PJM Manual 28:

Operating Agreement Accounting

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Section 4: Regulation Accounting

Welcome to the Regulation Accounting section of the ***PJM Manual for Operating Agreement Accounting***. In this section, you will find the following information:

- A description of how Regulation is provided and accounted for in the PJM Regulation Markets (see "Regulation Accounting Overview").
- How credits are calculated for providers of Regulation (see "Regulation Credits").
- How charges are calculated for users of Regulation (see "Regulation Charges").
- How regulation charge reconciliations are calculated (see "Reconciliation for Regulation Charges").

4.1 Regulation Accounting Overview

Regulation is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at 60 cycles per second (60 Hz). PJM commits on-line resources whose output is raised or lowered as necessary to follow moment-to-moment changes in load. Regulation is predominantly achieved using automatic generation control equipment. Regulating resources include both generators and Demand Resources.

PJM operates the Regulation Market where the Regulation Market Clearing Prices are determined based on Regulation offers and opportunity costs. PJM assigns the most economically efficient set of regulating resources available in real-time to separately meet the applicable NERC regions' regulation zone requirements. For more detailed information about how regulating requirements are developed and how Regulation is assigned, see PJM Manual 12: Balancing Operations. For an overview of the Regulation Market, see PJM Manual 11: Energy & Ancillary Services Market Operations.

Resource owners supplying pool-scheduled Regulation are credited for each Regulation MW at the higher of the five minute Regulation Market Performance and Capability Clearing Prices, with consideration of the resource's Regulation performance, and where applicable the mileage ratio, or their five-minute Regulation offer price (plus real-time opportunity cost including shoulder intervals' lost opportunity costs, for generating resources).

Resource owners supplying self-scheduled Regulation are credited based on the Real-time Settlement Interval (five minute) Regulation Market Capability Clearing Price (RMCCP) and Regulation Market Performance Clearing Price (RMPCP) for each MW of Regulation supplied, with consideration of the resource's Regulation performance, and where applicable, the ratio between the requested mileage for the regulation dispatch signal assigned to the resource and the mileage for the traditional regulation signal (mileage ratio).

Each Market Participant that is a Load Serving Entity (LSE) or Regulation buyer has an hourly Regulation Obligation equal to their Load Ratio Share prorated to reflect the total amount of Regulation actually supplied. This obligation can be satisfied from their own resources capable of providing Regulation, by contractual arrangements with other Market Participants capable of providing Regulation, and/or by purchases of Regulation from the PJM Regulation Market.

Each Market Participant that is a Load Serving Entity (LSE) or Regulation buyer are charged an obligation ratio share of the total hourly Regulation Market Capability Clearing Price (RMCCP) credits and Regulation Market Performance Clearing Price (RMPCP) credits plus their percentage share of any Regulation provider's unrecovered costs over and above their total Regulation Clearing Price credits.

4.2 Regulation Credits

Regulation credits are paid to Market Participants that supply their resource to PJM either by pool-scheduled or self-scheduled. PJM sums the 5-minute Regulation credits (both Regulation Clearing Price credits and Lost Opportunity Cost credits) to determine the total credit for each Regulation market participant. Regulation credits for joint-owned generators supplying Regulation are allocated to the owners based on their ownership shares.

4.2.1 Regulation Clearing Price Credit

Each resource supplying pool-scheduled or self-scheduled Regulation is credited based on the five minute RMCCP and RMPCP with consideration of the resource's Regulation performance, and where applicable, the mileage ratio. Lost opportunity cost credits are described in Section 4.2.2 of this PJM Manual.

Any resource with a five minute performance score below the applicable threshold for minimum performance as defined in PJM Manual 11: Energy & Ancillary Services Market Operations, Section 3.2.10 receives zero regulation credits for that five minute interval. **PJM Actions**

- PJM retrieves the following information for the Regulation Clearing Price Credit (further definitions of terms may be found in PJM Manual 11: Energy & Ancillary Services Market Operations or Operating Agreement of PJM Interconnection, L.L.C.):
  - Performance Score o Mileage Ratio (MWh) o PJM-Assigned Reg MW o Self-schedule Reg MW
  - Regulation Market Capability Clearing Price (RMCCP) ($/MWh) o Regulation Market Performance Clearing Price (RMPCP) ($/MWh)
- From the Regulation log, PJM identifies each resource that supplied Regulation (both pool-scheduled and self-scheduled) with a five minute performance score greater than or equal to the applicable threshold for minimum performance as defined in PJM Manual 11: Energy & Ancillary Services Market Operations, Section 3.2.10.
- PJM calculates the total Regulation Clearing Price Credit as the RMCCP Credit plus the RMPCP Credit for that 5-minute interval. o *Regulation Clearing Price Credit = RMCCP Credit + RMPCP Credit*
- PJM calculates the five minute RMCCP Credit for each applicable regulating resource by multiplying each increment of such Regulation in megawatts during the five minute interval by the Regulation Market Capability Clearing Price (RMCCP) and the resource's actual performance score for that five minute interval. This result is then divided by 12 to determine the five minute interval RMCCP Credit.

- *RMCCP Credit = Five minute integrated Regulation MW * Five minute Performance Score * Five minute RMCCP / 12)*

- PJM calculates the five minute RMPCP Credit for each applicable regulating resource by multiplying each increment of such Regulation in megawatts during the five minute interval by the Regulation Market Performance Clearing Price (RMPCP) for that five minute interval, the applicable mileage ratio, and the resource's actual performance score for that five minute interval. The result is then divided by 12 to determine the five minute interval RMPCP Credit
  - *RMPCP Credit = Five minute integrated Regulation MW * Five minute Performance Score * Mileage Ratio * Five minute RMPCP / 12*

4.2.2 Regulation Lost Opportunity Cost Credit

Lost opportunity cost credits for regulation are calculated for the regulation intra-hour and shoulder intervals. Resources supplying pool-scheduled Regulation, PJM sums the resource's Regulation offer and lost opportunity lost credits, including shoulder intervals' lost opportunity cost credits, then compares it to its 5-minute Regulation Clearing Price credits. If the resulting amount is positive, then lost opportunity cost credits are allocated, however, if the resulting amount is negative, then the credit is $0. Resource supply self-scheduled Regulation are not eligible for lost opportunity cost credits.

Lost Opportunity Cost Credit = ((Regulation Offer + Intra-Hour Lost Opportunity Cost + Shoulder Interval Lost Opportunity Cost) / 12) – Regulation Clearing Price Credit

4.2.2.1 Intra-Hour

The five minute lost opportunity costs calculated as part of the real-time pricing algorithm as adjusted by the applicable performance score and unit-specific benefits factor are used in the settlement calculation for intra-hour lost opportunity costs.

Since hydro units operate on a schedule and do not have an energy bid, lost opportunity costs for these units are calculated using the average of the real-time LMP at the hydro unit bus for the appropriate on peak (0700 - 2259) or off-peak (0000 – 0659, 2300 - 2359) period, excluding those hours during which all available units at the hydro plant were operating.

If a hydro units is in spill during those five minute intervals, the average of the real-time LMP value is set to zero such that the lost opportunity cost is equal to (i) the five minute regulation setpoint (biased to reflect the actual regulation signal and adjusted by the applicable five minute performance score and benefits factor) multiplied by (ii) the full value of the five minute real-time LMP at the generator bus.

If a hydro unit is committed day-ahead with MW greater than zero, the lost opportunity cost is equal to (i) the five minute regulation setpoint (biased to reflect the actual regulation signal and adjusted by the applicable five minute performance score and benefits factor) multiplied by (ii) the difference between the five minute real-time LMP at the generator bus and the average real-time LMP (calculated as stated above). If this average real-time LMP value is higher than the five minute real-time LMP at the generator bus, the lost opportunity cost is zero.

If a hydro unit is not committed day-ahead with MW greater than zero, the lost opportunity cost is equal to (i) the five minute regulation setpoint (biased to reflect the actual regulation signal and adjusted by the applicable five minute performance score and benefits factor) multiplied by (ii) the difference between the average real-time LMP (calculated as stated above) minus the five minute real-time LMP at the generator bus. If the actual five minute real-time LMP is higher than the average real-time LMP, the lost opportunity cost is zero.

Additional details on hydro units in the Regulation Market can be found in PJM Manual 11: Energy & Ancillary Services Market Operations.

4.2.2.2 Shoulder Intervals

The preceding three 5-minute intervals (including limits and assigned MW) before the regulation hour are the ramp-in 5-minute intervals. Lost opportunity costs from the ramp-in 5-minute intervals applied to the first 5-minute interval of the regulating hour. The following three 5minute intervals (including limits and assigned MW) after the regulation hour are the ramp-out 5-minute intervals. Lost opportunity costs from the ramp-out 5-minute intervals applied to the last 5-minute interval of the regulating hour.

CT[1] and hydro generators are not eligible for shoulder hour lost opportunity costs.

Ramp-in lost opportunity cost generator eligibility is determined for each of the three ramp-in five minute intervals if all of the following conditions are met:

- it is online in the ramp-in five minute interval;
- the Regulation assignment starts at the top of the hour;
- it is not regulating in all of the ramp-in five minute intervals;
- the LMP Desired from the ramp-in five minute interval is not already within the regulation limits from the first five minute interval at the top of the regulation hour.

Ramp-in lost opportunity cost credits for when a generator must reduce its output to provide regulation and foregoes revenues, its shoulder hour lost opportunity cost in that five minute interval equals the amount of its energy offer* at the preceding five minute interval economically desired level (capped at the stability limit in effect) in excess of its energy offer* at its Regulation setpoint at the start of the regulation hour.

Ramp-in lost opportunity cost credit for when a generator must increase its output to provide regulation and incurs additional costs, its shoulder hour lost opportunity cost in that five minute interval equals the amount of its energy offer* at its Regulation setpoint at the start of the regulating hour in excess of its energy offer* at the preceding five minute interval economically desired level (capped at the stability limit in effect).

Ramp-out lost opportunity cost generator eligibility is determined for each of the three ramp-out five minute intervals if all of the following conditions are met:

- it is online in the ramp-out five minute interval;

[1] Unless otherwise specified, diesel unit types are treated as CTs in settlements based on their similar operating characteristics.

- the Regulation assignment ends at the top of the following hour;
- it is not regulating in all of the ramp-out five minute intervals;
- the LMP Desired from the ramp-out five minute interval is not already within the regulation limits from the last five minute interval of the regulating hour.

Ramp-out lost opportunity cost credits for when a generator increased its output to provide regulation and incurs additional costs, its shoulder hour lost opportunity cost in that five minute interval equals the amount of its energy offer* at its Regulation setpoint at the end of the regulating hour in excess of its energy offer* at the following five minute interval economically desired level (capped at the stability limit in effect).

Ramp-out lost opportunity cost credits for when a generator reduced its output to provide regulation and foregoes revenues, its shoulder hour lost opportunity cost in that five minute interval equals the amount of its energy offer* at the following five minute interval economically desired level (capped at the stability limit in effect) in excess of its energy offer* at its Regulation setpoint at the end of the regulating hour.

The regulation set point equals the regulation low limit plus the regulation assigned MW in the applicable five minute interval the unit regulated, when the LMP desired MW, is less than or equal to the regulation low limit in the applicable five minute interval the unit regulated.

The regulation set point equals the regulation high limit minus the regulation assigned MW in the applicable five minute interval the unit regulated, when the LMP desired MW is greater than or equal to the regulation high limit in the applicable five minute interval the unit regulated.

*The energy offer referenced is the generator's incremental energy offer curve that is associated with the price-based or cost-based schedule used in the real-time dispatch of the unit

4.3 Regulation Charges

Each Market Participant that is a Load Serving Entity (LSE) or other Regulation buyer, is charged an hourly Regulation Obligation Share of the total hourly Regulation Market Capability Clearing Price (RMCCP) credits, Regulation Market Performance Clearing Price (RMPCP) credits and Lost Opportunity Cost credits.

PJM sums the Regulation charges (both Regulation Clearing Price charges and Lost Opportunity charges) to determine the total hourly charge for each Regulation market participant.

4.3.1 Regulation Clearing Price Charge

PJM calculates the hourly charge separately for RMCCP and RMPCP. The hourly Regulation Obligations equal the Load Serving Entity's or Regulation buyer's Load Ratio Share of the total amount of Regulation supplied excluding the mileage ratio component by PJM that hour and adjusted for any bilateral Regulation transactions.

PJM Actions

- PJM retrieves the following information for the Regulation Clearing Price Charge: o Market Participant’s Load Ratio Share (MWh)
  - o Bilateral Regulation transactions (sales and purchases) (MWh) o Mileage Ratio (MWh)
  - o Regulation Market Capability Clearing Price (RMCCP) credit ($)
  - o Regulation Market Performance Clearing Price (RMPCP) credit ($)
- PJM determines each Load Serving Entity’s (LSE’s) or Regulation buyer’s applicable Regulation Obligation Share based on their Load Ratio Share.
  - o *Regulation Obligation Share = Adjusted Regulation Obligation / Total PJM Regulation Adjusted Obligation* o *Adjusted Regulation Obligation = Regulation Obligation - Regulation MW Purchased + Regulation MW Sold* o
  - o *Regulation Obligation = Load Ratio Share * Total Regulation Supplied (excluding mileage)*
  - o Total Regulation Supplied (excluding mileage) is for both pool-scheduled and selfscheduled resources by summing the 5-minute intervals Regulation MW multiplied by the Performance Score for all eligible resources integrated for an hour
- PJM calculates the Regulation Capability Clearing Price Charge for each Market Participant by multiplying their Regulation Obligation Share for the hour by the total Regulation Market Capability Clearing Price (RMCCP) credits for that hour.
  - o *Regulation Capability Clearing Price Charge = Regulation Obligation Share * Total RMCCP Credits*
- PJM calculates Regulation Performance Clearing Price Charge for each Market Participant by multiplying their Regulation Obligation Share for the hour by the total Regulation Market Performance Clearing Price (RMPCP) credits for that hour.
  - o *Regulation Performance Clearing Price Charge = Regulation Obligation Share * Total RMPCP Credits*

4.3.2 Regulation Lost Opportunity Cost Charge

In addition to the Regulation Clearing Price charges, PJM also calculates charges to Market Participants for the lost opportunity costs. Market Participants that are considered Net Regulation Purchases are charged a proportionate share of any lost opportunity credits paid to regulating generators for unrecovered costs over and above their Regulation Clearing Price credits.

If any lost opportunity of other unrecovered costs due to regulating were credited to Regulation providers, each Regulation market buyer is allocated a share of the hourly costs based on the amount of Regulation they purchased from the market that hour

PJM Actions

- PJM retrieves the following information for the Regulation Lost Opportunity Cost Charge:
    - o Market Participant's Load Ratio Share (MWh)
    - o Bilateral Regulation transactions (sales and purchases) (MWh) o Mileage Ratio (MWh)
    - o Regulation Lost Opportunity Cost credit (4)
    - o Self-scheduled Regulation (MWh)
- PJM calculates the hourly Regulation lost Opportunity Cost Charge by taking the product of the Total Regulation Lost Opportunity Cost Credits and Net Regulation Purchase and dividing it by the Total PJM Regulation Purchases
    - o *Regulation Lost Opportunity Cost Charge = (Total Regulation Lost Opportunity Cost Credits * Net Regulation Purchase) / Total PJM Regulation Purchases*
- PJM calculates each Market Participant's hourly Net Regulation Purchase by subtracting the amount of self-scheduled regulation MW provided from their Adjusted Obligation o *Net Regulation Purchase = Regulation Adjusted Obligation – Self Scheduled regulation MW*

4.4 Reconciliation for Regulation Charges

PJM will calculate reconciled Regulation charges for EDCs and Retail Load Aggregators (a.k.a. Electric Generation Suppliers) for past monthly billings on a two month lag that were based on Load Ratio Shares. The reconciliation kWh data must be supplied to PJM by the EDCs no later than the last day of the billing month that is two months after the original billing month. For example, all reconciliation data for January must be submitted by March 31 at 23:59.

The reconciliation kWh data represents the difference between the scheduled Retail Load Responsibility or Wholesale Load Responsibility InSchedule and the "actual" usage based on metered data. This hourly kWh data must be reported separately for each applicable InSchedule contract.

PJM calculates the Regulation charge reconciliations by multiplying the kWh data (de-rated for transmission losses) by the Regulation billing determinant for that hour. The hourly Regulation charge billing determinant (in $/MWh) is calculated by dividing the total hourly Regulation charges by the total real-time PJM load (de-rated for transmission losses) for in that hour. These charge reconciliations are then totaled for the month for each EDC or Retail Load Aggregator. Note that the reconciliation for Regulation charges for a month may be either a positive or a negative value, and may even be such that the reconciled load responsibility MWh results in a negative load quantity.

Section 5: Operating Reserve Accounting

Welcome to the Operating Reserve Accounting section of the ***PJM Manual for Operating Agreement Accounting***. In this section, you will find the following information:

- A description of how Operating Reserve is provided and accounted for in the Day-ahead and Balancing PJM Energy Markets (see “Operating Reserve Accounting Overview”).
- How day-ahead and balancing credits are calculated for providers of pool-scheduled Operating Reserve (see “Credits for Operating Reserve”).
- How the total pool cost of day-ahead and balancing Operating Reserve, Synchronous Condensing, and Reactive Services are allocated (see “Charges for Operating Reserve”).

5.1 Operating Reserve Accounting Overview

Accounting for Operating Reserve is performed on a daily basis. A pool-scheduled resource of a PJM Member is eligible to receive credits for providing Operating Reserve in the day-ahead market and, provided that the resource was available for the entire time specified in its offer data, in the balancing market. The total resource offer amount for generation, including startup and no-load costs as applicable, is compared to its total energy market value for specified operating period segments during the day (including any amounts credited for day-ahead scheduling reserve in excess of the day-ahead scheduling reserve offer plus opportunity cost, any amounts credited for synchronized reserve in excess of the synchronized reserve offer plus opportunity cost, any amounts credited for non-synchronized reserve in excess of the opportunity cost and any amounts credited for resources providing reactive services). If the total value is less than the offer amount, the difference is credited to the PJM Member.

Credits are also provided for pool-scheduled energy transactions, for dispatchable economic load reduction resources, for generating units operating as synchronous condensers (not for synchronized reserve nor for reactive services) at the direction of PJM, for cancellation of poolscheduled resources, for units whose output is suspended or reduced due to a transmission constraint or other reliability reason, for units performing an annual black start test, for units providing reactive services at the direction of PJM, and for pool-scheduled and dispatchable self-scheduled resources eligible for dispatch differential lost opportunity cost credits.

Market power mitigation and offer capping rules are detailed in PJM Manual 11: Energy & Ancillary Services Market Operations, Section 2.3.6.1.

The total cost of Day-ahead Operating Reserve for the Operating Day, excluding the total cost for resources scheduled to provide Black Start Service, Reactive Services or transfer interface control, is allocated and charged to PJM Members in proportion to their total cleared day-ahead demand, decrement bids, and up-to congestion transactions at the sink end of the transaction plus their cleared day-ahead exports for that Operating Day. The total cost of Balancing Operating Reserve for the Operating Day, excluding the total cost associated with scheduling units for Black Start service or testing of Black Start units, is allocated and charged to PJM Members in proportion to their locational real-time deviations from day-ahead schedules and generating resource deviations during that Operating Day, or to PJM Members in proportion to their real-time load plus exports during that Operating day for generator credits provided for reliability. In order to determine the reason why the Operating Reserve credit has been earned so that the charges related can be properly allocated, PJM conducts a Balancing Operating Reserve Cost Analysis (BORCA). PJM also calculates a Regional Balancing Operating Reserve rate for the costs of Operating Reserves that result from actions to control transmission constraints that are solely within pre-defined regions in the RTO. Additional costs of Operating Reserves that result from actions to control transmission constraints that benefit the entire RTO will continue to be allocated equally to deviations across the entire RTO. A detailed description of the Regional Balancing Operating Reserve Cost Analysis (BORCA) analysis can be found in Manual 11: Energy & Ancillary Services Market Operations. The total cost of synchronous condenser payments (other than that for synchronized reserve or reactive services) for the Operating Day is allocated and charged to PJM Members in proportion to their total load plus their exports during that Operating Day. The total cost of Reactive Services for the Operating Day is allocated and charged to PJM Members in proportion to their total load in the applicable transmission zone. The total cost of Day-ahead Operating Reserve for the Operating Day for resources scheduled to provide Reactive Services or transfer interface control because the resource is known or expected to be needed to maintain system reliability in a zone(s) is allocated and charged to PJM Members in proportion to their total real-time load in the applicable transmission zone(s). The total cost of Operating Reserves for resources providing Black Start service or testing of Black Start units is allocated to Network and Point-toPoint Transmission Customers based on their monthly transmission use on a megawatt basis. Additional details on this allocation can be found in PJM Manual 27: Open Access Transmission Tariff Accounting, Section 7.

5.2 Credit for Operating Reserve

Credits for Operating Reserve are calculated for each of the following situations:

- pool-scheduled generating resources (day-ahead and balancing markets)
- pool-scheduled transactions (day-ahead and balancing markets)
- synchronous condensing for purposes other than providing synchronized reserve or Reactive Services (balancing market)
- canceled pool-scheduled resources (balancing market)
- resources reduced or suspended due to a transmission constraint or for other reliability purposes (balancing market)
- resources performing annual scheduled black start tests (balancing market)
- resources scheduled to provide Black Start service (day-ahead and balancing market)
- synchronous condensing for purposes other than providing synchronized reserve
- resources providing Reactive Services, including synchronous condensing to main reactive reliability
- pool-scheduled and dispatchable self-scheduled resources eligible for dispatch differential lost opportunity cost credits (balancing market)

- dispatchable economic load reduction resources that follow dispatch (day-ahead and balancing markets). See Section 11 for details on Load Response Operating Reserves Credits and Charges.

5.2.1 Credits for Pool-Scheduled Generating Resources

At the end of each Operating Day, PJM calculates the credits due each PJM Member for pool-scheduled generating resources.

PJM Actions

- PJM retrieves the following information: o dispatcher generation scheduling and operations logs o resource offer data
    - the resource's Final Offer, which is the offer on which the resource was dispatched by the Office of the Interconnection for a particular clock hour for the Operating Day
    - the resource's Committed Offer. For pool scheduled resources, the Committed Offer is the offer on which the resource was scheduled by the Office of the Interconnection for a particular clock hour of the Operating Day. For selfscheduled resources, the Committed Offer is either the offer on which the Market Seller has elected to schedule the resource or the applicable offer based on a) any offer price capping or b) parameter limited schedule restrictions for the a particular clock hour of the Operating Day.
  - o hourly scheduled MWh for generation offers cleared in day-ahead market o five minute revenue meter generation MW values from PJM Power Meter if available o Five minute state estimator or telemetry generation MW, scaled to match hourly revenue meter generation MWh from PJM Power Meter as described in Section 1A of this PJM Manual
  - o hourly scheduled MWh for InSchedule "Generation" contracts, if applicable o five minute interval generator dispatch rates, UDS basepoint MW, and ramp-limited desired MW
  - o generator hourly day-ahead LMPs o five minute real-time LMPs
- PJM calculates the resource's hourly day-ahead offer amount based on its day-ahead Committed Offer and its cleared day-ahead Scheduled MWh for that hour.
- PJM accounting process applies the startup and hourly no-load bids if the start-up and no-load switch is set in the resource offer data and if the start-up bid is applicable for the MWh and status of the resource.
- Day-ahead credits for startup reflect the appropriate hot, intermediate, or cold state of the resource as it was scheduled in the day-ahead market.
- PJM calculates the resource's hourly day-ahead energy market value as:

  *Scheduled MWh * Day ahead LMP*

- PJM calculates the daily Day-ahead Operating Reserve credits for each resource as follows:
    - o Sum hourly day-ahead offer amounts, including applicable no-load and startup costs, for the day
    - o Sum hourly day-ahead energy market values for the day
    - o Day-ahead Operating Reserve credit equals any portion of the resource's total dayahead offer amount in excess of its total day-ahead market value
    - o Day-ahead Operating Reserve credits can be further adjusted by the Day-ahead Operating Reserve Offset as described below to remove any commitment costs, including start-up and no-load costs that are credited through Balancing Operating Reserve credits. For each Operating Day, PJM calculates for each resource, hourly Day-ahead Operating Reserve and a Balancing Operating Reserve Targets. These hourly targets are summed to obtain a Day-ahead Operating Reserve Target and a Balancing Operating Reserve Target for each Operating Day.
- The Day-ahead Operating Reserve Target is calculated as follows:

Day-ahead Operating Reserve Target = (Start-up costs + No-load and Energy Offer Costs) – Day-ahead Revenues

- The No-load and Energy Offer Costs are equal to the sum of the day-ahead no-load and energy offer costs over the Real-time Settlement Intervals that coincide with day-ahead settlement intervals that the resource was scheduled to provide energy. The hourly day-ahead no-load and energy offer costs are divided by twelve to calculate the cost for each Real-time Settlement Interval.
- The Day-ahead Revenues are equal to the sum of the day-ahead scheduled MWh multiplied by the hourly day-ahead LMP at the resource bus divided by twelve for each Real-time Settlement Interval that coincides with a Day-ahead Settlement Interval that the resource was scheduled to provide energy.
- The Balancing Operating Reserve Target is calculated as follows:

Balancing Operating Reserve Target = Resource Costs – (Real-Time Energy Revenue + Reserve Revenue)

- The Resource Costs are equal to the sum of the start-up, no-load and energy offer costs for all Real-time Settlement Intervals that coincide with day-ahead settlement intervals that the resource was scheduled to provide energy.
- The Real-Time Energy Revenue is equal to the five minute revenue data for settlement MW value multiplied by the five minute real-time LMP at the generator's bus summed over the applicable Real-time Settlement Intervals.
- The Reserve Revenue is equal to the sum of revenues for Day-ahead Scheduling Reserves, Synchronized Reserves, Non-Synchronized Reserves, and Reactive Services over the applicable Real-time Settlement Intervals.
- The Day-ahead Operating Reserve credits are adjusted by the following offset:

Day-ahead Operating Reserve Offset = Max (Day-ahead Operating Reserve Target – Balancing Operating Reserve Target, 0)

- PJM sums the Day-ahead Operating Reserve generating resource credits for each PJM Member, taking into account joint-ownership of generating units.
- PJM determines eligibility for Balancing Operating Reserve credits for each generating resource from dispatcher logs. The following operating guidelines are used in the determination of Operating Reserve credits:
  - Resource must operate according to the on and off times requested by PJM, and units tripping during pool-scheduled periods of operation will retain their eligibility up through the five minute interval in which the unit trips.
  - Resources that trip or fail to start are required to notify PJM per the Synchronization and Disconnection procedures in PJM Manual 14D: Generator Operational Requirements.
  - Resources that trip, are requested to restart by PJM, and return to operate as requested, are eligible to receive credits for the latter period of operation. Resources that trip or failed to start, are requested to restart by PJM for reliability, and operate as requested, are eligible for additional startup costs.
- PJM determines the resource's five minute Real-time MW as described in Section 1A of this PJM Manual.
- Generation resources that are scheduled in the Day-ahead Market are financially responsible for selling their output in real-time. Section 3.2.3(f-1)(ii) of the PJM OATT details provisions for lost opportunity credits for those Flexible Resources that were scheduled in the Day-ahead Market but are not called on by PJM to run in real-time (See Section 5.2.6 – Credits for Resources Reduced or Suspended due to a Transmission Constraint or for Other Reliability Reasons). Flexible Resources eligible to be called on in real-time must have a startup plus notification time of 2 hours or less and a minimum run time of 2 hours or less for PJM to accurately assess the economic value of the unit and are therefore the only units eligible for these provisions. Any resource scheduled in the Day-ahead Market with a startup plus notification time of greater than 2 hours and a minimum run time of greater than 2 hours should assume that they are committed by PJM in real-time for the duration of the Day-ahead commitment and are therefore only eligible for the aforementioned make whole provisions if PJM denies the commitment of that unit in real-time for either a transmission constraint or reliability.
- If a generation owner calls PJM to bring on a Flexible Resource per its Day-ahead schedule and PJM does not permit the unit to operate in real-time either for reliability or a transmission constraint, it may receive lost opportunity costs as described in section 3.2.3(f-1)(ii) of the OATT as it was not permitted to run by PJM in real-time (See Section 5.2.6 – Credits for Resources Reduced or Suspended due to a Transmission Constraint or for Other Reliability Reasons).
- If a Flexible Resource is committed in the Day-ahead Market with a startup plus notification time of 2 hours or less and a minimum run time of 2 hours or less at the time of the Day-ahead commitment and then extends its startup plus notification time to more

than 2 hours or its minimum run time to more than 2 hours, it will not be eligible to receive the aforementioned lost opportunity cost provisions in section 3.2.3(f-1)(ii) of the PJM Tariff.

- PJM determines the resource's five minute interval Operating Reserve Desired MW based on its ramp-limited desired MW or UDS basepoint MW, when available. If available, UDS basepoint MW is used when 1.) the UDS basepoint MW are less than or equal to the ramp-limited desired MW or 2.) the UDS basepoint MW is greater than the ramp-limited desired MW and the resource's Real-time MW is greater than the ramp-limited desired MW.
- PJM determines the resource's percent off dispatch for each five minute interval as the lesser of the difference between the resource's Real-time MW and the UDS basepoint MW or the Real-time MW and the ramp-limited desired MW, if available. UDS LMP desired MW is used to calculate a resource's percent off dispatch when 1.) data is unavailable due to technical difficulties or 2.) a resource's real-time economic minimum is greater than its day-ahead economic minimum by 5% or 5 MW, whichever is greater, or its real-time economic maximum is less than its day-ahead economic maximum 5% or 5MW, whichever is lower.
- If the resource's UDS basepoint MW and ramp-limited desired MW are not available or the percent off dispatch is greater than 20%, PJM determines the resource's five minute interval UDS LMP Desired MW based on its dispatch rate, applicable schedule's offer data, where the applicable schedule's offer is the Final Offer and minimum and maximum energy limits for that five minute interval. For steam units, the lesser of the day-ahead scheduled and real-time economic minimum limits and the greater of the day-ahead scheduled and real-time economic maximum limits are used. For Combustion Turbine units, operating at PJM direction, the actual five minute interval real-time output is used as the Operating Reserve Desired MW value.
- PJM calculates the resource's five minute interval real-time energy offer amount based on its applicable schedule's offer data, where the applicable schedule's offer is lesser of the Committed Offer and the Final Offer, and its Real-time MW for that five minute interval. However, for any five minute interval where the resource's Real-time MW is greater than 110% of its Operating Reserve Desired MW, Operating Reserve Desired MW is used to determine the five minute interval real-time energy offer amount.
- PJM applies the startup and hourly no-load bids if the startup and no-load switch is set in the resource offer data and if the startup bid is applicable for the status of the resource.
- If applicable, when a resource is started during the day at the direction of PJM, the resource's real-time offer amount for that day includes its startup costs based on the appropriate hot, intermediate, or cold state of the resource. For resources that start generating for PJM from a condensing state, the applicable startup cost for that resource equals the amount submitted in writing to the PJM Market Settlement Operations Department to be in effect that Operating Day.
- PJM calculates the resource's balancing energy market value for each five minute interval in an hour as:

*[(Real time MW** – Day-ahead Scheduled MW) * five minute RT LMP] /12*

Where the Real-time MW is the greater of [Real-time MW or the lesser of

(greater of (Real-time Dispatch Desired MW and Original Scheduled Desired MW Using the Committed Offer) and Day-ahead Scheduled MW] and the Day-ahead Scheduled MW is a flat-profile of the hourly scheduled MWh across each of the five minute intervals of the hour

***If a resource is committed in the Day-ahead market and increases the cost offer in real-time resulting in a reduction in Real-time MW from the DA Scheduled MW and is not the result of a PJM dispatch direction (including regulation, synchronized reserves, reactive services, or reductions due to transmission constraints or reliability concerns), the maximum of the Realtime MW and greater of the Real-time Dispatch Desired MW and the original Scheduled Desired MW using the Committed Offer (capped at the Day-ahead Scheduled MW) will be used in the balancing energy market value calculation, otherwise Real time MW are used.*

- Balancing Operating Reserve credits are calculated by operating segment within an Operating Day. A resource will be made whole for the duration of the greater of the day-ahead schedule and minimum run time specified at the time of the commitment (minimum down time specified at the time of the commitment for Demand Resources) and made whole separately for the block of real-time five minute settlement intervals it is operated at PJM's direction in excess of the greater of the day-ahead schedule and minimum run time specified at the time of the commitment (minimum down time specified at the time of the commitment for demand resources). Startup costs (shut down costs for Demand Resources), as applicable, will be included in the segment represented by the longer of the day-ahead schedule and minimum run time specified at the time of the commitment (minimum down time specified at the time of the commitment for Demand Resources).
- PJM calculates the daily Balancing Operating Reserve credits for each generating resource's operating segment as follows:
    - Sum five minute interval real-time offer amounts and include applicable no-load costs divided by twelve and startup costs for the segment
    - Sum five minute interval balancing energy market values for the segment
- For each operating segment, Balancing Operating Reserve credit equals any portion of the resource's total real-time offer amount in excess of: 1) its total day-ahead market value, plus 2) its total balancing market value, plus 3) any Day-ahead Operating Reserve credits, plus 4) any Day-Ahead Scheduling Reserve Market revenues in excess of its offer plus opportunity cost, plus 5) any Synchronized Reserve Market revenue in excess of its offer plus opportunity cost plus energy use plus startup costs, plus 6) any NonSynchronized Reserve Market revenue in excess of its opportunity costs, plus 7) any Reactive Services revenue.
    - Synchronized Reserve, Non-Synchronized Reserve, and the real-time five minute interval share of the Day-ahead Scheduling Reserve credits are netted against the Operating Reserve credit in the corresponding five minute interval in which those credits were accrued.

  - o A resource that operates outside of its unit-specific parameters is not eligible to receive Balancing Operating Reserve credits nor be made whole when operating to those parameters when not dispatched by PJM unless the resource owner can justify to PJM that the operation outside of the unit-specific parameters was the result of an actual system constraint.

- For any Operating Day in which PJM declares a Maximum Generation Emergency or a Maximum Generation Emergency Alert, or schedules units based on the anticipation of a Max Generation Emergency or Maximum Generation Emergency Alert, if a generator's priced-based offer results in revenues for applicable "economic" five minute intervals

  to produce an effective offer price greater than or equal to $1000/MWh and is greater than a Market Seller's lowest available and applicable cost-based offer, that generator shall not receive any operating reserve credits in accordance with the PJM Operating Agreement sections 3.2.3 (l), (m), and (n).

  - o For the Real-time market, PJM calculates an effective offer price by summing the Operating Reserve credits which would have been applicable absent this exemption, plus the real-time LMP market value provided to the generator during "economic" five minute intervals, all divided by the sum of the generation MW during those "economic" five minute intervals. "Economic" five minute intervals are defined as: 1) those five minute intervals in which the real-time LMP is at or above the generator's offer price; 2) those five minute intervals that PJM dispatched the generator in excess of its min run time and the generator's offer price is above the real-time LMP; and, 3) those five minute intervals that a generator with a min run time of less than or equal to 1 hour and more than one available starts per day is operated at the request of PJM.

- PJM sums the Balancing Operating Reserve generating resource credits for each PJM Member, taking into account joint-ownership of generating units.

5.2.2 Credits for Pool-Scheduled Transactions

At the end of each Operating Day, PJM calculates the credits due each PJM Member for pool-scheduled energy sales to the spot market.

PJM Actions

- PJM retrieves the following information:
  - o dispatcher transaction logs
  - o day-ahead and real-time external energy sales to spot market o

    hourly transaction bid rate and MW ($/MWh, MW) o day-ahead and

    real-time LMPs

- PJM calculates the hourly day-ahead offer amount for each spot market import transaction by multiplying the cleared day-ahead transaction MWh by the transaction offer price.

- PJM calculates the hourly day-ahead energy market value for each spot market import transaction by multiplying the cleared day-ahead transaction MWh by the day-ahead LMP at the sink of the transaction.
- PJM calculates the daily Day-ahead Operating Reserve credits for each transaction as follows:
  - o Sum hourly day-ahead offer amounts for the day o Sum hourly

    day-ahead energy market values for the day
  - o Day-ahead Operating Reserve credit equals any portion of the transaction's total day-ahead offer amount in excess of its total day-ahead market value
- PJM sums the Day-ahead Operating Reserve transaction credits for each PJM Member.
- PJM calculates for each five minute interval the real-time offer amount for each spot market import transaction by multiplying the real-time transaction MW by the transaction offer price divided by twelve.
- PJM calculates for each five minute interval the balancing energy market value for each spot market import transaction by multiplying the real-time five minute interval deviation from the cleared day-ahead transaction MW amount by the real-time LMP at the sink of the transaction divided by twelve.
- PJM calculates the daily Balancing Operating Reserve credits for each transaction as follows:
  - o Sum the five minute interval real-time offer amounts for the day o

    Sum the five minute interval balancing energy market values for the

    day
- Balancing Operating Reserve credit equals any portion of the transaction's total real-time offer amount in excess of: 1) its total day-ahead market value, plus 2) its total balancing market value, plus 3) any Day-ahead Operating Reserve credits.
- PJM sums the Balancing Operating Reserve transaction credits for each PJM Member.

5.2.3 Credits for Synchronous Condensing

At the end of each Operating Day, PJM calculates the credits due each PJM Member for synchronous condensing for purposes other than providing synchronized reserve or Reactive Services.

PJM Actions

- PJM retrieves the following information: o dispatcher generation scheduling and

  operations logs o resource offer data o resource generation data o real-time LMPs
- PJM calculates the duration of each pool-scheduled period of synchronous condensing operations based on logged start and stop times.

- PJM calculates each eligible resource's condensing cost for each period by multiplying the duration (in five minute intervals) by the hourly cost to condense plus energy use cost divided by twelve as specified in the offer data.
- When a resource is requested to start condensing from an off state, a condensing credit is provided equal to the resource's condensing startup cost as specified in the offer data.
- PJM calculates the daily synchronous condensing cost for each resource by summing all five minute interval condensing and energy use costs, including applicable startup costs, for the day.
- PJM calculates the unit-specific lost opportunity cost credits on a five minute interval for providing synchronous condensing for purposes other than providing synchronized reserve or Reactive Services.
- Five Minute Lost Opportunity Cost Credit = [(Five Minute RT LMP – Offer at Five Minute LMP Desired MW) * (Five Minute LMP Desired MW – Max (Five Minute Unit MW, 0))] / 12 only if quantity is positive.
- PJM sums the synchronous condensing credits for all resources for each PJM Member.

5.2.4 Credits for Canceled Pool-Scheduled Resources

At the end of each month, PJM calculates the credits due to each PJM Member for poolscheduled resources that were canceled before coming on-line.

PJM Actions

- PJM retrieves the following information:
  - list of canceled resources (dispatcher log) o resource startup cost data o resource generation data
  - written confirmation of actual costs incurred by participants due to cancellations (to be received within 45 days of date invoice was received by participant for the month in question)
- PJM credits each PJM Member for cancellations based on the actual costs incurred and submitted in writing to the PJM Market Settlement Operations Department. Eligibility is confirmed using resource generation data and dispatcher logs. The cancellation fee is defined as the actual costs incurred, that are typically included in Start-up Costs, when PJM cancels a pool-scheduled generation resource's start and the resource has not yet reached the point after generator breaker closure which is typically indicated by telemetered or aggregated state estimator MWs greater than zero., Cancellation Fees shall be capped at the appropriate Start-up Cost for the resource as specified in its offer data.
- PJM sums the Balancing Operating Reserve cancellation fees for all pool-scheduled resources for each PJM Member.
- PJM Market Settlement Operations Department enters the appropriate adjustment into the current month's billing.

5.2.5 Reserved for Future Use

5.2.6 Credits for Resources Reduced or Suspended due to a Transmission Constraint or for Other Reliability Reasons

At the end of each Operating Day, PJM calculates the credits due to each PJM Member for resources incurring lost opportunity costs associated with following PJM's request to reduce or suspend the output of a generating resource due to a transmission constraint or for other reliability reasons. A generating resource that is reduced to honor a stability limitation is not eligible for lost opportunity cost credits for the MWh reduction associated with honoring the stability limit.

5.2.6.1 Pool-Scheduled Generators

Pool-scheduled generators whose output is reduced or suspended and the five minute real-time LMP at the unit's bus is higher than its offer corresponding to the level of output requested by PJM are credited for each five minute interval in an amount equal to:

> *[(Lost Opportunity Cost (LOC)) Deviation * (Five Minute Real-time LMP at generator bus) – Total Opportunity Cost Offer] / 12*

- The LOC Deviation is the difference between the generating resource's Desired MW output using the Final Offer based on the five minute real-time LMP at the generator's bus and the generating resources actual output. The Desired MW output is adjusted for any effective regulation or synchronized reserve assignments and is limited to the lesser of the unit's economic maximum, the stability limit in effect or the unit's maximum output as specified in the Interconnection Service Agreement. If a unit does not have an Interconnection Service Agreement with PJM, the Desired MW is limited to the lesser of the unit's economic maximum or the economic maximum adjusted by the stability limit in effect.
- Total Lost Opportunity Cost Offer is the five minute interval offer integrated under the applicable offer curve for the LOC Deviation where the applicable offer curve is the greater of the Committed Offer or the Final Offer for each hour of the Operating Day.

5.2.6.2 Self-Scheduled Generators

Self-scheduled generators whose output is reduced or suspended and the five minute real-time LMP at the unit's bus is higher than its offer corresponding to the level of output requested by PJM are credited for each five minute interval in an amount equal to:

> *[(LOC Deviation * Five Minute Real-time LMP at the generator bus) – Total Lost Opportunity Cost] / 12*

- The LOC Deviation is the difference between the generating resource's Desired MW output using the applicable real-time offer based on the five minute real-time LMP at the generator bus and the generating resource's actual output. The Desired MW output is adjusted for any effective regulation or synchronized reserve assignments and is limited to the lesser of the unit's economic maximum, the stability limit in effect or the unit's maximum output as specified in the Interconnection Service Agreement. If a unit does not have an Interconnection Service Agreement with PJM, the Desired MW is limited to the lesser of the unit's economic maximum or the economic maximum adjusted by the stability limit in effect.

- The Total Lost Opportunity Cost Offer is the five minute interval offer integrated under the applicable offer curve for the LOC Deviation as determined below:
  - For a self-scheduled generator operating on a cost-based offer, the applicable offer curve is the greater of the originally submitted cost-based offer or the cost-based offer that the generator was dispatched.
  - For a self-scheduled generator operating on a market-based offer, the applicable offer is determined by the following process:

− If there is only one available cost-based offer:

- Step 1: Select the greater of cost-based Day-ahead offer and the updated cost-based Real-time offer.
- Step 2: Compare the offer from Step 1 with the market-based Day-ahead offer and the market-based Real-time offer and select the greatest offer as the applicable offer.

− If there are multiple cost-based offers available,

- Step 1: For each available cost-based offer, select the greater of the Dayahead offer and the updated Real-time offer.
- Step 2: Compare the cost-based offers from Step 1 and select the lesser of all the cost-based offers.
- Step 3: Compare the cost-based offer from Step 2 with the market-based Day-ahead offer and the market-based Real-time offer and select the greatest offer as the applicable offer.

5.2.6.3 Flexible Resources

Pool-scheduled Flexible Resources that are scheduled to produce energy in the day-ahead market, but are not called on by PJM and do not operate in the corresponding five minute real-time interval, are credited for each five minute interval in an amount equal to the higher of the:

*[(Real-time LMP – Day-ahead LMP) * Day-ahead scheduled MW] / 12;*

Or

[(Day-ahead committed MWh Real-time LMP) – (Total Lost Opportunity Cost Offer including no-load costs)] / 12 + (the start-up costs/number of contiguous hours scheduled in the Day-ahead Energy Market)*

- The Total Lost Opportunity Cost Offer is the five minute interval offer integrated under the applicable offer curve for the Day-ahead committed MW where the applicable offer curve is the greater of the Committed Offer or the last Real-time Offer submitted for the offer that the generating resource was committed in the Day-ahead Energy Market for each hour of the Operating Day.

- In the case where a Flexible Resource operates in real-time following PJM dispatch and at least one five minute interval of real-time operation coincides with the any of the hours of the day-ahead commitment, the start-up costs will be excluded from the calculation.

Flexible Resources that submit a Real-time offer greater than their resource's Committed Offer in the Day-ahead energy market are not eligible to received Lost Opportunity Cost Credits.

5.2.6.4 Wind Generators

Pool-scheduled or self-scheduled wind generators whose output is reduced or suspended at the request of the Office of the Interconnection and the five minute real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by PJM are credited for each five minute interval in an amount equal to:

*[(LOC Deviation * Real-time LMP at the generator bus) – Total Lost Opportunity Cost Offer] / 12*

- The LOC Deviation is the difference between the wind generator's scheduled output which is the lesser of the PJM forecasted output or the Desired MW using the Final Offer based on the five minute real-time LMP at the generator bus and wind generator's actual output. The Desired MW is also limited to the lesser of the unit's economic maximum, the stability limit in effect or the unit's maximum output as specified in the Interconnection Service Agreement. If a unit does not have an Interconnection Service Agreement with PJM, the Desired MW is limited to the lesser of the unit's economic maximum or the economic maximum adjusted by the stability limit in effect.
- The Total Lost Opportunity Cost Offer for pool-scheduled and self-scheduled wind generators is determined in the same manner as described in this section for poolscheduled and self-scheduled generators respectively.
- Pool-scheduled or self-scheduled wind generators are only eligible for the abovereferenced credit if they:
    - Operated the resource according to PJM Manual and Tariff requirements for wind resources (PJM Manual 14D: Generator Operational Requirements)
    - Have SCADA capability to transmit and receive instructions from PJM

If PJM experiences a technical issue (e.g. computer system failure or disruption or failure of communications equipment) resulting in an erroneous forecast, PJM and the Market Participant will determine a mutually agreeable settlement value. Recommendations for reconciliation include but are not limited to:

- Using the forecast values as determined by PJM wind forecasting tool from before and after the technical issue to determine forecast value during the issue
- Using the forecast value as determined by PJM wind forecasting tool from before the technical issue for the first half of the duration of the technical issue and forecast value from after the technical issue for the latter half of the duration of the technical issue • Using Market Seller's forecast value during the technical issue

PJM Actions

- PJM retrieves the following information:
  - o list of units and timeframes reduced or suspended for a transmission constraint or other reliability reason (dispatcher logs and Market Operations eligibility data)
  - o resource offer data
  - o hourly scheduled MWh for generation offers cleared in day-ahead market o five minute revenue meter generation MW values from PJM Power Meter if available o five minute state estimator or telemetry generation MW, scaled to match hourly revenue meter generation MWh from PJM Power Meter as described in Section 1A of this PJM Manual
  - o hourly scheduled MWh for InSchedule "Generation" contracts, if applicable o generator hourly day-ahead LMPs o five minute real-time LMPs
  - o assigned regulation MW, performance scores and marginal benefit factors o assigned synchronized reserve MW
  - o five minute wind forecast from PJM's wind forecasting tool o maximum facility output MW from Interconnection Service Agreements
- PJM sums the Balancing Operating Reserve lost opportunity cost credits for all reduced or suspended generating resources for each PJM Member.

5.2.7 Credits for Resources Performing Annual Scheduled Black Start Tests

At the end of each month, PJM calculates the credits due to each PJM Member for resources performing annual black start tests. Compensation for energy delivered to the transmission system shall be provided for the unit's minimum run time at the higher of the unit's cost-capped offer or real-time LMP plus start-up and no-load for up to two start attempts, if necessary. Compensation for tests where no energy was delivered to the transmission system shall be provided for the unit's start-up costs for up to two start attempts, if necessary.

PJM Actions

- PJM retrieves the following information:
  - o list of units performing annual scheduled black start tests (PJM Performance Compliance Department log) oresource cost-capped offer data o resource generation data o applicable real-time LMP o applicable start-up and no-load costs
- PJM sums the Balancing Operating Reserve annual black start test credits for all resources for each PJM Member.
- PJM Market Settlement Operations Department enters the appropriate adjustment into the current month's billing.

5.2.8 Credits for Resources Providing Reactive Services

At the end of each month, PJM credits each PJM Member for Reactive Services that are provided during the month. Generators whose active energy output is increased at the request of PJM for the purpose of maintaining reactive reliability within the PJM Region and the five minute real-time LMP at the generator bus is lower than its offer corresponding to the level of output requested by PJM are credited for each five minute interval in an amount equal to:

> *[(Real-time MW – Desired MW) * (Offer - Five Minute real-time LMP at the generator bus)] / 12*

Only if the difference between the Offer and the Five Minute real-time LMP at the generator bus is positive

- Desired MW is the MW amount of the generator using the Final Offer based on the five minute real-time LMP at the generator bus. The Desired MW is adjusted for any effective regulation or synchronized reserve assignments and capped at the stability limit in effect.
- Offer is the cost for the generator using the lesser of the Final Offer or Committed Offer at the increased MW level.

In addition, these generators are also credited for lost opportunity costs if the five minute real-time LMP at the generator's bus is higher than its offer corresponding to the level of output requested by PJM. Pool-scheduled generators are credited in the same manner as described in Section 5.2.6.1, and self-scheduled generators are credited in the same manner as described in Section 5.2.6.2.

Generators operating as synchronous condensers for the purpose of maintaining reactive reliability at the request of PJM, are credited for each five minute interval of condensing an amount equal to the higher of: 1) the Synchronized Reserve Market Clearing Price for the five minute interval divided by 12 multiplied by the amount of synchronized reserve provided (i.e., economic maximum limit of the unit); or 2) the sum of the unit's offered cost to condense, energy use cost, start-up cost, and the unit-specific lost opportunity cost of the resource supplying the increment of Synchronized Reserve divided by 12. **PJM Actions**

- PJM retrieves the following information: o dispatcher generation scheduling and operations logs o resource offer data
  - o hourly scheduled MWh for generation offers cleared in day-ahead market o state estimator generation MWh
  - o five minute revenue meter generation MW values from PJM Power Meter, if available o state estimator or telemetry generation MW, scaled to match hourly revenue meter generation MWh from PJM Power Meter as described in Section 1A of this PJM Manual) o hourly scheduled MWh for InSchedule "Generation" contracts, if applicable o generator hourly day-ahead LMPs o five minute real-time LMPs

- o assigned regulation MW, performance scores and marginal benefit factors o
  assigned synchronized reserve MW
- o maximum facility output MW from Interconnection Service Agreements

- PJM sums the reactive services credits for all generating resources for each PJM Member.

5.2.9 Dispatch Differential Lost Opportunity Cost Credits

As noted in Manual 11, a pricing run calculates the Locational Marginal Prices distinct from the security-constrained economic dispatch of the system. This results in the need for a lost opportunity cost credit to ensure that resources dispatched down in the security-constrained economic dispatch continue to follow PJM's dispatch instructions to address the inflexibility of Fast-Start resources.

Only pool-scheduled or dispatchable self-scheduled resources that are dispatched for energy only by PJM are eligible for Dispatch Differential Lost Opportunity Cost credits.

Pool-scheduled and dispatchable self-scheduled resources that are 1) dispatched by PJM to provide regulation or ancillary services; or 2) manually dispatched by PJM due to a transmission constraint or for other reliability reasons are not eligible to receive Dispatch Differential Lost Opportunity Cost credits.

Dispatch Differential Lost Opportunity Cost credits are only calculated in the balancing energy market.

PJM calculates the Dispatch Differential Lost Opportunity Cost credits for an eligible resource for each five minute real-time settlement interval as the positive difference between the revenue above cost for the pricing run and the revenue above cost for the dispatch run. **PJM Actions**

- PJM retrieves the following information:
  - o dispatcher generation scheduling and operations logs ofive minute interval generator dispatch MW values
  - o resource offer data - the resource's Final Offer, which is the offer on which the resource was dispatched by the Office of the Interconnection for a particular clock hour for the Operating Day
  - o five minute revenue meter generation MW values from PJM Power Meter, if available o state estimator or telemetry generation MW, scaled to match hourly revenue meter generation MWh from PJM Power Meter as described in Section 1A of this PJM Manual) o five minute real-time LMPs

The revenue above cost for the pricing run is calculated for each five minute settlement interval as follows:

Pricing Run Revenue Above Cost = (Resource Expected MW Output * Five Minute real-time LMP at the resource bus) – Real-time Market Offer

- The Resource Expected MW Output is the Desired MW (capped at the stability limit in effect) value of the resource based on the Final Offer at the five minute real-time LMP at the resource bus.
- The Real-time Market Offer is the five minute interval offer integrated under the Final Offer for the Resource Expected MW Output.

The revenue above cost for the dispatch run is calculated for each five-minute settlement interval as follows:

Dispatch Run Revenue Above Cost = Max(Five Minute Dispatch MW * Five Minute real-time LMP at the resource bus, Five Minute Revenue Data for Settlements MW * Five Minute realtime LMP at the resource bus) – Min(Cost of the Five Minute Dispatch MW, Cost of Five Minute Revenue Data for Settlement MW)

- The Five Minute Dispatch MW is the MW setpoint for a resource as determined in the security-constrained economic dispatch run.
- The Cost of the Five Minute Dispatch MW is the five minute interval offer integrated under the Final Offer for the Five Minute Dispatch MW.
- The Cost of the Five Minute Revenue Data for Settlements MW is the five minute interval offer integrated under the Final Offer for the Five Minute Revenue Data for Settlements
MW.

Dispatch Differential Lost Opportunity Cost Credit = Max(Pricing Run Revenue Above Cost – Dispatch Revenue Above Cost, 0)

- PJM sums the Dispatch Differential Lost Opportunity Cost credits for all generating resources for each PJM Member for each hour of the Operating Day.

5.3 Charges for Operating Reserve

The total cost of providing Operating Reserve for the Operating Day is the sum of the credits provided to PJM Market Participant for supplying the Day-ahead and Balancing Market Operating Reserve except those Operating Reserve credits associated with the scheduling of units for Black Start service or testing of Black Start Units, Reactive Services or transfer interface. Credits associated with Black Start service or testing of Black Start Units, Reactive Service or transfer interface control are charged separate of Day-ahead Operating Reserves and Balancing Operating Reserves.

Any Operating Reserve charges attributable to generators operated on behalf of transmission owners for local constraints, or on behalf of generation owners for special unit constraints, are directly assessed to the applicable requesting party.

5.3.1 Day-ahead Operating Reserves

The daily total cost of Day-ahead Operating Reserve excluding the total cost for resources scheduled to provide Black Start Service, Reactive Services or transfer interface control is determined only for the RTO region, allocated and charged to PJM Market Participants in proportion to their cleared day-ahead demand, decrement bids, and up-to congestion transactions at the sink end of the transaction plus their cleared day-ahead exports. Charge allocations for Black Start Service are described in Section 5.3.4 of this PJM Manual and for Reactive Services are described in Section 5.3.5 of this PJM Manual.

PJM Actions

- PJM retrieves the following information for Day-ahead Operating Reserve Charges:
  - Cleared Day-ahead demand (MWh) o Cleared Day-ahead decrement bid (MWh) o Cleared Day-ahead exports (MWh)
  - Cleared Day-ahead up-to congestion transactions (MWh) o Total Day-ahead Operating Reserve generating resource credits ($) o Total Day-ahead Operating Reserve transaction credit ($)
- PJM calculates the Day-ahead Operating Reserve Charge as the Market Participant's ratio share of the total Day-ahead Operating Reserve credits as follows:
  - *Day-ahead Operating Reserve Charge = Total Day-ahead Operating Credits * ((Cleared Day-ahead demand + decrement bids + up-to congestion transactions + exports) / (Total cleared Day-ahead demand + decrement bids + exports)*
  - *Total Day-ahead Operating Credits = Total Day-ahead Operating Reserve generating resource credits + Total Day-ahead Operating Reserve transaction credits*

5.3.2 Balancing Operating Reserves

The daily total cost of Balancing Operating Reserve excluding the total cost for resources scheduled to provide Black Start Service is determined for each region (RTO, East and West) which is allocated and charged to PJM Market Participants depending if the Balancing Operating Reserve credits are deemed for reliability or deviations.

The regions are defined as follows:

- RTO region = the East and West regions plus exports that are at the interfaces or hubs not completely contained in either the East or West region
- East region = transmission zones AEC, BGE, Dominion, DPL, JCPL, MW, PECO, Penelec, PEPCO, PPL, PSEG and RE
- West region = transmission zones AEP, APS, ATSI, ComEd, DEOK, DUQ, DAY, EKPC and OVEC

PJM determine if Balancing Operating Reserve credits should be charged to the East region or West region, instead of the RTO region, when the resource is needed for a transmission constraint that occur on transmission lines equal to or less than 345 kV.

5.3.2.1 Balancing Operating Reserves for Reliability Charge

PJM calculates for each Operating Day the total Regional Cost of Balancing Operating Reserve to be charged for reliability for each region and for all PJM Market Participants excluding those credits associated with the scheduling of units for Black Start service or testing of Black Start units. PJM allocates these total costs for reliability to each PJM Market Participant based on their daily share of the sum of their Real-time load plus Real-time exports in each region (RTO, East, West).

PJM Actions

- PJM retrieves the following information for Balancing Operating Reserve charges for reliability by region:
  - Real-time load o Real-time exports
  - Total Balancing Operating Reserve resource credits for reliability ($)
- PJM calculates the Balancing Operating Reserve charge for reliability as the Market Participant's Real-time load plus exports share of the total Balancing Operating Reserve credits for reliability by region as follows:
  - *Balancing Operating Reserve for Reliability Charge (by region) = Total Balancing Operating Reserve Credits for Reliability * (Real-time load = Real-time exports)*

5.3.2.2 Balancing operating Reserves for Deviation Charge

PJM calculates for each Operating Day the total cost of Balancing Operating Reserve to be charged for deviations for each region and for all PJM Market Participants excluding those credits associated with the scheduling of units for Black Start service or testing of Black Start units. PJM allocates these total costs for deviations to each PJM Market Participant based on their daily share of the sum of their 5-minute interval deviations associated with generating resources, withdrawals and injections in each region (RTO, East, West).

PJM Actions

- PJM retrieves the following information for Balancing Operating Reserve charges for deviation by region:
  - Total Regional Balancing Operating Reserve generating resource credits for deviations ($)
  - Total Balancing Operating Reserve demand resource credits ($) o Total Balancing Operating Reserve transaction credits ($) o Total Balancing Operating Reserve cancellation fees ($) o Total Balancing Operating Reserve quick start resource credits ($) o Total Balancing Operating Reserve reduction/suspension credits ($)
- PJM calculates the Balancing Operating Reserve charge for deviations as the Market Participant's total deviations share of the total Balancing Operating Reserve credits for deviation by region as follows:

- *Balancing Operating Reserve for Deviations Charge (by region) = Total Balancing Operating Reserve Credit for Deviations * total MW deviations* o *Total MW deviations = determined for each Market Participant as further described in Sections 5.3.2.3, 5.3.2.4 and 5.3.2.5 of this PJM Manual*

5.3.2.3 Deviation Calculations for Generating Resources

- PJM calculates for each hour of the Operating Day the individual generating resource deviations as the sum of the absolute value of the five minute interval deviations in the hour divided by 12 for generating resources that are not following dispatch for each five minute interval as follows:
  - Each pool-scheduled or dispatchable self-scheduled generator not following PJM dispatch due to its actual output not being between its ramp-limited Desired MW and UDS Basepoint MW, and its % off dispatch is > 10%, will be assessed deviations as Real-time MW – ramp-limited desired MW. If the % off dispatch is > 20%, deviations will be assessed as Real-time MW – UDS LMP Desired MW (as determined in the Credits for Pool-Scheduled Generating Resources section of this manual).
  - For each self-scheduled generating resource with an economic maximum limit less than or equal to 110% of the economic minimum limit or not dispatched by PJM above its economic minimum, unless the resource is lowering its output in accordance with PJM direction in response to a minimum generation emergency event (or declaration) will be assessed deviations as Real-time MW – Day-ahead Schedule MW.
  - Each unit that has tripped or is scheduled Day-ahead and does not run in Real-time will be assessed deviations as Real-time MW – Day-ahead scheduled MW
  - Each unit that is dispatchable Day-Ahead but is Fixed Gen in real-time will be assessed deviations as Real-time MW – UDS LMP Desired MW
  - Each unit that is not dispatchable in both the Day-ahead and Real-time market will be assessed deviations as Real-time MW – Day-ahead scheduled MW. Units that choose to participate in the Day-ahead pumped storage optimization program are considered not dispatchable in the Day-ahead market.
  - Each unit where the real-time economic minimum is greater than its Day-ahead economic minimum by 5% or 5 MW, whichever is greater, or its real-time economic maximum is less than its day-ahead economic maximum by 5% or 5MW, whichever is lower, and UDS LMP Desired MW for the hours is either below the real-time economic minimum or above the real-time economic maximum, will be assessed deviations as Real-time MW – UDS LMP Desired MW
  - Deviations are not calculated if the absolute value of the deviation MW ratio to applicable day-ahead scheduled MW or desired MW is less than or equal to 5%

- Five minute intervals during which a generator is assigned by PJM for: Regulation; assigned by PJM for Synchronized Reserve (and actual MW are less than day-ahead scheduled MW), assigned by PJM for Non-Synchronized Reserve (and actual MW are less than the day-ahead scheduled MW), or Tier 1 resources that respond to a synchronized reserve event are omitted from this calculation.
- Resource five minute interval deviations for units located at a "single bus" will be able to offset one another. A "single bus" will be any unit located at the same site and that has the identical electrical impacts on the transmission system ("supplier netting"). Unit parameters do not have to be identical for the units' deviation MW to offset one another. Units at a "single bus" must be contained in the same customer account.
- If the hourly sum of the absolute value of the five minute interval deviations for a generating resource divided by 12 for an hour is less than 5 MWh, then the generating resource is not assessed a Balancing Operating Reserve deviation for that hour.

5.3.2.4 Deviation Calculations for Withdrawals

- PJM calculates for each hour of the Operating Day the withdrawal deviations as the sum of the five minute interval real-time deviations from day-ahead values for each customer account as follows:
  - Absolute Value of (cleared day-ahead demand bid MW + cleared day-ahead decrement bid MW + cleared up-to congestion transaction MW at the sink end of the transaction + day-ahead sale transaction MW – real-time load de-rated for transmission losses including the impact of load reconciliation MW – real-time sale transaction MW) divided by 12
  - Withdrawal deviations will be calculated separately for each zone, hub, and interface whereby allowing netting to occur within each of those locations. Further netting will also occur for any hubs and aggregates fully contained within a given zone. o
    Dynamically scheduled export transactions are omitted from this calculation.
  - Positive demand deviations (real-time withdrawal MWs less than day-ahead withdrawal MWs) will not be included in the total withdrawal deviation by location during five minute intervals in which an Primary Reserve or Synchronized Reserve shortage in real-time occurs or when PJM initiates the request for emergency load reductions in real-time in order to avoid a Primary Reserve or Synchronized Reserve shortage.

5.3.2.5 Deviation Calculation for Injections

- PJM calculates for each hour of the Operating Day the injection deviations as the sum of the five minute interval real-time deviations from day-ahead values for each customer account as follows:
  - Absolute Value of (cleared day-ahead increment offer MW + day-ahead purchase transaction MW – real-time purchase transaction MW) divided by 12
  - Injection deviations will be calculated separately for each zone, hub, and interface whereby allowing netting to occur within each of those locations. Further zonal

netting will also occur for any hubs and aggregates fully contained within a given zone.

5.3.3 Synchronous Condenser

The total daily cost of synchronous condenser payments (other than that for synchronized reserve or Reactive Services) is allocated and charged to PJM Market Participants in proportion to their Load Ratio Share during that Operating Day.

5.3.4 Black Start

The total monthly cost of Operating Reserves for resource providing Black Start service or testing of Black Start units is allocated to Network and Point-to-Point Transmission Customers based on their monthly transmission use on a megawatt basis. Additional details on this allocation can be found in PJM Manual 27: Open Access Transmission Tariff Accounting, Section 7.

5.3.5 Reactive Services

The total daily cost for resource scheduled to provide Reactive Services or transfer interface control because they are known or expected to be needed to maintain system reliability in a zone(s) sums the costs from both Day-ahead and Balancing. This total daily cots are allocated and charged to reach market Participant based on their Load Ratio Share in the applicable transmission zone(s).

5.3.6 Dispatch Differential Lost Opportunity Cost

The total hourly cost of the Dispatch Differential Lost Opportunity Cost credits are allocated and charged to PJM Market Participants on an RTO wide basis in proportion to their real-time load (excluding losses and Direct Charging Energy) plus exports during that Operating Day.

5.4 Reconciliation for Operating Reserve Charges

PJM will calculate reconciled Operating Reserve charges for EDCs and Retail Load Aggregators (a.k.a. Electric Generation Suppliers) for past monthly billings on a two month lag that were based on Load Ratio Shares. The reconciliation kWh data must be supplied to PJM by the EDCs no later than the last day of the billing month that is two months after the original billing month. For example, all reconciliation data for January must be submitted by March 31 at 23:59. The reconciliation kWh data represents the difference between the scheduled Retail Load Responsibility or Wholesale Load Responsibility InSchedule (in MWh) and the “actual” usage based on metered data. This hourly kWh data must be reported separately for each applicable InSchedule contract.

PJM calculates the Operating Reserve charge for Reliability reconciliations by multiplying the daily kWh data (de-rated for transmission losses) for the region (RTO, East, and West) by the Operating Reserve charge for Reliability billing determinants for that region and day. The daily Operating Reserve charge for Reliability billing determinant (in $/MWh) for each region is calculated by dividing the total Balancing Operating Reserve charges for Reliability in that region by the total real-time load (de-rated for transmission losses) and real-time exports in that region for that day. These charge reconciliations are then totaled for the month for each EDC or Retail Load Aggregator. Note that the reconciliation for Operating Reserve charges for

Reliability for a month may be either a positive or a negative value, and may even be such that the reconciled load responsibility MWh results in a negative load quantity.

PJM calculates the Reactive Services charge reconciliations by multiplying the daily kWh data (de-rated for transmission losses) for the transmission zone by the Reactive Services billing determinants for that zone and day. The daily Reactive Services billing determinant (in $/MWh) for each transmission zone is calculated by dividing the total Reactive Services charge in that transmission zone by the total real-time load (de-rated for transmission losses) in that transmission zone for that day. These charge reconciliations are then totaled for the month for each EDC or Retail Load Aggregator. Note that the reconciliation for Operating Reserve charges for reactive services for a month may be either a positive or a negative value, and may even be such that the reconciled load responsibility MWh results in a negative load quantity.

PJM calculates the Synchronous Condensing charge reconciliations by multiplying the daily kWh data (de-rated for transmission losses) for the PJM Region by the Synchronous Condensing billing determinants for that day. The daily Synchronous Condensing billing determinant (in $/MWh) for the PJM Region is calculated by dividing the total Synchronous Condensing charges in the PJM Region by the total real-time load (de-rated for transmission losses) and real-time exports in the PJM Region for that day. These charge reconciliations are then totaled for the month for each EDC or Retail Load Aggregator. Note that the reconciliation for Operating Reserve charges for synchronous condensing for a month may be either a positive or a negative value, and may even be such that the reconciled load responsibility MWh results in a negative load quantity.

Section 6: Synchronized Reserve Accounting

Welcome to the Synchronized Reserve Accounting section of the ***PJM Manual for Operating Agreement Accounting***. In this section, you will find the following information:

- A description of how Synchronized Reserve are provided and accounted for in the PJM Energy Markets (see "Synchronized Reserve Accounting Overview").
- How credits are calculated for providers of Synchronized Reserve (see "Credits for Synchronized Reserve").
- How the total cost of Synchronized Reserve is allocated (see "Charges for Synchronized Reserve").
- How Synchronized Reserve charge reconciliations are calculated (see "Reconciliation for Synchronized Reserve Charges").

6.1 Synchronized Reserve Accounting Overview

Synchronized Reserve shall be supplied from resources located within the metered boundaries of PJM Resources participating in the Synchronized Reserve market are divided into two tiers. Tier 1 is comprised of all those resources on-line following economic dispatch and able to ramp up from their current output in response to a synchronized reserve event. Tier 2 consists of the additional resources that are synchronized to the grid and operating at a point that deviates from economic dispatch (including condensing mode) to provide additional Synchronized Reserve not available from Tier 1 resources. Synchronized Reserve resources include generators and Demand Resources.

The total PJM Synchronized Reserve Requirement is defined as the amount of 10-minute reserve that must be synchronized to the grid in accordance with the applicable NERC Council standards.

Tier 1 Synchronized Reserve credits are awarded to all resource owners whose resources increased output or decreased consumption in response to a synchronized reserve event (with the exception of those resources that were assigned Tier 2 Synchronized Reserve). Tier 1 Synchronized Reserve resources are also compensated when the Non-Synchronized Reserve Market Clear Price is non-zero. Tier 2 Synchronized Reserve credits are awarded to all resource owners that have assigned self-scheduled or pool-scheduled Synchronized Reserve.

The Synchronized Reserve offer price for Tier 2 resources is capped at a maximum value of the unit's Operating and Maintenance cost (as determined by the Cost Development Task Force) plus $7.50/MWh.

Generator resources on-line and providing Tier 2 are made eligible for make-whole payments to recover applicable start-up, no-load and minimum energy costs in the Balancing Operating Reserve billing line item. Demand Resources that respond to a Synchronized Reserve event, and are eligible for make-whole payments to recover shutdown cost are made-whole in the Operating Reserve for Load Response billing line item.

Resources that are assigned regulation when a Synchronized Reserve event is initiated are compensated based on the amount of response provided beyond their regulation commitment, as well as for any response in excess of their regulation high limit or economic maximum (whichever is lower). Additional details can be found in PJM Manual 11: Energy & Ancillary Services Market Operations, Section 4.2.11.

Each Market Participant that is a Load Serving Entity (LSE) or synchronized buyer that is not part of an agreement to share reserves with external entities subject to the requirements in NERC Reliability Standard BAL-002 incurs a synchronized reserve obligation based on their Load Ratio Share and applicable reserve zone's requirements during that hour. During hours when the Synchronized Reserve Market Clearing Price (SRMCP) is the same throughout the reserve zone, an LSE's Synchronized Reserve obligation is equal to its Load Ratio Share times the amount of synchronized reserve assigned for all five minute intervals for the entire reserve zone. During hours when congestion causes the SRMCP to separate, each LSE's Synchronized Reserve obligation is equal to its Load Ratio Share within its reserve zone or sub-zone and the amount of Synchronized Reserve assigned in that reserve zone or sub-zone.

Participants may fulfill their Synchronized Reserve obligations by owning Tier 1 resources from which PJM obtains Synchronized Reserve, entering bilateral arrangements with other PJM Market Participants, or purchasing Synchronized Reserve from the PJM Synchronized Reserve Market.

6.2 Credits for Synchronized Reserve

Synchronized Reserve credits are paid to Market Participants that supply their resource to PJM. PJM sums the Synchronized Reserve credits (both Synchronized Reserve Clearing Price credits and Synchronized Reserve Lost Opportunity Cost credits) to determine the total hourly credit for each Synchronized Reserve market participant. Synchronized Reserve credits for joint-owned generators supplying Synchronized Reserves are allocated to the owners based on their ownership share.

6.2.1 Synchronized Reserve Clearing Price Credit

Synchronized Reserve credits are paid to Tier 1 resources and Tier resources. Since Tier 1 resources are online units following economic dispatch and Tier 2 resources offer and must be cleared through the Synchronized Reserve Market, there are different compensation methodologies. Lost opportunity cost credits are descried in Section 6.2.2 of this PJM Manual.

PJM Actions

- PJM retrieves the following information for the Tier 1 Synchronized Reserve Clearing Price credit:
    - Synchronized Reserve Ramp rate for Tier 1 resources o

      Synchronized Reserve maximum for Tier 1 resources o 5

      minute MW response o Synchronized energy premium price
    - Total PJM Synchronized Reserve requirement as determined in whole MW for each five minute interval of the operating day

- Synchronized Reserve Market Clearing Price (SRMCP) ($/MWh) o Non-Synchronized Reserve Market Clearing Price (NSRMCP) ($/MWh)

- PJM calculates the five minute interval Synchronized Reserve credits for each Tier 1 resource for when the five minute intervals NSRMCP is zero for the same reserve zone or sub-zone that a Tier 1 resource is located, Tier 1 Synchronized Reserve credits are equal to the increase in MW generator output (or decrease in MW consumption for demand side response resources) from each resource for each five minute interval during the length of a Synchronized Reserve event multiplied by the synchronized energy premium divided by 12. The synchronized energy premium is $50/MWh.
  - *Tier 1 Synchronized Reserve Credit = Five Minute MW Response * $50/MWh / 12*

- PJM calculates the five minute interval Synchronized Reserve credit for each Tier 1 resource for when the five minute intervals NSRMCP is non-zero for the applicable reserve zone or subzone, Tier 1 synchronized reserve credits are equal to the applicable reserve zone or sub-zone Synchronized Reserve Market Clearing Price multiplied by the lesser of the increase in MW output or decrease in MW of consumption from each resource for each five minute interval during the length of a synchronized reserve event and the estimated Tier 1 the resource could have provided. During five minute intervals when no synchronized reserve event occurs in the applicable reserve zone or sub-zone, the Tier 1 resource will be compensated using the estimated Tier 1 amount for only those resources that can reliably provide Synchronized Reserve service per the rules in Manual 11: Energy & Ancillary Services Market Operations, Section 4.2.1.
  - *Tier 1 Synchronized Reserve Credit = (Lesser of Five Minute Actual Response OR Five Minute Estimated Tier 1 Response) * SRMCP / 12*

- PJM retrieves the following information for the Tier 2 Synchronized Reserve Clearing Price credit:
  - Synchronized Reserve availability o Synchronized Reserve assigned quantity (MW) o Synchronized Reserve offer price o Synchronized Reserve bilateral transactions o Energy use for condensing resource o Condense startup cost o 5-minute interval LMP data
  - Total PJM Synchronized Reserve requirement
  - Synchronized Reserve Market Clearing Price (SRMCP) ($/MWh)

- PJM calculates the five minute interval Synchronized Reserve Clearing Price credits for both pool-scheduled and self-scheduled Tier 2 resource to equal the five minute SRMCP divided by 12 times the resource's five minute Synchronized Reserve capability less any shortfall for the five minute interval due to failure to provide assigned capability during a Synchronized Reserve event.
  - *Tier 2 Synchronized Reserve Credit = (SRMCP / 12) * (Assigned Synchronized*

Reserve MW – Synchronized Reserve MW Shortfall)

6.2.2 Synchronized Reserve Lost Opportunity Cost Credit

PJM calculates a Synchronized Reserve Lost Opportunity Cost Credit for pool-scheduled Tier 2 resources if the Synchronized Reserve Lost Opportunity Cost (excluding any reduction for a stability limit) is greater than the SRMCP Credit for the resource for the five minute interval. If the resulting amount is negative, then the credit is $0.

PJM Actions

- PJM retrieves the following information for the Synchronized Reserve Lost Opportunity Cost credit:
  - Real-time LMP
  - Energy use (only used for condensing units) o Applicable offer curves
  - Synchronized Reserve Market Clearing Price (SRMCP) credit
- PJM calculates a Synchronized Reserve Lost Opportunity Cost Credit if the lost opportunity cost is greater than the Synchronized Reserve Market Clearing Price credit for the resource for the five minute interval.
  - *Synchronized Reserve Lost Opportunity Cost Credit = (Synchronized Lost Opportunity Cost / 12) – SRMCP Credit* o *Synchronized Lost Opportunity Cost = (Energy Use * 5-minute real-time LMP) + (MW deviation * (5-minute real-time LMP – Offer Price))*
- Since hydro units operate on a schedule and do not have an energy bid, lost opportunity costs for these units are calculated using the average of the real-time LMP at the hydro unit bus for the appropriate on peak (0700 – 2259) or off-peak (0000 – 0659, 2300-2359) period, excluding those hours during which all available units at the hydro plant were operating.
- If a hydro unit is in spill, the lost opportunity cost for each five minute interval is equal to (i) the Synchronized Reserve assigned MW multiplied by (ii) the real-time five minute LMP at the generator bus.
- If a hydro unit is committed day-ahead with MW greater than zero, the lost opportunity cost for each five minute interval is equal to (i) the Synchronized Reserve assigned MW multiplied by (ii) the difference between the real-time five minute LMP at the generator bus and the average real-time LMP (calculated as stated above). If this average realtime LMP value is higher than the real-time five minute LMP at the generator bus, the lost opportunity cost will be zero.
- If a hydro unit is not committed day-ahead, the lost opportunity cost is equal to zero.

6.3 Charges for Synchronized Reserve

The total cost of providing Synchronized Reserve for each hour is the sum of the five minute credits provided to PJM Members for supplying Synchronized Reserve in that hour. The cost of Tier 1 and Tier 2 Synchronized Reserve is allocated separately and charged to PJM Members.

6.3.1 Synchronized Reserve Clearing Price Charge

Each Market Participant that is a Load Serving Entity (LSE) or synchronized buyer that is not part of an agreement to share reserves with external entities subject to the requirements in NERC Reliability Standard BAL-002 incurs a Synchronized Reserve Obligation based on their Load Ratio Share and applicable reserve zone's requirements during that hour. A Load Serving Entity (LSE) whose reserve obligations are satisfied through an agreement to share reserves with external entities subject to the requirements in NERC Reliability Standard BAL-002 do not have a Synchronized Reserve Obligation. **PJM Actions**

- PJM retrieves the following information for the Synchronized Reserve Clearing Price Charge: o Synchronized Reserve bilateral transactions
  - o Total PJM Synchronized Reserve assigned by reserve zone and sub-zone o Total Synchronized Reserve shortfall (MWh) by reserve zone and sub-zone
- PJM calculates the Synchronized Reserve Tier 1 charges for each Market Participant for the applicable zone or subzone by multiply the total Tier 1 credits by the Tier 1 Allocation to Obligation ratio for that hour
  - o *Tier 1 Charges = Total Tier 1 Credit * (Tier 1 Allocation to Obligation / Total Tier 1 Allocation to Obligation)* o *Tier 1 Allocation to Obligation = Lesser of (Remaining Bilateral Adjusted Obligation or Obligation Ratio Share of Excess Tier 1) + Lesser of (Adjusted Synchronized Reserve Obligation or Tier 1 Estimate MWh)* o *Remaining Bilateral Adjusted Obligation = Adjusted Synchronized Reserve Obligation – Tier 1 Estimate MWh* o *Obligation Ratio Share of Excess Tier 1 = Total Tier 1 Excess * (Remaining Bilateral Adjusted Obligation / Total Remaining Bilateral Adjusted Obligation)* o *Adjusted Synchronized Reserve Obligation = Synchronized Reserve Obligation +*
  Bilateral Synchronized Reserve Sales – Bilateral Synchronized Reserve Purchases o *Synchronized Reserve Obligation = (Total Tier 1 Estimated and Tier 2 Assigned) * Market Participant Load / Total Load)*
- PJM calculates the Synchronized Reserve Tier 2 charges for each Market Participant for the applicable zone or subzone by the appropriate hourly Tier 2 Synchronized Reserve credits times the Market Participant's ratio share of Synchronized Reserve adjusted obligation MW, less any Tier 1 Synchronized Reserve applied to obligation.
  - o *Tier 2 Charges = (above Obligation Tier 1 Adjustment / Total PJM Above Obligation Tier 1 Adjustment) * Total PJM Synchronized reserve Tier 2 Credits* o *Above Obligation Tier 1 Adjustment = Adjusted Synchronized Reserve Obligation – Tier 1 Allocation to Obligation* o If the hourly-integrated SRMCP is equal for all the sub-zones within a reserve zone, the Total PJM Synchronized Reserve Tier 2 Credits in the reserve zone are allocated based on a Market Participant's above obligation ration share in the reserve zone.

- o If the hourly-integrated SRMCP is different for the sub-zones within a reserve zone, the Total PJM Synchronized Reserve Tier 2 Credits in the sub-zone are allocated based on a Market Participant's above obligation ration share in the sub-zone.

6.3.2 Synchronized Reserve Lost Opportunity Cost Charge

- The amount of unrecovered costs allocated to each Market Participant is determined based on each Market Participant's ratio share of Tier 2 Synchronized Reserve purchased from the market. A Market Participant's purchases equals their Synchronized Reserve obligation MW less any Tier 1 Synchronized Reserve applied to obligation, less any self-scheduled Tier 2 MW.
  - o *Synchronized Reserve Lost Opportunity Cost Charge Cleared = Total Lost Opportunity Cost Credits * (Synchronized Reserve Purchase / Total PJM Synchronized Reserve Purchases)* o *Synchronized Reserve Purchase = (Above Obligation Tier 1 Adjustment – Tier 2 Self Scheduled MWh)*
- The cost of Tier 2 resources assigned by PJM during the operating hour in addition to that which resulted from the Tier 2 clearing process due to reduced availability of Tier 1 Synchronized Reserve are allocated to those entities for which less Tier 1 was available during the hour that was estimated prior to the hour (Tier 1 Lost MW), in proportion to the reduction in Tier 1 availability. If there are no entities with a reduction in Tier 1 availability, the cost of these resources assigned during the hour is allocated based on a participant's purchases from the market.
  - o *Synchronized Reserve Lost Opportunity Cost Charge Added = Total Lost Opportunity Cost Credit Added * (Tier 1 Lost MW / Total Tier 1 Lost MW)*
- A Market Participant is also charged a share of any unrecovered costs incurred by assigned Tier 2 pool-schedule resources, including those Tier 2 resources assigned in addition to that which was estimated prior to a given hour, over and above those Tier 2 resources clearing price credits.

6.3.3 Synchronized Reserve Tier 2 Retroactive Penalty Charge

Tier 2 resources that fail to provide assigned Tier 2 capability during a Synchronized Reserve Event incur a retroactive obligation to refund at SRMCP the amount of the shortfall for the five minute interval measured in MW for all of the five minute intervals the resource was assigned over the immediate past interval, the duration of which is equal to the lesser of the average number of days between events as determined by the annual review of the last 2 years, or the number of days since the resource last failed to respond with its assigned or self-scheduled Synchronized Reserve amount in response to a synchronized reserve event.

- Market Participants that own multiple resources assigned or self-scheduled to provide Tier 2 Synchronized Reserve are permitted to demonstrate aggregate response, such that any resource that responds greater than their assignment or self-schedule can be used to offset any resource that responds less than their assignment or self-schedule of Tier 2 Synchronized Reserve during a Synchronized Reserve Event.

- The Market Participant's aggregate response does not affect how an individual resource is credited for Tier 2 Synchronized Reserve it provides as described above, but is used to determine what the Market Participant owes in refund charges for each resource that was assigned or self-scheduled to provide Tier 2 Synchronized Reserve and responded less than their assignment or self-schedule of Tier 2 Synchronized Reserve.

  o *Tier 2 Retroactive Penalty Charge = Resource Retroactive Shortfall MW * SRMCP / 12* o *Resource Retroactive Shortfall MW = Resource Shortfall MW – ((Resource Shortfall MW / Participant's Total Shortfall MW) * Participant's Total Over Response MW)*

- If the Retroactive Shortfall MW value per the above equation is less than 0 MW, the Retroactive Shortfall MW is equal to 0 MW.

Note:
If there are multiple Synchronized Reserve Events during a day, the maximum Resource Retroactive Shortfall MWh for the day is used to determine what the Market Participant owes in refund charges.

The retroactive penalty charges calculated above are allocated based on a Market Participant's ratio share of the Synchronized Reserve obligation MW less any Tier 1 Synchronized Reserve applied to obligation on the five minute intervals of the Synchronized Reserve event for the subzone or Reserve Zone for which the Synchronized Reserve event occurred. If the event spans multiple hours, the penalty charges are prorated hourly based on the duration of the event within each hour. Participants that incur a penalty charge and also have an applicable Synchronized Reserve obligation during the hours(s) of the Synchronized Reserve Event are not included in the allocation of such penalties. Additional details on verification and non-performance can be found in PJM Manual 11: Energy & Ancillary Services Market Operations, Section 4.

6.4 Reconciliation for Synchronized Reserve Charges

PJM calculates reconciled Synchronized Reserve charges for EDCs and Retail Load Aggregators (a.k.a. Electric Generation Suppliers) for past monthly billings on a two month lag that are based on Load Ratio Shares. The reconciliation kWh data must be supplied to PJM by the EDCs no later than the last day of the billing month that is two months after the original billing month. For example, all reconciliation data for January must be submitted by March 31 at 23:59. The reconciliation kWh data represents the difference between the scheduled Retail Load Responsibility or Wholesale Load Responsibility InSchedule (in MWh) and the "actual" usage based on metered data. This hourly kWh data must be reported separately for each applicable InSchedule contract.

PJM calculates the Synchronized Reserve charge reconciliations by multiplying the kWh data (de-rated for transmission losses) by the Synchronized Reserve billing determinants for that hour. The hourly Synchronized Reserve charge billing determinants (in $/MWh) for each reserve zone and sub-zone is calculated by dividing the total hourly Synchronized Reserve charges in that reserve zone or sub-zone by the total PJM real-time load (de-rated for transmission losses) in that reserve zone or sub-zone for that hour. These charge reconciliations are then totaled for the month for each EDC or Retail Load Aggregator. Note that the reconciliation for Synchronized Reserve charges for a month may be either a positive or a negative value,

and may even be such that the reconciled load responsibility MWh results in a negative load quantity.