2023 State of the Market Report for PJM

Special MC

April 30, 2024

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

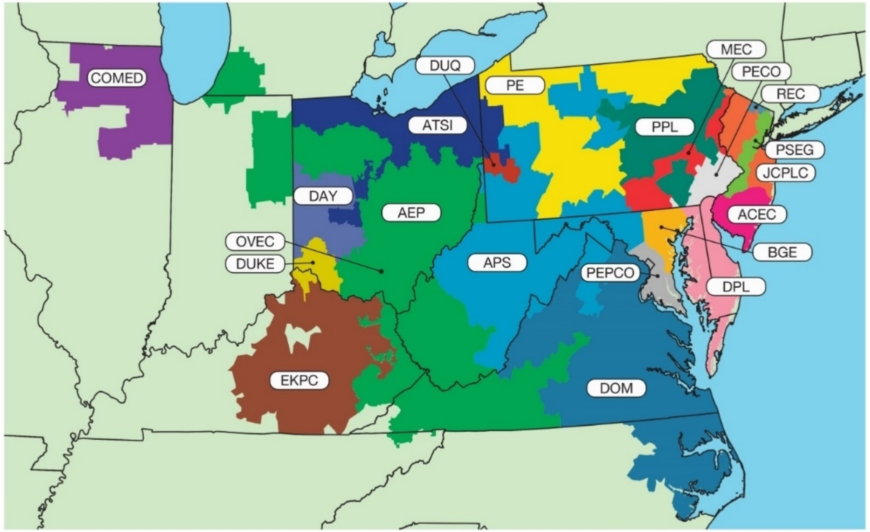
Role of Market Monitoring

- 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 Footprint



Legend

- Allegheny Power Company (APS)
- American Electric Power Co., Inc (AEP)
- American Transmission Systems, Inc. (ATSI)
- Atlantic Electric Company (ACEC)
- Baltimore Gas and Electric Company (BGE)
- ComEd (COMED)
- Dayton Power and Light Company (DAY)
- Delmarva Power and Light (DPL)
- Dominion (DOM)
- Duke Energy Ohio/Kentucky (DUKE)
- Duquesne Light (DUQ)
- Eastern Kentucky Power Cooperative (EKPC)
- Jersey Central Power and Light Company (JCPLC)
- Metropolitan Edison Company (MEC)
- Ohio Valley Electric Corporation (OVEC)
- PECO Energy (PECO)
- Pennsylvania Electric Company (PE)
- Pepco (PEPCO)
- PPL Electric Utilities (PPL)
- Public Service Electric and Gas Company (PSEG)
- Rockland Electric Company (REC)

Total Price of Wholesale Power

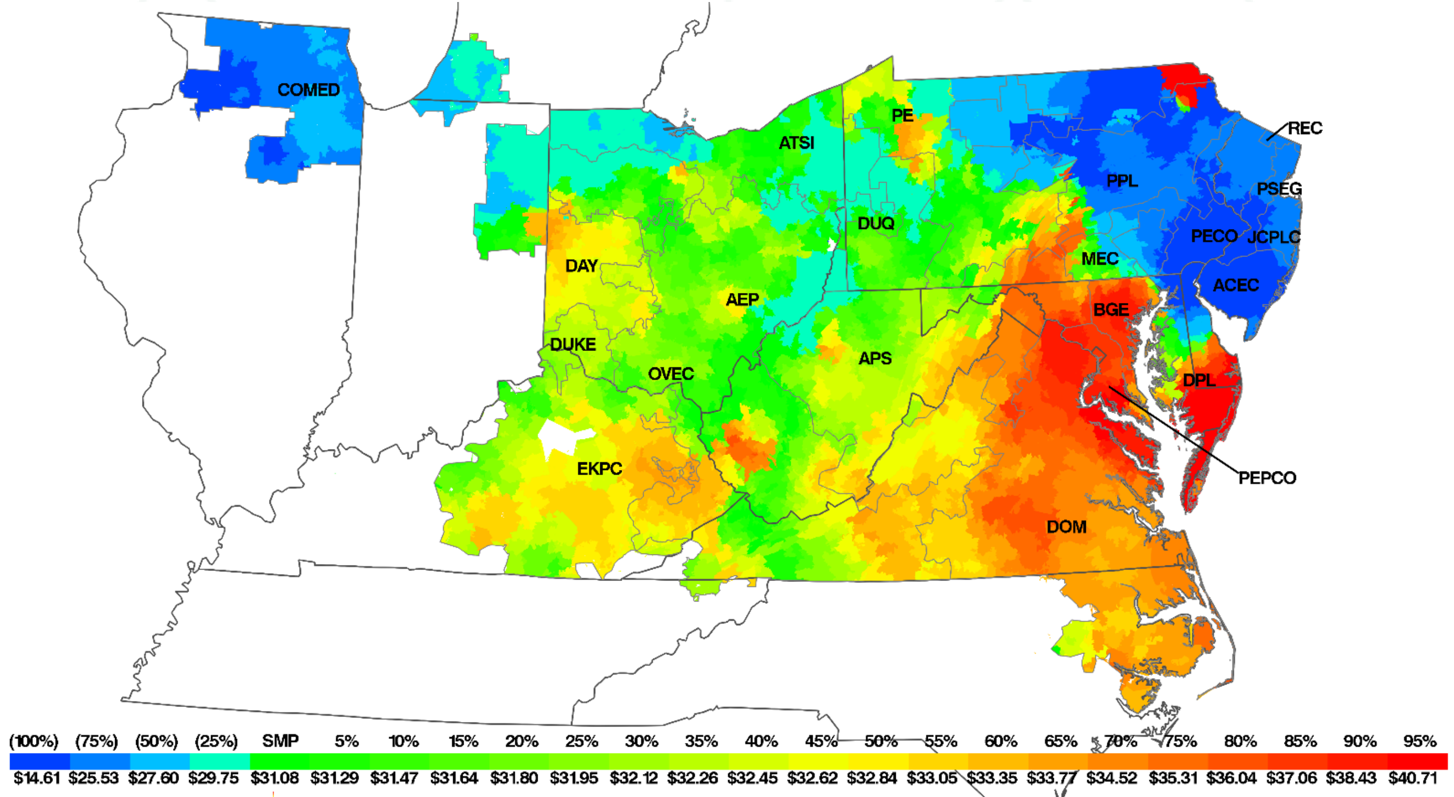
PJM summary statistics

	2022	2023	Percent Change
Average Hourly Load Plus Exports (MWh)	94,301	92,455	(2.0%)
Average Hourly Generation Plus Imports (MWh)	96,147	94,165	(2.1%)
Peak Load Plus Export (MWh)	149,531	152,797	2.2%
Installed Capacity at December 31 (MW)	183,385	178,253	(2.8%)
Load Weighted Average Real Time LMP ($/MWh)	$80.14	$31.08	(61.2%)
Total Congestion Costs ($ Million)	$2,501.3	$1,068.6	(57.3%)
Total Uplift Credits ($ Million)	$284.5	$158.7	(44.2%)
Total PJM Billing ($ Billion)	$86.24	$48.61	(43.6%)

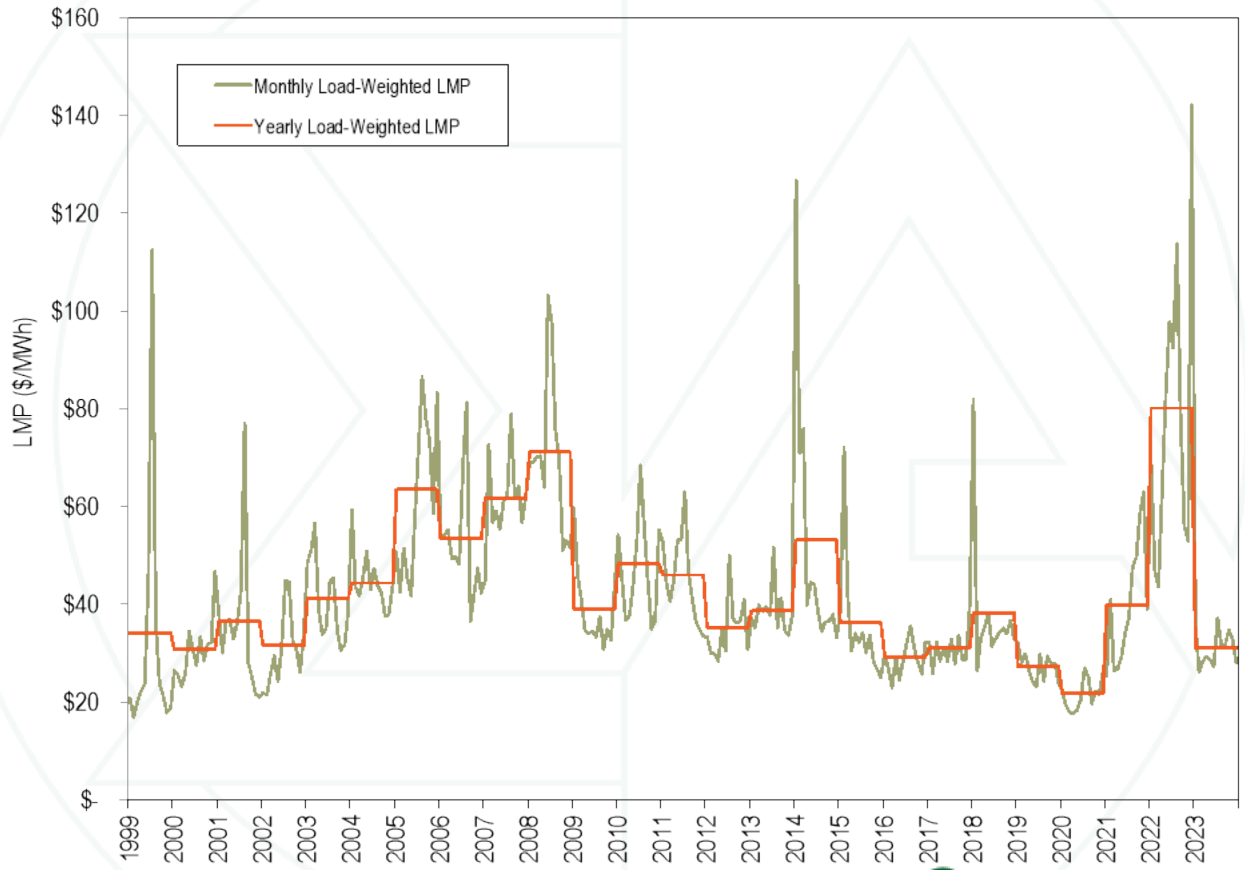
The energy market results were competitive

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

RT load-weighted average LMP



RT monthly and yearly load-weighted average LMP



RT load-weighted average LMP

	Real-Time Load-Weighted Average LMP			Year to Year Change			
	Average	Median	Standard Deviation	Average	Average Percent	Median	Standard Deviation
1998	$24.16	$17.60	$39.29	NA	NA	NA	NA
1999	$34.07	$19.02	$91.49	$9.91	41.0%	8.1%	132.8%
2000	$30.72	$20.51	$28.38	($3.34)	(9.8%)	7.9%	(69.0%)
2001	$36.65	$25.08	$57.26	$5.93	19.3%	22.3%	101.8%
2002	$31.60	$23.40	$26.75	($5.06)	(13.8%)	(6.7%)	(53.3%)
2003	$41.23	$34.96	$25.40	$9.64	30.5%	49.4%	(5.0%)
2004	$44.34	$40.16	$21.25	$3.10	7.5%	14.9%	(16.3%)
2005	$63.46	$52.93	$38.10	$19.12	43.1%	31.8%	79.3%
2006	$53.35	$44.40	$37.81	($10.11)	(15.9%)	(16.1%)	(0.7%)
2007	$61.66	$54.66	$36.94	$8.31	15.6%	23.1%	(2.3%)
2008	$71.13	$59.54	$40.97	$9.47	15.4%	8.9%	10.9%
2009	$39.05	$34.23	$18.21	($32.09)	(45.1%)	(42.5%)	(55.6%)
2010	$48.35	$39.13	$28.90	$9.30	23.8%	14.3%	58.7%
2011	$45.94	$36.54	$33.47	($2.41)	(5.0%)	(6.6%)	15.8%
2012	$35.23	$30.43	$23.66	($10.71)	(23.3%)	(16.7%)	(29.3%)
2013	$38.66	$33.25	$23.78	$3.43	9.7%	9.3%	0.5%
2014	$53.14	$36.20	$76.20	$14.47	37.4%	8.9%	220.4%
2015	$36.16	$27.66	$31.06	($16.98)	(31.9%)	(23.6%)	(59.2%)
2016	$29.23	$25.01	$16.12	($6.93)	(19.2%)	(9.6%)	(48.1%)
2017	$30.99	$26.35	$19.32	$1.76	6.0%	5.4%	19.9%
2018	$38.24	$29.55	$32.89	$7.25	23.4%	12.1%	70.2%
2019	$27.32	$23.63	$23.12	($10.92)	(28.6%)	(20.0%)	(29.7%)
2020	$21.77	$19.07	$12.50	($5.55)	(20.3%)	(19.3%)	(45.9%)
2021	$39.78	$32.11	$27.72	$18.02	82.8%	68.4%	121.8%
2022	$80.14	$60.09	$135.55	$40.36	101.4%	87.2%	389.1%
2023	$31.08	$26.83	$19.77	($49.06)	(61.2%)	(55.3%)	(85.4%)

Components of RT LMP (Unadjusted)

Element	2022 Contribution to LMP	2022 Percent	2023 Contribution to LMP	2023 Percent	Change in Percent
Gas	$41.42	51.7%	$13.60	43.7%	(7.9%)
Coal	$5.66	7.1%	$4.49	14.4%	7.4%
Positive Markup	$7.29	9.1%	$3.29	10.6%	1.5%
Variable Maintenance	$2.40	3.0%	$2.31	7.4%	4.4%
Ten Percent Adder	$4.70	5.9%	$1.95	6.3%	0.4%
CO_2 Cost	$1.74	2.2%	$1.93	6.2%	4.0%
Transmission Constraint Penalty Factor	$4.63	5.8%	$1.62	5.2%	(0.6%)
Variable Operations	$0.94	1.2%	$1.10	3.5%	2.4%
Opportunity Cost Adder	$1.58	2.0%	$0.87	2.8%	0.8%
NO_x Cost	$2.17	2.7%	$0.51	1.6%	(1.1%)
Ancillary Service Redispatch Cost	$1.45	1.8%	$0.50	1.6%	(0.2%)
Market-to-Market	$2.48	3.1%	$0.41	1.3%	(1.8%)
LPA Rounding Difference	$0.64	0.8%	$0.40	1.3%	0.5%
Oil	$1.42	1.8%	$0.31	1.0%	(0.8%)
NA	$0.25	0.3%	$0.15	0.5%	0.2%
Increase Generation Differential	$0.35	0.4%	$0.13	0.4%	(0.0%)
Scarcity	$5.05	6.3%	$0.07	0.2%	(6.1%)
Landfill Gas	$0.02	0.0%	$0.06	0.2%	0.2%
Other	$0.02	0.0%	$0.02	0.1%	0.0%
SO_2 Cost	$0.00	0.0%	$0.00	0.0%	0.0%
Emergency Demand Response	$1.75	2.2%	$0.00	0.0%	(2.2%)
PJM Administrative Cap	($1.39)	(1.7%)	$0.00	0.0%	1.7%
LPA-SCED Differential	($0.03)	(0.0%)	($0.00)	(0.0%)	0.0%
Decrease Generation Differential	($0.04)	(0.1%)	($0.01)	(0.0%)	0.0%
Renewable Energy Credits	($0.39)	(0.5%)	($0.07)	(0.2%)	0.3%
Negative Markup	($3.96)	(4.9%)	($2.56)	(8.2%)	(3.3%)
Total	$80.14	100.0%	$31.08	100.0%	0.0%

Components of RT LMP (Adjusted)

Element	2022 Contribution to LMP	Percent	2023 Contribution to LMP	Percent	Change in Percent
Gas	$41.42	51.7%	$13.60	43.7%	(7.9%)
Coal	$5.66	7.1%	$4.49	14.4%	7.4%
Positive Markup	$10.02	12.5%	$4.28	13.8%	1.3%
Variable Maintenance	$2.40	3.0%	$2.31	7.4%	4.4%
CO_2 Cost	$1.74	2.2%	$1.93	6.2%	4.0%
Transmission Constraint Penalty Factor	$4.63	5.8%	$1.62	5.2%	(0.6%)
Variable Operations	$0.94	1.2%	$1.10	3.5%	2.4%
Opportunity Cost Adder	$1.58	2.0%	$0.87	2.8%	0.8%
NO_x Cost	$2.17	2.7%	$0.51	1.6%	(1.1%)
Ancillary Service Redispatch Cost	$1.45	1.8%	$0.50	1.6%	(0.2%)
Market-to-Market	$2.48	3.1%	$0.41	1.3%	(1.8%)
LPA Rounding Difference	$0.64	0.8%	$0.40	1.3%	0.5%
Oil	$1.42	1.8%	$0.31	1.0%	(0.8%)
NA	$0.25	0.3%	$0.15	0.5%	0.2%
Increase Generation Differential	$0.35	0.4%	$0.13	0.4%	(0.0%)
Scarcity	$5.05	6.3%	$0.07	0.2%	(6.1%)
Landfill Gas	$0.02	0.0%	$0.06	0.2%	0.2%
Other	$0.02	0.0%	$0.02	0.1%	0.0%
Ten Percent Adder	$0.00	0.0%	$0.01	0.0%	0.0%
SO_2 Cost	$0.00	0.0%	$0.00	0.0%	0.0%
Emergency Demand Response	$1.75	2.2%	$0.00	0.0%	(2.2%)
PJM Administrative Cap	($1.39)	(1.7%)	$0.00	0.0%	1.7%
LPA-SCED Differential	($0.03)	(0.0%)	($0.00)	(0.0%)	0.0%
Decrease Generation Differential	($0.04)	(0.1%)	($0.01)	(0.0%)	0.0%
Renewable Energy Credits	($0.39)	(0.5%)	($0.07)	(0.2%)	0.3%
Negative Markup	($2.00)	(2.5%)	($1.61)	(5.2%)	(2.7%)
Total	$80.14	100.0%	$31.08	100.0%	0.0%

Components of change in real-time load-weighted average LMP

Component	2022	2023	Change in LMP	Percent
Fuel and Consumables	$49.45	$19.56	($29.89)	60.9%
Emission Related	$5.11	$3.24	($1.87)	3.8%
Market Power Related	$10.42	$4.99	($5.43)	11.1%
Scarcity	$5.05	$0.07	($4.99)	10.2%
Transmission Constraint Penalty Factor	$4.63	$1.62	($3.01)	6.1%
Ancillary Service Redispatch Cost	$1.45	$0.50	($0.95)	1.9%
Emergency Demand Response	$1.75	$0.00	($1.75)	3.6%
PJM Administrative Cap	($1.39)	$0.00	$1.39	(2.8%)
All Other	$3.67	$1.10	($2.56)	5.2%
Total	$80.14	$31.08	($49.06)	100.0%

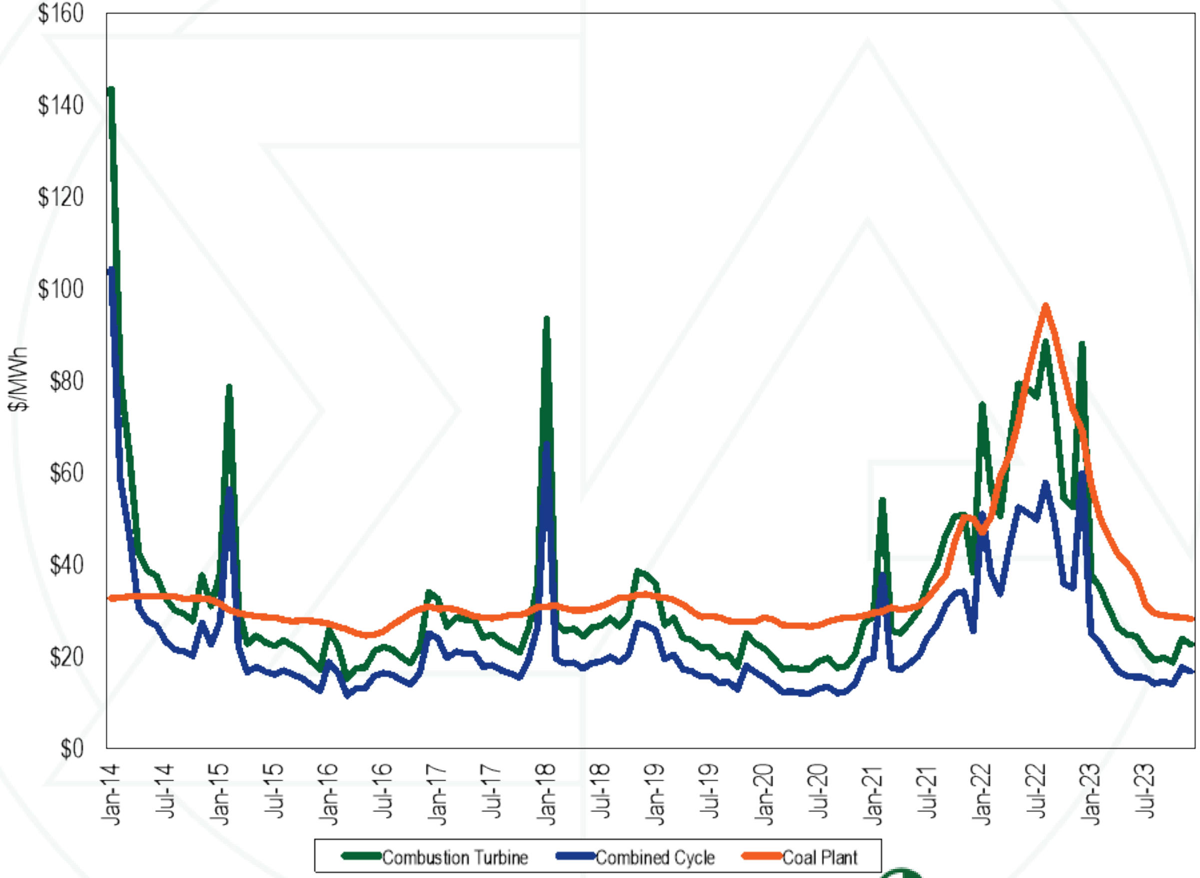
Generation by fuel source

		2022		2023		Change in
		GWh	Percent	GWh	Percent	Output
Coal		167,603.8	20.0%	120,876.1	14.7%	(27.9%)
	Bituminous	144,777.2	17.2%	108,651.3	13.2%	(25.0%)
	Sub Bituminous	16,267.5	1.9%	6,428.1	0.8%	(60.5%)
	Other Coal	6,559.0	0.8%	5,796.7	0.7%	(11.6%)
Nuclear		271,522.1	32.3%	273,488.6	33.3%	0.7%
Gas		335,707.2	40.0%	363,659.7	44.3%	8.3%
	Natural Gas CC	309,154.3	36.8%	331,766.8	40.4%	7.3%
	Natural Gas CT	18,571.0	2.2%	21,077.7	2.6%	13.5%
	Natural Gas Other Units	6,488.3	0.8%	9,571.2	1.2%	47.5%
	Other Gas	1,493.5	0.2%	1,244.0	0.2%	(16.7%)
Hydroelectric		15,662.5	1.9%	15,488.8	1.9%	(1.1%)
	Pumped Storage	6,092.9	0.7%	6,096.5	0.7%	0.1%
	Run of River	7,612.6	0.9%	7,644.6	0.9%	0.4%
	Other Hydro	1,957.0	0.2%	1,747.6	0.2%	(10.7%)
Wind		31,491.0	3.8%	28,937.2	3.5%	(8.1%)
Waste		4,056.0	0.5%	3,992.6	0.5%	(1.6%)
Oil		2,699.2	0.3%	2,676.7	0.3%	(0.8%)
	Heavy Oil	76.4	0.0%	38.2	0.0%	(50.0%)
	Light Oil	877.3	0.1%	918.5	0.1%	4.7%
	Diesel	163.1	0.0%	40.4	0.0%	(75.2%)
	Other Oil	1,582.4	0.2%	1,679.6	0.2%	6.1%
Solar		9,242.4	1.1%	11,097.7	1.4%	20.1%
Battery		25.4	0.0%	28.7	0.0%	12.7%
Biofuel		1,371.1	0.2%	1,265.0	0.2%	(7.7%)
Total		839,380.7	100.0%	821,511.0	100.0%	(2.1%)

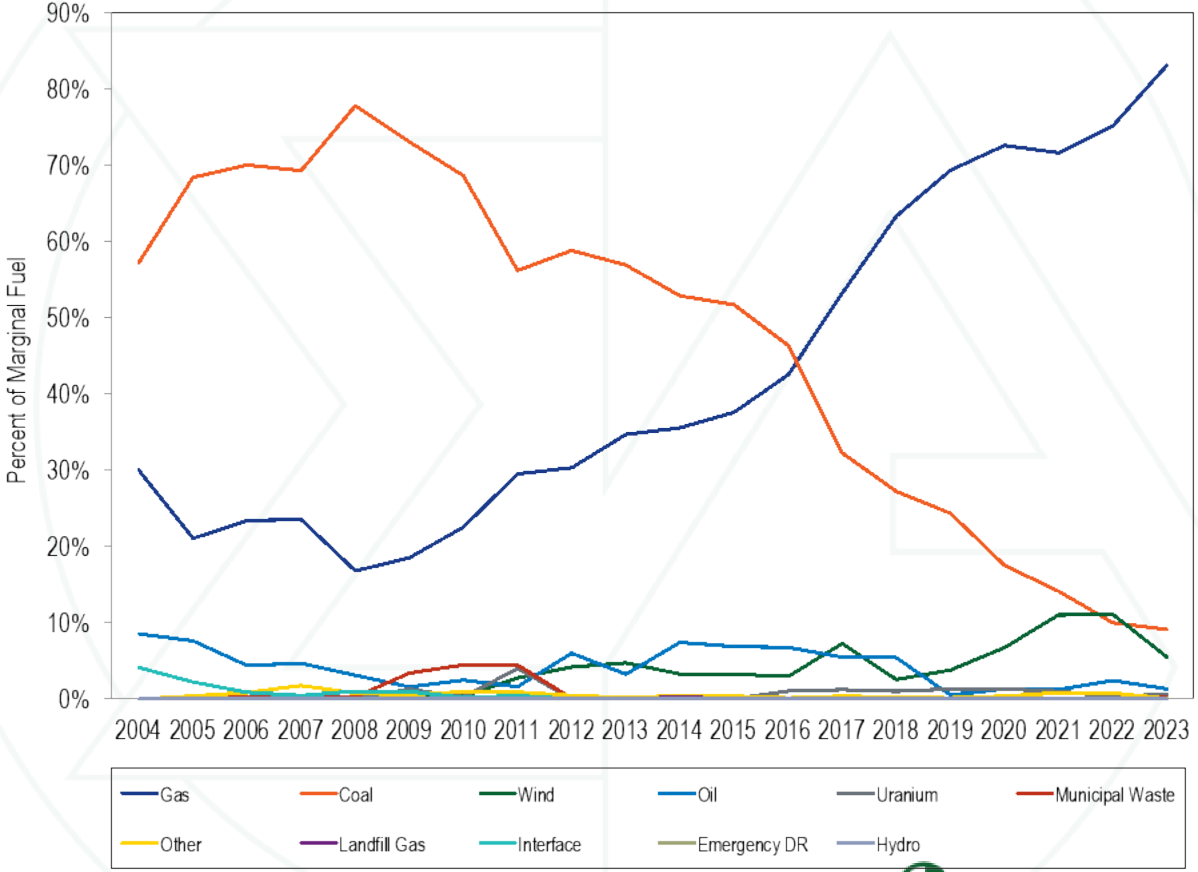
Generation by fuel source: 2008 through 2023

	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%

Average short run marginal costs

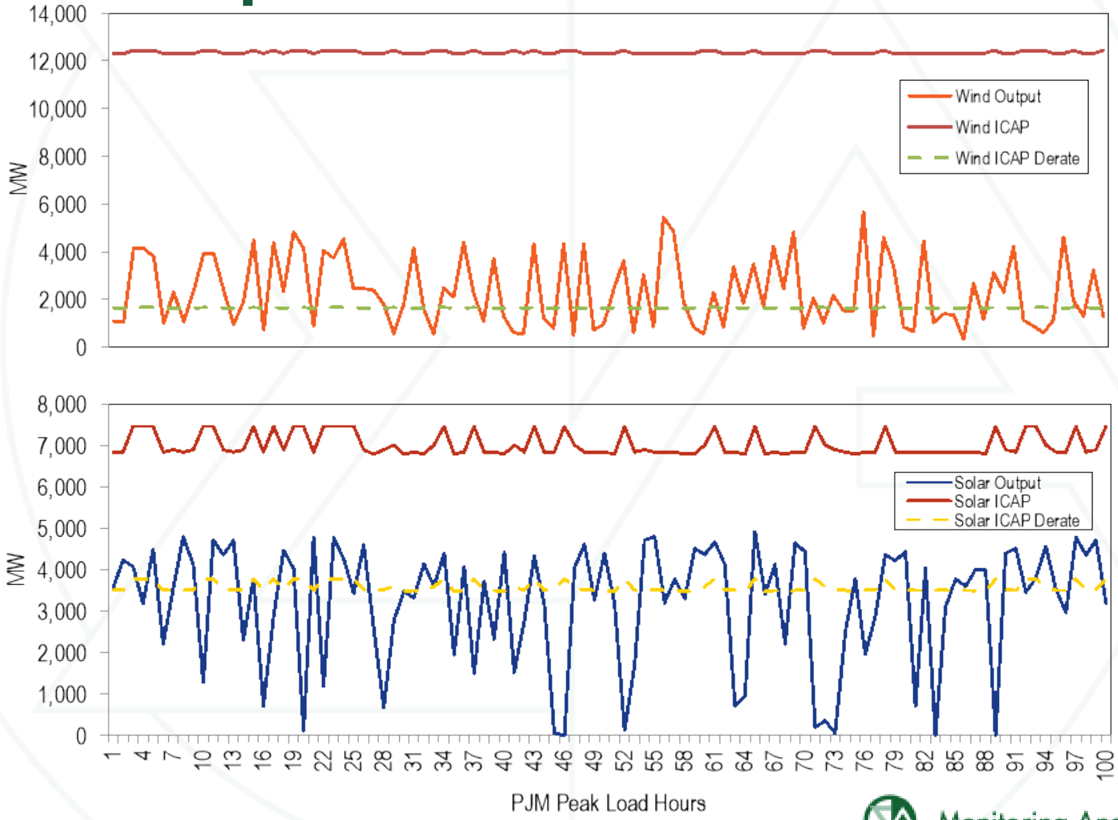


Type of fuel used (by RT marginal units

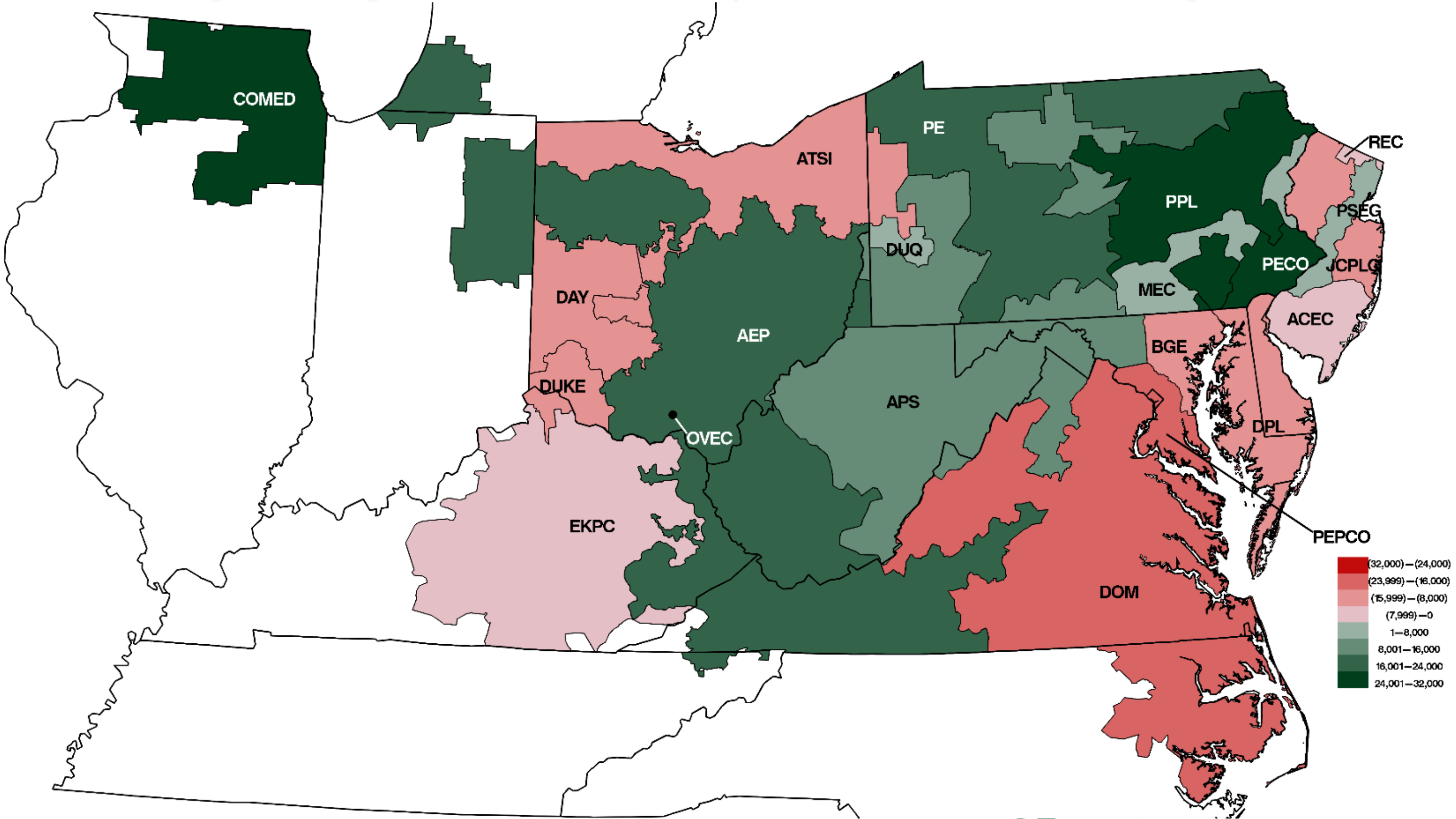


Monitoring Analytics

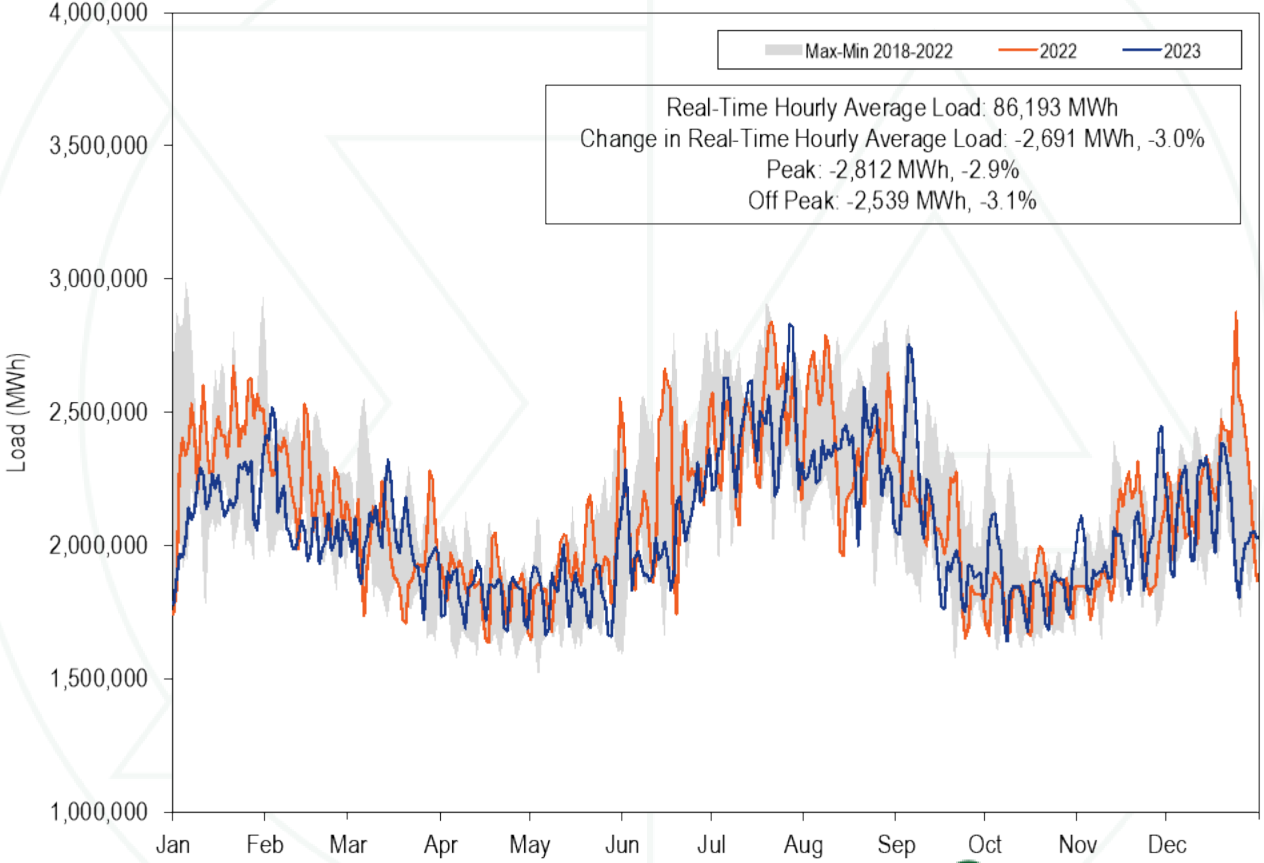
Figure 8-14 Wind and solar output during the top 100 load hours: 2023



Map of RT generation less RT load by zone



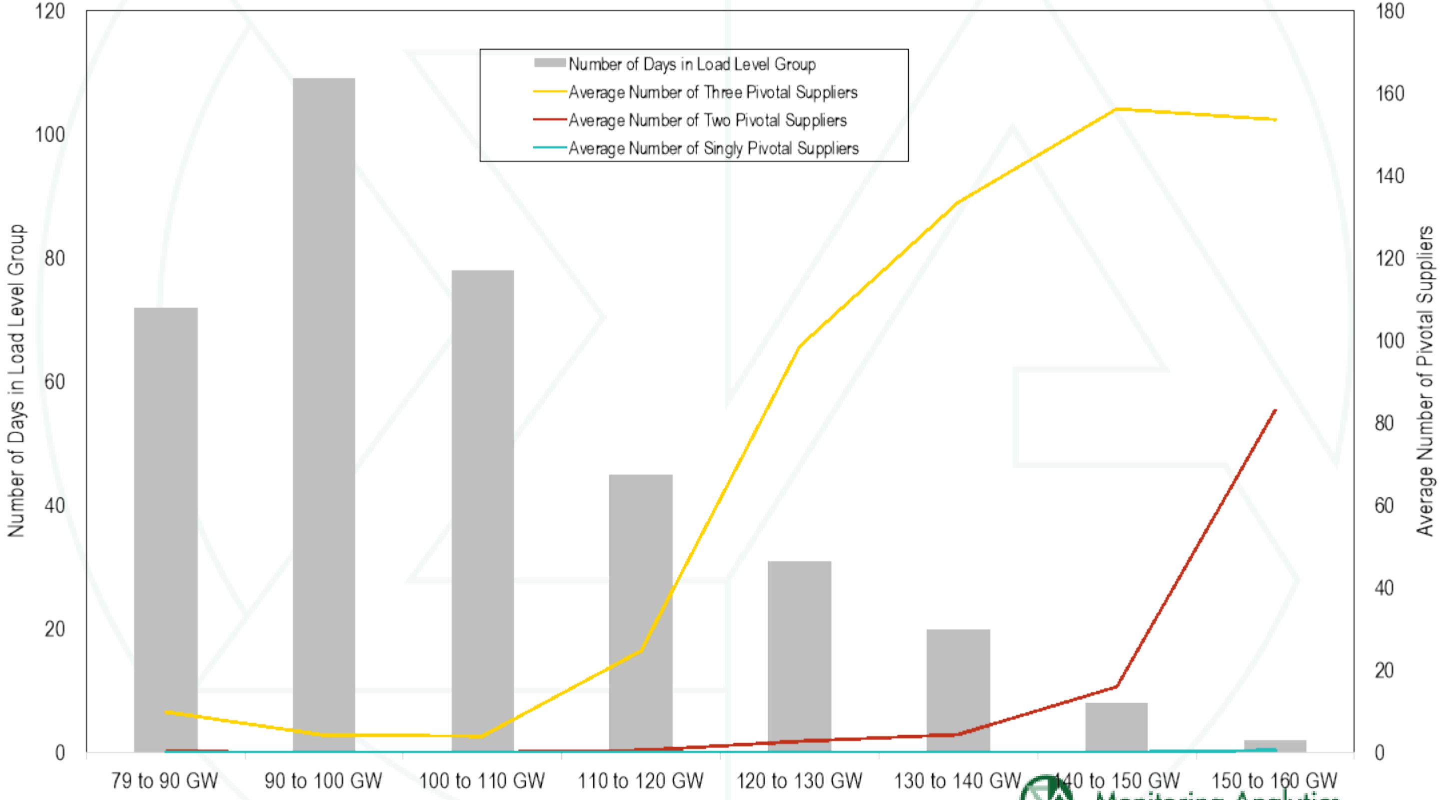
RT daily load



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%)

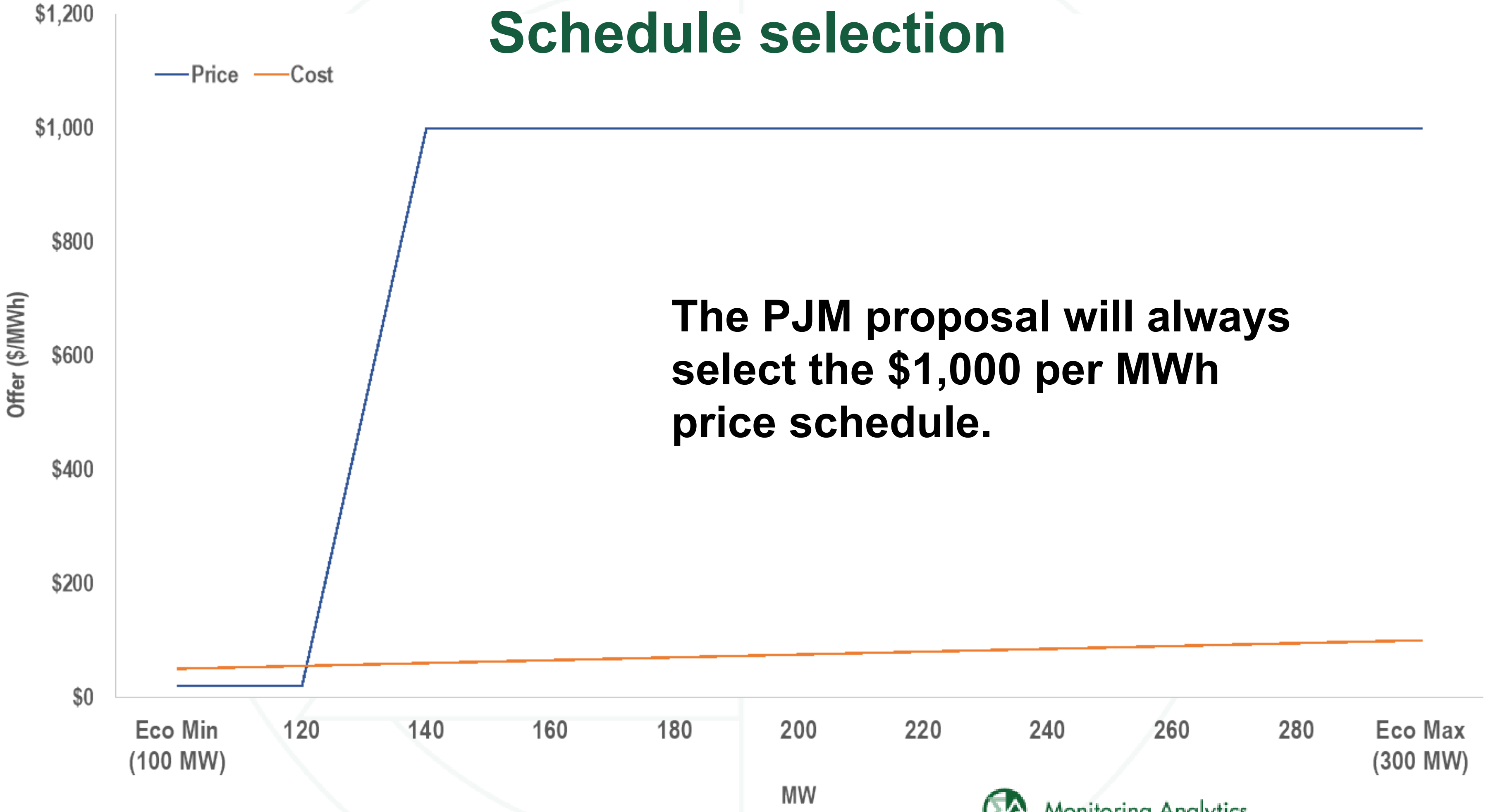
Average number of pivotal suppliers in the day-ahead energy market by load level



Average hourly capacity (MW) failing the energy market must offer requirement: 2023

Month	90th Percentile	Average	10th Percentile
Jan-23	2,218	1,257	265
Feb-23	1,252	676	295
Mar-23	1,440	808	364
Apr-23	5,299	3,781	1,878
May-23	5,151	4,449	3,832
Jun-23	4,158	3,323	2,603
Jul-23	2,750	2,030	1,232
Aug-23	2,196	1,540	982
Sep-23	2,650	1,918	1,099
Oct-23	3,396	2,568	1,884
Nov-23	2,771	2,102	1,562
Dec-23	3,324	2,549	1,877
2023	4,233	2,257	610

Schedule selection

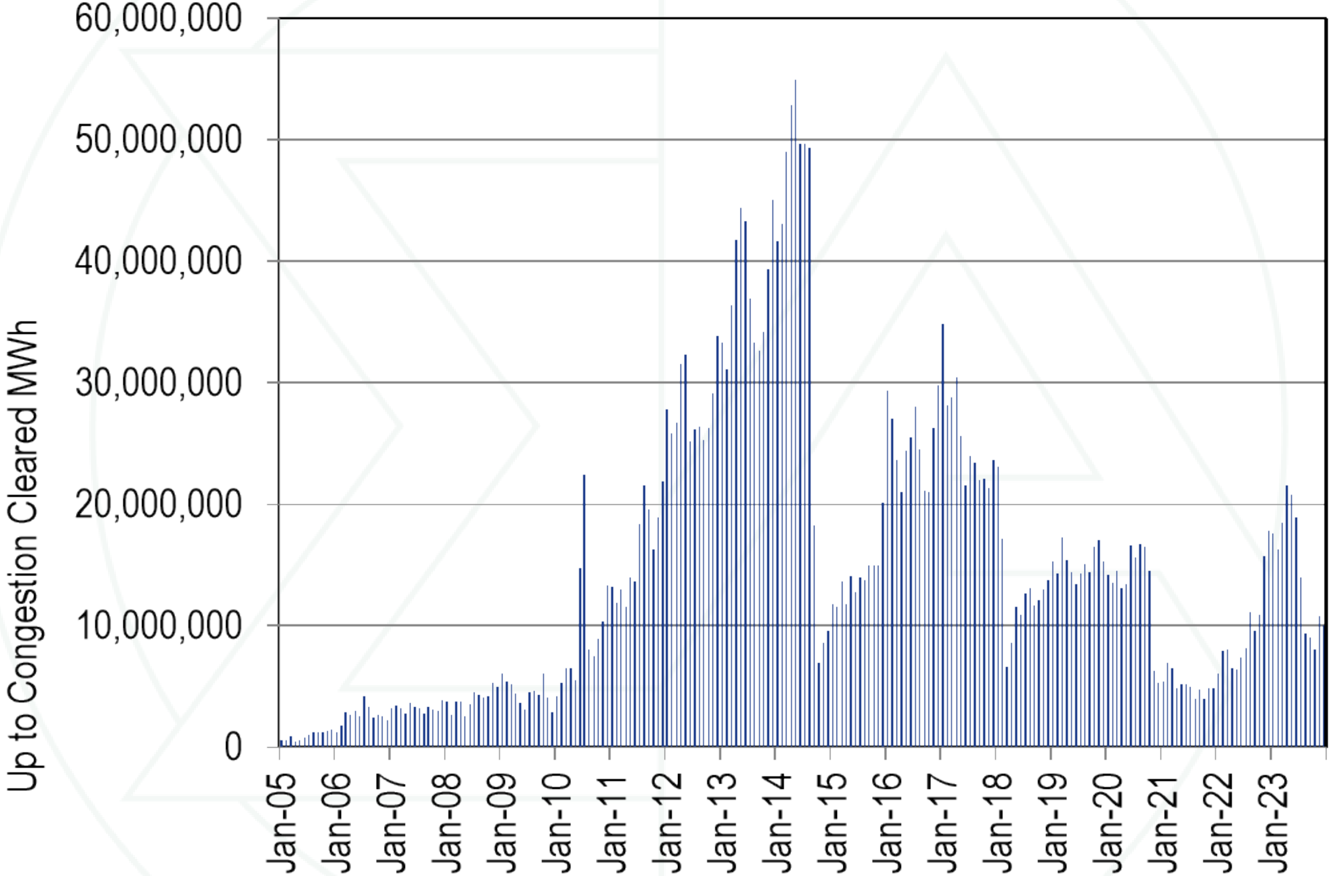


The PJM proposal will always select the $1,000 per MWh price schedule.

Frequency of reduction in control limit of line ratings (constraint intervals) in the real-time market: 2022 and 2023

Description	Frequency (Constraint Intervals) 2022	Frequency (Constraint Intervals) 2023	Constraints with Reduced Control Percent 2022	Constraints with Reduced Control Percent 2023	Average Reduction (Percent) 2022	Average Reduction (Percent) 2023
Violated Transmission Constraints	24,016	10,252	20,063	7,213	5.9%	5.5%
Binding Transmission Constraints	104,562	105,392	101,046	103,491	6.3%	6.3%
Market to Market Transmission Constraints	74,259	52,204	17,702	14,355	5.6%	5.7%
All Transmission Constraints	202,837	167,848	138,811	125,059	6.2%	6.2%

UTC cleared bids in MWh



Total congestion costs

	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%)	$41,680	1.4%
2020	$529	(9.4%)	$36,280	1.5%
2021	$995	88.2%	$54,130	1.8%
2022	$2,501	151.3%	$86,220	2.9%
2023	$1,069	(57.3%)	$48,600	2.2%

Recommendations: Energy Market

- **The MMU recommends that intermittent resources be subject to an enforceable ICAP must offer rule in the energy market that reflects the limitations of these resources. (Adopted 2023)**
- **The MMU recommends that storage resources be subject to an enforceable ICAP must offer rule in the energy market that reflects the limitations of these resources.**
- **The MMU recommends, in order to ensure effective market power mitigation, PJM always use cost-based offers for units that fail the TPS test, and always use flexible parameters for all cost-based and all price-based offers during high load conditions.**

The capacity market results were competitive

Market Element	Evaluation	Market Design
Market Structure: Aggregate Market	Not Competitive	
Market Structure: Local Market	Not Competitive	
Participant Behavior	Competitive	
Market Performance	**Competitive**	**Mixed**

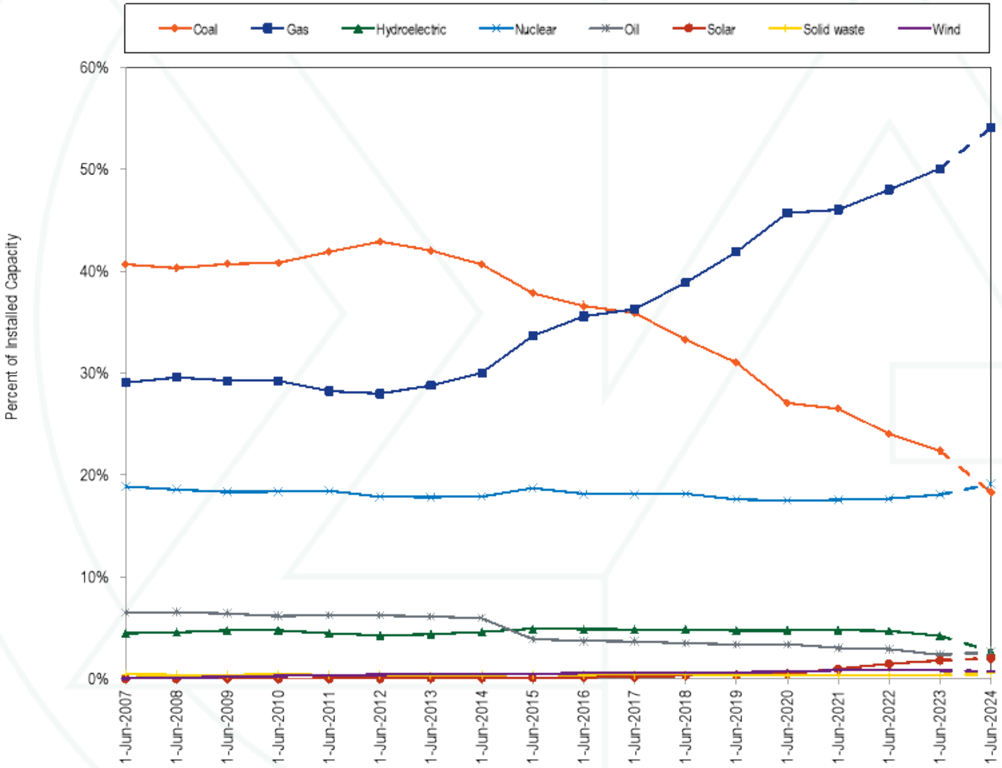
Capacity market issues

- PJM ELCC issues
- Market power mitigation
- DR
- EE
- Reserve margin
- RMR issues

Installed capacity by fuel source

	01-Jan-23		31-May-23		01-Jun-23		31-Dec-23	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Battery	0.0	0.0%	0.0	0.0%	4.0	0.0%	21.9	0.0%
Coal	42,937.0	23.4%	42,054.0	23.1%	39,903.2	22.5%	38,910.3	21.8%
Gas	87,931.3	47.9%	89,790.3	49.2%	87,899.2	49.7%	87,818.9	49.3%
Hydroelectric	8,491.7	4.6%	8,480.4	4.7%	7,507.2	4.2%	7,507.2	4.2%
Nuclear	31,971.0	17.4%	31,823.8	17.5%	32,184.1	18.2%	32,183.0	18.1%
Oil	5,196.2	2.8%	5,160.2	2.8%	4,194.0	2.4%	4,371.4	2.5%
Solar	2,711.1	1.5%	2,806.5	1.5%	3,183.5	1.8%	3,513.3	2.0%
Solid waste	649.4	0.4%	627.4	0.3%	627.4	0.4%	627.4	0.4%
Wind	3,501.1	1.9%	1,609.8	0.9%	1,481.8	0.8%	3,321.4	1.9%
Total	183,388.8	100.0%	182,352.4	100.0%	176,984.4	100.0%	178,252.9	100.0%

Installed capacity by fuel source



RPM reserve margin: 2019 to 2024

	01-Jun-19	01-Jun-20	01-Jun-21	01-Jun-22	01-Jun-23	01-Jun-24	
Forecast peak load ICAP (MW)	151,643.5	148,355.3	149,482.9	149,263.6	149,382.2	151,639.1	A
FRR peak load ICAP (MW)	12,284.2	11,488.3	11,717.7	28,292.8	29,554.6	30,431.0	B
PRD ICAP (MW)	0.0	558.0	510.0	230.0	235.0	305.0	C
Installed reserve margin (IRM)	16.0%	15.5%	14.7%	14.9%	14.9%	17.7%	D
Pool wide average EFORd	6.08%	5.78%	5.22%	5.08%	4.87%	5.10%	E
Forecast pool requirement (FPR)	1.0895	1.0882	1.0871	1.0906	1.0930	1.1170	F=(1+D)*(1-E)
RPM committed less deficiency UCAP (MW) (generation and DR)	162,276.1	159,560.4	156,633.6	137,944.8	136,408.5	139,810.2	G
RPM committed less deficiency ICAP (MW) (generation and DR)	172,781.2	169,348.8	165,260.2	145,327.4	143,391.7	147,323.7	H=G/(1-E)
RPM peak load ICAP (MW)	139,359.3	136,309.0	137,255.2	120,740.8	119,592.6	120,903.1	J=A-B-C
Reserve margin ICAP (MW)	33,421.9	33,039.8	28,005.0	24,586.6	23,799.1	26,420.6	K=H-J
Reserve margin (%)	24.0%	24.2%	20.4%	20.4%	19.9%	21.9%	L=K/J
Reserve margin in excess of IRM ICAP (MW)	11,124.4	11,911.9	7,828.5	6,596.3	5,979.8	5,020.8	M=K-D*J
Reserve margin in excess of IRM (%)	8.0%	8.7%	5.7%	5.5%	5.0%	4.2%	N=M/J
RPM peak load UCAP (MW)	130,886.3	128,430.3	130,090.5	114,607.2	113,768.4	114,737.0	P=J*(1-E)
RPM reliability requirement UCAP (MW)	151,832.0	148,331.5	149,210.1	131,679.9	130,714.7	135,048.8	Q=J*F
Reserve margin UCAP (MW)	31,389.8	31,130.1	26,543.1	23,337.6	22,640.1	25,073.2	R=G-P
Reserve cleared in excess of IRM UCAP (MW)	10,444.1	11,228.9	7,423.5	6,264.9	5,693.8	4,761.4	S=G-Q
Projected replacement capacity UCAP (MW)	0.0	0.0	0.0	0.0	0.0	0.0	T
Projected reserve margin	24.0%	24.2%	20.4%	20.4%	19.9%	21.9%	U=(H-T/(1-E))/J-1

Part V reliability service summary (RMR)

Unit Names	Owner	Fuel Type	ICAP (MW)	Cost Recovery Method	Docket Numbers	Start of Term	End of Term
Indian River 4	NRG Power Marketing LLC	Coal	410.0	Cost of Service Recovery Rate	ER22-1539	01-Jun-22	31-Dec-26
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 (RMR)

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)
Indian River 4	NRG Power Marketing LLC	$357,065,662	$520.25	$133,249,790	$561.31	$51.68
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

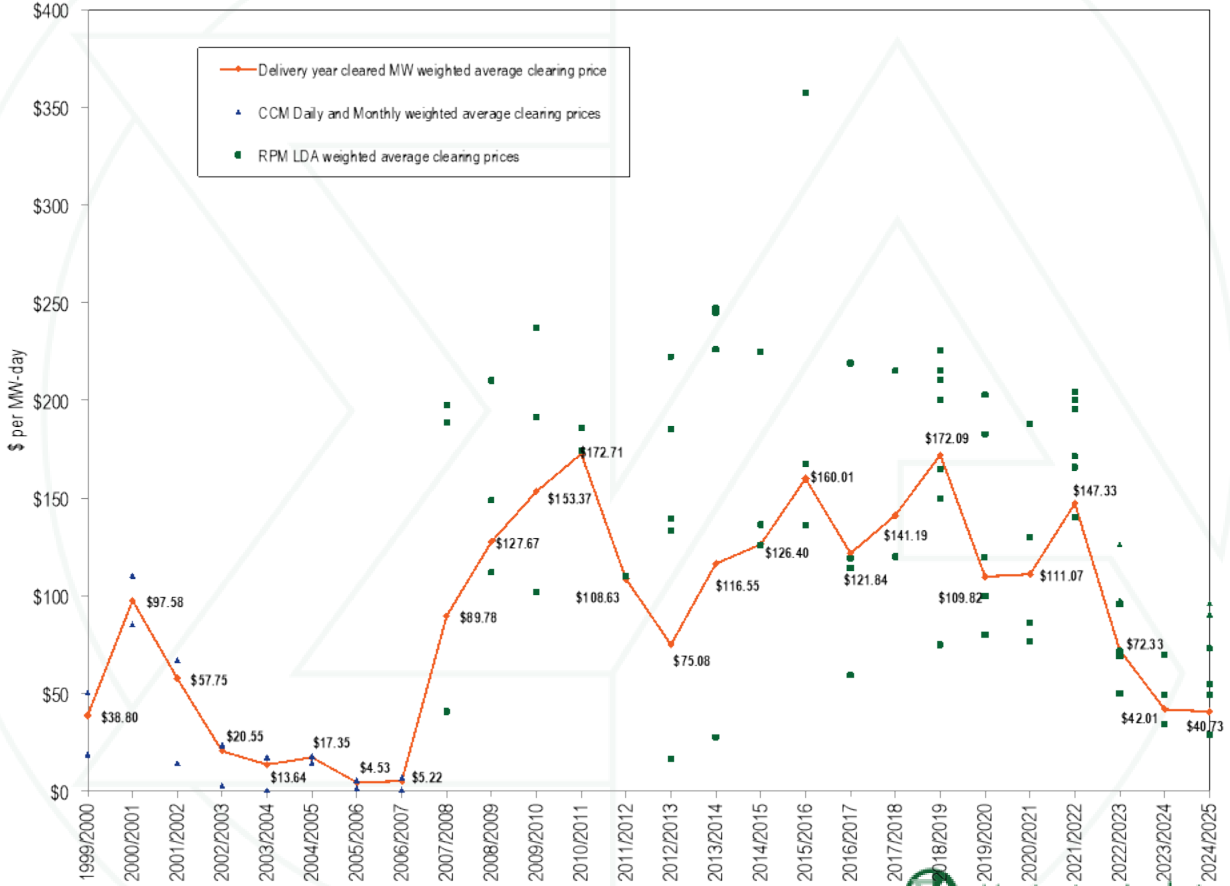
2024/2025 RPM BRA: RPM revenue impacts

			Scenario Impact		
			RPM Revenue	Percent Change	
		RPM Revenue	Change	Scenario	Actual to
Scenario	Scenario Description	($ per Delivery Year)	($ per Delivery Year)	to Actual	Scenario
0	Actual Results	$2,192,828,251	NA	NA	NA
1	Vertical VRR curve	$1,377,668,211	$815,160,040	59.2%	(37.2%)
2	VRR curve half way to vertical	$1,712,525,223	$480,303,029	28.0%	(21.9%)
3	Reduction in over forecasted peak load	$1,800,931,369	$391,896,882	21.8%	(17.9%)
4	Correction to overstated intermittent capacity	$2,272,074,858	($79,246,607)	(3.5%)	3.6%
5	Zero demand resources	$5,248,970,191	($3,056,141,939)	(58.2%)	139.4%
6	Zero EE offers and EE add back	$2,073,286,830	$119,541,421	5.8%	(5.5%)
7	Zero PRD offers	$2,259,815,834	($66,987,582)	(3.0%)	3.1%
8	Zero seasonal offers	$2,296,212,168	($103,383,917)	(4.5%)	4.7%
9	Matching seasonal offers only within LDAs	$2,197,384,603	($4,556,351)	(0.2%)	0.2%
10	Zero capacity imports	$2,400,001,217	($207,172,966)	(8.6%)	9.4%
11	Combined scenarios 4, 5, 6, 7, 8 and 10	$8,374,917,524	($6,182,089,273)	(73.8%)	281.9%
12	Zero categorically exempt offers	$5,200,707,712	($3,007,879,460)	(57.8%)	137.2%
13	All categorically exempt offers	$1,921,538,019	$271,290,232	14.1%	(12.4%)
14	All nuclear offers as price takers	$2,121,788,593	$71,039,658	3.3%	(3.2%)
15	Combined scenarios 2, 4, 5 and 10	$4,749,749,993	($2,556,921,742)	(53.8%)	116.6%

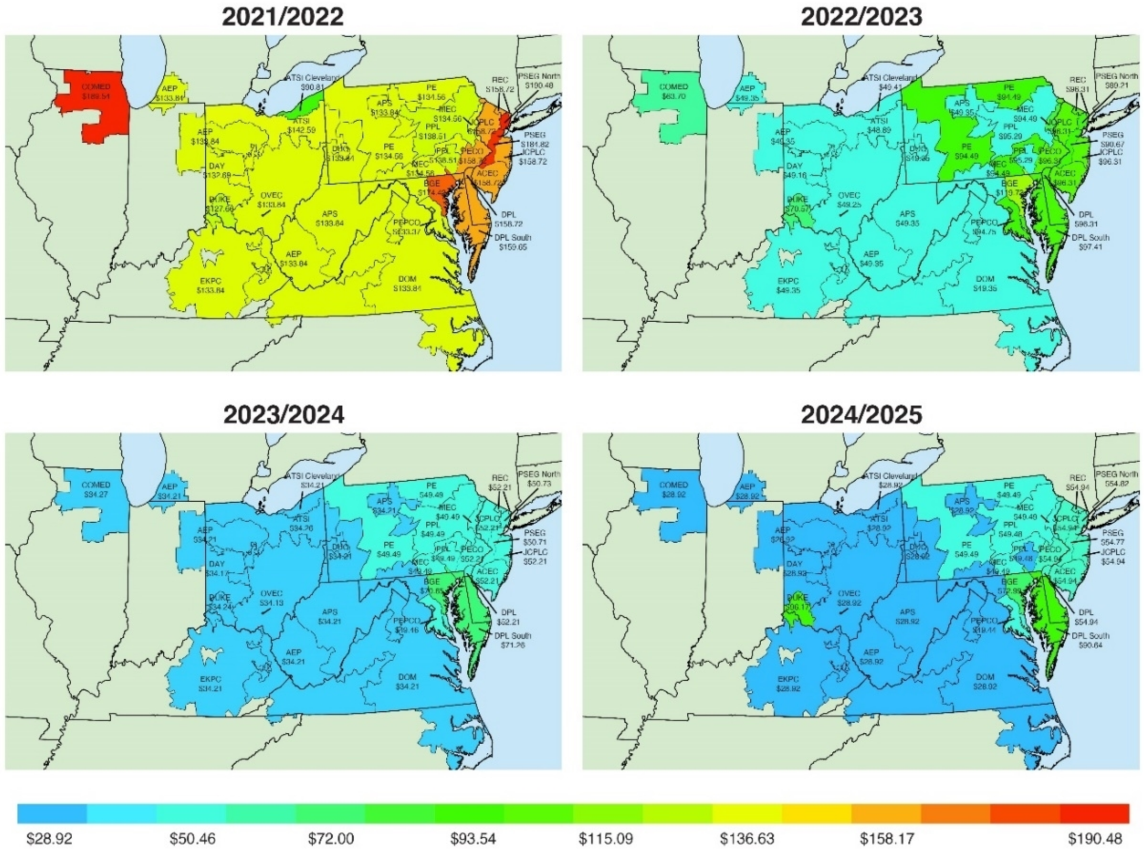
2024/2025 RPM BRA: RPM cleared UCAP MW Impacts

			Scenario Impact		
				Percent Change	
Scenario	Scenario Description	Cleared UCAP (MW)	Cleared UCAP Change (MW)	Scenario to Actual	Actual to Scenario
0	Actual Results	147,478.9	NA	NA	NA
1	Vertical VRR curve	139,392.1	8,086.8	5.8%	(5.5%)
2	VRR curve half way to vertical	143,011.6	4,467.3	3.1%	(3.0%)
3	Reduction in over forecasted peak load	143,653.5	3,825.4	2.7%	(2.6%)
4	Correction to overstated intermittent capacity	147,365.7	113.2	0.1%	(0.1%)
5	Zero demand resources	145,808.2	1,670.7	1.1%	(1.1%)
6	Zero EE offers and EE add back	139,810.6	7,668.3	5.5%	(5.2%)
7	Zero PRD offers	147,798.6	(319.7)	(0.2%)	0.2%
8	Zero seasonal offers	147,147.6	331.3	0.2%	(0.2%)
9	Matching seasonal offers only within LDAs	147,451.0	27.9	0.0%	(0.0%)
10	Zero capacity imports	147,472.5	6.4	0.0%	(0.0%)
11	Combined scenarios 4, 5, 6, 7, 8 and 10	135,524.0	11,954.9	8.8%	(8.1%)
12	Zero categorically exempt offers	145,773.2	1,705.7	1.2%	(1.2%)
13	All categorically exempt offers	145,162.6	2,316.3	1.6%	(1.6%)
14	All nuclear offers as price takers	147,466.3	12.6	0.0%	(0.0%)
15	Combined scenarios 2, 4, 5 and 10	142,653.2	4,825.7	3.4%	(3.3%)

History of capacity prices



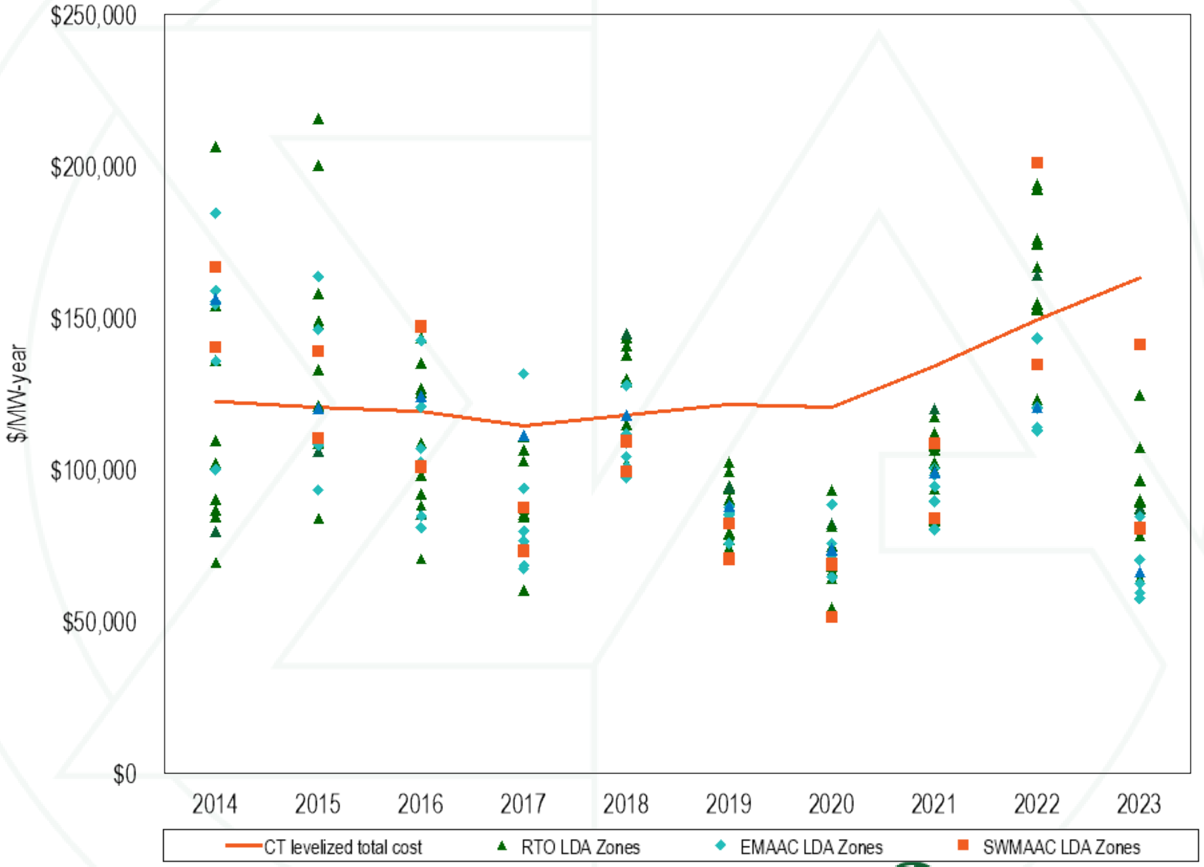
Map of RPM capacity prices



RPM reserve margin: June 1, 2019, to June 1, 2024

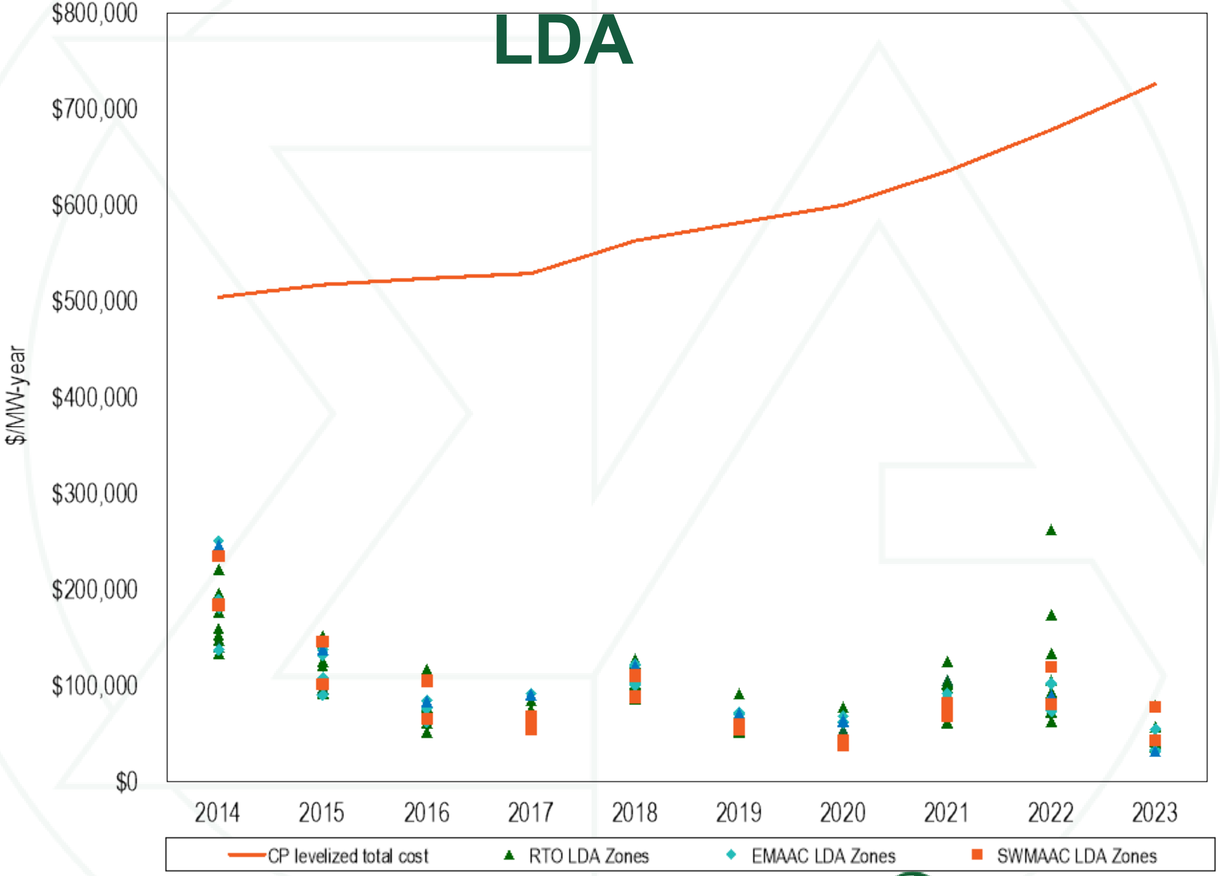
	01-Jun-19	01-Jun-20	01-Jun-21	01-Jun-22	01-Jun-23	01-Jun-24	
Forecast peak load ICAP (MW)	151,643.5	148,355.3	149,482.9	149,263.6	149,382.2	151,639.1	A
FRR peak load ICAP (MW)	12,284.2	11,488.3	11,717.7	28,292.8	29,554.6	30,431.0	B
PRD ICAP (MW)	0.0	558.0	510.0	230.0	235.0	305.0	C
Installed reserve margin (IRM)	16.0%	15.5%	14.7%	14.9%	14.9%	17.7%	D
Pool wide average EFORd	6.08%	5.78%	5.22%	5.08%	4.87%	5.10%	E
Forecast pool requirement (FPR)	1.0895	1.0882	1.0871	1.0906	1.0930	1.1170	F=(1+D)*(1-E)
RPM committed less deficiency UCAP (MW) (generation and DR)	162,276.1	159,560.4	156,633.6	137,944.8	136,408.5	139,810.2	G
RPM committed less deficiency ICAP (MW) (generation and DR)	172,781.2	169,348.8	165,260.2	145,327.4	143,391.7	147,323.7	H=G/(1-E)
RPM peak load ICAP (MW)	139,359.3	136,309.0	137,255.2	120,740.8	119,592.6	120,903.1	J=A-B-C
Reserve margin ICAP (MW)	33,421.9	33,039.8	28,005.0	24,586.6	23,799.1	26,420.6	K=H-J
Reserve margin (%)	24.0%	24.2%	20.4%	20.4%	19.9%	21.9%	L=K/J
Reserve margin in excess of IRM ICAP (MW)	11,124.4	11,911.9	7,828.5	6,596.3	5,979.8	5,020.8	M=K-D*J
Reserve margin in excess of IRM (%)	8.0%	8.7%	5.7%	5.5%	5.0%	4.2%	N=M/J
RPM peak load UCAP (MW)	130,886.3	128,430.3	130,090.5	114,607.2	113,768.4	114,737.0	P=J*(1-E)
RPM reliability requirement UCAP (MW)	151,832.0	148,331.5	149,210.1	131,679.9	130,714.7	135,048.8	Q=J*F
Reserve margin UCAP (MW)	31,389.8	31,130.1	26,543.1	23,337.6	22,640.1	25,073.2	R=G-P
Reserve cleared in excess of IRM UCAP (MW)	10,444.1	11,228.9	7,423.5	6,264.9	5,693.8	4,761.4	S=G-Q
Projected replacement capacity UCAP (MW)	0.0	0.0	0.0	0.0	0.0	0.0	T
Projected reserve margin	24.0%	24.2%	20.4%	20.4%	19.9%	21.9%	U=(H-T/(1-E))/J-1

New entrant CT net revenue and total cost by LDA

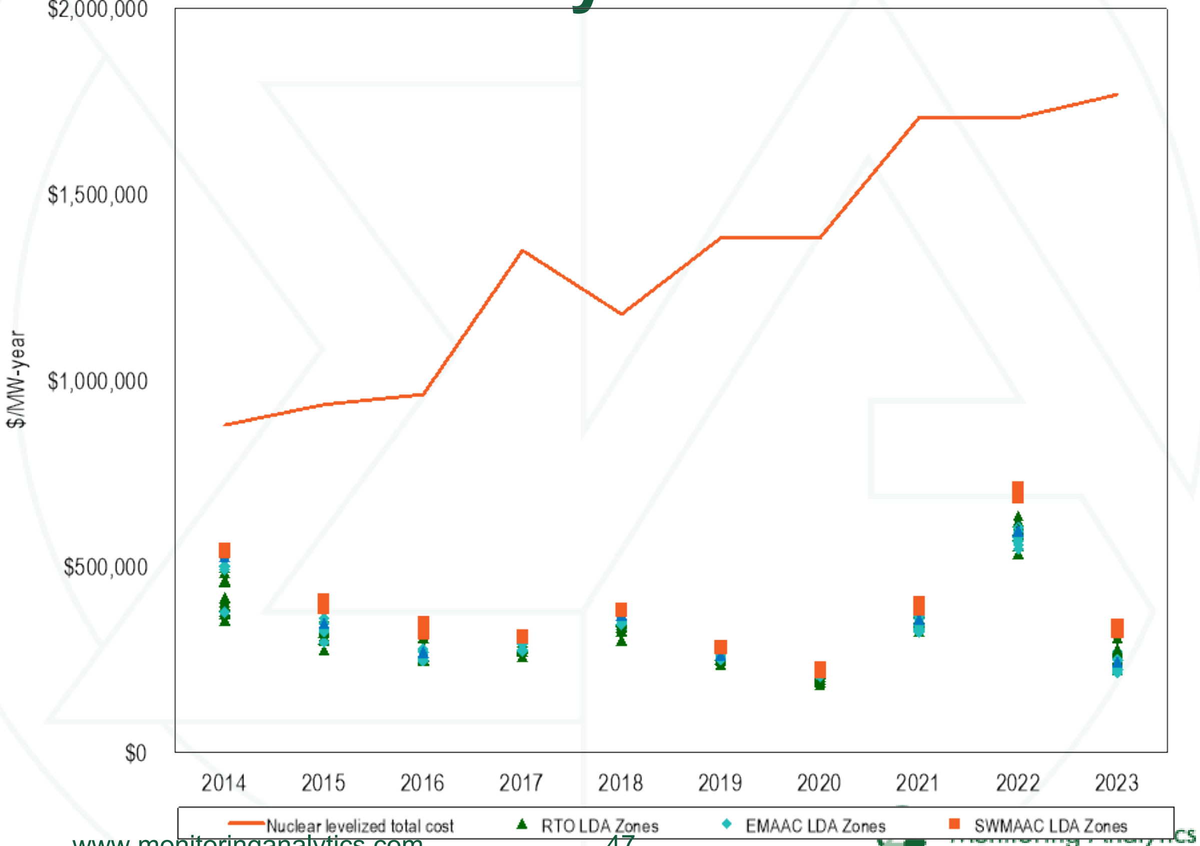


New entrant CC net revenue and total cost by LDA

New entrant CP net revenue and total cost by LDA



New entrant nuclear plant net revenue and total cost by LDA



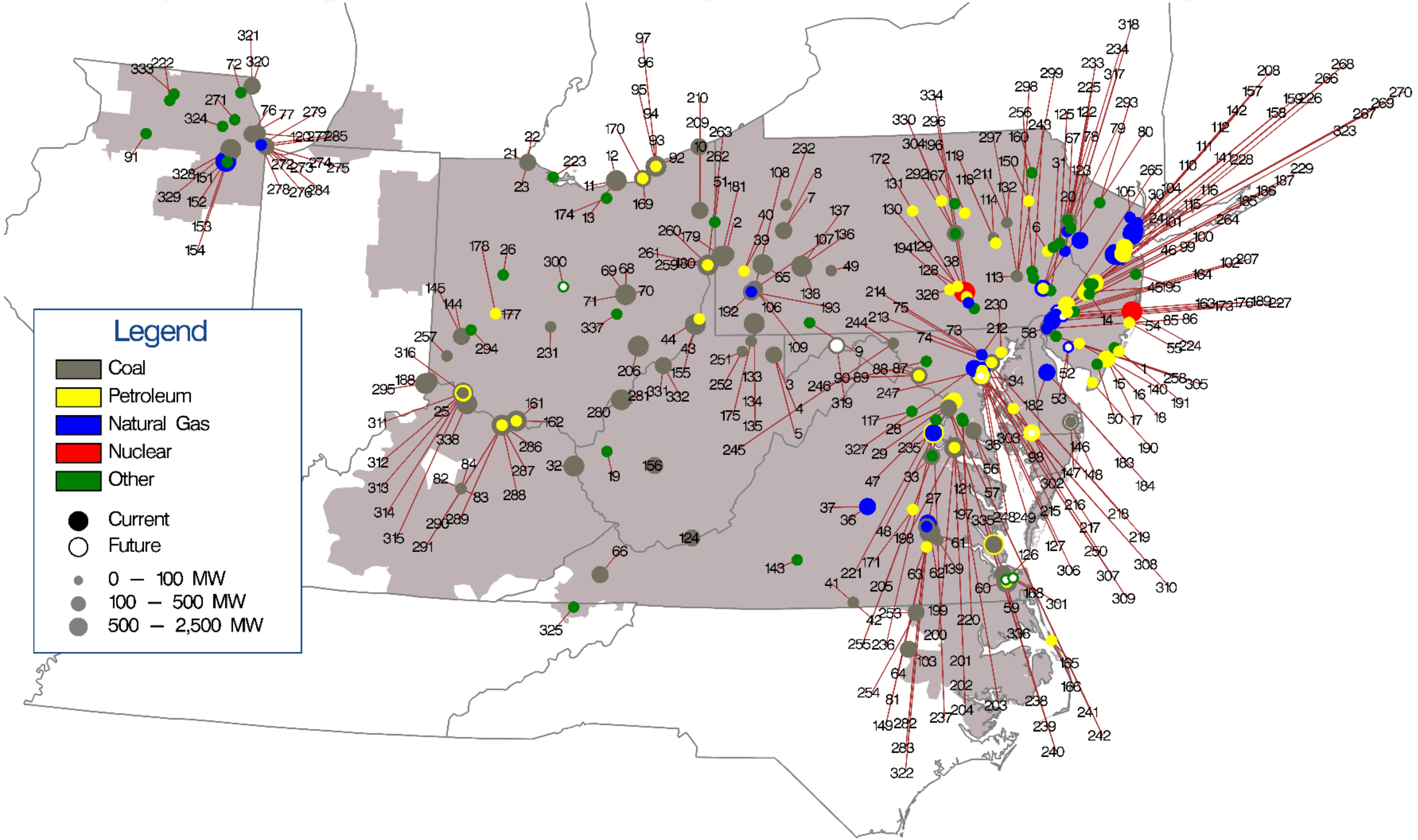
Nuclear unit surplus (shortfall)

	ICAP	Surplus (Shortfall) ($/MWh)															
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
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	$3.0
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	($0.6)
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	($1.0)
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	$10.0
Cook	2,177	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	($9.5)
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	($1.2)
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	$1.8	($2.2)	$11.0	$38.0	($2.2)
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	($0.9)
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	($2.4)
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
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
Peach Bottom	2,550	$53.7	$16.9	$24.2	$16.1	$2.3	$12.3	$25.5	$5.8	($2.2)	$1.4	$11.8	$0.7	($2.7)	$11.5	$38.4	($2.3)
Perry	1,240	NA	NA	NA	NA	($13.2)	($6.4)	$5.5	($0.3)	($4.0)	($7.4)	$1.9	($5.8)	($15.1)	$6.3	$32.1	($8.7)
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	$2.1	($2.4)	$12.7	$34.6	($1.4)
Salem	2,285	$54.0	$17.1	$24.5	$16.9	$2.6	$12.4	$26.0	$6.2	($2.1)	$1.5	$12.1	$1.6	($2.3)	$10.9	$37.8	($2.3)
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	$4.0	($2.6)	$17.2	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	($1.4)	($6.6)	$8.6	$36.3	($1.6)
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

Nuclear unit forward annual surplus (shortfall) for 2024

	ICAP (MW)	Surplus (Shortfall) ($/MWh)	Subsidy ($/MWh)	Surplus (Shortfall) Excluding Subsidy ($ in millions)	Surplus (Shortfall) Including Subsidy ($ in millions)
Beaver Valley	1,808	$11.15	$3.15	$169.5	$217.4
Braidwood	2,337	$6.19	$7.15	$121.6	$262.1
Byron	2,300	$5.43	$7.75	$105.0	$254.9
Calvert Cliffs	1,726	$17.10	$0.00	$248.0	$248.0
Cook	2,177	NA	$4.90	NA	NA
Davis Besse	894	($2.04)	$3.75	($15.4)	$12.8
Dresden	1,797	$5.72	$7.50	$86.4	$199.7
Hope Creek	1,172	$4.73	$10.00	$46.6	$145.1
LaSalle	2,265	$6.00	$7.30	$114.3	$253.3
Limerick	2,242	$4.44	$8.55	$83.8	$244.9
North Anna	1,892	NA	$1.15	NA	NA
Peach Bottom	2,550	$4.49	$8.50	$96.3	$278.5
Perry	1,240	($0.41)	$2.45	($4.3)	$21.2
Quad Cities	1,819	$4.56	$16.50	$69.7	$322.0
Salem	2,285	$4.59	$10.00	$88.2	$280.3
Surry	1,676	NA	$2.00	NA	NA
Susquehanna	2,494	$4.73	$8.30	$99.2	$273.2

Map of unit retirements: 2011 through 2026



Profile of units at risk of retirement

	MW expected to retire							Total MW
	2024	2025	2026	2027	2028	2029	2030	2024-2030
MW requested deactivation								
Coal	180	1,578	410	0	0	0	0	2,168
Natural Gas	149	886	0	0	0	0	0	1,035
Other	503	579	0	0	0	0	0	1,082
Total MW requested deactivation	833	3,043	410	0	0	0	0	4,285
MW expected to retire for regulatory reasons								
Coal	0	1,493	116	1,760	3,605	0	3,550	10,524
Natural Gas	0	0	0	2,314	0	0	6,247	8,561
Other	103	0	0	0	189	0	259	550
Total MW expected to retire for regulatory reasons	103	1,493	116	4,074	3,794	0	10,056	19,635
Additional MW uneconomic 2024-2026								
Coal								17,725
Natural Gas								14,611
Other								1,438
Total MW uneconomic								33,774
Total								
Coal	180	3,071	526	1,760	3,605	0	3,550	30,417
Natural Gas	149	886	0	2,314	0	0	6,247	24,207
Other	606	579	0	0	189	0	259	3,071
Total MW At Risk of Retirement	935	4,536	526	4,074	3,794	0	10,056	57,694

Retirements and expected retirements

	MW Retired														MW at Risk
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2011-2023	2024-2030
Coal	543	5,908	2,590	2,239	7,065	243	2,038	3,167	4,111	2,132	1,020	5,385	4,380	40,820	27,087
Natural Gas	523	250	82	294	1,319	74	34	1,441	447	233	220	340	1,493	6,748	26,048
Other	131	804	187	437	879	83	41	935	899	891	70	439	855	6,651	3,487
Total MW	1,197	6,962	2,859	2,970	9,263	400	2,113	5,543	5,456	3,255	1,310	6,163	6,728	54,219	56,622

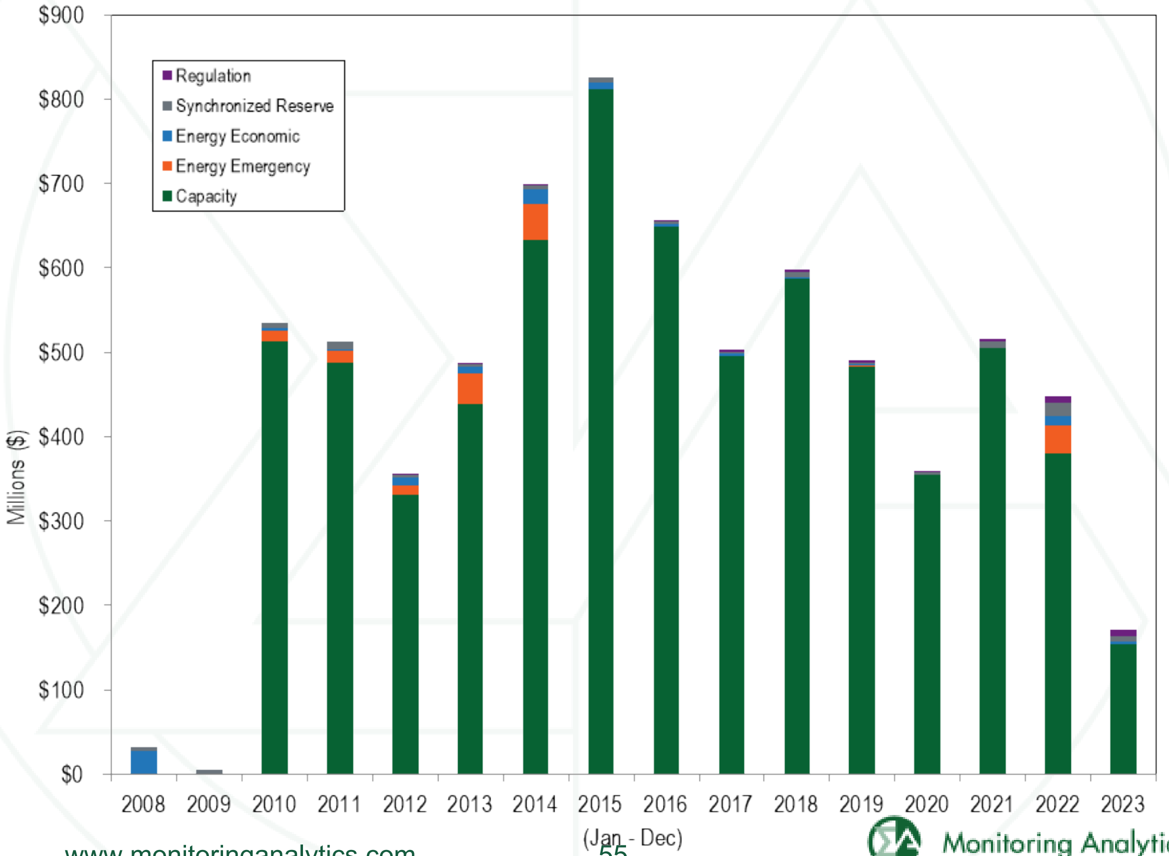
Units at risk of retirement if revenues doubled

MW expected to retire 2024-2030	
MW requested deactivation	4,285
MW expected to retire for regulatory reasons	19,635
MW uneconomic 2024-2026 if total revenues are doubled	
Coal	10,627
Natural Gas	7,428
Other	902
Total MW uneconomic	18,957
Total MW At Risk of Retirement	42,877

Gas pipeline capacity to replace units at risk of retirement

	MW At Risk	
Gas pipeline capacity need to replace units at risk of retirement	57,694	42,877
ICAP		
Coal	30,417	23,319
Natural Gas	24,207	17,024
Other	3,071	2,534
Total	57,694	42,877
New CC unit ICAP (MW)	1,100	1,100
New CC unit heat rate (mmbtu/MWh)	6.543	6.543
Number of new CC units needed to replace coal at risk	28	22
Dth needed to replace all coal at risk (Dth/day)	4,836,586	3,800,174
Bcf needed to replace all coal at risk (Bcf/day)	4.8	3.8
Dth needed to replace half of coal at risk (Dth/day)	2,418,293	1,900,087
Bcf needed to replace half of coal at risk (Bcf/day)	2.4	1.9

Demand response revenue by market



Energy efficiency resources (MW)

Delivery Year	EE RPM Cleared (UCAP MW)	Total RPM Cleared (UCAP MW)	EE Percent Cleared	EE RPM Revenue
2011/2012	76.4	134,139.6	0.1%	$139,812
2012/2013	666.1	141,061.8	0.5%	$11,408,552
2013/2014	904.2	159,830.5	0.6%	$21,598,174
2014/2015	1,077.7	161,092.4	0.7%	$42,308,549
2015/2016	1,189.6	173,487.4	0.7%	$66,652,986
2016/2017	1,723.2	179,749.0	1.0%	$68,709,670
2017/2018	1,922.3	180,590.3	1.1%	$86,147,605
2018/2019	2,296.3	175,957.4	1.3%	$103,105,796
2019/2020	2,528.5	177,040.6	1.4%	$92,569,666
2020/2021	3,569.5	173,688.5	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	7,668.7	147,505.6	5.2%	$117,133,991

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.**

Total energy uplift charges by category

Category	2022 Charges (Millions)	2023 Charges (Millions)	Change (Millions)	Percent Change
Day-Ahead Operating Reserves	$58.8	$49.7	($9.1)	(15.4%)
Balancing Operating Reserves	$223.7	$108.1	($115.6)	(51.7%)
Reactive Services	$1.5	$0.6	($0.9)	(59.7%)
Synchronous Condensing	$0.0	$0.0	$0.0	0.0%
Black Start Services	$0.5	$0.3	($0.2)	(34.3%)
Total	$284.5	$158.7	($125.7)	(44.2%)
Energy Uplift as a Percent of Total PJM Billing	0.3%	0.3%	(0.0%)	(1.0%)

Total energy uplift charges by unit type

Unit Type	2022 Credits (Millions)	2023 Credits (Millions)	Change	Percent Change	2022 Share	2023 Share
Combined Cycle	$29.8	$5.3	($24.5)	(82.2%)	10.5%	3.3%
Combustion Turbine	$172.7	$92.8	($79.9)	(46.3%)	60.7%	58.4%
Diesel	$3.1	$2.9	($0.2)	(7.4%)	1.1%	1.8%
Hydro	$8.3	$0.2	($8.1)	(97.6%)	2.9%	0.1%
Nuclear	$0.0	$0.0	($0.0)	(51.6%)	0.0%	0.0%
Solar	$0.1	$0.1	($0.0)	(17.6%)	0.0%	0.0%
Steam - Coal	$35.1	$36.1	$0.9	2.7%	12.3%	22.7%
Steam - Other	$32.6	$19.8	($12.8)	(39.2%)	11.5%	12.5%
Wind	$2.7	$1.6	($1.1)	(40.5%)	1.0%	1.0%
Total	$284.5	$158.7	($125.7)	(44.2%)	100.0%	100.0%

Recommendations: Energy Market Uplift

- PJM should ensure that units not following dispatch are not paid uplift.
- CTs should not be defined to be always following dispatch. (Adopted 2022)
- Flexible operating parameters should be required as a condition for receiving uplift.
- Uplift should not be paid to units backed down for reliability because there is no lost opportunity.
- Uplift should not be paid to units based on a fuel they are not burning.

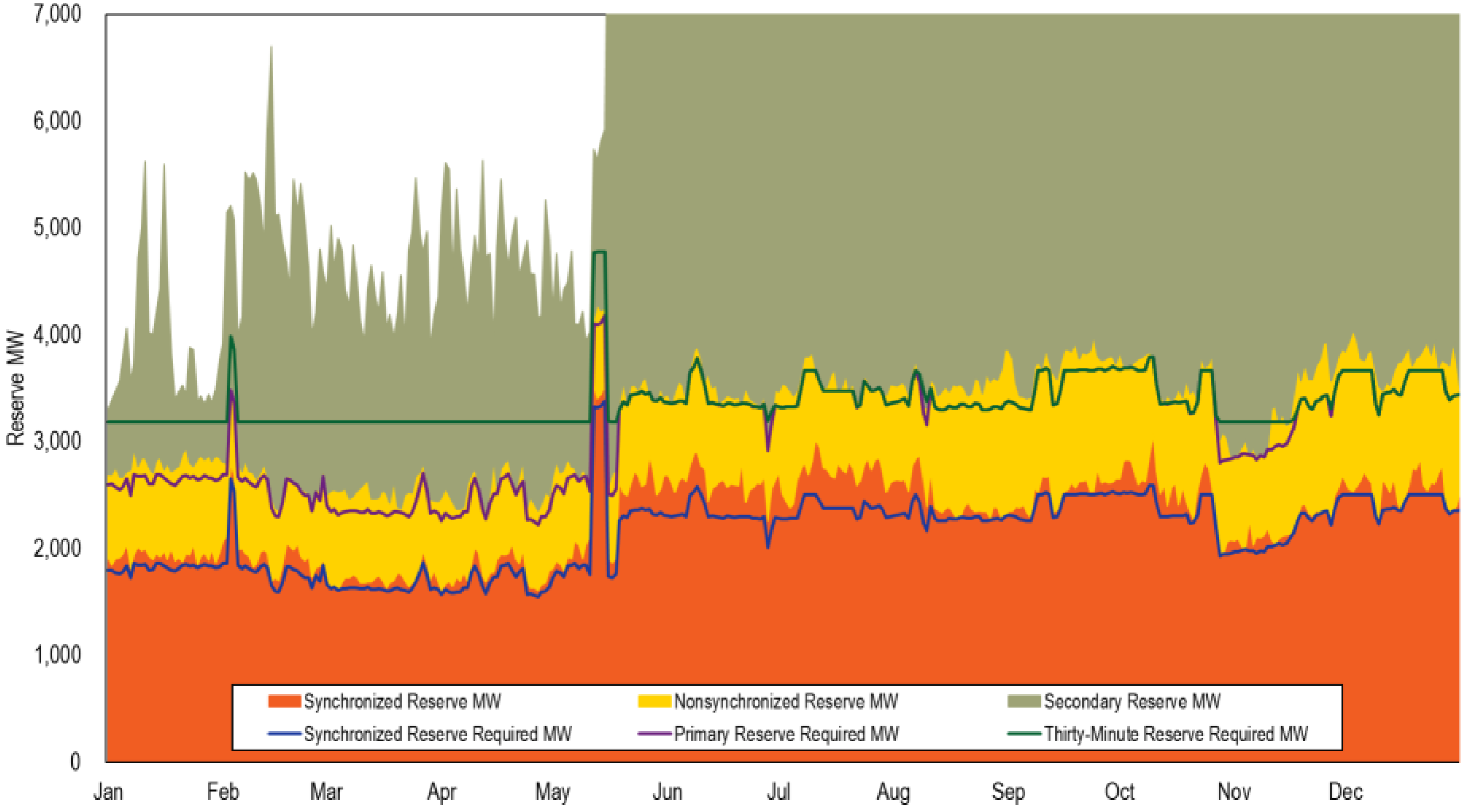
The regulation market results were not competitive

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

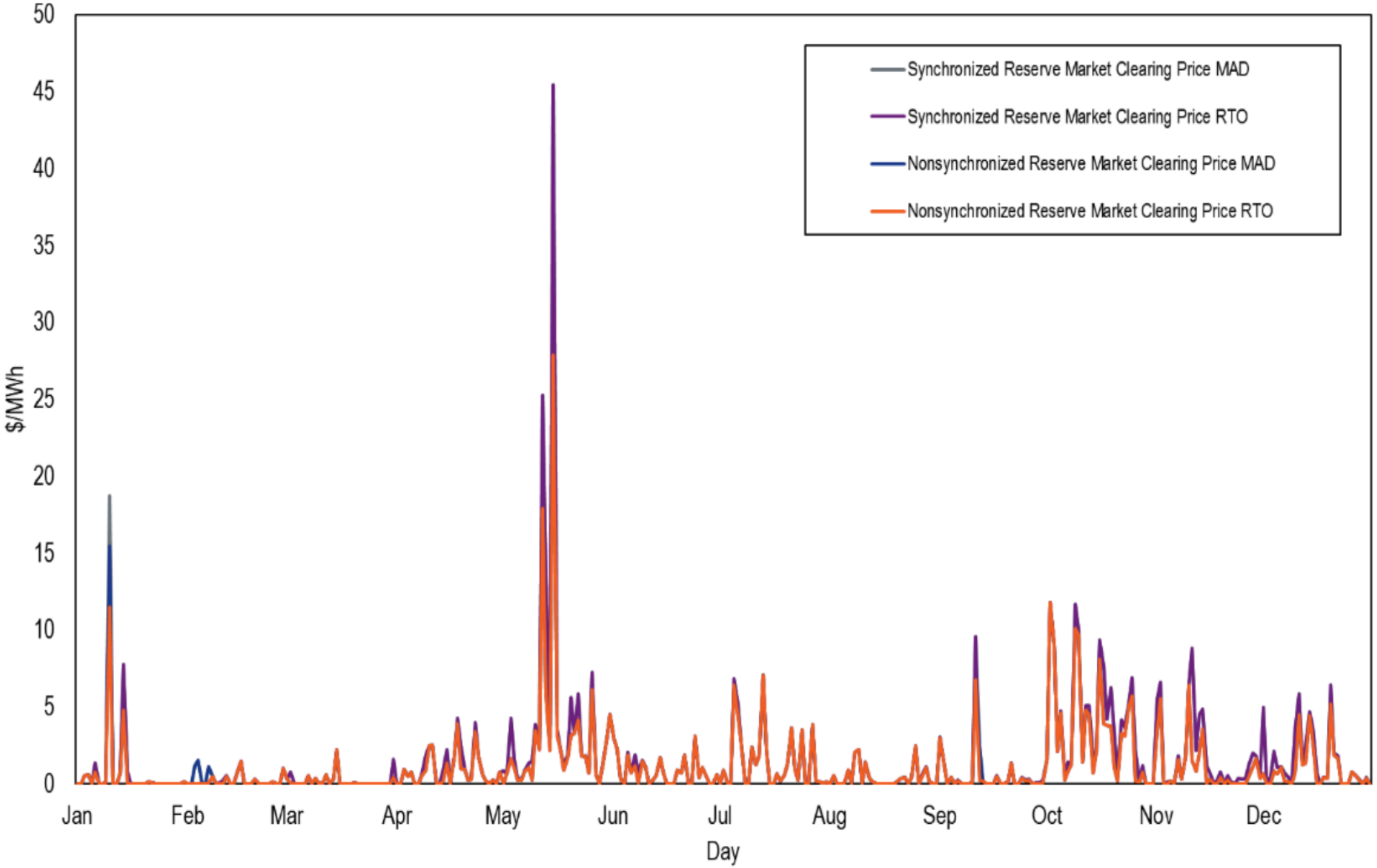
The synchronized reserve market results were competitive

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

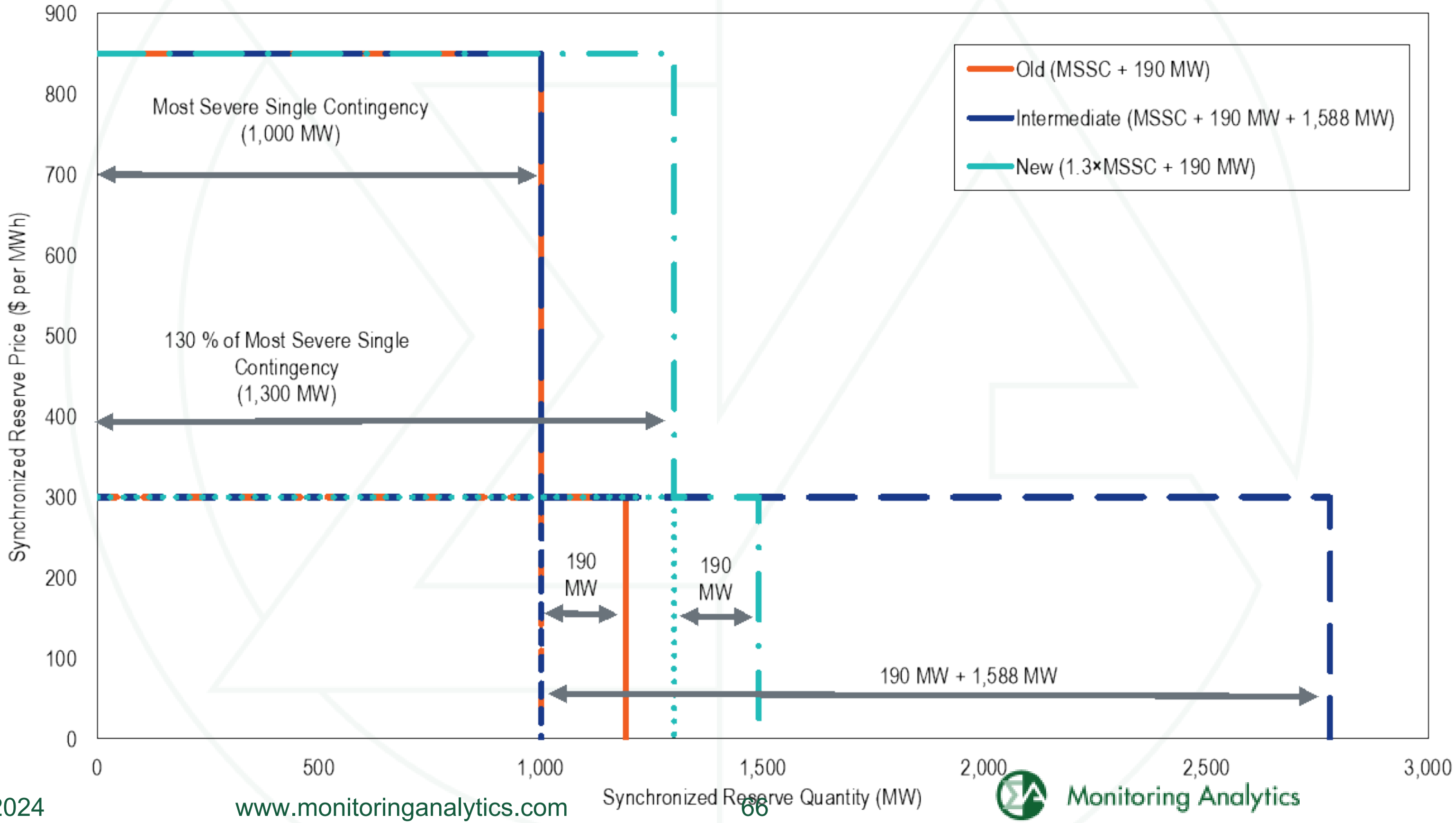
Daily average real-time reserves



Daily Average Reserve Prices



Example: old, intermediate, and new ORDCs



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.
- The MMU recommends that, for calculating the penalty for a synchronized reserve resource failing to meet its scheduled obligation during a spinning event, the unit repay all credits back to the last time that the unit successfully responded to an event 10 minutes or longer.

Excess black start capital recovery payments

	Capital Recovery Payments 2018 - 2040 ($ millions)	Overpayment ($ millions)
Had CRFs been updated on January 1, 2018	$428.7	
Current CRFs remain in place	$518.4	$89.7
Updated CRFs beginning July 1, 2024	$433.6	$4.9
Updated CRFs beginning January 1, 2025	$452.3	$23.6
Updated CRFs beginning January 1, 2026	$468.6	$39.9

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	$66,946,135	$313,527	$67,259,662

Reactive charges

Year	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	$388,044,837	$388,654,774

Recommendations: Ancillary Services

- The regulation market should be modified to incorporate a consistent application of the marginal benefit factor (MBF) throughout the optimization, assignment and settlement process.
- LOC should be based on actual unit ramp rates. Current LOC overstated significantly.
- Separate cost of service payments for reactive capability should be eliminated and the cost of reactive capability recovered in the capacity market.
- New CRF rates for black start units, incorporating current tax code changes, should be implemented immediately for all black start units.

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**

Recommendations: FTR/ARR

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

ARR and self scheduled FTR total congestion offset (in millions) for ARR holders

				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*	$527.4	$202.0	$913.0	($183.2)	$729.9	($30.7)	$5.5	$27.7	$698.7	95.7%	$551.7	75.6%	$573.9	78.6%	$573.9	78.6%
Total	$6,885.8	$3,858.9	$16,643.8	($3,411.7)	$13,232.1	($437.2)	$380.6	$1,796.2	$10,307.6	77.9%	$7,713.7	58.3%	$9,129.3	69.0%	$9,257.4	70.0%

*First seven months of 2023/2024

Zonal ARR/FTR total congestion offset

Zone	ARR Credits	Adjusted FTR Credits	Balancing+ M2M Charge	Surplus Allocation	Total Offset	Day Ahead Congestion	Balancing Congestion	M2M Payments	Total Congestion	Offset
ACEC	$2.8	$0.0	($2.27)	$0.08	$0.7	$8.5	($2.0)	($0.2)	$6.3	10.5%
AEP	$55.4	$16.6	($27.6)	$3.1	$47.5	$137.6	($24.9)	($2.8)	$110.0	43.1%
APS	$33.3	$14.5	($12.2)	$1.5	$37.1	$59.0	($11.2)	($1.0)	$46.8	79.3%
ATSI	$29.0	$0.4	($14.2)	$0.9	$16.1	$66.6	($12.8)	($1.4)	$52.4	30.7%
BGE	$72.6	$22.5	($7.1)	$2.5	$90.5	$34.4	($6.4)	($0.7)	$27.3	331.2%
COMED	$26.3	($0.0)	($18.3)	$0.8	$8.7	$142.7	($16.3)	($2.0)	$124.4	7.0%
DAY	$7.0	$0.4	($3.7)	$0.2	$3.9	$17.1	($3.4)	($0.4)	$13.4	29.2%
DOM	$67.9	$112.9	($29.2)	$0.9	$152.6	$134.1	($26.5)	($2.6)	$104.9	145.4%
DPL	$33.4	$15.0	($5.0)	$0.1	$43.6	$41.8	($4.6)	($0.4)	$36.8	118.5%
DUKE	$26.7	$0.9	($5.8)	$11.1	$32.9	$28.0	($5.2)	($0.6)	$22.3	147.8%
DUQ	$5.0	$0.2	($3.0)	$1.2	$3.4	$12.4	($2.7)	($0.3)	$9.4	36.2%
EKPC	$3.8	$0.0	($3.0)	$0.1	$0.9	$14.6	($2.7)	($0.3)	$11.6	7.5%
EXT	$0.9	$0.0	($5.2)	$0.0	($4.3)	$17.6	($5.2)	$0.0	$12.4	(34.8%)
JCPLC	$2.7	$0.0	($6.0)	$0.1	($3.2)	$24.3	($5.5)	($0.5)	$18.3	(17.5%)
MEC	$18.9	$0.4	($3.7)	$0.6	$16.3	$15.5	($3.4)	($0.3)	$11.8	137.4%
OVEC	($0.0)	$0.0	($0.2)	$0.0	($0.2)	$1.5	($0.2)	($0.0)	$1.3	(18.0%)
PE	$9.8	$7.3	($3.5)	$0.4	$14.0	$18.7	($3.1)	($0.4)	$15.2	91.6%
PECO	$9.3	$6.1	($8.3)	$0.4	$7.5	$31.8	($7.5)	($0.8)	$23.5	32.1%
PEPCO	$34.6	$4.2	($6.5)	$1.1	$33.3	$30.0	($5.9)	($0.6)	$23.4	142.4%
PPL	$45.6	$0.4	($8.5)	$1.4	$38.9	$39.0	($7.6)	($0.9)	$30.5	127.8%
PSEG	$40.5	$0.0	($9.4)	$1.2	$32.3	$35.9	($8.4)	($1.0)	$26.5	121.8%
REC	$1.6	$0.0	($0.3)	$0.0	$1.3	$1.5	($0.3)	($0.0)	$1.2	110.4%
Total	$527.2	$202.0	($183.2)	$27.7	$573.7	$912.7	($165.9)	($17.3)	$729.5	78.6%

Offset available to load if all ARRs self scheduled

	21/22 Planning Period					22/23 Planning Period					23/24 Planning Period				
	SS FTR	Residual ARR Credits	Bal+M2M Charges	Congestion +M2M	Offset	SS FTR	Residual ARR Credits	Bal+M2M Charges	Congestion +M2M	Offset	SS FTR	Residual ARR Credits	Bal+M2M Charges	Congestion +M2M	Offset
ACEC	$0.4	$0.1	($5.2)	$14.8	(31.4%)	$3.0	$0.0	($6.2)	$16.3	(19.6%)	$3.5	$0.0	($2.3)	$6.3	19.2%
AEP	$132.5	$0.5	($65.7)	$240.4	28.0%	$208.7	$1.0	($79.3)	$274.1	47.6%	$33.8	$0.4	($27.6)	$110.0	6.0%
APS	$93.3	$1.6	($29.7)	$122.8	53.1%	$70.4	$7.9	($31.4)	$105.8	44.3%	$45.8	$0.0	($12.2)	$46.8	71.8%
ATSI	$47.3	$0.0	($32.3)	$117.9	12.7%	$84.8	$0.7	($40.7)	$133.1	33.7%	$55.2	$0.0	($14.2)	$52.4	78.3%
BGE	$147.0	$0.1	($17.0)	$59.9	217.3%	$194.0	$0.0	($19.4)	$68.4	255.2%	$140.5	$0.0	($7.1)	$27.3	487.8%
COMED	$51.9	$0.2	($44.7)	$159.9	4.6%	$31.1	$0.5	($56.2)	$182.5	(13.5%)	$33.9	$0.0	($18.3)	$124.4	12.5%
DAY	$7.1	$0.2	($8.6)	$26.2	(4.7%)	$11.4	$0.0	($10.8)	$32.4	1.8%	$3.5	$0.0	($3.7)	$13.4	(1.7%)
DOM	$556.6	$11.5	($22.0)	$370.9	147.3%	$663.2	$19.2	($85.5)	$270.1	221.0%	$154.2	$0.3	($29.2)	$104.9	119.5%
DPL	$52.3	$2.9	($80.3)	($21.1)	119.3%	$56.2	$1.0	($13.7)	$64.6	67.3%	$83.7	$0.0	($5.0)	$36.8	213.9%
DUKE	$50.8	$0.7	($12.3)	$23.7	165.4%	$81.4	$0.0	($16.9)	$51.7	124.7%	$37.0	$0.0	($5.8)	$22.3	140.6%
DUQ	$7.0	$0.0	($6.4)	$45.3	1.2%	$15.0	$0.0	($8.3)	$18.5	36.5%	$15.1	$0.0	($3.0)	$9.4	128.9%
EKPC	$10.1	$0.0	($7.0)	$21.9	14.2%	$13.0	$0.0	($8.4)	$27.2	17.3%	$6.1	$0.0	($3.0)	$11.6	26.8%
EXT	$1.9	$0.0	($9.9)	$19.9	(40.0%)	NA	$0.0	($12.7)	$28.9	(43.8%)	$0.7	$0.0	($5.2)	$12.4	(36.7%)
JCPLC	$4.4	$0.0	($12.8)	$39.0	(21.7%)	$5.3	$0.0	($16.3)	$53.0	(20.8%)	$4.5	$0.0	($6.0)	$18.3	(8.1%)
MEC	$31.3	$0.0	($11.6)	$33.2	59.5%	$46.5	$0.0	($11.2)	$32.4	108.7%	($2.1)	$0.0	($3.7)	$11.8	(49.1%)
OVEC	NA	$0.0	($0.4)	$1.5	(29.4%)	NA	$0.0	($0.5)	$3.3	(15.4%)	($0.0)	$0.0	($0.2)	$1.3	(16.8%)
PE	$29.7	$0.1	($18.5)	$31.8	35.5%	$20.5	$0.2	($10.8)	$35.3	28.3%	$26.2	$0.0	($3.5)	$15.2	149.1%
PECO	$6.2	$0.8	($12.0)	$78.0	(6.5%)	$6.8	$0.0	($24.0)	$74.9	(22.8%)	$20.0	$0.0	($8.3)	$23.5	49.5%
PEPCO	$59.2	$0.0	($15.5)	$53.8	81.2%	$95.2	$0.0	($17.9)	$61.0	126.7%	$47.7	$0.0	($6.5)	$23.4	175.6%
PPL	$160.3	$0.0	($21.5)	$103.3	134.4%	$117.4	$0.0	($28.2)	$83.7	106.4%	$17.2	$0.0	($8.5)	$30.5	28.6%
PSEG	$94.0	$0.2	($23.1)	$76.0	93.4%	$48.7	$0.4	($27.1)	$75.4	29.1%	$31.2	$0.0	($9.4)	$26.5	82.2%
REC	$1.1	$0.0	($0.8)	$5.3	6.2%	$0.8	$0.0	($0.9)	$4.5	(4.2%)	$1.6	$0.0	($0.3)	$1.2	109.2%
Total	$1,544.3	$18.8	($457.4)	$1,624.6	68.1%	$1,773.4	$31.0	($526.4)	$1,697.1	75.3%	$759.2	$0.8	($183.2)	$729.5	79.1%

* First seven months of the 2023/2024 planning period

Monitoring Analytics

FTR profits and revenues by organization type and FTR direction: June through December, 2023/2024

	Purchased FTRs Profit			Self Scheduled FTRs Revenue Returned		
Organization Type	Prevailing Flow	Counter Flow	Total	Prevailing Flow	Counter Flow	Total
Financial	$116,811,316	($3,389,083)	$113,422,233			
Physical	$42,639,245	($19,143,736)	$23,495,509			
Physical ARR	$87,786,938	($56,945,358)	$30,841,580	$201,999,285	($7,893)	$201,991,393
Total	$247,237,500	($79,478,177)	$167,759,323	$201,999,285	($7,893)	$201,991,393

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