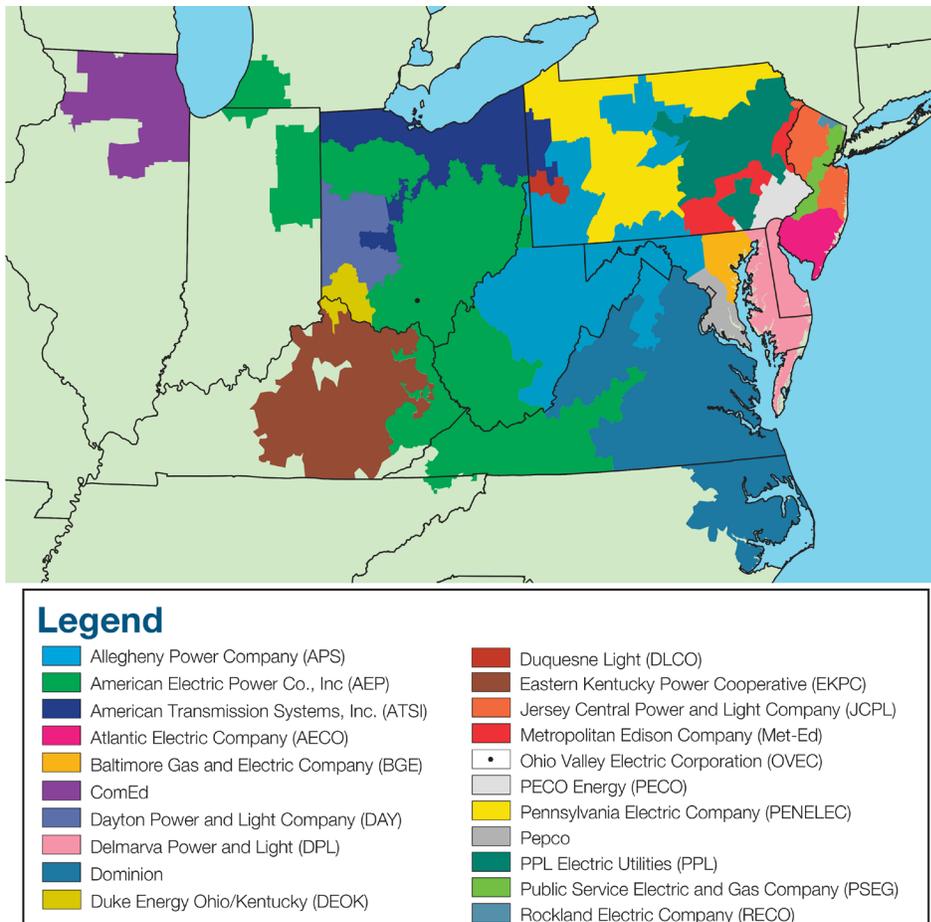


Appendix A PJM Overview

PJM Geography

In 2019, the PJM footprint included 21 control zones located in Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

Figure A-1 PJM's footprint and its 21 control zones



Analysis of 2019 market results includes comparisons to market results in prior years. In December 2018, PJM integrated the Ohio Valley Electric Corporation (OVEC.) In 2017, 2016, 2015 and 2014 no changes were made to the PJM footprint. In 2013, PJM integrated the Eastern Kentucky Power Cooperative (EKPC) Control Zone. In 2012, PJM integrated the Duke Energy Ohio and Kentucky (DEOK) Control Zone. In 2011, PJM integrated the ATSI Control Zone. In 2006 through 2010, the PJM footprint was stable. In 2004 and 2005, PJM integrated five new control zones, three in 2004 and two in 2005.

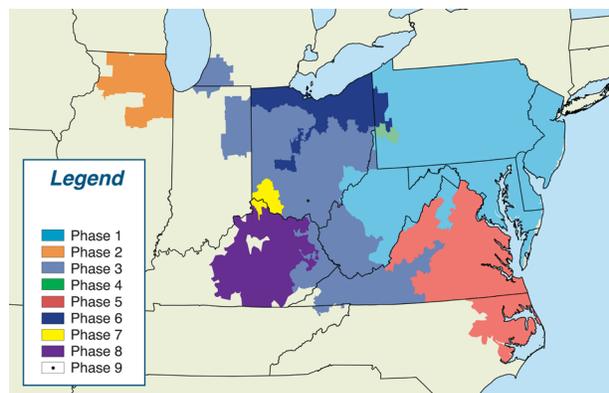
Figure A-2 shows the nine phases corresponding to market integration dates:¹

- **Phase 1 (2004).** The four-month period from January 1, through April 30, 2004, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones, and the Allegheny Power System (APS) Control Zone.^{2 3}
- **Phase 2 (2004).** The five-month period from May 1, through September 30, 2004, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones, the APS Control Zone and the ComEd Control Area.⁴
- **Phase 3 (2004).** The three-month period from October 1, through December 31, 2004, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones, the APS Control Zone and the ComEd Control Zone plus the American Electric Power Control Zone (AEP) and The Dayton Power & Light Company Control Zone (DAY). The ComEd Control Area became the ComEd Control Zone on October 1.
- **Phase 4 (2005).** The four-month period from January 1, through April 30, 2005, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones, the APS Control Zone, the ComEd Control Zone, the AEP Control Zone and the DAY Control Zone plus the Duquesne Light Company (DLCO) Control Zone which was integrated into PJM on January 1, 2005.
- **Phase 5 (2005 through 2011).** The period from May 1, 2005, through May 31, 2011, during which PJM was comprised of the Phase 4 elements plus the Dominion Control Zone which was integrated into PJM on May 1, 2005.
- **Phase 6 (2011).** The period from June 1, through December 31, 2011, during which PJM was comprised of the Phase 5 elements plus the ATSI

Control Zone which was integrated into PJM on June 1, 2011.

- **Phase 7 (2012).** The period from January 1, 2012, through May 31, 2013, during which PJM was comprised of the Phase 6 elements plus the DEOK Control Zone which was integrated into PJM on January 1, 2012.
- **Phase 8 (2013 through November 2018).** The period from June 1, 2013, through November 30, 2018, during which PJM was comprised of the Phase 7 elements plus the EKPC Control Zone which was integrated into PJM on June 1, 2013.
- **Phase 9 (December 2018 through the present).** The period from December 1, 2018, through the present, during which PJM was comprised of the Phase 8 elements plus the OVEC Control Zone which was integrated into PJM on December 1, 2018.

Figure A-2 PJM integration phases



A locational deliverability area (LDA), defined in the RPM Capacity Market, is a Control Zone, part of a Control Zone, or a combination of Control Zones within PJM with defined internal generation and defined transmission capability to import capacity.⁵

Figure A-3 shows LDAs that are combinations of Control Zones. Figure A-4 and Figure A-5 show LDAs that are part of a Control Zone.

¹ See the 2004 State of the Market Report (March 8, 2005) for more detailed descriptions of Phases 1, 2 and 3 and the 2005 State of the Market Report (March 8, 2006) for more detailed descriptions of Phases 4 and 5.

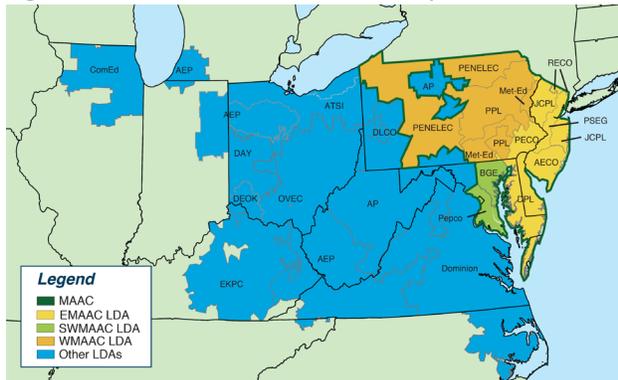
² The Mid-Atlantic Region is comprised of the AECO, BGE, DPL, JCPL, Met-Ed, PECCO, PENELEC, Pepco, PPL, PSEG and RECO Control Zones. The AP Control Zone was integrated in 2002. The RECO Control Zone was integrated in 2002.

³ Zones, control zones and control areas are geographic areas that customarily bear the name of a large utility service provider operating within their boundaries. Names apply to the geographic area, not to any single company. The geographic areas did not change with the formalization of these concepts during PJM integrations. For simplicity, zones are referred to as control zones for all phases. The only exception is ComEd which is called the ComEd Control Area for Phase 2 only.

⁴ During the five-month period May 1, through September 30, 2004, the ComEd Control Zone (ComEd) was called the Northern Illinois Control Area (NICA).

⁵ OATT Attachment DD § 2.38.

Figure A-3 PJM locational deliverability areas



In PJM's Reliability Pricing Model (RPM) Auctions, an LDA becomes a separate market when it cannot meet its reliability requirements through a combination of economic merit order imports and internal capacity without the purchase of out of merit capacity internal capacity. The regional transmission organization (RTO) market comprises the entire PJM footprint, unless an LDA is constrained. Each constrained LDA or group of LDAs is a separate market with a separate clearing price, and the Rest of RTO market is the balance of the footprint.

For the 2007/2008 and 2008/2009 Base Residual Auctions, the defined markets were RTO, EMAAC and SWMAAC. For the 2009/2010 Base Residual Auction, the defined markets were RTO, MAAC+APS and SWMAAC. The MAAC+APS LDA consists of the WMAAC, EMAAC, and SWMAAC LDAs, as shown in Figure A-3, plus the Allegheny Power System (APS) Zone as shown in Figure A-1. For the 2010/2011 Base Residual Auction, the defined markets were RTO and DPL South. The DPL South LDA is shown in Figure A-4. For the 2011/2012 Base Residual Auction, the only defined market was RTO. For the 2012/2013 Base Residual Auction, the defined markets were RTO, MAAC, EMAAC, PSEG North, and DPL South. The PSEG North LDA is shown in Figure A-4. For the 2013/2014 Base Residual Auction, the defined markets were RTO, MAAC, EMAAC, and Pepco. For the 2014/2015 Base Residual Auction, the defined markets were RTO, MAAC, and PSEG North. For the 2015/2016 Base Residual Auction, the defined markets were RTO, MAAC, and ATSI. For the 2016/2017 Base Residual Auction, the defined markets were RTO, MAAC, PSEG, and ATSI. For the 2017/2018 Base Residual Auction, the defined markets were RTO and PSEG. For the 2018/2019 Base Residual Auction, the

defined markets were RTO, EMAAC, and ComEd. For the 2019/2020 Base Residual Auction, the defined markets were RTO, EMAAC, ComEd, and BGE. For the 2020/2021 Base Residual Auction, the defined markets were RTO, MAAC, EMAAC, ComEd, and DEOK. For the 2021/2022 Base Residual Auction, the defined markets were RTO, EMAAC, PSEG, ATSI, ComEd, and BGE.

Figure A-4 PJM RPM EMAAC locational deliverability area, including PSEG North and DPL South

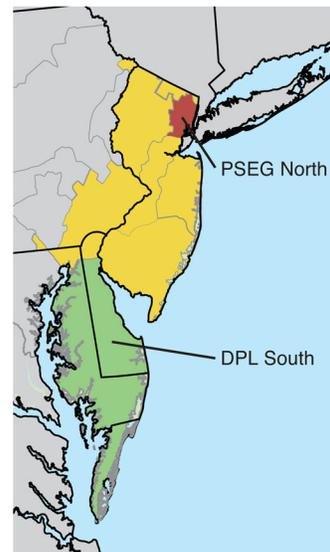
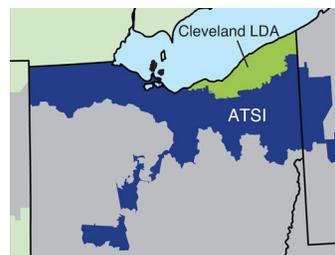


Figure A-5 Map of PJM RPM ATSI subzonal LDA



PJM Market Milestones

Table A-1 PJM Market Milestones: 1999 through 2019

Year	Month	Event
1996	April	FERC Order 888, "Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities"
1997	April	Energy Market with cost-based offers and market-clearing prices
	November	FERC approval of ISO status for PJM
1998	April	Cost-based Energy LMP Market
1999	January	Daily Capacity Market
	March	FERC approval of market-based rates for PJM
	March	Monthly and Multimonthly Capacity Market
	March	FERC approval of Market Monitoring Plan
	April	Offer-based Energy LMP Market
	April	FTR Market
2000	June	Regulation Market
	June	Day-Ahead Energy Market
	July	Customer Load-Reduction Pilot Program
2001	June	PJM Emergency and Economic Load-Response Programs
2002	April	Integration of AP Control Zone into PJM Western Region
	June	PJM Emergency and Economic Load-Response Programs
	December	Spinning Reserve Market
	December	FERC approval of RTO status for PJM
	May	Annual FTR Auction
2003	June	Auction Revenue Rights (ARRs)
2004	May	Integration of ComEd Control Area into PJM
	October	Integration of AEP Control Zone into PJM Western Region
	October	Integration of DAY Control Zone into PJM Western Region
2005	January	Integration of DLCO Control Zone into PJM
	May	Integration of Dominion Control Zone into PJM
2006	May	Balance of Planning Period FTR Auction
2007	April	First RPM Auction
	June	Marginal loss component in LMPs
2008	June	Day-Ahead Scheduling Reserve (DASR) Market
	August	Independent, External MMU created as Monitoring Analytics, LLC
	October	Long Term FTR Auction
	December	Modified Operating Reserve accounting rules
	December	Three Pivotal Supplier Test in Regulation Market
2011	June	Integration of ATSI Control Zone into PJM
2012	January	Integration of DEOK Control Zone into PJM
	October	Regulation Market: Slow and fast frequency response
	October	Scarcity pricing in Energy Market
2013	June	Integration of Eastern Kentucky Power Cooperative (EKPC) into PJM
2015	August	First Capacity Performance Auction
2018	December	Integration of Ohio Valley Electric Corporation (OVEC) into PJM

Total Price of Wholesale Power in PJM

The total price of wholesale power is the total price per MWh of purchasing wholesale electricity from PJM markets. The total price is an average price and actual prices vary by location and time period. The total price includes the price of energy, capacity, ancillary services, and transmission service, administrative fees, regulatory support fees and uplift charges billed through PJM systems. Table A-2 shows the average price, by component, for 1999 through 2019.

The total billing values shown in Table A-2 and Table A-3 are the total price per MWh multiplied by the total load. This represents the total dollars charged for purchasing wholesale electricity from PJM markets. This total is different from the total billing that PJM reports as shown in Table 1-1. PJM's reported total billing represents the total dollars that pass through the PJM settlement process. There are issues with the PJM total billing calculations. The PJM total billing calculation includes all billing line item charges including monthly billing adjustments for the month in which PJM makes the adjustment rather than the month to which the adjustment applies. Rather than adding positive and negative spot market and congestion charges, PJM calculates the average of the absolute value of the positive and negative charges. PJM also makes adjustments to eliminate certain transmission owners' network charges and monthly bilateral corrections.

Each of the components is defined in PJM's Open Access Transmission Tariff (OATT) and PJM Operating Agreement and each is collected through PJM's billing system.

Components of Total Price

- The Energy component is the real-time load weighted average PJM locational marginal price (LMP).
- The Capacity component is the average price per MWh of Reliability Pricing Model (RPM) payments.
- The Transmission Service Charges component is the average price per MWh of network integration charges, and firm and nonfirm point to point transmission service.⁶
- The Energy Uplift (Operating Reserves) component is the average price per MWh of day-ahead and balancing operating reserves and synchronous condensing charges.⁷
- The Reactive component is the average cost per MWh of reactive supply and voltage control from generation and other sources.⁸
- The Regulation component is the average cost per MWh of regulation procured through the PJM Regulation Market.⁹
- The PJM Administrative Fees component is the average cost per MWh of PJM's monthly expenses for a number of administrative services, including Advanced Control Center (AC2) and OATT Schedule 9 funding of FERC, OPSI, CAPS and the MMU.
- The Transmission Enhancement Cost Recovery component is the average cost per MWh of PJM billed (and not otherwise collected through utility rates) costs for transmission upgrades and projects, including annual recovery for the TrAIL and PATH projects.¹⁰
- The Capacity (FRR) component is the average cost per MWh under the Fixed Resource Requirement (FRR) Alternative for an eligible LSE to satisfy its Unforced Capacity obligation.¹¹
- The Emergency Load Response component is the average cost per MWh of the PJM Emergency Load Response Program.¹²
- The Day-Ahead Scheduling Reserve component is the average cost per MWh of day-ahead scheduling reserves procured through the PJM Day-Ahead Scheduling Reserve Market.¹³
- The Transmission Owner (Schedule 1A) component is the average cost per MWh of transmission owner scheduling, system control and dispatch services charged to transmission customers.¹⁴
- The Synchronized Reserve component is the average cost per MWh of synchronized reserve procured through the PJM Synchronized Reserve Market.¹⁵
- The Black Start component is the average cost per MWh of black start service.¹⁶
- The RTO Startup and Expansion component is the average cost per MWh of charges to recover AEP, ComEd and DAY's integration expenses.¹⁷
- The NERC/RFC component is the average cost per MWh of NERC and RFC charges, plus any reconciliation charges.¹⁸
- The Economic Load Response component is the average cost per MWh of day-ahead and real-time economic load response program charges to LSEs.¹⁹
- The Transmission Facility Charges component is the average cost per MWh of Ramapo Phase Angle Regulators charges allocated to PJM Mid-Atlantic transmission owners.²⁰
- The Nonsynchronized Reserve component is the average cost per MWh of non-synchronized reserve procured through the PJM Nonsynchronized Reserve Market.²¹
- The Emergency Energy component is the average cost per MWh of emergency energy.²²

6 OATT §§ 13.7, 14.5, 27A & 34.

7 OATT Schedules 1 §§ 3.2.3 & 3.3.3.

8 OATT Schedule 2 and OATT Schedule 1 § 3.2.3B. The line item in Table 18 includes all reactive services charges.

9 OATT Schedules 1 §§ 3.2.2, 3.2.2A, 3.3.2, & 3.3.2A; OATT Schedule 3.

10 OATT Schedule 12.

11 RAA Schedule 8.1.

12 OATT PJM Emergency Load Response Program.

13 OATT Schedules 1 §§ 3.2.3A.01 & OATT Schedule 6.

14 OATT Schedule 1A.

15 OATT Schedule 1 § 3.2.3A.01; PJM OATT Schedule 6.

16 OATT Schedule 6A. The line item in Table 18 includes all Energy Uplift (Operating Reserves) charges for Black Start.

17 OATT Attachments H-13, H-14 and H-15 and Schedule 13.

18 OATT Schedule 10-NERC and OATT Schedule 10-RFC.

19 OATT Schedule 1 § 3.6.

20 OATT Schedule 1 § 5.3b.

21 OATT Schedule 1 § 3.2.3A.001.

22 OATT Schedule 1 § 3.2.6.

Table A-2 shows the average price, by component of the total wholesale power price per MWh, for calendar years 1999 through 2019.

Table A-2 Total price per MWh by category: 1999 through 2019²³

Category	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
	\$/MWh	\$/MWh	\$/MWh	\$/MWh	\$/MWh	\$/MWh	\$/MWh	\$/MWh	\$/MWh	\$/MWh	\$/MWh
Load Weighted Energy	\$34.07	\$30.72	\$36.65	\$31.60	\$41.23	\$44.34	\$63.46	\$53.35	\$61.66	\$71.13	\$39.05
Capacity	\$0.14	\$0.25	\$0.27	\$0.12	\$0.08	\$0.09	\$0.04	\$0.11	\$3.58	\$7.84	\$10.79
Capacity	\$0.14	\$0.25	\$0.27	\$0.12	\$0.08	\$0.09	\$0.03	\$0.03	\$3.53	\$7.80	\$10.78
Capacity (FRR)	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Capacity (RMR)	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.02	\$0.08	\$0.05	\$0.04	\$0.01
Transmission	\$3.49	\$4.13	\$3.56	\$3.46	\$3.64	\$3.43	\$3.30	\$3.34	\$3.55	\$3.83	\$4.22
Transmission Service Charges	\$3.41	\$4.03	\$3.48	\$3.39	\$3.57	\$3.28	\$2.71	\$3.18	\$3.45	\$3.68	\$4.03
Transmission Enhancement Cost Recovery	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.01	\$0.06	\$0.11
Transmission Owner (Schedule 1A)	\$0.07	\$0.09	\$0.08	\$0.07	\$0.07	\$0.10	\$0.09	\$0.09	\$0.09	\$0.09	\$0.09
Transmission Seams Elimination Cost Assignment (SECA)	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.05	\$0.50	\$0.07	\$0.00	\$0.00	\$0.00
Transmission Facility Charges	\$0.01	\$0.01	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Ancillary	\$0.41	\$0.68	\$0.75	\$0.63	\$0.91	\$0.91	\$1.19	\$0.92	\$1.00	\$1.15	\$0.78
Reactive	\$0.26	\$0.29	\$0.22	\$0.20	\$0.24	\$0.26	\$0.26	\$0.29	\$0.29	\$0.34	\$0.36
Regulation	\$0.15	\$0.39	\$0.53	\$0.42	\$0.50	\$0.51	\$0.80	\$0.53	\$0.63	\$0.70	\$0.34
Black Start	\$0.00	\$0.00	\$0.00	\$0.00	\$0.02	\$0.02	\$0.02	\$0.02	\$0.02	\$0.02	\$0.02
Synchronized Reserves	\$0.00	\$0.00	\$0.00	\$0.01	\$0.15	\$0.13	\$0.11	\$0.08	\$0.06	\$0.08	\$0.05
Non-Synchronized Reserves	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Day Ahead Scheduling Reserve (DASR)	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.01	\$0.00
Administration	\$0.23	\$0.26	\$0.73	\$0.86	\$1.05	\$1.00	\$0.73	\$0.75	\$0.75	\$0.41	\$0.34
PJM Administrative Fees	\$0.23	\$0.26	\$0.71	\$0.86	\$1.05	\$0.93	\$0.72	\$0.74	\$0.72	\$0.39	\$0.31
NERC/RFC	\$0.00	(\$0.00)	\$0.01	\$0.01	\$0.01	\$0.01	\$0.01	(\$0.00)	\$0.01	\$0.01	\$0.02
RTO Startup and Expansion	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.06	\$0.01	\$0.01	\$0.01	\$0.01	\$0.01
Energy Uplift (Operating Reserves)	\$0.52	\$0.93	\$1.27	\$0.72	\$0.89	\$0.95	\$1.07	\$0.47	\$0.65	\$0.64	\$0.48
Demand Response	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.03	\$0.06	\$0.05	\$0.01
Load Response	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.03	\$0.06	\$0.05	\$0.01
Emergency Load Response	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Emergency Energy	\$0.07	\$0.02	\$0.00	\$0.00	\$0.02	\$0.00	\$0.02	\$0.00	\$0.00	\$0.00	\$0.00
Total Price (\$/MWh)	\$38.92	\$36.98	\$43.22	\$37.39	\$47.83	\$50.71	\$69.81	\$58.97	\$71.25	\$85.05	\$55.66
Total Load (GWh)	259,623	264,510	265,398	312,899	327,533	438,874	684,592	696,165	715,524	698,459	666,069
Total Billing (\$ Billions)	\$10.10	\$9.78	\$11.47	\$11.70	\$15.67	\$22.26	\$47.79	\$41.05	\$50.98	\$59.40	\$37.08

Category	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
	\$/MWh	\$/MWh	\$/MWh	\$/MWh	\$/MWh	\$/MWh	\$/MWh	\$/MWh	\$/MWh	\$/MWh
Load Weighted Energy	\$48.35	\$45.94	\$35.23	\$38.66	\$53.14	\$36.16	\$29.23	\$30.99	\$38.24	\$27.32
Capacity	\$12.17	\$10.37	\$6.66	\$7.29	\$9.25	\$11.25	\$10.96	\$11.27	\$13.02	\$11.27
Capacity	\$12.15	\$9.71	\$6.05	\$7.13	\$9.01	\$11.12	\$10.96	\$11.23	\$12.97	\$11.25
Capacity (FRR)	\$0.00	\$0.53	\$0.52	\$0.11	\$0.20	\$0.13	\$0.00	\$0.00	\$0.00	\$0.00
Capacity (RMR)	\$0.02	\$0.13	\$0.08	\$0.06	\$0.04	(\$0.00)	(\$0.00)	\$0.04	\$0.05	\$0.02
Transmission	\$4.33	\$4.86	\$5.32	\$5.65	\$6.46	\$7.69	\$8.42	\$9.54	\$9.47	\$10.39
Transmission Service Charges	\$4.04	\$4.49	\$4.90	\$5.21	\$5.96	\$7.09	\$7.81	\$8.83	\$8.81	\$9.75
Transmission Enhancement Cost Recovery	\$0.20	\$0.27	\$0.34	\$0.36	\$0.41	\$0.51	\$0.52	\$0.64	\$0.57	\$0.55
Transmission Owner (Schedule 1A)	\$0.09	\$0.09	\$0.08	\$0.08	\$0.09	\$0.09	\$0.09	\$0.10	\$0.09	\$0.09
Transmission Seams Elimination Cost Assignment (SECA)	\$0.00	(\$0.00)	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	(\$0.03)	\$0.00	\$0.00
Transmission Facility Charges	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Ancillary	\$0.90	\$0.90	\$0.84	\$1.24	\$0.99	\$0.91	\$0.71	\$0.76	\$0.80	\$0.72
Reactive	\$0.45	\$0.41	\$0.46	\$0.76	\$0.40	\$0.37	\$0.38	\$0.42	\$0.41	\$0.44
Regulation	\$0.36	\$0.32	\$0.26	\$0.25	\$0.33	\$0.23	\$0.11	\$0.14	\$0.18	\$0.12
Black Start	\$0.02	\$0.02	\$0.04	\$0.14	\$0.08	\$0.08	\$0.09	\$0.09	\$0.08	\$0.08
Synchronized Reserves	\$0.07	\$0.09	\$0.04	\$0.04	\$0.12	\$0.11	\$0.05	\$0.06	\$0.06	\$0.04
Non-Synchronized Reserves	\$0.00	\$0.00	\$0.00	\$0.00	\$0.02	\$0.02	\$0.01	\$0.01	\$0.02	\$0.02
Day Ahead Scheduling Reserve (DASR)	\$0.01	\$0.05	\$0.05	\$0.06	\$0.05	\$0.10	\$0.07	\$0.05	\$0.05	\$0.02
Administration	\$0.39	\$0.40	\$0.46	\$0.45	\$0.46	\$0.47	\$0.46	\$0.52	\$0.50	\$0.51
PJM Administrative Fees	\$0.36	\$0.37	\$0.43	\$0.42	\$0.43	\$0.43	\$0.43	\$0.48	\$0.47	\$0.47
NERC/RFC	\$0.02	\$0.02	\$0.02	\$0.02	\$0.03	\$0.03	\$0.03	\$0.03	\$0.03	\$0.03
RTO Startup and Expansion	\$0.01	\$0.01	\$0.01	\$0.01	\$0.01	\$0.01	\$0.00	\$0.00	\$0.00	\$0.00
Energy Uplift (Operating Reserves)	\$0.80	\$0.78	\$0.74	\$0.55	\$1.11	\$0.38	\$0.17	\$0.14	\$0.23	\$0.11
Demand Response	\$0.03	\$0.03	\$0.03	\$0.08	\$0.08	\$0.02	\$0.01	\$0.01	\$0.01	\$0.00
Load Response	\$0.01	\$0.01	\$0.02	\$0.01	\$0.03	\$0.02	\$0.01	\$0.01	\$0.01	\$0.00
Emergency Load Response	\$0.02	\$0.02	\$0.01	\$0.06	\$0.06	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Emergency Energy	\$0.00	\$0.00	\$0.00	\$0.00	\$0.01	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Total Price (\$/MWh)	\$66.97	\$63.28	\$49.28	\$53.93	\$71.49	\$56.87	\$49.97	\$53.23	\$62.27	\$50.33
Total Load (GWh)	697,391	723,101	764,300	773,790	780,505	776,093	778,269	758,775	791,094	771,929
Total Billing (\$ Billions)	\$46.70	\$45.76	\$37.67	\$41.73	\$55.80	\$44.14	\$38.89	\$40.39	\$49.27	\$38.85

²³ Note: The totals in this table include after the fact billing adjustments and may not match totals presented in past reports.

Table A-3 shows the inflation adjusted average price, by component of the total wholesale power price per MWh, for calendar years 1999 through 2019.²⁴

Table A-3 Inflation adjusted total price per MWh by category: 1999 through 2019²⁵

Category	1999 \$/MWh	2000 \$/MWh	2001 \$/MWh	2002 \$/MWh	2003 \$/MWh	2004 \$/MWh	2005 \$/MWh	2006 \$/MWh	2007 \$/MWh	2008 \$/MWh	2009 \$/MWh
Load Weighted Energy	\$33.04	\$28.80	\$33.45	\$28.35	\$36.24	\$37.91	\$52.37	\$42.73	\$48.06	\$53.27	\$29.46
Capacity	\$0.13	\$0.23	\$0.24	\$0.11	\$0.07	\$0.08	\$0.03	\$0.08	\$2.77	\$5.88	\$8.12
Capacity	\$0.13	\$0.23	\$0.24	\$0.11	\$0.07	\$0.08	\$0.02	\$0.02	\$2.73	\$5.85	\$8.11
Capacity (FRR)	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Capacity (RMR)	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.01	\$0.06	\$0.04	\$0.03	\$0.01
Transmission	\$3.38	\$3.88	\$3.25	\$3.10	\$3.20	\$2.93	\$2.73	\$2.68	\$2.76	\$2.87	\$3.18
Transmission Service Charges	\$3.31	\$3.79	\$3.17	\$3.04	\$3.13	\$2.80	\$2.24	\$2.55	\$2.69	\$2.76	\$3.04
Transmission Enhancement Cost Recovery	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.04	\$0.08
Transmission Owner (Schedule 1A)	\$0.07	\$0.08	\$0.07	\$0.06	\$0.06	\$0.08	\$0.07	\$0.07	\$0.07	\$0.07	\$0.06
Transmission Seams Elimination Cost Assignment (SECA)	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.04	\$0.41	\$0.06	\$0.00	\$0.00	\$0.00
Transmission Facility Charges	\$0.01	\$0.01	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Ancillary	\$0.40	\$0.64	\$0.68	\$0.56	\$0.80	\$0.77	\$0.98	\$0.74	\$0.78	\$0.86	\$0.59
Reactive	\$0.25	\$0.27	\$0.20	\$0.18	\$0.21	\$0.22	\$0.21	\$0.23	\$0.23	\$0.25	\$0.27
Regulation	\$0.15	\$0.37	\$0.48	\$0.38	\$0.44	\$0.43	\$0.66	\$0.42	\$0.49	\$0.52	\$0.26
Black Start	\$0.00	\$0.00	\$0.00	\$0.00	\$0.01	\$0.01	\$0.02	\$0.02	\$0.02	\$0.02	\$0.02
Synchronized Reserves	\$0.00	\$0.00	\$0.00	\$0.01	\$0.13	\$0.11	\$0.09	\$0.07	\$0.05	\$0.06	\$0.04
Non-Synchronized Reserves	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Day Ahead Scheduling Reserve (DASR)	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.01	\$0.00
Administration	\$0.22	\$0.24	\$0.66	\$0.77	\$0.93	\$0.85	\$0.61	\$0.60	\$0.58	\$0.31	\$0.25
PJM Administrative Fees	\$0.22	\$0.25	\$0.65	\$0.77	\$0.92	\$0.79	\$0.60	\$0.59	\$0.56	\$0.29	\$0.23
NERC/RFC	\$0.00	(\$0.00)	\$0.01	\$0.01	\$0.01	\$0.01	\$0.00	(\$0.00)	\$0.01	\$0.01	\$0.01
RTO Startup and Expansion	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.05	\$0.00	\$0.01	\$0.01	\$0.01	\$0.01
Energy Uplift (Operating Reserves)	\$0.50	\$0.87	\$1.15	\$0.65	\$0.78	\$0.81	\$0.88	\$0.38	\$0.51	\$0.48	\$0.36
Demand Response	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.02	\$0.05	\$0.03	\$0.00
Load Response	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.02	\$0.05	\$0.03	\$0.00
Emergency Load Response	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Emergency Energy	\$0.07	\$0.02	\$0.00	\$0.00	\$0.02	\$0.00	\$0.02	\$0.00	\$0.00	\$0.00	\$0.00
Total Price (\$/MWh)	\$37.75	\$34.68	\$39.44	\$33.54	\$42.04	\$43.36	\$57.63	\$47.23	\$55.51	\$63.71	\$41.97
Total Load (GWh)	259,623	264,510	265,398	312,899	327,533	438,874	684,592	696,165	715,524	698,459	666,069
Total Billing (\$ Billions)	\$9.80	\$9.17	\$10.47	\$10.50	\$13.77	\$19.03	\$39.45	\$32.88	\$39.72	\$44.50	\$27.95

Category	2010 \$/MWh	2011 \$/MWh	2012 \$/MWh	2013 \$/MWh	2014 \$/MWh	2015 \$/MWh	2016 \$/MWh	2017 \$/MWh	2018 \$/MWh	2019 \$/MWh
Load Weighted Energy	\$35.83	\$33.01	\$24.80	\$26.82	\$36.37	\$24.69	\$19.68	\$20.43	\$24.65	\$17.28
Capacity	\$9.02	\$7.46	\$4.69	\$5.06	\$6.31	\$7.66	\$7.38	\$7.43	\$8.37	\$7.13
Capacity	\$9.00	\$6.99	\$4.26	\$4.94	\$6.15	\$7.58	\$7.38	\$7.40	\$8.34	\$7.12
Capacity (FRR)	\$0.00	\$0.38	\$0.37	\$0.07	\$0.14	\$0.09	\$0.00	\$0.00	\$0.00	\$0.00
Capacity (RMR)	\$0.01	\$0.09	\$0.06	\$0.04	\$0.03	(\$0.00)	(\$0.00)	\$0.02	\$0.03	\$0.01
Transmission	\$3.21	\$3.49	\$3.74	\$3.92	\$4.41	\$5.24	\$5.67	\$6.29	\$6.10	\$6.57
Transmission Service Charges	\$2.99	\$3.23	\$3.45	\$3.61	\$4.07	\$4.84	\$5.26	\$5.82	\$5.67	\$6.16
Transmission Enhancement Cost Recovery	\$0.15	\$0.20	\$0.24	\$0.25	\$0.28	\$0.34	\$0.35	\$0.42	\$0.37	\$0.35
Transmission Owner (Schedule 1A)	\$0.07	\$0.06	\$0.06	\$0.06	\$0.06	\$0.06	\$0.06	\$0.06	\$0.06	\$0.06
Transmission Seams Elimination Cost Assignment (SECA)	\$0.00	(\$0.00)	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	(\$0.02)	\$0.00	\$0.00
Transmission Facility Charges	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Ancillary	\$0.66	\$0.64	\$0.59	\$0.86	\$0.67	\$0.62	\$0.48	\$0.50	\$0.51	\$0.46
Reactive	\$0.33	\$0.29	\$0.32	\$0.53	\$0.27	\$0.25	\$0.26	\$0.28	\$0.26	\$0.28
Regulation	\$0.27	\$0.23	\$0.18	\$0.17	\$0.22	\$0.16	\$0.07	\$0.09	\$0.12	\$0.07
Black Start	\$0.01	\$0.01	\$0.03	\$0.10	\$0.05	\$0.05	\$0.06	\$0.06	\$0.05	\$0.05
Synchronized Reserves	\$0.05	\$0.07	\$0.03	\$0.03	\$0.08	\$0.08	\$0.04	\$0.04	\$0.04	\$0.03
Non-Synchronized Reserves	\$0.00	\$0.00	\$0.00	\$0.00	\$0.01	\$0.01	\$0.01	\$0.01	\$0.01	\$0.01
Day Ahead Scheduling Reserve (DASR)	\$0.01	\$0.04	\$0.03	\$0.04	\$0.03	\$0.07	\$0.05	\$0.03	\$0.03	\$0.01
Administration	\$0.29	\$0.29	\$0.33	\$0.31	\$0.32	\$0.32	\$0.31	\$0.34	\$0.32	\$0.32
PJM Administrative Fees	\$0.27	\$0.26	\$0.30	\$0.29	\$0.29	\$0.29	\$0.29	\$0.32	\$0.30	\$0.30
NERC/RFC	\$0.02	\$0.01	\$0.02	\$0.02	\$0.02	\$0.02	\$0.02	\$0.02	\$0.02	\$0.02
RTO Startup and Expansion	\$0.01	\$0.01	\$0.01	\$0.01	\$0.01	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Energy Uplift (Operating Reserves)	\$0.59	\$0.56	\$0.52	\$0.38	\$0.77	\$0.26	\$0.12	\$0.09	\$0.15	\$0.07
Demand Response	\$0.02	\$0.02	\$0.02	\$0.05	\$0.05	\$0.01	\$0.01	\$0.00	\$0.00	\$0.00
Load Response	\$0.01	\$0.01	\$0.01	\$0.01	\$0.02	\$0.01	\$0.01	\$0.00	\$0.00	\$0.00
Emergency Load Response	\$0.01	\$0.01	\$0.01	\$0.04	\$0.04	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Emergency Energy	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Total Price (\$/MWh)	\$49.63	\$45.48	\$34.69	\$37.41	\$48.90	\$38.81	\$33.64	\$35.09	\$40.11	\$31.83
Total Load (GWh)	697,391	723,101	764,300	773,790	780,505	776,093	778,269	758,775	791,094	771,929
Total Billing (\$ Billions)	\$34.61	\$32.88	\$26.52	\$28.95	\$38.17	\$30.12	\$26.18	\$26.62	\$31.73	\$24.57

²⁴ US Consumer Price Index for all items, Urban Consumers (base period: January 1998), published by Bureau of Labor Statistics. <<http://download.bls.gov/pub/time.series/cu/cu.data.1.AllItems>> (January 14, 2020).

²⁵ Note: The totals in this table include after the fact billing adjustments and may not match totals presented in past reports.

Table A-4 shows the percent of average price, by component of the wholesale power price per MWh, for calendar years 1999 through 2019.

Table A-4 Percent of total price per MWh by category: 1999 through 2019²⁶

Category	Percent of Total Charges 1999	Percent of Total Charges 2000	Percent of Total Charges 2001	Percent of Total Charges 2002	Percent of Total Charges 2003	Percent of Total Charges 2004	Percent of Total Charges 2005	Percent of Total Charges 2006	Percent of Total Charges 2007	Percent of Total Charges 2008	Percent of Total Charges 2009
Load Weighted Energy	87.5%	83.1%	84.8%	84.5%	86.2%	87.4%	90.9%	90.5%	86.5%	83.6%	70.1%
Capacity	0.4%	0.7%	0.6%	0.3%	0.2%	0.2%	0.1%	0.2%	5.0%	9.2%	19.4%
Capacity	0.4%	0.7%	0.6%	0.3%	0.2%	0.2%	0.0%	0.0%	4.9%	9.2%	19.4%
Capacity (FRR)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Capacity (RMR)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.0%	0.0%
Transmission	9.0%	11.2%	8.2%	9.3%	7.6%	6.8%	4.7%	5.7%	5.0%	4.5%	7.6%
Transmission Service Charges	8.8%	10.9%	8.0%	9.1%	7.5%	6.5%	3.9%	5.4%	4.8%	4.3%	7.2%
Transmission Enhancement Cost Recovery	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.2%
Transmission Owner (Schedule 1A)	0.2%	0.2%	0.2%	0.2%	0.1%	0.2%	0.1%	0.1%	0.1%	0.1%	0.2%
Transmission Seams Elimination Cost Assignment (SECA)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Transmission Facility Charges	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Ancillary	1.1%	1.8%	1.7%	1.7%	1.9%	1.8%	1.7%	1.6%	1.4%	1.4%	1.4%
Reactive	0.7%	0.8%	0.5%	0.5%	0.5%	0.5%	0.4%	0.5%	0.4%	0.4%	0.7%
Regulation	0.4%	1.1%	1.2%	1.1%	1.1%	1.0%	1.1%	0.9%	0.9%	0.8%	0.6%
Black Start	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Synchronized Reserves	0.0%	0.0%	0.0%	0.0%	0.3%	0.3%	0.2%	0.1%	0.1%	0.1%	0.1%
Non-Synchronized Reserves	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Day Ahead Scheduling Reserve (DASR)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Administration	0.6%	0.7%	1.7%	2.3%	2.2%	2.0%	1.1%	1.3%	1.0%	0.5%	0.6%
PJM Administrative Fees	0.6%	0.7%	1.7%	2.3%	2.2%	1.8%	1.0%	1.3%	1.0%	0.5%	0.6%
NERC/RFC	0.0%	-0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	-0.0%	0.0%	0.0%	0.0%
RTO Startup and Expansion	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%
Energy Uplift (Operating Reserves)	1.3%	2.5%	2.9%	1.9%	1.9%	1.9%	1.5%	0.8%	0.9%	0.8%	0.9%
Demand Response	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.0%
Load Response	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.0%
Emergency Load Response	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Emergency Energy	0.2%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Total Price	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Category	Percent of Total Charges 2010	Percent of Total Charges 2011	Percent of Total Charges 2012	Percent of Total Charges 2013	Percent of Total Charges 2014	Percent of Total Charges 2015	Percent of Total Charges 2016	Percent of Total Charges 2017	Percent of Total Charges 2018	Percent of Total Charges 2019
Load Weighted Energy	72.2%	72.6%	71.5%	71.7%	74.3%	63.6%	58.5%	58.2%	61.4%	54.3%
Capacity	18.2%	16.4%	13.5%	13.5%	12.9%	19.8%	21.9%	21.2%	20.9%	22.4%
Capacity	18.1%	15.4%	12.3%	13.2%	12.6%	19.6%	21.9%	21.1%	20.8%	22.4%
Capacity (FRR)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Capacity (RMR)	0.0%	0.2%	0.2%	0.1%	0.1%	-0.0%	-0.0%	0.1%	0.1%	0.0%
Transmission	6.5%	7.7%	10.8%	10.5%	9.0%	13.5%	16.9%	17.9%	15.2%	20.6%
Transmission Service Charges	6.0%	7.1%	9.9%	9.7%	8.3%	12.5%	15.6%	16.6%	14.1%	19.4%
Transmission Enhancement Cost Recovery	0.3%	0.4%	0.7%	0.7%	0.6%	0.9%	1.0%	1.2%	0.9%	1.1%
Transmission Owner (Schedule 1A)	0.1%	0.1%	0.2%	0.2%	0.1%	0.2%	0.2%	0.2%	0.2%	0.2%
Transmission Seams Elimination Cost Assignment (SECA)	0.0%	-0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	-0.0%	0.0%	0.0%
Transmission Facility Charges	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Ancillary	1.3%	1.4%	1.7%	2.3%	1.4%	1.6%	1.4%	1.4%	1.3%	1.4%
Reactive	0.7%	0.6%	0.9%	1.4%	0.6%	0.7%	0.8%	0.8%	0.7%	0.9%
Regulation	0.5%	0.5%	0.5%	0.5%	0.5%	0.4%	0.2%	0.3%	0.3%	0.2%
Black Start	0.0%	0.0%	0.1%	0.3%	0.1%	0.1%	0.2%	0.2%	0.1%	0.2%
Synchronized Reserves	0.1%	0.1%	0.1%	0.1%	0.2%	0.2%	0.1%	0.1%	0.1%	0.1%
Non-Synchronized Reserves	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Day Ahead Scheduling Reserve (DASR)	0.0%	0.1%	0.1%	0.1%	0.1%	0.2%	0.1%	0.1%	0.1%	0.0%
Administration	0.6%	0.6%	0.9%	0.8%	0.6%	0.8%	0.9%	1.0%	0.8%	1.0%
PJM Administrative Fees	0.5%	0.6%	0.9%	0.8%	0.6%	0.8%	0.9%	0.9%	0.8%	0.9%
NERC/RFC	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%
RTO Startup and Expansion	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Energy Uplift (Operating Reserves)	1.2%	1.2%	1.5%	1.0%	1.6%	0.7%	0.3%	0.3%	0.4%	0.2%
Demand Response	0.0%	0.0%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%
Load Response	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Emergency Load Response	0.0%	0.0%	0.0%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%
Emergency Energy	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Total Price	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

26 Note: The totals in this table include after the fact billing adjustments and may not match totals presented in past reports.

Appendix B Energy Market

This appendix provides more detailed information about load, locational marginal prices (LMP), offer-capped units and energy market uplift (operating reserves).

History of Scarcity Pricing in PJM

On October 1, 2012, PJM introduced a new administrative scarcity pricing regime. Under these market rules, shortage pricing conditions are triggered when there is a shortage of synchronized or primary reserves in the RTO or in the Mid-Atlantic and Dominion (MAD) Subzone. In times of reserve shortage, the value of reserves is included as a penalty factor in the optimization and in the price of energy. Shortage pricing is also triggered when PJM issues a voltage reduction action or a manual load dump action for a reserve zone or a reserve subzone. When shortage pricing is triggered, the reserve penalty factors are incorporated in the calculation of the market clearing prices for the reserve that is short. The market clearing prices for reserves during reserve shortages in real time were determined based on vertical demand curves for synchronized and primary reserves, defined for the Mid-Atlantic Region and for the entire RTO, called the Operating Reserve Demand Curves (ORDC). The penalty factors for the reserve products in the ORDC started at \$250 per MWh for the 2012/2013 Delivery Year and gradually increased to \$850 per MWh for the 2015/2016 Delivery Year.

In 2015, PJM revised the rules to add a conditional second step to the operating reserve demand curves, that is only in effect during hot weather alerts, cold weather alerts and other emergency conditions, to allow PJM to procure additional reserves at a lower clearing price of \$300 per MWh. When there are no emergency conditions in place, the ORDC remains a single-step curve.

On May 11, 2017, PJM made revisions to the triggers for shortage pricing and implemented five minute shortage pricing in response to Order No. 825. These revisions did not change the operating reserve demand curves.

On July 12, 2017, PJM implemented updates to the Operating Reserve Demand Curves that determine the value of the penalty factors that are incorporated in the calculation of the synchronized and primary reserve market clearing prices and the locational marginal price

for energy. PJM added an extended reserve requirement to the operating reserve demand curves. The extended synchronized reserve requirement is defined as the synchronized reserve requirement plus 190 MW. The extended primary reserve requirement is defined as the primary reserve requirement plus 190 MW. PJM retains the ability to add a conditional extended reserve requirement during hot weather alerts, cold weather alerts or other emergencies that would increase the extended reserve requirement beyond 190 MW.

PJM Compliance Filing on Shortage Pricing

On January 11, 2017, PJM filed proposed tariff revisions to comply with Order No. 825 and requested a simultaneous implementation date of February 1, 2018, for the settlement interval reforms and shortage pricing reforms. In the January 11th Compliance Filing, PJM proposed to implement shortage pricing through the inclusion of the Reserve Penalty Factors in real-time LMPs when the real-time security constrained economic dispatch software determines that a primary reserve or synchronized reserve shortage exists on a five minute basis.

On February 1, 2017, the MMU filed comments generally supporting the January 11th Compliance Filing but seeking a number of refinements. The MMU recommended that: (i) the PJM rules require that dispatchable resources have five minute meters so that there can be accurate five minute settlements; (ii) the rules clarify the settlement interval applicable to withdrawals by generators; (iii) the exemption of DR from the five minute settlements requirement be removed; (iv) the rules consistently provide for division by 12; (v) that the rules include a precise mathematical formulation of deviation charges with clear definitions of withdrawals and injections, units of measurement, and time periods; and (vi) that the rules require PJM to document biasing practices that affect market outcomes, as used in SCED (Security Constrained Economic Dispatch) and ASO (Ancillary Services Optimizer) and to report its application of biasing.

On May 11, 2017, PJM implemented five minute shortage pricing. From May 11 through December 31, 2017, there were 21 intervals when five minute shortage pricing was triggered, all on the same day, September 21, 2017.

There were three five minute intervals with shortage pricing that occurred on two days in 2018. In 2019, there were 33 five minute intervals with shortage pricing that occurred on 17 days in PJM.

Load

Frequency Distribution of Load

Table B-1 provides the frequency distributions of PJM accounting load by hour, for 2007 through 2019.¹ The table shows the number of hours (frequency) and the percent of hours (cumulative percent) when the load was between zero GWh and 20 GWh and then by five GWh intervals. The integrations of the APS Control Zone in 2002, the ComEd, AEP and DAY Control Zones in 2004, the DLCO and Dominion Control Zones in 2005, the ATSI Control Zone in 2011, the DEOK Control Zone in 2012, the EKPC Control Zone in 2013, and the OVEC Control Zone in 2018 mean that annual comparisons of load frequency are significantly affected by PJM's growth.²

¹ The definitions of load are discussed in the *Technical Reference for PJM Markets*, at "Load Definitions." <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

² See the *2014 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography."

Table B-1 Frequency distribution of PJM real-time, hourly load: 2007 through 2019³

Load (GWh)	2007		2008		2009		2010		2011		2012		2013	
	Frequency	Cumulative Percent												
0 to 20	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
20 to 25	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
25 to 30	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
30 to 35	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
35 to 40	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
40 to 45	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
45 to 50	0	0.00%	0	0.00%	15	0.17%	12	0.14%	5	0.06%	0	0.00%	0	0.00%
50 to 55	79	0.90%	127	1.45%	376	4.46%	272	3.24%	104	1.24%	0	0.00%	0	0.00%
55 to 60	433	5.84%	517	7.33%	738	12.89%	582	9.89%	325	4.95%	104	1.18%	81	0.92%
60 to 65	637	13.12%	667	14.92%	836	22.43%	699	17.87%	602	11.83%	471	6.55%	390	5.38%
65 to 70	890	23.28%	941	25.64%	915	32.88%	805	27.05%	858	21.62%	629	13.71%	572	11.91%
70 to 75	878	33.30%	1,048	37.57%	1,342	48.20%	1,323	42.16%	1,120	34.41%	785	22.64%	728	20.22%
75 to 80	1,227	47.31%	1,535	55.04%	1,488	65.18%	1,272	56.68%	1,176	47.83%	1,010	34.14%	857	30.00%
80 to 85	1,338	62.58%	1,208	68.80%	966	76.21%	948	67.50%	1,259	62.20%	1,390	49.97%	1,177	43.44%
85 to 90	981	73.78%	916	79.22%	742	84.68%	794	76.56%	1,024	73.89%	1,233	64.00%	1,224	57.41%
90 to 95	741	82.24%	655	86.68%	549	90.95%	659	84.09%	719	82.10%	973	75.08%	1,042	69.30%
95 to 100	577	88.82%	457	91.88%	388	95.38%	487	89.65%	495	87.75%	691	82.95%	877	79.32%
100 to 105	382	93.18%	292	95.21%	205	97.72%	318	93.28%	279	90.94%	436	87.91%	682	87.10%
105 to 110	223	95.73%	181	97.27%	121	99.10%	195	95.50%	194	93.15%	289	91.20%	401	91.68%
110 to 115	179	97.77%	133	98.78%	48	99.65%	151	97.23%	173	95.13%	185	93.31%	270	94.76%
115 to 120	106	98.98%	58	99.44%	26	99.94%	108	98.46%	149	96.83%	152	95.04%	157	96.55%
120 to 125	43	99.47%	35	99.84%	5	100.00%	84	99.42%	95	97.91%	135	96.57%	127	98.00%
125 to 130	31	99.83%	14	100.00%	0	100.00%	40	99.87%	68	98.69%	121	97.95%	67	98.77%
130 to 135	12	99.97%	0	100.00%	0	100.00%	11	100.00%	49	99.25%	77	98.83%	42	99.25%
135 to 140	3	100.00%	0	100.00%	0	100.00%	0	100.00%	35	99.65%	46	99.35%	20	99.47%
140 to 145	0	100.00%	0	100.00%	0	100.00%	0	100.00%	16	99.83%	39	99.80%	14	99.63%
145 to 150	0	100.00%	0	100.00%	0	100.00%	0	100.00%	9	99.93%	16	99.98%	20	99.86%
150 to 155	0	100.00%	0	100.00%	0	100.00%	0	100.00%	6	100.00%	2	100.00%	12	100.00%
155 to 160	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
> 160	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%

Load (GWh)	2014		2015		2016		2017		2018		2019	
	Frequency	Cumulative Percent										
0 to 20	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
20 to 25	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
25 to 30	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
30 to 35	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
35 to 40	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
40 to 45	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
45 to 50	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
50 to 55	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
55 to 60	78	0.89%	76	0.87%	74	0.84%	87	0.99%	15	0.17%	54	0.62%
60 to 65	379	5.22%	447	5.97%	443	5.89%	463	6.28%	216	2.64%	403	5.22%
65 to 70	573	11.76%	636	13.23%	601	12.73%	606	13.20%	486	8.18%	539	11.37%
70 to 75	726	20.05%	793	22.28%	811	21.96%	840	22.79%	672	15.86%	784	20.32%
75 to 80	800	29.18%	867	32.18%	905	32.26%	1,005	34.26%	958	26.79%	1,014	31.89%
80 to 85	1,170	42.53%	1,289	46.89%	1,500	49.34%	1,417	50.43%	1,274	41.34%	1,385	47.71%
85 to 90	1,241	56.70%	1,083	59.26%	1,049	61.28%	1,211	64.26%	1,271	55.84%	1,122	60.51%
90 to 95	860	66.52%	803	68.42%	722	69.50%	955	75.16%	974	66.96%	922	71.04%
95 to 100	785	75.48%	625	75.56%	642	76.81%	641	82.48%	788	75.96%	747	79.57%
100 to 105	685	83.30%	558	81.93%	520	82.73%	449	87.60%	591	82.71%	540	85.73%
105 to 110	550	89.58%	515	87.81%	395	87.23%	333	91.40%	457	87.92%	391	90.19%
110 to 115	357	93.65%	384	92.19%	367	91.40%	294	94.76%	339	91.79%	235	92.88%
115 to 120	225	96.22%	286	95.46%	231	94.03%	196	97.00%	229	94.41%	198	95.14%
120 to 125	156	98.00%	162	97.31%	152	95.77%	117	98.33%	184	96.51%	178	97.17%
125 to 130	100	99.14%	128	98.77%	160	97.59%	82	99.27%	126	97.95%	123	98.57%
130 to 135	63	99.86%	72	99.59%	111	98.85%	36	99.68%	84	98.90%	76	99.44%
135 to 140	12	100.00%	34	99.98%	75	99.70%	19	99.90%	55	99.53%	35	99.84%
140 to 145	0	100.00%	2	100.00%	17	99.90%	9	100.00%	36	99.94%	6	99.91%
145 to 150	0	100.00%	0	100.00%	9	100.00%	0	100.00%	5	100.00%	8	100.00%
150 to 155	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
155 to 160	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
> 160	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%

3 Each range in the tables in this Appendix excludes the start value and includes the end value.

Off Peak and On Peak Load

Table B-2 shows summary load statistics for 1998 through 2019 for the off peak and on peak hours. Table B-3 shows the annual change in each statistic. The on peak period is defined for each weekday (Monday through Friday) as the hour ending 0800 to the hour ending 2300 Eastern Prevailing Time (EPT), excluding North American Electric Reliability Council (NERC) holidays.

Table B-2 Off peak and on peak load (MW): 1998 through 2019

	Average		Median		Standard Deviation				
	On Peak/		On Peak/		On Peak/		On Peak/		
	Off Peak	On Peak	Off Peak	On Peak	Off Peak	Off Peak	On Peak		
1998	25,269	32,344	1.28	24,729	31,081	1.26	4,091	4,388	1.07
1999	26,454	33,269	1.26	25,780	31,950	1.24	4,947	4,824	0.98
2000	26,917	33,797	1.26	26,313	32,757	1.24	4,466	4,181	0.94
2001	26,804	34,303	1.28	26,433	33,076	1.25	4,225	4,851	1.15
2002	31,734	40,314	1.27	30,590	38,365	1.25	6,111	7,464	1.22
2003	33,598	41,755	1.24	32,973	40,802	1.24	5,545	5,424	0.98
2004	44,631	56,020	1.26	43,028	56,578	1.31	10,845	12,595	1.16
2005	70,291	87,164	1.24	68,049	82,503	1.21	12,733	15,236	1.20
2006	71,810	88,323	1.23	70,300	84,810	1.21	11,348	12,662	1.12
2007	73,499	91,066	1.24	71,751	88,494	1.23	11,501	11,926	1.04
2008	72,175	87,915	1.22	70,516	85,431	1.21	11,378	11,205	0.98
2009	68,765	84,375	1.23	67,198	81,842	1.22	10,916	10,519	0.96
2010	72,222	88,087	1.22	70,354	85,504	1.22	12,935	13,775	1.06
2011	74,815	91,413	1.22	72,661	87,938	1.21	12,978	14,835	1.14
2012	79,046	96,193	1.22	76,930	92,199	1.20	13,182	14,426	1.09
2013	80,232	97,624	1.22	78,751	95,465	1.21	12,588	13,105	1.04
2014	80,942	98,456	1.22	78,993	97,042	1.23	13,086	13,161	1.01
2015	80,669	97,620	1.21	77,648	94,316	1.21	14,288	14,387	1.01
2016	80,676	97,737	1.21	78,001	94,087	1.21	14,227	15,806	1.11
2017	79,237	95,148	1.20	77,160	91,910	1.19	12,664	13,230	1.04
2018	82,854	98,857	1.19	80,633	95,900	1.19	13,604	14,118	1.04
2019	80,915	96,384	1.19	78,928	93,730	1.19	13,539	14,231	1.05

Table B-3 Changes in off peak and on peak load (MW): 1998 through 2019

	Average		Median		Standard Deviation				
	On Peak/		On Peak/		On Peak/		On Peak/		
	Off Peak	On Peak	Off Peak	On Peak	Off Peak	Off Peak	On Peak		
1998	NA	NA	NA	NA	NA	NA	NA	NA	NA
1999	4.7%	2.9%	(1.7%)	4.3%	2.8%	(1.4%)	20.9%	9.9%	(9.1%)
2000	1.8%	1.6%	(0.2%)	2.1%	2.5%	0.5%	(9.7%)	(13.3%)	(4.0%)
2001	(0.4%)	1.5%	1.9%	0.5%	1.0%	0.5%	(5.4%)	16.0%	22.6%
2002	18.4%	17.5%	(0.7%)	15.7%	16.0%	0.2%	44.6%	53.9%	6.4%
2003	5.9%	3.6%	(2.2%)	7.8%	6.4%	(1.3%)	(9.3%)	(27.3%)	(19.9%)
2004	32.8%	34.2%	1.0%	30.5%	38.7%	6.3%	95.6%	132.2%	18.7%
2005	57.5%	55.6%	(1.2%)	58.2%	45.8%	(7.8%)	17.4%	21.0%	3.0%
2006	2.2%	1.3%	(0.8%)	3.3%	2.8%	(0.5%)	(10.9%)	(16.9%)	(6.8%)
2007	2.4%	3.1%	0.7%	2.1%	4.3%	2.2%	1.3%	(5.8%)	(7.1%)
2008	(1.8%)	(3.5%)	(1.7%)	(1.7%)	(3.5%)	(1.8%)	(1.1%)	(6.0%)	(5.0%)
2009	(4.7%)	(4.0%)	0.7%	(4.7%)	(4.2%)	0.5%	(4.1%)	(6.1%)	(2.1%)
2010	5.0%	4.4%	(0.6%)	4.7%	4.5%	(0.2%)	18.5%	30.9%	10.5%
2011	3.6%	3.8%	0.2%	3.3%	2.8%	(0.4%)	0.3%	7.7%	7.3%
2012	5.7%	5.2%	(0.4%)	5.9%	4.8%	(1.0%)	1.6%	(2.8%)	(4.3%)
2013	1.5%	1.5%	(0.0%)	2.4%	3.5%	1.1%	(4.5%)	(9.2%)	(4.9%)
2014	0.9%	0.9%	(0.0%)	0.3%	1.7%	1.3%	4.0%	0.4%	(3.4%)
2015	(0.3%)	(0.8%)	(0.5%)	(1.7%)	(2.8%)	(1.1%)	9.2%	9.3%	0.1%
2016	0.0%	0.1%	0.1%	0.5%	(0.2%)	(0.7%)	(0.4%)	9.9%	10.3%
2017	(1.8%)	(2.6%)	(0.9%)	(1.1%)	(2.3%)	(1.2%)	(11.0%)	(16.3%)	(6.0%)
2018	4.6%	3.9%	(0.6%)	4.5%	4.3%	(0.2%)	7.4%	6.7%	(0.7%)
2019	(2.3%)	(2.5%)	(0.2%)	(2.1%)	(2.3%)	(0.2%)	(0.5%)	0.8%	1.3%

Locational Marginal Price (LMP)

Three measures of LMP are calculated: average LMP; load-weighted average LMP; and fuel-cost-adjusted, load-weighted, average LMP. Differences in average LMP measure the change in reported price. Differences in load-weighted, average LMP measure the change in reported price weighted by the actual hourly MWh load to reflect what customers actually pay for energy. Differences in fuel-cost adjusted, load-weighted, average LMP measure what the change in reported price actually paid by load would have been if fuel costs in 2019 had been the same as in 2018, holding everything else constant.⁴

The zonal LMP includes every bus in the zone and is not affected by the choices of LSEs. The day-ahead zonal LMP is defined by weighting each load bus LMP by its daily zonal distribution factor.⁵ The real-time zonal LMP is defined by weighting each load bus five minute interval LMP by its 5 minute contribution to total zonal load.⁶ The day-ahead LMP for a defined aggregate is calculated by weighting each included load bus LMP by its daily zonal distribution factor. The real-time LMP for a defined aggregate is calculated by weighting each included load bus five minute interval LMP by its five minute contribution to the total load of the defined aggregate.

During the settlement process, total load that is assigned to a load serving entity (LSE) in a zone is settled based on the LSE's choice to be charged either at the zonal price or at a different defined aggregate of nodal prices. Any LSE may request to settle at a different aggregate price instead of zonal LMP, but the change can only take effect on June 1 of each year.⁷ If an LSE chooses to settle at a different aggregate, the load of the LSE is distributed to all of the buses in the aggregate.⁸ If the LSE settles at the zonal price, the load of the LSE will be distributed to all of the buses in the zone.⁹

Market rules related to the use of zonal pricing will change starting with the 2015/2016 planning period.¹⁰ A residual zonal price will become the default price for load that has not elected to settle at nodal prices. When some load in a zone is nodally priced, the residual zonal price is the price of energy for the residual load, the load that is not priced nodally. The residual price is the average price at the nodes at which non-nodal load is served. The zonal LMP will continue to be used for virtual bidding, Financial Transmission Rights (FTRs), and bilateral energy transactions.

In the day-ahead energy market buyers may submit bids at specific locations such as a transmission zone, aggregate or a single bus. Price sensitive demand bids specify price and MW quantities and a location for the bid. Market participants may submit increment offers or decrement bids at any hub, transmission zone, aggregate, single bus or eligible external interfaces. PJM provides the definitions of the transmission zones, aggregates, and single buses.¹¹

Real-Time LMP

Frequency Distribution of Real-Time Average LMP

Table B-4 provides frequency distributions of PJM real-time hourly average LMP for 2007 through 2019. The table shows the number of hours (frequency) and the percent of hours (cumulative percent) when the hourly PJM real-time LMP was, when negative, within a \$100 per MWh price interval below \$0 per MWh, or, when positive, within a given \$10 per MWh price interval and lower than \$300 per MWh, or within a given \$100 per MWh price interval and higher than \$300 per MWh.

⁴ See the *Technical Reference for PJM Markets*, at "Calculating Locational Marginal Price."

⁵ In the day-ahead market clearing, the zonal load for every hour is distributed to the load pricing nodes in the zone based on the state estimator distribution at 8:00 a.m. one week prior to the operating day.

⁶ The load in PJM is metered hourly. The five minute contribution is the five minute share or one-twelfth of the metered load for that hour.

⁷ See PJM "Manual 27: Open Access Transmission Tariff Accounting," Revision 93 (August 31, 2020) § 5: Network Integration Transmission Service Accounting.

⁸ OATT. Common Service Provisions (Designation of Network Load) §31.7.

⁹ *Id.*

¹⁰ *Id.*

¹¹ See PJM "Manual 11: Energy & Ancillary Services Market Operations," Revision 111 (November 19, 2020), § 2: Overview of the PJM Energy Markets, p. 18.

Table B-4 Frequency distribution by hours of PJM Real-Time Energy Market LMP (Dollars per MWh): 2007 through 2019

LMP	2007		2008		2009		2010		2011		2012		2013	
	Frequency	Cumulative Percent												
-\$200 to -\$100	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	2	0.02%	0	0.00%
-\$100 to \$0	23	0.26%	45	0.51%	60	0.68%	34	0.39%	33	0.38%	50	0.59%	3	0.03%
\$0 to \$10	33	0.64%	49	1.07%	57	1.34%	31	0.74%	33	0.75%	79	1.49%	64	0.76%
\$10 to \$20	185	2.75%	129	2.54%	218	3.82%	127	2.19%	89	1.77%	510	7.30%	147	2.44%
\$20 to \$30	1,571	20.68%	490	8.12%	2,970	37.73%	1,810	22.85%	1,764	21.91%	4,002	52.86%	3,077	37.57%
\$30 to \$40	1,470	37.47%	1,443	24.54%	2,951	71.42%	3,150	58.81%	3,967	67.19%	2,801	84.74%	3,447	76.92%
\$40 to \$50	1,108	50.11%	1,533	42.00%	1,269	85.90%	1,462	75.50%	1,334	82.42%	668	92.35%	1,116	89.66%
\$50 to \$60	931	60.74%	1,212	55.79%	555	92.24%	766	84.25%	489	88.00%	244	95.13%	391	94.12%
\$60 to \$70	827	70.18%	845	65.41%	276	95.39%	427	89.12%	303	91.46%	136	96.68%	187	96.26%
\$70 to \$80	726	78.47%	709	73.49%	151	97.11%	274	92.25%	174	93.45%	75	97.53%	99	97.39%
\$80 to \$90	646	85.84%	502	79.20%	95	98.20%	165	94.13%	133	94.97%	51	98.11%	67	98.15%
\$90 to \$100	451	90.99%	385	83.58%	62	98.90%	134	95.66%	108	96.20%	38	98.54%	38	98.58%
\$100 to \$110	240	93.73%	352	87.59%	30	99.25%	82	96.60%	61	96.89%	32	98.91%	23	98.85%
\$110 to \$120	178	95.76%	265	90.61%	21	99.49%	71	97.41%	61	97.59%	20	99.13%	24	99.12%
\$120 to \$130	110	97.02%	199	92.87%	15	99.66%	61	98.11%	46	98.12%	15	99.31%	13	99.27%
\$130 to \$140	76	97.89%	144	94.51%	7	99.74%	44	98.61%	33	98.49%	10	99.42%	20	99.50%
\$140 to \$150	53	98.49%	111	95.78%	9	99.84%	29	98.94%	25	98.78%	7	99.50%	1	99.51%
\$150 to \$160	26	98.79%	102	96.94%	3	99.87%	22	99.19%	25	99.06%	8	99.59%	3	99.54%
\$160 to \$170	29	99.12%	68	97.71%	3	99.91%	11	99.32%	17	99.26%	5	99.65%	4	99.59%
\$170 to \$180	18	99.33%	52	98.30%	5	99.97%	13	99.46%	15	99.43%	1	99.66%	5	99.65%
\$180 to \$190	9	99.43%	45	98.82%	0	99.97%	12	99.60%	6	99.50%	2	99.68%	3	99.68%
\$190 to \$200	15	99.60%	29	99.15%	1	99.98%	9	99.70%	8	99.59%	3	99.72%	1	99.69%
\$200 to \$210	6	99.67%	20	99.37%	1	99.99%	7	99.78%	6	99.66%	2	99.74%	3	99.73%
\$210 to \$220	4	99.71%	11	99.50%	1	100.00%	4	99.83%	5	99.71%	1	99.75%	4	99.77%
\$220 to \$230	4	99.76%	14	99.66%	0	100.00%	3	99.86%	4	99.76%	0	99.75%	3	99.81%
\$230 to \$240	2	99.78%	10	99.77%	0	100.00%	5	99.92%	0	99.76%	4	99.80%	4	99.85%
\$240 to \$250	5	99.84%	2	99.80%	0	100.00%	3	99.95%	3	99.79%	5	99.85%	1	99.86%
\$250 to \$260	2	99.86%	5	99.85%	0	100.00%	1	99.97%	3	99.83%	5	99.91%	1	99.87%
\$260 to \$270	4	99.91%	4	99.90%	0	100.00%	0	99.97%	3	99.86%	0	99.91%	3	99.91%
\$270 to \$280	0	99.91%	1	99.91%	0	100.00%	0	99.97%	3	99.90%	1	99.92%	1	99.92%
\$280 to \$290	0	99.91%	1	99.92%	0	100.00%	1	99.98%	0	99.90%	1	99.93%	0	99.92%
\$290 to \$300	0	99.91%	0	99.92%	0	100.00%	0	99.98%	2	99.92%	0	99.93%	1	99.93%
\$300 to \$400	2	99.93%	6	99.99%	0	100.00%	2	100.00%	4	99.97%	6	100.00%	5	99.99%
\$400 to \$500	4	99.98%	1	100.00%	0	100.00%	0	100.00%	0	99.97%	0	100.00%	1	100.00%
\$500 to \$600	1	99.99%	0	100.00%	0	100.00%	0	100.00%	0	99.97%	0	100.00%	0	100.00%
\$600 to \$700	1	100.00%	0	100.00%	0	100.00%	0	100.00%	0	99.97%	0	100.00%	0	100.00%
\$700 to \$800	0	100.00%	0	100.00%	0	100.00%	0	100.00%	3	100.00%	0	100.00%	0	100.00%
\$800 to \$900	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
\$900 to \$1000	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
> \$1,000	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%

Table B-4 Frequency distribution by hours of PJM Real-Time Energy Market LMP (Dollars per MWh): 2007 through 2019 (continued)

LMP	2014		2015		2016		2017		2018		2019	
	Frequency	Cumulative Percent										
-\$200 to -\$100	0	0.00%	5	0.06%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
-\$100 to \$0	15	0.17%	31	0.41%	18	0.20%	19	0.22%	4	0.05%	4	0.05%
\$0 to \$10	40	0.63%	108	1.64%	67	0.97%	28	0.54%	13	0.19%	25	0.33%
\$10 to \$20	224	3.18%	1,091	14.10%	1,690	20.21%	1,143	13.58%	996	11.56%	2,536	29.28%
\$20 to \$30	2,662	33.57%	4,527	65.78%	4,931	76.34%	4,959	70.19%	3,954	56.70%	4,653	82.40%
\$30 to \$40	2,782	65.33%	1,477	82.64%	1,217	90.20%	1,605	88.52%	2,020	79.76%	966	93.42%
\$40 to \$50	1,161	78.58%	566	89.10%	382	94.55%	451	93.66%	746	88.28%	277	96.59%
\$50 to \$60	619	85.65%	270	92.18%	156	96.32%	225	96.23%	333	92.08%	119	97.95%
\$60 to \$70	287	88.93%	168	94.10%	116	97.64%	108	97.47%	173	94.05%	62	98.65%
\$70 to \$80	206	91.28%	116	95.42%	79	98.54%	68	98.24%	112	95.33%	29	98.98%
\$80 to \$90	142	92.90%	89	96.44%	49	99.10%	47	98.78%	76	96.20%	20	99.21%
\$90 to \$100	102	94.06%	77	97.32%	17	99.29%	33	99.16%	49	96.76%	11	99.34%
\$100 to \$110	71	94.87%	42	97.80%	22	99.54%	21	99.39%	57	97.41%	9	99.44%
\$110 to \$120	55	95.50%	31	98.15%	11	99.67%	15	99.57%	38	97.84%	5	99.50%
\$120 to \$130	50	96.07%	29	98.48%	7	99.75%	10	99.68%	29	98.17%	3	99.53%
\$130 to \$140	42	96.55%	24	98.76%	4	99.80%	6	99.75%	25	98.46%	7	99.61%
\$140 to \$150	21	96.79%	11	98.88%	4	99.84%	4	99.79%	11	98.58%	2	99.63%
\$150 to \$160	22	97.04%	21	99.12%	3	99.87%	6	99.86%	16	98.77%	5	99.69%
\$160 to \$170	22	97.29%	9	99.22%	2	99.90%	1	99.87%	18	98.97%	3	99.73%
\$170 to \$180	21	97.53%	12	99.36%	5	99.95%	3	99.91%	14	99.13%	5	99.78%
\$180 to \$190	24	97.81%	6	99.43%	0	99.95%	2	99.93%	12	99.27%	2	99.81%
\$190 to \$200	18	98.01%	6	99.50%	3	99.99%	0	99.93%	17	99.46%	2	99.83%
\$200 to \$210	17	98.21%	8	99.59%	0	99.99%	1	99.94%	4	99.51%	0	99.83%
\$210 to \$220	14	98.37%	5	99.65%	0	99.99%	0	99.94%	8	99.60%	1	99.84%
\$220 to \$230	11	98.49%	4	99.69%	1	100.00%	2	99.97%	0	99.60%	0	99.84%
\$230 to \$240	10	98.61%	4	99.74%	0	100.00%	0	99.97%	0	99.60%	1	99.85%
\$240 to \$250	8	98.70%	3	99.77%	0	100.00%	0	99.97%	4	99.65%	1	99.86%
\$250 to \$260	6	98.77%	4	99.82%	0	100.00%	0	99.97%	2	99.67%	1	99.87%
\$260 to \$270	5	98.82%	2	99.84%	0	100.00%	0	99.97%	3	99.70%	0	99.87%
\$270 to \$280	9	98.93%	1	99.85%	0	100.00%	1	99.98%	5	99.76%	0	99.87%
\$280 to \$290	10	99.04%	2	99.87%	0	100.00%	0	99.98%	4	99.81%	1	99.89%
\$290 to \$300	7	99.12%	1	99.89%	0	100.00%	0	99.98%	2	99.83%	1	99.90%
\$300 to \$400	35	99.52%	7	99.97%	0	100.00%	0	99.98%	12	99.97%	2	99.92%
\$400 to \$500	22	99.77%	3	100.00%	0	100.00%	1	99.99%	2	99.99%	3	99.95%
\$500 to \$600	6	99.84%	0	100.00%	0	100.00%	0	99.99%	1	100.00%	2	99.98%
\$600 to \$700	1	99.85%	0	100.00%	0	100.00%	1	100.00%	0	100.00%	2	100.00%
\$700 to \$800	2	99.87%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	0.00%
\$800 to \$900	4	99.92%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	0.00%
\$900 to \$1000	1	99.93%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	0.00%
> \$1,000	6	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	0.00%

Off Peak and On Peak, PJM Real-Time, Load-Weighted Average LMP

Table B-5 shows load-weighted, average real-time LMP for 2018 and 2019 during off peak and on peak periods.

Table B-5 Off peak and on peak, PJM load-weighted, average LMP (Dollars per MWh): 2018 and 2019

	2018		2019		Percent Change		
	Off Peak	On Peak	Off Peak	On Peak	Off Peak	On Peak	On Peak/Off Peak
Average	\$33.85	\$42.46	1.25	\$23.32	\$31.17	1.34	(31.1%) (26.6%) 6.5%
Median	\$25.32	\$33.81	1.33	\$20.95	\$25.96	1.24	(17.3%) (23.2%) (7.2%)
Standard deviation	\$35.05	\$30.08	0.86	\$15.32	\$28.16	1.84	(56.3%) (6.4%) 114.2%

Off Peak and On Peak, Real-Time, Fuel-Cost Adjusted, Load-Weighted, Average LMP

In a competitive market, changes in LMP result from changes in demand and changes in supply. The supply curve is a function of the short run marginal costs of marginal units, the units setting LMP. As competitive offers are the short run marginal costs of generation and fuel costs make up between 80 percent and 90 percent of short run marginal costs on average, fuel cost is a key factor affecting the competitive clearing price. In a competitive market, if fuel costs increase and nothing else changes, the competitive price also increases.

The impact of fuel cost on marginal cost and on LMP depends on the fuel burned by marginal units and changes in fuel costs.¹² Changes in emission allowance costs are another contributor to changes in the marginal cost of marginal units. To account for the changes in fuel and allowance costs between 2018 and 2019, the load-weighted, average LMP for 2019 was adjusted to reflect the daily price of fuels and emission allowances used by marginal units from a base period, 2018. The fuel cost adjusted, load-weighted, average LMP for 2019 is compared to the load-weighted, average LMP for 2018 and load-weighted, average LMP for 2019.¹³

Table B-6 shows the real-time, load-weighted, average LMP for 2019 and the real-time, fuel-cost adjusted, load-weighted, average LMP for 2019 for off peak and on peak hours.

The real-time, load-weighted, average LMP for 2019 off peak hours decreased by \$10.53 or 31.1 percent from real-time, load-weighted average LMP for 2018 off peak hours. The real-time load-weighted, average LMP for 2019 off peak hours was 17.3 percent lower than the real-time fuel-cost adjusted, load-weighted, average LMP for 2019 off peak hours. The real-time, fuel-cost adjusted, load-weighted, average LMP for 2019 off peak hours was 16.7 percent lower than the real-time load-weighted LMP for 2018 off peak hours. If fuel and emissions costs in 2019 off peak hours had been the same as in 2018 off peak hours, holding everything else constant, the real-time load-weighted LMP in 2019 off peak hours would have been lower, \$28.21 per MWh, than the observed \$23.32 per MWh. Only 46.4 percent of the decrease in off peak hours LMP, \$4.89 per MWh out of \$10.53 per MWh, is directly attributable to fuel costs. Contributors to the other \$5.64 per MWh are increased load, adjusted dispatch, and higher markups.

The real-time, load-weighted, average LMP for 2019 on peak hours decreased by \$11.30 or 26.6 percent from real-time load-weighted average LMP for 2018 on peak hours. The real-time load-weighted, average LMP for 2019 on peak hours was 11.9 percent lower than the real-time fuel-cost adjusted, load-weighted, average LMP for 2019 on peak hours. The real-time, fuel-cost adjusted, load-weighted, average LMP for 2019 on peak hours was 16.7 percent lower than the real-time load-weighted LMP for 2018 on peak hours. If fuel and emissions costs in 2019 on peak hours had been the same as in 2018 on peak hours, holding everything else constant, the real-time load-weighted LMP in 2019 on peak hours would have been higher, \$35.36 per MWh, than the observed \$31.17 per MWh. Only 37.2 percent of the decrease in on peak hours LMP, \$4.20 per MWh out of \$11.30 per MWh, is directly attributable to fuel costs. Contributors to the other \$7.10 per MWh are increased load, adjusted dispatch, and higher markups.

¹² See the *2019 State of the Market Report for PJM*, Volume II, Section 3, "Energy Market," at Table 3-7, "Type of fuel used (By real-time marginal units): 2013 through 2019."

¹³ See the *Technical Reference for PJM Markets*, at "Calculation and Use of Generator Sensitivity/Unit Participation Factors."

Table B-6 On peak and off peak real-time PJM fuel-cost adjusted, load-weighted, average LMP (Dollars per MWh): year over year

	2019 Fuel-Cost Adjusted, Load-Weighted LMP	2019 Load-Weighted LMP	Change	Percent Change
Off Peak Average	\$28.21	\$23.32	(\$4.89)	(17.3%)
Peak Average	\$35.36	\$31.17	(\$4.20)	(11.9%)
	2018 Load-Weighted LMP	2019 Fuel-Cost Adjusted, Load-Weighted LMP	Change	Percent Change
Off Peak Average	\$33.85	\$28.21	(\$5.64)	(16.7%)
Peak Average	\$42.46	\$35.36	(\$7.10)	(16.7%)
	2018 Load-Weighted LMP	2019 Load-Weighted LMP	Change	Percent Change
Off Peak Average	\$33.85	\$23.32	(\$10.53)	(31.1%)
Peak Average	\$42.46	\$31.17	(\$11.30)	(26.6%)

PJM Real-Time, Load-Weighted, Average LMP during Constrained Hours

Table B-7 provides a comparison of PJM load-weighted, average LMP during constrained and unconstrained hours for 2018 and 2019.

Table B-7 PJM real-time load-weighted, average LMP during constrained and unconstrained hours (Dollars per MWh): 2018 and 2019

	2018		2019		Percent Change	
	Unconstrained Hours LMP	Constrained Hours LMP	Unconstrained Hours LMP	Constrained Hours LMP	Unconstrained Hours	Constrained Hours
Average	\$24.71	\$41.15	\$21.07	\$28.33	(14.7%)	(31.2%)
Median	\$22.85	\$31.55	\$19.88	\$24.20	(13.0%)	(23.3%)
Standard deviation	\$7.97	\$35.40	\$7.10	\$24.60	(10.9%)	(30.5%)

Table B-8 shows the number of hours and the number of constrained hours in each month in 2018 and 2019.

Table B-8 PJM real-time constrained hours: 2018 and 2019

	2018			2019		
	Constrained Hours	Total Hours	Percent of Total	Constrained Hours	Total Hours	Percent of Total
Jan	564	744	75.8%	627	744	84.3%
Feb	517	672	76.9%	567	672	84.4%
Mar	724	743	97.4%	628	743	84.5%
Apr	681	720	94.6%	546	720	75.8%
May	725	744	97.4%	609	744	81.9%
Jun	511	720	71.0%	450	720	62.5%
Jul	431	744	57.9%	564	744	75.8%
Aug	464	744	62.4%	640	744	86.0%
Sep	599	720	83.2%	695	720	96.5%
Oct	624	744	83.9%	736	744	98.9%
Nov	651	721	90.3%	663	721	92.0%
Dec	603	744	81.0%	681	744	91.5%
Avg	591	730	81.0%	617	730	84.5%

Day-Ahead LMP

Frequency Distribution of Day-Ahead, Average LMP

Table B-9 provides frequency distributions of PJM day-ahead, hourly, average LMP for 2007 through 2019. The table shows the number of hours (frequency) and the percent of hours (cumulative percent) when the hourly PJM day-ahead LMP was, when negative, within a \$100 per MWh price interval below \$0 per MWh, or, when positive, within a \$10 per MWh price interval and lower than \$300 per MWh, or within a given \$100 per MWh price interval and higher than \$300 per MWh.

Table B-9 Frequency distribution by hours of PJM Day-Ahead Energy Market LMP (Dollars per MWh): 2007 through 2019

LMP	2007		2008		2009		2010		2011		2012		2013	
	Frequency	Cumulative Percent												
-\$200 to -\$100	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
-\$100 to \$0	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
\$0 to \$10	3	0.03%	0	0.00%	23	0.26%	5	0.06%	0	0.00%	19	0.22%	1	0.01%
\$10 to \$20	88	1.04%	19	0.22%	343	4.18%	31	0.41%	33	0.38%	467	5.53%	76	0.88%
\$20 to \$30	1,291	15.78%	320	3.86%	2,380	31.35%	1,502	17.56%	1,595	18.58%	3,402	44.26%	2,364	27.87%
\$30 to \$40	1,495	32.84%	1,148	16.93%	3,221	68.12%	2,851	50.10%	3,359	56.93%	3,521	84.35%	3,794	71.18%
\$40 to \$50	1,221	46.78%	1,546	34.53%	1,717	87.72%	2,131	74.43%	2,024	80.03%	908	94.68%	1,761	91.28%
\$50 to \$60	1,266	61.23%	1,491	51.50%	557	94.08%	954	85.32%	872	89.99%	247	97.50%	421	96.08%
\$60 to \$70	1,301	76.08%	1,107	64.11%	253	96.96%	471	90.70%	406	94.62%	106	98.70%	169	98.01%
\$70 to \$80	939	86.80%	942	74.83%	138	98.54%	302	94.14%	174	96.61%	39	99.15%	64	98.74%
\$80 to \$90	504	92.56%	682	82.59%	68	99.32%	193	96.35%	87	97.60%	21	99.39%	35	99.14%
\$90 to \$100	264	95.57%	542	88.76%	33	99.69%	125	97.77%	61	98.30%	12	99.52%	22	99.39%
\$100 to \$110	155	97.34%	289	92.05%	19	99.91%	86	98.76%	29	98.63%	7	99.60%	12	99.53%
\$110 to \$120	104	98.53%	193	94.25%	6	99.98%	46	99.28%	30	98.97%	6	99.67%	4	99.58%
\$120 to \$130	59	99.20%	131	95.74%	2	100.00%	29	99.61%	16	99.16%	7	99.75%	3	99.61%
\$130 to \$140	33	99.58%	112	97.02%	0	100.00%	14	99.77%	21	99.39%	4	99.80%	2	99.63%
\$140 to \$150	13	99.73%	67	97.78%	0	100.00%	7	99.85%	17	99.59%	2	99.82%	2	99.66%
\$150 to \$160	8	99.82%	54	98.39%	0	100.00%	6	99.92%	7	99.67%	1	99.83%	2	99.68%
\$160 to \$170	7	99.90%	46	98.92%	0	100.00%	3	99.95%	3	99.70%	3	99.86%	5	99.74%
\$170 to \$180	3	99.93%	23	99.18%	0	100.00%	2	99.98%	2	99.73%	1	99.87%	3	99.77%
\$180 to \$190	4	99.98%	20	99.41%	0	100.00%	0	99.98%	2	99.75%	0	99.87%	2	99.79%
\$190 to \$200	1	99.99%	16	99.59%	0	100.00%	2	100.00%	2	99.77%	2	99.90%	2	99.82%
\$200 to \$210	1	100.00%	8	99.68%	0	100.00%	0	100.00%	1	99.78%	2	99.92%	3	99.85%
\$210 to \$220	0	100.00%	9	99.78%	0	100.00%	0	100.00%	0	99.78%	2	99.94%	2	99.87%
\$220 to \$230	0	100.00%	4	99.83%	0	100.00%	0	100.00%	2	99.81%	1	99.95%	4	99.92%
\$230 to \$240	0	100.00%	3	99.86%	0	100.00%	0	100.00%	1	99.82%	2	99.98%	0	99.92%
\$240 to \$250	0	100.00%	2	99.89%	0	100.00%	0	100.00%	0	99.82%	0	99.98%	1	99.93%
\$250 to \$260	0	100.00%	0	99.89%	0	100.00%	0	100.00%	2	99.84%	1	99.99%	1	99.94%
\$260 to \$270	0	100.00%	4	99.93%	0	100.00%	0	100.00%	2	99.86%	0	99.99%	0	99.94%
\$270 to \$280	0	100.00%	0	99.93%	0	100.00%	0	100.00%	0	99.86%	1	100.00%	1	99.95%
\$280 to \$290	0	100.00%	2	99.95%	0	100.00%	0	100.00%	0	99.86%	0	100.00%	0	99.95%
\$290 to \$300	0	100.00%	2	99.98%	0	100.00%	0	100.00%	4	99.91%	0	100.00%	2	99.98%
\$300 to \$400	0	100.00%	2	100.00%	0	100.00%	0	100.00%	8	100.00%	0	100.00%	2	100.00%
\$400 to \$500	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
\$500 to \$600	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
\$600 to \$700	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
\$700 to \$800	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
\$800 to \$900	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
\$900 to \$1000	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
> \$1000	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%

Table B-9 Frequency distribution by hours of PJM Day-Ahead Energy Market LMP (Dollars per MWh): 2007 through 2019 (continued)

LMP	2014		2015		2016		2017		2018		2019	
	Frequency	Cumulative Percent										
-\$200 to -\$100	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
-\$100 to \$0	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
\$0 to \$10	12	0.14%	71	0.81%	35	0.40%	5	0.06%	0	0.00%	9	0.10%
\$10 to \$20	112	1.42%	871	10.75%	1,462	17.04%	1,056	12.11%	796	9.09%	2,114	24.24%
\$20 to \$30	2,106	25.46%	3,760	53.68%	4,509	68.37%	4,356	61.84%	3,312	46.89%	4,566	76.36%
\$30 to \$40	2,648	55.68%	2,430	81.42%	1,837	89.29%	2,342	88.57%	2,597	76.54%	1,580	94.39%
\$40 to \$50	1,866	76.99%	772	90.23%	592	96.03%	651	96.00%	1,153	89.70%	319	98.04%
\$50 to \$60	827	86.43%	293	93.57%	204	98.35%	173	97.98%	386	94.11%	88	99.04%
\$60 to \$70	346	90.38%	130	95.06%	73	99.18%	70	98.78%	120	95.48%	34	99.43%
\$70 to \$80	191	92.56%	97	96.16%	34	99.57%	35	99.18%	84	96.44%	16	99.61%
\$80 to \$90	108	93.79%	83	97.11%	21	99.81%	26	99.47%	62	97.15%	20	99.84%
\$90 to \$100	77	94.67%	64	97.84%	7	99.89%	16	99.66%	48	97.69%	5	99.90%
\$100 to \$110	51	95.25%	37	98.26%	6	99.95%	9	99.76%	28	98.01%	3	99.93%
\$110 to \$120	33	95.63%	34	98.65%	4	100.00%	8	99.85%	27	98.32%	2	99.95%
\$120 to \$130	26	95.92%	34	99.04%	0	100.00%	7	99.93%	33	98.70%	1	99.97%
\$130 to \$140	34	96.31%	17	99.24%	0	100.00%	2	99.95%	17	98.89%	2	99.99%
\$140 to \$150	18	96.52%	11	99.36%	0	100.00%	0	99.95%	19	99.11%	0	99.99%
\$150 to \$160	31	96.87%	10	99.47%	0	100.00%	1	99.97%	16	99.29%	0	99.99%
\$160 to \$170	22	97.12%	10	99.59%	0	100.00%	0	99.97%	7	99.37%	1	100.00%
\$170 to \$180	26	97.42%	8	99.68%	0	100.00%	0	99.97%	19	99.59%	0	100.00%
\$180 to \$190	29	97.75%	2	99.70%	0	100.00%	1	99.98%	8	99.68%	0	100.00%
\$190 to \$200	24	98.03%	4	99.75%	0	100.00%	1	99.99%	7	99.76%	0	100.00%
\$200 to \$210	14	98.18%	1	99.76%	0	100.00%	0	99.99%	2	99.78%	0	100.00%
\$210 to \$220	13	98.33%	3	99.79%	0	100.00%	0	99.99%	6	99.85%	0	100.00%
\$220 to \$230	15	98.50%	1	99.81%	0	100.00%	1	100.00%	1	99.86%	0	100.00%
\$230 to \$240	8	98.60%	1	99.82%	0	100.00%	0	100.00%	0	99.86%	0	100.00%
\$240 to \$250	10	98.71%	2	99.84%	0	100.00%	0	100.00%	2	99.89%	0	100.00%
\$250 to \$260	6	98.78%	2	99.86%	0	100.00%	0	100.00%	5	99.94%	0	100.00%
\$260 to \$270	9	98.88%	4	99.91%	0	100.00%	0	100.00%	2	99.97%	0	100.00%
\$270 to \$280	15	99.05%	3	99.94%	0	100.00%	0	100.00%	0	99.97%	0	100.00%
\$280 to \$290	7	99.13%	0	99.94%	0	100.00%	0	100.00%	1	99.98%	0	100.00%
\$290 to \$300	6	99.20%	1	99.95%	0	100.00%	0	100.00%	2	100.00%	0	100.00%
\$300 to \$400	31	99.55%	4	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
\$400 to \$500	15	99.73%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
\$500 to \$600	12	99.86%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
\$600 to \$700	6	99.93%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
\$700 to \$800	1	99.94%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
\$800 to \$900	1	99.95%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
\$900 to \$1000	4	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
> \$1000	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%

Off Peak and On Peak, Day-Ahead and Real-Time, Average LMP

Table B-10 shows PJM average LMP during off peak and on peak periods for the day-ahead and real-time energy markets in 2019. Figure B-1 and Figure B-2 show the difference between real-time and day-ahead LMP in 2019 during the on peak and off peak hours.

Table B-10 Off peak and on peak, average day-ahead and real-time LMP (Dollars per MWh): 2019

	Day Ahead		Real Time		Difference		Percent Change	
	Off Peak	On Peak	Off Peak	On Peak	Off Peak	On Peak	Off Peak	On Peak
Average	\$22.38	\$30.23	\$22.43	\$30.13	(\$0.06)	\$0.09	0.3%	(0.3%)
Median	\$21.07	\$27.95	\$20.35	\$25.34	\$0.72	\$2.61	(3.4%)	(9.3%)
Standard deviation	\$7.08	\$9.87	\$14.55	\$26.26	(\$7.47)	(\$16.39)	105.6%	166.1%

Figure B-1 Hourly real-time LMP minus day-ahead LMP (On-peak hours): 2019

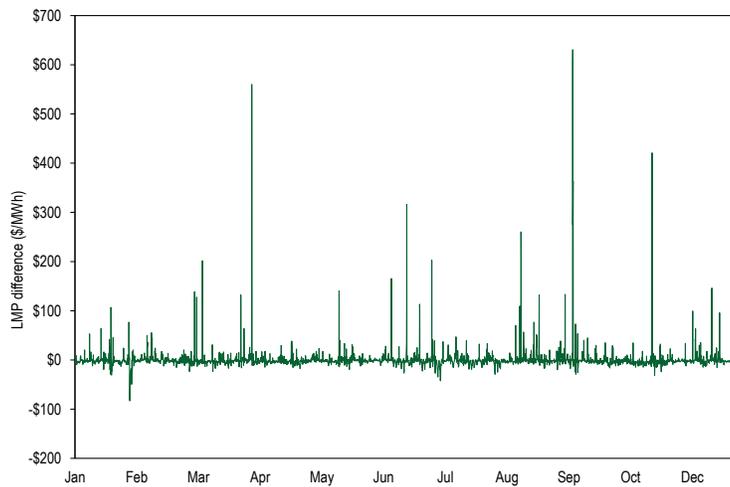
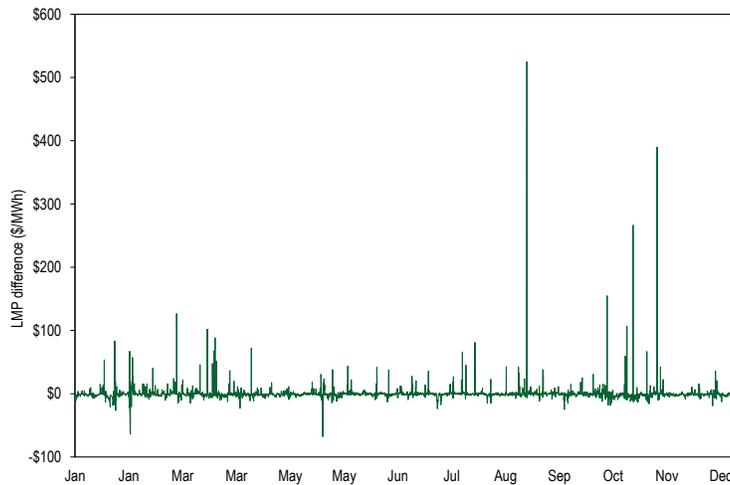


Figure B-2 Hourly real-time LMP minus day-ahead LMP (Off-peak hours): 2019



On Peak and Off Peak, Zonal, Day-Ahead and Real-Time, Average LMP

Table B-11 and Table B-12 show the on peak and off peak, average LMP for each zone in the day-ahead and real-time energy markets in 2018 and 2019.

Table B-11 On peak, zonal, average, day-ahead and real-time LMP (Dollars per MWh): 2018 and 2019

	2018				2019			
	Day Ahead	Real Time	Difference	Percent of Real Time	Day Ahead	Real Time	Difference	Percent of Real Time
AECO	\$31.91	\$31.71	(\$0.19)	(0.6%)	\$39.11	\$38.59	(\$0.51)	(1.3%)
AEP	\$34.19	\$33.35	(\$0.84)	(2.5%)	\$41.17	\$40.59	(\$0.58)	(1.4%)
APS	\$34.72	\$34.32	(\$0.40)	(1.2%)	\$42.68	\$42.04	(\$0.64)	(1.5%)
ATSI	\$35.25	\$34.97	(\$0.27)	(0.8%)	\$44.06	\$44.93	\$0.87	1.9%
BGE	\$37.97	\$37.15	(\$0.82)	(2.2%)	\$46.50	\$45.59	(\$0.91)	(2.0%)
ComEd	\$32.45	\$32.15	(\$0.31)	(1.0%)	\$34.62	\$33.70	(\$0.93)	(2.7%)
DAY	\$35.10	\$34.30	(\$0.80)	(2.3%)	\$43.25	\$42.55	(\$0.69)	(1.6%)
DEOK	\$34.65	\$33.78	(\$0.88)	(2.6%)	\$44.33	\$42.50	(\$1.84)	(4.3%)
DLCO	\$34.55	\$34.12	(\$0.43)	(1.3%)	\$44.19	\$44.99	\$0.80	1.8%
Dominion	\$36.75	\$36.03	(\$0.72)	(2.0%)	\$45.33	\$43.98	(\$1.35)	(3.1%)
DPL	\$34.58	\$34.31	(\$0.27)	(0.8%)	\$44.00	\$44.75	\$0.75	1.7%
EKPC	\$32.99	\$31.67	(\$1.32)	(4.2%)	\$38.73	\$37.81	(\$0.92)	(2.4%)
JCPL	\$32.84	\$32.80	(\$0.03)	(0.1%)	\$38.80	\$38.15	(\$0.64)	(1.7%)
Met-Ed	\$34.11	\$34.31	\$0.19	0.6%	\$39.52	\$38.69	(\$0.83)	(2.1%)
OVEC	\$35.39	\$35.81	\$0.42	1.2%	\$35.15	\$33.57	(\$1.58)	(4.7%)
PECO	\$31.91	\$31.96	\$0.05	0.2%	\$37.88	\$37.27	(\$0.61)	(1.6%)
PENELEC	\$33.58	\$34.30	\$0.72	2.1%	\$41.10	\$41.24	\$0.13	0.3%
Pepco	\$37.09	\$36.16	(\$0.93)	(2.6%)	\$45.10	\$44.07	(\$1.03)	(2.3%)
PPL	\$32.45	\$32.53	\$0.08	0.2%	\$37.68	\$36.87	(\$0.81)	(2.2%)
PSEG	\$33.77	\$33.93	\$0.16	0.5%	\$39.73	\$38.66	(\$1.07)	(2.8%)
RECO	\$33.88	\$33.98	\$0.11	0.3%	\$40.33	\$39.79	(\$0.54)	(1.3%)

Table B-12 Off peak, zonal, average, day-ahead and real-time LMP (Dollars per MWh): 2018 and 2019

	2018				2019			
	Day Ahead	Real Time	Difference	Percent of Real Time	Day Ahead	Real Time	Difference	Percent of Real Time
AECO	\$23.93	\$24.44	\$0.52	2.1%	\$30.80	\$31.51	\$0.71	2.2%
AEP	\$25.30	\$25.25	(\$0.04)	(0.2%)	\$30.41	\$31.20	\$0.78	2.5%
APS	\$25.75	\$25.91	\$0.16	0.6%	\$31.74	\$32.49	\$0.75	2.3%
ATSI	\$25.58	\$25.51	(\$0.07)	(0.3%)	\$31.04	\$31.68	\$0.64	2.0%
BGE	\$28.25	\$28.51	\$0.26	0.9%	\$35.03	\$35.55	\$0.51	1.4%
ComEd	\$22.17	\$22.23	\$0.06	0.3%	\$23.45	\$24.09	\$0.65	2.7%
DAY	\$25.74	\$25.66	(\$0.08)	(0.3%)	\$30.90	\$31.32	\$0.42	1.3%
DEOK	\$25.15	\$24.91	(\$0.24)	(1.0%)	\$31.22	\$31.26	\$0.04	0.1%
DLCO	\$25.14	\$25.01	(\$0.13)	(0.5%)	\$30.69	\$31.07	\$0.38	1.2%
Dominion	\$27.31	\$27.47	\$0.16	0.6%	\$34.20	\$34.80	\$0.59	1.7%
DPL	\$25.91	\$27.50	\$1.58	5.8%	\$33.14	\$33.83	\$0.69	2.0%
EKPC	\$24.68	\$24.61	(\$0.07)	(0.3%)	\$28.75	\$29.22	\$0.46	1.6%
JCPL	\$24.18	\$24.58	\$0.40	1.6%	\$30.46	\$30.97	\$0.51	1.7%
Met-Ed	\$24.25	\$24.49	\$0.24	1.0%	\$29.89	\$30.14	\$0.25	0.8%
OVEC	\$24.33	\$24.41	\$0.07	0.3%	\$28.71	\$28.70	(\$0.02)	(0.1%)
PECO	\$23.91	\$24.39	\$0.48	2.0%	\$30.12	\$30.51	\$0.39	1.3%
PENELEC	\$24.77	\$24.80	\$0.03	0.1%	\$30.45	\$31.02	\$0.57	1.8%
Pepco	\$27.68	\$27.85	\$0.17	0.6%	\$34.37	\$34.84	\$0.46	1.3%
PPL	\$23.81	\$24.10	\$0.28	1.2%	\$29.28	\$29.52	\$0.23	0.8%
PSEG	\$24.66	\$24.82	\$0.17	0.7%	\$30.64	\$30.89	\$0.25	0.8%
RECO	\$24.73	\$24.92	\$0.19	0.8%	\$30.62	\$30.73	\$0.11	0.4%

PJM Day-Ahead and Real-Time, Average LMP during Constrained Hours

Table B-13 shows the number of constrained hours for the day-ahead and real-time energy markets and the total number of hours in each month for 2019.

Table B-13 PJM day-ahead and real-time, market-constrained hours: 2019

	DA Constrained Hours	RT Constrained Hours	Total Hours
Jan	744	627	744
Feb	672	567	672
Mar	743	628	743
Apr	720	546	720
May	744	609	744
Jun	720	450	720
Jul	744	564	744
Aug	744	640	744
Sep	720	695	720
Oct	744	736	744
Nov	721	663	721
Dec	744	681	744
Avg	730	617	730

Table B-14 shows PJM average LMP during constrained and unconstrained hours in the day-ahead and real-time energy markets.

Table B-14 PJM average LMP during constrained and unconstrained hours (Dollars per MWh): 2019

	Day Ahead		Real Time		Difference		Percent Change	
	Unconstrained Hours LMP	Constrained Hours LMP						
Average	\$0.00	\$28.96	\$20.43	\$27.04	\$20.43	(\$1.92)	NA	(6.6%)
Median	\$0.00	\$26.87	\$19.52	\$23.48	\$19.52	(\$3.39)	NA	(12.6%)
Standard deviation	\$0.00	\$10.80	\$6.83	\$22.71	\$6.83	\$11.92	NA	110.4%

Price Convergence

Table B-15 provides frequency distributions of the differences between PJM real-time hourly LMP and PJM day-ahead hourly LMP for 2007 through 2019.

Table B-15 Frequency distribution by hours of PJM real-time LMP minus day-ahead LMP (Dollars per MWh): 2007 through 2019

LMP	2007		2008		2009		2010		2011		2012		2013	
	Frequency	Cumulative Percent												
< (\$1,000)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
(\$1,000) to (\$750)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
(\$750) to (\$500)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
(\$500) to (\$450)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
(\$450) to (\$400)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
(\$400) to (\$350)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
(\$350) to (\$300)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
(\$300) to (\$250)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
(\$250) to (\$200)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	1	0.01%	1	0.01%
(\$200) to (\$150)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	1	0.01%	4	0.06%	3	0.05%
(\$150) to (\$100)	0	0.00%	1	0.01%	0	0.00%	0	0.00%	2	0.03%	6	0.13%	5	0.10%
(\$100) to (\$50)	33	0.38%	88	1.01%	3	0.03%	13	0.15%	49	0.59%	17	0.32%	9	0.21%
(\$50) to \$0	4,600	52.89%	5,120	59.30%	5,108	58.34%	5,543	63.42%	5,614	64.68%	5,576	63.80%	5,994	68.63%
\$0 to \$50	3,827	96.58%	3,247	96.27%	3,603	99.47%	3,004	97.72%	2,880	97.56%	3,061	98.65%	2,659	98.98%
\$50 to \$100	255	99.49%	284	99.50%	41	99.94%	164	99.59%	185	99.67%	82	99.58%	64	99.71%
\$100 to \$150	31	99.84%	37	99.92%	5	100.00%	25	99.87%	21	99.91%	17	99.77%	12	99.85%
\$150 to \$200	5	99.90%	4	99.97%	0	100.00%	9	99.98%	2	99.93%	12	99.91%	10	99.97%
\$200 to \$250	1	99.91%	2	99.99%	0	100.00%	2	100.00%	3	99.97%	5	99.97%	1	99.98%
\$250 to \$300	3	99.94%	0	99.99%	0	100.00%	0	100.00%	0	99.97%	1	99.98%	2	100.00%
\$300 to \$350	2	99.97%	1	100.00%	0	100.00%	0	100.00%	0	99.97%	2	100.00%	0	100.00%
\$350 to \$400	1	99.98%	0	100.00%	0	100.00%	0	100.00%	0	99.97%	0	100.00%	0	100.00%
\$400 to \$450	1	99.99%	0	100.00%	0	100.00%	0	100.00%	0	99.97%	0	100.00%	0	100.00%
\$450 to \$500	1	100.00%	0	100.00%	0	100.00%	0	100.00%	0	99.97%	0	100.00%	0	100.00%
\$500 to \$750	0	100.00%	0	100.00%	0	100.00%	0	100.00%	3	100.00%	0	100.00%	0	100.00%
\$750 to \$1,000	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
\$1,000 to \$1,250	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
>= \$1,250	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%

LMP	2014		2015		2016		2017		2018		2019	
	Frequency	Cumulative Percent										
< (\$1,000)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
(\$1,000) to (\$750)	2	0.02%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
(\$750) to (\$500)	3	0.06%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
(\$500) to (\$450)	1	0.07%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
(\$450) to (\$400)	6	0.14%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
(\$400) to (\$350)	5	0.19%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
(\$350) to (\$300)	5	0.25%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
(\$300) to (\$250)	6	0.32%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
(\$250) to (\$200)	14	0.48%	1	0.01%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
(\$200) to (\$150)	14	0.64%	4	0.06%	0	0.00%	0	0.00%	0	0.01%	0	0.00%
(\$150) to (\$100)	45	1.15%	17	0.25%	0	0.00%	2	0.02%	2	0.05%	0	0.00%
(\$100) to (\$50)	91	2.19%	65	0.99%	13	0.15%	9	0.13%	9	0.41%	5	0.06%
(\$50) to \$0	5,829	68.73%	6,034	69.87%	5,780	65.95%	5,460	62.45%	5,460	65.65%	6,013	68.70%
\$0 to \$50	2,525	97.56%	2,467	98.04%	2,919	99.18%	3,231	99.34%	3,231	98.24%	2,681	99.30%
\$50 to \$100	120	98.93%	126	99.47%	58	99.84%	45	99.85%	45	99.52%	29	99.63%
\$100 to \$150	39	99.37%	34	99.86%	13	99.99%	8	99.94%	8	99.82%	16	99.82%
\$150 to \$200	18	99.58%	7	99.94%	1	100.00%	3	99.98%	3	99.87%	2	99.84%
\$200 to \$250	9	99.68%	3	99.98%	0	100.00%	0	99.98%	0	99.97%	3	99.87%
\$250 to \$300	8	99.77%	1	99.99%	0	100.00%	0	99.98%	0	99.98%	3	99.91%
\$300 to \$350	3	99.81%	1	100.00%	0	100.00%	0	99.98%	0	99.99%	1	99.92%
\$350 to \$400	3	99.84%	0	100.00%	0	100.00%	0	99.98%	0	99.99%	2	99.94%
\$400 to \$450	2	99.86%	0	100.00%	0	100.00%	1	99.99%	1	100.00%	1	99.95%
\$450 to \$500	0	99.86%	0	100.00%	0	100.00%	0	99.99%	0	100.00%	0	99.95%
\$500 to \$750	7	99.94%	0	100.00%	0	100.00%	1	100.00%	1	100.00%	4	100.00%
\$750 to \$1,000	0	99.94%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
\$1,000 to \$1,250	1	99.95%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
>= \$1,250	4	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%

LMP by Zone and by Jurisdiction

Jurisdiction Real-Time, Average LMP

Table B-16 Jurisdiction real-time, average LMP (Dollars per MWh): 2018 and 2019

	2018	2019	Difference	Percent Change
Delaware	\$36.30	\$24.50	(\$11.80)	(32.5%)
Illinois	\$28.57	\$23.53	(\$5.04)	(17.6%)
Indiana	\$33.43	\$26.03	(\$7.40)	(22.1%)
Kentucky	\$34.05	\$26.88	(\$7.17)	(21.1%)
Maryland	\$39.86	\$28.27	(\$11.59)	(29.1%)
Michigan	\$33.36	\$27.11	(\$6.25)	(18.7%)
New Jersey	\$34.50	\$24.01	(\$10.49)	(30.4%)
North Carolina	\$38.75	\$27.35	(\$11.40)	(29.4%)
Ohio	\$36.58	\$27.15	(\$9.43)	(25.8%)
Pennsylvania	\$34.74	\$24.57	(\$10.16)	(29.3%)
Tennessee	\$39.11	\$27.53	(\$11.58)	(29.6%)
Virginia	\$35.69	\$26.55	(\$9.14)	(25.6%)
West Virginia	\$0.00	\$0.00	\$0.00	0.0%
District of Columbia	\$39.24	\$28.09	(\$11.15)	(28.4%)

Hub Real-Time, Average LMP

Table B-17 Hub real-time, average LMP (Dollars per MWh): 2018 and 2019

	2018	2019	Difference	Percent Change
AEP Gen Hub	\$33.06	\$25.71	(\$7.36)	(22.3%)
AEP-DAY Hub	\$34.48	\$26.80	(\$7.67)	(22.2%)
ATSI Gen Hub	\$36.61	\$26.43	(\$10.18)	(27.8%)
Chicago Gen Hub	\$28.16	\$23.27	(\$4.90)	(17.4%)
Chicago Hub	\$28.68	\$23.65	(\$5.03)	(17.6%)
Dominion Hub	\$38.89	\$27.17	(\$11.71)	(30.1%)
Eastern Hub	\$38.47	\$25.09	(\$13.38)	(34.8%)
N Illinois Hub	\$28.48	\$23.49	(\$4.99)	(17.5%)
New Jersey Hub	\$34.44	\$23.94	(\$10.50)	(30.5%)
Ohio Hub	\$34.32	\$26.92	(\$7.40)	(21.6%)
West Interface Hub	\$37.62	\$26.45	(\$11.17)	(29.7%)
Western Hub	\$36.57	\$26.38	(\$10.19)	(27.9%)

Jurisdiction Real-Time, Load-Weighted, Average LMP

Table B-18 Jurisdiction real-time, load-weighted, average LMP (Dollars per MWh): 2018 and 2019

	2018	2019	Difference	Percent Change
Delaware	\$40.11	\$26.60	(\$13.51)	(33.7%)
Illinois	\$30.05	\$24.72	(\$5.33)	(17.7%)
Indiana	\$34.60	\$26.91	(\$7.69)	(22.2%)
Kentucky	\$37.11	\$28.45	(\$8.66)	(23.3%)
Maryland	\$43.99	\$30.18	(\$13.81)	(31.4%)
Michigan	\$34.55	\$28.53	(\$6.02)	(17.4%)
New Jersey	\$36.86	\$25.30	(\$11.56)	(31.4%)
North Carolina	\$43.73	\$28.34	(\$15.39)	(35.2%)
Ohio	\$38.81	\$28.50	(\$10.31)	(26.6%)
Pennsylvania	\$37.33	\$25.80	(\$11.53)	(30.9%)
Tennessee	\$43.38	\$29.08	(\$14.30)	(33.0%)
Virginia	\$38.12	\$27.69	(\$10.43)	(27.4%)
West Virginia	\$0.00	\$0.00	\$0.00	0.0%
District of Columbia	\$41.68	\$29.45	(\$12.24)	(29.4%)

Jurisdiction Day-Ahead, Average LMP

Table B-19 Jurisdiction day-ahead, average LMP (Dollars per MWh): 2018 and 2019

	2018	2019	Difference	Percent Change
Delaware	\$36.31	\$24.44	(\$11.87)	(32.7%)
Illinois	\$28.53	\$23.50	(\$5.04)	(17.6%)
Indiana	\$33.84	\$26.12	(\$7.72)	(22.8%)
Kentucky	\$34.15	\$26.75	(\$7.40)	(21.7%)
Maryland	\$40.07	\$28.27	(\$11.80)	(29.4%)
Michigan	\$33.36	\$26.86	(\$6.50)	(19.5%)
New Jersey	\$34.75	\$23.92	(\$10.83)	(31.2%)
North Carolina	\$38.36	\$27.20	(\$11.16)	(29.1%)
Ohio	\$36.23	\$27.16	(\$9.06)	(25.0%)
Pennsylvania	\$34.61	\$24.66	(\$9.96)	(28.8%)
Tennessee	\$39.37	\$27.57	(\$11.80)	(30.0%)
Virginia	\$35.53	\$26.53	(\$9.01)	(25.3%)
West Virginia	\$0.00	\$0.00	\$0.00	0.0%
District of Columbia	\$39.56	\$28.51	(\$11.05)	(27.9%)

Jurisdiction Day-Ahead, Load-Weighted, Average LMP

Table B-20 Jurisdiction day-ahead, load-weighted, average LMP (Dollars per MWh): 2018 and 2019

	2018	2019	Difference	Percent Change
Delaware	\$39.93	\$26.48	(\$13.45)	(33.7%)
Illinois	\$30.00	\$24.52	(\$5.48)	(18.3%)
Indiana	\$35.01	\$27.03	(\$7.97)	(22.8%)
Kentucky	\$36.83	\$28.32	(\$8.52)	(23.1%)
Maryland	\$43.78	\$30.12	(\$13.66)	(31.2%)
Michigan	\$34.45	\$28.08	(\$6.38)	(18.5%)
New Jersey	\$36.95	\$25.09	(\$11.86)	(32.1%)
North Carolina	\$42.85	\$28.62	(\$14.23)	(33.2%)
Ohio	\$38.22	\$28.37	(\$9.86)	(25.8%)
Pennsylvania	\$36.79	\$25.77	(\$11.02)	(29.9%)
Tennessee	\$43.30	\$29.06	(\$14.24)	(32.9%)
Virginia	\$37.84	\$27.71	(\$10.13)	(26.8%)
West Virginia	\$0.00	\$0.00	\$0.00	0.0%
District of Columbia	\$41.81	\$29.75	(\$12.06)	(28.8%)

Zonal Price Differences Between Day-Ahead and Real-Time

Table B-21 Zonal day-ahead and real-time average LMP (Dollars per MWh): 2019

	Day Ahead	Real Time	Difference	Percent of Real Time
AECO	\$23.70	\$23.72	(\$0.02)	(0.1%)
AEP	\$26.81	\$26.92	(\$0.11)	(0.4%)
APS	\$26.68	\$26.55	\$0.13	0.5%
ATSI	\$27.05	\$26.86	\$0.19	0.7%
BGE	\$29.22	\$28.95	\$0.27	0.9%
ComEd	\$23.59	\$23.53	\$0.06	0.2%
DAY	\$27.93	\$27.96	(\$0.03)	(0.1%)
DEOK	\$27.22	\$27.02	\$0.20	0.8%
DLCO	\$26.63	\$26.45	\$0.18	0.7%
Dominion	\$27.83	\$27.59	\$0.24	0.9%
DPL	\$25.06	\$25.16	(\$0.11)	(0.4%)
EKPC	\$26.39	\$26.54	(\$0.15)	(0.6%)
JCPL	\$23.78	\$23.90	(\$0.12)	(0.5%)
Met-Ed	\$24.60	\$24.92	(\$0.31)	(1.3%)
OVEC	\$25.91	\$25.98	(\$0.07)	(0.3%)
PECO	\$23.26	\$23.43	(\$0.16)	(0.7%)
PENELEC	\$25.57	\$25.19	\$0.38	1.5%
Peppo	\$28.38	\$28.03	\$0.36	1.3%
PPL	\$23.30	\$23.55	(\$0.25)	(1.1%)
PSEG	\$24.03	\$24.11	(\$0.08)	(0.3%)
RECO	\$24.60	\$24.44	\$0.16	0.7%

Jurisdictional Price Differences Between Day-Ahead and Real-Time

Table B-22 Jurisdiction day-ahead and real-time average LMP (Dollars per MWh): 2019

	Day Ahead	Real Time	Difference	Percent of Real Time
Delaware	\$24.44	\$24.50	(\$0.06)	(0.2%)
Illinois	\$23.50	\$23.53	(\$0.03)	(0.1%)
Indiana	\$26.12	\$26.03	\$0.09	0.3%
Kentucky	\$26.75	\$26.88	(\$0.13)	(0.5%)
Maryland	\$28.27	\$28.27	\$0.00	0.0%
Michigan	\$26.86	\$27.11	(\$0.24)	(0.9%)
New Jersey	\$23.92	\$24.01	(\$0.09)	(0.4%)
North Carolina	\$27.20	\$27.35	(\$0.15)	(0.5%)
Ohio	\$27.16	\$27.15	\$0.02	0.1%
Pennsylvania	\$24.66	\$24.57	\$0.08	0.3%
Tennessee	\$26.30	\$26.63	(\$0.33)	(1.2%)
Virginia	\$27.57	\$27.53	\$0.04	0.1%
West Virginia	\$26.53	\$26.55	(\$0.03)	(0.1%)
District of Columbia	\$28.51	\$28.09	\$0.42	1.5%

Offer-Capped Units

PJM's market power mitigation goals have focused on market designs that promote competition and that limit market power mitigation to situations where market structure is not competitive and thus where market design alone cannot mitigate market power. In the PJM energy market, this situation occurs primarily in the case of local market power. Offer capping occurs as a result of structurally noncompetitive local markets and

noncompetitive offers in the day-ahead and real-time energy markets. PJM also uses offer capping for units that are committed for reliability reasons, specifically for providing black start, reactive service and for units committed manually as part of conservative operations.

PJM rules provide for offer capping when conditions on the transmission system create a structurally noncompetitive local market, when units in that local market have made noncompetitive offers and when such offers would set the price above the competitive level in the absence of mitigation. Offer caps are set at the level of a competitive offer. Offer capped units receive the higher of the market price or their offer cap. Thus, if broader market conditions lead to a price greater than the offer cap, the unit receives the higher market price. The rules governing the exercise of local market power recognize that units in certain areas of the system would be in a position to extract monopoly profits, but for these rules.

Under existing rules, PJM suspends offer capping when structural market conditions, as determined by the three pivotal supplier test, indicate that suppliers are reasonably likely to behave in a competitive manner.¹⁴ The goal is to apply a clear rule to limit the exercise of market power by generation owners in load pockets, but to apply the rule in a flexible manner in real time and to lift offer capping when the exercise of market power is unlikely based on the real-time application of the market structure screen.

Levels of offer capping have generally been low and stable over the last five years. Table B-23 through Table B-26 show offer capping by month, including the average number of offer capped units, offer capped unit hours as a percentage of unit run hours, average offer capped MW, and offer capped MW as a percentage of total generation MW in the day-ahead and real-time energy markets. The statistics include units that are capped for failing the TPS test to provide constraint relief as well as units committed on their cost schedule for reliability reasons (reactive support, black start service and conservative operations).

¹⁴ See the *Technical Reference for PJM Markets*, Section 8, "Three Pivotal Supplier Test."

Table B-23 Average day-ahead, offer capped units: 2015 through 2019

	2015		2016		2017		2018		2019	
	Avg. Units Capped	Percent								
Jan	2.5	0.6%	0.8	0.2%	0.9	0.2%	1.0	0.2%	0.2	0.1%
Feb	2.3	0.5%	0.8	0.2%	1.6	0.4%	0.3	0.1%	0.4	0.1%
Mar	2.5	0.6%	0.8	0.2%	1.1	0.3%	0.5	0.1%	1.6	0.4%
Apr	4.3	1.1%	0.1	0.0%	0.4	0.1%	1.0	0.2%	2.2	0.5%
May	4.4	1.1%	0.6	0.1%	0.6	0.2%	1.1	0.2%	3.4	0.8%
Jun	5.4	1.2%	0.2	0.0%	0.0	0.0%	2.8	0.6%	6.2	1.3%
Jul	2.7	0.6%	0.2	0.0%	0.0	0.0%	1.5	0.3%	9.5	1.8%
Aug	2.2	0.5%	0.2	0.0%	0.1	0.0%	0.4	0.1%	9.1	1.8%
Sep	0.9	0.2%	1.2	0.3%	0.5	0.1%	1.1	0.2%	13.9	3.0%
Oct	1.0	0.3%	0.4	0.1%	0.6	0.1%	1.4	0.3%	13.0	3.1%
Nov	1.8	0.5%	1.2	0.3%	0.2	0.0%	0.7	0.1%	8.0	1.9%
Dec	0.7	0.2%	0.8	0.2%	0.2	0.1%	1.1	0.3%	3.8	0.9%

Table B-24 Average day-ahead, offer capped MW: 2015 through 2019

	2015		2016		2017		2018		2019	
	Avg. MW Capped	Percent								
Jan	311	0.3%	144	0.1%	502	0.5%	120	0.1%	88	0.1%
Feb	355	0.3%	159	0.2%	525	0.6%	72	0.1%	110	0.1%
Mar	402	0.4%	91	0.1%	565	0.6%	153	0.2%	460	0.5%
Apr	1,164	1.5%	8	0.0%	243	0.3%	373	0.5%	310	0.4%
May	1,015	1.2%	25	0.0%	372	0.5%	416	0.5%	430	0.5%
Jun	1,587	1.7%	36	0.0%	0	0.0%	806	0.8%	917	1.0%
Jul	858	0.8%	25	0.0%	2	0.0%	563	0.5%	749	0.7%
Aug	787	0.8%	9	0.0%	33	0.0%	148	0.1%	1,175	1.1%
Sep	110	0.1%	95	0.1%	76	0.1%	354	0.4%	1,803	1.9%
Oct	243	0.3%	56	0.1%	50	0.1%	501	0.6%	1,659	2.0%
Nov	355	0.4%	464	0.6%	66	0.1%	213	0.2%	1,625	1.9%
Dec	49	0.1%	415	0.4%	48	0.1%	256	0.3%	956	1.0%

Table B-25 Average real-time, offer capped units: 2015 through 2019

	2015		2016		2017		2018		2019	
	Avg. Units Capped	Percent								
Jan	3.7	0.8%	2.1	0.4%	2.0	0.4%	9.5	1.7%	4.3	0.8%
Feb	4.7	0.9%	1.5	0.3%	1.8	0.4%	4.2	0.8%	4.4	0.8%
Mar	3.9	0.8%	3.2	0.7%	1.6	0.3%	6.1	1.3%	5.5	1.1%
Apr	5.2	1.1%	1.3	0.3%	1.1	0.2%	5.8	1.1%	4.9	0.9%
May	5.5	1.1%	1.3	0.3%	1.7	0.3%	9.6	1.8%	7.6	1.4%
Jun	6.3	1.2%	1.6	0.3%	1.5	0.3%	7.2	1.3%	8.3	1.5%
Jul	3.5	0.6%	4.2	0.7%	2.1	0.4%	8.1	1.4%	19.9	3.1%
Aug	3.1	0.6%	3.3	0.5%	1.5	0.3%	6.9	1.1%	16.9	3.0%
Sep	2.3	0.5%	3.0	0.6%	4.2	0.8%	8.3	1.5%	18.2	3.5%
Oct	1.8	0.4%	2.5	0.5%	3.8	0.8%	9.4	1.8%	19.4	4.0%
Nov	2.5	0.6%	1.6	0.4%	1.8	0.4%	3.5	0.7%	9.9	2.1%
Dec	1.6	0.3%	1.4	0.3%	3.1	0.6%	4.5	0.9%	4.8	1.0%

Table B-26 Average real-time, offer capped MW: 2015 through 2019

	2015		2016		2017		2018		2019	
	Avg. MW Capped	Percent								
Jan	351	0.4%	216	0.2%	557	0.6%	699	0.7%	825	0.8%
Feb	353	0.3%	145	0.2%	496	0.6%	210	0.2%	660	0.7%
Mar	487	0.5%	276	0.3%	624	0.7%	345	0.6%	1,009	1.1%
Apr	1,091	1.4%	90	0.1%	281	0.4%	644	0.8%	733	0.9%
May	1,003	1.2%	69	0.1%	433	0.6%	1,371	1.6%	1,016	1.1%
Jun	1,580	1.7%	197	0.2%	124	0.1%	1,192	1.2%	1,334	1.4%
Jul	957	1.0%	437	0.4%	204	0.2%	1,143	1.1%	1,862	1.6%
Aug	708	0.7%	311	0.3%	128	0.1%	808	0.7%	2,014	1.9%
Sep	207	0.2%	196	0.2%	271	0.3%	1,046	1.1%	2,077	2.2%
Oct	248	0.3%	222	0.3%	212	0.3%	1,821	2.0%	2,204	2.7%
Nov	368	0.5%	537	0.7%	294	0.4%	583	0.6%	1,823	2.1%
Dec	100	0.1%	454	0.5%	229	0.2%	891	0.9%	1,661	1.7%

In order to help understand the frequency of offer capping in more detail, Table B-27 through Table B-31 show the number of generating units that met specified criteria for total offer capped run hours (constraint relief and reliability reasons) and percentage of offer capped run hours for the years 2015 through 2019 in the real-time energy market.

Table B-27 Offer-capped unit statistics: 2015

Run Hours Offer-Capped, Percent Greater Than Or Equal To:	2015 Offer-Capped Hours					
	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	2	0	0	0	1	4
80% and < 90%	0	1	1	0	0	6
75% and < 80%	0	0	0	0	0	3
70% and < 75%	0	0	0	0	0	4
60% and < 70%	0	0	0	1	0	9
50% and < 60%	0	0	0	0	1	9
25% and < 50%	0	0	0	0	1	26
10% and < 25%	0	0	5	2	5	34

Table B-28 Offer-capped unit statistics: 2016

Run Hours Offer-Capped, Percent Greater Than Or Equal To:	2016 Offer-Capped Hours					
	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	1	1	1	0	0	0
80% and < 90%	0	0	1	1	1	0
75% and < 80%	0	0	0	0	1	1
70% and < 75%	1	0	0	0	1	0
60% and < 70%	1	0	0	0	0	2
50% and < 60%	1	0	0	0	0	2
25% and < 50%	1	3	0	4	2	24
10% and < 25%	0	0	1	2	8	21

Table B-29 Offer-capped unit statistics: 2017

Run Hours Offer-Capped, Percent Greater Than Or Equal To:	2017 Offer-Capped Hours					
	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	0	0	1	1	1	1
80% and < 90%	0	0	1	2	0	1
75% and < 80%	0	0	0	1	1	0
70% and < 75%	1	0	0	0	0	1
60% and < 70%	0	0	0	0	1	1
50% and < 60%	0	0	0	1	0	1
25% and < 50%	1	0	1	1	6	31
10% and < 25%	0	0	1	1	14	36

Table B-30 Offer-capped unit statistics: 2018

Run Hours Offer-Capped, Percent Greater Than Or Equal To:	2018 Offer-Capped Hours					
	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	2	0	0	0	0	0
80% and < 90%	0	0	0	0	0	0
75% and < 80%	0	0	0	0	2	2
70% and < 75%	0	0	0	0	1	3
60% and < 70%	0	0	0	1	1	5
50% and < 60%	2	0	0	2	0	3
25% and < 50%	7	4	4	9	5	15
10% and < 25%	3	0	2	8	30	61

Table B-31 Offer-capped unit statistics: 2019

Run Hours Offer-Capped, Percent Greater Than Or Equal To:	2019 Offer-Capped Hours					
	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	0	0	0	0	0	1
80% and < 90%	0	0	0	0	2	4
75% and < 80%	0	0	0	0	0	3
70% and < 75%	2	0	0	0	1	2
60% and < 70%	9	0	1	1	1	10
50% and < 60%	7	2	6	5	1	15
25% and < 50%	17	7	11	25	14	32
10% and < 25%	2	5	6	10	11	51

Energy Uplift

On November 1, 2017, PJM implemented hourly offers and intraday offer updates. Hourly offers means that generators have the ability to offer hourly differentiated offers (up to one offer per hour instead of one offer per day). Intraday offer updates means that generators have the ability to make changes to an offer after the day-ahead market deadline and after the rebid period. These two features are primarily used by natural gas units. Natural gas trades in days that go from 10 AM to 10 AM the next day, so gas units need hourly offers to show the cost change at 10 AM. Because the cost of natural gas can also change from day-ahead to real-time and can change hourly during the operating day, gas units need the ability to make intraday offer updates.

Credits and Charges to Generators

Table B-32 and Table B-33 compare the share of balancing operating reserve charges paid by generators and balancing operating reserve credits paid to generators in the Eastern Region and the Western Region. Generator charges are defined in these tables as the allocation of charges paid by generators due to generator deviations from day-ahead schedules or not following PJM dispatch.

Table B-32 shows that on average, 11.7 percent of the RTO and Eastern Region balancing generator charges, including lost opportunity cost and canceled resources charges, were paid by generators deviating in the Eastern Region while these generators received 40.2 percent of all balancing generator credits.

Table B-32 Monthly balancing operating reserve charges and credits to generators in the Eastern Region (Millions): 2019

	Generators RTO Deviation Charges	Generators Regional Deviation Charges	Generators LOC and Canceled Resources Charges	Total Charges	Balancing, LOC and Canceled Resources Credits
Jan	\$0.2	\$0.2	\$0.1	\$0.4	\$4.5
Feb	\$0.1	\$0.0	\$0.0	\$0.2	\$1.5
Mar	\$0.2	\$0.0	\$0.1	\$0.3	\$2.4
Apr	\$0.2	\$0.0	\$0.1	\$0.3	\$1.5
May	\$0.2	\$0.0	\$0.2	\$0.4	\$1.8
Jun	\$0.3	\$0.0	\$0.1	\$0.4	\$1.6
Jul	\$0.6	\$0.0	\$0.2	\$0.8	\$3.8
Aug	\$0.4	\$0.0	\$0.2	\$0.6	\$2.5
Sep	\$0.3	\$0.0	\$0.5	\$0.8	\$2.6
Oct	\$0.4	\$0.1	\$0.2	\$0.7	\$2.8
Nov	\$0.2	\$0.0	\$0.2	\$0.4	\$1.9
Dec	\$0.1	\$0.1	\$0.1	\$0.3	\$1.0
East Generators Total	\$3.1	\$0.6	\$1.8	\$5.6	\$28.0
PJM Total	\$28.0	\$2.3	\$17.3	\$47.6	\$69.4
Share	11.2%	24.3%	10.7%	11.7%	40.3%

Table B-33 shows that generators in the Western Region paid 10.5 percent of the RTO and Western Region balancing generator charges including lost opportunity cost and canceled resources charges while these generators received 57.3 percent of all balancing generator credits.

Table B-33 Monthly balancing operating reserve charges and credits to generators in the Western Region (Millions): 2019

	Generators RTO Deviation Charges	Generators Regional Deviation Charges	Generators LOC and Canceled Resources Charges	Total Charges	Balancing, LOC and Canceled Resources Credits
Jan	\$0.2	\$0.0	\$0.1	\$0.2	\$1.5
Feb	\$0.1	\$0.0	\$0.0	\$0.1	\$1.1
Mar	\$0.1	\$0.0	\$0.0	\$0.2	\$1.7
Apr	\$0.2	\$0.0	\$0.1	\$0.2	\$2.4
May	\$0.2	\$0.0	\$0.2	\$0.3	\$1.9
Jun	\$0.3	\$0.0	\$0.1	\$0.3	\$3.0
Jul	\$0.5	\$0.0	\$0.2	\$0.8	\$6.6
Aug	\$0.3	\$0.0	\$0.2	\$0.5	\$4.2
Sep	\$0.4	\$0.0	\$0.6	\$1.0	\$7.7
Oct	\$0.3	\$0.0	\$0.2	\$0.5	\$5.2
Nov	\$0.2	\$0.0	\$0.1	\$0.3	\$3.2
Dec	\$0.1	\$0.0	\$0.1	\$0.2	\$1.4
West Generators Total	\$2.9	\$0.2	\$1.8	\$4.9	\$39.9
PJM Total	\$28.0	\$0.8	\$17.3	\$46.0	\$69.4
Share	10.4%	21.6%	10.3%	10.5%	57.5%

Table B-34 shows that on average in 2019, energy uplift charges paid by generators were 11.7 percent of all energy uplift charges, 2.6 percentage point lower than the average in 2018. Generators received 100.0 percent of all energy uplift credits.

Table B-34 Percentage of generators credits and charges of total credits and charges: 2018 and 2019

	2018		2019	
	Generators Share of Total Energy Uplift Charges	Generators Share of Total Energy Uplift Credits	Generators Share of Total Energy Uplift Charges	Generators Share of Total Energy Uplift Credits
Jan	17.8%	134.2%	8.8%	108.7%
Feb	3.3%	101.9%	6.4%	103.3%
Mar	8.5%	126.0%	7.0%	107.0%
Apr	12.9%	129.6%	11.7%	113.0%
May	12.8%	134.0%	13.0%	128.2%
Jun	6.1%	118.6%	9.7%	108.9%
Jul	12.5%	117.2%	13.1%	116.3%
Aug	15.9%	119.0%	11.9%	118.2%
Sep	11.4%	118.6%	14.5%	140.1%
Oct	13.4%	123.3%	13.5%	125.4%
Nov	11.2%	110.1%	13.3%	127.5%
Dec	13.3%	122.2%	15.5%	125.2%
Average	13.1%	125.9%	11.8%	119.7%

Energy Uplift Charges by Transaction/Resource Type

Table B-35 shows the energy uplift charges and applicable rates for each type of resource or transaction in PJM.

Table B-35 Energy uplift charge by transaction/resource type

Charge	Rate	Transaction / Resource Type									
		Load	Generation	Imports ¹	Exports ¹	Wheels	Economic				
						DR	INCs	DECs	IBTs	UTCs	
Day-Ahead Operating Reserve	Day-Ahead Operating Reserve Rate	X			X			X			
Balancing Operating Reserves for Reliability	RTO Reliability Rate	X			X						
	Regional (East or West) Reliability Rate	X			X						
Balancing Operating Reserves for Deviations ²	RTO Deviation Rate	X	X	X	X	X	X	X	X	X	
	Regional (East or West) Deviation Rate	X	X	X	X	X	X	X	X	X	
	LOC Rate	X	X	X	X	X	X	X	X	X	
	Canceled Resources Rate	X	X	X	X	X	X	X	X	X	
Reactive Services	Implicit Rates	X									
Black Start Services	Implicit Rates	X ³		X ⁴	X ⁴	X ⁴					
Synchronous Condensing	Implicit Rate	X			X						

¹ Dynamic scheduled transactions are exempt from operating reserve charges.

² Participants only pay deviation charges if they incur deviations based on the rules specified in Manual 28.

³ Load is charged black start services based on their zonal peak load contribution.

⁴ Interchange transactions are charged black start services based on their point to point firm and non-firm reservations.

Appendix C Local Energy Market Structure: TPS Results

The three pivotal supplier test is applied by PJM on an ongoing basis in order to determine whether structural market power requires offer capping to prevent the potential exercise of local market power for binding constraints.

The MMU analyzed the results of the three pivotal supplier tests conducted by PJM for the real-time energy market for the period January 1, 2019, through December 31, 2019. The three pivotal supplier test is applied every time the system solution indicates that out of merit resources are needed to relieve a transmission constraint. Until November 1, 2017, only uncommitted resources, started to relieve the transmission constraint, were subject to offer capping. Resources that were committed economically, that were ramped up to provide incremental relief for a binding constraint, could not be switched from the schedule that they were operating on. Beginning November 1, 2017, under certain circumstances, online resources that are committed beyond their original commitment (day-ahead or real-time), to provide relief for a constraint, can be offer capped if the owner fails the TPS test, and the latest available cost-based offer is determined to be cheaper than the price-based offer. The results of the TPS test are shown for tests that could have resulted in offer capping and tests that did result in offer capping.

Overall, the results confirm that the three pivotal supplier test results in offer capping when the local market is structurally noncompetitive and does not result in offer capping when that is not the case. Local markets are noncompetitive when the number of suppliers is relatively small.

The three pivotal supplier test is calculated as part of the Intermediate Term Security Constrained Economic Dispatch (IT SCED) tool. IT SCED looks ahead at multiple target times up to two hours ahead, and forecasts potential binding constraints and suggests unit commitment and dispatch changes to meet transmission limits. As a result of the remedial actions taken in advance in response to IT SCED forecasts, the set of constraints that appear to be potentially binding in IT SCED is not necessarily the same as the set of constraints that bind in the real-time SCED tool. This appendix provides data on the

TPS tests that were applied in PJM control zones that had congestion from one or more constraints for 100 or more hours in real time and for reactive transfer interface constraints regardless of the duration of their congestion. In 2019, the AECO, AEP, APS, ATSI, BGE, ComEd, Dominion, Met-Ed, PENELEC, and PPL Control Zones experienced congestion resulting from one or more constraints binding for 100 or more hours. Using the three pivotal supplier results for 2019, actual competitive conditions associated with each of these frequently binding constraints were analyzed for the real time energy market. The DAY, DEOK, DLCO, DPL, EKPC, JCPL, PECO, Pepco, PSEG and RECO Control Zones were not affected by constraints binding for 100 or more hours. Information is provided, by qualifying zone, for each constraint including the number of tests applied, the number of tests that could have resulted in offer capping and the number of tests that did result in offer capping. Information is also provided for binding constraints on the 500 kV transmission system and MISO flowgates that were binding for 100 or more hours. Additional information is provided for each constraint including the average MW required to relieve a constraint, the average supply available, the average number of owners included in each test and the average number of owners that passed or failed each test.

500 kV System Constraints

In 2019, there were six constraints that occurred for more than 100 hours on the 500 kV transmission system. Table C-1 shows the average constraint relief required, the average effective supply available to relieve the constraints, the average number of owners with available relief in the defined market and the average number of owners passing and failing for the six constraints. Table C-1 shows that for five out of the six constraints, there were more than three owners, on average, with available supply to relieve the constraints.

Table C-1 Three pivotal supplier test details for 500 kV system constraints: 2019

Constraint	Period	Average	Average	Average		Average
		Constraint Relief (MW)	Effective Supply (MW)	Number Owners	Number Owners	Number Owners
				Passing	Failing	
AP South	Peak	625	720	12	1	12
	Off Peak	529	599	12	2	10
Conastone	Peak	416	673	22	12	11
	Off Peak	291	741	21	16	5
Conastone - Peach Bottom	Peak	282	488	19	9	10
	Off Peak	257	455	18	8	10
East	Peak	897	960	16	1	15
	Off Peak	648	756	14	0	13
Keystone	Peak	279	363	17	3	14
	Off Peak	216	289	14	2	12
PA Central	Peak	55	219	3	0	3
	Off Peak	83	336	3	0	3

Table C-2 shows the total tests applied for the 500 kV system constraints, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. Table C-2 shows that for the 500kV constraints, 10 percent or fewer of the total tests applied during peak hours resulted in offer capping, and three percent or fewer of the total tests applied during off peak hours resulted in offer capping.

Table C-2 Summary of three pivotal supplier tests applied for 500 kV system constraints: 2019

Constraint	Period	Total Tests that Could Have Resulted in Offer Capping		Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
		Total Tests Applied	Resulted in Offer Capping				
AP South	Peak	375	354	94%	7	2%	2%
	Off Peak	179	153	85%	2	1%	1%
Conastone	Peak	5,161	5,161	100%	127	2%	2%
	Off Peak	3,200	3,198	100%	26	1%	1%
Conastone - Peach Bottom	Peak	55,707	55,686	100%	2447	4%	4%
	Off Peak	48,037	48,023	100%	1418	3%	3%
East	Peak	242	242	100%	24	10%	10%
	Off Peak	120	120	100%	2	2%	2%
Keystone	Peak	2,644	2,644	100%	49	2%	2%
	Off Peak	2,056	2,048	100%	57	3%	3%
PA Central	Peak	7,806	6,178	79%	3	0%	0%
	Off Peak	7,370	4,589	62%	0	0%	0%

AECO Control Zone Results

In 2019, there was one constraint that occurred for more than 100 hours in the AECO Control Zone. Table C-3 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owners passing and failing. Table C-3 shows that for the Monroe - Vineland constraint in the AECO Zone, there was one owner, on average, with available supply to relieve the constraint.

Table C-3 Three pivotal supplier test details for constraints located in the AECO Control Zone: 2019

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Monroe - Vineland	Peak	26	27	1	0	1
	Off Peak	22	23	1	0	1

Table C-4 shows the total tests applied for the constraint in the AECO Zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are economically committed, that are ramped up to provide incremental relief during their original commitment, cannot be offer capped, except when they update their offers. Table C-4 shows that for the Monroe - Vineland constraint in the AECO Zone, zero percent of the total tests applied during peak hours resulted in offer capping, and one percent of the total tests applied during off peak hours resulted in offer capping.

Table C-4 Summary of three pivotal supplier tests for constraints located in the AECO Control Zone: 2019

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Monroe - Vineland	Peak	250	158	63%	1	0%	1%
	Off Peak	315	198	63%	2	1%	1%

AEP Control Zone Results

In 2019, there were two constraints that occurred for more than 100 hours in the AEP Control Zone. Table C-5 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owners passing and failing. Table C-5 shows that for the Haviland constraint, there was one owner, on average, with available supply to relieve the constraint.

Table C-5 Three pivotal supplier test details for constraints located in the AEP Control Zone: 2019

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Haviland	Peak	27	29	1	0	1
	Off Peak	23	20	1	0	1
Tanners Creek - Miami Fort	Peak	153	183	5	0	5
	Off Peak	145	182	5	0	5

Table C-6 shows the total tests applied for the constraints in the AEP Zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are economically committed, that are ramped up to provide incremental relief during their original commitment, cannot be offer capped, except when they update their offers. Table C-6 shows that for the Tanners Creek – Miami Fort constraint in the AEP Zone, four percent of the total tests applied during peak hours resulted in offer capping, and two percent of the total tests applied during peak hours resulted in offer capping.

Table C-6 Summary of three pivotal supplier tests for constraints located in the AEP Control Zone: 2019

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Haviland	Peak	3,792	994	26%	2	0%	0%
	Off Peak	2,529	41	2%	0	0%	0%
Tanners Creek - Miami Fort	Peak	7,057	6,394	91%	278	4%	4%
	Off Peak	2,477	2,278	92%	57	2%	3%

APS Control Zone Results

In 2019, there was one constraint that occurred for more than 100 hours in the APS Control Zone. Table C-7 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owners passing and failing. Table C-7 shows that for the Harwick - Houseville constraint in the APS Zone, there was one owner on peak and off peak, on average, with available supply to relieve the constraint.

Table C-7 Three pivotal supplier test details for constraints located in the APS Control Zone: 2019

Constraint	Period	Average Constraint	Average Effective	Average Number	Average Number	Average Number
		Relief (MW)	Supply (MW)	Owners	Owners Passing	Owners Failing
Harwick - Houseville	Peak	20	29	1	0	1
	Off Peak	14	27	1	0	1

Table C-8 shows the total tests applied for the constraint in the APS Zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are economically committed, that are ramped up to provide incremental relief during their original commitment, cannot be offer capped, except when they update their offers. Table C-8 shows that for the constraint in the APS Zone, zero percent of the total tests applied resulted in offer capping.

Table C-8 Summary of three pivotal supplier tests for constraints located in the APS Control Zone: 2019

Constraint	Period	Total Tests Applied	Total Tests that	Percent Total Tests	Total Tests Resulted in Offer Capping	Percent Total	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
			Could Have Resulted in Offer Capping	that Could Have Resulted in Offer Capping		Tests Resulted in Offer Capping	
Harwick - Houseville	Peak	3,334	1,096	33%	1	0%	0%
	Off Peak	1,092	213	20%	2	0%	1%

ATSI Control Zone Results

In 2019, there was one constraint in the ATSI Control Zone that occurred for more than 100 hours. Table C-9 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owners passing and failing for the Nottingham constraint and the Cleveland interface constraint. Table C-9 shows that for the Nottingham constraint in the ATSI Zone, there were at least ten owners, on average, with available supply to relieve the constraint.

Table C-9 Three pivotal supplier test details for constraints located in the ATSI Control Zone: 2019

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Cleveland	Peak	NA	NA	NA	NA	NA
	Off Peak	392	369	27	0	27
Nottingham	Peak	89	145	12	3	9
	Off Peak	80	124	10	2	8

Table C-10 shows the subset of three pivotal supplier tests that could have resulted in the offer capping of uncommitted units and those tests that did result in offer capping for constraints in the ATSI Zone. The results reflect the fact that units that are economically committed, that are ramped up to provide incremental relief during their original commitment, cannot be offer capped, except when they update their offers. Table C-10 shows that one percent or fewer of the tests applied resulted in offer capping for the two constraints.

Table C-10 Summary of three pivotal supplier tests for constraints located in the ATSI Control Zone: 2019

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Cleveland	Peak	0	0	NA	0	NA	NA
	Off Peak	4	4	100%	0	0%	0%
Nottingham	Peak	10,784	10,762	100%	41	0%	0%
	Off Peak	6,495	6,481	100%	23	0%	0%

BGE Control Zone Results

In 2019, there were two constraints that occurred for more than 100 hours in the BGE Control Zone. Table C-11 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owner passing and failing. Table C-11 shows that for both of the constraints in the BGE Zone, there were at least 10 owners, on average, with available supply to relieve the constraint.

Table C-11 Three pivotal supplier test details for constraints located in the BGE Control Zone: 2019

Constraint	Period	Average	Average	Average	Average	Average
		Constraint	Effective	Number	Number	Number
		Relief (MW)	Supply (MW)	Owners	Owners Passing	Owners Failing
Bagley - Graceton	Peak	80	123	13	3	10
	Off Peak	57	80	11	2	9
Graceton - Safe Harbor	Peak	90	104	10	2	8
	Off Peak	72	101	11	3	8

Table C-12 shows the total tests applied for the two constraints in the BGE Zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are economically committed, that are ramped up to provide incremental relief during their original commitment, cannot be offer capped, except when they update their offers. Table C-12 shows that one percent or fewer of the tests applied to the constraints in the BGE Zone resulted in offer capping.

Table C-12 Summary of three pivotal supplier tests for constraints located in the BGE Control Zone: 2019

Constraint	Period	Total Tests	Total Tests that	Percent Total Tests	Total Tests	Percent Total	Tests Resulted in Offer
		Applied	Could Have	that Could Have	Resulted in	Tests Resulted	Capping as Percent of
			Resulted in	Resulted in Offer	Offer Capping	in Offer	Tests that Could Have
			Offer Capping	Capping		Capping	Resulted in Offer Capping
Bagley - Graceton	Peak	2,906	2,871	99%	30	1%	1%
	Off Peak	1,411	1,348	96%	8	1%	1%
Graceton - Safe Harbor	Peak	5,076	4,981	98%	11	0%	0%
	Off Peak	12,749	12,686	100%	73	1%	1%

ComEd Control Zone Results

In 2019, there were two constraints that occurred for more than 100 hours in the ComEd Control Zone. Table C-13 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owner passing and failing. Table C-13 shows that for both constraints in the ComEd Zone, on average, the number of owners with available supply was three or less.

Table C-13 Three pivotal supplier test details for constraints located in the ComEd Control Zone: 2019

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Kewance - Hennepin Tap	Peak	11	17	3	0	3
	Off Peak	11	13	2	0	2
Quad Cities - Cordova Energy	Peak	34	107	1	0	1
	Off Peak	47	76	1	0	1

Table C-14 shows the total tests applied for the two constraints in the ComEd Zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are economically committed, that are ramped up to provide incremental relief during their original commitment, cannot be offer capped, except when they update their offers. Table C-14 shows that for both the constraints, zero percent of the tests applied resulted in offer capping.

Table C-14 Summary of three pivotal supplier tests for constraints located in the ComEd Control Zone: 2019

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Kewance - Hennepin Tap	Peak	2,366	530	22%	0	0%	0%
	Off Peak	1,170	237	20%	0	0%	0%
Quad Cities - Cordova Energy	Peak	995	346	35%	0	0%	0%
	Off Peak	1,987	359	18%	0	0%	0%

Dominion Control Zone Results

In 2019, there was one constraint that occurred for more than 100 hours in the Dominion Control Zone. Table C-15 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owner passing and failing. Table C-15 shows that for the constraint in the Dominion Zone, on average, there were two owners with available supply to relieve the constraint.

Table C-15 Three pivotal supplier test details for constraints located in the Dominion Control Zone: 2019

Constraint	Period	Average	Average	Average		Average
		Constraint Relief (MW)	Effective Supply (MW)	Number Owners	Number Owners Passing	Number Owners Failing
Prince George	Peak	11	48	2	0	2
	Off Peak	12	44	2	0	2

Table C-16 shows the total tests applied for the constraint in the Dominion Zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are economically committed, that are ramped up to provide incremental relief during their original commitment, cannot be offer capped, except when they update their offers. Table C-16 shows that less than one percent of the tests applied to the constraints in the Dominion Zone resulted in offer capping.

Table C-16 Summary of three pivotal supplier tests for constraints located in the Dominion Control Zone: 2019

Constraint	Period	Total Tests Applied	Total Tests that	Percent Total Tests	Total Tests Resulted in Offer Capping	Percent Total	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
			Could Have Resulted in Offer Capping	that Could Have Resulted in Offer Capping		Tests Resulted in Offer Capping	
Prince George	Peak	2,398	690	29%	3	0%	0%
	Off Peak	1,747	828	47%	2	0%	0%

MetEd Control Zone Results

In 2019, there were two constraints that occurred for more than 100 hours in the MetEd Control Zone. Table C-17 shows the average constraint relief required on each constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owner passing and failing. Table C-17 shows that for both the constraints in the MetEd Zone, on average, the number of owners with available supply was three or less.

Table C-17 Three pivotal supplier test details for constraints located in the MetEd Control Zone: 2019

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Boonetown - South Reading	Peak	31	109	2	0	2
	Off Peak	28	65	3	0	3
Gardners - Texas Eastern	Peak	23	14	2	0	2
	Off Peak	18	10	1	0	1

Table C-18 shows the total tests applied for the constraints in the MetEd Zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are economically committed, that are ramped up to provide incremental relief during their original commitment, cannot be offer capped, except when they update their offers. Table C-18 shows that two percent or fewer of the tests applied to the constraints in the MetEd Zone resulted in offer capping.

Table C-18 Summary of three pivotal supplier tests for constraints located in the MetEd Control Zone: 2019

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Boonetown - South Reading	Peak	2,659	1,218	46%	4	0%	0%
	Off Peak	881	460	52%	0	0%	0%
Gardners - Texas Eastern	Peak	2,491	1,500	60%	8	0%	1%
	Off Peak	1,119	972	87%	20	2%	2%

MISO Flowgate Results

In 2019, there were 14 MISO flowgate constraints that occurred for more than 100 hours. Table C-19 shows the average constraint relief required on each constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owner passing and failing. Table C-19 shows that for the MISO flowgate constraints, on average, the number of owners with available supply was six or less.

Table C-19 Three pivotal supplier test details for MISO flowgate constraints: 2019

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Arcadian - Pleasant Prarie	Peak	55	9	2	0	2
	Off Peak	58	5	1	0	1
Chicago Ave - Praxair 3	Peak	42	25	4	0	4
	Off Peak	46	33	5	0	5
Fargo	Peak	39	22	3	0	3
	Off Peak	38	30	3	0	3
Goodland - Reynolds	Peak	9	3	1	0	1
	Off Peak	13	2	1	0	1
Marblehead	Peak	17	4	2	0	2
	Off Peak	19	5	2	0	2
Mohomet - ChampIP	Peak	24	20	4	0	3
	Off Peak	27	19	4	0	4
Munster	Peak	40	25	3	0	3
	Off Peak	38	24	3	0	3
North Lake George - Burlington	Peak	10	4	2	0	2
	Off Peak	10	3	2	0	2
Paradise - BR Tap	Peak	29	5	3	0	3
	Off Peak	40	5	2	0	2
Roxana - Praxair	Peak	31	26	6	0	6
	Off Peak	22	21	5	0	5
Sandburg	Peak	28	17	2	0	2
	Off Peak	29	16	2	0	2
Shadeland - Lafayette south	Peak	10	15	3	0	3
	Off Peak	10	17	3	0	3
Sub 85 - Rock Island	Peak	29	20	2	0	2
	Off Peak	28	18	2	0	2
Vermilion - Tilton Energy Center	Peak	21	19	2	0	2
	Off Peak	17	15	2	0	2

Table C-20 shows the total tests applied for the MISO flowgate constraints, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are economically committed, that are ramped up to provide incremental relief during their original commitment, cannot be offer capped, except when they update their offers. Table C-20 shows that two percent or fewer of the tests applied to the MISO flowgate constraints resulted in offer capping.

Table C-20 Summary of three pivotal supplier tests for MISO flowgate constraints : 2019

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Arcadian - Pleasant Prarie	Peak	720	288	40%	0	0%	0%
	Off Peak	420	147	35%	0	0%	0%
Chicago Ave - Praxair 3	Peak	1,698	1,235	73%	15	1%	NA
	Off Peak	3,337	2,636	79%	2	0%	0%
Fargo	Peak	2,046	1,042	51%	8	0%	1%
	Off Peak	2,554	1,201	47%	0	0%	0%
Goodland - Reynolds	Peak	780	58	7%	0	0%	0%
	Off Peak	414	42	10%	0	0%	0%
Marblehead	Peak	8,539	1,877	22%	1	0%	0%
	Off Peak	10,085	2,067	20%	0	0%	0%
Mohomet - ChampTP	Peak	742	529	71%	0	0%	0%
	Off Peak	3,036	2,230	73%	3	0%	0%
Munster	Peak	1,342	468	35%	29	2%	6%
	Off Peak	3,426	1,055	31%	8	0%	1%
North Lake George - Burlington	Peak	2,083	846	41%	14	1%	2%
	Off Peak	670	264	39%	0	0%	0%
Paradise - BR Tap	Peak	1,072	573	53%	13	1%	2%
	Off Peak	334	114	34%	0	0%	0%
Roxana - Praxair	Peak	3,744	2,971	79%	24	1%	1%
	Off Peak	8,279	6,443	78%	29	0%	0%
Sandburg	Peak	2,273	725	32%	1	0%	0%
	Off Peak	3,796	812	21%	0	0%	0%
Shadeland - Lafayette south	Peak	2,015	401	20%	0	0%	0%
	Off Peak	1,452	336	23%	0	0%	0%
Sub 85 - Rock Island	Peak	2,673	613	23%	0	0%	0%
	Off Peak	4,939	979	20%	0	0%	0%
Vermilion - Tilton Energy Center	Peak	1,539	1,045	68%	0	0%	0%
	Off Peak	3,155	1,993	63%	1	0%	0%

PENELEC Control Zone Results

In 2019, there were four constraints that occurred for more than 100 hours in the PENELEC Control Zone. Table C-21 shows the average constraint relief required on each constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owner passing and failing. Table C-21 shows that for the constraints in the PENELEC Zone, on average, the number of owners with available supply was two or less.

Table C-21 Three pivotal supplier test details for constraints located in the PENELEC Control Zone: 2019

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Asylum - East Towanda	Peak	16	258	1	0	1
	Off Peak	9	238	1	0	1
East Towanda - Hillside	Peak	21	136	2	0	2
	Off Peak	21	156	1	0	1
Lenox - North Meshoppen	Peak	19	46	2	0	2
	Off Peak	9	43	2	0	2
Mehoopany - North Meshoppen	Peak	7	64	2	0	2
	Off Peak	6	64	2	0	2

Table C-22 shows the total tests applied for the constraints in the PENELEC Zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are economically committed, that are ramped up to provide incremental relief during their original commitment, cannot be offer capped, except when they update their offers. Table C-22 shows that zero percent of the tests applied to the constraints in the PENELEC Zone resulted in offer capping.

Table C-22 Summary of three pivotal supplier tests for constraints located in the PENELEC Control Zone: 2019

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Asylum - East Towanda	Peak	1,952	215	11%	0	0%	0%
	Off Peak	1,317	110	8%	0	0%	0%
East Towanda - Hillside	Peak	7,813	4,117	53%	0	0%	0%
	Off Peak	4,843	1,949	40%	0	0%	0%
Lenox - North Meshoppen	Peak	11,403	7,125	62%	4	0%	0%
	Off Peak	8,617	3,670	43%	0	0%	0%
Mehoopany - North Meshoppen	Peak	841	26	3%	0	0%	0%
	Off Peak	2,261	102	5%	0	0%	0%

PPL Control Zone Results

In 2019, there were five constraints that occurred for more than 100 hours in the PPL Control Zone. Table C-23 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owner passing and failing. Table C-23 shows that, on average, there were four or fewer owners with available supply to relieve the constraints.

Table C-23 Three pivotal supplier test details for constraints located in the PPL Control Zone: 2019

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Bloomsburg Mills - Columbia	Peak	32	25	1	0	1
	Off Peak	21	16	1	0	1
Face Rock	Peak	24	10	2	0	2
	Off Peak	20	3	1	0	1
Siegfried	Peak	45	76	4	0	3
	Off Peak	44	74	3	0	3
Siegfried Transformer	Peak	44	51	3	0	3
	Off Peak	43	58	3	0	3
Wescosville	Peak	32	27	2	0	2
	Off Peak	34	27	3	0	3

Table C-24 shows the total tests applied for the five constraints in the PPL Zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are economically committed, that are ramped up to provide incremental relief during their original commitment, cannot be offer capped, except when they update their offers. Table C-24 shows that zero percent of the tests applied to the constraints in the PPL Zone resulted in offer capping.

Table C-24 Summary of three pivotal supplier tests for constraints located in the PPL Control Zone: 2019

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Bloomsburg Mills - Columbia	Peak	2,270	837	37%	7	0%	1%
	Off Peak	903	541	60%	2	0%	0%
Face Rock	Peak	938	235	25%	0	0%	0%
	Off Peak	1,146	242	21%	0	0%	0%
Siegfried Transformer	Peak	7,544	3,277	43%	1	0%	0%
	Off Peak	6,692	2,878	43%	1	0%	0%
Siegfried	Peak	3,012	1,715	57%	5	0%	0%
	Off Peak	1,970	835	42%	0	0%	0%
Wescosville	Peak	4,104	3,237	79%	0	0%	0%
	Off Peak	1,199	674	56%	0	0%	0%

Day-Ahead Local Market Power Mitigation

In the day-ahead energy market, the TPS test is performed in a tool that is separate from the day-ahead market clearing software, called PROBE. PROBE is third party software, and the details of how it dispatches the system, estimates binding constraints, and calculates TPS and offer capping results are proprietary information not available to PJM or the MMU. PROBE uses the results from PJM's Resource Scheduling and Commitment (RSC) tool as an input to generate its day-ahead market solution and TPS test results. PROBE includes both physical and virtual bids and offers, including generation, physical load, virtual supply (INCs), virtual demand (DECs) and up to congestion (UTC) transactions to clear the market. Transmission constraints in the day-ahead energy market can be caused by the flow of energy that results from all these transactions. PROBE uses only physical resources and virtual supply (increment offers) as sources of relief to binding transmission constraints. If a unit owner fails the TPS test for a constraint, PROBE picks the unit schedule resulting in the lowest bid production cost for the system over the 24 hour

commitment period. This calculation is internal to the PROBE software, so the MMU does not have access to the information necessary to evaluate its assumptions or accuracy.

A unit that is offer capped in PROBE does not necessarily result in the unit being offer capped in the final day-ahead market results. The process used to determine the final set of units subject to offer capping in the day-ahead market is not transparent and is not documented in the PJM manuals.

Real-Time Local Market Power Mitigation

In the real-time energy market, the TPS test is embedded in the IT SCED tool, which is a look ahead commitment and dispatch tool. In the real-time energy market, the TPS test uses physical resources, physical load forecasts, and reserve requirements to commit resources available in a look ahead window. The IT SCED tool is executed every five minutes and solves for four future intervals: a minimum of 135 minutes; 90 minutes; 45 minutes; and 30 minutes ahead. The TPS test results in offer capping recommendations applicable to online and offline resources.

PJM dispatchers use the recommendations from the IT SCED tool to commit resources to provide relief to a constraint on the cheaper of the price or cost schedule at the time of commitment, using the dispatch cost formula. Since each IT SCED case solution produces TPS test results for four look ahead intervals for each individual constraint that requires relief, it is unclear how dispatchers use all the available TPS results to select a unit to commit and the schedule to commit the unit on.

Another limitation of running the TPS test in IT SCED is that market conditions may differ between the IT SCED solution and the RT SCED solution that is used to dispatch and price the system. Constraints may create local market power differently in the RT SCED model than in the IT SCED model. Market power in the RT SCED may go unmitigated.

Appendix D Interchange Transactions

Submitting Transactions into PJM

In competitive wholesale power markets, market participants' decisions to buy and sell power are based on actual and expected prices. If contiguous wholesale power markets incorporate security constrained nodal pricing, well designed interface pricing provides economic signals for import and export decisions by market participants, although those signals may be attenuated by a variety of institutional arrangements. Unfortunately, interface prices are not well designed and result in incentives to engage in transactions that are not efficient and would not occur if there were a single set of consistent LMPs across all interconnected markets.

The institutional details of completing import and export transactions include the Open Access Same-Time Information System (OASIS), North American Electric Reliability Council (NERC) Tags, neighboring balancing authority check out processes, and transaction curtailment rules.¹

Real-Time Energy Market

Market participants that wish to transact energy into, out of, or through PJM in the real-time energy market are required to make their requests to PJM via a NERC Interchange Transaction Tag (NERC Tag). PJM's External Scheduling software (ExSchedule) interfaces with NERC Tags to create an interface that both PJM market participants and PJM can use to evaluate and manage external transactions that affect the PJM RTO.

Scheduling Requirements

External offers can be made either on the basis of an individual generator (resource specific offer), an aggregate of generation supply (aggregate offer) or an external market (pool supplied). Schedules are submitted to PJM by submitting a valid NERC Tag.

Specific timing requirements apply for the submission of schedules. Schedules can be submitted up to 20 minutes prior to the scheduled start time for hourly transactions.

Schedules can be submitted up to four hours prior to the scheduled start time for transactions that are more than 24 hours in duration.² Schedules utilizing the Real-Time with Price option, also known as dispatchable schedules, must be submitted prior to 1800 (EPT) the day prior to the scheduled start time. Schedules utilizing firm point to point transmission service must be submitted by 1000 (EPT) one day prior to start of schedule. Transactions utilizing firm point to point transmission submitted after 1000 (EPT) one day prior will be accommodated if practicable.

Acquiring Ramp

PJM allows market participants to reserve ramp while they complete their scheduling responsibilities. The ramp reservation is validated against the submitted NERC Tag to ensure that the energy profile and path match. Upon submission of a ramp reservation request, if PJM verifies ramp availability, the ramp reservation will move into a status of "Pending Tag" which means that it is a valid reservation that can be associated with a NERC Tag to complete the scheduling process.

Specific timing requirements apply for the submission of ramp reservations. Ramp reservations can be made up to 30 minutes prior to the scheduled start time for hourly transactions. Ramp reservations can be made up to 4 hours prior to start time for transactions that are more than 24 hours in duration. Ramp reservations utilizing the Real-Time with Price option must be made prior to 1800 (EPT) the day prior to the scheduled start time. Ramp reservations expire if they are not used.

With the implementation of the coordinated transaction scheduling (CTS) product with the NYISO, PJM modified how ramp is handled at the PJM/NYISO Interface. Effective November 4, 2014, PJM no longer holds ramp room for any transactions submitted between PJM and the NYISO at the time of submission. Only after the NYISO completes its real-time market clearing process, and communicates the results to PJM, will PJM perform a ramp evaluation on transactions scheduled with the NYISO. If, in the event the NYISO market clearing process violates ramp, PJM makes additional adjustments on a last-in first-out basis as determined by the timestamp on the NERC Tag. This process prevents the transactions scheduled at the PJM/

¹ The material in this section is based in part on PJM's Regional Transmission and Energy Scheduling Practices Document. See PJM, "Regional Transmission and Energy Scheduling Practices," Version 8 (June 23, 2019). <<http://www.pjm.com/~media/etools/oasis/regional-practices-clean-pdf.ashx>>.

² PJM ended the requirement for a day-ahead checkout for real-time transactions. Previously, for a schedule to be included in PJM's day-ahead checkout process, the NERC Tag had to have been approved by all entities who had approval rights, and be in a status of "Implemented," by 1400 (EPT) one day prior to start of schedule.

NYISO Interface from holding (or creating) ramp until they have completed their economic evaluation and are approved through the NYISO market clearing process. The MMU has not observed any adverse effects of the new process. The MMU will continue to monitor and evaluate the process.

Acquiring Transmission

All external transaction requests require a confirmed transmission reservation from the PJM OASIS.³ Due to ramp limitations, PJM may require market participants to shift their transaction requests. If the market participant shifts the request up to one hour in either direction, they are not required to purchase additional transmission. If the market participant chooses to fix a ramp violation by extending the duration of the transaction, they do not have to purchase additional transmission if the total MWh capacity of the transmission request is not exceeded, and the transaction does not extend beyond one hour prior to the start, or one hour past the end time of the transmission reservation.

Transmission Products

The OASIS products available for reservation include firm, network, nonfirm and spot import service. The product type designated on the OASIS reservation determines when and how the transaction can be curtailed.

- **Firm.** Transmission service that is intended to be available at all times.
- **Network.** Transmission service that is for the sole purpose of serving network load. Network transmission service is only eligible to network customers.
- **Nonfirm.** Point to point transmission service under the PJM tariff that is reserved and scheduled on an as available basis and is subject to curtailment or interruption. Nonfirm point to point transmission service is available for periods ranging from one hour to one month.
- **Spot Import.** The spot import service is an option for nonload serving entities to offer into the PJM spot market at the interface as price takers. Prior to April 2007, PJM did not limit spot import service. Effective April 2007, the availability of spot import service was limited by the Available Transmission Capacity (ATC) on the transmission path.

³ For additional details see PJM, "Regional Transmission and Energy Scheduling Practices," Version 8 (June 23, 2019). <<http://www.pjm.com/~media/etools/oasis/regional-practices-clean-pdf.ashx>>.

Source and Sink

For real-time import and export energy transactions, when a market participant selects the Point of Receipt (POR) and Point of Delivery (POD) on their OASIS reservation, the source and sink default to the associated interface price as defined by the POR/POD path. For example, if the selected POR is TVA and the POD is PJM, the source and sink would initially default to TVA's Interface Pricing point (SouthIMP). At the time the energy is scheduled, if the Generation Control Area (GCA) or Load Control Area (LCA) on the NERC Tag represents physical flow entering or leaving PJM at an interface other than the default interface pricing point, the source or sink would be assigned the new interface pricing point reflecting the interface pricing point where the physical energy enters or leaves the PJM footprint.

For a real-time wheel through energy transaction, when a market participant selects the Point of Receipt (POR) and Point of Delivery (POD) on their OASIS reservation, both the source and sink default to the associated interface prices as defined by the POR/POD path. For example, if the selected POR is TVA and the POD is NYIS, the source would initially default to TVA's Interface Pricing point (SouthIMP), and the sink would initially default to NYIS's Interface Pricing point (NYIS). At the time the energy is scheduled, if the GCA on the NERC Tag represents physical flow entering PJM at an interface other than the SouthIMP Interface, the source would then default to that new interface. Similarly, if the LCA on the NERC Tag represents physical flow leaving PJM at an interface other than the NYIS Interface, the sink would then default to that new interface.

Real-Time Market Schedule Submission

Market participants enter schedules in PJM by submitting a valid NERC Tag. A NERC Tag can be submitted without a ramp reservation. When ExSchedule detects a NERC Tag that has been submitted without a ramp reservation, it will create a ramp reservation which will be evaluated against ramp, and approved or denied based on available ramp room at the time the NERC Tag is submitted.

Real-Time with Price Schedule Submission

Real-Time with Price schedules, also known as dispatchable schedules, differ from other schedules. To enter a Real-Time with Price schedule, the market participant must

first make a ramp reservation in ExSchedule specifying “Real-Time with Price” and must enter a price associated with each energy block. Upon submission, the Real-Time with Price request will automatically move to the “Pending Tag” status, as Real-Time with Price schedules do not hold ramp. Once the information is entered in ExSchedule, a NERC Tag must be submitted with the ramp reservation associated on the NERC Tag. Upon implementation of the NERC Tag, PJM will curtail the tag to zero MW. During the operating day, if the dispatchable transaction is to be loaded, PJM will then reload the tag. The process of issuing curtailments and reloading the tag continues through the operating day as the economics of the system dictate.

Dynamic Transfers⁴

An entity that owns or controls a generating resource in the PJM Region may request that all or part of the generating resource’s output be electronically moved from the PJM Region (native BA) to another balancing authority (receiving BA). An entity that owns or controls a generating resource outside of the PJM Region may request that all or part of the generating resource’s output be electronically removed from its balancing authority to the PJM Region. This is referred to as a dynamic transfer. Dynamic transfers include dynamic schedules and pseudo ties.

Dynamic Schedule

A dynamic schedule is a time varying energy transfer that is updated in real time and included in scheduled net interchange in the same way as an interchange schedule in the Area Control Error (ACE) equation for both balancing authorities. A dynamically scheduled resource remains within its native balancing authority’s metered boundary while providing services to the receiving balancing authority. A dynamic schedule is modeled as an interchange schedule, and therefore is subject to NERC Tagging requirements.

Pseudo Tie

A pseudo tie is a time varying energy transfer that is updated in real-time and included in actual net interchange in the same way as a tie line in the ACE equation. A pseudo tie is accounted for as actual interchange. A pseudo tied resource is considered to be within the receiving BA’s metered boundary, and must therefore be modeled in the receiving BA’s Energy Management System (EMS). Pseudo ties are

usually not subject to NERC Tagging because they are part of congestion management procedures, like the PJM/MISO Market to Market Congestion Management Agreement.

Pseudo ties must register with the North American Energy Standards Board (NAESB) to assist with interregional coordination management. Pseudo ties are subject to NERC Tagging requirements unless the pseudo tie is included in congestion management procedures.

Real-Time Evaluation and Checkout

PJM conducts an hourly checkout with each adjacent balancing authority using both the electronic approval of schedules and telephone calls. Once the tag has been approved by all parties with approval rights, the tag status moves to an “Implemented” status, and the schedule is ready for the adjacent balancing authority checkout.

PJM operators must verify all requested energy schedules with PJM’s neighboring balancing authorities. Only if the neighboring balancing authority agrees with the expected interchange will the transaction flow. Both balancing authorities must enter the same values in their Energy Management Systems (EMS) to avoid inadvertent energy flows between balancing authorities.

With the exception of the New York Independent System Operator (NYISO), all neighboring balancing authorities handle transaction requests in the same way as PJM. While the NYISO also requires NERC Tags, the NYISO utilizes their Market Information System (MIS) as their primary scheduling tool. The NYISO’s Real-Time Commitment (RTC) tool evaluates all bids and offers each hour, performs a least cost economic dispatch solution, and accepts or denies individual transactions in whole or in part based on this evaluation. Upon market clearing, the NYISO implements NERC Tag adjustments to match the output of the RTC. PJM and the NYISO can verify interchange transactions once the NYISO Tag adjustments are sent and approved. The results of the adjustments made by the NYISO affect PJM operations, as the adjustments often cause large swings in expected interchange for the next hour.

⁴ The material in this section is based in part on PJM’s Manual 12: Balancing Operations. See PJM, “PJM Manual 12: Balancing Operations,” Rev. 41 (November 19, 2020) <<http://www.pjm.com/~media/documents/manuals/m12.ashx>>.

Real-Time with Price Evaluation and Checkout

Real-time with Price schedules, dispatchable schedules, are evaluated hourly to determine whether or not they will be loaded for the upcoming hour. Since Real-Time with Price schedules do not hold ramp room, there may be times when the schedule is economic but will not be loaded because ramp is not available.

Curtailed Transactions

Once a transaction has been implemented, energy flows between balancing authorities. Transactions can be curtailed based on economic and reliability considerations. There are three types of economic curtailments: curtailments of dispatchable schedules based on price; curtailments of transactions based on their OASIS designation as not willing to pay congestion; and self curtailments by market participant. Reliability curtailments are implemented by the balancing authorities and are termed TLRs or transmission loading relief.

Dispatchable transactions will be curtailed if the system operator does not believe that the transaction will be economic for the next hour. Not willing to pay congestion transactions will be curtailed when there is, or is expected to be, realized congestion between the designated source and sink. Transactions utilizing spot import service will be curtailed if the interface price where the transaction enters PJM reaches zero. All self curtailments must be requested on 15 minute intervals and will be approved only if there is available ramp.

Transmission Loading Relief (TLR)

TLRs are called to control flows on transmission facilities when economic redispatch cannot solve overloads on those facilities. TLRs are called to control flows related to external balancing authorities, as redispatch within an LMP market can generally resolve overloads on internal transmission facilities.

There are seven TLR levels and additional sublevels, determined by the severity of system conditions and whether the interchange transactions contributing to congestion on the impacted flowgates are using firm or nonfirm transmission. Reliability coordinators are not

required to implement TLRs in order. The TLR levels are described below.⁵

- **TLR Level 0 – TLR concluded:** A TLR Level 0 is initiated when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) violations are mitigated and the system is returned to a reliable state. Upon initiation of a TLR Level 0, transactions with the highest transmission priorities are reestablished first when possible. The purpose of a TLR Level 0 is to inform all affected parties that the TLR has been concluded.
- **TLR Level 1 – Potential SOL or IROL Violations:** A TLR Level 1 is initiated when the transmission system is still in a secure state but a reliability coordinator anticipates a transmission or generation contingency or other operating problem that could lead to a potential violation. No actions are required during a TLR Level 1. The purpose of a TLR Level 1 is to inform other reliability coordinators of a potential SOL or IROL.
- **TLR Level 2 – Hold transfers at present level to prevent SOL or IROL Violations:** A TLR Level 2 is initiated when the transmission system is still in a secure state but one or more transmission facilities are expected to approach, are approaching or have reached their SOL or IROL. The purpose of a TLR Level 2 is to prevent additional transactions that have an adverse impact on the identified transmission facility(ies) from starting.
- **TLR Level 3a – Reallocation of transmission service by curtailing interchange transactions using nonfirm point to point transmission service to allow interchange transactions using higher priority transmission service:** A TLR Level 3a is initiated when the transmission system is secure but one or more transmission facilities are expected to approach, or are approaching their SOL or IROL, when there are transactions using nonfirm point to point transmission service that have a greater than 5 percent effect on the facility and when there are transactions using a higher priority point to point transmission reservation that wish to begin. Curtailments to transactions in a TLR 3a begin on the top of the hour only. The purpose of TLR Level 3a is to curtail transactions using lower

⁵ Additional details regarding the TLR procedure can be found in NERC. "Standard IRO-006-4 – Reliability Coordination – Transmission Loading Relief" (October 23, 2007) <<http://www.nerc.com/files/IR0-006-4.pdf>>.

priority nonfirm point to point transmission to allow transactions using higher priority transmission to flow.

- **TLR Level 3b – Curtail interchange transactions using nonfirm transmission service arrangements to mitigate a SOL or IROL violation:** A TLR Level 3b is initiated when one or more transmission facilities is operating above their SOL or IROL; such operation is imminent and it is expected that facilities will exceed their reliability limits if corrective action is not taken; or one or more transmission facilities will exceed their SOL or IROL upon the removal from service of a generating unit or other transmission facility and transactions are flowing that are using nonfirm point to point transmission service and have a greater than 5 percent impact on the facility. Curtailments of transactions in a TLR 3b can occur at any time within the operating hour. The purpose of a TLR Level 3b is to curtail transactions using nonfirm point to point transmission service which impact the constraint by greater than 5 percent in order to mitigate a SOL or IROL.
- **TLR Level 4 – Reconfigure Transmission:** A TLR Level 4 is initiated when one or more transmission facilities are above their SOL or IROL limits or such operation is imminent and it is expected that facilities will exceed their reliability limits if corrective action is not taken. Upon issuance of a TLR Level 4, all transactions using nonfirm point to point transmission service, in the current and next hour, with a greater than 5 percent impact on the facility, have been curtailed under the TLR 3b. The purpose of a TLR Level 4 is to request that the affected transmission operators reconfigure transmission on their system, or arrange for reconfiguration on other transmission systems, to mitigate the constraint if a SOL or IROL violation is imminent or occurring.
- **TLR Level 5a – Reallocation of transmission service by curtailing interchange transactions using firm point to point transmission service on a pro rata basis to allow additional interchange transactions using firm point to point transmission service:** A TLR Level 5a is initiated when one or more transmission facilities are at their SOL or IROL; all interchange transactions using nonfirm point to point transmission service that affect the constraint by greater than 5 percent have been curtailed; no additional effective transmission configuration is available; and a transmission provider has been requested to begin an interchange transaction using previously arranged firm point to point transmission service. Curtailments to transactions in a TLR 5a begin on the top of the hour only. The purpose of a TLR Level 5a is to curtail existing interchange transactions, which are using firm point to point transmission service, on a pro rata basis to allow for the newly requested interchange transaction, also using firm point to point transmission service, to flow.
- **TLR Level 5b – Curtail transactions using firm point to point transmission service to mitigate an SOL or IROL violation:** A TLR Level 5b is initiated when one or more transmission facilities are operating above their SOL or IROL or such operation is imminent; one or more transmission facilities will exceed their SOL or IROL upon removal of a generating unit or another transmission facility; all interchange transactions using nonfirm point to point transmission service that affect the constraint by greater than 5 percent have been curtailed; and no additional effective transmission configuration is available. Unlike a TLR 5a, curtailments to transactions in a TLR 5b can occur at any time within the operating hour. The purpose of a TLR Level 5b is to curtail transactions using firm point to point transmission service to mitigate a SOL or IROL.
- **TLR Level 6 – Emergency Procedures:** A TLR Level 6 is initiated when all interchange transactions using both nonfirm and firm point to point transmission have been curtailed and one or more transmission facilities are above their SOL or IROL, or will exceed their SOL or IROL upon removal of a generating unit or other transmission facility. The purpose of a TLR Level 6 is to instruct balancing authorities and transmission providers to redispach generation, reconfigure transmission or reduce load to mitigate the critical condition.

Table D-1 below shows the number of TLRs, by level, issued by reliability coordinators in the Eastern Interconnection since 2004.

Table D-1 TLRs by level and reliability coordinator: 2004 through 2019

Reliability								Reliability										
Year	Coordinator	3a	3b	4	5a	5b	6	Total	Year	Coordinator	3a	3b	4	5a	5b	6	Total	
2004	EES	47	15	88	1	3	0	154	2012	ICTE	25	7	11	63	40	0	146	
	FPL	0	1	0	0	0	0	1		MISO	75	26	0	16	43	0	160	
	IMO	33	2	0	0	0	0	35		NYIS	60	0	0	0	0	0	60	
	MAIN	8	3	0	0	0	0	11		ONT	47	1	0	0	0	0	48	
	MISO	650	210	409	9	3	0	1,281		PJM	18	19	0	0	0	0	37	
	PJM	270	115	35	4	5	0	429		SOCO	0	1	0	0	0	0	1	
	SOCO	1	0	0	0	0	0	1		SWPP	248	165	5	78	33	0	529	
	SWPP	185	107	14	5	6	0	317		TVA	55	32	9	7	5	0	108	
	TVA	56	17	0	0	1	0	74		VACS	6	4	0	0	0	0	10	
	VACN	8	1	0	0	0	0	9		Total	534	255	25	164	121	0	1,099	
Total	1,258	471	546	19	18	0	2,312	2013	ICTE	0	0	0	0	0	0	0	0	
2005	EES	49	10	101	6	3	1		170	MISO	119	48	2	128	73	0	370	
	IMO	57	2	0	0	0	0		59	NYIS	3	0	0	0	0	0	3	
	MISO	776	296	200	5	14	0		1,291	ONT	7	0	0	0	0	0	7	
	PJM	201	94	29	1	1	0		326	PJM	25	22	0	1	1	0	49	
	SWPP	193	78	19	4	2	0		296	SOCO	0	0	0	0	0	0	0	
	TVA	172	61	12	2	3	0		250	SWPP	342	114	0	76	24	0	556	
	VACN	0	3	0	0	0	0		3	TVA	29	26	2	5	5	0	67	
	VACS	2	2	0	1	0	0		5	VACS	5	7	0	0	0	0	12	
	Total	1,450	546	361	19	23	1		2,400	Total	530	217	4	210	103	0	1,064	
	2006	EES	71	20	93	5	1	0	190	2014	MISO	63	45	1	16	16	0	141
ICTE		11	6	14	0	1	0	32	NYIS		2	0	0	0	0	0	2	
IMO		1	0	0	0	0	0	1	ONT		3	0	0	0	0	0	3	
MISO		414	214	136	17	19	0	800	PJM		3	3	0	1	1	0	8	
ONT		27	3	0	0	0	0	30	SOCO		4	1	0	0	0	0	5	
PJM		88	30	18	0	0	0	136	SWPP		260	80	0	54	34	0	428	
SWPP		189	121	201	11	13	0	535	TVA		31	40	2	25	34	0	132	
TVA		90	52	31	1	2	0	176	VACS		7	16	3	2	0	0	28	
VACS		0	1	0	0	0	0	1	Total		373	185	6	98	85	0	747	
Total		891	447	493	34	36	0	1,901	2015		MISO	28	32	0	16	12	0	88
2007	ICTE	95	42	139	19	10	0	305		NYIS	4	0	0	0	0	0	4	
	MISO	414	273	89	17	26	0	819		ONT	3	1	0	0	0	0	4	
	ONT	47	4	1	0	0	0	52		PJM	13	7	0	1	1	0	22	
	PJM	46	31	1	1	1	0	80		SOCO	0	0	0	0	0	0	0	
	SWPP	777	935	35	53	24	0	1,824		SWPP	102	59	0	32	19	0	212	
	TVA	45	40	25	2	2	0	114		TVA	36	64	0	24	36	0	160	
	VACS	4	1	0	0	0	0	5		VACS	0	2	0	0	1	0	3	
	Total	1428	1326	290	92	63	0	3,199		Total	186	165	0	73	69	0	493	
	2008	ICTE	132	41	112	43	25	0		353	2016	MISO	33	21	0	8	15	0
		MISO	320	235	21	8	15	0	599	NYIS		1	0	0	0	0	0	1
ONT		153	7	1	0	0	0	161	ONT	10		0	0	0	0	0	10	
PJM		55	92	2	0	1	0	150	PJM	4		3	0	1	1	0	9	
SWPP		687	1,077	11	59	44	0	1,878	SOCO	0		1	0	0	0	0	1	
TVA		48	72	29	5	4	0	158	SWPP	54		23	0	45	22	0	144	
Total		1,395	1,524	176	115	89	0	3,299	TVA	41		65	0	4	18	0	128	
2009		ICTE	82	35	55	75	18	1	266	VACS		1	1	0	0	0	0	2
		MISO	199	140	2	15	25	0	381	Total		144	114	0	58	56	0	372
		NYIS	101	8	0	0	0	0	109	2017		MISO	42	16	0	10	7	0
	ONT	169	0	0	0	0	0	169	NYIS		1	0	0	0	0	0	1	
	PJM	61	68	0	0	0	0	129	ONT		6	0	0	0	0	0	6	
	SWPP	383	1,466	33	77	24	0	1,983	PJM		4	2	0	0	0	0	6	
	TVA	8	22	29	0	0	0	59	SOCO		1	4	0	0	0	0	5	
	VACS	0	1	0	0	0	0	1	SWPP		34	4	0	54	19	0	111	
	Total	1,003	1,740	119	167	67	1	3,097	TVA		13	11	0	2	5	0	31	
	2010	ICTE	72	25	149	50	30	0	326		VACS	3	3	0	0	0	0	6
MISO		123	93	0	15	18	0	249	Total		104	40	0	66	31	0	241	
NYIS		104	0	0	0	0	0	104	2018		MISO	22	5	0	11	18	0	56
ONT		94	5	0	1	0	0	100		NYIS	1	1	0	0	0	0	2	
PJM		65	45	0	0	0	0	110		ONT	10	0	0	0	0	0	10	
SWPP		244	1,049	19	63	32	0	1,407		PJM	2	1	0	0	2	0	5	
TVA		37	64	8	1	6	0	116		SOCO	0	1	0	0	0	0	1	
VACS		1	1	0	0	0	0	2		SWPP	36	8	0	52	21	0	117	
Total		740	1,282	176	130	86	0	2,414		TVA	10	34	0	9	6	0	59	
2011		ICTE	23	12	123	54	48	0		260	VACS	2	8	0	0	0	0	10
	MISO	92	30	1	9	9	0	141		Total	83	58	0	72	47	0	260	
	NYIS	161	0	0	0	0	0	161		2019	MISO	19	17	0	12	12	0	60
	ONT	88	0	0	0	0	0	88	NYIS		9	0	0	0	0	0	9	
	PJM	34	28	0	0	0	0	62	ONT		8	2	0	0	0	0	10	
	SWPP	292	298	1	25	22	0	638	PJM		1	1	0	0	0	0	2	
	TVA	75	99	9	2	15	0	200	SOCO		0	0	0	0	0	0	0	
	VACS	9	3	0	0	0	0	12	SWPP		10	5	0	20	8	0	43	
	Total	774	470	134	90	94	0	1,562	TVA		10	19	0	4	8	0	41	
									VACS		3	4	0	0	0	0	7	
								Total	60		48	0	36	28	0	172		

Day-Ahead Energy Market

For day-ahead market scheduling, ExSchedule serves only as an interface to the eMKT application. Day-ahead market transactions are evaluated in the day-ahead energy market, and the results sent to ExSchedule. No checkout is performed on day-ahead market schedules as they are considered financially binding transactions and not physical schedules.

Submitting Day-Ahead Energy Market Schedules

Market participants can submit day-ahead market schedules to the eMKT application through ExSchedule. These schedules do not require a NERC Tag, as they are not physical schedules for actual flow. Day-ahead market schedules require an OASIS number to be associated upon submission.⁶ The path is identified on the OASIS reservation. In addition to the selection of OASIS and pricing points, the market participant must enter their energy profile. "Fixed" act as a price taker, "dispatchable" set a floor or ceiling price criteria for acceptance and "up-to" set the maximum amount of congestion the market participant is willing to pay.

NYISO Issues

If interface prices were defined in a comparable manner by PJM and the NYISO, if identical rules governed external transactions in PJM and the NYISO, if time lags were not built into the rules governing such transactions and if no risks were associated with such transactions, then prices at the interfaces would be expected to be very close and the level of transactions would be expected to be related to any price differentials. The fact that none of these conditions exists is important in explaining the observed relationship between interface prices and inter-ISO power flows, and those price differentials.⁷

There are institutional differences between PJM and the NYISO markets that are relevant to observed differences in border prices.⁸ The NYISO requires bids or offer prices for each export or import transaction and clears its market for

each 15 minute interval based on bids.⁹ Import transactions to the NYISO are treated by the NYISO as generator bids at the NYISO/PJM proxy bus. Export transactions are treated by the NYISO as price-capped load offers. Competing bids and offers are evaluated along with other NYISO resources and a proxy bus price is derived. Bidders are notified of the outcome. This process is repeated, with new bids and offers each 15 minute interval. A significant lag exists between the time when offers and bids are submitted to the NYISO and the time when participants are notified that they have cleared. The lag is a result of the Real-Time Commitment (RTC) system and the fact that transactions can only be scheduled at the beginning of the hour.

As a result of the NYISO's RTC timing, market participants must submit bids or offers by no later than 75 minutes before the operating hour. The bid or offer includes the MW volume desired and, for imports into NYISO, the asking price or, for exports out of the NYISO, the price the participants are willing to pay. The required lead time means that participants make price and MW bids or offers based on expected prices. Transactions are accepted only for a single 15 minute increment.

Under PJM operating practices, in the real-time energy market, participants must make a request to import or export power at one of PJM's interfaces at least 20 minutes before the desired start which can be any quarter hour.¹⁰ The duration of the requested transaction can vary from 15 minutes to an unlimited amount of time. Generally, PJM market participants provide only the MW, the duration and the direction of the real-time transaction. While bid prices for transactions are allowed in PJM, less than one percent of all transactions submit an associated price. Transactions are accepted, with virtually no lag, in order of submission, based on whether PJM has the capability to import or export the requested MW. If transactions do not submit a price, the transactions are priced at the real-time price for their scheduled imports or exports. As in the NYISO, the required lead time means that participants must make offers to buy or sell MW based on expected prices, but the required lead time is substantially shorter in the PJM market.

⁶ On September 17, 2010, up to congestion transactions no longer required a willing to pay congestion transmission reservation. Additionally, effective May 15, 2012, up to congestion transactions were required to be submitted for the PJM day-ahead market evaluation in the eMarket application, and are no longer accepted through the EES application. Additional details can be found under the "Up to Congestion" heading in Section 9: *Interchange Transactions* of this report.

⁷ See also the discussion of these issues in the *2005 State of the Market Report for PJM*, Section 4, "Interchange Transactions," (March 8, 2006).

⁸ See the *2005 State of the Market Report for PJM* (March 8, 2006), pp. 195-198.

⁹ See NYISO, "NYISO Transmission Services Manual," Version 2.0 (February 1, 2005) <https://www.nyiso.com/documents/20142/2923301/tran_ser_mnl.pdf/a6baa5ca-29f0-1279-6618-042442dd4d9e>.

¹⁰ See PJM, "Regional Transmission and Energy Scheduling Practices," Version 8 (June 23, 2019). <<http://www.pjm.com/~media/etools/oasis/regional-practices-clean-pdf.ashx>>.

The NYISO rules provide that the RTC results should be available 45 minutes before the operating 15 minute interval. Winning bidders then have 25 minutes from the time when the RTC results indicate that their transaction will flow to meet PJM's 20-minute notice requirement. To get a transaction cleared with PJM, the market participant must have a valid NERC Tag, an OASIS reservation and a PJM ramp reservation. Each of these requirements takes time to process.

The length of required lead times in both markets may be a contributor to the observed relationship between price differentials and flows. Market conditions can change significantly in a relatively short time. The resulting uncertainty could weaken the observed relationship between contemporaneous interface prices and flows.

Appendix E Ancillary Service Markets

This appendix covers five areas related to Ancillary Service Markets: area control error, Control Performance Standard 1 and Balancing Authority ACE Limit, Disturbance Control Standard (DCS), Primary Frequency Response, Regulation Market design changes, and the Synchronized Reserve Market clearing process.

Area Control Error (ACE)

Area control error (ACE) is a real-time measure of the instantaneous MW imbalance between load plus net interchange and generation within PJM.¹ PJM dispatchers seek to ensure grid reliability by balancing ACE. The metrics for success in balancing ACE are control performance standard 1 (CPS1) and balancing authority ACE limit (BAAL) performance. These measurements are mandated by the North American Electric Reliability Council (NERC).²

In the absence of a severe grid disturbance, the primary tool used by dispatchers to control ACE is regulation. Regulation is defined as a variable amount of energy under automatic control which is independent of economic cost signal and is obtainable within five minutes. Regulation contributes to maintaining the balance between load and generation by moving the output of selected generators up and down via an automatic generation control (AGC) signal.³

Control Performance Standard 1 (CPS1) and Balancing Authority ACE Limit (BAAL)

Control Performance Standard 1 (CPS1) and Balancing Authority ACE Limit (BAAL) are the NERC metrics for the effectiveness of power balance through ACE control. The goal of ACE control is to maintain power balance and interconnection frequency within predefined MW

and frequency profiles under all conditions (normal and abnormal).

Frequency (as it applies to the electric power grid) is the rate at which alternating current cycles between minimum and maximum. Usually this is 60 Hz (one Hz is one cycle per second). PJM measures the instantaneous frequency every two seconds. Frequency changes when there is an imbalance between generation and load causing a mismatch between actual and scheduled tie-line flow. PJM dispatchers seek to minimize this deviation. If the mismatch persists, a time error can accumulate.

Frequency bias is a physical attribute of a control area. It is defined as the natural response in MW of that control area (at estimated yearly peak demand) to a change in frequency of 0.1Hz.⁴ NERC requires each balancing authority to review and report its frequency bias by January 1 each year.

CPS1 and BAAL are performance standards used to measure and report how well PJM accomplishes ACE and frequency balance. CPS1 and BAAL are defined according to NERC Standard BAL-001-2.⁵

NERC Standard BAL-001-2 Real Power Balancing Control Performance

NERC Standard BAL-001-2 mandates two requirements. Paragraph R1 requires that control performance standard 1 (CPS1) be maintained greater than or equal to 100 percent for each of twelve previous months evaluated monthly, and paragraph R2 requires that the clock minute average of reporting ACE does not exceed its clock minute ACE limit (BAAL) for more than 30 consecutive clock minutes.⁶ Meeting the CPS1 standard requires PJM dispatchers to maintain ACE within a fixed range around zero.

¹ The PJM Manuals define ACE and the methodology for calculating it: "Area Control Error is a measure of the imbalance between sources of power and uses of power within the PJM RTO. This imbalance is calculated indirectly as the difference between scheduled and actual net interchange, plus the frequency bias contribution to yield ACE in megawatts. Two additional terms may be included in ACE under certain conditions--the time error bias term and PJM dispatcher adjustment term (manual add). These provide for automatic inadvertent interchange payback and error compensation, respectively.", "PJM Manual 12: Balancing Operations," Revision 39 (February 21, 2019), § 3.1.1.

² NERC standard BAL-001-2 "Real Power Balancing Control Performance," <<https://www.nerc.com/files/BAL-001-2.pdf>>.

³ See PJM, "Manual 11: Energy & Ancillary Services Market Operations," Revision 111 (November 19, 2020) § 3.1.

⁴ See Frequency Response and Bias Standard BAL-003-0.1a <http://www.nerc.com/files/BAL-003-0_1a.pdf>.

⁵ NERC, BAL-001-2 – Real Power Balancing Control Performance Standard Background Document, Attachment 2 (Feb. 2013) <http://www.nerc.com/pa/Stand/Project%202010141%20%20Phase%201%20of%20Balancing%20Authority%20Re/BAL-001-2_Background_Document_Clean-20130301.pdf>.

⁶ See PJM, "Manual 12: Balancing Operations," Revision 41 (November 19, 2020), Section 3, "NERC Control Performance Standard" pg. 20.

CPS1

CPS1 is a statistical measure of ACE variability and its relationship to frequency error. It is measured each minute and averaged over a year. CPS1 is defined as:

“the average of the clock-minute averages of a Balancing Area’s ACE divided by minus 10 B (where B is Balancing Area frequency bias) times the corresponding clock-minute averages of the Interconnection’s frequency error must be less than a specific limit. This limit, ‘ε’, is a constant derived from a targeted frequency bound (limit) that is reviewed and set, as necessary, by NERC.”⁷

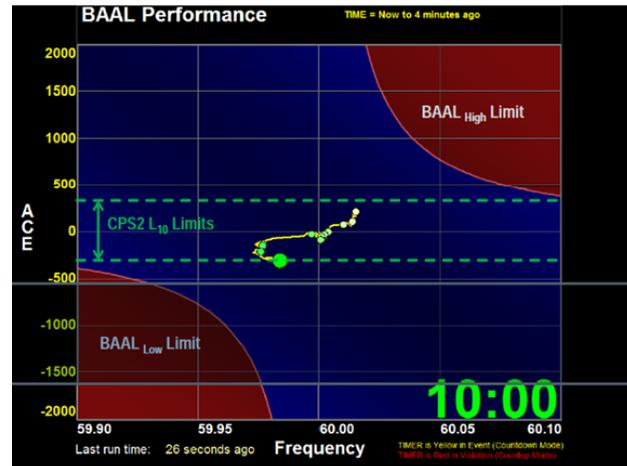
CPS1 is calculated as $CPS1 = (2-CF)*100\%$. The frequency related compliance factor (CF) is a ratio of the accumulating clock-minute compliance parameters for the most recent twelve consecutive calendar months, divided by the square of the target frequency bound (ε11). The ε11 value for the Eastern Interconnection is 0.018 Hz. It can be seen from this equation that if the yearly one-minute average deviations (CF) were zero the CPS1 score would be a perfect 200 percent. The maximum CPS1 score is 200 percent. This is achieved when either the frequency error is zero or the ACE is zero. The minimum passing score is 100 percent monthly.

The defined fixed range for the December 2018 through December 2019 operating year (+/- 257.1 MW/0.1Hz) is called L10. Compliance with the CPS1 standard requires that 90 percent of 10-minute periods have an average ACE value within the L10 range. The L10 was last changed on December 1, 2018. Previously it had been +/-258.2 MW/0.1Hz.

BAAL

The other NERC standard for maintaining power balance is the Balancing Authority ACE Limit (BAAL), which replaced the old CPS2. BAAL is a measure of the relationship between frequency and ACE such that both must remain within the blue area in Figure E-1. The BAAL_{High} and BAAL_{Low} limits are curves which are functions of measured frequency and scheduled frequency.

Figure E-1 Example set of BAAL measurements: Set of measurements is every two seconds for four minutes



PJM counts the total number of minutes that ACE complies with the BAAL limits (high and low) and divides it by the total number of minutes for a month, with a passing level for this goal being set at 99.0 percent for each month. BAAL high and low limits are defined dynamically.⁸

When actual frequency is less than Scheduled Frequency, BAAL_{High} does not apply, and BAAL_{Low} is calculated as:

$$BAAL_{Low} = (-10B_i \times (FTL_{Low} - F_s)) \times \frac{(FTL_{Low} - F_s)}{(F_A - F_s)}$$

When actual frequency is greater than Scheduled Frequency, BAAL_{Low} does not apply and the BAAL_{High} is calculated as:

$$BAAL_{High} = (-10B_i \times (FTL_{High} - F_s)) \times \frac{(FTL_{High} - F_s)}{(F_A - F_s)}$$

BAAL_{Low} is the Low Balancing Authority ACE Limit (MW), BAAL_{High} is the High Balancing Authority ACE Limit (MW), 10 is a constant to convert the Frequency Bias Setting from MW/0.1 Hz to MW/Hz, B_i is the Frequency Bias Setting for a Balancing Authority (expressed as MW/0.1 Hz), F_A is the measured frequency in Hz, F_S is the scheduled frequency in Hz, FTL_{Low} is the Low Frequency Trigger Limit (calculated as F_S + 3ε11 Hz), and FTL_{High} is the High Frequency Trigger Limit (calculated as F_S + 3ε11 Hz). The constant ε11 is derived from a targeted frequency bound for each

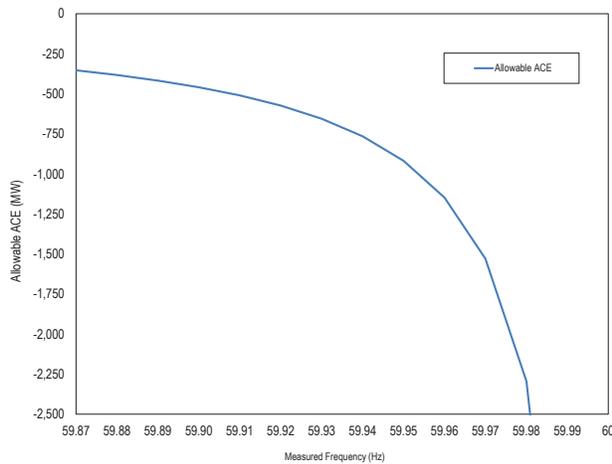
⁷ See PJM, "Manual 12: Balancing Operations," Revision 41 (November 19, 2020), Section 3, "System Control" pg. 21.

⁸ NERC BAL-001-2, Real Power Balancing Control Performance. Feb. 2013.

Interconnection as follows: Eastern Interconnection ϵ_{II} is 0.018 Hz, Western Interconnection ϵ_{II} is 0.0228 Hz, ERCOT Interconnection ϵ_{II} is 0.030 Hz, and Quebec Interconnection ϵ_{II} is 0.021 Hz.

Figure E-2 shows the relationship of measured frequency to allowable ACE deviation when measured frequency is less than scheduled frequency (defined by the $BAAL_{Low}$ equation, scheduled frequency = 60 Hz and negative ACE only). As the measured frequency approaches the scheduled frequency (typically 60 Hz), the allowable ACE increases in absolute value.

Figure E-2 Allowable ACE as a function of measured frequency



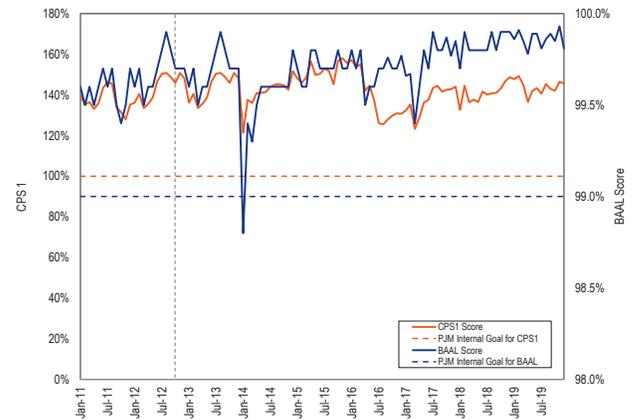
As an example consider a single 2-second measurement under the following scenario. The frequency bias is calculated by PJM each year. PJM’s current frequency bias (for December 1, 2016, through November 30, 2017) is -1,015 MW/0.1Hz. PJM’s frequency profile calls for a scheduled frequency of 60Hz (this can be changed by PJM dispatch under certain circumstances). Under this scenario, applying the formula for $BAAL_{Low}$ shows that ACE needs to be greater than -493.8975 MW at a real-time frequency of 59.92 Hz in order for this one measurement to be within acceptable BAAL limits. A complete scenario is provided by adding the ACE deviation for measured frequency greater than scheduled frequency $BAAL_{High}$ Figure E-1.

PJM’s CPS/BAAL Performance

The BAAL standard set by NERC states that, “the clock-minute average of Reporting ACE does not exceed its clock-minute limit for more than 30 consecutive

clock-minutes.”⁹ PJM has set an internal standard that measures the total number of minutes that ACE complies with the BAAL limits and divides it by the total number of minutes over the entire month, with a passing level set at 99.0 percent for each month. Figure E-3 shows PJM’s CPS1 and BAAL performance from January 2011 through December 2018. PJM did not meet its internal goal for BAAL performance in January 2014, however PJM has remained in compliance with the applicable NERC standards since January 2011, for compliance for both CPS1 and BAAL metrics.

Figure E-3 PJM CPS1/BAAL performance: January 2011 through December 2019



PJM’s DCS Performance

The NERC disturbance control standard (DCS) measures how well ACE recovers from a disturbance.¹⁰ A disturbance is defined by NERC as any ACE deviation caused by sudden loss of generation greater than, or equal to, 80 percent of PJM’s most severe single contingency loss. Disturbance control is measured and must be reported to NERC quarterly as percentage of recovery (R_i) as defined below.

If ACE was positive or zero just before the disturbance then ACE must be returned to zero within fifteen minutes. Full disturbance recovery within 15 minutes represents 100 percent performance under this measure. Less than full recovery in 15 minutes earns a score defined as:

$$R_i = \left(\frac{MW_{loss} - \max(0, ACE_a - ACE_m)}{MW_{loss}} \right) * 100\%$$

⁹ See PJM, “Manual 12: Balancing Operations,” Revision 41 (November 19, 2020), § 3.1.1.
¹⁰ For more information on the NERC DCS, see “Standard BAL-002-0 – Disturbance Control Performance” (4/1/2012) <www.nerc.com/files/BAL-002-0.pdf>.

If ACE was negative just before the disturbance then ACE must be returned to its pre-disturbance value. Full disturbance recovery within 15 minutes represents 100 percent performance under this measure. Less than full recovery in fifteen minutes earns a score as per:

$$R_i = \left(\frac{MW_{loss} - \max(0, -ACE_m)}{MW_{loss}} \right) * 100\%$$

Where MW_{loss} is the MW size of the disturbance from the beginning of the loss, ACE_a is the pre-disturbance ACE, ACE_m is the maximum algebraic value of the ACE measured within fifteen minutes following the disturbance.

PJM experienced 77 DCS events in 2015, 2016, 2017, 2018 and 2019. There were 17 DCS events in all of 2019. PJM DCS compliance has remained at 100 percent since 2011. (Table E-1).

Although PJM recovered from all DCS events by declaring a synchronized reserve event, not all synchronized reserve events are caused by DCS events. DCS events are “sudden unanticipated losses of supply-side resources.”¹¹ Several significant synchronized reserve events in 2013 and 2014, most notably the 68 minute event of September 10, 2013, the 33 minute event of October 28, 2013, and the 34 minute event of January 7, 2014 were caused by low ACE and were therefore not reportable as DCS events. There were five low ACE events in 2017, including the 16 minute event on September 21, 2017. There was one low ACE event in 2018 on July 10. There were two low ACE spinning events in 2019. There have been 26 spinning events between January 2013 and December 2019 caused by Low ACE (Table E-1).^{12 13 14 15 16 17 18}

Table E-1 Spinning Events and causes: 2019

Start Time	End Time	Duration (Minutes)	Spin Cause	Operator Comment
1/23/19 3:30	1/23/19 3:38	7.8	Unit Trip	Loss of unit: Greenville CC 1 in DOM tripped. Loss of 1299 MW
1/31/19 6:26	1/31/19 6:32	5.4	Unit Trip	Hummel CC 1 tripped. loss of 1108 MW
1/31/19 14:26	1/31/19 14:35	8.5	Unit Trip	Loss of unit: Hummel CC 1 tripped and part of Lackawanna. Loss of 1104 MW
2/25/19 5:25	2/25/19 5:34	8.3	Unit Trip	Unit Trip: FE Perry
3/3/19 17:31	3/3/19 17:40	9.4	Unit Trip	Gavin 1 tripped loaded at 1330mw.
3/7/19 3:05	3/7/19 3:15	9.8	Unit Trip	Greenville CC 1 tripped in Dominion. Loss of 1669 MW
7/27/19 23:31	7/27/19 23:37	6.3	Unit Trip	Perry 1 tripped. Loaded at 1266 MW
8/11/19 12:14	8/11/19 12:22	7.1	Unit Trip	Salem 2 tripped. Loss of 922 MW. PS reports feedwater control valve problem.
9/3/19 13:39	9/3/19 13:48	9.7	Shared reserve	Provided 183 MW Shared Reserve to NPCC.
9/23/19 16:06	9/23/19 16:18	11.5	Unit Trip	Braidwood #1 Nuclear tripped.
10/1/19 18:56	10/1/19 19:07	11.0	Low ACE	Low Forecast
12/11/19 21:08	12/11/19 21:16	8.1	Unit Trip	Loss of 997 MW of generation
12/18/19 15:07	12/18/19 15:16	9.6	Low ACE	

11 Standard BAL-002-0 – Disturbance Control Performance,” (April 1, 2005) <www.nerc.com/files/BAL-002-0.pdf> (61 KB) para. 1.4, page. 4.

12 Note that this information is publically available on PJM’s website. PJM. Operating Committee meeting (Feb. 6, 2018): PJM Operations Summary” <<https://pjm.com/-/media/committees-groups/committees/oc/20180206/20180206-item-04-january-2018-sos-summary.ashx>>.

13 PJM. Operating Committee meeting, “PJM Operations Summary,” (May 1, 2018) <<https://pjm.com/-/media/committees-groups/committees/oc/20180501/20180501-item-05-april-2018-sos-summary-partial.ashx>>.

14 PJM. Operating Committee meeting, “PJM Operations Summary,” (July, 10, 2018). <<https://pjm.com/-/media/committees-groups/committees/oc/20180710/20180710-item-07-june-2018-sos-summary.ashx>>.

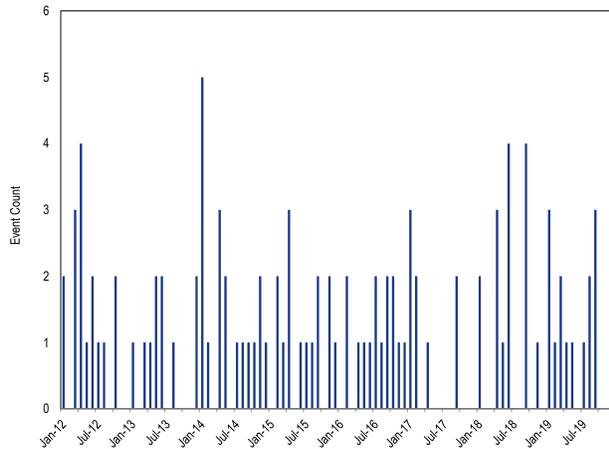
15 PJM. Operating Committee meeting, “PJM Operations Summary,” (August 7, 2018) <<https://pjm.com/-/media/committees-groups/committees/oc/20180807/20180807-item-05-sos-summary-july.ashx>>.

16 PJM. Operating Committee meeting, “PJM Operations Summary,” (September 11, 2018) <<https://pjm.com/-/media/committees-groups/committees/oc/20180911/20180911-item-04-august-2018-sos-summary.ashx>>.

17 PJM. Operating Committee meeting, “PJM Operations Summary,” (October 9, 2018) <<https://pjm.com/-/media/committees-groups/committees/oc/20181009/20181009-item-04-september-2018-sos-summary.ashx>>.

18 PJM. Operating Committee meeting, “PJM Operations Summary,” (November 6, 2018) <<https://pjm.com/-/media/committees-groups/committees/oc/20181106/20181106-item-04-october-2018-sos-summary.ashx>>.

Figure E-4 DCS event count (By month): January 2012 through December 2019



Primary Frequency Response

On November 17, 2016, FERC issued as Primary Frequency Response notice of proposed rulemaking (NOPR).¹⁹ The NOPR proposed a regulation requiring all new generating facilities, both synchronous and nonsynchronous to install and enable primary frequency response capability as a condition of interconnection. Nuclear units are exempted from this NOPR. Existing units are exempted from this NOPR.

The NOPR proposed that all newly interconnecting generating facilities to install and enable primary frequency response capability that would allow a maximum five percent droop; a +/- 0.036 Hz deadband setting; and automated timely and sustained response to frequency deviations.²⁰

The FERC standard is documented in NERC Reliability Standard BAL-003-2, Frequency Response and Frequency Bias Setting. PJM is currently conducting studies to define primary frequency events, compliance metrics, and requirement standards. A Markets and Reliability Task Force is conducting a study of NERC defined frequency excursion events. The study is expected to continue until December 2019.

¹⁹ 157 FERC ¶ 61,122

²⁰ Droop percentage is defined as $((\text{generator speed at no load}) - (\text{generator speed at full load})) / (\text{generator speed at no load})$. The NOPR requires that these parameters be based on nameplate capability.

Synchronized Reserve Market Clearing

PJM's market clearing engines consider resources capable of providing Tier 2 synchronized reserve to be either flexible or inflexible. CTs operating below their economically desired MW will sometimes be dispatched flexibly intra hour. Hydro resources are often a source of flexible T2. Inflexible units are scheduled by the hourly market solution sixty minutes before the operating hour, are committed to provide synchronized reserve for the entire hour, and are paid the higher of the SRMCP or their offer price plus LOC (demand response resources are paid SRMCP). Demand response resources are defined to be inflexible. Flexible units are identified and may be scheduled every time the market solution runs (hour ahead, intermediate term, and short term) and can be assigned to either synchronized reserve or to energy depending on the optimal economic solution. This flexibility allows for a less expensive hourly cost when intrahour events such as constraints binding, changes in imports or exports and performance problems occur.

The PJM Synchronized Reserve Market is recalculated and can be rescheduled both hourly and in all five minute intervals.

The market clearing engine first evaluates the most severe single contingency (MSSC). This becomes the synchronized reserve required MW.

One hour before the market hour, the ASO market clearing engine estimates the sum of the available Tier 1 synchronized reserve and the available transfer capacity from outside the RTO Zone. ASO subtracts this estimated sum from the synchronized reserve requirement to determine the amount of Tier 2 synchronized reserve needed to satisfy the requirement. If the synchronized reserve requirement is not filled from available Tier 1 and imports, then self-scheduled Tier 2 synchronized reserve is assigned. If the required synchronized reserve is still not satisfied, ASO clears a market for inflexible synchronized reserve. Tier 2 synchronized reserve flexible resources can be changed throughout the hour by both the intermediate term and short term market clearing software.

Half an hour before the market hour, the intermediate term solution (IT SCED) performs the same functions

as ASO up to the point of logging and committing individual resources, taking into account the amount of inflexible resources already committed by ASO. After IT SCED produces its solution, a PJM operator reviews the solution, calls the inflexible resources to commit them to provide Tier 2 synchronized reserve, and logs each resource separately. As with ASO, the amount of Tier 2 synchronized reserve provided by flexible resources is not logged and is not carried through to later steps in the clearing process.

Fifteen minutes before each five-minute period in the market hour, real-time solution (RT SCED) estimates the amount of needed Tier 2 synchronized reserve, taking into account the amount of inflexible resources already committed by ASO and IT SCED. RT SCED considers only flexible resources due to the notification-time requirements of inflexible resources. Once RT SCED generates its solution, RT SCED commits the resources from its solution and logs these resources.

Every five minutes within the market hour, LPC calculates market clearing prices by incorporating resource offers and LOC based on real-time LMP and the cost of the marginal unit. LPC computes the clearing price of Tier 2 synchronized based on these factors and the committed resources and uses this price as the within-hour five-minute clearing price. When there is a simultaneous shortage of primary reserve and synchronized reserves the real-time prices for synchronized reserve will be the sum of the primary reserve and synchronized reserve penalty factors.²¹

Whereas the hourly price is the average of the five-minute prices within the hour, the hourly cost (per MW) is the sum of credits for cleared and self-scheduled synchronized reserve and credits for after market lost opportunity cost divided by the total MW of synchronized reserve cleared and self-scheduled. PJM guarantees resources to be made whole to their offer plus opportunity costs.

History of Synchronized Reserve Events

Synchronized reserve is designed to provide relief for disturbances.^{22 23} A disturbance is defined as loss of the lesser of 900 MW or 80 percent of the most severe single contingency within 60 seconds. In the absence of a disturbance, PJM operators have used synchronized reserve as a source of energy to provide relief from low ACE.

The risk of using synchronized reserves for energy or any other nondisturbance reason is that it reduces the amount of synchronized reserve available for a disturbance. Disturbances are unpredictable. Synchronized reserve has a requirement to sustain its output for only up to 30 minutes. When the need is for reserve extending past 30 minutes, secondary reserve is the appropriate source of the response. The use of synchronized reserve is an expensive solution during an hour when the hour ahead market solution and reserve dispatch indicated no shortage of primary reserve. PJM's primary reserve levels have been sufficient to recover from disturbances and should remain available in the absence of disturbance.

From January 1, 2010, through December 31, 2019, PJM experienced 232 synchronized reserve events (Table E-2), approximately 2.1 events per month. During this period, synchronized reserve events had an average duration of 11.7 minutes.

²¹ See PJM, "Manual 11: Energy & Ancillary Services Market Operations," Revision 111 (November 19, 2020), p. 89.

²² 2013 *State of the Market Report for PJM*, Appendix F – PJM's DCS Performance, at 451–452.

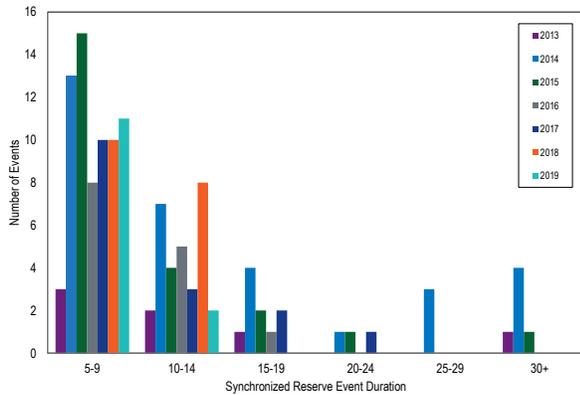
²³ See PJM "Manual 12: Balancing Operations," Rev.41 (November 19, 2020) § 4.1.2 Loading Reserves.

Table E-2 Synchronized reserve events: January 2010 through December 2019

Duration		Duration		Duration		Duration		Duration						
Effective Time	Region (Minutes)	Effective Time	Region (Minutes)	Effective Time	Region (Minutes)	Effective Time	Region (Minutes)	Effective Time	Region (Minutes)					
FEB-18-2010 13:27	Mid-Atlantic	19	JAN-11-2011 15:10	Mid-Atlantic	6	JAN-03-2012 16:51	RFC	9	JAN-22-2013 08:34	RTO	8	JAN-06-2014 22:01	RTO	68
MAR-18-2010 11:02	RFC	27	FEB-02-2011 01:21	RFC	5	JAN-06-2012 23:25	RFC	8	JAN-25-2013 15:01	RTO	19	JAN-07-2014 02:20	RTO	25
MAR-23-2010 20:14	RFC	13	FEB-08-2011 22:41	Mid-Atlantic	11	JAN-23-2012 15:02	Mid-Atlantic	8	FEB-09-2013 22:55	RTO	10	JAN-07-2014 04:18	RTO	34
APR-11-2010 13:12	RFC	9	FEB-09-2011 11:40	Mid-Atlantic	16	MAR-02-2012 19:54	RFC	9	FEB-17-2013 23:10	RTO	13	JAN-07-2014 11:27	RTO	11
APR-28-2010 15:09	Mid-Atlantic	8	FEB-13-2011 15:35	Mid-Atlantic	14	MAR-08-2012 17:04	RFC	6	APR-17-2013 01:11	RTO	11	JAN-07-2014 13:20	RTO	41
MAY-11-2010 19:57	Mid-Atlantic	9	FEB-24-2011 11:35	Mid-Atlantic	14	MAR-19-2012 10:14	RFC	10	APR-17-2013 20:01	RTO	9	JAN-10-2014 16:46	RTO	12
MAY-15-2010 03:03	RFC	6	FEB-25-2011 14:12	RFC	10	APR-16-2012 00:20	Mid-Atlantic	9	MAY-07-2013 17:33	RTO	8	JAN-21-2014 18:52	RTO	6
MAY-28-2010 04:06	Mid-Atlantic	5	MAR-30-2011 19:13	RFC	12	APR-16-2012 11:18	RFC	8	JUN-05-2013 18:54	RTO	20	JAN-22-2014 02:26	RTO	7
JUN-15-2010 00:46	RFC	34	APR-02-2011 13:13	Mid-Atlantic	11	APR-19-2012 11:54	RFC	16	JUN-08-2013 15:19	RTO	9	JAN-22-2014 22:54	RTO	8
JUN-19-2010 23:49	Mid-Atlantic	9	APR-11-2011 00:28	RFC	6	APR-20-2012 11:08	Mid-Atlantic	7	JUN-12-2013 17:35	RTO	10	JAN-25-2014 05:22	RTO	10
JUN-24-2010 00:56	RFC	15	APR-16-2011 22:51	RFC	9	JUN-20-2012 13:35	RFC	7	JUN-30-2013 01:22	RTO	10	JAN-26-2014 17:11	RTO	6
JUN-27-2010 19:33	Mid-Atlantic	15	APR-21-2011 20:02	Mid-Atlantic	6	JUN-26-2012 17:51	RFC	7	JUL-03-2013 20:40	RTO	13	JAN-31-2014 15:05	RTO	13
JUL-07-2010 15:20	RFC	8	APR-27-2011 01:22	RFC	8	JUL-23-2012 21:45	RFC	18	JUL-15-2013 18:43	RTO	29	FEB-02-2014 14:03	Dominion	8
JUL-16-2010 20:45	Mid-Atlantic	19	MAY-02-2011 00:05	Mid-Atlantic	21	AUG-03-2012 12:44	RFC	10	JUL-28-2013 14:20	RTO	10	FEB-08-2014 06:05	Dominion	18
AUG-11-2010 19:09	RFC	17	MAY-12-2011 19:39	RFC	9	SEP-08-2012 04:34	RFC	12	SEP-10-2013 19:48	RTO	68	FEB-22-2014 23:05	RTO	7
AUG-13-2010 23:19	RFC	6	MAY-26-2011 17:17	Mid-Atlantic	20	SEP-27-2012 17:19	Mid-Atlantic	7	OCT-28-2013 10:44	RTO	33	MAR-01-2014 05:18	RTO	26
AUG-16-2010 07:08	RFC	17	MAY-27-2011 12:51	RFC	6	OCT-17-2012 10:48	RTO	10	DEC-01-2013 11:17	RTO	9	MAR-05-2014 21:25	RTO	8
AUG-16-2010 19:39	Mid-Atlantic	11	MAY-29-2011 09:04	RFC	7	OCT-23-2012 22:29	RTO	19	DEC-07-2013 19:44	RTO	7	MAR-14-2014 10:39	RTO	8
SEP-15-2010 11:20	RFC	13	MAY-31-2011 16:36	RFC	27	OCT-30-2012 05:12	RTO	14				MAR-27-2014 10:37	RTO	56
SEP-22-2010 15:28	Mid-Atlantic	24	JUN-03-2011 14:23	RFC	7	NOV-25-2012 16:32	RTO	12				APR-14-2014 01:16	RTO	10
OCT-05-2010 17:20	RFC	10	JUN-06-2011 22:02	Mid-Atlantic	9	DEC-16-2012 07:01	RTO	9				APR-25-2014 17:33	RTO	6
OCT-16-2010 03:22	Mid-Atlantic	10	JUN-23-2011 23:26	RFC	8	DEC-21-2012 05:51	RTO	7				MAY-01-2014 14:18	RTO	13
OCT-16-2010 03:25	RFCNonMA	7	JUL-26-2011 22:03	Mid-Atlantic	10	DEC-21-2012 10:29	RTO	5				MAY-03-2014 17:11	RTO	13
OCT-27-2010 10:35	RFC	7	JUL-10-2011 11:20	RFC	10							MAY-14-2014 01:36	RTO	5
OCT-27-2010 12:50	Mid-Atlantic	10	JUL-28-2011 18:49	RFC	12							JUL-08-2014 03:07	RTO	9
NOV-26-2010 14:24	RFC	13	AUG-02-2011 01:08	RFC	6							JUL-25-2014 19:19	RTO	7
NOV-27-2010 11:24	RFC	8	AUG-18-2011 06:45	Mid-Atlantic	6							SEP-06-2014 13:32	RTO	18
DEC-08-2010 01:19	RFC	11	AUG-19-2011 14:49	RFC	5							SEP-20-2014 23:42	RTO	14
DEC-09-2010 20:07	RFC	5	AUG-23-2011 17:52	RFC	7							SEP-29-2014 10:08	RTO	15
DEC-14-2010 12:02	Mid-Atlantic	24	SEP-24-2011 15:48	RFC	8							OCT-20-2014 06:35	RTO	15
DEC-16-2010 18:40	Mid-Atlantic	20	SEP-27-2011 14:20	RFC	7							OCT-23-2014 11:03	RTO	27
DEC-17-2010 22:09	Mid-Atlantic	6	SEP-27-2011 16:47	RFC	9							NOV-01-2014 06:50	RTO	9
DEC-29-2010 19:01	Mid-Atlantic	15	OCT-30-2011 22:39	Mid-Atlantic	10							NOV-08-2014 02:08	RTO	8
			DEC-15-2011 14:35	Mid-Atlantic	8							NOV-22-2014 05:27	RTO	21
			DEC-21-2011 14:26	RFC	18							NOV-22-2014 08:19	RTO	10
												DEC-10-2014 18:58	RTO	8
												DEC-31-2014 21:42	RTO	12

Duration		Duration		Duration		Duration		Duration						
Effective Time	Region (Minutes)	Effective Time	Region (Minutes)	Effective Time	Region (Minutes)	Effective Time	Region (Minutes)	Effective Time	Region (Minutes)					
JAN-07-2015 22:36	RTO	8	JAN-18-2016 17:58	RTO	12	JAN-08-2017 03:21	RTO	7	JAN-01-2018 02:41	RTO	7	JAN-22-2019 22:30	RTO	8
FEB-24-2015 02:51	RTO	5	FEB-08-2016 15:05	RTO	10	JAN-09-2017 19:24	RTO	9	JAN-03-2018 03:00	RTO	13	JAN-31-2019 01:26	RTO	5
FEB-26-2015 15:20	RTO	6	FEB-28-2016 18:29	RTO	8	JAN-10-2017 13:05	MAD	9	JAN-07-2018 14:15	RTO	8	JAN-31-2019 09:26	RTO	9
MAR-03-2015 17:02	RTO	11	APR-14-2016 20:09	RTO	10	JAN-15-2017 20:13	RTO	9	APR-12-2018 13:28	RTO	10	FEB-25-2019 00:25	RTO	9
MAR-16-2015 10:25	RTO	24	MAY-11-2016 15:55	RTO	6	JAN-23-2017 09:08	RTO	7	JUN-04-2018 10:22	RTO	6	MAR-03-2019 12:31	RTO	9
MAR-17-2015 23:34	RTO	17	JUN-01-2016 09:01	RTO	5	FEB-13-2017 18:30	RTO	7	JUN-29-2018 15:21	RTO	9	MAR-06-2019 22:06	RTO	9
MAR-23-2015 23:44	RTO	15	JUL-06-2016 00:40	RTO	5	FEB-14-2017 00:11	RTO	6	JUN-30-2018 09:46	RTO	11	JUL-27-2019 23:31	RTO	7
APR-06-2015 14:23	RTO	8	JUL-28-2016 13:28	RTO	15	FEB-15-2017 06:37	RTO	6	JUL-04-2018 10:56	RTO	7	AUG-11-2019 12:14	RTO	8
APR-07-2015 17:11	RTO	31	AUG-31-2016 19:29	RTO	8	MAR-23-2017 06:48	RTO	24	JUL-10-2018 15:45	RTO	13	SEP-03-2019 13:39	RTO	9
APR-15-2015 08:14	RTO	8	SEP-09-2016 19:11	RTO	6	APR-08-2017 11:53	RTO	10	JUL-23-2018 09:02	RTO	8	SEP-23-2019 16:06	RTO	11
APR-25-2015 03:21	RTO	9	SEP-11-2016 19:30	RTO	9	MAY-08-2017 04:18	RTO	10	JUL-23-2018 15:43	RTO	6	OCT-01-2019 18:56	RTO	11
JUL-30-2015 14:04	RTO	10	OCT-12-2016 08:21	RTO	5	JUN-08-2017 03:39	RTO	10	JUL-24-2018 16:17	RTO	7	DEC-11-2019 21:08	RTO	8
AUG-05-2015 19:47	RTO	7	OCT-12-2016 14:40	RTO	7	JUN-20-2017 05:38	RTO	9	AUG-12-2018 11:06	RTO	11	DEC-18-2019 15:07	RTO	9
AUG-19-2015 16:47	RTO	9	NOV-04-2016 17:13	RTO	11	SEP-04-2017 20:18	MAD	15	SEP-13-2018 09:47	RTO	7			
SEP-05-2015 01:16	RTO	7	DEC-03-2016 00:11	RTO	7	SEP-07-2017 09:16	RTO	9	SEP-14-2018 13:24	RTO	7			
SEP-10-2015 10:12	RTO	8	DEC-31-2016 05:10	RTO	12	SEP-21-2017 14:15	RTO	16	SEP-26-2018 19:08	RTO	8			
SEP-29-2015 00:58	Mid-Atlantic	11							SEP-30-2018 11:29	RTO	11			
NOV-12-2015 16:42	RTO	8							OCT-30-2018 10:40	RTO	11			
NOV-21-2015 17:17	RTO	8												
DEC-04-2015 22:41	RTO	7												
DEC-24-2015 17:42	RTO	8												

Figure E-5 Synchronized reserve events duration distribution curve: January 2013 through December 2019



Regulation Market Design Issues

On October 20, 2011, FERC issued Order No. 755 directing PJM and other RTOs/ISOs to modify their regulation market rules to include fast response in addition to traditional regulation resources.²⁴

A rationale for the new market design was the assumption that new, fast response technologies could be used, in combination with traditional resources, to reduce the total amount of resources needed to meet regulation requirements and thereby reduce the cost of regulation. Order No. 755 required that the fast and slow resources be purchased in a single market, with compensation for both capacity (MW) and miles (Δ MW).²⁵ Regulation miles are calculated as the sum of the absolute value of a given regulation resource's movement (up and down) in response to a regulation signal.

To incorporate the new fast regulation, PJM developed a fast regulation signal (RegD) that responds faster to changes in ACE than the traditional slow regulation signal (RegA). Resources are free to choose which signal they will follow. A study by KEMA for PJM indicated that including a combination of RegA and RegD following resources in the regulation market would allow PJM to reduce its regulation requirement but still maintain

CPS1 scores close to the historical average (significantly above the passing score of 100 percent).²⁶

According to the study, the smaller the proportion of RegD MW and the greater the proportion of RegA, the greater the benefit to adding one more MW of RegD. The smaller the proportion of fast regulation used, the more slow regulation each MW of fast regulation can replace. Conversely, as the proportion of fast regulation increases, there is a decrease in the benefit of substituting fast capability for slow capability. This rate of substitution between fast and slow resources is the marginal benefit factor or MBF. The marginal benefit factor measures the equivalent MW of slow regulation that can be displaced by one MW of fast regulation. If one MW of fast regulation can replace two MW of slow regulation while maintaining the same overall regulation performance, the marginal benefit factor is 2.0. The marginal benefit factor decreases as the amount of fast resources increases. RegD MW additions are allowed (if economic) until the MBF is zero, at which point one MW of RegD does not reduce the amount of RegA needed to maintain the same overall regulation performance. Past this point, the addition of another MW of fast capability results in a MBF less than zero. An MBF less than zero means that adding another MW of fast regulation requires the addition of slow regulation in order to maintain a regulation performance target. At this point the rate of substitution is negative and the addition of fast resources makes it harder to maintain a regulation performance target.²⁷ It is possible for PJM to achieve a passing CPS1 score (100 percent) entirely with slow regulation resources as PJM has done since its inception, but PJM cannot achieve a passing CPS1 score using only fast regulation resources.

PJM administers the real-time regulation signal to resource owners on a two second scan rate using the RegA and RegD control signals. These signals are used to move regulating resources or fleets of resources within the total regulation capability (TRegA or TRegD) they can provide. PJM monitors compliance using the current regulation signals CRegA and CRegD. The CRegA signal tracks compliance with the RegA signal

²⁴ Order No. 755 at P 3. FERC ordered PJM "to compensate frequency regulation resources based on the actual service provided, including a capacity payment that includes the marginal unit's opportunity costs and a payment for performance that reflects the quantity of frequency regulation service provided by a resource when the resource is accurately following the dispatch signal."

²⁵ Id. at PP 99, 131 & 177.

²⁶ See KEMA, "KERMIT Study Report," (December 13, 2011).

²⁷ PJM calculates a marginal benefit factor using a function that is arbitrarily defined to have zero as its lower bound. The practical impact of this incorrect functional form is likely to be negligible in the near term because substantially more RegD resources would have to be added to result in a negative marginal benefit factor but the function should be corrected. See PJM, "Manual 11: Energy & Ancillary Services Markets Operations," Revision 111 (November 19, 2020), § 3.2.7.

and the CRegD signal tracks compliance with the RegD signal. The current regulation signals CRegA and CRegD are calculated every two seconds as the response of a regulation resource (or the sum of resources' responses in the case of a fleet of resources) to the regulation signal they are receiving.²⁸ Figure E-6 shows a screenshot of a typical 10-minute time period of PJM's RegA signal and CRegA signal for all RegA resources. Figure E-7 shows a screenshot of typical 10-minute time period of PJM's RegD signal and CRegD signal for all RegD resources.

Figure E-6 PJM RegA signal and CReg compliance signal: Example of typical 10-minute time period

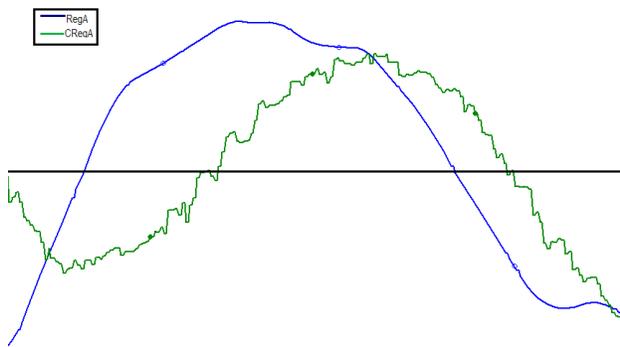
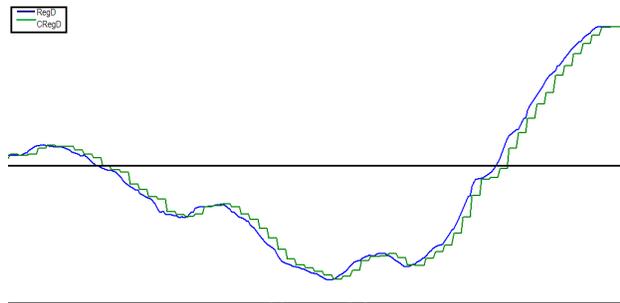


Figure E-7 PJM RegD signal and CRegD current regulation signal: Example of typical 10-minute time period



Regulation signals are designed for the purpose of moderating ACE, accounting for the characteristics of the expected response from the resources following the signal. The RegD signal is designed to contribute to the moderation of ACE given the attributes of fast regulation resources. The RegA signal is designed to contribute to the moderation of ACE given the attributes of traditional

sources of regulation. Even a very fast regulating unit will need to have some capability to provide sustained MWh to help with ACE correction, and even a unit with a large MW capability must be able to react with some speed to help with ACE correction. The relationship between the two types of regulating resources is under constant review and the relationship between the two (the marginal benefit factor) is subject to change.

- Regulation Offers.** All owners of generating and demand resources qualified to provide regulation may offer their regulation capability price in \$/MW at cost plus up to \$12 adder daily into the regulation market using the PJM market user interface. There is no must offer requirement for resources qualified to provide regulation. Users must also enter the signal type they want to follow (RegA or RegD), their regulation capability in MW, as well as cost validation parameters including fuel cost, heat rate at economic maximum, heat rate at regulation minimum, and the VOM rate. Regulating units may also self-schedule. Self-scheduled units have zero lost opportunity cost (LOC) and are the first to be assigned. Owners may also enter price based offers up to a maximum of \$100/MW. Demand resources are eligible to offer regulation and did so for the first time in November 2011. Demand resources have an LOC of zero. Under current PJM rules, no more than 25 percent of the total regulation requirement may be supplied by demand resources.²⁹ Total regulation offers are the sum of all regulation capable units that offer regulation into the market for the day and that are not out of service or fully committed to provide energy. Owners of units that have entered offers into the PJM market user interface system have the ability to set unit status to "unavailable" for regulation for the day, or for a specific hour or set of hours. They also have the ability to change the amount of regulation MW offered in each hour. Unit owners do not have the ability to change their regulation offer price during a day. All regulation offers that are not set to unavailable for the day are summed to calculate the total daily regulation offered, a figure that changes each hour.
- Regulation Offered and Eligible.** Sixty minutes before the market hour, PJM runs the Ancillary

²⁸ See PJM, "Manual 12: Balancing Operations," Revision 41 (November 19, 2020), § 4.4.2.

²⁹ See PJM, "Manual 11: Energy & Ancillary Services Markets Operations," Revision 111 (November 19, 2020), § 3.2.4.

Services Optimizer software (ASO) to determine the amount of Tier 2 synchronized reserve/nonsynchronized reserve required, develop regulation and synchronized reserve supply curves, and assign regulation, synchronized reserve, and non-synchronized reserve to specific units. All regulation resource units which have made offers in the daily regulation market are evaluated by ASO for regulation. ASO excludes units according to the following ordered criteria: daily or hourly unavailable status; units for which the economic minimum is set equal to economic maximum (unless the unit is a hydroelectric unit or has self-scheduled regulation); units assigned synchronized reserve; units for which regulation minimum is set equal to regulation maximum (unless the unit is a hydroelectric unit or has self-scheduled regulation); units that are offline (except combustion turbine units).³⁰

- **Regulation Market Clearing and Dispatch.** The regulation market is cleared by the ASO 60 minutes before the operational hour. The specific units scheduled to regulate are selected at that time based on the lowest price set of units sufficient to fill the regulation requirement. The actual unit dispatch happens at the start of the operational hour and is under the control of unit operators. The final Regulation Market Clearing Price used to settle the regulation market is based on the costs and LMPs of the units that are actually dispatched. Differences between market clearing and market dispatch can cause unnecessary uplift payments or a final price paid to all units based on a less than optimal set of dispatched regulating units.

Even after ASO has run and selected units for regulation, PJM dispatchers can dispatch units uneconomically to provide regulation for several reasons including: to control transmission constraints; to avoid over-generation during periods of minimum generation alert; to remove a unit temporarily unable to regulate; or to remove a unit with a malfunctioning data link.³¹

For each offered and eligible unit in the regulation supply, the regulation total capability offer price is

calculated using the sum of the unit's regulation cost-based offer (divided by the marginal benefit factor of the resource type and the historic performance score of the resource) plus the opportunity cost based on the forecast LMP, unit economic minimum and economic maximum, regulation minimum and regulation maximum, startup costs and relevant offer schedule. Based on this result, ASO determines if the period has three or fewer pivotal suppliers. If it does, all owners who are pivotal have their offers limited to the lesser of their cost or price offer. ASO uses price-based offers for those operators not offer capped and re-solves. Unit assignments based on this solution are final. The final clearing price is not determined at the time of unit assignment.

The regulation, synchronized reserve, and nonsynchronized reserve markets are cleared, prior to the hour, and supplementally within the hour, on a real-time basis. The regulation, synchronized reserve, and nonsynchronized reserve markets are cleared and priced interactively with the energy market and secondary reserve requirements to minimize the cost of the combined products subject to reactive limits, resource constraints, unscheduled power flows, inter area transfer limits, resource distribution factors, self-scheduled resources, limited fuel resources, bilateral transactions, hydrological constraints, generation requirements, reserve requirements and prior to the hour assignments for regulation and reserves.³² The final clearing prices are calculated at five-minute intervals based on the real-time prices and LMPs of energy. These five-minute prices are averaged to arrive at the final hourly clearing price. This price is sent to Settlements and used as the basis for credits and charges.

- **Cleared Regulation.** Regulation actually assigned by ASO is cleared regulation. The capability and performance prices are calculated every five minutes by the Locational Pricing Calculator (LPC) with the final hourly clearing price averaged from the five minute prices. In real time, resources that have been assigned an ancillary service are expected to provide that ancillary service for the designated hour.
- **Settled Regulation.** Owners of regulation resources are compensated by RMCP (Regulation Market Clearing Price) credits and opportunity cost credits. RMCP credits are the sum of RMCCP (Regulation

³⁰ See PJM, "Manual 11: Energy & Ancillary Services Markets Operations," Revision 111 (November 19, 2020), § 2.5.

³¹ See PJM, "Manual 11: Energy & Ancillary Services Markets Operations," Revision 11 (November 19, 2020), § 3.1.

³² See PJM, "Manual 11: Energy & Ancillary Services Markets Operations," Revision 11 (November 19, 2020), § 5.2.4.

Market Capability Clearing Price) credits and RMPCP (Regulation Market Performance Clearing Price) credits. RMCCP credits are calculated as MW of regulation capability times the performance score times RMCCP. For RegA resources, RMPCP credits are calculated as MW of regulation capability times performance score times RMPCP. For RegD resources, RMPCP credits are calculated as MW of regulation capability times performance score times RegD to RegA mileage ratio times RMPCP. When calculating RMCCP and RMPCP credits, the MW of regulation capability are defined as the actual MW provided (as opposed to cleared MW or effective MW). The owner of a regulation resource receives opportunity cost credits only if its RMCP credits are less than its offer plus opportunity cost (including lost opportunity cost during shoulder hours). The cost per actual MW of settled regulation can be higher than the regulation clearing price because actual MW and cleared MW may differ and RMCP credits may not completely cover lost opportunity costs.

Reactive Costs

Table E-3 through Table E-5 show reactive service charges, reactive capability revenue requirement charges and total charges by zone for 2014 through 2019. Reactive service charges are uplift charges to each zone for the reactive service provided. Reactive capability charges are charges to each zone for reactive capability. Table E-6 shows the total reactive charges, including reactive services charges and reactive capability charges for 2009 through 2019 by zone. Table E-7 shows the reactive services charges for 2009 through 2019 by zone. Table E-8 shows the reactive capability charges for 2009 through 2019 by zone. Table E-9 shows the total reactive service charges (energy uplift) for 2009 through 2019.

In 2011, some of the units needed for reactive power became uneconomic in the energy market. Rather than providing reactive power as a result of producing energy, the units were committed and dispatched by PJM out of merit solely in order to provide reactive power. As a further result, the incremental portion of the units' offers, net of energy market revenues, were categorized as reactive services charges because these costs were incurred in order to provide reactive power. The result was higher reactive services charges. The

units were offer capped under PJM's market power mitigation rules. The frequency of offer capping resulted in the units becoming eligible for FMU adders. The FMU adders increased the cost-based offers which further increased the charges for reactive.

In 2012, the increased level of reactive services charges led to a change in the treatment of reactive services charges in the day-ahead energy market and to a change in the categorization of energy uplift credits paid to units needed for reactive power. Prior to September 2012, the start and no load components of the offers of these units were categorized as balancing operating reserve charges and the incremental portion of the offers were categorized as reactive services charges. In September 2012, PJM began to commit units for reactive in the day-ahead energy market in order to eliminate the differences between the day-ahead and real-time markets that resulted from the commitment of the units for reactive solely in the real-time market. In September, October and November 2012, all of the reactive service charges were categorized as day-ahead operating reserve charges, and allocated following that definition, and not as reactive services charges.

In December 2012, PJM filed proposed revisions to PJM's tariff and operating agreement with FERC to change the rules governing the categorization of reactive services charges, which were approved retroactive to December 2012.³³ Starting in December 2012 all the costs of the units committed for reactive (including start and no load costs), net of energy market revenues, were categorized as reactive service charges.

The significant increase in reactive services charges in 2013 was the combined result of the categorization of all reactive service charges as reactive, lower energy market offsets, an increase in uneconomic commitment for reactive in the day-ahead market, the inclusion of start and no load costs in reactive services charges, and the use of FMU adders in cost-based offers.

In 2014, reactive services charges declined to the pre 2013 levels as the combined result of a reduction in the FMU adders used for the units supplying reactive power, the November 2014, FERC approval of the effective elimination of FMU adders, PJM operations' increased

³³ See PJM Interconnection, LLC, Docket No. ER13-481-000 (November 30, 2012).

reliance on combustion turbines and less on steam turbines, and transmission upgrades which reduced the need for reactive power.

Table E-3 Reactive service charges and reactive capability charges by zone: 2018 and 2019

Zone	2018			2019		
	Reactive Service Charges	Reactive Capability Charges	Total Charges	Reactive Service Charges	Reactive Capability Charges	Total Charges
AECO	\$7	\$4,335,705	\$4,335,712	\$0	\$4,302,762	\$4,302,762
AEP	\$775,231	\$41,478,130	\$42,253,361	\$14,219	\$47,745,214	\$47,759,433
APS	\$0	\$15,176,573	\$15,176,573	\$13,823	\$15,583,367	\$15,597,190
ATSI	\$0	\$22,023,002	\$22,023,002	\$696	\$25,548,260	\$25,548,957
BGE	\$30,956	\$7,513,585	\$7,544,541	\$74,264	\$7,193,645	\$7,267,910
ComEd	\$11,317,114	\$32,247,786	\$43,564,900	\$0	\$37,580,423	\$37,580,423
DAY	\$0	\$4,086,587	\$4,086,587	\$0	\$2,822,626	\$2,822,626
DEOK	\$0	\$8,302,064	\$8,302,064	\$0	\$9,626,063	\$9,626,063
Dominion	\$41,778	\$38,115,431	\$38,157,209	\$182,436	\$38,931,911	\$39,114,347
DPL	\$257,310	\$10,092,557	\$10,349,867	\$112,566	\$9,877,899	\$9,990,466
DLCO	\$0	\$573,120	\$573,120	\$0	\$572,031	\$572,031
EKPC	\$198,553	\$2,189,541	\$2,388,094	\$14,944	\$2,185,379	\$2,200,323
JCPL	\$0	\$7,944,006	\$7,944,006	\$0	\$7,429,259	\$7,429,259
Met-Ed	\$0	\$4,155,236	\$4,155,236	\$3,972	\$5,789,245	\$5,793,217
OVEC	\$0	\$0	\$0	\$0	\$0	\$0
PECO	\$0	\$19,818,286	\$19,818,286	\$0	\$19,382,232	\$19,382,232
PENELEC	\$435,628	\$11,908,652	\$12,344,280	\$137,176	\$13,009,585	\$13,146,762
Pepco	\$0	\$9,818,757	\$9,818,757	\$0	\$11,161,942	\$11,161,942
PPL	\$83,389	\$25,979,765	\$26,063,154	\$0	\$34,998,069	\$34,998,069
PSEG	\$0	\$27,253,784	\$27,253,784	\$0	\$27,651,850	\$27,651,850
RECO	\$0	\$0	\$0	\$0	\$0	\$0
(Imp/Exp/Wheels)	\$0	\$14,922,533	\$14,922,533	\$0	\$16,582,381	\$16,582,381
Total	\$13,139,966	\$307,935,099	\$321,075,065	\$554,098	\$337,974,146	\$338,528,244

Table E-4 Reactive service charges and reactive capability charges by zone: 2016 and 2017

Zone	2016			2017		
	Reactive Service Charges	Reactive Capability Charges	Total Charges	Reactive Service Charges	Reactive Capability Charges	Total Charges
AECO	\$250	\$5,097,197	\$5,097,448	\$8,686	\$4,247,222	\$4,255,908
AEP	\$76,833	\$37,638,226	\$37,715,059	\$178,314	\$39,234,081	\$39,412,395
APS	\$1,440	\$16,676,578	\$16,678,018	\$135,676	\$16,800,854	\$16,936,530
ATSI	\$1,860	\$21,809,408	\$21,811,268	\$77,078	\$21,342,021	\$21,419,099
BGE	\$895	\$7,592,963	\$7,593,858	\$1,694,486	\$8,205,331	\$9,899,817
ComEd	\$1,025,426	\$25,752,517	\$26,777,944	\$13,242,447	\$30,855,459	\$44,097,906
DAY	\$501	\$8,154,908	\$8,155,409	\$15,845	\$5,628,799	\$5,644,643
DEOK	\$765	\$6,096,321	\$6,097,086	\$25,386	\$8,057,110	\$8,082,496
Dominion	\$19,204	\$29,962,427	\$29,981,631	\$120,722	\$34,512,902	\$34,633,624
DPL	\$786,662	\$12,191,155	\$12,977,817	\$1,308,524	\$11,512,490	\$12,821,014
DLCO	\$365	\$130,487	\$130,852	\$12,737	\$779,263	\$792,000
EKPC	\$162,131	\$2,164,030	\$2,326,162	\$20,528	\$2,185,849	\$2,206,377
JCPL	\$608	\$9,065,146	\$9,065,753	\$19,441	\$8,973,314	\$8,992,755
Met-Ed	\$15,525	\$5,991,398	\$6,006,923	\$68,170	\$5,198,247	\$5,266,417
OVEC	\$0	\$0	\$0	\$0	\$0	\$0
PECO	\$1,113	\$22,688,891	\$22,690,004	\$103,510	\$22,285,794	\$22,389,303
PENELEC	\$250,696	\$9,503,976	\$9,754,672	\$1,675,853	\$11,645,044	\$13,320,897
Pepco	\$136,334	\$6,070,782	\$6,207,117	\$1,595,597	\$8,301,363	\$9,896,960
PPL	\$16,500	\$20,235,159	\$20,251,659	\$37,886	\$24,416,798	\$24,454,684
PSEG	\$1,133	\$29,783,733	\$29,784,865	\$37,255	\$27,659,023	\$27,696,277
RECO	\$37	\$0	\$37	\$1,239	\$0	\$1,239
(Imp/Exp/Wheels)	\$0	\$17,853,808	\$17,853,808	\$0	\$19,435,328	\$19,435,328
Total	\$2,498,279	\$294,459,111	\$296,957,390	\$20,379,379	\$311,276,291	\$331,655,670

Table E-5 Reactive service charges and reactive capability charges by zone: 2014 and 2015

Zone	2014			2015		
	Reactive Service Charges	Reactive Capability Charges	Total Charges	Reactive Service Charges	Reactive Capability Charges	Total Charges
AECO	\$106,829	\$6,619,214	\$6,726,043	\$17,555	\$6,341,664	\$6,359,219
AEP	\$864,219	\$40,080,753	\$40,944,971	\$458,265	\$38,198,374	\$38,656,639
APS	\$300,933	\$18,526,432	\$18,827,365	\$98,666	\$16,666,745	\$16,765,411
ATSI	\$12,057,257	\$15,273,809	\$27,331,066	\$3,844,142	\$15,277,869	\$19,122,011
BGE	\$55,746	\$7,703,534	\$7,759,280	\$63,849	\$7,825,069	\$7,888,919
ComEd	\$168,684	\$24,890,361	\$25,059,045	\$180,977	\$25,334,050	\$25,515,027
DAY	\$29,895	\$8,356,294	\$8,386,189	\$34,107	\$8,487,449	\$8,521,555
DEOK	\$29,300	\$5,655,802	\$5,685,102	\$53,426	\$5,153,000	\$5,206,427
Dominion	\$4,329,339	\$29,664,589	\$33,993,928	\$2,682,636	\$29,848,959	\$32,531,595
DPL	\$7,311,401	\$10,767,117	\$18,078,518	\$2,338,443	\$11,172,936	\$13,511,379
DLCO	\$15,641	\$0	\$15,641	\$25,334	\$0	\$25,334
EKPC	\$12,846	\$2,121,517	\$2,134,363	\$28,701	\$2,154,987	\$2,183,688
JCPL	\$39,367	\$7,064,041	\$7,103,408	\$39,781	\$7,175,487	\$7,215,268
Met-Ed	\$46,070	\$7,529,560	\$7,575,630	\$63,281	\$7,730,837	\$7,794,118
OVEC	\$0	\$0	\$0	\$0	\$0	\$0
PECO	\$445,657	\$17,468,722	\$17,914,379	\$73,554	\$17,744,319	\$17,817,873
PENELEC	\$3,232,172	\$6,386,846	\$9,619,018	\$313,316	\$7,303,956	\$7,617,272
Pepco	\$51,280	\$5,211,678	\$5,262,958	\$69,105	\$5,293,901	\$5,363,006
PPL	\$44,987	\$18,900,104	\$18,945,091	\$81,863	\$18,969,092	\$19,050,955
PSEG	\$417,079	\$27,028,845	\$27,445,924	\$73,686	\$28,662,896	\$28,736,582
RECO	\$1,749	\$0	\$1,749	\$2,499	\$0	\$2,499
(Imp/Exp/Wheels)	\$0	\$21,591,362	\$21,591,362	\$0	\$17,226,112	\$17,226,112
Total	\$29,560,453	\$280,840,576	\$310,401,029	\$10,543,187	\$276,567,702	\$287,110,889

Table E-6 Total reactive service and reactive capability charges by zone: 2009 through 2019

Zone	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
AECO	\$4,468,680	\$4,670,504	\$5,281,241	\$6,058,739	\$9,535,990	\$6,726,043	\$6,359,219	\$5,097,448	\$4,255,908	\$4,335,712	\$4,302,762
AEP	\$36,786,336	\$40,256,622	\$40,933,915	\$43,342,930	\$72,588,378	\$40,944,971	\$38,656,639	\$37,715,059	\$39,412,395	\$42,253,361	\$47,759,433
APS	\$19,118,180	\$31,233,415	\$20,310,685	\$22,886,264	\$30,996,202	\$18,827,365	\$16,765,411	\$16,678,018	\$16,936,530	\$15,176,573	\$15,597,190
ATSI	\$0	\$0	\$8,477,799	\$30,426,223	\$74,598,449	\$27,331,066	\$19,122,011	\$21,811,268	\$21,419,099	\$22,023,002	\$25,548,957
BGE	\$7,178,113	\$7,652,993	\$8,525,875	\$11,856,108	\$21,776,514	\$7,759,280	\$7,888,919	\$7,593,858	\$9,899,817	\$7,544,541	\$7,267,910
ComEd	\$20,521,747	\$22,758,881	\$25,726,883	\$26,872,588	\$43,927,193	\$25,059,045	\$25,515,027	\$26,777,944	\$44,097,906	\$43,564,900	\$37,580,423
DAY	\$7,651,501	\$7,697,304	\$8,280,466	\$8,789,368	\$11,701,654	\$8,386,189	\$8,521,555	\$8,155,409	\$5,644,643	\$4,086,587	\$2,822,626
DEOK	\$0	\$0	\$0	\$6,265,412	\$10,951,005	\$5,685,102	\$5,206,427	\$6,097,086	\$8,082,496	\$8,302,064	\$9,626,063
Dominion	\$28,031,746	\$67,225,948	\$31,336,152	\$33,014,968	\$50,145,153	\$33,993,928	\$32,531,595	\$29,981,631	\$34,633,624	\$38,157,209	\$39,114,347
DPL	\$8,871,883	\$13,863,327	\$22,790,883	\$25,697,951	\$59,085,829	\$18,078,518	\$13,511,379	\$12,977,817	\$12,821,014	\$10,349,867	\$9,990,466
DLCO	\$0	\$0	\$0	\$297,882	\$2,847,715	\$15,641	\$25,334	\$130,852	\$792,000	\$573,120	\$572,031
EKPC	\$0	\$0	\$0	\$0	\$3,078,702	\$2,134,363	\$2,183,688	\$2,326,162	\$2,206,377	\$2,388,094	\$2,200,323
JCPL	\$5,887,845	\$5,880,280	\$21,064,228	\$9,662,807	\$18,664,387	\$7,103,408	\$7,215,268	\$9,065,753	\$8,992,755	\$7,944,006	\$7,429,259
Met-Ed	\$6,913,516	\$6,913,646	\$7,528,865	\$8,117,240	\$10,738,607	\$7,575,630	\$7,794,118	\$6,006,923	\$5,266,417	\$4,155,236	\$5,793,217
OVEC	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
PECO	\$15,273,666	\$16,436,863	\$20,359,432	\$19,369,743	\$26,663,594	\$17,914,379	\$17,817,873	\$22,690,004	\$22,389,303	\$19,818,286	\$19,382,232
PENELEC	\$3,043,946	\$3,334,125	\$5,759,500	\$12,446,815	\$40,425,887	\$9,619,018	\$7,617,272	\$9,754,672	\$13,320,897	\$12,344,280	\$13,146,762
Pepco	\$5,224,159	\$8,170,035	\$7,468,962	\$8,522,491	\$11,475,283	\$5,262,958	\$5,363,006	\$6,207,117	\$9,896,960	\$9,818,757	\$11,161,942
PPL	\$14,439,786	\$15,497,270	\$16,833,467	\$21,456,809	\$27,341,025	\$18,945,091	\$19,050,955	\$20,251,659	\$24,454,684	\$26,063,154	\$34,998,069
PSEG	\$25,239,745	\$25,627,583	\$29,645,403	\$34,361,439	\$43,681,314	\$27,445,924	\$28,736,582	\$29,784,865	\$27,696,277	\$27,253,784	\$27,651,850
RECO	\$0	\$0	\$5,594	\$57,276	\$298,052	\$1,749	\$2,499	\$37	\$1,239	\$0	\$0
(Imp/Exp/Wheels)	\$33,375,996	\$34,090,011	\$20,149,382	\$19,462,321	\$19,038,717	\$21,591,362	\$17,226,112	\$17,853,808	\$19,435,328	\$14,922,533	\$16,582,381
Total	\$242,026,843	\$311,308,807	\$300,478,731	\$348,965,374	\$589,559,649	\$310,401,029	\$287,110,889	\$296,957,390	\$331,655,670	\$321,075,065	\$338,528,244

Table E-7 Reactive service charges by zone: 2009 through 2019

Zone	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
AECO	\$67,285	\$77,157	\$204,412	\$940,304	\$4,403,292	\$106,829	\$17,555	\$250	\$8,686	\$7	\$0
AEP	\$55,497	\$3,571,402	\$1,600,992	\$3,377,039	\$32,288,025	\$864,219	\$458,265	\$76,833	\$178,314	\$775,231	\$14,219
APS	\$210,444	\$12,349,162	\$63,488	\$1,098,407	\$9,279,229	\$300,933	\$98,666	\$1,440	\$135,676	\$0	\$13,823
ATSI	\$0	\$0	\$2,195	\$15,904,245	\$58,856,607	\$12,057,257	\$3,844,142	\$1,860	\$77,078	\$0	\$696
BGE	\$0	\$483,796	\$839,251	\$4,106,490	\$14,005,302	\$55,746	\$63,849	\$895	\$1,694,486	\$30,956	\$74,264
ComEd	\$0	\$1,482,811	\$99,900	\$1,993,905	\$19,358,913	\$168,684	\$180,977	\$1,025,426	\$13,242,447	\$11,317,114	\$0
DAY	\$0	\$55,306	\$10,772	\$375,657	\$3,264,499	\$29,895	\$34,107	\$501	\$15,845	\$0	\$0
DEOK	\$0	\$0	\$0	\$522,480	\$5,192,071	\$29,300	\$53,426	\$765	\$25,386	\$0	\$0
Dominion	\$500,408	\$39,618,969	\$1,736,679	\$3,172,919	\$20,219,951	\$4,329,339	\$2,682,636	\$19,204	\$120,722	\$41,778	\$182,436
DPL	\$1,650,115	\$5,439,801	\$13,204,103	\$16,032,605	\$49,034,124	\$7,311,401	\$2,338,443	\$786,662	\$1,308,524	\$257,310	\$112,566
DLCO	\$0	\$0	\$0	\$297,882	\$2,847,715	\$15,641	\$25,334	\$365	\$12,737	\$0	\$0
EKPC	\$0	\$0	\$0	\$0	\$2,008,773	\$12,846	\$28,701	\$162,131	\$20,528	\$198,553	\$14,944
JCPL	\$107,887	\$107,500	\$14,874,806	\$3,422,661	\$12,406,854	\$39,367	\$39,781	\$608	\$19,441	\$0	\$0
Met-Ed	\$4,710	\$13,420	\$130,626	\$658,370	\$3,258,954	\$46,070	\$63,281	\$15,525	\$68,170	\$0	\$3,972
OVEC	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
PECO	\$324,527	\$1,506,292	\$4,351,268	\$2,035,443	\$9,041,403	\$445,657	\$73,554	\$1,113	\$103,510	\$0	\$0
PENELEC	\$53,751	\$347,644	\$2,557,474	\$7,809,399	\$35,775,549	\$3,232,172	\$313,316	\$250,696	\$1,675,853	\$435,628	\$137,176
Pepco	\$0	\$2,699,808	\$1,603,928	\$2,971,912	\$6,217,818	\$51,280	\$69,105	\$136,334	\$1,595,597	\$0	\$0
PPL	\$12,380	\$1,087,783	\$607,296	\$4,152,942	\$8,468,810	\$44,987	\$81,863	\$16,500	\$37,886	\$83,389	\$0
PSEG	\$54,408	\$473,526	\$2,675,888	\$7,170,902	\$16,415,012	\$417,079	\$73,686	\$1,133	\$37,255	\$0	\$0
RECO	\$0	\$0	\$5,594	\$57,276	\$298,052	\$1,749	\$2,499	\$37	\$1,239	\$0	\$0
(Imp)/Exp/Wheels)	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Total	\$3,041,411	\$69,314,376	\$44,568,672	\$76,100,839	\$312,640,950	\$29,560,453	\$10,543,187	\$2,498,279	\$20,379,379	\$13,139,966	\$554,098

Table E-8 Reactive capability charges by zone: 2009 through 2019

Zone	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
AECO	\$4,401,395	\$4,593,347	\$5,076,829	\$5,118,435	\$5,132,698	\$6,619,214	\$6,341,664	\$5,097,197	\$4,247,222	\$4,335,705	\$4,302,762
AEP	\$36,730,839	\$36,685,220	\$39,332,922	\$39,965,891	\$40,300,353	\$40,080,753	\$38,198,374	\$37,638,226	\$39,234,081	\$41,478,130	\$47,745,214
APS	\$18,907,736	\$18,884,253	\$20,247,197	\$21,787,857	\$21,716,973	\$18,526,432	\$16,666,745	\$16,676,578	\$16,800,854	\$15,176,573	\$15,583,367
ATSI	\$0	\$0	\$8,475,604	\$14,521,977	\$15,741,842	\$15,273,809	\$15,277,869	\$21,809,408	\$21,342,021	\$22,023,002	\$25,548,260
BGE	\$7,178,113	\$7,169,197	\$7,686,624	\$7,749,618	\$7,771,212	\$7,703,534	\$7,825,069	\$7,592,963	\$8,205,331	\$7,513,585	\$7,193,645
ComEd	\$20,521,747	\$21,276,070	\$25,626,984	\$24,878,682	\$24,568,280	\$24,890,361	\$25,334,050	\$25,752,517	\$30,855,459	\$32,247,786	\$37,580,423
DAY	\$7,651,501	\$7,641,998	\$8,269,694	\$8,413,711	\$8,437,155	\$8,356,294	\$8,487,449	\$8,154,908	\$5,628,799	\$4,086,587	\$2,822,626
DEOK	\$0	\$0	\$0	\$5,742,932	\$5,758,934	\$5,655,802	\$5,153,000	\$6,096,321	\$8,057,110	\$8,302,064	\$9,626,063
Dominion	\$27,531,337	\$27,606,979	\$29,599,473	\$29,842,049	\$29,925,202	\$29,664,589	\$29,848,959	\$29,962,427	\$34,512,902	\$38,115,431	\$38,931,911
DPL	\$7,221,768	\$8,423,526	\$9,586,780	\$9,665,346	\$10,051,706	\$10,767,117	\$11,172,936	\$12,191,155	\$11,512,490	\$10,092,557	\$9,877,899
DLCO	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$130,487	\$779,263	\$573,120	\$572,031
EKPC	\$0	\$0	\$0	\$0	\$1,069,929	\$2,121,517	\$2,154,987	\$2,164,030	\$2,185,849	\$2,189,541	\$2,185,379
JCPL	\$5,779,958	\$5,772,779	\$6,189,422	\$6,240,146	\$6,257,533	\$7,064,041	\$7,175,487	\$9,065,146	\$8,973,314	\$7,944,006	\$7,429,259
Met-Ed	\$6,908,806	\$6,900,226	\$7,398,239	\$7,458,870	\$7,479,654	\$7,529,560	\$7,730,837	\$5,991,398	\$5,198,247	\$4,155,236	\$5,789,245
OVEC	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
PECO	\$14,949,138	\$14,930,572	\$16,008,164	\$17,334,300	\$17,622,191	\$17,468,722	\$17,744,319	\$22,688,891	\$22,285,794	\$19,818,286	\$19,382,232
PENELEC	\$2,990,195	\$2,986,481	\$3,202,026	\$4,637,417	\$4,650,339	\$6,386,846	\$7,303,956	\$9,503,976	\$11,645,044	\$11,908,652	\$13,009,585
Pepco	\$5,224,159	\$5,470,228	\$5,865,033	\$5,550,578	\$5,257,465	\$5,211,678	\$5,293,901	\$6,070,782	\$8,301,363	\$9,818,757	\$11,161,942
PPL	\$14,427,406	\$14,409,487	\$16,226,171	\$17,303,867	\$18,872,215	\$18,900,104	\$18,969,092	\$20,235,159	\$24,416,798	\$25,979,765	\$34,998,069
PSEG	\$25,185,337	\$25,154,057	\$26,969,515	\$27,190,537	\$27,266,302	\$27,028,845	\$28,662,896	\$29,783,733	\$27,659,023	\$27,253,784	\$27,651,850
RECO	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
(Imp)/Exp/Wheels)	\$33,375,996	\$34,090,011	\$20,149,382	\$19,462,321	\$19,038,717	\$21,591,362	\$17,226,112	\$17,853,808	\$19,435,328	\$14,922,533	\$16,582,381
Total	\$238,985,432	\$241,994,431	\$255,910,059	\$272,864,535	\$276,918,698	\$280,840,576	\$276,567,702	\$294,459,111	\$311,276,291	\$307,935,099	\$337,974,146

Table E-9 Total reactive service and reactive capability charges: 2009 through 2019

	Reactive Service Charges	Reactive Capability Charges	Total Charges
2009	\$3,041,411	\$238,985,432	\$242,026,843
2010	\$69,314,376	\$241,994,431	\$311,308,807
2011	\$44,568,672	\$255,910,059	\$300,478,731
2012	\$76,100,839	\$272,864,535	\$348,965,374
2013	\$312,640,950	\$276,918,698	\$589,559,649
2014	\$29,560,453	\$280,840,576	\$310,401,029
2015	\$10,543,187	\$276,567,702	\$287,110,889
2016	\$2,498,279	\$294,459,111	\$296,957,390
2017	\$20,379,379	\$311,276,291	\$331,655,670
2018	\$13,139,966	\$307,935,099	\$321,075,065
2019	\$554,098	\$337,974,146	\$338,528,244

Appendix F Congestion and Marginal Losses

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

SMP, MLMP and CLMP are products of the least cost, security constrained dispatch of system resources to meet system load.¹ SMP is the incremental cost of energy, given the current dispatch and given the choice of reference bus, or LMP net of losses and congestion. Losses refer to energy lost to physical resistance in the transmission network as power is moved from generation to load. Total losses refer to the total system-wide transmission losses as a result of moving power from injections to withdrawals on the system. Total system-wide transmission losses for 2019 were 15,208.5 GWh, a 2.6 percent decrease compared to 2018. Marginal losses are the incremental change in system losses caused by changes in load and generation. Congestion occurs when available, least-cost energy cannot be delivered to all load because transmission facilities are not adequate to deliver that energy and higher cost units in the constrained area must be dispatched to meet that load.² The result is that the price of energy in the constrained area is higher than in the unconstrained area.

Congestion is neither good nor bad, but is a direct measure of the extent to which there are multiple marginal generating units dispatched to serve load as a result of transmission constraints. Congestion is defined to be load payments in excess of generation revenues. Congestion revenues are the source of the funds to pay FTRs. In an LMP system, the only way to ensure that load receives the benefits associated with the use of the transmission system to deliver low cost energy is to use FTRs, or an equivalent mechanism, to pay back to load the difference between what load pays based on the higher price at load buses and what generators receive based on the price at the generator buses.

¹ For more information about LMP see the *Technical Reference for PJM Markets*, "Calculating Locational Marginal Price," <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

² 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. Dispatch within the constrained area follows merit order for the units available to relieve the constraint.

The energy, marginal losses and congestion metrics must be interpreted carefully. The term total congestion refers to what is actually net congestion, which is calculated as net implicit congestion costs plus net explicit congestion costs plus net inadvertent congestion charges. The net implicit congestion costs are the load congestion payments less generation congestion credits. This section refers to total energy costs and total marginal loss costs in the same way. As with congestion, total energy costs are more precisely termed net energy costs and total marginal loss costs are more precisely termed net marginal loss costs.

The components of LMP are the basis for calculating participant and location specific congestion and marginal losses.³

Congestion Costs

Zonal Congestion Costs

Positive or negative CLMPs caused by a specific constraint at a specific bus indicate whether that constraint is increasing or decreasing the LMP at that bus relative to the system marginal price. The total CLMP at a specific bus is the net sum of the positive and negative CLMPs caused by all binding constraints at that bus.

CLMPs are not congestion. CLMPs are a component of price paid by or to load and generation.

Constraint Based Congestion

The constraint based congestion calculation is the correct method of calculating local congestion. Constraint based congestion includes all energy charges or credits incurred to serve zonal load. Constraint based congestion is the congestion paid by the zonal load. Constraint based congestion calculations account for the total difference between what the zonal load pays in congestion charges and what the generation that serves that load is paid, regardless of whether the zone is a net importer or a net exporter of generation.

Constraint based congestion calculates congestion on a constraint by constraint basis. On a system wide basis, congestion results from transmission constraints that prevent the lowest cost generation from serving some

³ The total congestion and marginal losses were calculated as of January 17, 2020, and are subject to change, based on continued PJM billing updates.

load that must be served by higher cost generation. Transmission constraints cause differences in LMP, defined by the marginal cost of resolving the constraint given the need to meet power balance requirements, indicated by the shadow price of the constraint. The LMP at any point is equal to the system marginal price (SMP) plus the shadow price of the constraint times the DFAX of the binding constraint to the bus in question (the CLMP of the constraint at that bus), plus marginal losses (MLMP).

The total congestion caused by a constraint is equal to the product of the constraint shadow price times the net flow on the binding constraint. Total congestion caused by the constraint can also be calculated using the CLMPs caused by the constraint at every bus and the net MW injections or MW withdrawals at every affected bus. Congestion associated with a specific constraint is equal to load congestion charges (CLMP of that specific constraint at each bus times load MW at each bus) caused by that constraint in excess of generation congestion credits (CLMP of that specific constraint at each bus times generation MW at each bus) caused by that constraint.

In order to define the load that is actually paying congestion, constraint specific congestion is assigned to downstream (positive CLMP) load buses that paid the congestion caused by the constraint, in proportion to the congestion charges collected from that load due to that constraint. The congestion collected from each load bus due to a constraint is equal to the CLMP caused by that constraint times the MW of load at that load bus. This calculation is done for both day-ahead congestion and balancing congestion.

Constraint Specific Contribution to Zonal Congestion

Constraints can affect prices and congestion across multiple zones. Table F-1 through Table F-21 present the congestion costs of the top 20 constraints affecting each control zone, including the facility type, the location of the constrained facility, day-ahead event hours and real-time event hours for 2019. The tables present the top 20 constraints in descending order of the absolute value of congestion costs for each zone. In addition to the top 20 constraints, these tables show the congestion costs of all other constraints affecting the control zone.

Table F-1 AECO Control Zone top congestion cost impacts (By facility): 2019

Congestion Costs (Millions)														
No.	Constraint	Type	Location	Day-Ahead				Balancing				Event Hours		
				Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Grand Total	Day-Ahead	Real-Time
1	Monroe - Vineland	Line	AECO	\$1.6	\$0.6	\$0.3	\$1.3	(\$0.0)	(\$0.0)	(\$0.0)	(\$0.0)	\$1.3	4,560	108
2	Siegfried	Transformer	PPL	\$0.2	(\$0.5)	\$0.0	\$0.8	(\$0.0)	\$0.1	(\$0.0)	(\$0.1)	\$0.7	562	310
3	Conastone - Peach Bottom	Line	500	\$0.4	(\$0.0)	(\$0.0)	\$0.4	\$0.0	\$0.0	\$0.0	\$0.0	\$0.4	4,999	3,250
4	East	Interface	500	(\$0.2)	(\$0.6)	\$0.0	\$0.4	\$0.0	\$0.1	\$0.0	(\$0.1)	\$0.4	113	16
5	Clayton - Woodstown	Line	AECO	\$0.7	\$0.4	\$0.1	\$0.4	(\$0.0)	(\$0.0)	(\$0.0)	(\$0.0)	\$0.4	354	58
6	Coolspring - Milford	Line	DPL	\$0.1	(\$0.2)	\$0.0	\$0.3	(\$0.0)	(\$0.0)	(\$0.0)	(\$0.0)	\$0.3	463	42
7	Face Rock	Other	PPL	\$0.0	(\$0.3)	\$0.0	\$0.3	\$0.0	\$0.0	\$0.0	(\$0.0)	\$0.3	2,552	484
8	Tanners Creek - Miami Fort	Flowgate	MISO	(\$0.1)	(\$0.3)	\$0.0	\$0.2	\$0.0	\$0.0	\$0.0	\$0.0	\$0.2	882	0
9	Blooming Grove - Paupack	Line	PPL	\$0.1	(\$0.1)	\$0.0	\$0.2	\$0.0	\$0.0	\$0.0	\$0.0	\$0.2	97	0
10	Wescosville	Transformer	PPL	\$0.1	(\$0.1)	\$0.0	\$0.2	(\$0.0)	\$0.0	(\$0.0)	(\$0.0)	\$0.2	401	164
11	AP South	Interface	500	\$0.1	(\$0.1)	(\$0.0)	\$0.2	\$0.0	\$0.0	\$0.0	(\$0.0)	\$0.2	178	31
12	Cedar Creek - Red Lion	Line	DPL	\$0.1	(\$0.1)	\$0.0	\$0.2	(\$0.0)	(\$0.0)	(\$0.0)	(\$0.0)	\$0.2	780	57
13	Roxana - Praxair	Flowgate	MISO	(\$0.0)	(\$0.1)	\$0.0	\$0.1	\$0.0	\$0.0	(\$0.2)	(\$0.2)	(\$0.2)	1,274	603
14	Graceton - Safe Harbor	Line	BGE	\$0.2	\$0.0	\$0.0	\$0.2	\$0.0	\$0.0	\$0.0	(\$0.0)	\$0.2	1,631	563
15	Gardners - Texas Eastern	Line	Met-Ed	(\$0.1)	(\$0.2)	\$0.0	\$0.1	(\$0.0)	\$0.0	(\$0.0)	(\$0.0)	\$0.1	1,787	131
16	Pleasant View - Ashburn	Line	Dominion	\$0.1	(\$0.0)	\$0.0	\$0.1	\$0.0	\$0.0	(\$0.0)	(\$0.0)	\$0.1	339	70
17	Palisades - Argenta	Flowgate	MISO	(\$0.0)	(\$0.1)	\$0.0	\$0.1	\$0.0	(\$0.0)	(\$0.0)	(\$0.0)	\$0.1	738	91
18	Butler - Sherman	Line	AECO	\$0.1	\$0.0	\$0.1	\$0.1	\$0.0	\$0.0	\$0.0	\$0.0	\$0.1	947	0
19	PA Central	Interface	500	\$0.0	(\$0.1)	\$0.0	\$0.1	\$0.0	\$0.0	(\$0.0)	(\$0.0)	\$0.1	872	665
20	Greentown	Flowgate	MISO	(\$0.0)	(\$0.0)	(\$0.0)	\$0.0	(\$0.0)	\$0.0	(\$0.1)	(\$0.1)	(\$0.1)	111	51
Top 20 Total				\$3.3	(\$1.9)	\$0.6	\$5.7	\$0.0	\$0.3	(\$0.3)	(\$0.6)	\$5.1	23,640	6,694
All Other Constraints				\$0.4	(\$2.5)	\$0.4	\$3.2	\$0.1	\$0.3	(\$0.7)	(\$1.0)	\$2.3	57,507	14,908
Total				\$3.7	(\$4.4)	\$0.9	\$9.0	\$0.1	\$0.7	(\$1.1)	(\$1.6)	\$7.4	81,147	21,602

AEP Control Zone

Table F-2 AEP Control Zone top congestion cost impacts (By facility): 2019

Congestion Costs (Millions)														
No.	Constraint	Type	Location	Day-Ahead				Balancing				Event Hours		
				Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Grand Total	Day-Ahead	Real-Time
1	Conastone - Peach Bottom	Line	500	\$20.2	(\$0.5)	\$0.0	\$20.7	\$0.7	\$1.1	\$0.5	\$0.1	\$20.7	4,999	3,250
2	Conastone	Other	500	\$3.1	(\$0.1)	\$0.1	\$3.3	(\$0.2)	(\$0.6)	(\$0.2)	\$0.2	\$3.6	255	229
3	Tanners Creek - Miami Fort	Flowgate	MISO	(\$1.1)	(\$3.8)	\$0.0	\$2.8	\$0.0	\$0.0	\$0.0	\$0.0	\$2.8	882	0
4	Graceton - Safe Harbor	Line	BGE	\$2.7	\$0.0	\$0.0	\$2.6	\$0.1	\$0.2	\$0.1	(\$0.0)	\$2.6	1,631	563
5	AP South	Interface	500	\$1.3	(\$0.8)	(\$0.0)	\$2.1	\$0.0	\$0.1	\$0.0	(\$0.0)	\$2.1	178	31
6	Roxana - Praxair	Flowgate	MISO	(\$0.2)	(\$0.7)	\$0.5	\$1.0	\$0.4	\$0.6	(\$2.9)	(\$3.0)	(\$2.1)	1,274	603
7	Conastone - Northwest	Line	BGE	\$1.3	(\$0.6)	\$0.1	\$1.9	\$0.0	(\$0.0)	(\$0.1)	(\$0.1)	\$1.9	289	29
8	Coolspring - Milford	Line	DPL	(\$0.4)	(\$2.3)	\$0.0	\$1.9	(\$0.0)	(\$0.1)	(\$0.1)	(\$0.0)	\$1.9	463	42
9	Bagley - Graceton	Line	BGE	\$1.4	(\$0.4)	\$0.0	\$1.8	\$0.0	\$0.1	\$0.1	\$0.0	\$1.8	826	126
10	East Elkhart - Mottville Tap	Line	AEP	\$2.3	\$0.6	\$0.3	\$2.0	(\$0.1)	(\$0.0)	(\$0.1)	(\$0.2)	\$1.8	491	16
11	Wescosville	Transformer	PPL	\$1.0	(\$1.2)	(\$0.0)	\$2.2	(\$0.0)	\$0.3	(\$0.1)	(\$0.4)	\$1.8	401	164
12	Nottingham	Other	PECO	\$2.2	\$0.5	(\$0.0)	\$1.7	\$0.0	\$0.0	\$0.0	\$0.0	\$1.7	809	468
13	Hazard	Transformer	AEP	\$0.2	(\$1.3)	\$0.0	\$1.5	\$0.0	\$0.0	\$0.0	\$0.0	\$1.5	778	0
14	Lakin - Sporn	Line	AEP	\$1.7	\$0.3	\$0.2	\$1.5	(\$0.0)	(\$0.0)	(\$0.0)	(\$0.1)	\$1.5	366	10
15	PA Central	Interface	500	\$0.2	(\$1.6)	\$0.1	\$1.9	\$0.1	\$0.5	(\$0.0)	(\$0.5)	\$1.5	872	665
16	Palisades - Argenta	Flowgate	MISO	(\$0.1)	(\$1.6)	\$0.1	\$1.6	\$0.0	(\$0.0)	(\$0.1)	(\$0.1)	\$1.5	738	91
17	East	Interface	500	(\$0.7)	(\$2.4)	\$0.0	\$1.7	\$0.1	\$0.5	\$0.1	(\$0.3)	\$1.5	113	16
18	Pleasant View - Ashburn	Line	Dominion	\$1.1	(\$0.3)	\$0.0	\$1.4	\$0.1	\$0.2	(\$0.0)	(\$0.1)	\$1.3	339	70
19	Shadeland - Lafayette south	Flowgate	MISO	(\$0.1)	(\$1.5)	\$0.2	\$1.6	\$0.1	\$0.2	(\$0.2)	(\$0.3)	\$1.3	273	151
20	Miami Fort - Willey	Line	DEOK	\$1.0	(\$0.0)	\$0.3	\$1.2	\$0.0	\$0.0	\$0.0	\$0.0	\$1.2	466	0
Top 20 Total				\$37.1	(\$17.6)	\$1.9	\$56.7	\$1.3	\$3.1	(\$3.0)	(\$4.7)	\$51.9	16,443	6,524
All Other Constraints				\$9.4	(\$47.1)	\$8.6	\$65.1	(\$0.5)	\$5.3	(\$10.9)	(\$16.7)	\$48.4	71,961	15,068
Total				\$46.5	(\$64.8)	\$10.5	\$121.8	\$0.9	\$8.4	(\$13.9)	(\$21.4)	\$100.4	88,404	21,592

APS Control Zone

Table F-3 APS Control Zone top congestion cost impacts (By facility): 2019

Congestion Costs (Millions)														
No.	Constraint	Type	Location	Day-Ahead				Balancing				Event Hours		
				Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Grand Total	Day-Ahead	Real-Time
1	Conastone - Peach Bottom	Line	500	\$7.6	(\$0.2)	(\$0.0)	\$7.8	\$0.3	\$0.4	\$0.2	\$0.0	\$7.9	4,999	3,250
2	East Towanda - Hillside	Line	PENELEC	(\$0.8)	(\$3.4)	(\$0.0)	\$2.6	\$0.0	\$0.0	(\$0.0)	(\$0.0)	\$2.6	1,161	781
3	Wescosville	Transformer	PPL	\$1.2	(\$0.8)	(\$0.0)	\$1.9	(\$0.0)	\$0.1	(\$0.0)	(\$0.2)	\$1.8	401	164
4	Face Rock	Other	PPL	\$0.0	(\$1.4)	\$0.1	\$1.5	\$0.1	\$0.2	\$0.0	(\$0.1)	\$1.4	2,552	484
5	Conastone	Other	500	\$1.1	(\$0.0)	\$0.0	\$1.2	(\$0.1)	(\$0.2)	(\$0.1)	\$0.1	\$1.3	255	229
6	Seward - Towanda	Line	PENELEC	\$5.9	\$4.5	(\$0.1)	\$1.3	\$0.0	\$0.0	\$0.0	\$0.0	\$1.3	284	0
7	Siegfried	Transformer	PPL	\$0.7	(\$1.0)	\$0.0	\$1.7	(\$0.1)	\$0.3	(\$0.0)	(\$0.5)	\$1.2	562	310
8	Tanners Creek - Miami Fort	Flowgate	MISO	(\$0.4)	(\$1.5)	\$0.0	\$1.1	\$0.0	\$0.0	\$0.0	\$0.0	\$1.1	882	0
9	Gardners - Texas Eastern	Line	Met-Ed	\$0.0	(\$1.1)	\$0.0	\$1.1	(\$0.1)	\$0.0	(\$0.0)	(\$0.1)	\$1.0	1,787	131
10	Graceton - Safe Harbor	Line	BGE	\$1.0	\$0.0	\$0.0	\$1.0	\$0.0	\$0.1	\$0.0	(\$0.0)	\$1.0	1,631	563
11	AP South	Interface	500	\$0.5	(\$0.3)	(\$0.0)	\$0.9	\$0.0	\$0.0	\$0.0	(\$0.0)	\$0.9	178	31
12	Conastone - Northwest	Line	BGE	\$0.5	(\$0.2)	\$0.0	\$0.7	\$0.0	(\$0.0)	(\$0.0)	(\$0.0)	\$0.7	289	29
13	Bagley - Graceton	Line	BGE	\$0.5	(\$0.2)	\$0.0	\$0.7	\$0.0	\$0.0	\$0.0	\$0.0	\$0.7	826	126
14	Coolspring - Milford	Line	DPL	(\$0.1)	(\$0.8)	\$0.0	\$0.7	(\$0.0)	(\$0.0)	(\$0.0)	(\$0.0)	\$0.7	463	42
15	Nottingham	Other	PECO	\$0.8	\$0.2	(\$0.0)	\$0.7	\$0.0	\$0.0	\$0.0	\$0.0	\$0.7	809	468
16	Palisades - Argenta	Flowgate	MISO	(\$0.0)	(\$0.7)	\$0.0	\$0.7	\$0.0	(\$0.0)	(\$0.1)	(\$0.1)	\$0.6	738	91
17	Roxana - Praxair	Flowgate	MISO	(\$0.1)	(\$0.3)	\$0.2	\$0.4	\$0.2	\$0.2	(\$1.0)	(\$1.0)	(\$0.6)	1,274	603
18	PA Central	Interface	500	\$0.1	(\$0.6)	\$0.0	\$0.8	\$0.0	\$0.2	(\$0.0)	(\$0.2)	\$0.6	872	665
19	Pleasant View - Ashburn	Line	Dominion	\$0.4	(\$0.1)	\$0.0	\$0.6	\$0.0	\$0.1	(\$0.0)	(\$0.0)	\$0.6	339	70
20	Lenox - North Meshoppen	Line	PENELEC	(\$0.2)	(\$1.0)	\$0.0	\$0.8	\$0.0	\$0.3	\$0.0	(\$0.2)	\$0.5	569	757
Top 20 Total				\$18.8	(\$8.9)	\$0.4	\$28.1	\$0.4	\$1.7	(\$1.0)	(\$2.2)	\$25.9	20,871	8,794
All Other Constraints				\$3.5	(\$15.9)	\$1.9	\$21.3	\$0.0	\$1.4	(\$4.1)	(\$5.4)	\$15.9	60,725	12,821
Total				\$22.3	(\$24.8)	\$2.4	\$49.5	\$0.5	\$3.1	(\$5.0)	(\$7.7)	\$41.8	81,596	21,615

ATSI Control Zone

Table F-4 ATSI Control Zone top congestion cost impacts (By facility): 2019

Congestion Costs (Millions)														
No.	Constraint	Type	Location	Day-Ahead				Balancing				Event Hours		
				Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Grand Total	Day-Ahead	Real-Time
1	Conastone - Peach Bottom	Line	500	\$10.0	(\$0.2)	\$0.0	\$10.3	\$0.3	\$0.5	\$0.3	\$0.1	\$10.3	4,999	3,250
2	Conastone	Other	500	\$1.5	(\$0.0)	\$0.0	\$1.5	(\$0.1)	(\$0.3)	(\$0.1)	\$0.1	\$1.7	255	229
3	Tanners Creek - Miami Fort	Flowgate	MISO	(\$0.6)	(\$2.0)	\$0.0	\$1.5	\$0.0	\$0.0	\$0.0	\$0.0	\$1.5	882	0
4	Wescosville	Transformer	PPL	\$0.8	(\$0.8)	(\$0.0)	\$1.6	(\$0.0)	\$0.2	(\$0.0)	(\$0.2)	\$1.4	401	164
5	Graceton - Safe Harbor	Line	BGE	\$1.3	\$0.0	\$0.0	\$1.3	\$0.0	\$0.1	\$0.0	(\$0.0)	\$1.3	1,631	563
6	Coolspring - Milford	Line	DPL	(\$0.2)	(\$1.2)	\$0.0	\$1.0	(\$0.0)	(\$0.0)	(\$0.0)	(\$0.0)	\$1.0	463	42
7	Bagley - Graceton	Line	BGE	\$0.7	(\$0.2)	\$0.0	\$0.9	\$0.0	\$0.0	\$0.0	\$0.0	\$0.9	826	126
8	Roxana - Praxair	Flowgate	MISO	(\$0.1)	(\$0.4)	\$0.3	\$0.5	\$0.2	\$0.3	(\$1.4)	(\$1.4)	(\$0.9)	1,274	603
9	Logtown - North Delphos	Line	AEP	(\$1.4)	(\$2.2)	\$0.1	\$0.9	\$0.0	(\$0.0)	(\$0.0)	(\$0.0)	\$0.9	617	13
10	Conastone - Northwest	Line	BGE	\$0.6	(\$0.3)	\$0.0	\$0.9	\$0.0	(\$0.0)	(\$0.0)	(\$0.0)	\$0.9	289	29
11	Nottingham	Other	PECO	\$1.1	\$0.2	(\$0.0)	\$0.9	\$0.0	\$0.0	\$0.0	\$0.0	\$0.9	809	468
12	AP South	Interface	500	\$0.5	(\$0.3)	(\$0.0)	\$0.9	\$0.0	\$0.0	\$0.0	(\$0.0)	\$0.8	178	31
13	Palisades - Argenta	Flowgate	MISO	(\$0.0)	(\$0.9)	\$0.0	\$0.9	(\$0.0)	(\$0.0)	(\$0.1)	(\$0.1)	\$0.8	738	91
14	Pleasant View - Ashburn	Line	Dominion	\$0.6	(\$0.2)	\$0.0	\$0.9	\$0.1	\$0.1	(\$0.0)	(\$0.0)	\$0.8	339	70
15	PA Central	Interface	500	\$0.1	(\$0.8)	\$0.1	\$1.0	\$0.0	\$0.2	(\$0.0)	(\$0.2)	\$0.8	872	665
16	East	Interface	500	(\$0.3)	(\$1.2)	\$0.0	\$0.8	\$0.1	\$0.2	\$0.1	(\$0.1)	\$0.7	113	16
17	Smithton - Yukon	Line	APS	(\$0.4)	(\$1.0)	\$0.0	\$0.7	\$0.1	\$0.0	(\$0.1)	(\$0.0)	\$0.7	296	81
18	CPL - DOM	Interface	500	\$0.3	(\$0.3)	\$0.0	\$0.6	\$0.0	\$0.0	\$0.0	\$0.0	\$0.6	112	0
19	Keystone	Other	500	(\$0.1)	(\$0.6)	\$0.0	\$0.5	(\$0.0)	(\$0.0)	(\$0.0)	\$0.0	\$0.5	299	163
20	Cedar Creek - Red Lion	Line	DPL	\$0.0	(\$0.5)	\$0.1	\$0.6	(\$0.0)	(\$0.0)	(\$0.0)	(\$0.1)	\$0.5	780	57
Top 20 Total				\$14.3	(\$12.9)	\$0.8	\$28.0	\$0.8	\$1.3	(\$1.5)	(\$2.0)	\$26.0	16,173	6,661
All Other Constraints				\$3.8	(\$18.9)	\$2.9	\$25.7	(\$0.3)	\$2.6	(\$5.5)	(\$8.4)	\$17.3	66,784	14,950
Total				\$18.2	(\$31.9)	\$3.7	\$53.7	\$0.5	\$3.9	(\$7.0)	(\$10.4)	\$43.3	82,957	21,611

BGE Control Zone

Table F-5 BGE Control Zone top congestion cost impacts (By facility): 2019

Congestion Costs (Millions)														
No.	Constraint	Type	Location	Day-Ahead				Balancing				Event Hours		
				Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Grand Total	Day-Ahead	Real-Time
1	Conastone - Peach Bottom	Line	500	\$6.1	(\$0.2)	(\$0.0)	\$6.3	\$0.2	\$0.3	\$0.2	\$0.0	\$6.3	4,999	3,250
2	Conastone	Other	500	\$1.0	(\$0.0)	\$0.0	\$1.0	(\$0.1)	(\$0.2)	(\$0.0)	\$0.1	\$1.1	255	229
3	Conastone - Northwest	Line	BGE	\$0.7	(\$0.4)	\$0.0	\$1.1	\$0.0	(\$0.0)	(\$0.0)	(\$0.0)	\$1.1	289	29
4	Face Rock	Other	PPL	\$0.0	(\$1.0)	\$0.1	\$1.1	\$0.1	\$0.1	\$0.0	(\$0.1)	\$1.0	2,552	484
5	Bagley - Graceton	Line	BGE	\$0.6	(\$0.2)	\$0.0	\$0.8	\$0.0	\$0.0	\$0.0	\$0.0	\$0.8	826	126
6	Graceton - Safe Harbor	Line	BGE	\$0.8	\$0.0	\$0.0	\$0.8	\$0.0	\$0.1	\$0.0	(\$0.0)	\$0.8	1,631	563
7	AP South	Interface	500	\$0.5	(\$0.3)	(\$0.0)	\$0.8	\$0.0	\$0.0	\$0.0	(\$0.0)	\$0.8	178	31
8	Tanners Creek - Miami Fort	Flowgate	MISO	(\$0.3)	(\$1.0)	\$0.0	\$0.7	\$0.0	\$0.0	\$0.0	\$0.0	\$0.7	882	0
9	Gardners - Texas Eastern	Line	Met-Ed	\$0.0	(\$0.6)	\$0.0	\$0.6	(\$0.0)	\$0.0	(\$0.0)	(\$0.1)	\$0.5	1,787	131
10	Coolspring - Milford	Line	DPL	(\$0.1)	(\$0.6)	\$0.0	\$0.5	(\$0.0)	(\$0.0)	(\$0.0)	(\$0.0)	\$0.5	463	42
11	Roxana - Praxair	Flowgate	MISO	(\$0.0)	(\$0.2)	\$0.1	\$0.2	\$0.1	\$0.1	(\$0.7)	(\$0.7)	(\$0.5)	1,274	603
12	Nottingham	Other	PECO	\$0.6	\$0.1	(\$0.0)	\$0.4	\$0.0	\$0.0	\$0.0	\$0.0	\$0.4	809	468
13	Hazelwood Tap - Windy Edge	Line	BGE	\$0.0	\$0.0	\$0.0	\$0.0	(\$0.2)	\$0.1	(\$0.1)	(\$0.4)	(\$0.4)	0	15
14	BCPEP	Interface	Pepco	\$0.2	(\$0.1)	\$0.0	\$0.4	\$0.0	\$0.0	\$0.0	\$0.0	\$0.4	79	0
15	Palisades - Argenta	Flowgate	MISO	(\$0.0)	(\$0.4)	\$0.0	\$0.4	\$0.0	(\$0.0)	(\$0.0)	(\$0.0)	\$0.4	738	91
16	CPL - DOM	Interface	500	\$0.2	(\$0.2)	\$0.0	\$0.4	\$0.0	\$0.0	\$0.0	\$0.0	\$0.4	112	0
17	PA Central	Interface	500	\$0.0	(\$0.4)	\$0.0	\$0.5	\$0.0	\$0.1	(\$0.0)	(\$0.1)	\$0.3	872	665
18	Pleasant View - Ashburn	Line	Dominion	\$0.3	(\$0.1)	\$0.0	\$0.4	\$0.0	\$0.0	(\$0.0)	(\$0.0)	\$0.3	339	70
19	East	Interface	500	(\$0.2)	(\$0.6)	\$0.0	\$0.4	\$0.0	\$0.1	\$0.0	(\$0.1)	\$0.3	113	16
20	Riverside	Line	BGE	\$0.1	(\$0.2)	\$0.0	\$0.3	\$0.0	\$0.0	(\$0.0)	(\$0.0)	\$0.3	426	18
Top 20 Total				\$10.5	(\$6.2)	\$0.3	\$17.0	\$0.2	\$0.9	(\$0.7)	(\$1.4)	\$15.6	18,624	6,831
All Other Constraints				\$0.1	(\$7.6)	\$0.9	\$8.6	(\$0.1)	\$1.3	(\$2.7)	(\$4.0)	\$4.6	60,114	14,764
Total				\$10.6	(\$13.8)	\$1.2	\$25.7	\$0.1	\$2.2	(\$3.4)	(\$5.4)	\$20.2	78,738	21,595

ComEd Control Zone

Table F-6 ComEd Control Zone top congestion cost impacts (By facility): 2019

Congestion Costs (Millions)														
No.	Constraint	Type	Location	Day-Ahead				Balancing				Event Hours		
				Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Grand Total	Day-Ahead	Real-Time
1	Conastone - Peach Bottom	Line	500	\$15.3	(\$0.3)	\$0.0	\$15.6	\$0.5	\$0.8	\$0.4	\$0.1	\$15.7	4,999	3,250
2	Quad Cities	Transformer	ComEd	(\$0.7)	(\$3.4)	\$0.3	\$3.0	\$0.0	\$0.0	\$0.0	\$0.0	\$3.0	891	0
3	Powerton - Toulon	Line	ComEd	(\$4.4)	(\$5.4)	\$1.9	\$3.0	\$0.0	(\$0.0)	(\$0.0)	\$0.0	\$3.0	845	78
4	Conastone	Other	500	\$2.1	(\$0.1)	\$0.0	\$2.2	(\$0.1)	(\$0.5)	(\$0.1)	\$0.2	\$2.5	255	229
5	Marblehead	Flowgate	MISO	(\$1.2)	(\$3.2)	\$0.5	\$2.6	(\$0.1)	(\$0.0)	(\$0.2)	(\$0.3)	\$2.2	1,760	1,103
6	New Carlisle - Olive	Line	AEP	\$1.8	\$1.2	\$1.6	\$2.2	\$0.0	\$0.0	\$0.0	\$0.0	\$2.2	1,080	0
7	Graceton - Safe Harbor	Line	BGE	\$2.0	\$0.0	\$0.0	\$2.0	\$0.1	\$0.1	\$0.0	(\$0.0)	\$1.9	1,631	563
8	Tanners Creek - Miami Fort	Flowgate	MISO	(\$0.7)	(\$2.6)	\$0.0	\$1.9	\$0.0	\$0.0	\$0.0	\$0.0	\$1.9	882	0
9	Bosserman - New Carlisle	Line	AEP	\$2.6	\$2.3	\$1.4	\$1.6	\$0.0	\$0.0	\$0.0	(\$0.0)	\$1.6	1,009	4
10	Tollway	Transformer	ComEd	\$0.1	(\$1.3)	\$0.1	\$1.5	\$0.0	(\$0.0)	\$0.1	\$0.1	\$1.6	174	15
11	Fisk	Transformer	ComEd	\$2.5	\$1.9	(\$0.8)	(\$0.2)	(\$2.3)	(\$0.4)	\$0.6	(\$1.3)	(\$1.5)	767	81
12	Coolspring - Milford	Line	DPL	(\$0.3)	(\$1.8)	\$0.0	\$1.5	(\$0.0)	(\$0.1)	(\$0.1)	(\$0.0)	\$1.5	463	42
13	Silver lake	Transformer	ComEd	\$0.3	(\$1.1)	\$0.1	\$1.4	\$0.0	\$0.0	\$0.0	\$0.0	\$1.4	107	0
14	Edison - Olive	Line	AEP	(\$0.5)	(\$1.8)	\$0.1	\$1.4	\$0.0	\$0.0	\$0.0	\$0.0	\$1.4	124	0
15	State Line	Transformer	ComEd	(\$0.7)	(\$1.4)	\$0.7	\$1.4	\$0.0	(\$0.0)	(\$0.0)	(\$0.0)	\$1.4	277	17
16	Roxana - Praxair	Flowgate	MISO	(\$0.1)	(\$0.4)	\$0.3	\$0.6	\$0.9	\$1.2	(\$1.7)	(\$2.0)	(\$1.4)	1,274	603
17	AP South	Interface	500	\$0.8	(\$0.5)	(\$0.0)	\$1.3	\$0.0	\$0.0	\$0.0	(\$0.0)	\$1.3	178	31
18	Logtown - North Delphos	Line	AEP	(\$2.1)	(\$3.1)	\$0.2	\$1.3	\$0.0	(\$0.0)	(\$0.0)	(\$0.0)	\$1.3	617	13
19	Nottingham	Other	PECO	\$1.6	\$0.3	(\$0.0)	\$1.3	\$0.0	\$0.0	\$0.0	\$0.0	\$1.3	809	468
20	Bagley - Graceton	Line	BGE	\$1.0	(\$0.2)	\$0.0	\$1.2	\$0.0	\$0.1	\$0.0	\$0.0	\$1.3	826	126
Top 20 Total				\$19.4	(\$21.1)	\$6.4	\$47.0	(\$0.9)	\$1.3	(\$1.1)	(\$3.3)	\$43.7	18,968	6,623
All Other Constraints				\$1.7	(\$39.2)	\$6.7	\$47.6	(\$0.1)	\$4.6	(\$6.2)	(\$10.9)	\$36.7	65,426	14,969
Total				\$21.1	(\$60.4)	\$13.2	\$94.6	(\$1.1)	\$5.9	(\$7.3)	(\$14.3)	\$80.3	84,394	21,592

DAY Control Zone

Table F-7 DAY Control Zone top congestion cost impacts (By facility): 2019

Congestion Costs (Millions)														
No.	Constraint	Type	Location	Day-Ahead				Balancing				Event Hours		
				Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Grand Total	Day-Ahead	Real-Time
1	Conastone - Peach Bottom	Line	500	\$2.8	(\$0.1)	\$0.0	\$2.8	\$0.1	\$0.1	\$0.1	\$0.0	\$2.8	4,999	3,250
2	Tanners Creek - Miami Fort	Flowgate	MISO	(\$0.2)	(\$0.7)	\$0.0	\$0.5	\$0.0	\$0.0	\$0.0	\$0.0	\$0.5	882	0
3	Conastone	Other	500	\$0.4	(\$0.0)	\$0.0	\$0.5	(\$0.0)	(\$0.1)	(\$0.0)	\$0.0	\$0.5	255	229
4	Graceton - Safe Harbor	Line	BGE	\$0.4	\$0.0	\$0.0	\$0.4	\$0.0	\$0.0	\$0.0	(\$0.0)	\$0.3	1,631	563
5	Roxana - Praxair	Flowgate	MISO	(\$0.0)	(\$0.1)	\$0.1	\$0.1	\$0.1	\$0.1	(\$0.4)	(\$0.5)	(\$0.3)	1,274	603
6	Miami Fort - Willey	Line	DEOK	\$0.2	(\$0.0)	\$0.1	\$0.3	\$0.0	\$0.0	\$0.0	\$0.0	\$0.3	466	0
7	AP South	Interface	500	\$0.2	(\$0.1)	(\$0.0)	\$0.3	\$0.0	\$0.0	\$0.0	(\$0.0)	\$0.3	178	31
8	Logtown - North Delphos	Line	AEP	(\$0.4)	(\$0.6)	\$0.0	\$0.3	\$0.0	(\$0.0)	(\$0.0)	(\$0.0)	\$0.3	617	13
9	Coolspring - Milford	Line	DPL	(\$0.1)	(\$0.3)	\$0.0	\$0.3	(\$0.0)	(\$0.0)	(\$0.0)	(\$0.0)	\$0.3	463	42
10	Bagley - Graceton	Line	BGE	\$0.2	(\$0.0)	\$0.0	\$0.2	\$0.0	\$0.0	\$0.0	\$0.0	\$0.2	826	126
11	Nottingham	Other	PECO	\$0.3	\$0.1	(\$0.0)	\$0.2	\$0.0	\$0.0	\$0.0	\$0.0	\$0.2	809	468
12	Conastone - Northwest	Line	BGE	\$0.2	(\$0.1)	\$0.0	\$0.2	\$0.0	(\$0.0)	(\$0.0)	(\$0.0)	\$0.2	289	29
13	PA Central	Interface	500	\$0.0	(\$0.2)	\$0.0	\$0.3	\$0.0	\$0.1	(\$0.0)	(\$0.1)	\$0.2	872	665
14	Palisades - Argenta	Flowgate	MISO	(\$0.0)	(\$0.2)	\$0.0	\$0.2	(\$0.0)	(\$0.0)	(\$0.0)	(\$0.0)	\$0.2	738	91
15	Grant - Greentown	Line	AEP	\$0.0	(\$0.2)	\$0.0	\$0.2	(\$0.0)	(\$0.0)	\$0.0	\$0.0	\$0.2	762	3
16	Lakin - Sporn	Line	AEP	\$0.2	\$0.0	\$0.0	\$0.2	(\$0.0)	(\$0.0)	(\$0.0)	(\$0.0)	\$0.2	366	10
17	East	Interface	500	(\$0.1)	(\$0.3)	\$0.0	\$0.2	\$0.0	\$0.1	\$0.0	(\$0.0)	\$0.2	113	16
18	Tanners Creek - Miami Fort	Line	AEP	(\$0.0)	(\$0.0)	\$0.0	\$0.0	(\$0.0)	\$0.0	(\$0.1)	(\$0.2)	(\$0.2)	11	280
19	Pierce Duke (DEOK) - Pierce (OVEC)	Line	DEOK	\$0.1	(\$0.0)	\$0.0	\$0.2	\$0.0	\$0.0	\$0.0	\$0.0	\$0.2	556	0
20	Smithton - Yukon	Line	APS	(\$0.1)	(\$0.2)	\$0.0	\$0.2	\$0.0	\$0.0	(\$0.0)	(\$0.0)	\$0.2	296	81
Top 20 Total				\$4.1	(\$3.0)	\$0.3	\$7.5	\$0.2	\$0.4	(\$0.6)	(\$0.7)	\$6.7	16,403	6,500
All Other Constraints				\$1.0	(\$5.0)	\$0.8	\$6.9	(\$0.1)	\$0.8	(\$1.4)	(\$2.2)	\$4.6	67,168	15,092
Total				\$5.1	(\$8.1)	\$1.2	\$14.3	\$0.1	\$1.1	(\$2.0)	(\$3.0)	\$11.4	83,571	21,592

DEOK Control Zone

Table F-8 DEOK Control Zone top congestion cost impacts (By facility): 2019

Congestion Costs (Millions)														
No.	Constraint	Type	Location	Day-Ahead				Balancing				Event Hours		
				Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Grand Total	Day-Ahead	Real-Time
1	Conastone - Peach Bottom	Line	500	\$4.4	(\$0.1)	\$0.0	\$4.5	\$0.1	\$0.2	\$0.1	\$0.0	\$4.5	4,999	3,250
2	Tanners Creek - Miami Fort	Flowgate	MISO	(\$0.3)	(\$1.2)	\$0.0	\$0.9	\$0.0	\$0.0	\$0.0	\$0.0	\$0.9	882	0
3	Conastone	Other	500	\$0.7	(\$0.0)	\$0.0	\$0.8	(\$0.0)	(\$0.1)	(\$0.0)	\$0.1	\$0.8	255	229
4	Miami Fort - Hebron	Line	DEOK	\$0.5	(\$0.1)	\$0.0	\$0.6	\$0.0	\$0.0	\$0.0	\$0.0	\$0.6	113	0
5	Pierce Duke (DEOK) - Pierce (OVEC)	Line	DEOK	\$0.5	(\$0.0)	\$0.1	\$0.6	\$0.0	\$0.0	\$0.0	\$0.0	\$0.6	556	0
6	Miami Fort - Willey	Line	DEOK	\$0.5	(\$0.0)	\$0.1	\$0.6	\$0.0	\$0.0	\$0.0	\$0.0	\$0.6	466	0
7	Graceton - Safe Harbor	Line	BGE	\$0.6	\$0.0	\$0.0	\$0.6	\$0.0	\$0.0	\$0.0	(\$0.0)	\$0.5	1,631	563
8	Coolspring - Milford	Line	DPL	(\$0.1)	(\$0.5)	\$0.0	\$0.4	(\$0.0)	(\$0.0)	(\$0.0)	(\$0.0)	\$0.4	463	42
9	Roxana - Praxair	Flowgate	MISO	(\$0.0)	(\$0.1)	\$0.1	\$0.2	\$0.1	\$0.1	(\$0.6)	(\$0.6)	(\$0.4)	1,274	603
10	AP South	Interface	500	\$0.3	(\$0.2)	(\$0.0)	\$0.4	\$0.0	\$0.0	\$0.0	(\$0.0)	\$0.4	178	31
11	Bagley - Graceton	Line	BGE	\$0.3	(\$0.1)	\$0.0	\$0.4	\$0.0	\$0.0	\$0.0	\$0.0	\$0.4	826	126
12	Conastone - Northwest	Line	BGE	\$0.3	(\$0.1)	\$0.0	\$0.4	\$0.0	(\$0.0)	(\$0.0)	(\$0.0)	\$0.4	289	29
13	Nottingham	Other	PECO	\$0.4	\$0.1	(\$0.0)	\$0.3	\$0.0	\$0.0	\$0.0	\$0.0	\$0.3	809	468
14	Grant - Greentown	Line	AEP	\$0.0	(\$0.3)	\$0.1	\$0.3	(\$0.0)	(\$0.0)	\$0.0	\$0.0	\$0.3	762	3
15	Tanners Creek - Miami Fort	Line	AEP	(\$0.0)	(\$0.0)	\$0.0	\$0.0	(\$0.0)	\$0.1	(\$0.2)	(\$0.3)	(\$0.3)	11	280
16	PA Central	Interface	500	\$0.0	(\$0.3)	\$0.0	\$0.4	\$0.0	\$0.1	(\$0.0)	(\$0.1)	\$0.3	872	665
17	East	Interface	500	(\$0.1)	(\$0.5)	\$0.0	\$0.3	\$0.0	\$0.1	\$0.0	(\$0.1)	\$0.3	113	16
18	Palisades - Argenta	Flowgate	MISO	(\$0.0)	(\$0.3)	\$0.0	\$0.3	(\$0.0)	(\$0.0)	(\$0.0)	(\$0.0)	\$0.3	738	91
19	Hazard	Transformer	AEP	\$0.0	(\$0.2)	\$0.0	\$0.3	\$0.0	\$0.0	\$0.0	\$0.0	\$0.3	778	0
20	Greentown	Flowgate	MISO	(\$0.0)	(\$0.1)	(\$0.0)	\$0.1	(\$0.0)	\$0.0	(\$0.3)	(\$0.3)	(\$0.3)	111	51
Top 20 Total				\$7.8	(\$4.0)	\$0.6	\$12.4	\$0.2	\$0.6	(\$1.1)	(\$1.4)	\$11.0	16,126	6,447
All Other Constraints				\$1.2	(\$7.8)	\$1.3	\$10.3	(\$0.0)	\$1.2	(\$2.0)	(\$3.2)	\$7.1	65,375	15,145
Total				\$9.1	(\$11.8)	\$1.9	\$22.7	\$0.2	\$1.7	(\$3.1)	(\$4.6)	\$18.1	81,501	21,592

DLCO Control Zone

Table F-9 DLCO Control Zone top congestion cost impacts (By facility): 2019

Congestion Costs (Millions)														
No.	Constraint	Type	Location	Day-Ahead				Balancing				Event Hours		
				Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Grand Total	Day-Ahead	Real-Time
1	Conastone - Peach Bottom	Line	500	\$2.1	(\$0.0)	\$0.0	\$2.1	\$0.1	\$0.1	\$0.1	\$0.0	\$2.1	4,999	3,250
2	Conastone	Other	500	\$0.3	(\$0.0)	\$0.0	\$0.3	(\$0.0)	(\$0.1)	(\$0.0)	\$0.0	\$0.4	255	229
3	Tanners Creek - Miami Fort	Flowgate	MISO	(\$0.1)	(\$0.4)	\$0.0	\$0.3	\$0.0	\$0.0	\$0.0	\$0.0	\$0.3	882	0
4	Wescosville	Transformer	PPL	\$0.1	(\$0.1)	(\$0.0)	\$0.3	(\$0.0)	\$0.0	(\$0.0)	(\$0.0)	\$0.3	401	164
5	Coolspring - Milford	Line	DPL	(\$0.1)	(\$0.3)	\$0.0	\$0.2	(\$0.0)	(\$0.0)	(\$0.0)	(\$0.0)	\$0.2	463	42
6	Smithton - Yukon	Line	APS	(\$0.1)	(\$0.3)	\$0.0	\$0.2	\$0.0	\$0.0	(\$0.0)	(\$0.0)	\$0.2	296	81
7	Graceton - Safe Harbor	Line	BGE	\$0.2	\$0.0	\$0.0	\$0.2	\$0.0	\$0.0	\$0.0	(\$0.0)	\$0.2	1,631	563
8	Roxana - Praxair	Flowgate	MISO	(\$0.0)	(\$0.1)	\$0.1	\$0.1	\$0.1	\$0.1	(\$0.3)	(\$0.3)	(\$0.2)	1,274	603
9	Nottingham	Other	PECO	\$0.2	\$0.0	(\$0.0)	\$0.2	\$0.0	\$0.0	\$0.0	\$0.0	\$0.2	809	468
10	Pleasant View - Ashburn	Line	Dominion	\$0.1	(\$0.0)	\$0.0	\$0.2	\$0.0	\$0.0	(\$0.0)	(\$0.0)	\$0.2	339	70
11	AP South	Interface	500	\$0.1	(\$0.1)	(\$0.0)	\$0.2	\$0.0	\$0.0	\$0.0	(\$0.0)	\$0.2	178	31
12	Palisades - Argenta	Flowgate	MISO	(\$0.0)	(\$0.2)	\$0.0	\$0.2	(\$0.0)	(\$0.0)	(\$0.0)	(\$0.0)	\$0.2	738	91
13	PA Central	Interface	500	\$0.0	(\$0.2)	\$0.0	\$0.2	\$0.0	\$0.0	(\$0.0)	(\$0.0)	\$0.2	872	665
14	East	Interface	500	(\$0.1)	(\$0.2)	\$0.0	\$0.2	\$0.0	\$0.0	\$0.0	(\$0.0)	\$0.1	113	16
15	CPL - DOM	Interface	500	\$0.1	(\$0.1)	\$0.0	\$0.1	\$0.0	\$0.0	\$0.0	\$0.0	\$0.1	112	0
16	Tanners Creek - Miami Fort	Line	AEP	(\$0.0)	(\$0.0)	\$0.0	\$0.0	(\$0.0)	\$0.0	(\$0.1)	(\$0.1)	(\$0.1)	11	280
17	Keystone	Other	500	(\$0.0)	(\$0.1)	\$0.0	\$0.1	(\$0.0)	(\$0.0)	(\$0.0)	\$0.0	\$0.1	299	163
18	Cedar Creek - Red Lion	Line	DPL	(\$0.0)	(\$0.1)	\$0.0	\$0.1	(\$0.0)	(\$0.0)	(\$0.0)	(\$0.0)	\$0.1	780	57
19	Ebersole - Fostoria	Line	AEP	\$0.0	(\$0.1)	\$0.0	\$0.1	\$0.0	\$0.0	\$0.0	\$0.0	\$0.1	122	0
20	Siegfried	Transformer	PPL	\$0.0	\$0.0	\$0.0	\$0.0	(\$0.0)	\$0.1	(\$0.0)	(\$0.1)	(\$0.1)	562	310
Top 20 Total				\$2.9	(\$2.2)	\$0.1	\$5.3	\$0.1	\$0.4	(\$0.4)	(\$0.6)	\$4.7	15,136	7,083
All Other Constraints				\$0.0	(\$2.8)	\$0.4	\$3.2	(\$0.0)	\$0.4	(\$1.0)	(\$1.5)	\$1.7	63,124	14,498
Total				\$2.9	(\$5.0)	\$0.5	\$8.5	\$0.1	\$0.8	(\$1.4)	(\$2.1)	\$6.4	78,260	21,581

Dominion Control Zone

Table F-10 Dominion Control Zone top congestion cost impacts (By facility): 2019

Congestion Costs (Millions)														
No.	Constraint	Type	Location	Day-Ahead				Balancing				Event Hours		
				Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Grand Total	Day-Ahead	Real-Time
1	Conastone - Peach Bottom	Line	500	\$18.3	(\$0.4)	(\$0.0)	\$18.7	\$0.6	\$1.1	\$0.5	\$0.0	\$18.7	4,999	3,250
2	Conastone	Other	500	\$3.0	(\$0.1)	\$0.1	\$3.2	(\$0.2)	(\$0.5)	(\$0.1)	\$0.2	\$3.4	255	229
3	Face Rock	Other	PPL	\$0.1	(\$3.1)	\$0.2	\$3.4	\$0.2	\$0.4	\$0.0	(\$0.2)	\$3.2	2,552	484
4	AP South	Interface	500	\$1.8	(\$1.1)	(\$0.0)	\$2.8	\$0.0	\$0.1	\$0.0	(\$0.0)	\$2.8	178	31
5	Prince George	Transformer	Dominion	(\$2.7)	(\$5.5)	\$0.0	\$2.9	(\$0.0)	\$0.0	\$0.0	(\$0.0)	\$2.8	392	197
6	Tanners Creek - Miami Fort	Flowgate	MISO	(\$0.9)	(\$3.1)	\$0.0	\$2.3	\$0.0	\$0.0	\$0.0	\$0.0	\$2.3	882	0
7	Graceton - Safe Harbor	Line	BGE	\$2.3	\$0.1	\$0.0	\$2.3	\$0.1	\$0.2	\$0.1	(\$0.0)	\$2.2	1,631	563
8	Conastone - Northwest	Line	BGE	\$1.5	(\$0.7)	\$0.1	\$2.2	\$0.0	(\$0.0)	(\$0.1)	(\$0.1)	\$2.2	289	29
9	Pleasant View - Ashburn	Line	Dominion	\$1.8	(\$0.5)	\$0.1	\$2.3	\$0.2	\$0.3	(\$0.0)	(\$0.1)	\$2.2	339	70
10	Bagley - Graceton	Line	BGE	\$1.3	(\$0.4)	\$0.0	\$1.8	\$0.0	\$0.1	\$0.1	\$0.0	\$1.8	826	126
11	Wescosville	Transformer	PPL	\$1.0	(\$1.0)	(\$0.0)	\$2.0	(\$0.0)	\$0.3	(\$0.1)	(\$0.3)	\$1.6	401	164
12	Coolspring - Milford	Line	DPL	(\$0.4)	(\$2.0)	\$0.0	\$1.7	(\$0.0)	(\$0.1)	(\$0.1)	(\$0.0)	\$1.6	463	42
13	Roxana - Praxair	Flowgate	MISO	(\$0.2)	(\$0.5)	\$0.4	\$0.7	\$0.4	\$0.5	(\$2.1)	(\$2.2)	(\$1.4)	1,274	603
14	Nottingham	Other	PECO	\$1.8	\$0.4	(\$0.0)	\$1.4	\$0.0	\$0.0	\$0.0	\$0.0	\$1.4	809	468
15	CPL - DOM	Interface	500	\$0.6	(\$0.7)	\$0.0	\$1.4	\$0.0	\$0.0	\$0.0	\$0.0	\$1.4	112	0
16	Gardners - Texas Eastern	Line	Met-Ed	(\$0.7)	(\$2.1)	\$0.0	\$1.5	(\$0.1)	\$0.0	(\$0.0)	(\$0.2)	\$1.3	1,787	131
17	Palisades - Argenta	Flowgate	MISO	(\$0.0)	(\$1.3)	\$0.1	\$1.3	\$0.0	(\$0.0)	(\$0.1)	(\$0.1)	\$1.2	738	91
18	PA Central	Interface	500	\$0.2	(\$1.3)	\$0.1	\$1.5	\$0.0	\$0.4	(\$0.0)	(\$0.4)	\$1.2	872	665
19	East	Interface	500	(\$0.5)	(\$1.8)	\$0.0	\$1.3	\$0.1	\$0.4	\$0.1	(\$0.2)	\$1.1	113	16
20	Siegfried	Transformer	PPL	\$0.0	\$0.0	\$0.0	\$0.0	(\$0.2)	\$0.7	(\$0.0)	(\$0.9)	(\$0.9)	562	310
Top 20 Total				\$28.1	(\$25.2)	\$1.0	\$54.3	\$1.2	\$3.7	(\$2.0)	(\$4.5)	\$49.8	19,474	7,469
All Other Constraints				\$1.0	(\$26.0)	\$3.3	\$30.3	(\$0.0)	\$3.1	(\$8.6)	(\$11.7)	\$18.6	59,581	14,127
Total				\$29.1	(\$51.3)	\$4.3	\$84.7	\$1.1	\$6.8	(\$10.6)	(\$16.2)	\$68.5	79,055	21,596

DPL Control Zone

Table F-11 DPL Control Zone top congestion cost impacts (By facility): 2019

Congestion Costs (Millions)														
No.	Constraint	Type	Location	Day-Ahead				Balancing				Event Hours		
				Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Grand Total	Day-Ahead	Real-Time
1	Loretto - Vienna	Line	DPL	\$5.4	\$1.2	\$0.6	\$4.8	(\$0.0)	(\$0.0)	(\$0.0)	(\$0.0)	\$4.8	526	30
2	Preston - Tanyard	Line	DPL	\$4.7	\$1.3	\$0.6	\$4.0	\$0.0	(\$0.0)	(\$0.0)	\$0.0	\$4.0	889	1
3	Coolspring - Milford	Line	DPL	\$1.2	(\$1.8)	\$0.1	\$3.0	(\$0.0)	(\$0.1)	(\$0.1)	(\$0.0)	\$3.0	463	42
4	Cedar Creek - Red Lion	Line	DPL	\$1.1	(\$1.5)	\$0.3	\$2.9	(\$0.2)	(\$0.1)	(\$0.2)	(\$0.3)	\$2.6	780	57
5	Siegfried	Transformer	PPL	\$0.5	(\$1.0)	\$0.0	\$1.5	(\$0.0)	\$0.1	(\$0.0)	(\$0.2)	\$1.4	562	310
6	Easton - Emuni	Line	DPL	\$0.9	\$0.3	\$0.3	\$0.9	(\$0.0)	\$0.0	\$0.1	\$0.1	\$1.0	4,833	9
7	Kent - Vaughn	Line	DPL	\$0.8	\$0.1	\$0.1	\$0.9	\$0.0	\$0.0	(\$0.0)	(\$0.0)	\$0.9	232	6
8	East	Interface	500	(\$0.4)	(\$1.4)	\$0.0	\$1.0	\$0.1	\$0.2	\$0.1	(\$0.1)	\$0.8	113	16
9	Cedar Creek - Clayton	Line	DPL	\$0.7	\$0.1	\$0.0	\$0.7	(\$0.0)	\$0.0	(\$0.0)	(\$0.0)	\$0.6	74	4
10	Conastone - Peach Bottom	Line	500	\$0.6	(\$0.0)	(\$0.0)	\$0.6	\$0.0	\$0.0	\$0.0	\$0.0	\$0.6	4,999	3,250
11	Face Rock	Other	PPL	\$0.0	(\$0.5)	\$0.0	\$0.6	\$0.0	\$0.1	\$0.0	(\$0.0)	\$0.5	2,552	484
12	Milford - Steele	Line	DPL	(\$0.1)	(\$0.6)	\$0.0	\$0.5	(\$0.0)	(\$0.0)	(\$0.0)	\$0.0	\$0.5	85	5
13	Tanners Creek - Miami Fort	Flowgate	MISO	(\$0.2)	(\$0.6)	\$0.0	\$0.4	\$0.0	\$0.0	\$0.0	\$0.0	\$0.4	882	0
14	Church - New Meredith	Line	DPL	\$0.5	\$0.2	\$0.1	\$0.4	\$0.0	\$0.0	\$0.0	\$0.0	\$0.4	174	0
15	AP South	Interface	500	\$0.3	(\$0.2)	(\$0.0)	\$0.4	\$0.0	\$0.0	\$0.0	(\$0.0)	\$0.4	178	31
16	Wescosville	Transformer	PPL	\$0.2	(\$0.2)	\$0.0	\$0.4	(\$0.0)	\$0.1	(\$0.0)	(\$0.1)	\$0.3	401	164
17	Graceton - Safe Harbor	Line	BGE	\$0.3	\$0.0	\$0.0	\$0.3	\$0.0	\$0.0	\$0.0	(\$0.0)	\$0.3	1,631	563
18	Roxana - Praxair	Flowgate	MISO	(\$0.0)	(\$0.1)	\$0.1	\$0.1	\$0.1	\$0.1	(\$0.4)	(\$0.4)	(\$0.3)	1,274	603
19	Gardners - Texas Eastern	Line	Met-Ed	(\$0.1)	(\$0.4)	\$0.0	\$0.3	(\$0.0)	\$0.0	(\$0.0)	(\$0.0)	\$0.2	1,787	131
20	Palisades - Argenta	Flowgate	MISO	(\$0.0)	(\$0.2)	\$0.0	\$0.3	\$0.0	(\$0.0)	(\$0.0)	(\$0.0)	\$0.2	738	91
Top 20 Total				\$16.4	(\$5.4)	\$2.2	\$24.0	(\$0.1)	\$0.5	(\$0.5)	(\$1.1)	\$22.8	23,173	5,797
All Other Constraints				\$1.4	(\$5.3)	\$0.7	\$7.4	\$0.2	\$0.7	(\$1.7)	(\$2.3)	\$5.1	56,880	15,786
Total				\$17.8	(\$10.7)	\$2.9	\$31.4	\$0.0	\$1.2	(\$2.3)	(\$3.4)	\$27.9	80,053	21,583

EKPC Control Zone

Table F-12 EKPC Control Zone top congestion cost impacts (By facility): 2019

Congestion Costs (Millions)														
No.	Constraint	Type	Location	Day-Ahead				Balancing				Event Hours		
				Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Grand Total	Day-Ahead	Real-Time
1	Conastone - Peach Bottom	Line	500	\$2.0	(\$0.1)	\$0.0	\$2.1	\$0.1	\$0.1	\$0.1	\$0.0	\$2.1	4,999	3,250
2	Conastone	Other	500	\$0.3	(\$0.0)	\$0.0	\$0.4	(\$0.0)	(\$0.1)	(\$0.0)	\$0.0	\$0.4	255	229
3	Tanners Creek - Miami Fort	Flowgate	MISO	(\$0.1)	(\$0.4)	\$0.0	\$0.3	\$0.0	\$0.0	\$0.0	\$0.0	\$0.3	882	0
4	AP South	Interface	500	\$0.2	(\$0.1)	(\$0.0)	\$0.3	\$0.0	\$0.0	\$0.0	(\$0.0)	\$0.3	178	31
5	Graceton - Safe Harbor	Line	BGE	\$0.3	\$0.0	\$0.0	\$0.3	\$0.0	\$0.0	\$0.0	(\$0.0)	\$0.3	1,631	563
6	Miami Fort - Hebron	Line	DEOK	\$0.2	(\$0.0)	\$0.0	\$0.3	\$0.0	\$0.0	\$0.0	\$0.0	\$0.3	113	0
7	Miami Fort - Willey	Line	DEOK	\$0.2	(\$0.0)	\$0.1	\$0.2	\$0.0	\$0.0	\$0.0	\$0.0	\$0.2	466	0
8	Conastone - Northwest	Line	BGE	\$0.1	(\$0.1)	\$0.0	\$0.2	\$0.0	(\$0.0)	(\$0.0)	(\$0.0)	\$0.2	289	29
9	Coolspring - Milford	Line	DPL	(\$0.0)	(\$0.2)	\$0.0	\$0.2	(\$0.0)	(\$0.0)	(\$0.0)	(\$0.0)	\$0.2	463	42
10	Bagley - Graceton	Line	BGE	\$0.1	(\$0.0)	\$0.0	\$0.2	\$0.0	\$0.0	\$0.0	\$0.0	\$0.2	826	126
11	East	Interface	500	(\$0.1)	(\$0.3)	\$0.0	\$0.2	\$0.0	\$0.1	\$0.0	(\$0.0)	\$0.2	113	16
12	Lakin - Sporn	Line	AEP	\$0.2	\$0.0	\$0.0	\$0.2	(\$0.0)	(\$0.0)	(\$0.0)	(\$0.0)	\$0.2	366	10
13	Nottingham	Other	PECO	\$0.2	\$0.0	(\$0.0)	\$0.2	\$0.0	\$0.0	\$0.0	\$0.0	\$0.2	809	468
14	Roxana - Praxair	Flowgate	MISO	(\$0.0)	(\$0.1)	\$0.0	\$0.1	\$0.0	\$0.1	(\$0.2)	(\$0.3)	(\$0.2)	1,274	603
15	Hazard	Transformer	AEP	\$0.0	(\$0.1)	\$0.0	\$0.2	\$0.0	\$0.0	\$0.0	\$0.0	\$0.2	778	0
16	Palisades - Argenta	Flowgate	MISO	(\$0.0)	(\$0.2)	\$0.0	\$0.2	\$0.0	(\$0.0)	(\$0.0)	(\$0.0)	\$0.2	738	91
17	PA Central	Interface	500	\$0.0	(\$0.2)	\$0.0	\$0.2	\$0.0	\$0.0	(\$0.0)	(\$0.0)	\$0.2	872	665
18	Grant - Greentown	Line	AEP	\$0.0	(\$0.1)	\$0.0	\$0.2	(\$0.0)	(\$0.0)	\$0.0	\$0.0	\$0.2	762	3
19	Bellefonte	Transformer	AEP	\$0.2	\$0.0	(\$0.0)	\$0.2	(\$0.0)	\$0.0	(\$0.0)	(\$0.0)	\$0.2	578	49
20	CPL - DOM	Interface	500	\$0.1	(\$0.1)	\$0.0	\$0.1	\$0.0	\$0.0	\$0.0	\$0.0	\$0.1	112	0
Top 20 Total				\$3.9	(\$1.9)	\$0.2	\$6.1	\$0.1	\$0.3	(\$0.2)	(\$0.4)	\$5.7	16,504	6,175
All Other Constraints				\$0.2	(\$4.1)	\$0.6	\$5.0	(\$0.0)	\$0.6	(\$1.2)	(\$1.8)	\$3.2	65,100	15,417
Total				\$4.1	(\$6.1)	\$0.8	\$11.0	\$0.1	\$0.9	(\$1.4)	(\$2.1)	\$8.9	81,604	21,592

JCPL Control Zone

Table F-13 JCPL Control Zone top congestion cost impacts (By facility): 2019

Congestion Costs (Millions)														
No.	Constraint	Type	Location	Day-Ahead				Balancing				Event Hours		
				Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Grand Total	Day-Ahead	Real-Time
1	Siegfried	Transformer	PPL	\$0.6	(\$1.3)	\$0.0	\$2.0	(\$0.0)	\$0.1	(\$0.0)	(\$0.2)	\$1.8	562	310
2	Conastone - Peach Bottom	Line	500	\$1.2	(\$0.0)	(\$0.0)	\$1.3	\$0.0	\$0.1	\$0.0	\$0.0	\$1.3	4,999	3,250
3	Wescosville	Transformer	PPL	\$0.7	(\$0.4)	\$0.0	\$1.1	(\$0.0)	\$0.1	(\$0.0)	(\$0.1)	\$1.0	401	164
4	Monroe - Vineland	Line	AECO	\$1.1	\$0.4	\$0.2	\$0.9	(\$0.0)	(\$0.0)	(\$0.0)	(\$0.0)	\$0.9	4,560	108
5	East	Interface	500	(\$0.4)	(\$1.3)	\$0.0	\$0.9	\$0.1	\$0.2	\$0.1	(\$0.1)	\$0.8	113	16
6	Face Rock	Other	PPL	\$0.0	(\$0.6)	\$0.0	\$0.7	\$0.0	\$0.1	\$0.0	(\$0.0)	\$0.7	2,552	484
7	Coolspring - Milford	Line	DPL	\$0.0	(\$0.5)	\$0.0	\$0.5	(\$0.0)	(\$0.0)	(\$0.0)	(\$0.0)	\$0.5	463	42
8	Tanners Creek - Miami Fort	Flowgate	MISO	(\$0.2)	(\$0.7)	\$0.0	\$0.5	\$0.0	\$0.0	\$0.0	\$0.0	\$0.5	882	0
9	Bloomington - Paupack	Line	PPL	\$0.2	(\$0.3)	\$0.0	\$0.5	\$0.0	\$0.0	\$0.0	\$0.0	\$0.5	97	0
10	Harwood - Susquehanna	Line	PPL	\$0.0	(\$0.4)	\$0.0	\$0.5	\$0.0	\$0.0	\$0.0	\$0.0	\$0.5	252	0
11	AP South	Interface	500	\$0.2	(\$0.2)	(\$0.0)	\$0.4	\$0.0	\$0.0	\$0.0	(\$0.0)	\$0.4	178	31
12	Cedar Creek - Red Lion	Line	DPL	\$0.2	(\$0.2)	\$0.0	\$0.4	(\$0.0)	(\$0.0)	(\$0.0)	(\$0.0)	\$0.4	780	57
13	Graceton - Safe Harbor	Line	BGE	\$0.4	\$0.0	\$0.0	\$0.3	\$0.0	\$0.0	\$0.0	(\$0.0)	\$0.3	1,631	563
14	Roxana - Praxair	Flowgate	MISO	(\$0.0)	(\$0.1)	\$0.1	\$0.2	\$0.1	\$0.1	(\$0.5)	(\$0.5)	(\$0.3)	1,274	603
15	Gardners - Texas Eastern	Line	Met-Ed	(\$0.1)	(\$0.4)	\$0.0	\$0.3	(\$0.0)	\$0.0	(\$0.0)	(\$0.0)	\$0.3	1,787	131
16	Palisades - Argenta	Flowgate	MISO	(\$0.0)	(\$0.3)	\$0.0	\$0.3	\$0.0	(\$0.0)	(\$0.0)	(\$0.0)	\$0.3	738	91
17	Pleasant View - Ashburn	Line	Dominion	\$0.2	(\$0.1)	\$0.0	\$0.3	\$0.0	\$0.0	(\$0.0)	(\$0.0)	\$0.3	339	70
18	PA Central	Interface	500	\$0.0	(\$0.3)	\$0.0	\$0.3	\$0.0	\$0.1	(\$0.0)	(\$0.1)	\$0.2	872	665
19	Lenox - North Meshoppen	Line	PENELEC	(\$0.1)	(\$0.4)	\$0.0	\$0.3	\$0.0	\$0.1	\$0.0	(\$0.1)	\$0.2	569	757
20	Frackville - Siegfried	Line	PPL	\$0.0	(\$0.2)	(\$0.0)	\$0.2	\$0.0	\$0.0	\$0.0	\$0.0	\$0.2	86	0
Top 20 Total				\$4.1	(\$7.4)	\$0.5	\$11.9	\$0.2	\$0.9	(\$0.5)	(\$1.2)	\$10.7	23,135	7,342
All Other Constraints				\$0.7	(\$6.2)	\$0.7	\$7.6	\$0.1	\$0.6	(\$1.9)	(\$2.4)	\$5.1	58,095	14,235
Total				\$4.7	(\$13.6)	\$1.2	\$19.5	\$0.2	\$1.5	(\$2.4)	(\$3.6)	\$15.9	81,230	21,577

Met-Ed Control Zone

Table F-14 Met-Ed Control Zone top congestion cost impacts (By facility): 2019

Congestion Costs (Millions)														
No.	Constraint	Type	Location	Day-Ahead				Balancing				Event Hours		
				Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Grand Total	Day-Ahead	Real-Time
1	Conastone - Peach Bottom	Line	500	\$1.5	(\$0.0)	(\$0.0)	\$1.5	\$0.0	\$0.1	\$0.0	\$0.0	\$1.5	4,999	3,250
2	Siegfried	Transformer	PPL	\$0.5	(\$1.0)	\$0.0	\$1.5	(\$0.0)	\$0.1	(\$0.0)	(\$0.1)	\$1.3	562	310
3	Boontown - South Reading	Line	Met-Ed	(\$0.0)	(\$0.9)	\$0.0	\$0.9	\$0.0	\$0.0	(\$0.0)	(\$0.0)	\$0.9	553	333
4	Gardners - Texas Eastern	Line	Met-Ed	\$0.6	(\$0.3)	\$0.0	\$0.9	(\$0.2)	(\$0.1)	(\$0.1)	(\$0.2)	\$0.7	1,787	131
5	Wescosville	Transformer	PPL	\$0.5	(\$0.3)	\$0.0	\$0.7	(\$0.0)	\$0.0	(\$0.0)	(\$0.1)	\$0.7	401	164
6	Ironwood - North Lebanon	Line	Met-Ed	(\$0.0)	(\$0.6)	(\$0.0)	\$0.6	\$0.0	\$0.0	\$0.0	\$0.0	\$0.6	189	0
7	Roxbury - Shade Gap	Line	PENELEC	\$0.0	(\$0.0)	\$0.0	\$0.1	(\$0.2)	\$0.1	(\$0.3)	(\$0.5)	(\$0.5)	217	27
8	Face Rock	Other	PPL	\$0.0	(\$0.4)	\$0.0	\$0.5	\$0.0	\$0.0	\$0.0	(\$0.0)	\$0.4	2,552	484
9	Tanners Creek - Miami Fort	Flowgate	MISO	(\$0.1)	(\$0.5)	\$0.0	\$0.3	\$0.0	\$0.0	\$0.0	\$0.0	\$0.3	882	0
10	Harwood - Susquehanna	Line	PPL	\$0.0	(\$0.3)	\$0.0	\$0.3	\$0.0	\$0.0	\$0.0	\$0.0	\$0.3	252	0
11	Blooming Grove - Paupack	Line	PPL	\$0.1	(\$0.2)	(\$0.0)	\$0.3	\$0.0	\$0.0	\$0.0	\$0.0	\$0.3	97	0
12	AP South	Interface	500	\$0.2	(\$0.1)	(\$0.0)	\$0.3	\$0.0	\$0.0	\$0.0	(\$0.0)	\$0.3	178	31
13	Bair - Jackson	Line	Met-Ed	\$0.3	\$0.1	\$0.0	\$0.3	\$0.0	\$0.0	\$0.0	\$0.0	\$0.3	83	0
14	East	Interface	500	(\$0.1)	(\$0.4)	\$0.0	\$0.3	\$0.0	\$0.1	\$0.0	(\$0.1)	\$0.3	113	16
15	Conastone	Other	500	\$0.2	(\$0.0)	\$0.0	\$0.2	(\$0.0)	(\$0.0)	(\$0.0)	\$0.0	\$0.2	255	229
16	Coolspring - Milford	Line	DPL	(\$0.0)	(\$0.3)	\$0.0	\$0.2	(\$0.0)	(\$0.0)	(\$0.0)	(\$0.0)	\$0.2	463	42
17	Roxana - Praxair	Flowgate	MISO	(\$0.0)	(\$0.1)	\$0.1	\$0.1	\$0.1	\$0.1	(\$0.3)	(\$0.3)	(\$0.2)	1,274	603
18	Gracetown - Safe Harbor	Line	BGE	\$0.2	\$0.0	\$0.0	\$0.2	\$0.0	\$0.0	\$0.0	(\$0.0)	\$0.2	1,631	563
19	Palisades - Argenta	Flowgate	MISO	(\$0.0)	(\$0.2)	\$0.0	\$0.2	\$0.0	(\$0.0)	(\$0.0)	(\$0.0)	\$0.2	738	91
20	Nottingham	Other	PECO	\$0.2	\$0.0	(\$0.0)	\$0.2	\$0.0	\$0.0	\$0.0	\$0.0	\$0.2	809	468
Top 20 Total				\$4.0	(\$5.6)	\$0.2	\$9.8	(\$0.2)	\$0.5	(\$0.7)	(\$1.4)	\$8.4	18,035	6,742
All Other Constraints				\$1.3	(\$4.6)	\$0.5	\$6.5	\$0.0	\$0.7	(\$1.3)	(\$1.9)	\$4.5	65,287	14,854
Total				\$5.3	(\$10.2)	\$0.7	\$16.3	(\$0.2)	\$1.1	(\$2.0)	(\$3.3)	\$13.0	83,322	21,596

OVEC Control Zone

Table F-15 OVEC Control Zone top congestion cost impacts (By facility): 2019⁴

Congestion Costs (Millions)														
No.	Constraint	Type	Location	Day-Ahead				Balancing				Event Hours		
				Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Grand Total	Day-Ahead	Real-Time
1	DoeX530	Transformer	OVEC	(\$0.0)	(\$0.0)	\$0.3	\$0.3	\$0.0	\$0.0	\$0.0	\$0.0	\$0.3	1,853	0
2	Roxana - Praxair	Flowgate	MISO	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	(\$0.0)	\$0.1	\$0.1	\$0.1	1,274	603
3	Ontario Hydro	Flowgate	EXT	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	42	64
4	Athenia - Fair Lawn	Line	PSEG	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	(\$0.0)	\$0.0	\$0.0	\$0.0	176	99
5	Fisk	Transformer	ComEd	(\$0.0)	(\$0.0)	\$0.0	\$0.0	(\$0.0)	(\$0.0)	(\$0.0)	(\$0.0)	\$0.0	767	81
6	Maywood - Saddlebrook	Line	PSEG	\$0.0	\$0.0	(\$0.0)	(\$0.0)	\$0.0	\$0.0	(\$0.0)	(\$0.0)	(\$0.0)	57	22
7	Gibson - Petersburg	Flowgate	MISO	\$0.0	\$0.0	\$0.0	\$0.0	(\$0.0)	(\$0.0)	(\$0.0)	(\$0.0)	(\$0.0)	95	75
8	Lallendorf - Monroe	Line	ATSI	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	0	45
9	Nelson - Garden Plain	Line	ComEd	\$0.0	\$0.0	\$0.0	\$0.0	(\$0.0)	\$0.0	(\$0.0)	(\$0.0)	(\$0.0)	2	46
10	Hillsdale - New Milford	Line	PSEG	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	0	13
11	Siegfried	Transformer	PPL	\$0.0	\$0.0	\$0.0	\$0.0	(\$0.0)	\$0.0	(\$0.0)	(\$0.0)	(\$0.0)	562	310
12	Greentown	Flowgate	MISO	\$0.0	\$0.0	\$0.0	\$0.0	(\$0.0)	\$0.0	(\$0.0)	(\$0.0)	(\$0.0)	111	51
13	Munster	Flowgate	MISO	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	(\$0.0)	(\$0.0)	(\$0.0)	(\$0.0)	709	171
14	Tanners Creek - Miami Fort	Line	AEP	\$0.0	\$0.0	\$0.0	\$0.0	(\$0.0)	\$0.0	(\$0.0)	(\$0.0)	(\$0.0)	11	280
15	Lenox - North Meshoppen	Line	PENELEC	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	(\$0.0)	(\$0.0)	569	757
16	Haviland	Other	AEP	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	(\$0.0)	(\$0.0)	(\$0.0)	290	255
17	Volunteer - Phipps Bend	Flowgate	TVA	\$0.0	\$0.0	\$0.0	\$0.0	(\$0.0)	\$0.0	(\$0.0)	(\$0.0)	(\$0.0)	27	54
18	Sub 85 - Rock Island	Flowgate	MISO	\$0.0	\$0.0	\$0.0	\$0.0	(\$0.0)	\$0.0	(\$0.0)	(\$0.0)	(\$0.0)	206	270
19	PA Central	Interface	500	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	(\$0.0)	(\$0.0)	(\$0.0)	872	665
20	Cedar Grove Sub - William	Line	PSEG	\$0.0	\$0.0	\$0.0	\$0.0	(\$0.0)	\$0.0	(\$0.0)	(\$0.0)	(\$0.0)	272	76
Top 20 Total				(\$0.0)	(\$0.0)	\$0.3	\$0.3	\$0.0	(\$0.0)	\$0.1	\$0.1	\$0.4	7,895	3,937
All Other Constraints				(\$0.0)	\$0.0	(\$0.0)	(\$0.0)	\$0.0	\$0.0	(\$0.0)	(\$0.0)	(\$0.0)	57,131	17,127
Total				(\$0.0)	(\$0.0)	\$0.3	\$0.3	\$0.0	\$0.0	\$0.1	\$0.1	\$0.4	65,026	21,064

4 In December 2018, PJM integrated the Ohio Valley Electric Corporation (OVEC)

PECO Control Zone

Table F-16 PECO Control Zone top congestion cost impacts (By facility): 2019

Congestion Costs (Millions)														
No.	Constraint	Type	Location	Day-Ahead				Balancing				Event Hours		
				Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Grand Total	Day-Ahead	Real-Time
1	Siegfried	Transformer	PPL	\$1.1	(\$2.3)	\$0.1	\$3.5	(\$0.1)	\$0.3	(\$0.0)	(\$0.3)	\$3.1	562	310
2	Conastone - Peach Bottom	Line	500	\$1.8	(\$0.0)	(\$0.0)	\$1.8	\$0.1	\$0.1	\$0.0	\$0.0	\$1.8	4,999	3,250
3	East	Interface	500	(\$0.7)	(\$2.4)	\$0.0	\$1.7	\$0.1	\$0.5	\$0.1	(\$0.3)	\$1.5	113	16
4	Face Rock	Other	PPL	\$0.0	(\$1.1)	\$0.1	\$1.2	\$0.1	\$0.1	\$0.0	(\$0.1)	\$1.2	2,552	484
5	Tanners Creek - Miami Fort	Flowgate	MISO	(\$0.3)	(\$1.2)	\$0.0	\$0.9	\$0.0	\$0.0	\$0.0	\$0.0	\$0.9	882	0
6	Blooming Grove - Paupack	Line	PPL	\$0.3	(\$0.5)	\$0.0	\$0.8	\$0.0	\$0.0	\$0.0	\$0.0	\$0.8	97	0
7	AP South	Interface	500	\$0.5	(\$0.3)	(\$0.0)	\$0.8	\$0.0	\$0.0	\$0.0	(\$0.0)	\$0.8	178	31
8	Gardners - Texas Eastern	Line	Met-Ed	\$0.0	(\$0.7)	\$0.0	\$0.8	(\$0.0)	\$0.0	(\$0.0)	(\$0.1)	\$0.7	1,787	131
9	Wescosville	Transformer	PPL	\$0.4	(\$0.4)	(\$0.0)	\$0.9	(\$0.0)	\$0.1	(\$0.0)	(\$0.1)	\$0.7	401	164
10	Coolspring - Milford	Line	DPL	(\$0.2)	(\$0.8)	\$0.0	\$0.7	(\$0.0)	(\$0.0)	(\$0.0)	(\$0.0)	\$0.7	463	42
11	Graceton - Safe Harbor	Line	BGE	\$0.6	\$0.0	\$0.0	\$0.6	\$0.0	\$0.0	\$0.0	(\$0.0)	\$0.6	1,631	563
12	Roxana - Praxair	Flowgate	MISO	(\$0.1)	(\$0.2)	\$0.1	\$0.3	\$0.1	\$0.2	(\$0.8)	(\$0.8)	(\$0.5)	1,274	603
13	Palisades - Argenta	Flowgate	MISO	(\$0.0)	(\$0.5)	\$0.0	\$0.5	\$0.0	(\$0.0)	(\$0.0)	(\$0.0)	\$0.5	738	91
14	Pleasant View - Ashburn	Line	Dominion	\$0.4	(\$0.1)	\$0.0	\$0.5	\$0.0	\$0.1	(\$0.0)	(\$0.0)	\$0.5	339	70
15	PA Central	Interface	500	\$0.1	(\$0.5)	\$0.0	\$0.6	\$0.0	\$0.2	(\$0.0)	(\$0.1)	\$0.4	872	665
16	CPL - DOM	Interface	500	\$0.2	(\$0.2)	\$0.0	\$0.4	\$0.0	\$0.0	\$0.0	\$0.0	\$0.4	112	0
17	Plymouth Meeting - Whitpain	Line	PECO	(\$0.0)	(\$0.3)	\$0.0	\$0.3	\$0.1	\$0.0	(\$0.0)	\$0.0	\$0.4	152	24
18	Cedar Creek - Red Lion	Line	DPL	(\$0.0)	(\$0.4)	\$0.0	\$0.4	(\$0.0)	(\$0.0)	(\$0.0)	(\$0.0)	\$0.3	780	57
19	Greentown	Flowgate	MISO	(\$0.0)	(\$0.1)	(\$0.0)	\$0.1	(\$0.0)	\$0.0	(\$0.3)	(\$0.4)	(\$0.3)	111	51
20	Tanners Creek - Miami Fort	Line	AEP	(\$0.0)	(\$0.0)	\$0.0	\$0.0	(\$0.0)	\$0.1	(\$0.2)	(\$0.3)	(\$0.3)	11	280
Top 20 Total				\$4.0	(\$12.3)	\$0.5	\$16.8	\$0.3	\$1.6	(\$1.4)	(\$2.7)	\$14.1	18,054	6,832
All Other Constraints				\$0.9	(\$10.6)	\$1.2	\$12.8	\$0.1	\$1.1	(\$2.7)	(\$3.7)	\$9.0	63,197	14,835
Total				\$4.9	(\$22.9)	\$1.7	\$29.5	\$0.4	\$2.7	(\$4.1)	(\$6.4)	\$23.1	81,251	21,667

PENELEC Control Zone

Table F-17 PENELEC Control Zone top congestion cost impacts (By facility): 2019

Congestion Costs (Millions)														
No.	Constraint	Type	Location	Day-Ahead				Balancing				Event Hours		
				Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Grand Total	Day-Ahead	Real-Time
1	Conastone - Peach Bottom	Line	500	\$2.1	(\$0.1)	(\$0.0)	\$2.2	\$0.1	\$0.1	\$0.1	\$0.0	\$2.2	4,999	3,250
2	Siegfried	Transformer	PPL	\$0.5	(\$1.0)	\$0.0	\$1.5	(\$0.0)	\$0.1	(\$0.0)	(\$0.1)	\$1.4	562	310
3	East Towanda - Hillside	Line	PENELEC	(\$0.3)	(\$1.3)	(\$0.0)	\$1.0	\$0.0	\$0.0	(\$0.0)	(\$0.0)	\$1.0	1,161	781
4	Wescosville	Transformer	PPL	\$0.5	(\$0.3)	\$0.0	\$0.8	(\$0.0)	\$0.0	(\$0.0)	(\$0.1)	\$0.7	401	164
5	Seward - Towanda	Line	PENELEC	\$2.9	\$2.3	(\$0.0)	\$0.6	\$0.0	\$0.0	\$0.0	\$0.0	\$0.6	284	0
6	Face Rock	Other	PPL	\$0.0	(\$0.5)	\$0.0	\$0.5	\$0.0	\$0.1	\$0.0	(\$0.0)	\$0.5	2,552	484
7	Gardners - Texas Eastern	Line	Met-Ed	\$0.2	(\$0.4)	(\$0.0)	\$0.5	(\$0.1)	(\$0.0)	(\$0.0)	(\$0.1)	\$0.4	1,787	131
8	Berwick - Koonsville	Line	PPL	\$0.2	(\$0.0)	\$0.2	\$0.4	\$0.0	\$0.0	(\$0.0)	(\$0.0)	\$0.4	3,025	33
9	Tanners Creek - Miami Fort	Flowgate	MISO	(\$0.1)	(\$0.5)	\$0.0	\$0.4	\$0.0	\$0.0	\$0.0	\$0.0	\$0.4	882	0
10	Blooming Grove - Paupack	Line	PPL	\$0.1	(\$0.2)	(\$0.0)	\$0.3	\$0.0	\$0.0	\$0.0	\$0.0	\$0.3	97	0
11	Conastone	Other	500	\$0.3	(\$0.0)	\$0.0	\$0.3	(\$0.0)	(\$0.1)	(\$0.0)	\$0.0	\$0.3	255	229
12	Harwood - Susquehanna	Line	PPL	\$0.0	(\$0.3)	\$0.0	\$0.3	\$0.0	\$0.0	\$0.0	\$0.0	\$0.3	252	0
13	Graceton - Safe Harbor	Line	BGE	\$0.3	\$0.0	\$0.0	\$0.3	\$0.0	\$0.0	\$0.0	(\$0.0)	\$0.3	1,631	563
14	AP South	Interface	500	\$0.2	(\$0.1)	(\$0.0)	\$0.3	\$0.0	\$0.0	\$0.0	(\$0.0)	\$0.3	178	31
15	Coolspring - Milford	Line	DPL	(\$0.0)	(\$0.3)	\$0.0	\$0.2	(\$0.0)	(\$0.0)	(\$0.0)	(\$0.0)	\$0.2	463	42
16	East	Interface	500	(\$0.1)	(\$0.4)	\$0.0	\$0.3	\$0.0	\$0.1	\$0.0	(\$0.0)	\$0.2	113	16
17	Palisades - Argenta	Flowgate	MISO	(\$0.0)	(\$0.2)	\$0.0	\$0.2	(\$0.0)	(\$0.0)	(\$0.0)	(\$0.0)	\$0.2	738	91
18	Nottingham	Other	PECO	\$0.3	\$0.1	(\$0.0)	\$0.2	\$0.0	\$0.0	\$0.0	\$0.0	\$0.2	809	468
19	Roxbury - Shade Gap	Line	PENELEC	\$0.0	(\$0.0)	\$0.0	\$0.1	(\$0.1)	\$0.0	(\$0.1)	(\$0.3)	(\$0.2)	217	27
20	PA Central	Interface	500	\$0.0	(\$0.2)	\$0.0	\$0.3	\$0.0	\$0.1	(\$0.0)	(\$0.1)	\$0.2	872	665
Top 20 Total				\$6.9	(\$3.5)	\$0.3	\$10.7	(\$0.1)	\$0.5	(\$0.2)	(\$0.7)	\$10.0	21,278	7,285
All Other Constraints				\$2.2	(\$5.0)	\$0.7	\$7.9	\$0.0	\$0.7	(\$1.6)	(\$2.3)	\$5.6	61,746	14,318
Total				\$9.2	(\$8.5)	\$1.0	\$18.6	(\$0.1)	\$1.2	(\$1.8)	(\$3.0)	\$15.6	83,024	21,603

Pepco Control Zone

Table F-18 Pepco Control Zone top congestion cost impacts (By facility): 2019

Congestion Costs (Millions)														
No.	Constraint	Type	Location	Day-Ahead				Balancing				Event Hours		
				Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Grand Total	Day-Ahead	Real-Time
1	Conastone - Peach Bottom	Line	500	\$5.9	(\$0.1)	(\$0.0)	\$6.0	\$0.2	\$0.3	\$0.2	\$0.0	\$6.1	4,999	3,250
2	Conastone	Other	500	\$0.9	(\$0.0)	\$0.0	\$1.0	(\$0.1)	(\$0.2)	(\$0.0)	\$0.1	\$1.1	255	229
3	Face Rock	Other	PPL	\$0.0	(\$0.9)	\$0.1	\$1.0	\$0.1	\$0.1	\$0.0	(\$0.1)	\$1.0	2,552	484
4	Conastone - Northwest	Line	BGE	\$0.5	(\$0.3)	\$0.0	\$0.8	\$0.0	(\$0.0)	(\$0.0)	(\$0.0)	\$0.8	289	29
5	AP South	Interface	500	\$0.5	(\$0.3)	(\$0.0)	\$0.8	\$0.0	\$0.0	\$0.0	(\$0.0)	\$0.8	178	31
6	Graceton - Safe Harbor	Line	BGE	\$0.7	\$0.0	\$0.0	\$0.7	\$0.0	\$0.1	\$0.0	(\$0.0)	\$0.7	1,631	563
7	Tanners Creek - Miami Fort	Flowgate	MISO	(\$0.3)	(\$0.9)	\$0.0	\$0.7	\$0.0	\$0.0	\$0.0	\$0.0	\$0.7	882	0
8	Bagley - Graceton	Line	BGE	\$0.5	(\$0.1)	\$0.0	\$0.6	\$0.0	\$0.0	\$0.0	\$0.0	\$0.6	826	126
9	Coolspring - Milford	Line	DPL	(\$0.1)	(\$0.6)	\$0.0	\$0.5	(\$0.0)	(\$0.0)	(\$0.0)	(\$0.0)	\$0.5	463	42
10	Nottingham	Other	PECO	\$0.5	\$0.1	(\$0.0)	\$0.4	\$0.0	\$0.0	\$0.0	\$0.0	\$0.4	809	468
11	Roxana - Praxair	Flowgate	MISO	(\$0.0)	(\$0.2)	\$0.1	\$0.2	\$0.1	\$0.1	\$0.6	(\$0.6)	(\$0.4)	1,274	603
12	BCPEP	Interface	Pepco	\$0.2	(\$0.1)	\$0.0	\$0.4	\$0.0	\$0.0	\$0.0	\$0.0	\$0.4	79	0
13	Palisades - Argenta	Flowgate	MISO	(\$0.0)	(\$0.4)	\$0.0	\$0.4	\$0.0	(\$0.0)	(\$0.0)	(\$0.0)	\$0.4	738	91
14	CPL - DOM	Interface	500	\$0.2	(\$0.2)	\$0.0	\$0.3	\$0.0	\$0.0	\$0.0	\$0.0	\$0.3	112	0
15	Pleasant View - Ashburn	Line	Dominion	\$0.3	(\$0.1)	\$0.0	\$0.4	\$0.0	\$0.0	(\$0.0)	(\$0.0)	\$0.3	339	70
16	PA Central	Interface	500	\$0.0	(\$0.4)	\$0.0	\$0.4	\$0.0	\$0.1	(\$0.0)	(\$0.1)	\$0.3	872	665
17	East	Interface	500	(\$0.1)	(\$0.5)	\$0.0	\$0.4	\$0.0	\$0.1	\$0.0	(\$0.1)	\$0.3	113	16
18	Siegfried	Transformer	PPL	\$0.0	\$0.0	\$0.0	\$0.0	(\$0.1)	\$0.2	(\$0.0)	(\$0.3)	(\$0.3)	562	310
19	Greentown	Flowgate	MISO	(\$0.0)	(\$0.1)	(\$0.0)	\$0.1	(\$0.0)	\$0.0	(\$0.3)	(\$0.3)	(\$0.3)	111	51
20	Tanners Creek - Miami Fort	Line	AEP	(\$0.0)	(\$0.0)	\$0.0	\$0.0	(\$0.0)	\$0.1	(\$0.2)	(\$0.3)	(\$0.3)	11	280
Top 20 Total				\$9.7	(\$5.0)	\$0.3	\$15.0	\$0.3	\$1.0	(\$0.9)	(\$1.7)	\$13.4	17,095	7,308
All Other Constraints				\$0.1	(\$7.3)	\$0.9	\$8.2	(\$0.0)	\$0.9	(\$2.1)	(\$3.0)	\$5.2	60,787	14,287
Total				\$9.8	(\$12.3)	\$1.2	\$23.3	\$0.3	\$1.9	(\$3.0)	(\$4.7)	\$18.6	77,882	21,595

PPL Control Zone

Table F-19 PPL Control Zone top congestion cost impacts (By facility): 2019

Congestion Costs (Millions)														
No.	Constraint	Type	Location	Day-Ahead				Balancing				Event Hours		
				Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Grand Total	Day-Ahead	Real-Time
1	Siegfried	Transformer	PPL	\$1.3	(\$2.5)	\$0.1	\$3.9	(\$0.1)	\$0.3	(\$0.0)	(\$0.4)	\$3.5	562	310
2	Conastone - Peach Bottom	Line	500	\$3.3	(\$0.1)	(\$0.0)	\$3.4	\$0.1	\$0.2	\$0.1	\$0.0	\$3.4	4,999	3,250
3	Wescosville	Transformer	PPL	\$1.4	(\$0.8)	\$0.0	\$2.3	(\$0.0)	\$0.1	(\$0.0)	(\$0.2)	\$2.1	401	164
4	Berwick - Koonsville	Line	PPL	\$0.7	(\$0.0)	\$0.9	\$1.6	\$0.0	\$0.0	(\$0.0)	(\$0.0)	\$1.5	3,025	33
5	Face Rock	Other	PPL	\$0.0	(\$1.1)	\$0.1	\$1.2	\$0.1	\$0.1	\$0.0	(\$0.1)	\$1.1	2,552	484
6	Tanners Creek - Miami Fort	Flowgate	MISO	(\$0.3)	(\$1.2)	\$0.0	\$0.9	\$0.0	\$0.0	\$0.0	\$0.0	\$0.9	882	0
7	Harwood - Susquehanna	Line	PPL	\$0.0	(\$0.8)	\$0.0	\$0.8	\$0.0	\$0.0	\$0.0	\$0.0	\$0.8	252	0
8	Blooming Grove - Paupack	Line	PPL	\$0.3	(\$0.5)	(\$0.0)	\$0.8	\$0.0	\$0.0	\$0.0	\$0.0	\$0.8	97	0
9	AP South	Interface	500	\$0.5	(\$0.3)	(\$0.0)	\$0.8	\$0.0	\$0.0	\$0.0	(\$0.0)	\$0.8	178	31
10	Gardners - Texas Eastern	Line	Met-Ed	\$0.0	(\$0.8)	\$0.0	\$0.9	(\$0.0)	\$0.0	(\$0.0)	(\$0.1)	\$0.8	1,787	131
11	East	Interface	500	(\$0.3)	(\$1.1)	\$0.0	\$0.8	\$0.0	\$0.2	\$0.0	(\$0.1)	\$0.7	113	16
12	Coolspring - Milford	Line	DPL	(\$0.1)	(\$0.7)	\$0.0	\$0.6	(\$0.0)	(\$0.0)	(\$0.0)	(\$0.0)	\$0.6	463	42
13	Graceton - Safe Harbor	Line	BGE	\$0.6	\$0.0	\$0.0	\$0.5	\$0.0	\$0.0	\$0.0	(\$0.0)	\$0.5	1,631	563
14	Palisades - Argenta	Flowgate	MISO	(\$0.0)	(\$0.6)	\$0.0	\$0.6	\$0.0	(\$0.0)	(\$0.1)	(\$0.0)	\$0.5	738	91
15	Mountain	Transformer	PPL	(\$0.2)	(\$0.1)	\$0.6	\$0.5	\$0.0	\$0.0	\$0.0	\$0.0	\$0.5	1,390	0
16	Conastone	Other	500	\$0.4	(\$0.0)	\$0.0	\$0.5	(\$0.0)	(\$0.1)	(\$0.0)	\$0.0	\$0.5	255	229
17	CPL - DOM	Interface	500	\$0.2	(\$0.2)	\$0.0	\$0.5	\$0.0	\$0.0	\$0.0	\$0.0	\$0.5	112	0
18	Roxana - Praxair	Flowgate	MISO	(\$0.1)	(\$0.2)	\$0.2	\$0.3	\$0.1	\$0.2	(\$0.7)	(\$0.8)	(\$0.5)	1,274	603
19	Nottingham	Other	PECO	\$0.6	\$0.1	(\$0.0)	\$0.4	\$0.0	\$0.0	\$0.0	\$0.0	\$0.4	809	468
20	Pleasant View - Ashburn	Line	Dominion	\$0.4	(\$0.1)	\$0.0	\$0.5	\$0.0	\$0.1	(\$0.0)	(\$0.0)	\$0.4	339	70
Top 20 Total				\$8.6	(\$11.2)	\$1.9	\$21.7	\$0.3	\$1.1	(\$0.7)	(\$1.6)	\$20.1	21,859	6,485
All Other Constraints				\$2.6	(\$13.4)	\$1.4	\$17.4	\$0.0	\$1.4	(\$3.4)	(\$4.8)	\$12.7	61,332	15,118
Total				\$11.2	(\$24.6)	\$3.3	\$39.1	\$0.3	\$2.5	(\$4.1)	(\$6.4)	\$32.8	83,191	21,603

PSEG Control Zone

Table F-20 PSEG Control Zone top congestion cost impacts (By facility): 2019

Congestion Costs (Millions)														
No.	Constraint	Type	Location	Day-Ahead				Balancing				Event Hours		
				Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Grand Total	Day-Ahead	Real-Time
1	Siegfried	Transformer	PPL	\$1.1	(\$2.3)	\$0.1	\$3.5	(\$0.1)	\$0.3	(\$0.0)	(\$0.4)	\$3.1	562	310
2	Conastone - Peach Bottom	Line	500	\$2.4	(\$0.0)	(\$0.0)	\$2.4	\$0.1	\$0.1	\$0.1	\$0.0	\$2.5	4,999	3,250
3	Wescosville	Transformer	PPL	\$1.2	(\$0.7)	\$0.0	\$2.0	(\$0.0)	\$0.1	(\$0.0)	(\$0.1)	\$1.8	401	164
4	East	Interface	500	(\$0.7)	(\$2.4)	\$0.0	\$1.7	\$0.1	\$0.5	\$0.1	(\$0.3)	\$1.4	113	16
5	Coolspring - Milford	Line	DPL	\$0.6	(\$0.8)	\$0.0	\$1.4	(\$0.0)	(\$0.0)	(\$0.0)	(\$0.0)	\$1.4	463	42
6	Monroe - Vineland	Line	AECO	\$1.5	\$0.5	\$0.3	\$1.3	(\$0.0)	(\$0.0)	(\$0.0)	(\$0.0)	\$1.3	4,560	108
7	Face Rock	Other	PPL	\$0.0	(\$1.2)	\$0.1	\$1.3	\$0.1	\$0.1	\$0.0	(\$0.1)	\$1.3	2,552	484
8	Tanners Creek - Miami Fort	Flowgate	MISO	(\$0.4)	(\$1.3)	\$0.0	\$1.0	\$0.0	\$0.0	\$0.0	\$0.0	\$1.0	882	0
9	Harwood - Susquehanna	Line	PPL	\$0.0	(\$0.8)	\$0.0	\$0.8	\$0.0	\$0.0	\$0.0	\$0.0	\$0.8	252	0
10	Blooming Grove - Paupack	Line	PPL	\$0.3	(\$0.5)	\$0.0	\$0.8	\$0.0	\$0.0	\$0.0	\$0.0	\$0.8	97	0
11	Cedar Creek - Clayton	Line	DPL	\$0.9	\$0.1	\$0.0	\$0.8	(\$0.0)	\$0.0	(\$0.0)	(\$0.0)	\$0.8	74	4
12	Cedar Grove Sub - Roseland	Line	PSEG	(\$0.0)	(\$0.8)	(\$0.0)	\$0.7	(\$0.0)	\$0.0	\$0.0	(\$0.0)	\$0.7	246	16
13	AP South	Interface	500	\$0.4	(\$0.3)	(\$0.0)	\$0.7	\$0.0	\$0.0	\$0.0	(\$0.0)	\$0.7	178	31
14	Cedar Creek - Red Lion	Line	DPL	\$0.3	(\$0.4)	\$0.1	\$0.7	(\$0.0)	(\$0.0)	(\$0.0)	(\$0.0)	\$0.7	780	57
15	Graceton - Safe Harbor	Line	BGE	\$0.7	\$0.0	\$0.0	\$0.7	\$0.0	\$0.0	\$0.0	(\$0.0)	\$0.7	1,631	563
16	Roxana - Praxair	Flowgate	MISO	(\$0.1)	(\$0.2)	\$0.2	\$0.3	\$0.2	\$0.2	(\$0.9)	(\$0.9)	(\$0.6)	1,274	603
17	Gardners - Texas Eastern	Line	Met-Ed	(\$0.3)	(\$0.8)	\$0.0	\$0.6	(\$0.0)	\$0.0	(\$0.0)	(\$0.1)	\$0.5	1,787	131
18	Pleasant View - Ashburn	Line	Dominion	\$0.4	(\$0.1)	\$0.0	\$0.5	\$0.0	\$0.1	(\$0.0)	(\$0.0)	\$0.5	339	70
19	Palisades - Argenta	Flowgate	MISO	(\$0.0)	(\$0.5)	\$0.0	\$0.5	\$0.0	(\$0.0)	(\$0.1)	(\$0.0)	\$0.5	738	91
20	PA Central	Interface	500	\$0.1	(\$0.5)	\$0.0	\$0.6	\$0.0	\$0.2	(\$0.0)	(\$0.2)	\$0.5	872	665
Top 20 Total				\$8.5	(\$13.2)	\$0.8	\$22.5	\$0.3	\$1.5	(\$0.9)	(\$2.1)	\$20.4	22,800	6,605
All Other Constraints				\$1.4	(\$13.1)	\$1.5	\$16.0	(\$0.0)	\$1.4	(\$3.5)	(\$5.0)	\$11.0	58,783	14,972
Total				\$9.9	(\$26.3)	\$2.3	\$38.5	\$0.3	\$2.9	(\$4.4)	(\$7.1)	\$31.4	81,583	21,577

RECO Control Zone

Table F-21 RECO Control Zone top congestion cost impacts (By facility): 2019

Congestion Costs (Millions)														
No.	Constraint	Type	Location	Day-Ahead				Balancing				Event Hours		
				Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Grand Total	Day-Ahead	Real-Time
1	Maywood - Saddlebrook	Line	PSEG	\$0.0	\$0.0	(\$0.1)	(\$0.0)	(\$0.0)	(\$0.0)	(\$0.1)	(\$0.1)	(\$0.2)	57	22
2	Ramapo (ConEd) - S Mahwah (RECO)	Line	RECO	\$0.1	\$0.0	\$0.1	\$0.2	\$0.0	\$0.0	\$0.0	\$0.0	\$0.2	775	0
3	Athenia - Fair Lawn	Line	PSEG	\$0.0	\$0.0	\$0.0	\$0.0	(\$0.0)	(\$0.0)	(\$0.1)	(\$0.2)	(\$0.2)	176	99
4	Conastone - Peach Bottom	Line	500	\$0.1	(\$0.0)	(\$0.0)	\$0.1	\$0.0	\$0.0	\$0.0	\$0.0	\$0.1	4,999	3,250
5	Siegfried	Transformer	PPL	\$0.0	(\$0.1)	\$0.0	\$0.1	(\$0.0)	\$0.0	(\$0.0)	(\$0.0)	\$0.1	562	310
6	Burns - Corporate Road	Line	RECO	\$0.0	\$0.0	\$0.0	\$0.1	\$0.0	\$0.0	\$0.0	\$0.0	\$0.1	185	0
7	Ontario Hydro	Flowgate	EXT	(\$0.0)	(\$0.0)	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	42	64
8	East	Interface	500	(\$0.0)	(\$0.1)	\$0.0	\$0.1	\$0.0	\$0.0	\$0.0	(\$0.0)	\$0.0	113	16
9	Face Rock	Other	PPL	\$0.0	(\$0.0)	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	(\$0.0)	\$0.0	2,552	484
10	Harings Corner - West Nyack	Line	RECO	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	115	0
11	Roxana - Praxair	Flowgate	MISO	(\$0.0)	(\$0.0)	\$0.0	\$0.0	\$0.0	\$0.0	(\$0.0)	(\$0.0)	(\$0.0)	1,274	603
12	Niles Valley - Sabinsville	Line	PENELEC	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	14	23
13	Tanners Creek - Miami Fort	Flowgate	MISO	(\$0.0)	(\$0.1)	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	882	0
14	Blooming Grove - Paupack	Line	PPL	\$0.0	(\$0.0)	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	97	0
15	Coolspring - Milford	Line	DPL	(\$0.0)	(\$0.0)	\$0.0	\$0.0	(\$0.0)	(\$0.0)	(\$0.0)	(\$0.0)	\$0.0	463	42
16	Cedar Grove Sub - Roseland	Line	PSEG	(\$0.0)	(\$0.0)	(\$0.0)	\$0.0	(\$0.0)	\$0.0	\$0.0	(\$0.0)	\$0.0	246	16
17	Wescosville	Transformer	PPL	\$0.0	(\$0.0)	\$0.0	\$0.0	(\$0.0)	\$0.0	(\$0.0)	(\$0.0)	\$0.0	401	164
18	Graceton - Safe Harbor	Line	BGE	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	(\$0.0)	\$0.0	1,631	563
19	Harwood - Susquehanna	Line	PPL	\$0.0	(\$0.0)	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	252	0
20	Cedar Creek - Red Lion	Line	DPL	\$0.0	(\$0.0)	\$0.0	\$0.0	(\$0.0)	(\$0.0)	(\$0.0)	(\$0.0)	\$0.0	780	57
Top 20 Total				\$0.3	(\$0.4)	\$0.2	\$0.9	(\$0.0)	\$0.0	(\$0.3)	(\$0.3)	\$0.5	15,616	5,713
All Other Constraints				\$0.1	(\$0.5)	\$0.1	\$0.7	(\$0.0)	\$0.1	(\$0.1)	(\$0.2)	\$0.5	63,725	15,889
Total				\$0.4	(\$0.9)	\$0.2	\$1.5	(\$0.0)	\$0.1	(\$0.4)	(\$0.5)	\$1.0	79,341	21,602

Congestion Accounting Example: Actual Congestion versus Billed Congestion

Table F-22 shows an example of Day-Ahead Transmission Congestion Charges shown on the PJM bill. The example assumes that there was only one constraint binding for an hour and only three customers (A, B and C) participated in the PJM Day-Ahead Energy Market. The top portion of the table shows the total day-ahead congestion in the PJM system for an hour is \$960. For customer B, the total day-ahead transmission CLMP charges on the customer bill are \$296. The total day-ahead transmission CLMP charges on customer B's bill are not equal to the day-ahead congestion paid by customer B.

The congestion paid by customer B is the difference between what Customer B pays for withdrawing energy and what all the injections needed to serve Customer B's withdrawal are paid to provide that energy. Customer B needs 6 MWh more injections from network sources than it supplied to meet its 60 MWh withdrawal. Customer B's bill does not reflect the difference between what it paid for the 6 MWh of energy from the network and what the resources that supplied the 6 MWh of network energy were paid. The total day-ahead congestion cost paid by customer A is \$192 (Table F-23), not the \$296 in net CLMP credits found on its bill. Table F-23 shows that the actual total PJM day-ahead congestion costs paid by each customer due to the transmission constraint and the actual network sources of energy used to serve the customers.

Table F-22 Example of day-ahead CLMP charges by customer in PJM bi

Day-Ahead (Total)						
	Withdrawal	Injection	CLMP	Implicit Withdrawal Charges	Implicit Injection Credits	Total Charges
DEC	50.0	0.0	\$5.0	\$250.0	\$0.0	\$250.0
Demand	100.0	0.0	\$10.0	\$1,000.0	\$0.0	\$1,000.0
Export	30.0	0.0	\$7.0	\$210.0	\$0.0	\$210.0
Generation	0.0	150.0	\$2.0	\$0.0	\$300.0	(\$300.0)
Import	0.0	20.0	\$6.0	\$0.0	\$120.0	(\$120.0)
INC	0.0	10.0	\$8.0	\$0.0	\$80.0	(\$80.0)
Total	180.0	180.0		\$1,460.0	\$500.0	\$960.0
Day-Ahead (Participant A)						
DEC	20.0	0.0	\$5.0	\$100.0	\$0.0	\$100.0
Demand	10.0	0.0	\$10.0	\$100.0	\$0.0	\$100.0
Export	10.0	0.0	\$7.0	\$70.0	\$0.0	\$70.0
Generation	0.0	50.0	\$2.0	\$0.0	\$100.0	(\$100.0)
Import	0.0	6.0	\$6.0	\$0.0	\$36.0	(\$36.0)
INC	0.0	10.0	\$8.0	\$0.0	\$80.0	(\$80.0)
Total	40.0	66.0		\$270.0	\$216.0	\$54.0
Day-Ahead (Participant B)						
DEC	30.0	0.0	\$5.0	\$150.0	\$0.0	\$150.0
Demand	20.0	0.0	\$10.0	\$200.0	\$0.0	\$200.0
Export	10.0	0.0	\$7.0	\$70.0	\$0.0	\$70.0
Generation	0.0	50.0	\$2.0	\$0.0	\$100.0	(\$100.0)
Import	0.0	4.0	\$6.0	\$0.0	\$24.0	(\$24.0)
INC	0.0	0.0	\$8.0	\$0.0	\$0.0	\$0.0
Total	60.0	54.0		\$420.0	\$124.0	\$296.0
Day-Ahead (Participant C)						
DEC	0.0	0.0	\$5.0	\$0.0	\$0.0	\$0.0
Demand	70.0	0.0	\$10.0	\$700.0	\$0.0	\$700.0
Export	10.0	0.0	\$7.0	\$70.0	\$0.0	\$70.0
Generation	0.0	50.0	\$2.0	\$0.0	\$100.0	(\$100.0)
Import	0.0	10.0	\$6.0	\$0.0	\$60.0	(\$60.0)
INC	0.0	0.0	\$8.0	\$0.0	\$0.0	\$0.0
Total	80.0	60.0		\$770.0	\$160.0	\$610.0

Table F-23 Example of day-ahead congestion by customer

Day-Ahead						
	Withdrawal	Injection	CLMP	Implicit Withdrawal Charges	Implicit Injection Credits	Total Charges
DEC	50.0	0.0	\$5.0	\$250.0	\$0.0	\$250.0
Demand	100.0	0.0	\$10.0	\$1,000.0	\$0.0	\$1,000.0
Export	30.0	0.0	\$7.0	\$210.0	\$0.0	\$210.0
Generation	0.0	150.0	\$2.0	\$0.0	\$300.0	(\$300.0)
Import	0.0	20.0	\$6.0	\$0.0	\$120.0	(\$120.0)
INC	0.0	10.0	\$8.0	\$0.0	\$80.0	(\$80.0)
Total	180.0	180.0		\$1,460.0	\$500.0	\$960.0

Day-Ahead						
Participant	Demand	Injection	CLMP	Demand Charge	Demand Charge Proportion	Congestion
A	10.0	0.0	\$10.0	\$100.0	0.1	\$96.0
B	20.0	0.0	\$10.0	\$200.0	0.2	\$192.0
C	70.0	0.0	\$10.0	\$700.0	0.7	\$672.0
Total	100.0			\$1,000.0	1.0	\$960.0

Changes in UTC Volumes

UTCs have a significant impact on congestion events in the day-ahead market and, as a result, contribute to differences between day-ahead and real-time congestion events. The greater the volume of UTCs, the greater the number of congestion events in the day-ahead market and the greater the differences between the day-ahead and real-time congestion events.

On August 29, 2014, FERC issued an order which created an obligation for UTCs to pay any uplift determined to be appropriate based on Commission review, effective September 8, 2014.⁵

As a result of the potential requirement to pay uplift charges and the uncertainty about the level of the required uplift charges, market participants reduced up to congestion trading effective September 8, 2014. There was an increase in up to congestion volume starting in December 2015, coincident with the expiration of the fifteen month limit on the payment of prior uplift charges. (Section 206(b) of the Federal Power Act states that "...the Commission may order refunds of any amounts paid, for the period subsequent to the refund effective date through a date fifteen months after such refund effective date..."⁶

On February 20, 2018, FERC issued an order limiting the eligible bidding points for up to congestion transactions to hubs, residual metered load and interfaces.⁷ As a

result, market participants reduced up to congestion trading effective February 22, 2018. UTC trading has increase since then.

Congestion Event Summary for MISO Flowgates

PJM and MISO have a joint operating agreement (JOA) which defines a coordinated method for congestion management. This agreement establishes reciprocal, coordinated flowgates in the combined footprint whose operating limits are respected by the operators of both organizations.⁸ A flowgate is a facility or group of facilities that may act as constraint points on the regional system.⁹ PJM models

these coordinated flowgates and controls for them in its security-constrained, economic dispatch.

As of December 31, 2019, PJM had 141 flowgates eligible for M2M (Market to Market) coordination and MISO had 215 flowgates eligible for M2M coordination.

Table F-24 and Table F-25 show the MISO flowgates which PJM and/or MISO took dispatch action to control during 2019 and 2018, and which had the greatest congestion cost impact on PJM. 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 and MISO dispatch are presented by constraint, in descending order of the absolute value of total congestion costs. Among MISO flowgates in 2019, the Tanners Creek - Miami Fort Flowgate made the most significant contribution to positive congestion while the Roxana - Praxair Flowgate contributed to most negative congestion.

5 148 FERC ¶ 61,144 (2014).

6 16 U.S.C. § 824e.

7 162 FERC ¶ 61,139 (2018).

8 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008), Section 6.1, Effective Date: May 30, 2016. <<http://www.pjm.com/documents/agreements.aspx>>.

9 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008), Section 2.2.24, Effective Date: February 14, 2017. <<http://www.pjm.com/documents/agreements.aspx>>.

Table F-24 Top 20 congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): 2019

		Congestion Costs (Millions)											
		Day-Ahead				Balancing				Event Hours			
No.	Constraint	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Grand Total	Day- Ahead	Real- Time	
1	Tanners Creek - Miami Fort	(\$6.8)	(\$24.2)	\$0.3	\$17.6	\$0.0	\$0.0	\$0.0	\$0.0	\$17.6	882	0	
2	Roxana - Praxair	(\$1.2)	(\$4.1)	\$2.9	\$5.7	\$3.3	\$4.2	(\$17.6)	(\$18.5)	(\$12.8)	1,274	603	
3	Palisades - Argenta	(\$0.4)	(\$9.8)	\$0.5	\$9.9	\$0.0	(\$0.1)	(\$0.9)	(\$0.8)	\$9.1	738	91	
4	Greentown	(\$0.2)	(\$1.7)	(\$0.1)	\$1.5	(\$0.6)	\$0.9	(\$6.2)	(\$7.7)	(\$6.1)	111	51	
5	Marblehead	(\$3.2)	(\$8.4)	\$1.4	\$6.5	(\$0.3)	\$0.1	(\$2.3)	(\$2.8)	\$3.7	1,760	1,103	
6	Crete - St Johns Tap	(\$0.2)	(\$3.0)	\$0.3	\$3.1	\$0.0	\$0.0	\$0.0	\$0.0	\$3.1	134	0	
7	Munster	(\$0.1)	(\$2.0)	(\$0.3)	\$1.6	\$0.3	(\$0.2)	(\$5.1)	(\$4.6)	(\$3.1)	709	171	
8	Vermilion - Tilton	(\$0.1)	(\$1.5)	\$0.9	\$2.3	\$0.0	\$0.0	\$0.0	\$0.0	\$2.3	912	0	
9	Mohomet - ChampTP	(\$0.4)	(\$2.8)	\$0.6	\$2.9	\$0.3	\$0.6	(\$1.8)	(\$0.9)	\$2.0	238	192	
10	Sub 85 - Rock Island	(\$1.7)	(\$3.6)	\$0.1	\$2.0	(\$0.1)	\$0.2	(\$3.5)	(\$3.9)	(\$1.9)	206	270	
11	Quad Cities - Cordova	(\$1.4)	(\$2.8)	\$0.4	\$1.8	\$0.0	\$0.0	\$0.0	\$0.0	\$1.8	181	0	
12	Babcock - Stillwell	(\$0.8)	(\$2.5)	\$0.2	\$1.9	\$0.2	(\$0.1)	(\$0.5)	(\$0.3)	\$1.6	202	65	
13	Monroe - Lallendorf	(\$0.8)	(\$1.7)	\$0.5	\$1.4	\$0.0	\$0.0	\$0.0	\$0.0	\$1.4	95	0	
14	Chicago Ave - Praxair 3	(\$0.4)	(\$3.2)	\$0.1	\$2.9	\$1.0	\$0.5	(\$4.6)	(\$4.2)	(\$1.3)	326	260	
15	Sandburg	(\$2.0)	(\$4.1)	\$0.8	\$3.0	(\$0.1)	\$0.1	(\$1.6)	(\$1.9)	\$1.1	420	266	
16	Electric Jct	(\$0.2)	(\$1.2)	\$0.0	\$1.0	\$0.0	\$0.0	\$0.0	\$0.0	\$1.0	69	0	
17	Westwood	(\$0.1)	(\$2.0)	(\$0.9)	\$1.0	\$0.0	\$0.0	(\$0.0)	(\$0.0)	\$0.9	65	20	
18	Rock Creek - Beaver Channel	\$0.0	(\$0.1)	(\$0.1)	\$0.0	\$0.4	\$0.1	\$0.6	\$0.9	\$0.9	9	16	
19	East Frankfort - Crete	\$0.0	(\$0.7)	\$0.2	\$0.9	\$0.0	\$0.0	\$0.0	\$0.0	\$0.9	70	0	
20	Nelson	(\$0.2)	(\$1.0)	\$0.1	\$0.9	\$0.0	\$0.0	\$0.0	\$0.0	\$0.9	53	0	
	Top 20 Total	(\$20.2)	(\$80.4)	\$7.8	\$67.9	\$4.2	\$5.3	(\$43.6)	(\$44.6)	\$23.3	8,454	3,108	
	All Other Constraints	(\$4.7)	(\$19.6)	\$0.7	\$15.6	(\$0.2)	\$2.6	(\$8.7)	(\$11.5)	\$4.1	2,992	2,993	
	Total	(\$24.9)	(\$100.0)	\$8.5	\$83.6	\$4.0	\$7.9	(\$52.3)	(\$56.1)	\$27.4	11,446	6,101	

Table F-25 Top 20 congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): 2018

		Congestion Costs (Millions)											
		Day-Ahead				Balancing				Event Hours			
No.	Constraint	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Grand Total	Day- Ahead	Real- Time	
1	Tanners Creek - Miami Fort	(\$20.8)	(\$94.1)	(\$2.9)	\$70.4	\$0.0	\$0.0	\$0.0	\$0.0	\$70.4	1,511	0	
2	Batesville - Hubble	(\$13.1)	(\$55.9)	(\$10.3)	\$32.5	(\$0.6)	(\$2.2)	\$0.3	\$2.0	\$34.5	254	134	
3	Northport - Albion	(\$2.3)	(\$18.4)	(\$3.8)	\$12.3	(\$0.2)	(\$1.1)	\$1.3	\$2.2	\$14.5	132	28	
4	Brokaw - Leroy	\$0.8	(\$12.3)	(\$4.4)	\$8.6	\$0.5	(\$1.3)	\$3.0	\$4.8	\$13.5	1,232	261	
5	Monroe - Lallendorf	(\$1.4)	(\$11.7)	(\$0.4)	\$9.9	\$0.0	\$0.0	\$0.0	\$0.0	\$9.9	945	0	
6	Quad Cities - Cordova	(\$5.6)	(\$12.4)	\$2.6	\$9.4	\$0.0	\$0.0	\$0.0	\$0.0	\$9.4	1,522	0	
7	Flint Lake - Luchtman Road	\$0.2	(\$10.6)	(\$4.9)	\$5.8	(\$0.2)	(\$1.4)	\$1.8	\$3.0	\$8.8	890	365	
8	Olive	\$0.2	(\$6.6)	\$0.3	\$7.0	\$0.0	\$0.0	\$0.0	\$0.0	\$7.0	445	0	
9	Pierce - Beckjord	(\$2.2)	(\$9.1)	(\$0.1)	\$6.7	\$0.0	\$0.0	\$0.0	\$0.0	\$6.7	263	0	
10	Burnham - Munster	\$0.6	(\$4.5)	\$0.2	\$5.2	\$0.0	\$0.0	\$0.0	\$0.0	\$5.2	923	0	
11	Segreto - Palisades	(\$0.2)	(\$6.0)	\$0.6	\$6.4	(\$0.1)	\$0.1	(\$1.4)	(\$1.7)	\$4.7	441	117	
12	Plymouth - Leesburg	(\$1.9)	(\$7.7)	(\$2.0)	\$3.7	(\$0.5)	\$0.4	\$1.5	\$0.6	\$4.4	306	163	
13	Greentown	(\$0.0)	(\$0.8)	(\$0.2)	\$0.6	(\$0.9)	\$6.0	\$2.0	(\$4.8)	(\$4.2)	151	72	
14	Michigan City - Bosserman	(\$0.8)	(\$5.5)	(\$0.6)	\$4.0	\$0.0	\$0.0	\$0.0	\$0.0	\$4.0	809	0	
15	Braidwood - East Frankfort	(\$0.0)	(\$3.9)	(\$0.0)	\$3.9	\$0.0	\$0.0	\$0.0	\$0.0	\$3.9	74	0	
16	Holland - Neoga	(\$0.6)	(\$4.3)	(\$0.1)	\$3.5	\$0.2	\$0.0	\$0.0	\$0.2	\$3.7	106	41	
17	Northwest Tap - Purdue	(\$1.9)	(\$6.5)	(\$1.1)	\$3.5	\$1.1	\$2.3	\$1.3	\$0.1	\$3.6	477	242	
18	Eugene - Cayuga	(\$0.4)	(\$4.4)	(\$0.6)	\$3.4	\$0.0	\$0.0	(\$0.0)	(\$0.0)	\$3.4	293	23	
19	Roxana - Praxair	\$2.8	(\$4.4)	(\$4.2)	\$3.0	\$3.2	\$2.2	(\$7.2)	(\$6.2)	(\$3.2)	1,132	481	
20	Maroa - E GooseCreek	(\$0.1)	(\$3.5)	(\$0.6)	\$2.8	\$0.1	(\$0.1)	\$0.1	\$0.2	\$3.0	287	96	
	Top 20 Total	(\$46.9)	(\$282.5)	(\$32.8)	\$202.9	\$2.7	\$5.0	\$2.7	\$0.4	\$203.3	12,193	2,023	
	All Other Constraints	(\$8.9)	(\$53.5)	(\$2.9)	\$41.6	\$0.2	\$5.5	(\$6.7)	(\$12.0)	\$29.6	7,650	3,516	
	Total	(\$55.8)	(\$336.0)	(\$35.7)	\$244.5	\$2.9	\$10.5	(\$4.0)	(\$11.6)	\$232.9	19,843	5,539	

Congestion Event Summary for NYISO Flowgates

PJM and NYISO have a joint operating agreement (JOA) which defines a coordinated method for congestion management. This agreement establishes a structure and framework for the reliable operation of the interconnected PJM and NYISO transmission systems and efficient market operation through M2M coordination.¹⁰ Only a subset of all transmission constraints that exist in either market are eligible for coordinated congestion management. This subset of transmission constraints is identified as M2M flowgates. Flowgates eligible for the M2M coordination process are called M2M flowgates.¹¹

In 2018 and 2019, none of the NYISO flowgates were binding.

Congestion Event Summary for the 500 kV System

Constraints on the 500 kV system generally have a regional impact. Table F-26 and Table F-27 show the 500 kV constraints affecting congestion costs in PJM for 2019 and 2018. 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 affecting congestion costs in PJM are presented by constraint, in descending order of the absolute value of total congestion costs.

Table F-26 Regional constraints summary (By facility): 2019

Congestion Costs (Millions)													
No.	Constraint	Type	Day-Ahead				Balancing				Event Hours		
			Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Grand Total	Day-Ahead	Real-Time
1	Conastone - Peach Bottom	Line	\$108.1	(\$2.5)	(\$0.1)	\$110.5	\$3.6	\$6.0	\$2.8	\$0.4	\$111.0	4,999	3,250
2	Conastone	Other	\$16.4	(\$0.6)	\$0.4	\$17.3	(\$0.9)	(\$3.0)	(\$0.8)	\$1.3	\$18.6	255	229
3	AP South	Interface	\$9.1	(\$5.7)	(\$0.2)	\$14.6	\$0.2	\$0.3	\$0.1	(\$0.1)	\$14.5	178	31
4	East	Interface	(\$6.0)	(\$20.4)	\$0.1	\$14.6	\$0.9	\$4.0	\$0.9	(\$2.2)	\$12.4	113	16
5	PA Central	Interface	\$1.2	(\$9.7)	\$0.6	\$11.5	\$0.3	\$2.9	(\$0.1)	(\$2.7)	\$8.8	872	665
6	CPL - DOM	Interface	\$3.5	(\$4.2)	\$0.1	\$7.8	\$0.0	\$0.0	\$0.0	\$0.0	\$7.8	112	0
7	Keystone	Other	(\$1.2)	(\$5.7)	\$0.3	\$4.8	(\$0.0)	(\$0.2)	(\$0.1)	\$0.0	\$4.8	299	163
8	Three Mile Island	Transformer	\$2.6	(\$1.9)	\$0.1	\$4.6	(\$0.7)	(\$0.4)	\$0.2	(\$0.1)	\$4.5	252	39
9	Bedington - Black Oak	Interface	\$1.2	(\$0.9)	(\$0.0)	\$2.0	\$0.0	\$0.0	\$0.0	\$0.0	\$2.0	86	0
10	Yukon	Transformer	(\$0.3)	(\$0.9)	(\$0.0)	\$0.6	\$0.1	(\$0.2)	(\$0.1)	\$0.3	\$0.9	27	29
11	West	Interface	(\$0.3)	(\$1.0)	\$0.1	\$0.8	\$0.0	\$0.0	\$0.0	\$0.0	\$0.8	55	0
12	Conastone	Transformer	\$0.5	(\$0.2)	\$0.0	\$0.7	\$0.0	\$0.0	\$0.0	\$0.0	\$0.7	22	0
13	Cabot - Keystone	Line	(\$0.2)	(\$0.7)	\$0.0	\$0.5	\$0.0	(\$0.0)	(\$0.0)	\$0.0	\$0.5	36	6
14	Keeney - Rockspri	Line	\$0.0	\$0.0	\$0.0	\$0.0	\$0.6	(\$0.3)	(\$0.4)	\$0.5	\$0.5	0	29
15	AEP - DOM	Interface	\$0.2	(\$0.1)	\$0.1	\$0.4	\$0.0	\$0.0	\$0.0	\$0.0	\$0.4	23	0
16	Ladysmith	Transformer	(\$0.0)	(\$0.4)	(\$0.0)	\$0.3	\$0.0	\$0.0	\$0.0	\$0.0	\$0.3	56	12
17	Keystone - South Bend	Line	(\$0.0)	(\$0.2)	\$0.0	\$0.2	(\$0.0)	(\$0.0)	(\$0.0)	(\$0.0)	\$0.2	12	10
18	Juniata	Transformer	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	(\$0.0)	(\$0.2)	(\$0.2)	(\$0.2)	0	5
19	Lackawanna	Transformer	(\$0.0)	(\$0.1)	\$0.0	\$0.1	\$0.0	\$0.0	\$0.0	\$0.0	\$0.1	42	6
20	Conastone - Hunterstown	Line	\$0.0	\$0.0	\$0.0	\$0.0	\$0.1	(\$0.0)	\$0.0	\$0.1	\$0.1	0	20
Top 20 Total			\$134.6	(\$55.1)	\$1.6	\$191.4	\$4.2	\$9.0	\$2.2	(\$2.6)	\$188.8	7,439	4,510
All Other Constraints			(\$0.1)	(\$0.2)	\$0.0	\$0.1	\$0.0	\$0.0	(\$0.0)	\$0.0	\$0.1	19	3
Total			\$134.5	(\$55.4)	\$1.6	\$191.5	\$4.2	\$9.0	\$2.2	(\$2.6)	\$188.9	7,458	4,513

¹⁰ See "New York Independent System Operator, Inc. NYISO Tariffs," (September 16, 2019) Section 35.3.1, Effective Date: January 15, 2013. <<http://www.pjm.com/documents/agreements.aspx>>.

¹¹ See "New York Independent System Operator, Inc. NYISO Tariffs," (September 16, 2019) Section 35.23, Effective Date: May 1, 2017. <<http://www.pjm.com/documents/agreements.aspx>>.

Table F-27 Regional constraints summary (By facility): 2018

		Congestion Costs (Millions)											
		Day-Ahead				Balancing				Event Hours			
No.	Constraint	Type	Implicit	Implicit	Explicit	Total	Implicit	Implicit	Explicit	Total	Grand Total	Day-Ahead	Real-Time
			Withdrawal Charges	Injection Credits	Charges		Withdrawal Charges	Injection Credits	Charges				
1	AEP - DOM	Interface	\$55.6	(\$66.9)	(\$5.3)	\$117.2	\$13.4	\$18.7	\$9.0	\$3.8	\$121.0	720	150
2	5004/5005 Interface	Interface	(\$15.4)	(\$54.4)	(\$4.4)	\$34.6	\$0.8	\$1.7	\$2.1	\$1.1	\$35.7	175	47
3	Conastone - Peach Bottom	Line	\$29.8	\$0.7	(\$0.2)	\$28.9	\$1.6	\$0.8	(\$0.0)	\$0.7	\$29.6	1,100	422
4	Bedington - Black Oak	Interface	\$10.2	(\$14.0)	(\$1.4)	\$22.7	\$0.6	\$0.7	\$0.6	\$0.5	\$23.2	316	52
5	AP South	Interface	\$14.1	(\$8.3)	(\$1.6)	\$20.8	\$0.1	\$0.1	(\$0.0)	(\$0.0)	\$20.8	498	37
6	Yukon	Transformer	(\$2.6)	(\$9.7)	\$0.3	\$7.4	\$0.6	\$0.8	(\$0.5)	(\$0.7)	\$6.8	102	58
7	CPL - DOM	Interface	\$6.1	(\$1.2)	\$0.8	\$8.0	\$0.3	\$1.5	(\$0.4)	(\$1.6)	\$6.4	272	98
8	West	Interface	(\$1.4)	(\$6.2)	(\$0.8)	\$4.0	\$0.0	(\$0.0)	(\$0.0)	(\$0.0)	\$4.0	74	11
9	East	Interface	(\$2.3)	(\$5.9)	(\$0.1)	\$3.5	(\$0.0)	\$0.0	(\$0.1)	(\$0.1)	\$3.4	107	2
10	502 Junction	Transformer	(\$0.3)	(\$2.9)	\$0.0	\$2.7	\$0.0	\$0.0	\$0.0	\$0.0	\$2.7	37	0
11	Hunterstown	Transformer	(\$0.0)	(\$1.9)	\$0.0	\$1.9	\$0.0	\$0.0	\$0.0	\$0.0	\$1.9	169	367
12	Central	Interface	(\$3.2)	(\$6.2)	(\$1.3)	\$1.7	\$0.0	\$0.0	\$0.0	\$0.0	\$1.7	28	0
13	Keeney - Rockspring	Line	(\$0.8)	(\$1.9)	\$0.4	\$1.5	\$0.0	\$0.0	\$0.0	\$0.0	\$1.5	158	0
14	Breignsville - Wescosville	Line	\$0.0	(\$0.2)	\$0.4	\$0.6	\$0.0	\$0.0	\$0.0	\$0.0	\$0.6	108	0
15	Limerick	Transformer	(\$0.1)	(\$0.5)	\$0.1	\$0.4	\$0.0	\$0.0	\$0.0	\$0.0	\$0.4	103	0
16	Hopatcong - Lackawanna	Line	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	(\$0.1)	\$0.0	\$0.1	\$0.1	0	46
17	Wylie Ridge	Transformer	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	(\$0.0)	(\$0.2)	(\$0.1)	(\$0.1)	0	4
18	Three Mile Island	Transformer	\$0.0	(\$0.1)	(\$0.0)	\$0.1	\$0.0	\$0.0	\$0.0	\$0.0	\$0.1	4	0
19	Valley - Bath County	Line	(\$0.0)	(\$0.1)	\$0.0	\$0.1	\$0.0	\$0.0	\$0.0	\$0.0	\$0.1	2	0
20	Conastone	Transformer	\$0.0	(\$0.0)	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	4	0
Top 20 Total			\$89.4	(\$179.7)	(\$12.9)	\$256.2	\$17.5	\$24.2	\$10.4	\$3.6	\$259.8	3,977	1,294
All Other Constraints			(\$0.0)	(\$0.1)	\$0.0	\$0.1	\$0.0	\$0.0	(\$0.0)	\$0.0	\$0.1	18	5
Total			\$89.4	(\$179.8)	(\$12.9)	\$256.3	\$17.5	\$24.2	\$10.4	\$3.6	\$259.9	3,995	1,299

Congestion Costs by Physical and Financial Participants

In order to evaluate the recipients and payers of congestion, the MMU categorized all participants in PJM as either physical or financial. Physical entities include utilities and customers which primarily take physical positions in PJM markets. Financial entities include banks and hedge funds which primarily take financial positions in PJM markets. International market participants that primarily take financial positions in PJM markets are generally considered to be financial entities even if they are utilities in their own countries.

Financial entities were paid \$5.3 million in congestion charges in 2019 and were paid \$13.0 million in congestion charges in 2018 (Table F-28 and Table F-29). Physical entities paid \$588.7 million in congestion charges in 2019 and \$1,322.9 million in congestion charges in 2018.

Table F-28 Congestion cost by type of participant: 2019

		Congestion Costs (Millions)										
		Day-Ahead				Balancing				Inadvertent		Grand Total
		Implicit	Implicit	Explicit	Total	Implicit	Implicit	Explicit	Total	Inadvertent	Grand Total	
		Withdrawal Charges	Injection Credits	Charges		Withdrawal Charges	Injection Credits	Charges				
Financial		\$0.7	\$0.3	(\$0.2)	\$0.2	(\$0.5)	\$0.9	(\$4.1)	(\$5.5)	\$0.0	(\$5.3)	
Physical		\$245.3	(\$412.6)	\$55.9	\$713.8	\$4.2	\$50.1	(\$79.2)	(\$125.1)	\$0.0	\$588.7	
Total		\$246.0	(\$412.3)	\$55.7	\$714.0	\$3.7	\$51.1	(\$83.3)	(\$130.7)	\$0.0	\$583.3	

Table F-29 Congestion cost by type of participant: 2018

		Congestion Costs (Millions)										
		Day-Ahead				Balancing				Inadvertent		Grand Total
		Implicit	Implicit	Explicit	Total	Implicit	Implicit	Explicit	Total	Inadvertent	Grand Total	
		Withdrawal Charges	Injection Credits	Charges		Withdrawal Charges	Injection Credits	Charges				
Financial		\$44.2	(\$2.6)	(\$38.5)	\$8.2	(\$31.6)	\$5.8	\$16.2	(\$21.3)	(\$0.0)	(\$13.0)	
Physical		\$305.1	(\$1,045.9)	\$19.6	\$1,370.7	\$43.1	\$56.2	(\$34.8)	(\$47.8)	\$0.0	\$1,322.9	
Total		\$349.3	(\$1,048.6)	(\$18.9)	\$1,378.9	\$11.5	\$62.0	(\$18.5)	(\$69.1)	\$0.0	\$1,309.9	

Marginal Losses Component of LMP

Zonal Marginal Loss Costs

Table F-30 provides marginal loss costs by control zone and type for 2019. Table F-31 provides total marginal loss costs by control zone and month for 2018 and 2019. The total marginal loss cost for the External category was -\$18.0 million in 2019 and decreased \$17.6 million compared to -\$0.4 million 2018. It was mainly due to the decrease of marginal loss cost incurred by import transactions. The total marginal loss cost incurred by import transactions in 2019 was \$7.3 million, a decrease of \$18.2 million from \$25.5 million in 2018.¹²

Table F-30 Marginal loss costs by control zone and type (Dollars (Millions)): 2019

	Marginal Loss Costs by Control Zone (Millions)									
	Day Ahead				Balancing					
	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
AECO	\$0.8	(\$3.8)	(\$0.2)	\$4.4	\$0.1	(\$0.0)	\$0.2	\$0.3	(\$0.0)	\$4.7
AEP	(\$6.7)	(\$135.5)	\$9.0	\$137.8	\$1.7	\$2.1	(\$10.7)	(\$11.1)	(\$0.0)	\$126.8
APS	\$0.6	(\$38.5)	(\$0.0)	\$39.1	\$0.0	(\$0.7)	\$0.0	\$0.7	(\$0.0)	\$39.8
ATSI	\$28.8	(\$13.0)	\$2.8	\$44.6	(\$0.5)	\$0.1	(\$3.0)	(\$3.6)	(\$0.0)	\$41.0
BGE	\$26.8	\$6.6	\$2.7	\$22.8	(\$0.3)	(\$0.7)	(\$3.1)	(\$2.7)	(\$0.0)	\$20.1
ComEd	(\$107.6)	(\$220.4)	\$4.7	\$117.5	\$3.9	(\$3.2)	(\$4.9)	\$2.2	\$0.0	\$119.7
DAY	\$19.2	\$2.8	\$4.3	\$20.7	(\$0.5)	(\$0.3)	(\$5.2)	(\$5.3)	(\$0.0)	\$15.5
DEOK	\$0.6	(\$11.9)	(\$0.6)	\$11.9	\$0.3	(\$0.8)	\$0.7	\$1.8	(\$0.0)	\$13.7
DLCO	(\$1.0)	(\$7.0)	(\$0.1)	\$5.9	\$0.0	\$0.0	\$0.1	\$0.1	(\$0.0)	\$5.9
DPL	\$8.6	(\$0.7)	\$0.5	\$9.9	(\$0.5)	(\$0.4)	(\$1.1)	(\$1.1)	(\$0.0)	\$8.8
Dominion	\$34.8	(\$30.5)	\$0.3	\$65.6	\$0.5	(\$0.5)	(\$0.7)	\$0.2	\$0.0	\$65.8
EKPC	(\$3.8)	(\$5.0)	(\$0.0)	\$1.2	\$0.1	(\$0.2)	(\$0.3)	(\$0.0)	(\$0.0)	\$1.2
External	(\$13.1)	(\$8.3)	\$14.5	\$9.7	(\$3.2)	(\$1.3)	(\$25.8)	(\$27.7)	\$0.0	(\$18.0)
JCPL	\$0.6	(\$2.0)	(\$0.2)	\$2.5	\$0.3	\$0.0	\$0.2	\$0.5	(\$0.0)	\$2.9
Met-Ed	(\$5.1)	(\$21.1)	(\$0.6)	\$15.4	\$0.2	\$0.0	\$0.4	\$0.5	\$0.0	\$15.9
OVEC	(\$0.1)	(\$14.9)	\$4.0	\$18.8	(\$1.3)	\$0.3	(\$4.1)	(\$5.7)	\$0.0	\$13.2
PECO	(\$12.7)	(\$50.6)	\$0.5	\$38.3	\$0.3	\$0.5	(\$0.3)	(\$0.5)	(\$0.0)	\$37.8
PENELEC	(\$3.9)	(\$44.6)	(\$0.6)	\$40.1	\$0.2	\$1.2	(\$0.1)	(\$1.0)	(\$0.0)	\$39.1
PPL	(\$26.8)	(\$79.0)	\$2.5	\$54.8	\$0.9	\$0.6	(\$2.5)	(\$2.2)	(\$0.0)	\$52.6
PSEG	(\$2.2)	(\$22.8)	\$0.5	\$21.1	\$0.1	\$0.3	(\$0.5)	(\$0.8)	(\$0.0)	\$20.3
Pepco	\$15.0	(\$0.1)	(\$0.5)	\$14.6	\$0.1	(\$0.2)	\$0.5	\$0.8	\$0.0	\$15.4
RECO	(\$0.0)	(\$0.0)	(\$0.2)	(\$0.2)	\$0.0	\$0.0	\$0.2	\$0.2	(\$0.0)	(\$0.0)
Total	(\$47.1)	(\$700.3)	\$43.3	\$696.5	\$2.4	(\$3.1)	(\$60.0)	(\$54.5)	(\$0.0)	\$642.0

¹² 2019 State of the Market Report for PJM, Section 11: Congestion and Marginal Losses, at 549–551.

Table F-31 Monthly marginal loss costs by control zone (Dollars (Millions)): 2018 and 2019

Marginal Loss Costs by Control Zone (Millions)														
2018														
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Inadvertent Charges	Grand Total
AECO	\$2.5	\$0.3	\$0.2	\$0.0	\$0.3	\$0.3	\$1.0	\$1.3	\$0.5	\$0.2	\$0.8	\$0.7	\$0.0	\$7.9
AEP	\$57.9	\$11.5	\$15.5	\$10.9	\$13.4	\$14.0	\$17.8	\$19.4	\$14.5	\$13.5	\$15.7	\$13.8	\$0.0	\$218.0
APS	\$13.5	\$3.0	\$4.0	\$3.2	\$3.7	\$3.4	\$4.7	\$4.7	\$3.9	\$3.2	\$4.4	\$4.3	\$0.0	\$56.0
ATSI	\$8.0	\$3.4	\$4.8	\$4.7	\$4.8	\$4.8	\$5.6	\$5.3	\$5.5	\$4.4	\$4.4	\$3.8	\$0.0	\$59.5
BGE	\$6.9	\$1.6	\$1.9	\$1.3	\$1.6	\$1.7	\$3.1	\$3.2	\$2.2	\$1.7	\$2.2	\$1.9	\$0.0	\$29.4
ComEd	\$43.8	\$9.5	\$12.6	\$10.8	\$13.5	\$10.8	\$14.4	\$14.8	\$12.7	\$12.6	\$16.1	\$14.1	\$0.0	\$185.6
DAY	\$4.5	\$1.4	\$1.9	\$2.2	\$2.3	\$1.9	\$1.4	\$1.0	\$1.7	\$1.2	\$1.1	\$1.3	\$0.0	\$21.8
DEOK	(\$1.4)	\$0.7	\$0.5	\$1.0	\$1.3	\$1.7	\$1.8	\$1.6	\$1.6	\$2.3	\$1.8	\$1.7	\$0.0	\$14.5
DLCO	\$2.0	\$0.5	\$0.8	\$0.7	\$0.8	\$0.6	\$0.6	\$0.6	\$0.6	\$0.6	\$0.7	\$0.7	\$0.0	\$9.1
DPL	\$8.4	\$1.2	\$0.8	\$0.8	\$0.5	\$0.6	\$1.9	\$2.0	\$1.1	\$0.7	\$1.1	\$1.4	\$0.0	\$20.5
Dominion	\$20.7	\$4.1	\$6.6	\$4.5	\$7.0	\$6.9	\$9.0	\$8.8	\$7.6	\$6.3	\$6.0	\$6.3	\$0.0	\$94.0
EKPC	\$1.9	\$0.2	\$0.1	\$0.5	\$0.2	\$0.3	\$0.2	\$0.5	\$0.4	\$0.4	\$0.1	\$0.3	\$0.0	\$5.2
External	\$6.7	\$0.3	\$0.5	\$0.6	(\$1.0)	(\$1.1)	(\$0.4)	(\$0.6)	(\$1.0)	(\$1.5)	(\$1.3)	(\$1.5)	\$0.0	(\$0.4)
JCPL	\$5.7	\$0.5	\$0.4	\$0.5	\$0.5	\$0.2	\$0.6	\$0.7	\$0.1	\$0.0	\$0.1	\$0.5	\$0.0	\$9.8
Met-Ed	\$3.0	\$1.2	\$1.6	\$1.5	\$1.3	\$1.6	\$1.7	\$1.6	\$1.7	\$1.8	\$1.2	\$1.8	\$0.0	\$20.0
OVEC	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$1.5	(\$0.0)	\$1.5
PECO	\$5.3	\$2.0	\$3.8	\$3.3	\$3.7	\$3.7	\$3.8	\$3.7	\$3.9	\$3.2	\$4.4	\$3.1	\$0.0	\$43.8
PENELEC	\$8.4	\$2.9	\$4.4	\$3.3	\$3.1	\$4.3	\$5.0	\$4.1	\$3.0	\$3.3	\$3.7	\$4.7	\$0.0	\$50.2
PPL	\$11.0	\$2.1	\$2.2	\$2.3	\$2.4	\$4.3	\$5.1	\$5.3	\$6.0	\$4.7	\$5.2	\$4.4	\$0.0	\$55.0
PSEG	\$7.6	\$2.0	\$2.6	\$1.9	\$2.3	\$2.1	\$2.4	\$2.5	\$2.3	\$2.0	\$2.2	\$2.5	\$0.0	\$32.4
Pepco	\$6.2	\$1.3	\$2.1	\$1.3	\$1.8	\$1.5	\$2.4	\$2.5	\$1.9	\$1.4	\$2.1	\$1.5	\$0.0	\$25.9
RECO	\$0.4	\$0.0	(\$0.0)	\$0.0	\$0.0	(\$0.0)	\$0.0	\$0.0	\$0.0	(\$0.1)	(\$0.0)	\$0.0	\$0.0	\$0.5
Total	\$222.8	\$49.5	\$67.2	\$55.4	\$63.4	\$63.2	\$82.2	\$83.1	\$70.2	\$62.1	\$72.2	\$68.9	\$0.0	\$960.1
Marginal Loss Costs by Control Zone (Millions)														
2019														
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Inadvertent Charges	Grand Total
AECO	\$0.8	\$0.4	\$0.2	\$0.3	\$0.3	\$0.3	\$0.9	\$0.6	\$0.4	\$0.0	\$0.3	\$0.2	(\$0.0)	\$4.7
AEP	\$20.3	\$11.1	\$11.8	\$7.7	\$8.9	\$8.0	\$14.4	\$10.0	\$9.5	\$6.9	\$9.3	\$8.8	(\$0.0)	\$126.8
APS	\$5.5	\$3.3	\$3.6	\$2.1	\$2.5	\$2.5	\$4.4	\$3.7	\$3.2	\$2.6	\$3.1	\$3.3	(\$0.0)	\$39.8
ATSI	\$4.4	\$3.7	\$5.5	\$3.0	\$2.6	\$2.4	\$4.4	\$3.6	\$2.8	\$2.9	\$3.2	\$2.7	(\$0.0)	\$41.0
BGE	\$2.8	\$1.9	\$2.0	\$0.9	\$1.2	\$1.4	\$2.7	\$2.0	\$1.4	\$0.8	\$1.1	\$1.8	(\$0.0)	\$20.1
ComEd	\$17.2	\$10.3	\$12.7	\$8.6	\$8.8	\$7.1	\$11.4	\$8.7	\$8.1	\$7.3	\$10.5	\$9.2	\$0.0	\$119.7
DAY	\$1.0	\$0.9	\$0.8	\$1.2	\$1.0	\$1.3	\$1.7	\$1.4	\$1.5	\$1.5	\$2.1	\$1.2	(\$0.0)	\$15.5
DEOK	\$1.3	\$0.9	\$1.5	\$0.7	\$1.0	\$0.9	\$1.5	\$1.2	\$1.3	\$1.1	\$1.4	\$0.8	(\$0.0)	\$13.7
DLCO	\$0.8	\$0.5	\$0.5	\$0.5	\$0.5	\$0.4	\$0.6	\$0.5	\$0.5	\$0.3	\$0.6	\$0.5	(\$0.0)	\$5.9
DPL	\$2.0	\$0.9	\$0.9	\$0.1	\$0.2	\$0.7	\$1.8	\$1.1	\$0.4	(\$0.1)	\$0.2	\$0.5	(\$0.0)	\$8.8
Dominion	\$7.8	\$5.1	\$5.7	\$3.3	\$4.6	\$5.1	\$9.1	\$7.0	\$5.3	\$3.8	\$4.6	\$4.5	\$0.0	\$65.8
EKPC	\$0.2	\$0.1	(\$0.1)	\$0.0	(\$0.1)	(\$0.0)	\$0.3	\$0.1	\$0.2	\$0.2	\$0.2	\$0.1	(\$0.0)	\$1.2
External	(\$1.0)	(\$1.5)	(\$0.5)	(\$1.3)	(\$2.0)	(\$2.0)	(\$1.6)	(\$1.6)	(\$2.1)	(\$1.5)	(\$1.6)	(\$1.4)	\$0.0	(\$18.0)
JCPL	\$1.7	\$0.2	\$0.3	\$0.2	(\$0.0)	\$0.0	\$0.5	\$0.2	\$0.1	(\$0.2)	(\$0.2)	\$0.1	(\$0.0)	\$2.9
Met-Ed	\$1.8	\$1.4	\$1.4	\$0.8	\$1.0	\$1.3	\$1.9	\$1.8	\$1.5	\$1.2	\$0.8	\$0.9	\$0.0	\$15.9
OVEC	\$2.3	\$1.3	\$1.7	\$0.4	\$0.8	\$0.7	\$1.5	\$1.1	\$0.7	\$0.6	\$1.1	\$1.0	\$0.0	\$13.2
PECO	\$2.7	\$2.7	\$3.3	\$3.0	\$2.6	\$2.9	\$4.1	\$3.5	\$3.1	\$3.3	\$3.3	\$3.2	(\$0.0)	\$37.8
PENELEC	\$4.1	\$3.4	\$4.0	\$2.8	\$1.9	\$2.7	\$4.3	\$3.1	\$2.7	\$2.5	\$4.0	\$3.6	(\$0.0)	\$39.1
PPL	\$5.2	\$4.1	\$5.0	\$2.5	\$3.4	\$3.4	\$6.2	\$5.3	\$4.2	\$3.5	\$6.0	\$3.8	(\$0.0)	\$52.6
PSEG	\$3.2	\$1.9	\$1.9	\$1.3	\$1.0	\$1.0	\$2.2	\$1.6	\$1.6	\$1.6	\$1.3	\$1.9	(\$0.0)	\$20.3
Pepco	\$2.2	\$1.3	\$1.6	\$0.7	\$1.2	\$1.0	\$1.8	\$1.4	\$1.2	\$0.6	\$1.0	\$1.4	\$0.0	\$15.4
RECO	\$0.1	(\$0.0)	(\$0.0)	(\$0.0)	(\$0.0)	(\$0.0)	(\$0.0)	\$0.0	\$0.0	\$0.0	(\$0.0)	(\$0.0)	(\$0.0)	(\$0.0)
Total	\$86.5	\$53.9	\$63.5	\$38.8	\$41.3	\$41.1	\$73.8	\$56.3	\$47.6	\$39.0	\$52.2	\$48.1	(\$0.0)	\$642.0

Energy Component of LMP

Zonal Energy Costs (SMP)

Table F-32 provides energy costs, defined by SMP, by control zone and type for 2019. Table F-33 provides total energy costs by control zone and month for 2018 and 2019. The total energy cost for the External category in 2019 was \$566.7 million.

Table F-32 Energy costs by control zone and type (Dollars (Millions)): 2019

	Energy Costs by Control Zone (Millions)									
	Day Ahead				Balancing					
	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
AECO	\$309.1	\$217.9	\$0.0	\$91.2	(\$6.7)	(\$17.7)	\$0.0	\$11.0	(\$0.0)	\$102.1
AEP	\$4,184.9	\$4,742.8	\$0.0	(\$557.9)	(\$131.4)	(\$139.0)	\$0.0	\$7.5	(\$0.2)	(\$550.6)
APS	\$1,447.9	\$1,510.7	\$0.0	(\$62.8)	\$7.1	\$4.5	\$0.0	\$2.5	(\$0.1)	(\$60.3)
ATSI	\$2,230.2	\$1,497.9	\$0.0	\$732.3	(\$63.2)	(\$45.8)	\$0.0	(\$17.5)	(\$0.1)	\$714.7
BGE	\$1,441.3	\$1,090.1	\$0.0	\$351.2	(\$20.2)	(\$27.8)	\$0.0	\$7.6	(\$0.1)	\$358.8
ComEd	\$3,798.1	\$4,625.1	\$0.0	(\$826.9)	(\$110.6)	(\$30.2)	\$0.0	(\$80.5)	(\$0.2)	(\$907.6)
DAY	\$581.4	\$140.5	\$0.0	\$440.9	(\$15.8)	(\$3.1)	\$0.0	(\$12.7)	(\$0.0)	\$428.1
DEOK	\$822.2	\$559.9	\$0.0	\$262.3	(\$22.2)	(\$1.6)	\$0.0	(\$20.6)	(\$0.1)	\$241.7
DLCO	\$415.1	\$493.5	\$0.0	(\$78.4)	(\$8.9)	(\$15.6)	\$0.0	\$6.7	(\$0.0)	(\$71.7)
DPL	\$562.6	\$207.0	\$0.0	\$355.6	(\$17.3)	(\$11.6)	\$0.0	(\$5.8)	(\$0.0)	\$349.8
Dominion	\$5,281.7	\$5,239.3	\$0.0	\$42.4	\$1.3	(\$16.7)	\$0.0	\$18.1	(\$0.2)	\$60.2
EKPC	\$362.6	\$214.7	\$0.0	\$147.9	(\$6.1)	(\$4.7)	\$0.0	(\$1.4)	(\$0.0)	\$146.4
External	\$782.7	\$317.4	\$0.0	\$465.3	\$166.8	\$65.3	\$0.0	\$101.4	\$0.0	\$566.7
JCPL	\$662.9	\$374.1	\$0.0	\$288.8	(\$9.7)	(\$12.3)	\$0.0	\$2.6	(\$0.0)	\$291.3
Met-Ed	\$505.0	\$689.5	\$0.0	(\$184.5)	(\$10.5)	(\$17.3)	\$0.0	\$6.8	(\$0.0)	(\$177.8)
OVEC	\$2.7	\$326.2	\$0.0	(\$323.6)	\$27.9	(\$12.0)	\$0.0	\$39.9	(\$0.0)	(\$283.6)
PECO	\$1,219.7	\$2,034.9	\$0.0	(\$815.3)	(\$12.1)	(\$33.4)	\$0.0	\$21.3	(\$0.1)	(\$794.0)
PENELEC	\$1,828.6	\$2,473.0	\$0.0	(\$644.4)	(\$52.6)	(\$69.6)	\$0.0	\$17.0	(\$0.0)	(\$627.4)
PPL	\$1,354.4	\$2,016.5	\$0.0	(\$662.1)	(\$35.6)	(\$62.7)	\$0.0	\$27.2	(\$0.1)	(\$635.0)
PSEG	\$1,261.5	\$1,310.5	\$0.0	(\$49.0)	(\$22.9)	\$1.8	\$0.0	(\$24.6)	(\$0.1)	(\$73.7)
Pepco	\$1,935.4	\$1,477.6	\$0.0	\$457.8	(\$39.2)	(\$29.2)	\$0.0	(\$10.0)	(\$0.1)	\$447.8
RECO	\$44.3	\$3.7	\$0.0	\$40.6	(\$4.9)	(\$3.1)	\$0.0	(\$1.8)	(\$0.0)	\$38.8
Total	\$31,034.3	\$31,562.9	\$0.0	(\$528.6)	(\$386.9)	(\$481.8)	\$0.0	\$94.9	(\$1.5)	(\$435.2)

Table F-33 Monthly energy costs by control zone (Dollars (Millions)): 2018 and 2019

Energy Costs by Control Zone (Millions)														
2018														
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Inadvertent Charge	Grand Total
AECO	\$28.1	\$6.4	\$8.2	\$16.2	\$6.8	\$12.3	\$17.5	\$18.9	\$19.1	\$15.4	\$6.9	\$9.2	\$0.1	\$165.2
AEP	(\$292.2)	(\$78.8)	(\$78.4)	(\$38.3)	(\$70.8)	(\$95.8)	(\$133.1)	(\$159.2)	(\$85.2)	(\$91.3)	(\$84.1)	(\$48.3)	\$0.8	(\$1,254.8)
APS	\$57.7	\$9.2	\$10.2	\$23.8	(\$4.1)	(\$5.8)	\$1.0	\$4.8	\$10.2	\$15.7	\$8.8	\$10.2	\$0.3	\$142.1
ATSI	\$144.0	\$62.6	\$95.9	\$70.0	\$85.9	\$79.0	\$98.0	\$92.7	\$81.2	\$72.5	\$62.4	\$51.9	\$0.4	\$996.5
BGE	\$59.5	\$28.2	\$30.3	\$16.5	\$18.1	\$27.6	\$43.3	\$43.9	\$33.4	\$27.5	\$29.5	\$30.1	\$0.2	\$388.2
ComEd	(\$264.3)	(\$56.5)	(\$84.6)	(\$66.6)	(\$85.9)	(\$61.7)	(\$79.5)	(\$75.2)	(\$86.2)	(\$94.3)	(\$107.5)	(\$93.1)	\$0.5	(\$1,155.0)
DAY	\$46.9	\$19.2	\$24.5	\$9.4	\$19.7	\$43.0	\$47.4	\$49.7	\$42.7	\$46.3	\$53.3	\$51.1	\$0.1	\$453.4
DEOK	\$92.4	\$14.5	\$39.1	\$40.2	\$48.4	\$38.1	\$24.0	\$19.8	\$18.5	\$0.6	\$6.3	\$8.8	\$0.2	\$351.1
DLCO	(\$25.7)	(\$7.1)	(\$9.7)	(\$3.1)	(\$2.3)	(\$5.6)	\$1.2	\$2.3	(\$4.9)	\$1.1	(\$2.4)	(\$12.4)	\$0.1	(\$68.5)
DPL	\$90.2	\$27.7	\$33.1	\$24.9	\$29.4	\$33.2	\$38.7	\$35.1	\$29.5	\$24.0	\$40.4	\$43.7	\$0.1	\$449.9
Dominion	\$55.5	\$4.9	\$20.2	\$23.3	\$18.1	(\$11.5)	(\$10.9)	(\$5.8)	(\$18.7)	\$4.4	\$32.7	\$17.4	\$0.6	\$130.3
EKPC	\$23.1	\$10.2	\$16.4	\$11.6	\$13.9	\$4.3	\$9.7	\$3.8	\$8.4	\$9.9	\$18.4	\$12.6	\$0.1	\$142.6
External	(\$72.7)	\$17.0	(\$17.4)	(\$18.3)	\$8.4	\$42.4	\$45.2	\$57.2	\$66.6	\$68.3	\$36.2	\$62.1	\$0.0	\$295.0
JCPL	\$97.7	\$11.2	\$6.5	\$1.7	\$8.7	\$17.9	\$26.1	\$31.2	\$22.1	\$35.7	\$45.0	\$34.0	\$0.1	\$338.1
Met-Ed	(\$21.3)	(\$16.5)	(\$12.9)	(\$20.1)	(\$14.4)	(\$19.2)	(\$18.7)	(\$17.0)	(\$21.4)	(\$23.8)	(\$10.4)	(\$21.3)	\$0.1	(\$217.1)
OVEC	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	(\$33.3)	(\$0.0)	(\$33.3)
PECO	(\$86.6)	(\$57.7)	(\$70.8)	(\$84.8)	(\$95.0)	(\$65.7)	(\$75.7)	(\$71.9)	(\$70.8)	(\$69.0)	(\$92.2)	(\$79.9)	\$0.2	(\$920.1)
PENELEC	(\$195.7)	(\$55.7)	(\$72.6)	(\$66.3)	(\$59.4)	(\$71.9)	(\$84.7)	(\$65.5)	(\$42.1)	(\$45.3)	(\$66.5)	(\$75.4)	\$0.1	(\$900.8)
PPL	(\$49.4)	(\$15.3)	(\$8.8)	(\$12.9)	(\$17.1)	(\$51.9)	(\$65.7)	(\$81.6)	(\$83.5)	(\$62.1)	(\$63.3)	(\$55.0)	\$0.2	(\$566.5)
PSEG	\$23.1	(\$5.9)	(\$13.0)	(\$10.0)	\$7.7	(\$3.3)	(\$7.0)	(\$4.3)	(\$11.6)	(\$19.6)	(\$16.0)	(\$17.5)	\$0.2	(\$77.3)
Pepco	\$125.0	\$46.0	\$38.4	\$41.4	\$38.3	\$50.2	\$63.0	\$60.1	\$42.8	\$37.4	\$51.0	\$54.2	\$0.2	\$647.9
RECO	\$9.2	\$2.8	\$3.5	\$3.5	\$4.5	\$4.5	\$6.1	\$5.9	\$4.6	\$3.9	\$4.1	\$3.8	\$0.0	\$56.3
Total	(\$155.5)	(\$33.8)	(\$42.1)	(\$37.8)	(\$41.1)	(\$39.8)	(\$54.0)	(\$54.9)	(\$45.4)	(\$42.7)	(\$47.5)	(\$46.8)	\$4.6	(\$636.7)
Energy Costs by Control Zone (Millions)														
2019														
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Inadvertent Charge	Grand Total
AECO	\$9.1	\$6.2	\$15.0	\$1.6	\$5.7	\$10.4	\$17.1	\$12.8	\$6.8	\$7.1	\$4.5	\$5.9	(\$0.0)	\$102.1
AEP	(\$118.3)	(\$60.6)	(\$37.0)	(\$17.7)	(\$51.1)	(\$49.6)	(\$82.3)	(\$49.2)	(\$41.9)	(\$8.0)	(\$8.5)	(\$26.0)	(\$0.2)	(\$550.6)
APS	\$13.2	\$7.3	\$15.0	(\$1.6)	(\$7.5)	(\$6.7)	(\$14.7)	(\$16.7)	(\$23.8)	(\$13.9)	(\$5.6)	(\$5.4)	(\$0.1)	(\$60.3)
ATSI	\$78.1	\$60.9	\$81.6	\$41.0	\$48.7	\$46.3	\$78.2	\$54.7	\$54.2	\$54.5	\$65.1	\$51.5	(\$0.1)	\$714.7
BGE	\$41.2	\$38.8	\$39.3	\$19.8	\$18.4	\$26.4	\$45.5	\$33.7	\$24.1	\$18.8	\$23.7	\$29.2	(\$0.1)	\$358.8
ComEd	(\$114.4)	(\$66.7)	(\$94.0)	(\$87.7)	(\$78.8)	(\$60.4)	(\$63.0)	(\$52.9)	(\$64.2)	(\$64.1)	(\$88.0)	(\$73.2)	(\$0.2)	(\$907.6)
DAY	\$51.8	\$37.4	\$42.4	\$29.4	\$29.9	\$29.3	\$42.3	\$34.9	\$33.6	\$27.5	\$36.6	\$33.0	(\$0.0)	\$428.1
DEOK	\$21.8	\$14.4	\$2.6	\$26.2	\$6.1	\$17.5	\$27.3	\$23.7	\$17.7	\$30.5	\$33.3	\$20.8	(\$0.1)	\$241.7
DLCO	(\$11.9)	(\$6.7)	(\$11.4)	(\$10.0)	(\$7.6)	(\$3.2)	(\$1.1)	(\$1.6)	(\$3.9)	\$1.3	(\$7.6)	(\$8.1)	(\$0.0)	(\$71.7)
DPL	\$50.1	\$32.3	\$31.7	\$21.5	\$23.4	\$25.3	\$29.4	\$25.6	\$26.4	\$20.4	\$30.6	\$33.3	(\$0.0)	\$349.8
Dominion	\$18.7	(\$3.7)	\$18.7	\$6.7	\$22.4	(\$17.9)	(\$24.5)	(\$15.3)	\$9.5	\$19.6	\$24.5	\$1.7	(\$0.2)	\$60.2
EKPC	\$16.5	\$13.6	\$17.8	\$13.7	\$13.8	\$12.5	\$7.0	\$7.7	\$8.8	\$5.8	\$15.8	\$13.5	(\$0.0)	\$146.4
External	\$45.6	\$37.4	\$32.2	\$45.6	\$60.4	\$66.3	\$65.0	\$63.0	\$68.8	\$33.7	\$15.3	\$33.5	\$0.0	\$566.7
JCPL	\$44.2	\$25.2	\$24.6	\$8.4	\$20.6	\$20.3	\$40.0	\$26.5	\$19.1	\$17.0	\$20.3	\$25.1	(\$0.0)	\$291.3
Met-Ed	(\$21.4)	(\$19.0)	(\$18.4)	(\$1.8)	(\$11.4)	(\$19.5)	(\$24.2)	(\$23.5)	(\$20.2)	(\$14.0)	\$1.8	(\$6.2)	(\$0.0)	(\$177.8)
OVEC	(\$35.6)	(\$23.8)	(\$29.1)	(\$12.5)	(\$17.4)	(\$19.3)	(\$29.5)	(\$22.8)	(\$20.8)	(\$21.4)	(\$28.7)	(\$22.8)	(\$0.0)	(\$283.6)
PECO	(\$69.4)	(\$65.0)	(\$84.3)	(\$61.8)	(\$66.2)	(\$60.6)	(\$71.7)	(\$63.6)	(\$58.5)	(\$58.7)	(\$68.5)	(\$65.7)	(\$0.1)	(\$794.0)
PENELEC	(\$78.0)	(\$54.3)	(\$60.9)	(\$51.7)	(\$29.6)	(\$42.9)	(\$58.6)	(\$42.1)	(\$43.0)	(\$42.8)	(\$63.4)	(\$60.2)	(\$0.0)	(\$627.4)
PPL	(\$65.3)	(\$42.3)	(\$57.3)	(\$23.3)	(\$49.5)	(\$45.8)	(\$83.8)	(\$71.9)	(\$54.7)	(\$46.3)	(\$60.1)	(\$34.7)	(\$0.1)	(\$635.0)
PSEG	(\$2.2)	(\$12.8)	(\$10.7)	(\$6.1)	\$4.4	\$1.9	\$1.6	(\$0.1)	(\$6.5)	(\$17.7)	(\$9.7)	(\$15.5)	(\$0.1)	(\$73.7)
Pepco	\$62.4	\$42.7	\$37.2	\$31.6	\$34.7	\$38.0	\$46.3	\$37.1	\$30.4	\$21.9	\$30.2	\$35.4	(\$0.1)	\$447.8
RECO	\$4.0	\$2.8	\$3.2	\$2.6	\$2.7	\$3.1	\$5.2	\$3.9	\$3.1	\$2.6	\$2.9	\$2.7	(\$0.0)	\$38.8
Total	(\$59.7)	(\$36.0)	(\$41.9)	(\$26.2)	(\$27.9)	(\$28.6)	(\$48.3)	(\$36.1)	(\$34.9)	(\$26.2)	(\$35.7)	(\$32.3)	(\$1.5)	(\$435.2)

Appendix G FTR Volumes

This Appendix presents the data used to create Figure 13-1 in the 2019 State of the Market Report for PJM. Each table shows the FTR bid volume, cleared volume and net bid volume by planning period. The bid volume includes the buy, sell and self-scheduled offers. The cleared volume includes the cleared buy, cleared sell and self-scheduled offers. The net bid volume includes all bid and self-scheduled offers, excluding sell offers. The Annual Auction volume is included in June of each planning period.

Table G-1 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2003/2004

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-03	2,679,072	89,840	2,690,737
Jul-03	295,753	8,642	300,808
Aug-03	215,206	9,978	220,241
Sep-03	226,994	9,068	234,315
Oct-03	127,739	10,522	135,885
Nov-03	114,211	8,247	122,362
Dec-03	131,180	8,352	139,221
Jan-04	128,086	10,947	136,657
Feb-04	128,303	12,187	137,790
Mar-04	144,617	13,827	156,543
Apr-04	141,437	17,358	157,776
May-04	168,480	44,641	178,973
Total	4,501,077	243,608	4,611,308

Table G-2 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2004/2005

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-04	939,214	125,044	1,019,868
Jul-04	160,472	21,761	190,198
Aug-04	144,402	22,650	176,642
Sep-04	155,837	13,999	194,229
Oct-04	180,542	49,816	226,156
Nov-04	213,036	23,912	247,780
Dec-04	226,271	18,384	260,964
Jan-05	212,061	22,549	236,135
Feb-05	276,385	20,700	305,613
Mar-05	306,472	25,712	348,416
Apr-05	307,297	36,914	330,088
May-05	280,690	32,545	300,966
Total	3,402,681	413,987	3,837,056

Table G-3 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2005/2006

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-05	1,011,821	159,049	1,120,404
Jul-05	300,153	23,929	340,891
Aug-05	233,493	17,966	276,936
Sep-05	222,404	22,133	266,577
Oct-05	147,493	18,906	189,458
Nov-05	183,750	20,525	227,432
Dec-05	200,886	19,422	244,608
Jan-06	234,473	21,431	275,081
Feb-06	250,308	26,463	293,774
Mar-06	272,662	31,968	317,705
Apr-06	431,398	36,603	472,732
May-06	384,767	38,977	424,962
Total	3,873,608	437,372	4,450,561

Table G-4 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2006/2007

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-06	2,274,846	198,380	2,533,660
Jul-06	719,494	31,662	934,424
Aug-06	738,375	26,392	932,469
Sep-06	630,072	37,351	841,698
Oct-06	710,045	51,193	888,011
Nov-06	765,177	40,110	890,318
Dec-06	757,683	42,848	919,549
Jan-07	778,266	59,813	905,249
Feb-07	884,953	68,179	969,447
Mar-07	661,938	69,754	799,130
Apr-07	455,411	30,963	551,601
May-07	432,783	37,207	480,219
Total	9,809,046	693,852	11,645,776

Table G-5 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2007/2008

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-07	2,961,754	323,632	3,462,015
Jul-07	794,490	51,248	1,068,961
Aug-07	944,015	63,392	1,224,668
Sep-07	901,284	66,611	1,200,730
Oct-07	973,936	112,427	1,245,797
Nov-07	841,326	61,592	1,059,631
Dec-07	1,276,687	49,825	1,461,068
Jan-08	501,642	27,377	655,581
Feb-08	583,749	37,288	676,847
Mar-08	437,241	31,941	590,524
Apr-08	326,050	34,805	427,105
May-08	280,005	22,837	331,327
Total	10,822,178	882,975	13,404,256

Table G-6 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2008/2009

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-08	3,511,130	339,654	3,832,169
Jul-08	968,615	53,843	1,211,784
Aug-08	961,694	40,027	1,224,054
Sep-08	925,250	64,901	1,127,274
Oct-08	802,966	52,768	965,756
Nov-08	607,441	45,707	738,336
Dec-08	550,352	37,633	748,485
Jan-09	488,102	43,739	673,525
Feb-09	492,216	40,439	639,274
Mar-09	391,938	42,722	581,075
Apr-09	299,908	35,685	440,629
May-09	222,092	21,016	295,198
Total	10,221,706	818,134	12,477,560

Table G-7 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2009/2010

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-09	2,652,340	307,584	3,156,826
Jul-09	488,748	41,389	849,742
Aug-09	414,151	55,261	708,452
Sep-09	427,221	56,998	718,246
Oct-09	538,476	64,328	797,069
Nov-09	559,750	65,577	745,333
Dec-09	447,221	68,470	672,986
Jan-10	529,887	64,435	728,765
Feb-10	490,391	62,153	670,272
Mar-10	389,934	73,069	615,690
Apr-10	345,301	66,017	489,638
May-10	291,537	52,036	375,812
Total	7,574,956	977,318	10,528,830

Table G-8 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2010/2011

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-10	3,177,131	428,603	3,894,566
Jul-10	720,172	102,883	1,145,991
Aug-10	859,260	93,226	1,202,137
Sep-10	1,079,947	144,423	1,510,812
Oct-10	1,041,425	120,281	1,427,494
Nov-10	922,444	111,442	1,261,969
Dec-10	1,005,436	157,609	1,359,582
Jan-11	902,052	132,866	1,207,101
Feb-11	931,164	160,750	1,184,383
Mar-11	952,963	182,340	1,250,283
Apr-11	660,480	138,230	913,583
May-11	620,691	169,610	762,538
Total	12,873,166	1,942,261	17,120,443

Table G-9 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2011/2012

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-11	6,233,773	847,183	7,437,352
Jul-11	1,602,795	241,288	2,233,307
Aug-11	1,385,040	204,442	1,981,888
Sep-11	969,184	112,746	1,581,241
Oct-11	1,424,062	134,653	1,908,956
Nov-11	1,098,133	117,705	1,562,764
Dec-11	811,035	93,492	1,318,347
Jan-12	772,843	88,683	1,240,355
Feb-12	816,356	93,977	1,234,341
Mar-12	665,949	99,659	1,126,207
Apr-12	449,078	131,218	795,785
May-12	295,103	94,642	470,495
Total	16,523,352	2,259,688	22,891,036

Table G-10 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2012/2013

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-12	6,407,647	710,169	7,598,008
Jul-12	2,177,990	182,695	2,735,269
Aug-12	909,111	151,693	1,418,249
Sep-12	1,877,747	146,352	2,446,553
Oct-12	788,486	118,052	1,310,859
Nov-12	1,765,875	98,494	2,142,231
Dec-12	1,757,292	115,322	2,230,391
Jan-13	696,121	121,357	1,067,354
Feb-13	805,330	118,298	1,129,794
Mar-13	854,219	132,779	1,196,032
Apr-13	525,505	97,353	790,360
May-13	477,217	87,001	595,463
Total	15,684,148	1,522,778	19,881,561

Table G-11 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2013/2014

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-13	6,607,570	791,995	7,909,805
Jul-13	2,000,987	189,328	2,571,100
Aug-13	2,193,738	239,816	2,726,508
Sep-13	2,046,401	260,404	2,604,664
Oct-13	1,692,645	222,661	2,233,085
Nov-13	1,823,502	237,130	2,307,163
Dec-13	1,795,279	216,021	2,298,733
Jan-14	1,713,078	185,284	2,092,055
Feb-14	1,588,809	157,166	1,979,691
Mar-14	1,560,077	169,500	1,918,025
Apr-14	1,247,111	127,436	1,559,987
May-14	757,354	80,601	934,844
Total	25,026,550	2,877,341	31,135,659

Table G-12 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2014/2015

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-14	8,631,333	744,482	9,600,316
Jul-14	2,365,262	123,067	2,689,241
Aug-14	2,191,719	154,391	2,513,616
Sep-14	2,232,435	167,077	2,636,101
Oct-14	1,935,928	153,735	2,289,409
Nov-14	2,006,939	175,554	2,339,892
Dec-14	1,831,645	116,545	2,138,480
Jan-15	1,586,530	81,368	1,849,891
Feb-15	1,446,978	110,669	1,701,821
Mar-15	1,395,961	97,219	1,684,143
Apr-15	1,194,256	78,599	1,429,386
May-15	699,951	42,698	817,152
Total	27,518,938	2,045,403	31,689,447

Table G-13 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2015/2016

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-15	6,726,193	634,988	7,956,486
Jul-15	1,713,451	90,329	2,341,646
Aug-15	1,593,674	78,196	2,046,131
Sep-15	2,160,014	160,357	2,628,872
Oct-15	1,196,435	71,600	1,704,518
Nov-15	2,060,194	92,310	2,482,819
Dec-15	1,834,874	93,273	2,239,329
Jan-16	2,033,402	151,198	2,374,385
Feb-16	2,305,964	89,153	2,610,677
Mar-16	2,085,527	151,835	2,444,912
Apr-16	1,393,628	117,292	1,663,102
May-16	658,850	59,976	780,265
Total	25,762,206	1,790,507	31,273,141

Table G-14 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2016/2017

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-16	6,208,065	701,086	7,476,215
Jul-16	2,219,166	161,129	2,751,687
Aug-16	2,130,193	166,317	2,611,601
Sep-16	1,876,699	151,538	2,379,705
Oct-16	1,522,572	149,106	1,920,453
Nov-16	1,191,214	106,349	1,542,444
Dec-16	995,951	66,497	1,341,292
Jan-17	1,042,674	60,087	1,305,937
Feb-17	998,397	76,384	1,233,142
Mar-17	846,294	105,822	1,141,063
Apr-17	653,571	70,885	897,780
May-17	463,486	59,067	595,694
Total	20,148,281	1,874,268	25,197,013

Table G-15 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2017/2018

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-17	5,455,078	872,195	6,469,151
Jul-17	2,003,170	257,105	2,530,997
Aug-17	1,703,960	178,490	2,240,951
Sep-17	1,372,384	181,542	1,863,571
Oct-17	1,172,291	150,774	1,649,567
Nov-17	1,327,717	105,816	1,697,539
Dec-17	1,366,297	131,964	1,662,660
Jan-18	1,201,482	87,763	1,494,040
Feb-18	1,132,589	69,333	1,378,665
Mar-18	1,027,661	73,656	1,291,330
Apr-18	616,013	44,824	857,945
May-18	355,923	40,976	485,269
Total	18,734,565	2,194,438	23,621,686

Table G-16 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2018/2019

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-18	5,862,680	1,023,834	7,042,598
Jul-18	1,760,345	154,341	2,243,378
Aug-18	1,123,055	(27,571)	2,359,882
Sep-18	1,750,157	153,418	2,757,631
Oct-18	758,670	138,587	1,599,115
Nov-18	908,639	172,444	1,592,686
Dec-18	608,941	112,617	1,469,596
Jan-19	640,484	110,200	1,250,539
Feb-19	859,679	165,835	1,388,935
Mar-19	516,185	113,019	1,293,106
Apr-19	550,985	115,319	1,065,356
May-19	450,713	91,793	724,776
Total	15,790,534	2,323,835	24,787,597

Table G-17 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2019/2020 through December 2019

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-19	5,605,684	1,131,136	7,353,568
Jul-19	1,454,117	185,425	2,460,501
Aug-19	1,569,517	220,390	2,356,942
Sep-19	1,117,366	170,308	2,150,543
Oct-19	1,194,816	183,862	2,077,332
Nov-19	1,389,259	192,789	2,187,587
Dec-19	956,808	168,125	1,968,938
Total	13,287,567	2,252,035	20,555,409

Figure G-1 summarizes the total revenue associated with all FTRs, regardless of source, to FTR sinks that produced the largest positive and negative revenue from the 2019/2021 Long Term FTR Auction. The top 10 positive revenue producing FTR sinks accounted for \$184.1 million (52.77 percent of the total positive revenue from sinks) and 7.3 percent of all FTRs purchased in the auction. The top 10 negative revenue producing FTR sinks accounted for -\$53.3 million (28.7 percent of total negative revenue from sinks) and constituted 3.8 percent of all FTRs bought in the auction.

Figure G-1 Ten largest positive and negative revenue producing FTR sinks purchased in the Long Term FTR Auction: Planning periods 2019/2021

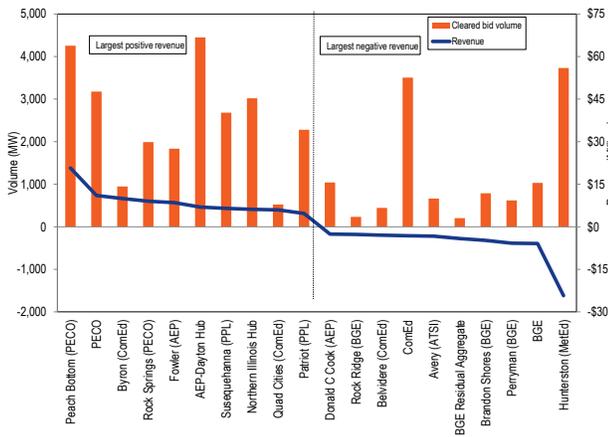


Figure G-2 summarizes the total revenue associated with all FTRs, regardless of sink, to FTR sources that produced the largest positive and negative revenue from the 2019/2022 Long Term FTR Auction. The top 10 positive revenue producing FTR sources accounted for \$206.8 million (58.9 percent of the total positive revenue from sources) and 14.1 percent of all FTRs bought in the auction. The top 10 negative revenue producing FTR sources accounted for -\$58.4 million (30.7 percent of total negative revenue from sources) and constituted 2.6 percent of all FTRs bought in the auction.

Figure G-2 Ten largest positive and negative revenue producing FTR sources purchased in the Long Term FTR Auction: Planning periods 2018/2021

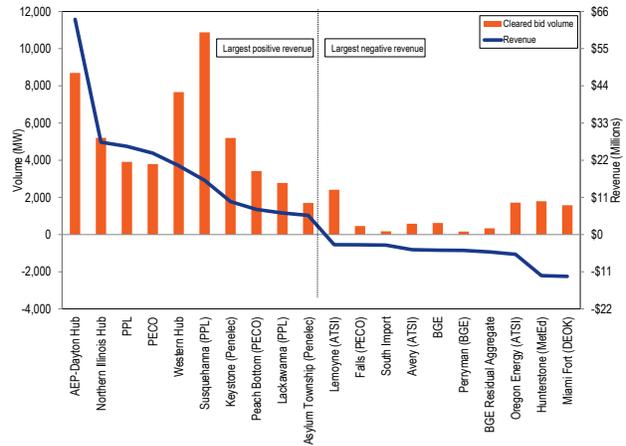


Figure G-3 summarizes the total revenue associated with all FTR sink points, regardless of source, that produced the largest positive and negative revenue in the Annual FTR Auction for the 2019/2020 planning period. The top 10 positive revenue sinks accounted for \$388.8 million (39.9 percent of total positive revenue from sinks) and 13.0 percent of all FTRs purchased. The top 10 negative revenue sinks accounted for -\$34.8 million (29.2 percent of total negative revenue from sinks) and 2.2 percent of all FTRs purchased.

Figure G-3 Ten largest positive and negative revenue producing FTR sinks purchased in the Annual FTR Auction: Planning period 2019/2020

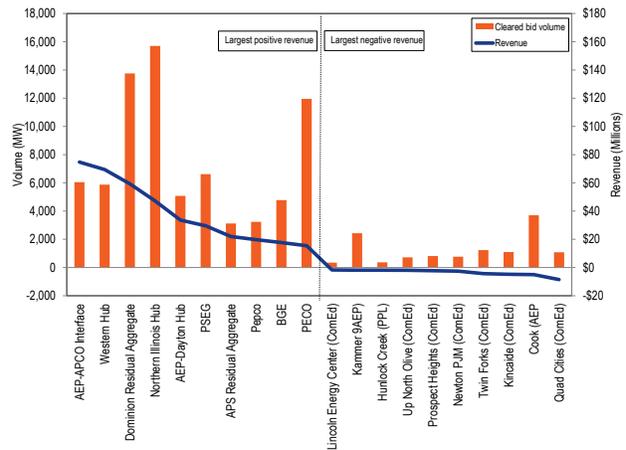


Figure G-4 summarizes total revenue associated with all FTR source points, regardless of sink, that produced the largest positive and negative revenue in the Annual FTR Auction for the 2019/2020 planning period. The top 10 positive revenue sources accounted for \$304.3 million (31.4 percent of total positive revenue from sources) and 7.7 percent of all FTRs purchased. The top 10 negative revenue sources accounted for -\$27.2 million (22.6 percent of total negative revenue from sources) and 1.4 percent of all FTRs purchased.

Figure G-4 Ten largest positive and negative revenue producing FTR sources purchased in the Annual FTR Auction: Planning period 2019/2020

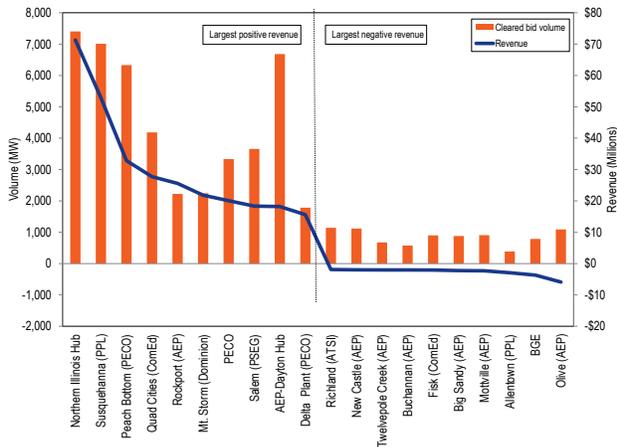


Figure G-5 summarizes total revenue associated with all FTRs, regardless of source, to the FTR sinks that produced the largest positive and negative revenue in the Monthly Balance of Planning Period FTR Auctions during the 2019/2020 planning period. The top 10 positive revenue sinks accounted for \$166.3 million (69.0 percent of total positive revenue from sinks) and 7.0 percent of all FTRs purchased. The top 10 negative revenue sinks accounted for -\$27.5 million (11.4 percent of total negative revenue from sinks) and 0.2 percent of all FTRs purchased.

Figure G-5 Ten largest positive and negative revenue producing FTR sinks purchased in the Monthly Balance of Planning Period FTR Auctions: planning period 2019/2020 through December 31, 2019

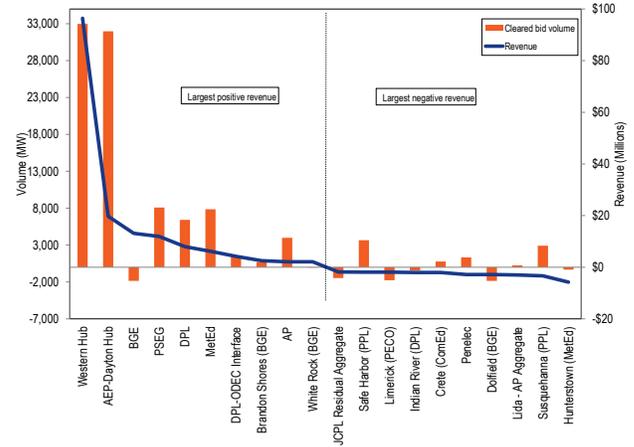
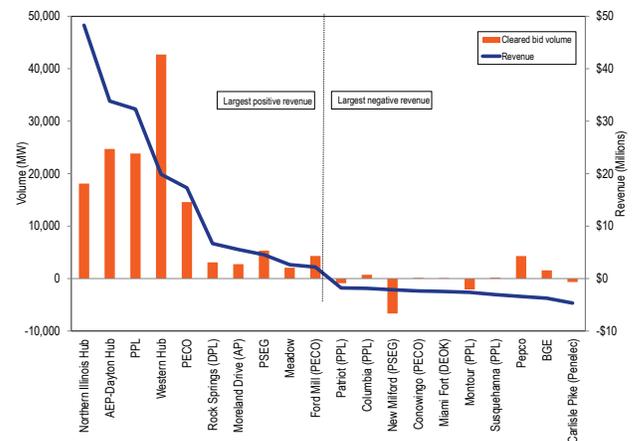


Figure G-6 summarizes the total revenue associated with all FTR source points, regardless of sink, that produced the largest positive and negative revenue in the Monthly Balance of Planning Period FTR Auctions during the 2019/2020 planning period. The top 10 positive revenue sources accounted for \$173.1 million (73.4 percent of total positive revenue from sources) and 10.8 percent of all FTRs purchased. The top 10 negative revenue sources accounted for -\$28.2 million (14.4 percent of total negative revenue from sources) and 0.3 percent of all FTRs purchased.

Figure G-6 Ten largest positive and negative revenue producing FTR sources purchased in the Monthly Balance of Planning Period FTR Auctions: planning period 2019/2020 through December 31, 2019



Appendix H Environmental and Renewable Energy Regulations

This appendix provides more detailed information about environmental and renewable energy regulations and the evolution of rules applicable within the PJM footprint.

Environmental and Renewable Energy Regulations

Environmental requirements and renewable energy mandates have a significant impact on PJM markets.

At the federal level, the Mercury and Air Toxics Standards Rule (MATS) requires significant investments for some fossil fuel fired power plants in the PJM footprint in order to reduce heavy metal emissions. The Environmental Protection Agency (EPA) has promulgated intrastate and interstate air quality standards and associated emissions limits for states. The Cross-State Air Pollution Rule (CSAPR) will require investments for some fossil fuel fired power plants in the PJM footprint in order to reduce SO₂ and NO_x emissions.

State regulations and multi-state agreements have an impact on PJM markets. New Jersey's high electric demand day (HEDD) rule limits NO_x emissions on peak energy demand days and requires investments for noncompliant units. CO₂ costs resulting from the Regional Greenhouse Gas Initiative (RGGI) affect some unit offers in the PJM energy market.

The investments required for environmental compliance have resulted in higher offers in the capacity market, and when units do not clear, in the retirement of units. Federal and state renewable energy mandates and associated incentives have resulted in the construction of substantial amounts of renewable capacity in the PJM footprint, especially wind and solar powered resources. Renewable energy credit (REC) markets created by state programs and federal tax credits have significant impacts on PJM wholesale markets.

Federal Environmental Regulation

The U.S. Environmental Protection Agency (EPA) administers the Clean Air Act (CAA). The CAA regulates air emissions by providing for the establishment of acceptable levels of emissions of hazardous air pollutants. The EPA issues technology based standards for major sources and area sources of emissions.^{1,2} The EPA's actions have and will continue to affect the cost to build and operate generating units in PJM, which in turn affects wholesale energy prices and capacity prices.

The EPA also administers the Clean Water Act (CWA), which regulates water pollution. The EPA implements the CWA through a permitting process, which regulates discharges from point sources that impact water quality and temperature in navigable waterways. In 2014, the EPA implemented new regulations for cooling water intakes under section 316(b) of the CWA.

Control of Mercury and Other Hazardous Air Pollutants

Section 112 of the CAA requires the EPA to promulgate emissions control standards, known as the National Emission Standards for Hazardous Air Pollutants (NESHAP), from both new and existing area and major sources.

On December 21, 2011, the U.S. Environmental Protection Agency (EPA) issued its Mercury and Air Toxics Standards rule (MATS), which applies the CAA maximum achievable control technology (MACT) requirement to new or modified sources of emissions of mercury and arsenic, acid gas, nickel, selenium and cyanide.³ The rule established a compliance deadline of April 16, 2015.

In a related EPA rule, also issued on December 16, 2011, regarding utility New Source Performance Standards (NSPS), the EPA required new coal and oil fired electric utility generating units constructed after May 3, 2011, to

¹ 42 U.S.C. § 7401 et seq. (2000).

² The EPA defines "major sources" as a stationary source or group of stationary sources that emit or have the potential to emit 10 tons per year or more of a hazardous air pollutant or 25 tons per year or more of a combination of hazardous air pollutants. An "area source" is any stationary source that is not a major source.

³ *National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil Fuel Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units*, EPA Docket No. EPA-HQ-OAR-2009-0234, 77 Fed. Reg. 9304 (February 16, 2012); *aff'd*, *White Stallion Energy Center, LLC v EPA*, No. 12-1100 (D.C. Cir. April 15, 2014).

comply with amended emission standards for SO₂, NO_x and filterable particulate matter (PM).⁴

The future of MATS is currently uncertain. On June 29, 2015, the U.S. Supreme Court remanded MATS to the U.S. Court of Appeals for the D.C. Circuit and ordered the EPA to consider cost earlier in the process when making the decision whether to regulate power plants under MATS.⁵ The U.S. Supreme Court ruled in 2015 that “the EPA acted unreasonably when it deemed cost irrelevant to the decision to regulate power plants.”⁶ The remand did not stay MATS and had no effect on the implementation of MATS. The EPA performed a cost review and made the required determination on cost in a supplemental finding.⁷ On April 14, 2016, the EPA issued the required finding that “a consideration of cost does not cause us to change our determination that regulation of hazardous air pollutant (HAP) emissions from coal and oil fired EGUs is appropriate and necessary.”⁸ The rule has been effective since April 14, 2016, and remains effective. In a case now pending before the U.S. Court of Appeals for the District of Columbia Circuit, the supplemental finding is under review.⁹ On April 28, 2017, the Court granted the EPA’s request to postpone scheduled oral argument “to allow the new Administration adequate time to review the Supplemental Finding to determine whether it will be reconsidered.”¹⁰

Air Quality Standards: Control of NO_x, SO₂ and O₃ Emissions Allowances

The CAA requires each state to attain and maintain compliance with fine particulate matter and ozone national ambient air quality standards (NAAQS). Under NAAQS, the EPA establishes emission standards for six air pollutants, including NO_x, SO₂, O₃ at ground level, PM, CO, and Pb, and approves state plans to implement these standards, known as State Implementation Plans (SIPs).¹¹ Standards for each pollutant are set and

periodically revised, most recently for SO₂ in 2010, and SIPs are filed, approved and revised accordingly.

On April 29, 2014, the U.S. Supreme Court upheld the EPA’s Cross-State Air Pollution Rule (CSAPR) and on October 23, 2014, the U.S. Court of Appeals for the District of Columbia Circuit lifted the stay imposed on CSAPR, clearing the way for the EPA to implement this rule and to replace the Clean Air Interstate Rule (CAIR) then in effect. On November 21, 2014, the EPA issued a rule requiring compliance with CSAPR’s Phase 1 emissions budgets effective January 1, 2015, and CSAPR’s Phase 2 emissions effective January 1, 2017.¹² The ruling and the EPA rules eliminated CAIR and replaced it with CSAPR.

In January, 2015, the EPA began implementation of the Cross-State Air Pollution Rule (CSAPR) to address the CAA’s requirement that each state prohibit emissions that significantly interfere with the ability of another state to meet NAAQS.¹³ The CSAPR requires specific states in the eastern and central United States to reduce power plant emissions of SO₂ and NO_x that cross state lines and contribute to ozone and fine particle pollution in other states. The CSAPR requires reductions to levels consistent with the 1997 ozone and fine particle and 2006 fine particle NAAQS.¹⁴ The CSAPR covers 28 states, including all of the PJM states except Delaware, and also excluding the District of Columbia.¹⁵

CSAPR establishes two groups of states with separate requirements standards. Group 1 includes a core region comprised of 21 states, including all of the PJM states except Delaware, and also excluding the District of Columbia.¹⁶ Group 2 does not include any states in the PJM region.¹⁷ Group 1 states must reduce both annual SO₂ and NO_x emissions to help downwind areas attain the 24-Hour and/or Annual Fine Particulate Matter¹⁸

4 NSPS are promulgated under CAA § 111.

5 Michigan et al. v. EPA, Slip Op. No. 14–46.

6 135 S. Ct. 2699, 2712 (2015).

7 See Supplemental Finding That It Is Appropriate and Necessary to Regulate Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units, EPA Docket No. EPA-HQ-OAR-2009-0234; see also White Stallion Energy Center, LLC v. EPA, Slip Op. No. 12-1100 (D.C. Cir. 2015) (per curiam).

8 Supplemental Finding that it is Appropriate and Necessary to Regulate Hazardous Air Pollutants from Coal- and Oil-Fired Electric Utility Steam Generating Units, EPA Docket No. EPA-HQ-OAR-2009-0234; see also White Stallion Energy Center, LLC v. EPA, Slip Op. No. 12-1100 (D.C. Cir. 2015) (per curiam).

9 See Case No. 16-1127, et al.

10 Respondent EPA’s Motion to Continue Oral Argument, Case No. 16-1127, et al. (April 18, 2017) at 1.

11 Nitric Oxides (NO_x), Sulfur Dioxide (SO₂), Ozone (O₃), Particulate Matter (PM), Carbon Monoxide (CO) and Lead (Pb).

12 Rulemaking to Amend Dates in Federal Implementation Plans Addressing Interstate Transport of Ozone and Fine Particulate Matter, EPA-HQ-OAR-2009-0491.

13 CAA § 110(a)(2)(D)(i)(I).

14 Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals, Final Rule, Docket No. EPA-HQ-OAR-2009-0491, 76 Fed. Reg. 48208 (August 8, 2011) (“CSAPR”); Revisions to Federal Implementation Plans To Reduce Interstate Transport of Fine Particulate Matter and Ozone, Final Rule, Docket No. EPA-HQ-2009-0491, 77 Fed. Reg. 10342 (February 21, 2012); Revisions to Federal Implementation Plans To Reduce Interstate Transport of Fine Particulate Matter and Ozone, Final Rule, Docket No. EPA-HQ-2009-0491, 77 Fed. Reg. 34830 (June 12, 2012).

15 *Id.*

16 Group 1 states include: New York, Pennsylvania, New Jersey, Maryland, Virginia, West Virginia, North Carolina, Tennessee, Kentucky, Ohio, Indiana, Illinois, Missouri, Iowa, Wisconsin, and Michigan.

17 Group 2 states include: Minnesota, Nebraska, Kansas, Texas, Alabama, Georgia and South Carolina.

18 The EPA defines Particulate Matter (PM) as “[a] complex mixture of extremely small particles and liquid droplets. It is made up of a number of components, including acids (such as nitrates and sulfates), organic chemicals, metals, and soil or dust particles.” Fine PM (PM_{2.5}) measures less than 2.5 microns across.

NAAQS and to reduce ozone season NO_x emissions to help downwind areas attain the 2008 8-Hour Ozone NAAQS.

CSAPR requires reductions of emissions for each state below certain assurance levels, established separately for each emission type. Assurance levels are the state budget for each type of emission, determined by the sum of unit-level allowances assigned to each unit located in such state, plus a variability limit, which is meant to account for the inherent variability in the state's yearly baseline emissions. Because allowances are allocated only up to the state emissions budget, any level of emissions in a state above its budget must be covered by allowances obtained through trading for unused allowances allocated to units located in other states included in the same group.

The rule provides for implementation of a trading program for states in the CSAPR region. Sources in each state may achieve those limits as they prefer, including unlimited trading of emissions allowances among power plants within the same state and limited trading of emission allowances among power plants in different states in the same group.

If state emissions exceed the applicable assurance level, including the variability limit, a penalty is assessed and allocated to resources within the state in proportion to their responsibility for the excess. The penalty requires surrender of two additional allowances for each allowance needed to cover the excess.

On September 7, 2016, the EPA issued a final rule updating the CSAPR ozone season NO_x emissions program to reflect the decrease to the ozone season NAAQS that occurred in 2008 (CSAPR Update).¹⁹ The CSAPR had been finalized in 2011 based on the 1997 ozone season NAAQS. The 2008 ozone season NO_x emissions level was lowered to 0.075 ppm from 0.08 in 1997.²⁰ The CSAPR Update increases the reductions required from upwind states to assist downwind states' ability to meet the lower 2008 standard.

The CSAPR Update also finalizes Federal Implementation Plans (FIPs) for each of the PJM states covered by

CSAPR.²¹ The EPA approves a FIP for states that fail to timely submit and obtain approval of their own implementation plan (SIPs).

Starting May 1, 2017, the CSAPR Update requires reduced summertime NO_x from power plants in certain PJM states: Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, Ohio, Pennsylvania, Tennessee, Virginia and West Virginia.²² The EPA has removed North Carolina from the ozone season NO_x trading program.²³

Clean Power Plan

On August 3, 2015, the EPA issued a final rule for regulating CO₂ from certain existing power generation facilities titled Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units (the Clean Power Plan). The rule required that individual state plans be submitted by September 6, 2016. However, on February 9, 2016, the U.S. Supreme Court issued a stay of the rule preventing its taking effect while under judicial review.

On October 10, 2017, the EPA proposed to repeal the Clean Power Plan based on its determination that the Plan exceeds the EPA's authority under Section 111 of the CAA. On August 8, 2017, the U.S. Court of Appeals for the District of Columbia Circuit issued an order continuing for 60 days to hold in abeyance court proceedings challenging the Clean Power Plan.

Federal Regulation of Greenhouse Gas Emissions

On June 19, 2019, the EPA repealed the prior administration's Clean Power Plan and replaced it with the Affordable Clean Energy (ACE) rule, which establishes emission guidelines for states to develop plans to address greenhouse gas emissions from existing coal-fired power plants. On August 3, 2015, the EPA issued a final rule for regulating CO₂ from certain existing power generation facilities titled Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units (the Clean Power Plan).

¹⁹ *Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS*, EPA-HQ-OAR-2015-0500, 81 Fed. Reg. 74504 (Oct. 26, 2016) ("CSAPR Update").

²⁰ *Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone*, NOPR, EPA-HQ-OAR-2009-0491, 75 Fed. Reg. 45210, 45220 (Aug. 2, 2010).

²¹ CSAPR Update at 74506 & n.9. PJM states that did not submit SIPs include Illinois, Maryland, Michigan, New Jersey, North Carolina, Pennsylvania, Tennessee, Virginia, and West Virginia; PJM states submitting SIPs but not obtaining approval include Indiana, Kentucky and Ohio. *Id.*

²² *Id.* at 74554.

²³ *Id.* at 74507 n.13.

The EPA regulates CO₂ as a pollutant using CAA provisions that apply to pollutants not subject to NAAQS.^{24 25}

The U.S. Court of Appeals for the Seventh Circuit has determined that a government agency can reasonably consider the global benefits of carbon emissions reduction against costs imposed in the U.S. by regulations in analyses known as the “Social Costs of Carbon.”²⁶ The Court rejected claims raised by petitioners that raised concerns that the Social Cost of Carbon estimates were arbitrary, were not developed through transparent processes, and were based on inputs that were not peer reviewed.²⁷ Although the decision applies only to the Department of Energy’s regulations of manufacturers, it bolsters the ability of the EPA and state regulators to rely on Social Cost of Carbon analyses.

Effective October 23, 2015, the EPA placed national limits on the amount of CO₂ that new, modified or reconstructed fossil fuel fired steam power plants would be allowed to emit based on the best system of emission reductions (BSER) determined by the EPA.²⁸ On December 12, 2018, the EPA proposed to revise the 2015 GHG NSR Rule by increasing the allowable emissions and eliminating the requirement for carbon capture for new coal units.²⁹

The BSER for new steam units is an efficient new supercritical pulverized coal utility boiler implementing partial carbon capture and storage (“CCS”), releasing no more than 1,400 lb CO₂/MWh-g.³⁰

The BSER for modified steam units is the most efficient operation achievable through operating practices and upgrades, releasing no more than the unit’s best historic

emissions (2002 through the date of the modifications).³¹ Restrictions on modified units can be no more stringent than 1,800 lb CO₂/MWh-g for sources with heat input >2,000 MMBtu/h or 2,000 lb CO₂/MWh-g for sources with heat input ≤2,000 MMBtu/h.³²

The BSER for reconstructed steam units is the most efficient generating technology, allowing for supercritical steam conditions for the larger units and subcritical conditions for the smaller units.³³ Units with heat input >2,000 MMBtu/h are required to meet an emissions limit of 1,800 lb CO₂/MWh-g. Units with heat input ≤2,000 MMBtu/h are required to meet an emissions limit of 2,000 lb CO₂/MWh-g.³⁴

The BSER for new and reconstructed CTs is efficient NGCC technology for base load natural gas units and clean fuel for non base load and multi fuel fired units. Base load natural gas fired unit are restricted to 1,000 lb CO₂/MWh-g or 1,030 lb CO₂/MWh-n.³⁵ Non base load units are limited to 120 lb CO₂/MMBtu. Multi fuel fired units are limited to 160 lb CO₂/MMBtu.³⁶

On December 12, 2018, the EPA proposed to revise the 2015 GHG NSR Rule.³⁷ The BSER for both new and reconstructed steam and IGCC units would be the most efficient generating technology in combination with best operating practices, dropping the CCS requirement for new units.³⁸ For modified units, the BSER would be best demonstrated performance. New and reconstructed units would share a raised emissions limit: 1,900 lb CO₂/MWh-gross for units with heat input >2,000 MMBtu/h; 2,000 lb CO₂/MWh-gross for units with heat input ≤2,000 MMBtu/h; or 2,200 lb CO₂/MWh-gross for coal refuse fired units.³⁹ No change was proposed for CTs.⁴⁰ The proposed rule would weaken the current greenhouse gas based BSER and standards for new source review. The proposed rule is pending at the EPA.

²⁴ See CAA § 111.

²⁵ On April 2, 2007, the U.S. Supreme Court overruled the EPA’s determination that it was not authorized to regulate greenhouse gas emissions under the CAA and remanded the matter to the EPA to determine whether greenhouse gases endanger public health and welfare. *Massachusetts v. EPA*, 549 U.S. 497. On December 7, 2009, the EPA determined that greenhouse gases, including carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride, endanger public health and welfare. See *Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act*, 74 Fed. Reg. 66496, 66497 (Dec. 15, 2009). In a decision dated June 26, 2012, the U.S. Court of Appeals for the D.C. Circuit upheld the endangerment finding, rejecting challenges brought by industry groups and a number of states. *Coalition for Responsible Regulation, Inc., et al. v. EPA*, No 09-1322.

²⁶ See *Zero Zone, Inc., et al., v. U.S. Dept. of Energy, et al.*, Case Nos. 14-2147, et al., Slip Op. (Aug. 8, 2016).

²⁷ *Id.*

²⁸ *Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units*, Proposed Rule, EPA-HQ-OAR-2013-0495, 90 Fed. Reg. 205 (October 23, 2015) (“2015 GHG NSR Rule”); 40 CFR Part 60, subpart TTTT.

²⁹ *Review of Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units*, EPA-HQ-OAR-2013-0495; FRL-9987-85- OAR, 83 Fed. Reg. 65424, 65427 (Dec. 20, 2018) (“2018 Proposed Rev. GHG NSR”).

³⁰ *Id.*

³¹ 2015 GHG NSR Rule at 205.

³² *Id.*

³³ *Id.*

³⁴ *Id.*

³⁵ *Id.*

³⁶ *Id.*

³⁷ *Review of Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units*, EPA-HQ-OAR-2013-0495; FRL-9987-85- OAR, 83 Fed. Reg. 65424, 65427 (Dec. 20, 2018) (“2018 Proposed Rev. GHG NSR”).

³⁸ *Id.*

³⁹ *Id.*

⁴⁰ *Id.*

On June 19, 2019, the EPA repealed the Clean Power Plan⁴¹ and replaced it with the Affordable Clean Energy (ACE) rule.⁴² The ACE rule establishes emission guidelines pursuant to which states must develop plans to address greenhouse gas emissions from existing coal fired power plants.

The ACE Rule (i) defines the BSER for existing power plants as on-site, heat-rate efficiency improvements and (ii) lists “candidate technologies” that states can use to establish standards of performance and incorporate into their plans.^{43 44}

The ACE Rule replaces the Clean Power Plan’s use of national greenhouse gas emissions limits with the application of emission reduction measures at the power plant. The ACE Rule allows states to establish standards of performance based on a proposed list of candidate technologies to achieve the BSER standard.⁴⁵ As a result, the impact on coal fired generation depends upon actions taken in their host state. Under the ACE Rule some states may permit more CO₂ emissions than under the Clean Power Plan.

The EPA finalized regulations governing implementation of ACE and any future emission guidelines issued under Section 111(d) of the CAA. The regulations clarify “that states have broad discretion in establishing and applying emissions standards consistent with the BSER.” The implementing regulations also coordinate state and federal deadlines: A state must issue State Implementation Plans (SIP) by June 19, 2022; if no SIP issues, the EPA must issue a Federal Implementation Plan (FIP) by June 19, 2024. The EPA will accept or reject a state’s SIP within 12 months after timely receipt, and, if a state’s SIP is rejected, issue an FIP for such state within two years.

41 *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, EPA-HQ-OAR-2013-0602, Final Rule *mimeo* (Aug. 3, 2015) (Clean Power Plan). The Clean Power Plan never took effect because it was subject to a stay issued by the U.S. Supreme Court.

42 See *Repeal of the Clean Power Plan; Emission Guidelines for Greenhouse Gas Emissions From Existing Electric Utility Generating Units; Revisions to Emission Guidelines Implementing Regulations*, EPA Docket No. EPA-HQ-OAR-2017-0355, et al., 84 Fed. Reg. 32520 (July 8, 2019) (“ACE Rule”).

43 See CAA § 111(d).

44 *Id.*

45 Candidate technologies include: Neural network/intelligent sootblowers, boiler feed pumps, air heater and duct leakage control, variable frequency drives, blade path upgrade (steam turbine), redesign/replace economizer, and improved operating and maintenance practices.

CWA: WOTUS Definition and Effluents

WOTUS

The Clean Water Act (CWA) applies to the navigable waters, which are defined as waters of the United States (WOTUS).⁴⁶

On October 22, 2010, the EPA issued a final rulemaking to rescind the definition of WOTUS proposed in the 2015 Clean Water Rule. The rule prevents the potential implementation of a broader definition of WOTUS included in the 2015 rule that was never implemented as the result of a stay issued by a reviewing Court. The U.S. Supreme Court reversed the stay, but the EPA amended the 2015 Clean Water Rule to establish an applicability date of February 6, 2020. In *Rapanos v. U.S.*, Supreme Court concurrently defined WOTUS to include (i) navigable waters that are “relatively permanent, standing or continuously flowing bodies of water” and (ii) waters with a “significant nexus” to navigable waters.⁴⁷

On January 23, 2020, the EPA and Department of the Army issued a final rule to define WOTUS.⁴⁸ The replacement rule narrows the scope of federal jurisdiction and expands the scope of state jurisdiction over waters compared to the current rule and its interpreting precedent. The rule will become effective 60 days after its publication in the Federal Register, which is pending.

The replacement rule defines four categories of waters subject to federal regulation: (i) the territorial seas, and waters which are currently used, or were used in the past, or may be susceptible to use in interstate or foreign commerce, including waters which are subject to the ebb and flow of the tide; (ii) tributaries; (3) lakes and ponds, and impoundments of jurisdictional waters; and (iv) adjacent wetlands.⁴⁹

The replacement rule specifically excludes from federal jurisdiction 12 categories of waters including: (i) waters or water features that are specified as regulated; (ii) groundwater, including groundwater drained through subsurface drainage systems; (iii) ephemeral features,

46 33 U.S.C. 1251 et seq.; 33 U.S.C. § 1362(7) (“The term “navigable waters” means the waters of the United States, including the territorial seas.”).

47 547 U.S. 715 (2006).

48 See *The Navigable Waters Protection Rule: Definition of “Waters of the United States,”* EPA Docket No. EPA-HQ-OW-2018-0149, ___ Fed. Reg. ____.

49 See *Id.*; 40 CFR § 328.3 (pending effective date).

including ephemeral streams, swales, gullies, rills, and pools; (iv) diffuse stormwater run-off and directional sheet flow over upland; (v) ditches; (vi) prior converted cropland; (vii) artificially irrigated areas, including fields flooded for agricultural production, that would revert to upland should application of irrigation water to that area cease; (viii) artificial lakes and ponds, including water storage reservoirs and farm, irrigation, stock watering, and log cleaning ponds, constructed or excavated in upland or in non-jurisdictional waters, so long as those artificial lakes and ponds are not impoundments of jurisdictional waters meeting certain conditions; (ix) water-filled depressions constructed or excavated in upland or in non-jurisdictional waters incidental to mining or construction activity, and pits excavated in upland or in non-jurisdictional waters for the purpose of obtaining fill, sand, or gravel; (x) stormwater control features constructed or excavated in upland or in nonjurisdictional waters to convey, treat, infiltrate, or store stormwater run-off; (xi) groundwater recharge, water reuse, and wastewater recycling structures, including detention, retention, and infiltration basins and ponds, constructed or excavated in upland or in non-jurisdictional waters; and (xii) waste treatment systems.⁵⁰ The replacement rule further refines the exclusions with definitions of adjacent wetlands; ditch; ephemeral; high tide line; intermittent; lakes and ponds and impoundments; ordinary high water mark; perennial; prior converted cropland; snowpack; tidal waters; tributary; typical year; upland; waste treatment system; and wetlands.⁵¹

Discharges and Intakes

The EPA regulates discharges from and intakes to power plants, including water cooling systems at steam electric power generating stations, under the CWA.

The EPA issues effluent limitation guidelines (“ELGs”) under the CWA, which apply a Best Available Technology Economically Available (“BAT”) to identified waste streams.⁵² The BAT standard requires the best technology, subject to cost considerations. On September 30, 2015, EPA issued a rule updating the standard for certain waste streams from steam power plants.⁵³ On April 12,

⁵⁰ *Id.*

⁵¹ *Id.*; 40 CFR 328.3(c) (pending effective date).

⁵² See 33 U.S.C. § 1311, 1314, 1362(11).

⁵³ See *Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*, 80 Fed. Reg. 67,838 (Nov. 3, 2015).

2019, the U.S. Court of Appeals for the Fifth Circuit vacated BAT standards for two identified categories, legacy wastewater (wastewater created, as determined by the permitting authority, between November 1, 2018 and December 31, 2023) and combustion residual leachate (wastewater percolating through landfills and impoundments).⁵⁴ The Court determined that reliance on impoundments for both categories is not BAT, and remanded to the EPA the determination of BATs consistent with the CWA.⁵⁵

Water cooling systems at steam electric power generating stations are subject to regulation under the CWA. EPA regulations of discharges from steam electric power generating stations are set forth in the Generating Effluent Guidelines and Standards in 1974. These standards were amended most recently in 2015.

Section 301(a) of the CWA prohibits the point source discharge of pollutants to a water of the United States, unless authorized by permit. Section 402 of the CWA establishes the required permitting process, known as the National Pollutant Discharge Elimination System (NPDES). NPDES permits limit discharges and include monitoring and reporting requirements. NPDES permits last five years before they must be renewed.

NPDES permits must satisfy the more stringent of a technology based standard, known as Best Technology Available (BTA), or water quality standards. In contrast to the BAT standard, the BTA standard requires the best technology without regard to cost. NPDES permits include limits designed to prevent discharges that would cause or contribute to violations of water quality standards. Water quality standards include thermal limits.

PJM states are authorized to issue NPDES permits, with the exception of the District of Columbia. Pennsylvania, Delaware, Indiana and Illinois are partially authorized; the other PJM states are fully authorized.

The EPA regulates intakes in addition to discharges.

Section 316(b) of the CWA requires that cooling water intake structures reflect the BTA for minimizing adverse environmental impacts. The EPA’s rule implementing

⁵⁴ See *Southwestern Electric Power Co., et al. v. EPA*, Slip. Op. 15-60821.

⁵⁵ *Id.* at 3.

Section 316(b) requires an existing facility to use BTA to reduce impingement of aquatic organisms (pinned against intake structures) if the facility withdraws 25 percent or more of its cooling water from WOTUS and has a design intake flow of greater than two million gallons per day (mgd).⁵⁶

Existing facilities withdrawing 125 mgd must conduct studies that may result in a requirement to install site-specific controls for reducing entrainment of aquatic organisms (drawn into intake structures). If a new generating unit is added to an existing facility, the rule requires addition of BTA that either (i) reduces actual intake flow at the new unit to a level at least commensurate with what can be attained using a closed-cycle recirculating system or (ii) reduces entrainment mortality of all stages of aquatic organisms that pass through a sieve with a maximum opening dimension of 0.56 inches to a prescribed level.

RCRA: Coal Ash

The EPA administers the Resource Conservation and Recovery Act (RCRA), which governs the disposal of solid and hazardous waste.⁵⁷ Solid waste is regulated under subtitle D. Subtitle D criteria are not directly enforced by the EPA. Subtitle C governs the disposal of hazardous waste. Hazardous waste is subject to direct regulatory control by the EPA from the time it is generated until its ultimate disposal.

In April 2015, the EPA issued a rule under RCRA, the Coal Combustion Residuals rule (CCRR), which sets criteria for the disposal of coal combustion residues (CCRs), or coal ash, produced by electric utilities and independent power producers.⁵⁸ CCRs include fly ash (trapped by air filters), bottom ash (scooped out of boilers) and scrubber sludge (filtered using wet limestone scrubbers). These residues are typically stored on site in ponds (surface impoundments) or sent to landfills.

The CCRR exempts: (i) beneficially used CCRs that are encapsulated (i.e. physically bound into a product); (ii) coal mine filling; (iii) municipal landfills; (iv) landfills receiving CCRs before the effective date; (v) surface impoundments closed by the effective date; and (vi) landfills and surface impoundments on the site of generation facilities that deactivate prior to the effective date. Less restrictive criteria may also apply to some surface impoundments deemed inactive under not yet clarified criteria.

⁵⁶ See EPA, *National Pollutant Discharge Elimination System—Final Regulations to Establish Requirements for Cooling Water Intake Structures at Existing Facilities and Amend Requirements at Phase I Facilities*, EPA-HQ-OW-2008-0667, 79 Fed. Reg. 48300 (Aug. 15, 2014).

⁵⁷ 42 U.S.C. §§ 6901 et seq.

⁵⁸ See *Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals From Electric Utilities*, 80 Fed. Reg. 21302 (April 17, 2015).

Table H-1 describes the criteria and implementation dates.

Table H-1 Minimum criteria for existing CCR ponds (surface impoundments) and landfills and date by which implementation is expected

Requirement	Description of requirement to be completed	Implementation Date
Location Restrictions (§ 257.60–§ 257.64)	For Ponds: Complete demonstration for placement above the uppermost aquifer, for wetlands, fault areas, seismic impact zones and unstable areas.	October 17, 2018
	For Landfills: Complete demonstration for unstable areas.	October 17, 2018
Design Criteria (§ 257.71)	For Ponds: Document whether CCR unit is either a lined or unlined CCR surface impoundment.	October 17, 2016
Structural Integrity (§ 257.73)	For Ponds: Install permanent marker.	December 17, 2015
	For Ponds: Compile a history of construction, complete initial hazard potential classification assessment, initial structural stability assessment, and initial safety factor assessment.	October 17, 2016
	Prepare emergency action plan.	April 17, 2017
Air Criteria (§ 257.80)	Ponds and Landfills: Prepare fugitive dust control plan.	October 17, 2015
Run-On and Run-Off Controls (§ 257.81)	For Landfills: Prepare initial run-on and run-off control system plan.	October 17, 2016
Hydrologic and Hydraulic Capacity (§ 257.82)	Prepare initial inflow design flood control system plan.	October 17, 2016
Inspections (§ 257.83)	For Ponds and Landfills: Initiate weekly inspections of the CCR unit.	October 17, 2015
	For Ponds: Initiate monthly monitoring of CCR unit instrumentation.	October 17, 2015
	For Ponds and Landfills: Complete the initial annual inspection of the CCR unit.	January 17, 2016
Groundwater Monitoring and Corrective Action (§ 257.90–§ 257.98)	For Ponds and Landfills: Install the groundwater monitoring system; develop the groundwater sampling and analysis program; initiate the detection monitoring program; and begin evaluating the groundwater monitoring data for statistically significant increases over background levels.	October 17, 2017
Closure and Post-Closure Care (§ 257.103–§ 257.104)	For Ponds and Landfills: Prepare written closure and post-closure care plans.	October 17, 2016
Recordkeeping, Notification, and Internet Requirements (§ 257.105–§ 257.107)	For Ponds and landfills: Conduct required recordkeeping; provide required notifications; establish CCR website.	October 17, 2015

On March 1, 2018, the EPA proposed a rule amending the CCRR.⁵⁹ Later in 2018, the EPA finalized parts of the proposed rule and deferred other parts to a future rulemaking. The finalized parts, effective August 29, 2019, (i) revised groundwater protections standards for constituents without an established MCL, (ii) established alternative performance standards and (iii) extended deadlines for placement of waste in CCR units closing for cause in certain situations.⁶⁰

In two recent cases, the U.S. Court of Appeals for the D.C. Circuit invalidated certain provisions of the CCRR and remanded it to the EPA.⁶¹ On November 4, 2019, the EPA proposed revisions in compliance with the court order.⁶²

The proposed rule would require (i) unlined surface impoundments (ponds) to cease receiving waste on August 31, 2020, rather than October 31, 2019, as specified in the current rule; (ii) removal of compacted soil lined and clay lined ponds from classification as lined and exempt from CCRR; and would require closure of all unlined ponds regardless of whether leakage is detected.⁶³

For impoundment facilities that fail restrictions on the minimum depth to or interaction with an aquifer, the proposed rule postpones the earliest required date to cease receipt of waste to August 31, 2020.⁶⁴

⁵⁹ See *Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals From Electric Utilities; Amendments to the National Minimum Criteria (Phase One, Part One)*, EPA Docket No. EPA-HQ-OLEM-2017-0286, 83 Fed. Reg. 36435 (July 30, 2018).

⁶⁰ *Id.*

⁶¹ *Utility Solid Waste Activities Group, et al. v. EPA*, No. 15-1219 (D.C. Cir. August 21, 2018); *Waterkeeper Alliance Inc. et al. v. EPA*, No. 18-1289 (D.C. Cir. March 13, 2019).

⁶² See *Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals From Electric Utilities; A Holistic Approach to Closure Part A: Deadline To Initiate Closure*, EPA-HQ-OLEM-2019-0172; FRL-10002-02-OLEM, 84 Fed. Reg. 65941 (Dec. 2, 2019).

⁶³ See *Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals From Electric Utilities; A Holistic Approach to Closure Part A: Deadline To Initiate Closure*, EPA EPA-HQ-OLEM-2019-0172, 84 Fed. Reg. 65941 (December 2, 2019).

⁶⁴ *Id.* at 65942.

Impoundment facilities unable to meet the earliest deadline would be able to obtain extensions until an alternative can be “technically feasibly implemented.”⁶⁵ Utilities may obtain an automatic extension to November 30, 2020, upon certification of need for additional time.⁶⁶ Upon receipt of required documentation, the EPA may grant a longer extension as far as October 15, 2023, on a case by case basis, and to as long as October 17, 2028, for a facility with a surface impoundment of 40 acres or greater that commits to a deadline for ending operations of its boiler.⁶⁷

Coal Combustion Residuals Rule (CCRR)

The EPA issued a rule under the Resource Conservation and Recovery Act (RCRA), the Coal Combustion Residuals rule (CCRR), which sets criteria for the disposal of coal combustion residues (CCRs), or coal ash, produced by electric utilities and independent power producers.⁶⁸ CCRs include fly ash (trapped by air filters), bottom ash (scooped out of boilers) and scrubber sludge (filtered using wet limestone scrubbers). These residues are typically stored on site in ponds (surface impoundments) or sent to landfills.

The CCRR exempts: (i) beneficially used CCRs that are encapsulated (i.e. physically bound into a product); (ii) coal mine filling; (iii) municipal landfills; (iv) landfills receiving CCRs before the effective date; (v) surface impoundments closed by the effective date; and (vi) landfills and surface impoundments on the site of generation facilities that deactivate prior to the effective date. Less restrictive criteria may also apply to some surface impoundments deemed inactive under not yet clarified criteria.

On March 1, 2018, the EPA proposed a rule amending the CCRR.⁶⁹ The proposal includes:

A change to allow a state regulatory program to establish alternative risk-based groundwater protection standards for constituents that do not have an established

maximum contaminant level (MCL), rather than the use of background levels that are currently required. The proposal also requests public comment on whether a facility may be allowed to establish alternative risk-based standards using a certified professional engineer or other means, subject to EPA oversight.

A request for comment on whether the current deadlines for groundwater monitoring and analysis remain appropriate.

A request for public comment on modifying the location restrictions and associated deadlines concerning construction or operation of a CCR landfill or surface impoundment in certain areas.

Changes to allow states to establish alternative requirements for how facilities respond to and remediate releases from CCR landfills and surface impoundments. The proposal also requests comment on allowing states to determine when an unlined surface impoundment that is leaking may undertake corrective action rather than be forced to stop receiving CCR and close.

The addition of boron to the list of constituents for which facilities would need to perform assessment monitoring.

Effective August 9, 2018, the EPA approved (i) revised groundwater protections standards for constituents without an established MCL, (ii) alternative performance standards and (iii) extended deadlines for placement of waste in CCR units closing for cause in certain situations.⁷⁰ The EPA indicated that additional revisions will be considered in a future rulemaking.

⁶⁵ *Id.* at 65945.

⁶⁶ *Id.* at 65942.

⁶⁷ *Id.*

⁶⁸ See *Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals From Electric Utilities*, 80 Fed. Reg. 21302 (April 17, 2015).

⁶⁹ EPA Press Release, EPA Proposes First of Two Rules to Amend Coal Ash Disposal Regulations, Saving Up To \$100M Per Year in Compliance Costs <<https://www.epa.gov/newsreleases/epa-proposes-first-two-rules-amend-coal-ash-disposal-regulations-saving-100m-year>> (March 1, 2018).

⁷⁰ See *Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals From Electric Utilities; Amendments to the National Minimum Criteria (Phase One, Part One)*, EPA Docket No. EPA-HQ-OLEM-2017-0286, 83 Fed. Reg. 36435 (July 30, 2018).

Emission Standards for Reciprocating Internal Combustion Engines

On January 14, 2013, the EPA signed a final rule amending its rules regulating emissions from a wide variety of stationary reciprocating internal combustion engines (RICE).⁷¹ RICE include certain types of electrical generation facilities like diesel engines typically used for backup, emergency or supplemental power, including facilities located behind the meter. These rules include: National Emission Standard for Hazardous Air Pollutants (NESHAP) for Reciprocating Internal Combustion Engines (RICE); New Source Performance Standards (NSPS) of Performance for Stationary Spark Ignition Internal Combustion Engines; and Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (collectively RICE Rules).⁷²

The RICE Rules apply to emissions such as formaldehyde, acrolein, acetaldehyde, methanol, CO, NO_x, volatile organic compounds (VOCs) and PM. The regulatory regime for RICE is complicated, and the applicable requirements turn on whether the engine is an “area source” or “major source,” and the starter mechanism for the engine (compression ignition or spark ignition).⁷³

On May 22, 2012, the EPA proposed amendments to the 2010 RICE NESHAP Rule.⁷⁴ The proposed rule would have allowed owners and operators of emergency stationary internal combustion engines to operate them in emergency conditions, as defined in those regulations, as part of an emergency demand response program for 100 hours per year or the minimum hours required by an Independent System Operator’s tariff, whichever is less. The rule would have increased the 2010 Rule’s 15 hour per year run limit. The exempted emergency demand response programs included RPM demand resources.

On May 1, 2015, the U.S. Court of Appeals for the District of Columbia Circuit reversed the portion of the final rule exempting 100 hours of run time for certain stationary reciprocating internal combustion engines (RICE) participating in emergency demand response programs from the otherwise applicable emission standards.⁷⁵ As a result, the national emissions standards uniformly apply to all RICE.⁷⁶ The Court held that the “EPA acted arbitrarily and capriciously when it modified the National Emissions Standards and the Performance Standards to allow backup generators to operate without emissions controls for up to 100 hours per year as part of an emergency demand-response program.”⁷⁷ Specifically, the Court found that the EPA failed to consider arguments concerning the rule’s “impact on the efficiency and reliability of the energy grid,” including arguments raised by the MMU.⁷⁸

On April 15, 2016, the EPA issued a letter explaining how it would implement the vacatur order.⁷⁹ The EPA explained upon issuance of the Court’s mandate, “an engine may not operate in circumstances described in the vacated [portions of the 2013 NESHAP RICE Rule] for any number of hours power per year.”⁸⁰ The EPA explained that such engines could, however, continue to operate for specified emergency and nonemergency reasons.⁸¹

On May 3, 2016, the Court issued a mandate to implement its May 1, 2015, order. Issuance of the mandate triggered implementation of the policy.

The MMU verifies every delivery year that resource portfolios remain in compliance. The MMU contacts all CSPs with demand resources using diesel fuel, to ensure compliance is met among all PJM resources.

⁷¹ *National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines*; *New Source Performance Standards for Stationary Internal Combustion Engines*, Final Rule, EPA Docket No. EPA-HQ-OAR-2008-0708, 78 Fed. Reg. 6674 (Jan. 30, 2013) (“2013 NESHAP RICE Rule”). In 2010, the EPA promulgated two rules with standards for hazardous air pollutant emissions from backup generators. The rules allowed backup generators to operate without emissions controls for fifteen hours each year as part of “demand response programs” during “emergency conditions that could lead to a potential electrical blackout.” EPA Docket No. EPA-HQ-OAR-2009-0234 & -2011-0044, codified at 40 CFR Part 63, Subpart ZZZZ; EPA Dockets Nos. EPA-HQ-OAR-2005-0030 & EPA-HQ-OAR-2005-0029, -2010-0295, codified at 40 CFR Part 60 Subpart JJJJ (“2010 RICH NESHAP Rule”).

⁷² *Id.*

⁷³ CAA § 112(a) defines “major source” to mean “any stationary source or group of stationary sources located within a contiguous area and under common control that emits or has the potential to emit considering controls, in the aggregate, 10 tons per year or more of any hazardous air pollutant or 25 tons per year or more of any combination of hazardous air pollutants,” and “area source” to mean, “any stationary source of hazardous air pollutants that is not a major source.”

⁷⁴ *National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines*; *New Source Performance Standards for Stationary Internal Combustion Engines*, Proposed Rule, EPA Docket No. EPA-HQ-OAR-2008-0708.

⁷⁵ Delaware Department of Natural Resources and Environmental Control (DENREC) v. EPA, Slip Op. No. 13-1093; *National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines*; *New Source Performance Standards for Stationary Internal Combustion Engines*, Final Rule, EPA Docket No. EPA-HQ-OAR-2008-0708, 78 Fed. Reg. 9403 (Jan. 30, 2013).

⁷⁶ *Id.*

⁷⁷ DENREC v. EPA at 3, 20-21.

⁷⁸ *Id.* at 22, citing Comments of the Independent Market Monitor for PJM, EPA Docket No. EPA-HQ-OAR-2008-0708 (Aug. 9, 2012) at 2.

⁷⁹ EPA, Memorandum, Peter Tsirigotis Guidance on Vacatur of RICE NESHAP and NSPS Provisions for Emergency Engines (April 15, 2016).

⁸⁰ See 40 CFR §§ 60.4211(f)(2)(ii)-(iii), 60.4243(d)(2)(ii)-(iii), and 63.6640(f)(2)(ii)-(iii) (Declared Emergency Alert Level 2 or 5 percent voltage/frequency deviations).

⁸¹ See 40 CFR §§ 60.4211(f)(1), 60.4243(d)(1), and 63.6640(f)(1) (“There is no time limit on the use of emergency stationary ICE in emergency situations.”); 40 CFR 60.4211(f)(3), 60.4243(d)(3), 63.6640(f)(3)-(4).

State Environmental Regulation

RGGI

The Regional Greenhouse Gas Initiative (RGGI) is a cooperative effort by Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey (as of January 1, 2020), New York, Rhode Island, and Vermont to cap CO₂ emissions from power generation facilities.⁸²

New Jersey, a founding member of RGGI, opted out in 2011 but rejoined RGGI in 2020.⁸³ Other PJM states have expressed interest in joining RGGI. The Virginia Air Pollution Control Board approved a regulation that would allow Virginia to join RGGI on January 1, 2021.⁸⁴ Pennsylvania Governor Tom Wolf issued an executive order on October 3, 2019, directing the Pennsylvania Department of Environmental Protection (DEP) to develop a proposal to limit carbon emissions from fossil fuel generators that is consistent with RGGI.⁸⁵ The order stipulates that the DEP is to present a rulemaking package to the Pennsylvania Environmental Quality Board by July 31, 2020.⁸⁶ The order further directs DEP to “engage with PJM Interconnection to promote the integration of this program in a manner that preserves orderly and competitive economic dispatch within PJM and minimizes emissions leakage.”

Table H-2 shows the RGGI CO₂ auction clearing prices and quantities for the 2008/2011 compliance period auctions, the 2012/2014 compliance period auctions, the 2015/2018 compliance period and the 2018/2020 compliance period auctions held as of December 4, 2019, in short tons and metric tonnes.⁸⁷

⁸² RGGI provides a link on its website to state statutes and regulations authorizing its activities, which can be accessed at: <http://www.rggi.org/design/regulations>.

⁸³ “Statement on New Jersey Greenhouse Gas Rule,” RGGI Inc., (June 17, 2019) <https://www.rggi.org/news-releases/rggi-releases>.

⁸⁴ See 9VAC5-140-6010-6430.

⁸⁵ Executive Order No. 2019-07- Commonwealth Leadership in Addressing Climate Change through Electric Sector Emissions Reductions, Tom Wolf, Governor (Oct. 3, 2019), <https://www.governor.pa.gov/newsroom/executive-order-2019-07-commonwealth-leadership-in-addressing-climate-change-through-electric-sector-emissions-reductions/>.

⁸⁶ Id.

⁸⁷ The September 3, 2015, auction included additional Cost Containment Reserves (CCRs) since the clearing price for allowances was above the CCR trigger price of \$6.00 per ton in 2015. The auctions on March 5, 2014, and September 3, 2015, were the only auctions to use CRRs.

Table H-2 RGGI CO₂ allowance auction prices and quantities in short tons and metric tonnes: 2009/2011, 2012/2014, 2015/2018, and 2018/2020 Compliance Periods⁸⁸

Auction Date	Short Tons			Metric Tonnes		
	Clearing Price	Quantity Offered	Quantity Sold	Clearing Price	Quantity Offered	Quantity Sold
September 25, 2008	\$3.07	12,565,387	12,565,387	\$3.38	11,399,131	11,399,131
December 17, 2008	\$3.38	31,505,898	31,505,898	\$3.73	28,581,678	28,581,678
March 18, 2009	\$3.51	31,513,765	31,513,765	\$3.87	28,588,815	28,588,815
June 17, 2009	\$3.23	30,887,620	30,887,620	\$3.56	28,020,786	28,020,786
September 9, 2009	\$2.19	28,408,945	28,408,945	\$2.41	25,772,169	25,772,169
December 2, 2009	\$2.05	28,591,698	28,591,698	\$2.26	25,937,960	25,937,960
March 10, 2010	\$2.07	40,612,408	40,612,408	\$2.28	36,842,967	36,842,967
June 9, 2010	\$1.88	40,685,585	40,685,585	\$2.07	36,909,352	36,909,352
September 10, 2010	\$1.86	45,595,968	34,407,000	\$2.05	41,363,978	31,213,514
December 1, 2010	\$1.86	43,173,648	24,755,000	\$2.05	39,166,486	22,457,365
March 9, 2011	\$1.89	41,995,813	41,995,813	\$2.08	38,097,972	38,097,972
June 8, 2011	\$1.89	42,034,184	12,537,000	\$2.08	38,132,781	11,373,378
September 7, 2011	\$1.89	42,189,685	7,487,000	\$2.08	38,273,849	6,792,094
December 7, 2011	\$1.89	42,983,482	27,293,000	\$2.08	38,993,970	24,759,800
March 14, 2012	\$1.93	34,843,858	21,559,000	\$2.13	31,609,825	18,558,001
June 6, 2012	\$1.93	36,426,008	20,941,000	\$2.13	33,045,128	18,997,361
September 5, 2012	\$1.93	37,949,558	24,589,000	\$2.13	34,427,270	22,306,772
December 5, 2012	\$1.93	37,563,083	19,774,000	\$2.13	34,076,665	17,938,676
March 13, 2013	\$2.80	37,835,405	37,835,405	\$3.09	34,323,712	34,323,712
June 5, 2013	\$3.21	38,782,076	38,782,076	\$3.54	35,182,518	35,182,518
September 4, 2013	\$2.67	38,409,043	38,409,043	\$2.94	34,844,108	34,844,108
December 4, 2013	\$3.00	38,329,378	38,329,378	\$3.31	34,771,837	34,771,837
March 5, 2014	\$4.00	23,491,350	23,491,350	\$4.41	21,311,000	21,311,000
June 4, 2014	\$5.02	18,062,384	18,062,384	\$5.53	16,385,924	16,385,924
September 3, 2014	\$4.88	17,998,687	17,998,687	\$5.38	16,328,139	16,328,139
December 3, 2014	\$5.21	18,198,685	18,198,685	\$5.74	16,509,574	16,509,574
March 11, 2015	\$5.41	15,272,670	15,272,670	\$5.96	13,855,137	13,855,137
June 3, 2015	\$5.50	15,507,571	15,507,571	\$6.06	14,068,236	14,068,236
September 3, 2015	\$6.02	25,374,294	25,374,294	\$6.64	23,019,179	23,019,179
December 2, 2015	\$7.50	15,374,274	15,374,274	\$8.27	13,947,311	13,947,311
March 9, 2016	\$5.25	14,838,732	14,838,732	\$5.79	13,461,475	13,461,475
June 1, 2016	\$4.53	15,089,652	15,089,652	\$4.99	13,689,106	13,689,106
September 7, 2016	\$4.54	14,911,315	14,911,315	\$5.00	13,527,321	13,527,321
December 7, 2016	\$3.55	14,791,315	14,791,315	\$3.91	13,418,459	13,418,459
March 8, 2017	\$3.00	14,371,300	14,371,300	\$3.31	13,037,428	13,037,428
June 7, 2017	\$2.53	14,597,470	14,597,470	\$2.79	13,242,606	13,242,606
September 8, 2017	\$4.35	14,371,585	14,371,585	\$4.80	13,037,686	13,037,686
December 8, 2017	\$3.80	14,687,989	14,687,989	\$4.19	13,324,723	13,324,723
March 14, 2018	\$3.79	13,553,767	13,553,767	\$4.18	12,295,774	12,295,774
June 13, 2018	\$4.02	13,771,025	13,771,025	\$4.43	12,492,867	12,492,867
September 9, 2018	\$4.50	13,590,107	13,590,107	\$4.96	12,328,741	12,328,741
December 5, 2018	\$5.35	13,360,649	13,360,649	\$5.90	12,120,580	12,120,580
March 13, 2019	\$5.27	12,883,436	12,883,436	\$5.81	11,687,660	11,687,660
June 5, 2019	\$5.62	13,221,453	13,221,453	\$6.19	11,994,304	11,994,304
September 4, 2019	\$5.20	13,116,447	13,116,447	\$5.73	11,899,044	11,899,044
December 4, 2019	\$5.61	13,116,444	13,116,444	\$6.18	11,899,041	11,899,041

New Jersey High Electric Demand Day (HEDD) Rules

The EPA's transport rules apply to total annual and seasonal emissions. Units that run only during peak demand periods have relatively low annual emissions, and have less reason to make such investments under the EPA transport rules.

New Jersey addressed the issue of NO_x emissions on peak energy demand days with a rule that defines peak energy usage days, referred to as high electric demand days or HEDD, and imposes operational restrictions and emissions control requirements on units responsible for significant NO_x emissions on such high energy demand days.⁸⁹ New Jersey's HEDD rule, which became effective May 19, 2009, applies to HEDD units, which include units that have a NO_x emissions rate on HEDD equal to or exceeding 0.15 lbs/MMBtu and lack identified emission control technologies.⁹⁰ NO_x emissions limits for coal units became effective December 15, 2012.⁹¹ NO_x emissions limits for other unit types became effective May 1, 2015.⁹² As of December 31, 2017, two Cedar Station units, three Middle Street units, three Missouri units, one Sherman Ave unit, three Burlington units, three Edison units, four Essex units, three Kearny units, one Mercer unit, one National Park unit, one Sewaren unit, eight Glen Gardner units and four Werner units identified as NJ HEDD units have retired.⁹³ In total, 37 NJ HEDD units have retired and the remaining

⁸⁹ N.J.A.C. § 7:27-19.

⁹⁰ CTS must have either water injection or selective catalytic reduction (SCR) controls; steam units must have either an SCR or selective noncatalytic reduction (SNCR).

⁹¹ N.J.A.C. § 7:27-19.4.

⁹² N.J.A.C. § 7:27-19.5.

⁹³ See Current New Jersey Turbines that are HEDD Units, <http://www.nj.gov/dcp/workgroups/docs/aprcluc_201110909turbineslist.pdf>.

⁸⁸ See Regional Greenhouse Gas Initiative, "Auction Results," <http://www.rggi.org/market/co2_auctions/results> (Accessed January 23, 2020).

41 NJ HEDD units are still operating after taking actions to comply with the HEDD regulations.

Table H-3 shows the HEDD emissions limits applicable to each unit type.

Table H-3 HEDD maximum NO_x emission rates⁹⁴

Fuel and Unit Type	NO _x Emission Limit (lbs/MWh)
Coal Steam Unit	1.50
Heavier than No. 2 Fuel Oil Steam Unit	2.00
Simple Cycle Gas CT	1.00
Simple Cycle Oil CT	1.60
Combined Cycle Gas CT	0.75
Combined Cycle Oil CT	1.20
Regenerative Cycle Gas CT	0.75
Regenerative Cycle Oil CT	1.20

Illinois Air Quality Standards (NO_x, SO₂ and Hg)

The State of Illinois has promulgated its own standards for NO_x, SO₂ and Hg (mercury) known as Multi-Pollutant Standards (MPS) and Combined Pollutants Standards (CPS).⁹⁵ MPS and CPS establish standards that are more stringent and take effect earlier than comparable Federal regulations, such as the EPA's MATS.

The Illinois Pollution Control Board has granted variances with conditions for compliance with MPS/CPS for Illinois units included in or potentially included in PJM markets.⁹⁶ In order to obtain variances, companies in PJM agreed to terms with the Illinois Pollution Control Board that resulted in investments in the installation of environmental pollution control equipment at units and deactivation of Illinois units that differ from what would have occurred had only Federal regulations applied.⁹⁷

State Renewable Portfolio Standards

Nine PJM jurisdictions have enacted legislation that requires that a defined percentage of retail load be served by renewable resources, for which there are many standards and definitions. These are typically known as renewable portfolio standards, or RPS. In PJM jurisdictions that have adopted an RPS, load serving entities are often required by law to meet defined shares of load using specific renewable and/or alternative

energy sources commonly called “eligible technologies.” Load serving entities may generally fulfill these obligations in one of two ways: they may use their own generation resources classified as eligible technologies to produce power or they may purchase renewable energy credits (RECs) that represent a known quantity of power produced with eligible technologies by other market participants or in other geographical locations. Load serving entities that fail to meet the percent goals set in their jurisdiction's RPS by generating power from eligible technologies or purchasing RECs are penalized with alternative compliance payments. As of December 31, 2018, Delaware, Illinois, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington, D.C. had renewable portfolio standards that are mandatory and include penalties in the form of alternative compliance payments for underperformance.

Two PJM jurisdictions have enacted voluntary renewable portfolio standards. Load serving entities in states with voluntary standards are not bound by law to participate and face no alternative compliance payments. Instead, incentives are offered to load serving entities to develop renewable generation or, to a more limited extent, purchase RECs. As of December 31, 2018, Virginia and Indiana had renewable portfolio standards that are voluntary and do not include penalties in the form of alternative compliance payments for underperformance.

In this section, voluntary standards will not be directly compared to RPS with enforceable compliance payments. Indiana's voluntary standard illustrates the issue. Although a voluntary standard including target shares was enacted by the Indiana legislature in 2011, no load serving entities have volunteered to participate in the program.⁹⁸

Three PJM states have no renewable portfolio standards. Kentucky and Tennessee have enacted no renewable portfolio standards. West Virginia had a voluntary standard, but the state legislature repealed their renewable portfolio standard on January 27, 2015, effective February 3, 2015.⁹⁹

⁹⁴ Regenerative cycle CTs are combustion turbines that recover heat from their exhaust gases and use that heat to preheat the inlet combustion air which is fed into the combustion turbine.

⁹⁵ 35 Ill. Admin. Code §§ 225.233 (Multi-Pollutant Standard (MPS)), 224.295 (Combined Pollutant Standard: Emissions Standards for NO_x and SO₂ (CPS)).

⁹⁶ See, e.g., Midwest Generation, LLC, Opinion and Order of the Board, Docket No. PCB 13-24 (Variance-Air) (April 4, 2013); Midwest Generation, LLC, Opinion and Order of the Board, Docket No. PCB 12-121 (Variance-Air) (Aug. 23, 2012).

⁹⁷ See *Id.*

⁹⁸ See the Indiana Utility Regulatory Commission's "2018 Annual Report," at 35-36 <<https://www.in.gov/iurc/files/IURC%20AR%202018%20WEB3.pdf>>.

⁹⁹ See Enr. Com. Sub. For H. B. No. 2001.

Appendix I Glossary

Ancillary Services

Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice.

Area Control Error (ACE)

Area Control Error of the PJM RTO is the actual net interchange minus the biased scheduling net interchange, including time error. It is the sum of tie-in errors and frequency errors.

Associated unit (AU)

A unit that is located at the same site as a frequently mitigated unit (FMU) and which has identical electrical and economic impacts on the transmission system as an FMU but which does not qualify for FMU status.

Auction Revenue Right (ARR)

A financial instrument entitling its holder to auction revenue from Financial Transmission Rights (FTRs) based on locational marginal price (LMP) differences across a specific path in the Annual FTR Auction.

Automatic Generation Control (AGC)

An automatic control system comprised of hardware and software. Hardware is installed on generators allowing their output to be automatically adjusted and monitored by an external signal and software is installed facilitating that output adjustment.

Average hourly LMP

An LMP calculated by averaging hourly LMP with equal hourly weights; also referred to as a simple average hourly LMP.

Avoidable cost rate (ACR)

The costs that a generation owner would not incur if the generating unit did not operate for one year, in particular the delivery year. The ACR calculation is based on the categories of cost that are specified in Section 6.8 of Attachment DD of the PJM Tariff.

Avoidable Project Investment Recovery Rate (APIR)

A component of the avoidable cost rate (ACR) calculation. Project investment is the capital reasonably required to enable a capacity resource to continue operating or improve availability during peak-hour periods during the delivery year.

Balancing energy market

Energy that is generated and financially settled during real time.

Base Residual Auction (BRA)

Reliability Pricing Model (RPM) auction held in May three years prior to the start of the delivery year. Allows for the procurement of resource commitments to satisfy the region's unforced capacity obligation and allocates the cost of those commitments among the LSEs through the Locational Reliability Charge.

Behind the Meter

Behind The Meter Generation refers to a generation unit that delivers energy to load without using the Transmission System or any distribution facilities (unless the entity that owns or leases the distribution facilities has consented to such use of the distribution facilities and such consent has been demonstrated to the satisfaction of the Office of the Interconnection); provided, however, that Behind The Meter Generation does not include (i) at any time, any portion of such generating unit's capacity that is designated as a Generation Capacity Resource; or (ii) in an hour, any portion of the output of such generating unit[s] that is sold to another entity for consumption at another electrical location or into the PJM Interchange Energy Market. (OATT 1.3B)

Bilateral agreement

An agreement between two parties for the sale and delivery of a service.

Black Start Unit

A generating unit with the ability to go from a shutdown condition to an operating condition and start delivering power without any outside assistance from the transmission system or interconnection.

Block Loaded

A resource offered to PJM in the energy or capacity market at a single MW output which is not dispatchable in the energy market and cannot be partially cleared in the capacity market.

Bottled generation

Economic generation that cannot be dispatched because of local operating constraints.

Burner tip fuel price

The cost of fuel delivered to the generator site equaling the fuel commodity price plus all transportation costs.

Bus

An interconnection point.

Capacity deficiency rate (CDR)

The CDR was designed to reflect the annual fixed costs of a new combustion turbine (CT) in PJM and the annual fixed costs of the associated transmission investment, including a return on investment, depreciation and fixed operation and maintenance expense, net of associated energy revenues. The CDR is used in applying penalties for capacity deficiencies. To express the CDR in terms of unforced capacity, it must be further divided by the quantity 1 minus the EFORD.

Capacity Emergency Transfer Limit (CETL)

The capability of the transmission system to support deliveries of electric energy to a given area experiencing a localized capacity emergency as determined in accordance with the PJM Manuals.

Capacity queue

A collection of Regional Transmission Expansion Planning (RTEP) capacity resource project requests received during a particular timeframe and designating an expected in-service date.

Combined Cycle (CC)

An electric generating technology in which electricity and process steam are produced from otherwise lost waste heat exiting from one or more combustion turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for use by a conventional steam turbine in the production of electricity. This process increases the efficiency of the electric generating facility.

Combustion Turbine (CT)

A generating unit in which a combustion turbine engine is the prime mover for an electrical generator.

Congestion Management Process (CMP)

A process used between neighboring balancing authorities to coordinate the re-dispatch of resources to relieve transmission constraints.

Control Zone

An area within the PJM Control Area, as set forth in the PJM Open Access Transmission Tariff and the RAA. Schedule 16 of the RAA defines the distinct zones that comprise the PJM Control Area.

Decrement Bids (DEC)

An hourly bid, expressed in MWh, to purchase energy in the PJM Day-Ahead Energy Market if the Day-Ahead LMP is less than or equal to the specified bid price. This bid must specify hourly quantity, bid price and location (transmission zone, hub, aggregate or single bus).

Demand deviations

Hourly deviations in the demand category, equal to the difference between the sum of cleared decrement bids, day-ahead load, day-ahead sales, and day-ahead-exports, to the sum of real-time load, real-time sales, and real-time exports.

Demand Resource

A capacity resource with a demonstrated capability to provide a reduction in demand or otherwise control load. A Demand Resource may be an existing or planned resource.

Dispatch Rate

The control signal, expressed in dollars per MWh, calculated and transmitted continuously and dynamically to direct the output level of all generation resources dispatched by PJM in accordance with the Offer Data.

Disturbance Control Standard

A NERC-defined metric measuring the ability of a control area to return area control error (ACE) either to zero or to its predisturbance level after a disturbance such as a generator or transmission loss.

Eastern Prevailing Time (EPT)

Eastern Prevailing Time (EPT) is equivalent to Eastern Standard Time (EST) or Eastern Daylight Time (EDT) as is in effect from time to time.

Eastern Region

Defined region for purposes of allocating balancing operating reserve charges. Includes the BGE, Dominion, PENELEC, Pepco, Met-Ed, PPL, JCPL, PECO, DPL, PSEG, and RECO transmission zones.

Economic generation

Units producing energy at an offer price less than or equal to LMP.

Effective MW

The MW of regulation provided by a regulating resource multiplied by that resource's marginal benefit factor and performance score.

End use customer

Any customer purchasing electricity at retail.

Equivalent availability factor (EAF)

The proportion of hours in a year that a unit is available to generate at full capacity.

Equivalent demand forced outage rate (EFORD)

A measure of the probability that a generating unit will not be available due to forced outages or forced deratings when there is a demand on the unit to generate.

Equivalent forced outage factor (EFOF)

The proportion of hours in a year that a unit is unavailable because of forced outages.

Equivalent maintenance outage factor (EMOF)

The proportion of hours in a year that a unit is unavailable because of maintenance outages.

Equivalent planned outage factor (EPOF)

The proportion of hours in a year that a unit is unavailable because of planned outages.

External resource

A generation resource located outside metered boundaries of the PJM RTO.

Financial Transmission Right (FTR)

A financial instrument entitling the holder to receive revenues based on transmission congestion measured as hourly energy LMP differences in the PJM Day-Ahead Energy Market across a specific path.

Firm Point-to-Point Transmission Service

Transmission Service that is reserved and/or scheduled between specified Points of Receipt and Delivery.

Firm Transmission Service

Transmission service that is intended to be available at all times to the maximum extent practicable, subject to an emergency, and unanticipated failure of a facility, or other event beyond the control of the owner or operator of the facility, or the Office of the Interconnection.

Fixed Demand Bid

Bid to purchase a defined MW level of energy, regardless of LMP.

Fixed Resource Requirement (FRR)

An alternative method for a party to satisfy its obligation to provide Unforced Capacity. Allows an LSE to avoid direct participation in the RPM Auctions by meeting their fixed capacity resource requirement using internally owned capacity resources.

Flowgate

A transmission facility or group of facilities that consist of the total interface between control areas, a partial interface, or an interface within a control area.

Frequently mitigated unit (FMU)

A unit that was offer-capped for more than a defined proportion of its real-time run hours in the most recent 12-month period. FMU thresholds are 60 percent, 70 percent and 80 percent of run hours. Such units are permitted a defined adder to their cost-based offers in place of the usual 10 percent adder.

Fuel Diversity Index

Objective metric of fuel diversity, defined by $FDI = 1 - \sum_{i=1}^N s_i^2$, where s_i is the share of fuel type i . The FDI is calculated separately for energy output and for installed capacity.

Generation Control Area (GCA) and Load Control Area (LCA)

Designations used on a NERC Tag to describe the balancing authority where the energy is generated (GCA) and the balancing authority where the load is served (LCA). Note: the terms “Control Area” in these acronyms are legacy terms for balancing authority, and are expected to be changed in the future.

Generator deviations

Hourly deviations in the generator category, equal to the difference between a unit’s cleared day-ahead generation, and a unit’s hourly, integrated real-time generation.

Generation Offers

Schedules of MW offered and the corresponding offer price.

Generation owner

A PJM member that owns or leases, with rights equivalent to ownership, facilities for generation of electric energy that are located within PJM.

Gross export volume (energy)

The sum of all export transaction volume (MWh).

Gross import volume (energy)

The sum of all import transaction volume (MWh).

Gigawatt (GW)

A unit of power equal to 1,000 megawatts.

Gigawatt-day

One GW of energy flow or capacity for one day.

Gigawatt-hour (GWh)

One GWh is a gigawatt produced or consumed for one hour.

Herfindahl-Hirschman Index (HHI)

HHI is calculated as the sum of the squares of the market share percentages of all firms in a market.

Hertz (Hz)

Electricity system frequency is measured in hertz.

Hot/Cold Weather Alerts

A Hot Weather Alert is issued to prepare personnel and facilities for extreme hot and/or humid weather conditions that may cause unit unavailability to be higher than forecast for an extended period. It can be issued on a control zone basis and PJM communicates to members whether fuel limited resources are to be placed into Maximum Emergency category.

A Cold Weather Alert is issued to prepare personnel and facilities for extreme cold weather conditions. It can be initiated when actual temperatures in a zone fall near or below ten degrees Fahrenheit or at higher temperatures if PJM projects a portion of gas fired capacity is unable to obtain spot market gas during load pick-up periods.

HRSG

Heat recovery steam generator. An air-to-steam heat exchanger.

Increment offers (INC)

Financial offers in the Day-Ahead Energy Market to supply specified amounts of MW at, or above, a given price.

Incremental Auction

Reliability Pricing Model (RPM) auction to allow for an incremental procurement of resource commitments to satisfy an increase in the region’s unforced capacity obligation due to a load forecast increase or a decrease in the amount of resource commitments due to a resource cancellation, delay, derating, EFORd increase, or decrease in the nominated value of a Planned Demand Resource.

Inframarginal unit

A unit that is operating, with an accepted offer that is less than the clearing price.

Installed capacity

Installed capacity is the as-tested maximum net dependable capability of the generator, measured in MW.

Load

Demand for electricity at a given time.

Load Management

Previously known as ALM (Active Load Management). ALM was a term that PJM used prior to the implementation of RPM where end use customer load could be reduced at the request of PJM. The ability to reduce metered load, either manually by the customer, after a request from the resource provider which holds the Load management rights or its agent (for Contractually Interruptible), or automatically in response to a communication signal from the resource provider which holds the Load management rights or its agent (for Direct Load Control).

Load-serving entity (LSE)

Load-serving entities provide electricity to retail customers. Load-serving entities include traditional distribution utilities and new entrants into the competitive power market.

Locational Deliverability Area (LDA)

Sub-regions used to evaluate locational constraints. LDAs include EDC zones, sub-zones, and combination of zones.

Marginal Benefit Factor

For RegD resources, this is the marginal rate of substitution between RegA and RegD resources.

Marginal unit

The last, highest cost, generation unit to supply power under a merit order dispatch system.

Market-clearing price

The price that is paid by all load and paid to all suppliers.

Market participant

A PJM market participant can be a market supplier, a market buyer or both. Market buyers and market sellers are members that have met creditworthiness standards as established by the PJM Office of the Interconnection.

Market user interface

A thin client application allowing generation sellers to provide and to view generation data, including bids, unit status and market results.

Maximum daily starts

The maximum number of times a unit can start in a day. An operating parameter incorporated in a unit's schedule.

Maximum weekly starts

The maximum number of times a unit can start in a week. An operating parameter incorporated in a unit's schedule.

Mean

The arithmetic average.

Median

The midpoint of data values. Half the values are above and half below the median.

Megawatt (MW)

A unit of power equal to 1,000 kilowatts.

Megawatt-day

One MW of energy flow or capacity for one day.

Megawatt-hour (MWh)

One MWh is a megawatt produced or consumed for one hour.

Megawatt-year

One MW of energy flow or capacity for one calendar year.

Minimum down time

The minimum amount of time that a unit has to stay off before starting again. An operating parameter incorporated in a unit's schedule.

Minimum Offer Price Rule (MOPR)

The MOPR rule sets a floor offer price in the RPM Capacity Market, based on the average net cost of new entry (CONE) for certain classes of new or uprated generation capacity resources as defined in the OATT Attachment DD 5.13(h).

Minimum run time

The minimum amount of time that a unit has to stay on before shutting down. An operating parameter incorporated in a unit's schedule.

Monthly CCM

The capacity credits cleared each month through the PJM Monthly Capacity Credit Market (CCM).

Multimonthly CCM

The capacity credits cleared through PJM Multimonthly Capacity Credit Market (CCM).

Net excess (capacity)

The net of gross excess and gross deficiency, therefore the total PJM capacity resources in excess of the sum of load-serving entities' obligations.

Net exchange (capacity)

Capacity imports less exports.

Net interchange (energy)

Gross import volume less gross export volume in MWh.

Network Transmission Service

Transmission service that is for the sole purpose of serving network load. Network transmission service is only available to network customers.

Noneconomic generation

Units producing energy at an offer price greater than the LMP.

Non-Firm Transmission Service

Point-to-point transmission service under the PJM tariff that is reserved and scheduled on an as available basis and is subject to curtailment or interruption. Non-firm point to point transmission service is available on a stand-alone basis for periods ranging from one hour to one month.

Nonsynchronized Reserve

Reserve MW available within ten minutes, but not synchronized to the grid.

North American Electric Reliability Council (NERC)

A voluntary organization of U.S. and Canadian utilities and power pools established to assure coordinated operation of the interconnected transmission systems.

Off peak

For the PJM Energy Market, off-peak periods are all NERC holidays (i.e., New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, Christmas Day) and weekend hours plus weekdays from the hour ending at midnight until the hour ending at 0700.

On peak

For the PJM Energy Market, on-peak periods are weekdays, except NERC holidays (i.e., New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, Christmas Day) from the hour ending at 0800 until the hour ending at 2300.

Opportunity cost

In general, the value of the opportunity foregone when a specific action is taken. In the ancillary services markets, the difference in compensation from the Energy Market between what a unit receives when providing regulation or synchronized reserve and what it would have received had it provided energy instead.

Parameter-limited schedule

A schedule for a unit that has parameters that are used when the unit fails the three pivotal supplier test, or in a maximum generation emergency event. These parameters are pre-determined by the MMU based on unit class, unless an exception is otherwise granted.

Performance Score

This is a measure of the quality of response of a regulating resource to its assigned regulation signal (RegA or RegD).

PJM member

Any entity that has completed an application and satisfies the requirements of the PJM Board of Managers to conduct business with PJM, including transmission owners, generating entities, load-serving entities and marketers.

PJM planning year

The calendar period from June 1 through May 31.

Point of Receipt (POR) and Point of Delivery (POD)

Designations used on a transmission reservation. The designations, when combined, determine the transmission reservations' market path.

Pool-scheduled resource

A generating resource that the seller has turned over to PJM for scheduling and control.

Price duration curve

A graphic representation of the percent of hours that a system's price was at or below a given level during the year.

Price-sensitive bid

Purchases of a defined MW level of energy only up to a specified LMP. Above that LMP, the load bid is zero.

Primary operating interfaces

Primary operating interfaces are typically defined by a cross section of transmission paths or single facilities which affect a wide geographic area. These interfaces are modeled as constraints whose operating limits are respected in performing dispatch operations.

Qualified Replacement Resource

Generation resource used to replace retired resources that were historical Stage 1A source points for FTRs.

Ramp-limited desired (MW)

The achievable MW based on the UDS requested ramp rate.

Reactive Service

Reactive Service, Reactive Supply and Voltage Control from Generation or Other Sources Service, is provided by generation and other sources (such as static VAR compensators and capacitor banks) of reactive power (measured in VAR). Reactive power helps maintain appropriate voltages on the transmission system and is essential to the flow of real power (measured in MW).

RegA

PJM's slow-oscillation regulation signal designed for resources with the ability to sustain energy output for long periods of time, but with limited ramp rates. PJM can satisfy the RTO-wide regulation requirement with only RegA resources.

RegD

PJM's fast-oscillation regulation signal designed for resources with the ability to quickly adjust energy output, but with limited ability to sustain energy output for long periods of time. PJM cannot satisfy the RTO-wide regulation requirement with only RegD resources.

Regional Transmission Expansion Planning (RTEP) Protocol

The process by which PJM recommends specific transmission facility enhancements and expansions based on reliability and economic criteria. Regulation is an ancillary service that corrects short-term imbalances between generation and load and is provided by resources capable of responding to a PJM-generated signal.

ReliabilityFirst Corporation

ReliabilityFirst Corporation (RFC) began operation January 1, 2006, as the successor to three other reliability organizations: the Mid-Atlantic Area Council (MAAC), the East Central Area Coordination Agreement (ECAR), and the Mid-American Interconnected Network (MAIN). PJM is registered with RFC to comply with its reliability standards for balancing authority (BA), planning coordinator (PC), reliability coordinator (RC), resource planner (RP), transmission operator (TOP), transmission planner (TP) and transmission service provider (TSP).

Reliability Pricing Model (RPM)

PJM's resource adequacy construct. The purpose of RPM is to develop a long term pricing signal for capacity resources and LSE obligations that is consistent with the PJM Regional Transmission Expansion Planning Process (RTEPP). RPM adds stability and a locational nature to the pricing signal for capacity.

Reserve

Energy available within a defined time for the purpose of correcting an imbalance between supply and demand.

Residual Metered Load

A Residual Metered Load aggregate represents all load buses in a fully metered EDC territory, minus all load that has been designated to be priced at specific non-zonal (or nodal) locations.

Seasonal Conditional Demand

An adjustment to the DASR requirement for summer and winter seasons. The SCD factor is calculated every year based on the top 10 peak load days from the prior year.

Selective catalytic reduction (SCR)

NO_x reduction equipment usually installed on combined-cycle generators.

Self-scheduled generation

Units scheduled to run by their owners regardless of system dispatch signal. Self-scheduled units do not follow system dispatch signal and are not eligible to set LMP. Units can be submitted as a fixed block of MW that must be run, or as a minimum amount of MW that must run plus a dispatchable component above the minimum.

Shadow price

The constraint shadow price represents the incremental reduction in congestion cost achieved by relieving a constraint by 1 MW. The shadow price multiplied by the flow (in MW) on the constrained facility during each hour equals the hourly gross congestion cost for the constraint.

Sources and sinks

Sources are the origins or the injection end of a transmission transaction. Sinks are the destinations or the withdrawal end of a transaction.

Spot Import Transmission Service

Transmission service introduced as an option for non-load serving entities to offer into the PJM spot market at the border/interface as price takers.

Spot market

Transactions made in the Real-Time and Day-Ahead Energy Market at hourly LMP.

Static Var compensator

A static Var compensator (SVC) is an electrical device for providing fast-acting, reactive power compensation on high-voltage electricity transmission networks.

Summer Net Capability

The Summer Net Capability of each unit or station shall be based on summer conditions and on the power factor level normally expected for that unit or station at the time of the PJM summer peak load.

Summer conditions shall reflect the 50 percent probability of occurrence (approximated by the mean) of temperature and humidity conditions of the time of the PJM summer peak load. Conditions shall be based on local weather bureau records of the past 15 years, updated at 5 year intervals. When local weather records are not available, the values shall be estimated from the best data available.

For steam units, summer conditions shall mean, where applicable, the probable intake water temperature of once-through or open cooling systems experienced in June, July, and August at the time of the PJM peak each weekday.

For combustion turbine units, summer conditions shall mean, where applicable, the probable ambient air temperature and humidity condition experienced at the unit location at the time of the annual summer PJM peak.

The determination of the Summer Net Capability of hydro and pumped storage units shall be based on operational data or test results taken once each year at any time during the year. The same operational data or test results can be used for the determination of the Winter Net Capability.

For combined-cycle units, summer conditions shall mean where applicable, the probable intake water temperature of once-through or open cooling systems experienced in June, July, and August at the time of the PJM peak each weekday, and the probable ambient air temperature and humidity condition experienced at the unit location at the time of the annual summer PJM peak.

Supply deviations

Hourly deviations in the supply category, equal to the difference between the sum of cleared increment offers, day-ahead purchases, and day-ahead imports, to the sum of real-time purchases and real-time imports.

Synchronized reserve

Reserve capability which is required in order to enable an area to restore its tie lines to the pre-contingency state within 10 minutes of a contingency that causes an imbalance between load and generation. During normal operation, these reserves must be provided by increasing energy output on electrically synchronized equipment, by reducing load on pumped storage hydroelectric facilities or by reducing the demand by demand-side resources. During system restoration, customer load may be classified as synchronized reserve.

System installed capacity

System total installed capacity measures the sum of the installed capacity (in installed, not unforced, terms) from all internal and qualified external resources designated as PJM capacity resources.

System lambda

The cost to the PJM system of generating the next unit of output.

Temperature-humidity index (THI)

A temperature-humidity index (THI) gives a single, numerical value reflecting the outdoor atmospheric conditions of temperature and humidity as a measure of comfort (or discomfort) during warm weather. THI is defined as: $THI = T_d - (0.55 - 0.55RH) * (T_d - 58)$ if T_d is > 58 ; else $THI = T_d$ (where T_d is the dry-bulb temperature and RH is the percentage of relative humidity.)

Transmission Adequacy and Reliability Assessment (TARA)

An analysis tool that can calculate generation to load impacts. This tool is used to facilitate loop flow analysis across the Eastern Interconnection.

Transmission Constraint Penalty Factor

In the PJM energy market optimization, the power flow on a transmission constraint is allowed to exceed its limit under some conditions. The violations incur a cost called a transmission penalty factor expressed in \$/MWh. Following the principles of optimization, the shadow price or the marginal value of the transmission constraint can never exceed the transmission constraint penalty factor. For this reason, the transmission constraint penalty factor is also called marginal value limit.

Turn down ratio

The ratio of dispatchable megawatts on a unit's schedule. Calculated by a unit's economic maximum MW divided by its economic minimum MW. An operating parameter of a unit's schedule.

Unforced capacity

Installed capacity adjusted by forced outage rates.

Western region

Defined region for purposes of allocating balancing operating reserve charges. Includes the AEP, AP, ComEd, DLCO, and DAY transmission zones.

Wheel-through

An energy transaction flowing through a transmission grid whose origination and destination are outside of the transmission grid.

Winter Weather Parameter (WWP)

WWP is wind speed adjusted temperature. WWP is defined as: $WWP = T_d - (0.5 * (WIND - 10))$ if $WIND > 10$ mph; $WWP = T_d$ if $WIND \leq 10$ mph (where T_d is the dry-bulb temperature and WIND is the wind speed.)

Zone

See "Control zone" (above).

Appendix J List of Acronyms

AC2	Advanced Control Center	BOR	Balancing Operating Reserve
ACE	Area control error	BORCA	Balancing operating reserve cost allocation
ACP	Alternative Compliance Payment	BRA	Base Residual Auction
ACR	Avoidable cost rate	BSER	Best System of Emission Reduction
AECI	Associated Electric Cooperative Inc.	BSSWG	Black Start Services Working Group
AECO	Atlantic City Electric Company	BAT	Best Available Technology
AEG	Alliant Energy Corporation	BTU	British thermal unit
AEP	American Electric Power Company, Inc.	BTM	Behind the meter
AFD	Adjusted Fixed Demand	C&I	Commercial and industrial customers
AGC	Automatic generation control	CAA	Clean Air Act
ALM	Active load management	CAAA	Clean Air Act Amendments
ALR	Automatic load rejection black start	CAIR	Clean Air Interstate Rule
ALTE	Eastern Alliant Energy Corporation	CAISO	California Independent System Operator
ALTW	Western Alliant Energy Corporation	CAMR	Clean Air Mercury Rule
AMI	Advanced Metering Infrastructure	CATR	Clean Air Transport Rule
AMIL	Ameren - Illinois	CBL	Customer base line
AMRN	Ameren	CC	Combined cycle
APS	Allegheny Power System	CCM	Capacity Credit Market
APIR	Avoidable Project Investment Recovery	CCR	Coal Combustion Residual
ARP	Acid Rain Program	CDR	Capacity deficiency rate
ARR	Auction Revenue Right	CDS	Cost Development Subcommittee
ARS	Automatic reserve sharing	CDTF	Cost Development Task Force
ASO	Ancillary Service Optimization	CETL	Capacity emergency transfer limit
ATC	Available transfer capability	CETO	Capacity emergency transfer objective
ATSI	American Transmission Systems, Inc.	CF	Coordinated flowgate under the Joint Operating Agreement between PJM and the Midwest Independent Transmission System Operator, Inc.
AU	Associated unit	CIP	Critical Infrastructure Protection
BA	Balancing authority	CIL	Capacity Import Limit
BAAL	Balancing authority ACE limit	CILC	Central Illinois Light Company Interface
BACT	Best Available Control Technology	CILCO	Central Illinois Light Company
BCPEP	BGE Pepco Interface	CIN	Cinergy Corporation
BGE	Baltimore Gas and Electric Company	CIR	Capacity Interconnection Rights
BGS	Basic generation service	CLMP	Congestion component of LMP
BME	Balancing market evaluation	ComEd	Commonwealth Edison Company

Con Edison	Consolidated Edison Company	DSIRE	Database of State Incentives for Renewables & Efficiency
CONE	Cost of new entry		
CP	Coal Plant	DSR	Demand side response
CPI	Consumer Price Index	DUK	Duke Energy Corporation
CPL	Carolina Power & Light Company	EAA	Emergency Action Area
CPS	Control Performance Standard, Combined Pollutants Standards	EAC	Excess Availability Capacity
		EAF	Equivalent availability factor
CRC	Central Repository for Curtailments	ECAR	East Central Area Reliability Council
CRF	Capital Recovery Factor	EDC	Electricity distribution company
CSA	Construction Service Agreement	EDT	Eastern Daylight Time
CSAPR	Cross State Air Pollution Rule	EE	Energy efficiency
CSP	Curtailment service provider	EEA	Emergency energy alert
CSTF	Capacity Senior Task Force	EERS	Energy Efficiency Standards
CT	Combustion turbine	EES	Enhanced energy scheduler
CTO	Combustion Turbine Optimizer	EFOF	Equivalent forced outage factor
CTR	Capacity transfer right	EFORd	Equivalent demand forced outage rate
CTS	Coordinated transaction scheduling		
CWA	Clean Water Act	EFORp	Equivalent forced outage rate during peak hours
DAOR	Day – Ahead Operating Reserve		
DASR	Day-Ahead Scheduling Reserve	EGU	Electric Generating Units
DARRCA	Day – ahead reliability and reactive cost allocation	EHV	Extra-high-voltage
		EIS	Environmental Information Services
DAY	Dayton Power & Light Company	EKPC	East Kentucky Power Cooperative, Inc.
DC	Direct current		
DCS	Disturbance control standard	ELRP	Economic load response program
DEC	Decrement bid	EMAAC	Eastern Mid-Atlantic Area Council
DER	Distributed energy resources	EMOF	Equivalent maintenance outage factor
DFAX	Distribution factor	EMS	Energy management system
DGP	Degree of Generator Performance	EMUSTF	Energy Market Uplift Senior Task Force
DL	Diesel		
DLC	Direct Load Control	EPA	Environmental Protection Agency
DLCO	Duquesne Light Company	EPOF	Equivalent planned outage factor
DPL	Delmarva Power & Light Company	EPT	Eastern Prevailing Time
DPLN	Delmarva Peninsula north	ESP	Electrostatic precipitators (Baghouses)
DPLS	Delmarva Peninsula south		
DR	Demand response	EST	Eastern Standard Time
DRS	Demand Response Subcommittee	ExGen	Exelon Generation Company, L.L.C.
DRSDTF	Demand Response Subzonal Dispatch Task Force	FCP	Fuel Cost Policy
		FE	FirstEnergy Corp.

FERC	The United States Federal Energy Regulatory Commission	ICCP	Inter-control center protocol
FDIc	Fuel Diversity Index for capacity	ICSA	Interconnection construction service agreement
FDIe	Fuel Diversity Index for energy generation	ICTR	Incremental Capacity Transfer Rights
FFE	Firm flow entitlement	IDC	Interchange distribution calculator
FFL	Firm Flow Limit	IESO	Ontario Independent Electricity System Operator
FGD	Flue-gas desulfurization	IGCC	Integrated Gasification Combined
FIP	Federal Implementation Plan	Cycle	
FMU	Frequently mitigated unit	ILR	Interruptible load for reliability
FPA	Federal Power Act	IMEP	Interregional Market Efficiency Process
FPR	Forecast pool requirement	INC	Increment offer
FRR	Fixed resource requirement	IP	Illinois Power Company
FSA	Facilities Study Agreement	IPI	Immediate Past Interval
FSL	Firm Service Level	IPL	Indianapolis Power & Light Company
FTR	Financial transmission right	IPP	Independent power producer
GACT	Generally Available Control Technology	IPSTF	Interconnection Process Senior Task Force
GADS	Generator Availability Data System	IRM	Installed reserve margin
GATS	Generation Attribute Tracking System	IROL	Interconnection Reliability Operating Limit
GCA	Generation control area	IRR	Internal rate of return
GE	General Electric Company	ISA	Interconnection service agreement
GHG	Greenhouse Gas	ISO	Independent system operator
GLD	Guaranteed load drop	ITC	Investment Tax Credit
GSU	Generator Step-Up Transformers	ITSCED	Intermediate term security constrained economic dispatch
GW	Gigawatt	JCPL	Jersey Central Power & Light Company
GWh	Gigawatt-hour	JOA	Joint operating agreement
HAP	Hazardous air pollutants	JOU	Jointly owned units
HE	Hour Ending	JRCA	Joint Reliability Coordination Agreement
HEDD	NJ High Energy Demand Day	KV	KiloVolt
HHI	Herfindahl-Hirschman Index	KDAEV	Known Day-Ahead Error Value
HRSR	Heat recovery steam generator	LAER	Lowest Achievable Emissions Rate
HVDC	High-voltage direct current	LAS	PJM Load Analysis Subcommittee
Hz	Hertz	LCA	Load control area
IA	RPM Incremental Auction	LDA	Locational deliverability area
IARR	Incremental ARR		
IBTs	Internal Bilateral Transactions		
ICAP	Installed capacity		

LF	Loss Factor	MIL	Mandatory interruptible load
LGEE	LG&E Energy, L.L.C.	MIS	Market information system
LGIA	Large generator interconnection agreement	MISO	Midcontinent Independent Transmission System Operator, Inc.
LGIP	Large generator interconnection procedure	MLMP	Marginal loss component of LMP
LIND	Linden Variable Frequency Transformer (VFT)	MMU	PJM Market Monitoring Unit
LM	Load management	Mon Power	Monongahela Power
LMP	Locational marginal price	MOPR	Minimum Offer Price Rule
LMTF	Load Management Task Force	MOPR-Ex	Minimum Offer Price Rule Extended
LOC	Lost opportunity cost	MP	Market participant
LPC	Locational Pricing Calculator	MP2	Monitored Priority 2
LSE	Load-serving entity	MPS	Multi Pollutant Standard
M2M	Market to market	MRC	Markets and reliability committee
MAAC	Mid-Atlantic Area Council	MRT	Minimum run time
MAAC+APS	Mid-Atlantic Area Council plus the Allegheny Power System	MRTS	Marginal Rate of Technical Substitution
MACRS	Modified accelerated cost recovery schedule	MSOC	Market Seller Offer Cap
MACT	Maximum Achievable Control Technology	MSSC	Most severe single contingency
MAD	Mid-Atlantic Dominion subzone	MTSL	Minimum Tank Suction Level
MAIN	Mid-America Interconnected Network, Inc.	MUI	Market user interface
MAPP	Mid-Continent Area Power Pool	MUR	Multi Value Project Usage Rate
MATS	Mercury and Air Toxics Standards rule	MVP	Multi Value Project
MBF	Marginal Benefit Factor	MW	Megawatt
MCP	Market-clearing price	MWh	Megawatt-hour
MDS	Maximum daily starts	MWS	Maximum weekly starts
MDT	Minimum down time	NAESB	North American Energy Standards Board
MEC	MidAmerican Energy Company	NAAQS	National Ambient Air Quality Standards
MECS	Michigan Electric Coordinated System	NBT	Net Benefits Test
Met-Ed	Metropolitan Edison Company	NCMPA	North Carolina Municipal Power Agency
MIC	Market Implementation Committee	NEI	Nuclear Energy Institute
MICHFE	The pricing point for the Michigan Electric Coordinated System and FirstEnergy control areas	NEPT	Neptune DC Line
		NERC	North American Electric Reliability Council
		NESHAP	National Emission Standards for Hazardous Air Pollutants
		NICA	Northern Illinois Control Area

NIPSCO	Northern Indiana Public Service Company	PATH	Potomac – Appalachian Transmission Highline
NJDEP	New Jersey Department of Environmental Protection	PAI	Performance Assessment Interval
NNL	Network and native load	PCLLRW	Post Contingency Local Load Relief Warning
NOPR	Notice of Proposed Rulemaking	PE	PECO Zone
NO _x	Nitrogen oxides	PEC	Progress Energy Carolinas, Inc.
NPDES	National Pollutant Discharge Elimination System	PECO	PECO Energy Company
NPS	National Park Service	PENELEC	Pennsylvania Electric Company
NSPS	New Source Performance Standards	Pepco	Formerly Potomac Electric Power Company or PEPCO
NSR	New Source Review	PHI	Pepco Holdings, Inc.
NSRMCP	Nonsynchronized Reserve Market Clearing Price	PJM	PJM Interconnection, L.L.C.
NUG	Non-utility generator	PJM/AEPNI	The interface between the American Electric Power Control Zone and Northern Illinois
NYISO	New York Independent System Operator	PJM/AEPPJM	The interface between the American Electric Power Control Zone and PJM
OA	Amended and Restated Operating Agreement of PJM Interconnection, L.L.C.	PJM/AEPVP	The single interface pricing point formed in March 2003 from the combination of two previous interface pricing points: PJM/American Electric Power Company, Inc. and PJM/Dominion Resources, Inc.
OASIS	Open Access Same-Time Information System	PJM/AEPVPEXP	The export direction of the PJM/AEPVP interface pricing point
OATI	Open Access Technology International, Inc.	PJM/AEPVPIMP	The import direction of the PJM/AEPVP interface pricing point
OATT	PJM Open Access Transmission Tariff	PJM/ALTE	The interface between PJM and the eastern portion of the Alliant Energy Corporation's control area
ODEC	Old Dominion Electric Cooperative	PJM/ALTW	The interface between PJM and the western portion of the Alliant Energy Corporation's control area
OEM	Original equipment manufacturer	PJM/AMRN	The interface between PJM and the Ameren Corporation's control area
OFO	Operational Flow Orders	PJM/CILC	The interface between PJM and the Central Illinois Light Company's control area
OI	PJM Office of the Interconnection	PJM/CIN	The interface between PJM and the Cinergy Corporation's control area
Ontario IESO	Ontario Independent Electricity System Operator		
OPSI	Organization of PJM States, Inc.		
OMC	Outside Management Control		
ORDC	Operating Reserve Demand Curve		
ORECs	Offshore wind renewable energy credits		
ORS	NERC Operating Reliability Subcommittee		
OVEC	Ohio Valley Electric Corporation		
PAR	Phase angle regulator		

PJM/CPLE	The interface between PJM and the eastern portion of the Carolina Power & Light Company's control area	PJM/NEPT	The interface between PJM and the New York Independent System Operator over the Neptune DC line
PJM/CPLW	The interface between PJM and the western portion of the Carolina Power & Light Company's control area	PJM/NIPS	The interface between PJM and the Northern Indiana Public Service Company's control area
PJM/CWPL	The interface between PJM and the City Water, Light & Power's (City of Springfield, IL) control area	PJM/NYIS	The interface between PJM and the New York Independent System Operator
PJM/DLCO	The interface between PJM and the Duquesne Light Company's control area	PJM/Ontario IESO	PJM/Ontario IESO pricing point
PJM/DUK	The interface between PJM and the Duke Energy Corp.'s control area	PJM/OVEC	The interface between PJM and the Ohio Valley Electric Corporation's control area
PJM/EKPC	The interface between PJM and the Eastern Kentucky Power Corporation's control area	PJM/TVA	The interface between PJM and the Tennessee Valley Authority's control area
PJM/FE	The interface between PJM and the FirstEnergy Corp.'s control area	PJM/VAP	The interface between PJM and the Dominion Virginia Power's control area
PJM/ICC	PJM Industrial Customer Coalition	PJM/WEC	The interface between PJM and the Wisconsin Energy Corporation's control area
PJM/IP	The interface between PJM and the Illinois Power Company's control area	PLC	Peak Load Contribution
PJM/IPL	The interface between PJM and the Indianapolis Power & Light Company's control area	PLS	Parameter limited schedule
PJM/LGEE	The interface between PJM and the Louisville Gas and Electric Company's control area	PMSS	Preliminary market structure screen
PJM/LIND	The interface between PJM and the New York System Operator over the Linden VFT line	PNNE	PENELEC's northeastern subarea
PJM/MEC	The interface between PJM and MidAmerican Energy Company's control area	PNNW	PENELEC's northwestern subarea
PJM/MECS	The interface between PJM and the Michigan Electric Coordinated System's control area	POD	Point of delivery
PJM/MISO	The interface between PJM and the Midwest Independent System Operator	POR	Point of receipt
		PPA	Power Purchase Agreement
		PPB	Parts per billion
		PPL	PPL Electric Utilities Corporation
		PRD	Price Responsive Demand
		PSE&G	Public Service Electric and Gas Company (a wholly owned subsidiary of PSEG)
		PSEG	Public Service Enterprise Group
		PSD	Prevention of Significant Deterioration
		PSN	PSEG north
		PSNC	PSEG north central
		PTC	Production Tax Credit

QF	Qualifying Facility	RTO	Regional transmission organization
QRR	Qualified Replacement Resource	SAA	Symmetrical Additive Adjustment
QTU	Qualifying Transmission Upgrade	SCE&G	South Carolina Energy and Gas
RAA	Reliability Assurance Agreement among Load-Serving Entities	SCD	Seasonal Conditional Demand
RAC	Reliability Assessment Commitment	SCED	Security Constrained Economic Dispatch
RCF	Reciprocal Coordinated Flowgate	SCPA	South central Pennsylvania subarea
RCIS	Reliability Coordinator Information System	SCR	Selective catalytic reduction
RCRA	Resource Conservation and Recovery Act	SECA	Seams Elimination Cost Assignment
REC	Renewable Energy Credit	SEPA	Southeast Power Administration
RECO	Rockland Electric Company zone	SEPJM	Southeastern PJM subarea
RERRA	Relevant Electric Retail Regulatory Authority	SERC	SERC Reliability Corporation
RFC	Reliability <i>First</i> Corporation	SGIA	Small Generator Interconnection Agreement
RFP	Request for Proposal	SGIP	Small Generator Interconnection Procedures
RGGI	Regional Greenhouse Gas Initiative	SIPs	State Implementation Plan
RICE	Reciprocating Internal Combustion Engines	SIS	System Impact Study
RLD (MW)	Ramp-limited desired (Megawatts)	SFT	Simultaneous feasibility test
RLR	Retail load responsibility	SMECO	Southern Maryland Electric Cooperative
RMCCP	Regulation market capability clearing price	SMP	System marginal price
RMCP	Regulation market-clearing price	SMR	Sustainable market rule
RMPCP	Regulation market performance clearing price	SNCR	Selective Non-Catalytic Reduction
RMR	Reliability Must Run	SNJ	Southern New Jersey
ROFR	Right of First Refusal	SO ₂	Sulfur dioxide
RPM	Reliability Pricing Model	SOUTHEXP	South Export pricing point
RPS	Renewable Portfolio Standard	SOUTHIMP	South Import pricing point
RRMSE	Relative Root Mean Squared Error	SPP	Southwest Power Pool, Inc.
RSI	Residual supply index	SPREGO	Synchronized reserve and regulation optimizer (market-clearing software)
RSIx	Residual supply index, using “x” pivotal suppliers	SRMCP	Synchronized reserve market-clearing price
RTC	Real-time commitment	SRSTF	System Restoration Strategy Task Force
RTEP	Regional Transmission Expansion Plan	STD	Standard deviation
RTSCED	Real time security constrained economic dispatch	STRPTAS	Short Term Resource Procurement Applicable Share
		SVC	Static Var compensator

SWMAAC	Southwestern Mid-Atlantic Area Council	WPL	Winter peak load
TARA	Transmission adequacy and reliability assessment	WWP	Winter Weather Parameter
TDR	Turn down ratio	XEFORd	EFORd modified to exclude OMC outages
TEAC	Transmission Expansion Advisory Committee	ZEC	Zero Emissions Credit
THI	Temperature-humidity index	ZWWAF	Zonal Winter Weather Adjustment Factor
TISTF	Transactions Issues Senior Task Force		
TLR	Transmission loading relief		
TMEP	Targeted market efficiency process		
TPS	Three pivotal supplier		
TPSTF	Three Pivotal Supplier Task Force		
TPY	Tons Per Year		
TrAIL	Trans - Allegheny Interstate Line		
TREG	Total Regulation Signal		
TSA	Thunderstorm Alert		
TSIN	NERC Transmission System Information Network		
TVA	Tennessee Valley Authority		
UCAP	Unforced capacity		
UCSA	Upgrade construction service agreement		
UDS	Unit dispatch system		
UGI	UGI Utilities, Inc.		
ULSD	Ultra-Low Sulfur Diesel		
UPF	Unit participation factor		
UTC	Up To Congestion Transaction		
VACAR	Virginia and Carolinas Area		
VAP	Dominion Virginia Power		
VFT	Variable frequency transformer		
VOCs	Volatile Organic Compounds		
VOM	Variable operation and maintenance expense		
VRR	Variable resource requirement		
WEC	Wisconsin Energy Corporation		
WLR	Wholesale load responsibility		
WOTUS	Waters of the United States		
WPC	Willing to pay congestion		