2024 Annual State of the Market Report for PJM

Press Briefing

March 13, 2025

IMM

Monitoring Analytics

Market Monitoring Unit

- Monitoring Analytics, LLC
  - Independent company
  - Formed August 1, 2008
- Independent Market Monitor for PJM
  - Independent from Market Participants
  - Independent from RTO management
  - Independent from RTO board of managers
- MMU Accountability
  - To FERC (per FERC MMU Orders and MM Plan)
  - To PJM markets
  - To PJM Board for administration of the contract

Role of Market Monitoring

- Market monitoring is required by FERC Orders
- Role of competition under FERC regulation
  - Mechanism to regulate prices
  - Competitive outcome = just and reasonable
  - Competitive markets replace traditional regulation
- FERC has enforcement authority
- Relevant model of competition is not laissez faire
- Competitive outcomes are not automatic
- Competitive outcomes require effective market power mitigation rules.

Role of Market Monitoring

- **Detailed rules required**
- **Detailed monitoring required:**
  - **Of participants**
  - **Of RTO**
  - **Of rules**
- **Market monitoring is primarily analytical**
  - **Adequacy of market rules**
  - **Compliance with market rules**
  - **Exercise of market power**
  - **Market manipulation**

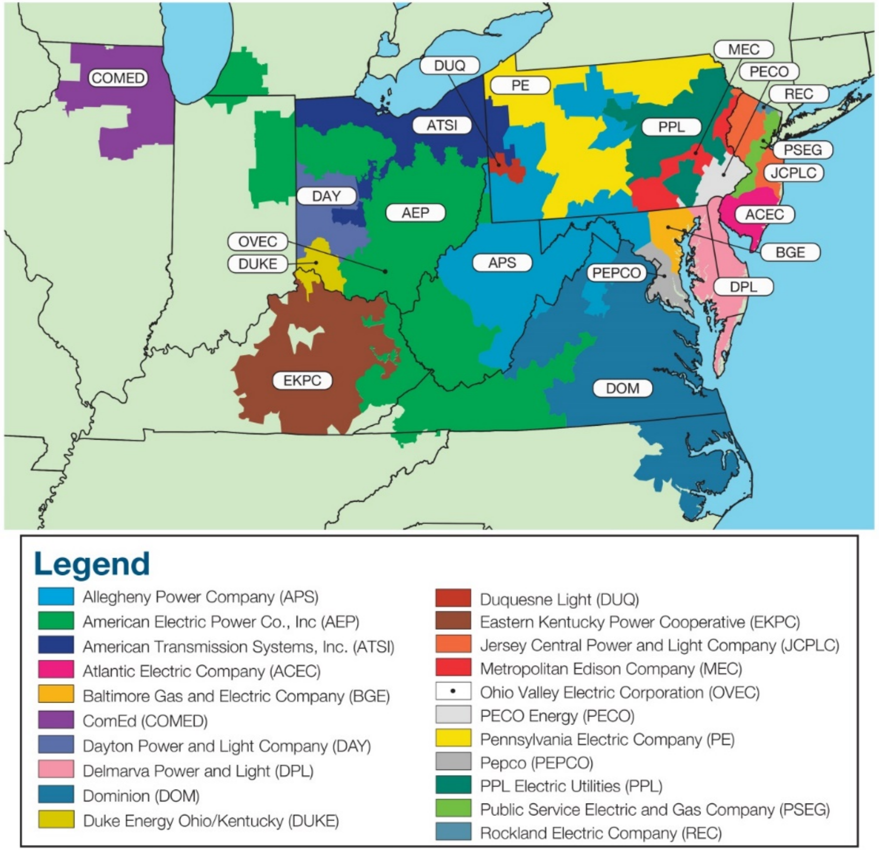
Role of Market Monitoring

- Market monitoring provides inputs to prospective mitigation
- Market monitoring provides retrospective mitigation
- Market monitoring provides information
  - To FERC
  - To state regulators
  - To market participants
  - To RTO

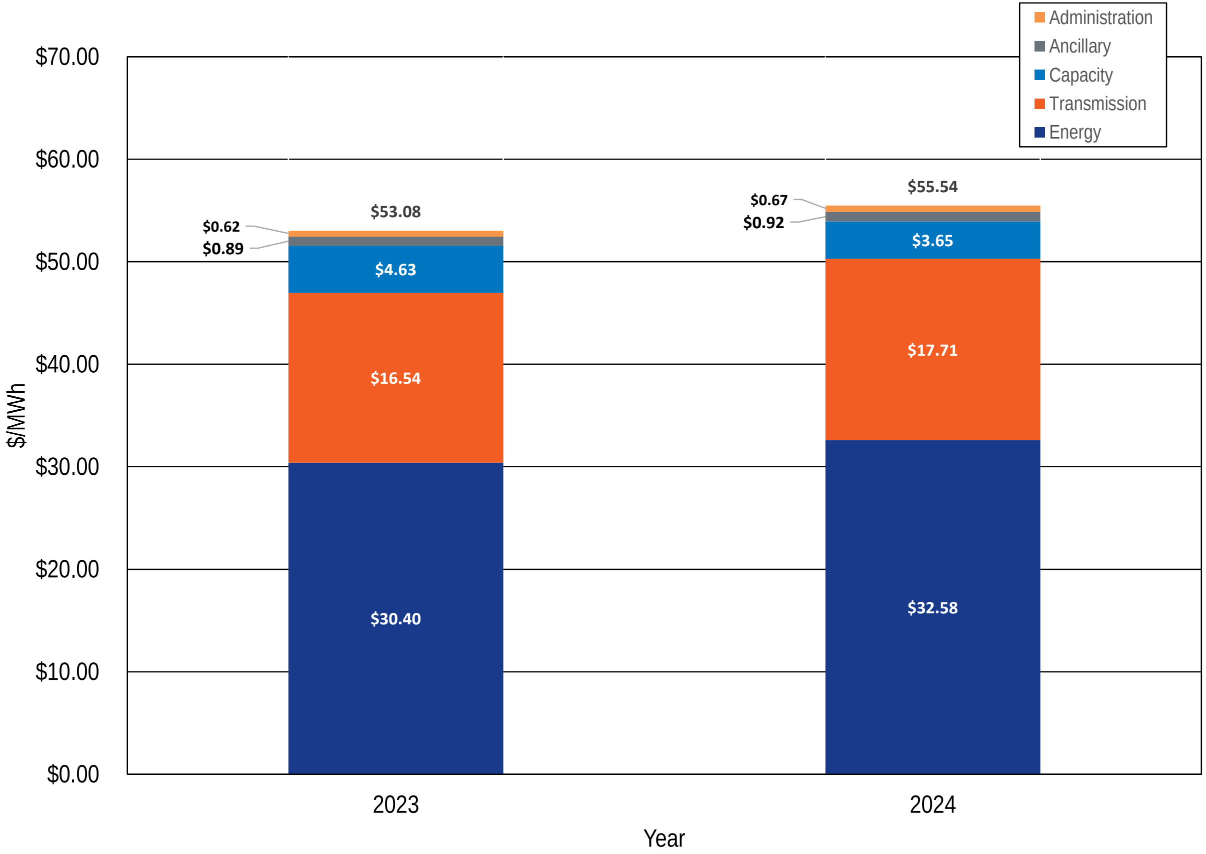
Market Monitoring Plan

- Monitor compliance with rules
  - Monitor the potential of market participants to exercise market power
  - Monitor for market manipulation
- Recommend changes to rules
  - Monitor actual or potential design flaws in rules
  - Monitor structural problems in the PJM market
- Report on market issues
  - State of the market reports
  - Other reports

PJM’s footprint



Total Cost of Wholesale Power



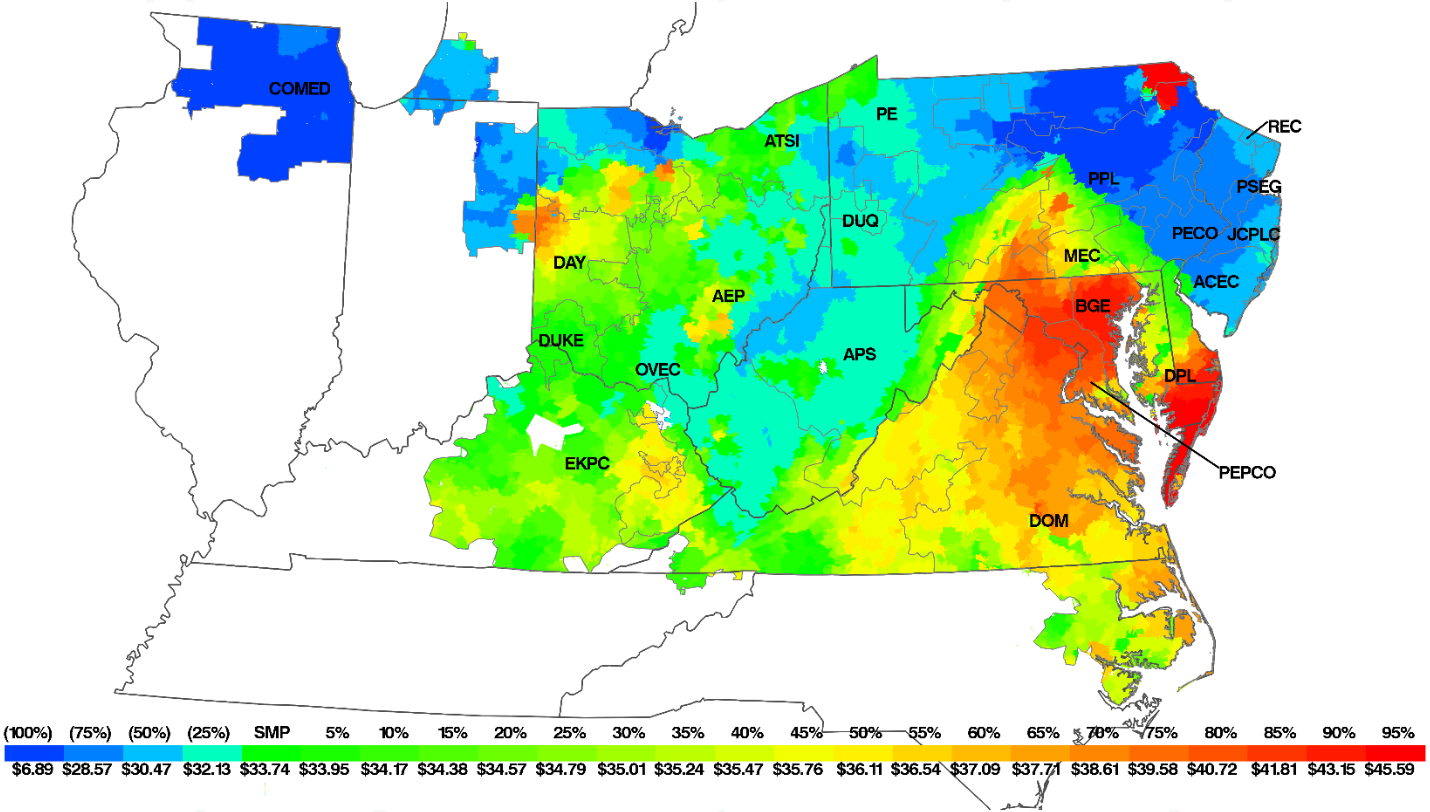
PJM market summary statistics

	2023	2024	Percent Change
Average Hourly Load Plus Exports (MWh)	92,455	94,787	2.5%
Average Hourly Generation Plus Imports (MWh)	94,165	96,605	2.6%
Peak Load Plus Export (MWh)	152,797	154,045	0.8%
Peak Load Excluding Export (MWh)	144,215	148,890	3.2%
Installed Capacity at December 31 (MW)	178,253	179,656	0.8%
Load Weighted Average Real Time LMP ($/MWh)	$31.08	$33.74	8.5%
Total Congestion Costs ($ Million)	$1,068.60	$1,754.40	64.2%
Total Uplift Credits ($ Million)	$156.9	$269.9	72.0%
Total PJM Billing ($ Billion)	$48.50	$51.74	6.7%

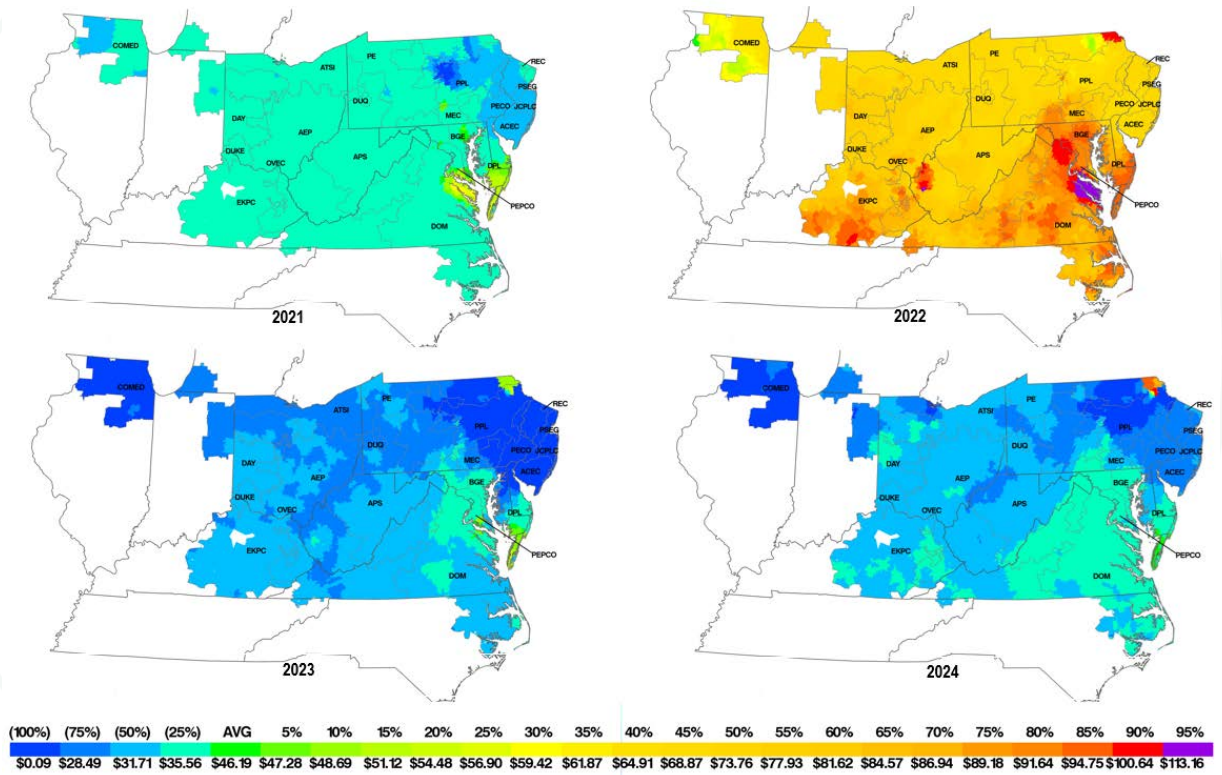
The energy market results were competitive

Market Element	Evaluation	Market Design
Market Structure: Aggregate Market	Partially Competitive	
Market Structure: Local Market	Not Competitive	
Participant Behavior	Competitive	
Market Performance	Competitive	Effective

Real-time load-weighted average LMP

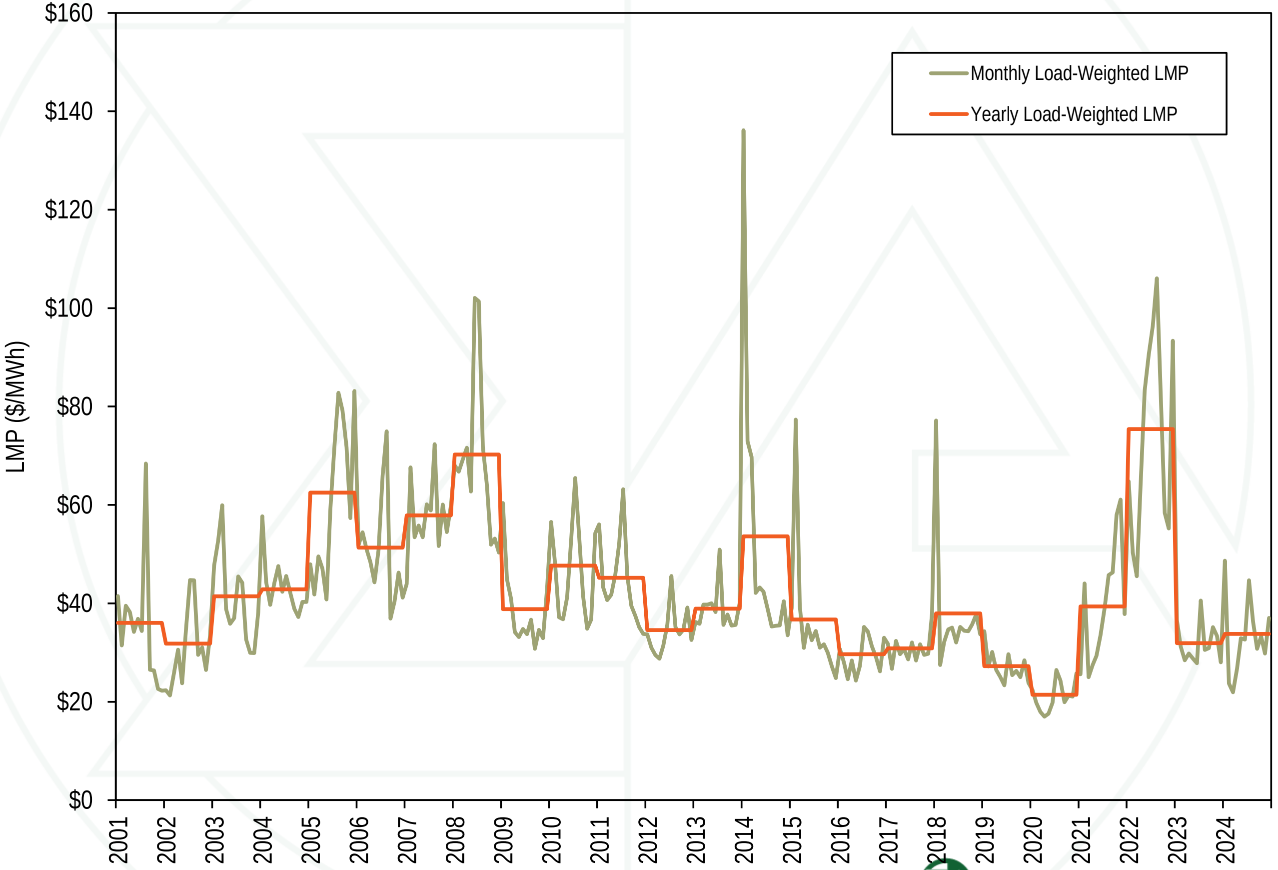


Real-time load-weighted average LMP map



Monitoring Analytics

DA monthly and yearly load-weighted average LMP



DA load-weighted average LMP

	Day-Ahead Load-Weighted Average LMP			Year to Year Change			
	Average	Median	Standard Deviation	Average	Average Percent	Median	Standard Deviation
2001	$36.01	$29.02	$37.48	NA	NA	NA	NA
2002	$31.80	$26.00	$20.68	($4.21)	(11.7%)	(10.4%)	(44.8%)
2003	$41.43	$38.29	$21.32	$9.63	30.3%	47.3%	3.1%
2004	$42.87	$41.96	$16.32	$1.44	3.5%	9.6%	(23.4%)
2005	$62.50	$54.74	$31.72	$19.62	45.8%	30.4%	94.3%
2006	$51.33	$46.72	$26.45	($11.16)	(17.9%)	(14.6%)	(16.6%)
2007	$57.88	$55.91	$25.02	$6.55	12.8%	19.7%	(5.4%)
2008	$70.25	$62.91	$33.14	$12.37	21.4%	12.5%	32.4%
2009	$38.82	$36.67	$14.03	($31.43)	(44.7%)	(41.7%)	(57.7%)
2010	$47.65	$42.06	$20.59	$8.83	22.7%	14.7%	46.8%
2011	$45.19	$39.66	$24.05	($2.46)	(5.2%)	(5.7%)	16.8%
2012	$34.55	$31.84	$15.48	($10.64)	(23.5%)	(19.7%)	(35.6%)
2013	$38.93	$35.77	$18.05	$4.37	12.7%	12.3%	16.6%
2014	$53.62	$39.84	$59.62	$14.70	37.8%	11.4%	230.4%
2015	$36.73	$30.60	$25.46	($16.89)	(31.5%)	(23.2%)	(57.3%)
2016	$29.68	$27.00	$11.64	($7.05)	(19.2%)	(11.8%)	(54.3%)
2017	$30.85	$28.21	$12.64	$1.17	3.9%	4.5%	8.6%
2018	$37.97	$32.49	$24.76	$7.13	23.1%	15.2%	95.9%
2019	$27.23	$25.28	$10.18	($10.74)	(28.3%)	(22.2%)	(58.9%)
2020	$21.40	$19.78	$7.59	($5.83)	(21.4%)	(21.7%)	(25.5%)
2021	$39.37	$33.72	$19.30	$17.97	84.0%	70.5%	154.3%
2022	$75.44	$64.13	$41.25	$36.07	91.6%	90.2%	113.8%
2023	$31.93	$29.04	$16.64	($43.51)	(57.7%)	(54.7%)	(59.7%)
2024	$33.79	$28.37	$21.75	$1.86	5.8%	(2.3%)	30.7%

Components of RT load-weighted average LMP

Element	2023 Contribution to LMP	Percent	2024 Contribution to LMP	Percent	Change in Percent
Gas	$13.60	43.7%	$13.41	39.7%	(4.0%)
Coal	$4.49	14.4%	$4.09	12.1%	(2.3%)
Positive Markup	$3.29	10.6%	$3.56	10.6%	(0.0%)
Variable Maintenance	$2.31	7.4%	$3.18	9.4%	2.0%
Transmission Constraint Penalty Factor	$1.62	5.2%	$3.01	8.9%	3.7%
Ten Percent Adder	$1.95	6.3%	$2.00	5.9%	(0.3%)
CO_2 Cost	$1.93	6.2%	$1.94	5.8%	(0.5%)
Variable Operations	$1.10	3.5%	$1.43	4.2%	0.7%
Ancillary Service Redispatch Cost	$0.50	1.6%	$1.33	3.9%	2.3%
Opportunity Cost Adder	$0.87	2.8%	$1.24	3.7%	0.9%
Oil	$0.31	1.0%	$1.08	3.2%	2.2%
Market-to-Market	$0.41	1.3%	$0.34	1.0%	(0.3%)
Increase Generation Differential	$0.13	0.4%	$0.24	0.7%	0.3%
LPA Rounding Difference	$0.40	1.3%	$0.18	0.5%	(0.8%)
Scarcity	$0.07	0.2%	$0.17	0.5%	0.3%
NA	$0.15	0.5%	$0.09	0.3%	(0.2%)
NO_x Cost	$0.51	1.6%	$0.09	0.3%	(1.4%)
Landfill Gas	$0.06	0.2%	$0.05	0.2%	(0.0%)
Other	$0.02	0.1%	$0.02	0.0%	(0.0%)
SO_2 Cost	$0.00	0.0%	$0.00	0.0%	(0.0%)
LPA-SCED Differential	($0.00)	(0.0%)	($0.00)	(0.0%)	0.0%
Decrease Generation Differential	($0.01)	(0.0%)	($0.04)	(0.1%)	(0.1%)
Renewable Energy Credits	($0.07)	(0.2%)	($0.07)	(0.2%)	0.0%
Negative Markup	($2.56)	(8.2%)	($3.58)	(10.6%)	(2.4%)
Total	$31.08	100.0%	$33.74	100.0%	0.0%

Components of Change in RT load-weighted average LMP

Component	2023	2024	Change in LMP	Change
Fuel and Consumables	$19.56	$20.06	$0.50	18.9%
Emission Related	$3.24	$3.19	($0.05)	(1.9%)
Market Power Related	$4.99	$5.16	$0.16	6.2%
Scarcity	$0.07	$0.17	$0.10	3.7%
Transmission Constraint Penalty Factor	$1.62	$3.01	$1.39	52.4%
Ancillary Service Redispatch Cost	$0.50	$1.33	$0.83	31.2%
Emergency Demand Response	$0.00	$0.00	$0.00	0.0%
PJM Administrative Cap	$0.00	$0.00	$0.00	0.0%
All Other	$1.10	$0.82	($0.28)	(10.6%)
Total Change	$31.08	$33.74	$2.66	100.0%

Comparison of components of RT load-weighted average LMP in the dispatch run and pricing run

Element	Dispatch Contribution to LMP	Percent	Pricing Contribution to LMP	Percent	Change in Percent
Gas	$12.57	40.1%	$13.41	39.7%	(0.4%)
Coal	$4.36	13.9%	$4.09	12.1%	(1.8%)
Positive Markup	$3.08	9.8%	$3.56	10.6%	0.7%
Variable Maintenance	$2.26	7.2%	$3.18	9.4%	2.2%
Transmission Constraint Penalty Factor	$2.90	9.3%	$3.01	8.9%	(0.3%)
Ten Percent Adder	$1.86	6.0%	$2.00	5.9%	(0.0%)
CO_2 Cost	$1.99	6.4%	$1.94	5.8%	(0.6%)
Variable Operations	$1.39	4.4%	$1.43	4.2%	(0.2%)
Ancillary Service Redispatch Cost	$0.93	3.0%	$1.33	3.9%	1.0%
Opportunity Cost Adder	$1.09	3.5%	$1.24	3.7%	0.2%
Oil	$0.97	3.1%	$1.08	3.2%	0.1%
Market-to-Market	$0.47	1.5%	$0.34	1.0%	(0.5%)
Increase Generation Differential	$0.18	0.6%	$0.24	0.7%	0.1%
LPA Rounding Difference	$0.26	0.8%	$0.18	0.5%	(0.3%)
Scarcity	$0.20	0.6%	$0.17	0.5%	(0.1%)
NA	$0.10	0.3%	$0.09	0.3%	(0.0%)
NO_x Cost	$0.08	0.2%	$0.09	0.3%	0.0%
Landfill Gas	$0.06	0.2%	$0.05	0.2%	(0.0%)
Other	$0.02	0.1%	$0.02	0.0%	(0.0%)
SO_2 Cost	$0.00	0.0%	$0.00	0.0%	(0.0%)
LPA-SCED Differential	$0.00	0.0%	($0.00)	(0.0%)	(0.0%)
Decrease Generation Differential	($0.02)	(0.1%)	($0.04)	(0.1%)	(0.1%)
Renewable Energy Credits	($0.08)	(0.2%)	($0.07)	(0.2%)	0.0%
Negative Markup	($3.36)	(10.7%)	($3.58)	(10.6%)	0.1%
Total	$31.31	100.0%	$33.74	100.0%	0.0%

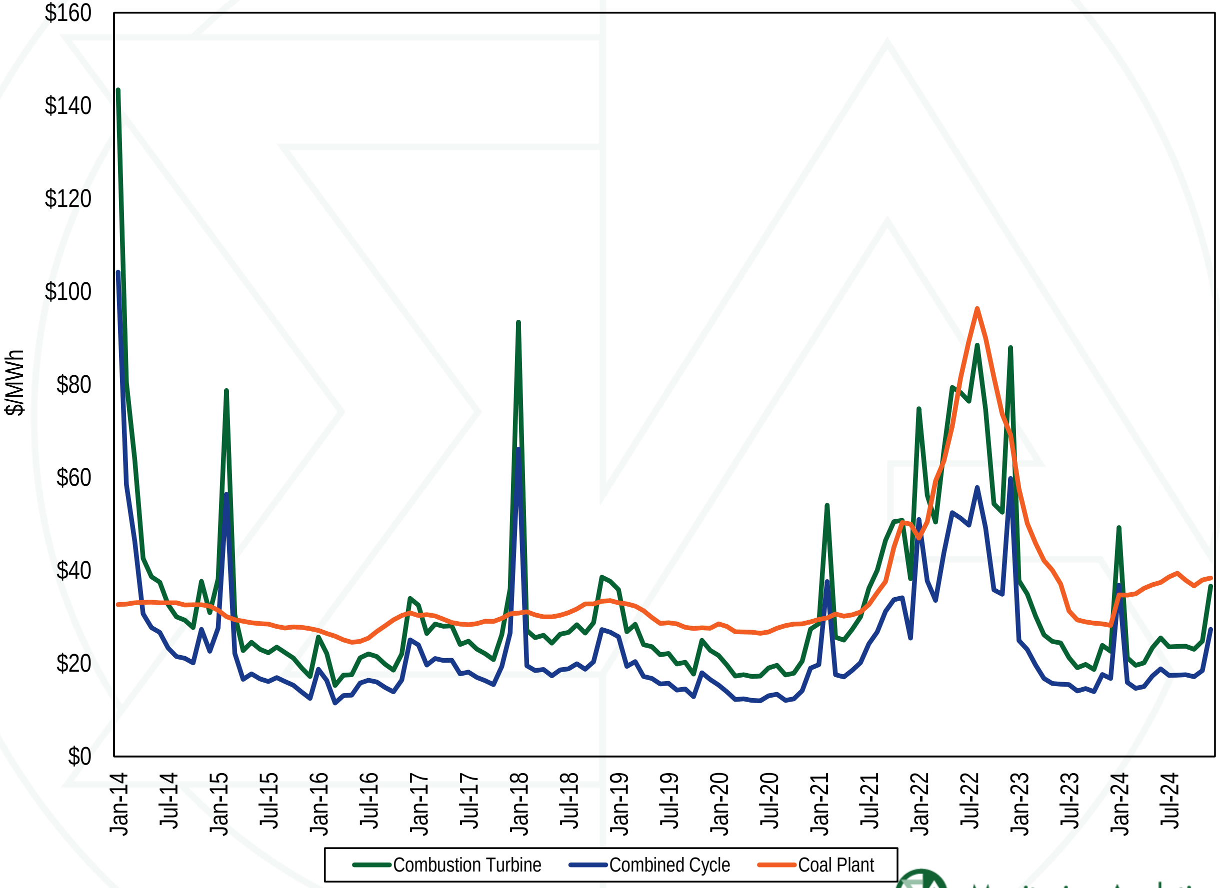
Generation by fuel source (GWh)

	2023		2024		Change in
	GWh	Percent	GWh	Percent	Output
Coal	120,876.1	14.7%	122,583.3	14.5%	1.4%
Bituminous	108,651.3	13.2%	107,270.7	12.7%	(1.3%)
Sub Bituminous	6,428.1	0.8%	9,548.2	1.1%	48.5%
Other Coal	5,796.7	0.7%	5,764.4	0.7%	(0.6%)
Nuclear	273,488.6	33.3%	272,744.4	32.2%	(0.3%)
Gas	363,659.7	44.3%	376,249.8	44.5%	3.5%
Natural Gas CC	331,767.3	40.4%	340,951.1	40.3%	2.8%
Natural Gas CT	21,077.7	2.6%	20,916.2	2.5%	(0.8%)
Natural Gas Other Units	9,570.7	1.2%	13,250.0	1.6%	38.4%
Other Gas	1,244.0	0.2%	1,132.6	0.1%	(9.0%)
Hydroelectric	15,488.8	1.9%	16,001.4	1.9%	3.3%
Pumped Storage	6,096.5	0.7%	6,430.5	0.8%	5.5%
Run of River	7,644.6	0.9%	7,624.6	0.9%	(0.3%)
Other Hydro	1,747.6	0.2%	1,946.3	0.2%	11.4%
Wind	28,937.2	3.5%	31,384.5	3.7%	8.5%
Waste	3,992.6	0.5%	3,912.1	0.5%	(2.0%)
Oil	2,676.7	0.3%	4,098.6	0.5%	53.1%
Heavy Oil	38.2	0.0%	156.8	0.0%	310.4%
Light Oil	918.5	0.1%	2,188.2	0.3%	138.2%
Diesel	40.4	0.0%	32.4	0.0%	(19.8%)
Other Oil	1,679.6	0.2%	1,721.2	0.2%	2.5%
Solar	11,097.7	1.4%	17,547.7	2.1%	58.1%
Battery	28.7	0.0%	51.7	0.0%	80.4%
Biofuel	1,265.0	0.2%	1,249.4	0.1%	(1.2%)
Total	821,511.0	100.0%	845,823.0	100.0%	3.0%

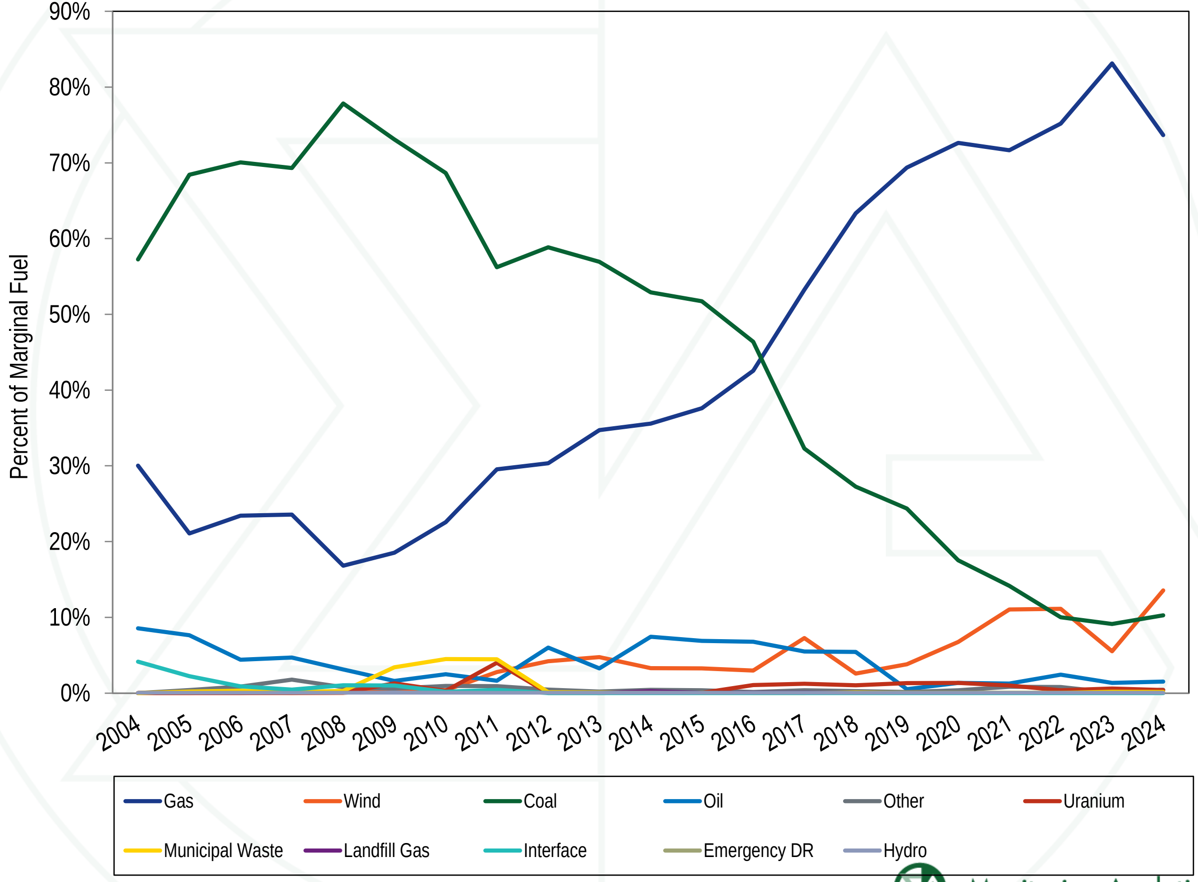
Share of generation by fuel source

	Natural Gas	Coal	Nuclear	Other Fuel Type
2008	7.4%	54.9%	34.7%	3.0%
2009	10.0%	50.3%	35.9%	3.7%
2010	11.7%	49.3%	34.6%	4.4%
2011	14.1%	47.1%	34.5%	4.3%
2012	18.8%	42.1%	34.6%	4.5%
2013	16.7%	44.2%	34.8%	4.3%
2014	17.8%	43.3%	34.4%	4.5%
2015	23.0%	36.2%	35.5%	5.3%
2016	26.5%	33.9%	34.4%	5.3%
2017	26.8%	31.8%	35.6%	5.9%
2018	30.6%	28.6%	34.2%	6.6%
2019	36.2%	23.8%	33.6%	6.4%
2020	39.6%	19.3%	34.2%	6.9%
2021	37.7%	22.2%	32.8%	7.4%
2022	39.8%	20.0%	32.3%	7.9%
2023	44.1%	14.7%	33.3%	7.9%
2024	44.3%	14.5%	32.2%	8.9%

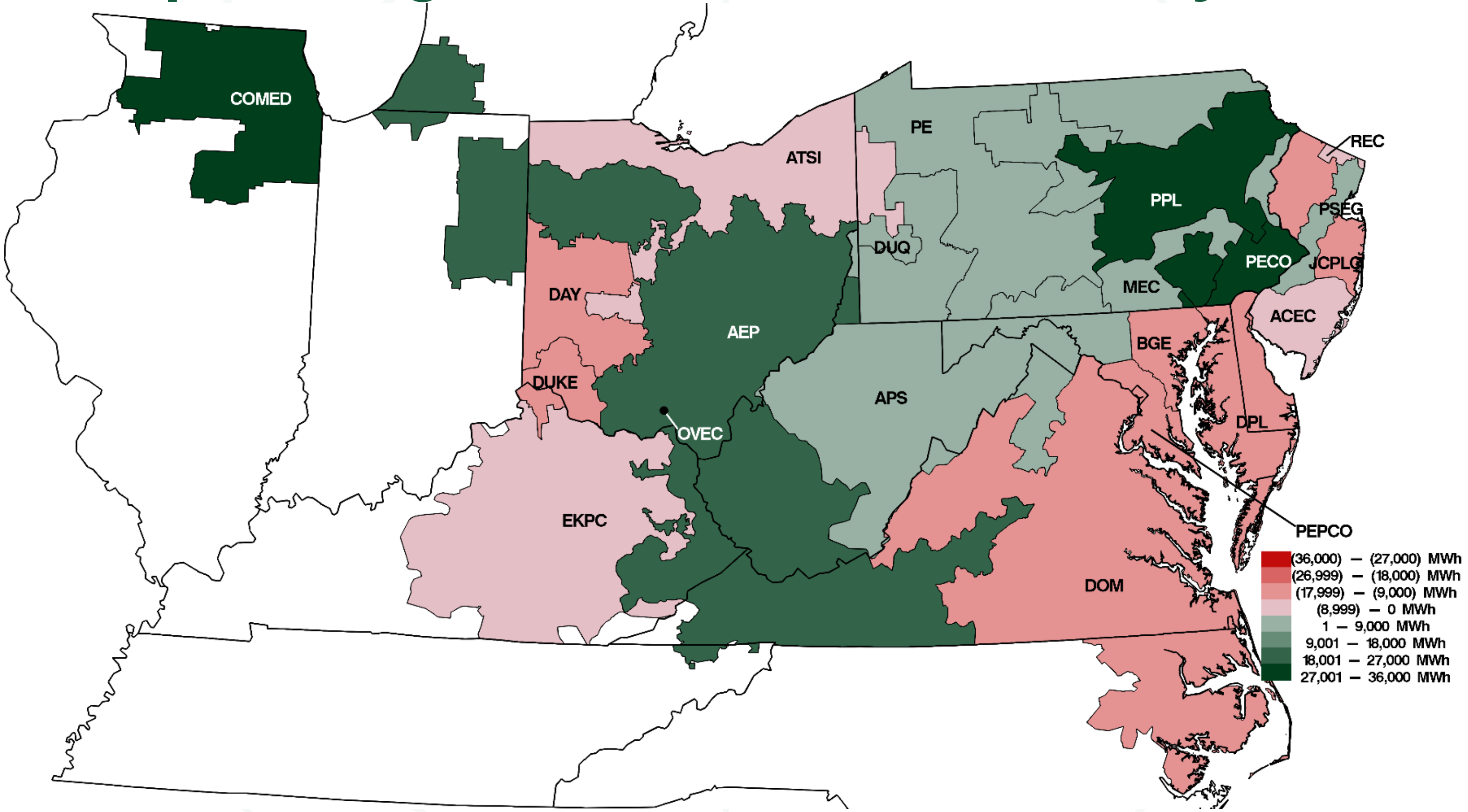
Average short run marginal costs



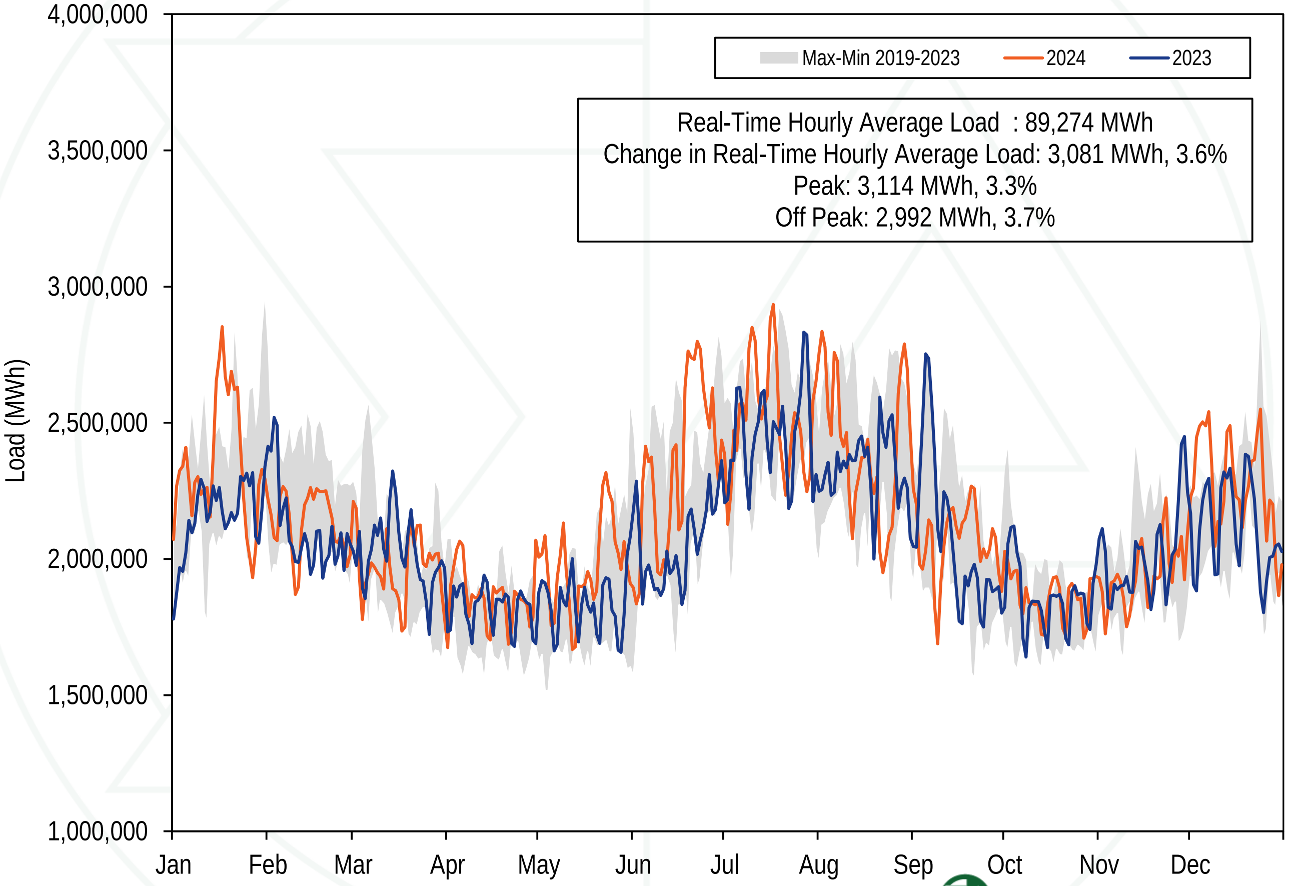
Type of fuel used by RT marginal units



Map of RT generation less RT load by zone



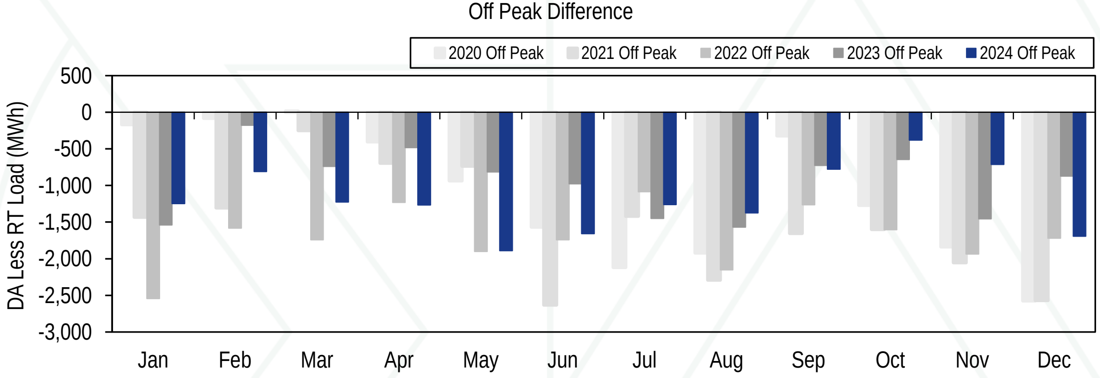
RT daily load

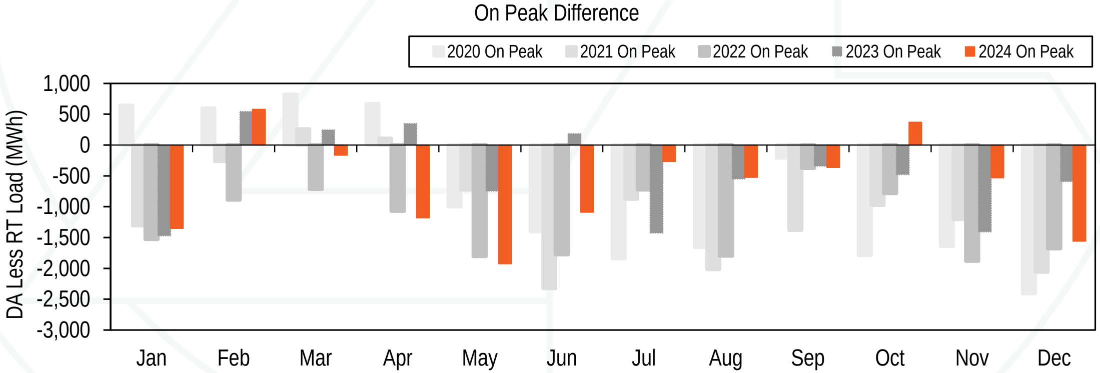


RT hourly average load and load plus exports

	PJM Real-Time Demand (MWh)				Year to Year Change			
	Load		Load Plus Exports		Load		Load Plus Exports	
	Load	Standard Deviation	Demand	Standard Deviation	Load	Standard Deviation	Demand	Standard Deviation
2001	30,297	5,873	32,165	5,564	NA	NA	NA	NA
2002	35,776	7,976	37,676	8,145	18.1%	35.8%	17.1%	46.4%
2003	37,395	6,834	39,380	6,716	4.5%	(14.3%)	4.5%	(17.5%)
2004	49,963	13,004	54,953	14,947	33.6%	90.3%	39.5%	122.6%
2005	78,150	16,296	85,301	16,546	56.4%	25.3%	55.2%	10.7%
2006	79,471	14,534	85,696	15,133	1.7%	(10.8%)	0.5%	(8.5%)
2007	81,681	14,618	87,897	15,199	2.8%	0.6%	2.6%	0.4%
2008	79,515	13,758	86,306	14,322	(2.7%)	(5.9%)	(1.8%)	(5.8%)
2009	76,034	13,260	81,227	13,792	(4.4%)	(3.6%)	(5.9%)	(3.7%)
2010	79,611	15,504	85,518	15,904	4.7%	16.9%	5.3%	15.3%
2011	82,541	16,156	88,466	16,313	3.7%	4.2%	3.4%	2.6%
2012	87,011	16,212	92,135	16,052	5.4%	0.3%	4.1%	(1.6%)
2013	88,332	15,489	92,879	15,418	1.5%	(4.5%)	0.8%	(3.9%)
2014	89,099	15,763	94,471	15,677	0.9%	1.8%	1.7%	1.7%
2015	88,594	16,663	92,665	16,784	(0.6%)	5.7%	(1.9%)	7.1%
2016	88,601	17,229	93,551	17,498	0.0%	3.4%	1.0%	4.3%
2017	86,618	15,170	91,015	15,083	(2.2%)	(11.9%)	(2.7%)	(13.8%)
2018	90,308	15,982	94,351	16,142	4.3%	5.4%	3.7%	7.0%
2019	88,120	15,867	92,920	16,085	(2.4%)	(0.7%)	(1.5%)	(0.4%)
2020	84,584	16,016	90,059	16,233	(4.0%)	0.9%	(3.1%)	0.9%
2021	87,606	15,725	92,774	16,485	3.6%	(1.8%)	3.0%	1.6%
2022	88,884	15,689	94,301	16,047	1.5%	(0.2%)	1.6%	(2.7%)
2023	86,193	13,926	92,455	14,324	(3.0%)	(11.2%)	(2.0%)	(10.7%)
2024	89,274	15,630	94,787	15,766	3.6%	12.2%	2.5%	10.1%

Difference between DA and RT on peak and off peak hourly average load by month

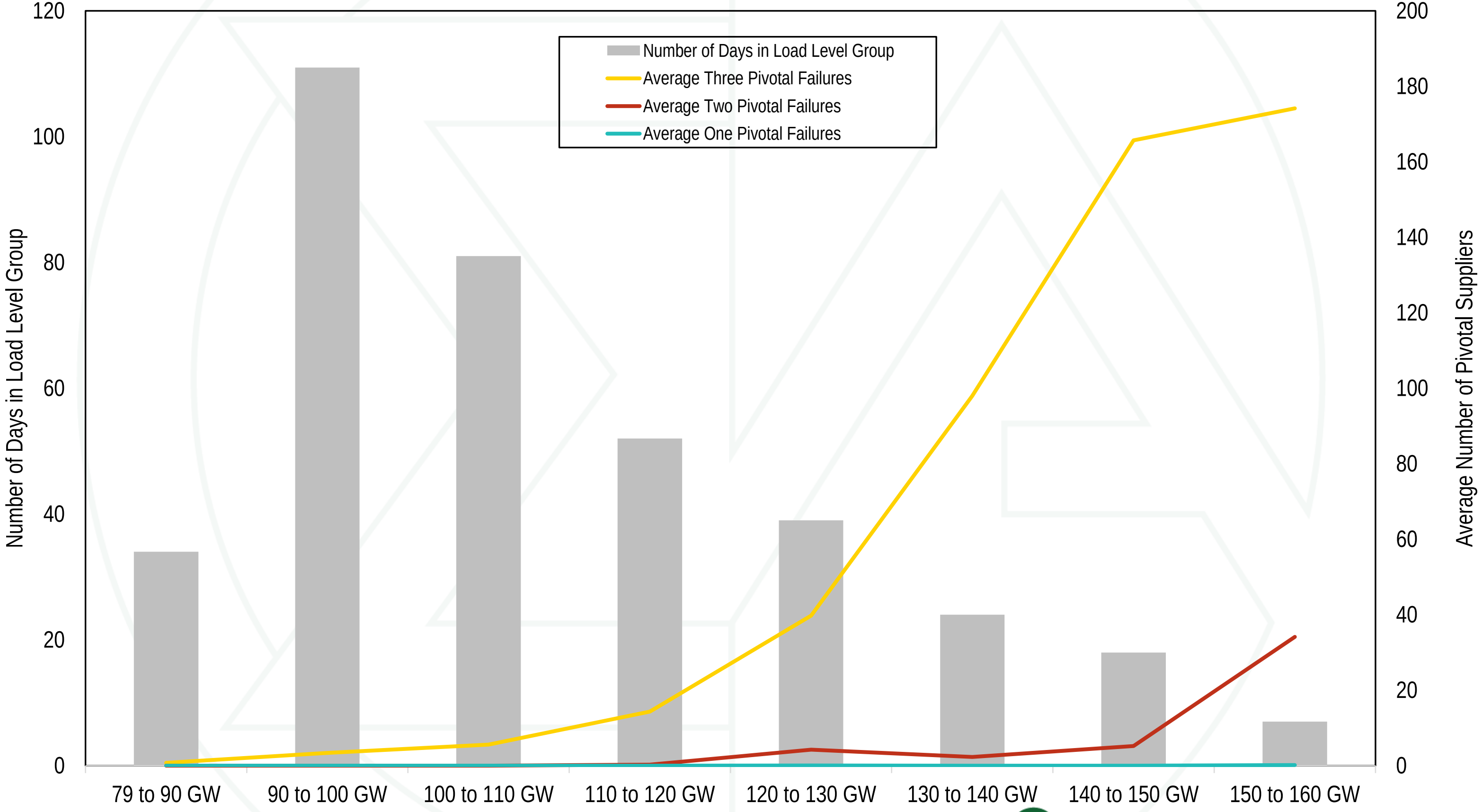




DA and RT average LMP

	2023				2024			
	Day-Ahead	Real-Time	Difference	Percent of Real-Time	Day-Ahead	Real-Time	Difference	Percent of Real-Time
Average	$30.38	$29.69	($0.69)	(2.3%)	$31.41	$31.32	($0.09)	(0.3%)
Median	$27.98	$25.80	($2.19)	(8.5%)	$26.76	$25.37	($1.39)	(5.5%)
Standard deviation	$14.60	$18.42	$3.82	20.7%	$19.40	$24.84	$5.44	21.9%
Peak average	$36.01	$35.13	($0.88)	(2.5%)	$37.77	$37.32	($0.45)	(1.2%)
Peak median	$32.49	$30.22	($2.28)	(7.5%)	$32.26	$30.17	($2.09)	(6.9%)
Peak standard deviation	$17.12	$21.87	$4.75	21.7%	$22.38	$27.86	$5.48	19.7%
Off peak average	$25.51	$24.97	($0.53)	(2.1%)	$25.86	$26.08	$0.22	0.8%
Off peak median	$23.68	$21.85	($1.83)	(8.4%)	$22.37	$21.30	($1.07)	(5.0%)
Off peak standard deviation	$9.64	$13.08	$3.44	26.3%	$14.20	$20.49	$6.29	30.7%

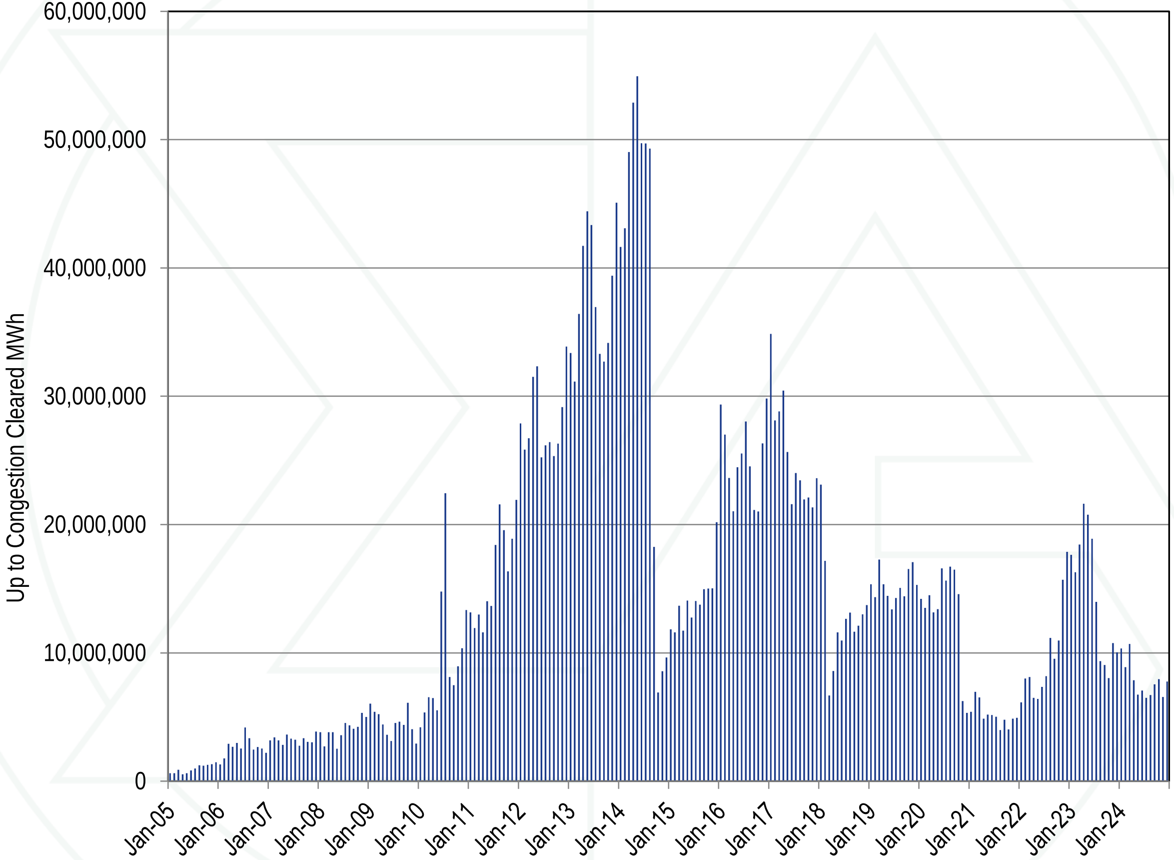
Average number of pivotal suppliers (DA)



Average hourly estimated capacity (MW) failing the ICAP must offer requirement

Month	90th Percentile	Average	10th Percentile
Jan-24	2,434	1,785	1,228
Feb-24	2,099	1,659	1,307
Mar-24	3,396	2,815	2,409
Apr-24	2,251	1,700	1,188
May-24	3,323	2,513	1,803
Jun-24	3,314	2,238	1,343
Jul-24	3,394	2,325	1,357
Aug-24	2,885	1,865	806
Sep-24	3,272	2,322	985
Oct-24	3,476	2,726	2,034
Nov-24	3,950	2,498	920
Dec-24	3,910	2,983	2,054
2024	3,336	2,290	1,292

Monthly up to congestion cleared bids



Recommendations: Energy Market

- **The MMU recommends, in order to ensure effective market power mitigation, that PJM commit all resources that fail the TPS test on their cost-based offers, that the Market Seller designate the cost-based offer if there is more than one, and that PJM implement this solution as soon as possible. (Priority: High. New recommendation. Status: Not adopted.)**

Total energy uplift charges by category

Category	2023 Charges (Millions)	2024 Charges (Millions)	Change (Millions)	Percent Change
Day-Ahead Operating Reserves	$49.7	$114.7	$65.0	130.7%
Balancing Operating Reserves	$105.6	$152.1	$46.5	44.0%
Reactive Services	$0.1	$0.9	$0.8	1,024.9%
Black Start Services	$0.3	$0.3	$0.0	1.3%
Local Congestion Charges	$0.6	$1.3	$0.7	121.7%
Total	$156.3	$269.3	$113.0	72.3%
Energy Uplift as a Percent of Total PJM Billing	0.3%	0.5%	0.2%	61.5%

Monthly energy uplift charges

	2023 Charges (Millions)						2024 Charges (Millions)					
	Day-Ahead	Balancing	Reactive Services	Local Congestion	Black Start Services	Total	Day-Ahead	Balancing	Reactive Services	Local Congestion	Black Start Services	Total
Jan	$1.7	$5.5	$0.0	$0.0	$0.0	$7.2	$32.7	$23.9	$0.9	$0.2	$0.0	$57.6
Feb	$1.0	$3.5	$0.0	$0.1	$0.1	$4.7	$1.2	$5.44	$0.0	$0.0	$0.1	$6.8
Mar	$1.3	$4.7	$0.0	$0.0	$0.1	$6.2	$1.1	$10.75	$0.0	$0.0	$0.0	$12.0
Apr	$2.0	$13.0	$0.0	$0.0	$0.1	$15.1	$12.1	$19.34	$0.0	$0.1	$0.0	$31.6
May	$0.4	$10.9	$0.0	$0.0	$0.0	$11.3	$12.5	$20.94	$0.0	$0.0	$0.0	$33.5
Jun	$1.8	$6.6	$0.0	$0.4	$0.0	$8.8	$14.4	$12.65	$0.0	$1.0	$0.0	$28.1
Jul	$10.6	$12.5	$0.0	$0.0	$0.0	$23.1	$8.4	$11.50	$0.0	$0.0	$0.0	$19.9
Aug	$12.0	$6.4	$0.0	$0.0	$0.0	$18.5	$6.9	$10.90	$0.0	$0.0	$0.0	$17.8
Sep	$11.9	$8.9	$0.0	$0.0	$0.0	$20.9	$4.4	$6.88	$0.0	$0.0	$0.0	$11.3
Oct	$2.8	$13.7	$0.1	$0.0	$0.0	$16.7	$6.4	$9.0	$0.0	$0.0	$0.0	$15.4
Nov	$3.7	$12.4	$0.0	$0.0	$0.0	$16.1	$3.2	$8.8	$0.0	$0.0	$0.0	$12.0
Dec	$0.4	$7.4	$0.0	$0.0	$0.0	$7.9	$11.3	$12.1	$0.0	$0.0	$0.0	$23.4
Total	$49.7	$105.61	$0.1	$0.6	$0.3	$156.3	$114.7	$152.1	$0.9	$1.3	$0.3	$269.3
Share	31.8%	67.6%	0.1%	0.4%	0.2%	100.0%	42.6%	56.5%	0.3%	0.5%	0.1%	100.0%

Uplift Concentration

- The data show that uplift is highly concentrated among a small subset of resources and owners, especially day ahead uplift.
- Most uplift is due to unit specific or location specific issues, rather than general market design issues.
- This was the case for the year 2024. The unit specific data for the year is published in the State of the Market Report.
- Uplift was also highly concentrated during the 2025 Polar Vortex, as shown by January 2025 uplift data.

Top 10 recipients of total uplift: 2024

Rank	Unit Name	Zone	Total Uplift Credit	Share of Total Uplift Credits
1	BC BRANDON SHORES 2 F	BGE	$31,118,688	11.5%
2	BC BRANDON SHORES 1 F	BGE	$22,184,006	8.2%
3	PEP CHALKPOINT 3 F	PEPCO	$20,530,544	7.6%
4	PEP CHALKPOINT 4 F	PEPCO	$13,474,563	5.0%
5	BC WAGNER 3 F	BGE	$10,637,591	3.9%
6	BC WAGNER 4 F	BGE	$7,883,568	2.9%
7	PL BRUNNER ISLAND 3 F	PPL	$3,926,768	1.5%
8	BC WAGNER 1 F	BGE	$2,429,167	0.9%
9	PL MARTINS CREEK 4 F	PPL	$2,294,786	0.9%
10	DPL INDIAN RIVER 4 F	DPL	$2,151,960	0.8%
Total of Top 10			$116,631,640	43.2%
Total Uplift Credits			$269,850,402	100.0%

Recommendations: Energy Market Uplift

- **The MMU recommends that PJM not pay uplift to units not following dispatch.**
- **The MMU recommends that self scheduled units not be paid energy uplift credits for their startup cost when the units are scheduled by PJM to start before the self scheduled hours.**
- **The MMU recommends reincorporating the use of net regulation revenues as an offset in the calculation of balancing generator credits.**

Capacity market issues

- 2025/2026 BRA results: Parts A, B, C, D, E, F
- Issues for 26/27 BRA
- PJM ELCC issues
- DR
- CIRs/Interconnection queue
- Market power mitigation
- Reserve margin
- RMR issues (implied markup)
- Gas availability/dual fuel options

Recommendations: Capacity

- **ELCC should be modified:**
  - **Unit specific; hourly**
  - **Recognize PJM commitment impact on performance data.**
  - **Winter thermal resource ratings**
  - **Weight summer and winter risk in a more balanced manner**
  - **Eliminate PAI risks**
  - **Pay for actual hourly performance.**

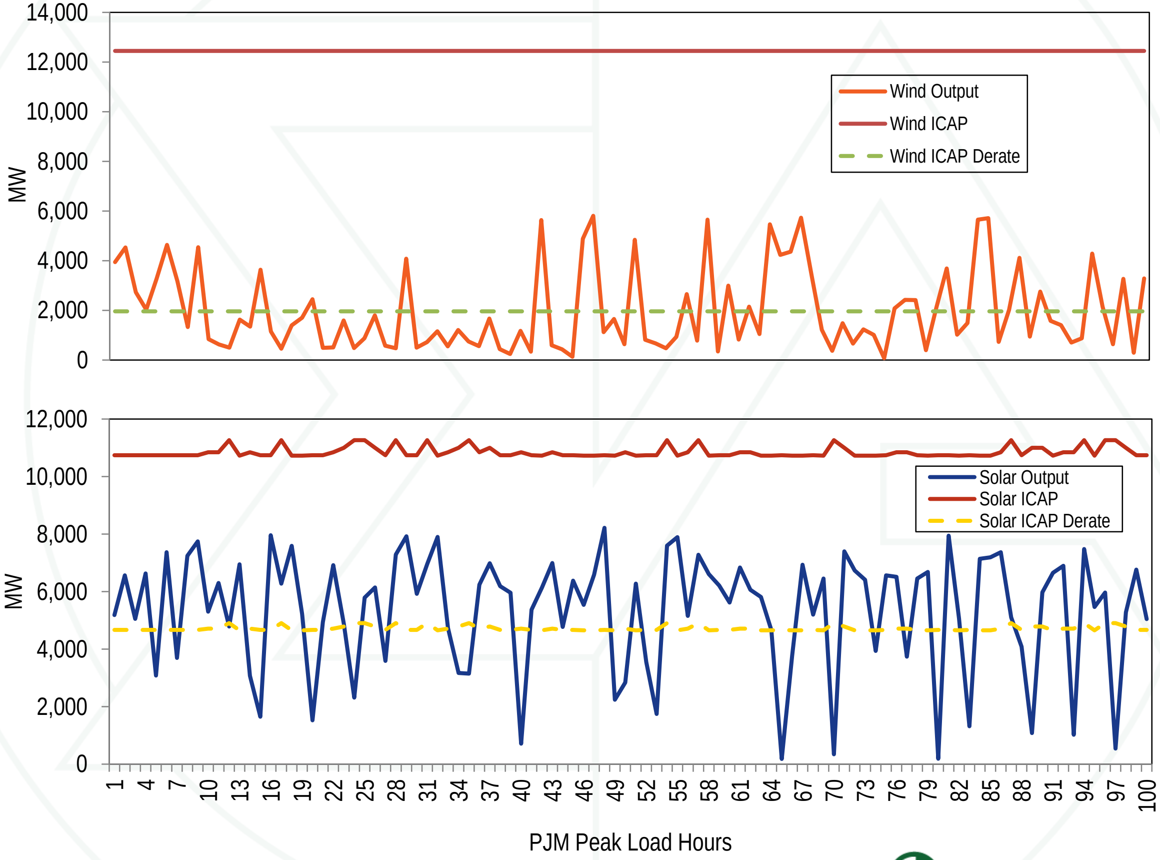
Recommendations: Capacity

- Reference resource should be a CT.
- Must offer requirement for all capacity resources.
- RMR resources should be treated consistently.
- Max VRR price should be 1.5 * Net CONE.
- Capacity should be physical resources.

Installed capacity by fuel source

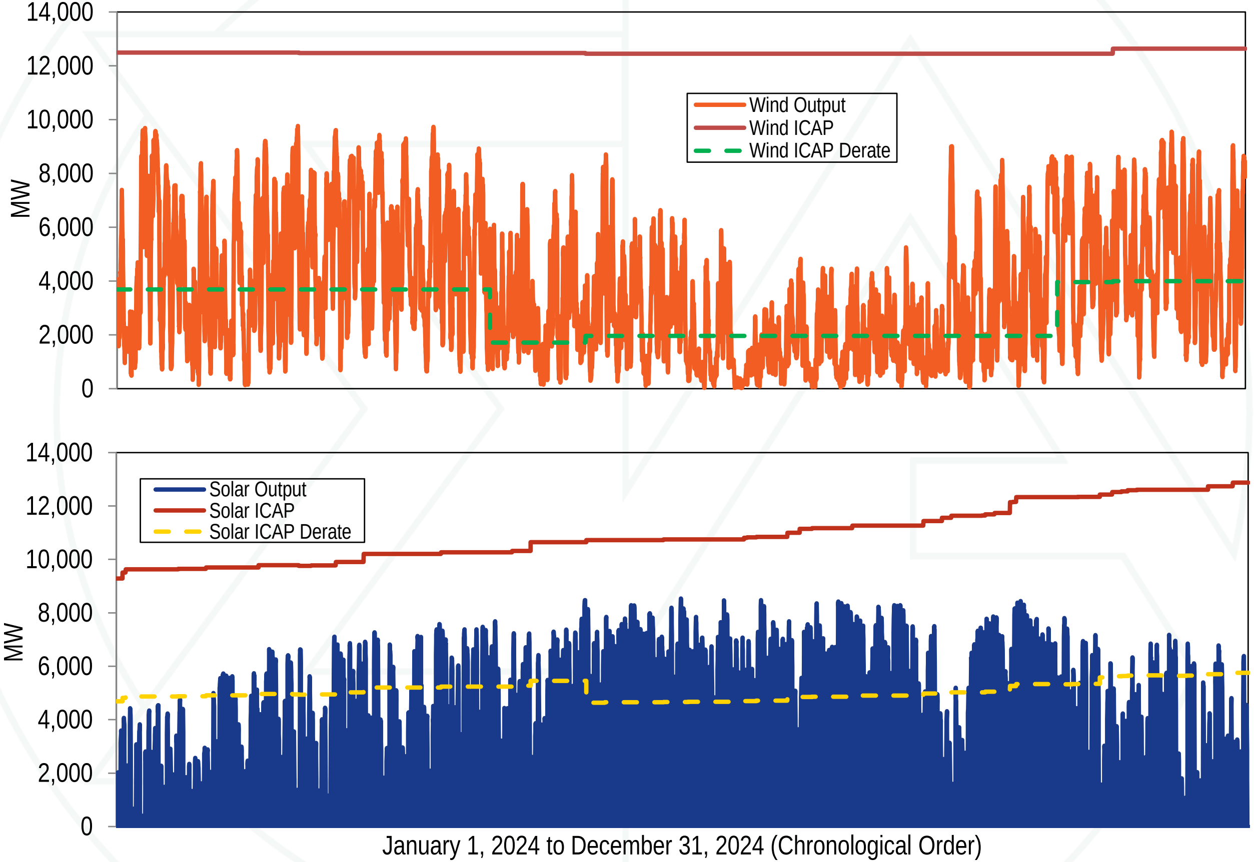
	01-Jan-24		31-May-24		01-Jun-24		31-Dec-24	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Battery	21.9	0.0%	21.9	0.0%	21.5	0.0%	21.5	0.0%
Coal	37,936.3	21.3%	38,013.1	21.5%	37,751.4	21.3%	37,793.7	21.0%
Gas	88,868.7	49.8%	88,815.5	50.3%	88,860.7	50.2%	88,760.5	49.4%
Hybird	10.2	0.0%	10.2	0.0%	9.3	0.0%	9.3	0.0%
Hydroelectric	7,507.2	4.2%	7,507.2	4.3%	7,673.1	4.3%	7,674.7	4.3%
Nuclear	32,183.0	18.0%	32,180.5	18.2%	32,180.5	18.2%	32,179.9	17.9%
Oil	4,295.6	2.4%	4,184.4	2.4%	3,865.1	2.2%	3,965.9	2.2%
Solar	3,603.3	2.0%	3,780.6	2.1%	4,279.2	2.4%	5,046.5	2.8%
Solid waste	627.4	0.4%	627.4	0.4%	627.4	0.4%	609.4	0.3%
Wind	3,321.4	1.9%	1,478.9	0.8%	1,717.1	1.0%	3,594.8	2.0%
Total	178,375.0	100.0%	176,619.7	100.0%	176,985.3	100.0%	179,656.2	100.0%

Wind and solar output during the top 100 load hours

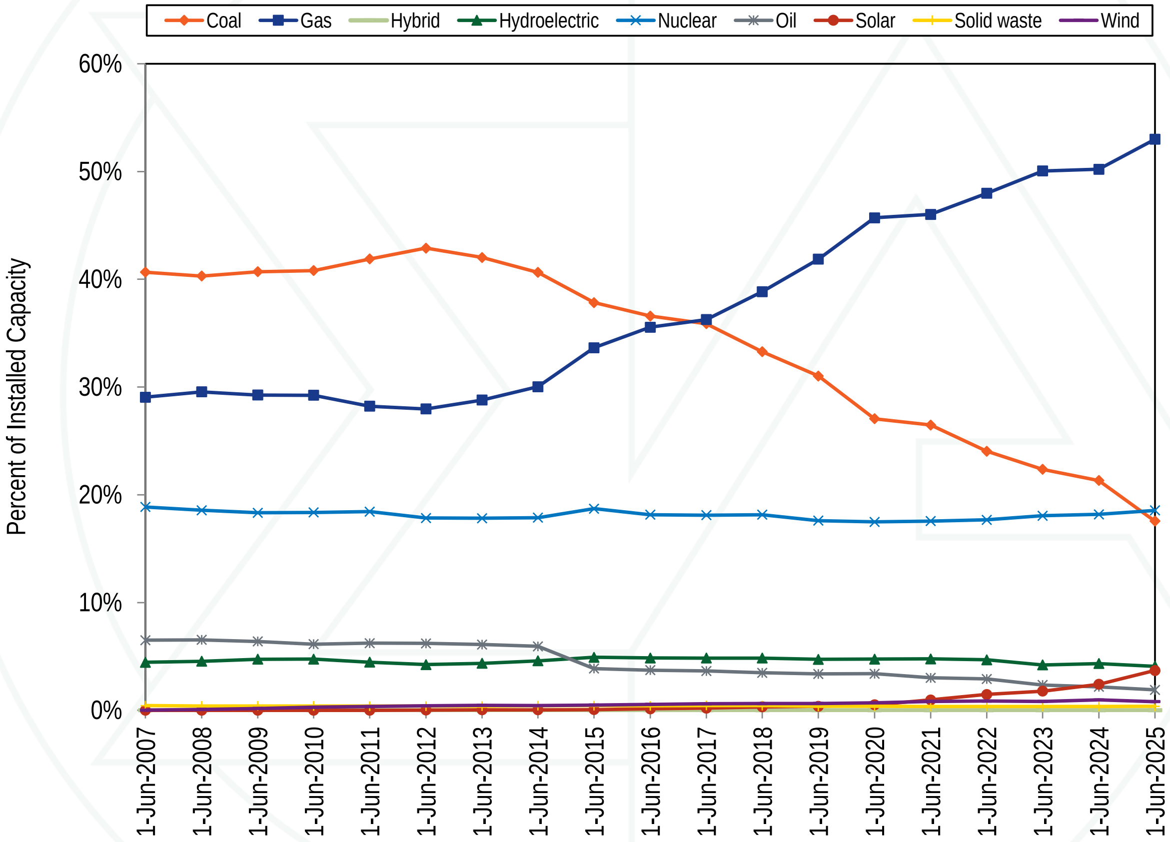


Monitoring Analytics

Wind and solar output: 2024



Percent of installed capacity by fuel source



RPM reserve margin

	01-Jun-21	01-Jun-22	01-Jun-23	01-Jun-24	01-Jun-25	
Forecast peak load ICAP (MW)	149,482.9	149,263.6	149,382.2	151,631.1	153,883.0	A
FRR peak load ICAP (MW)	11,717.7	28,292.8	29,554.6	30,431.0	11,597.3	B
PRD ICAP (MW)	510.0	230.0	235.0	305.0	224.0	C
Installed reserve margin (IRM)	14.7%	14.9%	14.9%	17.7%	17.8%	D
Pool wide average EFORd	5.22%	5.08%	4.87%	5.10%		E
Pool wide accredited UCAP factor					79.69%	F
Forecast pool requirement (FPR)	1.0871	1.0906	1.0930	1.1170	0.9387	G=(1+D)*(1-E) or G=(1+D)*F
RPM committed less deficiency UCAP (MW) (generation and DR)	156,633.6	137,944.8	136,401.8	138,318.6	134,224.2	H
RPM committed less deficiency ICAP (MW) (generation and DR)	165,260.2	145,327.4	143,384.6	145,751.9	168,432.9	J=H/(1-E) or J=H/F
RPM peak load ICAP (MW)	137,255.2	120,740.8	119,592.6	120,895.1	142,061.7	K=A-B-C
Reserve margin ICAP (MW)	28,005.0	24,586.6	23,792.0	24,856.9	26,371.2	L=J-K
Reserve margin (%)	20.4%	20.4%	19.9%	20.6%	18.6%	M=L/K
Reserve margin in excess of IRM ICAP (MW)	7,828.5	6,596.3	5,972.7	3,458.4	1,084.2	N=L-D*K
Reserve margin in excess of IRM (%)	5.7%	5.5%	5.0%	2.9%	0.8%	P=N/K
RPM peak load UCAP (MW)	130,090.5	114,607.2	113,768.4	114,729.4	113,209.0	Q=K*(1-E) or Q=K*F
RPM reliability requirement UCAP (MW)	149,210.1	131,679.9	130,714.7	135,039.8	133,353.3	R=K*G
Reserve margin UCAP (MW)	26,543.1	23,337.6	22,633.4	23,589.2	21,015.2	S=H-Q
Reserve cleared in excess of IRM UCAP (MW)	7,423.5	6,264.9	5,687.1	3,278.8	870.9	T=H-R
Projected replacement capacity UCAP (MW)	0.0	0.0	0.0	0.0	0.0	U
Projected reserve margin	20.4%	20.4%	19.9%	20.6%	18.6%	V=(J-U/(1-E))/K-1 or V=(J-U/F)/K-1

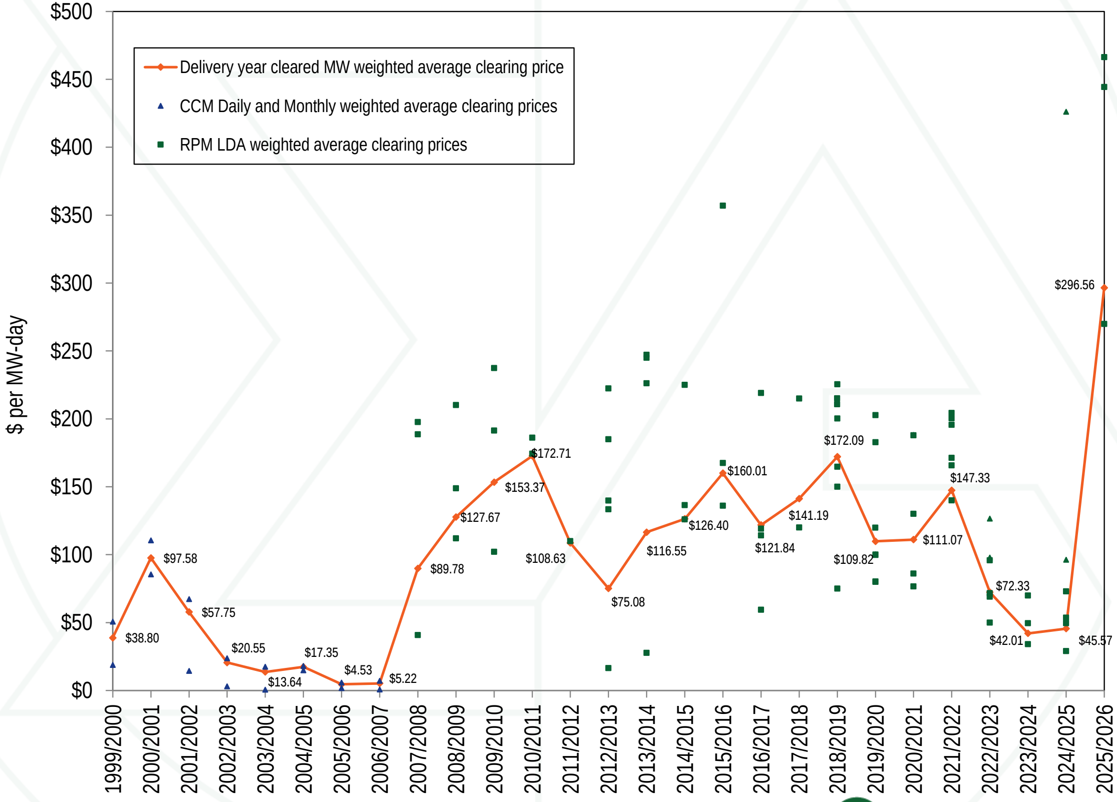
Part V reliability service summary

Unit Names	Owner	Fuel Type	ICAP (MW)	Cost Recovery Method	Docket Numbers	Start of Term	End of Term
Brandon Shores 1	Talen Energy Corporation	Coal	635.0	Cost of Service Recovery Rate	ER24-1790	01-Jun-25	31-Dec-28
Brandon Shores 2	Talen Energy Corporation	Coal	638.0	Cost of Service Recovery Rate	ER24-1790	01-Jun-25	31-Dec-28
Wagner 3	Talen Energy Corporation	Coal	305.0	Cost of Service Recovery Rate	ER24-1787	01-Jun-25	31-Dec-28
Wagner 4	Talen Energy Corporation	Oil	397.0	Cost of Service Recovery Rate	ER24-1787	01-Jun-25	31-Dec-28
Indian River 4	NRG Power Marketing LLC	Coal	410.0	Cost of Service Recovery Rate	ER22-1539	01-Jun-22	24-Feb-25
B.L. England 2	RC Cape May Holdings, LLC	Coal	150.0	Cost of Service Recovery Rate	ER17-1083	01-May-17	01-May-19
Yorktown 1	Dominion Virginia Power	Coal	159.0	Deactivation Avoidable Cost Rate	ER17-750	06-Jan-17	13-Mar-18
Yorktown 2	Dominion Virginia Power	Coal	164.0	Deactivation Avoidable Cost Rate	ER17-750	06-Jan-17	13-Mar-18
B.L. England 3	RC Cape May Holdings, LLC	Oil	148.0	Cost of Service Recovery Rate	ER17-1083	01-May-17	24-Jan-18
Ashtabula	FirstEnergy Service Company	Coal	210.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	11-Apr-15
Eastlake 1	FirstEnergy Service Company	Coal	109.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Eastlake 2	FirstEnergy Service Company	Coal	109.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Eastlake 3	FirstEnergy Service Company	Coal	109.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Lakeshore	FirstEnergy Service Company	Coal	190.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Elrama 4	GenOn Power Midwest, LP	Coal	171.0	Cost of Service Recovery Rate	ER12-1901	01-Jun-12	01-Oct-12
Niles 1	GenOn Power Midwest, LP	Coal	109.0	Cost of Service Recovery Rate	ER12-1901	01-Jun-12	01-Oct-12
Cromby 2 and Diesel	Exelon Generation Company, LLC	Natural gas/oil, Diesel	203.7	Cost of Service Recovery Rate	ER10-1418	01-Jun-11	01-Jan-12
Eddystone 2	Exelon Generation Company, LLC	Coal	309.0	Cost of Service Recovery Rate	ER10-1418	01-Jun-11	01-Jun-12
Brunot Island CT2A, CT2B, CT3 and CC4	Orion Power MidWest, L.P.	Natural gas	244.0	Cost of Service Recovery Rate	ER06-993	16-May-06	05-Jul-07
Hudson 1	PSEG Energy Resources & Trade LLC and PSEG Fossil LLC	Natural gas	355.0	Cost of Service Recovery Rate	ER05-644, ER11-2688	25-Feb-05	08-Dec-11
Sewaren 1-4	PSEG Energy Resources & Trade LLC and PSEG Fossil LLC	Natural gas	453.0	Cost of Service Recovery Rate	ER05-644	25-Feb-05	01-Sep-08

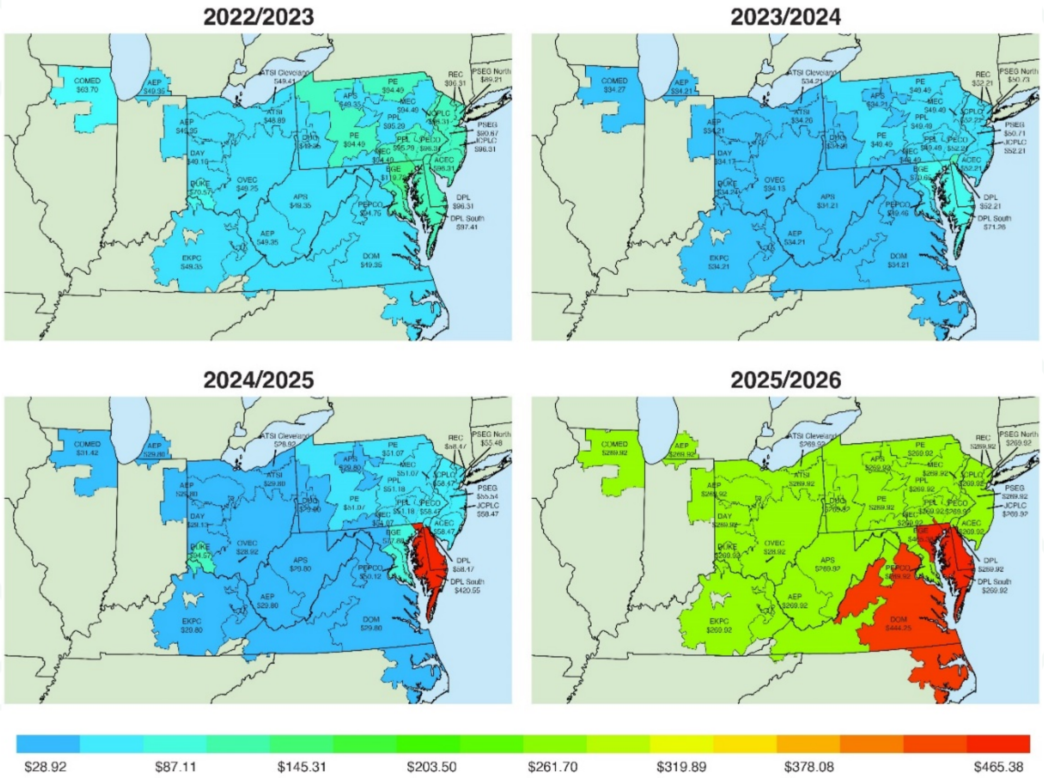
Part V reliability service cost summary

Unit Names	Owner	Initial Filing Total Cost	Initial Filing Cost per MW-day	Actual Total Cost	Actual Cost per MW-day	Weighted Average RPM Clearing Price ($ per MW-day)
Brandon Shores 1	Talen Energy Corporation	$327,039,342	$393.45	NA	NA	$296.56
Brandon Shores 2	Talen Energy Corporation	$328,584,409	$393.45	NA	NA	$296.56
Wagner 3	Talen Energy Corporation	$64,791,528	$162.29	NA	NA	$296.56
Wagner 4	Talen Energy Corporation	$84,335,202	$162.29	NA	NA	$296.56
Indian River 4	NRG Power Marketing LLC	$357,065,662	$871.76	$167,337,698	$431.89	$54.04
B.L. England 2	RC Cape May Holdings, LLC	$35,953,561	$328.34	$51,779,892	$472.88	$154.51
Yorktown 1	Dominion Virginia Power	$9,739,434	$142.12	$8,427,011	$122.97	$134.64
Yorktown 2	Dominion Virginia Power	$10,045,705	$142.12	$9,529,149	$134.81	$134.64
B.L. England 3	RC Cape May Holdings, LLC	$28,710,481	$723.84	$10,058,665	$253.60	$138.95
Ashtabula	FirstEnergy Service Company	$35,236,541	$176.25	$25,177,042	$125.94	$107.91
Eastlake 1	FirstEnergy Service Company	$20,842,416	$257.01	$18,484,399	$227.93	$102.73
Eastlake 2	FirstEnergy Service Company	$20,182,025	$248.87	$17,683,994	$218.06	$102.73
Eastlake 3	FirstEnergy Service Company	$20,192,938	$249.00	$17,391,797	$214.46	$102.73
Lakeshore	FirstEnergy Service Company	$33,993,468	$240.47	$20,532,969	$145.25	$102.73
Elrama 4	GenOn Power Midwest, LP	$15,435,472	$739.88	$7,576,435	$363.17	$75.08
Niles 1	GenOn Power Midwest, LP	$9,510,580	$715.19	$4,829,423	$363.17	$75.08
Cromby 2 and Diesel	Exelon Generation Company, LLC	$20,213,406	$463.70	$17,776,658	$407.80	$108.63
Eddystone 2	Exelon Generation Company, LLC	$165,993,135	$1,467.74	$85,364,570	$754.81	$108.63
Brunot Island CT2A, CT2B, CT3 and CC4	Orion Power MidWest, L.P.	$60,933,986	$601.76	$23,507,795	$232.15	$89.78
Hudson 1	PSEG Energy Resources & Trade LLC and PSEG Fossil LLC	$28,934,341	$32.90	$62,364,359	$70.92	$132.72
Sewaren 1-4	PSEG Energy Resources & Trade LLC and PSEG Fossil LLC	$47,633,115	$81.89	$79,580,435	$136.82	$97.39

History of capacity prices: 1999/2000 through 2025/2026



Map of RPM capacity prices: 2022/2023 through 2025/2026



Monitoring Analytics

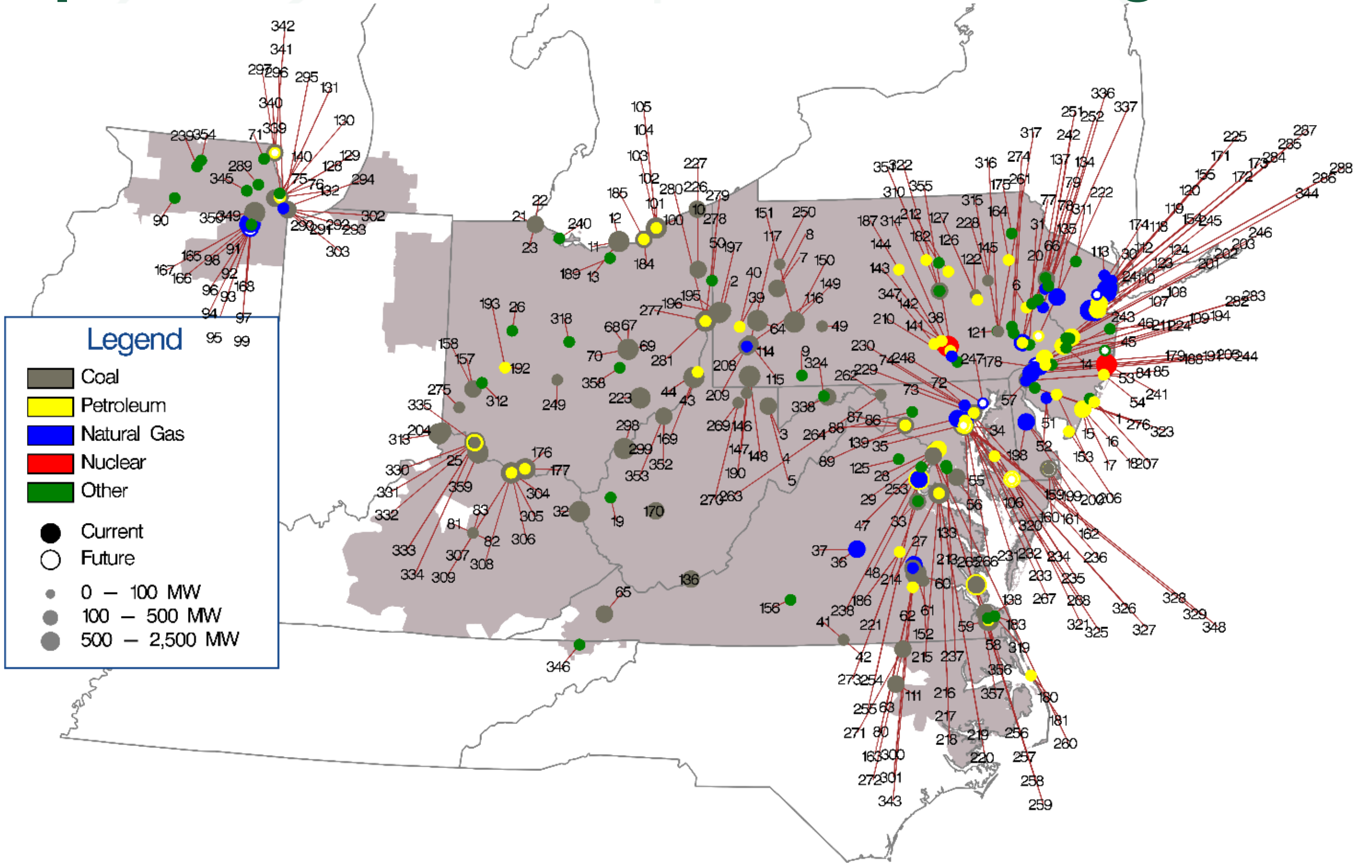
Nuclear unit surplus (shortfall)

	ICAP	Surplus (Shortfall) ($/MWh)																
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Beaver Valley	1,808	$26.3	$6.3	$10.5	$8.8	($3.3)	$1.4	$11.7	$3.2	($0.4)	$2.6	$13.9	$3.7	($2.7)	$15.0	$42.4	$2.1	$12.0
Braidwood	2,337	$24.9	$2.5	$6.4	$3.4	($6.1)	($2.6)	$7.2	($1.2)	($3.2)	($1.6)	$5.9	$3.9	($0.0)	$15.1	$35.0	($1.5)	$10.3
Byron	2,300	$24.5	($1.3)	$3.4	($0.6)	($9.4)	($3.6)	$4.9	($6.1)	($9.6)	($2.8)	$5.8	$3.2	($0.6)	$14.1	$34.5	($1.9)	$10.6
Calvert Cliffs	1,726	$60.6	$20.9	$28.6	$17.9	$4.5	$14.6	$31.6	$14.1	$7.2	$6.1	$16.3	$5.4	($0.9)	$19.4	$54.6	$9.1	$13.5
Cook	2,177	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Davis Besse	894	NA	NA	NA	NA	($13.2)	($7.0)	$6.6	($1.2)	($4.0)	($8.4)	($0.9)	($6.3)	($15.1)	$5.9	$31.6	($10.0)	($0.0)
Dresden	1,797	$25.6	$3.0	$7.6	$4.4	($5.2)	($1.0)	$9.1	$0.3	($1.6)	($0.1)	$7.1	$4.5	$0.5	$15.7	$36.2	($2.1)	$10.8
Hope Creek	1,172	$54.0	$17.0	$24.5	$16.9	$2.6	$12.4	$26.0	$6.3	($1.9)	$1.6	$12.3	$8.8	$7.8	$21.0	$48.0	$6.9	$11.7
LaSalle	2,265	$24.8	$2.5	$6.4	$3.3	($6.1)	($1.9)	$7.7	($0.9)	($3.6)	($1.9)	$6.0	$3.7	($0.2)	$14.8	$34.7	($1.8)	$10.0
Limerick	2,242	$54.1	$17.1	$24.7	$16.6	$2.6	$12.2	$25.7	$6.5	($2.1)	$1.5	$12.1	$1.6	($2.6)	$11.6	$38.2	($3.3)	$11.2
North Anna	1,892	$52.0	$14.6	$25.5	$16.8	$0.2	$5.7	$23.2	$10.9	$3.0	$4.7	$16.0	$4.8	($2.0)	$17.9	NA	NA	NA
Oyster Creek	608	$47.5	$8.4	$15.9	$7.2	($8.2)	$3.3	$16.4	($4.7)	($11.6)	($9.9)	NA	NA	NA	NA	NA	NA	NA
Peach Bottom	2,550	$53.7	$16.9	$24.2	$16.1	$2.3	$12.3	$25.5	$5.8	($2.2)	$1.4	$11.9	$0.6	($2.8)	$11.4	$38.3	($3.3)	$11.3
Perry	1,240	NA	NA	NA	NA	($13.2)	($6.4)	$5.5	($0.3)	($4.0)	($7.4)	$1.9	($5.9)	($15.2)	$6.2	$32.0	($9.3)	$0.0
Quad Cities	1,819	$24.1	($0.4)	$2.4	($1.8)	($13.2)	($6.9)	$0.6	($7.7)	($9.5)	($3.5)	$4.3	$18.8	$14.4	$29.4	$51.3	$14.4	$12.1
Salem	2,285	$54.0	$17.1	$24.5	$16.9	$2.6	$12.4	$26.0	$6.2	($2.1)	$1.5	$12.2	$8.5	$7.5	$20.7	$47.6	$6.6	$11.4
Surry	1,676	$48.8	$13.8	$24.2	$16.4	($0.0)	$5.1	$21.6	$10.8	$2.6	$4.5	$16.0	$4.2	($2.5)	$17.4	NA	NA	NA
Susquehanna	2,494	$46.8	$15.2	$22.4	$16.1	$1.4	$11.1	$24.6	$6.3	($1.6)	$1.8	$10.1	($1.7)	($6.9)	$8.3	$35.9	($2.8)	$10.7
Three Mile Island	803	$40.7	$6.5	$13.3	$4.6	($9.6)	$0.9	$13.7	($6.8)	($12.4)	($10.3)	($3.8)	NA	NA	NA	NA	NA	NA

Nuclear unit forward annual surplus (shortfall)

	Surplus (Shortfall) ($/MWh)		Subsidy ($/MWh)		Surplus (Shortfall) Excluding Subsidy ($ in millions)		Surplus (Shortfall) Including Subsidy ($ in millions)	
	2025	2026	2025	2026	2025	2026	2025	2026
Beaver Valley	$21.18	$31.80	$0.00	$8.30	$319.1	$479.0	$319.1	$604.0
Braidwood	$12.08	$19.88	$1.70	$12.30	$235.2	$387.1	$268.3	$626.5
Byron	$10.22	$20.64	$3.20	$12.05	$195.8	$395.5	$257.1	$626.4
Calvert Cliffs	$26.47	$37.47	$0.00	$6.40	$380.6	$538.8	$380.6	$630.8
Cook	NA	NA	$2.60	$0.00	NA	NA	NA	NA
Davis Besse	$6.71	$17.63	$0.00	$9.00	$50.0	$131.3	$50.0	$198.3
Dresden	$11.67	$22.24	$2.05	$11.45	$174.7	$332.9	$205.4	$504.3
Hope Creek	$17.29	$27.38	$4.17	$1.60	$168.8	$267.3	$209.5	$282.9
LaSalle	$11.98	$19.79	$1.80	$12.35	$226.1	$373.5	$260.0	$606.5
Limerick	$16.40	$26.68	$0.00	$10.05	$306.4	$498.2	$306.4	$685.9
North Anna	NA	$31.23	$0.00	$10.75	NA	$618.2	NA	$787.7
Peach Bottom	$16.59	$26.80	$0.00	$9.90	$352.5	$569.4	$352.5	$779.7
Perry	$10.12	$20.91	$0.00	$7.90	$104.5	$216.0	$104.5	$297.6
Quad Cities	$8.16	$18.65	$16.50	$16.50	$123.6	$282.6	$373.7	$532.6
Salem	$17.15	$27.31	$4.17	$1.70	$326.4	$519.8	$405.7	$552.2
Surry	NA	$29.31	$0.00	$11.40	NA	$520.8	NA	$679.9
Susquehanna	$14.28	$24.01	$0.00	$10.80	$296.7	$498.9	$296.7	$723.3

Map of unit retirements: 2011 through 2028



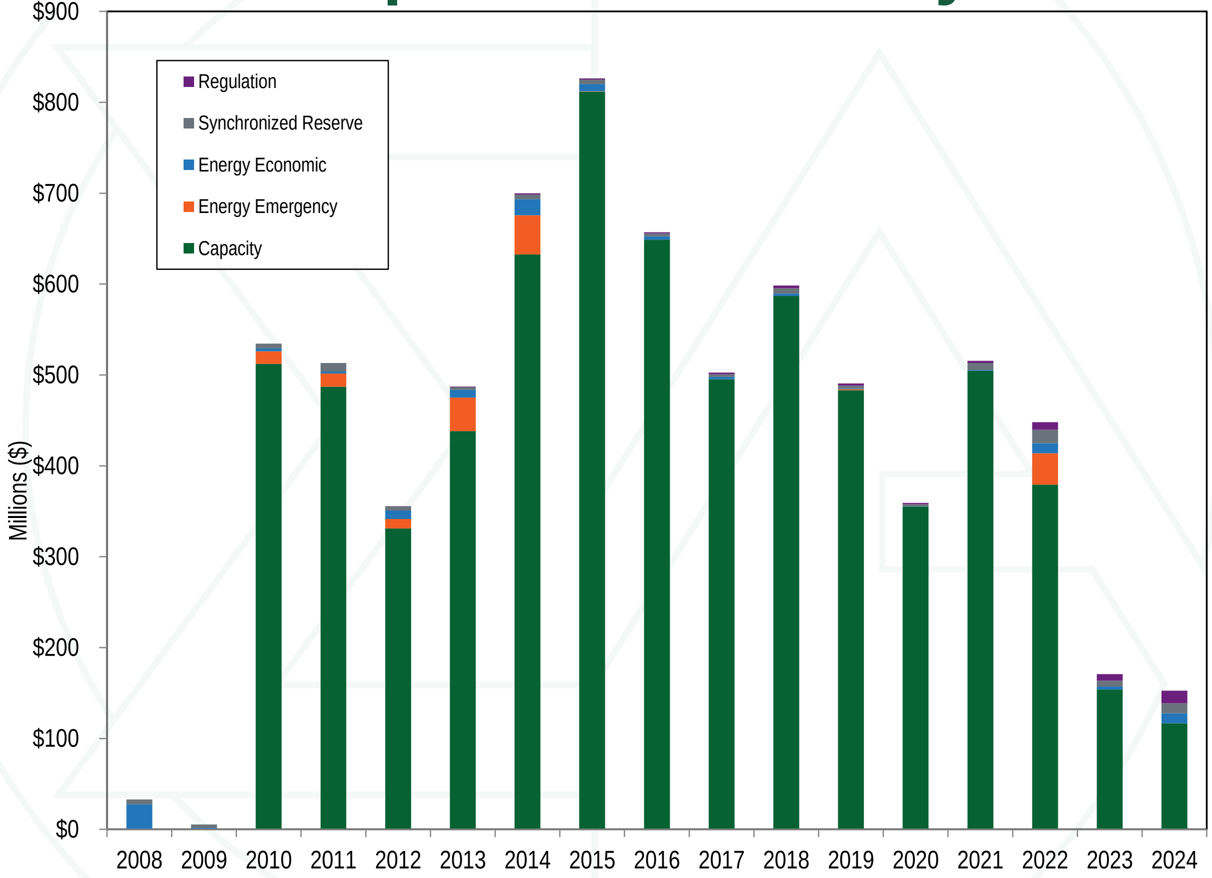
Recommendations: Demand Response

- The MMU recommends that PJM report the response of demand capacity resources to dispatch by PJM as the actual change in load rather than simply the difference between the amount of capacity purchased by the customer and the actual metered load. The current approach significantly overstates the response to PJM dispatch.
- The MMU recommends that demand resources offering as supply in the capacity market be required to offer a guaranteed load drop (GLD) to ensure that demand resources provide an identifiable MW resource to PJM when called.

Recommendations: Demand Response

- **The MMU recommends that PJM define when operators can and should call on demand resources, given that a call on demand resources no longer triggers a PAI.**
- **The MMU recommends that the ELCC for demand resources be based on measured response rather than assumption of perfect response.**
- **The MMU recommends that demand resources be required to provide their nodal location.**
- **The MMU recommends that measurement and verification methods for demand resources be modified to reflect compliance more accurately.**

Demand response revenue by market



Energy efficiency resources (MW)

Delivery Year	EE Paid (MW)	Total RPM Cleared (UCAP MW)	EE MW/ Capacity MW	EE Revenue
2011/2012	76.4	134,182.6	0.1%	$139,812
2012/2013	666.1	141,295.6	0.5%	$11,408,552
2013/2014	904.2	159,844.5	0.6%	$21,598,174
2014/2015	1,077.7	161,214.4	0.7%	$42,308,549
2015/2016	1,189.6	173,845.5	0.7%	$66,652,986
2016/2017	1,723.2	179,773.6	1.0%	$68,709,670
2017/2018	1,922.3	180,590.5	1.1%	$86,147,605
2018/2019	2,296.3	175,996.0	1.3%	$103,105,796
2019/2020	2,528.5	177,064.2	1.4%	$92,569,666
2020/2021	3,569.5	174,023.8	2.1%	$101,348,169
2021/2022	4,806.2	174,713.0	2.8%	$185,755,803
2022/2023	5,734.8	150,465.2	3.8%	$135,265,303
2023/2024	5,896.4	150,143.9	3.9%	$93,603,058
2024/2025	7,716.0	154,362.5	5.0%	$130,780,274
2025/2026	1,459.8	135,684.0	1.1%	$144,180,260

Recommendations: Planning

- **The MMU recommends that PJM establish an expedited PJM managed queue process to identify commercially viable projects that could help eliminate or reduce the need for specific RMRs or that could address specific reliability needs and allow the identified projects to advance in the queue ahead of projects which have failed to make progress, subject to rules to prevent gaming. (Priority: High. Q2 2024. Status: Not adopted.)**
- **PJM’s RRI option.**

Recommendations: Planning

- **The MMU recommends that the implementation of Grid Enhancing Technology (GET) be opened to competition from third parties, subject to NERC standards and guidelines, subject to review by NERC, PJM and the MMU, and approval by FERC. (Priority: Medium. Q2 2024. Status: Not adopted.)**

Recommendations: Planning

- **The MMU recommends that all PJM transmission owners investigate the applicability and potential cost savings of Grid Enhancing Technology (GET) and that all PJM transmission owners implement cost effective GET, subject to NERC standards and guidelines, subject to review by NERC, PJM and the MMU, and approval by FERC. (Priority: Medium. Q2 2024. Status: Not adopted.)**

Recommendations: Interchange

- **The MMU recommends eliminating the mechanism that defines FFE and M2M payments. These mechanisms are not consistent with markets and are not needed for efficient interface pricing. The MMU recommends that PJM file with the Commission to eliminate the FFE calculation and M2M payment of the PJM and MISO joint operating agreement. (Priority: Medium. Q2 2024. Status: Not adopted.)**

RT scheduled net interchange volume by interface (GWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	(60.5)	(11.3)	34.9	12.7	144.4	3.2	(7.7)	(19.0)	(2.9)	(11.5)	28.4	20.8	131.7
CPLW	0.0	0.0	0.0	0.1	1.0	0.4	0.9	0.4	0.0	(0.1)	0.0	0.0	2.8
DUK	349.4	651.4	465.2	427.9	436.6	(215.9)	254.7	180.6	114.6	462.1	362.9	366.5	3,855.9
LGEE	(89.3)	(91.1)	(101.0)	(50.7)	(55.7)	(66.5)	(67.4)	(68.2)	(58.7)	(66.5)	(90.6)	(101.8)	(907.6)
MISO	(1,798.4)	(2,048.3)	(2,097.1)	(1,367.9)	(995.1)	(2,004.9)	(1,100.9)	(1,873.0)	(1,458.0)	(307.9)	(403.6)	(622.5)	(16,077.7)
ALTE	(495.5)	(508.9)	(613.7)	(409.0)	(221.7)	(435.2)	(230.4)	(335.9)	(123.7)	(38.9)	(45.7)	(80.0)	(3,538.6)
ALTW	(19.3)	(28.7)	(46.7)	(45.4)	(36.7)	(83.9)	(4.3)	(29.6)	1.4	11.7	9.6	(6.6)	(278.6)
AMIL	204.0	51.9	117.3	257.5	104.7	(16.8)	138.0	44.0	84.3	238.7	308.2	349.4	1,881.1
CIN	(696.8)	(699.5)	(626.0)	(485.4)	(235.5)	(573.7)	(370.2)	(625.0)	(451.1)	(13.0)	(160.6)	(347.9)	(5,284.6)
CWLP	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
IPL	3.4	(3.6)	(5.4)	(16.5)	(11.7)	(27.0)	(7.3)	(11.5)	(22.9)	(7.2)	(25.7)	19.0	(116.5)
MEC	(464.9)	(492.9)	(467.6)	(487.3)	(500.1)	(490.9)	(446.5)	(542.0)	(532.1)	(396.0)	(426.8)	(517.6)	(5,764.6)
MECS	(228.7)	(263.7)	(329.7)	(107.8)	(55.0)	(227.0)	(68.8)	(237.4)	(217.1)	9.8	22.8	140.9	(1,561.6)
NIPS	(0.5)	(1.2)	(0.5)	(0.4)	(0.8)	(17.5)	(40.5)	(52.6)	(100.2)	(77.1)	(88.7)	(100.1)	(480.1)
WEC	(100.1)	(101.6)	(125.0)	(73.6)	(38.2)	(132.9)	(71.0)	(82.9)	(96.6)	(35.8)	3.2	(79.5)	(934.2)
NYISO	(2,222.8)	(1,824.3)	(1,748.7)	(1,131.4)	(1,127.8)	(1,695.8)	(1,693.2)	(1,841.0)	(1,620.1)	(1,628.7)	(1,657.4)	(2,177.3)	(20,368.4)
HUDS	(416.4)	(375.4)	(369.0)	(213.4)	(173.4)	(284.1)	(334.1)	(387.4)	(277.0)	(224.3)	(209.3)	(171.7)	(3,435.4)
LIND	(235.4)	(221.1)	(235.1)	(145.9)	(213.2)	(210.3)	(210.3)	(222.7)	(225.2)	(237.4)	(175.1)	(237.8)	(2,569.5)
NEPT	(491.9)	(465.7)	(499.0)	(471.8)	(391.9)	(470.2)	(494.9)	(497.6)	(337.0)	(496.6)	(425.1)	(493.5)	(5,535.2)
NYIS	(1,079.1)	(762.0)	(645.7)	(300.3)	(349.3)	(731.1)	(653.8)	(733.3)	(780.9)	(670.4)	(848.0)	(1,274.3)	(8,828.3)
TVA	17.1	229.3	153.7	79.2	92.8	(118.4)	(187.0)	(196.5)	(76.1)	326.4	120.5	230.3	671.3
Total	(3,804.4)	(3,094.3)	(3,293.1)	(2,030.1)	(1,503.8)	(4,097.8)	(2,800.5)	(3,816.7)	(3,101.2)	(1,226.2)	(1,639.8)	(2,284.0)	(32,692.0)

New Recommendations: Reserve Markets

- **The MMU recommends that to minimize lag, PJM use an electronic synchronized reserve event notification process for all resources and that all resources be required to have the ability to receive and respond to the notifications. (Priority: Medium. First reported 2023. Status: Partially adopted December 17, 2024.)**

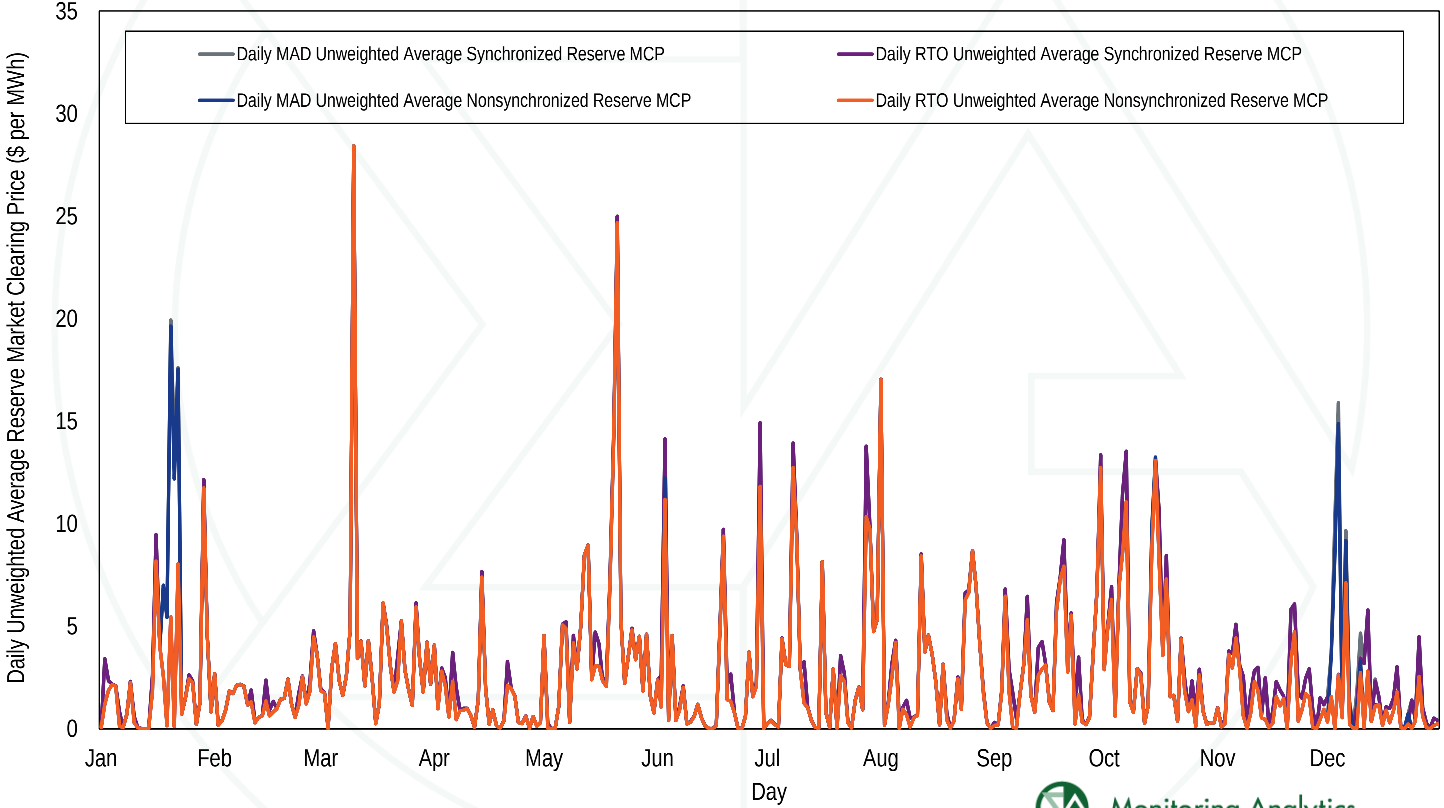
- **The MMU recommends that PJM remove the 30 percent increase to the synchronized reserve reliability requirement. (Priority: High. New recommendation. Status: Not adopted.)**

The synchronized reserve market results were not competitive

Market Element	Evaluation	Market Design
Market Structure: Regional Markets	Not Competitive	
Participant Behavior	Competitive	
Market Performance	Not Competitive	Flawed

Daily average RT reserve products cleared and daily average RT reserve service requirements used by RT SCED: 2024

Daily average market clearing prices for synchronized reserve and nonsynchronized reserve



Recommendations: Ancillary Services

- The procurement for fuel assured black start units should be reevaluated in order to prevent overpayment and double procurement of fuel assured resources.
- Use of Net CONE in payment for black start base formula rate.

The regulation market results were not competitive

Market Element	Evaluation	Market Design
Market Structure	Not Competitive	
Participant Behavior	Competitive	
Market Performance	Not Competitive	Flawed

Black start revenue requirement charges

Year	Revenue Requirement Charges	Uplift Charges	Total
2010	$11,490,379	$0	$11,490,379
2011	$13,695,331	$0	$13,695,331
2012	$18,749,617	$8,384,651	$27,134,269
2013	$20,874,535	$86,701,561	$107,576,097
2014	$26,945,112	$32,906,733	$59,851,845
2015	$56,425,648	$5,175,644	$61,601,292
2016	$69,376,257	$279,017	$69,655,275
2017	$69,258,169	$257,174	$69,515,342
2018	$64,439,926	$294,753	$64,734,679
2019	$64,327,918	$226,014	$64,553,932
2020	$64,643,080	$230,754	$64,873,834
2021	$67,694,868	$316,437	$68,011,305
2022	$68,110,179	$476,876	$68,587,055
2023	$66,950,499	$323,028	$67,273,527
2024	$73,515,489	$326,675	$73,842,164

Reactive service charges and capability charges

	Reactive Service Charges	Reactive Capability Charges	Total
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	$294,389,603	$296,887,882
2017	$20,379,379	$302,704,116	$323,083,495
2018	$13,183,120	$303,465,206	$316,648,326
2019	$570,589	$329,215,657	$329,786,246
2020	$428,629	$345,647,272	$346,075,901
2021	$909,343	$364,007,391	$364,916,734
2022	$1,513,558	$384,991,729	$386,505,287
2023	$609,938	$388,451,473	$389,061,411
2024	$1,500,424	$379,153,040	$380,653,464

Recommendations: FTR/ARR

- **Rights to all congestion revenues should be assigned to load.**

The FTR/ARR markets results were partially competitive

Market Element	Evaluation	Market Design
Market Structure	Competitive	
Participant Behavior	Partially Competitive	
Market Performance	Partially Competitive	Flawed

Total congestion costs (Dollars (Millions))

	Congestion Cost	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$2,052	NA	$34,300	6.0%
2009	$719	(65.0%)	$26,550	2.7%
2010	$1,423	98.0%	$34,770	4.1%
2011	$999	(29.8%)	$35,890	2.8%
2012	$529	(47.0%)	$29,180	1.8%
2013	$677	28.0%	$33,860	2.0%
2014	$1,932	185.5%	$50,030	3.9%
2015	$1,385	(28.3%)	$42,630	3.2%
2016	$1,024	(26.1%)	$39,050	2.6%
2017	$698	(31.9%)	$40,170	1.7%
2018	$1,310	87.8%	$49,790	2.6%
2019	$583	(55.5%)	$41,690	1.4%
2020	$529	(9.4%)	$36,300	1.5%
2021	$995	88.2%	$54,100	1.8%
2022	$2,501	151.3%	$86,240	2.9%
2023	$1,069	(57.3%)	$48,500	2.2%
2024	$1,754	64.2%	$51,740	3.4%

ARR and self scheduled FTR total congestion offset (in millions) for ARR holders: 2011/2012 through 2024/2025 planning periods

Revenue									Pre 2017/2018 (Without Balancing)		2017/2018 (With Balancing)		Post 2017/2018 (With Balancing and Surplus)		Effective Offset	
Planning Period	ARR Credits	Unadjusted SS FTR Credits	Day Ahead Congestion	Balancing + M2M Congestion	Total Congestion	Surplus Revenue Pre 2017/2018 Rules	Surplus Revenue 2017/2018 Rules	Post 2017/2018 Rules	Total ARR/FTR Offset	Percent Offset	Current Revenue Received	Percent Offset	New Revenue Received	New Offset	Cumulative Revenue	Offset
2011/2012	$515.6	$310.0	$1,025.4	($275.7)	$749.7	($50.6)	$35.6	$113.9	$775.0	103.4%	$585.5	78.1%	$663.8	88.5%	$775.0	103.4%
2012/2013	$356.4	$268.4	$904.7	($379.9)	$524.8	($94.0)	$18.4	$62.1	$530.7	101.1%	$263.2	50.2%	$306.9	58.5%	$530.7	101.1%
2013/2014	$339.4	$626.6	$2,231.3	($360.6)	$1,870.6	($139.4)	($49.0)	($49.0)	$826.5	44.2%	$556.3	29.7%	$556.3	29.7%	$826.5	44.2%
2014/2015	$487.4	$348.1	$1,625.9	($268.3)	$1,357.6	$36.7	$111.2	$400.6	$872.2	64.2%	$678.4	50.0%	$967.8	71.3%	$872.2	64.2%
2015/2016	$641.8	$209.2	$1,098.7	($147.6)	$951.1	$9.2	$42.1	$188.9	$860.2	90.4%	$745.5	78.4%	$892.3	93.8%	$860.2	90.4%
2016/2017	$648.1	$149.9	$885.7	($104.8)	$780.8	$15.1	$36.5	$179.0	$813.1	104.1%	$729.6	93.4%	$872.1	111.7%	$813.1	104.1%
2017/2018	$429.6	$212.3	$1,322.1	($129.5)	$1,192.6	$52.3	$80.4	$370.7	$694.2	58.2%	$592.8	49.7%	$883.1	74.1%	$592.8	49.7%
2018/2019	$531.6	$130.1	$832.7	($152.6)	$680.0	($5.8)	$16.2	$112.2	$655.87	96.4%	$525.3	77.2%	$621.3	91.4%	$621.3	91.4%
2019/2020	$547.6	$91.9	$612.1	($169.4)	$442.7	($1.6)	$21.6	$157.8	$637.9	144.1%	$491.7	111.1%	$627.9	141.8%	$627.9	141.8%
2020/2021	$392.7	$179.9	$899.6	($256.2)	$643.4	($43.2)	($0.0)	($0.0)	$529.31	82.3%	$316.4	49.2%	$316.4	49.2%	$316.4	49.2%
2021/2022	$469.7	$500.5	$2,069.2	($457.4)	$1,611.8	($104.6)	($2.9)	($2.9)	$865.6	53.7%	$509.9	31.6%	$509.9	31.6%	$509.9	31.6%
2022/2023	$998.7	$630.0	$2,223.5	($526.5)	$1,697.1	($80.6)	$65.1	$235.2	$1,548.2	91.2%	$1,167.4	68.8%	$1,337.5	78.8%	$1,337.5	78.8%
2023/2024	$912.1	$371.4	$1,618.9	($327.0)	$1,291.9	($44.1)	$24.6	$117.2	$1,239.4	95.9%	$981.2	76.0%	$1,073.7	83.1%	$1,073.7	83.1%
2024/2025*	$552.4	$283.7	$1,352.1	($185.4)	$1,166.8	($35.6)	$0.2	$0.9	$800.5	68.6%	$650.9	55.8%	$651.7	55.9%	$651.7	55.9%
Total	$7,823.0	$4,312.1	$18,701.8	($3,740.9)	$14,960.9	($486.3)	$400.0	$1,886.6	$11,648.8	77.9%	$8,794.1	58.8%	$10,280.8	68.7%	$10,409.0	69.6%

*First seven months of the 2024/2025 planning period

Zonal ARR and self scheduled FTR total congestion offset (in millions) for ARR holders: 2024/2025 planning period

Zone	ARR Credits	Adjusted FTR Credits	Balancing+ M2M Charge	Surplus Allocation	Total Offset	Day Ahead Congestion	Balancing Congestion	M2M Payments	Total Congestion	Offset
ACEC	$2.6	($0.0)	($2.34)	$0.0	$0.2	$13.8	($2.2)	($0.2)	$11.5	1.7%
AEP	$41.8	$32.2	($28.0)	$0.1	$46.0	$218.8	($25.8)	($2.2)	$190.7	24.1%
APS	$37.2	$22.8	($12.6)	$0.1	$47.5	$93.4	($11.8)	($0.8)	$80.8	58.8%
ATSI	$35.8	$0.6	($14.4)	$0.0	$22.1	$115.2	($13.2)	($1.2)	$100.8	22.0%
BGE	$82.8	$10.7	($7.2)	$0.1	$86.4	$56.3	($6.6)	($0.5)	$49.2	175.8%
COMED	$32.4	$0.0	($18.6)	$0.0	$13.8	$174.1	($17.0)	($1.6)	$155.5	8.9%
DAY	$7.3	$1.0	($3.8)	$0.0	$4.5	$27.3	($3.5)	($0.3)	$23.4	19.3%
DOM	$44.6	$186.9	($28.1)	$0.0	$203.4	$193.7	($25.9)	($2.2)	$165.7	122.8%
DPL	$46.7	$13.2	($5.1)	$0.0	$54.8	$54.2	($4.8)	($0.3)	$49.2	111.5%
DUKE	$27.1	$0.8	($5.8)	$0.2	$22.3	$38.4	($5.4)	($0.5)	$32.6	68.5%
DUQ	$6.9	$0.2	($3.0)	$0.1	$4.2	$18.3	($2.8)	($0.2)	$15.3	27.6%
EKPC	$4.7	$0.0	($3.0)	$0.0	$1.7	$21.6	($2.8)	($0.2)	$18.6	9.1%
EXT	$0.4	$0.0	($3.9)	$0.0	($3.5)	$19.0	($3.9)	$0.0	$15.1	(23.2%)
JCPLC	$5.4	$0.0	($6.2)	$0.0	($0.8)	$37.3	($5.8)	($0.4)	$31.1	(2.7%)
MEC	$13.4	$0.6	($4.8)	$0.0	$9.2	$22.6	($4.6)	($0.3)	$17.8	51.4%
OVEC	$0.0	$0.0	($0.2)	$0.0	($0.2)	$2.0	($0.2)	($0.0)	$1.8	(12.2%)
PE	$24.6	$6.2	($4.0)	$0.0	$26.8	$28.6	($3.8)	($0.3)	$24.6	109.3%
PECO	$17.0	($0.1)	($8.8)	$0.0	$8.2	$51.6	($8.1)	($0.7)	$42.8	19.1%
PEPCO	$33.9	$6.2	($6.6)	$0.0	$33.5	$46.6	($6.1)	($0.5)	$40.0	83.8%
PPL	$38.8	$2.1	($8.8)	$0.0	$32.2	$60.0	($8.1)	($0.7)	$51.2	62.8%
PSEG	$47.2	$0.3	($9.7)	$0.0	$37.7	$56.7	($9.0)	($0.8)	$47.0	80.4%
REC	$1.9	$0.0	($0.3)	$0.0	$1.5	$2.6	($0.3)	($0.0)	$2.2	68.3%
Total	$552.4	$283.7	($185.4)	$0.9	$651.7	$1,352.1	($171.5)	($13.9)	$1,166.8	55.9%

Offset available to load if all ARRs are held: 2022/2023 through 2024/2025 planning periods

	22/23 Planning Period				23/24 Planning Period				24/25 Planning Period*			
	ARR Held TA	Bal+M2M Charges	Congestion+ M2M	Offset	ARR Held TA	Bal+M2M Charges	Congestion+ M2M	Offset	ARR Held TA	Bal+M2M Charges	Congestion+ M2M	Offset
ACEC	$3.8	($6.2)	$16.3	(14.6%)	$4.9	($3.8)	$10.8	9.7%	$2.6	($2.3)	$11.5	2.3%
AEP	$187.1	($79.3)	$274.1	39.3%	$185.2	($50.4)	$201.8	66.8%	$93.2	($28.0)	$190.7	34.2%
APS	$104.0	($31.4)	$105.8	68.6%	$85.5	($22.4)	$87.6	72.1%	$53.9	($12.6)	$80.8	51.1%
ATSI	$39.6	($40.7)	$133.1	(0.8%)	$50.3	($25.6)	$99.4	24.8%	$36.3	($14.4)	$100.8	21.7%
BGE	$151.5	($19.4)	$68.4	193.2%	$145.8	($12.5)	$44.4	300.4%	$89.7	($7.2)	$49.2	167.9%
COMED	$42.4	($56.2)	$182.5	(7.5%)	$44.9	($31.4)	$215.9	6.3%	$32.4	($18.6)	$155.5	8.9%
DAY	$9.9	($10.8)	$32.4	(2.7%)	$13.3	($6.7)	$23.7	27.7%	$8.0	($3.8)	$23.4	17.8%
DOM	$218.5	($85.5)	$270.1	49.3%	$642.0	($52.0)	$181.8	324.6%	$249.1	($28.1)	$165.7	133.4%
DPL	$95.3	($13.7)	$64.6	126.3%	$69.6	($8.4)	$51.2	119.7%	$53.4	($5.1)	$49.2	98.3%
DUKE	$48.7	($16.9)	$51.7	61.5%	$52.1	($10.3)	$37.7	110.9%	$28.8	($5.8)	$32.6	70.5%
DUQ	$11.2	($8.3)	$18.5	15.8%	$8.6	($5.2)	$15.1	22.5%	$7.1	($3.0)	$15.3	26.7%
EKPC	$6.8	($8.4)	$27.2	(5.6%)	$6.5	($5.7)	$20.6	4.0%	$4.7	($3.0)	$18.6	9.1%
EXT	$0.0	($12.7)	$28.9	(43.8%)	$1.9	($9.6)	$26.4	(29.1%)	$0.7	($3.9)	$15.1	(20.9%)
JCPLC	$7.6	($16.3)	$53.0	(16.4%)	$4.6	($10.4)	$32.4	(18.1%)	$5.4	($6.2)	$31.1	(2.7%)
MEC	$50.1	($11.2)	$32.4	119.6%	$34.2	($6.7)	$21.8	126.3%	$14.2	($4.8)	$17.8	52.4%
OVEC	NA	($0.5)	$3.3	(15.4%)	($0.0)	($0.4)	$2.1	(19.1%)	$0.0	($0.2)	$1.8	(12.2%)
PE	$28.5	($10.8)	$35.3	50.2%	$22.2	($6.5)	$28.3	55.6%	$29.2	($4.0)	$24.6	102.5%
PECO	$36.6	($24.0)	$74.9	16.8%	$21.2	($14.9)	$42.3	14.8%	$17.5	($8.8)	$42.8	20.3%
PEPCO	$76.3	($17.9)	$61.0	95.8%	$65.4	($11.6)	$38.3	140.7%	$38.2	($6.6)	$40.0	79.1%
PPL	$151.0	($28.2)	$83.7	146.6%	$80.0	($15.6)	$57.9	111.2%	$39.9	($8.8)	$51.2	60.8%
PSEG	$103.5	($27.1)	$75.4	101.4%	$69.3	($16.4)	$50.3	105.0%	$47.6	($9.7)	$47.0	80.5%
REC	$0.9	($0.9)	$4.5	(1.0%)	$2.7	($0.6)	$2.2	98.8%	$1.8	($0.3)	$2.2	65.8%
Total	$1,373.4	($526.4)	$1,697.1	49.9%	$1,610.1	($327.0)	$1,291.9	99.3%	$853.6	($185.4)	$1,166.8	57.3%

* First seven months of the 2024/2025 planning period

Top 5 and bottom 5 FTR profits by ownership type: June through December, 2024/2025

Organization Type	Total MWh	Top 5 Profit	Top 5 Profit/MWh	Top 5 Market Share in MWh	Top 5 Profit Share Among Profitable Participants	Bottom 5 Loss	Bottom 5 Loss/MWh	Bottom 5 Market Share in MWh	Bottom 5 Loss Share Among Unprofitable Participants
Financial	2,375,554,547	$151,514,758	$0.29	22.0%	38.5%	($5,476,760)	($0.21)	1.1%	54.0%
Physical	464,184,898	$88,429,300	$0.46	41.4%	56.9%	($8,061,720)	($0.25)	6.9%	67.5%
Physical ARR	173,950,948	$17,703,080	$0.37	27.4%	75.8%	($30,132,228)	($0.34)	51.0%	93.4%
All	3,013,690,392	$163,607,634	$0.38	14.2%	28.6%	($32,593,178)	($0.30)	3.6%	60.0%

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