for Reserve Sharing Event transaction &lt;i&gt;t&lt;/i&gt; in Dispatch Interval &lt;i&gt;i&lt;/i&gt;. Note use of the Asset Owner subscript for the counterparty does not require that counterparty to become a Market Participant or be represented by a Market Participant. This is only required in this case to effectuate an automated billing mechanism.</td>
</tr>
<tr>
<td>RtRsgHrlyAmt&lt;sub&gt;a, h&lt;/sub&gt;</td>
<td>$</td>
<td>Hour</td>
<td>Real-Time Reserve Sharing Group Agreement Amount per Asset Owner per Hour - The RTBM amount to SPP from the RSG counterparty AO for assistance provided by SPP or the RTBM amount from SPP to the RSG counterparty AO for assistance provided by the RSG counterparty in Hour &lt;i&gt;h&lt;/i&gt;. Note use of the Asset Owner subscript for the counterparty does not require that counterparty to become a Market Participant or be represented by a Market Participant. This is only required in this case to effectuate an automated billing mechanism.</td>
</tr>
<tr>
<td>RtRsgDlyAmt&lt;sub&gt;a, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Reserve Sharing Group Agreement Amount per Asset Owner per Operating Day - The RTBM amount to SPP from the RSG counterparty AO for assistance provided by SPP or the RTBM amount from SPP to the RSG counterparty AO for assistance provided by the RSG counterparty in Operating Day &lt;i&gt;d&lt;/i&gt;. Note use of the Asset Owner subscript for the counterparty does not require that counterparty to become a Market Participant or be represented by a Market Participant. This is only required in this case to effectuate an automated billing mechanism.</td>
</tr>
</tbody>
</table>

<code>a</code> none none An Asset Owner.
<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>$h$</td>
<td>none</td>
<td>none</td>
<td>An Hour.</td>
</tr>
<tr>
<td>$i$</td>
<td>none</td>
<td>none</td>
<td>A Dispatch Interval.</td>
</tr>
<tr>
<td>$t$</td>
<td>none</td>
<td>none</td>
<td>A single tagged Interchange Transaction, a single virtual energy transaction, a single Financial Schedule, a single contracted Operating Reserve transaction, a single TCR instrument, a single ARR award or a single Reserve Sharing Event transaction.</td>
</tr>
</tbody>
</table>
4.5.9.23  Real-Time Reserve Sharing Group Distribution Amount

(1) A RTBM charge or credit will be calculated for each Asset Owner for each Settlement Location for each hour. The Asset Owner amount will be equal to the Asset Owner’s real-time load ratio share of the Real-Time Reserve Sharing Group Amount. The amount to each Asset Owner is calculated as follows:

\[ #RtRsgDistHrlyAmt_{a,s,h} = \]

\[ RtRsgSppHrlyAmt_h \times RtLoadRatioShareHrlyFct_{a,s,h} \times (-1) \]

Where,

\[ RtRsgSppHrlyAmt_h = \sum_a RtRsgHrlyAmt_{a,h} \]

(2) For each Asset Owner, a daily amount is calculated at each Settlement Location. The daily amount is calculated as follows:

\[ RtRsgDistDlyAmt_{a,s,d} = \sum_h RtRsgDistHrlyAmt_{a,s,h} \]

(3) For each Asset Owner associated with Market Participant \( m \), a daily amount is calculated. The daily amount is calculated as follows:

\[ RtRsgDistAoAmt_{a,m,d} = \sum_s RtRsgDistDlyAmt_{a,s,d} \]

(4) For each Market Participant, a daily amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The daily amount is calculated as follows:

\[ RtRsgDistMpAmt_{m,d} = \sum_a RtRsgDistAoAmt_{a,m,d} \]
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>RtRsgDistHrlyAmt $a,s,h$</td>
<td>$\text{dollars ($)}$</td>
<td>Hour</td>
<td>Real-Time Reserve Sharing Group Distribution Amount per AO per Settlement Location per Hour - The amount to AO $a$ for AO $a$’s share of the total of $\text{RtRsgHrlyAmt}_{a,h}$ at Settlement Location $s$ in Hour $h$.</td>
</tr>
<tr>
<td>RtLoadRatioShareHrlyFct $a,s,h$</td>
<td>Ratio</td>
<td>Hour</td>
<td>Real-Time Load Ratio Share Factor per AO per Settlement Location per Hour – The value calculated under Section 4.5.9.11.</td>
</tr>
<tr>
<td>RtRsgHrlyAmt $a,h$</td>
<td>$\text{dollars ($)}$</td>
<td>Hour</td>
<td>Real-Time Reserve Sharing Group Amount per AO per Hour – The value calculated under Section 4.5.9.22.</td>
</tr>
<tr>
<td>RtRsgSppHrlyAmt $h$</td>
<td>$\text{dollars ($)}$</td>
<td>Hour</td>
<td>Real-Time Reserve Sharing Group Amount per AO per Hour – The SPP total of the values calculated under Section 4.5.9.22 in Hour $h$.</td>
</tr>
<tr>
<td>RtRsgDistDlyAmt $a,s,d$</td>
<td>$\text{dollars ($)}$</td>
<td>Operating Day</td>
<td>Real-Time Reserve Sharing Group Distribution Amount per AO per Settlement Location per Operating Day - The amount to AO $a$ for total Reserve sharing group charges/credit in Operating Day $d$.</td>
</tr>
<tr>
<td>RtRsgDistAoAmt $a,m,d$</td>
<td>$\text{dollars ($)}$</td>
<td>Operating Day</td>
<td>Real-Time Reserve Sharing Group Distribution Amount per AO per Operating Day - The amount to AO $a$ associated with Market Participant $m$ for total Reserve Sharing Group charges/credits in Operating Day $d$.</td>
</tr>
<tr>
<td>RtRsgDistMpAmt $m,d$</td>
<td>$\text{dollars ($)}$</td>
<td>Operating Day</td>
<td>Real-Time Reserve Sharing Group Distribution Amount per MP per Operating Day The amount to MP $m$ for total Reserve Sharing Group charges/credits in Operating Day $d$.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>$a$</td>
<td>none</td>
<td>none</td>
<td>An Asset Owner.</td>
</tr>
<tr>
<td>$s$</td>
<td>none</td>
<td>none</td>
<td>A Settlement Location.</td>
</tr>
<tr>
<td>$h$</td>
<td>none</td>
<td>none</td>
<td>An Hour.</td>
</tr>
<tr>
<td>$d$</td>
<td>none</td>
<td>none</td>
<td>An Operating Day.</td>
</tr>
<tr>
<td>$m$</td>
<td>none</td>
<td>none</td>
<td>A Market Participant.</td>
</tr>
</tbody>
</table>
4.5.10 ARR and TCR Auction Settlement

The charges and credits to ARR holders and TCR holders resulting from the annual and monthly TCR auctions described under Section 5 are calculated on a daily basis and included on the Settlement Statements consistent with the timing of the DA Market settlement and Real-Time Balancing Market settlement.

(1) TCR Bid and Offer Settlement from TCR Auction

(a) For each period and round in the Annual TCR Auction and each month and round in the Monthly TCR Auction, each Market Participant is charged or credited for each TCR purchased.

(b) For each period and round in the Annual TCR Auction and each month and round in the Monthly TCR Auction, each Market Participant that sold a TCR is credited or charged for each TCR sold.

(c) For each period, the amounts calculated above are divided by the numbers of days in the period and then included as daily charges and credits.

(2) ARR Settlement from TCR Auction

(a) For each period in the Annual ARR Allocation, each Market Participant is credited (or charged) for each ARR awarded based on the source and sink Auction Clearing Prices for each round associated with the Annual TCR Auction and the Monthly TCR Auction.

(b) For each period, the amounts calculated above are divided by the numbers of days in the period and then included as daily charges and credits.

(3) Revenue Neutrality

(a) For each day, if net charges collected under TCR Settlements as described in (1) above are less than the net credits paid under ARR Settlements described in (2) above, the deficiency will be collected from ARR holders in proportion to absolute value of their ARR instrument economic values as described under (2)(a) above.

(b) For each day, if net charges collected under TCR Settlements are greater than the net credits paid under ARR Settlements, the excess is carried forward to the end of the month and used to payback ARR holders from whom daily deficiency was
collected in that month and any remaining excess is carried forward to the end of year.

(c) At the end of the year, excess carried forward from the monthly process is used to payback ARR holders from whom daily deficiency was collected in the year and that was not refunded during the monthly process.

(d) To the extent that the net charges collected under TCR Settlements are greater than the net credits paid under ARR Settlements and ARR holders from whom daily deficiency was collected in the year have been fully reimbursed in the monthly and end-of-year processes, the excess is distributed to ARR holders in proportion to their ARR Nomination Caps.

The following subsections describe the ARR/TCR auction settlement charge types. For each charge type, the initial calculation is performed at the daily level for each Asset Owner and Market Participant for the sum of all ARRs and TCRs awarded. Each charge type calculation is described in the following subsections.
4.5.10.1 Transmission Congestion Rights Auction Transaction Amount

(1) A Transmission Congestion Rights auction charge or credit for each Asset Owner is calculated for each TCR instrument purchased or sold in the TCR auctions. The amount to each applicable Asset Owner for each auction and round is calculated as follows.

$$
#\text{TcrAucTxnDlyAmt}_a, aid, d = \sum_t \{ (\text{TcrAucQty}_a, t, aid, source, sink \times \text{TcrAucPrc}_aid, source, sink) \times \text{TcrAucBuySellFlg}_a, t / \text{NumDaysInPeriod}_aid \}
$$

Where,

$$\text{TcrAucPrc}_aid, source, sink = \text{AuctionClearingPrice}_aid, sink - \text{AuctionClearingPrice}_aid, source$$

(2) For each Asset Owner associated with Market Participant $m$, a daily amount is calculated. The net daily amount is calculated as follows:

$$\text{TcrAucTxnAoAmt}_a, m, d = \sum_{aid} \text{TcrAucTxnDlyAmt}_a, aid, d$$

(3) For each Market Participant, a daily amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The daily amount is calculated as follows:

$$\text{TcrAucTxnMpAmt}_m, d = \sum_d \text{TcrAucTxnAoAmt}_a, m, d$$
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>TcrAucTxnDlyAmt&lt;sub&gt; a, aid, d &lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Transmission Congestion Right Auction Daily Amount per AO per Auction ID per Operating Day – The amount to AO &lt;i&gt;a&lt;/i&gt; for purchases and sales of TCRs for Operating Day &lt;i&gt;d&lt;/i&gt; for TCR auction ID &lt;i&gt;aid&lt;/i&gt;.</td>
</tr>
<tr>
<td>TcrAucQty&lt;sub&gt; a, t,aid, source, sink &lt;/sub&gt;</td>
<td>MW</td>
<td>Month or Season</td>
<td>Transmission Congestion Right Quantity per AO per Transaction per Auction ID per Source and Sink – AO &lt;i&gt;a&lt;/i&gt;’s TCR quantity purchased or sold for each transaction &lt;i&gt;t&lt;/i&gt; in any TCR auction &lt;i&gt;aid&lt;/i&gt; at the associated source and sink point.</td>
</tr>
<tr>
<td>TcrAucPre&lt;sub&gt; aid, source, sink &lt;/sub&gt;</td>
<td>$/MW</td>
<td>Month or Season</td>
<td>Transmission Congestion Right Auction Clearing Price per Auction ID – The TCR Auction clearing prices for TCR auction ID &lt;i&gt;aid&lt;/i&gt; at the associated source and sink point.</td>
</tr>
<tr>
<td>TcrAucBuySellFlg&lt;sub&gt; a, t &lt;/sub&gt;</td>
<td>none</td>
<td>Month or Season</td>
<td>Transmission Congestion Right Auction Buy/Sell Flag per AO per Transaction – A flag indicating whether AO &lt;i&gt;a&lt;/i&gt;’s TcrAucQty&lt;sub&gt; a, t, aid, source, sink &lt;/sub&gt; was a purchase or a sale. This flag is set equal to +1 for purchases or to (-1) for sales.</td>
</tr>
<tr>
<td>NumDaysInPeriod&lt;sub&gt; aid &lt;/sub&gt;</td>
<td>none</td>
<td>none</td>
<td>Number of Days in the Period associated per Auction ID – The number of Operating Days in month or seasons associated with TCR Auction ID &lt;i&gt;aid&lt;/i&gt;.</td>
</tr>
<tr>
<td>AuctionClearingPrice&lt;sub&gt; aid, sink &lt;/sub&gt;</td>
<td>$/MW</td>
<td>Month or Season</td>
<td>TCR Auction Clearing Price per Auction ID at the Sink - The Auction clearing prices for TCR auction ID &lt;i&gt;aid&lt;/i&gt; at the associated sink point.</td>
</tr>
<tr>
<td>AuctionClearingPrice&lt;sub&gt; aid, source &lt;/sub&gt;</td>
<td>$/MW</td>
<td>Month or Season</td>
<td>Auction Clearing Price per Auction ID at the Source - The Auction clearing prices for TCR auction aid at the associated source point.</td>
</tr>
<tr>
<td>TcrAucTxnAoSamt&lt;sub&gt; a, m, d &lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Transmission Congestion Right Auction Daily Amount per AO per Operating Day – The amount to AO &lt;i&gt;a&lt;/i&gt; for purchases and sales of TCRs for Operating Day &lt;i&gt;d&lt;/i&gt;.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>--------------------</td>
<td>------</td>
<td>---------------------</td>
<td>---------------------------------------------------------------------------</td>
</tr>
<tr>
<td>TcrAucTxnMpAmt(_{m,d})</td>
<td>$</td>
<td>Operating Day</td>
<td><em>Transmission Congestion Right Auction Daily Amount per MP per Operating Day</em> – The amount to MP (m) for purchases and sales of TCRs in the annual and monthly TCR Auctions for Operating Day (d).</td>
</tr>
<tr>
<td>(a)</td>
<td>none</td>
<td>none</td>
<td>An Asset Owner.</td>
</tr>
<tr>
<td>(t)</td>
<td>none</td>
<td>none</td>
<td>A single tagged Interchange Transaction, a single virtual energy transaction, a single Financial Schedule, a single contracted Operating Reserve transaction, a single TCR instrument, a single ARR award or a single Reserve Sharing Event transaction.</td>
</tr>
<tr>
<td>(aid)</td>
<td>none</td>
<td>none</td>
<td>TCR Auction ID (separate ID for each round and type).</td>
</tr>
<tr>
<td>(m)</td>
<td>none</td>
<td>none</td>
<td>A Market Participant.</td>
</tr>
<tr>
<td>(source)</td>
<td>none</td>
<td>none</td>
<td>The Settlement Location identified as the source point for TCR (t).</td>
</tr>
<tr>
<td>(sink)</td>
<td>none</td>
<td>none</td>
<td>The Settlement Location identified as the sink point for TCR (t).</td>
</tr>
</tbody>
</table>
4.5.10.2 Auction Revenue Rights Funding Amount

(1) ARRs are valued at the prices from the annual and monthly TCR auctions during the lifetime of the instrument. The quantity of ARRs settled for each auction and round is a fraction of the instrument as a whole. These fractions are described under Section 5.6. An Auction Revenue Rights charge or credit for each Asset Owner for each auction and round is calculated as follows.

\[
\text{#ArrAucTxnDlyAmt}_{a, aid, d} = \left( \frac{\text{ArrQty}_{a, aid, source, sink} \times \text{TcrAucPre}_{aid, source, sink}}{\text{NumDaysInPeriod}_{aid}} \right) \times (-1)
\]

(2) For each Asset Owner associated with Market Participant \( m \), a daily amount is calculated. The net daily amount is calculated as follows:

\[
\text{ArrAucTxnAoAmt}_{a, m, d} = \sum_{aid} \text{ArrAucTxnDlyAmt}_{a, aid, d}
\]

(3) For each Market Participant, a daily amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The daily amount is calculated as follows:

\[
\text{ArrAucTxnMpAmt}_{m, d} = \sum_{a} \text{ArrAucTxnAoAmt}_{a, d}
\]
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>( \text{ArrAucTxnDlyAmt}_{a,\ aid, \ d} )</td>
<td>$</td>
<td>Operating Day</td>
<td>\textit{Auction Revenue Rights Daily Amount per AO per TCR Auction ID per Operating Day}– The ARR revenue amount to AO ( a ) for Operating Day ( d ) for TCR Auction ID ( \text{aid} ).</td>
</tr>
<tr>
<td>( \text{ArrQty}_{a, \ aid, \ source, \ sink} )</td>
<td>MW</td>
<td>Month or Season</td>
<td>\textit{Auction Revenue Right Quantity per AO per Transaction per Auction ID per Source and Sink} – AO ( a )’s total ARR award quantity on the associated ( source ) and ( sink ) that is subject to reduction for settlement purposes based on the rules listed under Section 5.6 for related TCR auction ID ( \text{aid} ).</td>
</tr>
<tr>
<td>( \text{TcrAucPre}_{aid, \ source, \ sink} )</td>
<td>$/MW</td>
<td>Month or Season</td>
<td>\textit{Transmission Congestion Right Auction Clearing Price per Month per Auction Type per Transaction per Auction Round} – The value defined under Section 4.5.10.1</td>
</tr>
<tr>
<td>( \text{NumDaysInPeriod}_{aid} )</td>
<td>none</td>
<td>none</td>
<td>\textit{Number of Days in the Month} – The value defined under Section 4.5.10.1</td>
</tr>
<tr>
<td>( \text{ArrAucTxnAoAmt}_{a, \ m, \ d} )</td>
<td>$</td>
<td>Operating Day</td>
<td>\textit{Auction Revenue Rights Daily Amount per AO per Operating Day}– The ARR revenue amount to AO ( a ) for Operating Day ( d ).</td>
</tr>
<tr>
<td>( \text{ArrAucTxnMpAmt}_{m, \ d} )</td>
<td>$</td>
<td>Operating Day</td>
<td>\textit{Auction Revenue Right Daily Amount per MP per Operating Day} – The amount to MP ( m ) for all ARR awards for Operating Day ( d ).</td>
</tr>
<tr>
<td>( a )</td>
<td>none</td>
<td>none</td>
<td>An Asset Owner.</td>
</tr>
<tr>
<td>( t )</td>
<td>none</td>
<td>none</td>
<td>A single tagged Interchange Transaction, a single virtual energy transaction, a single Financial Schedule, a single contracted Operating Reserve transaction, a single TCR instrument, a single ARR award or a single Reserve Sharing Event transaction.</td>
</tr>
<tr>
<td>( \text{aid} )</td>
<td>none</td>
<td>none</td>
<td>TCR Auction ID (separate ID for each round and type).</td>
</tr>
<tr>
<td>( m )</td>
<td>none</td>
<td>none</td>
<td>A Market Participant.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>----------</td>
<td>------</td>
<td>---------------------</td>
<td>------------</td>
</tr>
<tr>
<td>source</td>
<td>none</td>
<td>none</td>
<td>The Settlement Location identified as the source point for TCR $t$.</td>
</tr>
<tr>
<td>sink</td>
<td>none</td>
<td>none</td>
<td>The Settlement Location identified as the sink point for TCR $t$.</td>
</tr>
</tbody>
</table>
4.5.10.3 Auction Revenue Rights Uplift Amount

(1) A charge will be calculated for each Asset Owner holding ARRs for each auction and round for each Operating Day to the extent that TCR auction revenues collected in each auction and round over the Operating Day are not sufficient to fund the net of the total amounts calculated under Section 4.5.10.2 for each auction and round over the Operating Day. The amount is calculated as follows:

\[
\text{ArrUpliftDlyAmt}_{a, aid, d} = \text{TcrArrUnderDlyAmt}_{aid, d} \times \left[ \frac{\text{ABS}(\text{ArrAucTxnDlyAmt}_{a, aid, d})}{\text{ArrAucTxnSppDlyAmt}_{aid, d}} \right]
\]

Where,

(a) \[ \text{ArrAucTxnSppDlyAmt}_{aid, d} = \sum_{a} \text{ABS}(\text{ArrAucTxnDlyAmt}_{a, aid, d}) \]

(b) \[ \text{TcrArrUnderDlyAmt}_{aid, d} = (-1) \times \min \left( \sum_{a} \text{TcrAucTxnDlyAmt}_{a, aid, d} + \sum_{a} \text{ArrAucTxnDlyAmt}_{a, aid, d}, 0 \right) \]

(2) For each Asset Owner associated with Market Participant \( m \), a daily amount is calculated. The net daily amount is calculated as follows:

\[ \text{ArrUpliftAoAmt}_{a, m, d} = \sum_{aid} \text{ArrUpliftDlyAmt}_{a, aid, d} \]

(3) For each Market Participant, a daily amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The daily amount is calculated as follows:

\[ \text{ArrUpliftMpAmt}_{m, d} = \sum_{a} \text{ArrUpliftAoAmt}_{a, m, d} \]
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>ArrUpliftDlyAmt (_{a, aid, d})</td>
<td>$</td>
<td>Operating Day</td>
<td><em>Auction Revenue Rights Daily Uplift Amount per AO per TCR Auction ID per Operating Day</em> - The uplift amount to AO (a) associated with shortfalls in TCR auction revenues required to fully fund ARRs associated for Operating Day (d) and TCR auction ID (aid).</td>
</tr>
<tr>
<td>TcrArrUnderDlyAmt (_{aid, d})</td>
<td>$</td>
<td>Operating Day</td>
<td><em>Auction Revenue Rights Under Funding Amount per TCR Auction ID per Operating Day</em> – The amount by which the net amounts under Section 4.5.10.2 are underfunded in Operating Day (d) for TCR auction ID (aid).</td>
</tr>
<tr>
<td>ArrAucTxnSppDlyAmt (_{aid, d})</td>
<td>$</td>
<td>Operating Day</td>
<td><em>Auction Revenue Rights Daily Amount per TCR Auction ID per Operating Day</em> – The SPP total of the absolute value of the values calculated under Section 4.5.10.2.</td>
</tr>
<tr>
<td>ArrAucTxnDlyAmt (_{a, aid, d})</td>
<td>$</td>
<td>Operating Day</td>
<td><em>Auction Revenue Rights Funding Amount per AO per TCR Auction ID per Operating Day</em> - The value calculated under Section 4.5.10.2.</td>
</tr>
<tr>
<td>TcrAucTxnDlyAmt (_{a, aid, d})</td>
<td>$</td>
<td>Operating Day</td>
<td><em>Transmission Congestion Right Auction Daily Amount per AO per TCR Auction ID per Operating Day</em> – The value calculated under Section 4.5.10.1.</td>
</tr>
<tr>
<td>ArrUpliftAoAmt (_{a, m, d})</td>
<td>$</td>
<td>Operating Day</td>
<td><em>Auction Revenue Rights Daily Uplift Amount per AO per Operating Day</em> - The uplift amount to AO (a) associated with shortfalls in TCR auction revenues required to fully fund ARRs associated for Operating Day (d).</td>
</tr>
<tr>
<td>ArrUpliftMpAmt (_{m, d})</td>
<td>$</td>
<td>Operating Day</td>
<td><em>Auction Revenue Rights Daily Uplift Amount per MP per Operating Day</em> - The uplift amount associated with shortfalls in TCR auction revenues required to fully fund ARRs to MP (m) for all AO’s associated with Market Participant (m) for Operating Day (d).</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>----------</td>
<td>------</td>
<td>---------------------</td>
<td>-------------------------------------------</td>
</tr>
<tr>
<td>$a$</td>
<td>none</td>
<td>none</td>
<td>An Asset Owner.</td>
</tr>
<tr>
<td>$d$</td>
<td>none</td>
<td>none</td>
<td>An Operating Day.</td>
</tr>
<tr>
<td>$aid$</td>
<td>none</td>
<td>none</td>
<td>TCR Auction ID (separate ID for each round and type).</td>
</tr>
<tr>
<td>$m$</td>
<td>none</td>
<td>none</td>
<td>A Market Participant.</td>
</tr>
</tbody>
</table>
4.5.10.4 Auction Revenue Rights Monthly Payback Amount

(1) A monthly credit or charge\(^{25}\) will be calculated for each Asset Owner receiving charges under Section 4.5.10.3 over the month in order to ensure full funding of ARRs to the extent possible. The amount is calculated as follows:

\[
#\text{ArrPaybackMnthlyAmt}_{a, mn} = (-1) \times \min \{ \text{ArrUpliftAoMnthlyAmt}_{a, mn}, \\
\text{ARFMnthlyAmt}_{mn} \times \text{ArrUpliftAoMnthlyAmt}_{a, mn} / \text{ArrUpliftSppMnthlyAmt}_{mn} \}
\]

Where,

(a) \(\text{ArrUpliftAoMnthlyAmt}_{a, mn} = \sum_a \sum_{aid} \text{ArrUpliftDlyAmt}_{a, aid, d}\)

(b) \(\text{ArrUpliftSppMnthlyAmt}_{mn} = \sum_a \sum_d \sum_{aid} \text{ArrUpliftDlyAmt}_{a, aid, d}\)

(c) \(\text{ARFMnthlyAmt}_{mn} = \sum_d \text{ARFDlyAmt}_{d}\)

(c.1) \(\text{ARFDlyAmt}_{d} = \max \{ 0, \sum_a \sum_{aid} [ \text{ArrAucTxnDlyAmt}_{a, aid, d} + \text{TcrAucTxnDlyAmt}_{a, aid, d} ] \}\)

(2) For each Market Participant, a monthly amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The monthly amount is calculated as follows:

\[
\text{ArrPaybackMnthlyMpAmt}_{m, mn} = \sum_a \text{ArrPaybackMnthlyAmt}_{a, mn}
\]

---

\(^{25}\) Note that this charge type will almost always produce a credit. The charge is included here for the rare occasion when a charge may be produced as a result of a data error and/or a resettlement.
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td><code>ArrPaybackMnthlyAmt_{a, mn}</code></td>
<td>$</td>
<td>Month</td>
<td><em>Auction Revenue Rights Monthly Payback Amount per AO per month</em> - AO a’s share of the <code>ARFMnthlyAmt_{mn}</code> in month <code>mn</code> limited to the amount required to fully fund AO a’s ARRs in month <code>mn</code>.</td>
</tr>
<tr>
<td><code>ARFMnthlyAmt_{mn}</code></td>
<td>$</td>
<td>Month</td>
<td><em>Auction Revenue Fund Monthly Amount</em> – The sum of <code>ARFDlyAmt_{d}</code> in month <code>mn</code>.</td>
</tr>
<tr>
<td><code>ARFDlyAmt_d</code></td>
<td>$</td>
<td>Operating Day</td>
<td><em>Auction Revenue Fund Daily Amount</em> – The net excess between Auction Revenue Rights and TCR Auction collections for Operating Day <code>d</code>.</td>
</tr>
<tr>
<td><code>ArrAucTxnDlyAmt_{a, aid, d}</code></td>
<td>$</td>
<td>Operating Day</td>
<td><em>Auction Revenue Rights Funding Amount per TCR Auction ID per AO per Operating Day</em> - The value calculated under Section 4.5.10.2.</td>
</tr>
<tr>
<td><code>TcrAucTxnDlyAmt_{a, aid, d}</code></td>
<td>$</td>
<td>Operating Day</td>
<td><em>Transmission Congestion Right Auction Daily Amount per TCR Auction ID per AO per Operating Day</em> – The value calculated under Section 4.5.10.1.</td>
</tr>
<tr>
<td><code>ArrUpliftDlyAmt_{a, aid, d}</code></td>
<td>$</td>
<td>Operating Day</td>
<td><em>Auction Revenue Rights Daily Uplift Amount per AO per TCR Auction ID per Operating Day</em> - The value calculated under Section 4.5.10.3.</td>
</tr>
<tr>
<td><code>ArrUpliftAoMnthlyAmt_{a, mn}</code></td>
<td>$</td>
<td>Month</td>
<td><em>Auction Revenue Rights Monthly Uplift Amount per AO per Month</em> - The sum of AO a’s values calculated under Section 4.5.10.3 for month <code>mn</code>.</td>
</tr>
<tr>
<td><code>ArrUpliftSppMnthlyAmt_{mn}</code></td>
<td>$</td>
<td>Year</td>
<td><em>Auction Revenue Rights Daily Uplift Amount per Year</em> - The SPP total of the sum of all AO’s <code>ArrUpliftAoMnthlyAmt_{a, yr}</code> for the year.</td>
</tr>
<tr>
<td><code>ArrPaybackMnthlyMpAmt_{m, mn}</code></td>
<td>$</td>
<td>Month</td>
<td><em>Auction Revenue Rights Annual Payback Amount per MP per Year</em> - MP a’s share of the <code>ARFMnthlyAmt_{yr}</code> in year <code>yr</code> limited to the amount required to fully fund MP m’s ARRs.</td>
</tr>
</tbody>
</table>

- `a` none none An Asset Owner.
- `d` none none An Operating Day.
- `mn` none none A month.
- `aid` none none TCR Auction ID (separate ID for each round and type).
- `yr` none none A year.
- `m` none none A Market Participant.
### 4.5.10.5 Auction Revenue Rights Annual Payback Amount

(1) An annual credit or charge\(^{26}\) will be calculated for each Asset Owner receiving charges under Section 4.5.10.3 over the year that were not fully reimbursed in the monthly payback process in order to ensure full funding of ARRs to the extent possible. The amount is calculated as follows:

\[
\#\text{ArrPaybackYrlyAmt}_{a, yr} = (-1) \times \min \{ \text{ArrNetUpliftAoYrlyAmt}_{a, yr}, \]
\[
\text{ARFYrlyAmt}_{yr} \times \frac{\text{ArrNetUpliftAoYrlyAmt}_{a, yr}}{\text{ArrNetUpliftSppYrlyAmt}_{yr}} \}
\]

Where,

(a) \(\text{ArrNetUpliftAoYrlyAmt}_{a, yr} = \)

\[
\sum_{a} \sum_{aid} \text{ArrUpliftDlyAmt}_{a, aid, d} + \sum_{mn} \text{ArrPaybackMnthlyAmt}_{a, mn}
\]

(b) \(\text{ArrNetUpliftSppYrlyAmt}_{yr} = \sum_{a} \text{ArrNetUpliftAoYrlyAmt}_{a, yr} \)

(c) \(\text{ARFYrlyAmt}_{yr} = \)

\[
\sum_{mn} \text{ARFMnthlyAmt}_{mn} + \sum_{a} \sum_{mn} \text{ArrPaybackMnthlyAmt}_{a, mn}
\]

(2) For each Market Participant, an annual amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The annual amount is calculated as follows:

\[
\text{ArrPaybackYrlyMpAmt}_{m, yr} = \sum_{a} \text{ArrPaybackYrlyAmt}_{a, yr}
\]

---

\(^{26}\) Note that this charge type will almost always produce a credit. The charge is included here for the rare occasion when a charge may be produced as a result of a data error and/or a resettlement.
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>ArrPaybackYrlyAmt&lt;sub&gt;a,yr&lt;/sub&gt;</td>
<td>$</td>
<td>Year</td>
<td>Auction Revenue Rights Annual Payback Amount per AO per year - AO a’s share of the ARFYrlyAmt&lt;sub&gt;yr&lt;/sub&gt; in year yr limited to the amount required to fully fund AO a’s ARRs.</td>
</tr>
<tr>
<td>ARFYrlyAmt&lt;sub&gt;yr&lt;/sub&gt;</td>
<td>$</td>
<td>Year</td>
<td>Auction Revenue Fund Yearly Amount – The total excess TCR auction revenues remaining at the end of year yr after taking into account the total amounts paid under the monthly payback process in year yr.</td>
</tr>
<tr>
<td>ArrUpliftDlyAmt&lt;sub&gt;a,aid,d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Auction Revenue Rights Daily Uplift Amount per AO per TCR Auction ID per Operating Day - The value calculated under Section 4.5.10.3.</td>
</tr>
<tr>
<td>ArrNetUpliftAoYrlyAmt&lt;sub&gt;a,yr&lt;/sub&gt;</td>
<td>$</td>
<td>Year</td>
<td>Auction Revenue Rights Net Uplift Amount per AO per Year - The total ARR uplift remaining to reimbursed for AO a in year yr.</td>
</tr>
<tr>
<td>ArrNetUpliftSppYrlyAmt&lt;sub&gt;yr&lt;/sub&gt;</td>
<td>$</td>
<td>Year</td>
<td>Auction Revenue Rights Net Uplift Amount per Year - The SPP total of the total ARR uplift remaining to reimbursed in year yr.</td>
</tr>
<tr>
<td>ArrPaybackYrlyMpAmt&lt;sub&gt;m,yr&lt;/sub&gt;</td>
<td>$</td>
<td>Month</td>
<td>Auction Revenue Rights Annual Payback Amount per MP per Year - MP a’s share of the ARFYrlyAmt&lt;sub&gt;yr&lt;/sub&gt; in year yr. limited to the amount required to fully fund MP m’s ARRs.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>a</td>
<td>none</td>
<td>none</td>
<td>An Asset Owner.</td>
</tr>
<tr>
<td>d</td>
<td>none</td>
<td>none</td>
<td>An Operating Day.</td>
</tr>
<tr>
<td>mn</td>
<td>none</td>
<td>none</td>
<td>A month.</td>
</tr>
<tr>
<td>yr</td>
<td>none</td>
<td>none</td>
<td>A year.</td>
</tr>
<tr>
<td>m</td>
<td>none</td>
<td>none</td>
<td>A Market Participant.</td>
</tr>
</tbody>
</table>
### 4.5.10.6 Auction Revenue Rights Annual Closeout Amount

(1) An annual credit or charge\(^27\) will be calculated for each Asset Owner with ARR Nomination Caps established under Section (4) to the extent that there are any funds remaining once all credits are paid under Section 4.5.10.4. The amount is calculated as follows:

\[
\text{ArrCloseoutYrlyAmt}_{a, yr} = (-1) \times \left[ \text{ARFYrlyAmt}_{yr} + \text{ArrPaybackSppYrlyAmt}_{yr} \right] \\
\times \left[ \frac{\text{ArrNominationCapAoYrlyQty}_{a, yr}}{\text{ArrNominationCapSppYrlyQty}_{yr}} \right]
\]

Where,

\[
\text{ArrPaybackSppYrlyAmt}_{yr} = \sum_{a} \text{ArrPaybackYrlyAmt}_{a, yr}
\]

(2) For each Market Participant, an annual amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The annual amount is calculated as follows:

\[
\text{ArrCloseoutYrlyMpAmt}_{m, yr} = \sum_{a} \text{ArrCloseoutYrlyAmt}_{a, yr}
\]

---

\(^27\) Note that this charge type will almost always produce a credit. The charge is included here for the rare occasion when a charge may be produced as a result of a data error and/or a resettlement.
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>$arrCloseoutYrlyAmt_{a,yr}$</td>
<td>$</td>
<td>Year</td>
<td>Auction Revenue Rights Annual Payback Amount per AO per Year - AO a’s share of any remaining $arrFYlyAmt_{mn}$ in year yr.</td>
</tr>
<tr>
<td>$arrPaybackYrlyAmt_{a,yr}$</td>
<td>$</td>
<td>Year</td>
<td>Auction Revenue Rights Annual Payback Amount per AO per Year - The value calculated under Section 4.5.8.17.</td>
</tr>
<tr>
<td>$arrNominationCapAoYrlyQty_{a,yr}$</td>
<td>MW</td>
<td>Year</td>
<td>ARR Nomination Cap per AO per Year – The sum of the values described under Section 4.5.10.3 for AO a for year yr.</td>
</tr>
<tr>
<td>$arrNominationCapSppYrlyQty_{yr}$</td>
<td>MW</td>
<td>Year</td>
<td>ARR Nomination Cap Total per Year – The value calculated under Section 4.5.8.18.</td>
</tr>
<tr>
<td>$arrPaybackSppYrlyAmt_{yr}$</td>
<td>$</td>
<td>Year</td>
<td>Auction Revenue Rights Annual Payback Amount per Year - The value calculated under Section 4.5.8.18.</td>
</tr>
<tr>
<td>$arrFYlyAmt_{yr}$</td>
<td>$</td>
<td>Year</td>
<td>Auction Revenue Fund Yearly Amount – The sum of $arrFMthlyAmt_{mn}$ in year yr.</td>
</tr>
<tr>
<td>$arrNominationCapQty_{a,d}$</td>
<td>MW</td>
<td>Operating Day</td>
<td>ARR Nomination Cap per AO per Operating Day – The value described under Section 4.5.10.3.</td>
</tr>
<tr>
<td>$arrCloseoutYrlyMpAmt_{m,yr}$</td>
<td>$</td>
<td>Year</td>
<td>Auction Revenue Rights Annual Payback Amount per MP per Year - MP a’s share of the $arrFYlyAmt_{yr}$ in year yr.</td>
</tr>
</tbody>
</table>

$a$ none none An Asset Owner.

$d$ none none An Operating Day.

$yr$ none none A year.

$m$ none none A Market Participant.
4.5.11 Miscellaneous Amount

(1) In certain circumstances, it may be necessary to recalculate or make changes to previously billed charges that cannot be handled though a standard final settlement or resettlement execution for that operating day. This is anticipated to occur only on an exception basis. SPP will manually calculate the adjustment and post as a manual adjustment to the appropriate final or resettlement statement for the Operating Day in question. SPP will post supporting documentation for the manual calculation of any miscellaneous charge to the Portal no later than the time the Settlement Statement including the miscellaneous charge has been posted. In some situations the charge or credit assessed must be excluded from Revenue Neutrality Uplift calculations such that SPP is left with a net receivable or payable amount for the settlement of the OD.

(2) In addition, through Balancing Authority Agreements with adjacent external Balancing Authorities, SPP may supply Emergency Export Interchange Transactions when requested by the applicable external Balancing Authority or SPP may request, under SPP Emergency conditions, that applicable external Balancing Authorities supply Emergency Import Interchange Transactions to SPP. To the extent that such transactions are confirmed, credits to SPP for Emergency Export Interchange Transactions and charges to SPP for Emergency Import Interchange Transactions are included in this charge type.

(3) A miscellaneous charge type will be utilized for each distinct charge type and any other charges and credits not specifically accounted for under a distinct charge type. Miscellaneous charges and credits to the affected Asset Owners are represented for each Operating Day as follows:

\[ \text{MiscDlyAmt}_{a, ct, s, rnu, d} \]
The above variable is defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>MiscDlyAmt(_{a, ct, s, rnu, d})</td>
<td>$</td>
<td>Operating Day</td>
<td>Miscellaneous Amount per AO per Settlement Location per Settlement Location per Operating Day – The miscellaneous amount to AO (a) for charge type (ct) at Settlement Location (s) in Operating Day (d).</td>
</tr>
<tr>
<td>(a)</td>
<td>none</td>
<td>none</td>
<td>An Asset Owner (assumes SPP and External BA will be identified as Asset Owners).</td>
</tr>
<tr>
<td>(ct)</td>
<td>none</td>
<td>none</td>
<td>Any charge type specified under Sections 4.5.7, 4.5.9 or 4.5.9.21 or any other miscellaneous charges not specifically accounted for under a distinct charge type.</td>
</tr>
<tr>
<td>(s)</td>
<td>none</td>
<td>none</td>
<td>A Settlement Location.</td>
</tr>
<tr>
<td>(rnu)</td>
<td>none</td>
<td>none</td>
<td>A flag which instructs the settlement system to include the amount in Revenue Neutrality Uplift calculations ((1 = Y, 0 = N)).</td>
</tr>
<tr>
<td>(d)</td>
<td>none</td>
<td>none</td>
<td>An Operating Day.</td>
</tr>
</tbody>
</table>
4.5.12 Revenue Neutrality Uplift Distribution Amount

(1) A charge or credit will be calculated at each Settlement Location for each Asset Owner for each hour in order for SPP to remain revenue neutral. Contributors to revenue non-neutrality include:

(a) Rounding errors;
(b) Inadvertent Interchange (as calculated as shown in equation b.3 below);
(c) Joint Operating Agreement Charges/Credits;
(d) RTBM congestion (as calculated as shown in equation b.4 below);
(e) RTBM Regulation Deployment Adjustment;
(f) Make-Whole payments for Out-of-Merit Energy; and
(g) Miscellaneous Charges/Credits.

The amount will be determined by multiplying the Asset Owner hourly determinant by a daily Revenue Neutrality Uplift (RNU) rate. The Asset Owner hourly determinant is equal to the sum that Asset Owner’s actual generation MWh, actual load MWh, actual Interchange Transaction MWh, DA Market cleared Virtual Offer MWh and DA Market cleared Virtual Bid MWh for the Hour, where all of these values are assumed to be positive values.

The amount to each applicable Asset Owner is calculated as follows.

\[
\#RtRnuHrlyAmt_{a,s,h} = (RtRnuSppDistRate_{d} \times RtRnuDistHrlyQty_{a,s,h}) \times (-1)
\]

Where,

(a) \(\#RtRnuDistHrlyQty_{a,s,h} = \text{ABS}\left\{ \sum_i RtBillMtr5minQty_{a,s,i} / 12 \right\} \)

\[+ \text{ABS}\left\{ \sum_i \sum_t (RtImpExp5minQty_{a,s,i,t} / 12) \times (1 - \text{RsgCrdFlg}_t) \right\} \]

\[+ \text{ABS}\left\{ \sum_t DaClrdVHrlyQty_{a,s,h,t} \right\} \]

(b) \(\#RtRnuSppDistRate_{d} = \)

\[
(\text{DaRevInadqcSppAmt}_{spp,d} + RtRevInadqcSppAmt_{spp,d})
\]
+ \text{RtOomSppAmt}_{spp,d} + \text{RtRegAdjSppAmt}_{spp,d}

+ \text{RtJoaSppAmt}_{spp,d} - \text{RtNetInadvertentSppAmt}_{spp,d}

+ \text{RtCongestionSppAmt}_{spp,d}) / \text{RtRnuDistSppQty}_{spp,d}

Where,

\[ \text{RtOomSppAmt}_{spp,d} = \sum_{m} \text{RtOomMpAmt}_{m,d} \]

\[ \text{RtRegAdjSppAmt}_{spp,d} = \sum_{m} \text{RtRegAdjMpAmt}_{m,d} \]

\[ \text{RtJoaSppAmt}_{spp,d} = \sum_{a} \sum_{h} \sum_{f} \text{RtJoaHrlyAmt}_{a,h,f} \]

\[ \text{RtRnuDistSppQty}_{spp,d} = \sum_{a} \sum_{s} \sum_{h} \text{RtRnuDistHrlyQty}_{a,s,h} \]

(b.1) \[ \text{DaRevInadqcSppAmt}_{spp,d} = \]

\[ \sum_{m} ( \text{DaEnergyMpAmt}_{m,d} + \text{DaNEnergyMpAmt}_{m,d} + \text{DaVEnergyMpAmt}_{m,d} \]

+ \text{DaRegUpMpAmt}_{m,d} + \text{DaSpinMpAmt}_{m,d} + \text{DaSuppMpAmt}_{m,d} \]

+ \text{DaRegDnMpAmt}_{m,d} + \text{DaRegUpDistMpAmt}_{m,d} + \text{DaSpinDist MpAmt}_{m,d} \]

+ \text{DaSuppDistMpAmt}_{m,d} + \text{DaRegDnDistMpAmt}_{m,d} + \text{DaMwpMpAmt}_{m,d} \]

+ \text{DaMwpDistMpAmt}_{m,d} + \text{TcrFundMpAmt}_{m,d} + \text{TcrUpliftDlyMpAmt}_{m,d} \]

+ \text{DaOclDistMpAmt}_{m,d} + \text{TcrAucTxnMpAmt}_{m,d} + \text{ArrAucTxnMpAmt}_{m,d} \]

+ \text{ArrUpliftMpAmt}_{m,d} ) - \text{ECFDlyAmt}_{d} - \text{ARFDlyAmt}_{d} \]
(b.2) \[ \text{RtRevInadqcSppAmt}_{spp, d} = \]
\[ \sum_m \left( \text{RtEnergyMpAmt}_{m, d} + \text{RtNEnergyMpAmt}_{m, d} + \text{RtVEnergyMpAmt}_{m, d} \right. \]
\[ + \text{RtRegUpMpAmt}_{m, d} + \text{RtRegDnMpAmt}_{m, d} + \text{RtSpinMpAmt}_{m, d} \]
\[ + \text{RtSuppMpAmt}_{m, d} + \text{RtMwpMpAmt}_{m, d} \]
\[ + \text{RtMwpDistMpAmt}_{m, d} + \text{RtRegNonPerfMpAmt}_{m, d} \]
\[ + \text{RtRegNonPerfDistMpAmt}_{m, d} + \text{RtCRDeplFailMpAmt}_{m, d} \]
\[ + \text{RtOclDistMpAmt}_{m, d} + \text{RtCRDeplFailDistMpAmt}_{m, d} \]
\[ + \text{RtRegUpDistMpAmt}_{m, d} + \text{RtRegDnDistMpAmt}_{m, d} \]
\[ + \text{RtSpinDistMpAmt}_{m, d} + \text{RtSuppDistMpAmt}_{m, d} \]
\[ + \text{RtRsgDistMpAmt}_{m, d} \right) + \sum_a \text{RtRsgDlyAmt}_{a, d} \]
\[ + \sum_a \sum_c \sum_s \{ \text{IF rnu} = 1, \text{THEN MiscDlyAmt}_{a, c, s, rnu, d}, \text{ELSE} 0 \} + \]
\[ \text{RtNetInadvertentSppAmt}_{spp, d} \]
\[ - \text{RtCongestionSppAmt}_{spp, d} \]

(b.3) \[ \text{RtNetInadvertentSppAmt}_{spp, d} = \sum_i \text{RtNetInadvertentSpp5minAmt}_{i} \]

(b.3.1) \[ \#\text{RtNetInadvertentSpp5minAmt}_{i} = \]
\[ ( ( \text{RtNetActIntrchngSpp5minQty}_{i} - \text{RtNetSchedIntrchngSpp5minQty}_{i} ) \]
\[ \ast \text{RtMec5minPrc}_{i} ) / 12 \]
(b.4) \[ \#RtCongestionSppAmt_{spp, d} = \]
\[
\sum_{a} \sum_{s} \sum_{i} \left( \left( \text{RtBillMtr5minQty}_{a, s, i} - \text{DaClrdHrlyQty}_{a, s, h} \right) + \left( \text{RtImpExp5MinQty}_{a, s, i, t} - \text{DaImpExp5MinQty}_{a, s, i, t} \right) - \text{DaClrdVHrlyQty}_{a, s, h, t} \right) \times \text{RtMcc5minPrc}_{a, s, i} / 12
\]

(2) For each Asset Owner, a daily amount is calculated at each Settlement Location. The amount is calculated as follows:

\[ \text{RtRnuDlyAmt}_{a, s, d} = \sum_{h} \text{RtRnuHrlyAmt}_{a, s, h} \]

(3) For each Asset Owner associated with Market Participant \( m \), a daily amount is calculated. The daily amount is calculated as follows:

\[ \text{RtRnuAoAmt}_{a, m, d} = \sum_{s} \text{RtRnuDlyAmt}_{a, s, d} \]

(4) For each Market Participant, a daily amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The daily amount is calculated as follows:

\[ \text{RtRnuMpAmt}_{m, d} = \sum_{a} \text{RtRnuAoAmt}_{a, m, d} \]
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>$\text{RtRnuHrlyAmt}_{a,s,h}$</td>
<td>$$/h</td>
<td>Hour</td>
<td>$\text{Real-Time Revenue Neutrality Uplift Amount per AO per Settlement Location per Hour}$ – The amount for revenue neutrality to AO $a$ at Settlement Location $s$ in Hour $h$.</td>
</tr>
<tr>
<td>$\text{RtRnuSppDistRate}_{d}$</td>
<td>$$/MW</td>
<td>Operating Day</td>
<td>$\text{Real-Time Revenue Neutrality Uplift SPP Distribution Rate per Operating Day}$ – The rate applied to AO $a$’s $\text{RtRnuDistHrlyQty}_{a,s,h}$ in each Hour $h$ at Settlement Location $s$ in Operating Day $d$.</td>
</tr>
<tr>
<td>$\text{RtRnuDistHrlyQty}_{a,s,h}$</td>
<td>MWh</td>
<td>Hour</td>
<td>$\text{Real-Time Revenue Neutrality Uplift Quantity per AO per Hour per Settlement Location}$ – The total MWh RNU allocation determinant for AO $a$ at Settlement Location $s$ for Hour $h$.</td>
</tr>
<tr>
<td>$\text{RtRnuDistSppQty}_{spp,d}$</td>
<td>MWh</td>
<td>Operating Day</td>
<td>$\text{Real-Time Revenue Neutrality Uplift Quantity for SPP per Operating Day}$ – The total MWh RNU allocation determinant for SPP on a system-wide basis.</td>
</tr>
<tr>
<td>$\text{DaClrdVHrlyQty}_{a,s,h,t}$</td>
<td>MWh</td>
<td>Hour</td>
<td>$\text{Day-Ahead Cleared Virtual Energy Quantity per AO per Transaction per Settlement Location per Hour}$ – The value defined under Section 4.5.8.3.</td>
</tr>
<tr>
<td>$\text{RtOomSppAmt}_{spp,d}$</td>
<td>$$/d</td>
<td>Operating Day</td>
<td>$\text{Real-Time Out-Of-Merit Make-Whole-Payment Amount for SPP per Operating Day}$ – The SPP system-wide total of the values described under Section 4.5.9.9.</td>
</tr>
<tr>
<td>$\text{RtRegAdjSppAmt}_{spp,d}$</td>
<td>$$/d</td>
<td>Operating Day</td>
<td>$\text{Real-Time Regulation Deployment Adjustment Amount for SPP per Operating Day}$ – The SPP system-wide total of the values described under Section 4.5.9.18.</td>
</tr>
<tr>
<td>$\text{RtJoaSppAmt}_{spp,d}$</td>
<td>$$/d</td>
<td>Operating Day</td>
<td>$\text{Real-Time Joint Operating Agreement Amount for SPP per Operating Day}$ – The SPP system-wide total of the values calculated under Section 4.5.9.21.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>-------------------------------</td>
<td>-----------</td>
<td>---------------------</td>
<td>---------------------------------------------------------------------------</td>
</tr>
<tr>
<td>DaRevInadqcSppAmt&lt;sub&gt;spp, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Revenue Inadequacy Amount – The amount of mismatch on an SPP-wide basis between total DA Market charges and DA Market credits for Operating Day &lt;i&gt;d&lt;/i&gt;.</td>
</tr>
<tr>
<td>DaEnergyMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Asset Energy Amount per MP per Operating Day – The value calculated under Section 4.5.8.1.</td>
</tr>
<tr>
<td>DaNEnergyMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Non-Asset Energy Amount per MP per Operating Day – The value calculated under Section 4.5.8.2.</td>
</tr>
<tr>
<td>DaVEnergyMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Virtual Energy Amount per MP per Operating Day – The value calculated under Section 4.5.8.3.</td>
</tr>
<tr>
<td>DaRegUpMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Regulation-Up Amount per MP per Operating Day – The value calculated under Section 4.5.8.4.</td>
</tr>
<tr>
<td>DaRegDnMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Regulation-Down Amount per MP per Operating Day – The value calculated under Section 4.5.8.5.</td>
</tr>
<tr>
<td>DaSpinMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Spinning Reserve Amount per MP per Operating Day – The value calculated under Section 4.5.8.6.</td>
</tr>
<tr>
<td>DaSuppMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Supplemental Reserve Amount per MP per Operating Day – The value calculated under Section 4.5.8.7.</td>
</tr>
<tr>
<td>DaRegUpDistMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Regulation-Up Distribution Amount per MP per Operating Day – The value calculated under Section 4.5.8.8.</td>
</tr>
<tr>
<td>DaRegDnDistMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Regulation-Down Distribution Amount per MP per Operating Day – The value calculated under Section 4.5.8.9.</td>
</tr>
<tr>
<td>DaSpinDistMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Spinning Reserve Distribution Amount per MP per Operating Day – The value calculated under Section 4.5.8.10.</td>
</tr>
<tr>
<td>DaSuppDistMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Supplemental Reserve Distribution Amount per MP per Operating Day – The value calculated under Section 4.5.8.11.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>------------------------------</td>
<td>-------</td>
<td>---------------------</td>
<td>----------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>DaMwpMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Make-Whole-Payment Amount per MP per Operating Day – The value calculated under Section 4.5.8.12.</td>
</tr>
<tr>
<td>DaMwpDistMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Make-Whole-Payment Distribution Amount per MP per Operating Day – The value calculated under Section 4.5.8.13.</td>
</tr>
<tr>
<td>TcrFundMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Transmission Congestion Rights Funding Amount per MP per Operating Day – The value calculated under Section 4.5.8.14.</td>
</tr>
<tr>
<td>TcrUpliftDlyMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Transmission Congestion Rights Uplift Amount per MP per Operating Day – The value calculated under Section 4.5.8.15.</td>
</tr>
<tr>
<td>ECFDlyAmt&lt;sub&gt;d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Excess Congestion Fund Amount per Operating Day – The value calculated under Section 4.5.8.16.</td>
</tr>
<tr>
<td>ARFDlyAmt&lt;sub&gt;d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Auction Revenue Fund Amount per Operating Day – The value calculated under Section 4.5.10.4.</td>
</tr>
<tr>
<td>DaOclDistMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Day-Ahead Over Collected Losses Distribution Amount per MP per Operating Day - The value calculated under Section 4.5.8.19.</td>
</tr>
<tr>
<td>TcrAucTxnMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Transmission Congestion Right Auction Daily Amount per MP per Operating Day – The value calculated under Section 4.5.10.1.</td>
</tr>
<tr>
<td>ArrAucTxnMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Auction Revenue Rights Funding Amount per MP per Operating Day – The value calculated under Section 4.5.10.2.</td>
</tr>
<tr>
<td>ArrUpliftMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Auction Revenue Rights Funding Uplift Amount per MP per Operating Day – The value calculated under Section 4.5.10.3.</td>
</tr>
<tr>
<td>RtRevInadqcSppAmt&lt;sub&gt;spp, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Revenue Inadequacy Amount – The amount of mismatch on an SPP-wide basis between total RTBM charges and RTBM credits.</td>
</tr>
<tr>
<td>RtBillMtr5minQty&lt;sub&gt;a, s, i&lt;/sub&gt;</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Billing Meter Quantity per AO per Settlement Location per Dispatch Interval - The value described under Section 4.5.9.1.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>----------------------------------</td>
<td>------------</td>
<td>--------------------</td>
<td>---------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td><strong>RtImpExp5minQty</strong>&lt;sub&gt;a, s, i, t&lt;/sub&gt;</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Interchange Transaction Quantity per AO per Settlement Location per Dispatch Interval per Transaction – The value described under Section 4.5.9.2.</td>
</tr>
<tr>
<td><strong>RsgCrdFlg</strong></td>
<td>none</td>
<td>none</td>
<td>Reserve Sharing Group Contingency Reserve Deployment Flag per Event – The value described under Section 4.5.8.8.</td>
</tr>
<tr>
<td><strong>DaCldVHrlqTy</strong>&lt;sub&gt;a, s, h, t&lt;/sub&gt;</td>
<td>MWh</td>
<td>Hour</td>
<td>Day-Ahead Virtual Energy Quantity per AO per Settlement Location per Hour per Transaction – The value described under Section 4.5.8.3.</td>
</tr>
<tr>
<td><strong>DaCldHrlyQty</strong>&lt;sub&gt;a, s, h&lt;/sub&gt;</td>
<td>MWh</td>
<td>Hour</td>
<td>Day-Ahead Asset Energy Quantity per AO per Settlement Location. The value described under Section 4.5.8.1.</td>
</tr>
<tr>
<td><strong>DaImpExp5MinQty</strong>&lt;sub&gt;a, s, i, t&lt;/sub&gt;</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Day-Ahead Interchange Transaction Quantity per AO per Settlement Location per Dispatch Interval per Transaction – The value described under Section 4.5.8.2.</td>
</tr>
<tr>
<td><strong>RtMcc5minPrce</strong>&lt;sub&gt;a, s, i&lt;/sub&gt;</td>
<td>$/MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Marginal Congestion Component of Real-Time LMP – The Marginal Congestion Component of the Real-Time LMP at Settlement Location s for Dispatch Interval i.</td>
</tr>
<tr>
<td><strong>RtEnergyMpAmt</strong>&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Energy Amount per MP per Operating Day – The value described under Section 4.5.9.1.</td>
</tr>
<tr>
<td><strong>RtNEnergyMpAmt</strong>&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Non-Asset Energy Amount per MP per Operating Day – The value described under Section 4.5.9.2.</td>
</tr>
<tr>
<td><strong>RtVEnergyMpAmt</strong>&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Virtual Energy Amount per MP per Operating Day – The value described under Section 4.5.9.3.</td>
</tr>
<tr>
<td><strong>RtRegUpMpAmt</strong>&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Regulation-Up Amount per MP per Operating Day – The value described under Section 4.5.9.4.</td>
</tr>
<tr>
<td><strong>RtRegDnMpAmt</strong>&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Regulation-Down Amount per MP per Operating Day – The value described under Section 4.5.9.5.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>------------------------------</td>
<td>------</td>
<td>---------------------</td>
<td>-----------------------------------------------------------------------------</td>
</tr>
<tr>
<td>RtSpinMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Spinning Reserve Amount per MP per Operating Day – The value described under Section 4.5.9.6.</td>
</tr>
<tr>
<td>RtSuppMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Supplemental Reserve Amount per MP per Operating Day – The value described under Section 4.5.9.7.</td>
</tr>
<tr>
<td>RtMwpMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>RUC Make-Whole-Payment Amount per MP per Operating Day – The value described under Section 4.5.9.8</td>
</tr>
<tr>
<td>RtOomMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Out-Of-Merit Make-Whole-Payment Amount per MP per Operating Day - The value described under Section 4.5.9.9.</td>
</tr>
<tr>
<td>RtMwpDistMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>RUC Make-Whole-Payment Distribution Amount per MP per Operating Day – The value described under Section 4.5.9.10.</td>
</tr>
<tr>
<td>RtRegNonPerfMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Regulation Non-Performance Amount per MP per Operating Day – The value described under Section 4.5.9.15.</td>
</tr>
<tr>
<td>RtCRDeplFailMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Contingency Reserve Deployment Failure Amount per MP per Operating Day – The value described under Section 4.5.9.17.</td>
</tr>
<tr>
<td>RtRegAdjMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Regulation Deployment Adjustment Amount per MP per Operating Day - The value described under Section 4.5.9.19.</td>
</tr>
<tr>
<td>RtOclDistMpAmt&lt;sub&gt;m, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Over Collected Losses Distribution Amount per MP per Operating Day - The value calculated under Section 4.5.9.20.</td>
</tr>
<tr>
<td>RtNetInadvertentSpp5minAmt&lt;sub&gt;i&lt;/sub&gt;</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time SPP Inadvertent Energy Amount per Dispatch Interval – SPP net Inadvertent Energy for Dispatch Interval &lt;i&gt;i&lt;/i&gt; valued at the Real-Time LMP MEC.</td>
</tr>
<tr>
<td>RtNetInadvertentSppAmt&lt;sub&gt;spp, d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time SPP Inadvertent Energy Amount per Operating Day – The sum of RtNetInadvertentSpp5minAmt&lt;sub&gt;i&lt;/sub&gt; for Operating Day &lt;i&gt;d&lt;/i&gt;.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>-----------------------------------------------</td>
<td>------</td>
<td>---------------------</td>
<td>-----------------------------------------------------------------------------</td>
</tr>
<tr>
<td>$RtCongestionSppAmt_{spp,d}$</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time SPP Net Congestion Revenue Amount – The net amount of total Real-Time congestion revenue collected over Operating Day $d$.</td>
</tr>
<tr>
<td>$RtNetActIntrchngSpp5minQty_i$</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time SPP Net Actual Interchange per Dispatch Interval – SPP Net Actual Interchange in Dispatch Interval $i$.</td>
</tr>
<tr>
<td>$RtNetSchedIntrchngSpp5minQty_i$</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time SPP Net Scheduled Interchange per Dispatch Interval – SPP Net Actual Interchange in Dispatch Interval $i$.</td>
</tr>
<tr>
<td>$RtMec5minPrc_i$</td>
<td>$MW</td>
<td>Dispatch Interval</td>
<td>Marginal Energy Component of Real-Time LMP per Dispatch Interval – The Real-Time LMP MEC in Dispatch Interval $i$.</td>
</tr>
<tr>
<td>$RtJoaHrlyAmt_{a,h,f}$</td>
<td>$</td>
<td>Hour</td>
<td>Real-Time Joint Operating Agreement Hourly Amount - The value calculated under Section 4.5.9.21.</td>
</tr>
<tr>
<td>$RtRegNonPerfDistMpAmt_{m,d}$</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Regulation Non-Performance Distribution Amount - The value calculated under Section 4.5.9.16.</td>
</tr>
<tr>
<td>$RtCRDepFailDistMpAmt_{m,d}$</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Contingency Reserve Deployment Failure Distribution Amount - The value calculated under Section 4.5.9.18.</td>
</tr>
<tr>
<td>$RtRegUpDistMpAmt_{m,d}$</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Regulation-Up Distribution Amount – The value calculated under Section 4.5.9.11.</td>
</tr>
<tr>
<td>$RtRegDnDistMpAmt_{m,d}$</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Regulation-Down Distribution Amount – The value calculated under Section 4.5.9.12.</td>
</tr>
<tr>
<td>$RtSpinDistMpAmt_{m,d}$</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Spinning Reserve Distribution Amount – The value calculated under Section 4.5.9.13.</td>
</tr>
<tr>
<td>$RtSuppDistMpAmt_{m,d}$</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Supplemental Reserve Distribution Amount – The value calculated under Section 4.5.9.14.</td>
</tr>
<tr>
<td>$RtRsgDistMpAmt_{m,d}$</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Reserve Sharing Group Distribution Amount – The amount calculated under Section 4.5.9.23.</td>
</tr>
<tr>
<td>$RtRsgDlyAmt_{a,d}$</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Reserve Sharing Group Amount – The amount calculated under Section 4.5.9.22.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>-------------------</td>
<td>------</td>
<td>---------------------</td>
<td>----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>MiscDlyAmt&lt;sub&gt;a,c,d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td><em>Real-Time Miscellaneous Amount per AO per Charge Type per Operating Day</em> – The miscellaneous amount to AO &lt;i&gt;a&lt;/i&gt; for charge type &lt;i&gt;c&lt;/i&gt; in Operating Day &lt;i&gt;d&lt;/i&gt; as described under Section 4.5.10.4.</td>
</tr>
<tr>
<td>RtRnuDlyAmt&lt;sub&gt;a,s,d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td><em>Real-Time Revenue Neutrality Uplift Amount per AO per Settlement Location per Operating Day</em> – The amount for revenue neutrality to AO &lt;i&gt;a&lt;/i&gt; at Settlement Location &lt;i&gt;s&lt;/i&gt; in Operating Day &lt;i&gt;d&lt;/i&gt;.</td>
</tr>
<tr>
<td>RtRnuAoAmt&lt;sub&gt;a,m,d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td><em>Real-Time Revenue Neutrality Uplift Amount per AO per Operating Day</em> – The amount for revenue neutrality to AO &lt;i&gt;a&lt;/i&gt; associated with Market Participant &lt;i&gt;m&lt;/i&gt; in Operating Day &lt;i&gt;d&lt;/i&gt;.</td>
</tr>
<tr>
<td>RtRnuMpAmt&lt;sub&gt;m,d&lt;/sub&gt;</td>
<td>$</td>
<td>Operating Day</td>
<td><em>Real-Time Revenue Neutrality Uplift Amount per MP per Operating Day</em> – The amount for revenue neutrality to MP &lt;i&gt;m&lt;/i&gt; in Operating Day &lt;i&gt;d&lt;/i&gt;.</td>
</tr>
<tr>
<td>&lt;i&gt;a&lt;/i&gt;</td>
<td>none</td>
<td>none</td>
<td>An Asset Owner.</td>
</tr>
<tr>
<td>&lt;i&gt;s&lt;/i&gt;</td>
<td>none</td>
<td>none</td>
<td>A Resource Settlement Location.</td>
</tr>
<tr>
<td>&lt;i&gt;h&lt;/i&gt;</td>
<td>none</td>
<td>none</td>
<td>An Hour.</td>
</tr>
<tr>
<td>&lt;i&gt;i&lt;/i&gt;</td>
<td>none</td>
<td>none</td>
<td>A Dispatch Interval.</td>
</tr>
<tr>
<td>&lt;i&gt;t&lt;/i&gt;</td>
<td>none</td>
<td>none</td>
<td>A single tagged Interchange Transaction, a single virtual energy transaction, a single Financial Schedule, a single contracted Operating Reserve transaction, a single TCR instrument, a single ARR award or a single Reserve Sharing Event transaction.</td>
</tr>
<tr>
<td>&lt;i&gt;f&lt;/i&gt;</td>
<td>none</td>
<td>none</td>
<td>A flowgate identified in the applicable JOA.</td>
</tr>
<tr>
<td>&lt;i&gt;d&lt;/i&gt;</td>
<td>none</td>
<td>none</td>
<td>An Operating Day.</td>
</tr>
<tr>
<td>&lt;i&gt;rnu&lt;/i&gt;</td>
<td>none</td>
<td>none</td>
<td>A flag which instructs the settlement system to include the amount in Revenue Neutrality Uplift calculations (1 = Y, 0 = N).</td>
</tr>
<tr>
<td>&lt;i&gt;m&lt;/i&gt;</td>
<td>none</td>
<td>none</td>
<td>A Market Participant.</td>
</tr>
</tbody>
</table>
4.5.13 Settlement Statement Process

4.5.13.1 Meter Data Submittal

All meter data submitted by noon on the previous Business Day will be included in the Settlement(s) scheduled to be executed. Except in the case of a four day holiday as discussed in Section 4.5.13.7, reported values for an Operating Day must be received by noon according to the following schedule on the Business Day prior to:

1. Day 5 calendar day for inclusion in Initial Settlement statement.
2. Day 45 calendar day for inclusion in Final Settlement statement.
3. Day 75 calendar day for inclusion in Resettlement 1 statement.
4. Day 105 calendar day for inclusion in Resettlement 2 statement.
5. Day 135 calendar day for inclusion in Resettlement 3 statement.
6. Day 165 calendar day for inclusion in Resettlement 4 statement.
7. Day 195 calendar day for inclusion in Resettlement 5 statement.
8. Day 225 calendar day for inclusion in Resettlement 6 statement.
9. Day 255 calendar day for inclusion in Resettlement 7 statement.
10. Day 285 calendar day for inclusion in Resettlement 8 statement.
11. Day 315 calendar day for inclusion in Resettlement 9 statement.
12. Day 345 calendar day for inclusion in Resettlement 10 statement.
13. Day 375 calendar day for inclusion in Resettlement 11 statement.

4.5.13.2 Daily Settlement Statement

The Settlement Statement(s) will be made available for each Operating Day and will be published for Market Participants and associated Asset Owners electronically through the Portal on Business Days. The Market Participant is responsible for accessing the information from the Portal once posted by SPP. In order to issue a Settlement Statement, SPP may use estimated, disputed or calculated meter data. An initial and final Settlement Statement will be created for each Operating Day. Resettlement Statements can be created for any given Operating Day having met the dispute-filing deadline and prior to twelve months elapsed time from the Operating Day. When actual validated data are available and all of the settlement and billing
disputes raised by Market Participants during the validation process have been resolved, SPP shall recalculate the amounts payable and receivable by the affected Market Participant.

For each Market Participant, Settlement Statement(s) will denote:

1. Operating Day;
2. Associated Asset identifier;
3. Market Participant identifier;
4. Type of statement (Initial, Final or Resettlement); 
5. Statement version number;
6. Unique Statement identification code; and
7. Market services settled.

Settlement Statements will include charges and credits by Asset Owner, appropriate Settlement Interval and Settlement Location.

4.5.13.3 Settlement Statement Access

Market Participants and associated Asset Owners can access all Settlement Statements pertaining to them electronically via the following steps:

1. Secured entry on the Portal;
2. eXtensible Markup Language (XML) download.

4.5.13.4 Initial Settlement Statements

SPP will use settlement data to produce the initial Settlement Statements for each Market Participant for the given Operating Day. For non-holidays as shown in Exhibit 4-21, Initial Settlement Statements will be created at the end of the seventh (7th) calendar day following the Operating Day. If the seventh (7th) calendar day is not a Business Day, the initial Settlement Statement is issued no later than the next Business Day thereafter. For holidays, the Initial Settlement Statements will be created as shown in Exhibit 4-22.

4.5.13.5 Final Settlement Statements

SPP will use settlement data to produce the final Settlement Statements for each Market Participant for the given Operating Day. Final Settlement Statements will be created at the end of the forty-seventh (47th) calendar day following the Operating Day. If the forty-seventh (47th) calendar day is not a Business Day, the final Settlement Statement is issued on the next Business...
Day thereafter. The final Settlement Statement will reflect changes to settlement charges generated on the Operating Day’s initial Settlement Statement.

### 4.5.13.6 Resettlement Statements

A resettlement Settlement Statement will be produced using corrected settlement data due to resolution of disputes, or correction of data errors. Resettlements occurring prior to the production of the final Settlement Statement will be included in the final Settlement Statement.

1. Resettlement Settlement Statements 1 through 11 will be created at the end of the following calendar days following the Operating Day. If the calendar day is not a Business Day, the respective resettlement Settlement Statement is issued on the next Business Day thereafter.

   - (a) Resettlement 1, 77 days after Operating Day
   - (b) Resettlement 2, 107 days after Operating Day
   - (c) Resettlement 3, 137 days after Operating Day
   - (d) Resettlement 4, 167 days after Operating Day
   - (e) Resettlement 5, 197 days after Operating Day
   - (f) Resettlement 6, 227 days after Operating Day
   - (g) Resettlement 7, 257 days after Operating Day
   - (h) Resettlement 8, 287 days after Operating Day
   - (i) Resettlement 9, 317 days after Operating Day
   - (j) Resettlement 10, Ad Hoc
   - (k) Resettlement 11, Ad Hoc
   - (l) Resettlement 12, Ad Hoc

2. Any settlement and billing dispute of initial Settlement Statements resolved in accordance with Dispute Resolution process of the Tariff will be corrected on the final Settlement Statement for the Operating Day. In the event that the final Settlement Statement does not resolve a dispute from an initial Settlement Statement for a given Operating Day, SPP will resolve the dispute on a resettlement Settlement Statement for that Operating Day. Only Disputes for which the RTO is notified by the end of the time period for as defined under Section 4.5.15 will be considered for resettlement.

3. Any dispute of initial and final Settlement Statements resolved subsequent to the final Settlement Statement, in accordance with the Dispute Resolution process of the Tariff,
will be corrected on the next available invoice after the R2 resettlement Settlement Statement run has been executed.

(4) Any dispute resolved subsequent to the R2 resettlement Settlement Statement, in accordance with the Dispute Resolution process of the Tariff, will be corrected on the next available invoice after the R4 resettlement Settlement Statement run has been executed.

(5) Resettlement Settlement Statements R1 and R3 will be utilized only if Dispute Resolution for a Granted or Granted with Exception Dispute results in at least a 25% financial change in a Market Participant’s Settlement Statement for the operating date as compared with the most recent previous Settlement Statement for that operating date. Resettlement Settlement Statements R5 to R9 will only be used to resolve Disputes of previous resettlements, which are limited to incremental changes. Resettlement Settlement Statements R10 to R12 will be used only on an Ad Hoc basis to resolve any remaining disputes, in accordance with the Dispute Resolution process of the Tariff.

(6) SPP shall post a resettlement schedule through the Portal indicating that a specific Operating Day will be resettled and the date the resettlement Settlement Statement will be issued by SPP.

4.5.13.7 Settlement Timeline

SPP shall create Settlement Statements and Settlement Determinant Reports daily for each Market Participant and associated Asset Owner, detailing each Market Participant’s and associated Asset Owners cost responsibility. Settlement Statements are published through the Portal on each Business Day. SPP shall prepare a Settlement Invoice each billing cycle for each Market Participant showing the net amount to be paid or received by the Market Participant. Settlement Determinant Reports shall provide sufficient detail to allow verification of the billing amounts and completion of the Market Participant’s internal accounting. SPP’s settlement systems shall allow Market Participants and associated Asset Owners to search for Settlement Statements by issuance date and invoice date and Settlement Determinant Reports by operating date. Settlement Statements shall be issued in accordance with the timelines shown in Exhibits 4-21 and 4-22.
Exhibit 4-21: Settlements Timeline – Non Holiday Example

<table>
<thead>
<tr>
<th></th>
<th>Sunday</th>
<th>Monday</th>
<th>Tuesday</th>
<th>Wednesday</th>
<th>Thursday</th>
<th>Friday</th>
<th>Saturday</th>
</tr>
</thead>
<tbody>
<tr>
<td>Day 1</td>
<td>Day 2</td>
<td>Day 3</td>
<td>Day 4</td>
<td>Day 5</td>
<td>Day 6</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Day 7</td>
<td>Day 8</td>
<td>Day 9</td>
<td>Day 10</td>
<td>Day 11</td>
<td>Day 12</td>
<td>Day 13</td>
<td></td>
</tr>
<tr>
<td>ISS Day 1</td>
<td>ISS Day 2</td>
<td>ISS Day 3</td>
<td>ISS Day 4</td>
<td>ISS Day 5</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Day 14</td>
<td>Day 15</td>
<td>Day 16</td>
<td>Day 17</td>
<td>Day 18</td>
<td>Day 19</td>
<td>Day 20</td>
<td></td>
</tr>
<tr>
<td>ISS Day 6</td>
<td>ISS Day 7</td>
<td>ISS Day 8</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
| Time Lapse for Day 21 to Day 48

<table>
<thead>
<tr>
<th></th>
<th>Day 49</th>
<th>Day 50</th>
<th>Day 51</th>
<th>Day 52</th>
<th>Day 53</th>
<th>Day 54</th>
<th>Day 55</th>
</tr>
</thead>
<tbody>
<tr>
<td>ISS Day 41</td>
<td>ISS Day 42</td>
<td>ISS Day 43</td>
<td>ISS Day 44</td>
<td>ISS Day 45</td>
<td>ISS Day 46</td>
<td>ISS Day 47</td>
<td>FSS Day 6</td>
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<tr>
<td>FSS Day 3</td>
<td>FSS Day 4</td>
<td>FSS Day 5</td>
<td>FSS Day 7</td>
<td>FSS Day 8</td>
<td>FSS Day 9</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

ISS-Initial Settlement Statement
FSS-Final Settlement Statement

Exhibit 4-21 applies to all Thursday through Sunday holidays and similar logic will apply to other 4 day holiday weekend scenarios:
Exhibit 4-22: Settlements Timeline –Holiday Example

<table>
<thead>
<tr>
<th>Sunday</th>
<th>Monday</th>
<th>Tuesday</th>
<th>Wednesday</th>
<th>Thursday</th>
<th>Friday</th>
<th>Saturday</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nov 14</td>
<td>Nov 15</td>
<td>Nov 16</td>
<td>Nov 17</td>
<td>Nov 18</td>
<td>Nov 19</td>
<td>Nov 20</td>
</tr>
<tr>
<td></td>
<td>MD (11/11)</td>
<td>MD (11/12)</td>
<td>MD (11/13)</td>
<td>MD (11/14)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Nov 21</td>
<td>Nov 22</td>
<td>Nov 23</td>
<td>Nov 24</td>
<td>Nov 25</td>
<td>Nov 26</td>
<td>Nov 27</td>
</tr>
<tr>
<td></td>
<td>MD (11/18)</td>
<td>MD (11/19)</td>
<td>MD (11/21)</td>
<td>MD (11/22)</td>
<td>Holiday</td>
<td>Holiday</td>
</tr>
<tr>
<td></td>
<td></td>
<td>MD (11/20)*</td>
<td></td>
<td>ISS (11/17)</td>
<td>ISS (11/18)</td>
<td>ISS (11/19)</td>
</tr>
<tr>
<td>Nov 28</td>
<td>Nov 29</td>
<td>Nov 30</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Holiday</td>
<td>MD (11/23)</td>
<td>MD (11/25)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>MD (11/24) *</td>
<td>MD (11/26)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>ISS (11/20)</td>
<td>ISS (11/22)</td>
<td>ISS (11/23)</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Meter Data (MD) due by Noon on days indicated.
* Meter Data due by 3:00 pm instead of normal noon deadline.
Initial Settlement Statement (ISS)

4.5.14 Settlement Invoice

SPP prepares weekly Settlement Invoices from Settlements Statements. Settlement Invoices will be prepared on a net basis, with payments made to or from SPP.

Invoices will be posted on the Portal by 8:00 a.m. CPT (see Section 4.5.14.3 Holiday Invoice Calendar for exceptions). The Market Participant is responsible for accessing the Settlement Invoice information via the Portal once posted by SPP.

Each Market Participant with a net debit balance will pay any net debit whether or not there is any settlement and billing dispute regarding the amount. Each Market Participant with a net...
credit balance will receive the balance shown on the Settlement Invoice, adjusted for balances not collected from Market Participants with net debit balances.

4.5.14.1 Timing and Content of Invoice

SPP will electronically post for each Market Participant, an invoice based on any initial final, and resettlement Settlement Statements produced since the prior settlement invoice. SPP shall post the settlement invoices to the Market Participant in accordance with the Settlement Calendar. The Market Participant is responsible for accessing the information from the Portal once posted by SPP.

Invoices will be issued on a weekly basis as defined in SPP invoice calendars described in Sections 4.5.14.2 and 4.5.14.3. The SPP invoice calendar will be posted annually on the SPP Portal. Invoice items will be grouped by initial, final, and resettlement categories and will be sorted by Operating Day within each category. Each settlement invoice will contain:

1. Market Participant ID – the name, address and contact information for the Market Participant being invoiced;
2. Net Amount Due/Payable – the aggregate summary of all charges owed or due by a Market Participant;
3. Amount Due/Payable by Asset Owner, Operating Date and Settlement Date — the aggregate of charges owed or due by an Asset Owner, listed by Operating Day which shall be identified by calendar date;
4. Time Periods – the time period covered for each settlement statement run date identified by a range of calendar dates;
5. Run Date – the date in which the invoice was created and published;
6. Invoice Reference Number – a unique number generated by the SPP applications for payment tracking purposes;
7. Settlement Statement ID – an identification code used to reference each Settlement Statement invoiced;
8. Payment Date and Time – the date and time that invoice amounts are to be paid or received;
9. Remittance Information Details – details including the account number, bank name and electronic transfer instructions of the SPP account to which any amounts owed by the
Invoice Recipient are to be paid or of the Invoice Recipient’s account to which SPP shall
draw payments due;

(10) Overdue Terms – the terms that would be applied if payments were received late;

(11) Late fees; and

(12) Miscellaneous charges from tariff billing not otherwise covered above with details
provided or referenced on what the miscellaneous charges include and how they are
derived.

4.5.14.2 Invoice Calendar

Weekly invoices will be distributed every Thursday by no later than 8:00 a.m. CPT with the
exceptions described in Section 4.5.14.3 for holidays. Weekly invoices will include the seven
(7) daily Settlement Statements (initial, final & resettlements) produced for the previous
Wednesday through Tuesday cycle. Market Participant balances owed to SPP are due by 5:00
p.m. (CPT) of the first (1st) Wednesday following the Thursday invoice date. Balances owed by
SPP to Market Participants will be paid on the second (2nd) Friday following the invoice date by
5:00 p.m. (CPT).

4.5.14.3 Holiday Invoice Calendar

The Thursday invoice date and the following Wednesday and Friday payment dates as described
in Section 4.5.14.2 will be changed to the next business day if the invoice date or payment date
fall on a SPP Holiday. In those cases when a payment date falls on a bank holiday but not a SPP
holiday, the payment date will be the next SPP business day. If there are two (2) consecutive
SPP holidays, the following calendar will apply (all invoice dates assume the invoice will be
made available to customers by 8:00 a.m. (CPT) on the date shown):

<table>
<thead>
<tr>
<th>Holiday</th>
<th>Invoice Date</th>
<th>Customer Pmt Due Date</th>
<th>SPP Pmt Due Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mon-Tue</td>
<td>Previous Thu</td>
<td>Fri</td>
<td>Tue</td>
</tr>
<tr>
<td>Tue-Wed</td>
<td>Following Mon</td>
<td>Fri</td>
<td>Tue</td>
</tr>
<tr>
<td>Wed-Thu</td>
<td>Following Mon</td>
<td>Fri</td>
<td>Tue</td>
</tr>
<tr>
<td>Thu-Fri</td>
<td>Following Mon</td>
<td>Fri</td>
<td>Tue</td>
</tr>
<tr>
<td>Fri-Mon</td>
<td>Normal Sched</td>
<td>Fri</td>
<td>Tue</td>
</tr>
</tbody>
</table>
4.5.15  Disputes

A Market Participant may dispute items set forth in any Settlement Statement (initial, final, or resettlement). The dispute must be filed on the Portal using the Contents of Notice dispute form as shown in Exhibit 4-23 with the following minimum content:

(1)  Statement type (initial, final, resettlement 1-11, ad hoc resettlement);
(2)  Charge type;
(3)  Estimated dispute amount in dollars;
(4)  Operating Day;
(5)  Start interval;
(6)  End interval;
(7)  Statement ID;
(8)  Transmission Customer ;
(9)  Settlement Location;
(10) Long description; and
(11) Short description.
Exhibit 4-23: Contents of Notice Dispute Form

<table>
<thead>
<tr>
<th>Request Information</th>
</tr>
</thead>
<tbody>
<tr>
<td>Request Category:</td>
</tr>
<tr>
<td>Statement Type:</td>
</tr>
<tr>
<td>Charge Type:</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Settlement Dispute Information</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dispute Amount ($)</td>
</tr>
<tr>
<td>Operating Day:</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Start Interval:</td>
</tr>
<tr>
<td>End Interval:</td>
</tr>
<tr>
<td>Statement ID:</td>
</tr>
<tr>
<td>Transmission Customer:</td>
</tr>
<tr>
<td>Settlement Location:</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Short Description:</td>
</tr>
<tr>
<td>Long Description:</td>
</tr>
<tr>
<td>Proposed Resolution:</td>
</tr>
</tbody>
</table>

Browse to Attach up to 5 Documents:
- [Browse...](#)
- [Browse...](#)
- [Browse...](#)
- [Browse...](#)
- [Browse...](#)

Fields in bold are required.
4.5.15.1 Dispute Submission Timeline

A Market Participant may dispute settlement of any Operating Day as soon as the initial Settlement Statement for that Operating Day is issued, and up to 90 calendar days after the final Settlement Statement for that Operating Day is issued. In the case of resettlement Settlement Statements, a Market Participant may only dispute incremental changes in settlement data that occur between issuance of the final Settlement Statement and the first resettlement Settlement Statement or between issuance of resettlement Settlement Statements. A dispute relating to a resettlement Settlement Statement must be filed within 14 calendar days of issuance of the resettlement Settlement Statement.

In the event that the Portal is unavailable on the day prior to the deadline for submission of a dispute due to technical or other reasons, SPP shall extend the dispute submittal deadline by the number of Business Days equal to the sequential number of Business Days on which the Portal was unavailable.

4.5.15.2 SPP Dispute Processing

SPP shall determine if the dispute is accepted by verifying that the dispute was submitted within the specified time and contains at least the minimum required information as described in Attachment AE of the SPP OATT.

(a) SPP shall make reasonable attempts to remedy any informational deficiencies by working with the Market Participant(s);

(b) Contents of Notice will be rejected if SPP determines required information is missing. The Dispute will be returned to the Market Participant with an explanation of the missing data no later than 30 days after the receipt of the original or resubmitted dispute. A Market Participant will be able to resubmit the dispute with additional information within 20 Business Days after the Dispute is returned to the Market Participant unless SPP grants an extension of this deadline for good cause. Once the Market Participant sends all required information and SPP determines the settlement and billing dispute is timely and complete, the dispute status will be considered “Open”;

(c) SPP will issue a settlement and billing dispute resolution report containing information related to the disposition of the dispute;

(d) SPP will make all reasonable attempts to resolve all “Open” disputes relating to all Settlement Statements within 30 calendar days after the settlement and billing dispute due date as specified in the Settlement Calendar. SPP will post the necessary adjustments for
resolved settlement and billing disputes on the next resettlement or final Settlement Statement process;

(e) For settlement and billing disputes requiring complex research or additional time for resolution, and late disputes that can be reasonably processed, SPP will notify the Market Participant of the length of time expected to research and post those disputes and, if a portion or all of the dispute is granted, SPP will post the necessary adjustments on the next available Settlement Statement for the Operating Day, if any portion or all of the dispute is Granted. Market Participants have the right to proceed to the External Arbitration process in Dispute Resolution of the Tariff for timely filed disputes that cannot be resolved through the settlement and billing dispute process.

4.5.15.2.1 Dispute Status

Each dispute will have a status as defined in the following paragraphs. Valid status designation includes:

1. **OPEN & CLOSED:** A Dispute will be deemed “Open” when submitted in a timely and complete manner. “Closed” is the final status for all Disputes;

2. **DENIED:** The Dispute will be “Denied” if SPP concludes that the information used in the Dispute is incorrect. SPP will notify the Market Participant when a Dispute is “Denied”, and will document the supporting research for the denial. If the Market Participant is not satisfied with the outcome of a Denied Settlement and Billing Dispute, the Market Participant may proceed to External Arbitration as described in Dispute Resolution of the Tariff, Dispute Resolution of these Rules. If after 30 calendar days from receiving notice of a “Denied” dispute, the Market Participant does not begin External Arbitration, the dispute will be “Closed”;

3. **GRANTED:** SPP may determine a settlement and billing dispute is “Granted”. SPP will notify the Market Participant of the resolution, and will document the basis for resolution. Upon resolution of the issue, the settlement and billing dispute will be processed on the next prescribed Settlement Statement for the Operating Day. Once the necessary adjustments appear on the next prescribed Settlement Statement, the settlement and billing dispute is then “Closed”;

4. **GRANTED with EXCEPTIONS:** SPP may determine a settlement and billing dispute is “Granted with Exceptions” when the information is partially correct and SPP will provide the exception information to the Market Participant. SPP will require an
acknowledgement from the Market Participant of the dispute Granted with Exceptions within twenty Business Days. The acknowledgement must indicate acceptance or rejection of the documented exceptions to the dispute. If accepted, SPP will post the necessary adjustments on the next prescribed Settlement Statement for the Operating Day and will change the dispute status to “Closed”. If SPP does not receive a response from the Market Participant within 30 calendar days, the dispute will be considered accepted and “Closed”.

If the Market Participant rejects the SPP determination of a dispute, which is “Granted with Exceptions”, the dispute will be investigated further. After further investigation, if the settlement and billing dispute is subsequently granted, the dispute will be processed on the next prescribed Settlement Statement to be issued. The dispute is then “Closed”. If exceptions to the dispute still exist, the Market Participant may either accept the dispute for resolution as “Granted with Exceptions”, or begin External Arbitration according to Dispute Resolution of the Tariff, Dispute Resolution of these Rules.

4.5.16 Invoice Payment Process

4.5.16.1 Overview of Payment Process

Payments shall be made in a two-step process where:

(1) All Settlement Invoices due with net debits owed by Market Participant are paid by 5:00 p.m. (CPT) of the first Wednesday following the Thursday invoice date, and

(2) All Settlement Invoices due with net credits owed to Market Participant are paid by 5:00 p.m. (CPT) of the second Friday following the invoice date

Payments due to SPP and payments due to Market Participant will be made by Electronic Funds Transfer (EFT) in U.S. Dollars.

4.5.16.2 Invoice Payments Due SPP

Each Market Participant owing monies to SPP shall remit the amount shown on its invoice so SPP receives this amount no later than 5:00 p.m. (CPT) on the first Wednesday following the Thursday invoice date. Payments due will be made by Electronic Funds Transfer (EFT) in U.S. Dollars. Payments will be made regardless of any settlement or invoice dispute regarding the amount of the debit. Payments not received by the due date will be subject to interest charges as approved by the Federal Energy Regulatory Commission.
4.5.16.3 SPP Payments to Invoice Recipients

On the first Thursday following the invoice date (or 1 day after payments are due from Market Participants), SPP shall calculate (via a payout report) the amounts for distribution to Market Participants with net credits and remit to those Market Participants no later than 5:00 p.m. (CPT) the next day. Once each payout report has been finalized, they will be posted to the Portal by 3:00 p.m. (CPT) on Thursday. At that time, Market Participants will be able to access information regarding their respective Friday payout amounts. The finalized payout calculations will also be provided to the SPP Customer Relations Department on Thursday afternoon by 3:00 p.m (CPT) should Market Participants have any questions regarding the payout amounts posted to the Portal.

4.5.17 Billing Determinant Anomalies

Circumstances may occur where billing determinants received from system interfaces contain erroneous data anomalies that would have significant adverse financial impacts on Market Participants if these determinants were used to produce Settlement Statements. In these situations when certain billing determinants deviate beyond prescribed tolerance levels, SPP will substitute the following acceptable values.

1. **SCADA** – 5-minute interval value
   - (a) High Tolerance Band - Greater than 120% of the RTBM Resource Maximum Emergency Capacity Operating Limit;
   - (b) Substitution value – Dispatch Instructions (results in zero URD);
   - (c) Low Tolerance Band – Less than RTBM Resource Minimum Economic Capacity Operating Limit;
   - (d) Substitution value – Dispatch Instructions (results in zero URD).

2. **Dispatch Instruction** – 5-minute interval value
   - (a) High Tolerance Band - Greater than 120% of the RTBM Resource Maximum Emergency Capacity Operating Limit;
   - (b) Substitution value – Use SCADA value (results in zero URD);
   - (c) Low Tolerance Band – Less than Zero;
   - (d) Substitution value – Use SCADA value (results in zero URD).

3. **Resource Meter Data**
   - (a) High Tolerance Band - Trigger value supplied by meter agent/Market Participant;
(b) Substitution value – SCADA;
(c) Low Tolerance Band – Auxiliary negative value supplied by meter agent/Market Participant;
(d) Substitution value – SCADA.

4) **Load Meter Data**

(a) High Tolerance Band - 150% of previous year annual peak;
(b) Substitution value – SCADA;
(c) Low Tolerance Band – Zero value;
(d) Substitution value – SCADA.

5) **Settlement Area Inter-Tie Meter Data**

(a) High Tolerance Band - Trigger value supplied by meter agent/Market Participant;
(b) Substitution value – SCADA;
(c) Low Tolerance Band – Trigger value supplied by meter agent/Market Participant;
(d) Substitution value – SCADA.
5. Transmission Congestion Rights Markets Process

The TCR Markets Process includes an annual ARR allocation process and annual and monthly TCR Auctions.

TCRs are monthly and seasonal financial instruments whose values are determined as part of the DA Market settlement based on the MW amount of the TCR and the DA Market differential of the Marginal Congestion Component of LMP between specified sinks and sources. TCRs are of the obligation type which means they can result in a credit or a charge. They provide a financial hedge against congestion costs in the DA Market as long as the MCC of the TCR sink Settlement Location is greater than the MCC of the TCR source Settlement Location. If the MCC at the TCR sink Settlement Location is less than the MCC of the TCR source Settlement Location, the TCR holder is charged (this type of TCR is commonly referred to as a “Counter-Flow TCR”).

Auction Revenue Rights (ARRs) are obtained by Eligible Entities during the annual ARR allocation process and/or incremental ARR allocation process. Holders of ARRs are entitled to receive the Annual and Monthly TCR Auction revenues associated with awarded TCR Bids. However, ARRs are of the obligation type which means they can result in the holder receiving a portion of the TCR auction revenues or contributing to the TCR auction revenues.

TCRs are obtained by Market Participants through the Annual and Monthly TCR Auctions. Optionally, ARR holders may directly convert their ARRs into TCRs in the Annual and Monthly TCR Auctions and either hold the TCRs or offer these TCRs for sale in the auctions.

There are 7 key steps associated with obtaining a TCR and/or offering an awarded TCR for sale.

1. Annual ARR Registration Process;
2. Annual ARR Allocation Process;
3. Annual TCR Auction Process;
4. Monthly TCR Auction Process;
5. Incremental ARR Allocation Process (if requested by Eligible Entity);
6. ARR Allocation and TCR Auction Settlements; and
7. TCR Secondary Markets.

Exhibit 5-1 provides an overall representative timeline related to the ARR Allocation and TCR Auction processes and Exhibit 5-2 provides additional details related to auction timing and available transmission system capability of the TCR Auction processes.
Exhibit 5-1: ARR Allocation/TCR Auction Processes Timeline
Exhibit 5-2: TCR Auction Processes Summary

<table>
<thead>
<tr>
<th>Auction Month</th>
<th>Auction Type</th>
<th>TCR Award Periods</th>
<th>TCR Products</th>
<th>Auction Rounds</th>
<th>Total Auctions</th>
</tr>
</thead>
<tbody>
<tr>
<td>May</td>
<td>Annual (System Capability %)</td>
<td>Jun (100)</td>
<td>Jul (90)</td>
<td>Aug (90)</td>
<td>Sep (90)</td>
</tr>
<tr>
<td>Jun</td>
<td>Monthly (System Capability %)</td>
<td>Jul (100)</td>
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<td></td>
<td></td>
</tr>
<tr>
<td>Jul</td>
<td>Monthly (System Capability %)</td>
<td>Aug (100)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Aug</td>
<td>Monthly (System Capability %)</td>
<td>Sep (100)</td>
<td></td>
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<tr>
<td>Sep</td>
<td>Monthly (System Capability %)</td>
<td>Oct (100)</td>
<td></td>
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</tr>
<tr>
<td>Oct</td>
<td>Monthly (System Capability %)</td>
<td>Nov (100)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Nov</td>
<td>Monthly (System Capability %)</td>
<td>Dec (100)</td>
<td></td>
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<td></td>
</tr>
<tr>
<td>Dec</td>
<td>Monthly (System Capability %)</td>
<td>Jan (100)</td>
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<tr>
<td>Jan</td>
<td>Monthly (System Capability %)</td>
<td>Feb (100)</td>
<td></td>
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</tr>
<tr>
<td>Feb</td>
<td>Monthly (System Capability %)</td>
<td>Mar (100)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Mar</td>
<td>Monthly (System Capability %)</td>
<td>Apr (100)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Apr</td>
<td>Monthly (System Capability %)</td>
<td>May (100)</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

^28 October and November
^29 December, January, February, March
^30 April and May
Key process and design assumptions of each of these seven (7) key steps are described in the following sub-sections.

5.1 Annual ARR Verification Process

Only Eligible Entities are eligible to nominate candidate ARRs as described under Section 5.2. Eligible Entities are Transmission Customers with firm SPP transmission service and entities with firm non-SPP transmission service (commonly referred to as a “grandfathered agreement or GFA”) into, out of, within or through the SPP Region that has been confirmed prior to the Annual ARR Allocation Process. Eligible Entities must verify such services with SPP during the Annual ARR Verification Process in order to be eligible to nominate candidate ARRs. All Eligible Entities must be a Market Participant and/or Asset Owner. The following rules apply to verification of transmission service for conversion to ARRs.

5.1.1 Transmission Service Verification

In order for Eligible Entities to obtain candidate ARRs, SPP must first verify existing transmission service entitlements. In order to qualify for candidate ARRs in a particular month and/or season, an Eligible Entity’s transmission service must span the entire monthly or seasonal period within the applicable year. SPP will verify Eligible Entity existing transmission service entitlements as follows:

(1) For Eligible Entities taking Network Integration Transmission Service (NITS) and/or Firm Point-To-Point Transmission Service (FPTP) under the SPP Tariff:

   (1) SPP will obtain source, sink and Reserved Capacity information from the SPP OASIS for each monthly and seasonal period for the applicable year in which the transmission service spans the entire period;

   (2) SPP will provide this information to each Eligible Entity for verification;

   (3) Eligible Entities will notify SPP within two (2) weeks following receipt of this information identifying and correcting inaccurate data. Otherwise, the SPP provided data will be considered verified.

(2) For Eligible Entities taking GFA service:

   (a) If the transmission customer under the GFA desires to nominate ARRs associated with the GFA sources and sinks identified in the Grandfathered Agreement, the GFA Parties must notify SPP that such GFA exists and provide SPP with sources, sinks and Reserved Capacity information. In addition, the parties to the GFA
must agree that the transmission customer under the GFA is eligible to nominate the ARRs associated with the GFA and both parties must confirm such with SPP. To the extent that the transmission service specified in the GFA is identified as the equivalent of SPP NITS, the transmission customer under the GFA must provide the historical non-coincident annual peak loads (“GFA Annual Peak Load”) being served under the GFA since February 1, 2007.

5.1.2 Candidate ARRs

Following verification of Eligible Entity transmission service, candidate ARRs associated with such transmission service are assigned as follows:

1. For each Eligible Entity with NITS, the Eligible Entity’s NITS Candidate ARRs from a specific source is then equal to the source Reserved Capacity. An Eligible Entity may nominate NITS Candidate ARRs, as described under Section 5.2.1 from a specific source to one or more sinks up to the amount of its NITS Candidate ARRs associated with the source subject to the total nomination limit described under Section (4);

2. For each Eligible Entity with FPTP service, the Eligible Entity’s FPTP Candidate ARRs for a specific source and sink is equal to the Reserved Capacity associated with that source and sink. An Eligible Entity may nominate FPTP Candidate ARRs, as described under Section 5.2.1, for this specific source and sink up to the amount of its FPTP Candidate ARRs subject to the total nomination limit described under Section (4);

3. For each Eligible Entity with equivalent NITS GFA service, the Eligible Entity’s GFA NITS Candidate ARRs from a specific source is equal to the source Reserved Capacity. An Eligible Entity may nominate GFA NITS Candidate ARRs, as described under Section 5.2.1, from a specific source to one or more sinks up to the amount of its GFA NITS Candidate ARRs subject to the total nomination limit described under Section (4);

4. For each Eligible Entity with equivalent FPTP GFA service, the Eligible Entity’s GFA FPTP Candidate ARRs for a specific source and sink is equal to the Reserved Capacity associated with that source and sink. An Eligible Entity may nominate GFA FPTP Candidate ARRs, as described under Section 5.2.1, for this specific source and sink up to the amount of its GFA FPTP Candidate ARRs subject to the total nomination limit described under Section (4).
5.1.3 ARR Nomination Cap

An Eligible Entity’s ARR Nomination Cap will be as follows:

1) For NITS Transmission Customers, the NITS ARR Nomination Cap is equal to the minimum of a) the sum of NITS Candidate ARRs as calculated under Section 5.1.2 and NITS Incremental Candidate ARRs as calculated under Section 5.5.2 or b) 103% of the average of that customer’s three highest non-coincident Network Peak Loads since February 1, 2007. This value may be adjusted as required to account for wholesale load shifts between Transmission Customers;

2) For FPTP Transmission Customers, the FPTP ARR Nomination Cap is equal to the sum of FPTP Candidate ARRs as calculated under Section 5.1.2 and FPTP Incremental Candidate ARRs as calculated under Section 5.5.2;

3) For GFA customers taking the equivalent of SPP NITS, the GFA NITS ARR Nomination Cap is equal to the minimum of a) the sum of GFA NITS Candidate ARRs as calculated under Section 5.1.2 and GFA NITS Incremental Candidate ARRs as calculated under Section 5.5.2 or b) 103% of the average of that customer’s three highest GFA Annual Peak Loads since February 1, 2007;

4) For GFA customers taking the equivalent of SPP FPTP, the GFA FPTP ARR Nomination Cap is equal to the sum of GFA FPTP Candidate ARRs as calculated under Section 5.1.2 and GFA FPTP Incremental Candidate ARRs as calculated under Section 5.5.2;

5) An Eligible Entity’s ARR Nomination Cap is equal the sum of its NITS ARR Nomination Cap, FPTP ARR Nomination Cap, GFA NITS ARR Nomination Cap and GFA FPTP ARR Nomination Cap.

5.2 Annual ARR Allocation Process

The Annual ARR Allocation Process addresses how candidate ARRs verified in the Annual ARR Verification Process may be nominated and converted to ARRs. Eligible Entities may nominate the candidate ARRs that they wish to receive up to their ARR Nomination Caps. The annual allocation process determines the portion of the nominated candidate ARRs that are simultaneously feasible to allocate to each Eligible Entity. 100% of the SPP Residual Transmission System Capability, as defined under Section 5.2.3, is made available during the Annual ARR Allocation Process. Candidate ARRs are nominated on a monthly and seasonal basis in a three-round process. No later than five (5) Business Days prior the start of the Annual ARR Allocation Process, SPP will post the transmission system network topology data for each
of the monthly and seasonal on-peak and off-peak models, along with corresponding loop flow and transmission line outage assumptions, that SPP will use in the upcoming allocation process for use by Eligible Entities in developing their candidate ARR nomination strategies. Exhibit 5-3 provides a representative timeline of the three-round annual ARR allocation process.

Exhibit 5-3: Annual ARR Allocation Process Timeline

The following rules apply to the annual allocation of ARRs.

5.2.1 ARR Nominations

For each month and season included in the Annual ARR Allocation Process period, Eligible Entities may nominate candidate ARRs in 0.1 MW increments for specific source to sink pairs that total up to their ARR Nomination Caps as calculated under Section (4). Nominations occur separately for On-Peak and Off-Peak periods (8 separate transmission system models created representing each month in an annual allocation period and on-peak and off-peak periods within each month and 6 separate transmission system models created representing each season in an
annual allocation period and on-peak and off-peak periods within each season). Prior to each ARR nomination round, Eligible Entities submit the following information:

1. Source (valid candidate ARR source Settlement Location for Rounds 1 and 2, any source Settlement Location for Round 3);
2. Sink (valid candidate ARR sink Settlement Location for Rounds 1 and 2, any sink Settlement Location for Round 3);
3. Class (on-peak or off-peak);
4. Period (month or season);
5. Nominated ARR MW.

   a. In Round 1 and Round 2, the total candidate ARR MW nominated from a source Settlement Location cannot exceed the source candidate ARRs.
   b. In Round 3, any source to sink path may be nominated, subject to the limitation described under Section 5.2.2(3).

### 5.2.2 ARR Allocation

ARRs are allocated in a three-round process as follows:

1. In Round 1, Eligible Entities may nominate:
   a. ARRs from their NITS Candidate ARRs that total to no more than 50% of their NITS ARR Nomination Cap;
   b. ARRs from their GFA NITS Candidate ARRs that total to no more than 50% of their GFA NITS ARR Nomination Cap;
   c. ARRs from their FPTP Candidate ARRs that total to no more than 50% of their FPTP ARR Nomination Cap; and
   d. ARRs from their GFA FPTP Candidate ARRs that total to no more than 50% of their GFA FPTP ARR Nomination Cap.

2. In Round 2, Eligible Entities may nominate:
   a. ARRs from their NITS Candidate ARRs that total to no more than 100% of their NITS ARR Nomination Cap less any nominated NITS Candidate ARRs awarded in Round 1;
(b) ARRs from their GFA NITS Candidate ARRs that total to no more than 100% of their GFA NITS ARR Nomination Cap less any nominated GFA NITS Candidate ARRs awarded in Round 1;

(c) ARRs from their FPTP Candidate ARRs that total to no more than 100% of their FPTP ARR Nomination Cap less any nominated FPTP Candidate ARRs awarded in Round 1; and

(d) ARRs from their GFA FPTP Candidate ARRs that total to no more than 100% of their GFA FPTP ARR Nomination Cap less any nominated GFA FPTP Candidate ARRs awarded in Round 1.

(3) In Round 3, Eligible Entities may nominate from any source to sink that total to no more than 100% of their ARR Nomination Cap less any nominated candidate ARR amounts awarded in Rounds 1 and 2.

Exhibit 5-4 provides an example of valid Round 1 NITS Candidate ARR nominations for a NITS Transmission Customer with a three year average historical annual peak load of 1942 MW and total Candidate ARRs of 2400 MW.

**Exhibit 5-4: Candidate ARR Nomination for NITS**

<table>
<thead>
<tr>
<th>NITS ARR Nomination Cap</th>
<th>Round 1 ARR Nomination Limit</th>
<th>NITS Candidate ARR MW</th>
<th>Source</th>
<th>Sink</th>
<th>Nominated NITS Candidate ARR MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>2000 MW(^{31})</td>
<td>1000 MW(^{32})</td>
<td>1200</td>
<td>G1</td>
<td>L1</td>
<td>800</td>
</tr>
<tr>
<td></td>
<td></td>
<td>800</td>
<td>G2</td>
<td>L1</td>
<td>200</td>
</tr>
<tr>
<td></td>
<td></td>
<td>400</td>
<td>G3</td>
<td>L1</td>
<td>0</td>
</tr>
<tr>
<td>Total</td>
<td>2400</td>
<td></td>
<td></td>
<td></td>
<td>1000</td>
</tr>
</tbody>
</table>

\(^{31}\) Lesser of \((1.03 \times 1942 \text{ MW})\) or 2400 MW

\(^{32}\) 50% of ARR Nomination Cap
5.2.3 Simultaneous Feasibility

A Simultaneous Feasibility Test (SFT) analysis is performed in each round to ensure that the nominated candidate ARRs, with nominated candidate ARR MW modeled as generation injection at the source and a corresponding load withdrawal at the sink, do not violate any normal transmission line thermal ratings under normal system conditions and do not violate short-term Emergency transmission line thermal ratings following a single contingency (N-1 contingency analysis). The SFT is performed consistent with the transmission system loading analysis that is performed as part the Security Constrained Economic Dispatch process in the DA Market.

1. The SPP Transmission System topology used in the SFT is the most up-to-date Network Model for the June through September allocation period, updated for forecasted transmission topology changes including planned maintenance outages, and is the most up-to-date planning models for the Fall, Winter and Spring allocation periods.

   a. For withdrawals at sink Settlement Locations containing more than one Pnode, SPP will distribute the Settlement Location withdrawal down to the Pnode level using load distribution percentages from the peak hour of the corresponding most recent historical period (i.e. June, July, August, September, Fall, Winter and Spring). These load distribution percentages are calculated using the methodology described under Section 4.1.2.1.7.

2. Prior to assessing simultaneous feasibility, the normal and emergency ratings of all flowgates and monitored transmission system elements are adjusted as follows to arrive at an SPP Residual Transmission System Capability:

   a. Adjusted Monitored Transmission Line Rating (normal and Emergency) =

   \[(\text{Monitored Transmission Line Rating (normal and Emergency – Loop Flow impact)}\)

   b. Adjusted Flowgate Rating (normal and Emergency) =

   \[(\text{Flowgate Rating – Loop Flow impact)}\]

5.2.4 Annual ARR Awards

If all of the nominated candidate ARRs are confirmed feasible, all nominated candidate ARRs are awarded. If the nominated candidate ARRs are not feasible, the amount of nominated candidate ARRs to be awarded will be reduced using a weighted least squares method. The
weighted least squares method minimizes the least squares deviation from the nominated candidate ARR MW weighted by the reciprocal of the nominations resulting in a higher percentage ARR reduction for those nominations having the greatest impact on the constraints. ARR reductions associated with nominations that have an equal impact on the constraints are reduced by the same percentage.

5.3 Annual TCR Auction

The Annual TCR Auction Process is the mechanism through which Market Participants may obtain annual TCRs through submission of TCR Bids to purchase TCRs and/or through direct conversion of ARRs into TCRs through self-conversion. Various percentages of the SPP Residual Transmission System Capability, as calculated under Section 5.2.3 is made available during the Annual TCR Auction Process as shown in Exhibit 5-2. TCRs in the annual auction are auctioned in a single round process for all months and seasons. If there are any changes to the transmission system topology or loop flow data after the conclusion of Annual ARR Allocation Process, SPP will post such changes no later than three (3) Business Days prior to the start of the Annual TCR Auction Process. Exhibit 5-5 provides a representative timeline of the two-round and single round annual TCR auction process.

Exhibit 5-5: Annual TCR Auction Processes Timeline
The following rules apply to the Annual TCR Auction:

### 5.3.1 TCR Offer and Bid Submittal

1. Any Market Participant that has satisfied the applicable credit requirements may participate in the Annual TCR Auction;

2. Market Participants holding ARRs may elect to self-convert all or a portion of those ARRs into TCRs with the same source and sink by specifying the Self-Convert option as part of the TCR Bid submittal;

3. For each month and season included in the Annual TCR Auction period, Market Participants may submit TCR Bids in 0.1 MW increments separately, for On-Peak and Off-Peak periods (8 separate transmission system models created representing each month in an annual auction period and on-peak and off-peak periods within each month and 6 separate transmission system models created representing each season in an annual auction period and on-peak and off-peak periods within each season). The following information is submitted for a TCR Bid or TCR Offer:
   
   a. Source (any valid Settlement Location);
   
   b. Sink (any valid Settlement Location);
   
   c. Class (on-peak or off-peak);
   
   d. Period (month or season);
   
   e. Type (Bid, or Self-Convert);
   
   f. TCR MW;
   
   g. TCR Price ($/MW);
      
      i. TCR Bids and Offers cannot exceed $100,000/MW;
      
      ii. TCR Bids and Offers cannot be less than ($100,000/MW).

4. For each TCR Round, a Market Participant is limited to a maximum combined submittal of 2000 TCR Bids and/or TCR Offers for each Asset Owner it represents.

### 5.3.2 Annual TCR Auction Process

TCRs are auctioned in a single-round process for each month and season using the SPP Residual Transmission System Capability as defined under Section 5.2.3 as follows:
(1) 100% of the SPP Residual Transmission System Capability is made available for the month of June, 90% of the SPP Residual Transmission System Capability is made available for the July-September period and 60% of the SPP Residual Transmission System Capability is made available for the Fall, Winter and Spring seasons;

(a) TCR Bids of the Self-Convert Type may be submitted for each source to sink pair that the Market Participant desires to convert the associated ARRs into TCRs. The Self-Convert Type option will convert ARRs associated with the specified source to sink pair into the TCR MW specified subject to simultaneous feasibility.

(b) Only Eligible Entities holding ARRs may submit a Self-Convert TCR Bid.

(c) The Self-Convert TCR Bid must specify the same source and sink as the associated ARR and the TCR MW must be less than or equal to the associated ARR MW.

5.3.3 Annual TCR Auction Clearing and Simultaneous Feasibility

The Auction is performed using a Linear Program algorithm with an objective function to maximize the total TCR auction value while ensuring that the cleared TCRs are also simultaneously feasible.

(1) The SFT is performed as described under Section 5.2.3 with TCR Bid MW modeled as an injection at the source and a corresponding withdrawal at the sink.

(2) The SPP Transmission System topology and loop flow assumptions used in the SFT are normally the same as used in the Annual ARR Allocation process. However, unforeseen events that drastically impact transmission system topology that occur following the ARR Allocation but prior to the Annual TCR Auction will be accounted for in the models for the Annual TCR Auctions.

5.3.4 Annual TCR Awards

Simultaneously feasible TCRs are awarded based upon the TCR Bid prices such that the total TCR auction value is maximized. Self-Converted TCRs are evaluated simultaneously with submitted TCR Bids. Auction Clearing Prices (ACP) are calculated for each Settlement Location using the formula for the Marginal Congestion Component as described under Section 4.5.4.1.2 ($\text{MCC}_i = - \sum_{k=1}^{K} \text{Sens}_{ik} * \text{SP}_k$).
For example, if we assume a 3 bus system (Bus A, B and C) and Bus A is the Reference Bus, we can calculate the ACP at Bus B as follows:

Transmission Line B-C is at its limit with a Shadow Price = $40/MW  
Transmission Line A-C is at its limit with a Shadow Price = $30/MW  
Transmission Line A-B is not at its limit (Shadow Price = $0/MW)  
Shift Factor for Bus B on Line B-C is 30%  
Shift Factor for Bus B on Line A-C is -80%  

Then ACP at Bus B is equal to - [$40/MW * .3) + ($30/MW * (-.8))] = $12/MW

A similar calculation is performed for Bus C based on Bus C Shift Factors. The ACP at Bus A is equal to zero since Bus A is the Reference Bus.

### 5.4 Monthly TCR Auction Processes

The Monthly TCR Auction Process is the mechanism through which Market Participants may obtain TCRs over and above those obtained in the Annual TCR Auction Process through submission of TCR Bids to purchase TCRs and/or through direct conversion of remaining ARRs awarded in the Annual ARR Allocation Process and/or ARRs awarded in the Incremental ARR Allocation Process into TCRs through Self-Conversion. Market Participants may also offer for sale TCRs awarded in the Annual TCR Auction Process. 100% of the SPP Transmission System capability is made available during the Monthly TCR Auction Process. The remaining TCRs for the months of July through September are auctioned in a single-round process. The remaining TCRs for the months of October through May are auctioned in a two-round process. No later than three (3) Business Days prior the start of the Monthly TCR Auction Process, SPP will post the transmission system network topology data, along with corresponding loop flow and...
transmission line outage assumptions, that SPP will use in the upcoming Monthly TCR Auction Process for use by Market Participants in developing their TCR Bid, TCR Offer and/or TCR self-conversion strategies. Exhibit 5-6 provides a representative timeline of the single-round and two-round Monthly TCR Auction Processes.

**Exhibit 5-6: Monthly TCR Auction Processes Timeline**

The following rules apply to the Monthly TCR Auction Processes:

**5.4.1 TCR Offer and Bid Submittal**

1. Any Market Participant that has satisfied the applicable credit requirements may participate in the Monthly TCR Auction Process;

2. Market Participants may submit TCR Bids and TCR Offers separately, for On-Peak and Off-Peak periods (two (2) separate transmission system models created). The following information is submitted for a TCR Bid or TCR Offer:
(a) Source (any valid Settlement Location);
(b) Sink (any valid Settlement Location);
(c) Class (on-peak or off-peak);
(d) Type (Bid, Offer or Self-Convert);
(e) TCR MW (0.1 MW increments, may not exceed ARR MW held on path if Self-Convert Type selected);
(f) TCR Price ($/MW);
   (i) TCR Bids and Offers cannot exceed $100,000/MW;
   (ii) TCR Bids and Offers cannot be less than ($100,000/MW).

(3) For each TCR Round, a Market Participant is limited to a maximum combined submittal of 2000 TCR Bids and/or TCR Offers.

### 5.4.2 Monthly TCR Auction Process

TCRs are auctioned in a single-round process for the months of July through September and 100% of the SPP Residual Transmission System Capability, as calculated under Section 5.2.3 is made available. Any amounts of ARRs awarded in the Incremental ARR Allocation Process plus: the lesser of (i) 10% of the ARRs obtained in the Annual ARR Allocation Process or (ii) the difference between the ARRs obtained in the Annual ARR Allocation Process and the amount of Self-Converted TCRs awarded in the Annual TCR Auction Process may be Self-Converted during this single-round auction and any TCRs obtained in the Annual TCR Auction may be offered for sale.

TCRs are auctioned in a two-round process for the months of October through May. In the two-round process:

1. **Round 1 - 50% of the Residual SPP Transmission System Capability remaining following the Annual TCR Auction, as calculated under Section 5.2.3 is made available**;
   
   a. TCR Bids of the Self-Convert Type must be submitted in this round for each source to sink pair that the Market Participant desires to convert the remaining ARRs obtained in the Annual ARR Allocation Process and/or ARRs obtained in the Incremental ARR Allocation Process into TCRs. The Self-Convert Type option will convert ARRs associated with the specified source to sink pair into the TCR MW specified subject to simultaneous feasibility. All remaining ARRs not
accounted for in the Annual TCR Auction Process and/or all ARRs awarded in the Incremental ARR Allocation Process may be submitted for Self-Conversion;

(i) Only Eligible Entities holding ARRs obtained in the Annual ARR Allocation Process and/or Incremental ARR Allocation Process may submit a Self-Convert TCR Bid.

(ii) The Self-Convert TCR Bid must specify the same source and sink as the associated ARR and the TCR MW must be less than or equal to the associated ARR MW.

(b) Any TCRs awarded in the Annual TCR Auction may be offered for sale.

(2) Round 2 - The remaining 50% of the Residual SPP Transmission System Capability, as calculated under Section 5.2.3 is made available;

(a) Any Self-Converted TCR MW requested and not awarded in Round 1 will be converted to TCRs subject to simultaneous feasibility;

(b) Any TCRs awarded in Round 1 or the Annual TCR Auction, including Self-Converted TCRs, may be offered for sale.

5.4.3 Monthly TCR Auction Clearing and Simultaneous Feasibility

The Auction is performed using a Linear Program algorithm to maximize the total TCR auction value while ensuring that the cleared TCRs are also simultaneously feasible:

(1) The SPP Transmission System topology used in the SFT will be the most up-to-date Network Model updated for forecasted transmission topology changes, including planned maintenance outages, for the auction month;

(a) For withdrawals at sink Settlement Locations containing more than one Pnode, SPP will distribute the Settlement Location withdrawal down to the Pnode level using load distribution percentages from the peak hour of the corresponding most recent historical period (i.e. June for the month of July). These load distribution percentages are calculated using the methodology described under Section 4.1.2.1.7.

(2) The SFT is performed as described under Section 5.2.3 with TCR Bid MW modeled as an injection at the source and a corresponding withdrawal at the sink. TCR Offers associated with the sale of an existing TCR are modeled as an injection at the sink and a
withdrawal at the source. Residual SPP Transmission System Capability includes the most up to date loop flow assumptions.

(a) For Round 1, all TCRs awarded in the Annual TCR Auction for the month are modeled as fixed injections and withdrawals. To the extent that the fixed injections and withdrawals representing TCRs awarded in the Annual TCR Auction are not feasible, SPP will increase the ratings of the applicable transmission lines to ensure feasibility prior to the Round 1 auction. SPP will report back to the MWG on a quarterly basis regarding the number of times that that transmission line ratings had to be adjusted to ensure feasibility;

(b) For Round 2, all TCRs previously awarded for the month are modeled as fixed injections and withdrawals prior to clearing the TCR Bids and Offers.

5.4.4 Monthly TCR Awards

Simultaneously feasible TCRs are awarded based upon the TCR Bid and Offer prices such that the total TCR auction value is maximized. Self-Converted TCRs are evaluated simultaneously with submitted TCR Bids and Offers. Auction Clearing Prices (ACP) are calculated as described under Section 5.3.4.

5.5 Incremental ARR Allocation Process

Eligible Entities with firm transmission service that has been confirmed following completion of the Annual TCR Auction Process and prior to the next Annual ARR Verification Process or with firm transmission service confirmed during the Annual ARR Verification Process that includes a partial season are eligible to nominate incremental candidate ARRs associated with such services. Incremental Candidate ARRs may be nominated for each remaining month in the current Annual ARR Allocation Process period for which the firm transmission service applies that was not eligible for conversion into ARRs during the Annual ARR Allocation Process. To the extent that the Eligible Entity’s firm transmission service term extends beyond the current Annual ARR Allocation Process period, such remaining service will be included in the next Annual ARR Verification Process. Eligible Entities must verify such services with SPP in order to be eligible to nominate incremental candidate ARRs. The following rules apply to verification of transmission service for conversion to incremental candidate ARRs.
5.5.1 Incremental ARR Transmission Service Verification

In order for Eligible Entities to obtain incremental candidate ARRs, SPP must first verify existing transmission service entitlements. In order to qualify for incremental candidate ARRs in a particular month, an Eligible Entity’s transmission service must span the entire month within the applicable year. SPP will verify Eligible Entity existing transmission service entitlements as follows:

1. An Eligible Entity must submit a request to SPP no later than ten days prior to the start of the applicable TCR Monthly Auction Process specifying its desire to obtain incremental candidate ARRs associated with the approved and confirmed Transmission Service Request. The request must contain source, sink and Reserved Capacity information;

2. SPP will verify that the source, sink and Reserved Capacity information submitted has been accurately reflected on the SPP OASIS for the applicable month;

3. SPP will notify the Eligible Entity no later than two days following receipt of the request if the OASIS data does not match the data submitted in the request. Otherwise the Eligible Entity should consider the request approved;

4. If SPP notifies the Eligible Entity as described in (3) above that it cannot verify the Eligible Entity’s request, the Eligible Entity must either correct the OASIS data or resubmit its request with corrected data that matches the OASIS data no later than six days prior to the start of the applicable TCR Monthly Auction Process.

5.5.2 Incremental Candidate ARRs

Following verification of Eligible Entity transmission service, incremental candidate ARRs associated with such transmission service are assigned as follows:

1. For each Eligible Entity with NITS confirmed and verified following completion of the Annual TCR Auction Process, the Eligible Entity’s NITS Incremental Candidate ARRs from a specific source is then equal to the source Reserved Capacity. An Eligible Entity may nominate NITS Incremental Candidate ARRs, as described under Section 0 from a specific source to one or more sinks up to the amount of its NITS Incremental Candidate ARRs associated with the source subject to its NITS ARR Nomination Cap described under Section (4);

2. For each Eligible Entity with FPTP service confirmed and verified following completion of the Annual TCR Auction Process, the Eligible Entity’s FPTP Incremental Candidate
ARRs for a specific source to sink pair is equal to the Reserved Capacity for that source to sink pair. An Eligible Entity may nominate FPTP Incremental Candidate ARRs, as described under Section 0, for this specific source and sink pair up to the amount of its FPTP Incremental Candidate ARRs subject to its FPTP ARR Nomination Cap described under Section (4);

(3) For each Eligible Entity with equivalent NITS GFA service confirmed and verified following completion of the Annual TCR Auction Process, the Eligible Entity’s GFA NITS Incremental Candidate ARRs from a specific source is equal to the source Reserved Capacity. An Eligible Entity may nominate GFA NITS Incremental Candidate ARRs, as described under Section 0, from a specific source to one or more sinks up to the amount of its GFA NITS Incremental Candidate ARRs subject to the total nomination limit described under Section (4);

(4) For each Eligible Entity with equivalent FPTP GFA service confirmed and verified following completion of the Annual TCR Auction Process, the Eligible Entity’s GFA FPTP Incremental Candidate ARRs for a specific source to sink pair is equal to the Reserved Capacity associated with that source to sink pair. An Eligible Entity may nominate GFA FPTP Incremental Candidate ARRs, as described under Section 0, for this specific source to sink pair up to the amount of its GFA FPTP Incremental Candidate ARRs subject to the total nomination limit described under Section (4).

5.5.3 Incremental ARR Nominations

Five (5) days prior to the start of each applicable Monthly TCR Auction Process, Eligible Entities may nominate in a single round process (i) NITS Incremental Candidate ARRs in 0.1 MW increments along specific source to sink paths that total to no more than the difference between their NITS ARR Nomination Cap and ARRs associated with NITS Candidate ARRs awarded in the Annual ARR Allocation process; (ii) FPTP Incremental Candidate ARRs in 0.1 MW increments along specific source to sink paths that total to no more than the difference between their FPTP ARR Nomination Cap and ARRs associated with FPTP Candidate ARRs awarded in the Annual ARR Allocation process; (iii) GFA NITS Incremental Candidate ARRs in .1 MW increments along specific source to sink paths that total to no more than the difference between their GFA NITS ARR Nomination Cap and ARRs associated with GFA NITS Candidate ARRs awarded in the Annual ARR Allocation process; and/or (iv) GFA FPTP Incremental Candidate ARRs in 0.1 MW increments along specific source to sink paths that total to no more than the difference between their GFA FPTP ARR Nomination Cap and ARRs
associated with GFA FPTP Candidate ARRs awarded in the Annual ARR Allocation process. Nominations occur separately for On-Peak and Off-Peak periods. Eligible Entities submit the following information:

1. Source (valid incremental candidate ARR source Settlement Location);
2. Sink (valid incremental candidate ARR sink Settlement Location);
3. Class (on-peak or off-peak);
4. ARR MW.
   (a) the total ARR MW nominated from a source Settlement Location cannot exceed the source incremental candidate ARRs.

5.5.4 Simultaneous Feasibility

The SFT to assess feasibility of nominated incremental candidate ARRs is performed as described under Section 5.2.3 with the following adjustments:

1. The SPP Transmission System model used in the SFT will be the same model to be used in the upcoming Monthly TCR Auction Process which will include the most up-to-date Network Model updated for forecasted transmission topology changes, including planned maintenance outages, and updated loop flow assumptions;
   (a) For withdrawals at sink Settlement Locations containing more than one Pnode, SPP will distribute the Settlement Location withdrawal down to the Pnode level using load distribution percentages from the peak hour of the corresponding most recent historical period (i.e. June for the month of July). These load distribution percentages are calculated using the methodology described under Section 4.1.2.1.7.

2. 100% of the Residual SPP Transmission System Capability is made available; and

3. All TCRs previously awarded in the Annual TCR Auction Process and all remaining ARRs not accounted for in the Annual TCR Auction Process (as defined under Section 5.6) for the applicable month are modeled as fixed injections at the specified sources and fixed withdrawals at the specified sinks. To the extent that these fixed injections and withdrawals are not feasible, SPP will increase the ratings of the applicable transmission lines to ensure feasibility prior to assessing incremental ARR feasibility. SPP will report back to the MWG on a quarterly basis regarding the number of times that transmission line ratings had to be adjusted to ensure feasibility.
5.5.5 **Incremental ARR Awards**

If all of the nominated incremental candidate ARRs are confirmed feasible, all nominated incremental candidate ARRs are awarded in the form of ARRs. If the nominated incremental candidate ARRs are not feasible, the amount of ARRs to be awarded will be reduced using a weighted least squares method. The weighted least squares method minimizes the least squares deviation from the nominated incremental candidate ARR MW weighted by the reciprocal of the nominations resulting in a higher percentage ARR reduction for those incremental candidate ARR nominations having the greatest impact on the constraints. ARR reductions associated with incremental candidate ARR nominations that have an equal impact on the constraints are reduced by the same percentage.

5.6 **ARR Allocation/TCR Auction Settlements**

The charges and credits to ARR holders and TCR holders will be calculated on a daily basis and included on the settlement statements consistent with the timing of the Energy and Operating Reserve Markets settlement as described under Section 4.5.10. For the purposes of calculating charges and credits to ARR holders, the following amounts of ARR awards will be used:

1. **ARR Settlement for Annual TCR Auction by path:**
   - (a) For the month of June, 100% of annual ARR award;
   - (b) For the months of July through September, the greater of (i) 90% of annual ARR award or (ii) Self-Convert TCR award;
   - (c) For the Fall, Winter and Spring season, the greater of (i) 60% of annual ARR award or (ii) Self-Convert TCR award.

2. **ARR Settlement for Monthly TCR Auction:**
   - (a) For the months of July through September, remaining ARRs not accounted for in ARR Settlement in the Annual TCR Auction as described in (1)(b) above plus all incremental ARR awards;
   - (b) For the months of October through May for Round 1, the greater of (i) (50% of incremental ARR awards plus: (50% of the difference between the annual ARR award and the remaining ARRs not accounted for in the Annual TCR Auction as described in (1)(c) above) or (ii) Self-Convert TCR awards; and
(c) For the months of October through May for Round 2, the difference between: (i) the sum of annual ARR awards and incremental ARR awards and (ii) the sum of ARR MW accounted for under Section (1)(c) above and the ARR MW accounted for under Section (2)(b) above.

5.7 TCR Secondary Market

SPP will facilitate a secondary market for TCRs as follows:

(1) Bilateral trading of existing TCRs is facilitated through a bulletin board system;

(2) TCRs may be broken down into small MW increments that total the original TCR;

(3) TCRs may be traded daily, for On-Peak and/or Off-Peak periods;

(4) The TCR purchaser pays TCR seller directly;

(5) TCRs may not be reconfigured (path must remain the same);

(6) SPP accounts for transfer of TCR ownership; and

(7) Purchaser must meet applicable credit requirements.
6. Market Registration

All Market Participants must register their loads and Resources, excluding Behind the Meter Generation less than 10 MW, prior to participation in the SPP Integrated Marketplace. Registration is accomplished by entering the required information via the SPP Market Registration Portal. In addition, each Market Participant is required to execute the service agreement specified in Tariff Attachment AH. Registration identifies each load and/or Resource to Asset Owners, associated Market Participants and Settlement Locations, Meter Agents, and settlement responsibilities.

A Market Participant may represent one or more Asset Owners and may appoint a Designated Agent to perform its functions under these protocols.

Assets are the registered loads and Resources to an Asset Owner at specific Settlement Locations and have a designated Meter Agent. Market Participants have the legal relationship with SPP. The Market Participants may participate in the SPP Integrated Marketplace as any combination of Resource entities, load serving entities, Meter Agents, and/or power marketers. The Market Participant is also responsible for insuring that SPP receives Settlement Location data from the Meter Agent in a suitable electronic format.

Registration data is used for operation and settlement of the SPP Integrated Marketplace, identifying responsibilities and identifying discrete entities. The registration data is also used in the interaction of SPP Customer Relations personnel with Market Participants.

Exhibit 6-1 provides an overview of how the registration data is used in developing settlement related items in the Commercial Model. Please note the diagram does not show all of the Node to Meter Settlement Location to Meter Data Submittal Location relationships, only a sample subset. Each Meter Data Submittal Location will have a minimum of a single PNode (Meter Settlement Location) associated with it and each PNode will have a single Node associated with it.
6.1 Registration of Resources

Any Market Participant operating Resources within SPP or representing Asset Owners that are not Market Participants that are operating Resources within SPP must register with SPP via the SPP Market Registration Portal and be capable of performing the functions of a Resource as described herein. Resources are registered on a nodal basis to Settlement Locations. Resources at the same physical and electrically equivalent injection point to the transmission grid may register at the unit or plant level. Failure or refusal to register a Resource will result in SPP filing an unexecuted version of the service agreement as specified in Tariff Attachment AH for that Resource with FERC under the name of the generation interconnection customer under an interconnection agreement with SPP or the applicable TO.

6.1.1 Responsibilities of the Resource Asset Owner

Each Asset Owner shall be responsible for conducting its operations in accordance with all applicable SPP market rules and guidelines. Each Asset Owner shall supply operating characteristics of its Resource, including, but not limited to: location of physical Resource, Legal owner, Resource type as specified below, and all of the non-price related operating parameters listed under Section 4.2.2.1. Registration shall also include identification of the Settlement Location and Settlement Area of the Resource. The Market Participant representing the applicable Asset Owner is responsible for ensuring that real-time settlement meter data is submitted to SPP. Valid Resource Types are:

1. Generating Unit (“Gen”);
2. Plant (“PLT”);
3. Dispatchable Demand Response (“DDR”) Resource;
4. Block Demand Response (“BDR”) Resource;
5. Combined Cycle (“CC”) Resource;
6. Jointly Owned Unit (“JOU”) Resource;
7. Variable Energy Resource (“VER”); and

For each Resource registered, the Asset must specify whether Settlement Meter Data will be submitted on an hourly basis or on a 5-minute basis.
6.1.2 Energy Production Prior to Completion of Market Registration

Market Participants and associated Asset Owners will be allowed to generate energy prior to the effective date of a submitted market registration packet under the following conditions:

1. The Market Participant, or its agent, has submitted a completed registration packet so that the Resource will be registered and recognized in the SPP market systems on the next model update;

2. If real-time data is not being provided via telemetry to SPP BA, the Market Participant or its agent shall provide hourly updates of current output and expected output for each 5-minute interval of the upcoming hour. The actual five (5) minute output for the previous hour shall also be provided;

3. If the energy production is expected to contribute to any real-time reliability issues on the transmission grid, interruption must occur within 15 minutes upon directive from the SPP BA;

4. Energy shall be limited to a maximum of 10 MW, or a greater amount agreed to by the SPP Balancing Authority and interconnect Transmission Owner;

5. Energy generated under these provisions will not be settled in the SPP. SPP will not be responsible for making any compensation to the generation owner or any Market Participant for the energy produced.

6.1.3 Common Bus

Asset Owners of Resources located at an electrically equivalent bus may elect Common Bus treatment for these Resources. SPP will verify that the specified Resources are located at an electrically equivalent bus prior to creating the Common Bus relationship in the Commercial Model.

6.1.4 Dispatchable Demand Response Resource

In addition to the responsibilities described under Section 6.1.1, Asset Owners registering a Dispatchable Demand Response (DDR) Resource must:

1. Identify an associated Demand Response Load Meter Data Submittal Location;

2. Identify an associated Dispatchable Controllable Load Settlement Location;

3. Specify one of the following two options for calculation of the DDR Resource output as described under Section 4.2.2.5.1:
(a) Submitted Resource Output;
(b) Calculated Resource Output.

(4) Certify that the Calculated Resource Output method, if selected, is consistent with the retail tariff or agreement under which the load is purchasing energy from its retail provider, and SPP will notify the applicable retail provider and the relevant electric retail regulatory authority of the registration and the expected level of participation.

6.1.5 Block Demand Response Resource

In addition to the responsibilities described under Section 6.1.1, Asset Owners registering a Block Demand Response (BDR) Resource must:

(1) Identify an associated Demand Response Load Meter Data Submittal Location;
(2) Identify an associated Block Controllable Load Settlement Location; and
(3) Certify that the Calculated Resource Output method that must be used for a BDR is consistent with the retail tariff or agreement under which the load is purchasing energy from its retail provider, and SPP will notify the applicable retail provider and the relevant electric retail regulatory authority of the registration and the expected level of participation.

6.1.6 Stored Energy Resource

In addition to the responsibilities described under Section 6.1.1, Asset Owners registering a Stored Energy Resource (SER) must register an associated load Settlement Location for use during times when the SER is in the recharge mode (i.e. is withdrawing Energy from the system).

6.1.7 Jointly Owned Resource

In addition to the responsibilities described under Section 6.1.1, Market Participants wishing to model each ownership share as a separate Resource must choose one of the two options described below and provide the specified additional information. A Resource registered as a Combined Cycle Resource may not register as a JOU.

6.1.7.1 Individual Resource Option

Under the Individual Resource Option, each ownership share is modeled as a separate Resource for the purposes of commitment and dispatch and each Resource may be committed independent
of the other Resource shares. In order to qualify for this option, all Asset Owners must certify that if their ownership share Resource is the only Resource committed, that their ownership share is greater than or equal to the minimum physical capacity operating limit of the Physical JOU Resource. The following additional information must also be provided and/or specified:

(1) Specification of a single Asset Owner that will be responsible for submittal of the following operating data representing the physical operating characteristics of entire JOU Resource for use in data validation as described under Section 4.2.2.5.4;

   (a) JOU maximum physical capacity operating limit;

   (b) JOU minimum physical capacity operating limit; and

   (c) Maximum physical 10-minute response from an off-line state.

(2) Specification of each Asset Owner and Settlement Location associated with each individual ownership share.

The default presumption is that the operating owner’s Meter Agent will be the Meter Agent for that JOU Resource unless each individual JOU Resource owner registers a different Meter Agent for its share of the Resource.

6.1.7.2 Combined Resource Option

Under the Combined Resource Option, each ownership share is modeled as a separate Resource for the dispatch purposes but commitment related parameters are submitted representing the entire physical Resource. Under this option, the commitment decision is made assuming that all Resource shares must be committed or none at all. This option must be selected if the eligibility criteria stated under the Individual Resource Option cannot be met. The following additional information must also be provided:

(1) Specification of a single Market Participant that will be responsible for submittal of all unit commitment related data and the following operating data representing the physical operating characteristics of entire JOU Resource for use in data validation as described under Section 4.2.2.5.4;

   (a) JOU maximum physical capacity operating limit;

   (b) JOU minimum physical capacity operating limit; and

   (c) maximum physical 10-minute response from an off-line state.
(2) Specification of each Asset Owner, ownership share and Settlement Location associated with each individual ownership share JOU Resource.

The default presumption is that the operating owner’s Meter Agent will be the Meter Agent for that JOU Resource unless each individual JOU Resource owner registers a different Meter Agent for its share of the Resource.

6.1.8 Combined Cycle Resource

In addition to the responsibilities described under Section 6.1.1, Market Participants registering a Resource as a Combined Cycle Resource shall register their Resources for Commercial Modeling purposes using one of the three options described below.

(1) Each combustion turbine and steam turbine may be registered as a separate Resource asset. Each individual Resource asset will be assigned a unique Settlement Location and each Resource asset must be registered to the same Asset Owner.

(a) Each Resource asset will be committed and dispatched as an independent Resource. Each individual Resource asset will be settled at its Settlement Location. Telemetering and Settlement meter data must be submitted for each registered Resource asset.

(b) The Market Participant may optionally request that all Resource assets be registered at a Common Bus.

(2) An aggregate unit configuration may be registered as a single Resource asset in the Commercial Model and is assigned an APNode Settlement Location.

(a) The aggregate Resource asset will be committed and dispatched as a separate Resource and will be settled at its APNode Settlement location.

(b) Settlement meter data must be submitted for the aggregate Resource;

(c) Telemetering must be submitted for each component of the aggregate Resource that is modeled in the Network Model.

(3) The Combined Cycle Resource may be registered in the Commercial Model as several “pseudo” unit assets, each unit representing a combination of one combustion turbine and a portion of a steam turbine. Each pseudo unit asset is assigned an APNode Settlement Location.

(a) Each pseudo unit asset will be committed and dispatched as a separate Resource and will be settled at its APNode Settlement location.
(b) Settlement meter data must be submitted for each individual pseudo unit asset.

(c) Telemetering must be submitted for each component - of each individual pseudo unit asset that is modeled in the Network Model.

(d) The Market Participant may optionally request that all pseudo unit assets be registered at a Common Bus.

6.1.9 Wind Variable Energy Resource Data Requirements

Wind Variable Energy Resource data submittal requirements are defined in the SPP Criteria.

6.1.10 Resources External to the SPP BA

Resources external to the SPP BA wishing to participate in the SPP Integrated Marketplace must Pseudo-tie into the SPP Balancing Authority (BA) utilizing the SPP OATT Attachment AO or equivalent agreement approved by SPP. In addition to the responsibilities outlined in the Attachment AO agreement, the Resource will be responsible for registering and performing all responsibilities that are required of any other Resource in the SPP Integrated Marketplace.

6.1.11 Operating Reserve Certification

Asset Owners of registered Resource must meet the following certification requirements in order to be eligible to submit Operating Reserve Offers for use in the SPP Integrated Marketplace.

6.1.11.1 Spin Qualified Resources

There are no specific testing requirements for a Resource to become a Spin Qualified Resource. An Asset Owner will self-certify that its Resource is capable of deploying Spinning Reserve or on-line Supplemental Reserve during the registration process. In such case, that Resource will become a Spin Qualified Resource. However, SPP may perform random Contingency Reserve deployment tests in order to verify that any cleared Spinning Reserve or on-line Supplemental Reserve is capable of being deployed as follows:

(1) SPP will only perform a Spinning Reserve or on-line Supplemental Reserve deployment test on a Resource that has cleared for Spinning Reserve or Supplemental Reserve in Real-Time (and not Regulation-Up and Regulation-Down) and that has not had a change in Dispatch Instruction between the last Dispatch Interval and the current Dispatch Interval;

(2) SPP will issue a Contingency Reserve Deployment Instruction to the Resource being tested that is equal to the amount of Spinning Reserve cleared on the Resource;
(3) Simultaneously with the beginning and end of the Spinning Reserve or on-line Supplemental Reserve deployment test (which will span a period equivalent to the Contingency Reserve Deployment Period), SPP will take a snapshot of the Resource MW output. The difference between the Resource MW output at the end of the test and the Resource MW output at the beginning of the test will be equal to the Resource response.

(a) SPP will communicate the results of the test to the affected Asset Owner no later than 60 minutes following the end of the test.

(b) If the Resource response is greater than or equal to 75% of the MW specified in the Contingency Reserve Deployment Instruction, the Resource has passed the test and no further action is required.

(i) For settlement purposes, this instruction shall be considered a Manual Dispatch Instruction and the Resource will be eligible for compensation for Out-Of-Merit-Energy as described under Section 4.5.9.9.

(ii) If this test was a retest requested by the Asset Owner as described under (c) below, the Resource will not be eligible for compensation for Out-Of-Merit-Energy as described under Section 4.5.9.9.

(c) If the Resource response is less than 75% of the MW specified in the Contingency Reserve Deployment Instruction, the Resource has failed the test and the following actions will be taken:

(i) The Resource will not be eligible for compensation for Out-Of-Merit-Energy as described under Section 4.5.9.9;

(ii) SPP will multiply the Resources submitted Ramp-Rate-Up and Ramp Rate by the Resource response percentage until such time that the Resource requests and passes a retest;

(iii) The Asset Owner of the Resource must obtain SPP approval regarding the timing of the retest.

6.1.11.2 Supplemental Qualified Resources

There are no specific testing requirements for an off-line Resource to become a Supplemental Qualified Resource. An Asset Owner will self-certify that its off-line Resource is capable of deploying Supplemental Reserve during the registration process. In such case, that Resource will become a Supplemental Qualified Resource. However, SPP may perform random
Contingency Reserve deployment tests in order to verify that any cleared Supplemental Reserve is capable of being deployed as follows:

1. SPP will only perform a Supplemental Reserve deployment test on an off-line Quick-Start Resource that has cleared Real-Time Supplemental Reserve;

2. SPP will issue a Contingency Reserve Deployment Instruction to the Resource being tested that is equal to the amount of Supplemental Reserve cleared on the Resource;

3. Simultaneously with the end of the Supplemental Reserve deployment test (which will span a period equivalent to the Contingency Reserve Deployment Period), SPP will take a snapshot of the Resource MW output. The difference between the Resource MW output at the end of the test will be equal to the Resource response.

   a. SPP will communicate the results of the test to the affected Asset Owner no later than 60 minutes following the end of the test.

   b. If the Resource response is greater than or equal to 75% of the MW specified in the Contingency Reserve Deployment Instruction, the Resource has passed the test and no further action is required.

      i. For settlement purposes, this instruction will be considered as an SPP commitment and the Resource will be eligible for RUC Make-Whole-Payment compensation as described under Section 4.5.9.8.

      ii. If this test was a retest requested by the Asset Owner as described under (c) below, the Resource will not be eligible for RUC Make-Whole-Payment compensation as described under Section 4.5.9.8.

   c. If the Resource response is less than 75% of the MW specified in the Contingency Reserve Deployment Instruction, the Resource has failed test and the following actions will be taken:

      i. The Resource will not be eligible for compensation for RUC Make-Whole-Payment compensation as described under Section 4.5.9.8;

      ii. SPP will multiply the Resource’s submitted Maximum Off-Line Response Limit by the Resource response percentage until such time that the Resource requests and passes a retest.

      iii. The Asset Owner of the Resource must obtain SPP approval regarding the timing of the retest.
6.11.3 Regulation Qualified Resources

There are specific testing requirements for a Resource to become a Regulation Qualified Resource, Regulation-Up Qualified Resource or Regulation-Down Qualified Resource:

1. A resource may be certified as a Regulation Qualified Resource, Regulation-Up Qualified Resource or Regulation-Down Qualified Resource only after it achieves three consecutive Regulation Test Scores of 75% or above through the testing procedures described under Section (7);

2. The first of these tests may be performed internally by the Asset Owner. Notification to perform a regulation test must be made to SPP at least 20 minutes before the test;

3. SPP makes the final determination about whether a regulation test can be performed;

4. Only one test may be performed on a Resource each Operating Day;

5. SPP may perform a regulation test on any Regulation Qualified Resource, Regulation-Up Qualified Resource or Regulation-Down Qualified Resource to verify continued certification;

6. A Market Participant may request a re-test if its Resource was disqualified as a Regulation Qualified Resource, Regulation-Up Qualified Resource or Regulation-Down Qualified Resource by SPP as described under Section 4.4.3.1. The Resource must attain a test score of 75% or greater in order to be re-qualified;

7. After initial certification, a Compliance Rating of 75% or above must be maintained as described under Section 6.11.3.3.

6.11.3.1 Regulation Testing Procedures

The Regulation test to verify both Regulation-Up and Regulation-Down capability is run during a continuous 40-minute period. The Regulation test to verify either Regulation-Up Capability or Regulation-Down capability is run during a continuous 20-minute period. Such tests are run when, in the judgment of the SPP test administrator, economic or other conditions do not otherwise change the Dispatch Instruction of the Resources that are being tested. Changes in Dispatch Instructions for a Resource during the test period invalidate the test for that Resource. During the Regulation test, the Setpoint Instruction is fixed in each of two or four consecutive 10-minute periods. The following steps describe the implementation of the test. It is assumed that the Regulation-Up deployment is positive and Regulation-Down deployment is negative. A test may start with either a Regulation-Up deployment (if certifying as Regulation Qualified
Resource or Regulation-Up Qualified Resource) or a Regulation-Down deployment (if certifying as Regulation Qualified Resource or Regulation-Down Qualified Resource) but the steps below assume that the test starts with a Regulation-Up deployment.

(1) **Step One:** T0-T10 — During this time period, the stepped Setpoint Instruction is equal to the Dispatch Instruction (i.e. Regulation-Up or Regulation-Down deployment is equal to zero). This is the initiation of the Regulation test. This ten-minute period is provided so that the Resource settles at its Dispatch Instruction. At T10, the actual loading is sampled and the resulting value defines the Base Loading for that Resource which is shown as the zero axis in Exhibit 6-1.

(2) **Step Two:** T10-T20 — At the start of this 10 minute period, the stepped Setpoint Instruction is increased by 5 times the Resource’s Regulation Ramp Rate to simulate the maximum amount of Regulation-Up deployment available on the Resource (Note that this step is skipped for Regulation-Down Qualified Resource certification).

(3) **Step Three:** T20-T30 — At the start of this 10 minute period, the stepped Setpoint Instruction is returned back to the Resource’s Base Loading level (i.e., the Regulation-Up deployment is set to zero). Note that for a Resource that is only certifying to provide Regulation-Up only, this step constitutes the end of the test.

(4) **Step Four:** T30-T40 — At the start of this 10 minute period, the stepped Setpoint Instruction is reduced by 5 times the Resource’s Regulation Ramp Rate to simulate the maximum amount of Regulation-Down deployment available on the Resource. Note that for a Resource that is only certifying to provide Regulation-Down only, this step constitutes the beginning of the test.

(5) **Step Five:** T40 — At this time, the stepped Setpoint Instruction is returned back to the Resource’s Base Loading level to terminate the test at T50.

Exhibit 6-5 illustrates these five steps.

**Exhibit 6-2: Regulation Testing Procedure**
6.1.11.3.2 Regulation Testing Scoring

Scoring the Regulation Test Score is based on the average of two independent test scores: Rate of Response Compliance test score and Regulation Mismatch Compliance test score.

(1) **Rate of Response Compliance** — The rate of response compliance is a measure of a Resource’s ability to achieve its Regulation deployment within five (5) minutes. The Rate of Response Compliance is an average of four \(^3\) compliance calculations corresponding to the end of each of the four (4) 5-minute ramping periods (T15, T25, T35 and T45) \(^4\) during the test and is determined as follows:

\[
\text{RORC15} = 100 - \left[ \frac{\left| \text{ABS} \left( \text{Ramped Setpoint Instruction} - \text{AG15} \right) \right|}{\text{Ramp-Rate-Up} \times 5} \times 100 \right] \\
\]

(2) At T15, a snapshot of Resource output is taken. This value is called AG15. The Rate of Response Compliance at time T15 (RORC15) is:

\[
\text{RORC15} = 100 - \left[ \frac{\left| \text{ABS} \left( \text{Ramped Setpoint Instruction} - \text{AG15} \right) \right|}{\text{Ramp-Rate-Up} \times 5} \times 100 \right] \\
\]

(3) The calculation is repeated at T25, T35 and T45, yielding RORC25, RORC35 and RORC45.

(4) The Rate of Compliance is then equal to:

\[
\text{Rate of Compliance} = \frac{[\text{RORC15} + \text{RORC25} + \text{RORC35} + \text{RORC45}]}{4} \\
\]

(5) **Regulation Mismatch Compliance** — The Regulation mismatch compliance is a measure of a Resource’s ability to maintain its actual output at a constant desired level

---

\(^3\) For Resources only certifying to supply Regulation-Up or Regulation-Down, this value is equal to two.

\(^4\) For Resources only certifying to supply Regulation-Up, only T15 and T25 are used. For Resources only certifying to supply Regulation-Down, only T35 and T45 are used.
for five minutes. The Regulation Mismatch Compliance is an average of four\textsuperscript{35} mismatch calculations, corresponding to samples taken during three, five minute periods when the Resource response yields an actual loading equal to the ramped Setpoint Instruction. These time periods are T15-T20, T25-T30, T35-T40 and T45-T50\textsuperscript{36}. During these time periods, the actual loading is sampled.

(a) During the time period T15-T20, a number of Resource output snapshots, \( n \), of actual loading, \( AG_1, AG_2, AG_n \), are taken. The Regulation Mismatch Compliance for the T15-T20 period (RMRC20) is:

\[
RMRC20 = \left\{ \sum_{n}^{\infty} \left\{ 100 - \left[ \left\lfloor \text{ABS} \left[ \text{Ramped Setpoint Instruction} - AG_n \right] \right\rfloor \right\} \right\} / n
\]

(b) The calculation is repeated for T25-T30, T35-T40 and T45-T50 yielding RMRC30, RMRC40 and RMRC50.

(c) The Regulation Mismatch Compliance is then equal to:

\[
\text{Regulation Mismatch Compliance} = \frac{\text{RMRC20} + \text{RMRC30} + \text{RMRC40} + \text{RMRC50}}{4}
\]

(6) \textbf{Regulation Test Score} — The Regulation Test Score is calculated as the average of the Rate of Compliance test score and the Regulation Mismatch Compliance test score:

\[
\text{Regulation Test Score} = \frac{\text{Rate of Compliance} + \text{Regulation Mismatch Compliance}}{2}
\]

6.1.11.3.3 \textbf{Regulation Qualified Resource Compliance Rating}

A Resource’s Regulation Test Score is defined as the sliding average of the five highest Regulation Test Scores (as described in the previous section) of the last seven valid regulation tests, weighted by MW of Regulation-Up, Regulation-Down or the sum of Regulation-Up and Regulation-Down cleared as applicable. If a Regulation Qualified Resource, Regulation-Up Qualified Resource or Regulation-Down Qualified Resource has a limited number of available

\[\text{35}\text{ For Resources only certifying to supply Regulation-Up or Regulation-Down, this value is equal to two.}\]

\[\text{36}\text{ For Resources only certifying to supply Regulation-Up, only T15-T20 and T25-T30 are used. For Resources only certifying to supply Regulation-Down, only T35-T40 and T45-T50 are used.}\]
Regulation Test Scores, the Regulation Test Score calculation can use a minimum of three test scores as follows:

1. For a Resource with only three valid Regulation Test Scores, no tests are excluded from the compliance rating calculation;
2. For a Resource with only four valid Regulation Test Scores, exclude the lowest test score from the compliance rating calculation;
3. For a resource with five or six valid Regulation Test Scores, exclude the two lowest test scores from the compliance rating calculation.

The Resource’s average Compliance Rating is then calculated as follows:

\[
\text{Compliance Rating} = \frac{\sum \left( \text{Regulation Test Score} \times \text{Cleared Regulation MW} \right)}{\sum \text{Cleared Regulation MW}}
\]

### 6.2 Registration of Load

Any Market Participant with load within SPP must register with SPP via the SPP Market Registration Portal and be capable of performing the functions of load as described herein. Loads are registered at Settlement Locations within Settlement Areas. Loads may choose to be registered at a Settlement Location consisting of either a single Meter Settlement Location (Pnode) or multiple Meter Settlement Locations (APNode). For each load registered, the Asset Owner must specify whether Settlement Meter Data will be submitted on an hourly basis or on a 5-minute basis.

An APNode load Settlement Location is not limited by Settlement Area boundaries.

#### 6.2.1 Responsibilities of the Load

Each Market Participant shall be responsible for conducting its operations in accordance with all applicable SPP market rules and guidelines. The Market Participant is responsible for ensuring that settlement meter data is submitted to SPP.
6.2.2 Non-Conforming Load

Each Asset Owner must identify any Non-Conforming Load asset and the Pnode at which it resides. For the purposes of this registration requirement, any Non-Conforming Load of 50 MW or greater must be identified.

6.2.3 Demand Response Load

As part of the registration of a Dispatchable Demand Response Resource or Block Demand Response Resource, the Asset Owner must also identify a corresponding Pnode at which the associated Demand Response Load resides. The Demand Response Load is used by SPP to verify DDR and BDR compliance with Dispatch Instructions and Operating Reserve deployment instructions and does not have to be a valid Settlement Location.

6.2.4 Dispatchable Controllable Load

As part of the registration of a Dispatchable Demand Response Resource, the Asset Owner must also identify a corresponding Settlement Location at which the associated Dispatchable Controllable Load resides. The Dispatchable Controllable Load is used by SPP for settlements.

6.2.5 Block Controllable Load

As part of the registration of a Block Demand Response Resource, the Asset Owner must also identify a corresponding Settlement Location at which the associated Block Controllable Load resides. The Block Controllable Load is used by SPP for settlements.

6.3 Registration of Meter Agent

All Meter Agents (MA) providing meter data under SPP Tariff must register with SPP via the SPP Market Registration Portal. To become registered, MA must be able to demonstrate to SPP that it is capable of performing the functions as described herein. Meter data will be provided with the content and format prescribed in these protocols. The Market Participant is also responsible for insuring that SPP also receives Settlement Location Data from the Meter Agent in a suitable electronic format.

6.4 Network and Commercial Model Updates

Exhibit 6-6 shows the Model Update Timeline. Market Registration related model changes take place Bi-Monthly. Detailed model update timing relating to registration of new assets and changes to existing asset is included in Appendix E.
Exhibit 6-3: Model Update Timeline

<table>
<thead>
<tr>
<th>Production Upload date</th>
<th>Model</th>
<th>Reliability-related model changes</th>
<th>Market Registration related model changes</th>
</tr>
</thead>
<tbody>
<tr>
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7. Procedures for Correcting LMPs and/or MCPs Resulting From Market Software and Data Input Errors

SPP shall monitor for possible market software errors that do not accurately reflect the application of the Tariff, and data input errors in the DA Market and/or RTBM that result in inaccurate LMPs and/or MCPs.

Events that may result in data input errors include, but are not limited to:

1. Bad or missing SCADA (RTBM);
2. Load Forecast Error (RTBM) due to bad or missing SCADA;
3. Missing Intervals (RTBM);

The occurrence of any of these events may warrant a revision to LMPs and/or MCPs and are flagged by SPP. SPP will investigate all such events and determine if a price revision is necessary.

7.1.1 Procedure for Evaluating and Correcting Market Software and Data Input Errors

In any instance in which SPP makes price corrections, it shall, as soon as possible thereafter, correct the market software and data input errors that resulted in incorrect prices. SPP shall undertake this work in consultation and cooperation with Market Participants and jurisdictional agencies, as appropriate and as time permits.

7.1.2 Procedures for Revising Prices in Response to Market Software and Data Input Errors

SPP shall revise LMPs and MCPs when they deviate from what would be produced absent an identified market software and/or data input error.

7.1.2.1 Notice to Market Participants and the Public

1. In any hour for which SPP reasonably believes that a data or software error has occurred that may require correction of one or more LMPs and/or MCPs, SPP shall post a notice that it is considering a correction for that hour on its OASIS and website and shall notify Market Participants as soon as practicable, but not later than 5:00 p.m. the following Operating Day.
(2) Prior to making a price correction, SPP must post on its OASIS and website a description of its proposed price correction and shall notify Market Participants as soon as reasonably practicable. In any event, SPP must post a description of the proposed price correction within five (5) Calendar Days after the date on which a notice of a price correction is posted. If SPP determines that a price correction is not necessary, it shall withdraw the notice of possible price correction from its OASIS and website as soon as reasonably practicable.

7.1.2.2 Price Corrections Identified After the End of the Notice Period

If SPP identifies a market software and/or data input error requiring a price correction subsequent to the issuance of the Final Settlement Statement, but does not (a) post a notice of price correction or (b) post a description of the proposed price correction within the required time periods, SPP shall request a Tariff waiver from FERC to perform the necessary price correction. SPP shall utilize the following process for requesting such Tariff waiver:

(1) First, SPP shall review with the appropriate SPP organizational group the need for the price correction and the schedule for fixing the market software and/or data input error causing the need for price correction;

(2) Second, SPP shall seek approval of the SPP Board of Directors for filing a price correction Tariff waiver request at FERC. Prior to seeking the Board’s approval, SPP shall submit its request proposal to the SPP Market Working Group and the SPP Markets and Operations Policy Committee for approval; and

(3) Third, after approval by the SPP Board of Directors, SPP shall file the price correction Tariff waiver request at FERC as soon as reasonably practicable.

This process ensures that SPP stakeholders are consulted prior to the implementation of any price correction that does not occur within the allotted time frame for such corrections.

7.1.2.3 Process for Recalculating DA Market Cleared Amounts and Prices

SPP shall recalculate LMPs, MCPs and DA Market cleared amounts in a manner that reflects, as closely as practicable, the DA Market results that would have resulted but for the market software and/or data input error while maintaining the original DA Market unit commitment, and shall perform a resettlement using these recalculated values, if required. Such recalculated DA Market results shall be provided to Market Participants in the same manner as LMPs and MCPs determined in the ordinary course of business (i.e. in a programmatically downloadable file).
7.1.2.4 Process for Recalculating RTBM Prices

SPP shall recalculate LMPs and/or MCPs while maintaining the original cleared Operating Reserve amounts and shall perform a resettlement using these recalculated values, if required. Such recalculated LMPs and/or MCPs shall be provided to Market Participants in the same manner as LMPs and MCPs determined in the ordinary course of business (i.e. in a programmatically downloadable file).

7.1.2.5 Compensatory Payments to Market Participants

For cases in which RTBM prices have been recalculated, compensation to Market Participants shall be as follows:

(1) For instances where the recalculated RTBM LMP is less than a Resource’s Energy Offer Curve price, compensation shall be as described under Section 4.5.9.9(1)(a);

(2) For instances where a Resource’s recalculated RTBM LMP is greater than the DA Market LMP and the Market Participant is buying back its DA Market position as a result of an SPP Dispatch Instruction, compensation shall be as described under Section 4.5.9.9(1)(b) except that, the MW amount eligible for compensation shall be equal to the difference between the Resource’s DA Market MW position and the greater of that Resource’s actual MW output in the Dispatch Interval or the Resource’s average Setpoint Instruction in the Dispatch Interval;

(3) For instances where a Resource’s recalculated RTBM MCP is greater than the DA Market MCP and the Market Participant is buying back its DA Market Operating Reserve product position resulting from SPP clearing all or a portion of that Operating Reserve product on a different Resource in the market solution, compensation shall be as described under Section 4.5.9.9(1)(c).

7.1.3 Disputes and Resettlement Provisions

If a Market Participant does not agree with a price correction made by SPP, the Market Participant may use the dispute and resettlement mechanism provided in Section 4.5.15 to resolve such disagreement.
8. Market Monitoring and Mitigation

Market monitoring and mitigation is intended to provide for the monitoring by the SPP Market Monitor of the SPP Integrated Marketplace and other services provided under the SPP OATT (“SPP Markets and Services”) and mitigation by the Transmission Provider of the potential exercise of horizontal and vertical market power by Market Participants. Market monitoring and mitigation are essential functions for Regional Transmission Organizations (RTOs) and are required by FERC’s Order 2000.

8.1 Market Monitoring Plan

8.1.1 Purpose and Objective

The objective of the Market Monitoring Plan is to provide for the independent, impartial, and effective monitoring of (a) the SPP Markets and Services for abuses of horizontal and vertical market power and (b) the efficiency and implementation of the SPP Markets and Services. The Market Monitor will work to ensure that their functions and activities are implemented fairly and consistently, and that they protect and foster competition while minimizing interference with open and competitive markets. Correcting market inefficiencies and preventing the exercise of market power in advance rather than punishing offenders afterward shall be the preferred approach.

The Market Monitor will evaluate existing and proposed market rules, Tariff provisions, and market design elements and recommend proposed rules and tariff changes to the Transmission Provider, the Commission’s Office of Energy Market Regulation (or its successor organization) staff, and other interested entities such as state commissions and Market Participants. The Market Monitor will limit distribution of its identifications and recommendations to the Transmission Provider and the Commission’s Office of Energy Market Regulations (or its successor organization) staff in the event that the Market Monitor believes that broader dissemination could lead to exploitation, with an explanation of why further dissemination should be avoided.

The Market Monitor will review the performance of the wholesale market and provide an annual report on the state of the market as provided in Section 7 of Attachment AE of the SPP OATT.
8.1.2 Resolution of Conflicts

In the event there is a conflict between this Section 8 of the Market Protocols and Attachment AG of the SPP Tariff or any other provision of the Tariff, Attachment AG will control.

8.1.3 Independent Market Monitor

The Market Monitor shall be granted complete independence to perform those activities necessary to provide impartial and effective market monitoring within the scope of the Protocols. No person or entity may screen, alter, delete or delay the findings, conclusions and recommendations developed by the Market Monitor that fall within the scope of the market monitoring responsibilities contained in the SPP Tariff and these Protocols.

8.1.3.1 Staffing and Resources

The Market Monitoring function for SPP will be staffed by internal employees. FERC in an order, 109 FERC ¶ 61, 009 in October 2004 granting RTO status to SPP states that:

“In addition, we note that Order No. 2000’s market monitoring requirements may be satisfied with various market monitoring unit structures. If SPP determines that another structure to meeting its market monitoring obligations is appropriate, such as through an internal market monitoring unit, SPP may propose such a market monitoring unit consistent with what the Commission has approved for other RTOs.”

The SPP Market Monitoring Unit (MMU) is responsible for all functions and shall be an organization within SPP reporting to the Board of Directors, excluding any SPP management representatives serving on the Board of Directors.

8.1.3.2 Relationships and Notifications

As a general principle, the Market Monitor may obtain input from the MWG, FERC Staff, SPP Staff, the RSC, and affected state regulatory authorities for the purpose of executing its duties. The Market Monitor shall bring any instances of market behavior that may require investigation (including, but not limited to, suspected Tariff violations, suspected violations of Commission-approved rules and regulations, suspected market manipulation, and inappropriate dispatch) to the attention of the Board, the officers of SPP, FERC’s Office of Enforcement (or its successor organization) staff, and other affected state regulatory authorities, as the Market Monitor may deem necessary or appropriate. After any initial inquiry, the Market Monitor shall also provide notification to the Board of Directors, the President of SPP, and FERC’s Office of Enforcement (or its successor organization) staff, and other interested entities such as relevant state regulatory
commissions and Market Participants, as soon as practicable in the event it identifies a significant market problem that may require (a) further review, (b) a change in SPP’s tariffs or market rules, or (c) referral to FERC. In the event the Market Monitor believes broader dissemination could lead to exploitation, it may limit distribution of its identifications and recommendations to the Board of Directors, the President of SPP, and FERC Staff with an explanation of why further dissemination should be avoided at that time.

The MMU shall also interface with FERC Staff and other RTO and ISO market monitors in adjacent regions as needed for the purpose of addressing electricity market issues in a comprehensive manner. The Market Monitor shall report to the SPP Board of Directors.

8.1.3.3 Standards of Conduct

The MMU shall abide by SPP’s Standards of Conduct, which shall be appropriate for establishing the professional and financial independence of the MMU. The MMU shall certify compliance with such policies to the Board. Consistent with Order No. 719 requirements for MMU ethics standards, the Market Monitor and its employees shall comply with those standards outlined in Section 3.3 of Attachment AG of the SPP OATT.

8.1.4 Market Monitoring

The primary purposes of market monitoring are to (a) obtain objective information about the SPP Markets and Services, (b) assess the behavior of Market Participants, and (c) assess the behavior of other markets and services that impact the performance of the SPP Markets and Services. Key aspects of such market monitoring are (a) assessing the design and structure of the SPP Markets and Services to ensure market efficiency, (b) determining Market Participants’ compliance with market rules and (c) preventing the exercise of horizontal and/or vertical market power, which includes whether a Market Participant is affecting SPP’s ability to provide reliable and non-discriminatory service.

8.1.4.1 Markets to be Monitored

The Market Monitor will monitor the SPP Markets and Services provided under its OATT. The Market Monitor will not monitor bilateral energy, transmission or capacity markets and services not administered, coordinated or facilitated by SPP, except to assess the effect of these markets and services on the SPP Markets and Services, or the effects of the SPP Markets and Services on these unmonitored markets. Similarly, the Market Monitor will not monitor the energy, transmission or capacity markets and services in regions adjacent to SPP except to assess the
effect of these markets and services on the SPP Markets and Services, or the effects of the SPP Markets and Services on these adjacent markets.

8.1.4.2 Monitoring Activities

The Market Monitor will implement the market monitoring protocols and will monitor SPP’s Markets and Services by reviewing and analyzing market data and information including, but not limited to:

1. Resource Registration data required under Section 6;
2. Resource Offer data and other Resource offer parameters required for use in either the DA Market or RTBM;
3. Demand Bids for the purchase of Energy in the DA Market;
4. Virtual Energy Bids and Offers for the purchase or sale of Energy in the DA Market;
5. Export Interchange Transaction Bids and Import Interchange Transaction Offers for the purchase or sale of Energy in the DA Market or RTBM;
6. Actual commitment and dispatch of Resources, including but not limited to Resource MW capability and output, MVAR capability and output, status, and outages;
7. Locational Marginal Prices and Market Clearing Prices at all nodes and designated Settlement Areas in or affecting any of the SPP Markets and Services;
8. SPP Balancing Authority Area data, including but not limited to demand, area control error, net scheduled interchange, actual total net interchange, and forecasts of operating reserves and peak demand;
9. Conditions or events both inside and outside the SPP Balancing Authority Area affecting the supply and demand for, and the quantity and price of, products or services sold or to be sold in the SPP Markets and Services;
10. Information regarding transmission services and rights, including the estimating and posting of Available Transfer Capability (“ATC”) or Available Flowgate Capability (“AFC”), administration of SPP’s tariff, the operation and maintenance of the transmission system, any auctions or other markets for transmission rights, and the reservation and scheduling of transmission service;
11. Information regarding the nature and extent of transmission congestion in the region and, to the extent practicable, transmission congestion on any other system that affects the
SPP Markets and Services, including but not limited to causes of, costs of and charges for transmission congestion, transmission facility loading, MVA capability, line status and outages;

(12) Settlement data for the SPP Markets and Services;

(13) Any information regarding collusive or other anticompetitive or inefficient behavior in or affecting any of the SPP Markets and Services; and

(14) Generation resource operating cost data for estimating Resource incremental cost, including fuel input costs, heat rates where applicable, start-up fuel requirements, environmental costs and variable operating and maintenance expenses.

In addition to the monitoring of market data and information, the Market Monitor may communicate with SPP Staff and Market Participants at any time for the purpose of monitoring and assessing market conditions.

8.1.4.3 Instances of Market Power

The Market Monitor will analyze market data with regard to Instances of Market Power and refer possible cases to FERC when there is sufficient credible information to warrant such action. When the case is referred to FERC, the Market Monitor is required to desist from any further action independent of FERC’s investigation into the case.

The Market Monitor will keep SPP and Interested Government Agencies apprised of the potential for and the implications of abusive market power behavior, and make recommendations as to how to remove the potential for and ability to exercise market power.

Specific monitoring activities regarding physical and economic withholding shall include but not be limited to assessment on (a) availability of Resources, (b) artificial barriers to entry, (c) impact of the use of Resources for reliability versus energy purposes, (d) market response to price spikes, and (e) analysis of bidding patterns. On an ongoing basis, the Market Monitor will consult with the MWG on examining other areas for instances of market power.

8.1.4.4 Market Participant Behavior Warranting Possible Mitigation

The Market Monitor shall monitor SPP’s Markets and Services for potential abuse associated with the following categories of Market Participant behavior:

(1) Economic Withholding;

(2) Uneconomic Production;
(3) Physical Withholding;

(4) Uneconomic Virtual Bids and Offers.

The mitigation measures and monitoring metrics for each of the Market Participant behaviors in (a)-(d) are fully developed in Section 8.2. When the Market Monitor determines there is sufficient credible information about a specific abusive practice, the issue will be referred to the Commission for further review.

8.1.5 Inquiries

8.1.5.1 Requests

Any Market Participant or Interested Government Agency may submit in writing a complaint or request for inquiry to the Market Monitor. Upon receipt of such complaint or request, the Market Monitor will decide whether an inquiry should be conducted. As an initial screen, the Market Monitor should not pursue any complaint pertaining to issues not related to the SPP Markets and Services or monitored and overseen by the Market Monitor. An inquiry will be conducted if either Market Monitor determines it should be conducted.

Requests by Market Participants and Interested Government Agencies for the Market Monitor to conduct an inquiry can be made confidentially. The Market Monitor shall keep the identity of the requestor confidential and shall keep the existence of any inquiry conducted confidential from all uninvolved parties and from involved parties, other than the requesting party, to the extent practicable.

Nothing in this section should be interpreted as preventing the Market Monitor from conducting inquiries, either confidentially or publicly, without first receiving a complaint from a Market Participant or Interested Government Agency. The Market Monitor may initiate inquiries into any matter at any time that pertains to the SPP Markets and Services that is part of their market monitoring or market power mitigation obligation.

8.1.5.2 Conducting Inquiries

Market Participants shall cooperate fully with the Market Monitor during any inquiry. The process flow chart for conducting an inquiry is shown below.
8.1.5.3 Reporting

The Market Monitor is responsible for notifying the requesting party of the results. The Market Monitor will coordinate reporting of the results of inquiry to the Board, FERC and the RSC, as necessary. If the findings of the inquiry directly relate to any Market Participant other than the requesting party, the designated market monitoring contact of the affected Market Participant will be notified of the findings regarding his or her company. A summary of inquiries conducted and/or requested and an assessment of inquiry issues and trends will be presented in the Annual State of the Market Report were appropriate and consistent with inquiry procedures approved by the Board.

8.1.6 Compliance and Corrective Actions

8.1.6.1 Compliance

The Market Monitor shall administer SPP’s Market Monitoring Plan as described in SPP’s OATT Attachment AG and report any actual or potential abuse of market power or market
design inefficiencies as part of its monitoring process. However, such enforcement is limited to matters that (i) are expressly set forth in SPP’s OATT; (ii) involve objectively-identifiable behavior; and (iii) do not subject the Market Participant to sanctions or other consequences other than those expressly approved by the Commission and set forth in the OATT. Other enforcement matters shall be subject to Commission determination in the first instance. As part of the inquiry process, the Market Monitor may issue a demand letter requesting Market Participants causing the issue to arise to change actions as the Market Monitor deem proper to achieve compliance.

The Market Monitor may also engage in discussions with persons or entities other than Market Participants that they deem may have information that may be helpful to any investigatory or compliance process.

8.1.6.2 Corrective Actions for Market Design

If the Market Monitor discerns any weaknesses or failures in market design and protocols, including the determination that the SPP Markets and Services are not resulting in just and reasonable prices or providing appropriate incentives for investment in needed infrastructure, either in the aggregate or in any portion or location thereof, the Market Monitor shall notify the appropriate Organizational Group of SPP, the SPP President, the RSC, appropriate state authorities, FERC Staff, and relevant Market Participants. In the event the Market Monitor believes providing such information could lead to exploitation, it will restrict such notification to the President of SPP, the Chairman of the SPP Oversight Committee, and FERC Staff, and will provide a justification for such limited notification. Should the appropriate SPP Organizational Group not respond within 60 days, the Market Monitor may recommend changes in market design and protocols to the Board, FERC and the RSC as needed. If the appropriate SPP Organizational Group responds, but does not recommend changes to market design and market rules that are acceptable to the Market Monitor, the Market Monitor shall report to the Board, and the appropriate regulatory body or bodies as needed, and then SPP or the Market Monitor may file a petition or submission seeking appropriate action from FERC or any other appropriate enforcement agency. The Market Monitor shall also make recommendations for changes to SPP’s OATT, Criteria, and Market Protocols as necessary to correct weaknesses or failures in SPP’s Markets and Services.

In the event that any weaknesses or failures in market design require immediate corrective action to ensure just and reasonable prices, the Market Monitor may request the SPP President to authorize an immediate FERC filing requesting implementation of a corrective action while the
appropriate Organizational Group of SPP responds to the Market Monitor’s notification as described above. The requested immediate corrective action should be the method least intrusive or disruptive to the SPP Markets and Services necessary to resolve the market weakness or failure as determined by the Market Monitor. Prior to making such a request to the SPP President, the Market Monitor will make reasonable efforts to discuss with affected Market Participants and the Staff of affected Interested Government Agencies the market weakness or failure potentially requiring immediate corrective action, unless the Market Monitor determines that such discussion would lead to exploitation.

8.1.7 Reporting

The Market Monitor, with the support of the MWG, SPP Staff, and any other SPP Organizational Group, is responsible for producing (a) an Annual State of the Market Report and (b) Monthly, Quarterly and Annual Metrics Reports for assessing the efficiency, effectiveness and competitiveness of SPP markets and Services as requested by the SPP Board of Directors or required by FERC. The Market Monitor shall have complete independence in developing and producing reports, and no person or entity may screen, alter, delete or delay the Market Monitor’s findings, conclusions and recommendations. SPP and Market Participants may comment on any report made pursuant to this section, through the appropriate stakeholder process. The Market Monitor shall be free to disregard suggestions with which it disagrees.

8.1.7.1 Annual State of the Market Report

The Annual State of the Market Report shall assess the performance of the SPP Markets and Services as discussed in Section 8.1.1. Such report will discuss the progress made on the development of SPP Markets and Services and inter-RTO coordination and will include any recommendations of the Market Monitor for the improvement of the SPP Markets and Services, or of the monitoring, reporting and other functions undertaken pursuant to these Protocols. The report where appropriate will also include a summary of requests for inquiries and the resolution or disposition thereof.

The report will be rendered to the Board, the Transmission Provider, Market Participants, and other interested entities. The report shall be submitted to FERC. Copies of the report shall be provided to the RSC and other appropriate state regulatory authorities on request and made publicly available by SPP through a posting of the document on the SPP website. Confidential information will be subject to redaction or other measures necessary for the protection of Confidential Information.
8.1.7.2 Monthly, Quarterly and Annual Metrics Reports

The Market Monitor will prepare Monthly, Quarterly and Annual Metrics Reports. The purpose of these metrics is to provide transparency of the SPP Markets and Services and to provide a standardized basis to evaluate the performance of SPP’s market structure and market power mitigation over time. This information will also be used to compare the performance of the SPP Markets and Services with that of other RTOs and ISOs. Copies of the reports shall be made publicly available by SPP through posting on the SPP website, subject to redaction or other measures necessary for the protection of Confidential Information.

8.1.7.3 Communication of Market Monitoring Reports

Conference calls related to the Market Monitor reports may be attended by the Transmission Provider, the Board of Directors, FERC Staff and other affected regulatory authorities, Regional State Committee, and Market Participants regardless of which party initiates the conference call. The Market Monitor shall make one or more of its staff members available for regular conference calls.

8.1.7.4 Other Reports

The Market Monitor shall prepare other reports or briefings on matters within their responsibility as may be requested by the Board or FERC, or as they deem necessary.

8.1.8 Performance Indices, Metrics and Screens

Performance indices, metrics and screens form the necessary objective basis for observing the functioning of the SPP Markets and Services, including the conduct of Market Participants in such markets, and for providing reports and market analyses.

8.1.8.1 Development

The Market Monitor, with the assistance and input of the MWG and the RSC, will develop performance indices, metrics and screens for reviewing market data and other information collected. Consideration should be given to the inter-RTO metrics in use by other RTOs, ISOs and the FERC during such development.

8.1.9 Market Behavior Rules

All suppliers with market-based rates are required to comply with the Market Behavior Rules defined in FERC Order No. 670 and the Conditions for Public Utility Market-Based Rate
Authorization Holders defined in FERC Order No. 674, as they may be amended from time to time. The Market Monitor shall monitor for violations of these rules and report any suspected violations to FERC Staff in accordance with the FERC’s reporting protocols for market monitor in a timely manner. Market Participants are required to abide by these market behavior rules.

The Market Monitor shall monitor for violations of these rules or any other Commission-approved rules and regulations, or of SPP’s Tariff and report any suspected violations by Market Participants or SPP to FERC’s Office of Enforcement (or its successor organization) staff in accordance with the FERC’s reporting protocols for referral by market monitors as specified in 18 CFR 35.28(g)(3)(iv) in a timely manner. Any such reports by the Market Monitor to FERC Staff shall be on a confidential basis, and all information and documents included in such reports will not be released to any other party except to the extent FERC directs or authorizes such release, unless such information and documents are already in the public domain.

8.1.10 Market Manipulation

The Market Monitor will monitor the SPP Markets and Services for potential instances of market manipulation. Such actions or transactions that are without a legitimate business purpose and that are intended to or foreseeable could manipulate market prices, market conditions, or market rules for electric energy or electric products are prohibited. Potential behavior activities of concern include: (a) wash trades, (b) submission of false data, (c) actions to cause artificial congestion, and (d) collusive acts. The Market Monitor will report to FERC any potential market manipulation in the SPP Markets and Services in a timely manner when there is sufficient credible information to warrant such action.

8.1.11 Monitoring for Potential Transmission Market Power Activities

The Market Monitor shall monitor the SPP Markets and Services for potential transmission market power activities by reviewing and analyzing data and information related to the availability of transmission facilities that impact access particularly with respect to the withholding of transmission facilities or transmission capacity, including activities such as but not limited to, the following:

(1) Physical withholding by Transmission Owners by providing improper information related to the availability of transmission, such as information related to the capability or other modeling data used by SPP for use in system operations;
(2) Economic withholding by Transmission Owners through the use of methods and data for estimating costs of interconnection and system upgrades that is not comparable for affiliates and non-affiliates;

(3) Unavailability of transmission facilities through planned and unplanned maintenance outages that routinely exceed historical baselines;

(4) Withholding of transmission capacity by transmission users through excess reservations that are not actually used.

The Market Monitor shall refer any instance(s) of potential transmission market power directly to FERC utilizing the protocols for referral to the Commission for suspect market violations and perceived and perceived market design flaws and recommend tariff language changes as found in 18 CFR 35.28(g)(3)(iv), when there is sufficient credible information to warrant such action. Where appropriate, the Market Monitor shall also provide the FERC with an estimate of damages equal to (i) the effect on prices multiplied by (ii) the affected energy produced by the Transmission/Generation Owner. All such referrals by the Market Monitor to FERC will be on a confidential basis, and all information and documents included in such reports will not be released to any other party except to the extent FERC directs or authorizes such release.

8.1.12 Data Access, Collection and Retention

SPP shall regularly collect and maintain Data and Information necessary for monitoring the SPP Markets and Services and implementing mitigation protocols.

8.1.12.1 Confidentiality

The Market Monitor is subject to and will abide by the confidential rules as delineated in the SPP OATT.

8.1.12.2 Access to SPP Data and Information

The Market Monitor shall have access to all Data and Information gathered or generated by SPP in the course of its operations. This Data and Information shall include, but not be limited to, that listed in Section 8.1.4 of these Protocols. All Data and Information listed in Section 8.1.4 shall be retained by SPP for a minimum period of three years.
8.1.12.3 Access to Market Participant Data and Information

Market Participants shall retain all Data and Information listed below, and in Section 8.1.4 of the Market Monitoring Plan as applicable, that is in the custody and control of Market Participants, for a minimum of three years and will promptly provide any such Data and Information to the Market Monitor upon request. Market Participants shall be capable, upon request, of providing the Data in native format and a description of the format used by the Market Participant. If necessary, due to proprietary format restrictions, the MP shall be capable of providing the data in a non-proprietary format, such as CSV or XML format.

Data and Information to be retained by Market Participants and provided to the Market Monitor upon request:

(1) All Data and Information relating to the costs of operating a Resource, including but not limited to, heat rates, start-up fuel requirements, fuel purchase costs, environmental costs, and operating and maintenance expenses;

(2) All Data and Information regarding opportunity costs of a Resource, including but not limited to, regulatory, environmental, technical, or other restrictions that limit the runtime or other Resource operating characteristics;

(3) All Data and Information relating to the operating status of a Resource, including Resource logs showing the generating status of a specified unit, including information relating to a forced outage, planned outage or derating of a Resource;

(4) All Data and Information relating to the operating status of a transmission facility, a contingency, or other operating consideration, including forced outages, planned outages or derating of a transmission system component;

(5) All Data and Information relating to transmission system planning, including studies, reports, plans, models, analyses, and filings with FERC or any state regulatory commission;

(6) All Data and Information relating to the ability of a Market Participant or its Affiliate to determine the pricing or output level of generating capacity owned by another entity, including but not limited to any document setting forth the terms or conditions of such ability.

(7) All Data and Information used in the course of business operations in arriving at a decision by a Reserve Sharing Group (RSG) member to call an Operating Reserve Contingency and request assistance.
If any additional Data and Information not listed above or in the Market Monitoring section of these protocols is required from Market Participants by the Market Monitor for the purpose of fulfilling its responsibilities, the Market Monitor may request such Data and Information from Market Participants. Such Data and Information shall be provided in a timely manner by Market Participants. Any such request shall be accompanied by an explanation of the need for such data or other information, a specification of the form or format in which the data is to be produced, and an acknowledgement of the obligation of the Market Monitor to maintain the confidentiality of the data.

If a Market Participant receiving a request for Data and Information not listed above or in the Market Monitoring section of these protocols believes that production of the requested Data and Information would impose a substantial burden or expense, or would require the party to produce information that is not relevant to achieving the purposes or objectives of these market monitoring protocols, the Market Participant receiving the request shall promptly so notify the Market Monitor. The Market Monitor shall review the request with the receiving Market Participant to determine whether, without unduly compromising the objectives of these market monitoring protocols, the request can be narrowed or otherwise modified to reduce the burden or expense of compliance, and if so shall so modify the request. No party that is the subject of a data request shall be required to produce any summaries, analyses or reports of the data that do not exist at the time of the data request.

If the Market Monitor determines that the requested Data and Information has not or will not be provided in a timely manner, the Market Monitor may utilize (a) SPP’s dispute resolution procedures in its OATT or Bylaws as applicable or (b) a filing with the appropriate regulatory or enforcement agency to compel the production of the requested information.

### 8.1.12.4 Data Created by the Market Monitor

Any data created by the Market Monitor, including any reconfiguration of Data and Information obtained from SPP or Market Participants, will remain within the Market Monitor’s exclusive control. Such data may be shared with SPP and Market Participants at the Market Monitor’s sole discretion and on a non-discriminatory basis, subject to the confidentiality provisions specified in the SPP’s OATT Section 8.1 of Attachment AG and Section 8 of Attachment AE.
8.1.13  Miscellaneous Provisions

8.1.13.1  Rights and Remedies

This Plan does not restrict SPP and Market Participants from asserting any rights they may have under state and federal regulation and laws, including initiating proceedings before the FERC regarding any matter which is subject to this Plan.

8.1.13.2  Disputes

Disputes as to the implementation of, or compliance with, this Plan shall be subject to the dispute resolution procedures under the SPP Tariff or under the SPP Bylaws as applicable or subject to review by FERC.

8.1.13.3  Review of Market Monitor

The activities of the Market Monitor shall be reviewed from time to time by the Board of Directors.

8.2  Market Power Mitigation and Monitoring

8.2.1  Purpose and Objectives

The Transmission Provider shall implement these Market Mitigation Protocols in conjunction with the Market Mitigation Plan in Attachment AF of the SPP OATT.

There are two basic themes with regard to market power mitigation. First, mitigation measures must offer the opportunity for extensive intervention in energy markets, if necessary, to suppress price spikes resulting from the exercise of market power. Mitigation measures are meant to block generators with the potential for market power abuse from bidding above the price level that would otherwise prevail in a competitive market. Second, that intervention must explicitly be balanced with the goal of assuring system reliability in the long term.

8.2.2  Economic Withholding

This section develops the market power mitigation measures that are applied to the Day-Ahead and the Real-Time Balancing Energy Markets, collectively referred to as the SPP Energy Markets.
8.2.2.1 Principles

There are two principles for mitigating Economic Withholding in the SPP Energy Markets.

8.2.2.1.1 Mitigate Only in the Presence of Local Market Power

The electricity marketplace in the SPP Region is workably competitive, with an adequate supply of electricity and diversity of suppliers, absent reliability conditions or congestion on the transmission system that create the potential for abuse of local market power. Therefore, mitigation will be applied only at the time of, and in places with, a congested transmission element or facility, or a local reliability issue not represented by a flowgate constraint.

8.2.2.1.2 Do Not Mitigate Below Long Run Marginal Cost of New Investment

Mitigation should not create or exacerbate a shortage by capping prices below the level needed to attract investment that would relieve the shortage. This level shall be based on the long run marginal cost of the least-cost generation supply that could be developed within the shortest period of time, which is currently a new, natural gas-fired combustion turbine, peaking Resource.

8.2.2.2 Mitigation Measures

The following Resource Offer parameters are subject to mitigation measures in the DA Market, RTBM, and the RUC processes: the Energy Offer Curves that are used for SCED calculations; and the Energy Offer Curves, Start-Up Offers, No-Load Offers, and Transition States Offers used to determine commitment costs during the SCUC calculations. A determination of offer capped Resources is performed according to Section 8.2.2.2.1. The Energy Offer Curve associated with an offer capped Resource shall have an effective energy offer no higher than the Resource’s Energy Offer Cap; additionally, the Resource’s Start-Up, No-Load, and Transition State Offers shall be capped at the Default Start-Up, No-Load, and Transition Start Offers in the calculation of an effective commitment cost for the SCUC. The effective energy offer and commitment cost are used by the Market Operating System to determine unit commitment, prices, and dispatch instructions. The effective energy offer and commitment cost are also used in the determination of DA and RUC Make-Whole-Payments.

8.2.2.2.1 Determination of Offer Capped Resources

An Energy Offer Cap and Default Start-Up, No-Load, and Transition State Offers, as calculated in accordance with Sections 8.2.2.3-8.2.2.4, shall apply to all Resources that are committed by SPP to address a local reliability issue not represented by a transmission constraint and to certain Resources, regardless of ownership, that are on the same side of an activated transmission
constraint as the constrained load and within electrical proximity to the transmission element or facility associated with the transmission constraint. Resources subject to the Energy Offer Cap and Default Start-Up, No-Load, and Transition State Offers will be determined for each activated transmission constraint through the use of the Resource-to-Load Distribution Factors (RLDF). All Resources that are located on the importing side (side with the constrained load) of an activated transmission constraint that have RLDF greater than or equal to 5% (i.e., for each 100 MW increase in Resource output, the imports across the flowgate are reduced by 5 MWs or greater) shall be subject to an Energy Offer Cap. If any of a Market Participant’s Resources are subject to the Energy Offer Cap based on the RLDF, all Resources owned by that Market Participant that are located on the importing side of the same activated transmission constraint shall also be subject to an Energy Offer Cap. A list of all Resources subject to mitigation shall be electronically posted at the www.SPP.org website for each transmission constraint. Further, SPP shall provide through the Portal, to parties with access to information regarding each Resource, the list of transmission constraints and the Resource-to-Load-Distribution Factor, for the Resource with respect to each transmission constraint, that are above 5% for each Resource.

RLDF values will be reassessed at least once a year. RLDF values will also be reviewed and revised if needed when there are significant changes to the transmission grid within or affecting the SPP Energy and Operating Reserve Markets area.

8.2.2.2.2 Reassessment of Offer Capped Status

The Transmission Provider will reassess the status of Resources subject to Offer Caps when transmission and Resource additions, changes, outages, or changes in ownership occur that may reasonably cause the Resources’ Offer Capped status to change. In any event, the Transmission Provider will reassess the status of Offer Capped Resources on an annual basis.

8.2.2.3 Calculation of Energy Offer Caps

The Energy Offer Cap for each Resource subject to an Energy Offer Cap will be calculated daily, posted at the www.SPP.org website and the SPP Portal for such Resource, and will be effective until replaced by a new Energy Offer Cap. Specifically, Energy Offer Caps will be equal to the sum of (a) the estimated annual fixed cost of a new, natural gas-fired, combustion turbine peaking generation facility in $/megawatt-year divided by the annual hours of constraint, (b) an adder equal to the estimated non-fuel variable operation and maintenance costs of a new, natural gas-fired, combustion turbine peaking generation facility in $/megawatt-hour, and (c) the fuel cost of the peaking facility in $/megawatt-hour calculated as the heat rate multiplied by a natural gas price index. The formula for the calculation is as follows:
Energy Offer Cap = \( \frac{\text{AFC}}{\text{AHC}} + \text{VOM} + \text{FC} \)

Wherein the variables are defined as:

- **AFC** = Annual Fixed Cost (Annual Investment Recovery Requirement ($/megawatt-year) + Annual Fixed Operations and Maintenance Adder ($/megawatt-year))
- **AHC** = Annual Hours of Constraint
- **VOM** = Variable Non-Fuel Operations and Maintenance Adder ($/megawatt-hour)
- **FC** = Fuel Cost (Heat Rate * Natural Gas Price Index) ($/megawatt-hour)

Energy Offer Caps do not function as price caps on the SPP Energy Markets because the marginal Resources may not be subject to an Energy Offer Cap and there are other factors that affect prices such as congestion costs. Resources not subject to an Energy Offer Cap may bid higher than, and set a price in the SPP Energy Markets that is above an Energy Offer Cap for another Resource. For offer capped Resources, the market operating system limits the effective Energy Offer Curve used in determining LMP to a maximum equal to the offer capped Resources’ Energy Offer Caps. All Resources, including those Resources identified subject to Energy Offer Caps, will be charged/compensated based upon the Locational Marginal Price associated with each Resource.

### 8.2.2.3.1 Annual Fixed Cost

The annual fixed cost of a new, natural gas-fired, combustion turbine peaking generation facility shall be based on the calculated value of the annual carrying cost associated with the recovery of the total fixed costs to develop, build and finance such a facility plus the fixed operation and maintenance costs. Such cost shall be reviewed annually by the Transmission Provider with input from Market Participants. Any changes to such costs, along with justification for the changes, shall be filed with the Commission for approval after such review. Such costs, along with any studies justifying the costs, shall be reflected in the Tariff and posted electronically by SPP. The Annual Fixed Cost currently approved by the Commission and contained in the SPP OATT is $100,970/Megawatt-year.
8.2.2.3.2 Variable Non-Fuel O&M Adder

The adder equal to the estimated non-fuel variable operation and maintenance costs of a new, natural gas-fired, combustion turbine peaking generation facility shall be based on the non-fuel operating and maintenance costs of such a facility not included in the calculation of annual fixed costs as described above. Such cost shall be reviewed annually by the Transmission Provider with input from Market Participants. Any changes to such costs, along with justification for the changes, shall be filed with the FERC for approval after such review. Such costs, along with any studies justifying the costs, shall be reflected in the Tariff and posted electronically by SPP. The current approved rate contained in the SPP OATT is $3.79/Megawatt-hour.

8.2.2.3.3 Annual Hours of Constraint

The annual hours of constraint will be calculated individually for each Resource subject to an Energy Offer Cap and is equal to the number of hours during the most recent 365 day period, as is operationally feasible, that a transmission constraint for which the Resource has a significant effect, as determined by the RLDF, is binding or exceeded in the RTBM. In the event that multiple constraints simultaneously affect a Resource, coincident hours of constraint will be only be counted as one hour for the Offer Cap calculation for such a Resource.

Additionally, all hours for which a Resource was committed by SPP to address a local reliability issue not represented by a flowgate constraint during the most recent 365 day period will be included in the Annual Hours of Constraint.

During the first year of operation of the SPP Integrated Marketplace, the annual hours of constraint calculation will use congestion data from the RTBM in combination with congestion data from the SPP Energy Imbalance Service Market to obtain a full year of historical data. The annual hours of congestion for each Resource will be updated daily and will be posted electronically by SPP on the www.SPP.org. The annual hours of constraint will be updated daily for inclusion in the daily calculation of the Offer Cap on each Resource and will be posted electronically by SPP for each Resource on the www.SPP.org website. The annual hours of constraint for each flowgate included in the daily calculation of the Offer Cap on each Resource shall also be posted by SPP on the Portal by flowgate for each Resource.

8.2.2.3.4 New Transmission Constraints

When a new transmission constraint is established, the annual hours of constraint used in the calculation of the Energy Offer Cap for each Resource that has a significant effect on the transmission constraint as determined by the RLDF will be 32 hours until the actual number of
hours of constraint associated with the new transmission constraint has exceeded 32 or the transmission constraint has been established for at least 12 months. Thereafter, the actual hours of constraint will be used for the 12 month rolling sum. If a Resource is pivotal on a new transmission constraint, in addition to other established transmission constraints, the annual hours of constraint for the Resource will be the higher of the actual hours of constraint or 32 hours until the new transmission constraint has been established for at least 12 months. SPP will post on the Portal by transmission constraint for each Resource whether any transmission constraint included in the daily calculation of the Offer Cap on each Resource is considered new as defined in this section.

8.2.2.3.5 Fuel Cost

The fuel cost of a new, natural gas-fired, combustion turbine peaking generation facility shall be based on the estimated full-load heat rate of the facility multiplied by a fuel price index. The fuel price index for each Resource will be based on an industry accepted natural gas pricing index for the natural gas pricing point nearest to the Offer Capped Resource(s) of each Market Participant. The fuel price shall be further modified based on an estimate of the distribution cost for moving natural gas to the Offer Capped Resource(s). Alternative pricing points and fuel price modifiers shall be evaluated annually by the Transmission Provider with input from Market Participants. The fuel price portion of each Offer Cap shall be recalculated daily for inclusion in each Offer Cap and posted daily on the SPP.org website as well as on the Portal for each Resource. The current approved heat rate contained in the SPP OATT is 10,450 Btu/kilowatt-hour.

8.2.2.3.6 Energy Offer Cap Revisions

Market Participants with offer capped Resources may request an exception to an Energy Offer Cap for a Resource by submitting a cost based offer curve for the Resource to the Market Monitor. The data submission must include sufficient Resource parameters and fuel cost data for the Market Monitor to verify the reasonableness of the cost based offer curve.

8.2.2.4 Default Start-Up, No Load, and Transition State Offers

Default Start-Up, No-Load, and Transition State Offers shall be calculated daily for each Resource by the Transmission Provider. For each Resource, offers for the previous ninety days that cleared during competitive periods shall be identified. The default offer shall be set equal to 110% times the lower of the mean or median of the identified offers. The cleared offers used in the determination of the default offers will be adjusted for changes in fuel prices.
In the case that a sufficient offer history is not available for a Resource, the default offers shall be set by one or a combination of the following methods: (i) the default offers will be determined through consultation with the Market Participant and the Market Monitor; (ii) the Market Monitor will set the default offers by estimating the Start-Up, No-Load, or Transition States costs based on physical parameters and fuel costs for the Resource; (iii) the default offers will be based on averages of offers from similar resources. This methodology for setting default offers for Resources with insufficient offer history will apply to all Resources at the start of the market.

8.2.2.5 Additional Mitigation Measures for Resource Offer Parameters

Competitive outcomes can also be distorted by submitting offers that do not reflect the physical capabilities of Resources. The mitigation measures in this section are intended to provide the Transmission Provider with the means to mitigate the effects of physical parameter offers that are inconsistent with competitive conduct. The mitigation measures in this section apply to all Offer parameters in Section 4.2.2.1 expressed in units other than dollars and will only apply in the presence of local market power as described in Section 8.2.2.1.1.

A reference level for each Offer parameter that reflects the physical capability of the Resource shall be determined prior to the start of the Market by one or a combination of the following methods: (i) the reference levels will be determined through consultation with the Market Participant and the Market Monitor; (ii) the reference levels will be based on averages of Offer parameters from similar resources. This methodology for setting reference levels for Offer parameters shall apply to all Resources at the start of the market and to all new Resources that join the Market subsequent to the start of the Market.

The following thresholds shall be used by the Transmission Provider to identify Resource Offers that may warrant mitigation and shall be determined with respect to the corresponding reference level:

**Time-based Offer parameters**: An increase of three (3) hours, or an increase of six (6) hours in total for multiple time-based Offer parameters.

**Offer parameters expressed in units other than time or dollars**: A 100 percent increase for Offer parameters that are minimum values, or a 50 percent decrease for Offer parameters that are maximum values.

In the case that a Resource Offer fails the thresholds described above, the Market Monitor, in consultation with the Transmission Provider, shall determine if the impact on prices or make-whole payments warrants the application of mitigation measures. If the Market Monitor
determines that mitigation measures may be warranted, the Market Monitor will initiate a discussion with the Market Participant concerning an explanation of the parameter changes. If the Market Monitor concludes that the Market Participant’s parameter does not reflect the Resource’s actual capabilities, the mitigation measures consisting of replacing the Offer parameter with the corresponding reference level will be applied. Mitigation measures will remain in place until such time that the Market Participant demonstrates the validity of the Offer parameter; the Market Participant submits a dispute of the Market Monitor’s conclusion; or the Offer parameter is changed by the Market Participant. In the event that the Market Participant submits a dispute, the mitigation measure will remain in place until the resolution of the dispute.

8.2.3 Uneconomic Production

The Market Monitor will monitor for cases where uneconomic production by an Asset Owner’s Resources causes congestion on transmission constraints or between Reserve Zones that is not justified by reliability concerns. The specific steps are as follows:

1. Determine the MW impacts of generation on the transmission constraint or Reserve Zone from the following sources:
   - Self committed Resources with uneconomic generation (Resource incremental cost exceeds Resource LMP);
   - Market committed Resources generating outside of the Operating Tolerance band.

2. Determine that the MW impact from uneconomic production is causing the transmission congestion or binding Reserve Zone;

3. Determine that the uneconomic production is not obviously justified by reliability or other operational concerns.

The Market Monitor will conduct evaluations as specified in (a) to (c) and other related assessments to determine if there is sufficient credible information to justify referral to the Commission.

8.2.4 Measures and Mitigation for Virtual Energy Bids and Offers

The Market Monitor will monitor the level of divergence between the DA Market LMP and the RTBM LMP. This section defines the monitoring metric and thresholds, as well as the mitigation measures to be imposed by the Transmission Provider when the Virtual Energy Bids or Offers of one or more Market Participants are shown to have caused excessive LMP divergence.
8.2.4.1 Metric and Threshold Specifications

The Market Monitor will compute the hourly LMP deviation between the DA Market and RTBM using the following formula: \((LMP_{RTBM} / LMP_{DA Market}) - 1\). The average hourly LMP deviation is computed over a rolling four week period or any other period length that the Market Monitor determines is appropriate to achieve the desired purpose. If the four week rolling average is below negative 10% or in excess of 10%, then the divergence is considered excessive and additional studies are required.

8.2.4.2 Excessive Divergence and Mitigation Measures

If a determination is made that excessive divergence exists and the divergence is the result of the Virtual Energy Bids or Offers of one or more Market Participants, then mitigation measures shall be imposed by the Transmission Provider. The mitigation measures will restrict the Market Participants that caused the divergence from submitting any Virtual Energy Bids or Offers at the settlement locations or similar settlement locations where the Market Participant’s Virtual Energy Bids or Offers caused the excessive divergence. The mitigation measures shall be imposed for a period of three months at which time the restriction will no longer apply.

8.2.5 Offer Caps and Floors

Submission of Energy Offer Curves and Operating Reserve Offers by Market Participants for use in the DA Market and the RTBM will be limited by the following offer caps and floors.

1. Safety-Net Energy Offer Cap = $1000/MWh;
2. Regulation Offer Cap = $500/MW;
3. Contingency Reserve Offer Cap = $100/MW;
4. Energy Offer Floor = Negative $500/MWh;
5. Regulation Offer Floor = Negative $500/MW;
6. Contingency Reserve Offer Floor = Negative $100/MW;

8.2.6 Physical Withholding

The Market Monitor will monitor behavior to determine whether decisions to participate in the Energy and Operating Reserve Markets have a significant adverse impact on market outcomes. If appropriate, the Market Monitor will make a referral to the Commission’s Office of Enforcement (or its successor organization).
8.2.7 Unavailability of Facilities

The Market Monitor will monitor for any potential instances of Unavailability of Facilities and, if appropriate, shall refer any such instances to the Commission’s Office of Enforcement (or its successor organization).

8.2.8 Maintenance and Implementation of the Mitigation Protocols

The Transmission Provider is responsible for implementing the market power mitigation measures as approved by FERC. The Transmission Provider is also responsible for periodically reviewing and recommending revisions to the mitigation protocols and supporting SPP Regulatory Staff in obtaining approval from FERC for any such updates with input and support from the MWG.
9. **Protocol Revision Request Process**

A request to make additions, edits, deletions, revisions, or clarifications to these Protocols, including any attachments and exhibits to these Protocols, is called a “Protocol Revision Request” (PRR). Unless specifically provided in other Sections of these Protocols, this Section shall be followed for all PRRs.

9.1 **Submission of a Protocol Revision Request**

The following Entities may submit a PRR:

1. Any Market Participant;
2. Any Transmission Customer;
3. Any Entity that is an SPP Member;
4. Any staff member of a governmental authority having jurisdiction over the SPP or any member company;
5. SPP Staff;
6. SPP Market Monitor; and
7. Any SPP Committee or Working Group.

9.2 **Protocol Revision Procedure**

Exhibit 9-1 provides an overview of the protocol revision process.
Exhibit 9-1: Process Flow Chart for Protocol Revision Requests

Process Flowchart for Protocol Revision Request

<table>
<thead>
<tr>
<th>Stage</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Qualified Entity</td>
<td>Submit PRR Request via <a href="mailto:protocols.revisions@spp.org">protocols.revisions@spp.org</a></td>
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<tr>
<td></td>
<td>Notify Submitter within 5 days for Completion</td>
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<tr>
<td></td>
<td>Submit Corrected PRR to Market Design</td>
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<tr>
<td></td>
<td>Receive &amp; Review Request for Accuracy</td>
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<tr>
<td></td>
<td>Accurately Completed?</td>
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<td></td>
<td>Impact Analysis?</td>
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<tr>
<td></td>
<td>Yes</td>
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<tr>
<td></td>
<td>Notification to Vendor for Impact Analysis</td>
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<tr>
<td></td>
<td>Post Within 3 Days &amp; Set 14-Day Comment Period</td>
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<tr>
<td></td>
<td>Yes</td>
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<td></td>
<td>Collaboration to determine system Impact for assessment</td>
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<td></td>
<td>Ops</td>
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<td>VM &amp; OPS</td>
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<td></td>
<td>Complete Vendor Assessment</td>
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<td>No</td>
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<td></td>
<td>To Market Design for submission with PRR to MWG</td>
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<tr>
<td></td>
<td>BOD/FERC Review</td>
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<tr>
<td></td>
<td>Tariff Implications?</td>
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<td></td>
<td>Yes</td>
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<tr>
<td></td>
<td>Approval of PRR without Tariff Changes or IA</td>
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<tr>
<td></td>
<td>Protocols Update</td>
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<tr>
<td></td>
<td>No</td>
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<tr>
<td></td>
<td>Action by MOPC Pooled Within 3 Days</td>
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<tr>
<td></td>
<td>Appealed to MOPC Action Submitted Within 10 days</td>
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<td>BOD Review</td>
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<td>Protocol Update</td>
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<tr>
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<td>No</td>
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<tr>
<td></td>
<td>BOD Decision on PRR</td>
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<tr>
<td></td>
<td>Communicate with Project Business Owner</td>
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<tr>
<td></td>
<td>Project Completed &amp; Implemented in Protocols</td>
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<tr>
<td></td>
<td>Project Coord / Project Mgmt.</td>
</tr>
<tr>
<td></td>
<td>Initiate Project Request</td>
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<tr>
<td></td>
<td>PRPC Review and Ranking</td>
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<tr>
<td></td>
<td>Submit Resource Request to PAO</td>
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<tr>
<td></td>
<td>Protocol Completion</td>
</tr>
<tr>
<td></td>
<td>Protocols Update</td>
</tr>
</tbody>
</table>
A description of the process is provided in the following subsections.

9.2.1    Review and Posting of Protocol Revision Requests

PRRs shall be submitted electronically to SPP by completing the designated form provided at the SPP website ([PRR Request/Comment Forms](#)). All PRRs are to be submitted to the email address found on the SPP website ([protocolrevisions@spp.org](#)). Any PRRs not submitted appropriately will not be processed.

The PRR shall include the following information:

1. Description of requested revision;
2. Reason for the suggested change;
3. Impacts and benefits of the suggested change on SPP market structure, SPP operations, and Market Participants, to the extent that the submitter may know this information;
4. PRR Impact Analysis (IA) (developed and submitted by SPP Staff);
5. List of affected Protocol Sections and subsections;
6. List of affected Tariff, Business Practice or Criteria sections;
7. General administrative information (organization, contact name, etc.); and
8. Suggested language for requested revision.

SPP shall evaluate the PRR for completeness and shall notify the submitter, within five (5) Business Days of receipt, if the PRR is incomplete, including the reasons for such status. SPP may provide information to the submitter that will render it complete. An incomplete PRR shall not receive further consideration until it is completed. In order to pursue the revision requested, a submitter must submit a completed version of the PRR with the deficiencies corrected.

If a submitted PRR is complete or once a PRR is corrected, SPP shall post a complete PRR to the SPP website and distribute the PRR to the MWG within three (3) Business Days. The PRR will be reviewed at the next regularly scheduled meeting of the MWG after the official comment period of the PRR.

The “next regularly scheduled meeting” shall mean the next regularly scheduled meeting for which required notice can be timely given regarding the item(s) to be addressed, as specified in the appropriate Board, committee, or working procedures.
All decisions of the Market Working Group (MWG), the Operating Reliability Working Group (ORWG), the Regional Tariff Working Group (RTWG), the Market and Operations Policy Committee (MOPC) and the SPP Board of Directors (BOD) with respect to any PRR shall be posted to the SPP website within three (3) Business Days of the date of the decision. All such postings shall be maintained on the SPP website until the PRR is closed. A PRR is considered closed if it has been implemented in the Protocols, rejected, or withdrawn.

9.2.2 Comments on a PRR

Any interested entity may comment on a PRR. Comments on the PRR should be delivered electronically to SPP using the comment form provided on the SPP website within fourteen (14) days from the date of posting/distribution of the PRR. If an entity proposes language changes to the PRR, the entity shall submit a comment form with the proposed revisions to the original PRR language. Comments submitted after the due date of the fourteen (14) day comment period may be considered at the discretion of MWG.

All comments received in the proper format will be posted to the SPP website within two (2) Business Days of receipt. The comments shall include identification of the commenting entity.

MWG may review the PRR at its next regularly scheduled meeting after the end of the fourteen (14) day comment period, unless the fourteen (14) day comment period ends less than three (3) days prior to the next regularly scheduled MWG meeting. In that case, the PRR may be reviewed at the subsequent regularly scheduled MWG meeting.

9.2.3 Impact Analysis

A Protocol Revision Request Impact Analysis (IA) should assess the impact of the proposed PRR on SPP computer systems, operations, or business functions and shall contain the following information:

(1) An estimate of any cost and budgetary impacts to SPP for both implementation and ongoing operations;

(2) The estimated amount of time required to implement the revised Protocol language;

(3) The identification of alternatives to the original proposed language that may result in more efficient implementation; and

(4) The identification of any manual workarounds that may be used as an interim solution and estimated costs of the workaround.
SPP shall perform an IA or indicate one is not necessary. The results of the evaluation will be documented on an IA form and posted in the applicable PRR folder for review.

It will be at the discretion of the MWG to review and/or take action on a PRR contingent upon review of a completed IA. Upon completion of the IA, the MWG may review or modify actions taken on a PRR prior to the completion of the IA. A PRR will not be submitted for review to the ORWG, RTWG, or MOPC before the completion of the IA.

If MWG approves a PRR contingent upon review of an IA, SPP shall prepare an IA based on the PRR Recommendation Report. Unless a longer review period is warranted due to the complexity of the proposed PRR Recommendation Report or the quantity of approved PRRs, SPP shall issue the IA for the recommended PRR within twenty-five (25) days after MWG approval of the PRR. SPP shall post the results of the completed IA on the SPP website. If a longer review period is required for SPP Staff to complete a full IA, SPP Staff shall submit a schedule for completion of the IA to the MWG chair.

**9.2.4 Market Working Group Review and Action**

The MWG is to review and recommend action to the MOPC on PRRs. The MWG will submit PRRs to the RTWG and ORWG, and other working groups/committees as appropriate, prior to the MWG recommendation to the MOPC.

The MWG may take action on the PRR to:

1. Recommend approval as submitted or modified, which approval may be subject to review of a IA or updated IA if such review is determined by MWG to be necessary;

2. Reject. A PRR shall be considered rejected if a majority of MWG members fail both to reject and approve the PRR, either as submitted or modified;

3. Defer action on the PRR; or

4. Refer the PRR to a workgroup, or task force it deems appropriate. The PRR may be referred to a task force created by MWG and/or to one or more existing working groups or task forces of MOPC for review and comment on the PRR. Suggested modifications—or alternative modifications if a consensus recommendation is not achieved by a non-voting working group or task force—to the PRR should be submitted by the chair or the chair’s designee on behalf of the working group or task force as comments on the PRR for consideration by MWG. However, the MWG shall retain ultimate responsibility for the processing of all PRRs.
Within seven (7) days after MWG takes action to approve, approve with modifications, or reject the PRR, SPP shall post a report (“PRR Recommendation Report”) to the SPP web site reflecting the MWG action. The MWG staff secretary notifies the SPP staff secretaries of appropriate organizational groups of the posting of PRR recommendation reports and applicable IAs. A PRR recommendation report shall contain the following items:

1. Identification of submitter;
2. Modified Protocol, Criteria and Tariff language proposed by the MWG;
3. Comments submitted;
4. Proposed effective date(s) of the PRR;
5. MWG rating and rank for any PRRs requiring a system change project; and
6. Recommended action: approval, approval with modified language.

The MWG Chair shall notify MOPC of PRRs rejected by MWG.

9.2.5 Operations Reliability Working Group Review

Upon notification of the posting of a PRR Recommendation Report, the ORWG shall review the recommended changes to determine if the proposed change conflicts with requirements outlined in the SPP Criteria. In the event the ORWG identifies what it believes are conflicts with the SPP Criteria, which have not previously been identified by the MWG, or issues concerning the proposed changes, the ORWG will submit comments to the PRR to be considered by MWG at its next regularly scheduled meeting or by MOPC during its review of the Recommendation Report.

9.2.6 Regional Tariff Working Group Review

Upon notification of the posting of a PRR Recommendation Report, the RTWG shall review the recommended changes to determine if the proposed change conflicts with requirements outlined in the Tariff. The RTWG shall review and provide comments on any proposed Tariff changes included in the Recommendation Report. In the event the RTWG identifies what it believes are conflicts with the Tariff, which have not previously been identified by the MWG, or issues regarding the proposed changes, the RTWG will submit comments to the PRR to be considered by the MWG at its next regularly scheduled meeting or by the MOPC during its review of the Recommendation Report.
9.2.7 Market and Operations Policy Committee Action

MOPC shall consider any PRRs that MWG has submitted to MOPC for consideration for which a final PRR Recommendation Report has been posted on the SPP website for at least six (6) days or those accepted for expedited treatment by the MOPC. The following information must be included for each PRR considered by MOPC:

(1) The PRR Recommendation Report and IA, if any; and

(2) Any comments timely received in response to the PRR Recommendation Report.

MOPC shall take one of the following actions regarding the PRR Recommendation Report:

(1) Approve the PRR as recommended in the PRR Recommendation Report or as modified by MOPC;

(2) Reject the PRR. A PRR shall be considered rejected if MOPC members fail both to reject or approve the PRR, either as submitted or modified; or

(3) Remand the PRR to the MWG with instructions.

If the PRR Recommendation Report is approved by the MOPC, as recommended by MWG or modified, the MOPC shall review and approve or modify the proposed effective date. The MOPC’s decision regarding approval or rejection of a PRR shall be posted on the SPP website within three (3) Business Days after the MOPC’s decision. If the MOPC rejects a PRR, the submitter may file an appeal with the SPP Board.

If the MOPC approves a change or changes to the Protocols, such change(s) shall be incorporated into the Protocols posted on the SPP website as soon as practicable, but no later than one (1) day before the effective date of the changes. Where a PRR does not take effect immediately, the PRR shall be shown in the Protocols in gray-boxed text that indicates the anticipated effective date of the PRR.

9.2.8 SPP Board of Directors Review and Action

If the PRR requires Criteria or Tariff revisions, after a PRR has been approved by the MOPC, it must be submitted to the SPP Board of Directors (BOD) for review and action. The BOD will review the PRR at the next regularly scheduled meeting and take one of the following actions:

(1) Approve the PRR as recommended in the PRR Recommendation Report or as modified by the SPP Board of Directors;
(2) Reject the PRR. A PRR shall be considered rejected if SPP BOD fail both to reject or approve the PRR, either as submitted or modified; or

(3) Remand the PRR to the MOPC with instructions.

### 9.2.9 Withdrawal of Protocol Revision Request

Upon notice to the MWG, the submitter of a PRR may withdraw the PRR at any time prior to approval of the PRR by the MWG. SPP shall post a notice of the submitter’s withdrawal of a PRR on the SPP website within one (1) Business Day of the submitter’s notice to MWG.

If a PRR is approved by the MWG it cannot be withdrawn except with approval of the MWG.

### 9.2.10 Expedited Review Requests

The party submitting a PRR may request that the PRR be considered for Expedited Review when the submitter is requesting action from the MWG on a PRR that has not met the minimum comment period described in Section 9.2.2.

A valid motion in a regularly scheduled meeting of the MWG is required to waive the minimum comment period and treat a PRR with Expedited Review status. If approved for Expedited Review by the MWG, the PRR will be treated the same as one that has met the minimum comment period. If the request for Expedited Review is rejected, the PRR will be considered by the MWG after the minimum period; in most cases at the next regularly scheduled MWG meeting.

### 9.2.11 Urgent Action Requests

The party submitting a PRR may request that the PRR be considered for Urgent Action. Urgent Action Requests should be reserved for instances when existing Protocol is impairing or could imminently impair SPP System reliability or wholesale or retail market operations, or is causing or could imminently cause a discrepancy between any of SPP’s governing documents.

The MWG shall consider the Urgent Action PRR at its earliest regularly scheduled meeting or at a special meeting called by the MWG chair. In some cases, an Urgent Action Request will occur concurrently with an Expedited Review Request. A valid motion and vote of the MWG are required to designate the PRR for Urgent Action. After approval, Urgent Action PRRs shall be given priority high enough to ensure implementation within the timeline necessary to mitigate concerns about SPP system reliability or market operations under the unmodified language, or any other significant issues identified in the PRR.
If approved, SPP shall submit an Urgent Action PRR Recommendation Report to the chair and staff secretary of the MOPC, RTWG, and ORWG within two (2) Business Days to address the urgency of the PRR. The MOPC, RTWG and ORWG chairs may request action from the working groups to address the urgency of the PRR.

9.2.12 Appeal of Decision

If MWG rejects the PRR, any entity eligible to submit a PRR may appeal directly to the MOPC. Such appeal to the MOPC must be submitted to SPP within ten (10) Business Days after the date of the relevant decision. Appeals made after this time shall be rejected. Appeals to the MOPC shall be posted on the SPP website within three (3) Business Days and placed on the agenda of the next available regularly scheduled MOPC meeting, provided that the appeal is provided to SPP at least eleven (11) days in advance of the MOPC meeting; otherwise the appeal will be heard by the MOPC at the next regularly scheduled MOPC meeting.

If MOPC rejects the PRR, any entity eligible to submit a PRR may appeal directly to the SPP Board. Such appeal to the SPP Board must be submitted to SPP within ten (10) Business Days after the date of the relevant decision. Appeals made after this time shall be rejected. Appeals to the SPP Board shall be posted on the SPP website within three (3) Business Days and placed on the agenda of the next available regularly scheduled SPP Board meeting, provided that the appeal is provided to the SPP General Counsel at least eleven (11) Business days in advance of the Board meeting; otherwise the appeal will be heard by the Board at the next regularly scheduled Board meeting.

In the event FERC rejects the tariff modifications associated with a PRR, the PRR will be deemed rejected by FERC action. In the event FERC accepts with changes the tariff modifications associated with a PRR, the SPP staff will prepare a PRR to conform the Market Protocols with the FERC order.
10. **Market Process and System Change Process**

This section outlines the methods that govern SPP System changes that directly impact members’ processes, systems, or interfaces with SPP systems. The intent of this section is to ensure there is transparency when member-impacting changes occur to SPP processes and/or systems.

(1) The SPP CWG (Change Working Group) is the group responsible for monitoring and coordinating all planned member-impacting system or process changes that meet one or more of the following criteria:

   (1) The change will result in members having to make changes to their internal systems or interfaces;

   (2) The change will require members to coordinate testing with SPP prior to the change being released to Production systems;

   (3) The change will cause members to change their internal processes;

   (4) The change modifies or creates a system interface between SPP and its members;

   (5) The risk associated with the change justifies inclusion as a member-impacting change.

(2) The CWG and SPP will develop and maintain a plan outlining member-impacting change initiatives. This plan will be updated at least quarterly and posted to the CWG page on the SPP Corporate website. The plan will reflect the relative priority of all member-impacting change initiatives. These priorities will be determined based on the PRR ranking process conducted by the SPP Market Working Group (MWG) as well as internal project prioritization processes in place at SPP. System changes that cannot be implemented according to the requested priority will be identified and communicated to the MWG, after coordination with the CWG. The plan will include, at a minimum, the following:

   (1) Listing and description of planned member-impacting projects;

   (2) Updated current status of planned member-impacting projects;

   (3) Identifiable milestones of planned member-impacting projects, including, but not limited to:

      (a) Requirements Signoff;
(b) Schedule of Testing and Training;
(c) Communication of Expectations / Specifications;
(d) Release of Required Documentation;
(e) System Release Dates.

(3) All member-impacting change initiatives are classified as minor, medium, major or emergency changes. The classification of these initiatives will be routinely reviewed and discussed by the Change Working Group and alternative timelines will be recommended, depending on the scope of the individual projects. SPP will maintain a list of system changes and their associated classifications for discussion and coordination with the CWG.

(a) Minor Change – a change to an SPP system that corrects or changes existing functionality but does not require members to make any changes to their systems, nor test the new functionality in a coordinated fashion with SPP. An example of a minor member-impacting change would be an enhancement to member accessible web page that includes adding newly available options or functionality. For minor member-impacting changes, SPP staff is required to notify the membership at least two (2) weeks prior to implementation in production.

(b) Medium Change - a change to an SPP system that involves changes to system interfaces between SPP and its members, such as changes to XML file specifications or Application Programmable Interfaces (API). The process for interface changes must allow sufficient time for members to assess the impact of the change to their systems, make appropriate revisions, and complete testing in an offline environment, where applicable. SPP staff is required to notify the membership at least four (4) weeks prior to implementation in production, or as defined and agreed to by the CWG.

(c) Major Change - a change to an SPP system that introduces a new member-facing application, major system functionality or wholesale process changes. These changes will always be managed by SPP as projects, with milestones defined on the plan that is updated quarterly, and will include member participation, coordination, and testing throughout the project phases. For major changes that require the development of new applications or interfaces by members, SPP staff is required to coordinate the project schedule by means of the Change Working
Group to determine the appropriate lead times for documentation, testing, and implementation.

(d) **Emergency Change** – a member-impacting change to an SPP system that is required to immediately restore or correct existing functionality. If changes to member systems or processes are required as a result of an Emergency Change, where appropriate, SPP staff will:

(i) Communicate the need for the change with SPP members via an emergency conference call. The communication will include a discussion of impacts, risks, and timelines.

## 10.1 Root Cause Analysis

Within 30 calendar days of any unplanned system outage, in which Market Participants were instructed by SPP to hold their deployment levels for a period of time, SPP staff will perform a root cause analysis of the event and publish an executive summary of its findings to the CWG distribution list, and other applicable SPP member distribution lists. Staff will provide bi-weekly updates (via e-mail) to the CWG on the progress associated with the root cause analysis. The analysis will outline the root cause of the event, describe remediation actions to prevent future reoccurrences, and specify if changes or workarounds that may have been put into place, will remain in production on a permanent or temporary basis.
Appendix A – Registration Portal

Reserved for screen shots/directions on how to use Registration Portal, to be completed at a later date.
Appendix B - XML Specifications

Detailed XML specifications to be completed at a later date.
Appendix C - Meter Technical Protocols
1. **Scope**

This document will serve as a definitive technical resource concerning the expected duties, responsibilities, processes, standards, and liabilities with regards to the Metering Parties for the SPP Integrated Marketplace metering implementation.

2. **Purpose**

This document will provide the metering technical standards for installation, maintenance and validation of facilities by which the Metering Parties will participate in the SPP Integrated Marketplace.

3. **Definitions**

The terms used in this document are defined as defined in Section 1 of the Market Protocols.

4. **Applicable Standards**

- ANSI C12.1 American National Standard For Watthour Meters, Code For Electricity Metering
- ANSI C12.7 American National Standard Requirements for Watthour Meter Sockets
- ANSI C12.9 American National Standard For Test Switches for Transformer-Rated Meters
- ANSI C12.10 American National Standard For Watthour Meters
- ANSI C12.11 American National Standard For Instrument Transformers For Revenue Metering, 10kV BIL through 350 kV BIL
- ANSI C12.16 American National Standard For Solid State Electricity Meters
- ANSI C12.20 American National Standard For 0.2 and 0.5 Accuracy Class
- ANSI C93.1 Standard Requirements for Power Line Coupling Carrier Capacitors and Coupling Capacitor Voltage Transformers
- IEEE Std 100 The New IEEE Standard Dictionary of Electrical and Electronic Terms
- IEEE C57.13 IEEE Standard Requirement for Instrument Transformers
- NFPA 70 National Electrical Code® 2011 edition, Chapter 1 General, Section II. 600 Volts, Nominal, or Less, Article 110.26 Spaces About Electrical Equipment.
5. General

5.1 Introduction

This Appendix will apply to SPP metering facilities including specifications and practices required to provide accurate metering of electrical quantities for settlement. These guidelines are not applicable to measurements intended for local monitoring, station relaying, control, or operation.

5.2 Existing Facilities

Existing meter facilities as of January 1, 2006 are acceptable for SPP market transactions ("grandfathered"), as long as the following criteria is met:

1. Market Participant is capable of providing at least hourly MWh interval data information;
2. The Metering Parties mutually agree that the existing metering facilities are acceptable;
3. Meets other SPP transmission tariff requirements.

5.3 Physical Location of Meter

The Market Participant metering facility shall be designed to sustain an environment within the limits of the operating characteristics of the meter and metering devices as stated by the meter manufacturer.

A clear space shall be provided in front and to the side of the meter as outlined in The National Electric Code, Article 110.26, Spaces About Electrical Equipment.

Adequate lighting should be provided at the meter’s location for testing, maintenance, and adjustment.

5.4 Metering of Tie lines (Interchange)

Sufficient metering, as defined in Section 7, shall be installed for the settlement of interchange in accordance with the terms of the applicable Interconnection Agreement or Network Operating Agreement.

5.5 Metering for Resources

Sufficient metering, as defined in Section 7 of this Appendix, shall be installed for Resources either at the Resource terminals or at the Meter Settlement Location in accordance with the terms of the applicable Interconnection Agreement or Network Operating Agreement. All metered
Resource data values are to be supplied to SPP as net generation and compensated to the SPP Transmission Tariff Facilities (Node).

5.6 Metering for Loads

Sufficient metering, as defined in Section 7 of this Appendix, shall be installed for the settlement of Loads in accordance with the terms of the applicable Interconnection Agreement or Network Operating Agreement.

5.7 Measurement Quantity Verification

Measurement quantity verification shall be accomplished by reading the appropriate register of the meter.

5.8 Measurement Governance

The owner/operator of the meter shall provide the measurement quantity at the meter connection. The measurement quantity may contain loss compensation, if performed within the meter.

6. Timing Standard

6.1 Remote Terminal Unit (RTU) Freeze Contact or Signal

When an RTU requires a freeze contact or signal to synchronize an accumulator reading, the timing contact shall be provided by either the EMS system or RTU whose timing element meets the accuracy requirement of Section 6.4 or a meter whose timing element meets the accuracy requirement of Section 6.3.

6.2 Accumulators / Register Values

Accumulators / meter register values will be synchronized to the end of the timing interval. This can be done by providing a frozen register value from the meter, by providing the last recorded interval reading from the interval data recorder in the meter, or an RTU frozen accumulator reading at the end of the interval.

6.3 Accuracy - Meter

When the timing element of the meter is used to send a freeze contact closure or signal to the RTU, freeze a meter register reading, and/or control the interval data recorder timing, the time
clock shall be within +/- 1 minute per any 30 day period. If the timing element is found to exceed this value, it will be resynchronized to Central Standard Time from a NIST source.

6.4 **Accuracy – EMS/RTU**

When the timing element of the EMS/RTU is used to provide a freeze contact closure or signal to the RTU, the time clock shall be within +/- 1 minute per any 30 day period. If the timing element is found to exceed this value, it will be resynchronized to Central Standard Time from a NIST source.

7. **Meters**

7.1 **Measurement Quantities**

The meter shall be capable of reporting watthours (Wh) and varhours (VARh) for 4 quadrants.

1. Quadrant 1 shall measure active power and reactive power delivered by the SPP network.

2. Quadrant 2 shall measure active power received by the SPP network and reactive power delivered by the SPP network.

3. Quadrant 3 shall measure active power and reactive power received by the SPP network.

4. Quadrant 4 shall measure active power delivered by the SPP network and reactive power received by the SPP network.

The Wh and VARh may be expressed in kilo or mega values as agreed to by the Metering Parties. Refer to Appendix E for reporting requirements.

7.2 **Measurement Configuration**

Metering shall be installed and configured in such a manner as to comply with the following:

1. Current transformers shall be installed, one in each phase, for metering which is connected to a four-wire wye neutral grounded system or in two phases for metering which is connected to a three-wire ungrounded system. Voltage transformers for a four-wire wye neutral grounded system (three single phase units or one three phase unit) shall be installed, one from each phase conductor to the circuit neutral. Voltage transformers (two single phase units) for a three-wire ungrounded system shall be installed from phase to common phase.

2. For three wires delta connected power transformers connected to a four wire wye grounded source at a Transmission level voltage two element metering is acceptable. The
equipment owner shall ensure that no single-phase Loads are connected between the metering transformers and the three-wire delta connected power transformer. Voltage transformers (two single phase units) shall be installed from phase to common phase.

7.3 Accuracy

Meters shall meet the following minimum percent tolerances. If the test results exceed these tolerances, the meter must be calibrated to bring it within the acceptable tolerance range as defined in Table 1.

<table>
<thead>
<tr>
<th>% Test Amp</th>
<th>Power Factor</th>
<th>Tolerance %</th>
</tr>
</thead>
<tbody>
<tr>
<td>100</td>
<td>1.0</td>
<td>±0.2%</td>
</tr>
<tr>
<td>10</td>
<td>1.0</td>
<td>±0.2%</td>
</tr>
<tr>
<td>100</td>
<td>0.5 lagging</td>
<td>±0.3%</td>
</tr>
</tbody>
</table>

The individual elements shall be tested for balance before or at time of installation to within ±0.3%. A final Series Test as defined by ANSI C12.1 shall be made after any calibration.

7.4 Testing

7.4.1 Testing Equipment

All meter testing equipment shall be traceable back to National Institute of Standards and Technology (NIST) as per ANSI C12.1 Appendix B. Specifically, the reference standard used to perform the comparison test on the meter shall be of the accuracy class that meets or exceeds ± 0.05% so as to achieve a 4 to 1 Accuracy Ratio between the standard and the meter.

7.4.2 Acceptance Testing

All meters shall meet the applicable sections in ANSI C12.1 and ANSI 12.20.

7.4.3 In-Service Testing

The accuracy of all meters required to transact energy services shall be verified by tests conducted by the equipment owner. The test interval shall be determined by agreement between the affected Market Participants but in all cases it shall never be more than 1 year. The metering equipment owner shall provide reasonable advance notification to the other metering parties of
this periodic test and provide the test results to them. If such test identifies or other indications show a meter is out of service or inaccurate, the Market Participant must take action to restore the meter to correct operation within a reasonable period of time. In the interim, backup metering or integrated real time metering may be used as mutually agreed by the Metering Parties involved. However in no case shall the reasonable period of time exceed a period of 30 days from the date of discovery, or from a date mutually agreed upon by the Metering Parties. If equipment installation or replacement is required to resolve the inaccuracy, all equipment must be correctly operating at a date mutually agreed upon by the Metering Parties. SPP will be notified of the inaccuracy, interim procedures, and resolution for auditing purposes.

Periodic accuracy compliance testing may be requested by SPP member agreement groups, as required. Authentication of existing meter systems and validation of newly installed or repaired meter systems are required as described in Section 7.11 of this Appendix.

### 7.4.4 Verification Records and Retention

The Control Area Operator and/or Wires Facilities owner(s) shall maintain sufficient documentation to verify the integrity and accuracy of a Settlement Location. All meter records and associated documentation must be retained by the Market Participant for a period of seven years for independent auditing purposes by the SPP. This documentation shall include but is not limited to the following:

1. Schematic drawings (both detailed and one-line) of the Settlement Location. Such drawings shall be dated, bear the current drawing revision number, and show all wiring, connections, and devices in the circuit.

2. The results of all accuracy testing listed in Section 7.4.1 through 7.4.3 of this Appendix. The accuracy values shall be calculated based on Method 1 of ANSI C12.1.

### 7.5 Real Time Metering

#### 7.5.1 General

If the metering should fail, the real time metering may be used, if available, to estimate the usage as long as the same voltage and current transformers are used. The real time metering is normally accomplished using a watt transducer. The MW quantity from this device will be integrated over the hour that the meter has failed, which will produce the estimated MWh. To the extent that real time metering is installed and used as above, the standards are indicated in this section.
7.5.2 Measurement Configuration

The transducer shall be installed and configured in such a manner as to comply with the following:

(1) Current transformers shall be installed, one in each phase, for metering which is connected to a four-wire wye neutral grounded system or in two phases for metering which is connected to a three-wire ungrounded system. Voltage transformers for a four-wire wye neutral grounded system (three single phase units or one three phase unit) shall be installed, one from each phase conductor to the circuit neutral. Voltage transformers (two single phase units) for a three-wire ungrounded system shall be installed from phase to common phase.

(2) For three wire delta connected power transformers connected to a four wire wye grounded source at a Transmission level voltage, two element metering is acceptable. The equipment owner shall ensure that no single-phase Loads are connected between the metering transformers and the three-wire delta connected power transformer. Voltage transformers (two single phase units) shall be installed from phase to common phase.

7.5.3 Accuracy

The transducer shall meet the following minimum percent tolerances. If the test results exceed these tolerances, the transducer must be calibrated to bring it within the acceptable tolerance range as defined in Table 2.

<table>
<thead>
<tr>
<th>Watts</th>
<th>Power Factor</th>
<th>Tolerance %</th>
</tr>
</thead>
<tbody>
<tr>
<td>100</td>
<td>1.0</td>
<td>±0.2</td>
</tr>
</tbody>
</table>

7.5.4 Testing

7.5.4.1 Testing Equipment

All transducer testing equipment shall be traceable back to National Institute of Standards and Technology (NIST).
7.5.4.2 Acceptance Testing

The transducer shall pass Section 4.7.3.1 Test 15, Section 4.7.3.2 Test 16, Section 4.7.3.3 Test 17, Section 4.7.3.11 Test 25, Section 4.7.3.14 Test 28, Section 4.7.3.16 Test 30, and Section 4.7.3.17 Test 31 as specified in ANSI C12.1. These shall be done in series. The transducer shall have been deemed to pass if it meets the criteria specified in section 4.6.2.1 of ANSI C12.1

7.5.4.3 Operating Conditions

A transducer will maintain the accuracy as shown in Table 2 under the following conditions:

1. Temperature Range: -20°C to +70°C
2. Humidity: 0 to 95% non condensing
3. Potential Range: 70 to 130% of nominal input voltage rating
4. Current Range: 0 to 200% of nominal current rating

7.5.4.4 Output Characteristics

The transducer will be able to measure 99% of the true measured value in no more than 400 milliseconds. The AC Component of the output shall be no more than 0.5% peak of the rated output.

7.5.4.5 In Service Testing

The accuracy of all transducers required for real time metering to transact energy services shall be verified by tests conducted by the equipment owner at time of commissioning or with a certified factory test. If there are indications that show that a transducer is out of service, the Market Participant must take action to restore the transducer to correct operation within a reasonable period of time. However in no case shall the reasonable period of time exceed a period of 30 days from the date of discovery, or from a date mutually agreed upon by the Metering Parties. If equipment installation or replacement is required to resolve the inaccuracy, all equipment must be correctly operating at a date mutually agreed upon by the Metering Parties. SPP will be notified of the inaccuracy, interim procedures, and resolution for auditing purposes.

Periodic accuracy compliance testing may be requested by SPP member agreement groups, as required. Authentication of existing real time metering and validation of newly installed or repaired real time metering is required as described in Section 7.11 of this Appendix.
7.5.4.6 Verification Records and Retention

The Control Area Operator and/or Wires Facilities owner(s) shall maintain sufficient documentation to verify the integrity and accuracy of a Settlement Location. This documentation shall include but is not limited to the following:

1. Schematic drawings (both detailed and one-line) of the Settlement Location. Such drawings shall be dated, bear the current drawing revision number, and show all wiring, connections, and devices in the circuit.

2. The transducer manufacturer’s original test specifications shall be sufficient to verify the accuracy of this device.

7.6 New Current and Voltage Sensing Technologies

Fiber optic current and voltage transformers are considered technologies that shall be periodically tested until proven to provide stable accuracy. SPP may determine that this testing is not required once these devices after testing have shown themselves to be stable. If these devices have shown themselves to be unstable, then the participant shall discontinue the use of these devices for settlement purposes.

Fiber optic sensors, at a minimum are to provide the same accuracy class as wire wound devices. Until there is general agreement that the proven accuracy of the optical sensors is the same as wire wound devices, the frequency of accuracy testing of the fiber optic sensors is to be at least every five years. Once long term accuracy data is developed, routine field calibration may no longer be required to ensure the ANSI 0.3% accuracy class.

7.7 Current Transformers

7.7.1 Nameplate

The nameplate data shall include but is not limited to the following information: Manufacturer, Serial Number or Identification Number, Type, Current Transformer Ratios, Accuracy class and Burden Rating, Rating Factor, and BIL. Current transformers shall comply with ANSI 0.3 accuracy class or better for B0.1 through B1.8. If the current transformers are not accessible due to energized components or extensive disassembly is required that may impact asset availability, note the unavailability and request the Market Participant to identify a scheduled outage when the current transformer nameplate may be accessed safely. If a nameplate doesn’t exist showing the ANSI 0.3 accuracy class, testing as described in IEEE C57.13 shall be performed to establish
this level of accuracy and a nameplate created. This nameplate shall be affixed to the current transformer or the device in which it is included.

7.7.2 Polarity

The polarity marks on all current transformers shall follow the same convention, (e.g., all facing the line or all facing the Load). If there is more than one primary conductor passing through the current transformer, then all conductors shall be of the same phase. If the current transformers are not accessible due to energized components or extensive disassembly is required that may impact asset availability, note the unavailability and request the Market Participant to identify a scheduled outage when the current transformers polarity may be verified safely. If current transformers polarity markings don’t exist, testing as described in IEEE C57.13 shall be performed to establish terminal polarity. The terminals shall be permanently marked with this information.

7.7.3 Burden Testing

The current transformer burdens shall be kept as small as practicable and the metering circuit shall be limited to billing meters and transducers. Relays shall not be connected to the metering circuit. Current transformers shall comply with ANSI 0.3 accuracy class for B0.1 through B1.8 or better. During annual testing, the total current transformer burden shall be checked by the addition of a known burden to determine that the specified burden capability of the current transformer is not exceeded.

7.7.4 Paralleling

Paralleling of current transformers is not recommended. However, when it is necessary, the following guidelines shall be adhered to.

1. All current transformers must have the same nominal rating regardless of the circuits in which they are connected.

2. All current transformers which have their secondaries paralleled must be connected to the same phase of the primary circuits.

3. The secondary circuits shall be connected in a configuration to allow for testing of individual instrument transformers. The secondary circuits shall be paralleled at the meter test switch.
(4) There shall be only one ground per isolated secondary of all paralleled current transformers. It is recommended that the ground be located at the meter or at the nearest terminal block to the meter.

(5) The secondary circuits must be so designed that the maximum possible burden on any current transformer will not exceed its rating.

(6) A common voltage must be available for the meter. This condition is met if the circuits share a common bus that is normally operated with closed bus ties.

(7) The meter must have sufficient current capacity to carry the sum of the currents from all the current transformers to which it is connected.

7.8 Coupling Capacitor Voltage Transformers

7.8.1 General
Coupling Capacitor Voltage Transformers are not to be used on new installations. For existing installations, Coupling Capacitor Voltage Transformers shall be tested at least every five years to ensure revenue class accuracy. If this device shows itself to be unstable, the SPP may require the participant to discontinue the use of this device for Settlement purposes. Coupling Capacitor Voltage Transformers at a minimum are to provide the same accuracy class as wire wound devices.

7.8.2 Nameplate
The nameplate data shall include but is not limited to the following information: Manufacturer, Serial Number or Identification Number, Type, Voltage Transformer Ratios, Accuracy Class and Burden Rating, and BIL. Coupling Capacitor Voltage Transformers shall comply with ANSI 0.3 accuracy class or better for W, X, M, Y, Z, and ZZ burden levels. If the Coupling Capacitor Voltage transformers are not accessible due to energized components or extensive disassembly is required that may impact asset availability, note the unavailability and request the participant to identify a scheduled outage when the voltage transformer nameplate may be accessed safely. If a nameplate doesn’t exist showing the ANSI 0.3 accuracy class, testing as described in ANSI C93.1 shall be performed to establish this level of accuracy and a nameplate created. This nameplate shall be affixed to the Coupling Capacitor Voltage Transformer.
7.8.3 Polarity

The polarity marks on all Coupling Capacitor Voltage Transformers shall follow the same convention as the current transformers, (e.g., all facing the line or all facing the Load). If the voltage transformers are not accessible due to energized components or extensive disassembly is required that may impact asset availability, note the unavailability and request the Market Participant to identify a scheduled outage when the voltage transformers polarity may be verified safely. If Coupling Capacitor Voltage Transformers polarity markings don’t existing, testing as described in ANSI C93.1 shall be performed to establish terminal polarity. The terminals shall be permanently marked with this information.

7.8.4 Burden

The Coupling Capacitor Voltage Transformer burdens should be kept as small as practical. The total burden/volt-ampere rating on the voltage transformer secondary shall not exceed the accuracy burden listed on the nameplate of the voltage transformer. This burden shall include the meter, the secondary leads, and any equipment connected in the circuit.

7.9 Wire Wound Voltage Transformers

7.9.1 Nameplate

The nameplate data shall include but is not limited to the following information: Manufacturer, Serial Number or Identification Number, Type, Voltage Transformer Ratios, Burden Rating, thermal rating, BIL, and Class. Voltage transformers shall comply with ANSI 0.3 accuracy class or better for W, X, M, Y, Z, and ZZ burden levels. If the voltage transformers are not accessible due to energized components or extensive disassembly is required that may impact asset availability, note the unavailability and request the Market Participant to identify a scheduled outage when the voltage transformer nameplate may be accessed safely. If a nameplate doesn’t exist showing the ANSI 0.3 accuracy class, testing as described in IEEE C57.13 shall be performed to establish this level of accuracy and a nameplate created. This nameplate shall be affixed to the voltage transformer or the device in which it is included.

7.9.2 Polarity

The polarity marks on all voltage transformers shall follow the same convention as the current transformers, (e.g., all facing the line or all facing the Load). If the voltage transformers are not accessible due to energized components or extensive disassembly is required that may impact asset availability, note the unavailability and request the Market Participant to identify a
scheduled outage when the voltage transformers polarity may be verified safely. If voltage transformers polarity markings don’t exist, testing as described in IEEE C57.13 shall be performed to establish terminal polarity. The terminals shall be permanently marked with this information.

7.9.3 Burden

The voltage transformer burdens should be kept as small as practical. The total burden/volt-ampere rating on the voltage transformer secondary shall not exceed the accuracy burden listed on the nameplate of the voltage transformer. This burden shall include the meter, the secondary leads, and any equipment connected in the circuit.

7.10 Ancillary Devices

7.10.1 Wiring

7.10.1.1 Phase Wiring

The integrity of the secondary wiring of the current and voltage transformers shall be verified. No other ancillary device other than SPP Settlement Location metering shall be installed in the CT circuit. The VT circuit may have an ancillary device installed in it, if mutually agreed upon by the metering parties. The integrity of the secondary wire shall include but is not limited to the following items.

(1) Each current and voltage transformer shall have its own polarity conductor.

(2) No splices will be allowed in the current or voltage transformer secondary circuit except through the use of terminal block connections.

7.10.1.2 Neutral Returns

A separate common return conductor shall be utilized for each set of isolated current transformer secondary windings and a separate common return conductor for each set of isolated voltage transformer secondary windings.

The common terminals of each set of current transformers and voltage transformers shall be grounded at only one point. It is recommended that the ground connection be located at the meter or at the nearest terminal block to the meter.

This ground lead shall be of the same wire size as the leads used for the polarity and common that connects to the meter.
7.10.1.3 Induced Voltage on Wiring

Secondary circuits should be routed so as to mitigate the possibility of induced voltages and the effects of high ground fault voltages. The secondary circuit should be designed to minimize these effects. Suitable protection against the effects of fault and switching generated over-voltages should be provided in the metering equipment (Refer to IEEE C37.90.1).

7.10.1.4 Fusing

Monitoring of the voltage circuit is required, if fusing of the secondary circuit is necessary. This can be accomplished by the meter or an external device. If the voltage transformer is shared by a relay group, the fusing shall be done after the metering branch point.

Fusing is not allowed in any primary or secondary circuit of a current transformer.

7.10.1.5 Test Switches

Test switches shall be installed in the instrument transformer secondary circuits to provide a means to measure quantities required to certify the facility and allow the application of test quantities to the meter. Test switches shall be capable of handling parallel currents. Test switches shall conform to ANSI C12.9.

7.11 Metering Site Procedures

7.11.1 General

Except in those cases where the involved Metering Parties agree to the contrary, the equipment owner shall be responsible for any maintenance and calibration.

The equipment owner may modify the following procedures and any other procedure herein as it deems necessary to meet efficient and proper test procedures and methodology as found by practice.

When the Meter Settlement Location meter is being tested, care should be taken to minimize the potential impact on operations.

The Metering Parties shall be notified of these procedures with sufficient time to be present and shall have the right to witness these procedures.
7.11.2 Site Verification Procedure

These procedures will be completed at the commissioning of the Settlement Location metering site or if the wiring or instrument transformers are modified. The site verification procedure that will be completed by the equipment owner shall include but is not limited to the following items:

1. Verification that the documentation and drawings accurately represent the equipment and circuits installed at the specific location.

2. Inspection of the primary and secondary connections of all instrument transformers so as to verify that the polarity marks on all instrument transformers are following the same convention (i.e. all polarity marks connected using the same convention, e.g., facing the same source).

3. The instrument transformers nameplate data shall match the drawings.

4. A burden test shall be performed on the metering circuit to determine that the circuit burdens do not exceed the burden rating of the instrument transformers.

5. The magnitude and phase angles for each of the phase voltages and currents at the meter test switch shall be measured to ensure the proper metering connection.

6. The meter shall meet the accuracy tests as stated in Sections 7.4.2 and 7.4.3 of this Appendix for watthour functions for both Quadrant 1 and 2. For auxiliary metered Loads only the Quadrant 1 watthour function need be tested.

Upon request, the Transmission Owner(s), Transmission Customer(s) and the Transmission Provider shall be provided with a copy of all of the equipment owner’s documentation and drawings for the specific location.

7.11.3 Periodic Test Procedure

These procedures will be completed during the meter’s Periodic Test or if the meter is exchanged. The Periodic Test procedure that will be completed by the equipment owner shall include but is not limited to the following items:

1. A burden test shall be performed on the metering circuit to determine that the circuit burdens do not exceed the burden rating of the instrument transformers.

2. The magnitude and phase angles for each of the phase voltages and currents at the meter test switch shall be measured to insure the proper metering connection.
(3) The meter shall meet the accuracy tests as stated in Sections 7.4.2 and 7.4.3 of this Appendix for watthour functions for both Quadrant 1 and 2. For auxiliary metered Loads, only the Quadrant 1 watthour function need be tested.

Upon request, the Transmission Owner(s), Transmission Customer(s) and Transmission Provider shall be provided with a copy of all of the equipment owner’s documentation for the specific location.
7.12 Node Loss Compensation

7.12.1 General

A1 = Generation Injection Value

A2…An = Generation Injection Value with Node Loss Compensation.

Node Loss Compensation is a combination of any or all of the following to the Generation Node Point.

(1) Transformer No Load Loss;
(2) Transformer Full Load Losses;
(3) Distribution Losses;
(4) Transmission losses other than SPP Transmission System losses.
Node Loss Compensation is a combination of any or all of the following to the load Node Point.

(1) Transformer No Load Loss;
(2) Transformer Full Load Losses;
(3) Distribution Losses;
(4) Transmission losses other than SPP Transmission System losses.

7.12.2 Methods for Compensation

7.12.2.1 Flat Percentage Adjustment

This adjustment is made on the value delivered from the Meter to an external system and not in the meter. The percentage will be an agreed upon value between the Metering Parties and applied as shown below:

L1...Ln = Load Withdrawal Value
Y1..Yn = Load Withdrawal Node Value with Node Loss Compensation.
7.12.2.2 Engineered Adjustment with Assumptions

This type of adjustment is made on the meter quantities received by the external system using the formulas shown below:

\[
Gen\_Injection\_Node\_value = \text{meter}_\text{value} \times (1 - \text{adjustment}_\text{percentage})
\]

\[
Load\_Withdrawal\_Node\_value = \text{meter}_\text{value} \div (1 - \text{adjustment}_\text{percentage})
\]

\[
NLL\_const = NLWL_{MTR} \times 1\text{hour}
\]

The variables that are used in these formulas shall be calculated as described in Section 7.12.3 by either an engineer or a metering professional.

7.12.2.3 Engineered Adjustment

The loss compensated Generation Injection Node value or loss compensated Load Injection Node value shall be calculated internally in the meter. This will be done using the meter manufacturer’s recommended procedures. The compensation percentages as presented in Section 7.12.3.7 shall be used in the meter. These shall be calculated as described in Section 7.12.3 by either an engineer or metering professional.

7.12.3 Node Loss Compensation Variables and Calculations

7.12.3.1 Transformer Test Data

<table>
<thead>
<tr>
<th>Transformer Test Information</th>
<th>Units</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rating of the Transformer or the 3 Transformer Bank** (TVA)</td>
<td>MVA</td>
</tr>
<tr>
<td>Rated Primary Voltage (line to line) (RPV)</td>
<td>kV</td>
</tr>
<tr>
<td>Rated Secondary Voltage (line to line) (RSV)</td>
<td>V</td>
</tr>
<tr>
<td>No Load Watts Loss at (X\text{C}) (NLWL_{T})</td>
<td>kW</td>
</tr>
<tr>
<td>Full Load Watts Loss at (X\text{C}) (FLWL_{T})</td>
<td>kW</td>
</tr>
<tr>
<td>Impedance at (X\text{C}) (IZ%)</td>
<td>Decimal</td>
</tr>
<tr>
<td>Exciting Current at Rated Voltage and (X\text{C}) (%)</td>
<td>Decimal</td>
</tr>
</tbody>
</table>

*The temperature that these values are reported must be at the same temperature base. \(X\) is usually either 75°C or 85°C.
**This is the same rating at which the losses are measured.

7.12.3.2 Calculating data not supplied with Transformer Test Data

Calculate the full Load amps (FLA) at rated secondary voltage.

\[
FLA = \frac{TVA \times 1000}{RSV \times \sqrt{3}}
\]

Calculate the Full Load VAr Loss (FLVL) at rated secondary voltage.

\[
FLVL = \sin \left[ \arccos \left( \frac{FLWL}{TVA \times 1000 \times IZ\%} \right) \right] \times [TVA \times 1000 \times IZ\%]
\]

Calculate the No Load VAr Loss (FLVL) at rated secondary voltage.

\[
NLVL = \sin \left[ \arccos \left( \frac{NLWL}{TVA \times 1000 \times %I} \right) \right] \times [TVA \times 1000 \times %I]
\]

7.12.3.3 Transmission line losses

Transmission line losses are the result of series resistance, inductance, and shunt capacitance. The following items are required to calculate this value.

<table>
<thead>
<tr>
<th>Transmission Line Loss Components</th>
<th>Units</th>
</tr>
</thead>
<tbody>
<tr>
<td>Series resistance ((r_{TL}))</td>
<td>Ohms / mile</td>
</tr>
<tr>
<td>The effective series reactance ((x_{TL}))</td>
<td>Ohms / mile</td>
</tr>
<tr>
<td>The length of the line ((L_{TL}))</td>
<td>mile</td>
</tr>
</tbody>
</table>

Calculation of the transmission load line watts loss. #

---

# The Full Load Amperage (FLA) shall be used unless the load is served using the arrangement illustrated by Y2 of Section 7.12.1. If this is the case, the maximum amperage used is the value obtained by multiplying the primary current rating of the Current Transformer by the rating factor at 25ºC of this Current Transformer.
Calculation of the transmission load line VAr loss.

\[
FLWL_{TL} = \frac{FLA^2 \times r_{TL} \times L_{TL} \times \left( \frac{RSV}{RPV \times 1000} \right)}{1000}
\]

Calculation of the transmission no load line watts loss.

\[
NLWL_{TL} = \left[ \frac{NLWL_T}{RPV \times \sqrt{3}} \right]^2 \times r_{TL} \times L_{TL} \frac{1000}{1000}
\]

Calculation of the transmission no load line VAr loss.

\[
NLVL_{TL} = \left[ \frac{NLWL_T}{RPV \times \sqrt{3}} \right]^2 \times x_{TL} \times L_{TL} \frac{1000}{1000}
\]

7.12.3.4 Secondary line losses

Secondary line losses are the result of series resistance, inductance, and shunt capacitance. The following items are required to calculate this value.

<table>
<thead>
<tr>
<th>Secondary Line Loss Components</th>
<th>Units</th>
</tr>
</thead>
<tbody>
<tr>
<td>Series resistance ((r_{SL}))</td>
<td>Ohms / mile</td>
</tr>
<tr>
<td>The effective series reactance ((x_{SL}))</td>
<td>Ohms / mile</td>
</tr>
<tr>
<td>The length of the line ((L_{SL}))</td>
<td>mile</td>
</tr>
</tbody>
</table>

@ The No Load Watts Transformer Losses \((NLWL_T)\) shall be used unless the load is served using the arrangement illustrated by Y2 of Section 7.12.1. If this is the case, the No Load Watts Transformer Losses shall be multiplied by the ratio of the total yearly energy for the metering point and the total yearly energy for the transformer for the previous year.
Calculation of the secondary line watts loss.

\[ FLWL_{SL} = \frac{FLA^2 \times r_{SL} \times L_{SL}}{1000} \]

Calculation of the secondary line VAr loss.

\[ FLVL_{SL} = \frac{FLA^2 \times x_{SL} \times L_{SL}}{1000} \]

The Full Load Amperage (FLA) shall be used unless the load is served using the arrangement illustrated by Y2 of Section 7.12.1. If this is the case, the maximum amperage used is the value obtained by multiplying the primary current rating of the Current Transformer by the rating factor at 25°C of this Current Transformer.
7.12.3.5 Totalization of losses

<table>
<thead>
<tr>
<th>Summary of Losses</th>
<th>No Load Loss (kW)</th>
<th>Full Load Loss (kW)</th>
<th>No Load Loss (kVArs)</th>
<th>Full Load Loss (kVArs)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Transformer</td>
<td>NLWL_T\textcircled{\textregistered}</td>
<td>FLWL_T\textcircled{\Phi}</td>
<td>NLVL_T\textcircled{\textregistered}</td>
<td>FLVL_T\textcircled{\textLambda}</td>
</tr>
<tr>
<td>Secondary</td>
<td></td>
<td>FLWL_SL</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Transmission</td>
<td>NLWL_TL</td>
<td>FLWL_TL</td>
<td>NLVL_TL</td>
<td>FLVL_TL</td>
</tr>
<tr>
<td>Total Losses</td>
<td>NLWL_TOT</td>
<td>FLWL_TOT</td>
<td>NLVL_TOT</td>
<td>FLVL_TOT</td>
</tr>
</tbody>
</table>

\textcircled{\textregistered} The No Load Watts Transformer Losses (NLWL\_T) shall be used unless the load is served using the arrangement illustrated by Y2 of Section 7.12.1. If this is the case, the No Load Watts Transformer Losses shall be multiplied by the ratio of the total yearly energy for the metering point and the total yearly energy for the transformer for the previous year.

\textcircled{\Phi} The Full Load Watts Transformer Loss Value (FLWL\_T) shall be used unless the load is served using the arrangement illustrated by Y2 of Section 7.12.1. If this is the case, the maximum amperage (FLA) used is the value obtained by multiplying the primary current rating of the Current Transformer by the rating factor at 25ºC of this Current Transformer and then applying the following formula.

\[
3 \times FLA^2 \times \frac{\left(\frac{FLWL_T}{TVA \times 1000}\right) \times \left(\frac{RSV}{1000}\right)^2 \times 1000}{TVA \times 1000} = FLWL_T
\]

\textcircled{\textLambda} The Full Load VAr Transformer Loss Value (FLVL\_T) shall be used unless the load is served using the arrangement illustrated by Y2 of Section 7.12.1. If this is the case, the maximum amperage (FLA) used is the value obtained by multiplying the primary current rating of the Current Transformer by the rating factor at 25ºC of this Current Transformer and then applying the following formula.

\[
3 \times FLA^2 \times \frac{\left(\frac{FLWL_T}{TVA \times 1000}\right)^2 \times \left(\frac{RSV}{1000}\right)^2 \times 1000}{TVA \times 1000} = FLVL_T
\]
7.12.3.6 Application to Meter

### Site Information

<table>
<thead>
<tr>
<th></th>
<th>Primary (CTP) / Secondary (CTS)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Current Transformer Ratio</td>
<td></td>
</tr>
<tr>
<td>Voltage Transformer Ratio</td>
<td></td>
</tr>
<tr>
<td>Meter Voltage</td>
<td>$V_M$</td>
</tr>
<tr>
<td>Meter Test Amps</td>
<td>$TA$</td>
</tr>
<tr>
<td>Transformer Primary Tap (kV) to which the transformer is set</td>
<td>$TPV$</td>
</tr>
</tbody>
</table>

#### Calculate the meter kVA

For a 3 element meter

$$VA_M = \frac{3 \times V_M \times TA \times CTP \times VTP}{1000 \times CTS \times VTS}$$

For a 2 element meter

$$VA_M = \frac{\sqrt{3} \times V_M \times TA \times CTP \times VTP}{1000 \times CTS \times VTS}$$

#### Calculating the No Load Watt Loss.

$$NLWL_{MTR} = \left[ V_M \times \left( \frac{VTP}{VTS} \right) \times \frac{TPV \times 1000}{RSV} \times \frac{RPV \times 1000}{\sqrt{3}} \right]^4 \times NLWL_{TOT}$$
Calculating the Full Load Watt Loss.

\[ FLWL_{MTR} = \left( \frac{TA \times \left( \frac{CTP}{CTS} \right)}{FLA} \right)^2 \times FLWL_{TOT} \]

Calculating the No Load VAr Loss

\[ NLVL_{MTR} = \left( \frac{V_M \times \left( \frac{VTP}{VTS} \right) \times TPV \times 1000}{RPV \times 1000 \times \sqrt{3}} \right)^4 \times NLVL_{TOT} \]

Calculating the Full Load VAr Loss.

\[ FLVL_{MTR} = \left( \frac{TA \times \left( \frac{CTP}{CTS} \right)}{FLA} \right)^2 \times FLVL_{TOT} \]

7.12.3.7 Compensation Percentages

No Load Watts Loss Percentage

\[ NLWL\% = \frac{NLWL_{MTR}}{VA_{MTR}} \times 100 \]

Full Load Watts Loss Percentage

\[ FLWL\% = \frac{FLWL_{MTR}}{VA_{MTR}} \times 100 \]

No Load VAr Loss Percentage

\[ NLVL\% = \frac{NLVL_{MTR}}{VA_{MTR}} \times 100 \]

* The Full Load Amperage (FLA) shall be used unless the load is served using the arrangement illustrated by Y2 of Section 7.12.1. If this is the case, the maximum amperage used is the value obtained by multiplying the primary current rating of the Current Transformer by the rating factor at 25°C of this Current Transformer.
Full Load VAr Loss Percentage

\[ FLVL\% = \frac{FLVL_{MTR}}{VA_{MTR}} \times 100 \]

7.13 Record Retention

The Market Participant must maintain sufficient documentation of the meter process and values in order to verify the integrity and accuracy of the reported data.

This documentation shall include but is not limited to the following:

1. Loss percentages as agreed to by Metering Parties for each meter;
2. Compensation methodology;
3. SPP Transmission Tariff Facilities (Node) values;
4. Meter testing documents;
5. Meter and supporting equipment change history [to the extent that change history includes sufficient documentation of the modification, the obsolete substation/plant drawings are not required].

The records must be retained for a period of six (6) years.
Appendix D - Settlement Metering Data Management Protocols
1. **Scope**

This document will serve as a definitive resource concerning the expected responsibilities, duties, standards, processes, and liabilities with regard to the Market Participants for the SPP Integrated Marketplace settlement meter data.

2. **Purpose**

This document will provide the standards by which the Meter Agent, on behalf of the Market Participants, consistent with other sections of the Market Protocols and the Open Access Transmission Tariff of SPP will collect, calculate, document, and report settlement meter data for the SPP Integrated Marketplace.

3. **Definitions**

The terms used in this document are defined in Section 1 of the Market Protocols.

4. **Market Participants**

This document will define what is expected of the Market Participant with regards to their Meter Settlement Locations.

4.1 **Responsibilities**

The Market Participant is responsible for the quality, accuracy and timeliness of meter data submitted to SPP for the purposes of, and use in, the execution of the SPP Integrated Marketplace settlements. At all times, SPP maintains a financial, legal and operational relationship with the Market Participant, and not the Meter Agent.

4.2 **Meter Agent(s) Designation**

The Market Participant must designate a Meter Agent for each of its Meter Data Submittal Location. The Market Participant will be responsible for any and all data supplied by its designated Meter Agent.

The Market Participant can have more than one Meter Agent, but only one designated Meter Agent per Meter Data Submittal Location.
SPP will at all times use the data provided by the Meter Agent until such time as the Market Participant revokes the designation of an entity as its Meter Agent and replaces that entity with a substitute entity.

Any dispute between the Meter Agent and the Market Participant concerning the accuracy of values reported to SPP shall be resolved between the two parties absent the involvement of SPP.

5. Meter Agent

The Meter Agent is expected to fulfill the Market Participant’s responsibility for submitting Meter Data Submittal Location data for which it is responsible and registered.

The Meter Agent will adhere to the standards for calculating and reporting settlement data as defined in this Appendix.

The Meter Agent will act on behalf of the Market Participant to provide settlement meter data to SPP, the Market Participant, and the entity responsible for Residual Load.

6. Data Format

The settlement data must be submitted according to the following conventions.

6.1 Unit of Measure

The following rules apply to the submittal of meter data:

(1) Settlement meter data must be submitted, at a minimum, in hourly intervals;

(2) Settlement meter data may be submitted in 5-minute intervals for Resources and/or load if this option is specified during market registration;

(3) Megawatt-hour (MWh) is the standard unit of service measurement. Service may be measured in kilowatt-hours (kWh) if required by the specific service, local or state regulations, host utilities, service providers, or as are mutually agreed upon by the parties involved. Service information provided in kWh must be converted to MWh before submission to SPP;

(4) Settlement Location data can be submitted in fractional MWhs; and

(5) Hourly metered interchange between Settlement Areas must be submitted in whole MWhs.
6.2 Sign Convention of Data

Meter Data Submittal Locations:

- Net Injection into the SPP Transmission System will be negative [-].
- Net Withdraws out of the SPP Transmission System will be positive [+].

Meter Data Submittal Location between Settlement Areas:

- Hourly metered interchange will be reported based on the Settlement Area perspective.
- Into the Settlement Area will be reported as negative [-].
- Out of the Settlement Area will be reported as positive [+].

6.3 Meter Technical Standards

Any data supplied to SPP from existing metering or other equipment must comply with the meter data technical standards specified under Appendix C. The metering used for data submission must meet all SPP interconnect guidelines.

6.4 Data Submission Standards

Settlement Data must be communicated to SPP in electronic format in order to ensure timely settlement. Please refer to the Meter Data Submission Standards (Appendix B) for electronic format of submissions.

7. Settlement Meter Data Types

There are three basic types of interval settlement data required for the SPP Integrated Marketplace.

Meter Data Submittal Locations:

1. Resources (generation)
2. Loads
3. Settlement Area: (Hourly metered interchange between Settlement Areas)
7.1 Resource Metering

7.1.1 Net

Resource data will be provided as net at the Meter Data Submittal Location and must be submitted in either 5-minute or hourly intervals as indicated during market registration.

According to the sign convention, a negative [-] value will indicate a net injection, where a positive [+] value will indicate a net withdrawal (e.g., auxiliary Load not covered by generation gross output) for that MDSL. The “net” shall be determined by the “gross” output (reflected as a negative number) plus the unit auxiliary power and applicable losses.

When metering limitations do not allow for direct measurement of the net, a “gross” to “net” calculation method must be mutually agreed upon between SPP, Market Participant, and Metering Parties.

7.1.2 Joint Owned Unit (JOU) Generation

JOU Meter Data Submittal Location data reporting must be consistent with the JOU registration outlined in Section 6.1.6.

7.1.3 Generation Loss Compensation

Metering for a Resource must be loss compensated, when the meter is not at the SPP Node. Please reference to Section 9 of this Appendix for the complete loss compensation requirements.

7.2 Load Metering

7.2.1 General

Load data must be submitted in either 5-minute or hourly intervals according to the sign convention. All Loads should be reported as a positive [+] value to indicate a net withdrawal at the SPP Node.

7.2.2 Load Loss Compensation

Metering for a Load must be compensated for any distribution and transmission losses up to the point of interconnection with the SPP Transmission System (Node). Submitted meter data for Load, other than Residual Load, does not include SPP Transmission System losses. Please reference Section 7.12 of Appendix C for the complete loss compensation requirements.
7.2.3 Residual Load

Residual Load in a Settlement Area is the sum of the hourly metered interchange plus the sum of all Resource Meter Data Submittal Locations less all other load Meter Data Submittal Location as reported separately under Section 7.2.2 for that Settlement Area. Residual Load is submitted in the same manner as other Meter Data Submittal Locations for loads. SPP adjusts the submitted Residual Load for transmission system losses as described under Section 4.5.9.1.

7.3 Hourly Metered Interchange

Each Settlement Area is required to report hourly metered interchange for each Settlement Area with which it is interconnected. If a Settlement Area interconnection point is not at the meter location, loss compensation is needed unless all Metering Parties have agreed to another method. The hourly metered interchange is to only include SPP data. If a Settlement Area has load in a non-SPP Transmission Owner System, that interchange is to be excluded from the values reported. This meter data must be submitted in hourly intervals according to the sign convention. Hourly metered interchange is reported based on the Settlement Area’s prospective. See Section 6: Data Format for sign convention. The hourly metered interchange is needed for the calibration function of settlements (See Section 4.5.9.1 for a description of the calibration calculation). The Settlement Area Meter Agent will report hourly metered interchange.
7.3.1 Substitution for Missing Data

In the event that a Meter Agent fails to submit Settlement Area hourly metered interchange data, SPP will initially use the value calculated by the State Estimator until the actual value is submitted prior to final settlement.

8. Settlement Location Anatomy

8.1 General

These sections describe standards for providing meter data under the following conditions:

1. The actual meter location can be on a distribution voltage system or transmission voltage system.
2. The physical meter is not at the defined Meter Location.
3. Aggregation of multiple Meter Settlement Locations for reporting a Meter Data Submittal Locations.
4. Each physical meter value will need to have applicable losses applied to the meter data to determine Meter Settlement Location. The applicable losses only include losses up to a single SPP Meter Settlement Location.
5. A Node will be at the point of interchange with the facilities under the SPP Transmission Tariff.
6. A Meter Data Submittal Location includes one or more Meter Settlement Locations. A Settlement Location includes one or more Meter Data Settlement Locations which may be located in multiple Settlement Areas. A Settlement Area includes one or more Meter Data Submittal Location(s). Meter Data Submittal Location(s) meter data is a component of the settlement billing process.
7. Meter Data Submittal Location meter data reported is effectively at a Resource bus (including transmission losses).

8.2 Making of a Settlement Location

A Settlement Location is made up of one or more Meter Data Submittal Locations. A Meter Data Submittal Location is made up of one or more Meter Settlement Locations. A Meter Settlement Location is made of only one Node. A Node is made up of only one meter. A Meter
Settlement Location is simply a single meter compensated for losses, if applicable. Loss compensation methods will be addressed later in this document.

### 8.2.1 Resource and Load Settlement Locations

The diagrams in Section 7.12.1 of Appendix C provide one-line views of the build up to a Resource or load Meter Settlement Location.

The following diagram illustrates the components of the Settlement Location for either a Resource or load. Each component is manipulated to achieve the next value. It is very important that each step of this methodology is completed in order in your calculations.

![Diagram of Resource and Load Settlement Locations](image)

- **Meter A**
- **Meter B**
- **Meter n**
- **Actual Load or Resource meter interval data**
- **Increase (load) or decrease (generation) for losses as needed to represent the point of interface with the SPP Transmission System and should correspond to a pricing point (LMP)**
- **SPP Transmission System Point of Interchange SPP Market pricing point (LMP)**
- **SPP node**
- **Meter Settlement Location (MSL) A**
- **SPP node**
- **SPP node**
- **Meter Settlement Location (MSL) B**
- **Meter Settlement Location (MSL) n**
- **Meter Data Submittal Location (MDSL)**
- **Settlement Location (SL)**
- **The sum of one or many MSLs that will be reported for a single MDSL. If Truncate and Carry is required apply after aggregation and before submittal at the MDSL**
- **MSL represents the settlement value for a single meter in the SPP Market**
- **Settlement Location is the point of entry for Market Settlement charge type calculations, based on whole or fractional MWhs. Aggregation of multiple MDSLS to a single SL occurs within SPP systems.**

*Note that generators may only be aggregated within a single substation voltage level.*
8.2.2 Overview of Settlement Area Load Settlement Locations

Multiple Meter Agents may use a single Meter Settlement Location as part of their calculations of a Settlement Location. This requires coordination and method agreement between all Metering Parties and Market Participants involved in that joint Meter Settlement Location. The following diagram illustrates all Load Settlement Locations within a Settlement Area. Load D is the Residual Load.

Table 1 – Load Inclusion and Coordination
### 9. Loss Compensation

#### 9.1 General

The Meter Agent will submit Meter Data Submittal Location data for Resources and Loads with the applicable compensations for the applicable Meter Settlement Location. Load Meter Settlement Locations may have line losses, transformer step-downs, shared metering, etc. Resource Meter Settlement Locations may have transformer losses, auxiliary Loads, shared metering between units, commercial Load off generation bus, etc. These sections cannot cover all possible situations; therefore, fair business practices with the Metering Parties will hold as the common sense rule. The Market Participants along with their Meter Agent will be responsible for appropriate meter data adjustments and submissions. Loss Compensation methods are described under Section 7.12 of Appendix C.

#### 9.2 Loss Compensation Examples

There are several elements that can require loss compensation prior to the Meter Settlement Location. A couple of examples of this are: 1) Meter is located on the distribution system and...
needs to be adjusted to the Node and 2) Meter is located on the transmission system not at the Node and needs to be adjusted to the Node.

Formula for calculation of Meter Settlement Location will be taking known actual meter value divided by (1- Loss %). This formula will be used for all calculations of the Meter Settlement Location. Actual meter value divided by (1-Loss %).

### 9.2.1 Loss Compensation to Node when Meter is on Distribution System

**Loss Compensation to Node – Example 1 Assumptions:**

1. Meter is on distribution system @ 12 kV
2. Transformer between distribution and transmission system requires compensation for a transmission voltage at SPP Node.
3. Actual meter reads 20000 kWh.
4. Transformer loss is 5%.
5. Transmission owner has modeled their network with transmission voltage at 69kV.

**Calculating from Meter to Node:**

1. Actual meter reads 20000 kWh divided by (1- 5%). $20000/(1–0.05)$ or $20000/0.9500$
2. SPP Node Value = 21052.631 kWh

**Example 1 – Loss Compensation to SPP Node when Meter is on Distribution System**
(3) All resolution below kWh of 21052 is dropped

(4) This rule can be applied when distribution line losses are required along with transformer losses.

(5) The Market Participant can apply the compensation process separately for each loss percentage or sum percentages together and then apply the process for the sum of losses to calculate the Node value.

Calculating Aggregation of Meter Settlement Locations to report Meter Data Submittal Location

(1) A Meter Agent can combine two or more Meter Settlement Locations for Loads within a Settlement Area to report the registered Meter Data Submittal Location.

(2) A Meter Agent may combine two or more Meter Settlement Locations to report a Resource Meter Data Submittal Location as long as all the combined Meter Settlement Locations are electrically equivalent.
9.2.2 Loss Compensation to Node when Meter and Node at Different Location

**Loss Compensation to Node – Example 2 Assumptions:**

1. Meter is on transmission system @ 69kV
2. The Node is not at the same location as the meter. (i.e. losses on line between meter and Node will be applied to provide the correct value at the Node)
3. Actual meter reads 20000 kWh.
4. Line losses between meter and SPP Node is 2%
5. This 69kV line starting at the Node is under the SPP Transmission Tariff.

**Calculating from the Meter to the SPP Node value:**

1. Actual meter reads 20000 kWh divided by (1 - 2%)
2. \( \frac{20000}{1 - 0.02} \) or \( \frac{20000}{0.9800} \)
3. SPP Node value = 20408.163 kWh
4. All resolution below kWh of 20408 is dropped

**Calculating Aggregation of Meter Settlement Locations to report Meter Data Submittal Location**

1. A Meter Agent can combine two or more Meter Settlement Locations for Loads within a Settlement Area to report the registered Meter Data Submittal Location.
(2) A Meter Agent may combine two or more Meter Settlement Locations to report a Resource Meter Data Submittal Location as long as all the combined Meter Settlement Locations are electrically equivalent.

9.3 Meter Data Exchange and Submission

Settlement Location meter data shall be entered, modified and retrieved solely via the XML specification for submission of interval Settlement Data.

The Settlement Location meter data will be available via the Portal and include the files uploaded from the Meter Agent. There will also be the capability of reviewing any rejected values with the specific errors associated with the attempt to process the rejected values. Values successfully processed shall also be available via the Portal for that Market Participant.

Other parties may have access to Settlement Location data, as allowed by SPP.

9.3.1 Actual Meter Data (Idata)

If a meter is installed to include interval data capabilities, then the Meter Agent will always report this meter as Interval Data. There are three types of Interval Meter Data to be submitted as Channel 1 as outlined in the XML Data Submission Standards.

(1) Actual (A) - Actual meter interval data:
   (a) This data is reported as (A)ctual;
   (b) There are three types of actual meter interval data: Telemetered pulses/register, Interval Data Recorder (IDR) data, and analog MW integrations (MWI);
   (c) Loss Compensation applies for all types of Actual meter interval data.

(2) Estimated (E) - Estimated meter interval data:
   (a) If actual meter interval data becomes unavailable, it is appropriate to estimate that data. This data is reported as (E)stimated;
   (b) See Section 11.2 for data estimation options;
   (c) Estimated data can be short-term or long-term;
      (i) Short-term would be the use of a temporary estimate, until actual interval data can be obtained, in order to meet a data reporting timeline. Once the
actual data is obtained, it should be resubmitted as (A)ctual data, not (E)stimated.

(ii) Long-term data would be a permanent estimate. This would include situations where the data cannot be obtained or retrieved and an estimate is the only option. In these cases, the data would remain as (E)stimated Data throughout all Settlement Statements.

(d) Loss Compensation applies to all types of estimated meter interval data.

(3) Missing (9) - Missing meter interval data:

(a) Do not use this type. If data is missing, estimate the data and submit as “E”.

9.3.2 Alternate Settlement Meter Data

Under circumstances where one or more Meter Agents fails to submit Settlement Location meter data in accordance with the timelines set forth for Settlement Statements, SPP will substitute missing Settlement Location meter data with the State Estimator data for that Settlement Location until Settlement Location meter data is provided. SPP will notify all MPs and Meter Agents when a Meter Agent fails to submit Settlement Location meter data. Refer to Market Protocols Section 4.5.9.1 for treatment of substitution data for calibration purposes.

10. Data Source and Estimating

Primary source meter data must be used to calculate Settlement Locations, unless it becomes unavailable. When the primary data source is not available, use the following steps:

(1) Use another primary data meter source to replace the typically used primary data source,

(2) Use a backup data source,

(3) Use a meter data estimating option.

10.1 Actual Meter Data (Idata – Actual)

Actual data is sourced from the meter or electrical device(s) in the field. Actual data is reported to SPP as Idata “A”, see Section 9.4.1(1).
10.1.1 Primary Data Sources

There are two primary sources for meter data: 1) Telemetered pulses/register and 2) Interval Data Recorder (IDR) Data.

Telemetered pulses/register can be used as a primary data source, as long as a verification of that data is performed against the Meter (register or IDR). If the verification indicates any material differences, resubmission of the Settlement Location using the corrected data must be completed.

If the Market Participant’s primary data source becomes unavailable, it is acceptable to use the other type primary source to replace the data. (Example: Market Participant typically uses telemetered pulses as primary data source, and then IDR data could be used when telemetered pulses are unavailable.)

10.1.2 Backup Data Sources

If backup data sources are available, they must be used when primary data sources are unavailable. These are reported as Idata “A”. Examples of Backup Data Sources are:

MWI – Analog MW integration data: MWI is derived from a calculation of retrieved instantaneous (i.e. analog) data signals over an hour then integrated to an hourly value.

Backup metering: If backup metering exists, they can also be used to replace the primary sources when they are not available.

10.2 Estimated Meter Data (Idata – Estimated)

10.2.1 Estimation Methods

The Market Participant must use one of the following methods to estimate missing Actual Idata when the actual meter data source values are not available. Estimated meter data is reported as Idata “E”. “E” for Estimated, reference Section 9.4.1(2).

The following methods are in priority preference order for estimating missing actual meter data. The estimated meter value determined by this process below will be utilized by all parties to the meter for Settlement Location calculations.

If the first option is not available, move to the next option until a data method is available for the use in estimating meter data:

(1) Existing Contracts or Operating Guidelines: If there is an existing contract or operating guidelines established for the interconnection location, those should be used.
(2)  Alternative Metered Load(s) Integrated: If there are other load(s) and/or generator(s) that can be used to determine the interval value for the missing meter data, they can be integrated and used as estimates for the missing interval meter data.

(3)  State Estimator Integrated Data: If this data is available, it should be used for estimating the meter data.

(4)  Other: Data Shaping and Similar Hour

(a)  Data Shaping: This method uses data from previous and/or subsequent hours around the missing data to estimate the use during the missing hours.

(b)  Similar Hour: This method uses data from a similar day to estimate the missing data. A Similar day can include one or more of these parameters: comparing temperatures, day of week (weekend, weekday, holiday considerations), and/or usage profile (knowledge of customer’s load and generator at time of missing data, such as behind the load meter generator on line, load switched to another circuit, etc.).

10.2.2  Replacing Estimated Meter Data

Resubmission of a Settlement Location value that used estimated meter data must be done once more accurate or actual interval data becomes available. If the actual interval data does not become available, the Settlement Location value will remain submitted as Estimated “E”.

11.  Verification Meter SL Values

Verification of meter data used as a component of Settlement Location value calculations shall be performed. Verification of meter data would be performed by the party responsible for the operations of that meter. The Market Participant needs to confirm that the verification process is conducted for all meters that they use in calculation of Settlement Location values. Verification can be done in various ways. Methods of verification are based on the type of data and communication technology used.

11.1  Data Types and Verification Methods

The listing that follows is not complete, but represents the majority of types with verification method.
11.1.1 **Telemetered Pulses via Remote Terminal Unit (RTU)**

If the data used to calculate the Settlement Location value is obtained from Telemetered Pulse values which are transferred to a data collection system, then verification shall be performed against the meter Interval Data Recorder (IDR) values or meter’s register.

If there is an IDR installed, then the telemetered data needs to be verified against the IDR’s data for the time period.

If there is no IDR available, the meter register will be the verification source. The verification procedure would require a start reading and a stop reading of the register for the same period that the telemetered data was collected. The difference in meter reads would be compared to the total usage determined from the telemetered data. The meter read can be obtained remotely or at the meter location as the meter technology dictates.

11.1.2 **Register Transfer via Other Communication Options**

If the data used to calculate the Settlement Location values is using register values electronically transfer to an EMS, the meter register will be the verification source. The verification procedure would require a start reading and a stop reading of the register for the same period that the remote read was obtained. The difference in the meter reads would be compared to the total usage determined from the EMS meter reads. The meter read can be obtained remotely using a different communication path or at the meter location as the meter technology dictates.

11.1.3 **Interval Data Recorder Collection System (IDRCS)**

If the data used to calculate Settlement Location values is interval data from an IDRCS, then the meter register will be the verification source. The verification procedure would require a start reading and a stop reading of the register for the same period that the IDRCS read was obtained. The difference in the meter reads would be compared to the total usage determined from the IDRSC meter reads. The meter read can be obtained remotely or at the meter location as the meter technology dictates.

11.1.4 **Inter Control Center Protocol (ICCP) Data**

ICCP as specified in IEC Standard 870-6 is a protocol that enables the communication of interchange data over wide area networks (WAN) between a number of utilities and control center computer servers used to tabulate interchange data. This communication method can fail just like RTU data, Register Transfer, etc.
The source of the ICCP would be one of the types listed above and the source would be responsible for the verification.

If the data is for Balancing Authority Ties, then the hourly checkout of the tie values between the Balancing Authorities would be sufficient verification for the receiving party of the data via this communication method.

The Market Participant needs to confirm with the source of the meter data that one of the verification methods has been performed for any meter data they use from that source.

11.1.5 Alternate Data for Verification

Integrated Analog values that meet the accuracy and location requirements of Appendix D can also be used to confirm the quality of the data used. This is secondary verification option after the above listed.

11.2 Periodicity of Verification

11.2.1 Telemetered Pulses via Remote Terminal Unit (RTU)

Verification of telemetered meter data values shall be performed monthly.

11.2.2 Other Data Transfers

The register transfers and/or IDRCS type data is an interrogation of the meter’s register microprocessor. The data captured shall include register and interval data. Verification of this data should be performed monthly, due to the impacts to the Market Settlements.

11.3 Verification Uncovers Discrepancy

After the verification process is completed and a discrepancy is revealed, the verifier needs to determine the cause of the discrepancy, i.e. meter data, telemetered data, MV90 type data, etc.

11.3.1 Identify the Cause for the Discrepancy

Identification of the cause is critical in understanding what solution is needed to correct the data. All data sources can be incorrect due to data transfer issues and other equipment/software issues. Therefore, one source is not superior to another.
11.3.2 Impact to Settlement Location Values Submitted

Once you have identified the cause, a decision needs to be made if a change is needed to the Settlement Location values already provided to SPP.

11.3.2.1 Settlement Data Values Correct

If the meter data source used to calculate the Settlement Location value reported is correct then there is no need to resubmit corrected data to SPP.

11.3.2.2 Settlement Data Values Incorrect

If the cause impacts the meter data source used to calculate the Settlement Location values, then editing the data is required and resubmission of the meter data will be required based on the following criteria.

11.3.2.2.1 Requirement for Resubmission

If the Settlement Location value difference is greater than 100 MWhs over a verification period, then the Settlement Location values must be corrected. See Section 13: Settlement Location Value Corrections.

11.3.2.2.2 Good Utility Business Practices/Contractual Requirements

If the error value is not greater than 100 MWhs over a verification period, then the verifier needs to consider other impacts. Many meters locations have interconnection agreements that outline when a correction of data is required. Therefore, the verifier needs to consider the need to update the Settlement Location data on those agreements and also consider the use of Good Utility Practices in their decision making. If it is determined that correction to the submitted Settlement Location values is required, then the resubmission need to follow the procedure in Section 13: Settlement Location Value Corrections.

12. Real Time Data Reporting to SPP Balancing Authority

In addition to the data reporting requirements specified under SPP Criteria 7, all Resources, other than Demand Response Resources, are to submit the following data via ICCP to SPP.

(1) Unit power output (MW);
(2) Unit MVar output;
(3) Current on/off line status;
(4) Current AGC status (on/off).

13. **Record Retention**

In addition to the record retention requirements listed under Section 7.13 of Appendix C, the Market Participant must maintain the following additional documentation of the meter process and values in order to verify the integrity and accuracy of the reported data.

   (1) Raw Meter values;
   (2) Truncate and Carry Process and Results;
   (3) Meter Settlement Location values;
   (4) Settlement Location values.

The records must be retained for a period of six (6) years.
Appendix E - Network and Commercial Model Update Timing

Anticipated types of SPP System Changes with Typical Durations for Related Updates

*General Notes -

1. The "Update Duration" starts when the completed Registration Package and all required technical information is received by SPP and ends when the change is fully implemented in all affected Models, systems, and/or databases such that the change is effective in the Production (PROD) environment.
2. SPP will work to implement each Model Update as soon as possible and insure the updates are implemented in a period that is no later/longer than the applicable indicated update duration, unless otherwise noted.
3. SPP will inform MPs of the applicable scheduled periodic Model Update in which their requested model changes will be implemented and also the deadline for providing SPP with completed Registration Packages and required technical information for all requested changes in order for the changes to be included in the specific scheduled Model Update.

<table>
<thead>
<tr>
<th>System Update Type</th>
<th>* Update Duration</th>
<th>* Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>New Market Registration</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Transmission Customer</td>
<td>* 45 Days/ 2 months</td>
<td>OASIS Change only if TC not a Market Participant. Access to OASIS is part of Process for Becoming a TC.</td>
</tr>
<tr>
<td>Market Participant</td>
<td>6 Months</td>
<td>A minimum of 6 Months for this addition, which is presumed to include adding all associated assets. (Especially if addition involves changes to Market Boundary) Include in Applicable scheduled periodic Model Update.</td>
</tr>
<tr>
<td>Designated Agent</td>
<td>* 45 days / 4 Months</td>
<td>45 days if DA is current SPP TC. 4 months if a new DA that is not currently a SPP TC or MP.</td>
</tr>
<tr>
<td>Asset Owner Information</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Asset Owner Company</td>
<td>4 Months</td>
<td>4 Months for this addition. (This for an addition to a current MP). Include in Applicable scheduled periodic Model Update.</td>
</tr>
<tr>
<td><strong>Market Protocols for SPP Integrated Marketplace</strong></td>
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<tr>
<td>--------------------------------------------------</td>
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<table>
<thead>
<tr>
<th><strong>Meter Agent (MA)</strong></th>
<th>45 days / 4 Months</th>
<th>45 days if MA is current SPP TC. 4 months if a new MA that is not currently a SPP TC or MP.</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Asset Information</strong></td>
<td></td>
<td><strong>Settlement Location</strong></td>
</tr>
<tr>
<td><strong>Plant</strong></td>
<td>45 Days / 4 months</td>
<td><strong>Unit</strong></td>
</tr>
<tr>
<td><strong>Load</strong></td>
<td>45 Days / 4 months</td>
<td><strong>Load Pricing Zones</strong></td>
</tr>
<tr>
<td>Settlement Area</td>
<td>4 Months / 6 Months</td>
<td><strong>NERC Source (Via Trans Table)</strong></td>
</tr>
<tr>
<td><strong>NERC Sink (Via Trans Table)</strong></td>
<td>2 Weeks</td>
<td>(Same as note above.)</td>
</tr>
<tr>
<td><strong>External Generator</strong></td>
<td>4 Months / 6 Months</td>
<td><strong>Market Registration Changes</strong></td>
</tr>
</tbody>
</table>

| **Contact Information Changes** | 2 weeks | Information is updated in COS and forwarded to billing and credit. |

<table>
<thead>
<tr>
<th><strong>Market Footprint Changes</strong></th>
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</table>

<table>
<thead>
<tr>
<th><strong>Move Footprint SA to 1st Tier</strong></th>
<th>6 Months</th>
<th><strong>Implement in applicable scheduled seasonal/periodic update.</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Move 1st Tier BA to Footprint</strong></td>
<td>6 Months</td>
<td><strong>Implement in applicable scheduled seasonal/periodic update.</strong></td>
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<tr>
<th><strong>Name Changes</strong></th>
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<tr>
<td>Role Description</td>
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<tr>
<td>Transmission Customer (Long Name)</td>
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<tr>
<td>Transmission Customer (NERC ID)</td>
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<tr>
<td>Market Participant or Asset Owner</td>
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<tr>
<td>Designated Agent</td>
</tr>
<tr>
<td><strong>Asset Owner Changes</strong></td>
</tr>
<tr>
<td>Asset Owner Company</td>
</tr>
<tr>
<td><strong>Meter Agent (MA)</strong></td>
</tr>
<tr>
<td><strong>Asset Information Changes</strong></td>
</tr>
<tr>
<td>Settlement Location</td>
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<td>Plant</td>
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<tr>
<td>Unit</td>
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<td>Load</td>
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<tr>
<td>Load Pricing Zones</td>
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<tr>
<td>Settlement Area</td>
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<tr>
<td><strong>External Generator Changes</strong></td>
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<tr>
<td><strong>Commercial Model Relationship Changes</strong></td>
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<tr>
<td>Event</td>
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<td>-----------------------------------</td>
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<td>Market Participant / Asset Owner</td>
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<tr>
<td>Meter Data Submittal Location / Settlement Area</td>
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<tr>
<td>Meter Data Submittal Location / Meter Agent</td>
</tr>
<tr>
<td>Settlement Area / Meter Agent</td>
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<tr>
<td>NERC Source/Sink / Settlement Location</td>
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<tr>
<td>De-aggregating a Plant to Individual Units</td>
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<td>Aggregating Individual Units to a Plant</td>
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<tr>
<td>Breaking out an Individual Unit from a Plant</td>
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<td>IDC Mapping Changes</td>
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<tr>
<td>Change Type</td>
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<td>NERC Source/Sink Mapping Changes</td>
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<td>Certification Changes</td>
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<td>Resource Reasonable Limit MW Value Changes</td>
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<td>Load Pricing Zone Changes</td>
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<td>Individual Loads to Load Aggregate Changes</td>
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<td><strong>Market Termination Request</strong></td>
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<td>Transmission Customer</td>
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<td>Unit</td>
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<td>Load Pricing Zone</td>
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<td>Settlement Area</td>
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<tr>
<td>1st Tier CA/External Aggregate</td>
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<tr>
<td>NERC Source (via Translation Table)</td>
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<td>NERC Sink (via Translation Table)</td>
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### Add EMS NETMOM/GENMOM/SCADAMOM Equipment

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<tbody>
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<td>Asset Owner Company</td>
<td><strong>4 months / 6 Months</strong></td>
</tr>
<tr>
<td>4 Months for limited scope changes. 6 Months for Moderate to large scope changes. This change will also impact COS, MOS, and other models. (Include in applicable periodic Update)</td>
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<tr>
<td>Units</td>
<td><strong>45 Days / 4 months</strong></td>
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<td>(Same as note above.)</td>
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</tr>
<tr>
<td>Loads</td>
<td><strong>45 Days / 4 months</strong></td>
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<tr>
<td>(Same as note above.)</td>
<td></td>
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<tr>
<td>Other Equipment</td>
<td><strong>45 Days / 4 months</strong></td>
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<tr>
<td>ND, LD, LN, CAP, XFMR, ZBR, DCLN, CB, DSC, LS</td>
<td>(Same as note above.)</td>
</tr>
</tbody>
</table>

### Outside of Market Footprint

| **45 Days / 4 months** | (Same as note above.) |

### Modify EMS NETMOM/GENMOM/SCADAMOM Equipment

### Changes - In Market Footprint
### Market Protocols for SPP Integrated Marketplace

**Asset Owner Company**

<table>
<thead>
<tr>
<th>Type</th>
<th>Time Frame</th>
<th>Notes</th>
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<tbody>
<tr>
<td>45 Days / 4 months</td>
<td>45 Days for limited scope changes. 4 Months for Moderate to large scope changes. (Include in periodic Update)</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Units</th>
<th>45 Days / 4 months</th>
<th>(Same as note above.)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Loads</td>
<td>45 Days / 4 months</td>
<td>(Same as note above.)</td>
</tr>
</tbody>
</table>

**Other Equipment**

<table>
<thead>
<tr>
<th>Equipment</th>
<th>Time Frame</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>ND, LD, LN, CAP, XFMR, ZBR, DCLN, CB, DSC, LS</td>
<td>45 Days / 4 months</td>
<td>(Same as note above.)</td>
</tr>
</tbody>
</table>

**All Other Changes**

<table>
<thead>
<tr>
<th>Time Frame</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>45 Days / 4 months</td>
<td>(Same as note above.)</td>
</tr>
</tbody>
</table>

### Remove EMS NETMOM/GENMOM/SCADAMOM Equipment

#### In Market Footprint

<table>
<thead>
<tr>
<th>Type</th>
<th>Time Frame</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Asset Owner Company</td>
<td>45 Days / 4 months</td>
<td>45 Days for limited scope changes. 4 Months for Moderate to large scope changes. (Include in periodic Update)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Units</th>
<th>45 Days / 4 months</th>
<th>(Same as note above.)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Loads</td>
<td>45 Days / 4 months</td>
<td>(Same as note above.)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Other Equipment</th>
<th>Time Frame</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>ND, LD, LN, CAP, XFMR, ZBR, DCLN, CB, DSC, LS</td>
<td>45 Days / 4 months</td>
<td>(Same as note above.)</td>
</tr>
</tbody>
</table>

#### In 1st Tier Entity

<table>
<thead>
<tr>
<th>Type</th>
<th>Time Frame</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Control Area/EMS Company</td>
<td>45 Days / 4 months</td>
<td>45 Days for limited scope changes. 4 Months for Moderate to large scope changes. (Include in periodic Update)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Loads</th>
<th>45 Days / 4 months</th>
<th>(Same as note above.)</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th>Other Equipment</th>
<th>Time Frame</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>ND, LD, LN, CAP, XFMR, ZBR, DCLN, CB, DSC, LS</td>
<td>45 Days / 4 months</td>
<td>(Same as note above.)</td>
</tr>
</tbody>
</table>

#### Beyond 1st Tier

<table>
<thead>
<tr>
<th>Time Frame</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>45 Days / 4 months</td>
<td>(Same as note above.)</td>
</tr>
</tbody>
</table>

### Add EMS Contingency
<table>
<thead>
<tr>
<th><strong>Both inside and outside of Market Footprint</strong></th>
<th>2 weeks</th>
<th>Include in scheduled and coordinated rolling type updates. (This type change may need to be implemented prior to the next scheduled periodic Model Update.)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Add New Flowgate</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>In SPP Region</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>AFC</td>
<td>45 Days</td>
<td>Implement in applicable periodic update.</td>
</tr>
<tr>
<td>Coordinated</td>
<td>45 Days</td>
<td>Implement in applicable periodic update.</td>
</tr>
<tr>
<td>Reciprocal</td>
<td>45 Days</td>
<td>Implement in applicable periodic update.</td>
</tr>
<tr>
<td>Temporary</td>
<td>On the fly.</td>
<td>Implement this type change as needed.</td>
</tr>
<tr>
<td><strong>In Other Regions</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Coordinated</td>
<td>45 Days</td>
<td>Implement in applicable periodic update.</td>
</tr>
<tr>
<td>Reciprocal</td>
<td>45 Days</td>
<td>Implement in applicable periodic update.</td>
</tr>
<tr>
<td><strong>Modify Flowgate Data</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Changes - In SPP Region</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>AFC</td>
<td>45 Days</td>
<td>Implement in applicable periodic update.</td>
</tr>
<tr>
<td>Coordinated</td>
<td>45 Days</td>
<td>Implement in applicable periodic update.</td>
</tr>
<tr>
<td>Reciprocal</td>
<td>45 Days</td>
<td>Implement in applicable periodic update.</td>
</tr>
<tr>
<td>Temporary</td>
<td>On the fly.</td>
<td>Implement this type change as needed.</td>
</tr>
<tr>
<td><strong>Changes - In Other Regions</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Coordinated</td>
<td>45 Days</td>
<td>Implement in applicable periodic update.</td>
</tr>
<tr>
<td>Reciprocal</td>
<td>45 Days</td>
<td>Implement in applicable periodic update.</td>
</tr>
<tr>
<td><strong>Remove Flowgate</strong></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
In SPP Region

<table>
<thead>
<tr>
<th>AFC</th>
<th>45 Days</th>
<th>Implement in applicable periodic update.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coordinated</td>
<td>45 Days</td>
<td>Implement in applicable periodic update.</td>
</tr>
<tr>
<td>Reciprocal</td>
<td>45 Days</td>
<td>Implement in applicable periodic update.</td>
</tr>
<tr>
<td>Temporary</td>
<td>On the fly.</td>
<td>(Planned Function)</td>
</tr>
</tbody>
</table>

In Other Regions

<table>
<thead>
<tr>
<th>Coordinated</th>
<th>45 Days</th>
<th>Implement in applicable periodic update.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reciprocal</td>
<td>45 Days</td>
<td>Implement in applicable periodic update.</td>
</tr>
</tbody>
</table>

Define New ICCP Inbound

<table>
<thead>
<tr>
<th>In Market Footprint</th>
<th>1 Week / 4 Months</th>
<th>1 Week for basic ICCP/Scada Ref. additions. 4 Months for Generation and load related changes</th>
</tr>
</thead>
<tbody>
<tr>
<td>In Reliability Area</td>
<td>1 Week / 4 Months</td>
<td>(Same as note above.)</td>
</tr>
<tr>
<td>PNODE</td>
<td>1 Week / 4 Months</td>
<td>(Same as note above.)</td>
</tr>
<tr>
<td>EMS Equipment or Station Name</td>
<td>1 Week / 4 Months</td>
<td>(Same as note above.)</td>
</tr>
<tr>
<td>IDC Bus or Machine ID</td>
<td>1 Week / 4 Months</td>
<td>(Same as note above.)</td>
</tr>
</tbody>
</table>

Change ICCP Inbound

<table>
<thead>
<tr>
<th>In Market Footprint</th>
<th>4 Months</th>
<th>4 Months for Generation and load related changes.</th>
</tr>
</thead>
<tbody>
<tr>
<td>In Reliability Area</td>
<td>4 Months</td>
<td>(Same as note above.)</td>
</tr>
<tr>
<td>PNODE</td>
<td>4 Months</td>
<td>(Same as note above.)</td>
</tr>
<tr>
<td>EMS Equipment or Station Name</td>
<td>4 Months</td>
<td>(Same as note above.)</td>
</tr>
<tr>
<td>IDC Bus or Machine ID</td>
<td>4 Months</td>
<td>(Same as note above.)</td>
</tr>
</tbody>
</table>

Delete ICCP Inbound points

| (Typical for any type ICCP Deletion) | 1 Week / 5 Weeks | The max time for deletions is five weeks unless there is no impact to any other system (local or remote). If there is no impact, the request can be completed in the next ICCP model update. |

Define New ICCP Outbound points

<table>
<thead>
<tr>
<th>In Market Footprint</th>
<th>4 Months</th>
<th>4 Months for Generation and load related changes.</th>
</tr>
</thead>
<tbody>
<tr>
<td>In Reliability Area</td>
<td>4 Months</td>
<td>(Same as note above.)</td>
</tr>
<tr>
<td>PNODE</td>
<td>4 Months</td>
<td>(Same as note above.)</td>
</tr>
<tr>
<td>EMS Equipment or Station Name</td>
<td>4 Months</td>
<td>(Same as note above.)</td>
</tr>
<tr>
<td>IDC Bus or Machine ID</td>
<td>4 Months</td>
<td>(Same as note above.)</td>
</tr>
</tbody>
</table>
In Market Footprint | 4 Months | 4 Months for Generation and load related changes.
---|---|---
In Reliability Area | 4 Months | (Same as note above.)
  PNODE | 4 Months | (Same as note above.)
  EMS Equipment or Station Name | 4 Months | (Same as note above.)
  IDC Bus or Machine ID | 4 Months | (Same as note above.)

**Delete ICCP Outbound points**

| (Typical for any type ICCP Deletion) | 1 Week / 5 Weeks | The max time for deletions is five weeks unless there is no impact to any other system (local or remote). If there is no impact, the request can be completed in the next ICCP model update. |
---|---|---|

**Add PLC Points**

**In Market Footprint**

| Plant | 4 Months | Implement in applicable periodic update. |
| Unit | 4 Months | Implement in applicable periodic update. |
| Other | 4 Months | Implement in applicable periodic update. |

**In Reliability Area**

| Plant | 4 Months | Implement in applicable periodic update. |
| Unit | 4 Months | Implement in applicable periodic update. |
| Other | 4 Months | Implement in applicable periodic update. |

**Change PLC Points**

**In Market Footprint**

| Plant | 4 Months | Implement in applicable periodic update. |
| Unit | 4 Months | Implement in applicable periodic update. |
| Other | 4 Months | Implement in applicable periodic update. |

**In Reliability Area**

| Plant | 4 Months | Implement in applicable periodic update. |
| Unit | 4 Months | Implement in applicable periodic update. |
| Other | 4 Months | Implement in applicable periodic update. |

**IDC Model Change**
<table>
<thead>
<tr>
<th>IDC Bus Name or Machine ID Change</th>
<th>45 Days</th>
</tr>
</thead>
<tbody>
<tr>
<td>Changes are incorporated during periodic Model Updates. IDC data updated on monthly and Semi-annual bases -- Monthly changes accumulate for the month and are implemented one day per month (includes time to re-map units to Market Systems). Semi-annual changes accumulate over six months and are implemented over four days twice a year. (June 1st and October 1st are the update times)</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>RSS</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Change to RSS Model only.</td>
<td></td>
</tr>
<tr>
<td>(This type change may need to be implemented prior to the next scheduled periodic Model Update.)</td>
<td></td>
</tr>
<tr>
<td>Add New Resources</td>
<td>1 Week</td>
</tr>
<tr>
<td>(Same as note above.)</td>
<td></td>
</tr>
<tr>
<td>Change Resource Information</td>
<td>1 Week</td>
</tr>
<tr>
<td>(Same as note above.)</td>
<td></td>
</tr>
<tr>
<td>Delete Resource Information</td>
<td>1 Week</td>
</tr>
<tr>
<td>(Same as note above.)</td>
<td></td>
</tr>
</tbody>
</table>
Appendix F - Settlement Examples
1. Introduction

1.1 Purpose

The purpose of this document is to add context to the settlement formulae from the FM protocols by providing transactional examples of the settlement charge types and intermediate calculations. Where practical the examples are presented with illustrations which show how different types of market instruments interact in achieving settlement results. In the interest of brevity and clarity the example calculations evaluate results in a single interval, be it 5-minute, hourly, daily or even monthly/yearly.

1.2 Definition of Terms

<table>
<thead>
<tr>
<th>Acronym</th>
<th>Term</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>AO</td>
<td>Asset Owner</td>
<td>The middle tier of financial entities in the CM, used for settlement</td>
</tr>
<tr>
<td></td>
<td></td>
<td>statements.</td>
</tr>
<tr>
<td>BA</td>
<td>Balancing Authority</td>
<td>A boundary defined by internal generation control to an instantaneous</td>
</tr>
<tr>
<td></td>
<td></td>
<td>NAI signal</td>
</tr>
<tr>
<td>BDR</td>
<td>Block Demand Response</td>
<td>Behind the meter load reduction which requires calculated response</td>
</tr>
<tr>
<td>CBA</td>
<td>Consolidated Balancing</td>
<td>Approach assumes the footprint will retain existing SAs for determining</td>
</tr>
<tr>
<td></td>
<td>Authority</td>
<td>residual load while supplying NSI &amp; NAI for the entire footprint to</td>
</tr>
<tr>
<td></td>
<td></td>
<td>calculate the impact of NI</td>
</tr>
<tr>
<td>CC</td>
<td>Combined Cycle (Resource)</td>
<td>Resource comprised of many operational configurations such as 1 gas</td>
</tr>
<tr>
<td></td>
<td></td>
<td>turbine &amp; 1 steam turbine or 2 gas turbines and 1 steam turbine etc.</td>
</tr>
<tr>
<td>CM</td>
<td>Commercial Model</td>
<td>The financial entities, network elements and relationships between them</td>
</tr>
<tr>
<td></td>
<td></td>
<td>constructing the backbone of the market</td>
</tr>
<tr>
<td>CP</td>
<td>Commitment Period</td>
<td>The date/time range of a DA market or RTBM resource Market or Self</td>
</tr>
<tr>
<td></td>
<td></td>
<td>commitment</td>
</tr>
<tr>
<td>COS</td>
<td>Commercial Operations Systems</td>
<td>A suite of market applications including settlements, customer service</td>
</tr>
<tr>
<td></td>
<td></td>
<td>and the portal</td>
</tr>
<tr>
<td>DA</td>
<td>Day Ahead (Market)</td>
<td>The future forward market for energy and operating reserves</td>
</tr>
<tr>
<td>DDR</td>
<td>Dispatchable Demand Response</td>
<td>Load reduction which can be metered</td>
</tr>
<tr>
<td>DRL</td>
<td>Demand Response Load</td>
<td>A meter location discretely representing the load behind which a demand</td>
</tr>
<tr>
<td></td>
<td></td>
<td>response resource is located. A DRL is not necessarily associated with a</td>
</tr>
<tr>
<td></td>
<td></td>
<td>SL which will be settled, its primary function is for acceptance of</td>
</tr>
<tr>
<td></td>
<td></td>
<td>metering which supports the calculated method for BDRs &amp; BDRs</td>
</tr>
<tr>
<td>DRR</td>
<td>Demand Response Resource</td>
<td>BDR or DDR</td>
</tr>
<tr>
<td>EIS</td>
<td>Energy Imbalance Service</td>
<td>The current SPP market</td>
</tr>
<tr>
<td>Acronym</td>
<td>Term</td>
<td>Definition</td>
</tr>
<tr>
<td>---------</td>
<td>-----------------------</td>
<td>-------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>FM</td>
<td>Future Market</td>
<td>SPP’s DA Market, RTBM and TCR Market for energy and Operating Reserves planned for implementation Q4 2012</td>
</tr>
<tr>
<td>EMS</td>
<td>Energy Management System</td>
<td>SPP repository and dashboard for MP SCADA data</td>
</tr>
<tr>
<td>JOU</td>
<td>Joint Owned Unit</td>
<td>Ownership of a physical resource shared among multiple financial entities</td>
</tr>
<tr>
<td>LRS</td>
<td>Load Ratio Share</td>
<td>The % of load at a single SL relative to the SPP total</td>
</tr>
<tr>
<td>MA</td>
<td>Meter Agent</td>
<td>Entity responsible for submittal of revenue quality interchange, resource and load meter data to settlements via the market portal</td>
</tr>
<tr>
<td>ML</td>
<td>Meter Location</td>
<td>A child of SL – the level at which meter data is submitted. It is usually 1:1 with SL, but in certain cases multiple MLs may relate to a single SL. MLs are confined to a single SA (necessary for the purpose of residual &amp; calibration calculation) while a SL may span multiple SAs.</td>
</tr>
<tr>
<td>MP</td>
<td>Market Participant</td>
<td>The highest tier of financial entities in the CM, used for invoicing and credit.</td>
</tr>
<tr>
<td>MS</td>
<td>Market Settlements</td>
<td>The system built to implement new market protocols</td>
</tr>
<tr>
<td>MTR</td>
<td>Meter Agent</td>
<td>Revenue Quality</td>
</tr>
<tr>
<td>MWP</td>
<td>Make Whole Payment</td>
<td>Cost guarantees during periods of SPP economic resource commitment</td>
</tr>
<tr>
<td>MWEP</td>
<td>Make-Whole Eligibility Period</td>
<td>The settlement subset of a CP considered in MWP calculations</td>
</tr>
<tr>
<td>NAI</td>
<td>Net Actual Interchange</td>
<td>The actual net flow into or out of CBA or SA</td>
</tr>
<tr>
<td>NI</td>
<td>Net Inadvertent</td>
<td>The difference between the actual and scheduled net flow into or out of SPP</td>
</tr>
<tr>
<td>NSI</td>
<td>Net Scheduled Interchange</td>
<td>The scheduled net flow into or out of CBA or SA</td>
</tr>
<tr>
<td>OCL</td>
<td>Over Collected Losses</td>
<td>Settlement surplus related to marginal loss pricing, which is rebated based on payment of marginal losses.</td>
</tr>
<tr>
<td>OD</td>
<td>Operating Day</td>
<td>The day boundary for a single settlement period</td>
</tr>
<tr>
<td>OR</td>
<td>Operating Reserve</td>
<td>Capacity held for regulation, spinning and supplemental reserve</td>
</tr>
<tr>
<td>POP</td>
<td>Post Operations Processor</td>
<td>A rudimentary system which consists primarily of a market system database dump, and bridges the gap between RT Operations and MS</td>
</tr>
<tr>
<td>RUC</td>
<td>Reliability Unit Commitment</td>
<td>Operations process and algorithm for determining which units should be started</td>
</tr>
<tr>
<td>RTBM</td>
<td>Real Time Balancing Market</td>
<td>Future market for dispatch of energy and operating reserves to meet current demand</td>
</tr>
<tr>
<td>RTOSS</td>
<td>Regional Transmission Organization Scheduling System</td>
<td>Manages interchange schedule data and NSI / NAI for the footprint</td>
</tr>
<tr>
<td>RNU</td>
<td>Revenue Neutrality Uplift</td>
<td>Market charge type for balancing daily settlement</td>
</tr>
<tr>
<td>RUC</td>
<td>Reliability Unit Commitment</td>
<td>Market process for committing resources needed to meet the load forecast</td>
</tr>
</tbody>
</table>
### Acronym | Term | Definition
--- | --- | ---
SA | Settlement Area | A boundary within the market footprint which defines the load balance equation to determine the residual quantity
SCADA | Supervisory Control And Data Acquisition | 4 second resource and load bus signals from MP equipment sent to SPP
SE | State Estimator | An operations system which smoothes, replaces and repairs SCADA data to create complete snapshots of the transmission system every 5 minutes
SL | Settlement Location | Pricing points in the footprint: Resource, Load, Interface & Hub types
TCR | Transmission Congestion Rights | The market (or instrument) for transmission planning and forward hedging of congestion rents
UOM | Unit of Measure | MW or MWh data submitted in 5-minute intervals
URD | Uninstructed Resource Deviation | Performance outside of a tolerance band from the dispatch setpoint

#### 1.3 Outstanding Issues/Assumptions

<table>
<thead>
<tr>
<th>Issue</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Combined Cycle Resources</td>
<td>CCs are settled in aggregate; all data necessary to support these calculations are available as input.</td>
</tr>
<tr>
<td>Joint Owned Units</td>
<td>JOUs are settled as separate assets; the same calculation and data expectations as any other resource apply.</td>
</tr>
</tbody>
</table>
2. Market Model

2.1 Commercial Model

The settlement examples are based on a miniature model of the SPP footprint, but one which provides substantial diversity in the different organizational structures or transactional scenarios found in actual market operations.

2.1.1 Financial Entities and Relationships

Three tiers of financial entities comprise the backbone of settlements.

- MP: the top level for invoicing and credit exposure calculations.
- AO: an organizational or accounting sub-group used to compartmentalize market activity, settlement statements are presented at this level.
- Asset: a resource or load owned by and AO, exclusive use of a SL for certain charge types.

Each of the settlement examples will provide a dialogue that associates the transactional activity to a single AO. The calculations themselves occur at various levels, primarily per SL, but in cases where SL granularity is not practical the results are at a zonal level or are summed to the AO.
Figure 1
2.1.2 Network Entities and Relationships

The relationships among MLs, SLs, SAs, LPs, RZNs, Common Bus described in the Market Protocols are not always important to settlement calculations; however, there are exceptions where an understanding of the underlying framework is essential.

Settlement formulae use the billable metering determinant as the point of entry for calculations which require revenue quality injection and withdrawal data, but it is in fact an intermediate determinant derived from a chain of other raw data elements.

- Actual submittals must be at a location, the ML, confined to a single SA for the purpose of calculating residual load. Where an SL consists of multiple MLs in different SAs the billable meter determinant is an aggregation of the submitted values.
- Calibration of SA residual is included with ML values in the roll-up to the SL level.
- Where metered load represents consumption net of demand response behind the meter the value is grossed up for the response.
- Where a top down calculation results in submittals inclusive of transmission losses, the SE value of the SA losses are backed out of the submittal.
- Demand response relying on the calculated method must be tied to a ML for which baseline data is available to support the calculation.
- Absent any submittal the settlement system substitutes SE values.
- Hourly meter submittals are profiled into 5 minute intervals.

The association of SLs to RZN is necessary for both the settlement of OR procured from resources and the cost allocation to zonal obligation. LPs are a modeling construct used to group SL members of a single financial entity together for the purpose of determining the loss factors, which in turn determine the rebate of OCL. Lastly, the Common Bus object is used as a tool to prevent charges for URD and contingency reserve deployment penalties where a group of resources measured in aggregate pass the performance threshold.
2.2 Transactional Legend

Day Ahead Cleared Energy

Resource or Load Settlement Location

Billable Meter MW

Any Settlement Location

Withdrawal

Injection

Withdrawal

Injection

Bid

Offer

Cleared Virtual Bid or Offer

Day Ahead Financial Schedule

Real Time Financial Schedule

Buy

Sell

Any Settlement Location

Interface Settlement Location

Import

Export

Day Ahead Import / Export

Real Time Import / Export

Any Settlement Locations

Transmission Congestion Right (source to sink)

Day Ahead Regulation, Spinning & Supplemental Reserves

Real Time Regulation, Spinning & Supplemental Reserves

RegUp

RegDn

Spin

Supp

RegUp

RegDn

Spin

Supp

Resource Settlement Location
## 3. Market Settlement Examples

### 3.1 Energy Charge Types

#### 3.1.1 Day Ahead Energy

The settlement of Day Ahead Energy is categorized in 3 separate Charge Types for i) resource/load locations, ii) import/export and other bilateral transactions and iii) virtual bids/offers.

The unit of measure for all DA Market prices is $/MWh – the value of 1 MW of service for the duration of an hour. DA Market clearing bids and offers and Financial Schedules are also in terms of MWh. Since Imports and Exports, even those that clear in the DA Market, can start off of the top of the hour the quantity data is natively in MWi and values can vary among the intervals in a single hour, however the integrated hourly value (the sum of the 5-minute interval quantities / 12) is the settlement quantity. In the interest of clarity, the examples in this section assume the same value in each interval.

### Asset Energy Settlement

\[
\text{DaEnergyHrlyAmt}_{a,s,h} = \text{DaLmpHrlyPrc}_{s,h} \times (\text{DaClrdHrlyQty}_{a,s,h} - \sum_t \text{DaEnFinHrlyQty}_{a,s,t,h})
\]

### Non-Asset Energy Settlement

\[
\text{DaNEnergyHrlyAmt}_{a,s,h} = \text{DaLmpHrlyPrc}_{s,h} \times (\sum_t \sum_i \text{DaImpExp5minQty}_{a,s,t,i} / 12 - \sum_t \text{DaNEnFinHrlyQty}_{a,s,t,h})
\]

### Virtual Energy Settlement

\[
\text{DaVEnergyHrlyAmt}_{a,s,h} = \text{DaLmpHrlyPrc}_{s,h} \times \sum_t \text{DaClrdVHrlyQty}_{a,s,h,t}
\]

---

*Market Protocols for SPP Integrated Marketplace

_Southwest Power Pool_
The activity of AO_U

- DaClrdHrlyQtyL3 = 90 MWh (Bid)
- DaClrdHrlyQtyG3 = -500 MWh (Offer)
- DaClrdVHrlyQtyG3 = 40 MWh (Bid)
- DaEnFinHrlyQtyG3 = -300 MWh (Seller to AO_X)
- DaEnFinHrlyQtyG3 = -101 MWh (Seller to AO_V)
- DaImpExpHrlyQtyI2 = 80 MWi (Export)

### Virtual Energy Settlement

Virtual Energy Settlement

- DaVEnergyHrlyAmtG3 = 25 $/MWh * 40 MWh = $1000

### Non-Asset Energy Settlement

Non-Asset Energy Settlement

- DaEnergyHrlyAmtL3 = 50 $/MWh * 90 MWh = $4500
- DaEnergyHrlyAmtG3 = 25 $/MWh * (-500 MWh - (-300 MWh + -101 MWh)) = -$2475

### Asset Energy Settlement

Asset Energy Settlement

- DaEnergyHrlyAmtL3 = 50 $/MWh * 90 MWh = $4500
- DaEnergyHrlyAmtG3 = 25 $/MWh * (-500 MWh - (-300 MWh + -101 MWh)) = -$2475

### Virtual Energy Settlement

Virtual Energy Settlement

- DaVEnergyHrlyAmtG3 = 25 $/MWh * 40 MWh = $1000
The activity of AO_V

- \( \text{DaClrdVHrlyQty}_{L3} = -100 \text{ MWh (Offer)} \)
- \( \text{DaNEnFinHrlyQty}_{G3} = 101 \text{ MWh (Buyer from AO_U)} \)
- \( \text{DaEnFinHrlyQty}_{L4} = 100 \text{ MWh (Buyer from AO_X)} \)
- \( \text{DaClrdHrlyQty}_{L4} = 475 \text{ MWh (Bid)} \)
- \( \text{DaImpExpHrlyQty}_{I3} = -160 \text{ MWi (Import)} \)

**Asset Energy Settlement**
\[
\text{DaVEnergyHrlyAmt}_{L3} = 50 \text{ $/MWh} \times (-100 \text{ MWh}) = -5000
\]

**Virtual Energy Settlement**
\[
\text{DaNEnergyHrlyAmt}_{I3} = 45 \text{ $/MWh} \times (12 \times (-160 \text{ MWi}) / 12 \text{ i/h} - 0) = -7200
\]

**Non-Asset Energy Settlement**
\[
\text{DaEnergyHrlyAmt}_{L4} = 30 \text{ $/MWh} \times (475 \text{ MWh} - 100 \text{ MWh}) = 11,250
\]
\[
\text{DaNEnergyHrlyAmt}_{G3} = 25 \text{ $/MWh} \times (0 - 101 \text{ MWh}) = -2525
\]
\[
\text{DaNEnergyHrlyAmt}_{I3} = 45 \text{ $/MWh} \times (12 \times (-160 \text{ MWi}) / 12 \text{ i/h} - 0) = -7200
\]

**Virtual Energy Settlement**
\[
\text{DaVEnergyHrlyAmt}_{I3} = 50 \text{ $/MWh} \times (-100 \text{ MWh}) = -5000
\]
The activity of AO_X

- DaNEnergyHrlyQty_{G3} = 300 MWh (Buyer from AO_U)
- DaNEnergyHrlyQty_{L4} = -100 MWh DA (Seller to AO_V)
- DaClrdVHrlyQty_{L4} = -195 MWh (Offer)
- DaNEnergyHrlyQty_{I3} = -200 MWh (Seller to AO_Z) at I3

### Virtual Energy Settlement

\[
\text{DaVEnergyHrlyAmt}_{L4} = 30 \text{ } \$/\text{MWh} \times (-195 \text{ MWh}) = -\$5,850
\]

### Asset Energy Settlement

None

### Non-Asset Energy Settlement

\[
\begin{align*}
\text{DaNEnergyHrlyAmt}_{G3} &= 25 \text{ } \$/\text{MWh} \times (0 - 300 \text{ MWh}) = -\$7,500 \\
\text{DaNEnergyHrlyAmt}_{I3} &= 45 \text{ } \$/\text{MWh} \times (0 - -200 \text{ MWh}) = \$9,000 \\
\text{DaNEnergyHrlyAmt}_{L4} &= 30 \text{ } \$/\text{MWh} \times (0 - -100 \text{ MWh}) = \$3,000
\end{align*}
\]

### Virtual Energy Settlement

\[
\text{DaVEnergyHrlyAmt}_{L4} = 30 \text{ } \$/\text{MWh} \times (-195 \text{ MWh}) = -\$5,850
\]
The activity of AO_Z

- DaClrdVHrlyQtyI2 = 30 MWh (Bid)
- DaNEnergyHrlyQtyI3 = 200 MWh (Buyer from AO_X)
- DaImpExpHrlyQtyI3 = 200 MWi (Export)
- DaClrdVHrlyQtyI2 = -60 MWh (Offer)

Virtual Energy Settlement

Virtual Energy Settlement

&n
3.1.2 Real Time Energy

The settlement of Real Time Energy is also categorized in 3 separate Charge Types for i) resource/load locations, ii) import/export and other bilateral transactions and iii) virtual bids/offers.

The unit of measure for all RTBM prices is $/MWh – the value of 1 MW of service for the duration of an hour. While metering is submitted by MAs in MWh (whether in hourly or 5-minute intervals), the process for determining the billable meter quantity converts it to MWi to put it on an equal basis with other settlement determinants. DA Market clearing bids and offers and RTBM Financial Schedules are in terms of MWh. Since Imports and Exports, even those that clear in the DA Market, can start off of the top of the hour the quantity data is natively in MWi and values can vary among the intervals in a single hour. The RTBM settlement quantity of an hourly determinant in every interval of that hour is the same value, but in MWi.

<table>
<thead>
<tr>
<th>Asset Energy Settlement</th>
</tr>
</thead>
<tbody>
<tr>
<td>[ \text{RtEnergy5minAmt}<em>{a,s,i} = \text{RtLmp5minPrc}</em>{s,i} \times [ (\text{RtBillMtr5minQty}<em>{a,s,i} - \text{DaClrdHrlyQty}</em>{a,s,h} ) - \sum_t \text{RtEnFinHrlyQty}_{a,s,t,h} ] / 12 ]</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Non-Asset Energy Settlement</th>
</tr>
</thead>
<tbody>
<tr>
<td>[ \text{RtNEnergy5minAmt}<em>{a,s,i} = \text{RtLmp5minPrc}</em>{s,i} \times [ (\sum_t \text{RtImpExp5minQty}<em>{a,s,t,i} - \sum_t \text{DaImpExp5minQty}</em>{a,s,t,i} ) - \sum_t \text{RtNEEnFinHrlyQty}_{a,s,t,h} ] / 12 ]</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Virtual Energy Settlement</th>
</tr>
</thead>
<tbody>
<tr>
<td>[ \text{RtVEnergy5minAmt}<em>{a,s,i} = ( \text{RtLmp5minPrc}</em>{s,i} \times (\sum \text{DaClrdVHrlyQty}_{a,s,h,t} / 12 ) ) \times (-1) ]</td>
</tr>
</tbody>
</table>
The activity of AO_W

- DaClrdVHrlyQty_{16} = 420 MWi (Bid)
- RtNEnFinHrlyQty_{16} = 22 MWi (Buyer from AO_Z)
- RtImpExp5minQty_{16} = 442 MWi (Export)
- DaImpExp5minQty_{16} = 0 MWi

<table>
<thead>
<tr>
<th>SL</th>
<th>RtlImp5minPrc</th>
</tr>
</thead>
<tbody>
<tr>
<td>L6</td>
<td>55</td>
</tr>
<tr>
<td>L7</td>
<td>65</td>
</tr>
<tr>
<td>G6</td>
<td>50</td>
</tr>
<tr>
<td>H4</td>
<td>45</td>
</tr>
<tr>
<td>16</td>
<td>50</td>
</tr>
<tr>
<td>17</td>
<td>30</td>
</tr>
<tr>
<td>18</td>
<td>40</td>
</tr>
</tbody>
</table>
### Asset Energy Settlement

None

### Non-Asset Energy Settlement

\[
\text{RtNEnergy5minAmt}_{16} = 50 \text{ $/MWh} \times \frac{[(442 \text{ MWi} - 0) - 22 \text{ MWi}]}{12 \text{ i/h}} = 1,750
\]

### Virtual Energy Settlement

\[
\text{RtVEnergy5minAmt}_{16} = 50 \text{ $/MWh} \times 420 \text{ MWi} / 12 \text{ i/h} \times (-1) = -1,750
\]
The activity of AO_X

- DaClrdVHrlyQty_{18} = -350 MWi (Offer)
- RtImpExp5minQty_{18} = -366 MWi (Import)
- DaImpExp5minQty_{18} = 0 MWi
- RtNEnFinHrlyQty_{G6} = -400 MWi (Seller to AO_Y)
- DaClrdVHrlyQty_{17} = 15 MWi (Bid)
- DaClrdVHrlyQty_{17} = -60 MWi (Offer)
Virtual Energy Settlement
RtVEnergy5minAmtI8 = 30 $/MWh * (15 MWi + (-60 MWi)) MW / 12 i/h * (-1) = $112.50
RtVEnergy5minAmtI8 = 40 $/MWh * (-350 MWi) / 12 i/h * (-1) = $1,166.67

The activity of AO_Y
- DaClrdHrlyQtyG6 = -500 MWi (Offer)
- RtBillMtr5minQtyG6 = -100 MWi (Injection)
- RtNEnFinHrlyQtyG6 = 400 MWi (Buyer from AO_X)
- DaClrdHrlyQtyL6 = 335 MWi (Bid)
- RtBillMtr5minQtyL6 = 350 MWi (Withdrawal)
- RtNEnFinHrlyQtyH4 = 15 MWi (Buyer from AO_Z)

Asset Energy Settlement
None

Non-Asset Energy Settlement
RtNEnergy5minAmtI8 = 40 $/MWh * [(-366 MWi - 0) - 0] / 12 i/h = -$1,220
RtNEnergy5minAmtG6 = 50 $/MWh * [(0 - 0) - (-400 MWi)] / 12 i/h = $1,666.67

Virtual Energy Settlement
RtVEnergy5minAmtI7 = 30 $/MWh * (15 MWi + (-60 MWi) MW / 12 i/h * (-1) = $112.50
RtVEnergy5minAmtI8 = 40 $/MWh * -350 MWi / 12 i/h * (-1) = $1,166.67

<table>
<thead>
<tr>
<th>SL</th>
<th>Rtlmp5minPrc</th>
</tr>
</thead>
<tbody>
<tr>
<td>L6</td>
<td>55</td>
</tr>
<tr>
<td>L7</td>
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</tr>
<tr>
<td>G6</td>
<td>50</td>
</tr>
<tr>
<td>H4</td>
<td>45</td>
</tr>
<tr>
<td>I6</td>
<td>50</td>
</tr>
<tr>
<td>I7</td>
<td>30</td>
</tr>
<tr>
<td>I8</td>
<td>40</td>
</tr>
</tbody>
</table>
Non-Asset Energy Settlement
RtNEnergy5minAmtH4
= 45 $/MWh * [(0 - 0) – 15 MWi] / 12 i/h = -$56.25

Virtual Energy Settlement
None

Asset Energy Settlement
RtEnergy5minAmtG6
= 50 $/MWh * [(100 MWi - 500 MWi) – 400 MWi] / 12 i/h = $0

RtEnergy5minAmtL6
= 55 $/MWh * [(350 MWi – 335 MWi) - 0] / 12 i/h = $68.75

Non-Asset Energy Settlement
RtNEnergy5minAmth4
= 45 $/MWh * [(0 - 0) – 15 MWi] / 12 i/h = -$56.25
The activity of AO_Z

- DaClrdHrlyQtyL7 = 750 MWi (Bid)
- RtBillMtr5minQtyL7 = 747 MWi (Withdrawal)
- RtNEnFinHrlyQtyH4 = -15 MWi (Seller to AO_Y)
- RtImpExp5minQtyL7 = -250 MWi (Import)
- RtImpExp5minQtyI7 = -135 MWi (Import)
- DaImpExp5minQtyI7 = -225 MWi (Import)
- DaImpExp5minQtyI7 = -160 MWi (Import)

Asset Energy Settlement
RtEnergy5minAmtL7 = 65 $/MWh * [(747 MWi – 750 MWi) - 0] / 12 i/h = -$16.25

Non-Asset Energy Settlement
RtNEnergy5minAmtL7 = 45 $/MWh * [0 - 0 - (-15 MWi)] / 12 i/h = $56.25
RtNEnergy5minAmtI7 = 30 $/MWh * [(-250 MWi + -135 MWi - (-225 MWi + -160 MWi)) - 0] / 12 i/h = $0

Virtual Energy Settlement
None
### 3.2 Charge Types for Procurement of Regulation & Reserves

#### 3.2.1 Day-Ahead Procurement

The settlement of Resources from which the market procures Regulation & Reserves in Day-Ahead is categorized in 4 separate Charge Types for i) Regulation Up, ii) Regulation Down iii) Spinning Reserve and iv) Supplemental Reserve. Zonal MCPs are mapped to the SL at which the resource provides the capacity.

The unit of measure for all DA Market prices is $/MWh – the value of 1 MW of service for the duration of an hour. DA Market clearing offers for OR products are also in terms of MWh.

<table>
<thead>
<tr>
<th>Charge Type</th>
<th>Formula</th>
</tr>
</thead>
<tbody>
<tr>
<td>Regulation Up</td>
<td>( \text{DaRegUpHrlyAmt}<em>{a,s,h} = (\text{DaRegUpMcpHrlyPrc}</em>{z,s,h} \times \text{DaRegUpHrlyQty}_{a,s,h}) \times (-1) )</td>
</tr>
<tr>
<td>Regulation Down</td>
<td>( \text{DaRegDnHrlyAmt}<em>{a,s,h} = (\text{DaRegDnMcpHrlyPrc}</em>{z,s,h} \times \text{DaRegDnHrlyQty}_{a,s,h}) \times (-1) )</td>
</tr>
<tr>
<td>Spinning Reserve</td>
<td>( \text{DaSpinHrlyAmt}<em>{a,s,h} = (\text{DaSpinMcpHrlyPrc}</em>{z,s,h} \times \text{DaSpinHrlyQty}_{a,s,h}) \times (-1) )</td>
</tr>
<tr>
<td>Supplemental Reserve</td>
<td>( \text{DaSuppHrlyAmt}<em>{a,s,h} = (\text{DaSuppMcpHrlyPrc}</em>{z,s,h} \times \text{DaSuppHrlyQty}_{a,s,h}) \times (-1) )</td>
</tr>
</tbody>
</table>
The activity of AO_V

- DaRegUpHrlyQty_g4 = 20 MWh
- DaRegDnHrlyQty_g4 = 30 MWh

Regulation Up
DaRegUpHrlyAmg_{4} = 35 \text{ $/MWh} \times 20 \text{ MWh} \times (-1) = -$700

Regulation Down
DaRegDnHrlyAmg_{4} = 30 \text{ $/MWh} \times 30 \text{ MWh} \times (-1) = -$900

Spinning Reserve
None

Supplemental Reserve
None
The activity of AO_W

- DaSpinHrlyQty\textsubscript{G4} = 50 MWh
- DaSuppHrlyQty\textsubscript{G4} = 25 MWh

Regulation Up
None

Regulation Down
None

Spinning Reserve
DaSpinHrlyAmt\textsubscript{G5} = 25 $/MWh \times 50 MWh \times (-1) = -$1,250

Supplemental Reserve
DaSuppHrlyQty\textsubscript{G5} = 10 $/MWh \times 25 MWh \times (-1) = -$250
3.2.2 Real-Time Procurement

The settlement of Resources from which the market procures Regulation & Reserves in Real-Time is also categorized in separate Charge Types for each of the 4 products: i) Regulation Up, ii) Regulation Down iii) Spinning Reserve and iv) Supplemental Reserve. Zonal MCPs are mapped to the SL at which the resource provides the capacity.

The unit of measure for all RTBM prices is $/MWh – the value of 1 MW of service for the duration of an hour. RTBM clearing offers are in terms of MWi. DA Market clearing offers are in terms of MWh. The RTBM settlement quantity of an hourly determinant in every interval of that hour is the same value, but in MWi.

\[
\text{Regulation Up} \\
RtRegUp5minAmn_{a,s,i} = (RtRegUpMcp5minPrc_{z,s,i} \times (RtRegUp5minQty_{a,s,i} - DaRegUpHrlyQty_{a,s,h}) / 12) \times (-1)
\]

\[
\text{Regulation Down} \\
RtRegDn5minAmn_{a,s,i} = (RtRegDnMcp5minPrc_{z,s,i} \times (RtRegDn5minQty_{a,s,i} - DaRegDnHrlyQty_{a,s,h}) / 12) \times (-1)
\]

\[
\text{Spinning Reserve} \\
RtSpin5minAmn_{a,s,i} = (RtSpinMcp5minPrc_{z,s,i} \times (RtSpin5minQty_{a,s,i} - DaSpinHrlyQty_{a,s,h}) / 12) \times (-1)
\]

\[
\text{Supplemental Reserve} \\
RtSupp5minAmn_{a,s,i} = (RtSuppMcp5minPrc_{z,s,i} \times (RtSupp5minQty_{a,s,i} - DaSuppHrlyQty_{a,s,h}) / 12) \times (-1)
\]
The activity of AO_V

- \( \text{RtRegUp5minQty}_{G4} = 25 \text{ MWi} \)
- \( \text{RtRegDn5minQty}_{G4} = 25 \text{ MWi} \)
- \( \text{DaRegUpHrlyQty}_{G4} = 20 \text{ MWi} \)
- \( \text{DaRegDnHrlyQty}_{G4} = 30 \text{ MWi} \)

**Regulation Up**
\[
\text{RtRegUp5minAmt}_{G4} = 33 \text{$/MWh} \times \frac{(25 \text{ MWi} - 20 \text{ MWi})}{12 \text{ i/h}} \times (-1) = -13.75
\]

**Regulation Down**
\[
\text{RtRegDn5minAmt}_{G4} = 36 \text{$/MWh} \times \frac{(25 \text{ MWi} - 30 \text{ MWi})}{12 \text{ i/h}} \times (-1) = 15
\]

**Spinning Reserve**
None

**Supplemental Reserve**
None
The activity of AO_W

- \( \text{RtSpin5minQty}_{G5} = 55 \text{ MWi} \)
- \( \text{DaSpinHrlyQty}_{G5} = 50 \text{ MWi} \)
- \( \text{RtSupp5minQty}_{G5} = 25 \text{ MWi} \)
- \( \text{DaSuppHrlyQty}_{G5} = 25 \text{ MWi} \)

**Regulation Up**
None

**Regulation Down**
None

**Spinning Reserve**
\[
\text{RtSpin5minAmt}_{G5} = 21 \$/\text{MWh} \times \frac{(55 \text{ MWi} - 50 \text{ MWi})}{12 \text{ i/h}} \times (-1) = -8.75
\]

**Supplemental Reserve**
\[
\text{RtSupp5minAmt}_{G5} = 12 \$/\text{MWh} \times \frac{(25 \text{ MWi} - 25 \text{ MWi})}{12 \text{ i/h}} \times (-1) = 0
\]
3.3 Charge Types for Cost Allocation of Day-Ahead Operating Reserves

The methods for allocating the cost of procuring the 4 products are identical and based on the obligation incurred through load and exports. This example explores the calculations for one product as a template for the other three. The OR cost allocation calculations are a chain of intermediate calculations designed to manipulate the data into final rate and quantity determinants which are multiplied to achieve the charge type result. The intermediate steps involved are as follows:

1. Zonal Load
2. Initial Obligation
3. Intermediate Obligation
4. Final Obligation
5. Exchange Supply Rate
6. Day-Ahead Zonal Cost
7. Zonal Distribution Rate

The unit of measure for all OR obligation is MWh – billable meter quantity and import / export values initially in MWi are integrated to the hourly level in determining zonal load. The Exchange Supply Rate and Zonal Distribution rate are expressed in $/MWh.
3.3.1 Zonal Load

Consider the load pattern described by the diagram below. Since the allocation methods utilize zonal rates it is important to establish the zonal location (A, B, C & D) of the obligation created by each load and export. Load and interface SLs can span multiple RZNs and the portion of load at each SL which fall into a RZN is determined by SE data from that day. This example assumes that interface SLs will actually map to a RZN, however it may be necessary that they belong to the default SPP RZN.
Zonal determination is also a function of market clearing. When a predefined zone is not impacted by the minimum or maximum amount to be cleared (a function of deliverability) in the zone, the cost allocation settlement is lumped into a common default zone. Since RZNs may bind differently in each hour or across products the “% in RZN” data may vary greatly and thus the zonal load may be different for each product.
The activity of AO_V

- RtBillMtr5minQtyL4 = 605 MWi (40% in RZN B & 60% in SPP RZN)
- RtBillMtr5minQtyL5 = 550 MWi (100% in the SPP RZN)
The activity of AO_W

- Location I5 not “owned” by AO_W
- RtImpExp5minQtyI5 = 250 MWi (100% in the SPP RZN)

\[
\text{Reserve Zone Load}\n\]

\[
\text{RtSpinRznLoadHrlyQty}_{a, s, z, h} = (\text{Max} (0, \sum_{i} \text{RtBillMtr5minQty}_{a, s, i}) + \text{Max} (0, \sum_{i} \sum_{t} \text{RtImpExp5minQty}_{a, s, z, i, t})) \times \text{PctSlinRznSpinHrlyFct}_{a, s, z, h} / 12
\]
The obligation to pay for OR procured in the DA Market is not only a function of zonal load, but also contracts for supply and Financial Schedules for OR obligation. Given the firm transmission available to affect the contract, AOs can meet the obligation from outside the footprint. The SPP clearing requirement is reduced for obligation met by external supply by contract. Financial Schedules merely swap obligation in a single RZN among 2 AOs.
### Initial Obligation

The AO’s initial obligation in each zone is determined by LRS of the AO’s zonal load as compared to the footprint as a whole times the SPP requirement for the product. The sum total of all contracts for supply reduces the amount which must be cleared in the DA Market, thus it must be added back in to get the total requirement. In this example the SPP reserve requirement is 400 MWh, 100 MWh of which is met via contract from outside the footprint and the total footprint load is 3930 MWh. The sum of all AO’s initial obligation will equal the original product requirement.

\[
\text{Spinning Reserve Initial Obligation}
\]

\[
\text{DaSpinIniAoObligHrlyQty}_{a, z, h} = (\text{DaSpinSppHrlyQty}_{h} + \text{ContrSpinSppHrlyQty}_{h}) \times \left( \sum_{s} \text{RtSpinRznLoadHrlyQty}_{a, s, z, h} / \text{RtLoadSppHrlyQty}_{h} \right)
\]

Spinning Reserve Initial Obligation

\[
\begin{align*}
\text{DaSpinIniAoObligHrlyQty}_{\text{AO, V-RZN B}} &= (300 \text{ MWh} + 100 \text{ MWh}) \times (242 \text{ MWh} / 3930 \text{ MWh}) = 24.631 \text{ MWh} \\
\text{DaSpinIniAoObligHrlyQty}_{\text{AO, V-RZN SPP}} &= (300 \text{ MWh} + 100 \text{ MWh}) \times (913 \text{ MWh} / 3930 \text{ MWh}) = 92.926 \text{ MWh} \\
\text{DaSpinIniAoObligHrlyQty}_{\text{AO, W-RZN SPP}} &= (300 \text{ MWh} + 100 \text{ MWh}) \times (250 \text{ MWh} / 3930 \text{ MWh}) = 25.445 \text{ MWh}
\end{align*}
\]
3.3.3 Intermediate Obligation

The intermediate obligation in each zone is simply the AO’s initial obligation as adjusted by contracts for supply. The intermediate obligation cannot go negative. To the extent the MAX is invoked, the sum of all AO’s intermediate obligation may be different than the sum of the sum of the original product requirement. In this example the total is reduced from 400 MWh to 374.555 MWh due to the fact that the AO_W’s external contract for supply exceeded its initial obligation in the SPP RZN.

\[
\text{Spinning Reserve Intermediate Obligation}
\]

\[
\text{DaSpinInterAoObligHrlyQty}_{a,z,h} = \text{Max} \left( 0, \text{DaSpinIniAoObligHrlyQty}_{a,z,h} - \sum_t \text{ContrSpinHrlyQty}_{a,z,h,t} \right)
\]

\[
\text{Spinning Reserve Intermediate Obligation}
\]

\[
\begin{align*}
\text{DaSpinInterAoObligHrlyQty}_{AO_V-RZN_B} &= \text{Max} \left( 0, 24.631 \text{ MWh} - 0 \right) = 24.631 \text{ MWh} \\
\text{DaSpinInterAoObligHrlyQty}_{AO_V-RZN_SPP} &= \text{Max} \left( 0, 92.926 \text{ MWh} - 0 \right) = 92.926 \text{ MWh} \\
\text{DaSpinInterAoObligHrlyQty}_{AO_W-RZN_SPP} &= \text{Max} \left( 0, 25.445 \text{ MWh} - 100 \text{ MWh} \right) = 0 \text{ MWh}
\end{align*}
\]
3.3.4 Final Obligation

The final obligation in each zone is simply the AO’s intermediate obligation scaled by an obligation ratio such that the total will equal the cleared quantity and adjusted by obligation Financial Schedules. The final obligation may be negative as a result of participation in Financial Schedules, but the zonal total is unaffected. After having entirely erased its obligation with external supply, AO_W also buys obligation via a Financial Schedule thus establishing a -100 MWh obligation in the SPP RZN. The seller of the Financial Schedule (AO_X) would have its obligation increased by 100 MWh in the same RZN.

\[
DaSpinAoObligHrlyQty_{a,z,h} = (DaSpinInterAoObligHrlyQty_{a,z,h} \times DaSpinObligRatio_h) - \sum_{t} SpinFinHrlyQty_{a,z,h,t}
\]

### Spinning Reserve Final Obligation

<table>
<thead>
<tr>
<th>Zone</th>
<th>Spinning Reserve Final Obligation</th>
</tr>
</thead>
<tbody>
<tr>
<td>AO_V-RZN_B</td>
<td>( (24.631 \text{ MWh} \times 300 \text{ MWh} / 374.555 \text{ MWh}) - 0 \text{ MWh} = 19.728 \text{ MWh} )</td>
</tr>
<tr>
<td>AO_V-RZN_SPP</td>
<td>( (92.926 \text{ MWh} \times 300 \text{ MWh} / 374.555 \text{ MWh}) - 0 \text{ MWh} = 74.429 \text{ MWh} )</td>
</tr>
<tr>
<td>AO_W-RZN_SPP</td>
<td>( (0 \text{ MWh} \times 300 \text{ MWh} / 374.555 \text{ MWh}) - 100 \text{ MWh} = -100 \text{ MWh} )</td>
</tr>
</tbody>
</table>
3.3.5 Exchange Supply Rate

RZNs clearing more product than their obligation contribute to an exchange at the zonal MCP, thus creating a supply of reserve valued at a weighted average rate. RZNs clearing less than their obligation pay the weighted average rate for the amount served by exchange supply. In this simplified example RZN A & B clear in excess of its obligation, so the exchange rate is between the values of the MCP of RZN A & B.

\[
\text{DaSpinSpxHrlyRate} = \frac{\sum_z (\text{Max}(0, \text{DaSpinRznHrlyQty}_z, h - \text{DaSpinObligRznHrlyQty}_z, h) \times \text{DaSpinMcpHrlyPrc}_z, h)}{\sum_z \text{Max}(0, \text{DaSpinRznHrlyQty}_z, h - \text{DaSpinObligRznHrlyQty}_z, h)}
\]

DaSpinSpxHrlyRate =

\[
\frac{\text{Max}(150 \text{ MWh} - 83.356 \text{ MWh}, 0) \times 5 \text{ $/MWh} + \text{Max}(50 \text{ MWh} - 40.313 \text{ MWh}, 0) \times 15 \text{ $/MWh} + \text{Max}(100 \text{ MWh} - 176.332 \text{ MWh}, 0) \times 10 \text{ $/MWh}}{\text{Max}(150 \text{ MWh} - 83.356 \text{ MWh}, 0) + \text{Max}(50 \text{ MWh} - 40.313 \text{ MWh}, 0) + \text{Max}(100 \text{ MWh} - 176.332 \text{ MWh}, 0)} = \text{5 $/MWh}
\]
3.3.6  Day Ahead Zonal Cost

For each RZN the cost of the zonal obligation is the sum of 1) the zonal MCP times the lesser of a) the zonal obligation or b) the quantity procured from the RZN and 2) the exchange rate times the greater of a) the deficiency (where the obligation is greater than the quantity procured from the RZN) or b) 0.

\[
\text{Day Ahead Zonal Cost} \\
\text{DaSpinRznHrlyCost}_{z,h} = \min (\text{DaSpinRznHrlyQty}_{z,h}, \text{DaSpinObligRznHrlyQty}_{z,h}) \times \text{DaSpinMcpHrlyPrc}_{z,h} \\
\quad + \max (0, (\text{DaSpinObligRznHrlyQty}_{z,h} - \text{DaSpinRznHrlyQty}_{z,h})) \times \text{DaSpinSpxHrlyRate}_{h}
\]

Day Ahead Zonal Cost and Exchange Supply Rate

\[
\text{Day Ahead Zonal Cost and Exchange Supply Rate} \\
\text{DaSpinRznHrlyCost}_{\text{RZN B}} = \\
\quad \min(50 \text{ MWh}, 40.313 \text{ MWh}) \times 15 \$/\text{MWh} \\
\quad + \max(0, (40.313 \text{ MWh} - 50 \text{ MWh})) \times 6.27 \$/\text{MWh} = \$604.69
\]

\[
\text{DaSpinRznHrlyCost}_{\text{RZN SPP}} = \\
\quad \min(100 \text{ MWh}, 176.332 \text{ MWh}) \times 10 \$/\text{MWh} \\
\quad + \max(0, (176.332 \text{ MWh} - 100 \text{ MWh})) \times 6.27 \$/\text{MWh} = \$1478.53
\]
3.3.7 Day-Ahead Zonal Distribution Rate

For each RZN the rate applied to AO’s obligation is the DA zonal cost divided by the total zonal obligation.

\[
\text{DaSpinDistHrlyRate}_{z,h} = \frac{\text{DaSpinRznHrlyCost}_{z,h}}{\text{DaSpinObligRznHrlyQty}_{z,h}}
\]

<table>
<thead>
<tr>
<th>Day-Ahead Zonal Distribution Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>[ \text{DaSpinDistHrlyRate}_{RZN , B} = \frac{604.69}{40.313 , \text{MWh}} = 15.0000 , / , \text{MWh} ]</td>
</tr>
</tbody>
</table>
3.3.8 Day-Ahead Zonal Distribution Charge Type Result

The charge type result for the AO is the product of the zonal obligation and the distribution rate in each zone.

\[
\text{Day-Ahead Zonal Distribution Charge Type Result}
\]

\[
\text{DaSpinDistHrlyAmt}_{a,z,h} = \text{DaSpinDistHrlyRate}_{z,h} \times \text{DaSpinAoObligHrlyQty}_{a,z,h}
\]

Day-Ahead Zonal Distribution Charge Type Result

- \(\text{DaSpinDistHrlyAmt}_{\text{AO-V-RZN B}} = \frac{15.0000}{\text{MWh}} \times 19.728 \text{ MWh} = 295.92\)
- \(\text{DaSpinDistHrlyAmt}_{\text{AO-V-RZN SPP}} = \frac{8.385}{\text{MWh}} \times 74.429 \text{ MWh} = 624.09\)
- \(\text{DaSpinDistHrlyAmt}_{\text{AO-W-RZN SPP}} = \frac{8.385}{\text{MWh}} \times -100 \text{ MWh} = -838.50\)
3.4 Charge Types for Transmission Congestion Rights

The settlement of congestion hedging instruments is achieved through 2 chains of dependent charge types: one for the TCRs themselves and a second for the ARRs at the origin of the entitlement:

1. Daily TCR Funding
2. Daily TCR Uplift
3. Monthly TCR Uplift Payback
4. Yearly TCR Uplift Payback
5. Yearly TCR Closeout

The unit of measure for TCRs is MWh, and the DA Market Marginal Congestion Component of LMP is in $/MWh.
3.4.1 Daily TCR Funding

TCRs are fully funded at the price indicated by the difference between the DA Market MCC at the sink and source of the instrument. Each TCR will have MWh quantity in Peak or Off-Peak hours only. The charge type is calculated as the sum of the transaction values in each hour. Given the transactional sample set of TCRs depicted below and the DA Market MCC captured in the table, the hourly TCR funding calculations for a single hour are as follows:

\[ TcrFundHrlyAmt_{a,h} = \sum_t (TcrHrlyQty_{a,h,t} \times (DaMccHrlyPrc_{source,h} - DaMccHrlyPrc_{sink,h})) \]
The activity among Asset Owners AO_T, AO_U, AO_V & AO_Y

- TcrHrlyQty_{G1 \rightarrow L1} = 300 \text{ MWh}: AO_T
- TcrHrlyQty_{G1 \rightarrow L4} = 290 \text{ MWh}: AO_V
- TcrHrlyQty_{G2 \rightarrow L4} = 310 \text{ MWh}: AO_V
- TcrHrlyQty_{G3 \rightarrow L2} = 400 \text{ MWh}: AO_U
- TcrHrlyQty_{G4 \rightarrow L6} = 100 \text{ MWh}: AO_Y

Asset Owner AO_T
\[
\text{TcrFundHrlyAmt} = 300 \text{ MWh} \times (19 \ \$\text{/MWh} - 3 \ \$\text{/MWh}) = 4,800 \ (\text{charge})
\]

Asset Owner AO_V
\[
\text{TcrFundHrlyAmt} = [290 \text{ MWh} \times (19 \ \$\text{/MWh} - 27 \ \$\text{/MWh}) + 310 \text{ MWh} \times (14 \ \$\text{/MWh} - 27 \ \$\text{/MWh})] = -6,350 \ (\text{credit})
\]

Asset Owner AO_U
\[
\text{TcrFundHrlyAmt} = 400 \text{ MWh} \times (28 \ \$\text{/MWh} - 18 \ \$\text{/MWh}) = 4,000 \ (\text{charge})
\]

Asset Owner AO_Y
\[
\text{TcrFundHrlyAmt} = 100 \text{ MWh} \times (0 \ \$\text{/MWh} - 36 \ \$\text{/MWh}) = -3,600 \ (\text{credit})
\]
3.4.2 Daily TCR Uplift

Concurrent with the full funding of TCRs, a daily uplift which balances the sum of the TCR funding charge type with the congestion funds available for the day is calculated for each AO. If available congestion is not sufficient to fully fund TCRs uplift charges make up the difference. The uplift is born by AOs pro rata based on the sum of the absolute value of the TCR instrument value. Assume the TCRs depicted below are the only instruments in the market and identically funded in each hour of the day and that a daily shortfall between TCR value and congestion collections of $13,680 realized in settlements. The daily shortfall and market wide denominator for the uplift ratio are calculated with data across all MPs and as such no single MP would be exposed to all of the input data required to shadow that calculation.

\[
\text{Transmission Congestion Rights Uplift}
\]

\[
\text{TcrUpliftDlyAmt}_{a, d} = \frac{\text{ShortFallDlyAmt}_{d} \cdot \text{TcrUpliftRatioAoDlyAmt}_{a, d}}{\text{TcrUpliftRatioSppDlyAmt}_{d}}
\]

Where,

(a) \[
\text{TcrUpliftRatioAoDlyAmt}_{a, d} = \sum_{h} \sum_{t} \text{ABS} \left( \text{TcrHrlyQty}_{a, h, t} \times \left( \text{DaMccHrlyPrc}_{source, h} - \text{DaMccHrlyPrc}_{sink, h} \right) \right)
\]

(b) \[
\text{TcrUpliftRatioSppDlyAmt}_{d} = \sum_{a} \sum_{h} \sum_{t} \text{ABS} \left( \text{TcrHrlyQty}_{a, h, t} \times \left( \text{DaMccHrlyPrc}_{source, h} - \text{DaMccHrlyPrc}_{sink, h} \right) \right)
\]

(c) \[
\text{ShortFallDlyAmt}_{d} = (-1) \cdot \text{MIN} \left\{ 0, \sum_{a} \sum_{s} \sum_{h} \left( \text{DaMccHrlyPrc}_{s, h} \times \left( \text{DaClrdHrlyQty}_{a, s, h} + \frac{\text{DaImpExp5minQty}_{a, s, i, t}}{12} + \text{DaClrdVHrlyQty}_{a, s, h, t} \right) \right) \right\} + \sum_{a} \sum_{h} \text{TcrFundHrlyAmt}_{a, h}
\]
The activity among Asset Owners AO_T, AO_U, AO_V & AO_Y

- $\text{TcrHrlyQty}_{G1 \rightarrow L1} = 300 \text{ MWh: AO}_T$
- $\text{TcrHrlyQty}_{G1 \rightarrow L4} = 290 \text{ MWh: AO}_V$
- $\text{TcrHrlyQty}_{G2 \rightarrow L4} = 310 \text{ MWh: AO}_V$
- $\text{TcrHrlyQty}_{G3 \rightarrow L2} = 400 \text{ MWh: AO}_U$
- $\text{TcrHrlyQty}_{G4 \rightarrow L6} = 100 \text{ MWh: AO}_Y$

uplift determinants:

- Asset Owner AO_T = $24 \times \text{ABS}(300 \text{ MWh} \times (19 \text{ $/MWh} - 3 \text{ $/MWh})) = $115,200$
- Asset Owner AO_V = $24 \times [\text{ABS}(290 \text{ MWh} \times (19 \text{ $/MWh} - 27 \text{ $/MWh}))$
  + \text{ABS}(310 \text{ MWh} \times (14 \text{ $/MWh} - 27 \text{ $/MWh}))] = $152,400$
- Asset Owner AO_U = $24 \times \text{ABS}(400 \text{ MWh} \times (28 \text{ $/MWh} - 18 \text{ $/MWh})) = $96,000$
- Asset Owner AO_Y = $24 \times \text{ABS}(100 \text{ MWh} \times (0 \text{ $/MWh} - 36 \text{ $/MWh})) = $86,400$

Market Total = $115,200 + $152,400 + $96,000 + $86,400 = $450,000$

- $\text{TcrUpliftDlyAmt}_{AO_T} = $13,680 \times ($115,200 / $450,000) = $3,502.08\ (\text{charge})$
- $\text{TcrUpliftDlyAmt}_{AO_V} = $13,680 \times ($152,400 / $450,000) = $4,632.96\ (\text{charge})$
- $\text{TcrUpliftDlyAmt}_{AO_U} = $13,680 \times ($96,000 / $450,000) = $2,918.40\ (\text{charge})$
- $\text{TcrUpliftDlyAmt}_{AO_Y} = $13,680 \times ($86,400 / $450,000) = $2,626.56\ (\text{charge})$
3.4.3 Monthly TCR Payback

Upon the settlement of the last day in a calendar month any excess congestion funds accumulated from the settlement of ODs in the month in which TCRS were fully funded is used to “pay back” those AOs which bore the cost of the uplift during the month. If the amount required to completely compensate for uplift in the month is available then excess is carried to an end-of-year process. If monthly uplift exceeds available excess congestion the entire amount is paid out pro rata based on the uplift amount born for the month.

Transmission Congestion Rights Monthly Payback

\[
\text{TcrPaybackMnthlyAmt}_{a, mn} = (-1) \times \min \{ \text{TcrUpliftAoMnthlyAmt}_{a, mn}, \text{ECFMnthlyAmt}_{mn} \times \text{TcrUpliftAoMnthlyAmt}_{a, mn} / \text{TcrUpliftSppMnthlyAmt}_{mn} \}
\]

Where,

(a) \[ \text{TcrUpliftAoMnthlyAmt}_{a, mn} = \sum_d \text{TcrUpliftDlyAmt}_{a, d} \]

(b) \[ \text{TcrUpliftSppMnthlyAmt}_{mn} = \sum_a \sum_d \text{TcrUpliftDlyAmt}_{a, d} \]

(c) \[ \text{ECFMnthlyAmt}_{mn} = \sum_d \text{ECFDlyAmt}_{d} \]

(c.1) \[ \text{ECFDlyAmt}_{d} = \max \{ 0, \sum_a \sum_s \sum_h [ \text{DaMccHrlyPrc}_{s, h} \times \text{DaClrdHrlyQty}_{a, s, h} + \sum_i \sum_t ( \text{DaImpExp5minQty}_{a, s, i, t} / 12 ) + \sum_t \text{DaClrdVHrlyQty}_{a, s, h, t} ] + \sum_a \sum_h \text{TcrFundHrlyAmt}_{a, h} \} \]
Assume the uplift paid in the previous example was duplicated for each of the first 30 days of the month and that $300,000 of excess congestion was realized on the last day of the month and available for the month end process. The monthly excess and market wide denominator for the pay back ratio are calculated with data across all MPs and as such no single MP would be exposed to all of the input data required to shadow that calculation.

<table>
<thead>
<tr>
<th>Transmission Congestion Rights Monthly Payback</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Asset Owner AO_T</strong></td>
</tr>
<tr>
<td>TcrPaybackMnthlyAmt = ((-1) \times \min{ 30 \times $3,502.08 \text{, } $300,000 \times \left[ 30 \times $3,502.08 / 30 \times $13,680 \right] } } = -$76,800</td>
</tr>
<tr>
<td><strong>Asset Owner AO_V</strong></td>
</tr>
<tr>
<td>TcrPaybackMnthlyAmt = ((-1) \times \min{ 30 \times $4,632.96 \text{, } $300,000 \times \left[ 30 \times $4,632.96 / 30 \times $13,680 \right] } } = -$101,600</td>
</tr>
<tr>
<td><strong>Asset Owner AO_U</strong></td>
</tr>
<tr>
<td>TcrPaybackMnthlyAmt = ((-1) \times \min{ 30 \times $2,918.40 \text{, } $300,000 \times \left[ 30 \times $2,918.40 / 30 \times $13,680 \right] } } = -$64,000</td>
</tr>
<tr>
<td><strong>Asset Owner AO_Y</strong></td>
</tr>
<tr>
<td>TcrPaybackMnthlyAmt = ((-1) \times \min{ 30 \times $2,626.56 \text{, } $300,000 \times \left[ 30 \times $2,626.56 / 30 \times $13,680 \right] } } = -$57,600</td>
</tr>
</tbody>
</table>

3.4.4 Yearly TCR Payback

Upon the settlement of the last day in a TCR year any excess congestion funds accumulated from the settlement of ODs in the months in which TCRs were fully funded, beyond that which was previously used in the monthly payback process is used to “pay back” those AOs whose cost of the uplift born during the year exceeds the revenue received in the monthly payback process. If the amount required to completely compensate for remaining uplift in the year is available then excess is allocated in an end-of-year close-out process. If remaining uplift exceeds available excess congestion the entire amount is paid out pro rata based on the remaining uplift amount born for the year.

Transmission Congestion Rights Yearly Payback

TcrPaybackYrlyAmt\_a, yr = 

\((-1) \times \text{Min}\{\text{TcrNetUpliftAoYrlyAmt}\_a, yr, \text{ECFYrlyAmt}\_yr \times \text{TcrNetUpliftAoYrlyAmt}\_a, yr / \text{TcrNetUpliftSppYrlyAmt}\_yr\}\)

Where,

(a) \text{TcrNetUpliftAoYrlyAmt}\_a, yr = \sum_d \text{TcrUpliftDlyAmt}\_a, d + \sum_{mn} \text{TcrPaybackMnthlyAmt}\_a, mn

(b) \text{TcrNetUpliftSppYrlyAmt}\_yr = \sum_a \left[ \sum_d \text{TcrUpliftDlyAmt}\_a, d + \sum_{mn} \text{TcrPaybackMnthlyAmt}\_a, mn \right]

(c) \text{ECFYrlyAmt}\_yr = \sum_{mn} \text{ECFMnthlyAmt}\_mn + \sum_{mn} \sum_a \text{TcrPaybackMnthlyAmt}\_a, mn
Assume the uplift paid and monthly payback in the previous examples were duplicated for each of the first 11 months of the year – meaning that no excess carried to the EOY process and there was uplift remaining from each of those 11 months. In the 12th month no uplift was required and an excess of $2,000,000 was realized. The yearly excess and market wide denominator for the payback ratio are calculated with data across all MPs and as such no single MP would be exposed to all of the input data required to shadow that calculation.

Transmission Congestion Rights Yearly Payback

Asset Owner AO_T

\[
TcrPaybackYrlyAmt = (-1) \cdot \min \left\{ 11 \cdot 30 \cdot \$3,502.08 + 11 \cdot -\$76,800 , \right. \\
\left. 2,000,000 \cdot \left[ 11 \cdot 30 \cdot \$3,502.08 + 11 \cdot -\$76,800 \right] \frac{1}{11 \cdot \$410,400 + 11 \cdot -\$300,000} \right\} = -\$310,886.40
\]

Asset Owner AO_V

\[
TcrPaybackYrlyAmt = (-1) \cdot \min \left\{ 11 \cdot 30 \cdot \$4,632.96 + 11 \cdot -\$101,600 , \right. \\
\left. 2,000,000 \cdot \left[ 11 \cdot 30 \cdot \$4,632.96 + 11 \cdot -\$101,600 \right] \frac{1}{11 \cdot \$410,400 + 11 \cdot -\$300,000} \right\} = -\$411,276.80
\]

Asset Owner AO_U

\[
TcrPaybackYrlyAmt = (-1) \cdot \min \left\{ 11 \cdot 30 \cdot \$2,918.40 + 11 \cdot -\$64,000 , \right. \\
\left. 2,000,000 \cdot \left[ 11 \cdot 30 \cdot \$2,918.40 + 11 \cdot -\$64,000 \right] \frac{1}{11 \cdot \$410,400 + 11 \cdot -\$300,000} \right\} = -\$259,072.00
\]

Asset Owner AO_Y

\[
TcrPaybackYrlyAmt = (-1) \cdot \min \left\{ 11 \cdot 30 \cdot \$2,626.56 + 11 \cdot -\$57,600 , \right. \\
\left. 2,000,000 \cdot \left[ 11 \cdot 30 \cdot \$2,626.56 + 11 \cdot -\$57,600 \right] \frac{1}{11 \cdot \$410,400 + 11 \cdot -\$300,000} \right\} = -\$233,164.80
\]
3.4.5 Yearly TCR Closeout

Upon the settlement of the last day in a TCR year the entire amount of excess congestion funds accumulated from the settlement of ODs in the months during the year in which TCRs were fully funded, beyond that which was previously used in the monthly and yearly payback process is allocated to the holders of Candidate TCRs pro rata based on the Nomination Cap – the fund is “closed out”. The yearly remaining excess and market wide denominator for the close out ratio are calculated with data across all MPs and as such no single MP would be exposed to all of the input data required to shadow that calculation.

Transmission Congestion Rights Yearly Closeout

\[ \text{TcrCloseoutYrlyAmt}_{a, yr} = (-1) \times [ \text{ECFYrlyAmt}_{yr} + \text{TcrPaybackSppYrlyAmt}_{yr} ] \]

\[ \times \frac{\text{ArrNominationCapAoYrlyQty}_{a, yr}}{\text{ArrNominationCapSppYrlyQty}_{yr}} \]

(a) \[ \text{TcrPaybackSppYrlyAmt}_{yr} = \sum_a \text{TcrPaybackYrlyAmt}_{a, yr} \]

(b) \[ \text{ArrNominationCapAoYrlyQty}_{a, yr} = \sum_d \text{ArrNominationCapQty}_{a, d} \]

(c) \[ \text{ArrNominationCapSppYrlyQty}_{yr} = \sum_a \sum_d \text{ArrNominationCapQty}_{a, d} \]
From the previous example, there is $785,600 remaining excess congestion after the yearly payback process. Nomination Cap data has not been introduced into the formulation thus far – for the calculations below we assume the following values: $AO_T = 300$ MW, $AO_V = 1200$ MW, $AO_U = 650$ MW & $AO_Y = 300$ MW (representing the entire market in this example). This example assumes the Nomination Cap values are constant across every day of the year.

| Transmission Congestion Rights Yearly Closeout | Asset Owner AO_T | TcrCloseoutYrlyAmt$_{a,yr}$ | $(-1) \times \left[ \frac{2,000,000 + 1,214,400}{365 \times (310 + 1200 + 700 + 290) \text{MW}} \right] = -$97,414.40 |
| Asset Owner AO_V | TcrCloseoutYrlyAmt$_{a,yr}$ | $(-1) \times \left[ \frac{2,000,000 + 1,214,400}{365 \times (310 + 1200 + 700 + 290) \text{MW}} \right] = -$377,088.00 |
| Asset Owner AO_U | TcrCloseoutYrlyAmt$_{a,yr}$ | $(-1) \times \left[ \frac{2,000,000 + 1,214,400}{365 \times (310 + 1200 + 700 + 290) \text{MW}} \right] = -$219,968.00 |
| Asset Owner AO_Y | TcrCloseoutYrlyAmt$_{a,yr}$ | $(-1) \times \left[ \frac{2,000,000 + 1,214,400}{365 \times (310 + 1200 + 700 + 290) \text{MW}} \right] = -$91,129.60 |
3.5 Charge Types for TCR Auctions and Auction Revenue Rights

The settlement of the TCR auction process is calculated as concurrent daily settlement of the TCRs bought and sold in auction and the revenue from those transactions passed to the holders of ARRs. Performing the settlement of a daily increment at a time on each day during the life of the instrument avoids the credit exposure associated with settling payments to an MP for an advance period when the instrument itself will collections from the MP on the settlement of the OD. In the event that the settlement of auction transactions and ARR funding does not sum to $0 the daily imbalance is treated as an uplift to Candidate ARRs.

1. Daily TCR Auction Transaction
2. Daily ARR Funding
3. Daily ARR Uplift

The unit of measure for ARRs are MW and the auction prices are $/MW-month.
3.5.1 Daily TCR Auction Transactions

TCRs transactions are settled at the price indicated by the difference between the auction clearing prices at the sink and source of the instrument. The TCR auctions are made unique by: auction type (annual or monthly), month, round and period (peak / off-peak) such that the auction transactions with a given set of those attributes must be settled at the price bearing the same set. The daily settlement is a fraction, based on the number of days in the month, of the total value indicated by the auction price. Settlement results are presented per each transaction. Though the quantity determinant is natively monthly there are circumstances which could make it necessary to allow transfer ownership of the transaction mid-month. The settlement examples will explore only one auction.

Transmission Congestion Rights Auction Transaction

\[ TcrAucTxnDlyAmt_{a,t} = \sum \{ ( TcrAucQty_{a,t,aid,source,sink} \times TcrAucPrc_{aid,source,sink} ) \times TcrAucBuySellFlg_{a,t} / \text{NumDaysInPeriod}_{aid} \} \]

Where…

\[ TcrAucPrc_{aid,source,sink} = \text{AuctionClearingPrice}_{aid,source,sink} - \text{AuctionClearingPrice}_{aid,source} \]
The activity among Asset Owners AO_T, AO_U, AO_V, AO_Y & AO_X

- AO_T Buys TcrAucMnthlyQtyG1 to L1 = 300 MW @ -$11,337/MW-month
- AO_V Buys TcrAucMnthlyQtyG1 to L4 = 290 MW @ $5,846/MW-month
- AO_V Buys TcrAucMnthlyQtyG2 to L4 = 310 MW @ $9,727/MW-month
- AO_U Sells TcrAucMnthlyQtyG3 to L2 = 400 MW @ -$6,203/MW-month
- AO_Y Sells TcrAucMnthlyQtyG4 to L6 = 100 MW @ $25,531/MW-month
- AO_X Buys TcrAucMnthlyQtyG2 to G3 = 5 MW @ $9,817/MW-month

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<thead>
<tr>
<th>SL</th>
<th>AuctionClearingPrice</th>
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<tbody>
<tr>
<td>G1</td>
<td>$13,459</td>
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<td>L2</td>
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<tr>
<td>L4</td>
<td>$19,305</td>
</tr>
<tr>
<td>L6</td>
<td>$25,531</td>
</tr>
</tbody>
</table>

Asset Owner AO_T

TcrAucTxnDlyAmt = 300 MW * -$11,337 $/MW-month * 1 / 30 d/month = -$113,370.00/d (credit)

Asset Owner AO_V

TcrAucTxnDlyAmt = 290 MW * $5,846 $/MW-month * 1 / 30 d/month = $56,511.33/d (charge)

TcrAucTxnDlyAmt = 310 MW * $9,727 $/MW-month * 1 / 30 d/month = $100,512.33/d (charge)

Asset Owner AO_U

TcrAucTxnDlyAmt = 400 MW * -$6,203 $/MW-month * -1 / 30 d/month = $20,676.67/d (charge)

Asset Owner AO_Y

TcrAucTxnDlyAmt = 100 MW * $25,531 $/MW-month * -1 / 30 d/month = -$85,103.33/d (credit)

Asset Owner AO_X

TcrAucTxnDlyAmt = 5 MW * $9,817 $/MW-month * 1 / 30 d/month = $1,636.17/d (charge)
3.5.2 Daily ARR Funding

ARRs are settled at the price indicated by the difference between the auction clearing prices at the sink and source of the instrument. ARR quantities are made unique by: auction type (annual or monthly), duration, round and period (peak / off-peak) such that the auction transactions with a given set of those attributes – as indicated by the auction ID (aid) - must be settled at the price bearing the same set. The daily settlement is a fraction, based on the number of days in the period, of the total value indicated by the auction price. Settlement results are presented per each ARR. Though the quantity determinant is natively monthly there are circumstances which could make it necessary to allow transfer ownership of the transaction mid-month. The settlement examples will explore only one auction.

Auction Revenue Rights Auction Transaction

\[
\text{ArrAucTxnDlyAmt}_{a,d,t} = \\
\left( \begin{array}{c}
\text{ArrQty}_{a,t,aid,source,sink} \times \text{TcrAucPrc}_{aid,source,sink} \\
\text{NumDaysInPeriod}_{aid} \end{array} \right) \times (-1)
\]

Where…

\[
\text{TcrAucPrc}_{aid,sink} = \text{AuctionClearingPrice}_{aid,sink} - \text{AuctionClearingPrice}_{aid,source}
\]
The ownership of ARRs among Asset Owners AO_T, AO_U, AO_V & AO_Y

- AO_T: ArrQtyG1 to L1 = 300 MW @ -$11,337/MW-month
- AO_V: ArrQtyG1 to L4 = 290 MW @ $5,846/MW-month
- AO_V: ArrQtyG2 to L4 = 310 MW @ $9,727/MW-month
- AO_U: ArrQtyG3 to L2 = 400 MW @ -$6,203/MW-month
- AO_Y: ArrQtyG4 to L6 = 100 MW @ $25,531/MW-month

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<th>SL</th>
<th>AuctionClearingPrice</th>
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<td>G1</td>
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<tr>
<td>L6</td>
<td>$25,531</td>
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</tbody>
</table>

Asset Owner AO_T

\[ \text{ArrAucTxnDlyAmt} = 300 \text{ MW} \times \frac{-11,337 \text{ $/MW-month}}{30 \text{ d/month}} \times -1 = \$113,370.00/d \text{ (charge)} \]

Asset Owner AO_V

\[ \text{ArrAucTxnDlyAmt} = 290 \text{ MW} \times \frac{5,846 \text{ $/MW-month}}{30 \text{ d/month}} \times -1 = \$56,511.33/d \text{ (credit)} \]

\[ \text{ArrAucTxnDlyAmt} = 310 \text{ MW} \times \frac{9,727 \text{ $/MW-month}}{30 \text{ d/month}} \times -1 = \$100,512.33/d \text{ (credit)} \]

Asset Owner AO_U

\[ \text{ArrAucTxnDlyAmt} = 400 \text{ MW} \times \frac{-6,203 \text{ $/MW-month}}{30 \text{ d/month}} \times -1 = \$20,676.67/d \text{ (charge)} \]

Asset Owner AO_Y

\[ \text{ArrAucTxnDlyAmt} = 100 \text{ MW} \times \frac{25,531 \text{ $/MW-month}}{30 \text{ d/month}} \times -1 = \$85,103.33/d \text{ (credit)} \]
3.5.3 Daily ARR Uplift

With the settlement of each OD the deficit between daily TCR auction proceeds and ARR funding is uplifted to the holders of Candidate ARRs pro rata based on the absolute value of ARR instrument economic value. Since the value of TCR auction transactions and ARRs is constant throughout the month there is no need to carry excess to the end of the month in the manner of the TCR payback process – each day in a month will result in identical uplift charge type amounts. Excess is carried all the way to an end of year process in which payers of ARR uplift during the year are made whole to the extent possible and if funds exist beyond the payback of uplift a closeout process depletes the account (this part of the funding process does mirror that employed in TCR funding and as such is not detailed in the settlement examples).

### Auction Revenue Rights Uplift

\[
\text{ArrUpliftDlyAmt}_{a,d} = \text{TcrArrUnderDlyAmt}_{d} \times \left\lfloor \frac{\text{ABS} (\text{ArrAucTxnDlyAmt}_{a,d})}{\text{ArrAucTxnSppDlyAmt}_{d}} \right\rfloor
\]

Where,

(a) \( \text{ArrAucTxnSppDlyAmt}_{d} = \sum_{a} \text{ABS} (\text{ArrAucTxnDlyAmt}_{a,d}) \)

(a) \( \text{TcrArrUnderDlyAmt}_{d} = (-1) \times \sum_{m} \text{Min} (\text{TcrAucTxnMpAmt}_{m,d} + \text{ArrAucTxnMpAmt}_{m,d}, 0) + \sum_{a} \sum_{h} \text{TcrFundHrlyAmt}_{a,h} \)
The previous example did not represent the entire set of auction transactions or ARRs, so the example arbitrarily sets the daily differential as a deficit of $1,000,000. Nomination Cap data values are the same as those used in the TCR yearly close-out calculations.

**Auction Revenue Rights Uplift**

**Asset Owner AO_T**

\[
\text{ArrUpliftDlyAmt}_{a,yr} = \frac{1,000,000 \times [310 \text{ MW} / (310 + 1200 + 700 + 290) \text{ MW}]}{1200} = 124,000
\]

**Asset Owner AO_V**

\[
\text{ArrUpliftDlyAmt}_{a,yr} = \frac{1,000,000 \times [1200 \text{ MW} / (310 + 1200 + 700 + 290) \text{ MW}]}{1200} = 480,000
\]

**Asset Owner AO_U**

\[
\text{ArrUpliftDlyAmt}_{a,yr} = \frac{1,000,000 \times [700 \text{ MW} / (310 + 1200 + 700 + 290) \text{ MW}]}{700} = 280,000
\]

**Asset Owner AO_Y**

\[
\text{ArrUpliftDlyAmt}_{a,yr} = \frac{1,000,000 \times [290 \text{ MW} / (310 + 1200 + 700 + 290) \text{ MW}]}{290} = 116,000
\]
3.6 Charge Types for Make Whole Payments

Resources committed economically by SPP in the DA Market or RUC are made whole to their production costs per the offer effective at the time of the commitment. While Commitment Periods may span multiple Operating Days, the settlement system treats each intersection of an Operating Day and Commitment Period as a separate Make Whole Eligibility Period. DA MWP are allocated to DA Market cleared load including virtual bids and exports by a rate which averages the daily total $MWP over the load MW for the entire day. RTBM MWP are allocated to various kinds of deviations between DA Market and RTBM instruments, again using a daily average rate. A comprehensive exploration of these charge types would require examples in many, many different scenarios. While related training documentation does provide this depth, this appendix will present only a selected subset of all possible settlement scenarios for the following charge types:

1. DA Market Make Whole Payment
2. RUC Make Whole Payment
3. DA Market Make Whole Payment Cost Allocation
4. RUC Make Whole Payment Cost Allocation

Note about incremental energy: this cost component is achieved by integrating the area under the offer curve to the cleared MW in DA or to the billable meter quantity in RT. The summation of cost accumulated from 1 to n-1 sloped or block offer sections and for the partial section in which the target MW lie is difficult to express in numerical examples. In the interest of clarity the following examples will be simplified by assuming the offer is a single block, thus the integrated amount is simply achieved by offer price * MW.
3.6.1 DA Market Make Whole Payment

Scenario 1: a CC resource is committed with a Market status in DA from 3 PM to 10 PM with a start-up cost of $10k and min run time of 4 hours. The resource is moved into a second configuration 2 hours in and a 3rd 4 hours in.

The resource is eligible for start-up as no other MWEP is adjacent. Additionally, transition costs are considered in the first hour of each configuration change. Costs exceed revenue in this example and the resource receives a $16,500 MWP.
Scenario 2: a resource is committed with Market status in DA from 5 PM to 7 PM with a start-up cost of $10k and min run time of 4 hours. This Market MWEP bridges a gap between 2 Self status periods. The resource is not eligible for start-up because the CP contains Self status committed hours. The remaining costs exceed revenue in this example and the resource receives a $1,000 MWP.
Scenario 3: a resource is committed with Market status in DA Market from 10 PM on the previous day to 3 AM current, and again between 6 AM and 11 AM on the current day with a start-up cost of $10k and min run time of 4 hours. Note that the split in the first CP into 2 MWEPS results in a different net total in MWP with all of the same hourly inputs.

The resource is eligible for start-up in both periods as there are no Self status hours. The costs in the abbreviated MWEP before midnight exceed revenue and the resource receives a $2,450 MWP, while in the remainder of the MWEP after midnight revenue exceeds cost and no MWP is necessary. When the two sections are considered together total revenue exceeds cost so no MWP is necessary for the period from HE 7 to HE 11.
3.6.2 RUC Make Whole Payment

**Scenario 1:** A CC resource is committed with Market in DA from 3 PM to midnight with a start-up cost of $10k and min run time of 1 hour. The resource is moved into a second, higher configuration in RT from 8 PM to 9 PM.

<table>
<thead>
<tr>
<th>Hour Ending</th>
<th>Market Clearing (Input)</th>
<th>RT Resource Offer (Input)</th>
<th>Production Cost Parameters</th>
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</thead>
<tbody>
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<tr>
<th>Interval</th>
<th>Cost per start ($)</th>
<th>Min-run Time (hours)</th>
<th>EwExpansion ($/MW)</th>
<th>Reg Down Offer ($/MW)</th>
<th>Spinning Offer ($/MW)</th>
<th>Supplemental Offer ($/MW)</th>
<th>ChldStartRatio (%)</th>
<th>RSSStartUpDownAmount ($)</th>
<th>ResSettleEnabledFlag (Y/N)</th>
<th>RTTransitionEnableOff ($/MW)</th>
<th>RTResCmpEnrAmount ($)</th>
<th>RTResCmpEnrAmount ($)</th>
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The resource is not eligible for start-up, but the MWP will consider a $2k transition cost and incremental no-load of $250 for the hour due to the higher configuration. The energy and OR costs are calculated on the basis of incremental MW.

Because the LMP and MCP rose above the resource’s costs in the 2nd half of the hour it was able to make back a portion of the incremental and no-load costs, but not enough to overcome the transition cost. No clawbacks affected the MWP in this scenario. The resource receives a $1,925 MWP.
Scenario 2: a resource is committed with Market status in RT from 8 PM to 9 PM, but Self status from 9 PM forward with a min run time of 1 hour. It is ineligible for start-up due to the Self status, but the start is cancelled 1/2 way into the start-up duration.

There are no revenue or clawback components to consider since the start-up was cancelled. No MWP is necessary, not even for the cancelled start because the resource would not have been eligible for start-up had the cancellation not been issued.
Scenario 3: a resource is committed with Market status in RT from 8 PM to 9 PM with a min run time of 1 hour. Since this MWEP is adjacent to the end of a DA MWEP it is ineligible for start-up. A RUC MWEP preceding a DA Self status CP is not necessarily ineligible for start-up cost recovery.
There are no clawback components to consider in this scenario. The costs in the economic hour exceed revenue in this example and the resource receives a $633 MWP.

<table>
<thead>
<tr>
<th>Hour Ending</th>
<th>Market Clearing (Input)</th>
<th>Market Prices (Input)</th>
<th>Resource Revenue</th>
<th>MWP calculations</th>
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**Scenario 4**: a resource is committed with Market status in RT from 8 PM to 9 PM with a min run time of 1 hour. Since the CP contains Self status intervals it is ineligible for start-up.
There are no clawback components to consider in this scenario. The costs in the economic hour exceed revenue in this example and the resource receives a $633 MWP.
**Scenario 5**: a resource is committed with Market status in RT from 7 PM to 9 PM with a min run time of 1 hour. No adjacent CPs impact eligibility for start-up. In this example the resource has revenue contributions from OOM and Reg Adjustment charge types.

<table>
<thead>
<tr>
<th>Hour Ending</th>
<th>Market Clearing (Input)</th>
<th>RT Resource Offer (Input)</th>
<th>Production Cost Parameters</th>
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<tbody>
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<td>DaDcDec/Com/Adj10L (MW)</td>
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<td></td>
<td>DaDcDec/Com/Adj11H (MW)</td>
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<td></td>
<td>DaDcDec/Com/Adj11L (MW)</td>
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<td>DaDcDec/Com/Adj12H (MW)</td>
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<td>DaDcDec/Com/Adj12L (MW)</td>
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<td>DaDcDec/Com/Adj13H (MW)</td>
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<td>DaDcDec/Com/Adj13L (MW)</td>
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<td></td>
<td>DaDcDec/Com/Adj14H (MW)</td>
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<td></td>
<td>DaDcDec/Com/Adj14L (MW)</td>
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<td>DaDcDec/Com/Adj15H (MW)</td>
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<td>DaDcDec/Com/Adj15L (MW)</td>
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<td>DaDcDec/Com/Adj16H (MW)</td>
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<td></td>
<td>DaDcDec/Com/Adj16L (MW)</td>
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<td></td>
<td>DaDcDec/Com/Adj17H (MW)</td>
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<td></td>
<td>DaDcDec/Com/Adj17L (MW)</td>
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<td></td>
<td>DaDcDec/Com/Adj18H (MW)</td>
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<td></td>
<td>DaDcDec/Com/Adj18L (MW)</td>
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<td></td>
<td>DaDcDec/Com/Adj19H (MW)</td>
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<tr>
<td></td>
<td>DaDcDec/Com/Adj19L (MW)</td>
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<tr>
<td></td>
<td>DaDcDec/Com/Adj20H (MW)</td>
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<tr>
<td></td>
<td>DaDcDec/Com/Adj20L (MW)</td>
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<tr>
<td></td>
<td>DaDcDec/Com/Adj21H (MW)</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>DaDcDec/Com/Adj21L (MW)</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
There are no clawback components to consider in this scenario. The costs in the economic hour exceed revenue in this example and the resource receives a $3,200 MWP.
Scenario 6: a resource is committed with Market status in RT from 7 PM to 9 PM with a min run time of 1 hour. No adjacent CPs impact eligibility for start-up. In this example the resource experiences clawbacks of incremental energy for URD, Manual status and raising limits.
The desired quantity and amount used in the clawback calculations are driven by a random function in the spreadsheet as a proxy for finding the quantity indicated by the LMP on the offer curve and integrating cost to that point. The costs in the economic hour exceed revenue in this example and the resource receives a $9,160 MWP.
3.6.3 DA Market Make Whole Payment Cost Allocation

The following set of examples are based on the settlement of an OD in which there are a total of $2M in DA MWP and Cost allocation determinants summing to 800,000 considering all hour of the OD, thus the hourly cost allocation rate is $2.50/MWh.

Cost Allocation Determinants

\[
\text{DaMwpDistHrlyQty}_{a,s,h} = \text{Max} \left( 0, \text{DaClrdHrlyQty}_{a,s,h} + \sum_t \text{DaClrdVHrlyQty}_{a,s,h,i,t} + \sum_i \sum_t \text{DaImpExp5minQty}_{a,s,i,t} / 12 \right)
\]

Settlement Amount

\[
\text{DaMwpDistHrlyAmt}_{a,s,h} = \text{DaMwpSppDistRate}_d \times \text{DaMwpDistHrlyQty}_{a,s,h}
\]
The DA Market activity of AO_U

- DaClrdHrlyQtyL3 = 90 MWh (Bid)
- DaClrdHrlyQtyG3 = -500 MWh (Offer)
- DaClrdVHrlyQtyG3 = 40 MWh (Bid)
- DaEnFinHrlyQtyG3 = -300 MWh (Seller to AO_X)
- DaEnFinHrlyQtyG3 = -101 MWh (Seller to AO_V)
- DaImpExpHrlyQtyI2 = 80 MWi (Export)
- DaClrdVHrlyQtyI2 = -60 MWh (Offer)

- Note that the generation and virtual withdrawal net out at G3 and the export and virtual injection at I2 partially cancel each other out, but that the 100 MW virtual injection at L3 cleared by another AO is not considered in netting with the DA cleared load at L3. The example assumes the export is in every 5-minute interval during the hour.

Cost Allocation Determinants

- DaMwpDistHrlyQtyL3 = Max( 0, 90 MWh + (0) + (0)/ 12) = 90 MWh
- DaMwpDistHrlyQtyG3 = Max( 0, -500 MWh + (40 MWh) + (0)/ 12) = 0 MWh
- DaMwpDistHrlyQtyI2 = Max( 0, 0 + (-60 MWh) + 12*(80 MWi)/ 12i/h) = 20 MWh

Settlement Amount

- DaMwpDistHrlyAmtL3 = $2.50 / MWh * 90 MWh = $225.00
- DaMwpDistHrlyAmtG3 = $2.50 / MWh * 0 MWh = $0.00
- DaMwpDistHrlyAmtI2 = $2.50 / MWh * 20 MWh = $50.00
The DA Market activity of AO_V

- DaClrdVHrlyQtyL3 = -100 MWh (Offer)
- DaClrdVHrlyQtyH2 = 30 MWh (Bid)
- DaClrdHrlyQtyL4 = 475 MWh (Bid)
- DaClrdVHrlyQtyL4 = -195 MWh (Offer)
- DaEnFinHrlyQtyG3 = 101 MWh (Buyer from AO_U)
- DaImpExpHrlyQtyI3 = -160 MWi (Import)
- DaImpExpHrlyQtyI3 = 200 MWi (Export)
- DaNEnFinHrlyQtyG3 = 200 MWh (Buyer from AO_X)

- Note that the withdrawal and virtual injection net out at L4 and the import and export at I3 partially cancel each other out, even if the instruments do not occur in the same 5-minute interval. The example assumes the import / export are in every 5-minute interval during the hour.

<table>
<thead>
<tr>
<th>Cost Allocation Determinants</th>
</tr>
</thead>
<tbody>
<tr>
<td>DaMwpDistHrlyQtyL3 = Max(0, -100 MWh + (0) + (0) / 12) = 0 MWh</td>
</tr>
<tr>
<td>DaMwpDistHrlyQtyH2 = Max(0, 0 + (30 MWh) + (0) / 12) = 30 MWh</td>
</tr>
<tr>
<td>DaMwpDistHrlyQtyL4 = Max(0, 475 MWh + (-195 MWh) + (0) / 12) = 280 MWh</td>
</tr>
<tr>
<td>DaMwpDistHrlyQtyI3 = Max(0, 0 + (0) + 12*(-160 MWi + 200 MWi) / 12i/h) = 40 MWh</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Settlement Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>DaMwpDistHrlyAmtL3 = $2.50 / MWh * 0 MWh = $0.00</td>
</tr>
<tr>
<td>DaMwpDistHrlyAmtI2 = $2.50 / MWh * 30 MWh = $75.00</td>
</tr>
<tr>
<td>DaMwpDistHrlyAmtL4 = $2.50 / MWh * 280 MWh = $700.00</td>
</tr>
<tr>
<td>DaMwpDistHrlyAmtI3 = $2.50 / MWh * 40 MWh = $100.00</td>
</tr>
</tbody>
</table>
### 3.6.4 RUC Make Whole Payment Cost Allocation

The following set of examples are based on the settlement of an OD in which there are a total of $500k in RTBM MWP and Cost allocation determinants summing to 50,000 MWh considering all hour of the OD, thus the hourly cost allocation rate is $10.00/MWh.

<table>
<thead>
<tr>
<th>Cost Allocation Determinants</th>
</tr>
</thead>
<tbody>
<tr>
<td>( \text{RtDevHrlyQty}<em>{a,s,h} = \text{RtNetSlDevHrlyQty}</em>{a,s,h} + \text{RtMinLimitDevHrlyQty}_{a,s,h} )</td>
</tr>
<tr>
<td>( \text{allocation} )</td>
</tr>
<tr>
<td>( + \text{RtMaxLimitDevHrlyQty}<em>{a,s,h} + \text{RtOutageDevHrlyQty}</em>{a,s,h} )</td>
</tr>
<tr>
<td>( + \text{RtStatusDevHrlyQty}<em>{a,s,h} + \text{RtRucScDevHrlyQty}</em>{a,s,h} )</td>
</tr>
<tr>
<td>( + \text{RtRucCommitDevHrlyQty}<em>{a,s,h} + \text{RtURDDevHrlyQty}</em>{a,s,h} )</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Allocation Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>( \text{RtMwpSppDistRate}<em>{d} = ( \text{RtMwpSppDlyAmt}</em>{d} / \text{RtDevSppDlyQty}_{d} ) \times (-1) )</td>
</tr>
<tr>
<td>( \text{Allocation} )</td>
</tr>
</tbody>
</table>

Where: \( \text{RtMwpSppDlyAmt}_{d} = \sum_{m} \text{RtMwpMpAmt}_{m,d} \)

<table>
<thead>
<tr>
<th>Settlement Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>( \text{RtMwpDistHrlyAmt}<em>{a,s,h} = \text{RtMwpSppDistRate}</em>{d} \times \text{RtDevHrlyQty}_{a,s,h} )</td>
</tr>
</tbody>
</table>

It is easily seen that an AO with 1 MWh of deviation at a SL will pay a charge of $10.00 for that deviation. The complexity in calculating the RUC MWP Cost Allocation is buried in the derivation of each of the 8 types of deviation.
3.6.4.1 Net Settlement Location Deviation

The Net Settlement Location Deviation is a measurement of the net energy imbalance between DA Market and RTBM per SL. Instruments are permitted to net together in this calculation. “Through” interchange schedules are treated as separate Import and Export transactions except that deviation is only measured on the outbound side. Interchange transactions in support of Contingency Reserve Events (to or from Reserve Sharing Group members outside the SPP footprint) are not counted towards deviation. The examples assume all the determinants at a single SL belong to the same AO and that the values depicted are constant across each of the 5-minute intervals in the hour.

The Net Settlement Location Deviation is calculated as follows:

\[
\text{RtNetSlDevHrlyQty}_{a,s,h} = \text{ABS} \sum_{i} \text{RtNetSlDev5minQty}_{a,s,i}
\]

\[
\text{RtNetSlDev5minQty}_{a,s,i} = \{ \text{Max} (0, \text{RtBillMtr5minQty}_{a,s,i}) - \text{Max} (0, \text{DaClrdHrlyQty}_{a,s,h}) 
\]

\[
+ \{ \sum_{t} \text{Max} (0, \text{RtImpExp5minQty}_{a,s,i,t,\text{dir}}) - \sum_{t} \text{Max} (0, \text{DaImpExp5minQty}_{a,s,i,t,\text{dir}}) \}
\]

\[
+ \{ \text{IF} \text{ DIR} \neq \text{“THROUGH”}, \text{THEN} \sum_{t} \text{Min} (0, \text{RtImpExp5minQty}_{a,s,i,t,\text{dir}}) - \sum_{t} \text{Min} (0, \text{DaImpExp5minQty}_{a,s,i,t,\text{dir}}) \}, \text{ELSE 0} \} \times (1 - \text{RsgCrdFlg}_{t})
\]

\[
- \sum_{t} \text{DaClrdVHrlyQty}_{a,s,h,t} / 12
\]
Settlement Location G1

\[ \text{RtNetSlDev5minQty} = \left\{ \max(0, -200 \text{ MWi}) - \max(0, -340 \text{ MWi}) \right\} \]

\[ + \left\{ \max(0, 0) - \max(0, 0) \right\} \]

\[ + \left\{ \min(0, 0) - \min(0, 0) \right\} \] \times (1 - 0)

\[ - 85 \} / 12 \text{ i/h} = 85 \text{ MWi} / 12 \text{ i/h} = 7.083 \text{ MWh} \]

\[ \text{RtNetSlDevHrlyQty} = \text{ABS} (12 \times 0 \text{ MWh}) = 0 \text{ MWh} \]

Settlement Location G2

\[ \text{RtNetSlDev5minQty} = \left\{ \max(0, -170 \text{ MWi}) - \max(0, -85 \text{ MWi}) \right\} \]

\[ + \left\{ \max(0, 0) - \max(0, 0) \right\} \]

\[ + \left\{ \min(0, 0) - \min(0, 0) \right\} \] \times (1 - 0)

\[ - 85 \} / 12 \text{ i/h} = 85 \text{ MWi} / 12 \text{ i/h} = 7.083 \text{ MWh} \]

\[ \text{RtNetSlDevHrlyQty} = \text{ABS} (12 \times 0 \text{ MWh}) = 85 \text{ MWh} \]

Settlement Location I1 – no “Through” transactions

\[ \text{RtNetSlDev5minQty} = \left\{ \max(0, 0) - \max(0, 0) \right\} \]

\[ + \left\{ \max(0, 75 \text{ MWi}) + \max(0, -50 \text{ MWi}) - \max(0, 70 \text{ MWi}) - \max(0, -45 \text{ MWi}) \right\} \] \times (1 - 0)

\[ - 0 \} / 12 \text{ i/h} = 0 \text{ MWi} / 12 \text{ i/h} = 0 \text{ MWh} \]

\[ \text{RtNetSlDevHrlyQty} = \text{ABS} (12 \times 0 \text{ MWh}) = 0 \text{ MWh} \]
### Settlement Location L1

\[
\text{RtNetSlDev5minQty} = \left\{ \max(0, 435 \text{ MWi}) - \max(0, 410 \text{ MWi}) + \left[ \max(0, 0) - \max(0, 0) \right] \right\} \times (1 - 0) - 0
\]

\[
\div 12 = \left\{ 435 \text{ MWi} - 410 \text{ MWi} - 25 \text{ MWi} \right\} \div 12 \text{ i/h} = 0 \text{ MWh}
\]

\[
\text{RtNetSlDevHrlyQty} = \left\lfloor 12 \times 0 \text{ MWh} \right\rfloor = 0 \text{ MWh}
\]

### Settlement Location L2

\[
\text{RtNetSlDev5minQty} = \left\{ \max(0, 215 \text{ MWi}) - \max(0, 205 \text{ MWi}) + \left[ \max(0, 0) - \max(0, 0) \right] \right\} \times (1 - 0)
\]

\[
\div 12 = \left\{ 215 \text{ MWi} - 205 \text{ MWi} \right\} \div 12 \text{ i/h} = 0.833 \text{ MWh}
\]

\[
\text{RtNetSlDevHrlyQty} = \left\lfloor 12 \times 0.833 \text{ MWh} \right\rfloor = 10 \text{ MWh}
\]

### Settlement Location H1

\[
\text{RtNetSlDev5minQty} = \left\{ \max(0, 0) - \max(0, 0) + \left[ \max(0, 0) - \max(0, 0) \right] \right\} \times (1 - 0)
\]

\[
\div 12 = \left\{ 85 \text{ MWi} \right\} \div 12 \text{ i/h} = 7.083 \text{ MWh}
\]

\[
\text{RtNetSlDevHrlyQty} = \left\lfloor 12 \times 7.083 \text{ MWh} \right\rfloor = 85 \text{ MWh}
\]
Settlement Location I6 – no through transactions

\[
\text{RtNetSlDev5minQty} = \\
\{ \text{Max} (0, 0) - \text{Max} (0, 0) \\
+ \left[ \text{Max} (0, 442 \text{ MWi}) - \text{Max} (0, 0 \text{ MWi}) \right] \\
+ \left[ \text{Min} (0, 442 \text{ MWi}) - \text{Min} (0, 0 \text{ MWi}) \right] \right] \times (1 - 0) - 420 / 12 \\
= \{ 442 \text{ MWi} - 420 \text{ MWi} \} / 12 \text{ i/h} = 22 \text{ MWi} / 12 \text{ i/h} = 1.833 \text{ MWh} \\
\text{RtNetSlDevHrlyQty} = \text{ABS} (12 \times 1.833 \text{ MWh}) = 22 \text{ MWh}
\]

Settlement Location I8 – no through transactions

\[
\text{RtNetSlDev5minQty} = \\
\{ \text{Max} (0, 0) - \text{Max} (0, 0) \\
+ \left[ \text{Max} (0, 442 \text{ MWi}) - \text{Max} (0, 0 \text{ MWi}) \right] \\
+ \left[ \text{Min} (0, 442 \text{ MWi}) - \text{Min} (0, 0 \text{ MWi}) \right] \right] \times (1 - 0) - 420 / 12 \\
= \{ 442 \text{ MWi} - 420 \text{ MWi} \} / 12 \text{ i/h} = 22 \text{ MWi} / 12 \text{ i/h} = 1.833 \text{ MWh} \\
\text{RtNetSlDevHrlyQty} = \text{ABS} (12 \times 1.833 \text{ MWh}) = 22 \text{ MWh}
\]

Settlement Location I7 – the 160 / 135 MW tag is part of a “Through” interchange transaction

\[
\text{RtNetSlDev5minQty} = \\
\{ \text{Max} (0, 0) - \text{Max} (0, 0) \\
+ \left[ \text{Max} (0, -250 \text{ MWi}) + \text{Max} (0, -135 \text{ MWi}) - \text{Max} (0, -225 \text{ MWi}) - \text{Max} (0, -160 \text{ MWi}) \right] \\
+ \left[ \text{IF } \text{DIR} \text{ <> "THROUGH", THEN Min} (0, -250 \text{ MWi}) - \text{Min} (0, -225 \text{ MWi}), \text{ELSE} 0 \right] \right] \times (1 - 0) \\
= \{ -250 \text{ MWi} + 15 \text{ MWi} \} / 12 = \{ -250 \text{ MWi} - 225 \text{ MWi} - 45 \text{ MWi} \} / 12 \text{ i/h} = 20 \text{ MWi} / 12 \text{ i/h} = 1.667 \text{ MWh} \\
\text{RtNetSlDevHrlyQty} = \text{ABS} (12 \times 1.667 \text{ MWh}) = 20 \text{ MWh}
\]
3.6.4.2 Minimum Limit Deviation

The Minimum Limit Deviation is a measurement of the degree to which a resource raising its minimum limit after clearing in the DA Market is forcing uneconomic energy into the RTBM. In order to be calculated for this type of deviation a resource must have cleared injection in the DA market and must be given a setpoint instruction = the applicable minimum limit, depending on whether it is regulating or not in RT, in an interval during the hour. The examples assume the interval values are constant through the hour.

Minimum Limit Deviation

\[
\text{RtMinLimitDevHrlyQty}_{a,s,h} = \sum \text{RtMinLimitDev5minQty}_{a,s,i}
\]

IF SetPointMinHrlyFlg\(_{a,s,h}\) = “1” AND DaClrdHrlyQty\(_{a,s,h}\) < 0

THEN

** Regulation is not cleared in RTBM **

IF ControlStatus5minFlg\(_{a,s,i}\) <> “Regulating” AND

\[
( \text{RtDispMinEconCapOL5minQty}_{a,s,i} - \text{DaComMinEconCapOLHrlyQty}_{a,s,h} ) > \text{ResOpTol5minQty}_{a,s,i}
\]

THEN

\[
\text{RtMinLimitDev5minQty}_{a,s,i} = \text{MAX} \left( \frac{\text{(RtDispMinEconCapOL5minQty}_{a,s,i} + \text{DaClrdHrlyQty}_{a,s,h})}{12}, 0 \right)
\]

A Resource offer with a 75 MW minimum economic limit clears -100 MWh in the DA Market. In RT it is not Regulating and has raised its economic limit to 120 MW. Its Operating Tolerance is 10 MW.

\[
\text{RtMinLimitDev5minQty} = \text{MAX} \left[ \left( 120 \text{ MWi} + -100 \text{ MWi} \right), 0 \right] / 12 \text{ i/h} = 1.667 \text{ MWh}
\]

\[
\text{RtMinLimitDevHrlyQty} = 12 * 1.667 \text{ MWh} = 20 \text{ MWh}
\]
** Regulation is cleared in both DA Market and RTBM **

ELSE IF ControlStatus5minFlg \( a, s, i \) = “Regulating” AND ( DaRegUpHrlyQty \( a, s, h \) + DaRegDnHrlyQty \( a, s, h \) ) > 0 AND

\( ( \text{RtDispMinRegCapOL5minQty} \_{a, s, i} - \text{DaComMinRegCapOLHrlyQty} \_{a, s, h} ) > \text{ResOpTol5minQty} \_{a, s, i} \)

THEN

\[ \text{RtMinLimitDev5minQty} \_{a, s, i} = \frac{\text{MAX} \left[ ( \text{RtDispMinRegCapOL5minQty} \_{a, s, i} + \text{DaClrdHrlyQty} \_{a, s, h} ), 0 \right]}{12} \]

A Resource offer with a 75 MW minimum regulating limit clears -100 MWh in the DA Market, and 10 MW of Regulation Up. In RT it is Regulating and has raised its regulating limit to 120 MW. Its Operating Tolerance is 10 MW.

\[ \text{RtMinLimitDev5minQty} = \text{MAX} \left[ ( 120 \text{ MW} + -100 \text{ MWi } ), 0 \right] / 12 \text{ i/h} = 1.667 \text{ MWh} \]

\[ \text{RtMinLimitDevHrlyQty} = 12 \times 1.667 \text{ MWh} = 20 \text{ MWh} \]

** Regulation is cleared in RTBM and not cleared in DA Market **

ELSE IF ControlStatus5minFlg \( a, s, i \) = “Regulating” AND ( DaRegUpHrlyQty \( a, s, h \) + DaRegDnHrlyQty \( a, s, h \) ) = 0 AND

\( ( \text{RtDispMinRegCapOL5minQty} \_{a, s, i} - \text{DaComMinRegCapOLHrlyQty} \_{a, s, h} ) > \text{ResOpTol5minQty} \_{a, s, i} \)

THEN

\[ \text{RtMinLimitDev5minQty} \_{a, s, i} = \frac{\text{MAX} \{ \text{RtDispMinRegCapOL5minQty} \_{a, s, i} - \text{MAX} [ \text{ABS} ( \text{DaClrdHrlyQty} \_{a, s, h} ), \text{DaComMinRegCapOLHrlyQty} \_{a, s, h} ], 0 \} }{12} \]

A Resource offer with a 75 MW minimum regulating limit clears -100 MWh in the DA Market, but no Regulation. In RT it is Regulating and has raised its regulating limit to 120 MW. Its Operating Tolerance is 10 MW.

\[ \text{RtMinLimitDev5minQty} = \text{MAX} \left[ ( 120 \text{ MWi } - \text{MAX}( \text{ABS}(-100 \text{ MWi}), 75 \text{ MWi } ), 0 \right] / 12 \text{ i/h} = 1.667 \text{ MWh} \]

\[ \text{RtMinLimitDevHrlyQty} = 12 \times 1.667 \text{ MWh} = 20 \text{ MWh} \]
3.6.4.3 Maximum Limit Deviation

The Maximum Limit Deviation is a measurement of the degree to which a resource lowering its maximum limit after clearing in the DA Market is limiting the energy RTBM would economically want from the resource. In order to be calculated for this type of deviation a resource must have cleared injection in the DA market and must be given a setpoint instruction = the applicable maximum limit, depending on whether it is regulating or not in RT, in an interval during the hour. The examples assume the interval values are constant through the hour.

**Maximum Limit Deviation**

\[ \text{RtMaxLimitDevHrlyQty}_{a,s,h} = \sum_{i} \text{RtMaxLimitDev5minQty}_{a,s,i} \]

IF SetPointMaxHrlyFlg_{a,s,h} = “1” AND DaClrdHrlyQty_{a,s,h} < 0

THEN

**Regulation is not cleared in RTBM**

IF ControlStatus5minFlg_{a,s,i} <> “Regulating” AND

\[ ( \text{DaComMaxEconCapOLHrlyQty}_{a,s,h} - \text{RtDispMaxEconCapOL5minQty}_{a,s,i} ) > \text{ResOpTol5minQty}_{a,s,i} \]

THEN

\[ \text{RtMaxLimitDev5minQty}_{a,s,i} = \text{MAX} \left( \text{ABS} \left( \text{DaClrdHrlyQty}_{a,s,h} \right) - \text{RtDispMaxEconCapOL5minQty}_{a,s,i} , 0 \right) / 12 \]

A Resource offer with a 150 MW maximum economic limit clears -100 MWh in the DA Market, but no Regulation. In RT it is not Regulating and has lowered its economic limit to 80 MW. Its Operating Tolerance is 10 MW.

\[
\text{RtMaxLimitDev5minQty} = \text{MAX} \left( \text{ABS}(-100 \text{ MWi}) - 80 \text{ MWi} , 0 \right) / 12 \text{ i/h} = 1.667 \text{ MWh}
\]

\[
\text{RtMaxLimitDevHrlyQty} = 12 \times 1.667 \text{ MWh} = 20 \text{ MWh}
\]
** Regulation is cleared in both DA Market and RTBM **

ELSE IF ControlStatus5minFlg_{a,s,i} = “Regulating” AND ( DaRegUpHrlyQty_{a,s,h} + DaRegDnHrlyQty_{a,s,h} ) > 0 AND

( DaComMaxRegCapOLHrlyQty_{a,s,h} - RtDispMaxRegCapOL5minQty_{a,s,i} ) > ResOpTol5minQty_{a,s,i}

THEN

$$RtMaxLimitDev5minQty_{a,s,i} = \max \left( \frac{\abs{DaClrdHrlyQty_{a,s,h}} - RtDispMaxRegCapOL5minQty_{a,s,i}}{12}, 0 \right)$$

A Resource offer with a 150 MW maximum regulating limit clears -100 MWh in the DA Market, and 10 MW Regulation Up. In RT it is Regulating and has lowered its regulating limit to 80 MW. Its Operating Tolerance is 10 MW.

RtMaxLimitDev5minQty = MAX ( \abs{-100 MWi} - 80 MWi , 0 ) / 12 i/h = 1.667 MWh

RtMaxLimitDevHrlyQty = 12 * 1.667 MWh = 20 MWh

** Regulation is cleared in RTBM and not cleared in DA Market **

ELSE IF ControlStatus5minFlg_{a,s,i} = “Regulating” AND ( DaRegUpHrlyQty_{a,s,h} + DaRegDnHrlyQty_{a,s,h} ) = 0 AND

( DaComMaxRegCapOLHrlyQty_{a,s,h} - RtDispMaxRegCapOL5minQty_{a,s,i} ) > ResOpTol5minQty_{a,s,i}

THEN

$$RtMaxLimitDev5minQty_{a,s,i} = \max \left( \min \left( \frac{\abs{DaClrdHrlyQty_{a,s,h}}}{12}, \frac{DaComMaxRegCapOLHrlyQty_{a,s,h} - RtDispMaxRegCapOL5minQty_{a,s,i}}{12}, 0 \right), 0 \right)$$

A Resource offer with a 140 MW maximum regulating limit clears -100 MWh in the DA Market, but no Regulation. In RT it is Regulating and has lowered its regulating limit to 80 MW. Its Operating Tolerance is 10 MW.

RtMaxLimitDev5minQty = MAX ( \min( \abs{-100 MWi}, 140 MWi ) - 80 MWi , 0 ) / 12 i/h = 1.667 MWh

RtMaxLimitDevHrlyQty = 12 * 1.667 MWh = 20 MWh
3.6.4.4 Outage Deviation

The Outage Deviation is a measurement of the degree to which a resource in an outage after clearing in the DA Market, but not having received a de-commit instruction from SPP is forcing RTBM to commit other units to replace the generation lost. In order to be calculated for this type of deviation a resource must have cleared injection in the DA Market, have withdrawal (>=0) billable meter data and must not have been given a de-commit instruction. The examples assume the interval values are constant through the hour.

Outage Deviation

\[
RtOutageDevHrlyQty_{a,s,h} = \sum_i RtOutageDev5minQty_{a,s,i}
\]

IF \( DaClrdHrlyQty_{a,s,h} < 0 \) AND \( RtBillMtr5minQty_{a,s,i} >= 0 \) AND \( ResDeCommit5minFlg_{a,s,i} <> "1" \)

THEN \( RtOutageDev5minQty_{a,s,i} = ABS\ ( DaClrdHrlyQty_{a,s,h} ) / 12 \)

A Resource offer clears -120 MWh in the DA Market, billable metering shows withdrawal of 1 MWi in RT and no de-commit was issued.

\( RtOutageDev5minQty = ABS(-120\ MWi) / 12\ i/h = 10\ MWh \)

\( RtOutageDevHrlyQty = 12 \ast 10\ MWh = 120\ MWh \)
### 3.6.4.5 Status Deviation

The Status Deviation is a measurement of the degree to which a resource going to manual control after clearing in the DA Market is off of the economic optimal output in RTBM. In order to be calculated for this type of deviation a resource must have cleared injection in the DA Market and have a Manual control status flag for an interval in the hour. The examples assume the interval values are constant through the hour.

\[
\text{RtStatusDevHrlyQty}_{a,s,h} = \sum_i \text{RtStatusDev5minQty}_{a,s,i}
\]

IF \(\text{ControlStatus5minFlg}_{a,s,i} = \text{"Manual"} \text{ AND DaClrdHrlyQty}_{a,s,h} < 0\)

THEN \(\text{RtStatusDev5minQty}_{a,s,i} = \text{ABS} (\text{RtBillMtr5minQty}_{a,s,i} + \text{RtDesiredEc5minQty}_{a,s,i}) / 12\)

A Resource offer clears -100 MWh in the DA Market and after having gone to manual control billable metering shows injection of -120 MWi in RT. RTBM LMP would place the resource at 110 MW on its offer curve.

\(\text{RtStatusDev5minQty} = \text{ABS}(-120 \text{ MWi} + 110 \text{ MWi}) / 12 \text{ i/h} = 0.833 \text{ MWh}\)

\(\text{RtStatusDevHrlyQty} = 12 * 0.833 \text{ MWh} = 10 \text{ MWh}\)
3.6.4.6 RUC Self-Commit Deviation

The RUC Self-Commit Deviation is a measurement of the degree to which a resource committing itself after the DA market is forcing energy into the RTBM. In order to be calculated for this type of deviation a resource must have self committed in the interval and must be given a setpoint instruction = the applicable minimum limit, depending on whether it is regulating or not in RT, in an interval during the hour. The examples assume the interval values are constant through the hour.

RUC Self-Commit Deviation

\[ \text{RtRucScDevHrlyQty}_{a,s,h} = \sum_{i} \text{RtRucScDev5minQty}_{a,s,i} \]

IF \( \text{RtRucComStat5minFlg}_{a,s,i} = “0” \) AND \( \text{SetPointMinHrlyFlg}_{a,s,h} = “1” \)

THEN \( \text{RtRucScDev5minQty}_{a,s,i} = \text{ABS} (\text{RtBillMtr5minQty}_{a,s,i} / 12) \)

A Resource does not clear in the DA Market and after having self committed in RT receives a setpoint instruction at it minimum limit. Billable metering shows injection of -120 MWi.

\[ \text{RtRucScDev5minQty} = \text{ABS}(-120 \text{ MWi}) / 12 \text{ i/h} = 10 \text{ MWh} \]

\[ \text{RtRucScDevHrlyQty} = 12 \times 10 \text{ MWh} = 120 \text{ MWh} \]
3.6.4.7 RUC Commit Deviation

The RUC Commit Deviation is a measurement of the degree to which a resource committed after the DA market, with either “Market” or “Self” status and subsequently found to be off-line, but not having received a de-commit instruction from SPP is forcing RTBM to commit other units to replace the generation lost. In order to be calculated for this type of deviation a resource must have been committed in a RUC process, have withdrawal (>=0) billable meter data and must not have been given a de-commit instruction. The examples assume the interval values are constant through the hour.

RUC Commit Deviation

\[ RtRucCommitDevHrlyQty_{a,s,h} = \sum_i RtRucCommitDev5minQty_{a,s,i} \]

IF \( RtRucComStat5minFlg_{a,s,i,c} = \text{“0” OR “1”} \) AND \( RtBillMtr5minQty_{a,s,i} \geq 0 \) AND \( ResDeCommit5minFlg_{a,s,i} \neq 1 \)

THEN \( RtRucCommitDev5minQty_{a,s,i} = \frac{RtDesiredEc5minQty_{a,s,i}}{12} \)

A Resource does not clear in the DA Market and after having been committed in RT experiences an outage, but is not issued a de-commit. Billable metering shows withdrawal of 1 MWi. RTBM LMP would place the resource at 110 MW on its offer curve. Its minimum economic limit was 120 MW for the interval

\[ RtRucCommitDev5minQty = 120 \text{ MWi} / 12 \text{ i/h} = 10 \text{ MWh} \]
### 3.6.4.8 URD Deviation

The URD Deviation is a measurement of the degree to which a resource not following dispatch is impacting economics in RTBM. The examples assume the interval values are constant through the hour.

\[
\text{URD Deviation}
\]

\[
\text{RtURDDevHrlyQty}_{a,s,h} = \sum_{i} \text{RtURDDev5minQty}_{a,s,i}
\]

\[
\text{IF ABS}(\text{URD5minQty}_{a,s,i}) > \text{ResOpTol5minQty}_{a,s,i} \text{ AND } (\text{XmptDev5minFlg}_{a,s,i} = 0)
\]

\[
\text{THEN } \text{RtURDD5minQty}_{a,s,i} = \text{ABS}(\text{URD5minQty}_{a,s,i}) / 12
\]

A Resource is injecting 200 MW – above a setpoint instruction of 140 MW. If its max emergency operating limit is 420 and the tolerance band parameters are 5% between a min of 5 and max of 20 MW the operating tolerance is 21 MW, so the unit is outside the tolerance and the entire amount over the setpoint is deviation. No exemption is granted.

\[
\text{RtURDD5minQty} = \text{ABS}(200 \text{ MWi} - 140 \text{ MWi}) / 12 \text{ i/h} = 5 \text{ MWh}
\]
3.7 Real-Time Out-Of-Merit Energy and Operating Reserve

During intervals when SPP issues a Manual Dispatch Instruction to a Resource, settlements will calculate a charge type which protects the Resource from the potential adverse economics of following the instruction. If the Resource is above where LMP would put it on its energy offer curve (the “Desired” economic point) it receives a credit equal to the net cost less revenue measured from its actual energy output to the Desired point. When the resource is below where it cleared in the DA market in terms of energy or Operating Reserves the credit offsets any reduction in revenue due to the resource buying back the product in the RTBM settlement at a price which is higher than the unit settled at in the DA Market.

Real-Time Out-Of-Merit Settlement

\[
RtOom5minAmt_{a,s,i} = RtOom5minFlg_{a,s,i} \times (RtOomeIncr5minAmt_{a,s,i} + RtOomeDecr5minAmt_{a,s,i} + RtOomor5minAmt) \times (-1)
\]

Where,

\[
RtOomeIncr5minAmt_{a,s,i} = \max(0, RtIncrEn5minAmt_{a,s,i} - RtDesiredEc5minAmt_{a,s,i} + \min(0, RtBillMtr5minQty_{a,s,i} + RtDesiredEc5minQty_{a,s,i}) \times \max(0, RtLmp5minPrc_{s,i}) / 12
\]

\[
RtOomeDecr5minAmt_{a,s,i} = \max(0, RtBillMtr5minQty_{a,s,i} - DaClrdHrlyQty_{a,s,h}) \times \max(0, RtLmp5minPrc_{s,i} - DaLmpHrlyPrc_{s,h}) / 12
\]

\[
RtOomor5minAmt_{a,s,i} = \frac{[\max(0, DaRegUpHrlyQty_{a,s,h} - RtRegUp5minQty_{a,s,i}) \times \max(0, RtRegUpMcp5minPrc_{s,i} - DaRegUpMcpHrlyPrc_{s,h})] + (\max(0, DaRegDnHrlyQty_{a,s,h} - RtRegDn5minQty_{a,s,i}) \times \max(0, RtRegDnMcp5minPrc_{s,i} - DaRegDnMcpHrlyPrc_{s,h})] + (\max(0, DaSpinHrlyQty_{a,s,h} - RtSpin5minQty_{a,s,i}) \times \max(0, RtSpinMcp5minPrc_{s,i} - DaSpinMcpHrlyPrc_{s,h})] + (\max(0, DaSuppHrlyQty_{a,s,h} - RtSupp5minQty_{a,s,i}) \times \max(0, RtSuppMcp5minPrc_{s,i} - DaSuppMcpHrlyPrc_{s,h})]}{12}
\]
A Resource is having cleared -100 MWh injection of Energy at $20/MWh and 25 MW Supplemental Reserve capacity for the hour in the DA Market, is moved by OOME instruction to -150 MWi actual output and no OR for the interval in RTBM. The LMP of 30 $ / MWh would put the Resource at 125 MW on its offer curve at an integrated cost of $2000, whereas the integrated cost at its actual output is $3000. The integrated cost of the DA market cleared injection on the Resource’s RTBM offer curve is $1000. The MCP of Supplemental Reserve increases from $5/MWh in the DA Market to $10/MWh in the RTBM.

\[
\text{RtOomeIncr5minAmt} = \max(0, (3000i/h - 1000i/h) - (2000i/h - 1000i/h) + \min(0, -150 MWi + 125 MWi) \times \max(0, 30 $/MWh)) / 12i/h = \max(0, 1000 - 750) / 12 = $20.83
\]

\[
\text{RtOomeDecr5minAmt} = \max(0, -150 MWi - (-200 MWi) \times \max(0, 30 $/MWh - 20 $/MWh) / 12i/h = $0
\]

\[
\text{RtOomor5minAmt} = [(\max(0,0)\times\max(0,X-Y) + \max(0,0)\times\max(0,X-Y) + \max(0,0)\times\max(0,X-Y) + \max(0,25 MWi-0) \times \max(0, 10/MWh - 5/MWh)] / 12i/h = $10.42
\]

\[
\text{RtOome5minAmt} = 1 \times (20.83 + 0 + 10.42) \times (-1) = -$31.25 \text{ (credit)}
\]

A Resource is having cleared -200 MWh injection of Energy at $20/MWh and no OR in either the DA Market or RTBM, is moved by OOME instruction to -150 MWi actual output. The LMP of 30 $ / MWh would put the Resource at 250 MW on its offer curve at an integrated cost of $4000, whereas the integrated cost at its actual output is $3000. The integrated cost of the DA market cleared injection on the Resource’s RTBM offer curve is $2000.

\[
\text{RtOomeIncr5minAmt} = \max(0, (3000i/h - 2000i/h) - (4000i/h - 2000i/h) + \min(0, -150 MWi + 250 MWi) \times \max(0, 30 $/MWh)) / 12i/h = \max(0, -1000 - 0) / 12 = $0
\]

\[
\text{RtOomeDecr5minAmt} = \max(0, -150 MWi - (-200 MWi) \times \max(0, 30 $/MWh - 20 $/MWh) / 12i/h = $41.67
\]

\[
\text{RtOomor5minAmt} = [(\max(0,0)\times\max(0,X-Y) + \max(0,0)\times\max(0,X-Y) + \max(0,0)\times\max(0,X-Y) + \max(0,0)\times\max(0,X-Y)] / 12i/h = $0
\]

\[
\text{RtOome5minAmt} = 1 \times (0 + 41.67 + 0) \times (-1) = -$41.67 \text{ (credit)}
\]
### 3.8 Real-Time Regulation Deployment Adjustment

Regulating Resources receive an adjustment, charge or credit, based on the differential between the RTBM LMP and the cost rate of the regulation deployment and the quantity deployed. The deployed quantities are determined by netting actual resource output and the combined instruction exclusive to energy dispatch and the component of set point for the regulation product.

\[
\text{RtRegAdj5minAmt}_{a,s,i} = \text{RtRegUpAdjAmt}_{a,s,i} + \text{RtRegDnAdjAmt}_{a,s,i}
\]

Where,

\[
\text{RtRegUpAdjAmt}_{a,s,i} = \frac{\text{RtRegUpDepl5minQty}_{a,s,i} \times (\text{RtLmp5minPrc}_{s,i} - \text{RtRegUpDeplCostRate}_{a,s,i})}{12}
\]

\[
\text{RtRegUpDepl5minQty}_{a,s,i} = \max (\text{RtAvgDispatch5minQty}_{a,s,i}, \min (\text{RtBillMtr5minQty}_{a,s,i} \times (-1), (\text{RtAvgDispatch5minQty}_{a,s,i} + \text{RtAvgRegUpSp5minQty}_{a,s,i})) - \text{RtAvgDispatch5minQty}_{a,s,i})
\]

\[
\text{RtRegDnAdjAmt}_{a,s,i} = \frac{\text{RtRegDnDepl5minQty}_{a,s,i} \times (\text{RtRegDnDeplCostRate}_{a,s,i} - \text{RtLmp5minPrc}_{s,i})}{12}
\]

\[
\text{RtRegDnDepl5minQty}_{a,s,i} = \text{RtAvgDispatch5minQty}_{a,s,i} - \min (\text{RtAvgDispatch5minQty}_{a,s,i}, \max (\text{RtBillMtr5minQty}_{a,s,i} \times (-1), (\text{RtAvgDispatch5minQty}_{a,s,i} - \text{RtAvgRegDnSp5minQty}_{a,s,i})))
\]
A Resource deployed up for regulation is at 200 MWi actual output. Its energy dispatch is 175 MW and the component of set point due to regulation is 15 MW. LMP is $30/MWh and the average cost of the deployment is $40/MWh.

\[
\text{RtRegUpDeplQty} = \max(175 \text{ MWi}, \min(-200 \text{ MWi} \times (-1), (175 \text{ MWi} + 15 \text{ MWi}))) - 175 \text{ MWi} = \max(175 \text{ MWi}, 190 \text{ MWi}) - 175 \text{ MWi} = 15 \text{ MWi}
\]

\[
\text{RtRegUpAdjAmt} = 15 \text{ MWi} \times (\frac{30}{\text{MWh}} - \frac{40}{\text{MWh}}) / 12 \text{ i/h} = -12.50
\]

\[
\text{RtRegAdj5minAmt} = -12.50 + 0 = -12.50
\]

A Resource deployed down for regulation is at 165 MWi actual output. Its energy dispatch is 175 MW and the component of set point due to regulation is 15 MW. LMP is $40/MWh and the average cost of the deployment is $30/MWh.

\[
\text{RtRegDnDeplQty} = 175 \text{ MWi} - \min(175 \text{ MWi}, \max(-165 \text{ MWi} \times (-1), (175 \text{ MWi} - 15 \text{ MWi}))) = 175 \text{ MWi} - \min(175 \text{ MWi}, \max(165 \text{ MWi}, 160 \text{ MWi})) = 10 \text{ MWi}
\]

\[
\text{RtRegDnAdjAmt} = 10 \text{ MWi} \times (\frac{30}{\text{MWh}} - \frac{40}{\text{MWh}}) / 12 \text{ i/h} = -8.33
\]

\[
\text{RtRegAdj5minAmt} = 0 + -8.33 = -8.33
\]
3.9 Load Ratio Share Cost Allocation

A number of charge types share a common calculation method - a market wide total $ amount * the LRS at the SL with respect to the footprint as a whole. The Settlement Examples will list the charge types falling into this category and detail the derivation of the LRS - the common element to all of these calculations – in a set of scenarios.

<table>
<thead>
<tr>
<th>Charge Type</th>
<th>Formula</th>
</tr>
</thead>
<tbody>
<tr>
<td>Real-Time Regulation-Up Distribution</td>
<td>$RtRegUpDistHrlyAm_{a,s,h} = RtRegUpSppHrlyAm_{h} \times RtLoadRatioShareHrlyFct_{a,s,h} \times (-1)$</td>
</tr>
<tr>
<td>Real-Time Regulation-Down Distribution</td>
<td>$RtRegDnDistHrlyAm_{a,s,h} = RtRegDnSppHrlyAm_{h} \times RtLoadRatioShareHrlyFct_{a,s,h} \times (-1)$</td>
</tr>
<tr>
<td>Real-Time Spinning Reserve Distribution</td>
<td>$RtSpinDistHrlyAm_{a,s,h} = RtSpinSppHrlyAm_{h} \times RtLoadRatioShareHrlyFct_{a,s,h} \times (-1)$</td>
</tr>
<tr>
<td>Real-Time Supplemental Reserve Distribution</td>
<td>$RtSuppDistHrlyAm_{a,s,h} = RtSuppSppHrlyAm_{h} \times RtLoadRatioShareHrlyFct_{a,s,h} \times (-1)$</td>
</tr>
<tr>
<td>Real-Time Regulation Non-Performance Distribution</td>
<td>$RtRegNonPerfDistHrlyAm_{a,s,h} = RtRegNonPerfSppHrlyAm_{h} \times RtLoadRatioShareHrlyFct_{a,s,h} \times (-1)$</td>
</tr>
<tr>
<td>Real-Time Contingency Reserve Deployment Failure Distribution</td>
<td>$RtCRDeplFailDistHrlyAm_{a,s,h} = RtCRDeplFailSppHrlyAm_{h} \times RtLoadRatioShareHrlyFct_{a,s,h} \times (-1)$</td>
</tr>
<tr>
<td>Real-Time Reserve Sharing Group Distribution</td>
<td>$RtRsgDistHrlyAm_{a,s,h} = RtRsgSppHrlyAm_{a,h} \times RtLoadRatioShareHrlyFct_{a,s,h} \times (-1)$</td>
</tr>
</tbody>
</table>
The Load Ratio Share at a Settlement Location is calculated as the sum of any positive net Billable Meter Data or net exports at the SL over the intervals in the hour divided by the total of all such SL sums for the SPP footprint. Netting over the intervals in the hour prior to taking the max of 0 or the determinant sum means that generation taking station power at the SL for only part of the hour will be excluded from cost allocation if the injection in other intervals outweighs the withdrawal. Likewise, Import Interchange Transactions in part of an hour may diminish the cost allocation to exports at the same SL in other intervals of the hour. Interchange Transactions for Contingency Reserve Deployment among the members of the Reserve Sharing Group are not considered in this calculation. The examples assume denominator of the LRS, the SPP total of load & exports, to be 40,000 MWh, all the transaction depicted at a S belong to the same AO and that all interval values in the hour are the same.

\[
R_{tLoad\text{RatioShareHrlyFct}}_{a,s,h} = \left[ \left[ \text{Max} \left( 0, \sum_{i} R_{tBillMtr5minQty}^{a,s,i} \right) + \text{Max} \left( 0, \sum_{t} \sum_{i} R_{tImpExp5minQty}^{a,s,i,t} \right) \right] * \left( 1 - R_{srgCrdFlg} \right) \right] / 12 \right] / R_{tLoadSppHrlyQty}^{h}
\]
Settlement Location I1
\[
RtLoadRatioShareHrlyFct = \left[ \text{Max}(0, 0) + \text{Max}(0, 12 \times 75 \text{ MWi} + -50 \text{ MWi}) \times (1 - 0) \right] / 12 \text{ i/h} / 12 * 40,000 \text{ MWi} / 12 \text{ i/h} = 0.0006
\]

Settlement Location L2
\[
RtLoadRatioShareHrlyFct = \left[ \text{Max}(0, 12 \times 215 \text{ MWi}) + \text{Max}(0, 0) \times (1 - 0) \right] / 12 \text{ i/h} / 12 * 40,000 \text{ MWi} / 12 \text{ i/h} = 0.0054
\]

Settlement Location G1
\[
RtLoadRatioShareHrlyFct = \left[ \text{Max}(0, 12 \times -200 \text{ MWi}) + \text{Max}(0, 0) \times (1 - 0) \right] / 12 \text{ i/h} / 12 * 40,000 \text{ MWi} / 12 \text{ i/h} = 0.0000
\]
3.10 Regulation Non-Performance

Resources cleared for regulation in the RTBM, but not following dispatch are charged a penalty equal to the amount the resource was credited for clearing regulation products in either the DA Market or RTBM.

\[
\text{Regulation Non-Performance}
\]

\[
\text{IF ABS (URD5minQty}_{a,s,i} > \text{ResOpTol5minQty}_{a,s,i} \text{ AND (RtRegUp5minQty}_{a,s,i} + \text{RtRegDn5minQty}_{a,s,i}) > 0 \text{ AND (XmptDev5minFlg}_{a,s,i} = 0) THEN}
\]

\[
\text{RtRegNonPerf5minAmt}_{a,s,i} = \text{Max (0, (DaRegUpHrlyQty}_{a,s,h} \times \text{DaRegUpMcpHrlyPrc}_{z,s,h} + (\text{RtRegUp5minQty}_{a,s,i} - \text{DaRegUpHrlyQty}_{a,s,h}) \times \text{RtRegUpMcp5minPrc}_{z,s,i}) / 12 )}
\]
\[
+ (\text{DaRegDnHrlyQty}_{a,s,h} \times \text{DaRegDnMcpHrlyPrc}_{z,s,h} + (\text{RtRegDn5minQty}_{a,s,i} - \text{DaRegDnHrlyQty}_{a,s,h}) \times \text{RtRegDnMcp5minPrc}_{z,s,i}) / 12 )
\]

ELSE

\[
\text{RtRegNonPerf5minAmt}_{a,s,i} = 0
\]

Regulation Non-Performance Example: setpoint is 100 MW, the tolerance band is defined as 10% of the Max Emergency Operating Limit ( = 200 MW) bound by a minimum of 5 and maximum of 25 MW) Billable Metered Output is at -125 MW. The Resource clears 10 MW of RegUp in the RTBM at a price of $24 in the interval

\[
\text{IF ABS (25 MWi) > 10 MWi AND (10 MWi + 0) > 0 AND (0 = 0) THEN}
\]

\[
\text{RtRegNonPerf5minAmt} = \text{Max (0, (0 * 0 + (10 MWi - 0) * $24 / MWh) / 12 i/h) + (0 * 0 + (0 - 0) * 0) / 12) = $20.00}
\]
Regulation Non-Performance Example: setpoint is 100 MW, the tolerance band is defined as 10% of the Max Emergency Operating Limit (\(= 200\) MW) bound by a minimum of 5 and maximum of 25 MW) Billable Metered Output is at -125 MW. The Resource clears 10 MW of RegUp in the DA Market, but is not cleared in the RTBM in the interval. Since the Resource did not clear regulation in RTBM in the interval it is not exposed to the penalty.

\[
\text{IF } \left| 25 \text{ MWi} \right| > 20 \text{ MWi} \text{ AND } (0 + 0) > 0 \text{ AND } (0 = 0) \\
\text{ELSE}
\]

\[
\text{RtRegNonPerf5minAmt} = 0
\]

Regulation Non-Performance Example: setpoint is 100 MW, the tolerance band is defined as 10% of the Max Emergency Operating Limit (\(= 200\) MW) bound by a minimum of 5 and maximum of 25 MW) Billable Metered Output is at -125 MW. The Resource clears 10 MW of RegUp in the DA Market, but only 5 MW in the RTBM at a price of $24 in the interval. Since the resource is already buying back regulation in RT at a net loss, there is no penalty.

\[
\text{IF } \left| 25 \text{ MWi} \right| > 20 \text{ MWi} \text{ AND } (5 \text{ MWi} + 0) > 0 \text{ AND } (0 = 0) \\
\text{THEN}
\]

\[
\text{RtRegNonPerf5minAmt} = \max \left( 0, \frac{(10 \text{ MWh} \times \$6 / \text{MWh} + (5 \text{ MWi} - 10 \text{ MWi}) \times \$24 / \text{MWh})}{12 \text{ i/h}} + (0 \times 0 + (0 - 0) \times 0) / 12 \right) \\
= \max \left( 0, \$5 + -\$10 \right) = 0
\]
3.11 Contingency Reserve Deployment Failure

The response of a Resource deployed for a Contingency Reserve Event is measured in 4 different ways. If the resource fails to show that it met the expected response in every one of the 4 ways it is charged a penalty equal to the RTBM LMP for the interval in which the events ends times the minimum of the failure test quantities. For resources which are members of a common bus model, the response is measured in aggregate of all of the resources which are members of the common bus, regardless of whether they were deployed during the event or not. In the case of a common bus failure the minimum aggregate failure test quantity is mapped to a pre-selected default SL where the RTBM LMP is applied to calculate the penalty.

Contingency Reserve Deployment

\[
\text{RtCRDeplFailAmt}_{a, s, i} = \text{RtCRSLShortfallQty}_{a, s, i} \times \text{ABS} (\text{RtLmp5minPrc}_{s, i})
\]

\[
\text{RtCRSLShortfallQty}_{a, s, i} = \text{Min} (\text{Test1SLShortfallQty}_{a, s, i}, \text{Test2SLShortfallQty}_{a, s, i}, \text{Test3SLShortfallQty}_{a, s, i}, \text{Test4SLShortfallQty}_{a, s, i})
\]

\[
\text{Test1SLShortfallQty}_{a, s, i} = \text{Max} (0, \text{RtEndTelemtr5minQty}_{a, s, i} + \text{RtEndInstRampSP5minQty}_{a, s, i})
\]

\[
\text{Test2SLShortfallQty}_{a, s, i} = \text{Max} (0, \text{RtEndTelemtr5minQty}_{a, s, i} + \text{RtEndInstStepSP5minQty}_{a, s, i})
\]

\[
\text{Test3SLShortfallQty}_{a, s, i} = \text{Max} (0, \{ \text{RtEndTelemtr5minQty}_{a, s, i} - \text{RtBeginTelemtr5minQty}_{a, s, i} \} + \{ \text{RtEndInstRampSP5minQty}_{a, s, i} - \text{RtBeginInstRampSP5minQty}_{a, s, i} \})
\]

\[
\text{Test4SLShortfallQty}_{a, s, i} = \text{Max} (0, \{ \text{RtEndTelemtr5minQty}_{a, s, i} - \text{RtBeginTelemtr5minQty}_{a, s, i} \} + \{ \text{RtEndInstStepSP5minQty}_{a, s, i} - \text{RtBeginInstStepSP5minQty}_{a, s, i} \})
\]
Resource G1 passes test 2: its telemetry exceeds the stepped setpoint at the end of the deployment – no penalty

Resource G2 passes test 1: its telemetry meets the ramped setpoint at the end of the deployment – no penalty

Resource G3 passes test 4: the difference between its telemetry from the beginning to the end of the deployment exceeds the difference in its stepped setpoint during that period – no penalty

Resource G4 passes test 4: the difference between its telemetry from the beginning to the end of the deployment exceeds the difference in its ramped setpoint during that period – no penalty

Resources G5 & G6 do not pass any of the criteria and are penalized for failing to deploy the reserves called for.

In this example if all of the individual Resources were members of a single common bus the group would not pass any of the criteria and aggregate shortfall is mapped back to a default SL which is determined by registration where the LMP is applied to determine the penalty. In this specific scenario the penalty is actually greater for the common bus than the sum of the penalties that would have been assessed on the individual Resources.

However if only G1 & G6 were members of a common bus the pair would pass test 2: the combined telemetry exceeds the aggregate stepped setpoint at the end of the deployment and there would be no penalty.
3.12  **Day-Ahead Over-Collected Losses Distribution**

The calculation of rebates for the over collection which results from use of marginal losses is a matter of first gathering the total amount of over collection then secondly deriving loss rebate factors which determine the amount of the total that goes back on a per AO / SL basis.

### 3.12.1.1  Day-Ahead Over Collected Losses Amount

That first element is accomplished by summing the product of every DA Market energy instrument quantity and the LMP less the MCC at that SL. This result reflects settlement of the entire DA Market absent the amounts associated with congestion instruments.

\[
\text{Day-Ahead Over Collected Losses Amount} = \sum_a \sum_s \sum_{lp} (\text{DaLmpHrlyPre}_{s,h} - \text{DaMccHrlyPre}_{s,h}) \times (\sum_{i,t} (\text{DaImpExp5minQty}_{a,s,lp,i,t} / 12) + \sum_{a,s,lp} \text{DaClrdVHrlyQty}_{a,s,lp,h,t})
\]

The second element, the loss rebate factors, are the result of a substantial chain of calculations in which the total net quantities at an SL are grouped into Loss Pools in order to determine a path, and thus a Δ source to sink MLC component, used to value the DA Market quantities – a proxy for the amount of marginal losses paid. Loss Pools which contain more injection quantities than withdrawal contribute surplus to an exchange, which is deemed to serve the Loss Pools in which withdrawal quantities exceed injection. Positive loss rebate factors are normalized to achieve the determinant by which over collection is distributed – a de facto loss ratio share.
3.12.1.2  Loss Pool Net Withdrawal

The calculation of the loss rebate factors starts with determining the net Loss Pool withdrawal at each SL, which is simply a collection of quantities which is agnostic to the AO of the instrument. Loss Pools are a grouping of an AO’s transactional activity at all SLs – as such an SL might appear in many Loss Pools. The AO net withdrawal is also necessary in order to prorate the net SL withdrawal among all AOs at a given location when opposing determinants may to some degree or completely cancel each other out. Financial Schedules are also used in determining the AO’s share of withdrawal, therefore the energy obligation they convey is accompanied by a transfer the determinants for loss rebates.

\[
\text{Loss Pool Net Withdrawal}
\]

\[
\text{DaSlNetWdrHrlyQt}_{a,s,lp,h} = \max(0, \sum_{a,lp} \sum_{t} (\text{DaClrdHrlyQt}_{a,s,lp,h} + \sum_{t} \text{DaClrdVHrlyQt}_{a,s,lp,h,t} + \sum_{i} \sum_{t} (\text{DaImpExp5minQt}_{a,s,lp,i,t} / 12 )))
\]

\[
\text{DaAoNetWdrHrlyQt}_{a,s,lp,h} = \max(0, \sum_{a,lp} \sum_{t} (\text{DaClrdHrlyQt}_{a,s,lp,h,t} - \text{DaEnFinHrlyQt}_{a,s,lp,h,t} - \text{DaNEnFinHrlyQt}_{a,s,lp,h,t} + \sum_{i} \sum_{t} (\text{DaImpExp5minQt}_{a,s,lp,i,t} / 12 ))
\]

\[
\text{DaLpNetWdrHrlyQt}_{a,s,lp,h} = \text{DaSlNetWdrHrlyQt}_{a,s,lp,h} \ast \{ \text{DaAoNetWdrHrlyQt}_{a,s,lp,h} / \text{DaAoNetWdrSppHrlyQt}_{a,s,lp,h} \}
\]

Where:  \[
\text{DaAoNetWdrSppHrlyQt}_{a,s,lp,h} = \sum_{a,lp} \sum_{t} \text{DaAoNetWdrHrlyQt}_{a,s,lp,h}
\]
DaSlNetWdrHrlyQty \_L4 = \text{Max} \left( 0, \left[ 550 \text{ MWh} + 0 + 0 / 12 \right] \right) = 550 \text{ MWh}

DaAoNetWdrHrlyQty_{AO \_V, L4, V} = \text{Max} \left( 0, (550 \text{ MWh} - 225 \text{ MWh} - 0 + ( 0 / 12 )) \right) = 325 \text{ MWh}

DaAoNetWdrHrlyQty_{AO \_T, L4, T} = \text{Max} \left( 0, (0 - 0 - -225 \text{ MWh} + ( 0 / 12 )) \right) = 225 \text{ MWh}

DaLpNetWdrHrlyQty_{AO \_V, L4, V} = 550 \text{ MWh} \times \{ 325 \text{ MWh} / 550 \text{ MWh} \} = 325 \text{ MWh}

DaLpNetWdrHrlyQty_{AO \_T, L4, T} = 550 \text{ MWh} \times \{ 225 \text{ MWh} / 550 \text{ MWh} \} = 225 \text{ MWh}
3.12.1.3 Loss Pool Net Injection

The calculation of the loss rebate factors continues with determining the net Loss Pool injection at each SL, which is simply a collection of quantities which is agnostic to the AO of the instrument. Loss Pools are a grouping of an AO’s transactional activity at all SLs – as such an SL might appear in many Loss Pools. The AO net injection is also necessary in order to prorate the net SL injection among all AOs at a given location when opposing determinants may to some degree or completely cancel each other out. Financial Schedules are also used in determining the AO’s share of injection, therefore the energy obligation they convey is accompanied by a transfer the determinants for loss rebates.

\[
\text{DaSlNetInjHrlyQty}_{s,h} = (-1) \ast \left\{ \text{Min} \left( 0, \sum_{lp} \sum_{a} \left[ \text{DaClrdHrlyQty}_{a,s,lp,h} + \sum_{t} \text{DaClrdVHrlyQty}_{a,s,lp,h,t} + \sum_{i} \sum_{t} \left( \text{DaImpExp5minQty}_{a,s,lp,i,t} / 12 \right) \right] \right\}
\]

\[
\text{DaAoNetInjHrlyQty}_{a,s,lp,h} = (-1) \ast \left\{ \text{Min} \left( 0, \text{DaClrdHrlyQty}_{a,s,lp,h} - \sum_{t} \text{DaEnFinHrlyQty}_{a,s,lp,h,t} - \sum_{i} \sum_{t} \left( \text{DaImpExp5minQty}_{a,s,lp,i,t} / 12 \right) \right) \right\}
\]

\[
\text{DaLpNetInjHrlyQty}_{a,s,lp,h} = \text{DaSlNetInjHrlyQty}_{s,h} \ast \left\{ \text{DaAoNetInjHrlyQty}_{a,s,lp,h} / \text{DaAoNetInjSppHrlyQty}_{s,h} \right\}
\]

Where: \[
\text{DaAoNetInjSppHrlyQty}_{s,h} = \sum_{lp} \sum_{a} \text{DaAoNetInjHrlyQty}_{a,s,lp,h}
\]
Loss Pool Net Injection

\[\text{DaSlNetInjHrlyQty}_{G_1} = (-1) \times \min(0, [-450 \text{ MWh} + 0 + (0 / 12)]) = 450 \text{ MWh}\]

\[\text{DaAoNetInjHrlyQty}_{AO_T, G_1, T} = (-1) \times \min(0, [-450 \text{ MWh} + 0 - 200 \text{ MWh} - 0 + (0 / 12)]) = 250 \text{ MWh}\]

\[\text{DaAoNetInjHrlyQty}_{AO_X, G_1, X} = (-1) \times \min(0, [0 + 0 - 200 \text{ MWh} + (0 / 12)]) = 200 \text{ MWh}\]

\[\text{DaLpNetInjHrlyQty}_{AO_T, G_1, T} = 450 \text{ MWh} \times \frac{250 \text{ MWh}}{450 \text{ MWh}} = 250 \text{ MWh}\]

\[\text{DaLpNetInjHrlyQty}_{AO_X, G_1, X} = 450 \text{ MWh} \times \frac{200 \text{ MWh}}{450 \text{ MWh}} = 200 \text{ MWh}\]
3.12.1.4 Internal & External Supply Factors

The summations of the net injection and withdrawal per Loss Pool (T, U, V, W, X, Y & Z corresponding to AOs) are used to determine to what degree withdrawal in the Loss Pool is being met with injection in the Loss Pool and if the Loss Pool is supplying the exchange.

\[
\text{Internal & External Supply Factors}
\]

\[
\begin{align*}
\text{IF } & \sum_{s} \text{DaLpNetWdrHrlyQty}_{s, lp, h} = 0 \text{ THEN } \text{DaLpIntSupplyHrlyFct}_{lp, h} = 0 \text{ ELSE } \text{DaLpIntSupplyHrlyFct}_{lp, h} = \text{Min} \left[ 1, \sum_{s} \right] \\
& \text{DaLpNetInjHrlyQty}_{s, lp, h} / \sum_{s} \text{DaLpNetWdrHrlyQty}_{s, lp, h} \right] \\
\text{IF } & \sum_{s} \text{DaLpNetInjHrlyQty}_{s, lp, h} = 0 \text{ THEN } \text{DaLpExtSupplyHrlyFct}_{lp, h} = 0 \text{ ELSE } \text{DaLpExtSupplyHrlyFct}_{lp, h} = \text{Max} \left[ 0, (1 - \sum_{s} \right] \\
& \text{DaLpNetWdrHrlyQty}_{s, lp, h} / \sum_{s} \text{DaLpNetInjHrlyQty}_{s, lp, h} ) \right] \\
\end{align*}
\]

Loss Pool X is a net injector and contributing to the exchange, Loss Pools T & V are net withdrawers and consuming from the exchange.

\[
\begin{align*}
\text{Loss Pool } T & \quad \text{DaLpIntSupplyHrlyFct} = \text{Min} \left[ 1, (250 \text{ MWh} + 275 \text{ MWh}) / (150 \text{ MWh} + 300 \text{ MWh} + 225 \text{ MWh})\right] = 0.7778 \\
& \quad \text{DaLpExtSupplyHrlyFct} = \text{Max} \left[ 0, (1 - (150 \text{ MWh} + 300 \text{ MWh} + 225 \text{ MWh}) / (250 \text{ MWh} + 275 \text{ MWh}))\right] = 0 \\
\text{Loss Pool } V & \quad \text{DaLpIntSupplyHrlyFct} = \text{Min} \left[ 1, (325 \text{ MWh}) / (325 \text{ MWh} + 100 \text{ MWh} + 500 \text{ MWh})\right] = 0.3514 \\
& \quad \text{DaLpExtSupplyHrlyFct} = \text{Max} \left[ 0, (1 - (325 \text{ MWh} + 100 \text{ MWh} + 500 \text{ MWh}) / (325 \text{ MWh}))\right] = 0 \\
\text{Loss Pool } X & \quad \text{DaLpIntSupplyHrlyFct} = \text{Min} \left[ 1, (200 \text{ MWh} + 500 \text{ MWh}) / (200 \text{ MWh} + 250 \text{ MWh})\right] = 1 \\
& \quad \text{DaLpExtSupplyHrlyFct} = \text{Max} \left[ 0, (1 - (200 \text{ MWh} + 250 \text{ MWh}) / (200 \text{ MWh} + 500 \text{ MWh}))\right] = 0.3571
\end{align*}
\]
3.12.1.5 Injection Weighted Average Marginal Loss Components

Withdrawal served from within a Loss Pool is valued at the source by the weighted average of the MLCs at SLs injecting in the Loss Pool. Withdrawal served from the exchange is valued at the source by the weighted average of the MLCs at SLs in Loss Pools supplying the exchange.

Loss Pool Injection Weighted Average Marginal Loss Component & the Exchange Weighted Average

\[
\text{IF } \sum_s \text{DaLpNetInjHrlyQty}_{s, lp, h} = 0 \text{ THEN } \text{DaLpIwaMlcHrlyPrc}_{lp, h} = 0
\]

\[
\text{ELSE } \text{DaLpIwaMlcHrlyPrc}_{lp, h} = \frac{\sum_s \text{DaLpNetInjHrlyQty}_{s, lp, h} \times \text{DaMlcHrlyPrc}_{s, h}}{\sum_s \sum_{lp} \left[ \text{DaLpExtSupplyHrlyFct}_{lp, h} \times \sum_s \left( \text{DaLpNetInjHrlyQty}_{s, lp, h} \times \text{DaMlcHrlyPrc}_{s, h} \right) \right]}
\]

\[
\text{DaSppIwaMlcHrlyPrc}_{h} = \frac{\sum_{lp} \left[ \text{DaLpExtSupplyHrlyFct}_{lp, h} \times \sum_s \left( \text{DaLpNetInjHrlyQty}_{s, lp, h} \times \text{DaMlcHrlyPrc}_{s, h} \right) \right]}{\sum_{lp} \sum_s \text{DaLpNetInjHrlyQty}_{s, lp, h}}
\]
Loss Pool T

$$\text{DaLpIwaMcHrlyPrc}_{\text{lp}, h} = \frac{(250 \text{ MWh} \times \$1/\text{MWh} + 275 \text{ MWh} \times \$1/\text{MWh})}{250 \text{ MWh} + 275 \text{ MWh}} = \$1.0000/\text{MWh}$$

Loss Pool V

$$\text{DaLpIwaMcHrlyPrc}_{\text{lp}, h} = \frac{(325 \text{ MWh} \times \$0/\text{MWh})}{325 \text{ MWh}} = \$0.0000/\text{MWh}$$

Loss Pool X

$$\text{DaLpIwaMcHrlyPrc}_{\text{lp}, h} = \frac{(200 \text{ MWh} \times \$1/\text{MWh} + 500 \text{ MWh} \times \$0/\text{MWh})}{200 \text{ MWh} + 500 \text{ MWh}} = \$0.2857/\text{MWh}$$

The Exchange

$$\text{DaSppIwaMcHrlyPrc}_{\text{spp}} = \left[ 0 \times (250 \text{ MWh} \times \$1/\text{MWh} + 275 \text{ MWh} \times \$1/\text{MWh}) \right. \\
+ 0.4483 \times (200 \text{ MWh} \times \$2/\text{MWh} + 25 \text{ MWh} \times \$2/\text{MWh} + 100 \text{ MWh} \times \$2/\text{MWh} + 400 \text{ MWh} \times \$2/\text{MWh}) \\
+ 0 \times (325 \text{ MWh} \times \$0/\text{MWh}) \\
+ 0.1667 \times (300 \text{ MWh} \times \$3/\text{MWh}) \\
+ 0.3571 \times (200 \text{ MWh} \times \$1/\text{MWh} + 500 \text{ MWh} \times \$0/\text{MWh}) \\
+ 0.5294 \times (200 \text{ MWh} \times \$3/\text{MWh} + 225 \text{ MWh} \times \$3/\text{MWh}) \\
+ 0 \times (100 \text{ MWh} \times \$2/\text{MWh} + 500 \text{ MWh} \times \$3/\text{MWh}) \\
\left. \right] / (0 \times 525 + 0.4483 \times 725 + 0 \times 325 + 0.1667 \times 300 + 0.3571 \times 700 + 0.5294 \times 425 + 0 \times 600) = \$1.8193/\text{MWh}$$
3.12.1.6 Loss Rebate Factors

The loss rebate factors are constructed by multiplying the portion of the net withdrawal served from within the Loss Pool at the SL by the Δ between the local MLC and the local Loss Pool’s injection weighted average MLC and summing that with the portion of the net withdrawal served by the exchange at the SL by the Δ between the local MLC and the exchange injection weighted average MLC. Again, since in this example there is no transposition of transactions at a single SL 1 AO is assigned all of the value of the net withdrawal at that SL. Positive loss rebate factors are normalized such that the set sums to 100%.

\[
\text{Loss Rebate Factors} = \left\{ \begin{array}{l}
\text{DaLossRbtHrlyFct}_{a,s,l_p,h} = \left\{ \text{DaLpIntSupplyHrlyFct}_{l_p,h} \times (\text{DaMlcHrlyPrc}_{s,h} - \text{DaLpIwaMlcHrlyPrc}_{l_p,h}) \\
+ (1 - \text{DaLpIntSupplyHrlyFct}_{l_p,h}) \times (\text{DaMlcHrlyPrc}_{s,h} - \text{DaSppIwaMlcHrlyPrc}_{h}) \right\} \times \\
\text{DaLpNetWdrHrlyQty}_{a,s,l_p,h} \\
\end{array} \right.
\]

IF DaLossRbtSppHrlyFct_{h} = 0 THEN DaNormLossRbtHrlyFct_{a,s,l_p,h} = 0 ELSE

\[
\text{DaNormLossRbtHrlyFct}_{a,s,l_p,h} = \frac{\text{Max} (0, \text{DaLossRbtHrlyFct}_{a,s,l_p,h})}{\text{DaLossRbtSppHrlyFct}_{h}}
\]

Where: \( \text{DaLossRbtSppHrlyFct}_{h} = \sum_{a} \sum_{s} \sum_{l_p} \text{Max} (0, \text{DaLossRbtHrlyFct}_{a,s,l_p,h}) \)
DaLossRbtHrlyFct_{AO\_V, L4, V} = \{ \[ 0.3514 \times (\$3/MWh - \$0.000/MWh) + (1 - 0.3514) \times (\$3/MWh - \$1.8193/MWh) \] \times 325 \text{ MWh} \} = \$591.47

DaNormLossRbtHrlyFct_{AO\_V, L4, V} = \text{Max}(0, \$591.47) / \$3,840.00 = 0.1540

DaLossRbtHrlyFct_{AO\_T, L4, T} = \{ \[ 0.7778 \times (\$3/MWh - \$1.0000/MWh) + (1 - 0.7778) \times (\$3/MWh - \$1.8193/MWh) \] \times 225 \text{ MWh} \} = \$409.03

DaNormLossRbtHrlyFct_{AO\_T, L4, T} = \text{Max}(0, \$409.04) / \$3,840.00 = 0.1065
3.12.1.7 Charge Type Results

The final product of this sequence of formulae is achieved by multiplying the normalized loss rebate factors and the hourly over-collection total.

\[
\text{Charge Type Result} \\
\text{DaOclDistHrlyAmt}_{a,s,lp,h} = \text{DaNormLossRbtHrlyFct}_{a,s,lp,h} \times \text{DaOclHrlyAmt}_{h} \times (-1)
\]

\[
\text{DaOclDistHrlyAmt}_{AO,V,L4,V} = 0.1540 \times 2050.00 \times (-1) = -315.76
\]

\[
\text{DaOclDistHrlyAmt}_{AO,T,L4,T} = 0.1065 \times 2050.00 \times (-1) = -218.36
\]
### 3.13 Real-Time Over-Collected Losses Distribution

The calculation of rebates for the over collection which results from use of marginal losses is a matter of first gathering the total amount of over collection then secondly deriving loss rebate factors which determine the amount of the total that goes back on a per AO / SL basis.

#### 3.13.1.1 Real-Time Over Collected Losses Amount

That first element is accomplished by summing the product of every RTBM incremental energy instrument quantity and the LMP less the MCC at that SL and backing out the value of footprint-wide Net Inadvertent. Since positive Net Inadvertent is a reflection of injection paid where no corresponding collection from withdrawal occurred, the Net Inadvertent amount is added into the total over-collection to establish the total discreetly associated with marginal loss over-collection. This result reflects settlement of the entire RTBM absent the amounts associated with congestion instruments; as such Net Inadvertent is valued at the MEC, which is constant across the footprint.

\[
RtIncrOclHrlyAmt_h = \sum_i \ RtIncrOcl5minAmt_i
\]

\[
RtIncrOcl5minAmt_i = (\sum_a \sum_t \sum_{lp} [ (RtLmp5minPrc_{s,i} - RtMcc5minPrc_{s,i}) \times (RtBillMtr5minQty_{a,s,lp,i} - DaClrdHrlyQty_{a,s,lp,h,t}) - DaClrdVHrlyQty_{a,s,lp,i} + \sum_t \ RtImpExp5minQty_{a,s,lp,i,t} ] / 12 + RtNetInadvertentSpp5minAmt_i )
\]

\[
RtNetInadvertentSpp5minAmt_{spp,i} = ((RtNetActIntrchngSpp5minQty_{spp,i} - RtNetSchedIntrchngSpp5minQty_{spp,i}) \times RtMcc5minPrc_{i}) / 12
\]
Note that absent the contribution of net Inadvertent, the market total would have been <0 – a deficit. It is not uncommon at all for the “over-collection” in the incremental RTBM settlement to be a negative. This simply means that more losses than actually occurred in RTBM were cleared in the DA Market. The allocation of negative over-collection amounts in RT will result in charges rather than credits to MPs.

The second element, the loss rebate factors, are the result of a substantial chain of calculations in which the total net incremental energy quantities at an SL are grouped into Loss Pools in order to determine a path, and thus a Δ source to sink MLC component, used to value the RTBM incremental quantities – a proxy for the amount of marginal losses paid. Loss Pools which contain more incremental injection quantities than incremental withdrawal contribute surplus to an exchange, which is deemed to serve the Loss
Pools in which incremental withdrawal quantities exceed incremental injection. Positive loss rebate factors are normalized to achieve the determinant by which over collection is distributed – a de facto loss ratio share.

### 3.13.1.2 Loss Pool Net Withdrawal

The calculation of the loss rebate factors starts with determining the net Loss Pool withdrawal at each SL, which is simply a collection of quantities which is agnostic to the AO of the instrument. Loss Pools are a grouping of an AO’s transactional activity at all SLs – as such an SL might appear in many Loss Pools. The AO net withdrawal is also necessary in order to prorate the net SL withdrawal among all AOs at a given location when opposing determinants may to some degree or completely cancel each other out. Financial Schedules are also used in determining the AO’s share of withdrawal, therefore the energy obligation they convey is accompanied by a transfer the determinants for loss rebates.

<table>
<thead>
<tr>
<th>Loss Pool Net Withdrawal</th>
</tr>
</thead>
</table>
| \[
\text{RtSlNetWdr5minQty}_{s,i} = \max (0, \sum_{lp} \sum_{a} (\text{RtBillMtr5minQty}_{a,s,lp,i} - \text{DaClrdHrlyQty}_{a,s,lp,h} - \sum_{t} \text{DaClrdVHrlyQty}_{a,s,lp,h,t}) + \sum_{t} \text{RtImpExp5minQty}_{a,s,lp,i,t} (1 - \text{RsgCrdFlg}_{t}) - \sum_{t} \text{DaImpExp5minQty}_{a,s,lp,i,t})) / 12
\] |

| \[
\text{RtAoNetWdr5minQty}_{a,s,lp,i} = \max (0, (\text{RtBillMtr5minQty}_{a,s,lp,i} - \text{DaClrdHrlyQty}_{a,s,lp,h} - \sum_{t} \text{DaClrdVHrlyQty}_{a,s,lp,h,t} - \sum_{t} \text{RtEnFinHrlyQty}_{a,s,lp,h,t} - \sum_{t} \text{RtNEEnFinHrlyQty}_{a,s,lp,h,t} + \sum_{t} \text{RtImpExp5minQty}_{a,s,lp,i,t} (1 - \text{RsgCrdFlg}_{t}) - \sum_{t} \text{DaImpExp5minQty}_{a,s,lp,i,t}))/12
\] |

| \[
\text{RtLpNetWdr5minQty}_{a,s,lp,i} = \text{RtSlNetWdr5minQty}_{s,i} \times \left\{ \frac{\text{RtAoNetWdr5minQty}_{a,s,lp,i}}{\text{RtAoNetWdrSpp5minQty}_{s,i}} \right\}
\] |

Where: \[
\text{RtAoNetWdrSpp5minQty}_{s,i} = \sum_{lp} \sum_{a} \text{RtAoNetWdr5minQty}_{a,s,lp,i}
\]
Market Protocols for SPP Integrated Marketplace

\[ \text{RtSlNetWdr5minQty}_{L3} = \max(0, (477 \text{ MW} - 0 - 250 \text{ MW} + 0 \times (1 - 0) - 0) / 12 \text{ i/h} = 18.917 \text{ MWh} \]

\[ \text{RtAoNetWdr5minQty}_{AO, U, L3, U} = \max(0, (477 \text{ MW} - 0 - 0 - 0 + 0 \times (1 - 0) - 0) / 12 \text{ i/h} = 39.75 \text{ MWh} \]

\[ \text{RtAoNetWdr5minQty}_{AO, X, L3, X} = \max(0, (0 - 0 - 250 \text{ MW} - 0 - 0 + 0 \times (1 - 0) - 0) / 12 \text{ i/h} = 0 \text{ MWh} \]

\[ \text{RtLpNetWdr5minQty}_{AO, U, L3, U} = (18.917 \text{ MWh} \times \{39.75 \text{ MWh} / 39.75 \text{ MWh}\} = 18.917 \text{ MWh} \]

\[ \text{RtLpNetWdr5minQty}_{AO, X, L3, X} = (18.917 \text{ MWh} \times \{0 / 39.75 \text{ MWh}\} = 0 \text{ MWh} \]

\[ \text{RtSlNetWdr5minQty}_{G5} = \max(0, (-416 \text{ MW} - 0 - 500 \text{ MW} + 0 \times (1 - 0) - 0) / 12 \text{ i/h} = 7.000 \text{ MWh} \]

\[ \text{RtAoNetWdr5minQty}_{AO, W, G5, W} = \max(0, (-416 \text{ MW} - 0 - 0 - 0 + 0 \times (1 - 0) - 0) / 12 \text{ i/h} = 0 \text{ MWh} \]

\[ \text{RtAoNetWdr5minQty}_{AO, X, G5, X} = \max(0, (0 - 0 - 500 \text{ MW} - 0 - 0 + 0 \times (1 - 0) - 0) / 12 \text{ i/h} = 41.667 \text{ MWh} \]

\[ \text{RtLpNetWdr5minQty}_{AO, W, G5, W} = (7.000 \text{ MWh} \times \{0 / 41.667 \text{ MWh}\} = 0 \text{ MWh} \]

\[ \text{RtLpNetWdr5minQty}_{AO, X, G5, X} = (7.000 \text{ MWh} \times \{41.667 \text{ MWh} / 41.667 \text{ MWh}\} = 7.000 \text{ MWh} \]
### 3.13.1.3 Loss Pool Net Injection

The calculation of the loss rebate factors continues with determining the net Loss Pool injection at each SL, which is simply a collection of quantities which is agnostic to the AO of the instrument. Loss Pools are a grouping of an AO’s transactional activity at all SLs – as such an SL might appear in many Loss Pools. The AO net injection is also necessary in order to prorate the net SL injection among all AOs at a given location when opposing determinants may to some degree or completely cancel each other out. Financial Schedules are also used in determining the AO’s share of injection, therefore the energy obligation they convey is accompanied by a transfer the determinants for loss rebates.

#### Loss Pool Net Injection

\[
\begin{align*}
RtSlNetInj5minQty_{s,i} &= (-1) \times \left\{ \min (0, \sum_{lp} \sum_{a} |RtBillMtr5minQty_{a,s,lp,i} - DaClrdHrlyQty_{a,s,lp,h,t} - \sum_{t} DaClrdVHrlyQty_{a,s,lp,h,t} \right) \\
& \quad + \sum_{t} RtImpExp5minQty_{a,s,lp,i,t} \times (1 - RsgCrdFlg_{t}) - \sum_{t} DaImpExp5minQty_{a,s,lp,i,t} \right\} / 12
\end{align*}
\]

\[
\begin{align*}
RtAoNetInj5minQty_{a,s,lp,i} &= (-1) \times \left\{ \min (0, \sum_{a} |RtBillMtr5minQty_{a,s,lp,i} - DaClrdHrlyQty_{a,s,lp,h,t} - \sum_{t} DaClrdVHrlyQty_{a,s,lp,h,t} \\
& \quad - \sum_{t} RtEnFinHrlyQty_{a,s,lp,h,t} - \sum_{t} RtNEFinHrlyQty_{a,s,lp,h,t} + \sum_{t} RtImpExp5minQty_{a,s,lp,i,t} \times (1 - RsgCrdFlg_{t}) - \sum_{t} DaImpExp5minQty_{a,s,lp,i,t} \right\} / 12
\end{align*}
\]

\[
RtLpNetInj5minQty_{a,s,lp,i} = RtSlNetInj5minQty_{s,i} \times \{RtAoNetInj5minQty_{a,s,lp,i} / RtAoNetInjSpp5minQty_{s,i}\}
\]

Where: \(RtAoNetInjSpp5minQty_{s,i} = \sum_{lp} \sum_{a} RtAoNetInj5minQty_{a,s,lp,i}\)
RtSlNetInj5minQty \_G5\_ = (-1) \* \{ \text{Min} \ (0, \ [-416 \text{ MWi} - 0 - -500 \text{ MWi} + 0 * (1 - 0) - 0] \} } / 12 = 0

RtAoNetInj5minQty \_AO\_W, \_G5\_W = (-1) \* \{ \text{Min} \ (0, \ [-416 \text{ MWi} - 0 - 0 - 0 + 0 * (1 - 0) - 0] \} } / 12 \ i/h = 34.667 \text{ MWh}

RtAoNetInj5minQty \_AO\_X, \_G5\_X = (-1) \* \{ \text{Min} \ (0, \ [0 - 0 - -500 \text{ MWi} - 0 - 0 + 0 * (1 - 0) - 0] \} } / 12 \ i/h = 0 \text{ MWh}

RtLpNetInj5minQty \_AO\_W, \_G5\_W = 0 * \{ 34.667 \text{ MWh} / 34.667 \text{ MWh} \} = 0

RtLpNetInj5minQty \_AO\_X, \_G5\_X = 0 * \{ 0 / 34.667 \text{ MWh} \} = 0
3.13.1.4 Internal & External Supply Factors

The summations of the net injection and withdrawal per Loss Pool (T, U, V, W, X, Y & Z representing Asset Owners) are used to determine to what degree withdrawal in the Loss Pool is being met with injection in the Loss Pool and if the Loss Pool is supplying the exchange.

Internal & External Supply Factors

IF \[ \sum_{s} \text{RtLpNetWdr5minQty}_{s,lp,i} = 0 \] THEN \( \text{RtLpIntSupply5minFct}_{lp,i} = 0 \) ELSE \( \text{RtLpIntSupply5minFct}_{lp,i} = \min \left[ 1, \frac{\sum_{s} \text{RtLpNetInj5minQty}_{s,lp,i}}{\sum_{s} \text{RtLpNetWdr5minQty}_{s,lp,i}} \right] \)

IF \[ \sum_{s} \text{RtLpNetInj5minQty}_{s,lp,i} = 0 \] THEN \( \text{RtLpExtSupply5minFct}_{lp,i} = 0 \) ELSE \( \text{RtLpExtSupply5minFct}_{lp,i} = \max \left[ 0, \left( 1 - \frac{\sum_{s} \text{RtLpNetWdr5minQty}_{s,lp,i}}{\sum_{s} \text{RtLpNetInj5minQty}_{s,lp,i}} \right) \right] \)

In terms of RTBM incremental energy Loss Pool W is a net injector and is contributing to the exchange, Loss Pools U & X are net withdrawers and consuming from the exchange.
<table>
<thead>
<tr>
<th>Loss Pool</th>
<th>RtLPIntSupply5minFct</th>
<th>RtLPExtSupply5minFct</th>
</tr>
</thead>
<tbody>
<tr>
<td>U</td>
<td>( \text{Min}\left[1, \frac{(50 \text{ MWi} / 12\text{i/h} + 19 \text{ MWi} / 12\text{i/h} + 3 \text{ MWi} / 12\text{i/h})}{(16 \text{ MWi} / 12\text{i/h} + 100 \text{ MWi} / 12\text{i/h} + 18.917 \text{ MWh})} \right] = 0.2099 )</td>
<td>( \text{Max}\left[0, \frac{1 - \frac{(16 \text{ MWi} / 12\text{i/h} + 100 \text{ MWi} / 12\text{i/h} + 18.917 \text{ MWh})}{(50 \text{ MWi} / 12\text{i/h} + 19 \text{ MWi} / 12\text{i/h} + 3 \text{ MWi} / 12\text{i/h})}} \right] = 0 )</td>
</tr>
<tr>
<td>W</td>
<td>( \text{RtLPIntSupply5minFct = No net withdrawal, therefore = 0.0000} )</td>
<td>( \text{RtLPExtSupply5minFct = Max}\left[0, \frac{1 - (0)}{(5 \text{ MWi} / 12\text{i/h})}\right] = 1.0000 )</td>
</tr>
<tr>
<td>X</td>
<td>( \text{RtLPIntSupply5minFct = Min}\left[1, \frac{(0)}{(84 \text{ MWi} / 12\text{i/h})}\right] = 0 )</td>
<td></td>
</tr>
</tbody>
</table>
3.13.1.5 Injection Weighted Average Marginal Loss Components

Incremental withdrawal served from within a Loss Pool is valued at the source by the weighted average of the MLCs at SLs injecting in the Loss Pool. Incremental withdrawal served from the exchange is valued at the source by the weighted average of the MLCs at SLs in Loss Pools supplying the exchange.

\[
\text{Loss Pool Injection Weighted Average Marginal Loss Component & the Exchange Weighted Average}
\]

\[
\text{IF } \sum_s \text{RtLpNetInj5minQty}_{s, lp, i} = 0 \text{ THEN } \text{RtLpIwaMlc5minPrc}_{lp, i} = 0
\]

\[
\text{ELSE } \text{RtLpIwaMlc5minPrc}_{lp, i} = \sum_s \text{RtLpNetInj5minQty}_{s, lp, i} \times \text{RtMlc5minPrc}_{s, i} / \sum_s \sum_s \text{RtSppIwaMlc5minPrc}_{s, i} = \sum_{lp} \left[ \text{RtLpExtSupply5minFct}_{lp, i} \times \sum_s \left( \text{RtLpNetInj5minQty}_{s, lp, i} \times \text{RtMlc5minPrc}_{s, i} \right) \right] / \sum_{lp} \sum_s \text{RtLpExtSupply5minFct}_{lp, i} \times \sum_s \text{RtLpNetInj5minQty}_{s, lp, i}
\]

<table>
<thead>
<tr>
<th>SL</th>
<th>RtMlc5minPrc $/MWh</th>
</tr>
</thead>
<tbody>
<tr>
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</tr>
<tr>
<td>G2</td>
<td>0</td>
</tr>
<tr>
<td>G3</td>
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</tr>
<tr>
<td>G4</td>
<td>-1</td>
</tr>
<tr>
<td>G5</td>
<td>-1</td>
</tr>
<tr>
<td>G6</td>
<td>2</td>
</tr>
<tr>
<td>D1</td>
<td>1</td>
</tr>
<tr>
<td>L1</td>
<td>1</td>
</tr>
<tr>
<td>L2</td>
<td>1</td>
</tr>
<tr>
<td>L3</td>
<td>2</td>
</tr>
<tr>
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</tr>
<tr>
<td>L7</td>
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</tr>
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</tr>
<tr>
<td>I2</td>
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</tr>
<tr>
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</tr>
<tr>
<td>H3</td>
<td>0</td>
</tr>
<tr>
<td>H4</td>
<td>3</td>
</tr>
</tbody>
</table>
Loss Pool U

\[ \text{RtLpIwaMlc5minPrc} = \frac{[(50 \text{ MWi} \times 1 \text{ $/MWh} + 19 \text{ MWi} \times 1 \text{ $/MWh} + 3 \text{ MWi} \times 1 \text{ $/MWh}) / 12 \text{i/h} ]}{[(50 \text{ MWi} + 19 \text{ MWi} + 3 \text{ MWi}) / 12 \text{i/h}]} = \$1.0000/\text{MWh} \]

Loss Pool W

\[ \text{RtLpIwaMlc5minPrc} = \frac{[(5 \text{ MWi} \times 2 \text{ $/MWh}) / 12 \text{i/h} ]}{[(5 \text{ MWi}) / 12 \text{i/h}]} = \$2.0000/\text{MWh} \]

Loss Pool X

\[ \text{RtLpIwaMlc5minPrc} = \text{No net injection, therefore} = \$0/\text{MWh} \]

The Exchange

\[ \text{RtSppIwaMlc5minPrc} = [0 \times (17 \text{ MWi} \times \$0/\text{MWh} + 13 \text{ MWi} \times \$0/\text{MWh}) ] + 0 \times (50 \text{ MWi} \times 1 \text{ $/MWh} + 19 \text{ MWi} \times 1 \text{ $/MWh} + 3 \text{ MWi} \times 1 \text{ $/MWh}) ] + 0.9256 \times (11 \text{ MWi} \times -1 \text{ $/MWh} + 100 \text{ MWi} \times 0 \text{ $/MWh} + 440 \text{ MWi} \times 2 \text{ $/MWh}) ] + 1.000 \times (5 \text{ MWi} \times 2 \text{ $/MWh}) ] + 0 \times ( ) ] + 0.8072 \times (8 \text{ MWi} \times 2 \text{ $/MWh} + 75 \text{ MWi} \times 2 \text{ $/MWh}) ] + 0 \times ( ) ] / 12 \text{i/h} ] / (0 \times 30 \text{ MWi} + 0 \times 72 \text{ MWi} + 0.9256 \times 551 \text{ MWi} + 1 \times 5 \text{ MWi} + 0 \times 0 \text{ MWi} + 0.8072 \times 83 \text{ MWi} + 0 \times 0 \text{ MWi}) / 12 \text{i/h} = \$1.6294/\text{MWh} \]
3.13.1.6 Loss Rebate Factors

The loss rebate factors are constructed by multiplying the portion of the incremental net withdrawal served from within the Looss Pool at the SL by the $\Delta$ between the local MLC and the local Loss Pool’s injection weighted average MLC and summing that with the portion of the incremental net withdrawal served by the exchange at the SL by the $\Delta$ between the local MLC and the exchange injection weighted average MLC. Positive loss rebate factors are aggregated (in this example by multiplying by 12) to hourly values are normalized such that the set sums to 100%.

\[
\text{Loss Rebate Factors}
\]

\[
\begin{align*}
\text{RtLossRbt5minFct}_{a, s, lp, i} & = \{ [ \text{RtLpIntSupply5minFct}_{lp, i} \times ( \text{RtMlc5minPrc}_{s, i} - \text{RtLpIwaMlc5minPrc}_{lp, i} ) ] \\
 & + ( 1 - \text{RtLpIntSupply5minFct}_{lp, i} ) \times ( \text{RtMlcHrlyPrc}_{s, i} - \text{RtSppIwaMlc5minPrc}_{i} ) \} \times \\
\text{RtLpNetWdr5minQty}_{a, s, lp, i}
\end{align*}
\]

\[
\text{RtLossRbtHrlyFct}_{a, s, lp, h} = \sum_i \text{Max} ( 0, \text{RtLossRbt5minFct}_{a, s, lp, i} )
\]

IF $\text{RtLossRbtSppHrlyFct}_{h} = 0$ THEN $\text{RtNormLossRbtHrlyFct}_{a, s, lp, h} = 0$ ELSE

\[
\text{RtNormLossRbtHrlyFct}_{a, s, lp, h} = \text{Max} ( 0, \text{RtLossRbtHrlyFct}_{a, s, lp, h} ) / \text{RtLossRbtSppHrlyFct}_{h}
\]

Where: $\text{RtLossRbtSppHrlyFct}_{h} = \sum_a \sum_s \sum_{lp} \text{Max} ( 0, \text{RtLossRbtHrlyFct}_{a, s, lp, h} )$
\begin{align*}
\text{RtLossRbt5minFct}_{AO, L3, U} &= \left\{ \left[ 0.2099 \times (2/\text{MWh} - 1.0000/\text{MWh}) + (1 - 0.2099) \times (2/\text{MWh} - 1.6294/\text{MWh}) \right] \times 18.917 \text{ MWh} \right\} = 9.51 \\
\text{RtLossRbtHrlyFct}_{AO, L3, U} &= 12 \times \max(0, 9.51) = 114.11 \\
\text{RtNormLossRbtHrlyFct}_{AO, L3, U} &= \frac{114.11}{294.29} = 0.3877 \\
\text{RtLossRbt5minFct}_{AO, L3, X} &= \left\{ \left[ 0 \times (2/\text{MWh} - 0/\text{MWh}) + (1 - 0) \times (2/\text{MWh} - 1.6294/\text{MWh}) \right] \times 18.917 \text{ MWh} \right\} = 0 \\
\text{RtLossRbt5minFct}_{AO, G5, X} &= \left\{ \left[ 0 \times (-1/\text{MWh} - 0/\text{MWh}) + (1 - 0) \times (-1/\text{MWh} - 1.6294/\text{MWh}) \right] \times 7.000 \text{ MWh} \right\} = -18.41 \\
\text{RtLossRbtHrlyFct}_{AO, G5, X} &= 12 \times \max(0, -18.41) = 0 \\
\text{RtNormLossRbtHrlyFct}_{AO, G5, X} &= \frac{0}{294.29} = 0.0000 \\
\text{RtLossRbt5minFct}_{AO, G5, W} &= \left\{ \left[ 0 \times (-1/\text{MWh} - 2/\text{MWh}) + (1 - 0) \times (-1/\text{MWh} - 1.6294/\text{MWh}) \right] \times 0 \text{ MWh} \right\} = 0
\end{align*}
<table>
<thead>
<tr>
<th>SL</th>
<th>RtmMicminPro $/MWh</th>
<th>RtlLossRbtHrrlyFct $</th>
<th>RtlNormLossRbtHrrlyFct %</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>AO T</td>
<td>AO U</td>
<td>AO V</td>
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<tr>
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</tbody>
</table>

794.29

100%
3.13.1.7  **Charge Type Results**

The final product of this sequence of formulae is achieved by multiplying the normalized loss rebate factors and the hourly over-collection total.

<table>
<thead>
<tr>
<th>Charge Type Result</th>
</tr>
</thead>
<tbody>
<tr>
<td>[ RtOclDistHrlyAmt_{a,s,lp,h} = RtNormLossRbtHrlyFct_{a,s,lp,h} \times RtIncrOclHrlyAmt_h \times (-1) ]</td>
</tr>
</tbody>
</table>

<p>| |</p>
<table>
<thead>
<tr>
<th></th>
</tr>
</thead>
</table>
| \[ \begin{align*} 
RtOclDistHrlyAmt_{AO\,U,\,L3\,U} &= 0.3877 \times (12 \times 8.66) \times (-1) = -42.31 
\end{align*} \] |