Duke Energy Kentucky
Case No. 2014-00454
Staff Second Set Data Requests
Date Received: March 11, 2015

STAFF-DR-02-012

REQUEST:

Refer to Duke Kentucky's response to Item 38 of the February 5, 2015 Request.

a. Stating that the only PJM charges/credits taken directly from the invoice and included in the FAC calculations are the native portion of billing line items 2370 and 2375, Duke Kentucky did not provide the amounts by month included in the FAC for the other billing line items. Provide the amounts or explain in detail why it is not possible to provide by month PJM amounts included in the FAC calculation by billing line item.

b. Describe in detail PJM billing line item 2210 and explain why Duke Kentucky does not also include this billing line item in the calculation of the FAC, given its inclusion of PJM billing line item 1210.

c. Describe in detail PJM billing line item 2220 and explain why Duke Kentucky does not also include this billing line item in the calculation of the FAC, given its inclusion of PJM billing line item 1220.

d. Describe in detail the following PJM billing line items and explain why each is not includable in the calculation of the FAC: 2217, 1218, 2218, 1230, 1245, 2245, 1250, 1420, 2420, 1260, 2260, and 1375.

e. By month for each PJM billing line item listed in subparts b., c., and d. above, provide the amount charged or credited to Duke Kentucky by PJM from

November 1, 2012, to the most current month available and, if different, the amount that would have been included in the calculation of the FAC if the items were found to be includable by the Commission.

f. State whether Duke Kentucky believes that the PJM billing line items included in the FAC should be the same across all Kentucky jurisdictional utilities that are members of PJM. If not, explain why the Commission should allow differences in those includable in the FAC.

RESPONSE:

a. The amounts of purchased power included in the FAC do not tie specifically to any PJM billing line items. An internal calculation is completed, using hourly information, to calculate the amount of purchase power attributable to the native load customer. This amount is essentially contained within PJM billing line items # 1200, 1205, 1210, 1215, 1220, and 1225, which equates to the day-ahead and real-time components of LMP for a given time period. These PJM billing line items are ***NET*** monthly amounts on the invoice for 100% of the generation sold and 100% load purchased. Furthermore, the asset energy revenues reported in the PSM and the purchase power reported on the FAC are part of these billing line items along with the congestion and losses which are the difference in LMP between native generation and native load as discussed in Staff-DR-02-006.

b. PJM billing line item 2210, or the Transmission Congestion credit, is not credited to the FAC because the cost that this is meant to offset is also not included in the FAC. The cost that this is meant to offset is the congestion cost incurred due to the difference in LMPs between the native load bus and the native generation bus as discussed in Staff-DR-02-006. In order to factor the congestion credit in the FAC, the corresponding congestion cost must also be included in the FAC.

c. PJM billing line item 2220, or the Transmission Losses credit, is not credited to the FAC because the corresponding cost that this is meant to offset is also not included in the FAC. This credit corresponds to transmission losses charged to Duke Energy Kentucky and, because such charges are not included in the FAC, the credit is likewise excluded from the FAC.

d. PJM billing line items # 2217, 1218, 2218, 1230, 1245, 2245, 1250, 1420, 2420, 1260, 2260, and 1375 are not included in Duke Energy Kentucky's FAC because the order in Case No. 2006-00172 approved a test year revenue requirement that included certain RTO costs, except for the purchased power costs as determined by the after the fact costing model. Some of the charges/credits included in the test year revenue requirement and, consequently, in base rates are (1) the congestion and losses which are the difference in the LMP between the native load and the native generation; (2) charges and credits related to the settlement of financial congestion management held by market participants; (3) charges and credits related to certain uplift costs that are socialized and collected from market participants; and (4) other miscellaneous charges, costs, and credits.

See Staff-DR-02-012(d) Attachment for a detailed explanation of these PJM billing line items. The Customer Guide to PJM billing is a PJM document explaining in detail the charges and credits included on the PJM invoice.

CUSTOMER GUIDE TO PJM BILLING			
Charge	**Credit**	**Description**	
	2217	Planning Period Excess Congestion	Page 2
1218		Planning Period Congestion Uplift	Page 3
	2218	Planning Period Congestion Uplift	Page 3
1230		Inadvertent Interchange	Page 4
1245		Pre-Emergency and Emergency Load Response	Page 4
	2245	Pre-Emergency and Emergency Load Response	Page 4
1250		Meter Error Correction	Page 4
1420		Load Reconciliation for Transmission Losses	Page 4
	2420	Load Reconciliation for Transmission Losses	Page 4
1260		Emergency Energy	Page 4
	2260	Emergency Energy	Page 4
1375		Balancing Operating Reserve	Page 9

e. See attachment Staff-DR-02-012(e) for the monthly amounts per the PJM invoice from November 1, 2012, to the most current month available for the billing line items listed in subparts b., c., and d.

If the items were found to be includable by the Commission in the FAC, it would also have to be determined if there are any additional charges or credits which should be included due to the interrelationship between the ones chosen to be in the FAC and the related billing line items not examined. The next step would be to allocate each item between native and non-native and then to calculate how much should be included in the FAC and how much should be included in the PSM.

f. Duke Energy Kentucky believes the same type of costs should be included in the FAC regardless if whether a utility is a member of a RTO or is its own balancing authority. In order to fairly accomplish this, the same types of costs need to be included in the base rates for each utility and each utility would also need the same rider recovery mechanisms, including profit sharing mechanisms, transmission riders, etc., for the charges and credits. In any event, the costs prudently incurred by each utility to serve native load should be fully recovered through some combination of base rates, FAC, PSM, or other riders.

RTO costs associated with the energy market that were known at the time of the Company's last base rate case, Case No. 2006-00172, except for purchased power costs as determined by the after-the-fact costing model and native portion of make-whole revenues, were included in the Company's test year and are currently reflected in base rates.

PERSON RESPONSIBLE: John Swez/Scott Burnside/Lisa Steinkuhl

CUSTOMER GUIDE TO PJM BILLING

- Billing Line Items include PJM Open Access Transmission Tariff (OATT) references, PJM Operating Agreement (OpAgr) references, and PJM Manual 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 7.8 Manual 27, Section 5)	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. ***Charges:*** 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. ***Credits:*** 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* *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 7.8 Manual 27, Section 6)	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. ***Charges:*** 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. ***Credits:*** 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 Manual 27, Section 6)	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. ***Charges:*** 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. ***Credits:*** 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. ***Charges:*** 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. ***Credits:*** 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 Manual 28, Section 3)	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. ***Day-ahead Charges:*** 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. ***Balancing Charges:*** 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. ***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.	***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 Manual 28, Section 8)	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. ***Day-ahead Charges:*** 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). ***Balancing Charges:*** 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). ***Credits:*** 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 and NYISO 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. ***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 congestion price on a two-month billing lag.	***Transmission Congestion Charge Summary*** ***Explicit Congestion Charges*** ***Implicit Congestion and Loss Charge Details*** ***FTR Target Credits*** ***Hourly Transmission Congestion Credits*** ***Congestion and Loss Load Recon Charges*** ***Congestion Uplift Charge Summary*** ***Network ARR Target Credit Summary*** ***Cross-Monthly Congestion Credit Summary***

Planning Period Congestion Uplift (OpAgr Schedules 5.2.5 & 5.2.6 Manual 28, Section 8)	For planning years in which the sum of actual Transmission Congestion credits paid to FTR holders during the planning year was less than the sum of their FTR Targets, Planning Period Congestion Uplift credits are awarded to the FTR holders at the end of the planning year (May) to completely fulfill those remaining FTR Target deficiencies. Planning Period Congestion Uplift credits and Planning Period Congestion Uplift charges can only occur at the end of the Annual Planning Period (which runs from June 1st through May 31st), so they will only apply to May monthly billing statements. The "Planning Period Congestion Uplift credit" is a "make-whole" congestion credit to FTR holders to satisfy any previously unfulfilled FTR Target Credits that remain at the end of the planning year. A summary of FTR Targets and all applicable Congestion Credits broken down by month can be viewed in the "Cross-Monthly Congestion Credit Summary" report in MSRS. Select the "All Billed" option for the period from 6/1/12 through 5/31/13 to see the complete set of details. The "Planning Period Congestion Uplift charge" is the participant's share of the allocated costs of providing the Uplift credits. Charges are allocated to FTR holders in proportion to their net positive total FTR Target Credits for the planning year. Details of this charge allocation can be viewed in the "Congestion Uplift Charge Summary" report in MSRS. The calculation for the Uplift charge is: (positive FTR Target credit / Total PJM Positive FTR Target Credit) * PJM Total FTR and ARR Uplift Credit. The uplift process is also outlined in Manual 28, sections 8.1 and 8.4.4	***Congestion Uplift Charge Summary*** ***Cross-Monthly Congestion Credit Summary***

Billing Line Item	Description	Reports
Transmission Losses (OpAgr Schedules 1-3.2.5, 3.4.2, & 5.4-5.5 Manual 28, Section 9)	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 Manual 28, Section 18)	***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 Manual 28, Section 11)	***Credits:*** Day-ahead and real-time economic and real-time pre-emergency and 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 pre-emergency and 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 Manual 28, Section 12)	***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 Manual 28, Section 10)	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 Manual 27, Section 2)	***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 – 2015 rate of $0.1692/MWh (with $0.0 refund rate for Jan-Mar) 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 – 2015 rate of $0.0025/FTR MWh (with $0.0/FTR MWh refund for Jan-Mar) charged to FTR holders based on FTR MW and hours each FTR is in effect (regardless of congested hours and dollar value of FTR). 2015 rate of $0.0017/bid-hour (with $0.0 refund rate for Jan-Mar) 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 – 2015 rate of $0.0373/MWh (with $0.0 refund rate for Jan-Mar) 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. 2015 rate of $0.0558 (with $0.0 refund rate for Jan-Mar) is charged for each energy bid/offer segment price/quantity pair submitted, including those submitted during the rebidding period. Regulation and Frequency Response Administration – 2015 rate of $0.2271/Regulation MWh (with $0.0 refund rate for Jan-Mar) charged to customers based on regulation obligation and regulation provided. Capacity Resource and Obligation Management – 2015 rate of $0.0864/MW-day (with $0.0 refund rate for Jan-Mar) 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 –Jan-Mar 2015 rate of $0.0044/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 Manual 27, Section 2.2)	***Charges:*** Jan-Mar 2015 rate of $0.0044/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 Manual 27, Section 2)	***Charges:*** Preliminary 2015 rate of $0.00475/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. Preliminary 2015 rate of $0.00454 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 Manual 27, Section 2)	***Charges:*** 2015 rate of $0.0670/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 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 Manual 27, Section 2)	***Charges:*** Preliminary 2015 rate of $0.00075/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 Manual 27, Section 2)	***Charges:*** 2015 rate of $0.0118/MWh charged to transmission customers based on their energy delivered to load in the PJM Region, excluding load in the Dominion and East Kentucky Power Cooperative zones. 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 Manual 27, Section 2)	***Charges:*** 2015 rate of $0.0192/MWh charged to transmission customers based on their energy delivered to load in the PJM Region, excluding load in the Dominion and East Kentucky Power Cooperative zones. 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 Manual 27, Section 2)	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 $0.0912/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 Manual 27, Section 3)	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 Manual 28, Section 4)	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 (with consideration of the resource's performance) priced at the regulation market capability clearing price. Generators and demand resources receive hourly credits for pool- and self-scheduled regulation (with consideration of the resource's performance and 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)) priced at the regulation market performance clearing prices. 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 regulation supplied excluding mileage (adjusted for any bilateral regulation transactions). PJM LSEs also have an hourly regulation mileage obligation equal to their adjusted obligation ratio share of the mileage component of the regulation supplied. Hourly charges calculated as adjusted obligations times the regulation market capability and performance clearing prices and the regulation mileage obligation times the regulation market performance clearing price. 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 Manual 28, Section 6)	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. ***Credits:*** Generators that increase output and demand resources that decrease consumption in response to a synchronized reserve event when non-synchronized reserve clearing prices are zero receive Tier 1 credits equal to response MWh times synchronized reserve energy premium less its hourly LMP. During hours when the non-synchronized reserve clearing price is non-zero resources receive Tier 1 credits equal to the lesser of the response MWh or the Tier 1 estimate times the applicable reserve zone's Synchronized Reserve Market Clearing Price. 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. ***Charges:*** PJM LSEs that are not part of an agreement to share reserves with external entities 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. ***Reconciliation Charges:*** 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 Synchronized Reserve 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*
Non-Synchronized Reserve (OpAgr Schedules 1-3.2.3A.001 & 3.3.5A Manual 28, Section 7)	PJM conducts non-synchronized reserve markets to ensure the capability of generation off-line and available to provide energy within ten minutes as necessary to meet the primary reserve requirement. ***Credits:*** Hourly credits provided to generation resources supplying non-synchronized reserve at the Non-Synchronized Reserve Clearing Price. Additional credits provided to non-synchronized reserve resources for any portion of non-synchronized reserve opportunity costs not recovered via Non-Synchronized Reserve Market Clearing Price revenues. ***Charges:*** PJM LSEs that are not part of an agreement to share reserves with external entities have an hourly non-synchronized reserve obligation equal to their real-time load (without losses) ratio share of their reserve market's total non-synchronized reserve supplied (adjusted for any bilateral non-synchronized reserve transactions). Hourly charges calculated as adjusted obligations times the Non-Synchronized Reserve Market Clearing Price. Additional charges are assessed for any unrecovered cost payments that PJM provides to non-synchronized reserve suppliers based on adjusted obligation 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 applicable reserve zone's $/MWh billing determinant calculated as the total applicable reserve zone Non-Synchronized Reserve charges divided by the total MWh of PJM real-time load served in the that market on a two-month billing lag.	*Non-Synchronized Reserve Summary* *Non-Synchronized Reserve Credits* *Non-Synchronized Reserve Load Recon Charge Summary*
Day-ahead Scheduling Reserve (OpAgr Schedules 1-3.2.3A.01 and OATT Schedule 6 Manual 28, Section 19)	PJM conducts day-ahead scheduling reserve markets to ensure the capability of generation and demand resources to meet reserve requirements on a forward basis. ***Credits:*** 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. ***Charges:*** 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. ***Reconciliation Charges:*** 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 Manual 28, Section 5 and Section 11)	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 plus opportunity cost; (5) any synchronized reserve market revenues in excess of offer plus opportunity, energy use, and startup costs; (6) any non-synchronized reserve market revenues in excess of opportunity costs and (7) 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 excluding the total cost for resources scheduled to provide Black Start Service, Reactive Services or transfer interface control 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 Manual 28, Section 5)	***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 Manual 28, Section 5)	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 and the total day-ahead Operating Reserve credits for resources scheduled to provide Reactive Services or transfer interface control 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 Manual 27, Section 7)	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 and day-ahead and balancing Operating Reserve credits associated with scheduling resources for black start service or testing 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 and day-ahead and balancing Operating Reserve credits associated with scheduling resources for black start service or testing 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 Manual 28, Section 16)	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 Manual 28, Section 17)	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 Manual 18, Section 9.3)	***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* *RPM Auction Charges* *RPM Auction Credits*
Locational Reliability (OATT Att. DD, Section 5.14 Manual 18, Section 9.2)	***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*
Capacity Transfer Rights (OATT Att. DD, Section 5.15 Manual 18, Section 9.3)	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, OATT Schedule 12A (b) Manual 18, Section 9.3)	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. Incremental CTRs for Incremental-Rights Eligible Required Transmission Enhancements are determined and allocated as defined in Schedule 12A of the Tariff. ***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 determined for an Incremental-Rights Eligible Required Transmission Enhancement are allocated to the responsible customers that are assigned cost responsibility for the transmission enhancements in accordance with the cost allocations in the appendix to Schedule 12. Responsible customers include Network customers, Transmission Customers with an agreement for Firm Point-to-Point Service, or Merchant Transmission Facility Owners. Network customers serving load in a responsible zone receive credits in proportion to their network service peak load share in that zone.	*Incremental CTR Credits* *Incremental CTR for Required Transmission Enhancement Credits*
Auction Specific MW Transaction (OATT Att. DD, Section 5.14 Manual 18, Section 9.3)	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 Compliance Penalty (OATT Att. DD, Section 11 Manual 18, Section 9.1)	Sellers with zonal aggregate committed Demand Resources that cannot demonstrate hourly real-time performance pay a penalty charge which is allocated to Demand Resource 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, weighted by the MWs cleared 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 Resources 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 and ILR Compliance Penalty Ch and Cr*** ***DR and ILR Compliance Penalty Residual Credit Summary***

Billing Line Item	Description	Reports
Capacity Resource Deficiency (OATT Att. DD, Section 8 Manual 18, Section 9.1)	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 Manual 18, Section 9.1)	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 Manual 18, Section 9.1)	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 Manual 18, Section 9.1)	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 Manual 18, Section 9.1)	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 Manual 18, Section 9.1)	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 AEP Zone pay AEP (expected to end May 2020). ***Charges:*** Monthly charges to AEP zonal network customers are calculated based on network service peak load contributions at a 2015 rate of $96.7615/MW/year.	*RTO Startup Cost Recovery Charge Summary*
Expansion Cost Recovery (OATT Schedule 13 Manual 27, Section 8)	All network customers (except those in the Dominion, Duke, EKPC and ATSI Zones) pay AEP, ComEd, and Dayton to recover their integration expenses. This charge is expected to continue through April 2015. ***Charges:*** For 2015, $5.42/MW-month of peak load is charged to all network customers serving load in the AEP, ComEd, and Dayton zones and $2.65/MW-month is charged in all other zones, except Dominion, Duke, ATSI and EKPC. ***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 Manual 28, Section 14)	***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 Manual 28, Section 15)	***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*
Michigan-Ontario Interface Phase Angle Regulators (OATT Schedule 10)	Schedule 10 recovers the costs allocated to PJM from MISO for a portion of the revenue requirement associated with the ITC Transmission's Phase Angle Regulators (PARs) on the Michigan-Ontario Interface. ***Charges:*** PJM charges each customer using Network Integration and Point-to-Point Transmission Service under this Tariff each month a charge equal to the ITC PARs Rate times the total quantity in MWhs of energy delivered to the load (including losses) that such customer serves in the PJM Region for the month in which the ITC PARs Rate is being calculated.	*Schedule 10 Michigan-Ontario PAR Charges*
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 the First Energy resource Ashtabula 5 based on a Cost of Service Recovery Rate which is ending in May 31, 2015. The monthly charges are allocated on a one-month lag in accordance with the following study results: http://www.pjm.com/~/media/planning/gen-retire/2012-2015-zonal-cost-allocation-for-retaining-ashtabula-east-lake-and-lake-shore-generators.ashx. Based on PJM's assessment of the contribution to the need for, and benefits expected to be derived from, the facilities, the zonal percentage cost allocation for September 1, 2012 through May 31, 2015 timeframe is: ATSI (93.80%), DUQ (2.54%), PENELEC (2.09%), and DOM (1.57%). 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.	*Generation Deactivation Charge Summary* *Generation Deactivation Refund Charge Summary*
Deferred Tax Adjustment (OATT Attachments H-8A and H-17C)	***Charges:*** Each Network Customer that serves one or more end-use customers taking distribution service from PPL Electric Utilities Corporation or from Duquesne Light Company under its applicable retail tariff on file with the Pennsylvania Public Utility Commission ("PPL Electric Distribution Customers" and/or "Duquesne Electric Distribution Customers") shall pay a Monthly Deferred Tax Adjustment Charge. This charge permits PPL Electric and Duquesne Light to recover a deferred income tax liability that is currently unfunded due to a Pennsylvania Public Utility decision to flow-through to customers certain income tax benefits.	*Deferred Tax Adjustment Charge Summary*

Duke Energy Kentucky

PJM Billing Statement Line Items

ID #	Description	Nov 2012	Dec 2012	Jan 2013	Feb 2013	Mar 2013	Apr 2013	May 2013	Jun 2013	Jul 2013	Aug 2013	Sep 2013	Oct 2013	Nov 2013	Dec 2013
	Charges														
1218	Planning Period Congestion Uplift	2.40	0.00	0.00	0.00	0.00	0.00	353,345.01	(11.67)	(604.55)	(1,283.80)	0.00	134.27	3.13	(7.78)
1230	Inadvertent Interchange	4,658.57	(264.43)	2,571.40	(644.74)	(1,874.16)	(3,156.10)	(1,727.58)	(3,395.08)	(6,118.25)	(4,106.75)	(5,524.54)	(4,572.60)	(6,252.20)	(7,271.93)
1245	Emergency Load Response	4,983.35	0.00	3,698.58									106,152.67	1,172.87	(38,455.53)
1250	Meter Error Correction	941.11	5,302.46	(2,050.35)	14.73	94.03	(811.87)	1,981.45	1,530.54	95.15	(25.51)	(527.61)	46.10	208.06	1,980.44
1260	Emergency Energy	0.00	0.00	64,575.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1375	Balancing Operating Reserve	49,063.10	67,048.30	112,972.67	42,410.20	36,663.24	57,123.88	90,843.87	103,381.01	175,772.75	55,212.94	93,436.30	30,069.82	47,992.84	82,624.40
1420	Load Reconciliation for Transmission Losses	(154.08)	(115.08)	(361.06)	(2,607.32)	(4,925.32)	(3,186.05)	(10,439.63)	(8,627.81)	(2,843.67)	180.92	333.59	24.33	0.00	(169.86)

+ number is an expense; - number is a revenue

ID #	Description	Nov 2012	Dec 2012	Jan 2013	Feb 2013	Mar 2013	Apr 2013	May 2013	Jun 2013	Jul 2013	Aug 2013	Sep 2013	Oct 2013	Nov 2013	Dec 2013
	Credits														
2210	Transmission Congestion	100,448.19	28,809.11	(23,585.97)	29,907.58	36,753.61	23,063.59	(686.56)	709.70	(2,207.34)	39,560.81	126,873.92	39,794.05	48,877.45	42,885.53
2217	Planning Period Excess Congestion													0.00	
2218	Planning Period Congestion Uplift	12.29	0.00	0.00	0.00	0.00	0.00	511,733.45	(2.14)	(3,195.31)	(422.17)	0.00	454.81	0.71	(1.60)
2220	Transmission Losses	141,078.16	127,487.43	200,930.09	167,679.84	160,554.07	104,815.06	88,855.13	150,738.39	276,303.09	175,404.26	157,105.10	125,169.01	120,760.99	177,774.35
2245	Emergency Load Response														
2260	Emergency Energy	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2420	Load Reconciliation for Transmission Losses	12.46	66.07	35.30	558.60	1,249.03	788.35	2,243.32	2,221.74	661.95	(34.28)	(35.50)	(11.07)	0.00	(15.18)

+ number is a revenue; - number is an expense

Duke Energy Kentucky

PJM Billing Statement Line Items

ID #	Description	Jan 2014	Feb 2014	Mar 2014	Apr 2014	May 2014	Jun 2014	Jul 2014	Aug 2014	Sep 2014	Oct 2014	Nov 2014	Dec 2014	Jan 2015	Feb 2015
	Charges														
1218	Planning Period Congestion Uplift	(367.39)	(2,889.73)		2,629.71	322,367.81	135.70	(1,172.42)	(0.04)	(163.92)		1,216.89	651.90	1,278.26	
1230	Inadvertent Interchange	(5,499.39)	(15,541.68)	(16,134.59)	(657.04)	1,797.36	7,881.64	3,696.54	2,789.02	4,233.34	421.06	(2,235.73)	(1,667.39)	4,698.28	15,224.83
1245	Emergency Load Response		(800.23)	185,819.12	570.82	18,591.96				(144.89)	(278.18)				
1250	Meter Error Correction	22.67	(156.73)	(308.69)	39.52	(5.84)	(685.79)	10,646.31	7,252.35	(7.56)	(93.42)	(307.82)	(19.32)	(28.79)	14.95
1260	Emergency Energy	390.34													
1375	Balancing Operating Reserve	2,097,771.30	52,198.28	1,239,033.85	67,020.18	105,641.51	80,582.38	40,510.09	38,954.21	59,666.50	19,087.31	23,345.85	29,807.03	62,392.81	202,885.97
1420	Load Reconciliation for Transmission Losses	(225.78)	(967.26)	380.48	(1,595.89)	(4,197.55)	61.26	(87.87)	97.31	(11,238.48)	(1,631.24)	560.95	146.08	54.24	(110.77)

+ number is an expense; - number is a revenue

ID #	Description	Jan 2014	Feb 2014	Mar 2014	Apr 2014	May 2014	Jun 2014	Jul 2014	Aug 2014	Sep 2014	Oct 2014	Nov 2014	Dec 2014	Jan 2015	Feb 2015
	Credits														
2210	Transmission Congestion	368,606.21	119,559.79	36,132.58	(2,981.49)	41,257.79	567,417.59	280,580.67	422,158.96	234,201.73	18,353.96	61,945.49	343,291.07	679,672.00	1,434,828.63
2217	Planning Period Excess Congestion														
2218	Planning Period Congestion Uplift	(1,236.21)	(9,948.13)		1,434.69	349,694.67	(23.63)	(748.37)	(0.01)	(17.51)		685.35	756.27	1,544.73	1,740.51
2220	Transmission Losses	796,119.75	343,271.94	294,086.56	96,659.52	124,444.50	178,905.72	166,043.08	147,956.07	140,206.74	138,058.55	153,083.15	141,751.11	218,769.88	419,318.97
2245	Emergency Load Response			79,960.51		1,571.72									
2260	Emergency Energy	1,964.33	(1,964.33)												
2420	Load Reconciliation for Transmission Losses	12.77	172.98	(176.90)	327.59	718.76	23.41	137.07	(33.70)	2,390.33	558.37	(102.23)	(63.73)	(24.56)	26.61

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