CUSTOMER GUIDE TO PJM BILLING

- Billing Line Items include PJM Open Access Transmission Tariff (OATT) and PJM Operating Agreement (OpAgr) references.
- Reports are available for viewing, printing, and downloading from PJM's Market Settlement Reporting System (MSRS).

Billing Line Item	Description	Reports
Network Integration Transmission Service (OATT Section 34, Attachments H-1 through H-17, Attachment H-A, and TOA Section 5.4)	Network customers pay daily demand charges to PJM transmission owners using the applicable zonal or non-zone Network Integration Transmission Service rates. All network customers in the AP zone receive rebates to hold them harmless from the network rate conversion upon PJM integration. For transmission owners (except those in ATSI, PPL, ComEd, Dayton, Duke, and Duquesne zones), the charges for their own transmission facilities are not actually paid (i.e., exempted with an equal amount credits) and are shown only to identify their cost responsibility as ordered by FERC. Low voltage charges also apply for the ATSI zone based on their peak load contribution in each ATSI utility service territory using the applicable customer's low voltage billing factor for each ATSI service territory. ***<u>Charges</u>:*** Daily demand charges calculated as network customers' daily network service peak load contribution times 1/365th of the applicable zonal rate(s) for the zone(s) in which the network load is located. Monthly negative offset charges are rebated to AP zone network customers based on the applicable rates in PJM tariff Attachment H-11, section 4. Non-zone network service peak load contributions are coincident with the PJM Region peak. Daily low voltage charges are assessed to network customers in the ATSI zone for use of transmission facilities below 138 kV based on their network service peak load contribution MW times the low voltage rate times the percentage of their load serving those facilities. ***<u>Credits</u>:*** PJM zonal network transmission service revenues allocated to the applicable zone's transmission owners on a transmission revenue requirement basis. PJM non-zone network revenues allocated to transmission owners based on transmission revenue requirement ratio shares, with the ComEd, AEP, and Dominion shares further allocated to their respective zonal network customers based on demand charge ratios.	***NITS Charge Summary*** ***Low Voltage NITS Charge Summary*** ***NITS Credit Summary*** ***NITS Offset Charge Summary*** ***Non-Zone NITS Credit Summary***
Firm Point-to-Point Transmission Service (OATT Section 13.7, Schedule 7, and TOA Section 5.4)	Firm point-to-point transmission customers pay demand charges for reserved capacity at the applicable tariff rates based on the term of the reservations. There is no charge for reserved capacity with a MISO point of delivery. ***<u>Charges</u>:*** Monthly demand charges for daily, weekly, monthly, and yearly delivery calculated based on the transmission customer's reserved capacity times the applicable tariff rate. The total demand charge in any week, pursuant to a reservation for daily delivery, shall not exceed the weekly delivery rate times the highest amount of reserved capacity in any day during such week. ***<u>Credits</u>:*** Total firm transmission service revenues allocated to PJM transmission owners based on transmission revenue requirement ratio shares, with the ComEd, AEP, and Dominion shares further allocated to their respective zonal network customers based on demand charge ratios.	***Firm PTP Charges*** ***Firm PTP Credit Summary***
Non-Firm Point-to-Point Transmission Service (OATT Sections 14.5 & 27A, Schedule 8)	Non-firm point-to-point transmission customers pay demand charges for reserved capacity at the discounted rate. There is no charge for reserved capacity with a MISO point of delivery. ***<u>Charges</u>:*** Monthly demand charges for hourly, daily, weekly, and monthly delivery calculated based on the transmission customer's reserved capacity (in MWh) times the discounted rate of $0.67/MWh. Rebates are provided for transaction MWh curtailed by PJM and for transmission congestion charges. ***<u>Credits</u>:*** Total non-firm transmission service revenues allocated to PJM network and firm point-to-point transmission customers in proportion to their monthly demand charges.	***Non-Firm PTP Charges*** ***Non-Firm PTP Credit Summary***
Transmission Enhancement (OATT Schedule 12)	All network customers and merchant transmission owners pay transmission owners for required transmission enhancement projects in accordance with the zonal cost responsibility allocations in the appendix to Schedule 12. All transmission projects collecting these payments are on PJM's website under Transmission Services/Formula Rates. ***<u>Charges</u>:*** All network customers serving load in a responsible zone pay for that zone's applicable projects' revenue requirements in proportion to their network service peak load share in that zone, and responsible merchant transmission owners also pay their share of applicable revenue requirements. Note that several EDCs bear these charges for the default suppliers in their territory. ***<u>Credits</u>:*** Total revenues allocated to the applicable transmission enhancement project owners, or the applicable transmission zone network customers for zonal TOs that include these project costs in their network rates.	***Transmission Enhancement Charge Summary*** ***Transmission Enhancement Credit Summary***

Billing Line Item	Description	Reports
Spot Market Energy (OpAgr Schedules 1-3.2.1 & 3.3.1 and OATT Schedule 4)	Day-ahead energy market net hourly PJM Interchange MWh are calculated for cleared day-ahead generation and increment offers, demand, decrement, and load response bids, and day-ahead energy transactions. Real-time energy market net hourly PJM Interchange MWh are calculated for real-time energy transactions, load (without losses), generation, and metered tie flows, as applicable. ***<u>Day-ahead Charges</u>:*** Net day-ahead PJM Interchange is charged hourly at the PJM-wide day-ahead system energy price. Charges are positive for net buyers and negative for net sellers of day-ahead spot market energy. ***<u>Balancing Charges</u>:*** Net real-time deviations from day-ahead PJM Interchange is charged hourly at the PJM-wide real-time system energy price. Charges may be positive or negative depending on the direction of the real-time deviation from day-ahead interchange. ***<u>Reconciliation Charges</u>:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the PJM-wide real-time system energy price on a two-month billing lag.	***DA Daily Energy Transactions*** ***RT Daily Energy Transactions*** for customer review and verification ***Spot Market Energy Charge Summary*** ***Energy & Inadvertent Load Recon Charge Summary***
Transmission Congestion (OpAgr Schedules 1-3.2.4, 3.4.1, & 5.1-5.2)	The increased energy costs due to redispatch during hours when the PJM transmission system is constrained are assessed to market participants based on the congestion price component of LMPs, and the revenues collected are allocated to FTR holders. ***<u>Day-ahead Charges</u>:*** A day-ahead Net Congestion Bill is calculated hourly as the sum of day-ahead withdrawal charges (i.e., all cleared day-ahead demand/decrement/load response bids and sale transactions priced at applicable buses' day-ahead congestion prices) minus the sum of day-ahead injection credits (i.e., all cleared day-ahead generation/increment offers and purchase transactions priced at applicable buses' day-ahead congestion prices). Hourly day-ahead implicit congestion charges equal the day-ahead Net Congestion Bill. Hourly explicit congestion charges for day-ahead energy transactions equal the scheduled MWh times the difference between day-ahead sink and source congestion prices and are assessed to the buyer (or point-to-point transmission customer, if applicable). ***<u>Balancing Charges</u>:*** A balancing Net Congestion Bill is calculated hourly as the sum of balancing withdrawal charges (i.e., all deviations between demand/decrement/load response bids and sale transactions cleared day-ahead and real-time load, without losses, and sale transactions priced at the applicable buses' real-time congestion prices) minus the sum of balancing injection credits (i.e., all deviations between generation/increment offers and purchase transactions cleared day-ahead and real-time generation and purchase transactions priced at the applicable buses' real-time congestion prices). Hourly balancing implicit congestion charges equal the balancing Net Congestion Bill. Hourly explicit congestion charges for balancing energy transactions equal any real-time deviations from the transaction MWh cleared day-ahead times the difference between real-time sink and source congestion prices and assessed to the buyer (or point-to-point transmission customer, if applicable). ***<u>Credits</u>:*** Total congestion revenues allocated as hourly credits based on FTR target allocations (FTR MW times the difference between day-ahead FTR sink and source congestion prices). Excess hourly congestion credits (including NYISO Unscheduled Transmission Service revenues, net MISO congestion adjustment, inadvertent interchange congestion contribution, and ARR and FTR Auction net revenues remaining after initial distribution to any ARR deficiencies) are used to proportionately eliminate target deficiencies in other hours of the month. Any additional excess monthly congestion revenues are allocated to previous deficient months of the planning period with any excess at the end of the planning period allocated proportionately to FTR holders with net positive FTR target allocations for that planning period. Any deficiencies remaining at the end of a planning period are eliminated by reallocating all planning period FTR congestion revenues among FTR holders to yield a uniform ratio of deficiency. ***<u>Reconciliation Charges:</u>*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the applicable source/sink congestion price on a two-month billing lag.	***Transmission Congestion Charge Summary*** ***Explicit Congestion Charges*** ***Implicit Congestion and Loss Charge Details*** ***FTR Target Credits*** ***Monthly Congestion Credit Summary*** ***Hourly Transmission Congestion Credits*** ***Congestion and Loss Load Recon Charges*** ***Congestion Uplift Charge Summary*** ***Network ARR Target Credit Summary***

Billing Line Item	Description	Reports
Transmission Losses (OpAgr Schedules 1-3.2.5, 3.4.2, & 5.4-5.5)	The increased costs of energy due to transmission losses represented in the PJM network model are assessed to market participants based on the loss component of LMPs, and the revenues collected are allocated to market participants' serving load and delivering PJM exports (that pay for PJM transmission service). ***Day-ahead Charges:*** An hourly day-ahead Net Loss Bill is calculated as day-ahead withdrawal charges (i.e., all cleared day-ahead demand/decrement/load response bids and sale transactions priced at applicable buses' day-ahead loss prices) minus day-ahead injection credits (i.e., all cleared day-ahead generation/increment offers and purchase transactions priced at applicable buses' day-ahead loss prices). Hourly day-ahead implicit loss charges equal the day-ahead Net Loss Bill. Hourly explicit loss charges for day-ahead energy transactions equal the scheduled MWh times the difference between day-ahead sink and source loss prices and assessed to the buyer (or point-to-point transmission customer, if applicable). ***Balancing Charges:*** An hourly balancing Net Loss Bill is calculated as balancing withdrawal charges (i.e., all deviations between demand/decrement/load response bids and sale transactions cleared day-ahead and real-time load, without losses, and sale transactions priced at the applicable buses' real-time loss prices) minus balancing injection credits (i.e., all deviations between generation/increment offers and purchase transactions cleared day-ahead and real-time generation and purchase transactions priced at the applicable buses' real-time loss prices). Hourly balancing implicit loss charges equal the balancing Net Loss Bill. Hourly explicit loss charges for balancing energy transactions equal any real-time deviations from day-ahead transaction MWh times the difference between real-time sink and source loss prices and assessed to the buyer (or point-to-point transmission customer, if applicable). ***Credits:*** Total hourly loss revenues, both day-ahead and balancing (including loss contribution of inadvertent interchange) allocated as hourly credits based on ratio shares of real-time load (without losses) plus exports that pay for transmission service (with non-firm exports receiving 31% of their allocation). ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the applicable source/sink loss price on a two-month billing lag. ***Reconciliation Credits:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using a $/MWh billing determinant calculated as the total loss credits divided by the total MWh of PJM real-time load plus exports (that pay for transmission service, with non-firm exports receiving 31% of their allocation) on a two-month billing lag.	***Transmission Loss Charge Summary*** ***Explicit Loss Charges*** ***Implicit Congestion and Loss Charge Details*** ***Transmission Loss Credit Summary*** ***Congestion and Loss Load Recon Charges*** ***Transmission Loss Load Recon Credit Summary***
Inadvertent Interchange (OpAgr Schedule 1-3.7)	***Charges:*** PJM hourly total inadvertent interchange charges (+/-) priced at the load weighted-average PJM real-time LMP and allocated based on real-time load ratio shares. ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the PJM-wide real-time system energy price on a two-month billing lag.	***Inadvertent Interchange Charge Summary*** ***Energy & Inadvertent Load Recon Charge Summary***
Load Response (OpAgr, just prior to Schedule 2)	***Credits:*** Day-ahead and real-time economic and real-time emergency load response credits are provided to CSPs equal to the reduced MWh times LMP (minus retail rate, as applicable). ***Charges:*** For day-ahead and real-time economic load response, the CSP's LSE is charged the difference between LMP and the retail rate, as applicable, times the MWh reduction. For emergency load response, all balancing energy market participants are allocated charges using the same method as for PJM emergency energy purchases.	***Load Response Summary*** ***Econ Load Response Zonal Charge Allocations*** ***Emergency Load Response Allocation Summary*** ***Emergency Load Response Allocation Credits***
Meter Error Correction (OpAgr Schedule 1-3.6)	***Charges:*** Monthly charges (+/-) to PJM fully-metered EDCs and generators for corrections to metered energy values, with PJM Mid-Atlantic 500kV corrections allocated based on real-time load ratio shares, using the applicable generator or PJM load weighted-average real-time LMP for the month. Meter correction charges for any external PJM tie-line corrections are allocated to all LSEs based on real-time load (without losses) ratio shares. Effective February 2010, EDCs may elect to have their charges (+/-) directly allocated by PJM to LSEs in their zone based on load ratio shares if all LSEs in the EDC territory concur.	***Meter Correction Charge Summary*** ***Meter Correction Allocation Charge Summary***
Emergency Energy (OpAgr Schedules 1-3.2.6, 3.3.4, 3.5.1, & 4.3)	PJM emergency energy transactions (made on behalf of market participants) are priced at 150% of LMP at the appropriate PJM interface in accordance with the PJM agreements with adjacent control areas. ***Charges:*** Hourly net costs of emergency energy purchased by PJM are allocated to real-time deviations from day-ahead net interchange that create a shorter real-time position, except for purchases for external control areas' MinGen Emergencies where costs are allocated to deviations that create a longer position. ***Credits:*** Hourly net revenues from emergency energy sold by PJM are allocated to real-time deviations from day-ahead net interchange that create a shorter real-time position and to any curtailed exports, except for PJM MinGen Emergency sales where revenues are allocated to deviations that create a longer position.	***Emergency Energy Charge and Credit Allocation Summary*** ***Emergency Energy Transactions***

Billing Line Item	Description	Reports
PJM Scheduling, System Control & Dispatch Service (OATT Schedules 1 and 9-1 through 9-6)	***Charges:*** PJM's monthly operating expenses for the following service categories are allocated to PJM members on an unbundled basis. Charge refunds are provided in the year following any year in which there is an over collection of PJM's monthly operating expenses. Control Area Administration – 2012 rate of $0.1692/MWh (with $0.0072 refund rate for Apr-Jun) charged to transmission customers based on their usage of the PJM transmission system. Monthly transmission use (in MWh) includes network customers' real-time load and point-to-point customers' real-time energy use. Financial Transmission Rights Administration – 2012 rate of $0.0025/FTR MWh (with $0.0001 refund rate for Apr-Jun) charged to FTR holders based on FTR MW and hours each FTR is in effect (regardless of congested hours and dollar value of FTR). 2012 rate of $0.0017/bid-hour (with $0.0001 refund rate for Apr-Jun) charged to FTR Auction participants based on the number of hours associated with each FTR obligation bid submitted in an FTR Auction (this rate is multiplied by 5 for FTR options). Market Support – 2012 rate of $0.0373/MWh (with $0.0016 refund rate for Apr-Jun) charged to transmission customers based on their network load and exports, to providers of generation and imports, and to day-ahead energy market participants based on their accepted increment offers, decrement bids, and up-to congestion bids. 2012 rate of $0.0558 (with $0.0014 refund rate for Apr-Jun) is charged for each energy bid/offer segment price/quantity pair submitted, including those submitted during the rebidding period. Regulation and Frequency Response Administration – 2012 rate of $0.2271/Regulation MWh (with $0.0111 refund rate for Apr-Jun) charged to customers based on regulation obligation and regulation provided. Capacity Resource and Obligation Management – 2012 rate of $0.0864/MW-day (with $0.0032 refund rate for Apr-Jun) charged to LSEs based on their daily unforced capacity obligations and to capacity resource owners based on their daily unforced capacity (including FRRs). Costs of Advanced Second Control Center (AC^2) – Starting June 2008, monthly accrued actual costs related to AC^2 are collected across all users of Schedule 9-1 through 9-5 based on usage shares with the costs allocated to the applicable schedules in accordance with the PJM tariff. Market Support Offset – Apr-Jun 2012 rate of $0.0059/MWh refunded to transmission customers based on their network load and exports, to providers of generation and imports, and to day-ahead energy market participants based on their accepted increment offers, decrement bids, and up-to congestion bids to reflect the reimbursement made to offset the PJM Settlement, Inc. charges. ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using a $/MWh billing determinant calculated as the Control Area Administration Service Rate plus the Market Support Service Rate for transmission customers on a two-month billing lag. Charge refund amounts are also reconciled using the applicable refund rate billing determinants. Schedule 9-6 AC2 charges are also reconciled using the applicable billing determinants.	***Schedule 9 and 10 Charge Details*** ***Advanced Second Control Center Charge Details*** ***Schedule 9 & 10 Load Recon Charge Summary***
PJM Settlement, Inc. (OATT Schedule 9-PJMSettlement)	***Charges:*** Apr-Jun 2012 rate of $0.0059/MWh charged to transmission customers based on their network load and exports, to providers of generation and imports, and to day-ahead energy market participants based on their accepted increment offers, decrement bids, and up-to congestion bids. This charge funds the administration of PJM Settlement, Inc. who acts as the contractual counterparty to PJM market transactions and performs the billing collection and credit management services for PJM members.	***Schedule 9 and 10 Charge Details***
MMU Funding (OATT Schedule 9-MMU)	***Charges:*** 2012 rate of $0.00449/MWh charged to transmission customers based on their network load and exports, to providers of generation and imports, and to day-ahead energy market participants based on their accepted increment offers, decrement bids, and up-to congestion bids. 2012 rate of $0.00397 is charged for each energy bid/offer segment price/quantity pair submitted, including those submitted during the rebidding period. ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the MMU rate on a two-month billing lag.	***Schedule 9 and 10 Charge Details*** ***Schedule 9 & 10 Load Recon Charge Summary***
FERC Annual Recovery (OATT Schedule 9-FERC)	***Charges:*** 2012 rate of $0.0689/MWh charged to transmission customers based on their usage of the PJM transmission system. Monthly transmission use includes network customers' real-time load and point-to-point transmission customers' real-time energy transactions. Note: The DEOK zone is exempt from Schedule-9 FERC charges until Oct 2012. ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the FERC rate on a two-month billing lag.	***Schedule 9 and 10 Charge Details*** ***Schedule 9 & 10 Load Recon Charge Summary***

Organization of PJM States, Inc. (OPSI) Funding (OATT Schedule 9-OPSI)	***Charges:*** 2012 rate of $0.00069/MWh charged to transmission customers based on their usage of the PJM transmission system. Monthly transmission use includes network customers' real-time load and point-to-point transmission customers' real-time energy transactions. ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the OPSI rate on a two-month billing lag.	***Schedule 9 and 10 Charge Details*** ***Schedule 9 & 10 Load Recon Charge Summary***
North American Electric Reliability Corp. (NERC) (OATT Schedule 10-NERC)	***Charges:*** 2012 rate of $0.0108/MWh charged to transmission customers based on their energy delivered to load in the PJM Region, excluding load in the Dominion zone. Each calendar year, any over or under collection of NERC's actual costs are trued up in that year's December billing cycle. ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the NERC rate on a two-month billing lag.	***Schedule 9 and 10 Charge Details*** ***Schedule 9 & 10 Load Recon Charge Summary***
Billing Line Item	**Description**	**Reports**
Reliability First Corp. (RFC) (OATT Schedule 10-RFC)	***Charges:*** 2012 rate of $0.0135/MWh charged to transmission customers based on their energy delivered to load in the PJM Region, excluding load in the Dominion zone. Each calendar year, any over or under collection of RFC's actual costs are trued up in that year's December billing cycle. ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the RFC rate on a two-month billing lag.	***Schedule 9 and 10 Charge Details*** ***Schedule 9 & 10 Load Recon Charge Summary***
Transmission Owner Scheduling, System Control and Dispatch Service (OATT Schedule 1A)	All Transmission Customers purchase this from PJM to schedule energy through, out, within, or into PJM. ***Charges:*** Monthly charges for the operation of the PJM transmission owners' control centers are calculated for transmission customers based on their monthly usage of the PJM transmission system. Point-to-Point Transmission Customers pay a pool-wide rate of $0.1019/MWh based on their energy deliveries including losses, and network customers pay applicable zonal rates provided in Schedule 1A of the Tariff based on the real-time MWh of monthly load they serve. ***Credits:*** The charges collected from network customers for each zone are provided to the applicable transmission owner, and the non-zone revenues (e.g., received from point-to-point customers) are allocated to PJM transmission owners based on fixed percentage shares provided in Schedule 1A of the Tariff. ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using zonal $/MWh billing determinants equal to the applicable zonal Schedule 1A rates on a two-month billing lag.	***Sched 1A Charge Summary*** ***Sched 1A Credit Summary*** ***Sched 1A Load Recon Charge Summary***
Reactive Supply and Voltage Control from Generation and Other Sources Service (OATT Schedule 2)	All Transmission Customers purchase this from PJM to maintain acceptable transmission voltages. ***Credits:*** Monthly credits provided to generation and transmission owners with FERC-approved reactive revenue requirements. ***Charges:*** Monthly pool-wide reactive revenue requirements allocated as charges to point-to-point customers (and to network customers in transmission zones with no reactive revenue requirements) based on their monthly peak usage of the PJM transmission system. Monthly peak usage equals the total hourly amounts of transmission capacity reserved, and not curtailed by PJM, divided by 24. The remaining reactive revenue requirements for each transmission zone not recovered from point-to-point customers are allocated to the network customers serving load in that zone based on their monthly network service peak load contributions.	***Reactive Charge Summary***
Regulation and Frequency Response Service (OpAgr Schedules 1-3.2.2, 3.2.2A, 3.3.2, & 3.3.2A and OATT Schedule 3)	PJM conducts a regulation market to continuously balance generation resources with PJM load and to maintain Interconnection frequency within acceptable limits. ***Credits:*** Generators and demand resources receive hourly credits for pool- and self-scheduled regulation priced at the regulation market clearing price. Additional credits provided to pool-scheduled regulating resources for any unrecovered portion of regulation offer plus opportunity cost. ***Charges:*** PJM LSEs have an hourly regulation obligation equal to their real-time load (without losses) ratio share of PJM assignments (adjusted for any bilateral regulation transactions). Hourly charges calculated by allocating total credits across all positive adjusted obligations. Additional charges are assessed for any unrecovered cost payments that PJM provides to regulation suppliers and allocated to regulation market purchasers based on their share of any portion of their adjusted obligation in excess of their self-scheduled regulation. ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using a $/MWh billing determinant calculated as the total regulation market charges divided by the total MWh of PJM real-time load served on a two-month billing lag.	***Regulation Summary*** ***Regulation Credits*** ***Load Response Regulation Credits*** ***Reg Load Recon Charge Summary***

Billing Line Item	Description	Reports
Synchronized Reserve (OpAgr Schedules 1-3.2.3A & 3.3.5 and OATT Schedule 5)	PJM conducts synchronized reserve markets to ensure the capability of synchronized generation and demand resources that can be converted fully into energy within ten minutes. ***<u>Credits</u>:*** Generators that increase output and demand resources that decrease consumption in response to a synchronized reserve event receive Tier 1 credits equal to response MWh times synchronized reserve energy premium less its hourly LMP. Resources receive Tier 2 hourly credits for pool- and self-scheduled synchronized reserve priced at the applicable reserve zone's Tier 2 clearing price. Additional credits provided to pool-scheduled synchronized reserve resources for any portion of synchronized reserve offer plus opportunity cost, energy use cost, and start-up cost not recovered via Synchronized Reserve Market Clearing Price revenues. ***<u>Charges</u>:*** PJM LSEs have an hourly synchronized reserve obligation equal to their real-time load (without losses) ratio share of their reserve market's total assignments (adjusted for any bilateral synchronized reserve transactions). Tier 1 charges for each participant equal their ratio share of the total Tier 1 credits based on the amount of Tier 1 synchronized reserve applied to their obligation. Tier 2 hourly charges for each participant equal their reserve market's hourly Tier 2 clearing price times the MWh of Tier 2 synchronized reserve self-scheduled that hour toward their obligation plus that which was purchased from that synchronized reserve market, plus their share of any unrecovered costs incurred by assigned Tier 2 resources above the Tier 2 clearing price, plus their share of costs of those Tier 2 resources assigned in addition to that which was estimated prior to a given hour. ***<u>Reconciliation Charges</u>:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the applicable reserve zone's $/MWh billing determinant calculated as the total applicable reserve zone charges divided by the total MWh of PJM real-time load served in the that market on a two-month billing lag.	***Synchronized Reserve Credit Summary*** ***Synchronized Reserve Tier 1 Credits*** ***Synchronized Reserve Tier 2 Credits*** ***Synchronized Reserve Obligation Details*** ***Synchronized Reserve Tier 1 Charge Summary*** ***Synchronized Reserve Tier 2 Charge Summary*** ***Load Response Tier 1 Credits*** ***Load Response Tier 2 Credits*** ***Synchronized Reserve Load Recon Charge Summary***
Day-ahead Scheduling Reserve (OpAgr Schedules 1-3.2.3A.01 and OATT Schedule 6)	PJM conducts day-ahead scheduling reserve markets to ensure the capability of generation and demand resources to meet reserve requirements on a forward basis. ***<u>Credits</u>:*** Daily credits provided to eligible generator and demand response resources cleared day-ahead based on their cleared MWh of day-ahead scheduling reserve times the day-ahead scheduling reserve clearing price. ***<u>Charges</u>:*** PJM LSEs have an hourly day-ahead scheduling reserve obligation equal to their real-time load (without losses) ratio share of the market's total assignments (adjusted for any bilateral day-ahead scheduling reserve transactions). Total hourly cost of day-ahead scheduling reserve is allocated based on obligation ratio shares. ***<u>Reconciliation Charges</u>:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the $/MWh billing determinant calculated as the total charges divided by the total MWh of PJM real-time load on a two-month billing lag.	***Day-ahead Scheduling Reserve Summary*** ***Day-ahead Scheduling Reserve Credits*** ***Day-ahead Scheduling Reserve Load Recon Charge Summary***

Billing Line Item	Description	Reports
Operating Reserve (OpAgr Schedules 1-3.2.3 & 3.3.3 and OATT Schedule 6)	To ensure adequate operating reserve and for spot market support, pool-scheduled generation and demand resources and that operate as requested by PJM are guaranteed to fully recover their daily offer amounts. ***Day-ahead Credits:*** Daily credits provided to pool-scheduled generators, demand response, and transactions cleared day-ahead for any portion of their offer amount in excess of their scheduled MWh times day-ahead bus LMP. ***Balancing Credits:*** Daily credits for specified operating period segments provided to eligible pool-scheduled generators, demand response, and import transactions in real-time for any portion of their offer amount in excess of: (1) scheduled MWh times day-ahead bus LMP; (2) MWh deviation from day-ahead schedule times real-time bus LMP; (3) any day-ahead operating reserve credits; (4) any day-ahead scheduling reserve market revenues in excess of offer; (5) any synchronized reserve market revenues in excess of offer plus opportunity, energy use, and startup costs; and (6) any applicable reactive services credits. Cancellation credits are based on actual costs submitted to PJM Market Settlements. Credits for lost opportunity costs are also provided to generators reduced or suspended by PJM for reliability purposes. ***Day-ahead Charges:*** Total daily cost of operating reserve in the day-ahead market is allocated based on day-ahead load (including cleared demand, demand response, and decrement bids) plus exports ratio shares. ***Balancing Charges:*** Total daily cost of operating reserve in the balancing market related to resources identified as Credits for Deviations is allocated based on regional shares of real-time locational deviations from the following day-ahead scheduled quantities of: (1) cleared generation offers (only for generating units not following PJM dispatch instructions and not assessed deviations based on their real-time desired MWh); (2) cleared increment offers and purchase transactions; and (3) cleared demand bids, decrement bids, and sale transactions. Total daily cost of operating reserve in the balancing market related to resources identified as Credits for Reliability is allocated based on regional shares of real-time load (without losses) plus exports. ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an daily basis using a $/MWh billing determinant calculated as the total charges allocated to real-time load plus exports divided by the total MWh of PJM real-time load plus exports on a two-month billing lag.	***Operating Reserve Charge Summary*** ***Operating Reserve Generator Credit Details*** ***Operating Reserve Lost Opportunity Cost Credits*** ***Operating Reserve Transaction Credits*** ***Operating Reserve Generator Deviations*** ***Operating Reserve Deviation Summary*** ***Operating Reserve Transaction Credits*** ***Operating Reserve for Load Response Credit Details*** ***Operating Reserve for Load Response Deviation Charge Summary*** ***Operating Reserve for Load Response Charge Allocations*** ***Regional Balancing Operating Reserve Charge Summary*** ***Balancing Operating Reserve Load Recon Charge Summary***
Synchronous Condensing (OpAgr Schedule 1-3.2.3)	***Credits:*** Daily credits for condensing and energy use costs are provided to eligible synchronous condensers dispatched by PJM for purposes other than synchronized reserve, post-contingency, or reactive services. ***Charges:*** Total daily cost of synchronous condensing (not for synchronized reserve or reactive services) is allocated based on real-time load (without losses) plus export ratio shares. ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using a $/MWh billing determinant calculated as the total charges divided by the total MWh of PJM real-time load plus exports on a two-month billing lag.	***Synchronous Condensing Credits*** ***Synchronous Condensing Charge Summary*** ***Synchronous Condensing Load Recon Charge Summary***
Reactive Services (OpAgr Schedule 1-3.2.3B)	Generating resources whose output is altered by PJM for the purpose of maintaining reactive reliability are guaranteed to fully recover their daily offer amounts or compensated for their lost opportunity costs. ***Credits:*** Daily credits are calculated for each eligible generator in real-time and equal the operating reserve credits for generation increased, or equal the lost opportunity costs for generation reduced or instructed to condense, to provide reactive services. ***Charges:*** Total daily cost of reactive services is allocated separately for each PJM transmission zone based on real-time load (without losses) ratio shares in the applicable transmission zone. ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the applicable zone's $/MWh billing determinant calculated as the total applicable zone's charges divided by the total MWh of real-time load served in the that zone on a two-month billing lag.	***Reactive Services Credits*** ***Synchronous Condensing Credits*** ***Reactive Services Charge Summary*** ***Reactive Svcs Load Recon Charge Summary***

Billing Line Item	Description	Reports
Black Start Service (OATT Schedule 6A)	All Transmission Customers purchase this from PJM to ensure the reliable restoration following a shut down of the PJM transmission system. ***Credits****:* Monthly credits provided to generators with approved black start revenue requirements. ***Charges****:* Monthly pool-wide black start revenue requirements allocated as charges to point-to-point customers based on their monthly peak usage of the PJM transmission system. Monthly peak usage equals the total hourly amounts of transmission capacity reserved, and not curtailed by PJM, divided by 24. The remaining black start revenue requirements nominated by each zonal Transmission Owner not recovered from point-to-point customers are allocated to the network customers serving load in that transmission zone based on their monthly network service peak load contributions.	***Black Start Charge Summary***
Financial Transmission Rights Auction (OpAgr Schedule 1-7.3.8)	PJM conducts annual and monthly FTR auctions for the transaction of FTRs at market clearing prices. Net auction revenues are allocated daily to ARR holders and then FTR holders as excess congestion revenues. ***Charges:*** Monthly auction charges are calculated for each market participant for each FTR (in 0.1 MW increments) purchased in the annual or monthly auctions based on the FTR's market price. ***Credits:*** Monthly auction credits are calculated for each market participant for each FTR (in 0.1 MW increments) sold in the annual or monthly auctions based on the FTR's market price.	***FTR Auction Charges and Credits***
Auction Revenue Rights (OpAgr Schedule 1-7.4)	Auction Revenue Rights (ARR) are entitlements to receive an allocation of net FTR auction revenues that are allocated annually and reassigned daily to network and firm point-to-point transmission customers. ***Credits:*** Annual FTR auction net revenues are allocated as daily credits based on ARR target allocations, which equal the ARR MW (divided by the number of auction rounds) times the difference between auction clearing prices at the ARR sink and source. Any ARR target deficiencies may be proportionately eliminated by any monthly FTR auction net revenues and excess congestion revenues in that planning period.	***ARR Target Credits***

Billing Line Item	Description	Reports
RPM Auction (OATT Att. DD, Section 5.14)	***Credits:*** Each sell offer for generation, demand, or qualified transmission upgrade resource MW cleared in an RPM Auction is paid the applicable resource's clearing price in the applicable auction. Resource make-whole payments are also provided to sell offers that clear less than the minimum amount specified. Sell offers are adjusted by approved unit-specific transactions for cleared capacity. ***Charges:*** Each buy bid MW cleared in an incremental auction adjusted by cleared buy bid transactions pays the applicable LDA's resource clearing price. Resource make-whole payments for an incremental auction are also allocated as charges to Market Buyers based on the MW shares of cleared buy bids adjusted by cleared buy bid transactions for the incremental auction. Resource make-whole payments for the base residual auction and the portion of the resource make-whole payment for an incremental auction that would be based on PJM cleared buy bids are allocated as charges to LSEs in the applicable LDA via the Final Zonal Capacity Price.	***RPM Auction Charges and Credits*** ***RPM Auction Make-Whole Charge Summary***
Locational Reliability (OATT Att. DD, Section 5.14)	***Charges:*** Each LSE is charged for their daily unforced capacity obligation priced at the applicable zonal capacity price for the delivery year.	***Locational Reliability Charge Summary***
Interruptible Load for Reliability (OATT Att. DD, Section 5.14)	***Credits:*** Each ILR resource is credited for their certified zonal MW priced at the applicable zonal ILR price.	***ILR Credit Summary***
Capacity Transfer Rights (OATT Att. DD, Section 5.15)	To recognize the value of import capability to constrained LDAs, Capacity Transfer Rights (CTRs) are allocated to LSEs in those LDAs to offset their higher load charges. ***Credits:*** CTRs equal to the unforced capacity imported into the LDA (less any incremental CTRs) are allocated to LSEs in that LDA based on daily unforced capacity obligations. These MW allocations are priced at the difference between the LDA's clearing price and the unconstrained price.	***CTR Credit Summary***
Incremental Capacity Transfer Rights (OATT Att. DD, Section 5.16)	Incremental CTRs are provided to fund for transmission upgrades (not including qualifying transmission upgrades cleared in the Base Residual Auction) that increase import capability into a constrained LDA. ***Credits:*** Incremental CTR MW are priced at the sum of: 1) locational price adder of the sink LDA minus that of the Source LDA from the Base Residual Auction; and 2) locational price adder of the sink LDA minus that of the source LDA from the Second Incremental Auction multiplied by the increase in unforced capacity imported into the sink LDA in the Second Incremental Auction compared to the Base Residual Auction, divided by the base unforced capacity imported into the sink LDA.	***Incremental CTR Credits***
Auction Specific MW Transaction (OATT Att. DD, Section 5.14)	Bilateral capacity transactions for multi-day durations are settled in the PJM capacity markets. ***Charges:*** Sellers are charged for the transaction MW times the transaction's pricing point for each day for which the transaction is in effect. ***Credits:*** Buyers are credited for the transaction MW times the transaction's pricing point for each day for which the transaction is in effect.	***Auction Specific MW Transaction Charges and Credits***
Demand Resource and ILR Compliance Penalty (OATT Att. DD, Section 11)	Sellers with zonal aggregate committed Demand Resources or nominated ILR that cannot demonstrate hourly real-time performance pay a penalty charge which is allocated to Demand Resource and ILR providers and, potentially, LSEs. This billing is performed on a three-month lag. ***Charges:*** For each non-compliant reduction event, under-compliance MW (on an unforced capacity basis) are charged at the lesser of one divided by the actual number of events during the year or 0.50 of the Weighted Annual Revenue Rate. The Weighted Annual Revenue Rate equals the average rate for all cleared Demand Resources and certified ILR, weighted by the MWs cleared or certified at each price, multiplied by the number of days in the Delivery Year. The total Compliance Penalty Charge for the Delivery Year is capped at the annual revenue received for such resources. ***Credits:*** Revenues from events in a given month are allocated to Demand Resource and ILR Providers that reduced in excess of their commitment. Any resource credit by event is capped at their excess MW times 1/5th of their Annual Revenue Rate. Revenues above that cap are allocated to LSEs based on their average daily unforced capacity obligations during the month of the event.	***DR & ILR Compliance Penalty Ch and Cr*** ***DR & ILR Compliance Penalty Residual Credit Summary***

Billing Line Item	Description	Reports
Capacity Resource Deficiency (OATT Att. DD, Section 8)	Capacity resources that are unable or unavailable to deliver unforced capacity, and do not obtain replacement unforced capacity to satisfy their cleared sell offer pay this charge which is allocated to eligible LSEs. ***Charges:*** Each capacity resource's deficiency MW for each day it is deficient pays the daily deficiency rate. ***Credits:*** Total revenues each day are allocated to LSEs that paid a Locational Reliability charge that day based on their daily unforced capacity obligations.	***Non-Compliance Charge Summary*** ***Deficiency Credit Summary***
Generation Resource Rating Test Failure (OATT Att. DD, Section 7)	Generation capacity resources that fail a capacity test pay this charge which is allocated to eligible LSEs. This billing is performed in the June billing cycle after the conclusion of the delivery year. ***Charges:*** Each capacity resource's installed capacity minus its highest rating in the relevant testing period (on an unforced capacity basis) pays a daily deficiency rate which is the weighted average capacity resource clearing price plus the higher of: 1) 0.2 times the weighted average capacity resource clearing price or 2) $20/MW-day; ***Credits:*** Total revenues each day are allocated to LSEs that paid a Locational Reliability charge that day based on their daily unforced capacity obligations.	***Non-Compliance Charge Summary*** ***Deficiency Credit Summary***
Qualifying Transmission Upgrade Compliance Penalty (OATT Att. DD, Section 12)	Cleared qualifying transmission upgrades delayed in coming into service for the applicable delivery year pay a daily penalty charge which is allocated to eligible LSEs. ***Charges:*** Capacity market sellers with import capability cleared in a base residual auction based on a qualifying transmission upgrade are charged each day that the upgrade is not in service during the applicable delivery year and the seller does not obtain replacement capacity resources. The import capability MW are charged at the higher of the following rates: 1) two times the locational price adder of the applicable LDA; or 2) the Net CONE less the clearing price in the applicable LDA. ***Credits:*** Total revenues each day are allocated to LSEs that paid a Locational Reliability charge that day based on their daily unforced capacity obligations.	***Non-Compliance Charge Summary*** ***Deficiency Credit Summary***
Peak Season Maintenance Compliance Penalty (OATT Att. DD, Section 9)	Each generation capacity resource must have available unforced capacity during the peak season to satisfy its cleared MW. This billing is performed in the June billing cycle after the conclusion of the delivery year. ***Charges:*** Each generation capacity resource's cleared MW for each day of the peak season that is out-of-service on a maintenance outage not authorized by PJM pays the daily deficiency rate times (1-EFORd). ***Credits:*** Total revenues each day are allocated to LSEs that paid a Locational Reliability charge that day based on their daily unforced capacity obligations.	***Non-Compliance Charge Summary*** ***Deficiency Credit Summary***
Peak-Hour Period Availability (OATT Att. DD, Section 10)	To ensure capacity resource availability during critical peak hours, incentives are provided to resources that exceed expected availability and penalties are assessed to those who fall short. This billing is performed in the August billing cycle after the conclusion of the delivery year. ***Charges:*** Net peak period capacity shortfall MW are charged at the weighted average resource clearing price for the applicable LDA (except for FRR capacity that are charged at the LDA's Net CONE). ***Credits:*** Total revenues for the delivery year for each LDA are allocated to resources with peak period excesses based on their excess MW. Since these allocations are capped, any remaining credits are allocated to LSEs that paid a Locational Reliability charge based on their daily unforced capacity obligations.	
Load Management Test Failure (OATT Att. DD, Section 11A)	Sellers with committed Demand Resources or nominated ILR that fail performance tests pay a penalty charge which is allocated to eligible LSEs. This billing is performed in the December billing cycle for June-December, then it is performed monthly for January-May. ***Charges:*** Net capability testing shortfall MW are charged daily at the weighted annual revenue rate for the applicable zone plus the greater of 0.2 times that weighted annual revenue rate or $20/MW-day. ***Credits:*** Total revenues each day are allocated to LSEs that paid a Locational Reliability charge that day based on their daily unforced capacity obligations.	***Load Management Test Failure Charge Summary*** ***Deficiency Credit Summary***

Billing Line Item	Description	Reports
RTO Start-up Cost Recovery (OATT Attachments H-13 and H-14)	All network customers in the ComEd Zone pay ComEd (expected to end May 2014) and in the AEP Zone pay AEP (expected to end May 2020). ***Charges:*** Monthly charges to ComEd zonal network customers are calculated based on network service peak load contributions (as used for Network Service charges) at a 2012 rate of $64.12/MW/year. Monthly charges to AEP zonal network customers are calculated based on network service peak load contributions at a 2012 rate of $96.29/MW/year.	***RTO Startup Cost Recovery Charge Summary***
Expansion Cost Recovery (OATT Schedule 13)	All network customers (except those in the Dominion, Duke, and ATSI Zones) pay AEP, ComEd, and Dayton to recover their integration expenses. This charge is expected to continue through April 2015. ***Charges:*** For 2012, $4.96/MW-month of peak load is charged to all network customers serving load in the AEP, ComEd, and Dayton zones and $2.43/MW-month is charged in all other zones, except Dominion, Duke, and ATSI. ***Credits:*** Total revenues are allocated to ComEd, AEP, and Dayton in accordance with Schedule 13.	***Expansion Cost Recovery Charge Summary*** ***Expansion Cost Recovery Credit Summary***
Unscheduled Transmission Service (OpAgr Sch1-5.3a)	***Charges:*** Hourly charges to NYISO for any costs incurred due to unscheduled use of the PJM transmission system in accordance with the PJM-NYPP Interconnection Agreement Schedule 6.02. ***Credits:*** Total hourly charges are allocated as credits with monthly excess congestion credits.	***Hourly Transmission Congestion Credits***
Ramapo Phase Angle Regulators (OpAgr Schedule 1-5.3b)	***Credits:*** PJM's share of monthly carrying charges for Ramapo Phase Angle Regulators (PARs) are credited to NYISO in accordance with the NYPP-PJM PARs Facilities Agreement. ***Charges:*** Charges are allocated to PJM Mid-Atlantic transmission owners based on transmission revenue requirement shares.	***Ramapo PAR Charge Summary***
Generation Deactivation (OATT Part V)	Revenues are collected for generators requesting retirement where PJM studies find reliability issues that require the generation to continue operating. Cost allocations to zonal load and firm withdrawal rights are determined by PJM based on the beneficiaries. These responsible customers pay the generation owners a share of the Deactivation Avoidable Cost Rate or the FERC-approved Cost of Service Recovery Rate. Any time that the zonal cost allocations change, notice is provided to the Markets and Reliability Committee, Market Implementation Committee, and Market Settlements Working Group prior to the change being implemented. ***Charges:*** Charges are being collected for a unit in the PSEG zone based on a Cost of Service Recovery Rate which is ending December 8, 2011. From September 2010 through December 2011, monthly charges are allocated on a one-month lag in accordance with the following study results: http://www.pjm.com/planning/generation-retirements/~/media/planning/gen-retire/2011-and-2012-zonal-cost-allocation-for-retaining-husdon-unit-1-generator.ashx. Since Hudson Transmission Partners' facility is not yet in service, their charges must be deferred resulting in the following normalized cost allocations: AE (0.61494%), ComEd (2.15787%), JCPL (8.95572%), Neptune (4.08095%), Penelec (2.23614%), ECP (3.17531%), PSEG (75.78265%), and RECO (2.99642%). Note that the zonal charges are further allocated based on network service peak load contributions within the applicable zone. Charge refunds are also being provided from September 2008 through February 2017 for a plant in the PSEG zone that was previously collecting payments but has since decided to stay operational. These refunds are being allocated to network customers in the PSEG (41.8707%), PECO (19.1279%), JCPL (25.2497%), Delmarva (6.1420%), AE (6.2832%), and RECO (1.3265%) zones based on the network service peak load contributions within the applicable zones. Charges are being collected for units in the PECO zone based on a Cost of Service Recovery Rate which is expected to end after December 2011 for Cromby and after May 2012 for Eddystone. Monthly charges are allocated on a one-month lag in accordance with the following study results: http://pjm.com/planning/generation-retirements/~/media/planning/gen-retire/cromby-2-zonal-cost-allocation-for-2012.ashx and http://pjm.com/planning/generation-retirements/~/media/planning/gen-retire/eddystone-2-zonal-cost-allocation-for-2012.ashx. Since Hudson Transmission Partners' facility is not yet in service, their charges must be deferred resulting in the following normalized cost allocations: for Cromby - PECO (100%); for Eddystone - JCPL (4.5760%), Neptune (0.4917%), PECO (81.1039%), ECP (0.3613%), PSEG (12.9553%), and RECO (0.5118%). Note that the zonal charges are further allocated based on network service peak load contributions within the applicable zone.	***Generation Deactivation Charge Summary*** ***Generation Deactivation Refund Charge Summary***