2020 State of the Market Report for PJM

Members Committee Briefing

March 29, 2021

IMM

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
- FERC has enforcement authority
- Relevant model of competition is not laissez faire
- Competitive outcomes are not automatic
- Detailed rules required
- Detailed monitoring required:
  - Of participants
  - Of RTO
  - Of rules

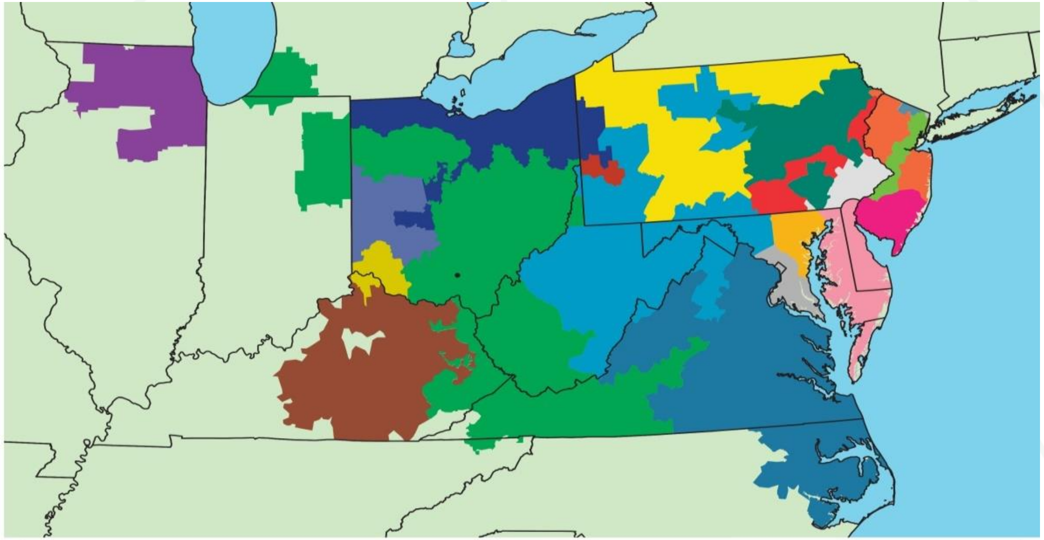
Role of Market Monitoring

- Market monitoring is primarily analytical
  - Adequacy of market rules
  - Compliance with market rules
  - Exercise of market power
  - Market manipulation
- 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 actual or potential design flaws in rules
- Monitor structural problems in the PJM market
- Monitor the potential of market participants to exercise market power
- Monitor for market manipulation

PJM



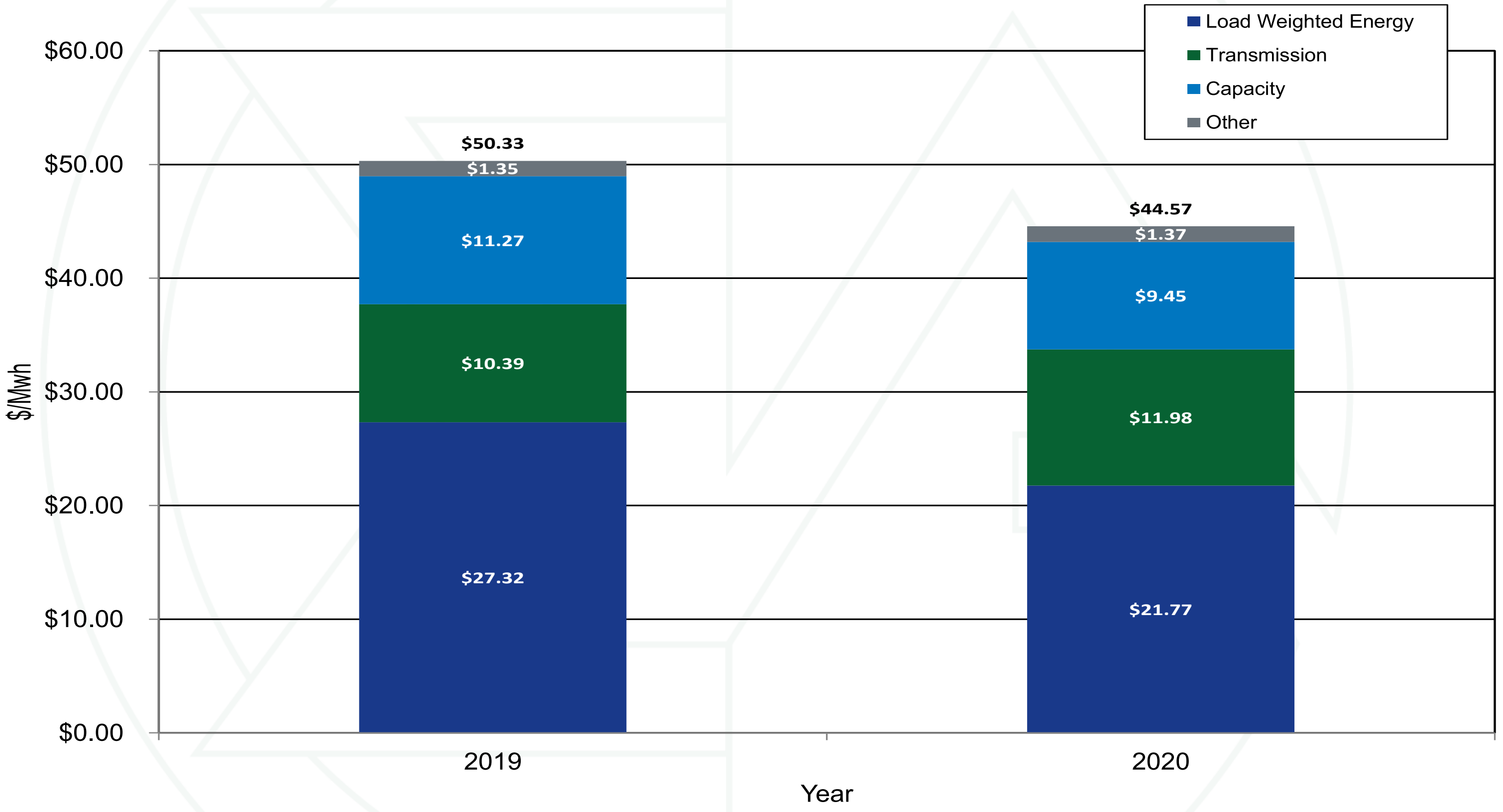
Legend

Allegheny Power Company (APS)	Duquesne Light (DLCO)
American Electric Power Co., Inc (AEP)	Eastern Kentucky Power Cooperative (EKPC)
American Transmission Systems, Inc. (ATSI)	Jersey Central Power and Light Company (JCPL)
Atlantic Electric Company (AECO)	Metropolitan Edison Company (Met-Ed)
Baltimore Gas and Electric Company (BGE)	Ohio Valley Electric Corporation (OVEC)
ComEd	PECO Energy (PECO)
Dayton Power and Light Company (DAY)	Pennsylvania Electric Company (PENELEC)
Delmarva Power and Light (DPL)	Pepco
Dominion	PPL Electric Utilities (PPL)
Duke Energy Ohio/Kentucky (DEOK)	Public Service Electric and Gas Company (PSEG)
	Rockland Electric Company (RECO)

PJM summary statistics

	2019	2020	Percent Change
Average Hourly Load Plus Exports (MW)	92,920	90,059	(3.1%)
Average Hourly Generation Plus Imports (MW)	94,618	91,681	(3.1%)
Peak Load (MW)	148,228	141,449	(4.6%)
Installed Capacity at December 31 (MW)	184,744	184,237	(0.3%)
Load Weighted Average Real Time LMP ($/MWh)	$27.32	$21.77	(20.3%)
Total Congestion Costs ($ Million)	$583.3	$528.6	(9.4%)
Total Uplift Credits ($ Million)	$88.5	$90.9	2.7%
Total PJM Billing ($ Billion)	$39.20	$33.64	(14.2%)

Total price of wholesale power



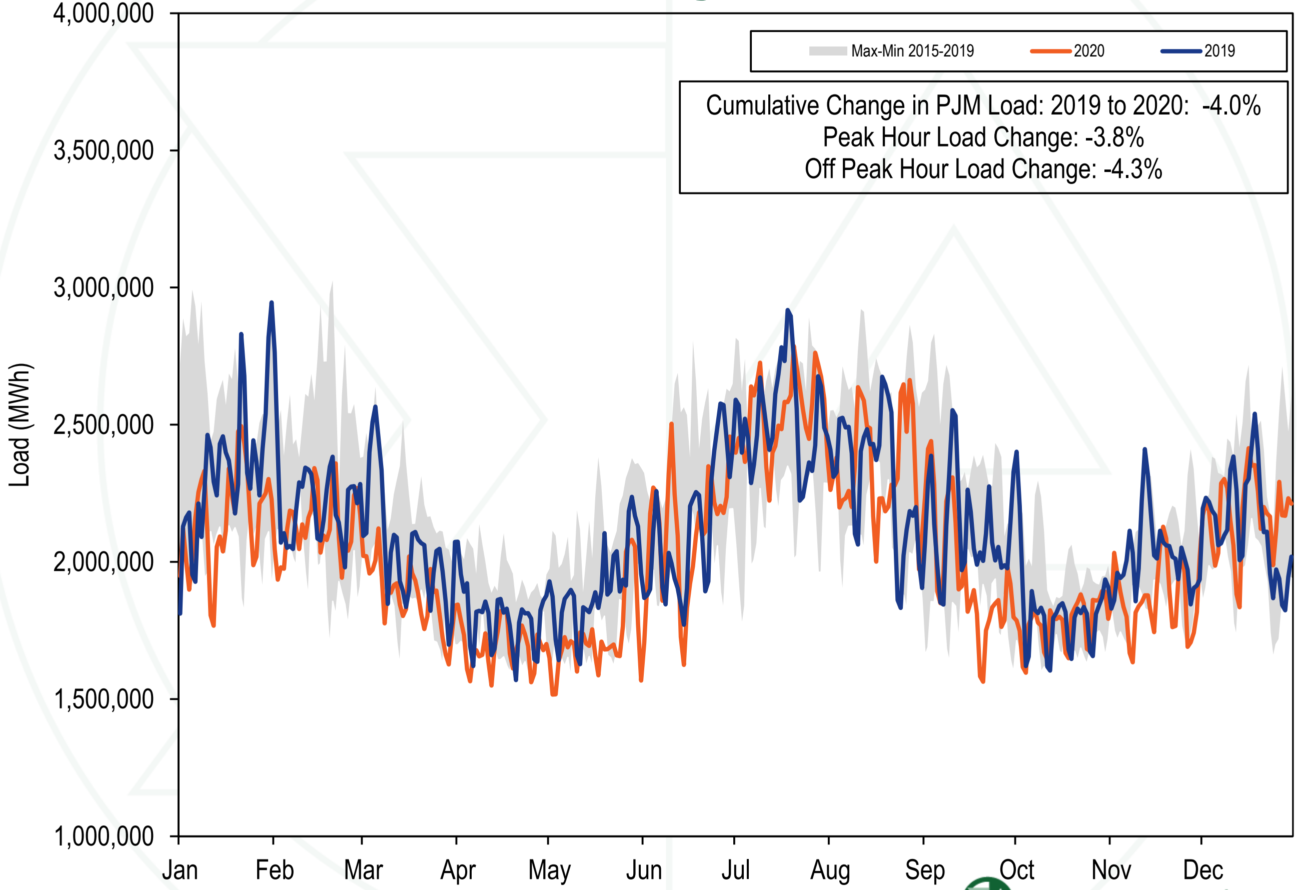
The energy market results were competitive

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

Recommendations: Energy Market

- The must offer requirement should be enforced.
- Fuel cost policies should be verifiable and enforceable.
- All resources should be required to follow their fuel cost policies at all times.
- The loopholes in offer capping implementation should be closed.
- Virtual bidding should be eliminated at nodes that aggregate only small portions of the transmission system.

RT daily load



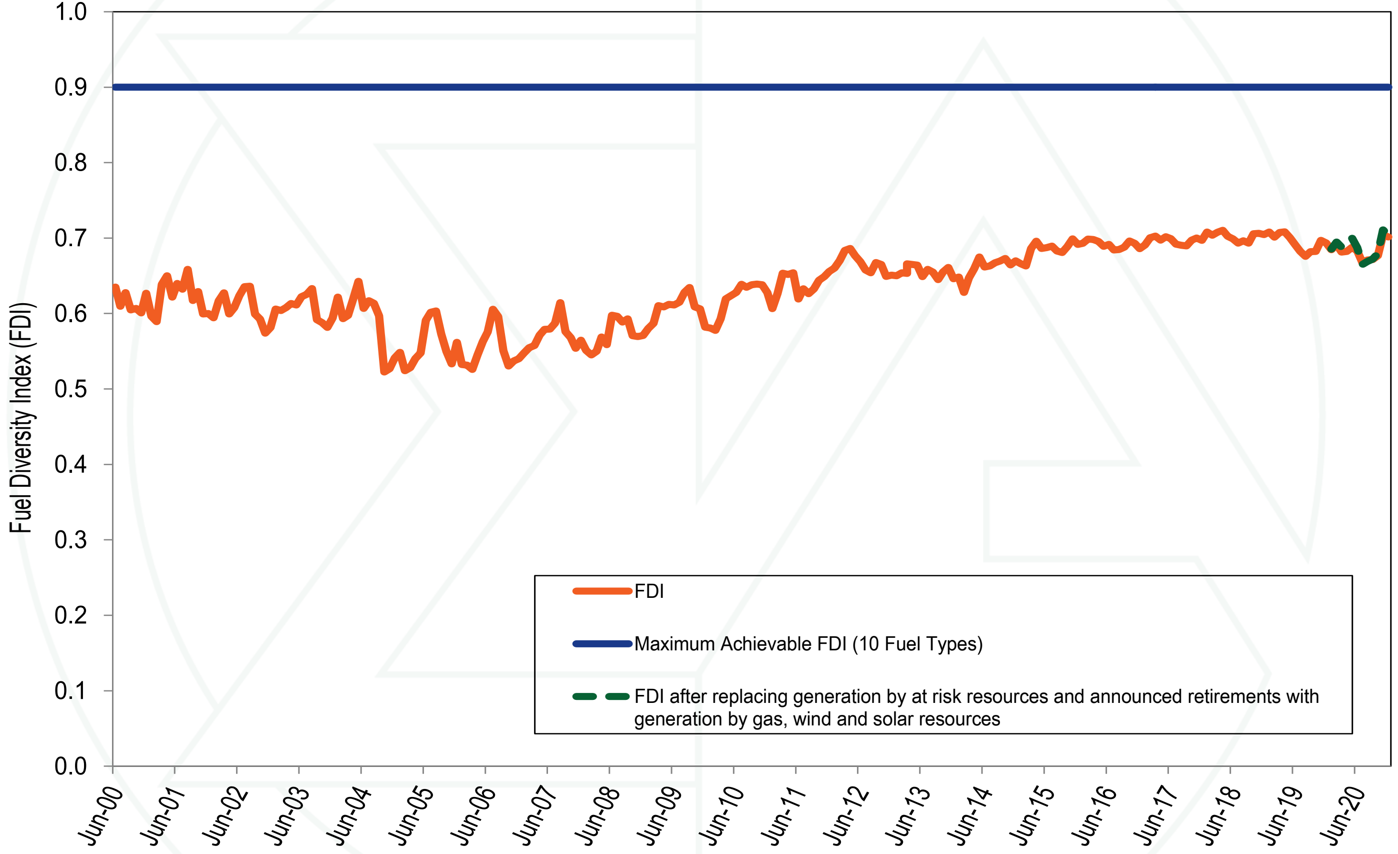
RT load and RT load plus exports

	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%

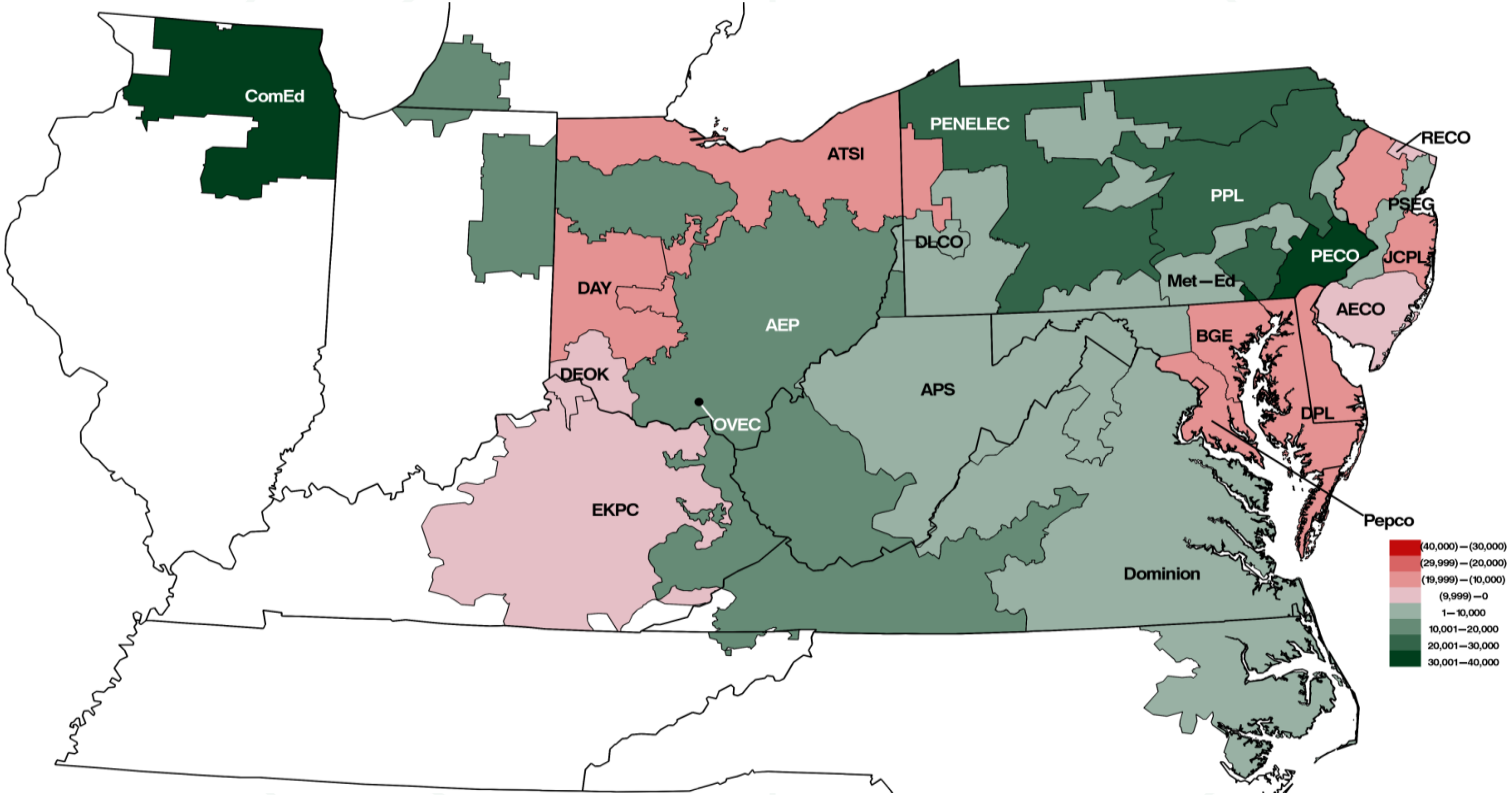
Generation by fuel source

		2019 GWh	Percent	2020 GWh	Percent	Change in Output
Coal		197,165.3	23.8%	156,575.9	19.3%	(20.6%)
	Bituminous	169,958.4	20.5%	143,556.3	17.7%	(15.5%)
	Sub Bituminous	20,981.7	2.5%	7,726.0	1.0%	(63.2%)
	Other Coal	6,225.2	0.8%	5,293.7	0.7%	(15.0%)
Nuclear		278,911.8	33.6%	276,607.6	34.2%	(0.8%)
Gas		302,116.9	36.4%	322,504.5	39.8%	6.7%
	Natural Gas CC	278,218.4	33.6%	294,712.8	36.4%	5.9%
	Natural Gas CT	15,955.2	1.9%	18,825.6	2.3%	18.0%
	Natural Gas Other Units	5,793.3	0.7%	7,019.2	0.9%	21.2%
	Other Gas	2,150.1	0.3%	1,946.9	0.2%	(9.4%)
Hydroelectric		16,696.7	2.0%	16,423.3	2.0%	(1.6%)
	Pumped Storage	4,642.9	0.6%	4,950.4	0.6%	6.6%
	Run of River	10,728.7	1.3%	10,036.7	1.2%	(6.5%)
	Other Hydro	1,325.1	0.2%	1,436.2	0.2%	8.4%
Wind		24,167.1	2.9%	26,460.7	3.3%	9.5%
Waste		4,237.3	0.5%	4,423.1	0.5%	4.4%
Oil		1,787.9	0.2%	2,054.8	0.3%	14.9%
	Heavy Oil	102.9	0.0%	86.0	0.0%	(16.4%)
	Light Oil	271.9	0.0%	282.2	0.0%	3.8%
	Diesel	71.7	0.0%	30.1	0.0%	(58.0%)
	Other Oil	1,341.4	0.2%	1,656.4	0.2%	23.5%
Solar, Net Energy Metering		2,780.6	0.3%	3,842.1	0.5%	38.2%
Battery		18.8	0.0%	36.1	0.0%	92.0%
Biofuel		1,279.6	0.2%	914.3	0.1%	(28.5%)
Total		829,162.0	100.0%	809,842.4	100.0%	(2.3%)

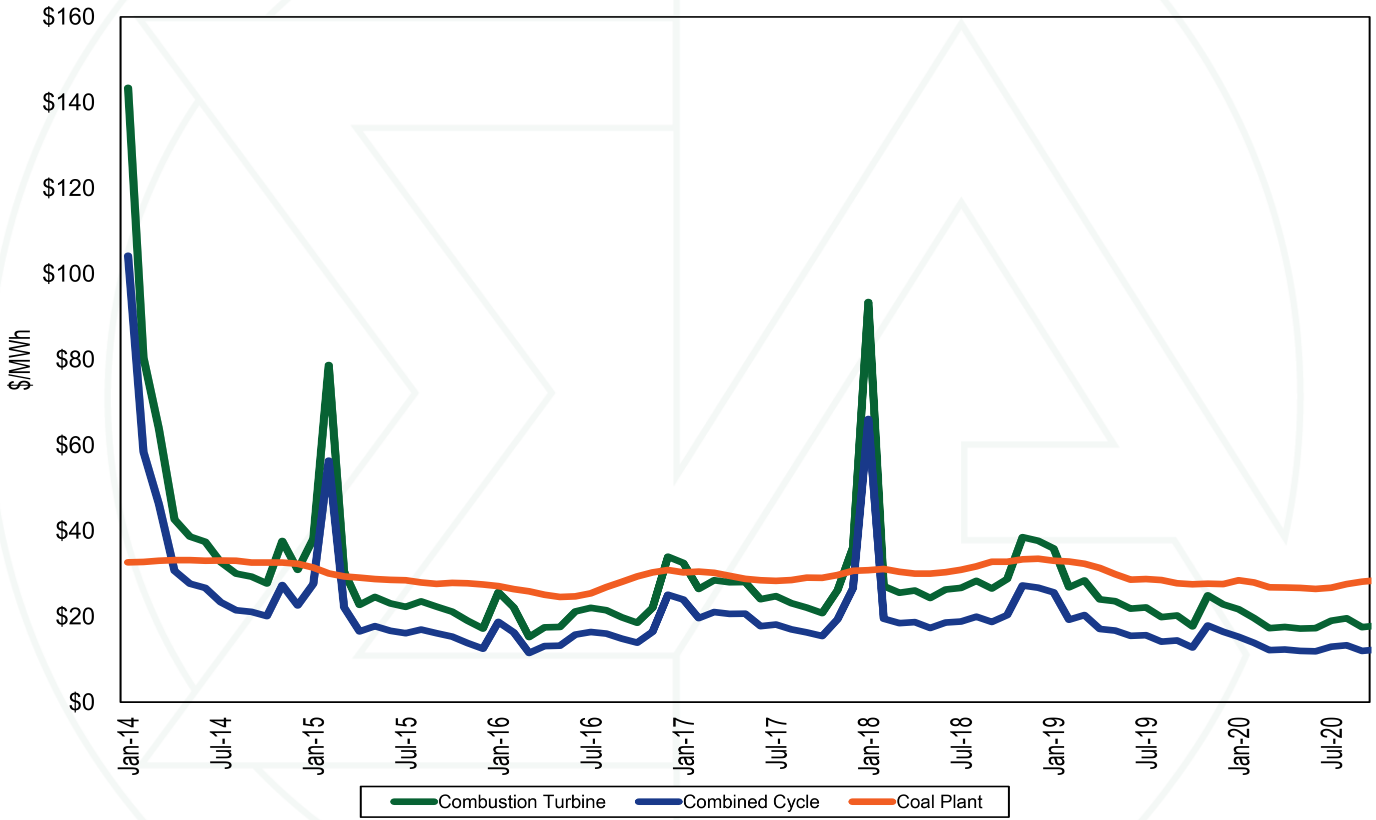
Fuel diversity index: energy



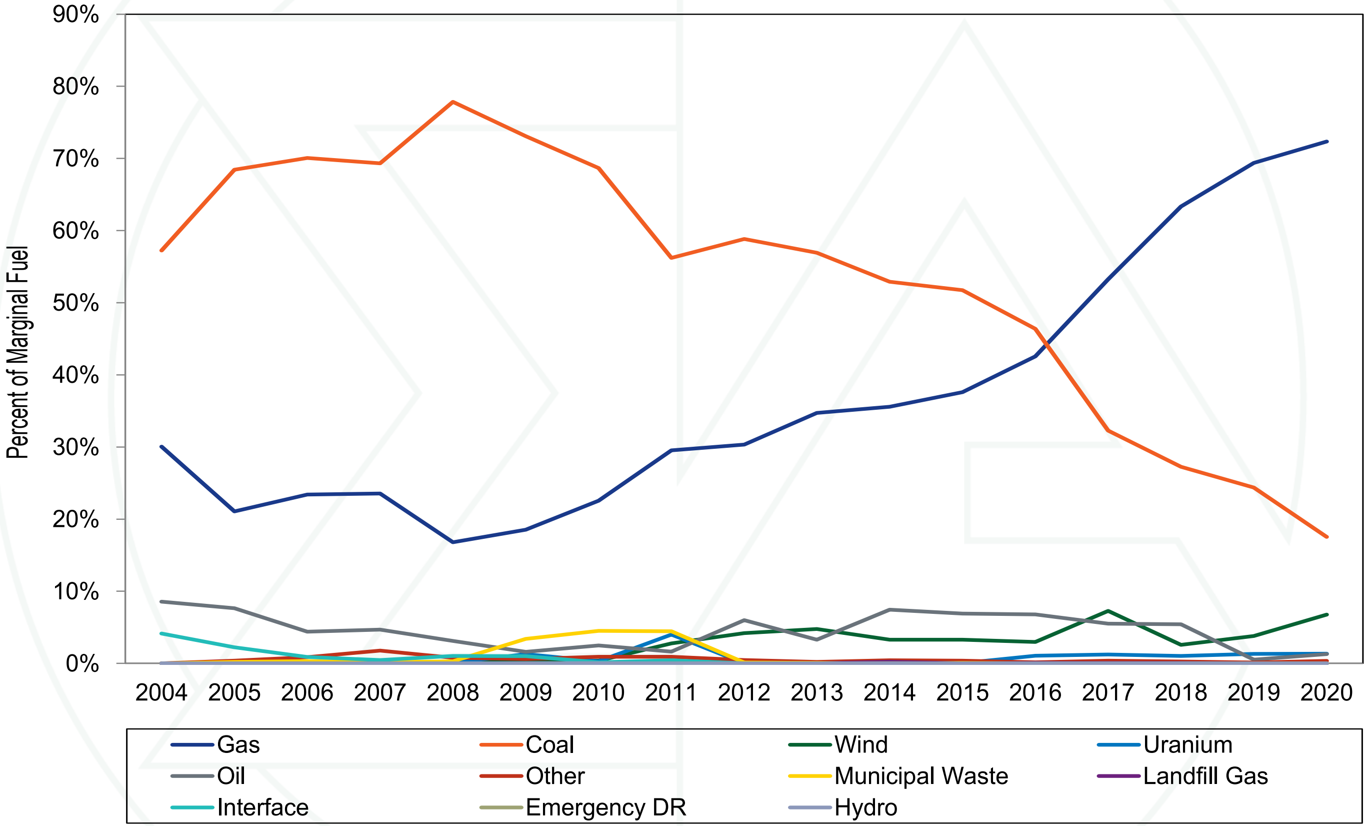
RT generation less RT load



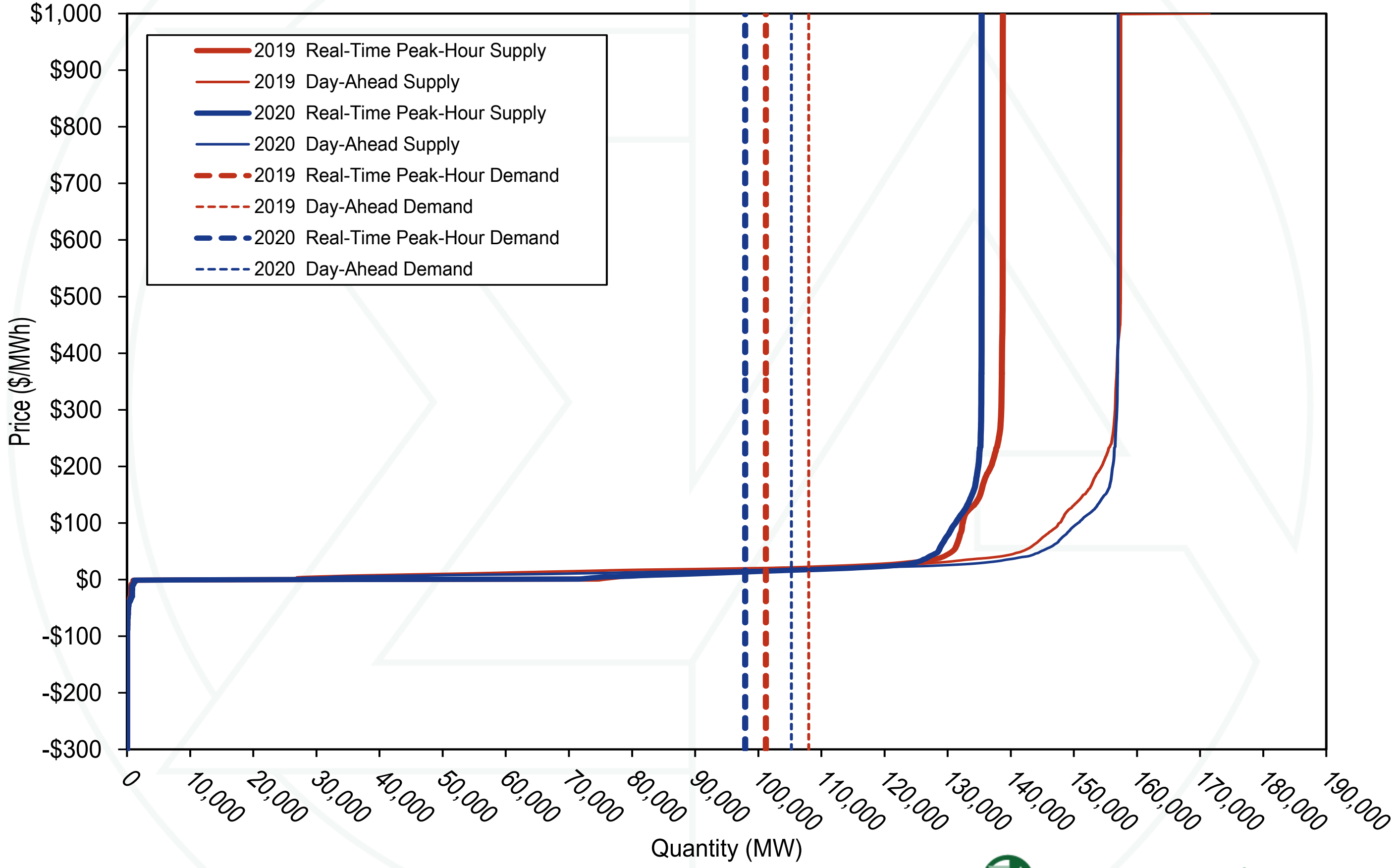
Average short run marginal costs



Type of fuel used by RT marginal units

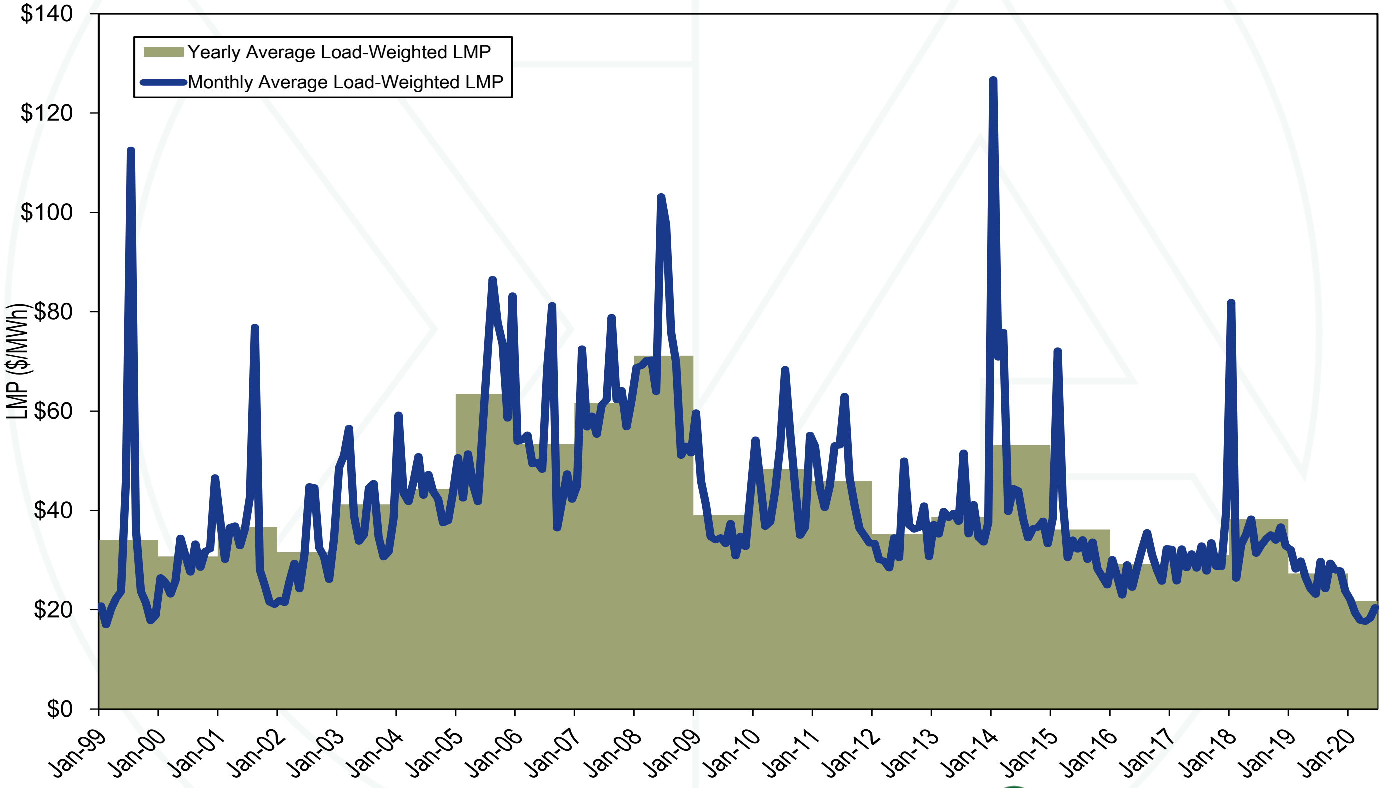


Hourly RT and aggregate DA supply curve

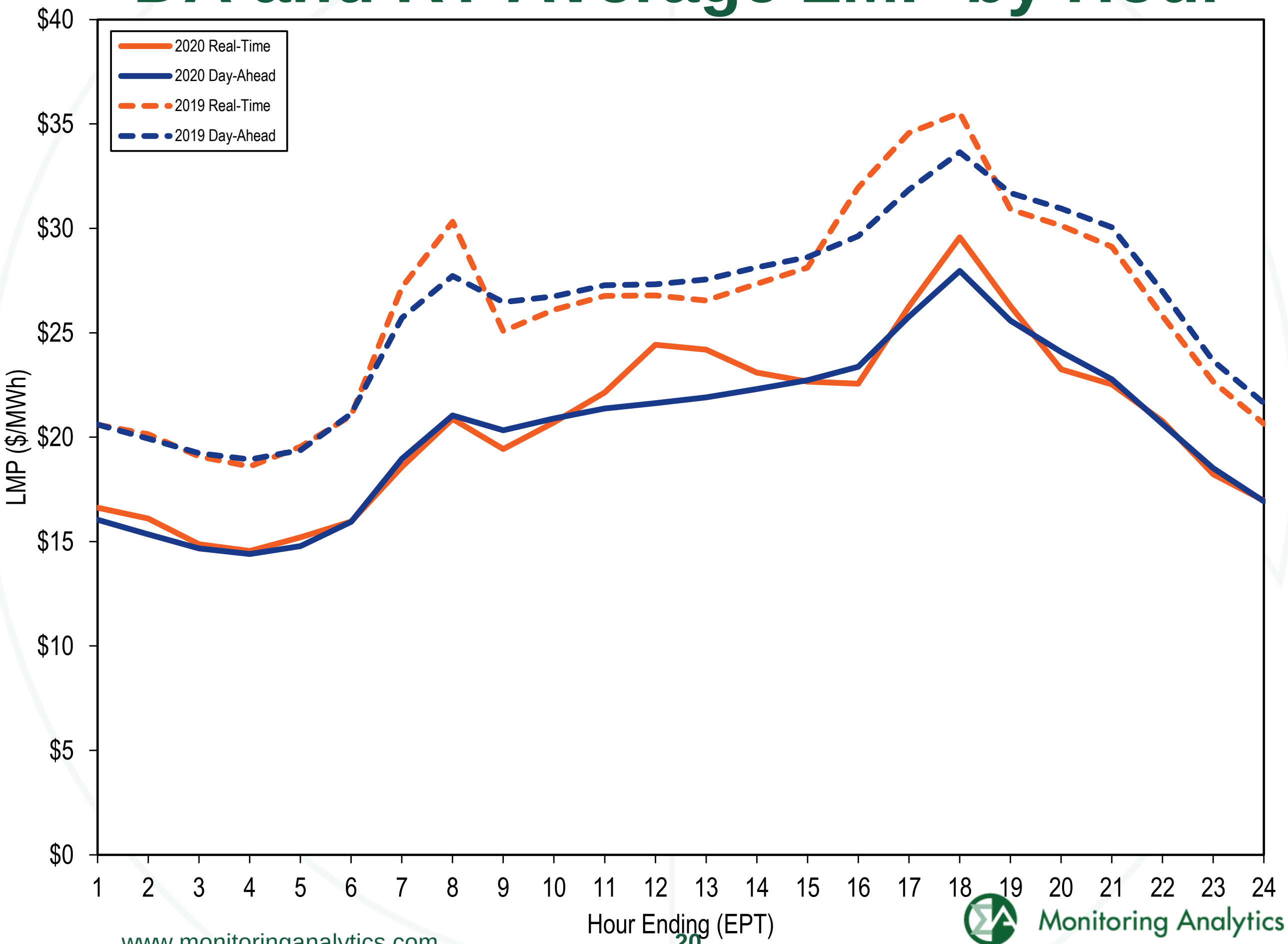


Monitoring Analytics

RT, monthly and annual, load-weighted, average LMP



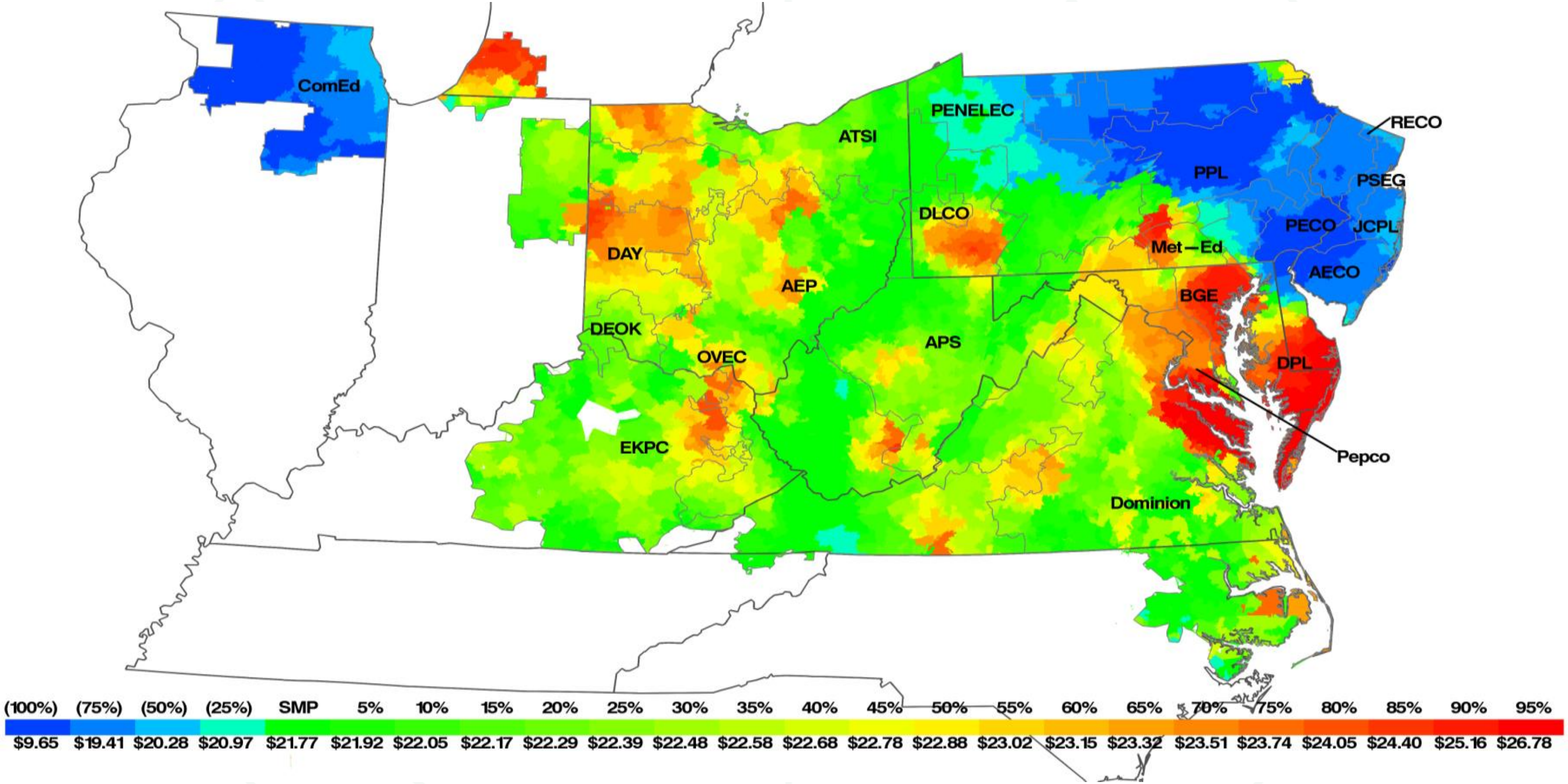
DA and RT Average LMP by Hour



RT, load-weighted, average LMP

	Real-Time, Load-Weighted, Average LMP			Year to Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$24.16	$17.60	$39.29	NA	NA	NA
1999	$34.07	$19.02	$91.49	41.0%	8.1%	132.8%
2000	$30.72	$20.51	$28.38	(9.8%)	7.9%	(69.0%)
2001	$36.65	$25.08	$57.26	19.3%	22.3%	101.8%
2002	$31.60	$23.40	$26.75	(13.8%)	(6.7%)	(53.3%)
2003	$41.23	$34.96	$25.40	30.5%	49.4%	(5.0%)
2004	$44.34	$40.16	$21.25	7.5%	14.9%	(16.3%)
2005	$63.46	$52.93	$38.10	43.1%	31.8%	79.3%
2006	$53.35	$44.40	$37.81	(15.9%)	(16.1%)	(0.7%)
2007	$61.66	$54.66	$36.94	15.6%	23.1%	(2.3%)
2008	$71.13	$59.54	$40.97	15.4%	8.9%	10.9%
2009	$39.05	$34.23	$18.21	(45.1%)	(42.5%)	(55.6%)
2010	$48.35	$39.13	$28.90	23.8%	14.3%	58.7%
2011	$45.94	$36.54	$33.47	(5.0%)	(6.6%)	15.8%
2012	$35.23	$30.43	$23.66	(23.3%)	(16.7%)	(29.3%)
2013	$38.66	$33.25	$23.78	9.7%	9.3%	0.5%
2014	$53.14	$36.20	$76.20	37.4%	8.9%	220.4%
2015	$36.16	$27.66	$31.06	(31.9%)	(23.6%)	(59.2%)
2016	$29.23	$25.01	$16.12	(19.2%)	(9.6%)	(48.1%)
2017	$30.99	$26.35	$19.32	6.0%	5.4%	19.9%
2018	$38.24	$29.55	$32.89	23.4%	12.1%	70.2%
2019	$27.32	$23.63	$23.12	(28.6%)	(20.0%)	(29.7%)
2020	$21.77	$19.07	$12.50	(20.3%)	(19.3%)	(45.9%)

RT, load-weighted, average LMP



Shortage Pricing Scenarios

A. **Marginal unit marginal cost is $50 per MWh.**
   One reserve product short in RTO zone.
   No violated transmission constraints.

B. **Marginal unit marginal cost is $50 per MWh.**
   All reserve products are short.
   No violated transmission constraints.

C. **Marginal unit marginal cost is $50 per MWh.**
   All reserve products are short.
   One violated transmission constraint.

Shortage Pricing Scenarios

D. **Marginal unit marginal cost is $1,000 per MWh.**
All reserve products are short.
One violated transmission constraint.

E. **Marginal unit marginal cost is $2,000 per MWh.**
All reserve products are short.
One violated transmission constraint.

Shortage Pricing Scenarios, Status Quo

Scenario	Energy Component of LMP	Synchronized Reserve Penalty Factor		Primary Reserve Penalty Factor		Capped Reserve Shortage Penalty Factor	Transmission Constraint Penalty Factor	Total LMP in MAD	Total LMP outside MAD
		RTO	MAD	RTO	MAD				
A	$50	$850	$0	$0	$0	$850	$0	$900	$900
B	$50	$850	$850	$850	$850	$1,700	$0	$1,750	$1,750
C	$50	$850	$850	$850	$850	$1,700	$2,000	$3,750	$3,750
D	$1,000	$850	$850	$850	$850	$1,700	$2,000	$4,700	$4,700
E	$2,000	$850	$850	$850	$850	$1,700	$2,000	$5,700	$5,700

Shortage Pricing Scenarios, Extended ORDC

Scenario	Energy Component of LMP	Synchronized Reserve Penalty Factor		Primary Reserve Penalty Factor		Secondary Reserve Penalty Factor	Transmission Constraint Penalty Factor	Total LMP in MAD	Total LMP outside MAD
		RTO	MAD	RTO	MAD	RTO			
A	$50	$2,000	$200	$200	$200	$0	$0	$2,650	$2,250
B	$50	$2,000	$2,000	$2,000	$2,000	$2,000	$0	$10,050	$6,050
C	$50	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$12,050	$8,050
D	$1,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$13,000	$9,000
E	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$14,000	$10,000

Reductions in Line Ratings for Transmission Penalty Factors

Description	Frequency (Constraint Intervals) 2019	2020	Constraints with Reduced Line Limits (Constraint Intervals) 2019	2020	Average Reduction (Percentage) 2019	2020
PJM Internal Violated Transmission Constraints	7,046	7,374	5,465	6,779	6.88%	6.80%
PJM Internal Binding Transmission Constraints	92,366	117,867	90,033	115,866	9.08%	8.87%
Market to Market Transmission Constraints	53,263	40,722	10,699	9,841	5.54%	5.94%
All Transmission Constraints	152,675	165,963	106,197	132,486	8.61%	8.54%

RT, fuel-cost adjusted, load-weighted average LMP (Dollars per MWh)

	2020 Fuel-Cost Adjusted, Load-Weighted LMP	2020 Load-Weighted LMP	Change	Percent Change
Average	$24.56	$21.77	($2.79)	(11.4%)
	2019 Load-Weighted LMP	**2020 Fuel-Cost Adjusted, Load-Weighted LMP**	**Change**	**Percent Change**
Average	$27.32	$24.56	($2.76)	(10.1%)
	2019 Load-Weighted LMP	**2020 Load-Weighted LMP**	**Change**	**Change**
Average	$27.32	$21.77	($5.55)	(20.3%)

Components of energy price

Element	2019 Contribution to LMP	Percent	2020 Contribution to LMP	Percent	Change Percent
Gas	$11.51	42.1%	$9.03	41.5%	(0.7%)
Coal	$7.21	26.4%	$5.17	23.7%	(2.7%)
Ten Percent Adder	$2.07	7.6%	$1.68	7.7%	0.1%
Constraint Violation Adder	$1.85	6.8%	$1.67	7.7%	0.9%
Variable Maintenance	$1.71	6.3%	$1.34	6.2%	(0.1%)
Variable Operations			$0.84	3.9%	3.9%
NA	$0.35	1.3%	$0.57	2.6%	1.3%
Markup	$1.55	5.7%	$0.50	2.3%	(3.4%)
CO2 Cost	$0.21	0.8%	$0.37	1.7%	0.9%
LPA Rounding Difference	$0.15	0.5%	$0.18	0.8%	0.3%
Ancillary Service Redispatch Cost	$0.24	0.9%	$0.13	0.6%	(0.3%)
Scarcity Adder	$0.24	0.9%	$0.08	0.4%	(0.5%)
Oil	$0.06	0.2%	$0.07	0.3%	0.1%
Opportunity Cost Adder	$0.10	0.4%	$0.07	0.3%	(0.0%)
Increase Generation Adder	$0.10	0.4%	$0.06	0.3%	(0.1%)
LPA-SCED Differential	$0.01	0.0%	$0.01	0.1%	0.0%
NOx Cost	$0.02	0.1%	$0.01	0.0%	(0.0%)
Market-to-Market Adder	$0.00	0.0%	$0.00	0.0%	0.0%
SO2 Cost	$0.00	0.0%	$0.00	0.0%	(0.0%)
Other	$0.00	0.0%	$0.00	0.0%	(0.0%)
Uranium	$0.00	0.0%	$0.00	0.0%	0.0%
Landfill Gas	$0.00	0.0%	($0.00)	(0.0%)	(0.0%)
Renewable Energy Credits	($0.02)	(0.1%)	($0.01)	(0.0%)	0.1%
Decrease Generation Adder	($0.05)	(0.2%)	($0.02)	(0.1%)	0.1%
Total	$27.32	100.0%	$21.77	100.0%	0.0%

Components of energy price (No ten percent adder)

Element	2019 Contribution to LMP	Percent	2020 Contribution to LMP	Percent	Change Percent
Gas	$11.51	42.1%	$9.03	41.5%	(0.7%)
Coal	$7.21	26.4%	$5.17	23.7%	(2.7%)
Markup	$3.63	13.3%	$2.19	10.0%	(3.2%)
Constraint Violation Adder	$1.85	6.8%	$1.67	7.7%	0.9%
Variable Maintenance	$1.71	6.3%	$1.34	6.2%	(0.1%)
Variable Operations			$0.84	3.9%	3.9%
NA	$0.35	1.3%	$0.57	2.6%	1.3%
CO_2 Cost	$0.21	0.8%	$0.37	1.7%	0.9%
LPA Rounding Difference	$0.15	0.5%	$0.18	0.8%	0.3%
Ancillary Service Redispatch Cost	$0.24	0.9%	$0.13	0.6%	(0.3%)
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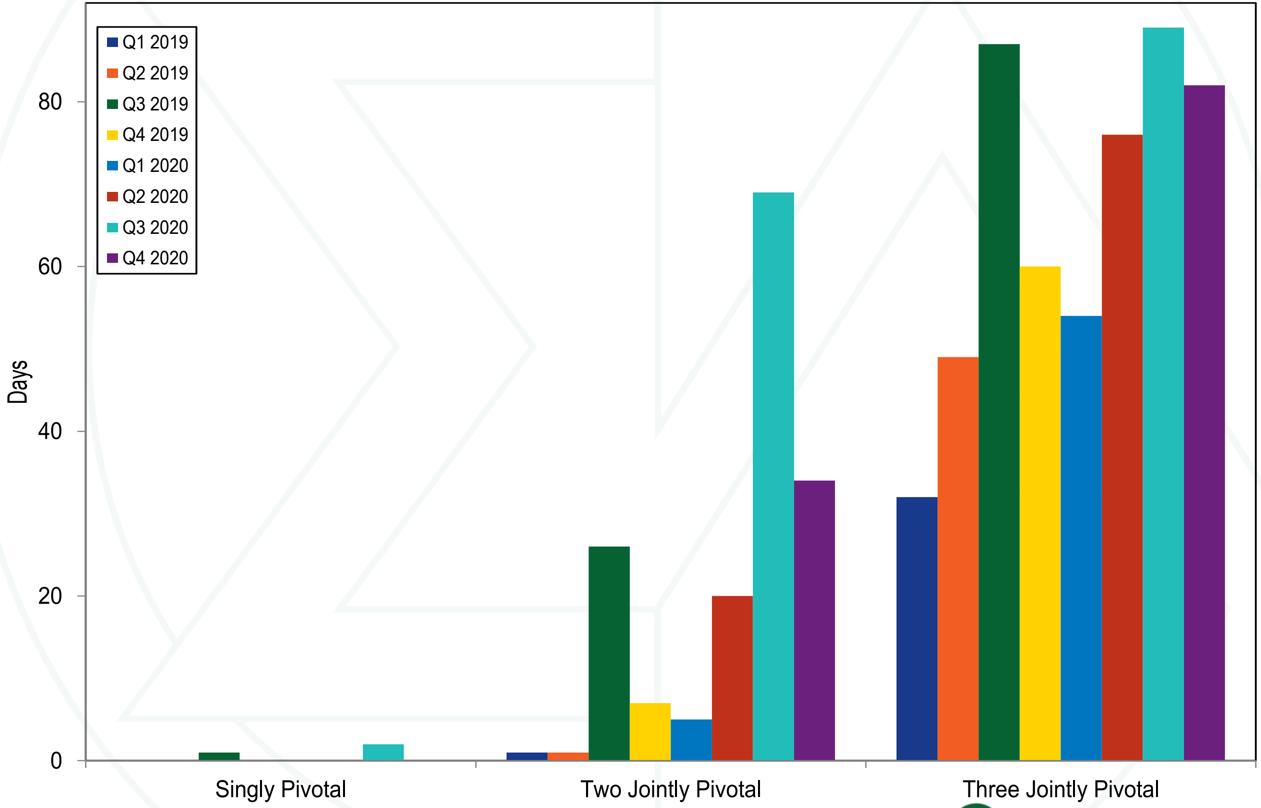
Oil	$0.06	0.2%	$0.07	0.3%	0.1%
Opportunity Cost Adder	$0.10	0.4%	$0.07	0.3%	(0.0%)
Increase Generation Adder	$0.10	0.4%	$0.06	0.3%	(0.1%)
LPA-SCED Differential	$0.01	0.0%	$0.01	0.1%	0.0%
NO_x Cost	$0.02	0.1%	$0.01	0.0%	(0.0%)
Market-to-Market Adder	$0.00	0.0%	$0.00	0.0%	0.0%
SO_2 Cost	$0.00	0.0%	$0.00	0.0%	(0.0%)
Ten Percent Adder	$0.00	0.0%	$0.00	0.0%	(0.0%)
Other	$0.00	0.0%	$0.00	0.0%	(0.0%)
Uranium	$0.00	0.0%	$0.00	0.0%	0.0%
Landfill Gas	$0.00	0.0%	($0.00)	(0.0%)	(0.0%)
Renewable Energy Credits	($0.02)	(0.1%)	($0.01)	(0.0%)	0.1%
Decrease Generation Adder	($0.05)	(0.2%)	($0.02)	(0.1%)	0.1%
Total	$27.32	100.0%	$21.77	100.0%	0.0%

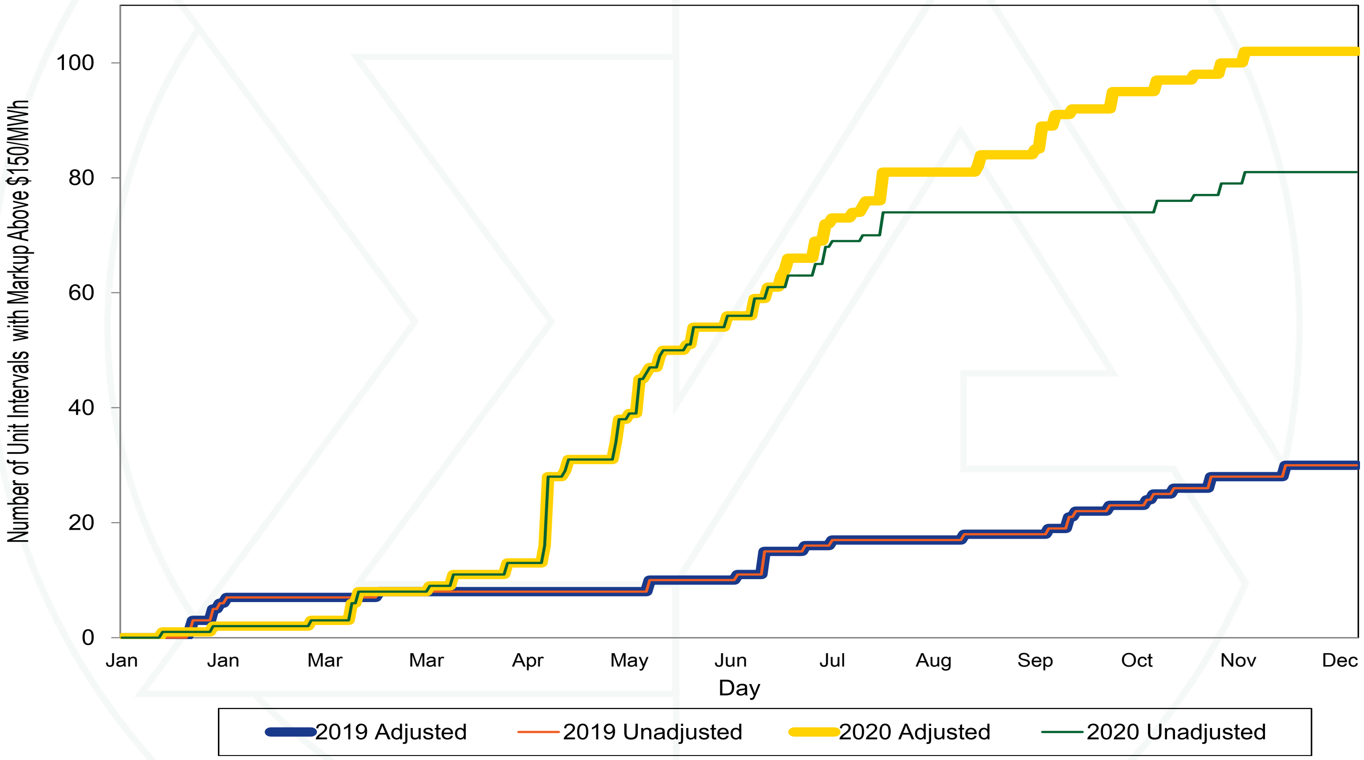
Pivotal suppliers: day-ahead energy market



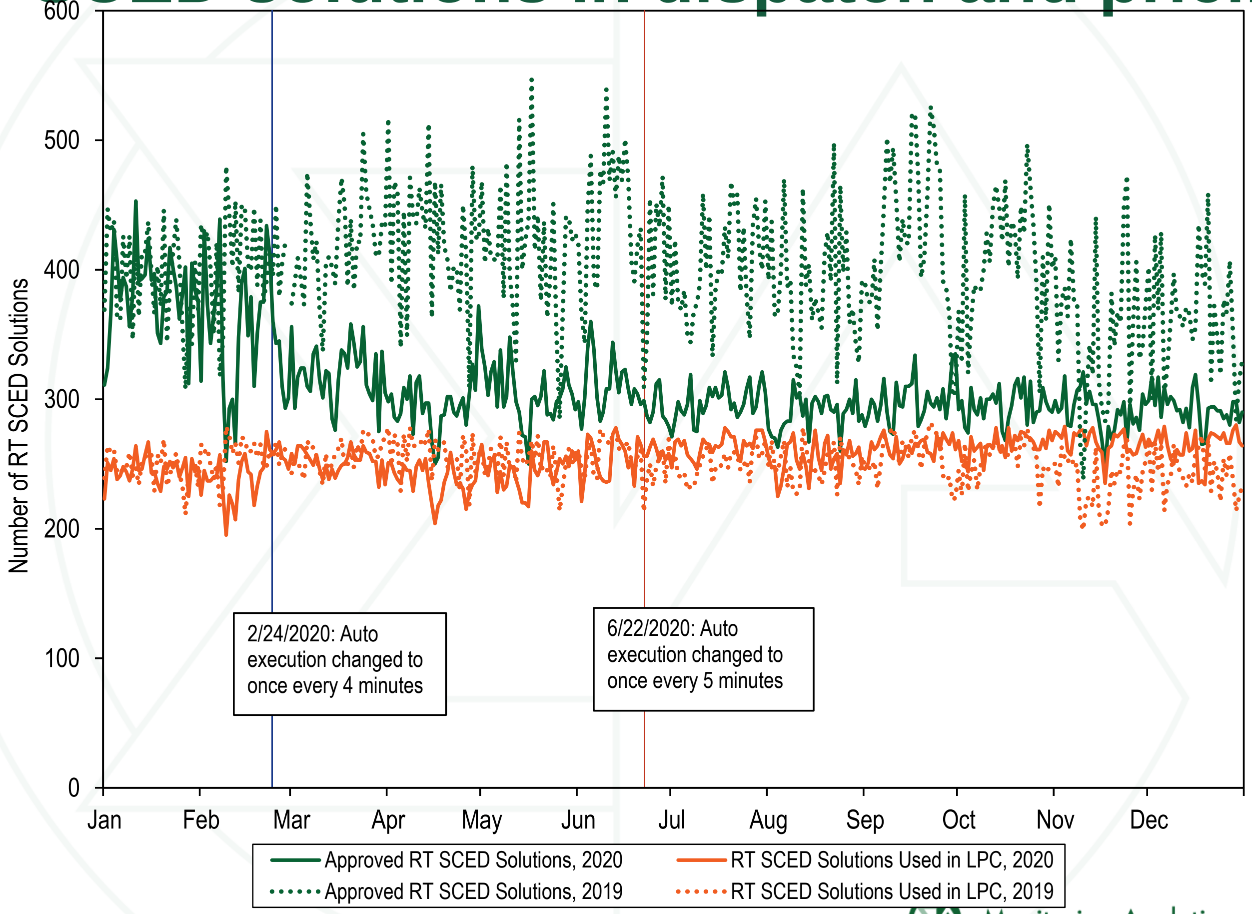
Marginal units with local market power and markup

	2019			2020		
Markup Category	Not Failing TPS Test	Failing TPS Test	Percent in Category	Not Failing TPS Test	Failing TPS Test	Percent in Category
Negative Markup	24.1%	11.5%	35.6%	34.0%	6.5%	40.5%
Zero Markup	12.6%	6.7%	19.4%	11.3%	3.8%	15.1%
$0 to $5	24.3%	6.9%	31.2%	33.8%	4.5%	38.3%
$5 to $10	7.9%	1.7%	9.6%	3.5%	0.4%	3.9%
$10 to $15	1.2%	0.5%	1.7%	0.6%	0.2%	0.8%
$15 to $20	0.5%	0.3%	0.8%	0.3%	0.0%	0.3%
$20 to $25	0.3%	0.1%	0.4%	0.4%	0.0%	0.4%
$25 to $50	0.5%	0.2%	0.7%	0.4%	0.0%	0.4%
$50 to $75	0.2%	0.1%	0.3%	0.1%	0.0%	0.1%
$75 to $100	0.1%	0.0%	0.1%	0.1%	0.0%	0.1%
Above $100	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%
Total Positive Markup	35.0%	10.0%	45.0%	39.2%	5.2%	44.4%
Total	71.8%	28.2%	100.0%	84.5%	15.5%	100.0%

Unit intervals with markups above $150/MWh



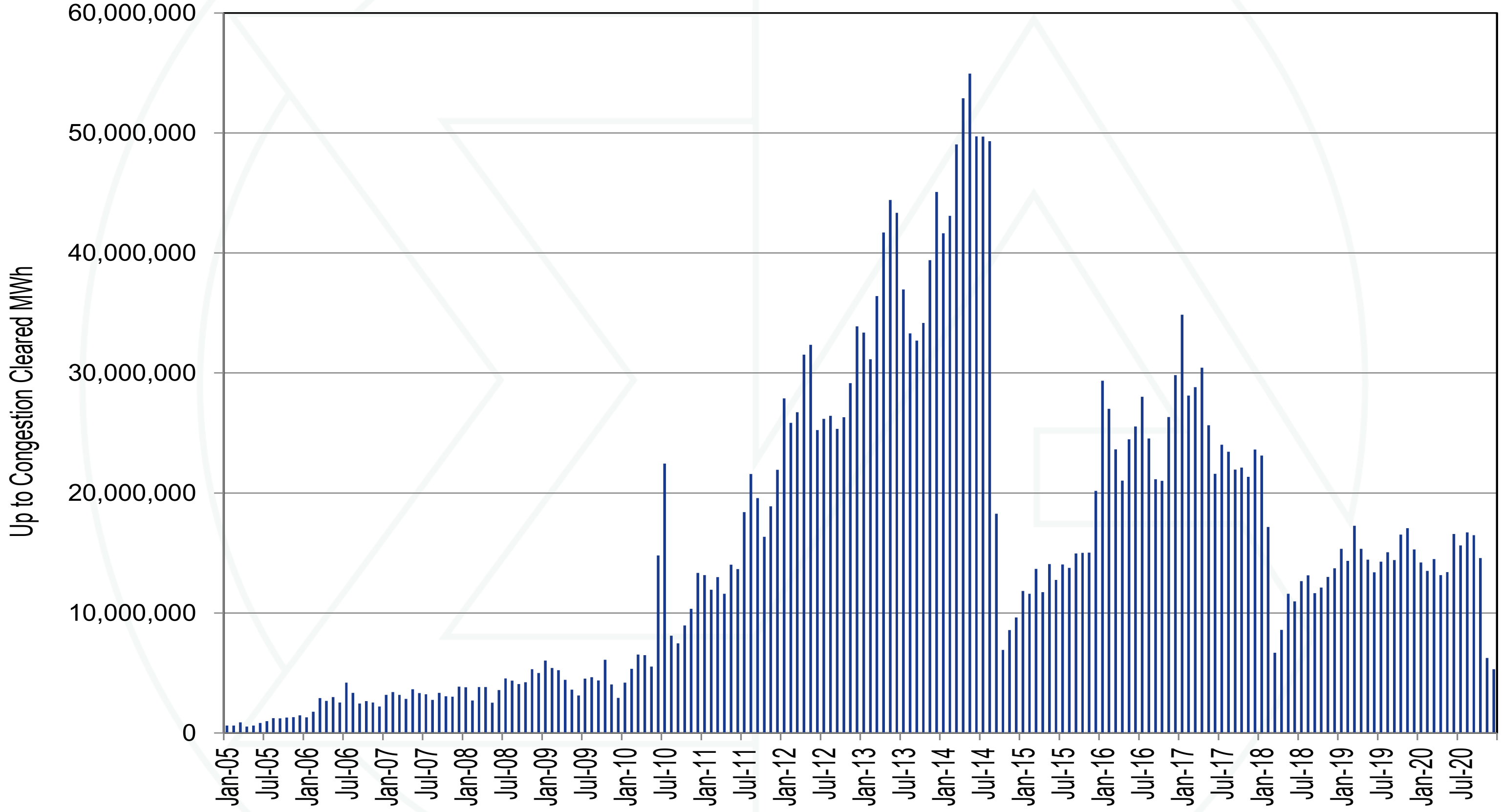
RT SCED solutions in dispatch and pricing



Dispatch reflected in concurrent prices

Period	RT SCED Automatic Execution Frequency	Dispatch Duration Reflected in Prices (Minutes:Seconds)	Percent Dispatch Duration Reflected in Prices
Jan 1, 2020 - Feb 23, 2020	Every 3 minutes	03:11	67.9%
Feb 24, 2020 - Jun 22, 2020	Every 4 minutes	03:27	67.2%
Jun 23, 2020 - Oct 14, 2020	Every 5 minutes	03:37	69.9%
Oct 15, 2020 - Dec 31, 2020	Every 5 minutes	00:39	9.9%

UTC cleared bids



Total congestion costs

Congestion Costs (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%)	$39,200	1.5%
2020	$529	(9.4%)	$33,640	1.6%

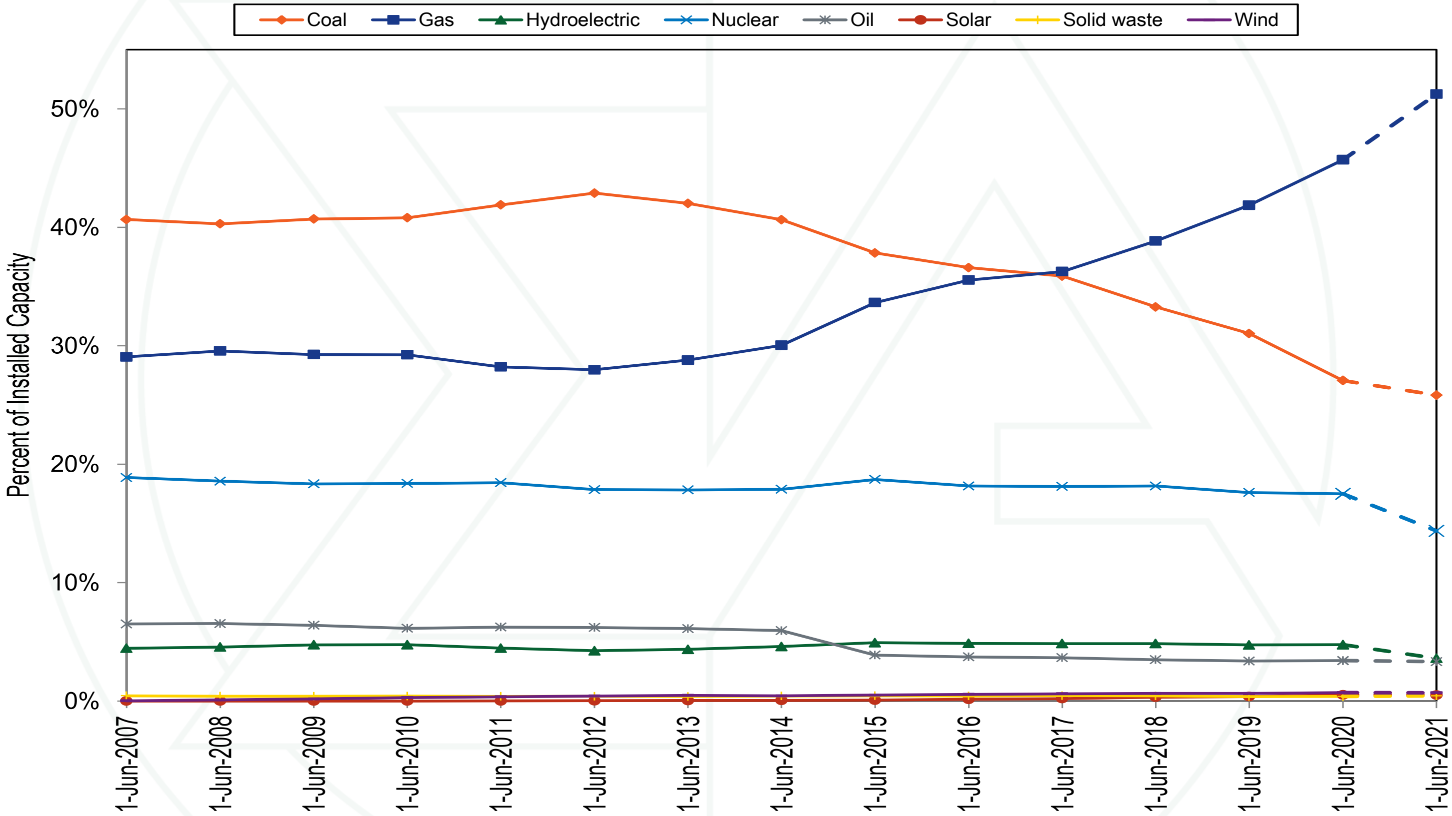
The capacity market results were not competitive

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

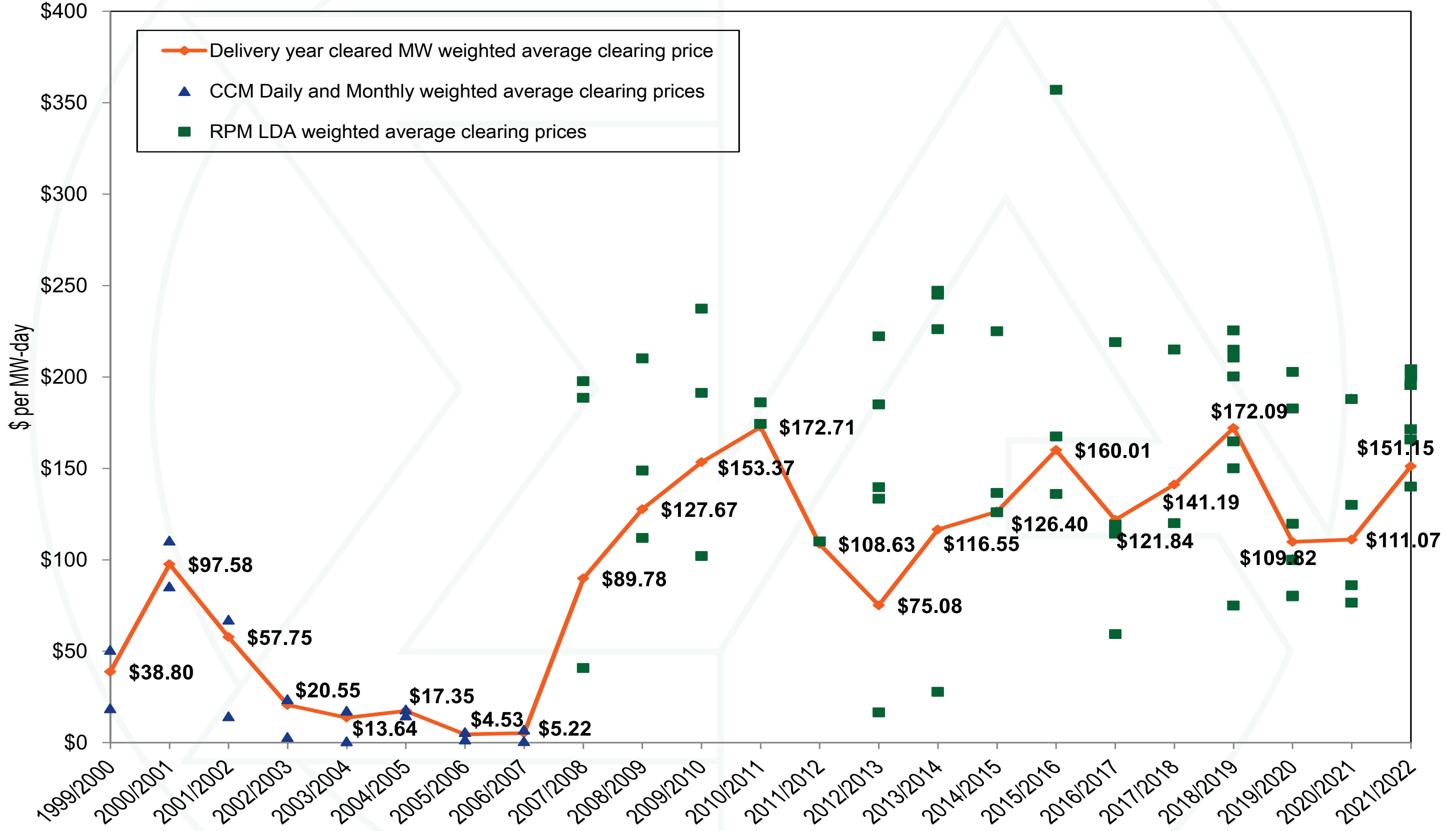
Capacity Market Issues

- **Market seller offer cap**
- **MOPR**
- **Definition of capacity**
- **ELCC**
- **DR/EE**
- **CRF values**

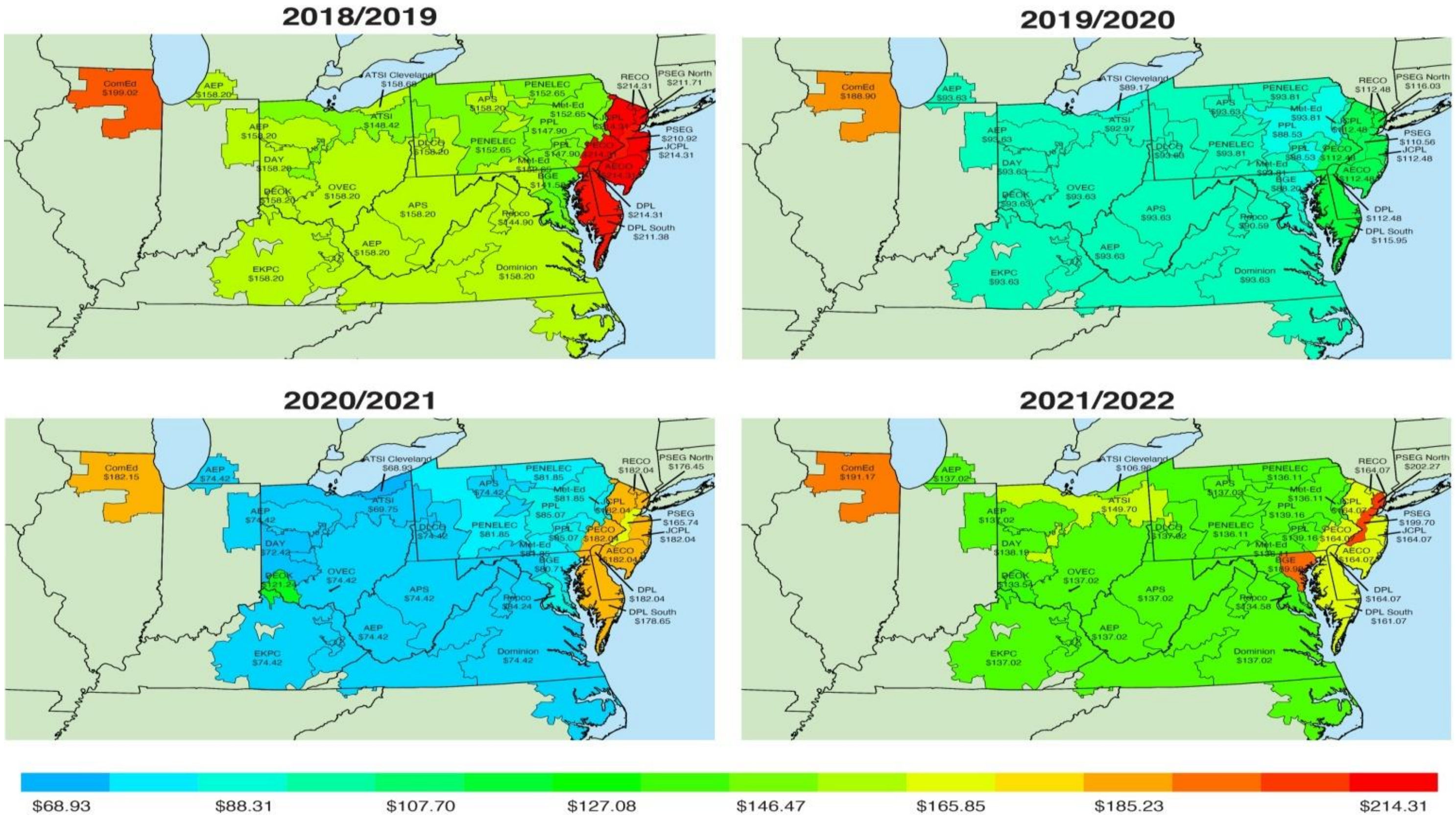
Installed capacity by fuel source



History of capacity prices

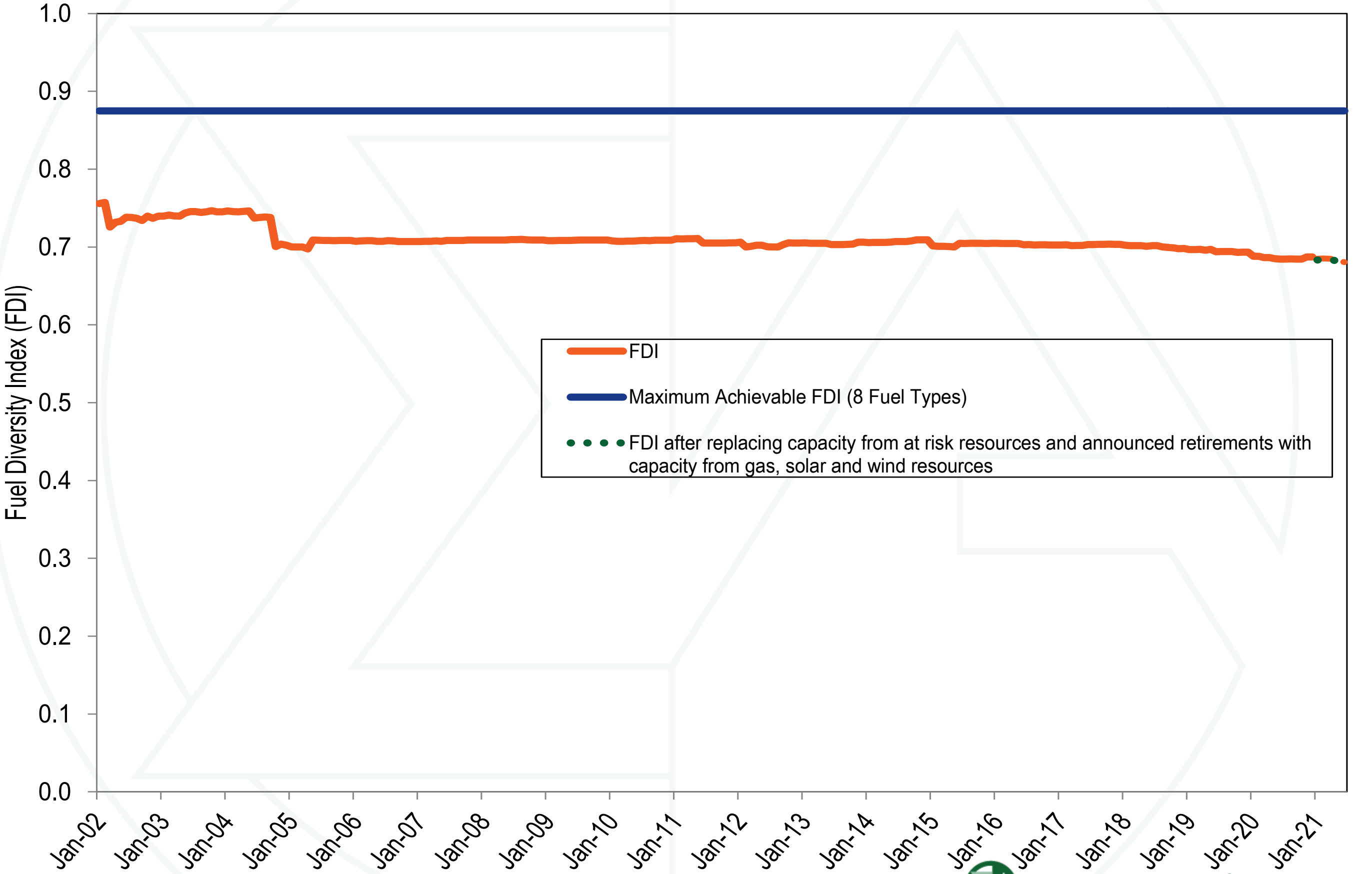


Map of RPM capacity prices



Monitoring Analytics

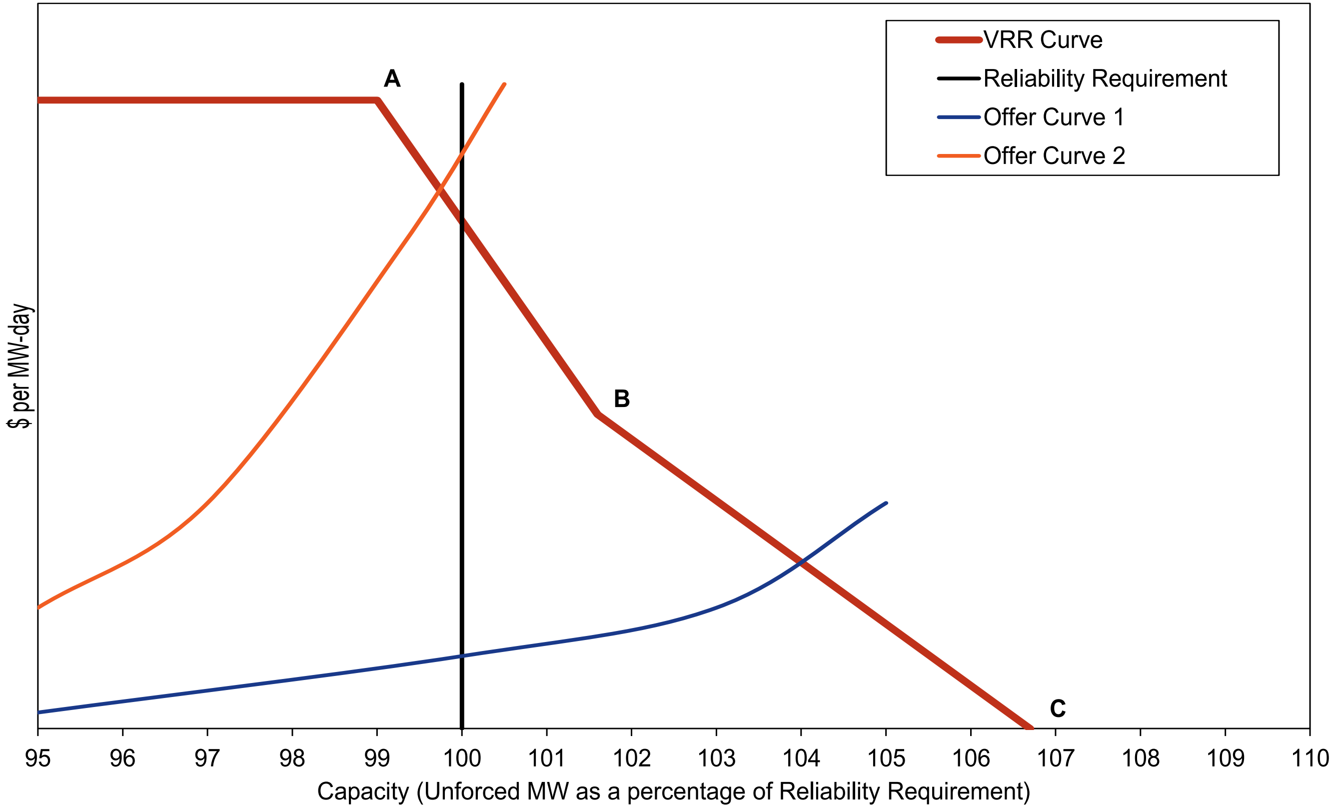
Fuel diversity index: capacity



Effective capacity in interconnection queues

Unit Type	MW in Queue	Completion Rate Adjusted MW in Queue	Completion Rate and Derate Adjusted MW in Queue
Battery	14,824.7	801.5	801.5
CC	23,095.1	15,849.4	15,849.4
CT - Natural Gas	5,483.8	3,895.2	3,895.2
CT - Oil	31.0	17.8	17.8
CT - Other	0.0	0.0	0.0
Fuel Cell	3.0	0.9	0.9
Hydro - Pumped Storage	700.0	700.0	700.0
Hydro - Run of River	148.6	58.2	58.2
Nuclear	189.5	64.2	64.2
RICE - Natural Gas	21.3	7.0	7.0
RICE - Oil	4.0	2.2	2.2
RICE - Other	0.0	0.0	0.0
Solar	79,029.2	9,609.6	4,487.7
Solar + Storage	17,922.2	287.2	287.2
Solar + Wind	199.0	0.0	0.0
Steam - Coal	76.0	25.9	25.9
Steam - Natural Gas	11.0	9.9	9.9
Steam - Oil	0.0	0.0	0.0
Steam - Other	0.0	0.0	0.0
Wind	31,736.6	5,885.3	953.4
Wind + Storage	106.3	0.0	0.0
Total	173,581.3	37,214.3	27,160.5

Capacity market demand curve: impact



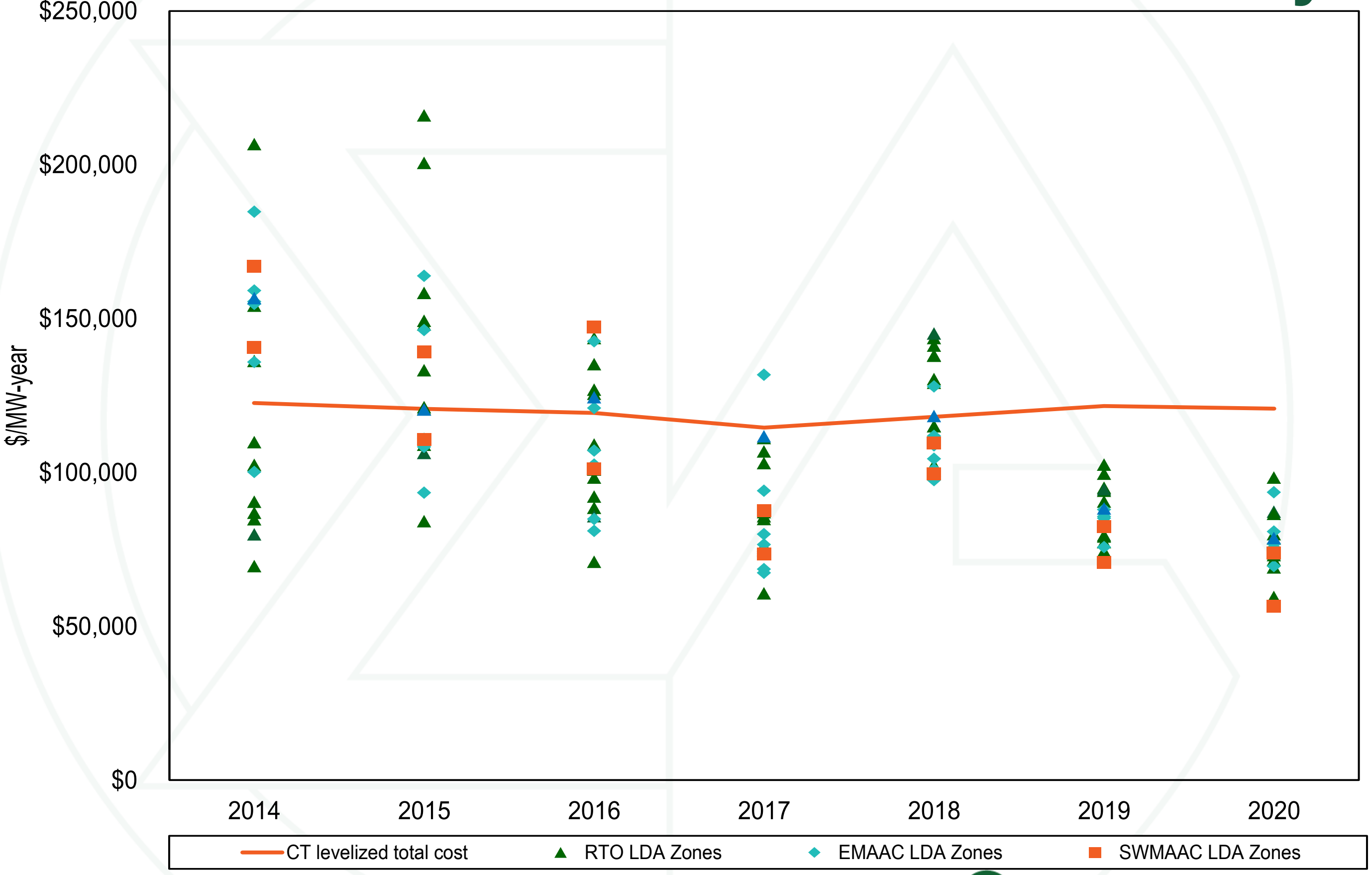
Reserve margin

	Generation and DR RPM Committed Less Deficiency UCAP (MW)	Forecast Peak Load	FRR Peak Load	PRD	RPM Peak Load	IRM	Pool Wide Average EFORd	Generation and DR RPM Committed Less Deficiency ICAP (MW)	Reserve Margin	Reserve Margin in Excess of IRM Percent	Reserve Margin in Excess of IRM ICAP (MW)	Projected Replacement Capacity using Cleared Buy Bids UCAP (MW)	Projected Reserve Margin
01-Jun-16	160,883.3	152,356.6	12,511.6	0.0	139,845.0	16.4%	5.91%	170,988.7	22.3%	5.9%	8,209.2	0.0	22.3%
01-Jun-17	163,872.0	153,230.1	12,837.5	0.0	140,392.6	16.6%	5.94%	174,220.7	24.1%	7.5%	10,522.9	0.0	24.1%
01-Jun-18	161,242.6	152,407.9	12,732.9	0.0	139,675.0	16.1%	6.07%	171,662.5	22.9%	6.8%	9,499.8	0.0	22.9%
01-Jun-19	162,276.1	151,643.5	12,284.2	0.0	139,359.3	16.0%	6.08%	172,781.2	24.0%	8.0%	11,124.4	0.0	24.0%
01-Jun-20	159,560.4	148,355.3	11,488.3	558.0	136,309.0	15.5%	5.78%	169,348.8	24.2%	8.7%	11,911.9	0.0	24.2%
01-Jun-21	164,267.3	149,482.9	11,717.7	510.0	137,255.2	14.7%	5.22%	173,314.3	26.3%	11.6%	15,882.6	6,818.8	21.0%

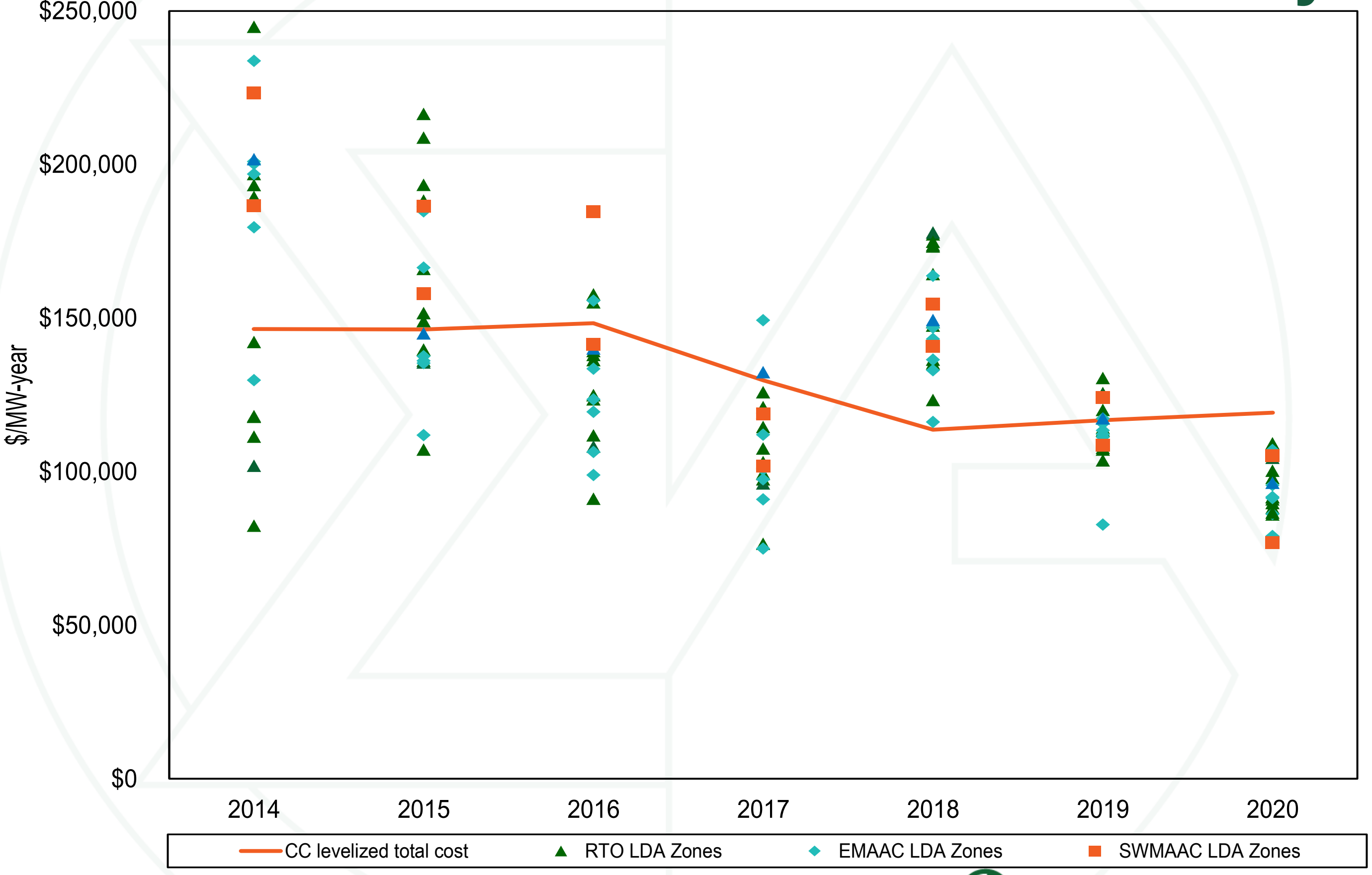
Proportion of units recovering avoidable costs

Technology	Units with full recovery from energy and ancillary net revenue										Units with full recovery from all markets									
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
CC - Combined Cycle	55%	46%	50%	72%	59%	63%	57%	66%	66%	67%	85%	79%	79%	95%	88%	93%	89%	98%	97%	93%
CT - Aero Derivative	15%	6%	6%	53%	15%	8%	10%	30%	7%	42%	100%	96%	76%	98%	100%	99%	100%	99%	96%	96%
CT - Industrial Frame	26%	23%	17%	38%	13%	8%	3%	21%	7%	21%	99%	98%	83%	100%	100%	100%	100%	96%	88%	86%
Coal Fired	31%	17%	27%	78%	16%	15%	12%	11%	2%	2%	82%	36%	54%	83%	64%	40%	36%	63%	26%	5%
Diesel	48%	42%	37%	69%	56%	33%	32%	39%	9%	37%	100%	100%	77%	100%	100%	100%	100%	97%	91%	89%
Hydro	74%	61%	95%	97%	81%	79%	95%	94%	95%	72%	81%	77%	97%	98%	100%	100%	97%	98%	100%	74%
Nuclear	-	-	50%	94%	17%	6%	17%	53%	0%	0%	-	-	61%	100%	56%	17%	50%	88%	81%	0%
Oil or Gas Steam	8%	6%	11%	15%	3%	0%	0%	10%	75%	6%	92%	78%	86%	85%	91%	88%	81%	76%	76%	34%
Pumped Storage	100%	100%	95%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Solar	-	95%	97%	99%	97%	95%	95%	98%	96%	95%	-	95%	97%	99%	97%	95%	95%	98%	96%	95%
Wind	88%	85%	96%	93%	92%	89%	93%	91%	88%	79%	88%	85%	96%	93%	92%	89%	93%	91%	89%	79%

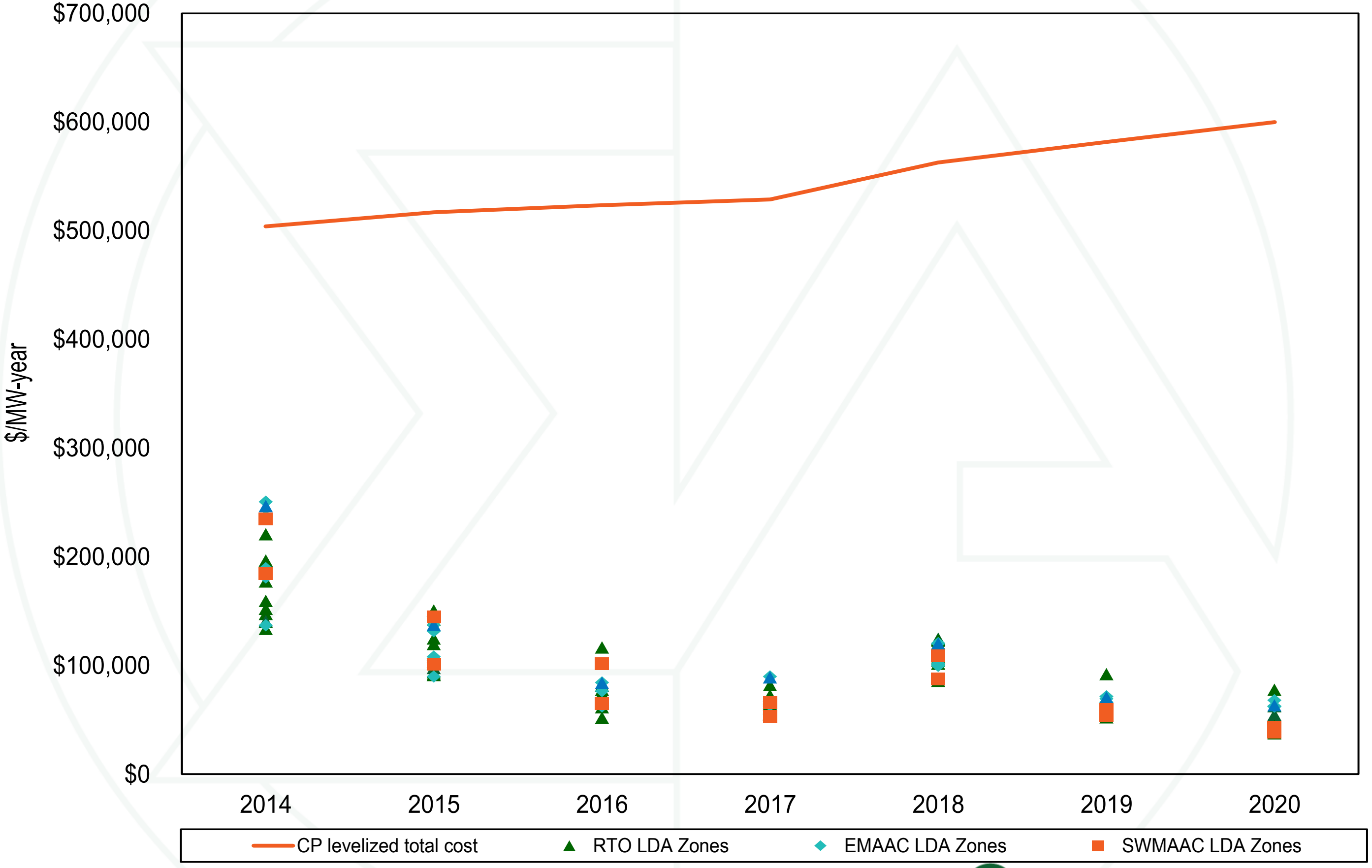
New entrant CT net revenue and total cost by LDA



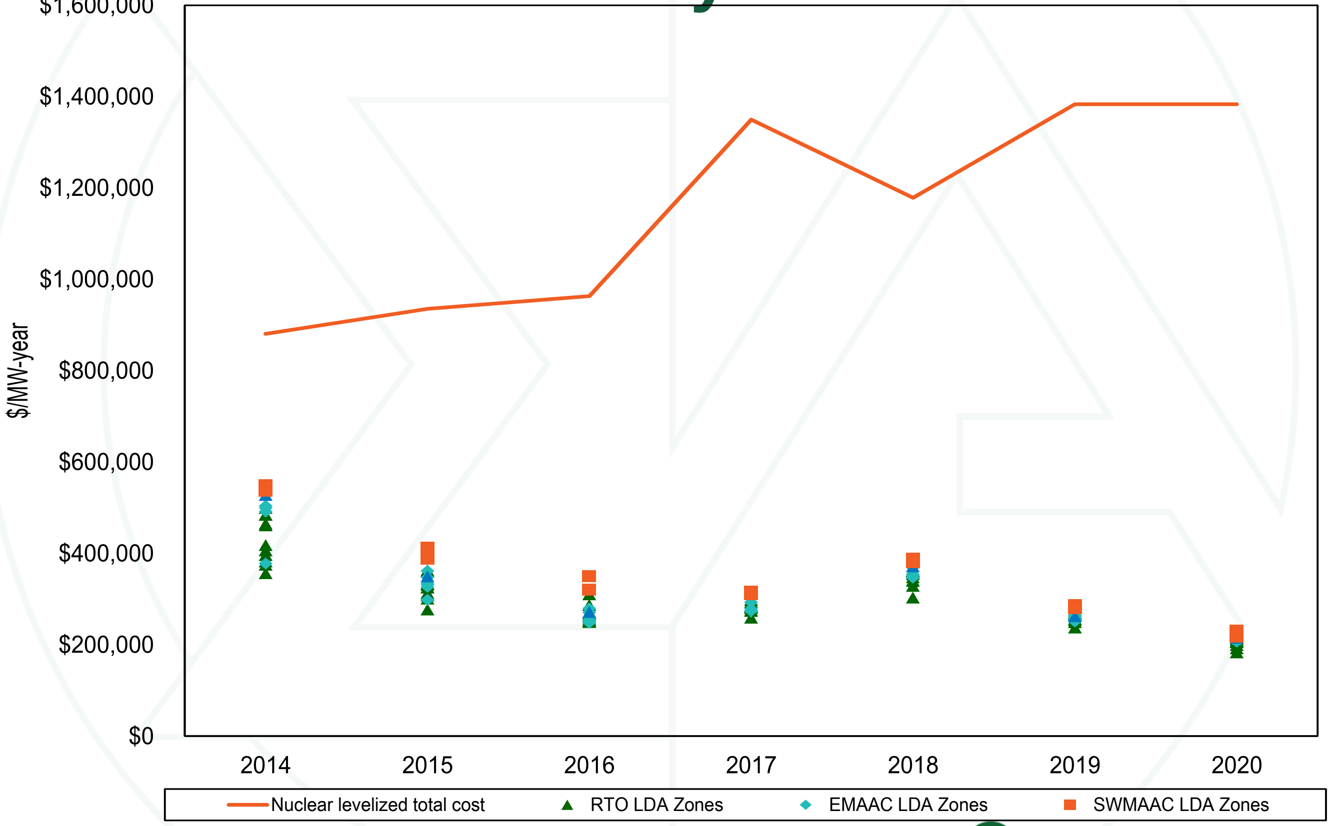
New entrant CC net revenue and total cost by LDA



New entrant CP net revenue and total cost by LDA



New entrant nuclear plant net revenue and total cost by LDA



Nuclear unit forward annual surplus (shortfall)

	ICAP (MW)	Surplus (Shortfall) ($/MWh) 2021	Surplus (Shortfall) ($ in millions) 2021
Beaver Valley	1,808	$3.13	$47.4
Braidwood	2,337	$4.05	$79.0
Byron	2,300	$3.23	$62.4
Calvert Cliffs	1,708	$4.54	$64.5
Davis Besse	894	($5.83)	($41.7)
Dresden	1,797	$4.81	$71.8
Hope Creek	1,172	$3.11	$30.6
LaSalle	2,271	$3.91	$74.1
Limerick	2,242	$2.76	$52.1
North Anna	1,892	$3.61	$57.0
Peach Bottom	2,347	$2.64	$52.3
Perry	1,240	($5.90)	($58.6)
Quad Cities	1,819	$1.33	$21.1
Salem	2,328	$2.80	$54.9
Surry	1,676	$2.69	$38.0
Susquehanna	2,520	($1.33)	($25.6)

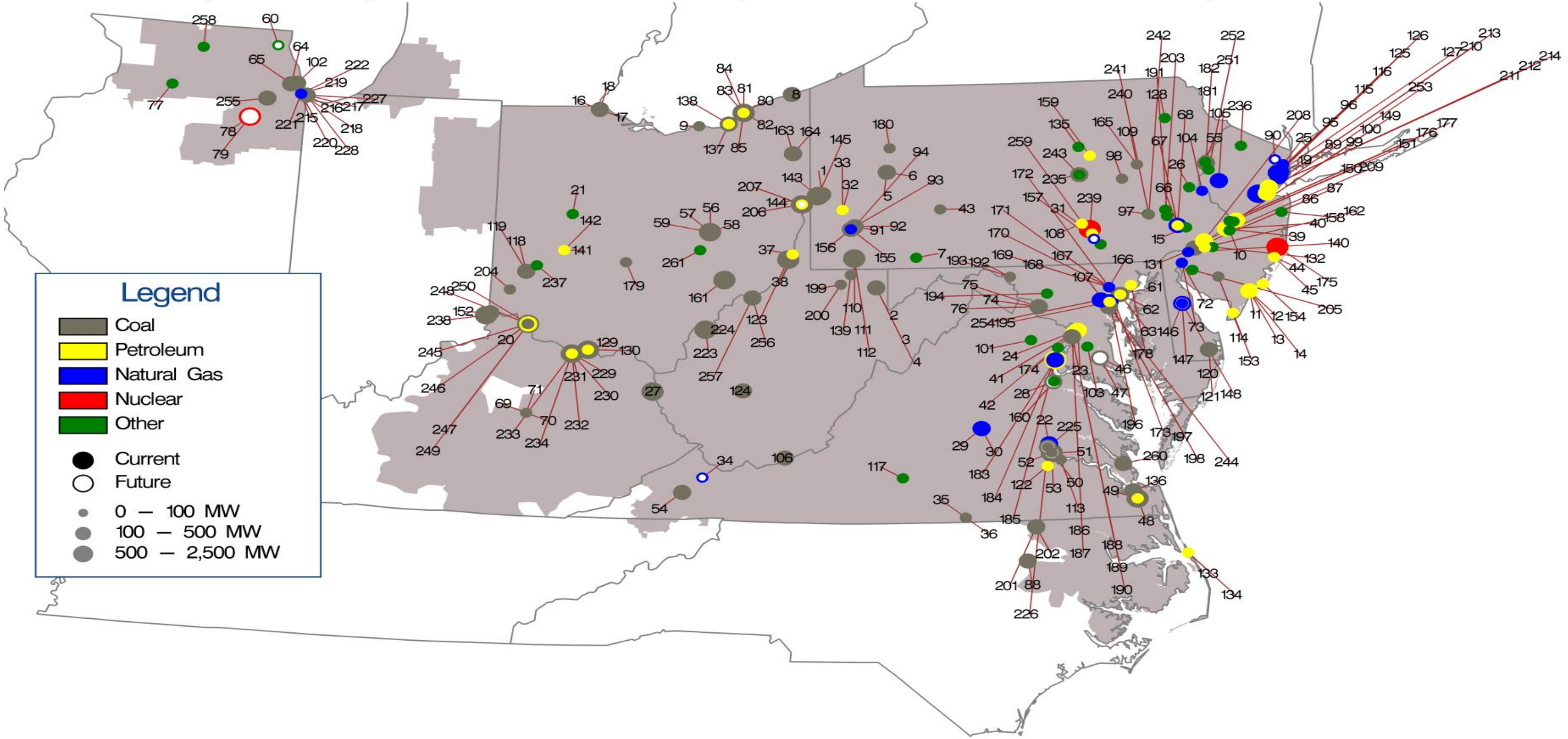
Nuclear unit net ACR

	ICAP (MW)	Net ACR ($/MWh)			Net ACR ($/MW-Day)			Net ACR Excluding Capital ($/MW-Day)		
		2021	2022	2023	2021	2022	2023	2021	2022	2023
Beaver Valley	1,808	$1.91	$0.04	$0.57	$42.48	$0.94	$12.76	$0.00	$0.00	$0.00
Braidwood	2,337	$4.47	$2.72	$3.21	$99.65	$60.67	$71.53	$0.00	$0.00	$0.00
Byron	2,300	$5.29	$3.60	$4.06	$117.84	$80.29	$90.61	$0.00	$0.00	$0.00
Calvert Cliffs	1,708	$0.67	$0.00	$0.00	$14.93	$0.00	$0.00	$0.00	$0.00	$0.00
Davis Besse	894	$11.68	$9.80	$10.33	$260.39	$218.44	$230.30	$97.63	$55.68	$67.54
Dresden	1,797	$3.71	$1.94	$2.43	$82.82	$43.35	$54.28	$0.00	$0.00	$0.00
Hope Creek	1,172	$4.64	$2.83	$3.28	$103.36	$63.15	$73.24	$0.00	$0.00	$0.00
LaSalle	2,271	$4.61	$2.87	$3.36	$102.84	$64.10	$74.84	$0.00	$0.00	$0.00
Limerick	2,242	$4.99	$3.17	$3.62	$111.15	$70.78	$80.80	$0.00	$0.00	$0.00
North Anna	1,892	$1.42	$0.00	$0.10	$31.77	$0.00	$2.18	$0.00	$0.00	$0.00
Peach Bottom	2,347	$5.10	$3.30	$3.74	$113.74	$73.53	$83.36	$0.00	$0.00	$0.00
Perry	1,240	$11.75	$9.87	$10.40	$262.00	$220.02	$231.89	$99.24	$57.26	$69.13
Quad Cities	1,819	$7.19	$5.67	$6.10	$160.32	$126.37	$136.07	$41.70	$7.75	$17.45
Salem	2,328	$4.94	$3.14	$3.59	$110.13	$69.94	$80.03	$0.00	$0.00	$0.00
Surry	1,676	$2.34	$0.58	$1.11	$52.27	$13.02	$24.76	$0.00	$0.00	$0.00
Susquehanna	2,520	$6.54	$5.09	$5.52	$145.75	$113.54	$123.01	$27.13	$0.00	$4.40

Profile of units at risk of retirement

Technology	No. Units	ACR ($/MW-Day)	ICAP (MW)	Avg. 2020 Run Hours	Avg. Unit Age (Yrs)	Avg. Heat Rate (Btu/Mwh)
Coal Fired	7	$118.68	2,361	5,354	43	10,558
CT	50	$98.46	1,829	381	45	15,160
Other	7	$55.96	574	2,841	47	10,785
Total	64	-	4,763	-	-	-

Map of unit retirements: 2011 through 2024



Recommendations: Planning

- Modify the transmission project proposal templates to include data necessary to perform a detailed project lifetime financial analysis. The required data includes, but is not limited to: capital expenditure; capital structure; return on equity; cost of debt; tax assumptions; ongoing capital expenditures; ongoing maintenance; and expected life.

- Storage resources not be includable as transmission assets for any reason.

Recommendations: Energy Market Uplift

- **PJM should implement processes to ensure that units not following dispatch not be paid uplift.**
- **Flexible operating parameters should be required as a condition for receiving uplift.**

Total energy uplift charges: 2001 through 2020

	Total Energy Uplift Charges (Millions)	Change (Millions)	Percent Change	Energy Uplift as a Percent of Total PJM Billing
2001	$284.0	$67.0	30.9%	8.5%
2002	$273.7	($10.3)	(3.6%)	5.8%
2003	$376.5	$102.8	37.6%	5.4%
2004	$537.6	$161.1	42.8%	6.1%
2005	$712.6	$175.0	32.6%	3.1%
2006	$365.6	($347.0)	(48.7%)	1.7%
2007	$503.3	$137.7	37.7%	1.6%
2008	$474.3	($29.0)	(5.8%)	1.4%
2009	$322.7	($151.6)	(32.0%)	1.2%
2010	$623.2	$300.5	93.1%	1.8%
2011	$603.4	($19.8)	(3.2%)	1.7%
2012	$649.8	$46.4	7.7%	2.2%
2013	$843.0	$193.2	29.7%	2.5%
2014	$961.2	$118.2	14.0%	1.9%
2015	$312.0	($649.2)	(67.5%)	0.7%
2016	$136.7	($175.3)	(56.2%)	0.4%
2017	$127.3	($9.4)	(6.9%)	0.3%
2018	$198.2	$70.9	55.7%	0.4%
2019	$88.5	($109.7)	(55.4%)	0.2%
2020	$90.9	$2.4	2.7%	0.3%

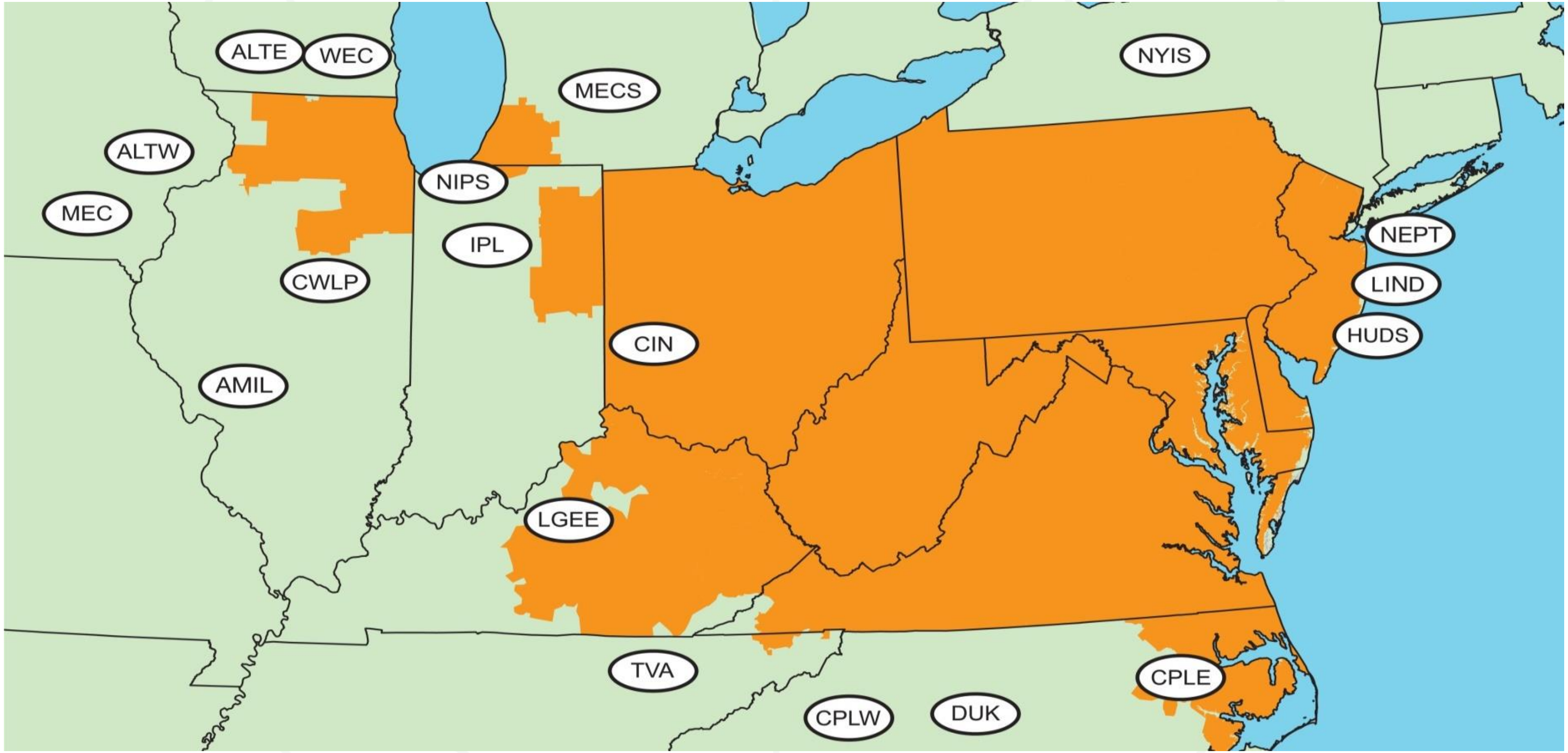
Operating reserve rates statistics

		Rates Charged ($/MWh)			
Region	Transaction	Maximum	Average	Minimum	Standard Deviation
East	INC	1.961	0.329	<0.001	0.341
	DEC	1.966	0.341	0.001	0.344
	DA Load	0.164	0.012	<0.001	0.025
	RT Load	0.625	0.040	<0.001	0.068
	Deviation	1.961	0.329	<0.001	0.341
West	INC	1.961	0.285	<0.001	0.314
	DEC	1.966	0.296	<0.001	0.317
	DA Load	0.164	0.012	<0.001	0.025
	RT Load	0.457	0.030	<0.001	0.051
	Deviation	1.961	0.285	<0.001	0.314

Recommendations: Transactions

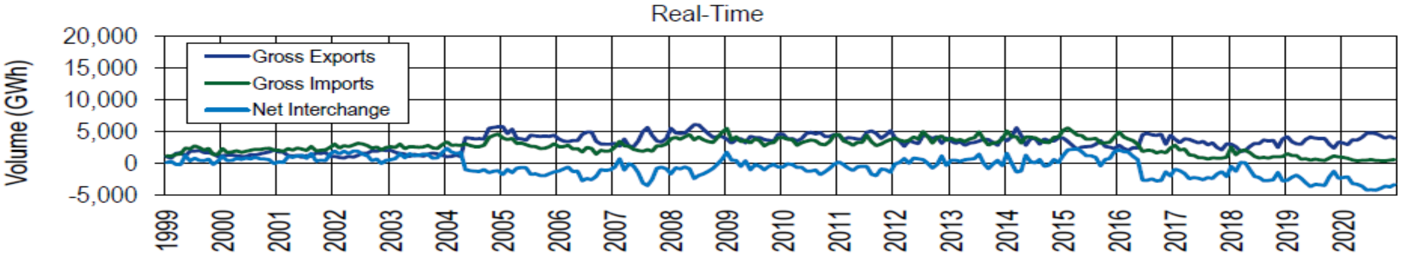
- **The MMU recommends that PJM end the practice of maintaining outdated definitions of interface pricing points, eliminate the NIPSCO, Southeast and Southwest interface pricing points from the day-ahead and real-time energy markets and, with VACAR, assign the transactions created under the reserve sharing agreement to the SouthIMP/EXP pricing point.**
- **The MMU recommends that PJM eliminate the NCMPAIMP and NCMPAEXP interface pricing points. It is not appropriate to have special pricing agreements between PJM and any external entity. The same market pricing should apply to all transactions.**

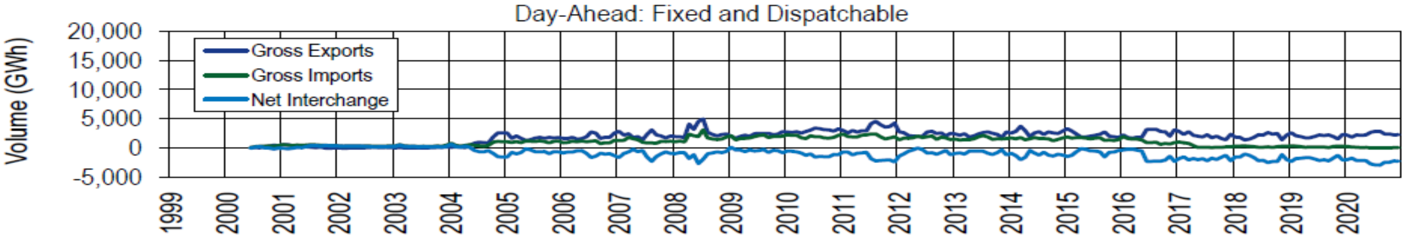
PJM's footprint and its external scheduling interfaces

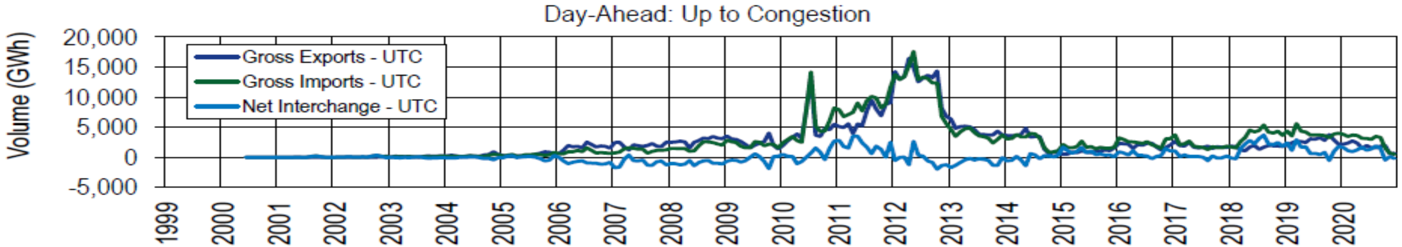


Monitoring Analytics

Scheduled import and export transaction volume history







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 tier 2 synchronized reserve market results were competitive

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

The DASR results were competitive

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

Recommendations: Ancillary Services

- **The details of VACAR Reserve Sharing Agreement (VRSA) be made public, including any responsibilities assigned to PJM and including the amount of reserves that Dominion commits to meet its obligations under the VRSA.**
- **The VRSA should be terminated and, if necessary, replaced by a reserve sharing agreement between PJM and VACAR South, similar to agreements between PJM and other bordering areas.**

New Recommendations: Ancillary Services

- **New CRF rates for black start units, incorporating current tax code changes, should be implemented immediately. The new CRF rates should apply to all black start units. The CRF rates for units going into service since the change in the tax code should incorporate applicable changes to depreciation treatment and tax rates. The CRF rates for units constructed prior to the new tax law and to which the new tax law depreciation rules did not apply should incorporate only the applicable changes to the tax rate.**
- **Black start units should be required to commit to providing black start service for the life of the unit.**

Compensation of black start units with updated CRF

Years	Existing Annual Revenue Requirement Total	Updated Annual Revenue Requirement Total	Difference Per Year Total	Updated Lifetime Difference Total
Pre 2017 units	$57,686,377	$51,326,744	$6,359,633	$32,307,265
Post 2017 Units	$28,479,043	$19,840,359	$8,638,684	$64,020,531
Total	$86,165,420	$71,167,103	$14,998,317	$96,327,797

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/FTR total congestion offset for ARR holders

Revenue									Pre 2017/2018		2017/2018 (With		Post 2017/2018 (With	
Planning Period	ARR Credits	Unadjusted 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
2011/2012	$512.2	$310.0	$1,025.4	($275.7)	$749.7	($50.6)	$35.6	$113.9	$771.6	102.9%	$582.1	77.6%	$660.4	88.1%
2012/2013	$349.5	$268.4	$904.7	($379.9)	$524.8	($94.0)	$18.4	$62.1	$523.9	99.8%	$256.4	48.9%	$300.1	57.2%
2013/2014	$337.7	$626.6	$2,231.3	($360.6)	$1,870.6	($139.4)	($49.0)	($49.0)	$824.8	44.1%	$554.6	29.7%	$554.6	29.7%
2014/2015	$482.4	$348.1	$1,625.9	($268.3)	$1,357.6	$36.7	$111.2	$400.6	$867.2	63.9%	$673.4	49.6%	$962.8	70.9%
2015/2016	$635.3	$209.2	$1,098.7	($147.6)	$951.1	$9.2	$42.1	$188.9	$853.7	89.8%	$739.0	77.7%	$885.9	93.1%
2016/2017	$640.0	$149.9	$885.7	($104.8)	$780.8	$15.1	$36.5	$179.0	$805.0	103.1%	$721.6	92.4%	$864.0	110.7%
2017/2018	$427.3	$212.3	$1,322.1	($129.5)	$1,192.6	$52.3	$80.4	$370.7	$692.0	58.0%	$590.6	49.5%	$880.9	73.9%
2018/2019	$529.1	$130.1	$832.7	($152.6)	$680.0	($5.8)	$16.2	$112.2	$653.34	96.1%	$522.7	76.9%	$618.8	91.0%
2019/2020	$542.0	$91.9	$612.1	($169.4)	$442.7	($1.6)	$21.6	$157.8	$632.3	142.8%	$486.1	109.8%	$622.2	140.6%
2020/2021*	$217.9	$102.2	$488.9	($103.2)	$385.7	($19.6)	($1.8)	($1.8)	$300.49	77.9%	$215.2	55.8%	$215.2	55.8%
Total	$4,673.5	$2,448.7	$11,027.3	($2,091.6)	$8,935.7	($197.8)	$311.1	$1,534.3	$6,924.4	77.5%	$5,341.7	59.8%	$6,564.9	73.5%

Zonal ARR/FTR total congestion offset for ARR holders

Zone	ARR Credits	Adjusted FTR Credits	Balancing+ M2M Charge	Surplus Allocation	Total Offset	Day Ahead Congestion	Balancing Congestion	M2M Payments	Total Congestion	Offset
AECO	$2.5	$0.0	($1.3)	($0.1)	$1.2	$4.8	($0.9)	($0.3)	$3.6	33.5%
AEP	$23.5	$16.5	($15.4)	($1.7)	$24.6	$83.7	($10.7)	($3.9)	$69.1	35.6%
APS	$19.3	$10.7	($5.9)	($1.0)	$24.1	$31.4	($4.2)	($1.5)	$25.8	93.2%
ATSI	$11.9	$0.1	($8.0)	($0.4)	$4.0	$37.6	($5.7)	($2.0)	$29.8	13.6%
BGE	$34.3	$2.0	($3.9)	($1.2)	$32.4	$18.7	($2.6)	($1.0)	$15.1	213.9%
ComEd	$21.3	$7.7	($11.9)	($0.9)	$17.2	$56.7	($8.1)	($3.0)	$45.6	37.7%
DAY	$3.5	$0.3	($2.1)	($0.1)	$1.7	$9.0	($1.5)	($0.5)	$7.0	24.1%
DEOK	$14.2	$1.6	($3.3)	($0.6)	$12.5	$13.3	($2.3)	($0.8)	$10.2	122.5%
DLCO	$3.3	$0.1	($2.3)	($0.1)	$1.1	$5.9	($1.3)	($0.6)	$4.1	27.1%
Dominion	$4.4	$49.9	($1.7)	($1.3)	$52.7	$68.0	($14.6)	($0.4)	$52.9	99.5%
DPL	$16.6	$3.8	($13.0)	($0.6)	$7.4	$25.9	($2.0)	($3.3)	$20.6	35.9%
EKPC	$1.8	$0.0	($1.6)	($0.1)	$0.2	$6.7	($1.1)	($0.4)	$5.2	4.1%
EXT	$0.3	$0.0	($6.5)	($0.0)	($6.2)	$13.7	($3.4)	($1.6)	$8.6	(72.4%)
JCPL	$3.5	$0.0	($2.9)	($0.1)	$0.6	$11.0	($2.0)	($0.7)	$8.2	7.5%
Met-Ed	$2.0	$0.4	($1.9)	($0.1)	$0.5	$13.2	($2.1)	($0.5)	$10.5	4.4%
OVEC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.8	($0.1)	$0.0	$0.7	0.0%
PECO	$8.8	$0.2	($4.9)	($0.3)	$4.0	$17.5	($3.2)	($1.2)	$13.0	30.7%
PENELEC	$3.5	$2.9	($2.1)	($0.2)	$4.4	$12.0	($1.6)	($0.5)	$9.8	44.6%
Pepco	$15.1	$2.2	($3.5)	($0.6)	$13.8	$15.1	($2.4)	($0.9)	$11.8	116.9%
PPL	$13.6	$1.8	($5.0)	($0.5)	$10.4	$21.8	($3.3)	($1.3)	$17.3	60.5%
PSEG	$14.3	$0.0	($5.6)	($0.5)	$8.8	$21.3	($3.9)	($1.4)	$16.0	54.8%
RECO	$0.1	$0.0	($0.2)	($0.0)	($0.1)	$0.8	($0.2)	($0.0)	$0.6	(11.3%)
Total	$217.9	$100.4	($103.2)	($10.4)	$215.2	$488.9	($77.3)	($25.9)	$385.7	55.8%

Congestion offset if all ARRs self scheduled

	17/18 Planning Period				18/19 Planning Period				19/20 Planning Period			
	SS FTR	Bal+M2M	Congestion+M2M	Offset	SS FTR	Bal+M2M	Congestion+M2M	Offset	SS FTR	Bal+M2M	Congestion+M2M	Offset
AECO	$1.8	($1.6)	$13.2	1.4%	$11.5	($1.9)	$9.7	99.3%	$2.6	($2.0)	$3.7	16.3%
AEP	$203.3	($20.4)	$189.3	96.6%	$84.9	($23.7)	$102.0	60.0%	$62.7	($26.2)	$79.9	45.7%
APS	$78.7	($7.8)	$57.2	123.9%	$37.4	($9.2)	$43.0	65.5%	$31.2	($10.1)	$30.9	68.2%
ATSI	$54.1	($10.6)	$71.2	61.0%	$45.3	($12.4)	$50.7	65.0%	$27.9	($13.5)	$35.8	40.3%
BGE	$83.1	($5.0)	$42.6	183.3%	$49.0	($5.8)	$19.2	224.9%	$53.7	($6.4)	$14.9	316.6%
ComEd	$110.9	($15.4)	$181.0	52.8%	$51.4	($17.8)	$95.9	35.1%	$40.6	($19.6)	$66.9	31.4%
DAY	$10.5	($2.8)	$21.2	36.7%	$11.2	($3.2)	$12.2	65.0%	$5.6	($3.5)	$9.5	21.3%
DEOK	$72.2	($4.3)	$37.6	180.5%	$50.4	($5.0)	$22.7	199.9%	$30.5	($5.6)	$14.5	171.6%
DLCO	$10.6	($2.2)	$12.2	68.9%	$7.2	($2.5)	$7.4	63.5%	$8.1	($3.8)	$5.0	86.2%
Dominion	$42.4	($15.8)	$133.8	19.9%	$55.8	($18.7)	$63.5	58.5%	$32.8	($2.8)	$57.7	52.1%
DPL	$38.0	($2.9)	$68.6	51.1%	$57.7	($3.4)	$58.5	92.8%	$27.3	($21.0)	$17.6	35.9%
EKPC	($3.5)	($2.1)	$20.5	(27.2%)	$0.9	($2.4)	$9.0	(16.8%)	$4.1	($2.7)	$7.2	20.3%
EXT	$3.4	($5.2)	$28.7	(6.3%)	$1.7	($7.5)	$13.6	(42.7%)	$0.9	($9.0)	$7.0	(115.0%)
JCPL	$2.7	($3.6)	$32.1	(2.7%)	$2.6	($4.2)	$19.7	(7.9%)	$2.3	($4.6)	$9.0	(25.3%)
Met-Ed	$7.6	($2.5)	$26.5	19.3%	$5.0	($2.9)	$14.0	14.9%	$0.8	($3.2)	$8.6	(27.8%)
OVEC	$0.0	$0.0	$0.0	0.0%	$0.0	$0.0	$0.0	0.0%	$0.0	$0.0	$0.3	0.0%
PECO	$15.7	($6.4)	$57.7	16.2%	$15.7	($7.5)	$28.7	28.5%	$16.8	($8.1)	$12.5	68.9%
PENELEC	$15.4	($2.7)	$30.5	41.7%	$17.5	($3.2)	$18.3	78.2%	$11.2	($3.5)	$10.6	72.2%
Pepco	$38.1	($4.8)	$39.2	84.9%	$19.5	($5.5)	$17.4	80.3%	$23.2	($6.0)	$13.3	128.9%
PPL	$14.7	($6.4)	$65.3	12.7%	$4.3	($7.6)	$35.3	(9.2%)	$39.2	($8.4)	$19.8	155.7%
PSEG	$58.6	($6.9)	$62.4	82.9%	$35.6	($8.1)	$37.5	73.5%	$21.3	($8.9)	$17.8	69.6%
RECO	($0.1)	($0)	$1.9	(17.1%)	$0.2	($0.3)	$1.7	(6.2%)	$0.2	($0.3)	$0.7	(18.0%)
Total	$858.0	($129.5)	$1,192.6	61.1%	$565.0	($152.7)	$680.2	60.6%	$443.0	($169.4)	$443.1	61.8%

FTR profits and revenues by organization type and FTR direction: 2020/2021, June through December 2020

	Purchased FTRs Profit			Self Scheduled FTRs Revenue Returned		
Organization Type	Prevailing Flow	Counter Flow	Total	Prevailing Flow	Counter Flow	Total
Financial	$90,794,341	$50,528,260	$141,322,601			
Financial without GreenHat	$90,793,495	$50,742,745	$141,536,240			
Physical	$30,623,624	($2,177,071)	$28,446,553			
Physical ARR	$18,981,886	($8,307,034)	$10,674,852	$102,175,029	($11,002)	$102,164,027
Total	$140,399,851	$40,044,155	$180,444,006	$102,175,029	($11,002)	$102,164,027

Market Monitoring Unit

The State of the Market Report is the work of the entire Market Monitoring Unit.

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