2018 State of the Market Report for PJM

Press Briefing

March 14, 2019

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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**
- **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**

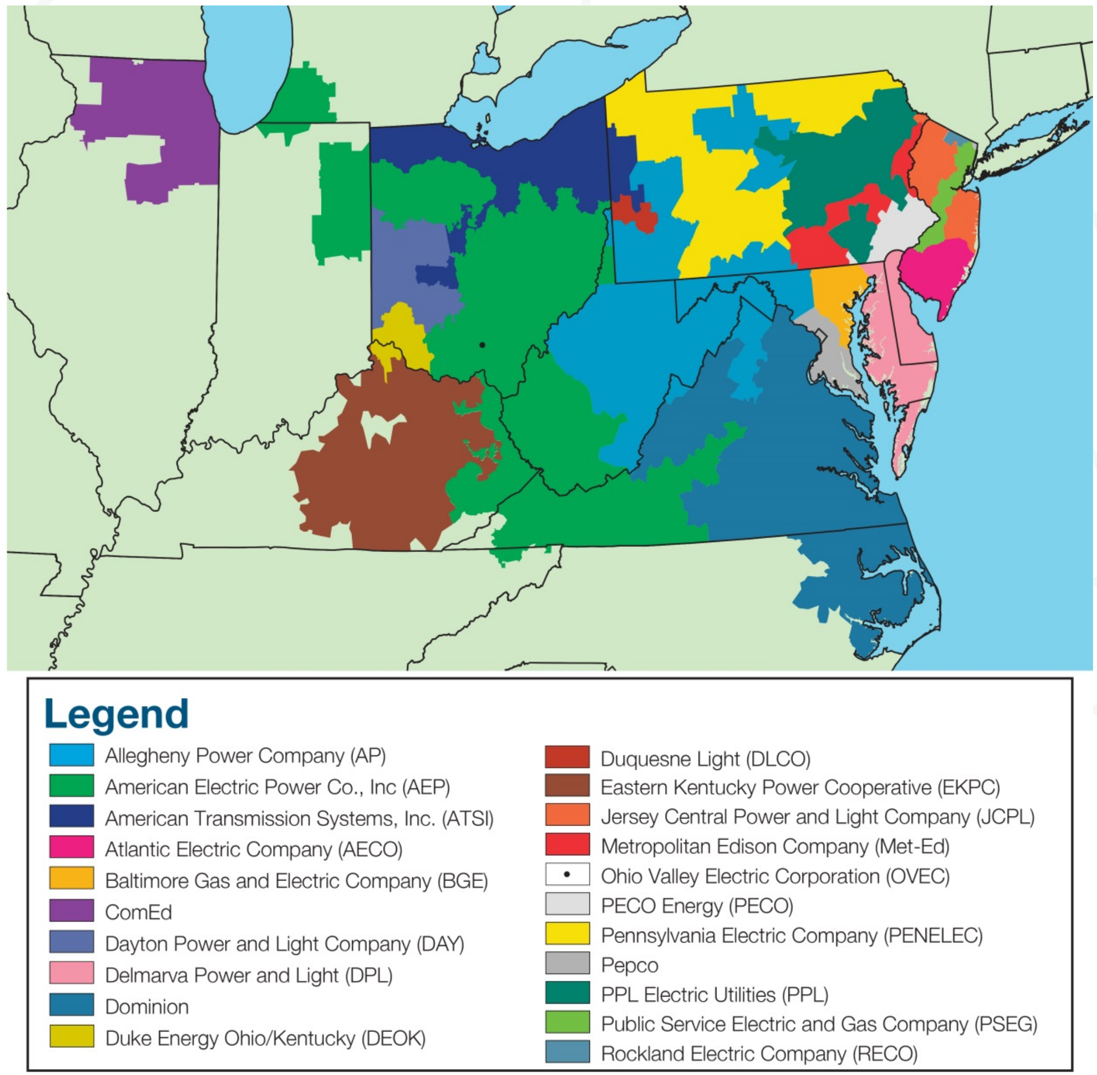
Role of Market Monitoring

- **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’s footprint and its 21 control zones



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

- Clear criteria for operator approval of RTSCED cases for dispatch and pricing.
- Cost based offers equal to short run marginal cost
  - Replace Manual 15 with clear definitions for cost-based offers
  - Clear definition of relevant operating expenses
  - Fuel cost policies: algorithmic, verifiable, systematic
- OEM parameters from CONE unit should be used for performance assessment and uplift
- Local market power mitigation improvements (TPS)
  - Constant markup on price and cost based offers
  - Cost based offer with same fuel as price based offer
  - PLS parameters at least as flexible as price based offer

Total price per MWh by category

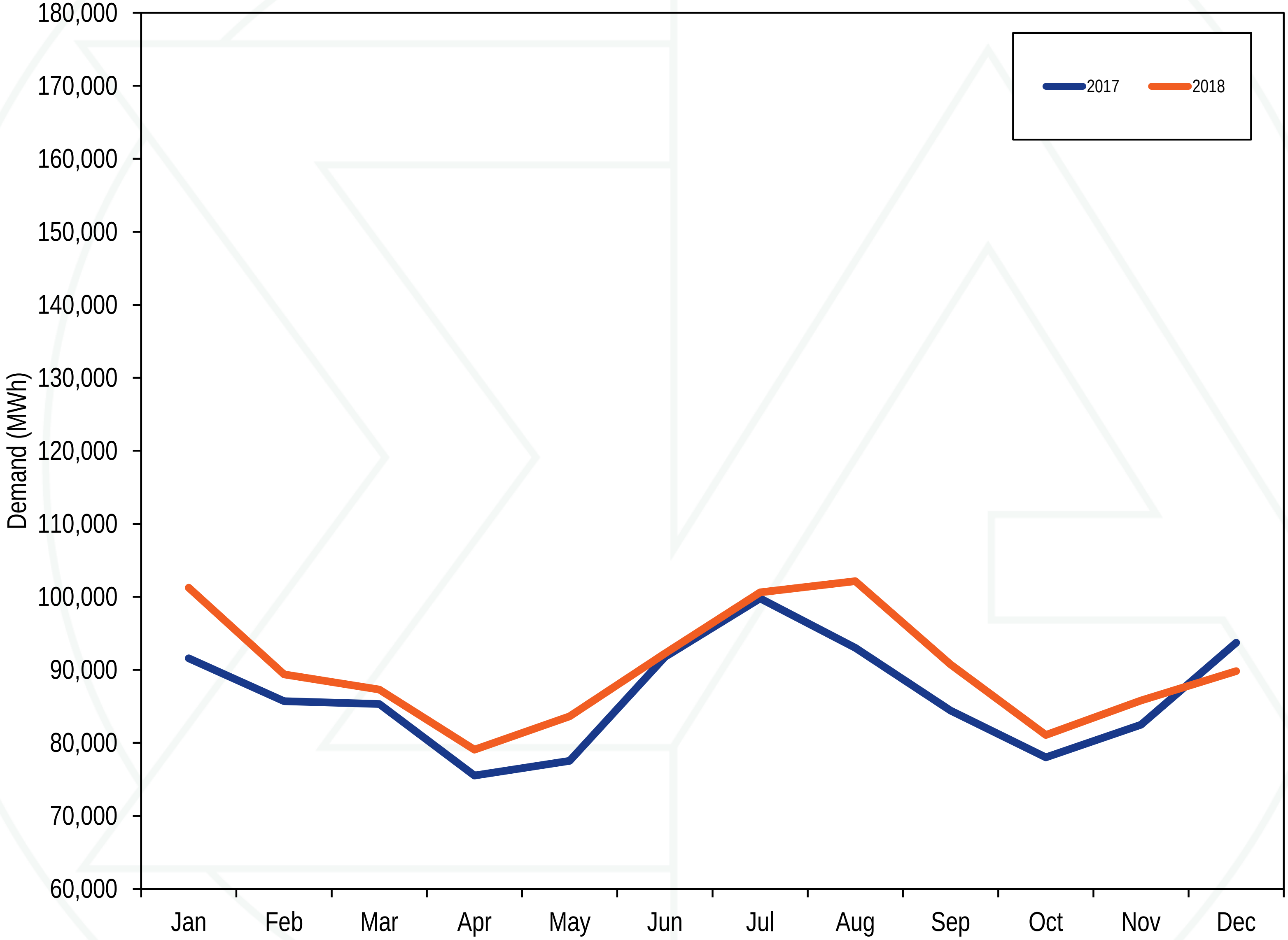
Category	2017 $/MWh	2017 ($ Millions)	2017 Percent of Total	2018 $/MWh	2018 ($ Millions)	2018 Percent of Total	Percent Change
Load Weighted Energy	$30.99	$23,513	58.2%	$38.24	$30,253	61.4%	23.4%
Capacity	$11.27	$8,552	21.2%	$13.01	$10,295	20.9%	15.5%
Capacity	$11.23	$8,524	21.1%	$12.97	$10,260	20.8%	15.5%
Capacity (FRR)	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Capacity (RMR)	$0.04	$28	0.1%	$0.04	$34	0.1%	17.1%
Transmission	$9.54	$7,242	17.9%	$9.47	$7,494	15.2%	(0.8%)
Transmission Service Charges	$8.83	$6,703	16.6%	$8.81	$6,966	14.1%	(0.3%)
Transmission Enhancement Cost Recovery	$0.64	$487	1.2%	$0.57	$454	0.9%	(10.6%)
Transmission Owner (Schedule 1A)	$0.10	$73	0.2%	$0.09	$74	0.2%	(3.0%)
Transmission Seams Elimination Cost Assignment (SECA)	($0.03)	($21)	(0.1%)	$0.00	$0	0.0%	(100.0%)
Transmission Facility Charges	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Ancillary	$0.77	$585	1.4%	$0.83	$654	1.3%	7.3%
Reactive	$0.43	$327	0.8%	$0.43	$342	0.7%	0.1%
Regulation	$0.14	$104	0.3%	$0.18	$145	0.3%	33.6%
Black Start	$0.09	$70	0.2%	$0.08	$65	0.1%	(10.7%)
Synchronized Reserves	$0.06	$42	0.1%	$0.06	$50	0.1%	14.7%
Non-Synchronized Reserves	$0.01	$7	0.0%	$0.02	$15	0.0%	106.4%
Day Ahead Scheduling Reserve (DASR)	$0.05	$35	0.1%	$0.05	$37	0.1%	2.0%
Administration	$0.52	$393	1.0%	$0.50	$399	0.8%	(2.8%)
PJM Administrative Fees	$0.48	$367	0.9%	$0.47	$371	0.8%	(2.9%)
NERC/RFC	$0.03	$24	0.1%	$0.03	$25	0.1%	(0.9%)
RTO Startup and Expansion	$0.00	$2	0.0%	$0.00	$2	0.0%	(3.2%)
Energy Uplift (Operating Reserves)	$0.14	$107	0.3%	$0.23	$186	0.4%	67.1%
Demand Response	$0.01	$5	0.0%	$0.01	$5	0.0%	(1.5%)
Load Response	$0.01	$5	0.0%	$0.01	$5	0.0%	(1.5%)
Emergency Load Response	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Emergency Energy	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Total Price	$53.24	$40,397	100.0%	$62.30	$49,285	100.0%	17.0%
Total Load (GWh)	758,775			791,093			4.3%
Total Billing ($ Billions)	$40.40			$49.29			22.0%

PJM Load

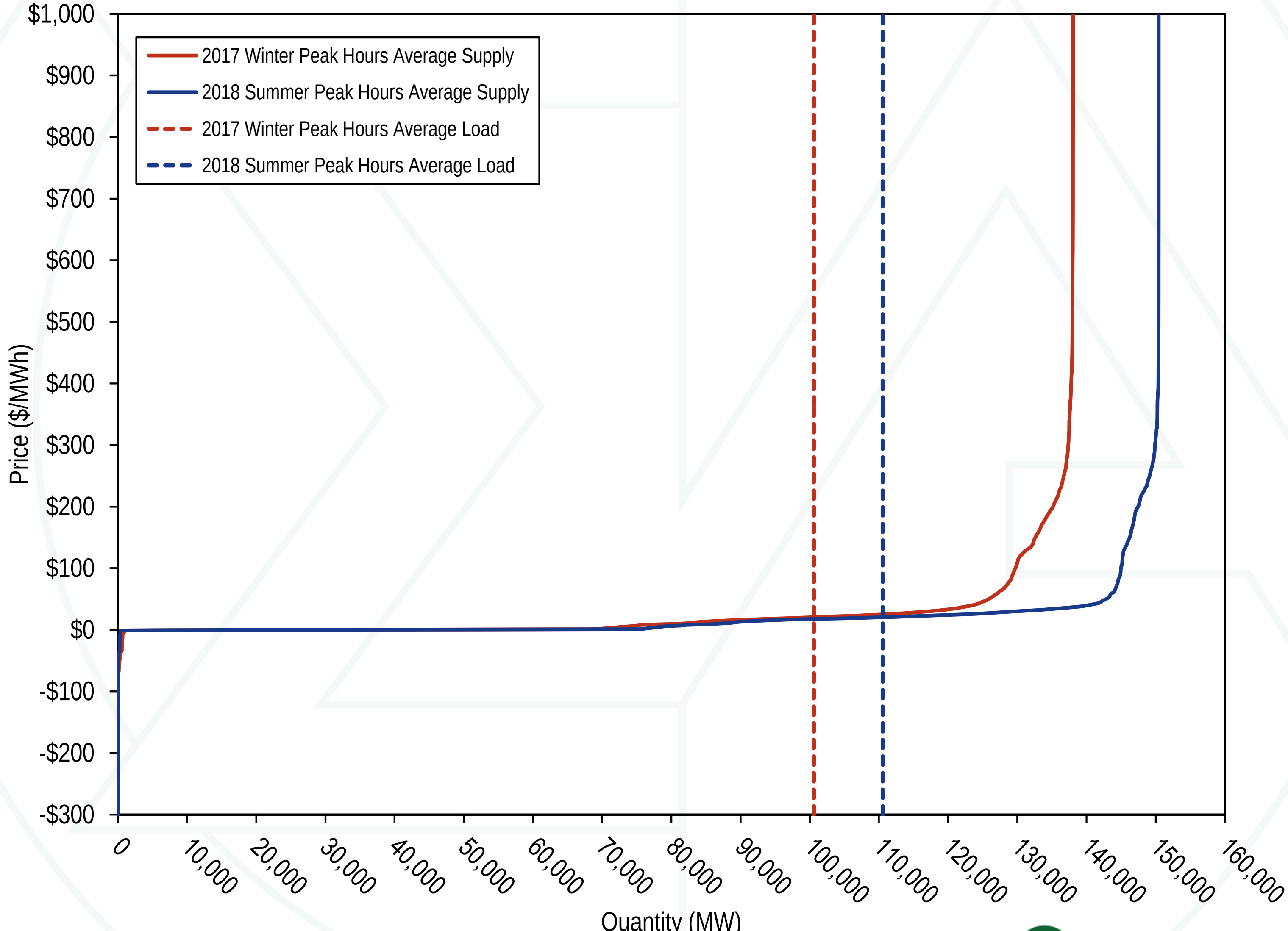
	PJM Real-Time Demand (MWh)				Year-to-Year Change			
	Load		Load Plus Exports		Load		Load Plus Exports	
	Load	Standard Deviation	Demand	Standard Deviation	Load	Standard Deviation	Demand	Standard Deviation
2001	30,297	5,873	32,165	5,564	NA	NA	NA	NA
2002	35,776	7,976	37,676	8,145	18.1%	35.8%	17.1%	46.4%
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	90,307	15,982	94,351	16,142	4.3%	5.4%	3.7%	7.0%

Monitoring Analytics

RT monthly average hourly load



Average RT generation supply curves



Generation by fuel source

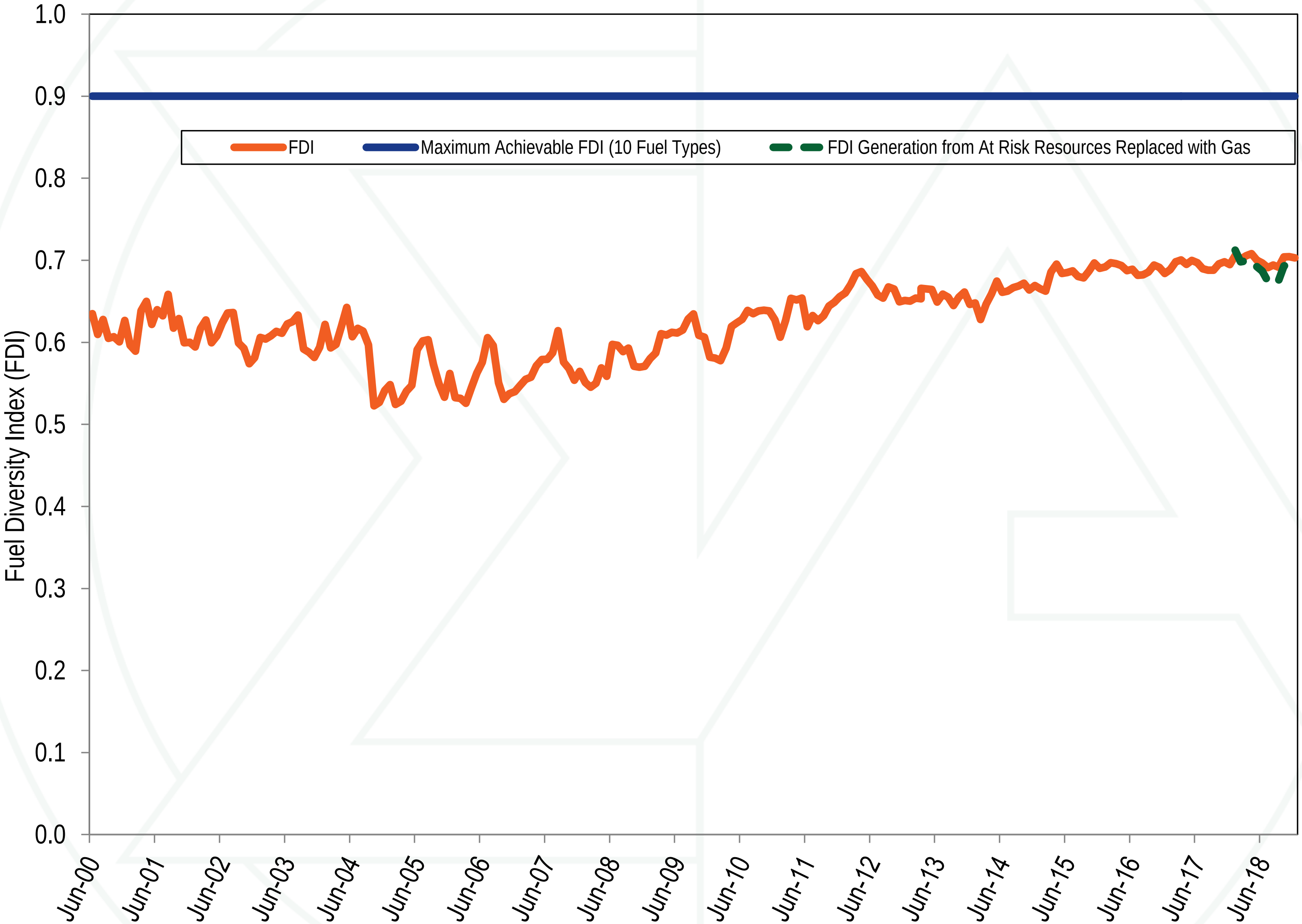
	2017 GWh	Percent	2018 GWh	Percent	Change in Output
Coal	256,613.8	31.8%	239,612.1	28.6%	(6.6%)
Bituminous	220,789.4	27.3%	201,123.6	24.0%	(8.9%)
Sub Bituminous	28,016.0	3.5%	30,136.0	3.6%	7.6%
Other Coal	7,808.4	1.0%	8,352.5	1.0%	7.0%
Nuclear	287,575.8	35.6%	286,155.4	34.2%	(0.5%)
Gas	219,205.1	27.1%	259,051.4	30.9%	18.2%
Natural Gas	216,758.6	26.8%	256,701.9	30.6%	18.4%
Landfill Gas	2,433.1	0.3%	2,309.7	0.3%	(5.1%)
Other Gas	13.4	0.0%	39.8	0.0%	197.2%
Hydroelectric	14,868.4	1.8%	19,415.5	2.3%	30.6%
Pumped Storage	5,132.6	0.6%	5,582.0	0.7%	8.8%
Run of River	8,119.8	1.0%	12,051.5	1.4%	48.4%
Other Hydro	1,616.0	0.2%	1,782.0	0.2%	10.3%
Wind	20,714.1	2.6%	21,628.0	2.6%	4.4%
Waste	3,984.1	0.5%	4,507.6	0.5%	13.1%
Solid Waste	3,740.7	0.5%	4,236.1	0.5%	13.2%
Miscellaneous	243.4	0.0%	271.5	0.0%	11.5%
Oil	2,301.7	0.3%	3,580.9	0.4%	55.6%
Heavy Oil	174.4	0.0%	435.5	0.1%	149.7%
Light Oil	340.3	0.0%	975.2	0.1%	186.5%
Diesel	81.7	0.0%	363.7	0.0%	345.4%
Gasoline	0.0	0.0%	0.0	0.0%	NA
Kerosene	15.2	0.0%	59.7	0.0%	292.0%
Jet Oil	3.1	0.0%	8.0	0.0%	157.4%
Other Oil	1,687.0	0.2%	1,738.8	0.2%	3.1%
Solar, Net Energy Metering	1,468.7	0.2%	2,110.6	0.3%	43.7%
Energy Storage	25.1	0.0%	14.4	0.0%	(42.8%)
Battery	25.1	0.0%	14.4	0.0%	(42.8%)
Compressed Air	0.0	0.0%	0.0	0.0%	NA
Biofuel	1,473.0	0.2%	1,572.5	0.2%	6.8%
Geothermal	0.0	0.0%	0.0	0.0%	NA
Other Fuel Type	0.0	0.0%	0.0	0.0%	NA
Total	808,229.7	100.0%	837,648.3	100.0%	3.6%

Capacity factor by unit type

Unit Type	2017 Generation (GWh)	2017 Capacity Factor	2018 Generation (GWh)	2018 Capacity Factor	Change in 2018 from 2017
Battery	25.1	0.9%	14.3	0.6%	(0.3%)
Combined Cycle	195,631.7	58.4%	234,614.7	60.0%	1.5%
Combustion Turbine	13,384.9	5.3%	17,590.9	6.9%	1.7%
Diesel	322.3	10.1%	351.8	10.4%	0.3%
Diesel (Landfill gas)	1,727.7	51.6%	1,712.8	51.8%	0.2%
Fuel Cell	226.7	86.2%	225.9	82.9%	(3.4%)
Nuclear	287,575.8	94.1%	286,155.4	94.2%	0.0%
Pumped Storage Hydro	6,475.4	14.6%	7,004.9	15.8%	1.2%
Run of River Hydro	8,393.0	32.0%	12,410.6	46.8%	14.8%
Solar	1,463.1	17.0%	2,104.9	17.7%	0.7%
Steam	272,282.7	40.8%	253,826.7	39.0%	(1.8%)
Biomass	5,859.6	59.3%	6,451.9	68.6%	9.2%
Coal	258,498.3	46.6%	241,022.0	44.4%	(2.2%)
Natural Gas	7,770.2	9.3%	5,987.5	7.5%	(1.8%)
Oil	154.6	0.8%	365.2	1.9%	1.2%
Wind	20,714.1	29.5%	21,626.8	28.4%	(1.1%)
Total	808,222.4	47.0%	837,639.8	47.4%	0.4%

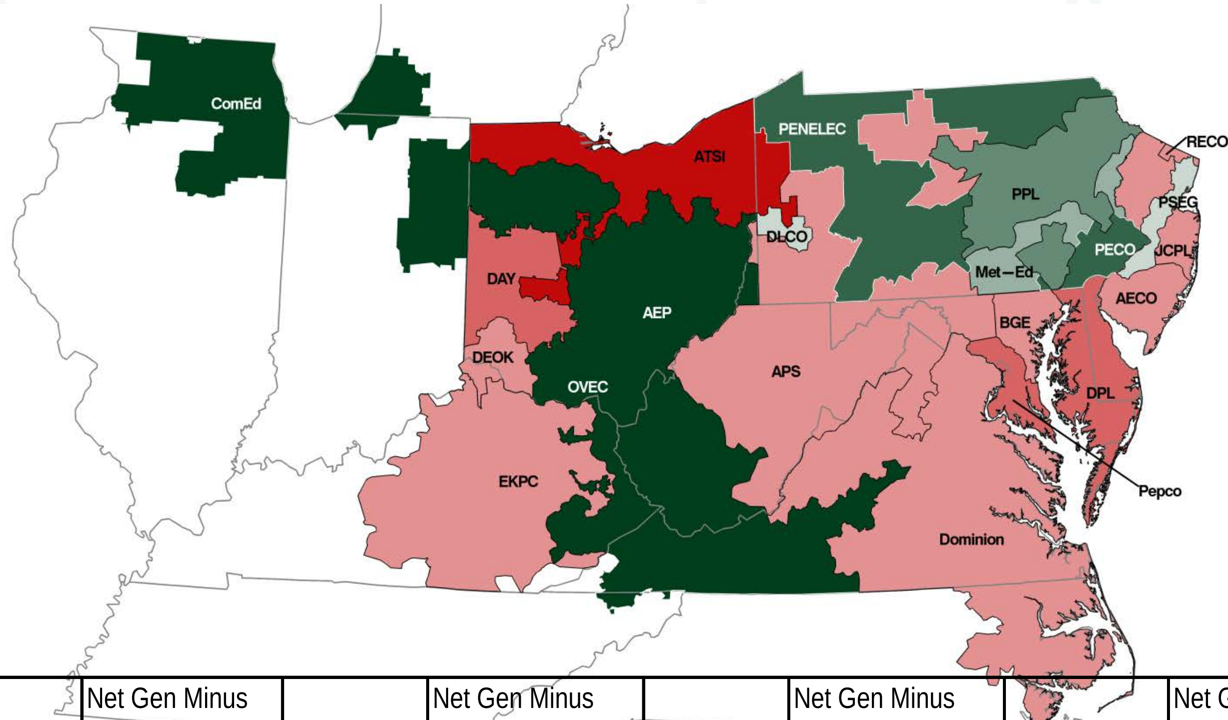
Monitoring Analytics

Fuel diversity index for energy



Monitoring Analytics

RT generation less RT load



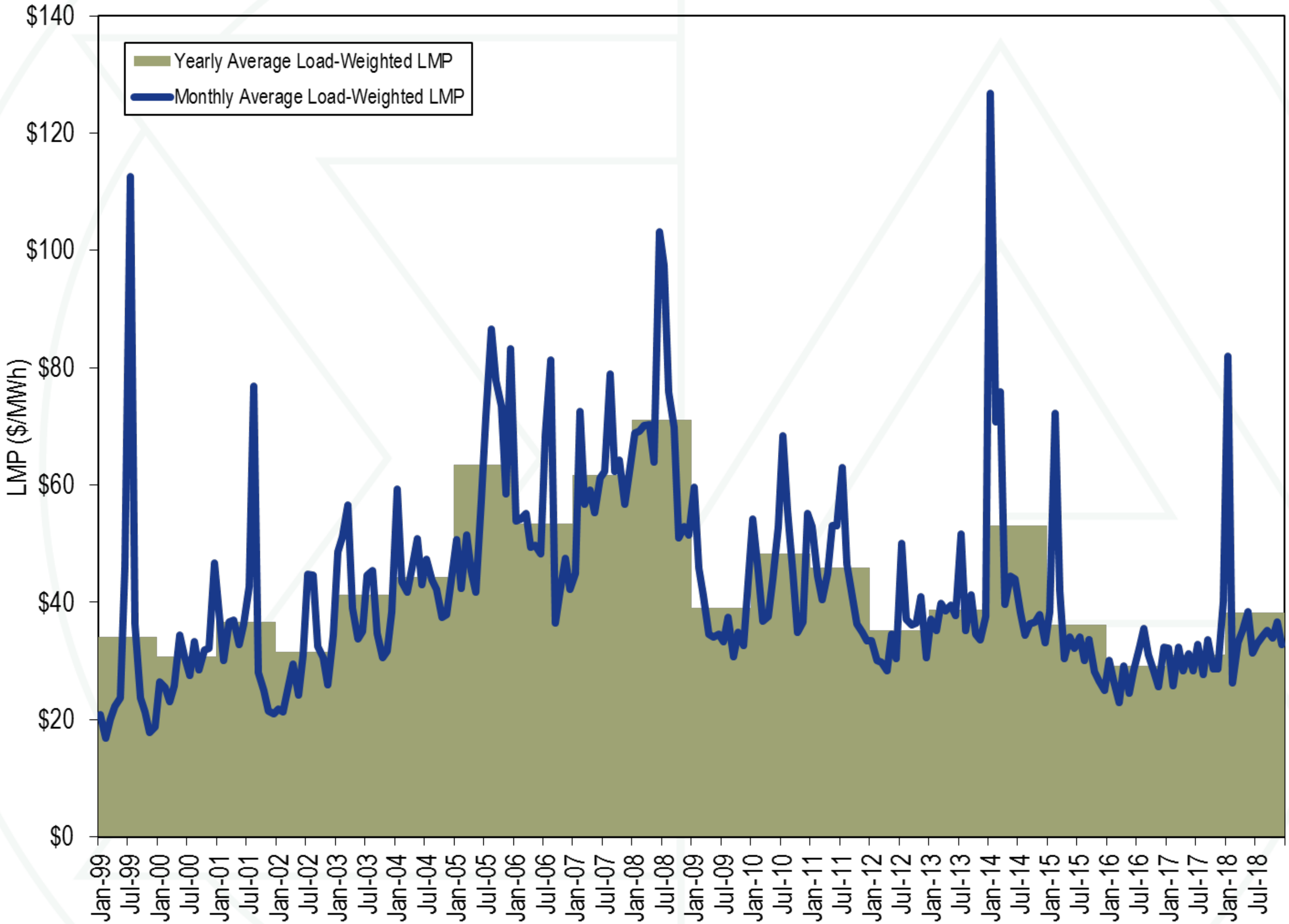
Zone	Net Gen Minus Load (GWh)	Zone	Net Gen Minus Load (GWh)	Zone	Net Gen Minus Load (GWh)	Zone	Net Gen Minus Load (GWh)
AECO	(4,581)	DAY	(13,047)	JCPL	(8,051)	PPL	16,317
AEP	31,999	DEOK	(8,005)	Met-Ed	7,011	PSEG	3,318
APS	(2,863)	Dominion	(4,610)	OVEC	1,079	RECO	(1,484)
ATSI	(27,308)	DPL	(12,440)	PECO	26,325		
BGE	(10,474)	DLCO	2,030	PENELEC	25,581		
ComEd	35,585	EKPC	(4,138)	Pepco	(17,828)		

Monitoring Analytics

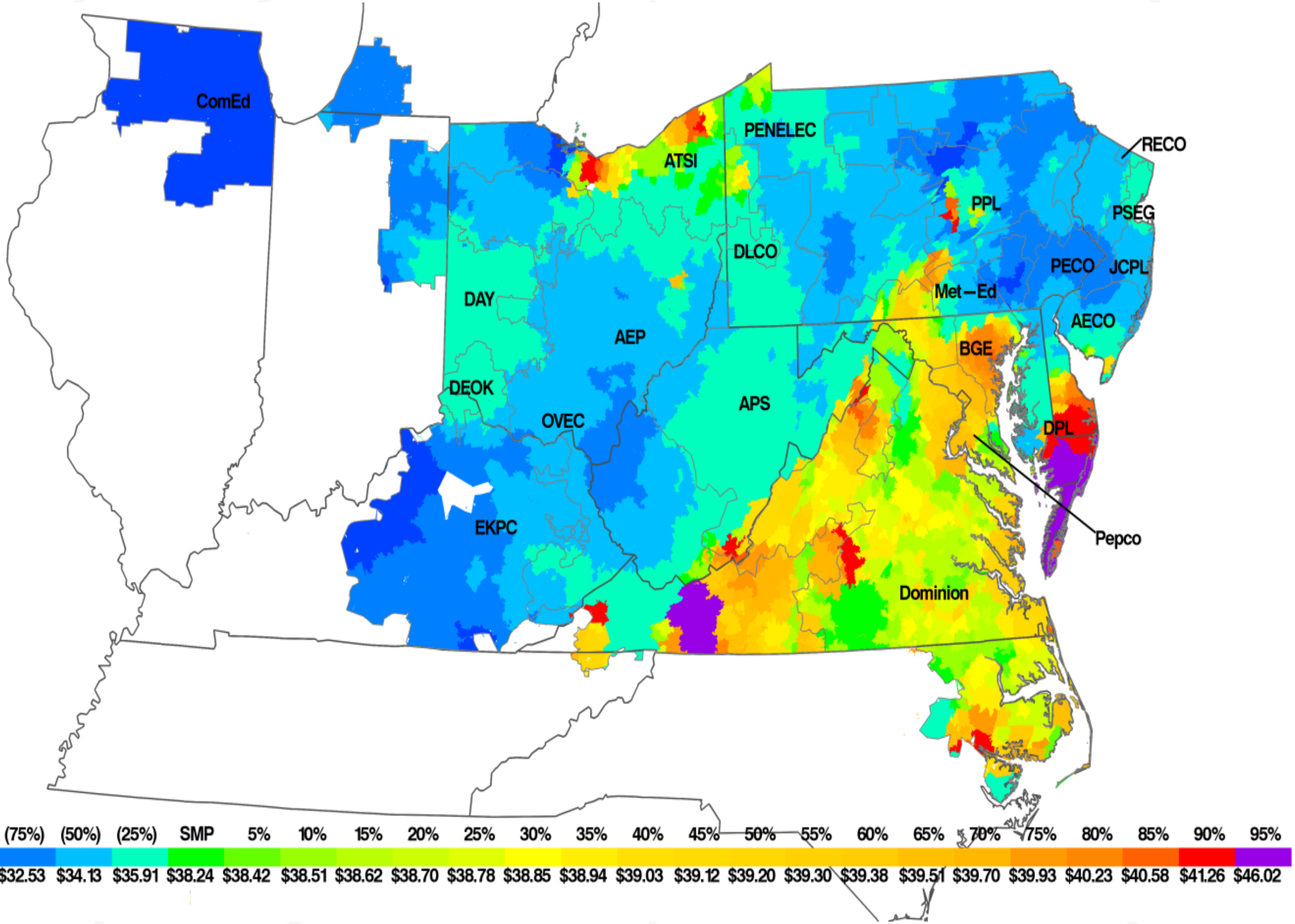
RT, load-weighted, average LMP

	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%	132.9%
2000	$30.72	$20.51	$28.38	(9.8%)	7.8%	(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%)	(0.8%)
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	37.5%	8.9%	220.4%
2015	$36.16	$27.66	$31.06	(32.0%)	(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%

RT, load-weighted, average LMP

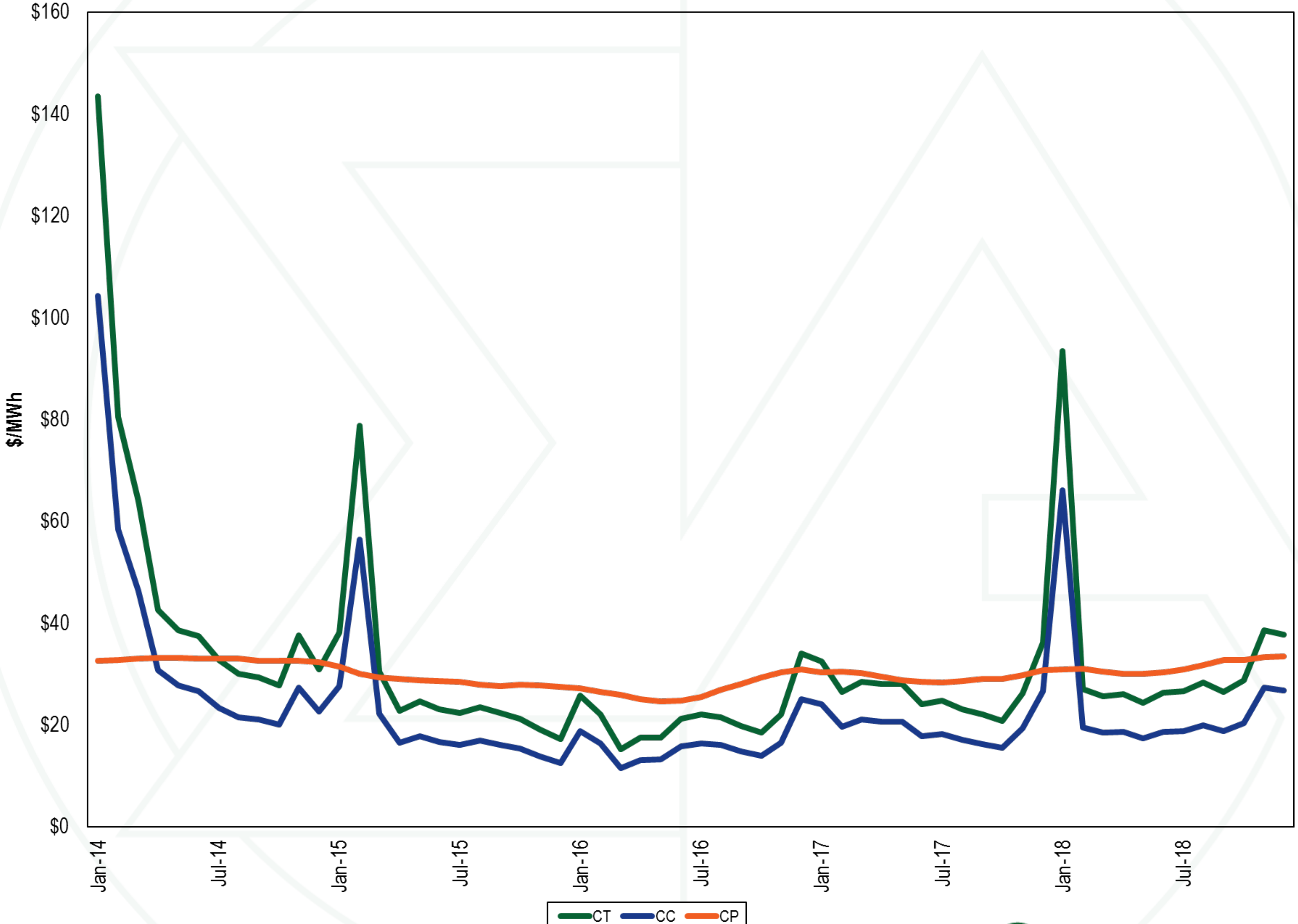


RT, load-weighted, average LMP



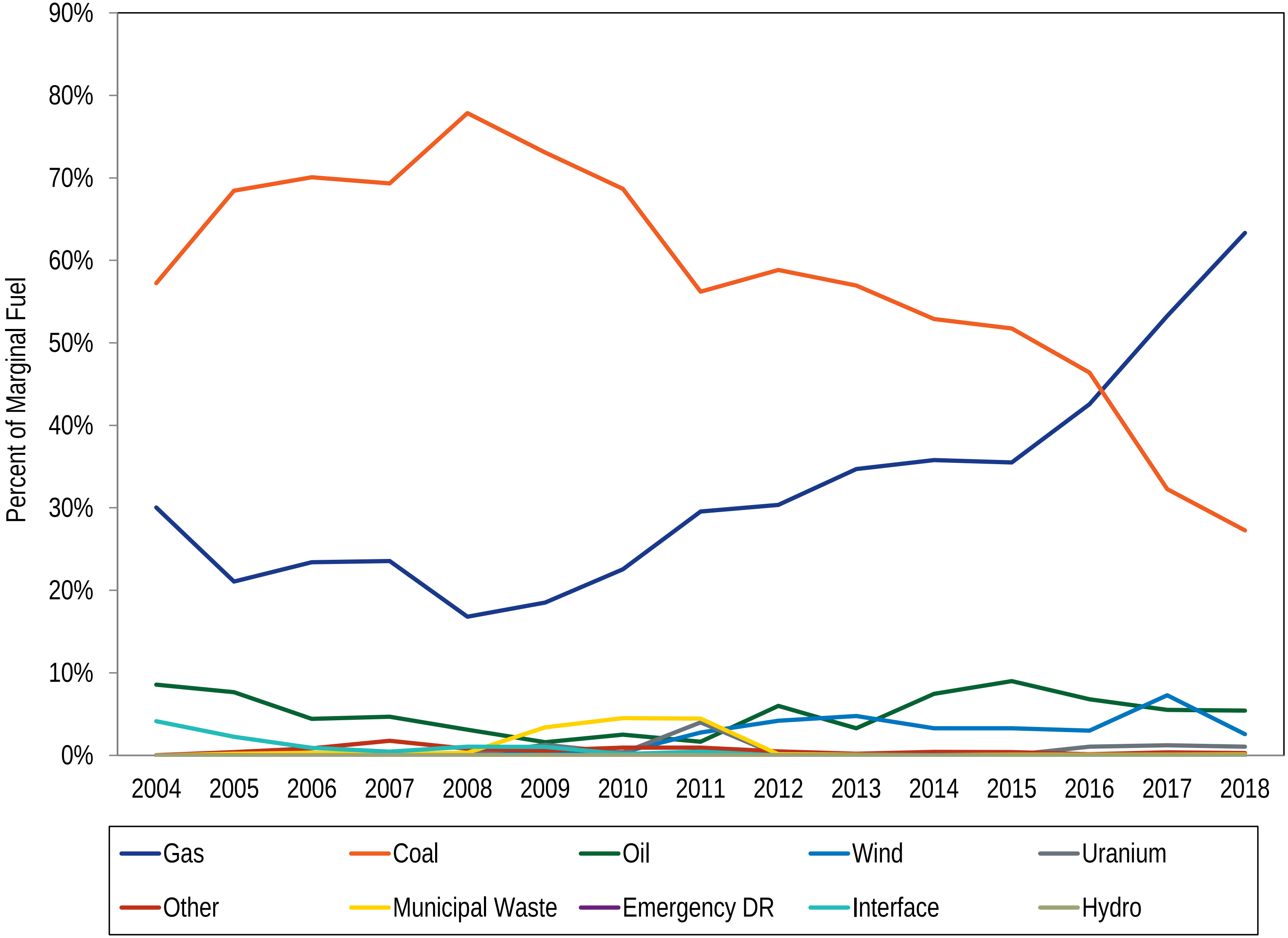
Monitoring Analytics

Short run marginal costs of generation



Monitoring Analytics

Type of fuel used by RT marginal units



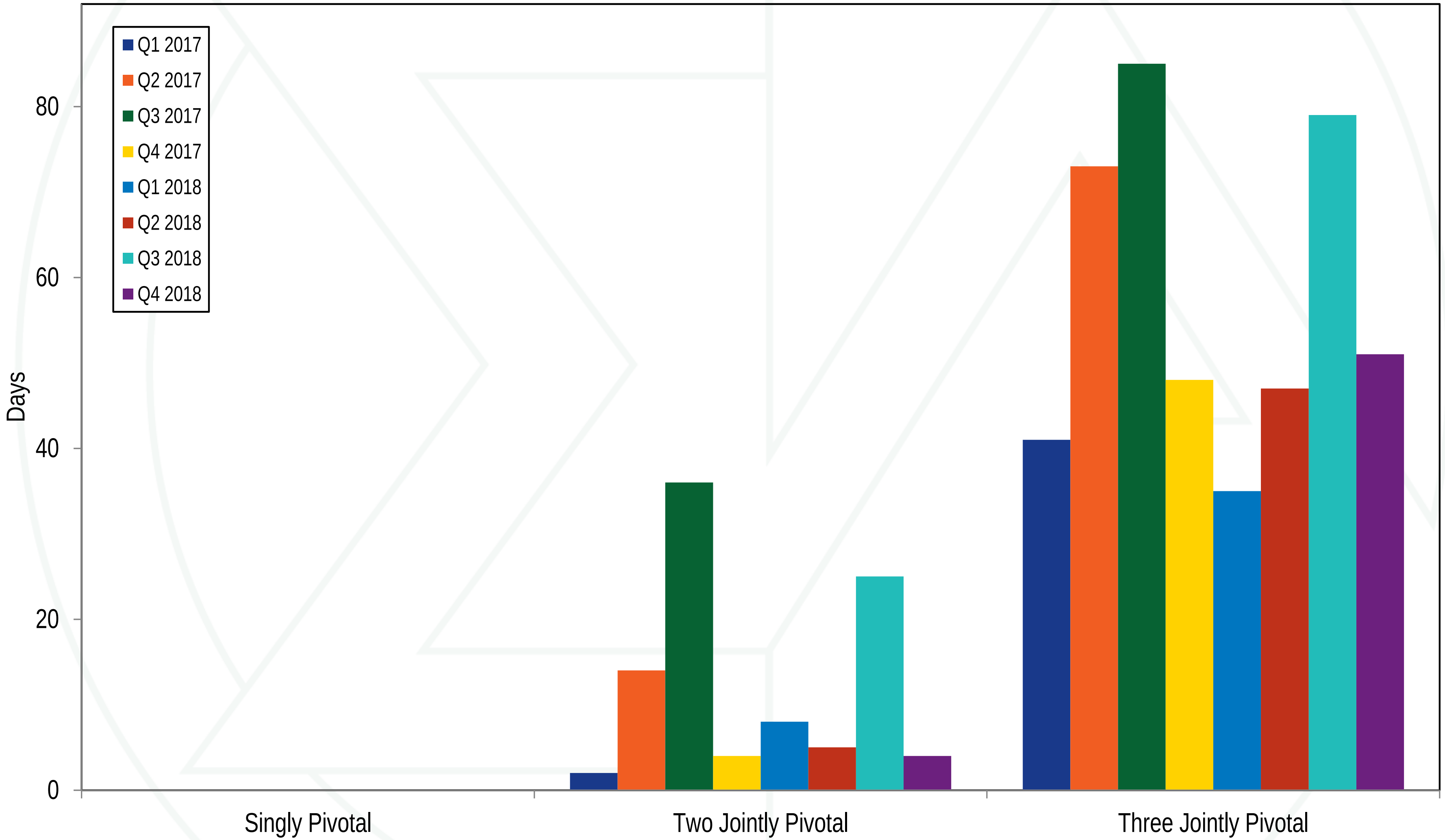
RT fuel-cost adjusted average LMP

	2018 Fuel-Cost Adjusted, Load-Weighted LMP	2018 Load-Weighted LMP	Change	Percent Change
Average	$35.68	$38.24	$2.57	7.2%
	2017 Load-Weighted LMP	2018 Fuel-Cost Adjusted, Load-Weighted LMP	Change	Percent Change
Average	$30.99	$35.68	$4.69	15.1%
	2017 Load-Weighted LMP	2018 Load-Weighted LMP	Change	Change
Average	$30.99	$38.24	$7.25	23.4%

Components of RT (Unadjusted) LMP

Element	2017 Contribution to LMP	2017 Percent	2018 Contribution to LMP	2018 Percent	Change Percent
Gas	$12.15	39.2%	$16.22	42.4%	3.2%
Coal	$8.97	28.9%	$7.43	19.4%	(9.5%)
Markup	$2.55	8.2%	$4.56	11.9%	3.7%
Ten Percent Adder	$2.39	7.7%	$2.73	7.1%	(0.6%)
NA	$0.81	2.6%	$1.88	4.9%	2.3%
Oil	$0.44	1.4%	$1.74	4.5%	3.1%
VOM	$1.70	5.5%	$1.46	3.8%	(1.7%)
Increase Generation Adder	$0.39	1.2%	$0.80	2.1%	0.8%
LPA Rounding Difference	$0.78	2.5%	$0.60	1.6%	(0.9%)
Ancillary Service Redispatch Cost	$0.25	0.8%	$0.44	1.2%	0.3%
CO_2 Cost	$0.09	0.3%	$0.16	0.4%	0.1%
Municipal Waste	$0.05	0.2%	$0.10	0.3%	0.1%
Opportunity Cost Adder	$0.04	0.1%	$0.10	0.3%	0.1%
NO_x Cost	$0.41	1.3%	$0.09	0.2%	(1.1%)
Other	$0.06	0.2%	$0.06	0.1%	(0.0%)
Scarcity Adder	$0.05	0.2%	$0.02	0.1%	(0.1%)
SO_2 Cost	$0.06	0.2%	$0.01	0.0%	(0.2%)
Market-to-Market Adder	$0.00	0.0%	$0.01	0.0%	0.0%
Constraint Violation Adder	$0.00	0.0%	($0.00)	(0.0%)	(0.0%)
Uranium	$0.00	0.0%	($0.00)	(0.0%)	(0.0%)
Wind	($0.11)	(0.4%)	($0.01)	(0.0%)	0.3%
LPA-SCED Differential	($0.01)	(0.0%)	($0.02)	(0.0%)	(0.0%)
Renewable Energy Credits	$0.00	0.0%	($0.03)	(0.1%)	(0.1%)
Decrease Generation Adder	($0.07)	(0.2%)	($0.10)	(0.3%)	(0.0%)
Total	$30.99	100.0%	$38.24	100.0%	0.0%

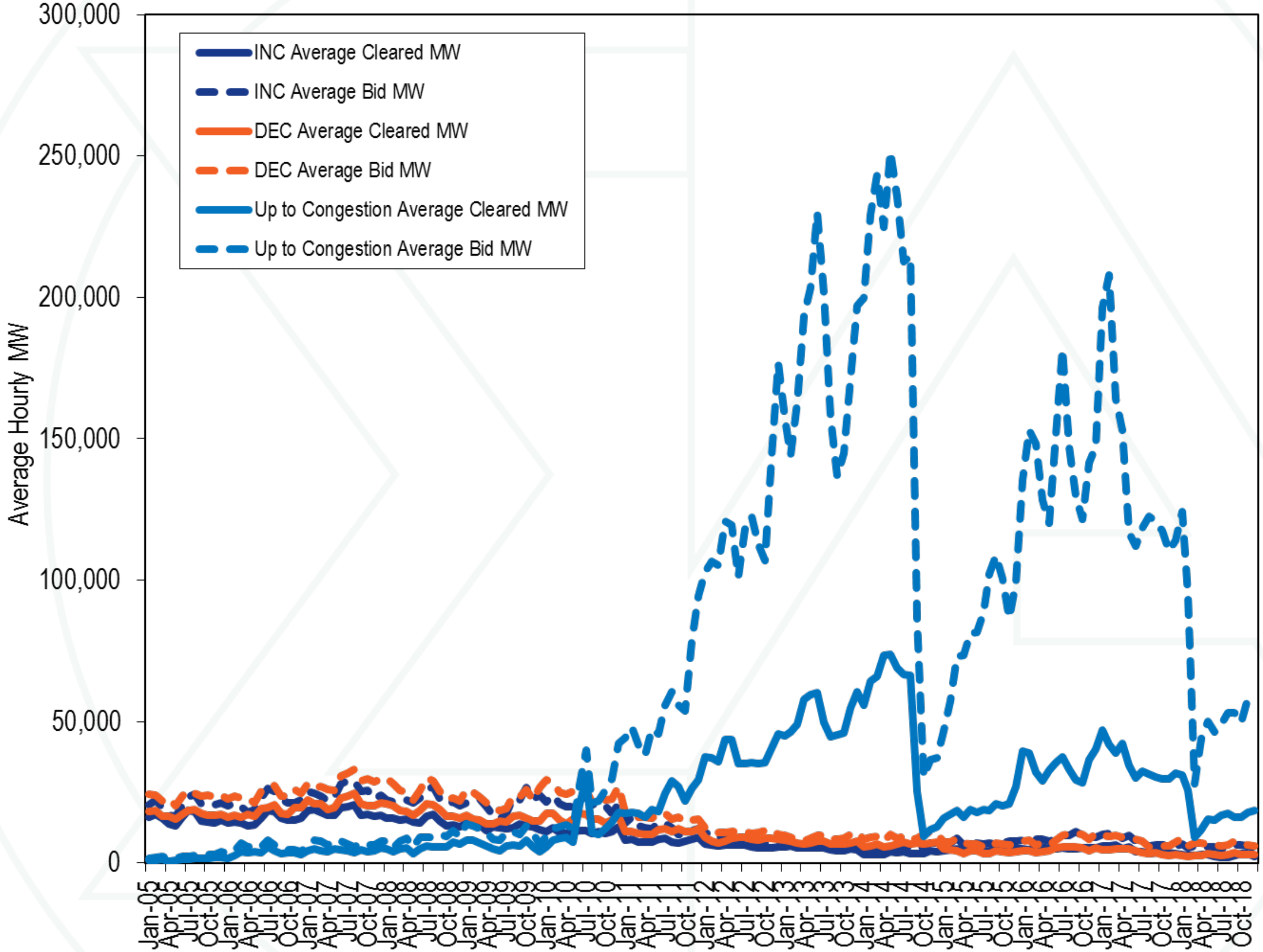
DA Energy Market: Days with pivotal suppliers



Offer capping statistics – energy only

	Real-Time		Day-Ahead	
Year	Unit Hours Capped	MWh Capped	Unit Hours Capped	MWh Capped
2014	0.9%	0.5%	0.6%	0.4%
2015	0.7%	0.8%	0.6%	0.7%
2016	0.4%	0.3%	0.1%	0.1%
2017	0.4%	0.4%	0.1%	0.2%
2018	1.0%	0.8%	0.2%	0.3%

Monthly bid and cleared INCs, DECs and UTCs



Monitoring Analytics

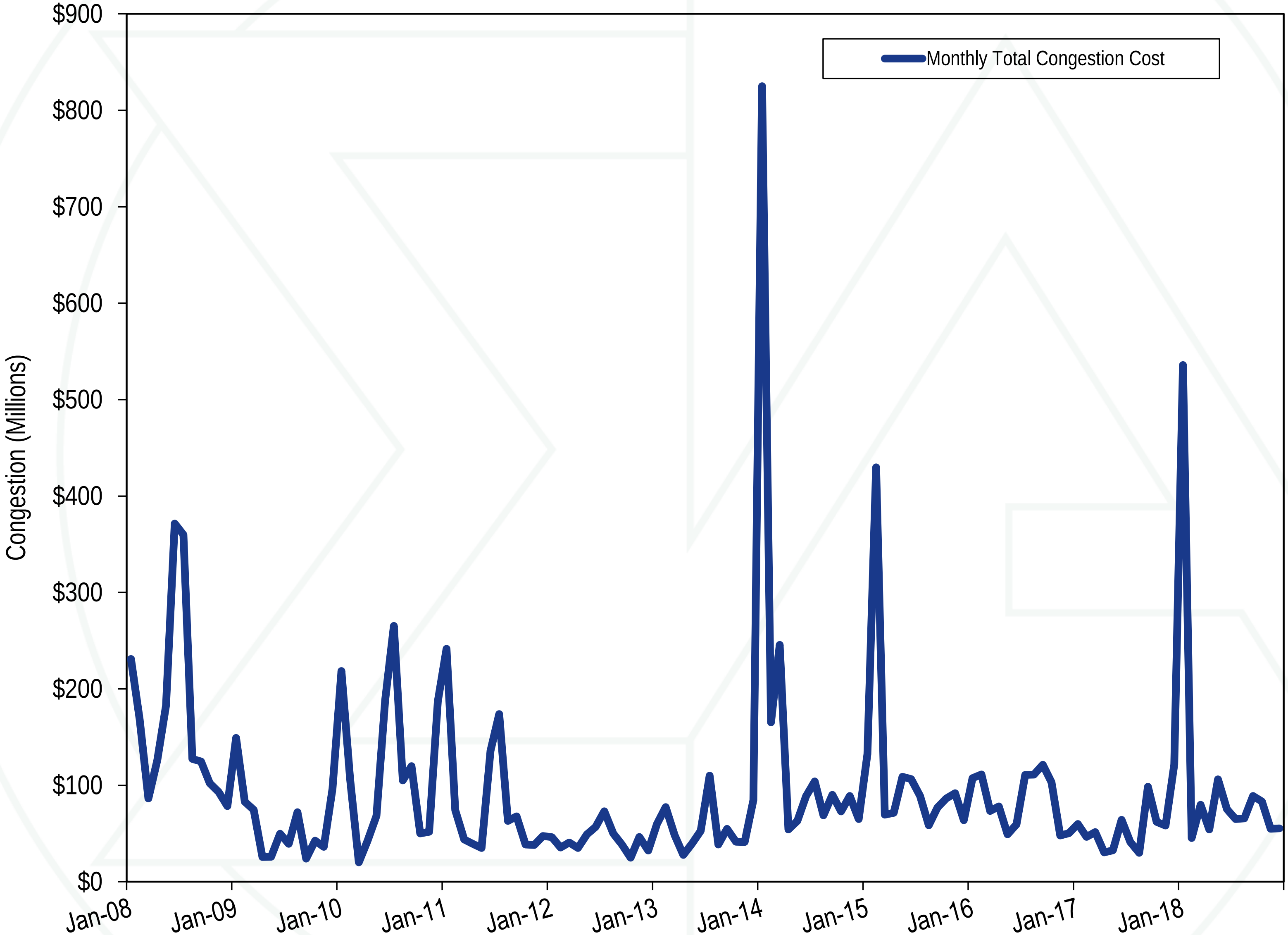
UTC transactions by type of parent

	2017				2018			
Category	Total Up to Congestion Bid	Percent	Total Up to Congestion Cleared MWh	Percent	Total Up to Congestion Bid	Percent	Total Up to Congestion Cleared MWh	Percent
Financial	1,142,283,154	94.9%	283,434,835	92.6%	505,934,059	98.5%	148,334,212	96.1%
Physical	61,503,398	5.1%	22,529,428	7.4%	7,838,021	1.5%	6,053,802	3.9%
Total	1,203,786,552	100.0%	305,964,263	100.0%	513,772,079	100.0%	154,388,014	100.0%

Total congestion

	Congestion Costs (Millions)			
	Congestion Cost	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$2,052	NA	$34,306	6.0%
2009	$719	(65.0%)	$26,550	2.7%
2010	$1,423	98.0%	$34,771	4.1%
2011	$999	(29.8%)	$35,887	2.8%
2012	$529	(47.0%)	$29,181	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%

Monthly total congestion cost



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

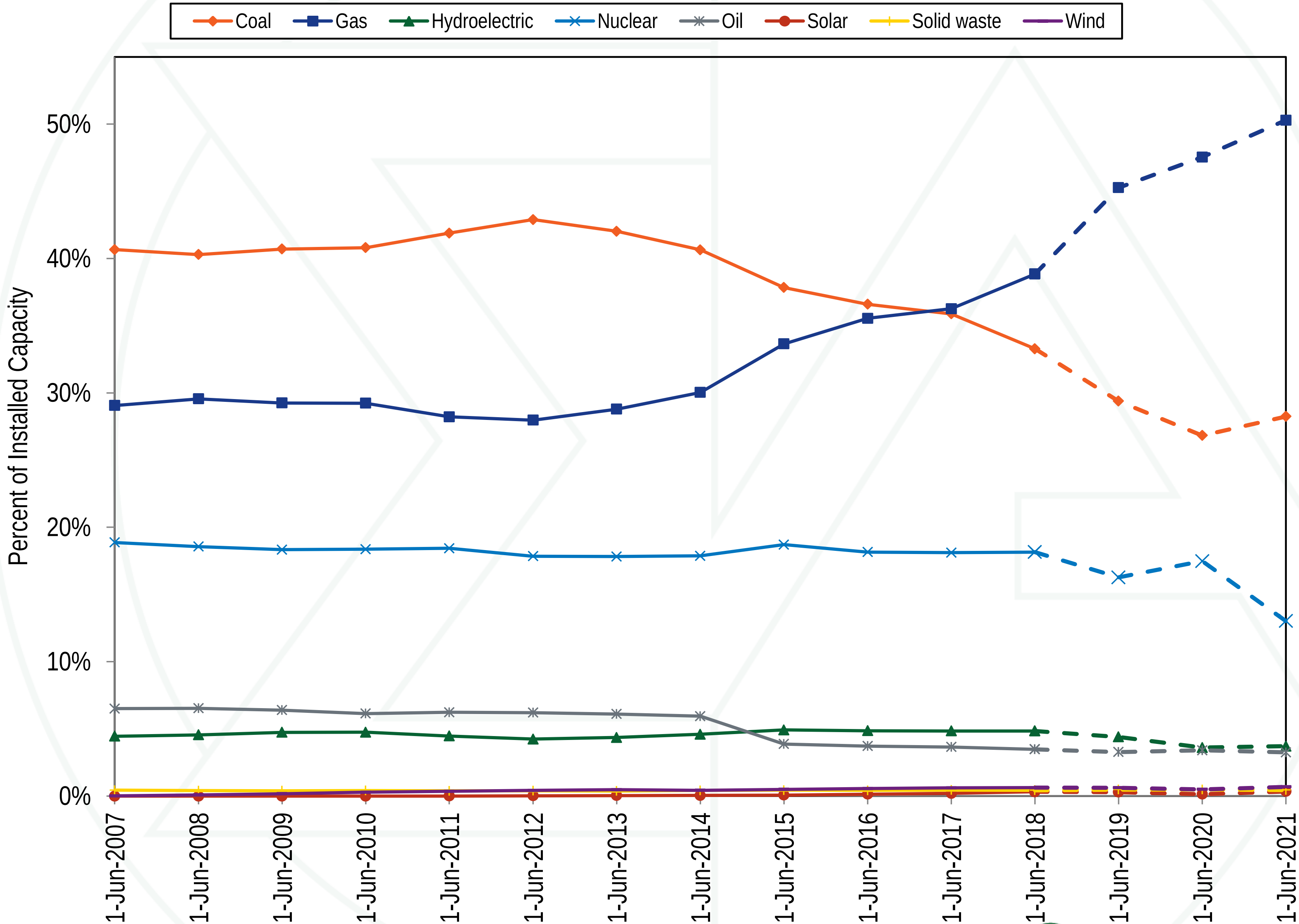
Recommendations: Capacity Market

- **Implement Sustainable Market Rule (SMR).**
- **Offer cap calculation should be based on economic logic of CP and actual PAH and not default to Net CONE*B.**
- **All capacity imports should be deliverable to an LDA.**
- **Consistent definition of a capacity resource as physical at time of auction and delivery year.**
- **Definition of LDA should be dynamic and market based.**
- **Net revenue calculation for offer caps should be based on lower of price or cost.**
- **Improve market clearing rules by including make whole and nesting in optimization.**
- **Maintain performance incentives and product definitions in Capacity Performance design.**
- **RMR rules should be modified.**

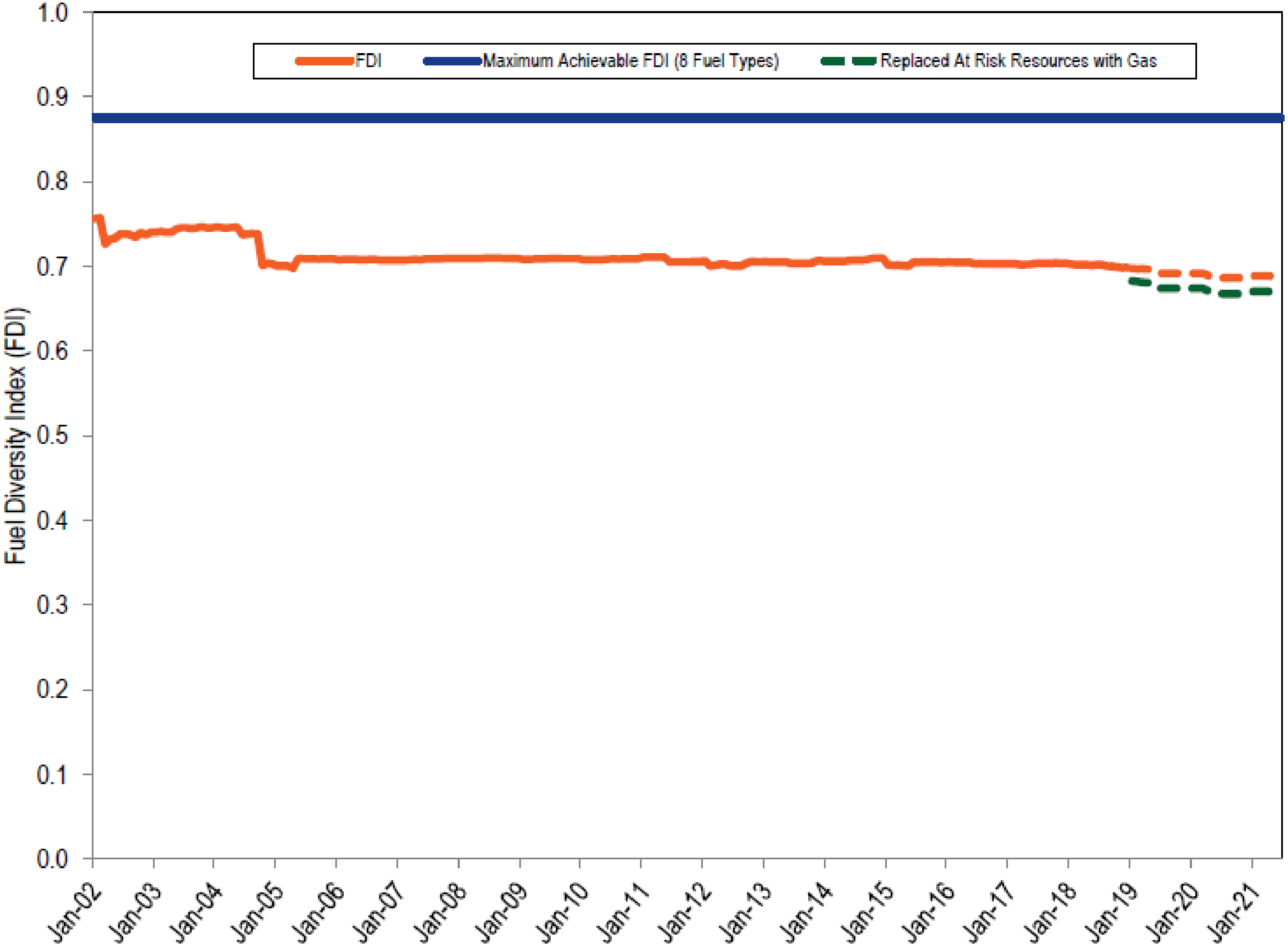
Installed capacity by fuel source

	01-Jan-18		31-May-18		01-Jun-18		31-Dec-18	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	65,144.0	35.4%	64,992.8	35.1%	61,033.1	33.3%	60,763.4	32.7%
Gas	67,811.4	36.9%	69,256.9	37.4%	71,241.8	38.8%	74,716.8	40.2%
Hydroelectric	8,856.2	4.8%	8,819.0	4.8%	8,888.2	4.8%	8,888.2	4.8%
Nuclear	33,163.5	18.0%	33,242.2	18.0%	33,292.2	18.2%	32,684.5	17.6%
Oil	6,587.2	3.6%	6,429.4	3.5%	6,388.2	3.5%	6,388.2	3.4%
Solar	374.0	0.2%	374.0	0.2%	589.1	0.3%	640.0	0.3%
Solid waste	809.4	0.4%	786.4	0.4%	795.3	0.4%	712.3	0.4%
Wind	1,136.7	0.6%	1,143.8	0.6%	1,158.3	0.6%	1,158.3	0.6%
Total	183,882.4	100.0%	185,044.5	100.0%	183,386.2	100.0%	185,951.7	100.0%

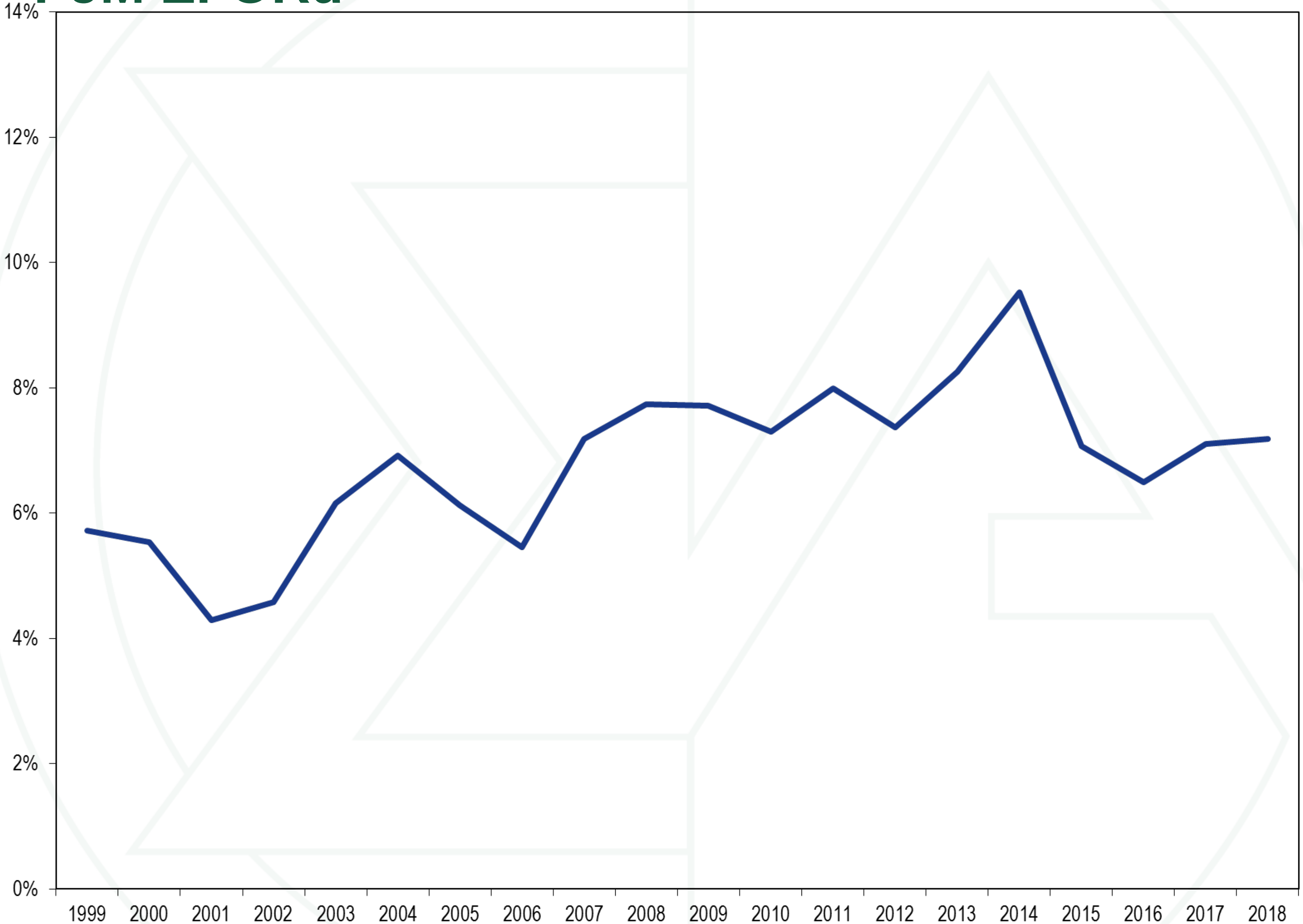
Percent of installed capacity by fuel source



Fuel Diversity Index for installed capacity



PJM EFORd



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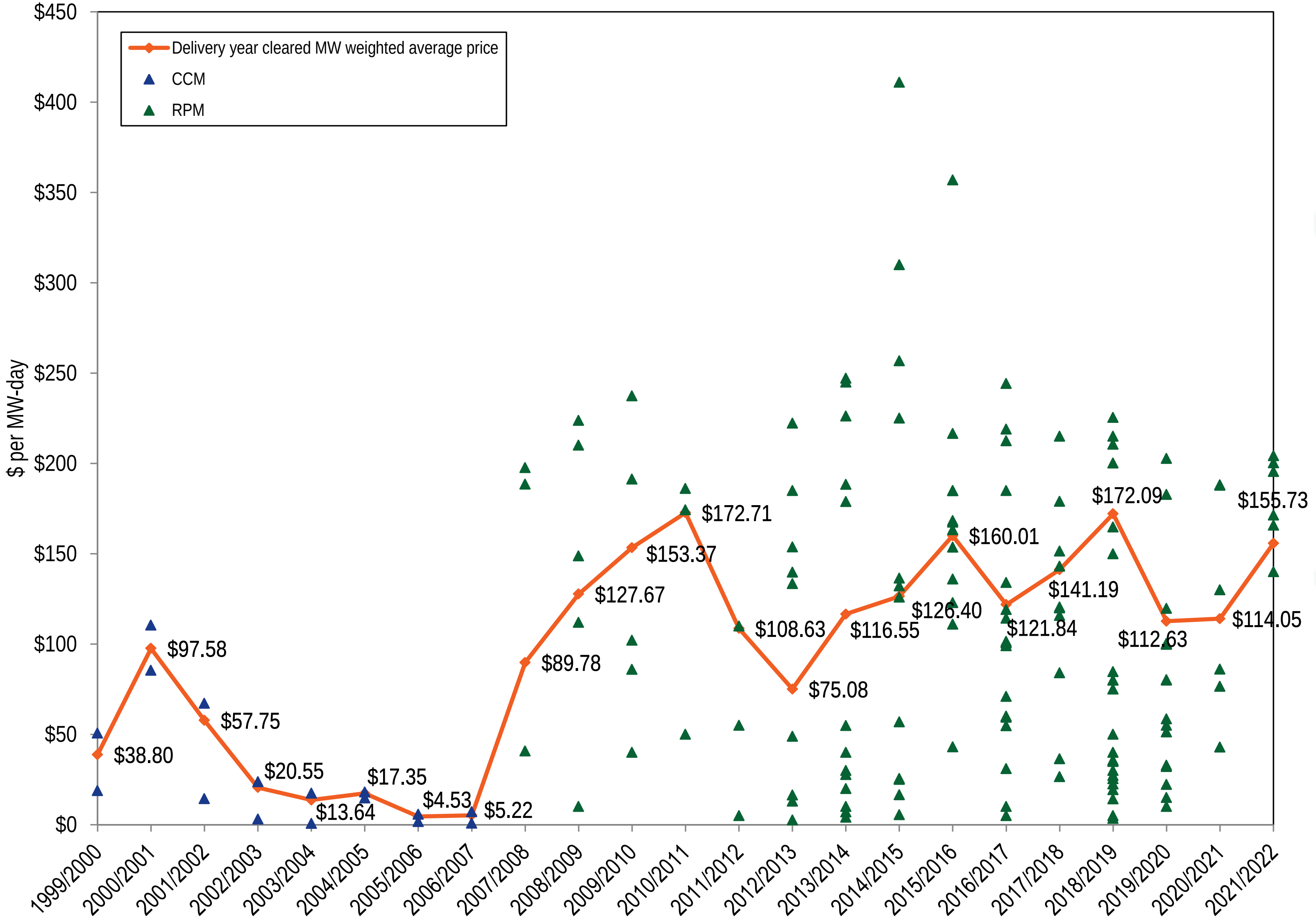
Capacity prices



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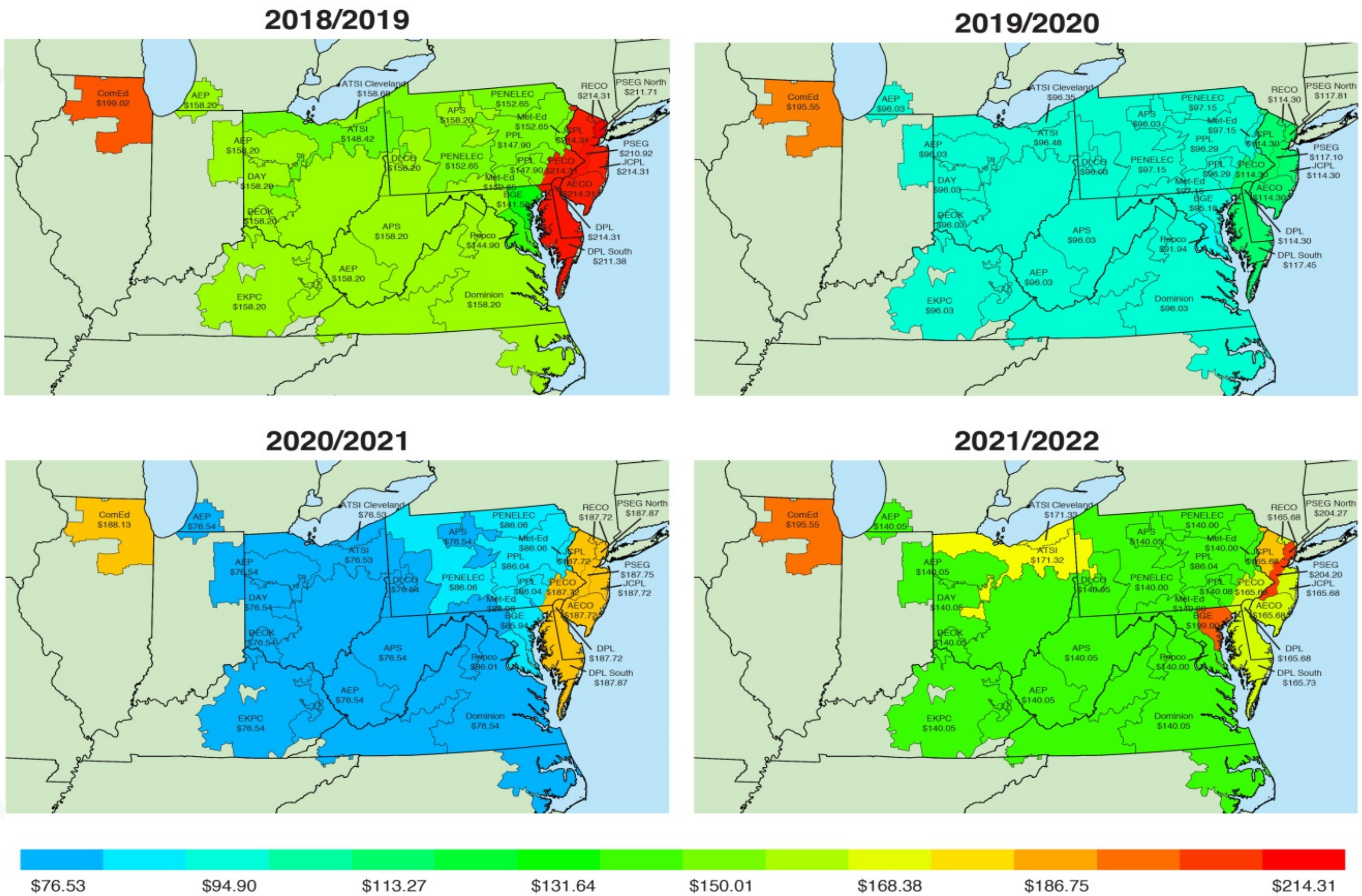
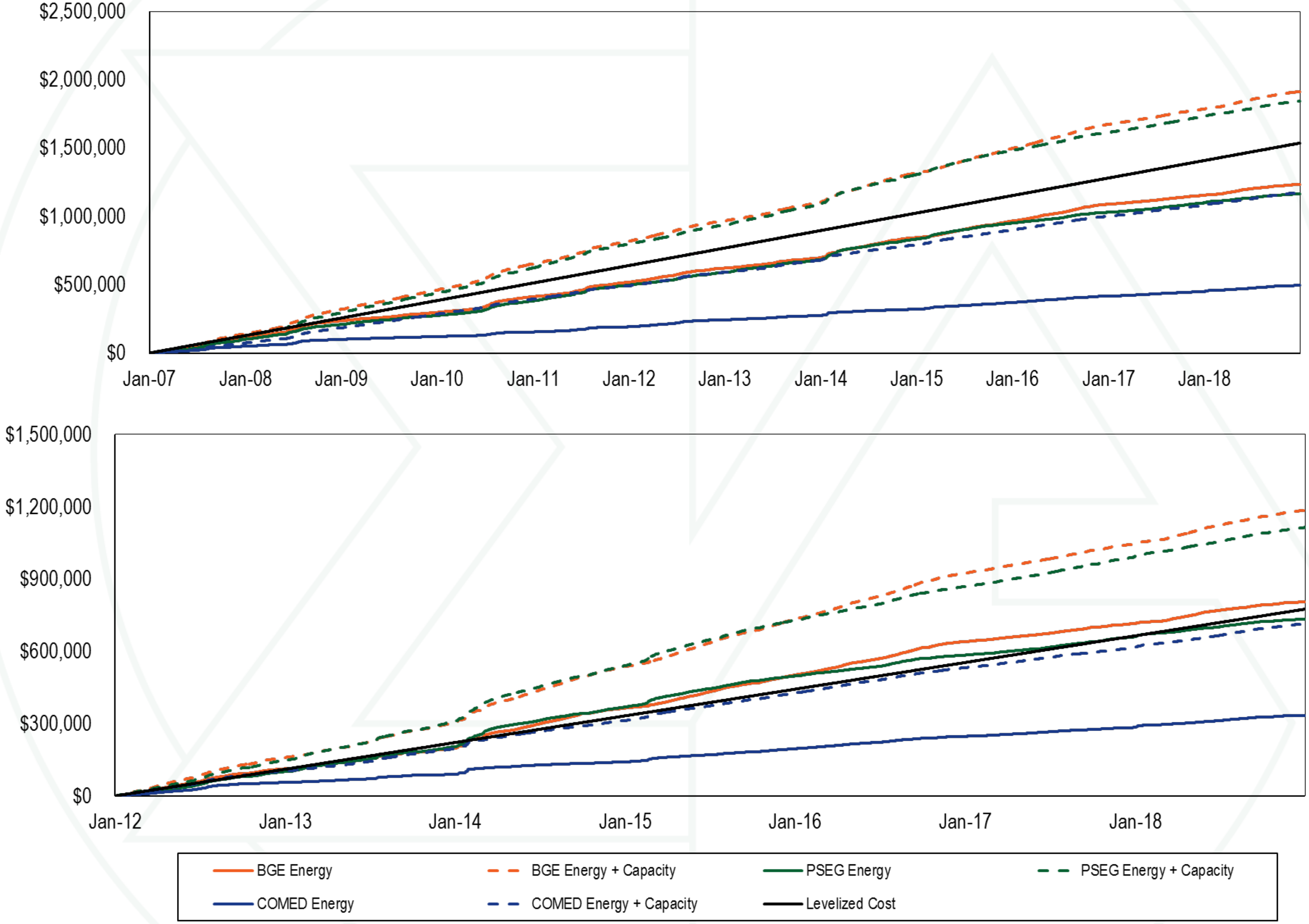
Capacity prices



Levelized cost of energy

	CT	CC	CP	DS	Nuclear	Wind (On Shore)	Wind (Off Shore)	Solar
Levelized cost ($/MW-Yr)	$118,116	$113,641	$562,747	$154,683	$1,178,607	$214,780	$460,730	$232,230
Short run marginal costs ($/MWh)	$34.10	$24.21	$31.48	$161.16	$8.50	$0.00	$0.00	$0.00
Capacity factor (%)	54%	88%	49%	2%	94%	28%	45%	13%
Levelized cost of energy ($/MWh)	$59	$39	$161	$882	$151	$88	$117	$198

Historical new entrant CC revenue adequacy



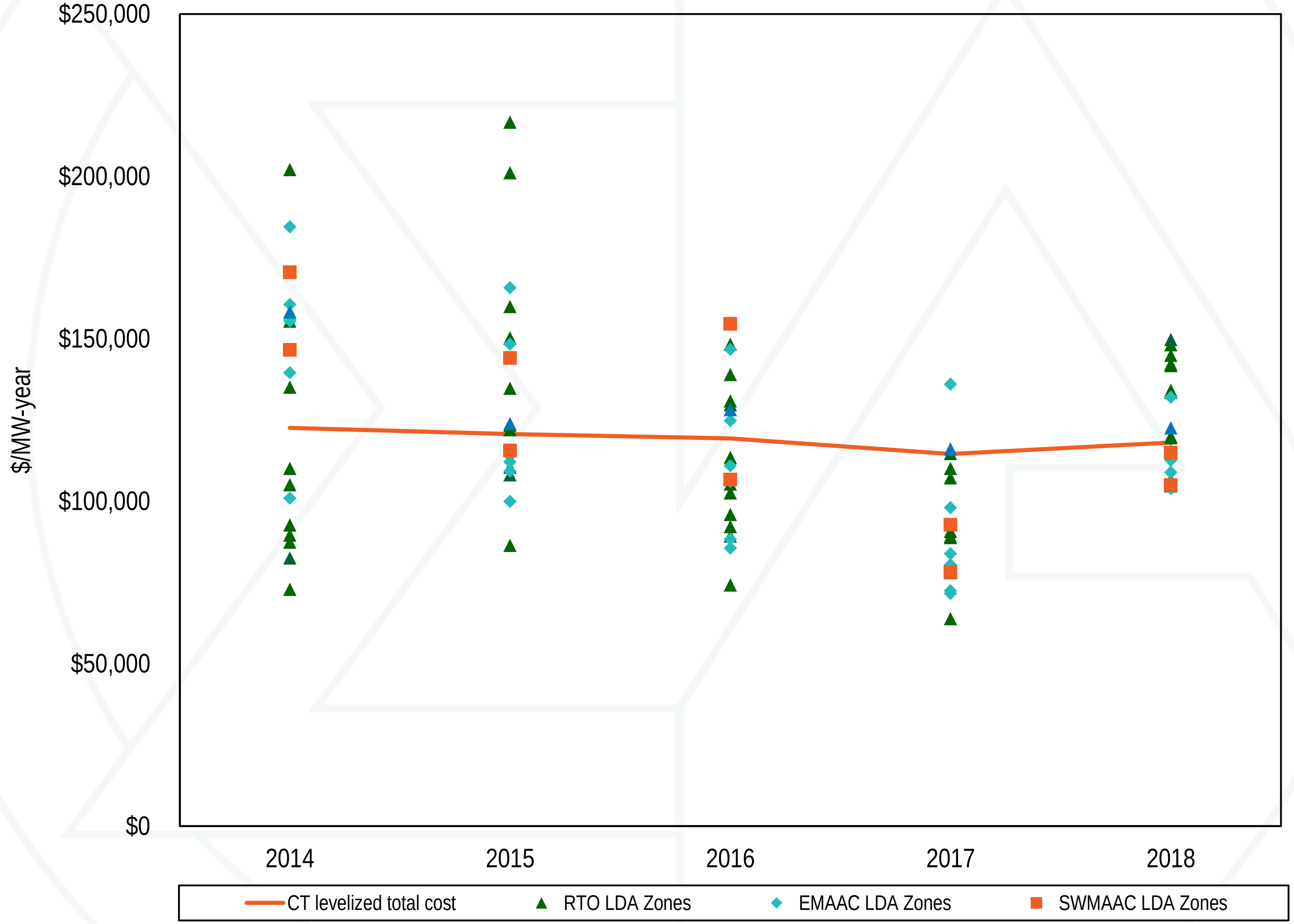
Avoidable cost recovery by quartile

Technology	Total Installed Capacity (ICAP)	Recovery of avoidable costs from energy and ancillary net revenue			Recovery of avoidable costs from all markets		
		First quartile	Median	Third quartile	First quartile	Median	Third quartile
CC - Combined Cycle	32,620	1%	195%	527%	449%	748%	948%
CT - Aero Derivative	5,998	41%	72%	127%	490%	614%	755%
CT - Industrial Frame	21,639	(2%)	28%	83%	342%	536%	654%
Coal Fired	48,320	17%	38%	65%	79%	124%	175%
Diesel	242	0%	42%	139%	464%	521%	656%
Hydro	2,750	349%	484%	555%	542%	673%	719%
Nuclear	33,233	87%	102%	107%	108%	123%	133%
Oil or Gas Steam	10,997	(10%)	0%	15%	104%	182%	227%
Pumped Storage	4,721	385%	664%	664%	1,084%	1,166%	1,356%

Proportion of units recovering avoidable costs

	Units with full recovery from energy and ancillary net revenue								Units with full recovery from all markets							
Technology	2011	2012	2013	2014	2015	2016	2017	2018	2011	2012	2013	2014	2015	2016	2017	2018
CC - Combined Cycle	55%	46%	50%	72%	59%	63%	57%	66%	85%	79%	79%	95%	88%	93%	89%	98%
CT - Aero Derivative	15%	6%	6%	53%	15%	8%	10%	30%	100%	96%	76%	98%	100%	99%	100%	99%
CT - Industrial Frame	26%	23%	17%	38%	13%	8%	3%	21%	99%	98%	83%	100%	100%	100%	100%	96%
Coal Fired	31%	17%	27%	78%	16%	15%	12%	11%	82%	36%	54%	83%	64%	40%	36%	63%
Diesel	48%	42%	37%	69%	56%	33%	32%	39%	100%	100%	77%	100%	100%	100%	100%	97%
Hydro	74%	61%	95%	97%	81%	79%	95%	94%	81%	77%	97%	98%	100%	100%	97%	98%
Nuclear	-	-	53%	95%	16%	5%	16%	53%	-	-	63%	100%	58%	16%	53%	84%
Oil or Gas Steam	8%	6%	11%	15%	3%	0%	0%	10%	92%	78%	86%	85%	91%	88%	81%	76%
Pumped Storage	100%	100%	95%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

CT net revenue and levelized total cost by LDA



CC net revenue and levelized total cost by LDA

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CP net revenue and levelized total cost by

Monitoring Analytics

NU net revenue and levelized total cost by LDA

Monitoring Analytics

Nuclear unit forward annual surplus (shortfall)

	Surplus (Shortfall) ($/MWh)		
	2019	2020	2021
Beaver Valley	$8.68	$6.05	$5.39
Braidwood	$4.99	$3.67	$2.19
Byron	$4.97	$3.65	$2.18
Calvert Cliffs	$8.97	$6.79	$6.03
Cook	$5.29	$2.61	$2.16
Davis Besse	($3.97)	($6.70)	($6.52)
Dresden	$6.03	$4.66	$3.14
Hope Creek	$5.57	$4.97	$4.03
LaSalle	$4.99	$3.67	$2.19
Limerick	$5.65	$5.03	$4.08
North Anna	$8.55	$6.14	$5.48
Peach Bottom	$5.44	$4.83	$3.90
Perry	($2.53)	($5.07)	($5.00)
Quad Cities	$3.56	$2.32	$0.90
Salem	$5.55	$4.95	$4.00
Surry	$8.39	$5.97	$5.32
Susquehanna	$3.41	$1.56	$1.06
Three Mile Island	($8.91)	($10.74)	($11.20)

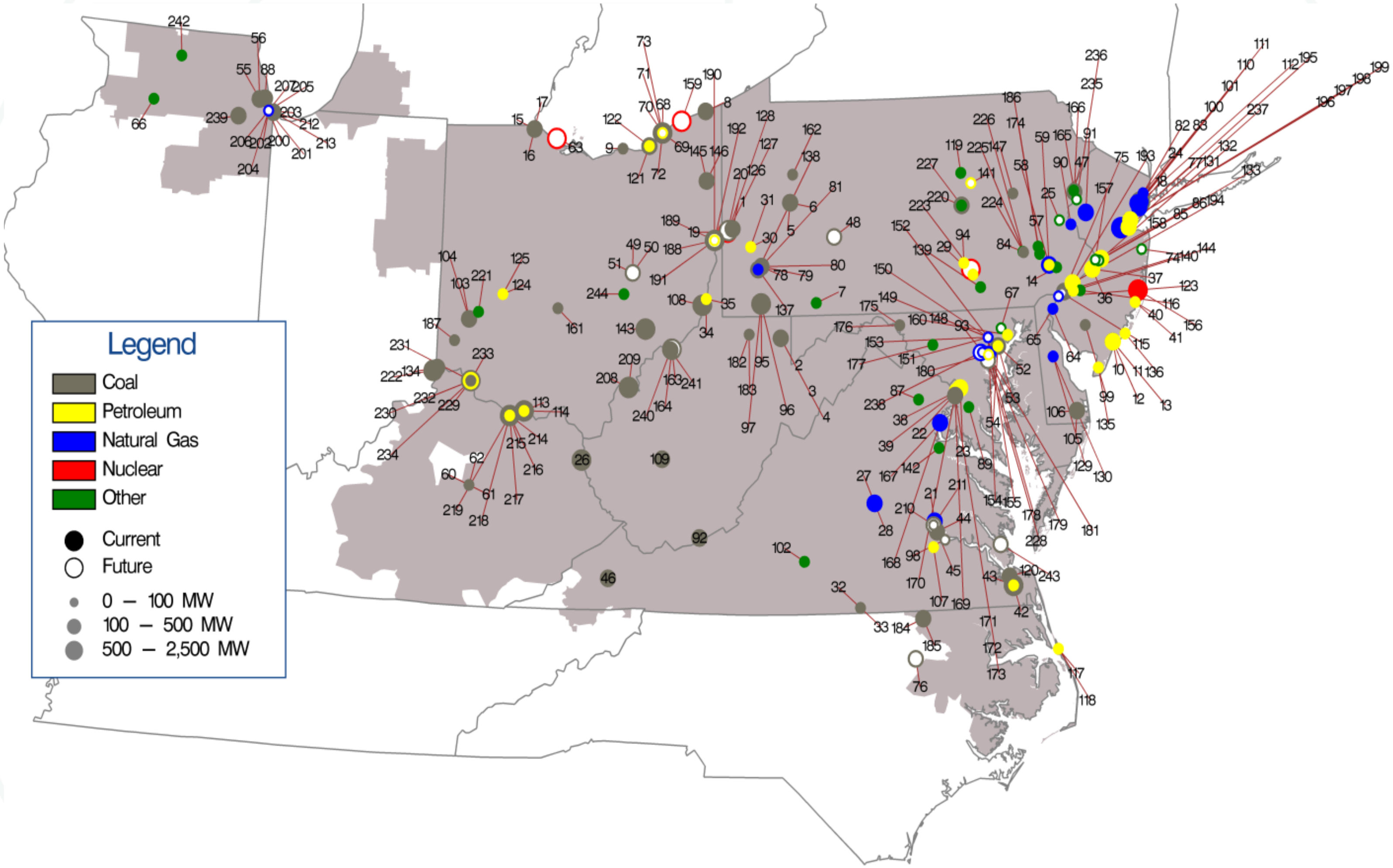
Coal and nuclear units at risk of retirement

Technology	No. Units	ICAP (MW)	Avg. 2018 Run Hrs	Avg. Unit Age (Yrs)	Avg. Heat Rate (Btu/MWh)
Coal Fired	24	12,017	3,983	51	10,029
Nuclear	3	2,937	-	38	-
Total	27	14,954			

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		Projected Replacement Capacity using Cleared Buy Bids UCAP (MW)	Projected Reserve Margin
										Percent	ICAP (MW)		
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	167,892.2	151,643.5	12,284.2	0.0	139,359.3	16.0%	6.08%	178,760.9	28.3%	12.3%	17,104.1	3,988.8	25.2%
01-Jun-20	165,943.4	152,245.4	12,065.2	558.0	139,622.2	15.9%	5.97%	176,479.2	26.4%	10.5%	14,657.1	3,446.6	23.8%
01-Jun-21	160,795.3	152,647.4	12,107.1	510.0	140,030.3	15.8%	5.89%	170,858.9	22.0%	6.2%	8,703.8	0.0	22.0%

Map of unit retirements: 2011 through 2022



RMR history

Unit Names	Owner	ICAP (MW)	Cost Recovery Method	Docket Numbers	Start of Term	End of Term
B.L. England 2	RC Cape May Holdings, LLC	150.0	Cost of Service Recovery Rate	ER17-1083	01-May-17	31-May-19
Yorktown 1	Dominion Virginia Power	159.0	Deactivation Avoidable Cost Rate	ER17-750	06-Jan-17	08-Mar-19
Yorktown 2	Dominion Virginia Power	164.0	Deactivation Avoidable Cost Rate	ER17-750	06-Jan-17	08-Mar-19
B.L. England 3	RC Cape May Holdings, LLC	148.0	Cost of Service Recovery Rate	ER17-1083	01-May-17	24-Jan-18
Ashtabula	FirstEnergy Service Company	210.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	11-Apr-15
Eastlake 1	FirstEnergy Service Company	109.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Eastlake 2	FirstEnergy Service Company	109.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Eastlake 3	FirstEnergy Service Company	109.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Lakeshore	FirstEnergy Service Company	190.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Elrama 4	GenOn Power Midwest, LP	171.0	Cost of Service Recovery Rate	ER12-1901	01-Jun-12	01-Oct-12
Niles 1	GenOn Power Midwest, LP	109.0	Cost of Service Recovery Rate	ER12-1901	01-Jun-12	01-Oct-12
Cromby 2 and Diesel	Exelon Generation Company, LLC	203.7	Cost of Service Recovery Rate	ER10-1418	01-Jun-11	01-Jan-12
Eddystone 2	Exelon Generation Company, LLC	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.	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	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	453.0	Cost of Service Recovery Rate	ER05-644	25-Feb-05	01-Sep-08

Recommendations: Planning

- **The rules governing cost/benefit analysis for evaluatioin of transmission projects should be modified to include all costs in all zones.**
- **CIRs should be terminated within one year if units cannot qualify to be capacity performance resources.**

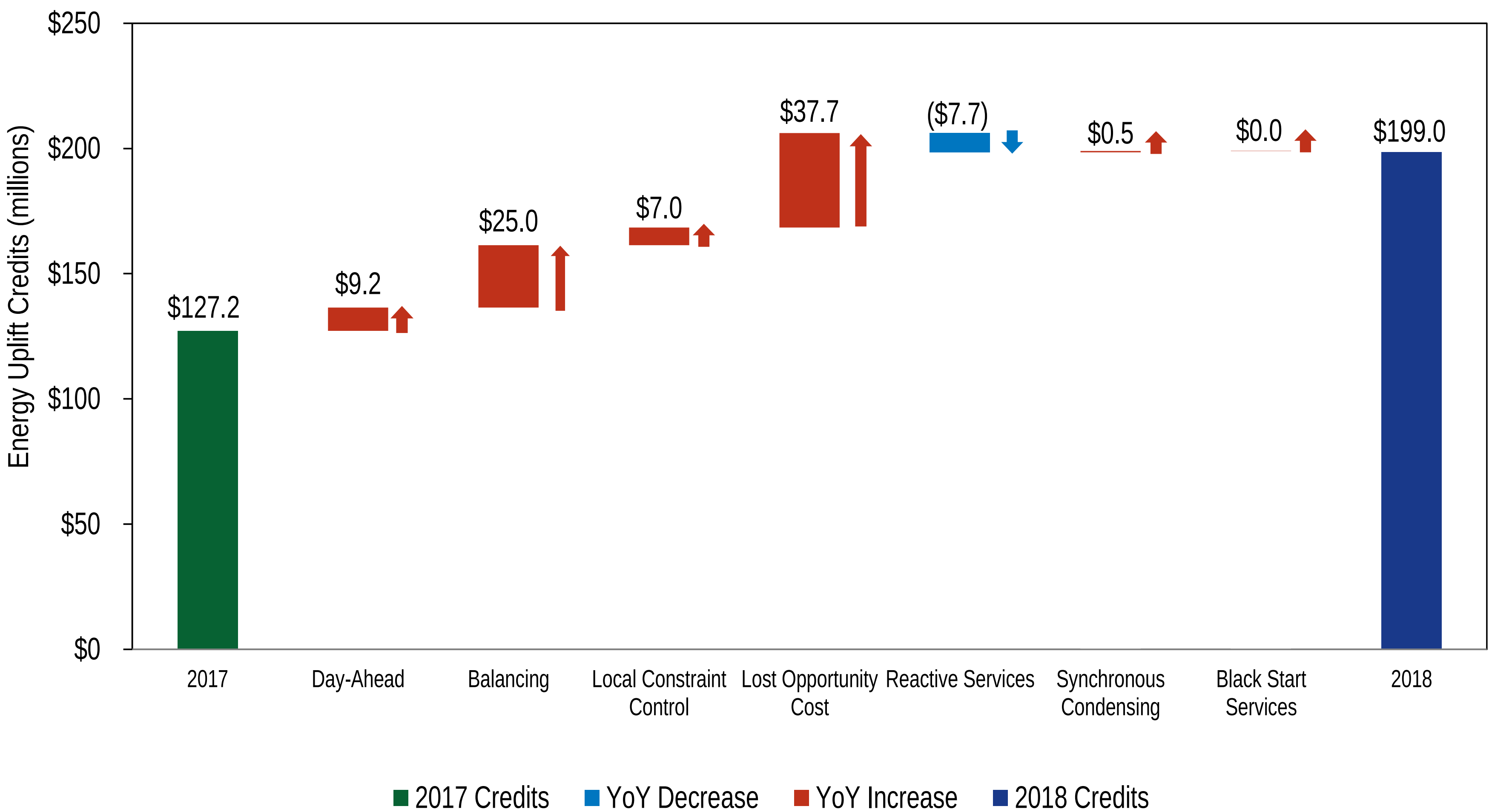
Recommendations: Energy Market Uplift

- **PJM should develop accurate metric to define when a unit is following dispatch**
- **PJM should not use closed loop interfaces to override LMP logic to accommodate: Issues with DR product, e.g. non nodal; Issues with reactive power modeling; Issues with scarcity pricing, e.g. not locational.**
- **PJM should not use price setting logic to override LMP logic to reduce uplift.**
- **Reduce uplift in a focused manner**
  - **Increase transparency**
  - **Require flexible parameters**
  - **Eliminate day ahead uplift.**
  - **Eliminate segmentation**
  - **Include regulation net revenue offset in uplift calculation.**
  - **UTCs should pay uplift.**

Total energy uplift charges

	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	$199.3	$72.0	56.5%	0.4%

Energy uplift credits changes by category



Energy uplift credits by unit type: 2017 and 2018

Unit Type	2017 Credits (Millions)	2018 Credits (Millions)	Change	Percent Change	2017 Share	2018 Share
Combined Cycle	$10.1	$20.3	$10.3	102.2%	7.9%	10.2%
Combustion Turbine	$62.1	$109.3	$47.2	76.0%	48.9%	55.0%
Diesel	$0.9	$1.7	$0.8	83.8%	0.7%	0.9%
Hydro	$0.1	$0.0	($0.1)	(100.0%)	0.1%	0.0%
Nuclear	$0.1	$0.4	$0.3	387.3%	0.1%	0.2%
Solar	$0.0	$0.0	($0.0)	(69.3%)	0.0%	0.0%
Steam - Coal	$45.7	$45.5	($0.1)	(0.3%)	36.0%	22.9%
Steam - Other	$5.8	$19.6	$13.7	235.4%	4.6%	9.9%
Wind	$2.2	$1.7	($0.4)	(20.3%)	1.7%	0.9%
Total	$126.9	$198.5	$71.6	56.4%	100.0%	100.0%

Energy uplift credits by unit type

Unit Type	Day-Ahead Generator	Balancing Generator	Canceled Resources	Local Constraints Control	Lost Opportunity Cost	Reactive Services	Synchronous Condensing	Black Start Services
Combined Cycle	8.6%	13.2%	0.0%	0.0%	10.4%	0.2%	0.0%	20.4%
Combustion Turbine	3.7%	76.4%	0.0%	0.8%	71.9%	8.5%	100.0%	79.6%
Diesel	0.0%	0.6%	0.0%	2.0%	1.7%	1.0%	0.0%	0.0%
Hydro	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Nuclear	0.0%	0.0%	0.0%	0.0%	0.7%	0.0%	0.0%	0.0%
Solar	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Steam - Coal	61.3%	5.5%	0.0%	25.1%	11.6%	88.0%	0.0%	0.0%
Steam - Others	26.5%	4.3%	0.0%	72.2%	0.4%	2.4%	0.0%	0.0%
Wind	0.0%	0.0%	0.0%	0.0%	3.3%	0.0%	0.0%	0.0%
Total (Millions)	$34.0	$90.2	$0.0	$8.6	$52.3	$13.1	$0.0	$0.3

Concentration of energy uplift credits

		Top 10 Units		Top 10 Organizations	
Category	Type	Credits (Millions)	Credits Share	Credits (Millions)	Credits Share
Day-Ahead	Generators	$24.2	71.2%	$33.0	97.0%
Balancing	Canceled Resources	$0.0	0.0%	$0.0	0.0%
	Generators	$11.1	12.3%	$64.6	71.6%
	Local Constraints Control	$8.5	99.5%	$8.6	100.0%
	Lost Opportunity Cost	$9.3	17.7%	$37.5	71.8%
Reactive Services		$12.6	96.0%	$13.1	100.0%
Synchronous Condensing		$0.0	100.0%	$0.0	100.0%
Black Start Services		$0.1	48.0%	$0.3	90.8%
Total		$42.1	21.2%	$148.2	74.6%

Operating reserve rates statistics

		Rates Charged ($/MWh)			
Region	Transaction	Maximum	Average	Minimum	Standard Deviation
East	INC	13.194	0.591	0.000	1.113
	DEC	13.336	0.632	0.000	1.126
	DA Load	0.357	0.041	0.000	0.059
	RT Load	0.733	0.044	0.000	0.076
	Deviation	13.194	0.591	0.000	1.113
West	INC	13.363	0.597	0.000	1.207
	DEC	13.505	0.639	0.000	1.222
	DA Load	0.357	0.041	0.000	0.059
	RT Load	0.731	0.040	0.000	0.077
	Deviation	13.363	0.597	0.000	1.207

Current and proposed operating reserve rates

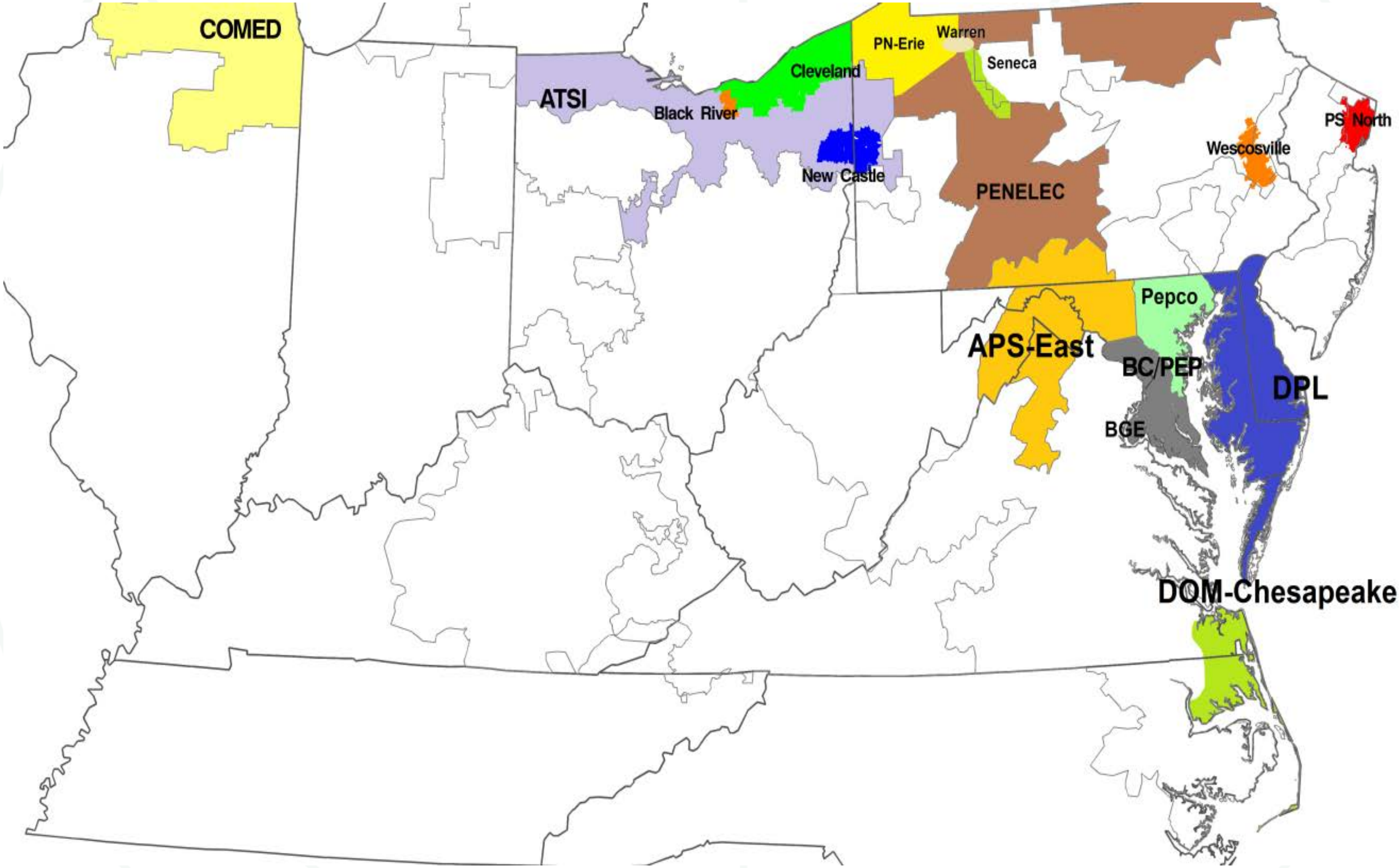
	Transaction	Current Average Rates	Average Rates with Proposed UTC Uplift Allocation (100% UTC Volume)	Average Rates with Proposed UTC Uplift Allocation (50% UTC Volume)
East	INC	0.681	0.233	0.347
	DEC	0.722	0.268	0.384
	DA Load	0.041	0.035	0.038
	RT Load	0.029	0.029	0.029
	Deviation	0.681	0.233	0.347
West	INC	0.693	0.227	0.342
	DEC	0.735	0.262	0.379
	DA Load	0.041	0.035	0.038
	RT Load	0.027	0.027	0.027
	Deviation	0.693	0.227	0.342
UTC	East to East	NA	0.500	0.731
	West to West	NA	0.489	0.721
	East to/from West	NA	0.495	0.726

Monitoring Analytics

Current and proposed energy uplift credits

Proposal	Credits Impacted	Current Credits (millions)	Proposal Credits (millions)	Difference (millions)
Eliminate day-ahead operating reserve credits	Day-ahead generator Day-ahead reactive	$45.8	$32.9	($12.9)
Include regulation offsets in the calculation of balancing operating reserves	Balancing operating reserve Local constraint Reactive	$100.1	$89.3	($0.9)
Calculate the need for balancing credits on a daily basis	Balancing operating reserve Local constraint Reactive	$100.1	$68.4	($21.8)
Calculate lost opportunity cost credits on a daily basis	Day-ahead LOC	$37.7	$28.9	($8.8)
Total combined impact of elimination of day-ahead credits, adding regulation offsets, and calculating balancing credits and day-ahead LOC credits on a daily basis	Day-ahead generator Day-ahead reactive Balancing operating reserve Day-ahead LOC	$183.6	$136.2	($47.4)

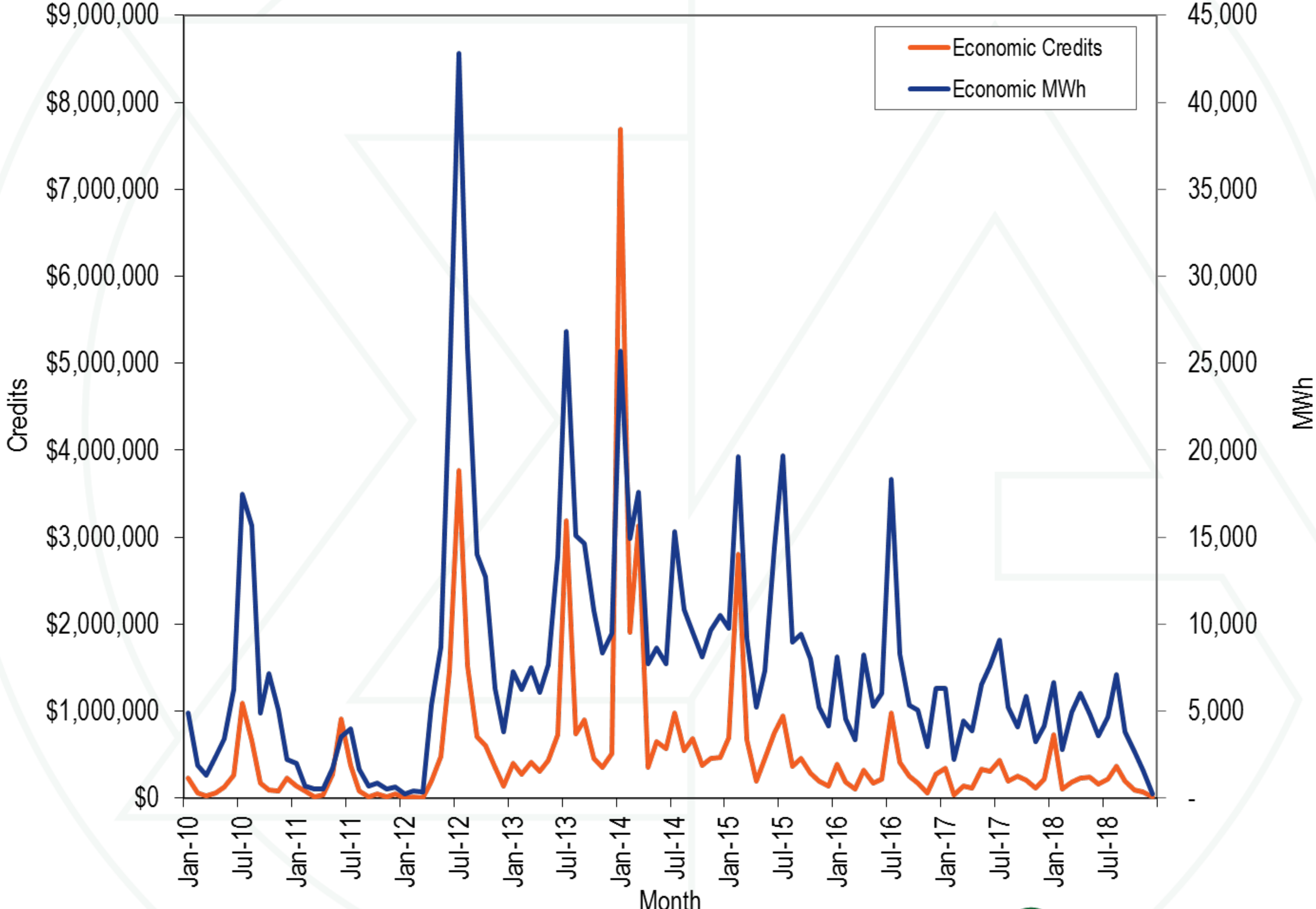
Closed loop interfaces map



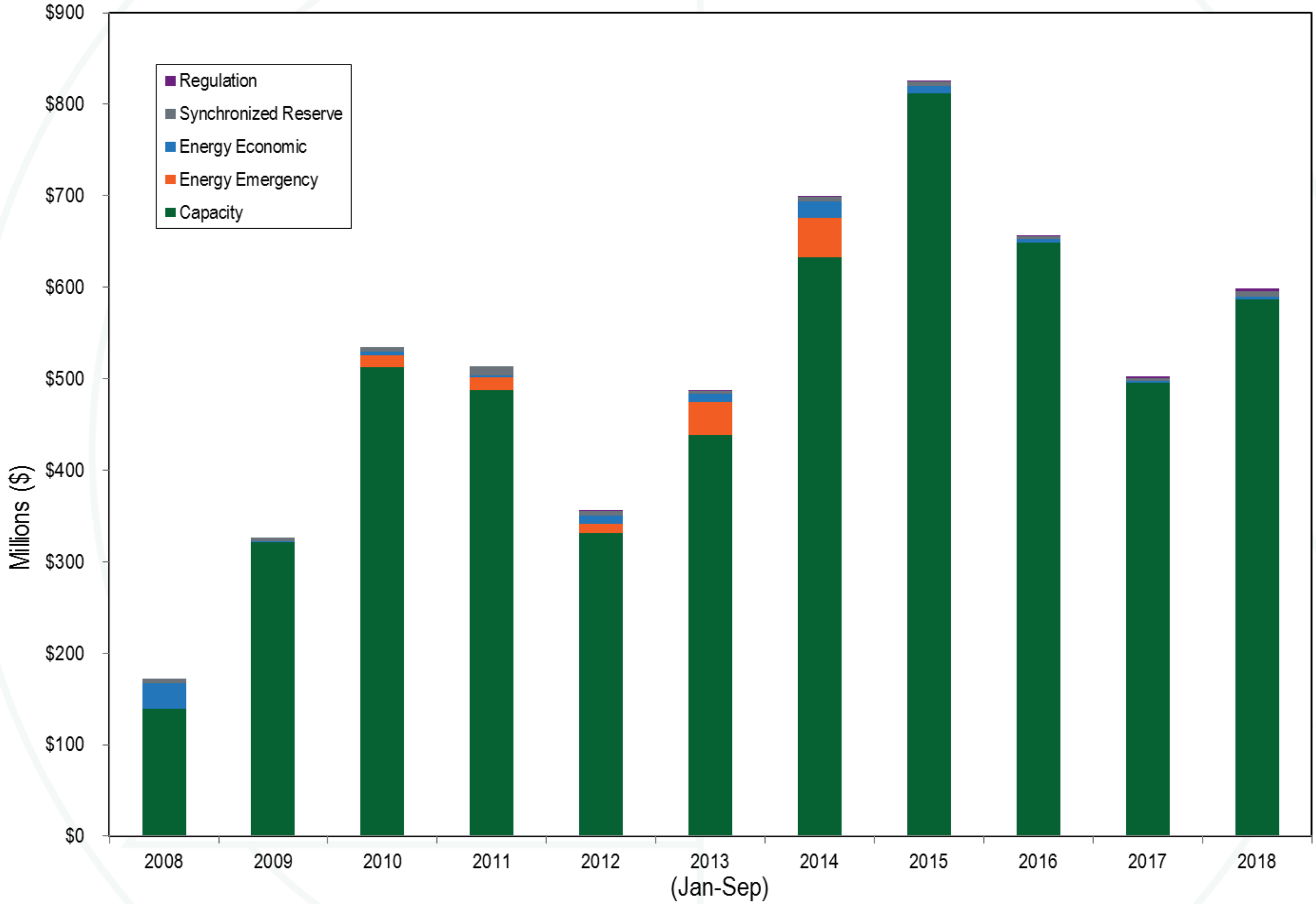
Recommendations: Demand Response

- Demand response and energy efficiency should be removed from PJM capacity market.
  - On demand side of market
  - Redesign to facilitate customers’ response to prices
  - Payment should be immediate
  - Impact on forecasts should be immediate
  - Metered use is sole basis for payment. No M&V.
- Eliminate guaranteed DR strike price; pay LMP
- DR offer cap should be the same as generation
- Demand response should be fully nodal
- Demand response should be an economic resource
- M&V: cap baselines at PLC uniformly including winter
- DR should be included in reserve calculations without a cap

Economic program credits and MWh by month



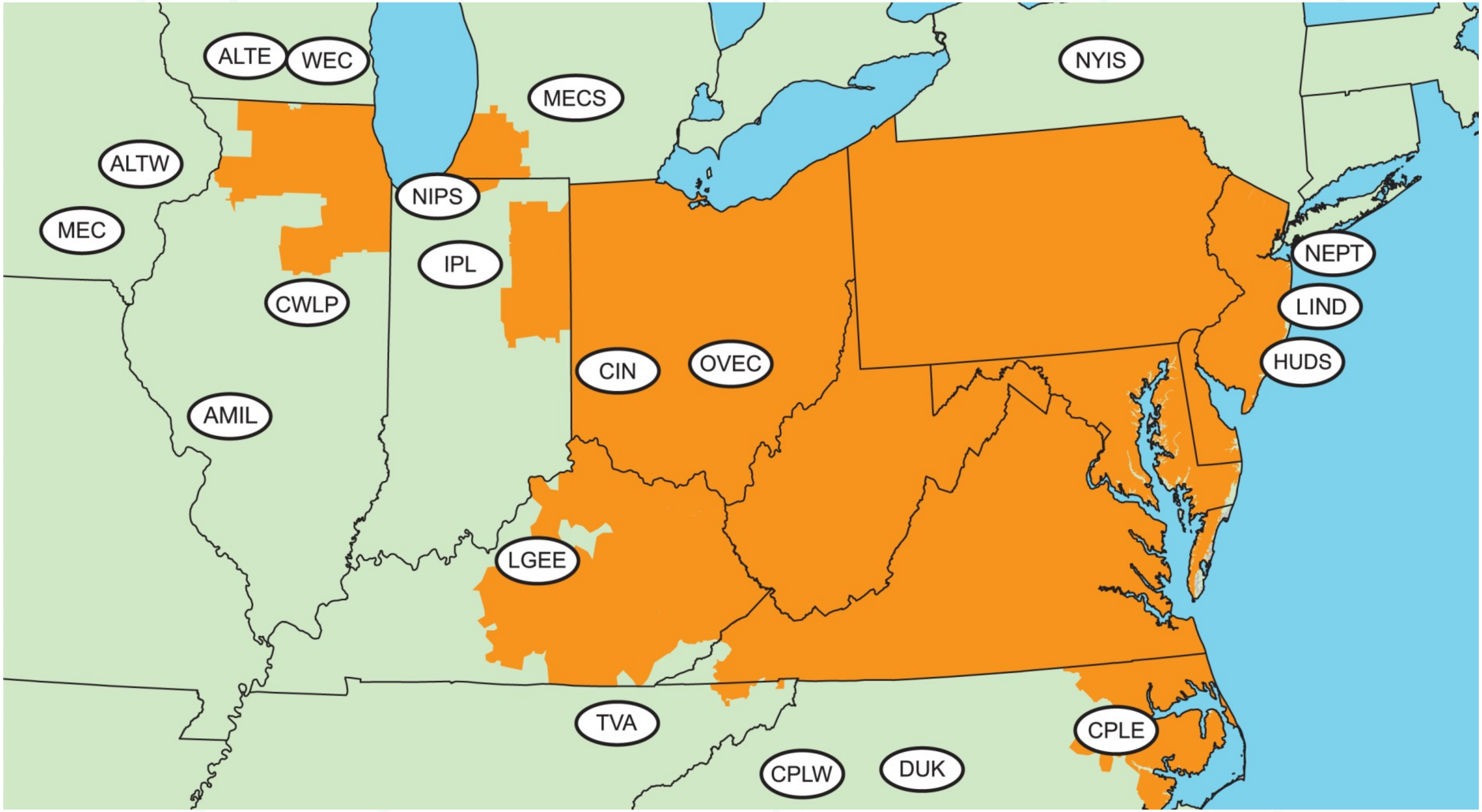
Demand response revenue by market



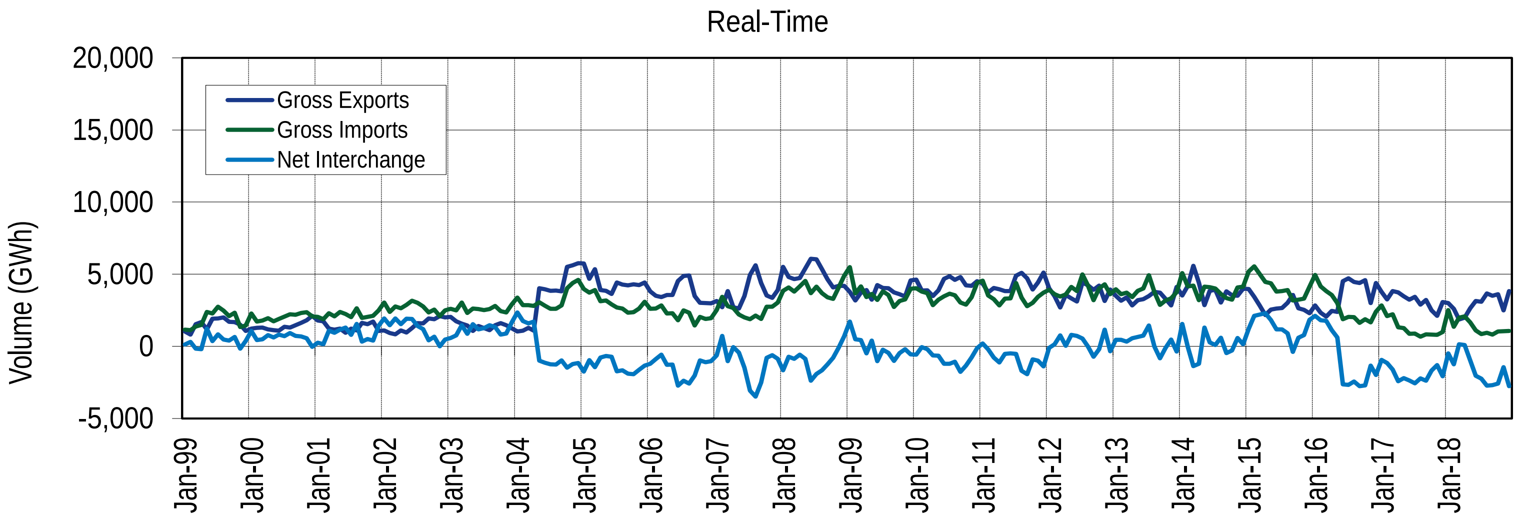
Recommendations: Transactions

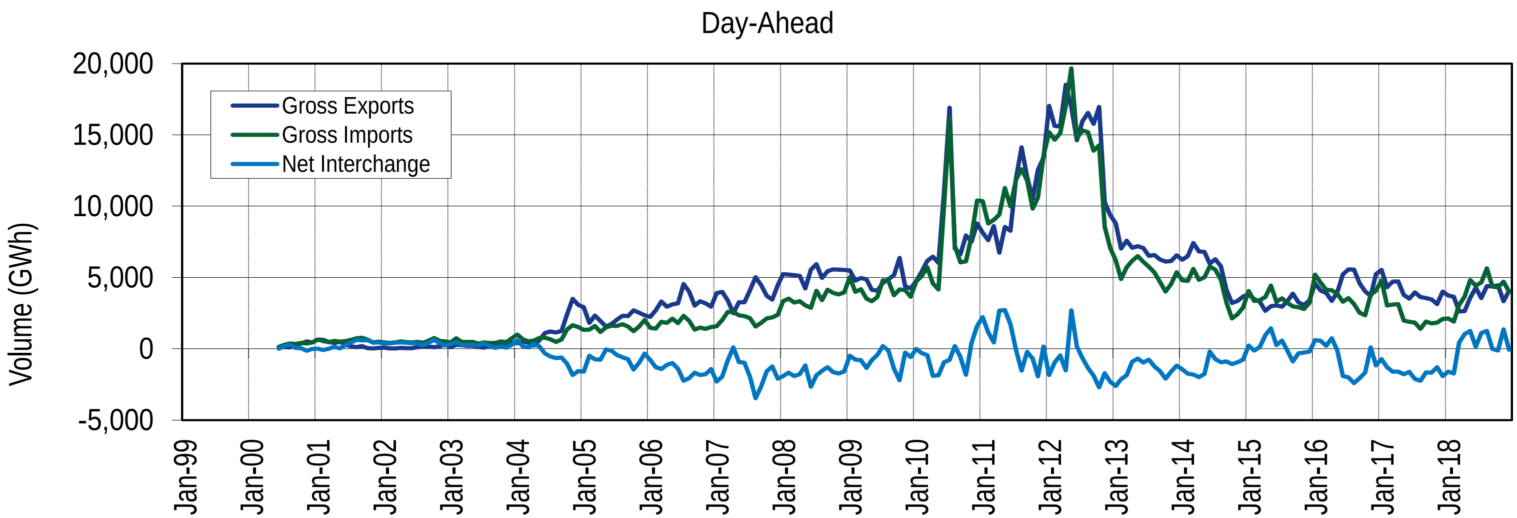
- **Submit transactions consistent with power flow not scheduled paths.**
- **Implement rules to prevent breaking up transactions to evade rules.**
- **Implement rules to prevent sham scheduling.**
- **Eliminate outdated definitions of interface pricing points.**
- **Permit unlimited spot imports.**
- **Interchange pricing should reflect LMP logic.**
  - **No need for scheduling physical transactions.**
- **Make actual flow data available for eastern interconnection to MMUs and RTOs/ISOs.**

PJM's footprint and its external DA and RT scheduling interfaces



RT and DA scheduled import and export transaction volume history





The regulation market results were competitive

Market Element	Evaluation	Market Design
Market Structure	Not Competitive	
Participant Behavior	Competitive	
Market Performance	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 market results were competitive

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

Recommendations: Ancillary Services

- Regulation market should incorporate consistent application of marginal benefit factor including optimization, assignment and settlements.
- LOC should be based on unit's operating schedule in the energy market.
- The $7.50 markup should be eliminated from synchronized reserve offers.
- Nonperformance penalties for synchronized reserves should begin with the last successful response.
- The cost of reactive capability should be incorporated in the capacity market.
- Minimum tank suction levels should be fixed.

Average price and cost for regulation

Year	Weighted Regulation Market Price	Weighted Regulation Market Cost	Regulation Price as Percent Cost
2009	$23.00	$30.68	75.0%
2010	$18.00	$32.86	54.8%
2011	$16.49	$29.72	55.5%
2012	$19.02	$25.32	75.1%
2013	$30.85	$35.79	86.2%
2014	$44.49	$53.82	82.7%
2015	$31.92	$38.36	83.2%
2016	$15.73	$18.13	86.7%
2017	$16.78	$23.04	72.8%
2018	$25.33	$31.94	79.3%

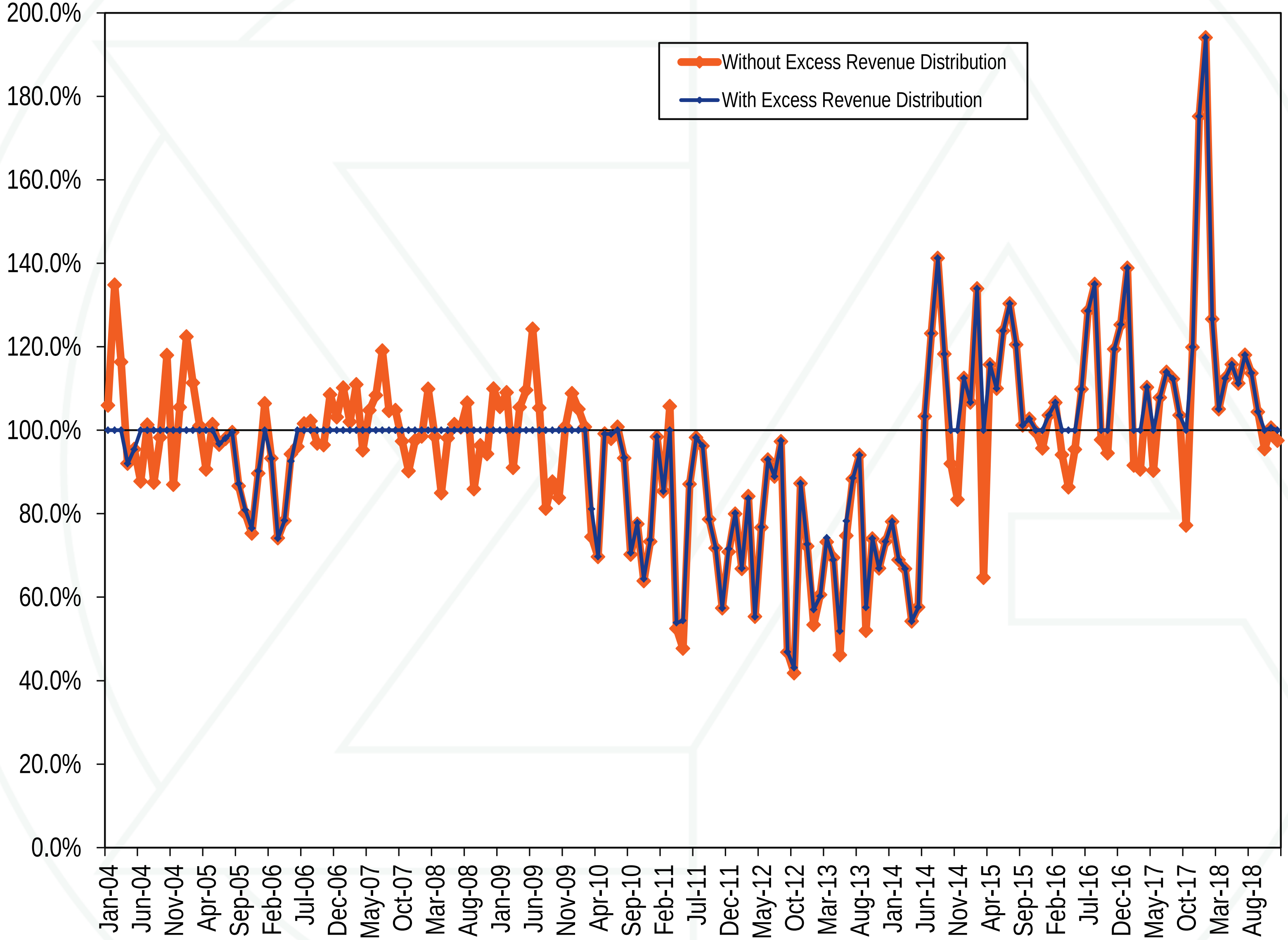
The FTR auction markets results were competitive

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

Recommendations: FTR/ARR

- **ARR/FTR design should be modified to ensure that load has the right to all congestion revenues.**
- **All FTR auction revenues and all congestion in excess of target allocations should be returned to load monthly.**
- **Eliminate use of generation to load contract paths for allocating ARRs.**
- **The long term FTR product should be eliminated.**

FTR payout ratio



Reported FTR payout ratio

Planning Period	FTR Payout Ratio
2003/2004	97.7%
2004/2005	100.0%
2005/2006	90.7%
2006/2007	100.0%
2007/2008	100.0%
2008/2009	100.0%
2009/2010	96.9%
2010/2011	85.0%
2011/2012	80.6%
2012/2013	67.8%
2013/2014	72.8%
2014/2015	100.0%
2015/2016	100.0%
2016/2017	100.0%
2017/2018	100.0%
2018/2019	100.0%

Actual total congestion offset for ARR holders

Planning Period	Total Offset
2011/2012	100.0%
2012/2013	100.0%
2013/2014	42.4%
2014/2015	65.3%
2015/2016	90.3%
2016/2017	100.0%
2017/2018	50.0%
2018/2019*	74.2%
* Seven months of 2018/2019	

ARR holder total congestion offset ($M)

Revenue					Pre 2017/2018 (Without Balancing)		2017/2018 (With Balancing)		Post 2017/2018 (With Surplus)	
Planning Period	ARR Credits	FTR Credits	Total Congestion	Excess Revenue	ARR/FTR Offset	Percent Offset	Revenue Received	Percent Offset	Revenue Received	New Offset
2011/2012	$512.2	$249.8	$749.7	($192.5)	$762.0	100.0%	$598.6	79.8%	$598.6	79.8%
2012/2013	$349.5	$181.9	$524.8	($292.3)	$531.4	100.0%	$275.9	52.6%	$275.9	52.6%
2013/2014	$337.7	$456.4	$1,870.6	($678.7)	$794.0	42.4%	$574.1	30.7%	$574.1	30.7%
2014/2015	$482.4	$404.4	$1,357.6	$139.6	$886.8	65.3%	$686.6	50.6%	$826.2	60.9%
2015/2016	$635.3	$223.4	$951.1	$42.5	$858.8	90.3%	$744.8	78.3%	$787.3	82.8%
2016/2017	$640.0	$169.1	$780.8	$72.6	$809.1	100.0%	$727.7	93.2%	$800.3	100.0%
2017/2018	$427.3	$294.2	$1,192.6	$371.2	$721.5	60.5%	$595.7	50.0%	$966.9	81.1%
2018/2019*	$308.9	$91.3	$468.8	$32.5	$417.76	89.1%	$333.1	71.1%	$365.6	74.2%
Total	$3,693.4	$2,070.4	$7,896.0	($505.2)	$5,781.3	73.2%	$4,536.7	57.5%	$5,194.9	65.6%

* Seven months of 2018/2019 planning period

FTR profits by organization type

	FTR Direction				
Organization Type	Prevailing Flow Profit	Self Scheduled Prevailing Flow Revenue Returned	Counter Flow Profit	Self Scheduled Counter Flow Revenue Returned	All
Financial	$16,767,068	$0	$76,897,508	$0	$93,664,575
Physical	($10,287,976)	$89,596,126	$42,583,579	$1,664,863	$123,556,592
Total	$6,479,092	$89,596,126	$119,481,087	$1,664,863	$217,221,168

Estimated additional LTFTR auction revenue at annual FTR auction prices

	Long Term FTR Product				
Planning Period	YR3	YR2	YR1	YRALL	Total Difference
2014/2015	$59,598,642	$30,284,173	$52,030,909	$926,989	$142,840,713
2015/2016	$67,896,588	$40,975,278	$9,936,078	$303,082	$119,111,026
2016/2017	$42,378,048	$3,854,373	$11,055,824	$1,079,901	$58,368,147
2017/2018	$6,134,076	($1,841,715)	$12,396,817	$227,524	$16,916,702
2018/2019	$7,872,604	$2,926,457	$13,480,353	($111,226)	$24,168,189
Total	$183,879,959	$76,198,567	$98,899,981	$2,426,270	$361,404,776

LT and annual auction cleared FTR MW

Effective Planning Period	Long Term FTR Product (Including YRALL)			Volume (MW)		Long Term Percent of Total Cleared
	YR3	YR2	YR1	Total Long Term	Annual (including self scheduled)	
2014/2015	81,666	86,754	131,911	300,330	356,522	45.7%
2015/2016	89,419	99,329	123,400	312,148	355,682	46.7%
2016/2017	97,837	95,637	107,182	300,656	397,258	43.1%
2017/2018	69,161	86,323	108,126	263,609	493,683	34.8%
2018/2019	87,232	109,827	177,018	374,078	395,506	48.6%

Status of MMU reported recommendations: 1999 through 2018

Status	Priority High	Priority Medium	Priority Low	Total	Percent of Total
Adopted	21	18	18	57	20.7%
Partially Adopted - Stakeholder Process	0	0	0	0	0.0%
Partially Adopted - FERC	1	0	0	1	0.4%
Partially Adopted (Continued Recommendation)	7	12	5	24	8.7%
Partially Adopted (Recommendation Closed)	2	3	5	10	3.6%
Partially Adopted (Total)	10	15	10	35	12.7%
Not Adopted	37	74	44	155	56.4%
Not Adopted (Pending before FERC)	4	2	0	6	2.2%
Not Adopted (Stakeholder Process)	1	3	1	5	1.8%
Not Adopted (Total)	42	79	45	166	60.4%
Replaced by Newer Recommendation	1	7	3	11	4.0%
Withdrawn	1	3	2	6	2.2%
Total	75	122	78	275	100.0%

Market Monitoring Unit

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

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