Congestion and Marginal Losses

The Locational Marginal Price (LMP) is the incremental price of energy at a bus. The LMP at any bus is made up of three components: the system marginal price (SMP), the marginal loss component of LMP (MLMP), and the congestion component of LMP (CLMP).

SMP, MLMP and CLMP are a product of the least cost, security constrained dispatch of system resources to meet system load. SMP is the incremental cost of energy, given the current dispatch, ignoring losses and congestion. Losses refer to energy lost to physical resistance in the transmission and distribution network as power is moved from generation to load. Marginal losses are the incremental change in system power losses caused by changes in the system load and generation patterns. Congestion occurs when available, least-cost energy cannot be delivered to all loads for a period because transmission facilities are not adequate to deliver that energy. When the least-cost available energy cannot be delivered to load in a transmission-constrained area, higher cost units in the constrained area must be dispatched to meet that load.[1] The result is that the price of energy in the constrained area is higher than in the unconstrained area because of the combination of transmission limitations and the cost of local generation.

Congestion is neither good nor bad but is a direct measure of the extent to which there are differences in the cost of generation that cannot be equalized because of transmission constraints.

The components of LMP are the basis for determining participant and location specific congestion and marginal losses. The Market Monitoring Unit (MMU) analyzed marginal losses and congestion in PJM markets for 2011.

1 This is referred to as dispatching units out of economic merit order. Economic merit order is the order of all generator offers from lowest to highest cost. Congestion occurs when loadings on transmission facilities mean the next unit in merit order cannot be used and a higher cost unit must be used in its place.

Overview

Marginal Loss Cost

Before June 1, 2007, the PJM economic dispatch and LMP models did not include marginal losses. The losses were treated as a static component of load, and the physical nature and location of power system losses were ignored. The PJM Tariff required implementation of marginal loss modeling when required technical systems became available. On June 1, 2007, PJM began including marginal losses in economic dispatch and LMP models.[2] The primary benefit of a marginal loss calculation is that it more accurately models the physical reality of power system losses, which permits increased efficiency and more optimal asset utilization. Marginal loss modeling creates a separate marginal loss price for every location on the power grid. This marginal loss price (MLMP) is a component of LMP that is charged to load and credited to generation. Total network losses are determined by using a linearized approximation model based on the loss sensitivities to location-specific changes in power injection and withdrawal. Average losses are then calculated from total losses.

Total marginal loss costs equal net marginal loss costs plus explicit marginal loss costs plus net inadvertent loss costs. Net marginal loss costs equal load loss payments minus generation loss credits. Explicit marginal loss costs are the net marginal loss costs associated with point-to-point energy transactions. Net inadvertent loss costs are the losses associated with hourly difference between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area in that hour.[3] Unlike the other categories of marginal loss accounting, inadvertent loss costs are common costs not directly attributable to specific participants. Inadvertent related loss costs are distributed to load on a load ratio basis. Each of these categories of marginal loss costs is comprised of day-ahead and balancing marginal loss costs. Day-ahead marginal loss costs are based on day-ahead MWh priced at the marginal loss price component of Locational Marginal Price (LMP) while balancing marginal loss costs are based on deviations between day-ahead and real-time MWh priced at the marginal loss price component of Locational Marginal Price (LMP) in the Real-Time Energy Market.

2 For additional information, see OATT Section 3.4.
3 OA. Schedule 1 (PJM Interchange Energy Market) §3.7

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Marginal loss charges can be positive or negative with respect to the reference bus. If an increase in load at a bus would decrease losses, the marginal loss component of LMP of that bus will be negative. If an increase in generation at a bus would result in an increase in losses, the marginal loss component of that bus will be negative. If an increase of load at a bus would increase losses, the marginal loss component of LMP at that bus will be positive. If an increase in generation at a bus results in a decrease of system losses, then the marginal loss component of LMP at that bus will be positive.

Day-ahead marginal loss charges and credits are based on MWh and LMP in the Day-Ahead Energy Market. Balancing marginal loss charges and credits are based on the load or generation deviations between the Day-Ahead and Real-Time Energy Markets and LMP in the Real-Time Energy Market. If a participant has real-time generation or load that is greater than its day-ahead generation or load then the deviation will be positive. If there is a positive load deviation at a bus where the real-time LMP has a positive marginal loss component, positive balancing marginal loss costs will result. Similarly, if there is a positive load deviation at a bus where real-time LMP has a negative marginal loss component, negative balancing marginal loss costs will result. If a participant has real-time generation or load that is less than its day-ahead generation or load then the deviation will be negative. If there is a negative load deviation at a bus where real-time LMP has a positive marginal loss component, negative balancing marginal loss costs will result. Similarly, if there is a negative load deviation at a bus where real-time LMP has a positive marginal loss component, negative balancing marginal loss costs will result.

Marginal loss credits or loss surplus is the remaining loss amount from overcollection of marginal losses, after accounting for net energy charges and residual market adjustments, that is paid back in full to load and exports on a load ratio basis. Marginal loss credits are calculated as the day-ahead and balancing transmission loss charges paid by all customer accounts each hour, plus the spot market energy value of the actual transmission loss MWh during that hour, plus residual net market adjustments in that hour.[4] Residual net market adjustments are common costs, not directly attributable to specific participants, that are deducted from total marginal loss credits before marginal loss credits are distributed on a load weighted ratio basis. Residual market adjustments consist of the Known Day-Ahead Error Value (KDAEV), day-ahead loss MW congestion value and balancing loss MW congestion value. KDAEV are costs associated with MW imbalances created by discontinuities in, and adjustments to, the day-ahead market solution. The day-ahead and balancing loss congestion values are congestion costs associated with loss related MW.

- **Total Marginal Loss Costs.** Total marginal loss charges decreased by $255.3 million or 15.6 percent, from $1,634.8 million in 2010 to $1,379.5 million in 2011. Day-ahead marginal loss costs decreased by $235.1 million or 14.1 percent, from $1,665.6 million in 2010 to $1,430.5 million in 2011. Balancing marginal loss costs decreased by $20.3 million or 65.9 percent from -$30.7 million in 2010 to -$51.0 million in 2011. On June 1, 2011, PJM integrated the American Transmission Systems, Inc. (ATSI) Control Zone. The metrics reported in this section treat ATSI as part of MISO for the period from January through May and as part of PJM for the period from June through December.

- **Monthly Marginal Loss Costs.** Fluctuations in monthly marginal loss costs continued to be substantial. In 2011, these differences were driven by varying load and energy import levels, different patterns of generation and weather-induced changes in demand. Monthly marginal loss costs in 2011 ranged from $70.6 million in December to $213.7 million in July.

- **Marginal Loss Credits.** Marginal Loss Credits are calculated as total net energy charges (total energy charges minus total energy credits) plus total net marginal loss charges (total marginal loss charges minus total marginal loss credits plus inadvertent and residual net market adjustments). Marginal loss credit or loss surplus is the remaining loss amount from overcollection of marginal losses, after accounting for net energy charges and residual market adjustments that is paid back in full to load and exports on a load ratio basis. The marginal loss

4 See PJM. "Manual 28: Operating Agreement Accounting," Revision 39 (January 1, 2008). Note that the over collection is not calculated by subtracting the prior calculation of average losses from the calculated total marginal losses.

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credits decreased by $250 million or 29.9 percent, from $836.7 million in 2010 to $586.7 million in 2011.

- **Zonal marginal loss costs.** In 2011, zonal marginal loss costs ranged from $3.2 million in RECO to $318.6 million in AEP. Compared to 2010, 2011 had a decrease in marginal loss costs across the PJM control zones, except PECO and DAY control zones. Total marginal loss costs in PJM in 2011 also changed due to the addition of the ATSI Control Zone, which accounted for $19.3 million or 1.4 percent of the total marginal loss costs.[5]

Congestion Cost

Total congestion costs equal net congestion costs plus explicit congestion costs plus net inadvertent congestion costs. Net congestion costs equal load congestion payments minus generation congestion credits. Explicit congestion costs are the net congestion costs associated with point-to-point energy transactions. Net inadvertent congestion costs are the congestion costs associated with hourly difference between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area in that hour. Unlike the other categories of congestion cost accounting, inadvertent congestion costs are common costs not directly attributable to specific participants. Inadvertent related congestion costs are distributed to load on a load ratio basis. Each of these categories of congestion costs is comprised of day-ahead and balancing congestion costs. Day-ahead congestion costs are based on day-ahead MWh while balancing congestion costs are based on deviations between day-ahead and real-time MWh priced at the congestion price in the Real-Time Energy Market.

Congestion charges can be both positive and negative. When a constraint binds, the price effects of that constraint vary. The system marginal price (SMP) is uniform for all areas, while the congestion components of Locational Marginal Price (LMP) will either be positive or negative in a specific area, meaning that actual LMPs are above or below the SMP.[6] If an area is downstream from the constrained element, the area will experience positive congestion costs. If an area is upstream from the constrained element, the area will experience negative congestion costs.

Day-ahead congestion charges and credits are based on MWh and LMP in the Day-Ahead Energy Market. Balancing congestion charges and credits are based on load or generation deviations between the Day-Ahead and Real-Time Energy Markets and LMP in the Real-Time Energy Market. If a participant has real-time generation or load that is greater than its day-ahead generation or load then the deviation will be positive. If there is a positive load deviation at a bus where real-time LMP has a positive congestion component, positive balancing congestion costs will result. Similarly, if there is a positive load deviation at a bus where real-time LMP has a negative congestion component, negative balancing congestion costs will result. If a participant has real-time generation or load that is less than its day-ahead generation or load then the deviation will be negative. If there is a negative load deviation at a bus where real-time LMP has a positive congestion component, negative balancing congestion costs will result. Similarly, if there is a negative load deviation at a bus where real-time LMP has a positive congestion component, negative balancing congestion costs will result.

- **Total Congestion.** Total congestion costs decreased by $425.4 million or 29.9 percent, from $1,423.6 million in 2010 to $998.2 million in 2011.[7] Day-ahead congestion costs decreased by $468.2 million or 27.3 percent, from $1,713.1 million in 2010 to $1,244.9 million in 2011. Balancing congestion costs increased by $42.8 million or 14.8 percent from -$289.5 million in 2010 to -$246.7 million in 2011. On June 1, 2011, PJM integrated the American Transmission Systems, Inc. (ATSI) Control Zone. The metrics reported in this section treat ATSI as part of MISO for the period from January through May and as part of PJM for the period from June through December.

- **Monthly Congestion.** Fluctuations in monthly congestion costs continued to be substantial. In 2011, these differences were driven by varying load and energy import levels, different patterns

5 See the *2011 State of the Market Report for PJM*, Volume II, Appendix G, "Congestion and Marginal Losses," at "Zonal Marginal Loss Costs."

6 The SMP is the price of the distributed load reference bus. The price at the reference bus is equivalent to the five minute real-time or hourly day-ahead load weighted PJM LMP.

7 The total zonal congestion numbers were calculated as of March 2, 2012 and are, based on continued PJM billing updates, subject to change.

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of generation, weather-induced changes in demand and variations in congestion frequency on constraints affecting large portions of PJM load. Monthly congestion costs in 2011 ranged from $35.0 million in May to $241.6 million in January.

- **Congestion Component of Locational Marginal Price (LMP).** To provide an indication of the geographic dispersion of congestion costs, the congestion component of LMP (CLMP) was calculated for control zones in PJM. Price separation among eastern, southern and western control zones in PJM was primarily a result of congestion on the AP South interface, the 5004/5005 interface, the Belmont transformer, West Interface, and the AEP-Dominion interface. (Table 10-27)

- **Congested Facilities.** Congestion frequency continued to be significantly higher in the Day-Ahead Market than in the Real-Time Market in 2011.[8] Day-ahead congestion frequency increased by 45.8 percent from 106,253 congestion event hours in 2010 to 154,868 congestion event hours in 2011. Day-ahead, congestion-event hours decreased on internal PJM interfaces while congestion-event hours increased on transmission lines, transformers and reciprocally coordinated flowgates between PJM and the MISO.

  Real-time congestion frequency decreased by 0.4 percent from 23,422 congestion event hours in 2010 to 22,468 congestion event hours in 2011. Real-time, congestion-event hours decreased on the internal PJM interfaces and transmission lines, while congestion-event hours increased on transformers and reciprocally coordinated flowgates between PJM and MISO.

  Facilities were constrained in the Day-Ahead Market more frequently than in the Real-Time Market. The Day-Ahead market is consequently more-frequent constrained conditions compared to its corresponding Real-Time Market. During 2011, for only 5.6 percent of Day-Ahead Market facility constrained hours were the same facilities also constrained in the Real-Time Market. During 2011, for 38.0 percent of Real-Time Market facility constrained hours, the same facilities were also constrained in the Day-Ahead Market.

  The AP South Interface was the largest contributor to congestion costs in 2011. With $238.9 million in total congestion costs, it accounted for 23.9 percent of the total PJM congestion costs in 2011. The top five constraints in terms of congestion costs together contributed $466.2 million, or 46.7 percent, of the total PJM congestion costs in 2011. The top five constraints were the AP South interface, the 5004/5005 interface, West interface, the Belmont transformer and the AEP – Dominion interface.

- **Zonal Congestion.**[9] Measured in terms of the total congestion bill, calculated by subtracting generation congestion credits from load congestion payments plus explicit congestion costs by zone, ComEd was the most congested zone in 2011.[10] ComEd had -$1,007.3 million in total load charges, -$1,277.3 million in total generation credits and -$30.9 million in explicit congestion, providing $239.0 million in total net congestion charges, reflecting significant local congestion between local generation and load, despite being on the upstream side of system wide congestion patterns. The Electric Junction – Nelson transmission line, Crete – St. Johns flowgate (a reciprocally coordinated flowgate between PJM and MISO), AP South interface, East Frankfort – Crete transmission line and the Bunsonville – Eugene flowgate contributed $104.7 million, or 43.8 percent of the total ComEd Control Zone congestion costs.

  Similarly, the AEP Control Zone recorded the second highest congestion cost in PJM in 2011, with $195.1 million. The AP South interface contributed $33.1 million, or 17.0 percent of the total AEP Control Zone congestion cost in 2011. The AP Control Zone recorded the third highest congestion cost in PJM in 2011, with a cost of $143.9 million. The AP South interface contributed $63.9 million, or 44.4 percent of the total AP Control Zone congestion cost in 2011. The control zones in the Western (AEP, AP, ATSI, ComEd, DAY and DLCO) and Southern (Dominion) regions accounted for $737.2 million,

8 In order to have a consistent metric for real-time and day-ahead congestion frequency, real-time congestion frequency is measured using the convention that an hour is constrained if any of its component five-minute intervals is constrained.

9 Tables reporting zonal congestion have been moved from this section of the report to Appendix G. See the *2011 State of the Market Report for PJM*, Volume II, Appendix G, "Congestion and Marginal Losses."

10 The total zonal congestion numbers were calculated as of March 2, 2012 and are, based on continued PJM billing updates, subject to change. As of March 2, 2012, the total zonal congestion related numbers presented here differed from the March 2, 2012 PJM totals by $0.72 Million, a discrepancy of 0.07 percent (.0007).

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or 73.9 percent of congestion cost and the control zones in the Eastern region accounted for $261.0 million or 26.1 percent of congestion cost.

- **Ownership.** In 2011, financial companies as a group were net recipients of congestion credits, and physical companies were net payers of congestion charges. In 2011, financial companies received $108.2 million in net congestion credits, a decrease of $60.3 million or 35.8 percent compared to 2010. In 2011, physical companies paid $1,107.2 million in net congestion charges, a decrease of $484.9 million or 30.4 percent compared to 2010.

Conclusion

Marginal losses are incremental change in real system power losses caused by changes in system load and generation patterns. Total marginal loss costs decreased by $255.3 million or 15.6 percent, from $1,634.8 million in 2010 to $1,379.5 million in 2011. Marginal loss costs were significantly higher in the Day-Ahead Market than the Real-Time Market.

The net marginal loss bill is calculated by subtracting the generation loss credits from the sum of load loss charges, net explicit loss charges and net inadvertent loss charges. Since the net marginal bill is calculated on the basis of marginal, rather than average losses, there is an overcollection of marginal loss related costs. This overcollection, net of total energy charges and residual market adjustments[11], is the source of marginal loss credits. Marginal loss credits are fully distributed back to load and exports. Marginal loss credits were $586.7 million in 2011.

Congestion reflects the underlying characteristics of the power system, including the nature and capability of transmission facilities, the cost and geographical distribution of generation facilities and the geographical distribution of load. Total congestion costs decreased by $425.4 million or 29.9 percent, from $1,423.6 million in 2010 to $998.2 million in 2011. Congestion costs were significantly higher in the Day-Ahead Market than in the Real-Time Market. Congestion frequency was also significantly higher in the Day-Ahead Market than in the Real-Time Market.

ARRs and FTRs served as an effective, but not total, offset against congestion. ARR and FTR revenues offset 96.8 percent of the total congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for the 2010 to 2011 planning period.[12] During the first seven months of the 2011 to 2012 planning period, total ARR and FTR revenues offset more than 100 percent of the congestion costs within PJM. FTRs were paid at 88.1 percent of the target allocation level for the 12-month period of the 2010 to 2011 planning period, and at 84.9 percent of the target allocation level for the first seven months of the 2011 to 2012 planning period.[13] Revenue adequacy, measured relative to target allocations for a planning period is not final until the end of the period.

The congestion metric requires careful review when considering the significance of congestion. The net congestion bill is calculated by subtracting generating congestion credits from load congestion payments. The logic is that increased congestion payments by load are offset by increased congestion revenues to generation, for the area analyzed. Net congestion, which includes both load congestion payments and generation congestion credits, is not a good measure of the congestion costs paid by load from the perspective of the wholesale market.[14] While total congestion costs represent the overall charge or credit to a zone, the components of congestion costs measure the extent to which load or generation bear total congestion costs. Load congestion payments, when positive, measure the total congestion cost to load in an area. Load congestion payments, when negative, measure the total congestion credit to load in an area. Negative load congestion payments result when load is on the lower priced side of a constraint or constraints. For example, congestion across the AP South interface means lower prices in western control zones and higher prices in eastern and southern control zones. Load in western control zones will benefit from lower prices and receive a congestion credit (negative

11 Residual net market adjustments are common costs, not directly attributable to specific participants, that are deducted from total marginal loss credits before marginal loss credits are distributed on a load weighted ratio basis. Residual market adjustments consist of the Known Day-Ahead Error Value (KDAEV), day-ahead loss MW congestion value and balancing loss MW congestion value. KDAEV are costs associated with MW imbalances created by discontinuities in, and adjustments to, the day-ahead market solution. The day-ahead and balancing loss congestion values are congestion costs associated with loss related MWs.

12 See the 2011 *State of the Market Report for PJM* Section 12, "Financial Transmission and Auction Revenue Rights," at Table 12-36, "ARR and FTR congestion hedging: Planning periods 2010 to 2011 and 2011 to 2012.

13 See the *2011 State of the Market Report for PJM* Section 12, "Financial Transmission and Auction Revenue Rights," at Table 12-22, "Monthly FTR accounting summary (Dollars (Millions)): Planning periods 2010 to 2011 and 2011 to 2012"

14 The actual congestion payments by retail customers are a function of retail ratemaking policies and may or may not reflect an offset for congestion credits.

load congestion payment). Load in the eastern and southern control zones will incur a congestion charge (positive load congestion payment). The reverse is true for generation congestion credits. Generation congestion credits, when positive, measure the total congestion credit to generation in an area. Generation congestion credits, when negative, measure the total congestion cost to generation in an area. Negative generation congestion credits are a cost in the sense that revenues to generators in the area are lower, by the amount of the congestion cost, than they would have been if they had been paid LMP without a congestion component, the total of system marginal price and the loss component. Negative generation congestion credits result when generation is on the lower priced side of a constraint or constraints. For example, congestion across the AP South interface means lower prices in the western control zones and higher prices in the eastern and southern control zones. Generation in the western control zones will receive lower prices and incur a congestion charge (negative generation congestion credit). Generation in the eastern and southern control zones will receive higher prices and receive a congestion credit (positive generation congestion credit).

As an example, total congestion costs in PJM in 2011 were $998.2 million, which was comprised of load congestion payments of $112.2 million, negative generation credits of $1,009.9 million and negative explicit congestion of $123.8 million (Table 10-15).

Locational Marginal Price (LMP)

Components

As of June 1, 2007, PJM changed from a single node reference bus to a distributed load reference bus. While there is no effect on the total LMP, the components of LMP change with a shift in the reference bus. With a distributed load reference bus, the energy component is now a load-weighted system price. There are no congestion or losses included in the load weighted reference bus price, unlike the case with a single node reference bus.

Locational Marginal Price (LMP) at a bus reflects the incremental price of energy at that bus. LMP at any bus is made up of three basic components: the system marginal price (SMP), marginal loss component of LMP (MLMP), and congestion component of LMP (CLMP).

SMP, MLMP and CLMP are a product of the least cost, security constrained dispatch of system resources to meet system load. SMP is the incremental cost of energy, given the current dispatch, ignoring incremental considerations of losses and transmission constraints. Losses refer to energy lost to physical resistance in the transmission and distribution network as power is moved from generation to load. The greater the resistance of the system to flows of energy from generation to loads, the greater the losses of the system and the greater the proportion of energy needed to meet a given level of load. Marginal losses are the incremental change in system power losses caused by changes in the system load and generation patterns.[15] The first derivative of total losses with respect to the power flow equals marginal losses, which are twice the average losses for that power flow. The term congestion is related to physical limitations of elements of the transmission system to move power from point to point. Congestion cost reflects the incremental cost of relieving transmission constraints while maintaining system power balance. Congestion occurs when available, least-cost energy cannot be delivered to all loads for a period because transmission facilities are not adequate to deliver that energy. When the least-cost available energy cannot be delivered to load in a transmission-constrained area, higher cost units in the constrained area must be dispatched to meet that load.[16] The result is that the price of energy in the constrained area is higher than in the unconstrained area because of the combination of transmission limitations and the cost of local generation.

Table 10-1 shows the PJM real-time, load-weighted average LMP components for calendar years 2008 to 2011. The PJM price is weighted by accounting load, which differs from the state-estimated load used in determination of the energy component (SMP). The components of the average PJM system price result from these different weights. The load-weighted average real-time LMP in 2011 decreased $2.41 or 5.0 percent from $48.35 in 2010 to $45.94 in 2011. The load-weighted average congestion component decreased $0.03 or 34.4 percent from $0.08 in 2010 to $0.05 in 2011. The load-weighted average loss component decreased $0.01 or

15 For additional information, see the *MMU Technical Reference for PJM Markets*, at "Marginal Losses."

16 This is referred to as dispatching units out of economic merit order. Economic merit order is the order of all generator offers from lowest to highest cost. Congestion occurs when loadings on transmission facilities mean the next unit in merit order cannot be used and a higher cost unit must be used in its place.

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34.8 percent from $0.04 in 2010 to $0.02 in 2011. The load-weighted average energy component decreased $2.37 or 4.9 percent from $48.23 in 2010 to $45.87 in 2011. In terms of proportion of real-time LMP, the congestion and loss components both decreased, while the energy component became a greater proportion in 2011.

Table 10-1 PJM real-time, load-weighted average LMP components (Dollars per MWh): Calendar years 2008 to 2011[17]

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
2008	$71.13	$71.02	$0.06	$0.05
2009	$39.05	$38.97	$0.05	$0.03
2010	$48.35	$48.23	$0.08	$0.04
2011	$45.94	$45.87	$0.05	$0.02

In the Real-Time Energy Market, the distributed load reference bus is weighted by system estimates of the load in real time. At the time the LMP is determined in the Real-Time Energy Market, the energy component equals the system load-weighted price. However, real-time bus-specific loads are adjusted, after the fact, according to updated information from meters. This meter adjusted load is accounting load that is used in settlements and forms the basis of the reported PJM load weighted prices. This after the fact adjustment means that the Real-Time Energy Market energy component of LMP (SMP) and the PJM real-time load-weighted LMP are not equal, as reported here. The difference between the real-time energy component of LMP and the PJM-wide real-time load-weighted LMP is due to the difference between estimated and meter corrected loads used to weight the load-weighted reference bus and the load-weighted LMP.

Table 10-2 shows the PJM day-ahead, load-weighted average LMP components for calendar years 2008 through 2011. The load-weighted average day-ahead LMP in 2011 decreased $2.46 or 5.2 percent from $47.65 in 2010 to $45.19 in 2011. The load-weighted average congestion component decreased $0.11 or 214.1 percent from $0.05 in 2010 to -$0.06 in 2011. The load-weighted average loss component decreased $0.08 or 124.3 percent from -$0.07 in 2010 to -$0.15 in 2011. The load-weighted average energy component decreased $2.27 or 4.8 percent from $47.67 in 2010 to $45.40 in 2011. In terms of proportion of day-ahead LMP, the congestion and loss components both decreased, while the energy component became a greater proportion in 2011.

17 The years 2006 and 2007 were removed from Table 2-20 and Table 2-24 because PJM did not begin to include marginal losses in economic dispatch and LMP models until June 1, 2007.

Table 10-2 PJM day-ahead, load-weighted average LMP components (Dollars per MWh): Calendar years 2008 to 2011

	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
2008	$70.25	$70.56	($0.08)	($0.22)
2009	$38.82	$38.96	($0.04)	($0.09)
2010	$47.65	$47.67	$0.05	($0.07)
2011	$45.19	$45.40	($0.06)	($0.15)

In the Day-Ahead Energy Market, the distributed load reference bus is weighted by fixed-demand bids only and the day-ahead energy component is, therefore, a system fixed demand weighted price. The day-ahead weighted system price calculation uses all types of demand, including fixed, price-sensitive and decrement bids. In the Real-Time Energy Market, the energy component equals the system load-weighted price. However, in the Day-Ahead Energy Market the day-ahead energy component of LMP and the PJM day-ahead load-weighted LMP are not equal. The difference between the day-ahead energy component of LMP and the PJM day-ahead load-weighted LMP is due to the difference in the types of demand used to weight the load-weighted reference bus and the load-weighted LMP.

Zonal Components

The components of LMP were calculated for each PJM control zone. The components of LMP for the control zones are presented in Table 10-3 and Table 10-4 for calendar years 2010 and 2011.

Table 10-3 shows the real-time load-weighted average LMP components by zone and PJM for calendar years 2010 and 2011. Price separation between eastern and western control zones in PJM was primarily a result of congestion on the AP South interface. This constraint generally had a positive congestion component of LMP in eastern and southern control zones located on the constrained side of the affected facilities while the unconstrained western zones had a negative congestion component of LMP.

Table 10-4 shows the day-ahead load-weighted average LMP components by zone and PJM for calendar years 2010 and 2011.

Table 10-3 Zonal and PJM real-time, load-weighted average LMP components (Dollars per MWh): Calendar years 2010 and 2011

	2010				2011			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$57.03	$49.69	$3.87	$3.47	$57.81	$50.11	$4.95	$2.75
AEP	$40.35	$47.45	($4.67)	($2.43)	$42.97	$48.64	($3.99)	($1.68)
AP	$47.08	$47.42	($0.05)	($0.28)	$48.57	$48.99	($0.22)	($0.20)
ATSI	NA	NA	NA	NA	$46.88	$51.24	($3.85)	($0.51)
BGE	$59.19	$48.69	$8.04	$2.46	$58.74	$49.82	$6.62	$2.30
ComEd	$36.21	$47.95	($8.85)	($2.90)	$38.97	$49.12	($7.32)	($2.83)
DAY	$40.51	$48.10	($6.66)	($0.93)	$43.90	$49.40	($4.57)	($0.93)
DLCO	$39.41	$47.89	($6.68)	($1.79)	$43.30	$49.12	($4.15)	($1.67)
Dominion	$56.08	$48.86	$6.30	$0.92	$54.47	$49.83	$4.04	$0.60
DPL	$56.51	$49.07	$4.59	$2.85	$56.76	$49.95	$3.82	$2.99
JCPL	$56.00	$49.58	$3.92	$2.51	$58.09	$50.73	$4.62	$2.74
Met-Ed	$53.47	$48.20	$4.22	$1.05	$53.64	$49.22	$3.42	$1.00
PECO	$53.60	$48.36	$3.54	$1.70	$55.19	$49.47	$3.82	$1.90
PENELEC	$45.17	$47.19	($1.73)	($0.28)	$48.18	$48.27	($0.46)	$0.37
Pepco	$58.16	$48.70	$7.94	$1.51	$55.71	$49.82	$4.63	$1.26
PPL	$51.50	$47.90	$2.84	$0.76	$53.76	$48.95	$3.85	$0.96
PSEG	$55.78	$48.58	$4.73	$2.47	$57.16	$49.71	$4.78	$2.67
RECO	$54.85	$49.48	$3.20	$2.17	$53.17	$50.88	($0.15)	$2.44
PJM	$48.35	$48.23	$0.08	$0.04	$49.48	$49.40	$0.05	$0.03

Table 10-4 Zonal and PJM day-ahead, load-weighted average LMP components (Dollars per MWh): Calendar years 2010 and 2011

	2010				2011			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$57.03	$49.69	$3.87	$3.47	$57.45	$49.53	$4.67	$3.25
AEP	$40.35	$47.45	($4.67)	($2.43)	$42.90	$48.10	($3.25)	($1.96)
AP	$47.08	$47.42	($0.05)	($0.28)	$47.66	$47.96	($0.16)	($0.15)
ATSI	NA	NA	NA	NA	$46.14	$50.87	($3.07)	($1.66)
BGE	$58.37	$48.37	$6.80	$3.20	$57.10	$49.19	$5.16	$2.75
ComEd	$35.48	$47.12	($7.62)	($4.02)	$38.12	$48.12	($6.46)	($3.55)
DAY	$40.18	$47.71	($5.52)	($2.01)	$43.25	$48.64	($4.21)	($1.18)
DLCO	$40.03	$47.49	($5.26)	($2.20)	$42.60	$48.39	($4.13)	($1.67)
Dominion	$56.08	$48.48	$6.05	$1.54	$53.16	$49.11	$3.35	$0.70
DPL	$55.76	$48.66	$3.73	$3.37	$56.97	$49.29	$4.20	$3.48
JCPL	$55.07	$48.61	$3.13	$3.32	$56.24	$49.45	$3.73	$3.06
Met-Ed	$52.78	$47.72	$3.70	$1.35	$52.37	$48.08	$3.28	$1.01
PECO	$53.63	$47.94	$3.18	$2.51	$55.35	$48.61	$4.33	$2.41
PENELEC	$45.52	$46.41	($0.88)	($0.00)	$47.41	$47.72	($0.56)	$0.24
Pepco	$56.41	$47.24	$6.85	$2.32	$54.99	$48.72	$4.49	$1.79
PPL	$50.92	$47.45	$2.51	$0.95	$52.82	$48.27	$3.63	$0.93
PSEG	$54.99	$48.02	$3.47	$3.50	$56.24	$48.89	$4.27	$3.09
RECO	$55.56	$49.69	$2.67	$3.20	$53.55	$49.45	$1.75	$2.35
PJM	$47.65	$47.67	$0.05	($0.07)	$48.34	$48.55	($0.05)	($0.16)

Energy Costs

Energy Accounting

The energy component of LMP is the system reference bus LMP, also called the system marginal price (SMP). The energy charge is based on the applicable day-ahead and real-time energy component of LMP (SMP). Total energy charges are equal to the load energy payments minus generation energy credits, plus explicit energy charges, incurred in both the Day-Ahead Energy Market and the balancing energy market.

Due to losses, total generation will be greater than total load in any hour. Since the hourly integrated energy component of LMP is the same across the every bus in every hour, the net energy bill is negative, with more generation credits than load charges in any given hour. This net energy bill is netted against total net marginal loss charges plus net residual market adjustments, which

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provides for full recovery of generation charges, with any remainder distributed back to load and exports as marginal loss credits.

- **Day-Ahead Load Energy Payments.** Day-ahead, load energy payments are calculated for all cleared demand, decrement bids and Day-Ahead Energy Market sale transactions. (Decrement bids and energy sales can be thought of as scheduled load.) Day-ahead, load energy payments are calculated using MW and the load bus energy component of LMP (energy LMP), the decrement bid energy LMP or the energy LMP at the source of the sale transaction, as applicable.

- **Day-Ahead Generation Energy Credits.** Day-ahead, generation energy credits are calculated for all cleared generation and increment offers and Day-Ahead Energy Market purchase transactions. (Increment offers and energy purchases can be thought of as scheduled generation.) Day-ahead, generation energy credits are calculated using MW and the generator bus energy LMP, the increment offer energy LMP or the energy LMP at the sink of the purchase transaction, as applicable.

- **Balancing Load Energy Payments.** Balancing, load energy payments are calculated for all deviations between a PJM member's real-time load and energy sale transactions and their day-ahead cleared demand, decrement bids and energy sale transactions. Balancing, load energy payments are calculated using MW deviations and the real-time energy LMP for each bus where a deviation exists.

- **Balancing Generation Energy Credits.** Balancing, generation energy credits are calculated for all deviations between a PJM member's real-time generation and energy purchase transactions and the day-ahead cleared generation, increment offers and energy purchase transactions. Balancing, generation energy credits are calculated using MW deviations and the real-time energy LMP for each bus where a deviation exists.

- **Explicit Energy Charges.** Explicit energy charges are the net energy charges associated with point-to-point energy transactions. These charges equal the product of the transacted MW and energy LMP differences between sources (origins) and sinks (destinations) in the Day-Ahead Energy Market. Balancing energy market explicit energy charges equal the product of the differences between the real-time and day-ahead transacted MW and the differences between the real-time energy LMP at the transactions' sources and sinks. The explicit energy charges will sum to zero because the LMP (SMP) at the transactions' sources and sinks will be the same for each transaction.

- **Inadvertent Energy Charges.** Inadvertent energy charges are energy charges resulting from the differences between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area each hour. This inadvertent interchange of energy may be positive or negative, where positive interchange typically results in a charge while negative interchange typically results in a credit. Inadvertent energy charges are common costs, not directly attributable to specific participants, that are distributed on a load ratio basis.[18]

Total Calendar Year Energy Costs

Total charges decreased 2.1 percent from 6.5 percent in 2010 to 4.4 percent in 2011 of annual total PJM billings.[19] Table 10-5 shows type of charges by year for 2010 and 2011. Energy charges decreased by $3.7 million from $797.9 million in 2010 to $794.2 million in 2011.

Table 10-5 Total annual PJM charges by component (Dollars (Millions)): Calendar years 2010 and 201120

PJM Billing Charges (millions)						
	Energy Charges	Loss Charges	Congestion Charges	Total Charges	Total PJM Billing	Total Charges Percent of PJM Billing
2010	($798)	$1,635	$1,424	$2,261	$34,770	6.5%
2011	($794)	$1,380	$998	$1,583	$35,887	4.4%
Total	($1,592)	$3,014	$2,422	$3,844	$70,657	5.4%

Total energy charges are shown in Table 10-6 and Table 10-7. Table 10-6 shows the 2010 and 2011 PJM energy costs by category. Table 10-7 shows the 2010 and 2011 PJM energy costs by market category. The 2011 PJM total energy costs were comprised of $47,656.9 million in load energy payments, $48,478.9 million in generation energy credits, $0.0 million in explicit energy charges and $27.8 million in inadvertent energy charges.

18 OA. Schedule 1 (PJM Interchange Energy Market) §3.7

19 Calculated values shown in Section 10, "Congestion and Marginal Losses," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

20 The Energy Charges, Loss Charges and Congestion Charges include net inadvertent charges.

Table 10-6 Total annual PJM energy costs by category (Dollars (Millions)): Calendar years 2010 and 2011

	Energy Costs (Millions)				
Year	Load Payments	Generation Credits	Explicit	Inadvertent Charges	Total
2010	$53,101.4	$53,886.8	$0.0	($12.5)	($797.9)
2011	$47,656.9	$48,478.9	$0.0	$27.8	($794.2)

Monthly Energy Costs

Table 10-8 shows a monthly summary of energy costs by type for 2011. The highest monthly energy cost was in July and totaled -$120.1 million or 15.1 percent of the total. The majority of the energy costs was in the Day-Ahead Energy Market and totaled -$735.1 million. The day-ahead costs were offset, in part, by a total of -$86.9 million in the balancing market.

Marginal Losses

Marginal Loss Accounting

With the implementation of marginal loss pricing, PJM calculates transmission loss charges for each PJM member. The loss charge is based on the applicable day-ahead and real-time loss component of LMP (MLMP). Each PJM member is charged for the cost of losses on the transmission system, based on the difference between the MLMP at the location where the PJM member injects energy and the MLMP where the PJM member withdraws energy.

More specifically, total loss charges are equal to the load loss payments minus generation loss credits, plus explicit loss charges, incurred in both the Day-Ahead Energy Market and the balancing energy market.

- **Day-Ahead Load Loss Payments.** Day-ahead, load loss payments are calculated for all cleared demand, decrement bids and Day-Ahead Energy Market sale transactions. (Decrement bids and energy sales can be thought of as scheduled load.) Day-ahead, load loss payments are calculated using MW and the load bus loss component of LMP (MLMP), the decrement bid MLMP or the MLMP at the source of the sale transaction, as applicable.

- **Day-Ahead Generation Loss Credits.** Day-ahead, generation loss credits are calculated for all cleared generation and increment offers and Day-Ahead Energy Market purchase transactions. (Increment offers and energy purchases can be thought of as scheduled generation.) Day-ahead, generation loss credits are calculated using MW and the generator

Table 10-7 Total annual PJM energy costs by market category (Dollars (Millions)): Calendar years 2010 and 2011

	Energy Costs (Millions)									
	Day Ahead				Balancing					
	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Inadvertent Charges	Grand Total
2010	$53,164.8	$53,979.1	$0.0	($814.3)	($63.4)	($92.3)	$0.0	$28.9	($12.5)	($797.9)
2011	$48,142.3	$48,877.4	$0.0	($735.1)	($485.3)	($398.4)	$0.0	($86.9)	$27.8	($794.2)

Table 10-8 Monthly energy costs by type (Dollars (Millions)): Calendar year 2011

	Energy Costs (Millions)									
	Day Ahead				Balancing					
	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Inadvertent Charges	Grand Total
Jan	$5,274.1	$5,364.4	$0.0	($90.3)	($51.6)	($46.4)	$0.0	($5.2)	$2.1	($93.3)
Feb	$3,465.4	$3,526.5	$0.0	($61.1)	($29.1)	($26.7)	$0.0	($2.4)	$2.3	($61.2)
Mar	$3,313.4	$3,365.7	$0.0	($52.4)	($31.0)	($25.6)	$0.0	($5.4)	$2.4	($55.3)
Apr	$3,073.2	$3,123.1	$0.0	($49.9)	($10.5)	($10.1)	$0.0	($0.4)	$2.5	($47.8)
May	$3,588.3	$3,643.0	$0.0	($54.8)	($0.7)	($0.5)	$0.0	($0.2)	$2.9	($52.1)
Jun	$4,968.7	$5,050.8	$0.0	($82.1)	($37.4)	($34.2)	$0.0	($3.2)	$1.2	($84.2)
Jul	$7,010.4	$7,120.4	$0.0	($110.0)	($87.7)	($71.0)	$0.0	($16.8)	$6.7	($120.1)
Aug	$4,713.0	$4,779.8	$0.0	($66.9)	($65.8)	($49.4)	$0.0	($16.4)	$4.9	($78.3)
Sep	$3,499.2	$3,554.2	$0.0	($55.0)	($78.6)	($73.2)	$0.0	($5.5)	$1.1	($59.4)
Oct	$3,110.0	$3,152.7	$0.0	($42.7)	($46.1)	($40.2)	$0.0	($5.9)	$0.3	($48.3)
Nov	$2,935.8	$2,966.0	$0.0	($30.2)	($12.8)	$1.8	$0.0	($14.6)	$0.8	($44.0)
Dec	$3,191.0	$3,230.6	$0.0	($39.6)	($34.1)	($23.0)	$0.0	($11.0)	$0.6	($50.1)
Total	$48,142.3	$48,877.4	$0.0	($735.1)	($485.3)	($398.4)	$0.0	($86.9)	$27.8	($794.2)

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bus MLMP, the increment offer MLMP or the MLMP at the sink of the purchase transaction, as applicable.

- **Balancing Load Loss Payments.** Balancing, load loss payments are calculated for all deviations between a PJM member's real-time load and energy sale transactions and their day-ahead cleared demand, decrement bids and energy sale transactions. Balancing, load loss payments are calculated using MW deviations and the real-time MLMP for each bus where a deviation exists.

- **Balancing Generation Loss Credits.** Balancing, generation loss credits are calculated for all deviations between a PJM member's real-time generation and energy purchase transactions and the day-ahead cleared generation, increment offers and energy purchase transactions. Balancing, generation loss credits are calculated using MW deviations and the real-time MLMP for each bus where a deviation exists.
- **Explicit Loss Charges.** Explicit loss charges are the net loss charges associated with point-to-point energy transactions. These charges equal the product of the transacted MW and MLMP differences between sources (origins) and sinks (destinations) in the Day-Ahead Energy Market. Balancing energy market explicit loss charges equal the product of the differences between the real-time and day-ahead transacted MWs and the differences between the real-time MLMP at the transactions' sources and sinks.
- **Inadvertent Loss Charges.** Inadvertent loss charges are loss charges resulting from the differences between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area each hour. This inadvertent interchange of energy may be positive or negative, where positive interchange typically results in a charge while negative interchange typically results in a credit. Inadvertent loss charges are common costs, not directly attributable to specific participants, that are distributed on a load ratio basis.[21]

Marginal loss charges can be both positive and negative and consequently the load payments and generation credits can also be both positive and negative. The loss component of LMP is calculated with respect to the system reference bus LMP, also called the system marginal price (SMP). An increase in generation at a bus that results in an increase in losses will cause the marginal loss component of that bus to be negative. If the increase in generation at the bus results in a decrease of system losses, then the marginal loss component is positive.

Total Calendar Year Marginal Loss Costs

Loss charges decreased by 0.9 percent from 4.7 percent in 2010 to 3.8 percent in 2011 of annual total PJM billings.[22] Table 10-9 shows total marginal loss charges by year for 2010 and 2011. Loss charges decreased by $255.3 million from $1,634.8 million in 2010 to $1,379.5 million in 2011.

Table 10-9 Total annual PJM Marginal Loss Charges (Dollars (Millions)): Calendar years 2010 and 2011

	Loss Charges	Percent Change	Total PJM Billing	Percent of PJM Billing
2010	$1,635	NA	$34,771	4.7%
2011	$1,380	(15.6%)	$35,887	3.8%
Total	$3,014		$70,658	4.3%

Total marginal loss costs for 2010 and 2011 are shown in Table 10-10 and Table 10-11. Table 10-10 shows the 2011 PJM marginal loss costs by category and Table 10-11 shows the 2011 PJM marginal loss costs by market category. The 2011 PJM total marginal loss costs were comprised of -$174.0 million in load loss payments, -$1,551.9 million in generation loss credits, $1.6 million in explicit loss costs and $12,775.2 in inadvertent loss charges.

Table 10-10 Total annual PJM marginal loss costs by category (Dollars (Millions)): Calendar years 2010 and 2011

	Marginal Loss Costs (Millions)				
Year	Load Payments	Generation Credits	Explicit	Inadvertent Charges	Total
2010	($122.3)	($1,707.0)	$50.2	($0.0)	$1,634.8
2011	($174.0)	($1,551.9)	$1.6	$0.0	$1,379.5

21 OA. Schedule 1 (PJM Interchange Energy Market) §3.7

22 Calculated values shown in Section 10, "Congestion and Marginal Losses," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

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Table 10-11 Total annual PJM marginal loss costs by market category (Dollars (Millions)): Calendar years 2010 and 2011

	Marginal Loss Costs (Millions)									
	Day Ahead				Balancing					
	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Inadvertent Charges	Grand Total
2010	($146.3)	($1,716.1)	$95.8	$1,665.6	$23.9	$9.1	($45.6)	($30.7)	($0.0)	$1,634.8
2011	($215.4)	($1,592.1)	$53.8	$1,430.5	$41.3	$40.2	($52.2)	($51.0)	$0.0	$1,379.5

Table 10-12 Monthly marginal loss costs by type (Dollars (Millions)): Calendar year 2011

	Marginal Loss Costs (Millions)									
	Day Ahead				Balancing					
	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Inadvertent charges	Grand Total
Jan	($16.6)	($192.8)	$12.3	$188.5	$5.3	$2.8	($5.4)	($2.9)	$0.0	$185.7
Feb	($9.9)	($124.8)	$6.8	$121.8	$3.3	$3.2	($1.9)	($1.8)	$0.0	$119.9
Mar	($10.5)	($112.5)	$6.8	$108.8	$2.0	$3.0	($3.8)	($4.8)	$0.0	$104.0
Apr	($10.3)	($91.6)	$3.4	$84.8	$1.7	$2.3	($5.1)	($5.6)	$0.0	$79.2
May	($8.6)	($93.9)	$9.0	$94.3	$3.3	$3.2	($7.1)	($7.0)	$0.0	$87.3
Jun	($34.4)	($158.4)	$5.9	$129.9	$4.2	$4.4	($4.3)	($4.5)	$0.0	$125.4
Jul	($40.0)	($254.3)	$3.1	$217.4	$8.4	$8.3	($3.8)	($3.7)	$0.0	$213.7
Aug	($25.3)	($162.1)	$1.2	$137.9	$2.0	$2.7	($2.7)	($3.5)	$0.0	$134.5
Sep	($18.6)	($123.1)	$3.1	$107.7	$5.4	$6.2	($3.9)	($4.7)	$0.0	$102.9
Oct	($9.8)	($93.5)	$2.0	$85.7	$1.7	$1.3	($4.1)	($3.6)	$0.0	$82.0
Nov	($15.9)	($93.5)	($1.6)	$76.0	$1.6	$0.5	($2.9)	($1.7)	$0.0	$74.3
Dec	($15.4)	($91.5)	$1.6	$77.8	$2.6	$2.4	($7.3)	($7.1)	$0.0	$70.6
Total	($215.4)	($1,592.1)	$53.8	$1,430.5	$41.3	$40.2	($52.2)	($51.0)	$0.0	$1,379.5

Monthly Marginal Loss Costs

Table 10-12 shows a monthly summary of marginal loss costs by type for 2011. The highest monthly loss cost was in July and totaled $213.7 million or 15.5 percent of the total. The majority of the marginal loss costs was in the Day-Ahead Energy Market and totaled $1,430.5 million. The day-ahead costs were offset, in part, by a total of -$51.0 million in the balancing market.

Marginal Loss Costs and Loss Credits

Marginal loss credits (loss surplus) are calculated by adding the total net energy costs, the total net marginal loss costs and net residual market adjustments. The total energy costs are equal to the net energy costs (generation energy credits less load energy payments plus net inadvertent energy charges plus net explicit energy charges). Total marginal loss costs are equal to the net marginal loss costs (generation loss credits less load loss payments plus net inadvertent loss charges plus net explicit loss charges). Ignoring interchange, the existence of losses will cause total generation to be greater than total load in any hour. Since the hourly integrated energy component of LMP is the same across every generator and load bus in every hour, the net energy bill will be negative (ignoring net interchange), with more generation credits than load charges collected in any given hour. This net energy bill is netted against total net marginal loss charges and net residual market adjustments, with the remainder distributed back to load and exports as marginal loss credits. Residual market adjustments consist of the known day-ahead error value, day-ahead loss MW congestion value and balancing loss MW congestion value. The known day-ahead error value is the financial calculation for the MW imbalance created when the day-ahead case is solved. The day-ahead and balancing loss MW congestion values are congestion values associated with loss MW that need to be deducted from the net of the total marginal loss costs, total energy costs and day-ahead known error value before marginal loss credits can be distributed.

Table 10-13 shows the total net energy charges, the total net marginal loss charges collected, the net residual

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market adjustments[23] and total loss credits redistributed in calendar years 2010 and 2011. Marginal loss charges totaled $1,379.5 million, energy charges totaled -$794.2 million and net residual market adjustments totaled -$1.4 million in 2011. The marginal loss credits paid back to load plus exports in 2011 was $586.7 million, which is a decrease of $250 million or 29.9 percent compared to $836.7 million in 2010.

Table 10-13 Marginal loss credits (Dollars (Millions)): Calendar years 2010 and 2011

Loss Credit Accounting (Millions)				
	Total Energy Charges	Total Marginal Loss Charges	Adjustments	Loss Credits
2010	($797.9)	$1,634.8	$0.2	$836.7
2011	($794.2)	$1,379.5	($1.4)	$586.7

The reduction in marginal loss credits between 2010 and 2011 is due, at least in part, to an anomalous pricing event which occurred on October 10, 2011. On October 10, 2011, loss credits were negative in every hour. In the cases reviewed, the low LMP was related to the marginal losses component of LMP being unusually large relative to the energy component of LMP. The anomalous results were caused by incorrect loss penalty factors being utilized for all 24 hours on October 10.

Congestion

Congestion Accounting

Transmission congestion can exist in PJM's Day-Ahead and Real-Time Energy Market.[24] Total congestion charges are equal to the net congestion bill plus explicit congestion charges plus net inadvertent congestions charges, incurred in both the Day-Ahead Energy Market and the balancing energy market.

The net congestion bill is calculated by subtracting generating congestion credits from load congestion payments. The logic is that increased congestion payments by load are offset by increased congestion revenues to generation, for the area analyzed. Whether the net congestion bill is an appropriate measure of congestion for load depends on who pays the load congestion payments and who receives the generation congestion credits. The net congestion bill is an appropriate measure of congestion for a utility that charges load congestion payments to load and credits generation congestion credits to load. The net congestion bill is not an appropriate measure of congestion in situations where load pays the load congestion payments but does not receive the generation credits as an offset.

In the 2011 analysis of total congestion costs, load congestion payments are netted against generation congestion credits on an hourly basis, by billing organization, and then summed for the given period.[25] A billing organization may offset load congestion payments with its generation portfolio or by purchasing supply from another entity via a bilateral transaction.

Load Congestion Payments and Generation Congestion Credits are calculated for both the Day-Ahead and Balancing Energy Markets.

- **Day-Ahead Load Congestion Payments.** Day-ahead load congestion payments are calculated for all cleared demand, decrement bids and Day-Ahead Energy Market sale transactions. (Decrement bids and energy sales can be thought of as scheduled load.) Day-ahead load congestion payments are calculated using MW and the load bus CLMP, the decrement bid CLMP or the CLMP at the source of the sale transaction, as applicable.
- **Day-Ahead Generation Congestion Credits.** Day-ahead generation congestion credits are calculated for all cleared generation and increment offers and Day-Ahead Energy Market purchase transactions. (Increment offers and energy purchases can be thought of as scheduled generation.) Day-ahead generation congestion credits are calculated using MW and the generator bus CLMP, the increment offer's CLMP or the CLMP at the sink of the purchase transaction, as applicable.
- **Balancing Load Congestion Payments.** Balancing load congestion payments are calculated for all deviations between a PJM member's real-time load and energy sale transactions and their day-ahead cleared demand, decrement bids and energy sale

23 Based on currently available data, the MMU is not able to independently calculate residual market adjustments. The adjustments numbers included in the table are comprised of the sum of the known day-ahead error value, day-ahead loss MW congestion value, balancing loss MW congestion value and measurement error caused by missing data. In sum, these elements reflect the difference between actual PJM loss credits and MMU calculations of loss credits based on available data.

24 The terms *congestion charges* and *congestion costs* are both used to refer to the costs associated with congestion. The term, *congestion charges*, is used in documents by PJM's Market Settlement Operations.

25 This analysis does not treat affiliated billing organizations as a single organization. Thus, the generation congestion credits from one organization will not offset the load payments of its affiliate. This may overstate or understate the actual load payments or generation credits of an organization's parent company.

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transactions. Balancing load congestion payments are calculated using MW deviations and the real-time CLMP for each bus where a deviation exists.

- **Balancing Generation Congestion Credits.** Balancing generation congestion credits are calculated for all deviations between a PJM member's real-time generation and energy purchase transactions and the day-ahead cleared generation, increment offers and energy purchase transactions. Balancing generation congestion credits are calculated using MW deviations and the real-time CLMP for each bus where a deviation exists.
- **Explicit Congestion Charges.** Explicit congestion charges are the net congestion charges associated with point-to-point energy transactions. These charges equal the product of the transacted MW and CLMP differences between sources (origins) and sinks (destinations) in the Day-Ahead Energy Market. Balancing energy market explicit congestion charges equal the product of the deviations between the real-time and day-ahead transacted MWs and the differences between the real-time CLMP at the transactions' sources and sinks.
- **Inadvertent Congestion Charges.** Inadvertent congestion charges are congestion charges resulting from the differences between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area each hour. This inadvertent interchange of energy may be positive or negative, where positive interchange typically results in a charge while negative interchange typically results in a credit. Inadvertent congestion charges are common costs, not directly attributable to specific participants, that are distributed on a load ratio basis.[26]

The congestion charges associated with specific constraints are the sum of the total day-ahead and balancing congestion costs associated with those constraints. The congestion charges in each zone are the sum of the congestion charges associated with each constraint that affects prices in the zone. The network nature of the transmission system means that congestion costs in a zone are frequently the result of constrained facilities located outside that zone.

Congestion costs can be both positive and negative and consequently load payments and generation credits can also be both positive and negative. The CLMP is calculated with respect to the system reference bus LMP, also called the system marginal price (SMP). When a transmission constraint occurs, the resulting CLMP is positive on one side of the constraint and negative on the other side of the constraint and the corresponding congestion costs are positive or negative. For each transmission constraint, the CLMP reflects the cost of a constraint at a pricing node and is equal to the product of the constraint shadow price and the distribution factor at the respective pricing node. The total CLMP at a pricing node is the sum of all constraint contributions to LMP and is equal to the difference between the actual LMP that results from transmission constraints, excluding losses, and the SMP. If an area experiences lower prices because of a constraint, the CLMP in that area is negative.[27]

Total Calendar Year Congestion

Congestion charges have ranged from 2.7 percent to 9.6 percent of annual total PJM billings since 2000.[28] Table 10-14 shows total congestion by year from 1999 through 2011. Congestion charges decreased by $425.4 million from $1,423.6 million in 2010 to $998.2 million in 2011.[29]

Table 10-14 Total annual PJM congestion (Dollars (Millions)): Calendar years 1999 to 2011

	Congestion Charges	Percent Change	Total PJM Billing	Percent of PJM Billing
1999	$65	NA	NA	NA
2000	$132	103.1%	$2,300	5.7%
2001	$271	105.3%	$3,400	8.0%
2002	$453	67.2%	$4,700	9.6%
2003	$464	2.4%	$6,900	6.7%
2004	$750	61.7%	$8,700	8.6%
2005	$2,092	178.8%	$22,630	9.2%
2006	$1,603	(23.4%)	$20,945	7.7%
2007	$1,846	15.1%	$30,556	6.0%
2008	$2,117	14.7%	$34,306	6.2%
2009	$719	(66.0%)	$26,550	2.7%
2010	$1,424	98.0%	$34,770	4.1%
2011	$998	(29.9%)	$35,887	2.8%
Total	$12,933	NA	$231,644	5.6%

26 OA. Schedule 1 (PJM Interchange Energy Market) §3.7

27 For an example of the congestion accounting methods used in this section, see *MMU Technical Reference for PJM Markets*, at "FTRs and ARRs."

28 Calculated values shown in Section 10, "Congestion and Marginal Losses," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

29 Congestion charges for 2010 reflect an updated calculation compared to the results in the *2010 State of the Market Report for PJM.*

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Table 10-15 Total annual PJM congestion costs by category (Dollars (Millions)): Calendar years 2010 to 2011

	Congestion Costs (Millions)				
Year	Load Payments	Generation Credits	Explicit	Inadvertent Charges	Total
2010	$251.2	($1,254.8)	($82.4)	$0.0	$1,423.6
2011	$112.2	($1,009.9)	($123.8)	$0.0	$998.2

Total congestion charges in Table 10-15 include both congestion charges associated with PJM facilities and those associated with reciprocal, coordinated flowgates in the MISO whose operating limits are respected by PJM.[30]

Table 10-16 shows the 2011 PJM congestion costs by category. The 2011 PJM total congestion costs were comprised of $112.2 million in load congestion payments, $1,009.9 million in negative generation congestion credits, and negative $123.8 million in explicit congestion costs.

Monthly Congestion

Table 10-17 shows that during calendar year 2011, monthly congestion charges ranged from a maximum of $241.6 million in January 2011 to a minimum of $35.0 million in May 2011. Table 10-18 shows the monthly congestion breakdown for calendar year 2010.

Congested Facilities

A congestion event exists when a unit or units must be dispatched out of merit order to control the impact of a contingency on a monitored facility or to control an actual overload. A congestion-event hour exists when a specific facility is constrained for one or more five-minute intervals within an hour. A congestion-event hour differs from a constrained hour, which is any hour during which one or more facilities are congested. Thus, if two facilities are constrained during an hour, the result is two congestion-event hours and one constrained hour. Constraints are often simultaneous, so the number of congestion-event hours likely exceeds the number of constrained hours and the number of congestion-event hours likely exceeds the number of hours within a year.

In order to have a consistent metric for real-time and day-ahead congestion frequency, real-time congestion frequency is measured using the convention that an hour is constrained if any of its component five-minute intervals is constrained. This is also consistent with the way in which PJM reports real-time congestion. In 2011, there were 154,868 day-ahead, congestion-event hours compared to 106,253 day-ahead, congestion-event

Table 10-16 Total annual PJM congestion costs by market category (Dollars (Millions)): Calendar years 2010 to 2011

	Congestion Costs (Millions)									
	Day Ahead				Balancing					
Year	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Inadvertent Charges	Grand Total
2010	$251.4	($1,364.9)	$96.9	$1,713.1	($0.1)	$110.1	($179.3)	($289.5)	($0.0)	$1,423.6
2011	$36.2	($1,141.8)	$66.9	$1,244.9	$75.9	$131.9	($190.7)	($246.7)	$0.0	$998.2

Table 10-17 Monthly PJM congestion charges (Dollars (Millions)): Calendar year 2011

	Congestion Costs (Millions)									
	Day Ahead				Balancing					
Month	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Inadvertent Charges	Grand Total
Jan	$27.0	($228.4)	$0.9	$256.4	$21.1	$15.6	($20.3)	($14.8)	$0.0	$241.6
Feb	$14.0	($77.5)	$1.0	$92.5	$5.6	$12.8	($10.9)	($18.0)	$0.0	$74.4
Mar	($2.5)	($58.8)	$2.2	$58.4	$0.2	$4.7	($10.0)	($14.6)	$0.0	$43.8
Apr	$5.0	($56.5)	$6.6	$68.0	$1.4	$6.4	($23.7)	($28.8)	$0.0	$39.2
May	$14.3	($41.5)	$8.6	$64.3	$3.0	$7.4	($24.9)	($29.3)	$0.0	$35.0
Jun	$1.8	($154.0)	$6.4	$162.3	$13.1	$22.4	($17.7)	($27.0)	$0.0	$135.2
Jul	$3.8	($184.1)	$6.5	$194.4	$21.2	$21.6	($20.2)	($20.6)	$0.0	$173.8
Aug	$4.7	($63.7)	$6.6	$75.0	($0.4)	$1.8	($9.7)	($11.9)	$0.0	$63.1
Sep	$0.0	($84.9)	$6.9	$91.9	$8.8	$21.2	($11.5)	($23.9)	$0.0	$67.9
Oct	($8.7)	($59.7)	$6.9	$58.0	$2.1	$6.2	($15.2)	($19.4)	$0.0	$38.6
Nov	($12.6)	($64.6)	$5.3	$57.3	($0.6)	$6.8	($11.9)	($19.2)	$0.0	$38.0
Dec	($10.6)	($68.1)	$9.0	$66.5	$0.5	$5.0	($14.6)	($19.1)	$0.0	$47.4
Total	$36.2	($1,141.8)	$66.9	$1,244.9	$75.9	$131.9	($190.7)	($246.7)	$0.0	$998.2

30 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (December 11, 2008) Section 6.1 <http://www.pjm.com/documents/agreements/~/media/documents/agreem ents/joa-complete.ashx > (Accessed March 13, 2012).

Table 10-18 Monthly PJM congestion charges (Dollars (Millions)): Calendar year 2010

	Congestion Costs (Millions)									
	Day Ahead				Balancing					
Month	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Inadvertent Charges	Grand Total
Jan	$37.8	($189.4)	$3.1	$230.2	$4.0	$3.1	($12.9)	($11.9)	($0.0)	$218.3
Feb	$25.5	($93.1)	$5.6	$124.2	($2.6)	$6.8	($8.3)	($17.7)	($0.0)	$106.4
Mar	$5.5	($27.8)	$4.2	$37.5	($2.6)	$6.6	($8.0)	($17.2)	($0.0)	$20.4
Apr	$6.1	($52.4)	$6.2	$64.7	($1.9)	$10.9	($9.3)	($22.1)	$0.0	$42.5
May	$35.0	($36.7)	$6.6	$78.2	$0.2	$1.1	($9.0)	($9.9)	($0.0)	$68.3
Jun	$62.6	($123.8)	$12.5	$199.0	$7.0	$1.3	($16.3)	($10.6)	($0.0)	$188.4
Jul	$39.1	($240.4)	$11.9	$291.4	$6.7	$11.3	($21.4)	($26.1)	($0.0)	$265.3
Aug	$23.9	($90.6)	$9.9	$124.4	$5.8	$10.8	($14.3)	($19.4)	($0.0)	$105.0
Sep	$7.3	($137.4)	$9.6	$154.4	$1.3	$16.6	($19.0)	($34.3)	($0.0)	$120.0
Oct	$0.8	($59.1)	$8.9	$68.8	($3.3)	$1.7	($13.5)	($18.6)	($0.0)	$50.2
Nov	($10.1)	($84.8)	$5.7	$80.3	($4.9)	$7.3	($16.5)	($28.6)	($0.0)	$51.7
Dec	$17.9	($229.3)	$12.8	$260.0	($9.8)	$32.5	($30.7)	($73.0)	$0.0	$187.1
Total	$251.4	($1,364.9)	$96.9	$1,713.1	($0.1)	$110.1	($179.3)	($289.5)	($0.0)	$1,423.6

hours in 2010. In 2011, there were 22,468 real-time, congestion-event hours compared to 23,422 real-time, congestion-event hours in 2010.

Facilities were constrained in the Day-Ahead Market more frequently than in the Real-Time Market. During 2011, for only 5.6 percent of Day-Ahead Market facility constrained hours were the same facilities also constrained in the Real-Time Market. During 2011, for 38.0 percent of Real-Time Market facility constrained hours, the same facilities were also constrained in the Day-Ahead Market.

Congestion by Facility Type and Voltage

In 2011, day-ahead, congestion-event hours increased on the reciprocally coordinated flowgates between PJM and MISO, transmission lines and transformers while congestion frequency on internal PJM interfaces decreased. Real-time, congestion-event hours increased on the reciprocally coordinated flowgates between PJM and the MISO and transformers, while congestion frequency on interfaces and transmission lines decreased.[31]

Day-ahead congestion costs increased on the reciprocally coordinated flowgates between PJM and MISO and transformers in 2011 and decreased on PJM interfaces and transmission lines in 2011. Balancing congestion costs decreased on the reciprocally coordinated flowgates between PJM and MISO and transformers and increased on PJM interfaces and transmission lines in 2011.

Table 10-19 provides congestion-event hour subtotals and congestion cost subtotals comparing the 2011 calendar year results by facility type: line, transformer, interface, flowgate and unclassified facilities.[32,33] For comparison, this information is presented in Table 10-20 for calendar year 2010.[34]

Total congestion costs associated with the reciprocally coordinated flowgates between PJM and the MISO increased by $2.5 million from $11.9 million in 2010 to $14.4 million in 2011.35 The flowgates day-ahead congestion cost and congestion event hours increased in 2011 compared to 2010. Flowgates balancing congestion costs decreased in 2011, while flowgates balancing congestion event hours increased in comparison to 2010. Balancing congestion costs on the reciprocally coordinated flow gates were generally negative in 2010 and 2011. The Crete – St Johns line flowgate accounted for $23.3 million in congestion costs and was the largest contributor to positive congestion costs among flowgates in 2011. The largest contribution to negative congestion costs among flowgates came from the Oak

31 As of March 2, 2012 the total zonal congestion related numbers presented here differed from the March 2, 2012 PJM totals by $0.72 Million, a discrepancy of 0.07 percent (.0007).

32 Unclassified constraints appear in the Day-Ahead Market only and represent congestion costs incurred on market elements which are not posted by PJM. Congestion frequency associated with these unclassified constraints is not presented in order to be consistent with the posting of constrained facilities by PJM.

33 The term *flowgate* refers to MISO flowgates in this context.

34 For 2008 and 2009, the load congestion payments and generation congestion credits represent the net load congestion payments and net generation congestion credits for an organization, as this shows the extent to which each organization's load or generation was exposed to congestion costs.

35 The congestion costs reported here for the reciprocally coordinated flowgates between PJM and the MISO flowgates are calculated in the same manner as all other internal PJM constraints and use the congestion accounting methods defined in this section. For the payments to and from the MISO based on the market-to-market settlement calculations, defined in the "Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.", see the *2010 State of the Market Report for PJM*, Volume II, Section 4, "Interchange Transactions," at "PJM and Midwest ISO Joint Operating Agreement."

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Grove - Galesburg flowgate with -$14.7 million in 2011 congestion costs.

Total congestion costs associated with interfaces decreased from $710.8 million in 2010 to $455.1 million in 2011. Interfaces typically include multiple transmission facilities and reflect power flows into or through a wider geographic area. Interface congestion constituted 45.6 percent of total PJM congestion costs in 2011. Among interfaces, the AP South, the 5004/5005 and West interfaces accounted for the largest contribution to positive congestion costs in 2011. The AP South interface, with $238.9 million in congestion, had the highest congestion cost of any facility in PJM, accounting for 23.9 percent of the total PJM congestion costs in 2011. The AP South, the 5004/5005 and West interfaces together accounted for $374.3 million or 82.2 percent of all interface congestion costs and were the largest contributors to positive congestion among interfaces in 2011.

Total congestion costs associated with transmission lines decreased 32.1 percent from $491.2 million in 2010 to $333.6 million in 2011. Transmission line congestion accounted for 33.4 percent of the total PJM congestion costs for 2011. The Electric Jct – Nelson, Dickerson – Quince Orchard and Graceton - Raphael Road lines together accounted for $61.4 million or 18.4 percent of all transmission line congestion costs and were the largest contributors to positive congestion among transmission lines in 2011.

Total congestion costs associated with transformers decreased 3.1 percent from $192.4 million in 2010 to $186.4 million in 2011. Congestion on transformers accounted for 18.7 percent of the total PJM congestion costs in 2011. The Belmont, Clover and Susquehanna transformers together accounted for $85.9 million or 46 percent of all transformer congestion costs and were the largest contributors to positive congestion costs among transformers in 2011.

Table 10-21 and Table 10-22 compare day-ahead and real-time congestion event hours. Among the hours for which a facility is constrained in the Day-Ahead Market, the number of hours during which the facility is also constrained in the Real-Time Market are presented in Table 10-21. In 2011, there were 154,868 congestion event hours in the Day-Ahead Market. Among those, only 8,623 (5.6 percent) were also constrained in the Real-Time Market. In 2010, among the 106,253 day-ahead congestion event hours, only 9,130 (8.6 percent) were binding in the Real-Time Market.

Among the hours for which a facility is constrained in the Real-Time Market, the number of hours during

Table 10-19 Congestion summary (By facility type): Calendar year 2011

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Type	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Flowgate	($110.1)	($215.5)	$12.0	$117.4	$8.4	$22.9	($88.5)	($103.0)	$14.4	23,982	7,385
Interface	$64.0	($395.3)	($10.7)	$448.7	$37.7	$38.3	$7.1	$6.4	$455.1	8,988	1,803
Line	$46.7	($343.6)	$38.4	$428.7	$23.2	$51.2	($67.1)	($95.1)	$333.6	88,573	9,252
Other	($0.5)	($4.7)	$0.6	$4.9	$2.2	$4.6	($0.4)	($2.8)	$2.0	1,227	248
Transformer	$35.1	($181.2)	$21.0	$237.3	$3.3	$14.5	($39.7)	($50.9)	$186.4	32,098	3,780
Unclassified	$1.1	($1.5)	$5.4	$8.0	$1.2	$0.3	($1.4)	($0.5)	$7.5	NA	NA
Total	$36.2	($1,141.8)	$66.9	$1,245.0	$75.9	$131.9	($190.0)	($246.0)	$999.0	154,868	22,468

Table 10-20 Congestion summary (By facility type): Calendar year 2010

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Type	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Flowgate	($59.3)	($125.8)	$5.5	$72.0	($0.8)	$6.0	($53.3)	($60.1)	$11.9	6,804	3,228
Interface	$163.1	($550.4)	$2.9	$716.3	$30.1	$31.4	($4.3)	($5.6)	$710.8	9,792	2,607
Line	$82.2	($528.3)	$68.9	$679.4	($22.6)	$64.1	($101.5)	($188.2)	$491.2	72,423	14,296
Other	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	0	0
Transformer	$64.7	($149.8)	$13.5	$228.1	($6.8)	$8.5	($20.3)	($35.7)	$192.4	17,234	3,291
Unclassified	$0.7	($10.5)	$6.2	$17.4	$0.0	$0.0	$0.0	$0.0	$17.4	NA	NA
Total	$251.4	($1,364.9)	$96.9	$1,713.1	($0.1)	$110.1	($179.3)	($289.5)	$1,423.6	106,253	23,422

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which the facility is also constrained in the Day-Ahead Market are presented in Table 10-22. In 2011, there were 22,468 congestion event hours in the Real-Time Market. Among these, 8,537 (38.0 percent) were also constrained in the Day-Ahead Market. In 2010, among the 23,422 real-time congestion event hours, only 8,936 (38.2 percent) were binding in the day-ahead.

Table 10-23 shows congestion costs by facility voltage class for 2011. In comparison to 2010 (shown in Table 10-24), congestion costs increased across 765 kV, 500 kV, 345 kV, 230 kV, 138 kV, 115 kV, 34 kV, 12 kV and unclassified facilities in 2011.

Congestion costs associated with 765 kV facilities increased from $5.9 million in 2010 to the $10.6 million experienced in 2011. Congestion on 765 kV facilities comprised 1.1 percent of total PJM congestion costs in 2011.

Congestion costs associated with 500 kV facilities decreased 30.8 percent from $876.5 million in 2010, to $544.0 million in 2011. Congestion on 500 kV facilities comprised 54.4 percent of total 2011 PJM congestion costs. The AP South, 5004/5005 and West interfaces accounted for $374.3 million or 68.8 percent of all 500 kV congestion costs; they were the largest contributors to positive congestion among 500 kV facilities in 2011.

Table 10-21 Congestion Event Hours (Day-Ahead against Real Time): Calendar Years 2010 to 2011

	Congestion Event Hours					
	2011			2010		
Type	Day Ahead Constrained	Corresponding Real Time Constrained	Percent	Day Ahead Constrained	Corresponding Real Time Constrained	Percent
Flowgate	23,982	2,884	12.0%	6,804	973	14.3%
Interface	8,988	1,144	12.7%	9,792	1,728	17.6%
Line	88,573	2,945	3.3%	72,423	4,999	6.9%
Other	1,227	13	1.1%	0	0	0.0%
Transformer	32,098	1,637	5.1%	17,234	1,430	8.3%
Total	154,868	8,623	5.6%	106,253	9,130	8.6%

Table 10-22 Congestion Event Hours (Real Time against Day-Ahead): Calendar Years 2010 to 2011

	Congestion Event Hours					
	2011			2010		
Type	Real Time Constrained	Corresponding Day Ahead Constrained	Percent	Real Time Constrained	Corresponding Day Ahead Constrained	Percent
Flowgate	7,385	2,894	39.2%	3,228	993	30.8%
Interface	1,803	1,143	63.4%	2,607	1,727	66.2%
Line	9,252	2,884	31.2%	14,296	4,890	34.2%
Other	248	9	3.6%	0	0	0.0%
Transformer	3,780	1,607	42.5%	3,291	1,326	40.3%
Total	22,468	8,537	38.0%	23,422	8,936	38.2%

Table 10-23 Congestion summary (By facility voltage): Calendar year 2011

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Voltage (kV)	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
765	$0.8	($9.3)	$2.3	$12.4	$2.9	$2.1	($2.6)	($1.8)	$10.6	1,098	183
500	$100.2	($465.4)	($5.5)	$560.1	$41.8	$46.0	($12.0)	($16.1)	$544.0	17,769	3,675
345	($98.0)	($264.2)	$15.7	$181.8	$10.3	$26.3	($69.4)	($85.5)	$96.3	29,924	4,535
230	$1.5	($176.9)	$12.6	$191.0	$18.9	$22.7	($36.2)	($40.0)	$151.0	23,742	3,554
161	($13.6)	($22.0)	$6.3	$14.6	($2.5)	$6.0	($20.8)	($29.3)	($14.7)	1,736	1,138
138	$20.7	($173.7)	$26.0	$220.4	$4.4	$19.0	($46.1)	($60.7)	$159.7	59,561	7,686
115	$7.4	($27.8)	$4.2	$39.5	$1.1	$7.3	($1.5)	($7.7)	$31.8	12,161	1,109
69	$16.1	($1.1)	($0.1)	$17.1	($2.2)	$2.2	$0.1	($4.4)	$12.7	8,839	583
35	$0.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	11	0
34	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	2	5
14	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	7	0
12	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	18	0
Unclassified	$1.1	($1.5)	$5.4	$8.0	$1.2	$0.3	($1.4)	($0.5)	$7.5	NA	NA
Total	$36.2	($1,141.8)	$66.9	$1,245.0	$75.9	$131.9	($190.0)	($246.0)	$999.0	154,868	22,468

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Table 10-24 Congestion summary (By facility voltage): Calendar year 2010

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Voltage (kV)	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
765	$1.0	($10.6)	$1.4	$12.9	($0.8)	$1.0	($5.2)	($7.0)	$5.9	540	261
500	$220.5	($673.1)	$16.0	$909.7	$27.9	$29.6	($31.5)	($33.2)	$876.5	17,232	5,803
345	($111.9)	($275.9)	$26.0	$190.1	($4.5)	$13.0	($84.3)	($101.8)	$88.3	13,919	3,845
230	$26.3	($173.7)	$23.8	$223.8	($5.5)	$28.6	($20.4)	($54.5)	$169.3	19,727	3,831
161	($0.3)	($0.6)	$0.2	$0.4	($0.2)	$0.7	($3.0)	($3.9)	($3.4)	114	242
138	$56.0	($214.5)	$21.9	$292.4	($8.7)	$30.6	($32.4)	($71.7)	$220.7	39,641	7,188
115	$41.1	($10.8)	$1.0	$52.9	($1.8)	$6.3	($2.0)	($10.1)	$42.8	7,597	1,589
69	$17.6	$4.7	$0.3	$13.3	($6.7)	$0.2	($0.5)	($7.4)	$5.9	7,091	644
35	($0.0)	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	0	0
34	$0.0	($0.1)	$0.0	$0.1	$0.1	$0.0	$0.0	$0.1	$0.2	37	19
14	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	21	0
13	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	1	0
12	$0.3	$0.2	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	333	0
Unclassified	$0.7	($10.5)	$6.2	$17.4	$0.0	$0.0	$0.0	$0.0	$17.4	NA	NA
Total	$251.4	($1,364.9)	$96.9	$1,713.1	($0.1)	$110.1	($179.3)	($289.5)	$1,423.6	106,253	23,422

Congestion costs associated with 345 kV facilities increased by 9.6 percent from $88.3 million in 2010, to $96.3 million in 2011. Congestion on 345 kV facilities comprised 9.6 percent of total 2011 PJM congestion costs. The Electrict Jct – Nelson line, the Crete – St. Johns Tap flowgate, and the East Frankfurt-Crete flowgate accounted for $65.4 million or 67.9 percent of all 345 kV congestion costs; they were the largest contributors to positive congestion among 345 kV facilities in 2011.

Congestion costs associated with 230 kV facilities decreased 10.8 percent from $169.3 million in 2010 to $151.0 million in 2011. Congestion on 230 kV facilities comprised 15.1 percent of total PJM congestion costs in 2011. The Clover transformer, Dickerson-Quince Orchard line and Susquehanna transformer accounted for $49.8 million or 33.0 percent of all 230 kV congestion costs and were the largest contributor to positive congestion among 230 kV facilities in 2011.

Congestion costs associated with 138 kV facilities decreased 27.6 percent from $220.7 million in 2010 to $159.7 million in 2011. Congestion on 138 kV facilities comprised 16.0 percent of total 2011 PJM congestion costs. The Brues-West Bellaire line and Busonville-Eugene flowgate together accounted for $20.9 million or 14.0 percent of all 138 kV congestion costs; they were the largest contributors to positive congestion among 138 kV facilities in 2011.

Congestion costs associated with 115 kV facilities decreased by 25.7 percent from $42.8 million in 2010, to $31.8 million in 2011. Congestion on 115 kV facilities comprised 3.2 percent of total 2011 PJM congestion costs. The Cly – Collins line and Glenarm-Windy Edge line together accounted for $8.7 million or 27.4 percent of all 115 kV congestion costs; they were the largest contributors to positive congestion among 115 kV facilities in 2011.

Congestion costs associated with 69 kV and below facilities increased by 115.3 percent from $5.9 million in 2011, to $12.7 million in 2011. Congestion on 69 kV comprised 1.3 percent of total 2011 PJM congestion costs. The Cromby transformer and Carnagie – Tidd line and accounted for $8.8 million in congestion costs. They had the largest contribution to congestion costs among 69 kV and below facilities.

Constraint Duration

Table 10-25 lists calendar year 2010 and 2011 constraints that were most frequently in effect and Table 10-26 shows the constraints which experienced the largest change in congestion-event hours from 2010 to 2011.

The South Mahwah – Waldwick line, AP South interface and Belmont Transformer were the most frequently occurring constraints in 2011. The South Mahwah – Waldwick line saw the largest increase in congestion-event hours from 2010. The Waterman – West Dekalb line saw the largest decrease in congestion-event hours from 2010 to 2011.

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Table 10-25 Top 25 constraints with frequent occurrence: Calendar years 2010 to 2011

			Event Hours						Percent of Annual Hours					
			Day Ahead			Real Time			Day Ahead			Real Time		
No.	Constraint	Type	2010	2011	Change	2010	2011	Change	2010	2011	Change	2010	2011	Change
1	South Mahwah - Waldwick	Line	0	5,269	5,269	8	494	486	0%	60%	60%	0%	6%	6%
2	AP South	Interface	4,622	4,111	(511)	1,516	1,013	(503)	53%	47%	(6%)	17%	12%	(6%)
3	Belmont	Transformer	1,872	4,367	2,495	203	497	294	21%	50%	28%	2%	6%	3%
4	Danville - East Danville	Line	647	4,608	3,961	0	0	0	7%	53%	45%	0%	0%	0%
5	Crete - St Johns Tap	Flowgate	2,051	3,354	1,303	810	1,115	305	23%	38%	15%	9%	13%	3%
6	Michigan City - Laporte	Flowgate	50	2,935	2,885	67	632	565	1%	34%	33%	1%	7%	6%
7	Electric Jct - Nelson	Line	1,495	2,926	1,431	258	158	(100)	17%	33%	16%	3%	2%	(1%)
8	Emilie - Falls	Line	81	2,920	2,839	24	11	(13)	1%	33%	32%	0%	0%	(0%)
9	Oak Grove - Galesburg	Flowgate	114	1,736	1,622	242	1,131	889	1%	20%	19%	3%	13%	10%
10	Wolfcreek	Transformer	220	2,547	2,327	8	226	218	3%	29%	27%	0%	3%	2%
11	Cox's Corner - Marlton	Line	16	2,625	2,609	0	0	0	0%	30%	30%	0%	0%	0%
12	Conesville	Transformer	0	2,610	2,610	0	0	0	0%	30%	30%	0%	0%	0%
13	Linden - VFT	Line	173	2,602	2,429	0	0	0	2%	30%	28%	0%	0%	0%
14	Bunsonville - Eugene	Flowgate	31	2,444	2,413	0	11	11	0%	28%	28%	0%	0%	0%
15	Pinehill - Stratford	Line	1,506	2,352	846	0	0	0	17%	27%	10%	0%	0%	0%
16	Brues - West Bellaire	Line	0	1,718	1,718	78	598	520	0%	20%	20%	1%	7%	6%
17	Fairview	Transformer	536	2,288	1,752	0	0	0	6%	26%	20%	0%	0%	0%
18	Wylie Ridge	Transformer	945	1,910	965	656	357	(299)	11%	22%	11%	7%	4%	(3%)
19	AEP-DOM	Interface	691	1,786	1,095	187	185	(2)	8%	20%	13%	2%	2%	(0%)
20	East Frankfort - Crete	Line	3,084	1,546	(1,538)	850	329	(521)	35%	18%	(18%)	10%	4%	(6%)
21	Cumberland - Bush	Flowgate	0	1,599	1,599	22	215	193	0%	18%	18%	0%	2%	2%
22	Conesville Prep - Conesville	Line	187	1,782	1,595	0	0	0	2%	20%	18%	0%	0%	0%
23	Redoak - Sayreville	Line	898	1,752	854	57	11	(46)	10%	20%	10%	1%	0%	(1%)
24	Waukegan - Zion	Line	95	1,734	1,639	0	7	7	1%	20%	19%	0%	0%	0%
25	Clover	Transformer	514	1,238	724	259	469	210	6%	14%	8%	3%	5%	2%

Table 10-26 Top 25 constraints with largest year-to-year change in occurrence: Calendar years 2010 to 2011

			Event Hours						Percent of Annual Hours					
			Day Ahead			Real Time			Day Ahead			Real Time		
No.	Constraint	Type	2010	2011	Change	2010	2011	Change	2010	2011	Change	2010	2011	Change
1	South Mahwah - Waldwick	Line	0	5,269	5,269	8	494	486	0%	60%	60%	0%	6%	6%
2	Danville - East Danville	Line	647	4,608	3,961	0	0	0	7%	53%	45%	0%	0%	0%
3	Michigan City - Laporte	Flowgate	50	2,935	2,885	67	632	565	1%	34%	33%	1%	7%	6%
4	Waterman - West Dekalb	Line	3,003	2	(3,001)	343	0	(343)	34%	0%	(34%)	4%	0%	(4%)
5	Emilie - Falls	Line	81	2,920	2,839	24	11	(13)	1%	33%	32%	0%	0%	(0%)
6	Belmont	Transformer	1,872	4,367	2,495	203	497	294	21%	50%	28%	2%	6%	3%
7	Conesville	Transformer	0	2,610	2,610	0	0	0	0%	30%	30%	0%	0%	0%
8	Cox's Corner - Marlton	Line	16	2,625	2,609	0	0	0	0%	30%	30%	0%	0%	0%
9	Wolfcreek	Transformer	220	2,547	2,327	8	226	218	3%	29%	27%	0%	3%	2%
10	Oak Grove - Galesburg	Flowgate	114	1,736	1,622	242	1,131	889	1%	20%	19%	3%	13%	10%
11	Linden - VFT	Line	173	2,602	2,429	0	0	0	2%	30%	28%	0%	0%	0%
12	Bunsonville - Eugene	Flowgate	31	2,444	2,413	0	11	11	0%	28%	28%	0%	0%	0%
13	Athenia - Saddlebrook	Line	3,317	1,398	(1,919)	364	4	(360)	38%	16%	(22%)	4%	0%	(4%)
14	Brues - West Bellaire	Line	0	1,718	1,718	78	598	520	0%	20%	20%	1%	7%	6%
15	Tiltonsville - Windsor	Line	2,723	1,004	(1,719)	506	72	(434)	31%	11%	(20%)	6%	1%	(5%)
16	East Frankfort - Crete	Line	3,084	1,546	(1,538)	850	329	(521)	35%	18%	(18%)	10%	4%	(6%)
17	Bedington - Black Oak	Interface	2,283	679	(1,604)	212	7	(205)	26%	8%	(18%)	2%	0%	(2%)
18	Cumberland - Bush	Flowgate	0	1,599	1,599	22	215	193	0%	18%	18%	0%	2%	2%
19	Doubs	Transformer	1,363	59	(1,304)	500	51	(449)	16%	1%	(15%)	6%	1%	(5%)
20	Fairview	Transformer	536	2,288	1,752	0	0	0	6%	26%	20%	0%	0%	0%
21	Waukegan - Zion	Line	95	1,734	1,639	0	7	7	1%	20%	19%	0%	0%	0%
22	Crete - St Johns Tap	Flowgate	2,051	3,354	1,303	810	1,115	305	23%	38%	15%	9%	13%	3%
23	Conesville Prep - Conesville	Line	187	1,782	1,595	0	0	0	2%	20%	18%	0%	0%	0%
24	Pleasant Valley - Belvidere	Line	2,529	1,093	(1,436)	467	315	(152)	29%	12%	(16%)	5%	4%	(2%)
25	Marquis - Dept of Energy	Line	6	1,498	1,492	0	0	0	0%	17%	17%	0%	0%	0%

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Table 10-27 Top 25 constraints affecting annual PJM congestion costs (By facility): Calendar year 2011

				Congestion Costs (Millions)									Percent of Total PJM Congestion Costs
				Day Ahead				Balancing					
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	2011
1	AP South	Interface	500	$96.1	($140.1)	($0.1)	$236.1	$18.7	$16.0	$0.0	$2.8	$238.9	24%
2	5004/5005 Interface	Interface	500	($25.2)	($101.5)	($4.6)	$71.7	$16.1	$19.3	$7.6	$4.3	$76.1	8%
3	West	Interface	500	($19.3)	($83.4)	($5.0)	$59.1	$0.2	$0.1	$0.1	$0.3	$59.3	6%
4	Belmont	Transformer	AP	$7.7	($49.9)	($2.2)	$55.5	($3.5)	($3.2)	($1.6)	($1.8)	$53.7	5%
5	AEP-DOM	Interface	500	$14.6	($21.5)	$2.1	$38.2	$2.0	$1.5	($0.4)	$0.1	$38.3	4%
6	Electric Jct - Nelson	Line	ComEd	($10.8)	($44.4)	$7.7	$41.3	$0.4	$3.7	($7.7)	($11.0)	$30.3	3%
7	Bedington - Black Oak	Interface	500	$10.9	($14.6)	($2.0)	$23.5	$0.2	$0.1	$0.0	$0.1	$23.7	2%
8	Crete - St Johns Tap	Flowgate	MISO	($32.9)	($66.4)	($5.3)	$28.2	$6.3	$6.7	($4.5)	($4.9)	$23.3	2%
9	Clover	Transformer	Dominion	$0.4	($21.4)	$4.6	$26.4	$2.8	$3.4	($7.8)	($8.5)	$17.9	2%
10	East	Interface	500	($11.5)	($31.5)	($1.2)	$18.7	$0.2	$1.3	$0.1	($1.0)	$17.8	2%
11	Dickerson - Quince Orchard	Line	Pepco	($9.4)	($28.8)	($1.7)	$17.7	$4.6	$7.4	$2.7	($0.2)	$17.5	2%
12	Oak Grove - Galesburg	Flowgate	MISO	($13.6)	($22.0)	$6.3	$14.6	($2.5)	$6.0	($20.8)	($29.3)	($14.7)	(1%)
13	Susquehanna	Transformer	PPL	($2.9)	($17.4)	($0.1)	$14.4	$0.0	$0.0	$0.0	$0.0	$14.4	1%
14	Graceton - Raphael Road	Line	BGE	$10.9	($1.1)	($0.8)	$11.2	$0.7	($1.1)	$0.5	$2.4	$13.5	1%
15	Wylie Ridge	Transformer	AP	$15.3	$3.6	$1.8	$13.6	$2.2	$1.2	($2.5)	($1.5)	$12.1	1%
16	East Frankfort - Crete	Line	ComEd	($10.0)	($23.7)	($1.3)	$12.4	$0.6	$0.6	($0.6)	($0.6)	$11.8	1%
17	Brues - West Bellaire	Line	AEP	$19.8	$4.5	$0.7	$16.1	($2.1)	$1.8	($1.5)	($5.4)	$10.7	1%
18	Breed - Wheatland	Line	AEP	($4.8)	($13.2)	$2.0	$10.5	$0.0	($0.0)	($0.1)	($0.0)	$10.4	1%
19	Waldwick	Transformer	PSEG	($0.5)	($2.3)	$2.1	$3.8	$0.1	$1.3	($12.5)	($13.8)	($9.9)	(1%)
20	Plymouth Meeting - Whitpain	Line	PECO	($0.9)	($10.8)	($0.0)	$9.9	$0.2	$0.2	($0.1)	($0.2)	$9.7	1%
21	Cloverdale	Transformer	AEP	$0.5	($7.6)	$1.6	$9.7	$0.7	$0.6	($0.1)	($0.0)	$9.7	1%
22	Bunsonville - Eugene	Flowgate	MISO	($11.5)	($19.0)	$2.1	$9.6	$0.0	($0.0)	($0.0)	($0.0)	$9.6	1%
23	Unclassified	Unclassified	Unclassified	$1.1	($1.5)	$5.4	$8.0	$1.2	$0.3	($1.4)	($0.5)	$7.5	1%
24	Pleasant Valley - Belvidere	Line	ComEd	($6.6)	($17.6)	$1.7	$12.7	($0.6)	$2.1	($3.0)	($5.7)	$7.0	1%
25	Cloverdale - Lexington	Line	500	$4.9	($2.9)	$1.3	$9.1	$3.3	$2.1	($3.8)	($2.7)	$6.4	1%

Constraint Costs

Table 10-27 and Table 10-28 present the top constraints affecting congestion costs by facility for calendar years 2011 and 2010. The AP South interface was the largest contributor to congestion costs in 2011. With $238.9 million in total congestion costs, it accounted for 23.9 percent of the total PJM congestion costs in 2011. The top five constraints in terms of congestion costs together comprised 46.7 percent of the total PJM congestion costs in 2011.

Congestion-Event Summary for MISO Flowgates

PJM and MISO have a joint operating agreement (JOA) which defines a coordinated methodology for congestion management. This agreement establishes reciprocal, coordinated flowgates in the combined footprint whose operating limits are respected by the operators of both organizations.[36] A flowgate is a facility or group of facilities that may act as constraint points on the regional system.[37] PJM models these coordinated flowgates and controls for them in its security-constrained, economic dispatch. Table 10-29 and Table 10-30 show the MISO flowgates which PJM took dispatch action to control during 2011 and 2010, respectively, and which had the greatest congestion cost impact on PJM. Total congestion costs are the sum of the day-ahead and balancing congestion cost components. Total congestion costs associated with a given constraint may be positive or negative in value. The top congestion cost impacts for MISO flowgates affecting PJM dispatch are presented by constraint, in descending order of the absolute value of total congestion costs. Among MISO flowgates in 2011, the Crete – St Johns Tap flowgate made the most significant contribution to positive congestion while the Oak Grove – Galesburg flowgate made the most significant contribution to negative congestion.

36 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (December 11, 2009) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx> (Accessed March 13, 2012).

37 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (December 11, 2009), Section 2.2.24 <http://www.pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx> (Accessed March 13, 2012) .

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Table 10-28 Top 25 constraints affecting annual PJM congestion costs (By facility): Calendar year 2010

				Congestion Costs (Millions)									Percent of Total PJM Congestion Costs
				Day Ahead				Balancing					
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	2010
1	AP South	Interface	500	$128.3	($292.9)	($2.3)	$419.0	$15.5	$15.7	$1.5	$1.3	$420.2	30%
2	Bedington - Black Oak	Interface	500	$44.6	($60.3)	$2.7	$107.7	$0.7	$1.9	($1.6)	($2.9)	$104.8	7%
3	5004/5005 Interface	Interface	500	($14.6)	($106.4)	$0.0	$91.8	$12.3	$10.8	($1.3)	$0.1	$92.0	6%
4	Doubs	Transformer	AP	$9.6	($57.8)	$0.7	$68.1	$3.1	$4.1	($2.8)	($3.8)	$64.4	5%
5	AEP-DOM	Interface	500	$10.2	($53.0)	$2.5	$65.8	$0.5	$1.2	($2.8)	($3.5)	$62.3	4%
6	East Frankfort - Crete	Line	ComEd	($22.0)	($67.5)	$6.1	$51.6	($3.9)	$0.2	($7.6)	($11.7)	$39.8	3%
7	Crete - St Johns Tap	Flowgate	MISO	($46.0)	($88.6)	($5.1)	$37.4	$1.4	$0.2	($9.0)	($7.8)	$29.6	2%
8	Cloverdale - Lexington	Line	500	$19.6	($11.2)	$3.0	$33.7	($2.5)	($3.4)	($5.5)	($4.7)	$29.1	2%
9	Belmont	Transformer	AP	$4.1	($26.8)	($0.6)	$30.2	($6.8)	($3.6)	($0.3)	($3.6)	$26.6	2%
10	Brandon Shores - Riverside	Line	BGE	($15.5)	($42.4)	($0.4)	$26.5	$0.2	$1.7	$0.4	($1.1)	$25.4	2%
11	Mount Storm - Pruntytown	Line	500	$11.8	($10.4)	$2.1	$24.3	$2.0	($2.9)	($4.8)	$0.1	$24.4	2%
12	West	Interface	500	($2.1)	($25.2)	($0.2)	$22.9	$1.0	$1.6	$0.0	($0.6)	$22.3	2%
13	Tiltonsville - Windsor	Line	AP	$6.0	($17.5)	$1.4	$24.9	($3.5)	$1.1	($0.9)	($5.5)	$19.4	1%
14	Unclassified	Unclassified	Unclassified	$0.7	($10.5)	$6.2	$17.4	$0.0	$0.0	$0.0	$0.0	$17.4	1%
15	Pleasant Valley - Belvidere	Line	ComEd	($17.5)	($37.7)	$3.5	$23.7	$0.2	$3.1	($4.9)	($7.8)	$15.9	1%
16	Graceton - Raphael Road	Line	BGE	$9.1	($3.8)	$0.6	$13.6	$0.4	($1.3)	($0.2)	$1.5	$15.1	1%
17	Brunner Island - Yorkana	Line	Met-Ed	$2.8	($9.9)	$0.4	$13.0	$1.2	($0.6)	($0.9)	$1.0	$14.0	1%
18	Crescent	Transformer	DLCO	$5.6	($7.5)	$0.8	$13.9	($0.1)	($0.6)	($1.0)	($0.4)	$13.5	1%
19	Clover	Transformer	Dominion	$2.8	($11.1)	$2.1	$15.9	($1.1)	($1.1)	($3.2)	($3.3)	$12.6	1%
20	Millville - Sleepy Hollow	Line	Dominion	$6.2	($5.8)	$0.3	$12.2	$0.0	$0.0	$0.0	$0.0	$12.2	1%
21	Millville - Old Chapel	Line	Dominion	$2.9	($8.3)	$1.0	$12.2	$0.0	$0.0	$0.0	$0.0	$12.2	1%
22	Branchburg - Readington	Line	PSEG	($4.7)	($17.7)	$0.7	$13.7	($0.3)	$1.6	$0.2	($1.8)	$11.9	1%
23	Kanawha - Kincaid	Line	AEP	$6.1	($4.0)	$1.5	$11.6	$0.0	$0.0	$0.0	$0.0	$11.6	1%
24	Pleasant Prairie - Zion	Flowgate	MISO	($4.2)	($8.7)	$3.0	$7.5	($0.4)	$1.2	($16.7)	($18.4)	($10.9)	(1%)
25	Eddystone - Island Road	Line	PECO	$3.1	($5.4)	$1.1	$9.6	($0.0)	($0.0)	$0.0	($0.0)	$9.5	1%

Table 10-29 Top congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): Calendar year 2011

		Congestion Costs (Millions)										
		Day Ahead				Balancing					Event Hours	
No.	Constraint	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Crete - St Johns Tap	($32.9)	($66.4)	($5.3)	$28.2	$6.3	$6.7	($4.5)	($4.9)	$23.3	3,354	1,115
2	Oak Grove - Galesburg	($13.6)	($22.0)	$6.3	$14.6	($2.5)	$6.0	($20.8)	($29.3)	($14.7)	1,736	1,131
3	Bunsonville - Eugene	($11.5)	($19.0)	$2.1	$9.6	$0.0	($0.0)	($0.0)	($0.0)	$9.6	2,444	11
4	Lakeview - Pleasant Prairie	($0.1)	($0.2)	$0.2	$0.3	($0.3)	($0.1)	($5.7)	($5.8)	($5.6)	24	302
5	Burnham - Munster	($10.9)	($19.0)	($3.0)	$5.1	$0.0	$0.0	$0.0	$0.0	$5.1	1,152	0
6	Stillwell	($0.0)	($0.4)	($0.1)	$0.3	($0.3)	$1.3	($3.6)	($5.2)	($4.9)	93	88
7	Michigan City - Laporte	($10.4)	($16.4)	$3.0	$9.0	($1.7)	($1.3)	($3.8)	($4.2)	$4.8	2,935	632
8	Pleasant Prairie - Zion	($1.2)	($2.3)	$2.0	$3.1	($0.1)	($0.5)	($7.9)	($7.5)	($4.4)	839	210
9	Breed - Wheatland	$0.0	$0.0	$0.0	$0.0	$0.4	$0.3	($4.4)	($4.2)	($4.2)	0	213
10	Cook - Palisades	($1.3)	($5.2)	$0.3	$4.1	$0.0	$0.0	($0.2)	($0.2)	$3.9	481	9
11	Rantoul - Rantoul Jct	($3.2)	($5.5)	$0.6	$3.0	$0.1	$0.0	($0.5)	($0.4)	$2.6	553	188
12	Benton Harbor - Palisades	($0.2)	($1.0)	$0.2	$1.0	$0.8	$1.2	($2.8)	($3.2)	($2.2)	67	132
13	St John - Liberty Park	($1.8)	($6.0)	$0.6	$4.8	$0.6	$1.0	($2.2)	($2.6)	$2.2	334	161
14	Nucor - Whitestown	$0.0	$0.0	$0.0	$0.0	$0.2	$0.5	($1.8)	($2.1)	($2.1)	0	56
15	Temporary Monticello - E Wiinamac	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.5	($1.2)	($1.7)	($1.7)	0	69
16	Eugene - Bunsonville	$0.0	$0.0	$0.0	$0.0	$0.1	$0.1	($1.7)	($1.6)	($1.6)	0	107
17	Cumberland - Bush	($1.0)	($5.8)	$2.1	$6.9	$0.2	$0.9	($4.6)	($5.3)	$1.6	1,599	215
18	Rising	($5.2)	($8.1)	($0.1)	$2.8	$0.0	$1.1	($3.3)	($4.4)	($1.6)	947	175
19	Green Acres - St John	$0.0	$0.0	$0.0	$0.0	$0.6	$1.4	($0.7)	($1.5)	($1.5)	0	147
20	Rantoul Jct - Sidney	($1.0)	($2.0)	$0.1	$1.1	$0.5	$0.0	($0.2)	$0.3	$1.3	62	113

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Table 10-30 Top congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): Calendar year 2010

		Congestion Costs (Millions)										
		Day Ahead				Balancing					Event Hours	
No.	Constraint	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Crete - St Johns Tap	($46.0)	($88.6)	($5.1)	$37.4	$1.4	$0.2	($9.0)	($7.8)	$29.6	2,051	810
2	Pleasant Prairie - Zion	($4.2)	($8.7)	$3.0	$7.5	($0.4)	$1.2	($16.7)	($18.4)	($10.9)	1,321	404
3	Benton Harbor - Palisades	$0.0	($0.0)	$0.0	$0.1	($0.0)	$0.8	($4.5)	($5.3)	($5.2)	11	114
4	Rising	($1.7)	($6.8)	$0.9	$6.0	($0.1)	$0.6	($0.9)	($1.6)	$4.4	875	80
5	Oak Grove - Galesburg	($0.3)	($0.6)	$0.2	$0.4	($0.2)	$0.7	($3.0)	($3.9)	($3.4)	114	242
6	Dunes Acres - Michigan City	($0.3)	($1.5)	$0.9	$2.1	($0.1)	($0.3)	$0.4	$0.6	$2.7	264	42
7	Palisades - Vergennes	$1.1	($2.2)	$0.5	$3.9	($0.1)	$0.5	($0.9)	($1.5)	$2.4	235	91
8	Breed - Wheatland	$0.0	$0.0	$0.0	$0.0	$0.1	$0.1	($2.0)	($2.1)	($2.1)	0	76
9	Burnham - Sheffield	($1.8)	($3.3)	$0.4	$2.0	$0.0	$0.0	$0.0	$0.0	$2.0	252	0
10	Cook - Palisades	$0.0	($0.1)	$0.1	$0.2	($0.3)	$0.2	($1.5)	($2.0)	($1.7)	13	39
11	Paxton - Sidney	$0.0	$0.0	$0.0	$0.0	$0.0	$0.2	($1.4)	($1.5)	($1.5)	0	29
12	Burr Oak	$0.2	($0.2)	$0.0	$0.4	$0.4	$0.4	($1.9)	($1.8)	($1.5)	140	210
13	State Line - Wolf Lake	$0.1	($0.9)	$0.6	$1.5	($0.1)	$0.0	($0.0)	($0.1)	$1.4	376	7
14	Marktown - Inland Steel	($0.7)	($2.2)	$0.7	$2.2	($0.9)	$0.8	($1.4)	($3.1)	($0.9)	424	344
15	Eugene - Bunsonville	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.1	($0.8)	($0.9)	($0.9)	0	51
16	Michigan City - Laporte	($0.0)	($0.2)	$0.1	$0.3	($0.2)	($0.0)	($0.7)	($0.9)	($0.7)	50	67
17	Lanesville	$0.0	$0.0	$0.0	$0.0	$0.0	$0.1	($0.4)	($0.5)	($0.5)	0	48
18	Beaver Valley - Sammis	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.1	($0.2)	($0.4)	($0.4)	0	8
19	Nucor - Whitestown	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.4)	($0.4)	($0.4)	0	23
20	Stillwell - Dumont	($0.2)	($0.4)	$0.1	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	42	0

Congestion-Event Summary for the 500 kV System

Constraints on the 500 kV system generally have a regional impact. Table 10-31 and Table 10-32 show the 500 kV constraints impacting congestion costs in PJM for year 2010 and 2011 respectively. Total congestion costs are the sum of the day-ahead and balancing congestion cost components. Total congestion costs associated with a given constraint may be positive or negative in value. The 500 kV constraints impacting congestion costs in PJM are presented by constraint, in descending order of the absolute value of total congestion costs. In 2011, the AP South interface constraint contributed to positive congestion. There were no significant contributions to negative congestion from 500 kV constraints in 2011.

Congestion Costs by Physical and Financial Participants

In the PJM market, both physical and financial participants make virtual supply offers (increments) and virtual demand bids (decrements). A participant is classified as a physical entity if the entity primarily takes physical positions in PJM markets. Physical entities include utilities and wholesale customers. Financial entities include banks, hedge funds, retail service providers and speculators, who primarily take financial positions in PJM markets. All affiliates are considered a single entity for this categorization. For example, under this classification, the trading affiliate of a utility would be treated as a physical company. In 2011, financial companies as a group were net recipients of congestion credits, whereas physical companies were net payers of congestion charges.[38] In 2011, financial companies received net $108.2 million, a decrease of $60.3 million or 35.8 percent compared to 2010. In 2011, physical companies paid net $1,107.2 million in congestion charges, a decrease of $484.9 million or 30.5 percent compared to 2010.

38 The total zonal congestion numbers were calculated as of March 2, 2012 and are, based on continued PJM billing updates, subject to change. As of March 2, 2012 the total zonal congestion related numbers presented here differed from the March 2, 2012 PJM totals by $0.72 Million, a discrepancy of 0.07 percent (.0007).

Table 10-31 Regional constraints summary (By facility): Calendar year 2011

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	$96.1	($140.1)	($0.1)	$236.1	$18.7	$16.0	$0.0	$2.8	$238.9	4,111	1,013
2	5004/5005 Interface	Interface	500	($25.2)	($101.5)	($4.6)	$71.7	$16.1	$19.3	$7.6	$4.3	$76.1	905	470
3	West	Interface	500	($19.3)	($83.4)	($5.0)	$59.1	$0.2	$0.1	$0.1	$0.3	$59.3	867	20
4	AEP-DOM	Interface	500	$14.6	($21.5)	$2.1	$38.2	$2.0	$1.5	($0.4)	$0.1	$38.3	1,786	185
5	Bedington - Black Oak	Interface	500	$10.9	($14.6)	($2.0)	$23.5	$0.2	$0.1	$0.0	$0.1	$23.7	679	7
6	East	Interface	500	($11.5)	($31.5)	($1.2)	$18.7	$0.2	$1.3	$0.1	($1.0)	$17.8	522	22
7	Cloverdale - Lexington	Line	500	$4.9	($2.9)	$1.3	$9.1	$3.3	$2.1	($3.8)	($2.7)	$6.4	602	427
8	Central	Interface	500	($1.5)	($2.8)	($0.0)	$1.3	($0.1)	($0.1)	($0.1)	($0.1)	$1.2	118	8
9	Mount Storm - Pruntytown	Line	500	$0.1	($0.2)	$0.0	$0.3	$0.2	$0.0	($0.1)	$0.0	$0.3	29	38
10	Doubs - Mount Storm	Line	500	$0.0	($0.3)	($0.0)	$0.3	($0.0)	$0.0	($0.0)	($0.0)	$0.3	9	4
11	Harrison - Pruntytown	Line	500	$0.0	($0.1)	$0.0	$0.1	($0.0)	($0.0)	$0.0	$0.0	$0.1	10	4
12	Kammer	Transformer	500	($0.0)	($0.1)	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	4	0
13	Dominion East	Interface	500	$0.0	$0.0	$0.0	$0.0	$0.3	$0.1	($0.2)	$0.0	$0.0	0	38
14	Conemaugh - Hunterstown	Line	500	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	0	9

Table 10-32 Regional constraints summary (By facility): Calendar year 2010

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	$128.3	($292.9)	($2.3)	$419.0	$15.5	$15.7	$1.5	$1.3	$420.2	4,622	1,516
2	Bedington - Black Oak	Interface	500	$44.6	($60.3)	$2.7	$107.7	$0.7	$1.9	($1.6)	($2.9)	$104.8	2,283	212
3	5004/5005 Interface	Interface	500	($14.6)	($106.4)	$0.0	$91.8	$12.3	$10.8	($1.3)	$0.1	$92.0	1,642	605
4	AEP-DOM	Interface	500	$10.2	($53.0)	$2.5	$65.8	$0.5	$1.2	($2.8)	($3.5)	$62.3	691	187
5	Cloverdale - Lexington	Line	500	$19.6	($11.2)	$3.0	$33.7	($2.5)	($3.4)	($5.5)	($4.7)	$29.1	1,128	684
6	Mount Storm - Pruntytown	Line	500	$11.8	($10.4)	$2.1	$24.3	$2.0	($2.9)	($4.8)	$0.1	$24.4	571	574
7	West	Interface	500	($2.1)	($25.2)	($0.2)	$22.9	$1.0	$1.6	$0.0	($0.6)	$22.3	181	65
8	East	Interface	500	($2.5)	($10.2)	$0.1	$7.8	($0.0)	($0.0)	$0.0	$0.0	$7.8	256	8
9	Harrison - Pruntytown	Line	500	$1.8	($4.2)	$0.8	$6.9	$0.4	$0.6	($2.7)	($2.9)	$4.0	231	223
10	Central	Interface	500	($0.9)	($2.2)	$0.1	$1.4	$0.2	$0.1	($0.1)	($0.0)	$1.4	117	13
11	Conemaugh - Hunterstown	Line	500	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.1	($0.1)	($0.3)	($0.3)	0	5
12	Doubs - Mount Storm	Line	500	$0.0	$0.0	$0.0	$0.0	$1.0	$1.3	($0.1)	($0.3)	($0.3)	0	45
13	Harrison Tap - North Longview	Line	500	$0.0	($0.1)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	6	0
14	Juniata - Keystone	Line	500	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	0	1

Table 10-33 Congestion cost by the type of the participant: Calendar year 2011

	Congestion Costs (Millions)									
	Day Ahead				Balancing					
Participant Type	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Inadvertent Charges	Grand Total
Financial	$80.3	$28.1	$70.7	$122.8	($44.6)	$12.2	($174.2)	($231.0)	$0.0	($108.2)
Physical	($44.0)	($1,169.9)	($3.8)	$1,122.1	$120.6	$119.7	($15.9)	($15.0)	$0.0	$1,107.2
Total	$36.2	($1,141.8)	$66.9	$1,245.0	$75.9	$131.9	($190.0)	($246.0)	$0.0	$999.0

Table 10-34 Congestion cost by the type of the participant: Calendar year 2010

	Congestion Costs (Millions)									
	Day Ahead				Balancing					
Participant Type	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Inadvertent Charges	Grand Total
Financial	$65.5	$31.5	$84.8	$118.9	($84.3)	$29.2	($173.9)	($287.4)	($0.0)	($168.5)
Physical	$185.9	($1,396.3)	$12.1	$1,594.3	$84.1	$80.8	($5.4)	($2.1)	($0.0)	$1,592.1
Total	$251.4	($1,364.9)	$96.9	$1,713.1	($0.1)	$110.1	($179.3)	($289.5)	$0.0	$1,423.6

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