2016 State of the Market Report for PJM

MC Special Session

March 23, 2017

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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

Role of Market Monitoring

- **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**

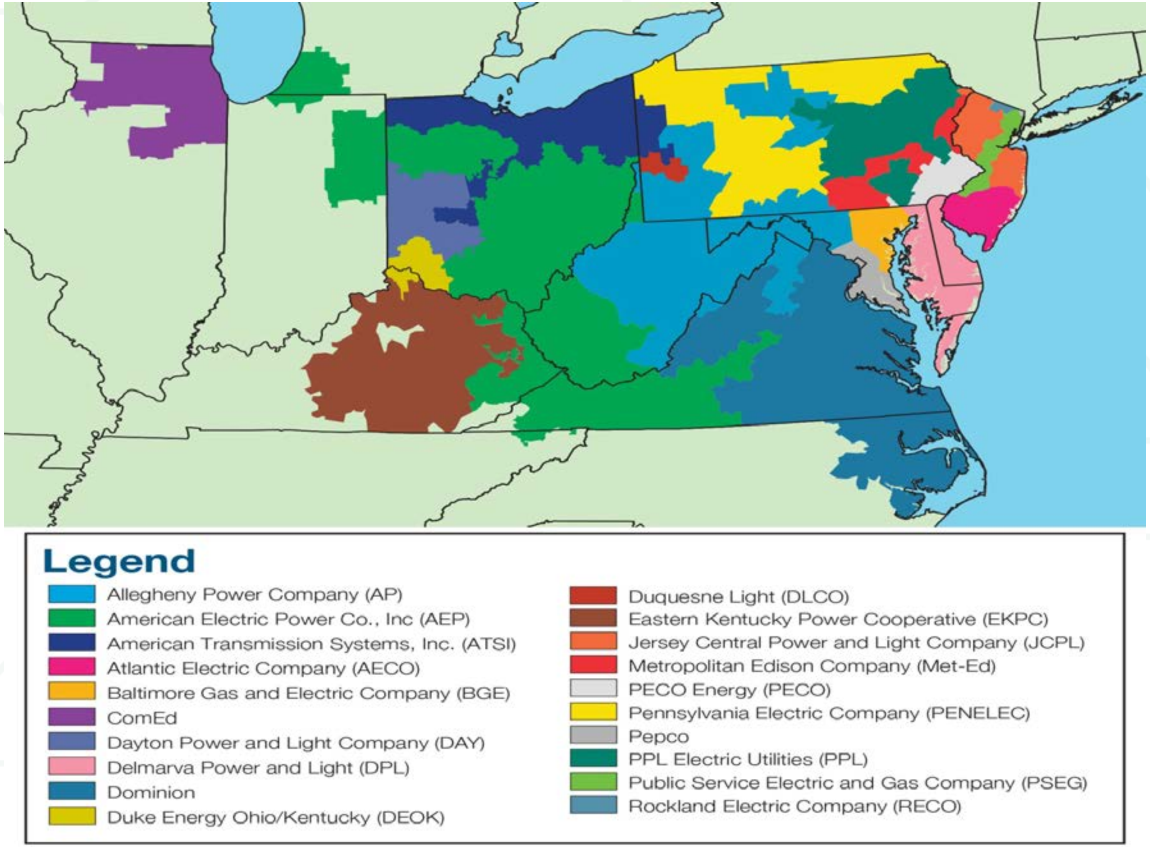
Role of Market Monitoring

- **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 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 20 control zones



The energy market results were competitive

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

Recommendations: Energy Market

- Cost based offers equal to short run marginal cost
  - Replace Manual 15 with clear definitions for cost-based offers
  - Fuel cost policies: algorithmic, verifiable, systematic
- 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

Recommendations: Energy Market

- **OEM parameters from CONE unit should be used for performance assessment and uplift**
- **Define explicit rules related to use of transmission penalty factors in setting LMP.**

Total price per MWh by category: 2015 and 2016

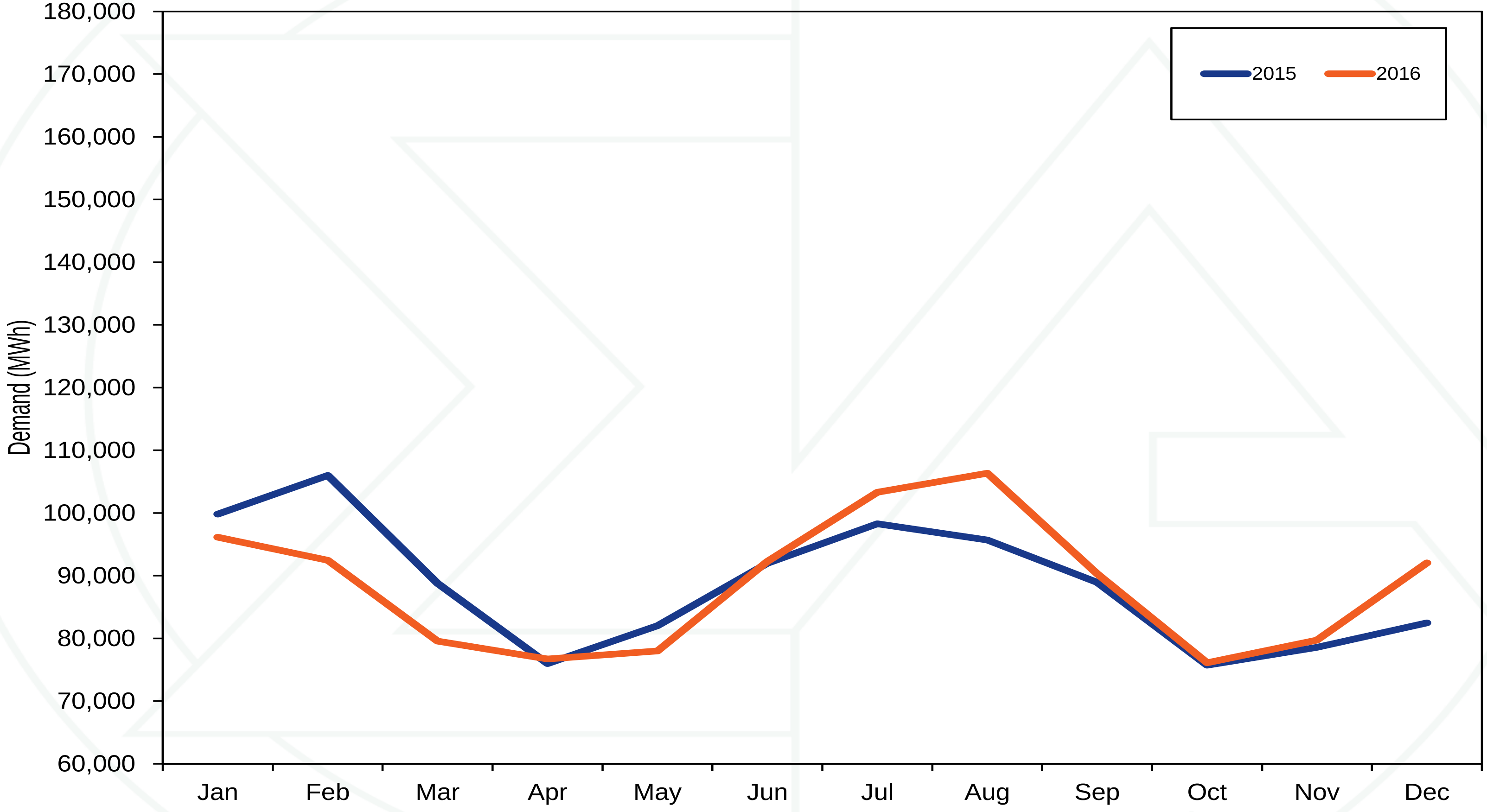
Category	2015 $/MWh	2015 Percent of Total	2016 $/MWh	2016 Percent of Total	Percent Change Totals
Load Weighted Energy	$36.16	63.6%	$29.23	58.5%	(19.2%)
Capacity	$11.12	19.6%	$10.96	21.9%	(1.5%)
Transmission Service Charges	$7.09	12.5%	$7.81	15.6%	10.1%
Transmission Enhancement Cost Recovery	$0.51	0.9%	$0.52	1.0%	2.1%
PJM Administrative Fees	$0.44	0.8%	$0.45	0.9%	2.5%
Reactive	$0.37	0.7%	$0.39	0.8%	4.9%
Energy Uplift (Operating Reserves)	$0.38	0.7%	$0.17	0.3%	(54.8%)
Regulation	$0.23	0.4%	$0.11	0.2%	(53.2%)
Transmission Owner (Schedule 1A)	$0.09	0.2%	$0.09	0.2%	3.8%
Black Start	$0.08	0.1%	$0.08	0.2%	8.8%
Day Ahead Scheduling Reserve (DASR)	$0.10	0.2%	$0.07	0.1%	(24.4%)
Synchronized Reserves	$0.11	0.2%	$0.05	0.1%	(53.5%)
NERC/RFC	$0.03	0.1%	$0.03	0.1%	3.0%
Load Response	$0.02	0.0%	$0.01	0.0%	(38.9%)
Non-Synchronized Reserves	$0.02	0.0%	$0.01	0.0%	(48.3%)
RTO Startup and Expansion	$0.01	0.0%	$0.00	0.0%	(43.4%)
Transmission Facility Charges	$0.00	0.0%	$0.00	0.0%	(59.2%)
Capacity (FRR)	$0.13	0.2%	$0.00	0.0%	(100.0%)
Emergency Load Response	$0.00	0.0%	$0.00	0.0%	(100.0%)
Emergency Energy	$0.00	0.0%	$0.00	0.0%	0.0%
Total Price	$56.88	100.0%	$49.99	100.0%	(12.1%)

Monitoring Analytics

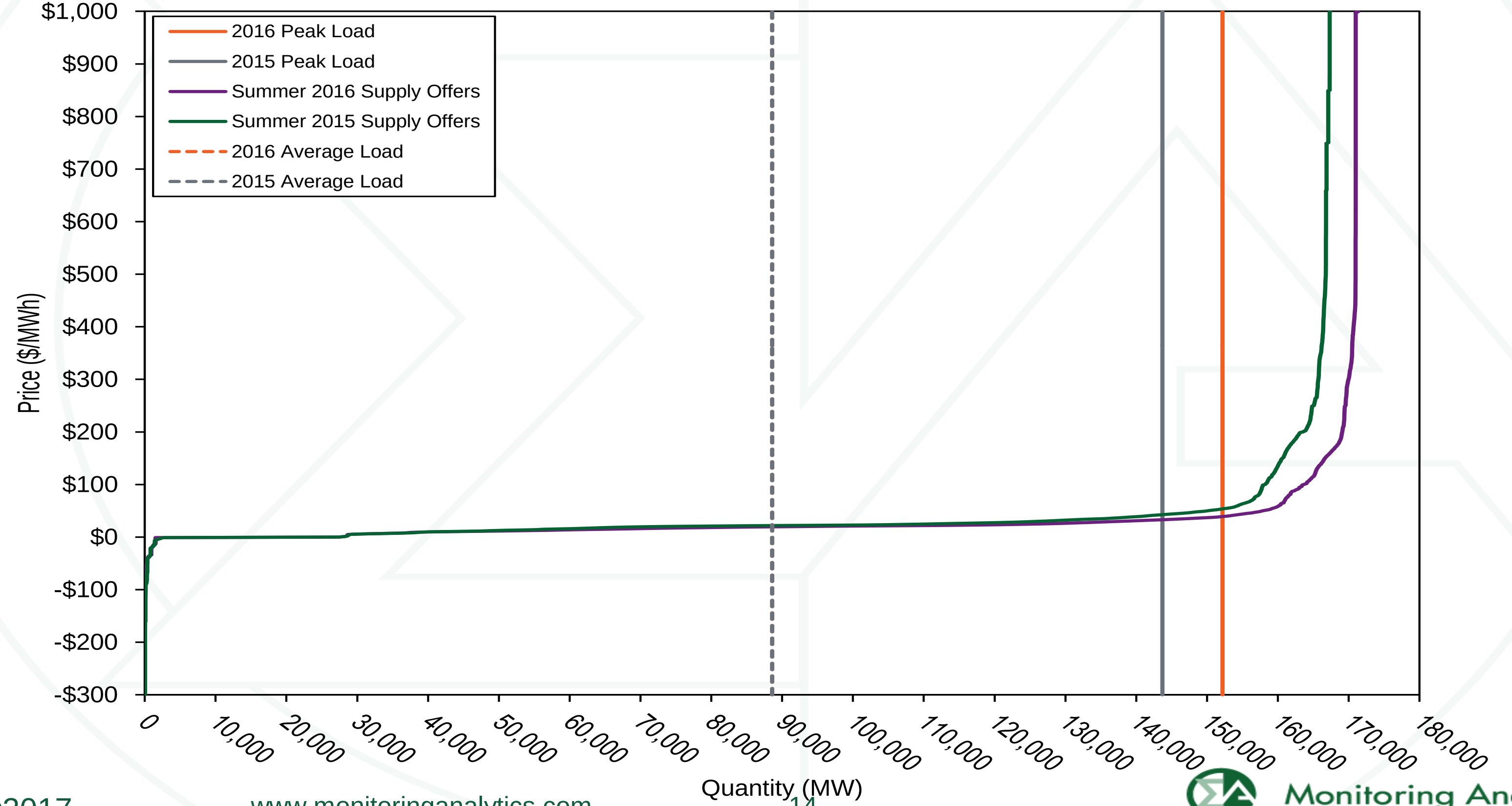
PJM load: 1998 through 2016

	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
1998	28,578	5,511	28,578	5,511	NA	NA	NA	NA
1999	29,641	5,955	29,641	5,955	3.7%	8.1%	3.7%	8.1%
2000	30,113	5,529	31,341	5,728	1.6%	(7.2%)	5.7%	(3.8%)
2001	30,297	5,873	32,165	5,564	0.6%	6.2%	2.6%	(2.9%)
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%

PJM real-time monthly average hourly load



Average PJM aggregate real-time generation supply curves: summer of 2015 and 2016



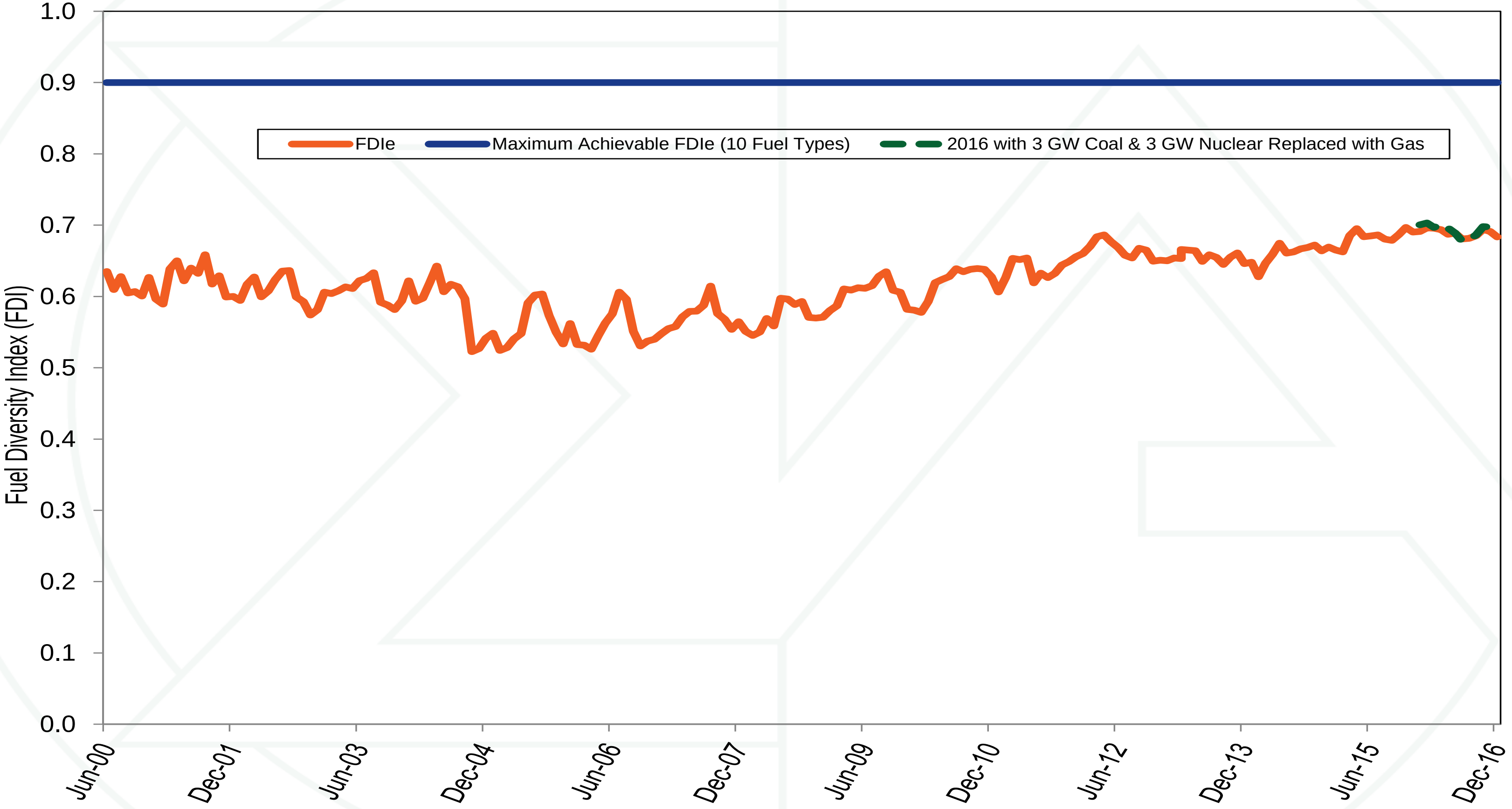
PJM generation by fuel source

	2015 GWh	Percent	2016 GWh	Percent	Change in Output
Coal	284,757.4	36.2%	275,281.7	33.9%	(3.3%)
Bituminous	257,700.0	32.8%	241,050.2	29.7%	(6.5%)
Sub Bituminous	22,528.7	2.9%	28,949.7	3.6%	28.5%
Other Coal	4,528.6	0.6%	5,281.7	0.7%	16.6%
Nuclear	279,106.5	35.5%	279,546.4	34.4%	0.2%
Gas	183,650.7	23.3%	217,214.5	26.7%	18.3%
Natural Gas	180,948.7	23.0%	215,022.4	26.5%	18.8%
Landfill Gas	2,275.8	0.3%	2,176.2	0.3%	(4.4%)
Other Gas	426.3	0.1%	15.9	0.0%	(96.3%)
Hydroelectric	13,067.2	1.7%	13,686.8	1.7%	4.7%
Pumped Storage	4,660.2	0.6%	4,840.2	0.6%	3.9%
Run of River	6,736.3	0.9%	7,332.8	0.9%	8.9%
Other Hydro	1,670.8	0.2%	1,513.8	0.2%	(9.4%)
Wind	16,609.7	2.1%	17,716.0	2.2%	6.7%
Waste	4,365.1	0.6%	4,139.8	0.5%	(5.2%)
Solid Waste	4,175.4	0.5%	4,139.8	0.5%	(0.9%)
Miscellaneous	189.7	0.0%	0.0	0.0%	(100.0%)
Oil	3,276.2	0.4%	2,163.6	0.3%	(34.0%)
Heavy Oil	622.9	0.1%	270.6	0.0%	(56.6%)
Light Oil	1,122.0	0.1%	341.1	0.0%	(69.6%)
Diesel	163.8	0.0%	59.4	0.0%	(63.7%)
Gasoline	0.0	0.0%	0.0	0.0%	NA
Kerosene	413.0	0.1%	74.8	0.0%	(81.9%)
Jet Oil	0.0	0.0%	0.0	0.0%	NA
Other Oil	954.5	0.1%	1,417.7	0.2%	48.5%
Solar, Net Energy Metering	548.4	0.1%	1,019.4	0.1%	85.9%
Energy Storage	7.6	0.0%	15.7	0.0%	106.7%
Battery	7.6	0.0%	15.7	0.0%	106.7%
Compressed Air	0.0	0.0%	0.0	0.0%	NA
Biofuel	1,309.6	0.2%	1,760.3	0.2%	34.4%
Geothermal	0.0	0.0%	0.0	0.0%	NA
Other Fuel Type	0.0	0.0%	0.0	0.0%	NA
Total	786,698.5	100.0%	812,544.1	100.0%	3.3%

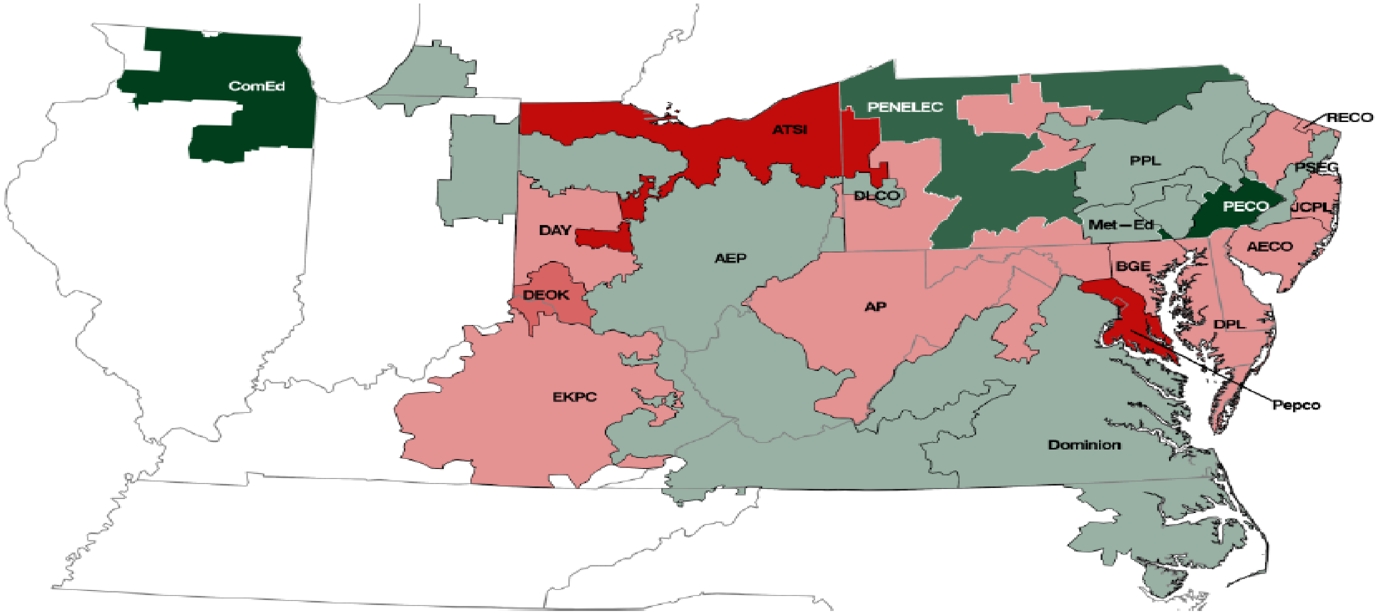
PJM capacity factor by unit type

	2015		2016		
Unit Type	Generation (GWh)	Capacity Factor	Generation (GWh)	Capacity Factor	Change in 2016 from 2015
Battery	7.6	0.5%	15.7	0.6%	0.1%
Combined Cycle	159,420.8	62.5%	187,368.5	62.0%	(0.5%)
Combustion Turbine	14,213.8	5.6%	17,980.5	6.8%	1.2%
Diesel	578.9	15.2%	662.7	16.9%	1.7%
Diesel (Landfill gas)	1,508.6	45.6%	1,501.9	45.1%	(0.4%)
Fuel Cell	227.1	86.4%	227.6	86.4%	(0.0%)
Nuclear	279,106.5	94.5%	279,546.4	93.0%	(1.4%)
Pumped Storage Hydro	6,038.4	12.8%	6,074.3	13.9%	1.1%
Run of River Hydro	7,000.9	30.5%	7,609.6	31.3%	0.8%
Solar	531.8	16.0%	970.3	17.7%	1.7%
Steam	388,709.8	43.8%	375,485.9	32.5%	(11.3%)
Wind	16,609.7	28.4%	17,696.2	28.0%	(0.3%)
Total	873,954.0	47.6%	895,139.6	41.2%	(6.4%)

Fuel diversity index for energy



PJM real-time generation less real-time load

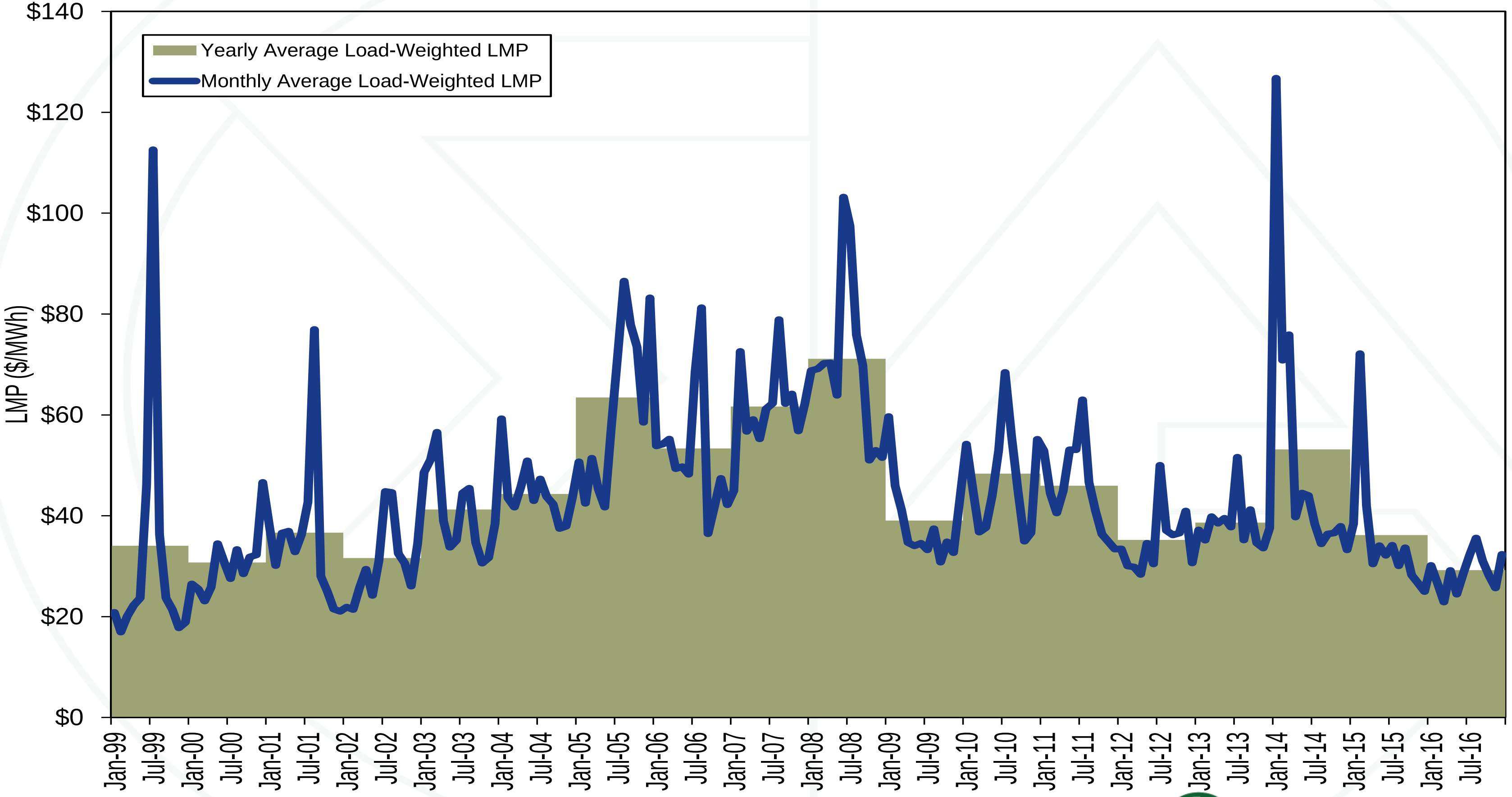


Zone	Net Gen Minus Load (GWh)	Zone	Net Gen Minus Load (GWh)	Zone	Net Gen Minus Load (GWh)	Zone	Net Gen Minus Load (GWh)
AECO	(3,427)	ComEd	31,369	DPL	(9,806)	PENELEC	20,307
AEP	14,986	DAY	(1,908)	EKPC	(2,765)	Pepco	(20,204)
AP	(574)	DEOK	(10,616)	JCPL	(4,712)	PPL	9,668
ATSI	(24,444)	DLCO	3,361	Met-Ed	6,937	PSEG	1,800
BGE	(9,363)	Dominion	264	PECO	24,506	RECO	(1,481)

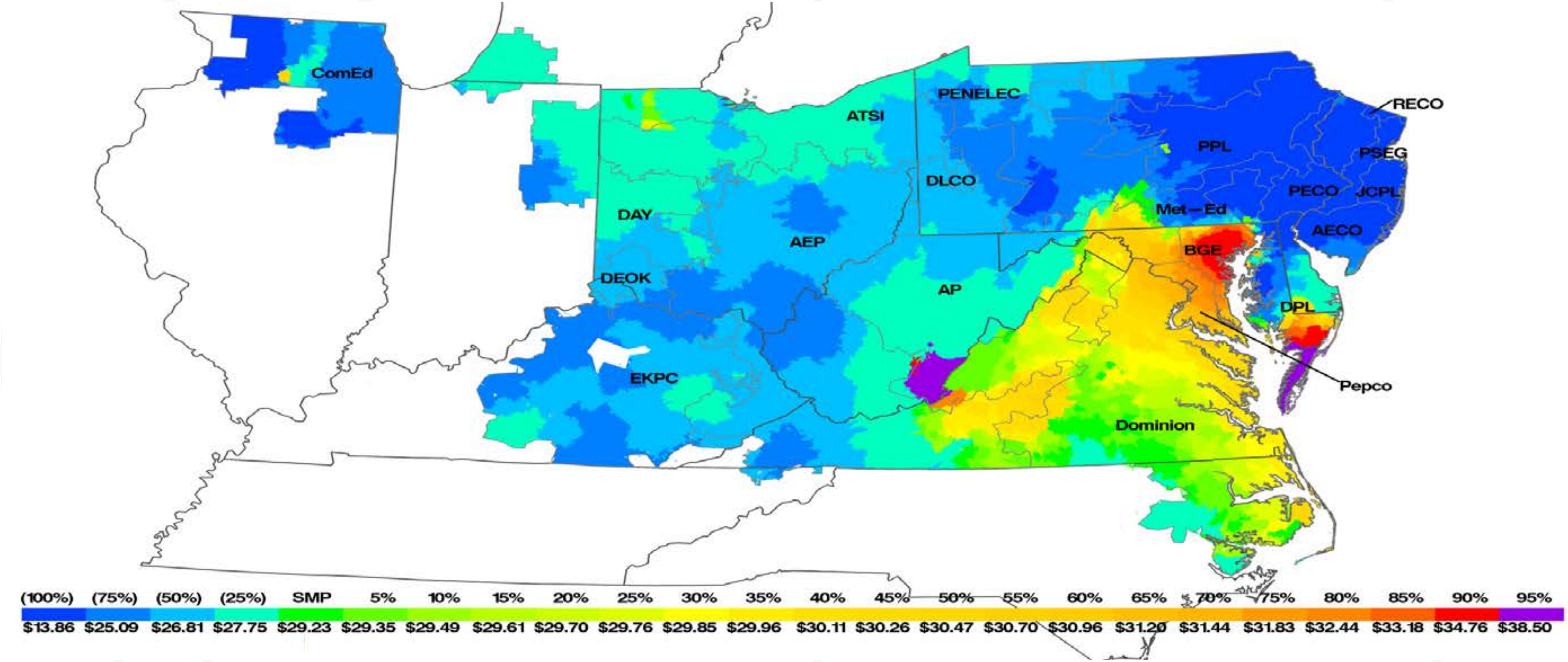
PJM real-time, load-weighted, average LMP

	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%)

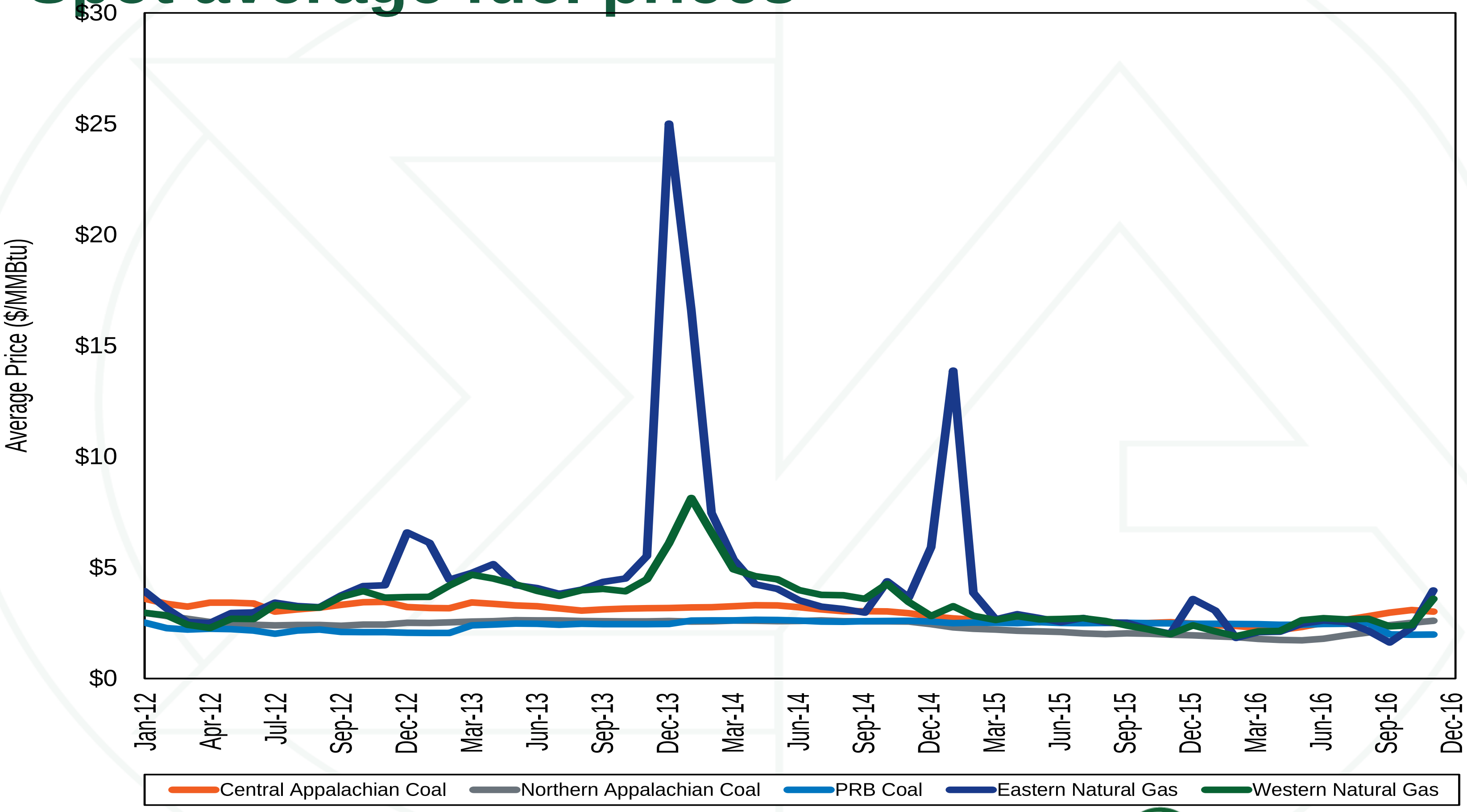
PJM real-time load-weighted average LMP



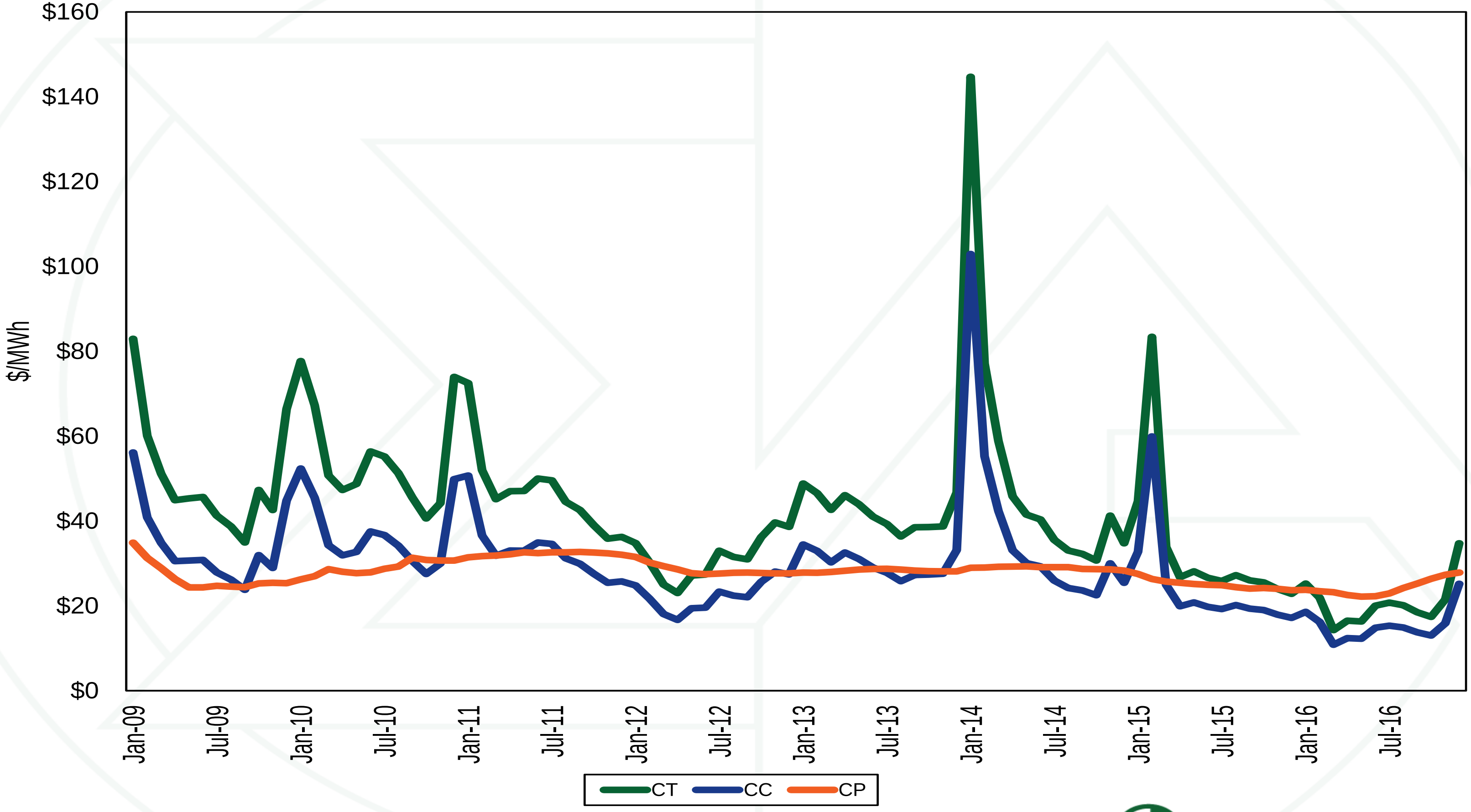
PJM real-time, load-weighted, average LMP: 2016



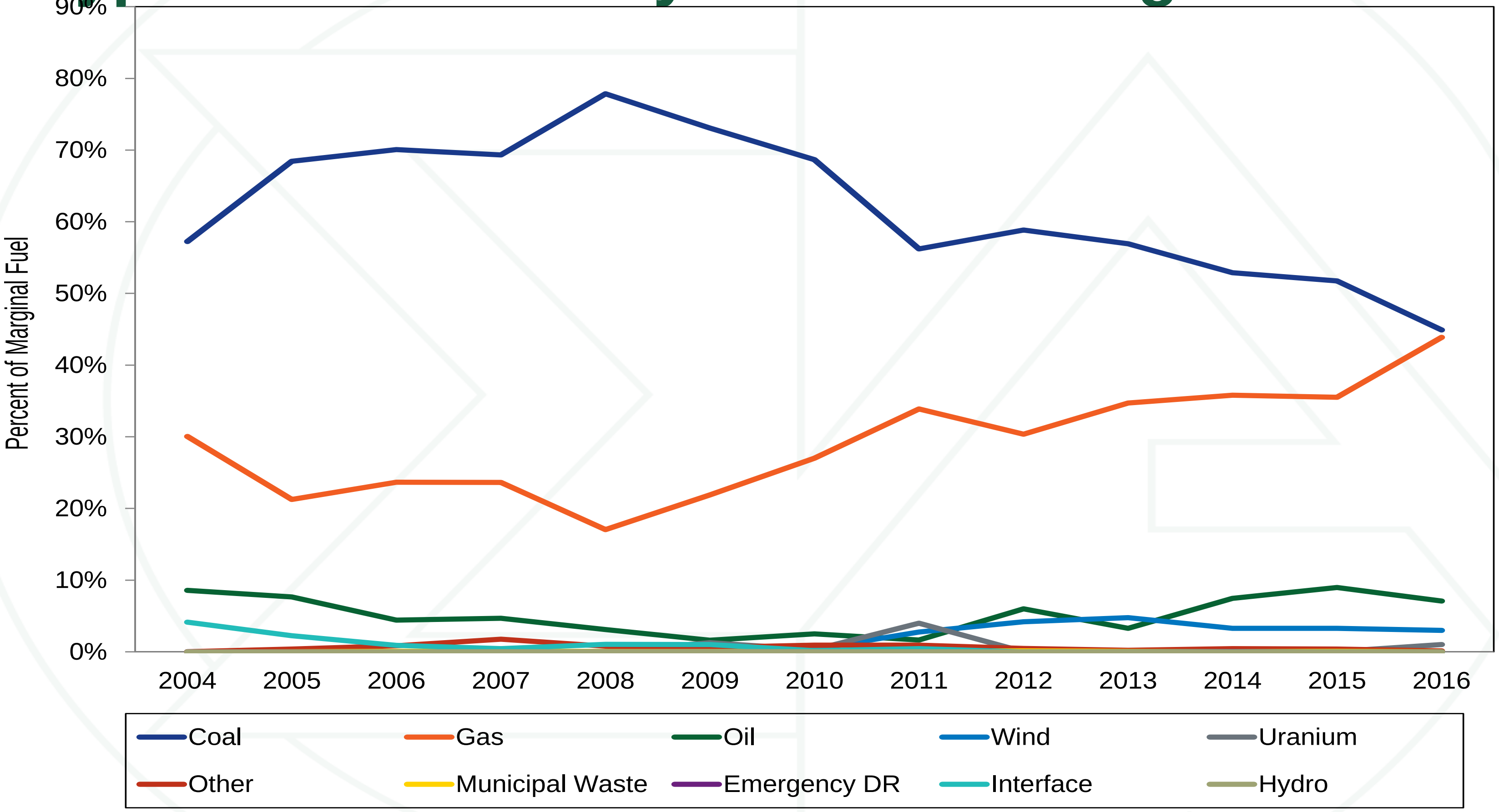
Spot average fuel prices



Short run marginal costs of generation



Type of fuel used by real-time marginal units



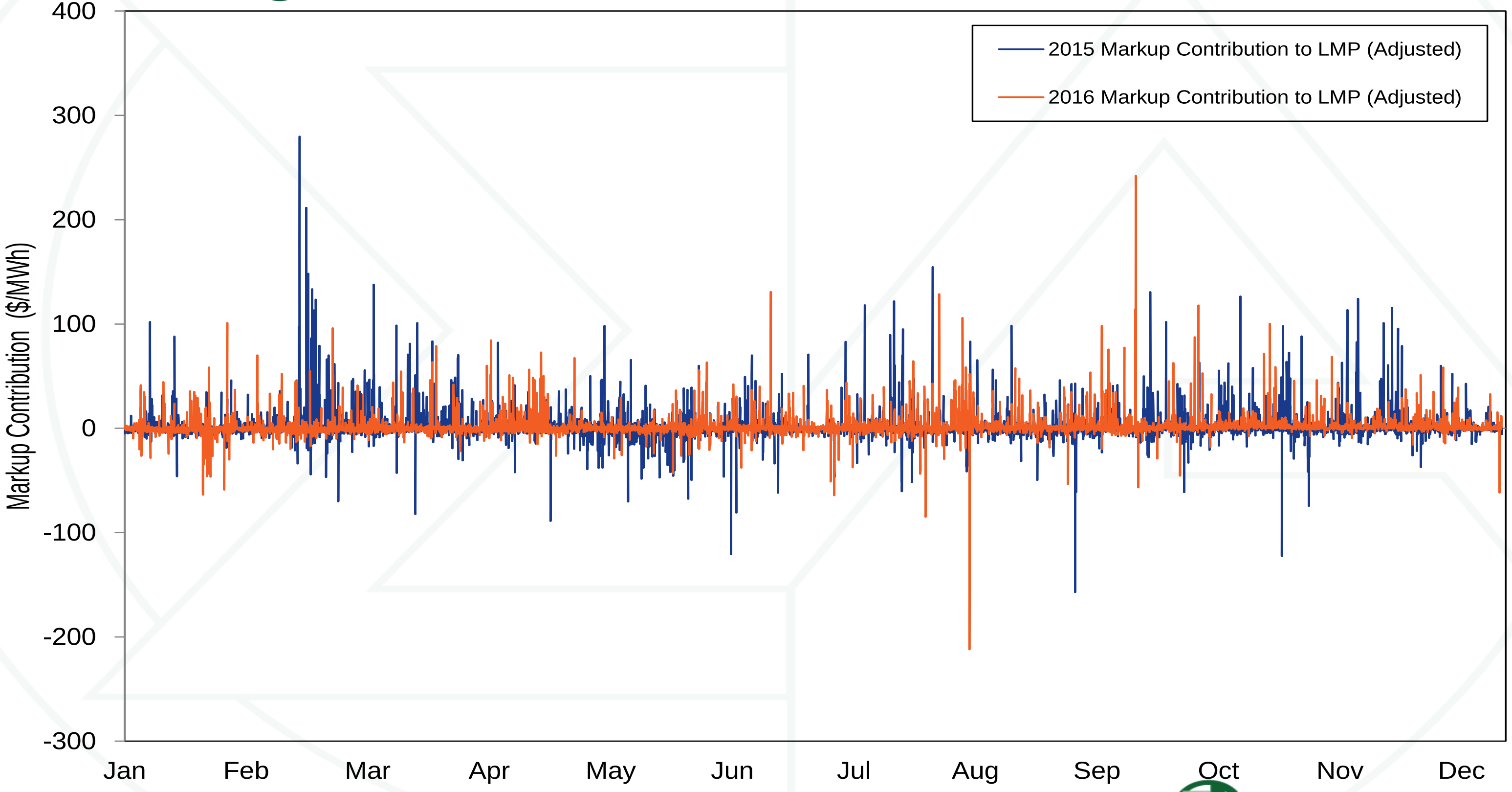
PJM real-time annual, fuel-cost adjusted, load-weighted average LMP

	2016 Load-Weighted LMP	2016 Fuel-Cost Adjusted, Load-Weighted LMP	Change
Average	$29.23	$29.72	1.7%
	2015 Load-Weighted LMP	2016 Fuel-Cost Adjusted, Load-Weighted LMP	Change
Average	$36.16	$29.72	(17.8%)
	2015 Load-Weighted LMP	2016 Load-Weighted LMP	Change
Average	$36.16	$29.23	(19.2%)

Components of PJM real-time load-weighted, average LMP

Element	2015 Contribution to LMP	2015 Percent	2016 Contribution to LMP	2016 Percent	Change Percent
Coal	$15.62	43.2%	$13.28	45.4%	2.2%
Gas	$9.85	27.2%	$7.96	27.2%	(0.0%)
VOM	$2.38	6.6%	$2.04	7.0%	0.4%
Markup	$1.75	4.8%	$1.77	6.1%	1.2%
NA	$0.89	2.4%	$1.23	4.2%	1.8%
Ten Percent Adder	$1.40	3.9%	$1.06	3.6%	(0.2%)
NO_x Cost	$0.29	0.8%	$0.42	1.4%	0.6%
Increase Generation Adder	$0.24	0.7%	$0.35	1.2%	0.5%
Ancillary Service Redispatch Cost	$1.06	2.9%	$0.33	1.1%	(1.8%)
LPA Rounding Difference	$0.94	2.6%	$0.29	1.0%	(1.6%)
Oil	$1.25	3.5%	$0.29	1.0%	(2.5%)
Other	$0.15	0.4%	$0.14	0.5%	0.1%
SO_2 Cost	$0.35	1.0%	$0.07	0.3%	(0.7%)
CO_2 Cost	$0.21	0.6%	$0.06	0.2%	(0.4%)
Market-to-Market Adder	$0.01	0.0%	$0.01	0.0%	(0.0%)
Uranium	($0.00)	(0.0%)	$0.00	0.0%	0.0%
FMU Adder	$0.00	0.0%	$0.00	0.0%	(0.0%)
Municipal Waste	$0.01	0.0%	$0.00	0.0%	(0.0%)
Constraint Violation Adder	($0.00)	(0.0%)	$0.00	0.0%	0.0%
LPA-SCED Differential	($0.11)	(0.3%)	($0.01)	(0.0%)	0.3%
Decrease Generation Adder	($0.06)	(0.2%)	($0.03)	(0.1%)	0.1%
Wind	($0.07)	(0.2%)	($0.05)	(0.2%)	0.0%
Total	$36.16	100.0%	$29.23	100.0%	0.0%

Markup contribution to real-time hourly load-weighted LMP



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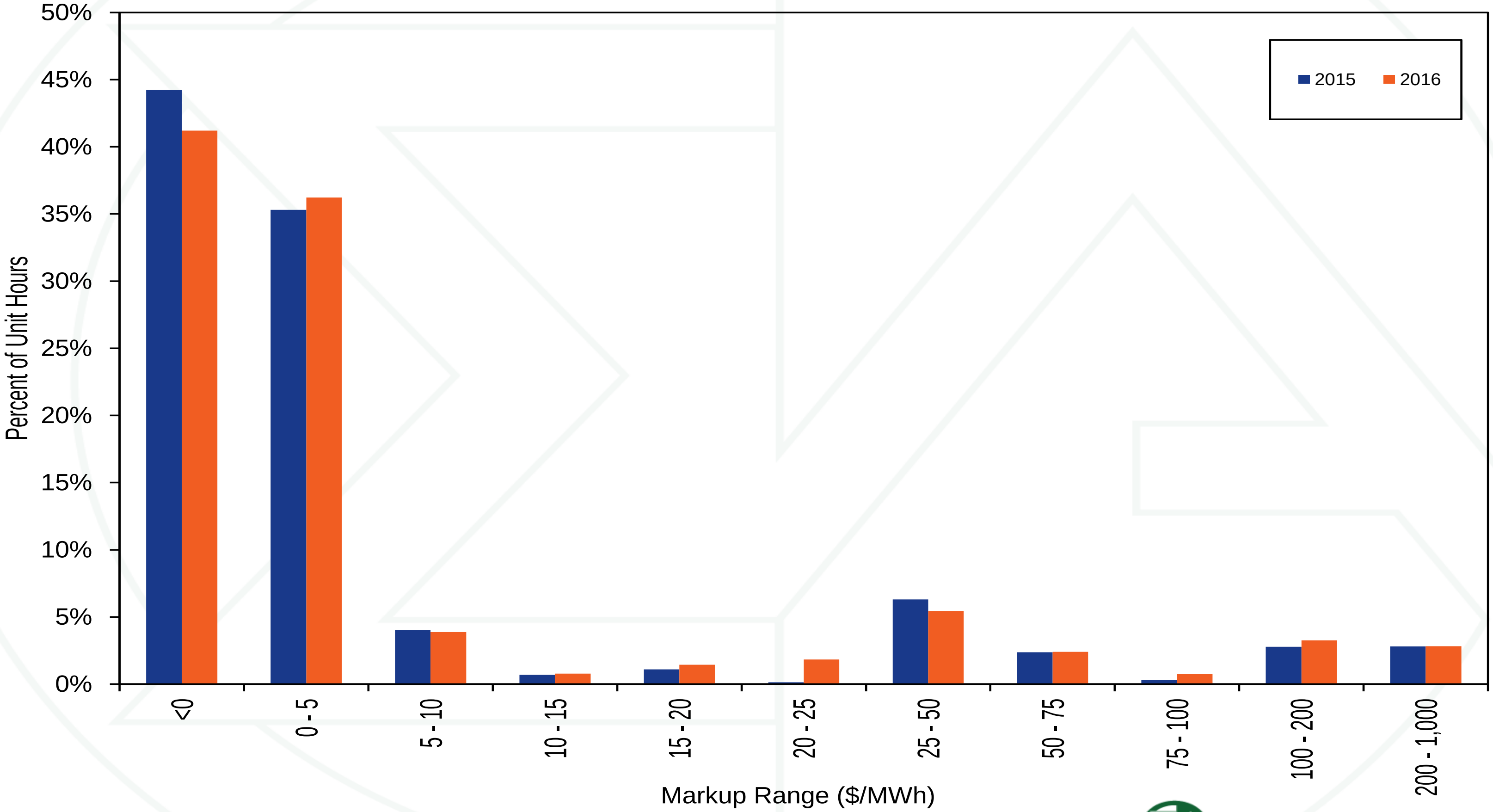
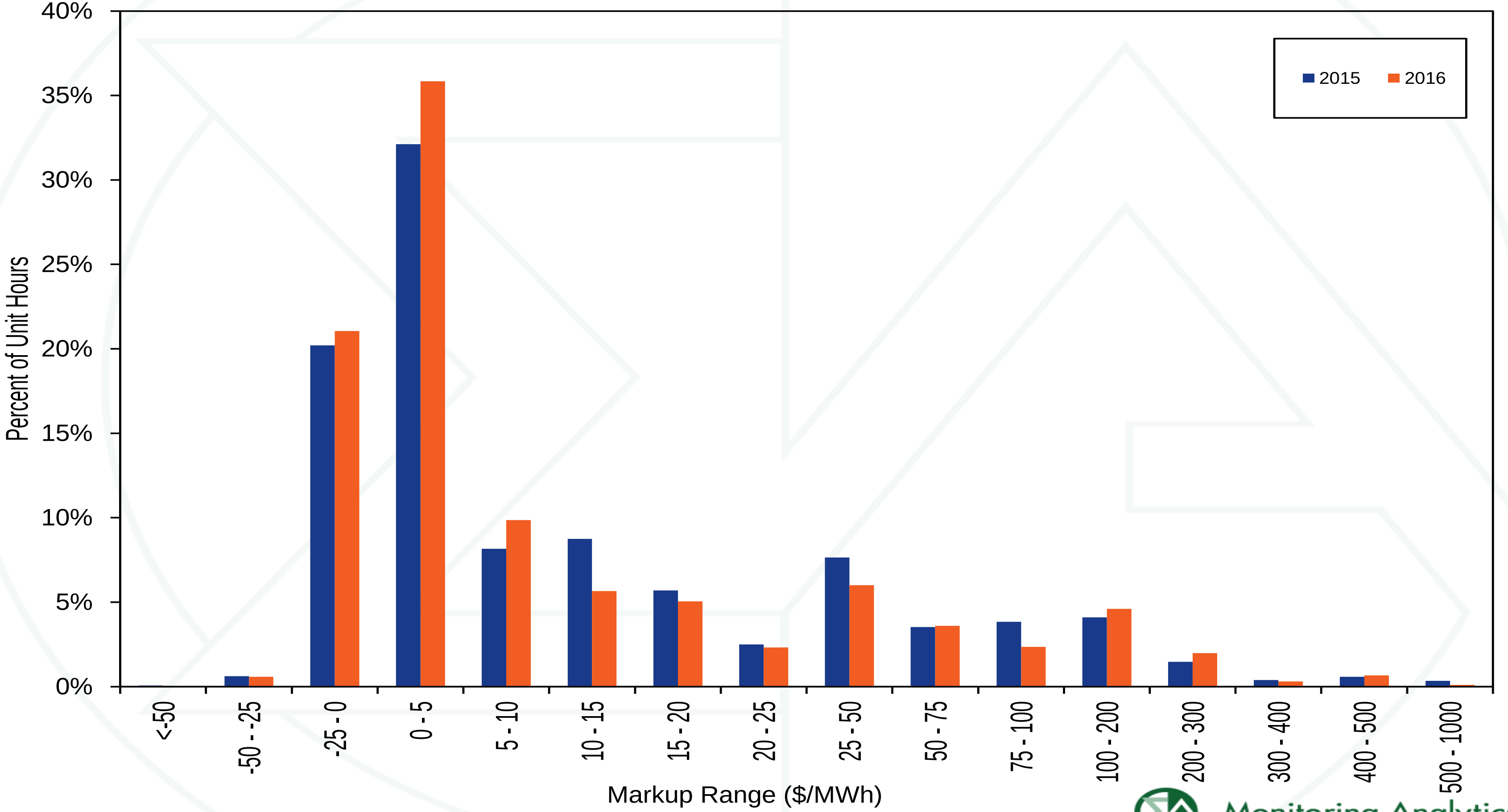
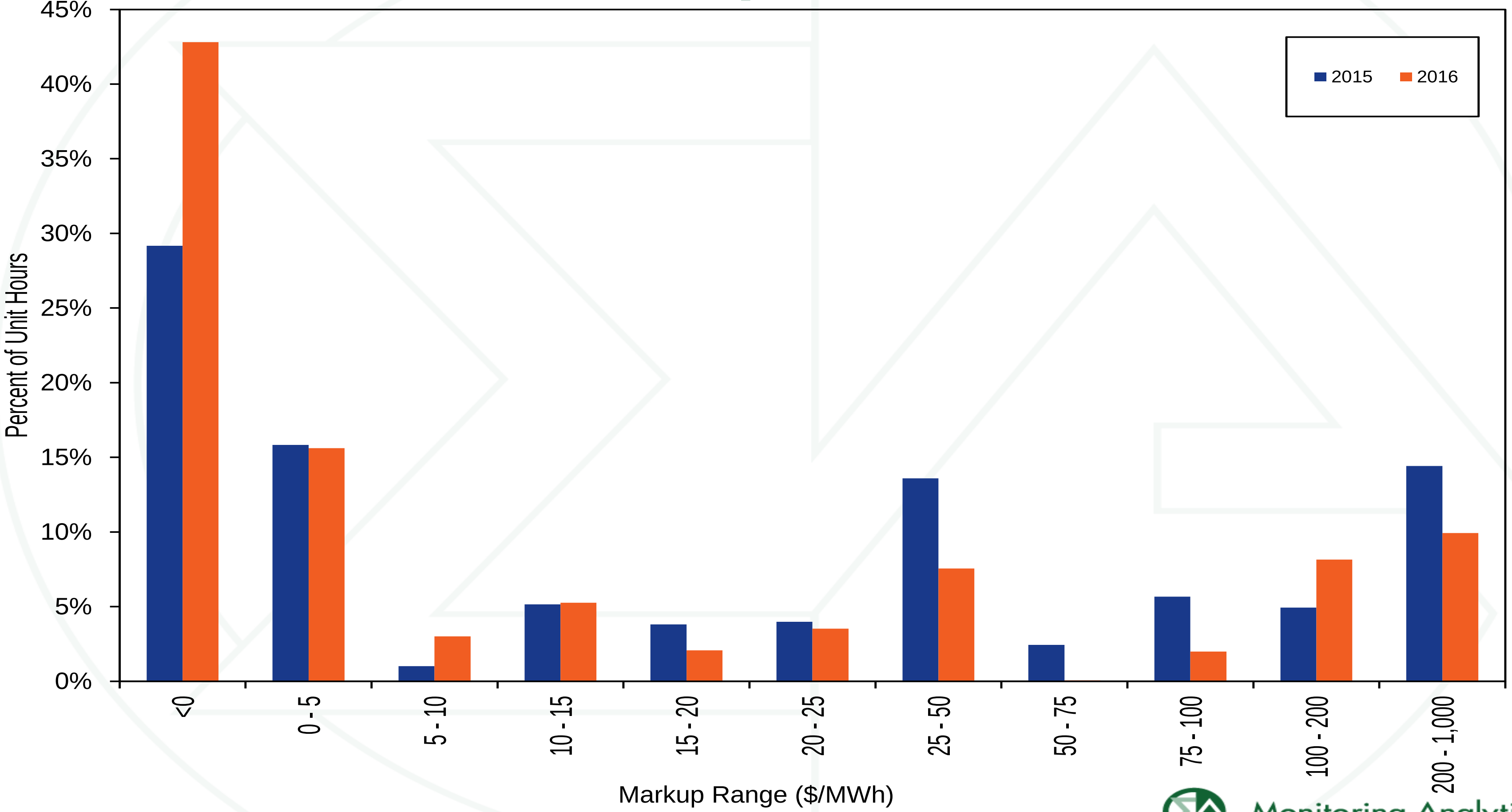
Distribution of markup of coal units



Distribution of markup of gas units



Distribution of markup of oil units



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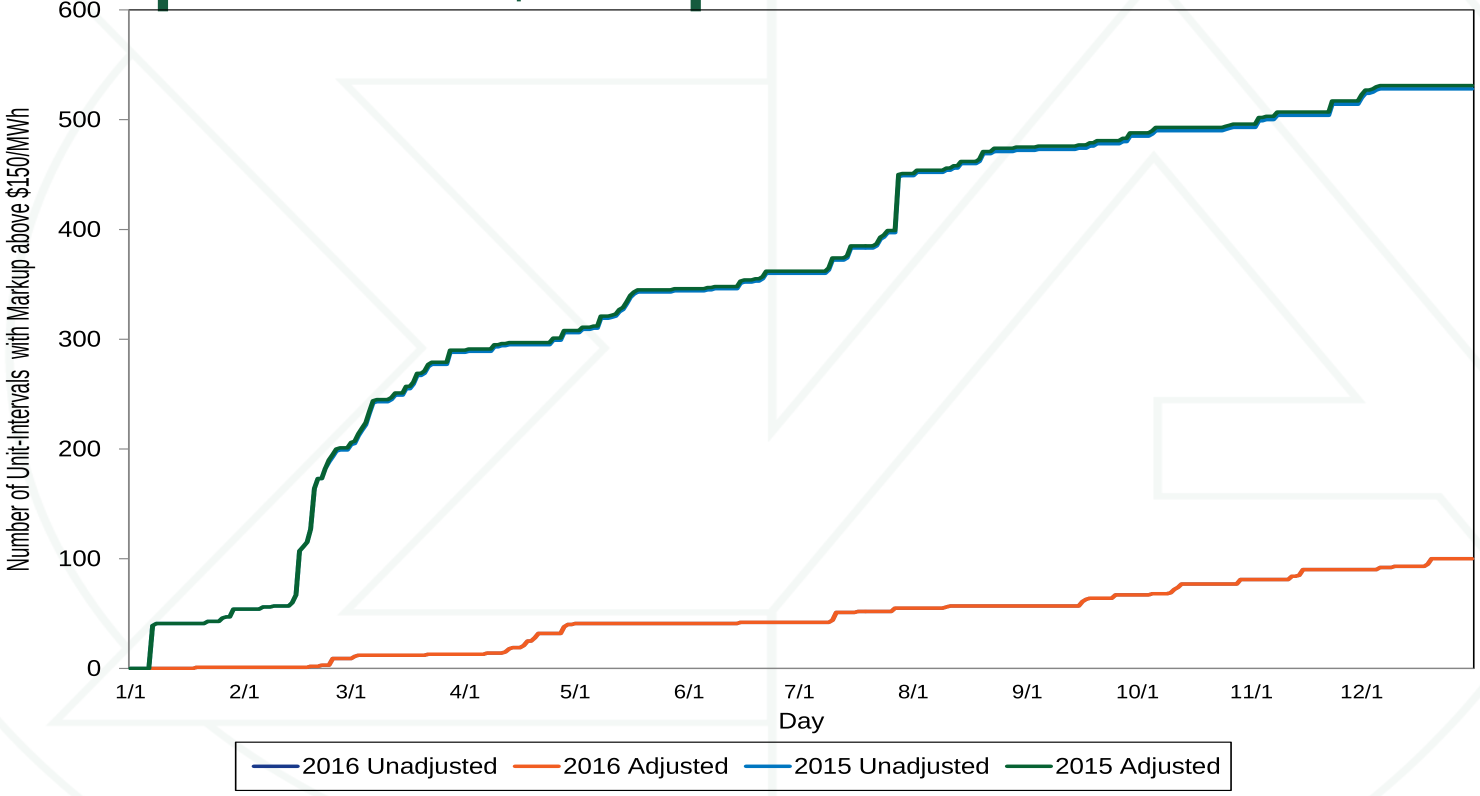
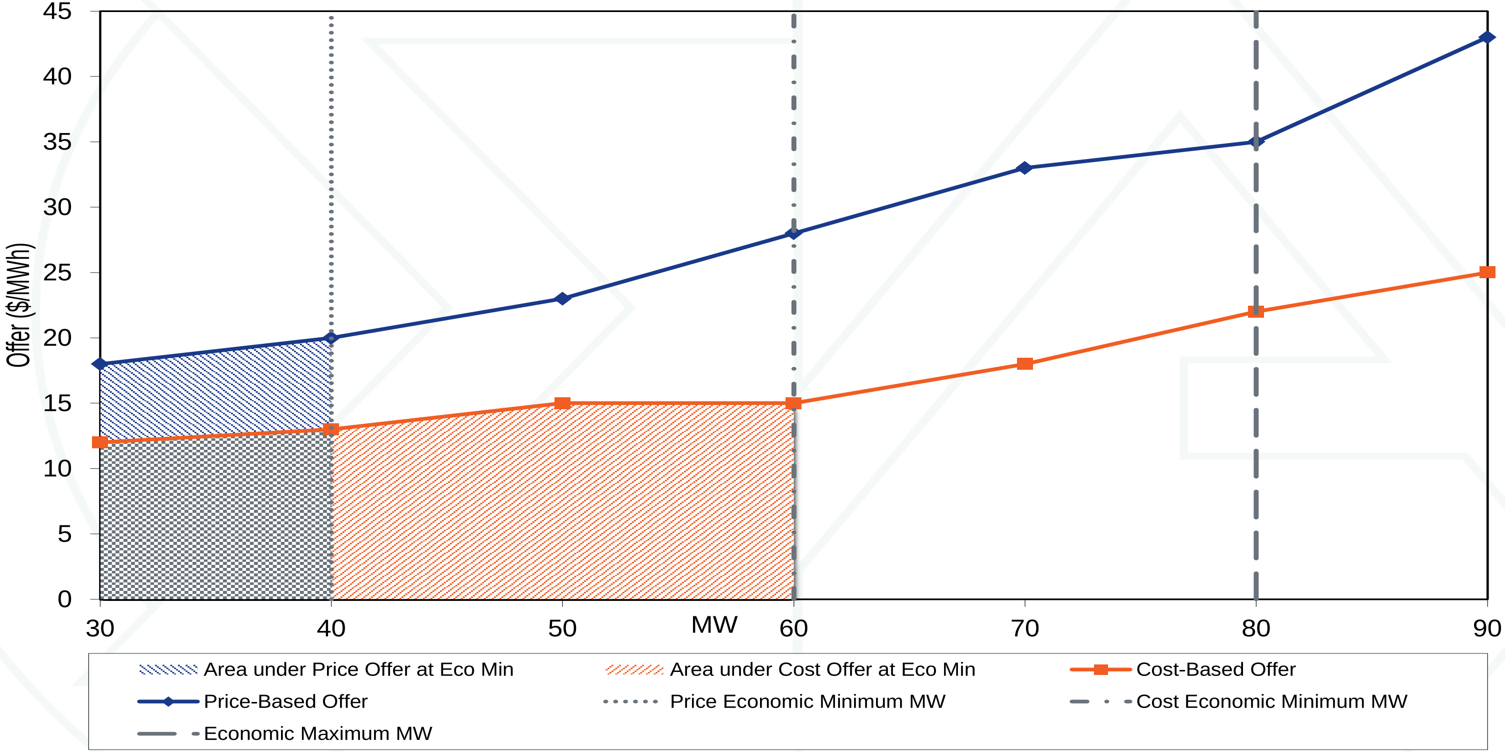
Cumulative number of unit intervals with markups above $150 per MWh



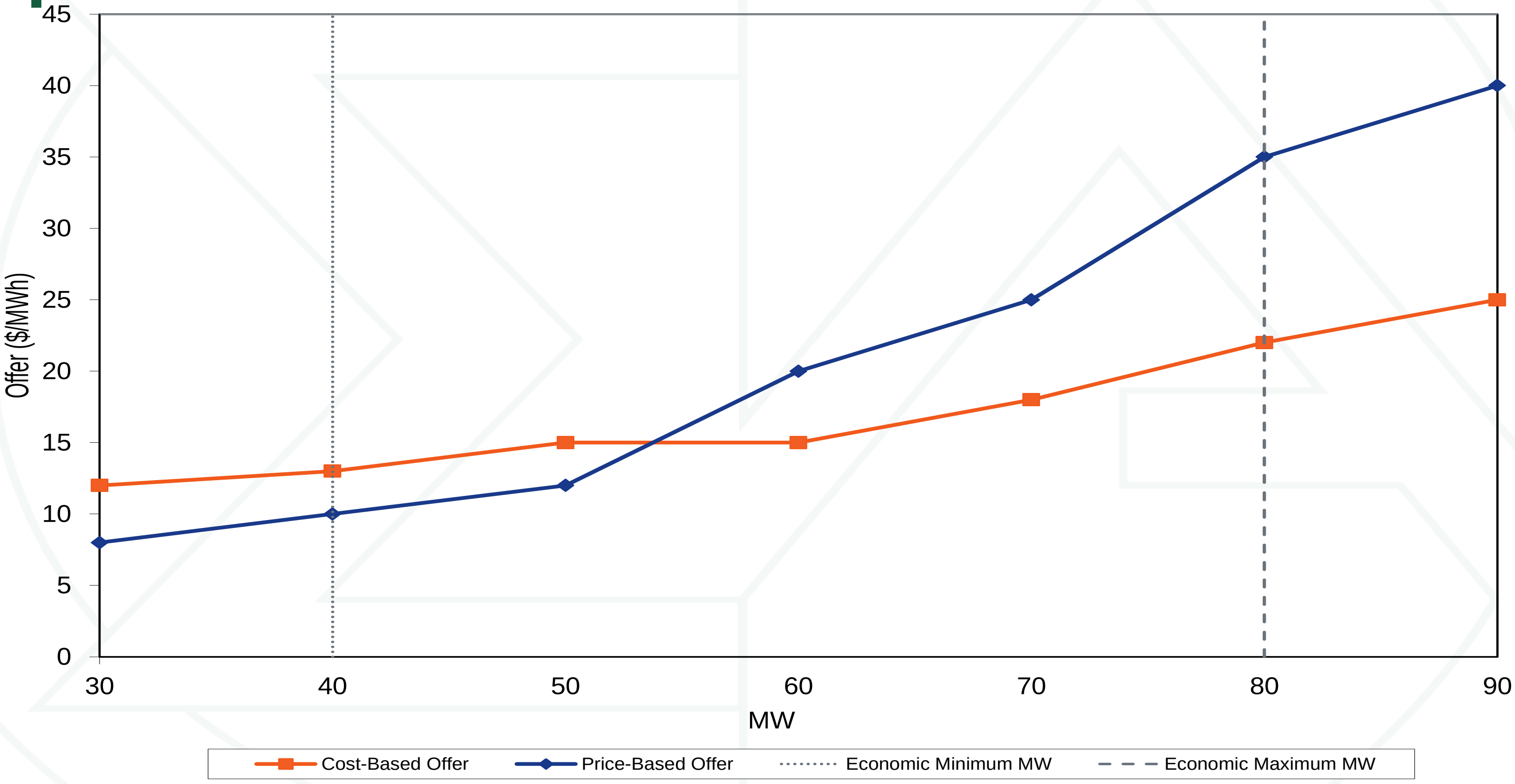
Offer capping – energy only

Year	Real Time Unit Hours Capped	Real Time MW Capped	Day Ahead Unit Hours Capped	Day Ahead MW Capped
2012	0.8%	0.4%	0.1%	0.1%
2013	0.4%	0.2%	0.1%	0.0%
2014	0.5%	0.2%	0.2%	0.1%
2015	0.4%	0.2%	0.2%	0.1%
2016	0.4%	0.2%	0.1%	0.0%

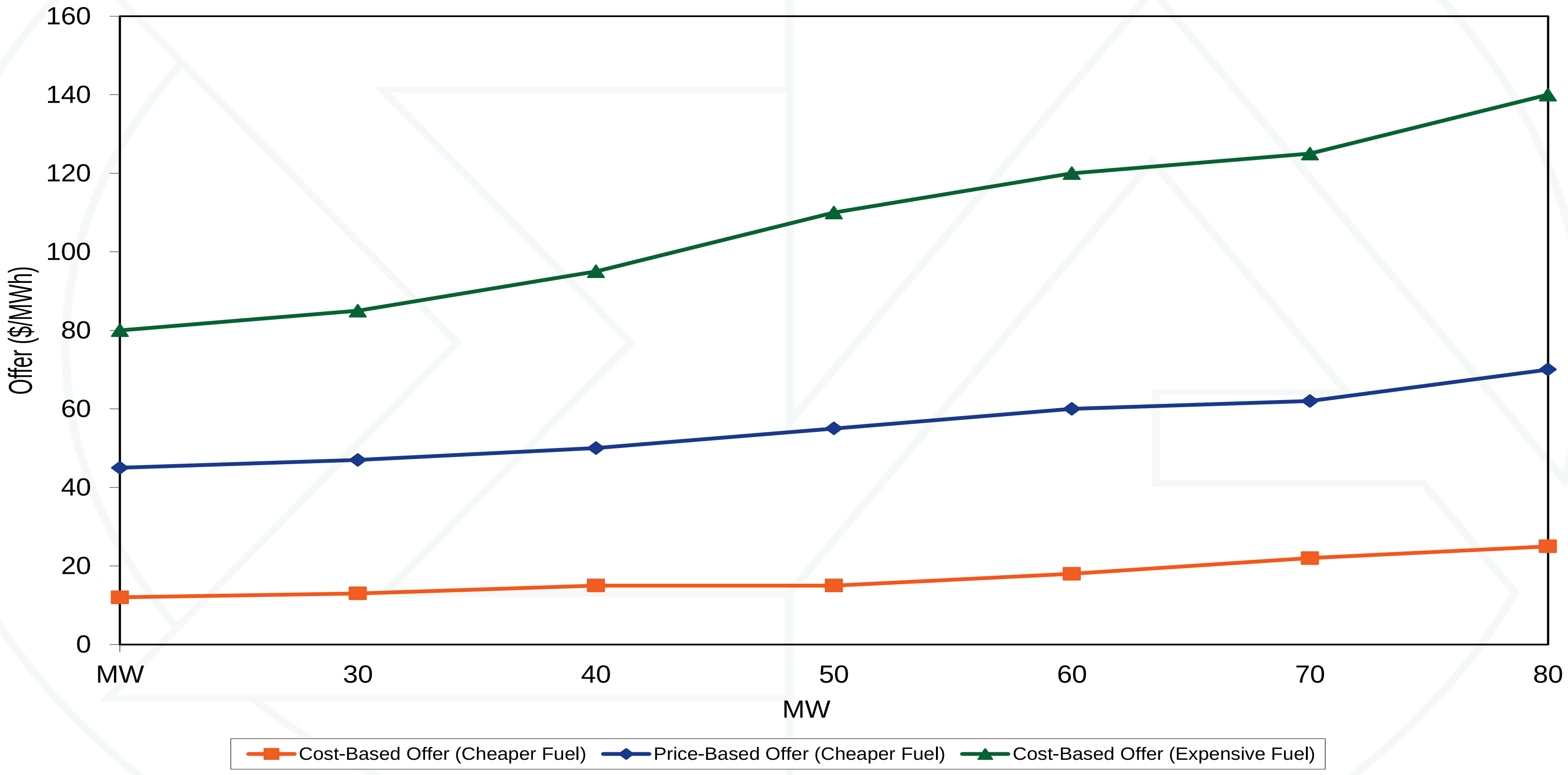
Offers with a positive markup but different economic minimum MW



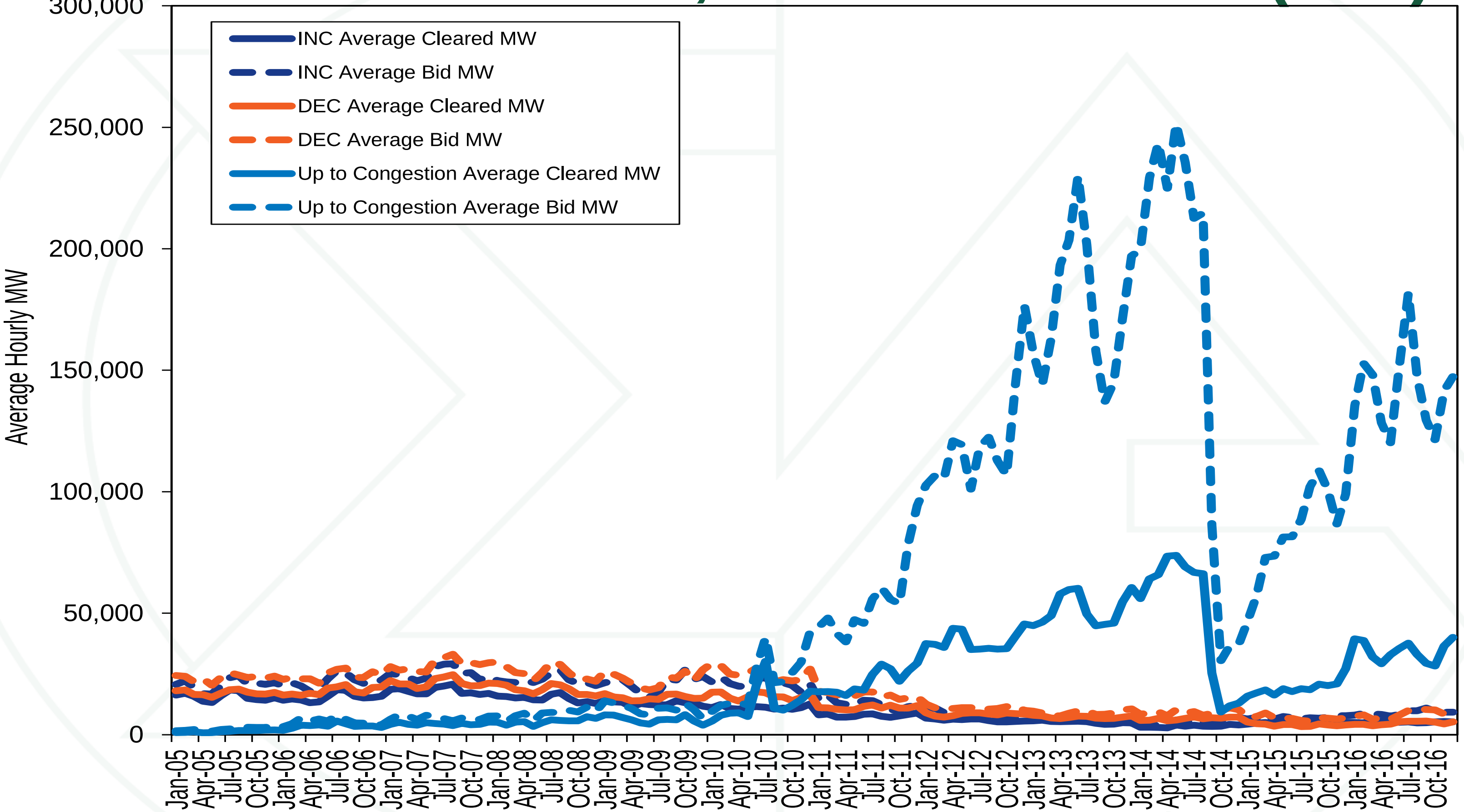
Offers with varying markups at different MW output levels



Dual fuel unit offers: cost and price



Bid and cleared INCs, DECs and UTCs (MW)



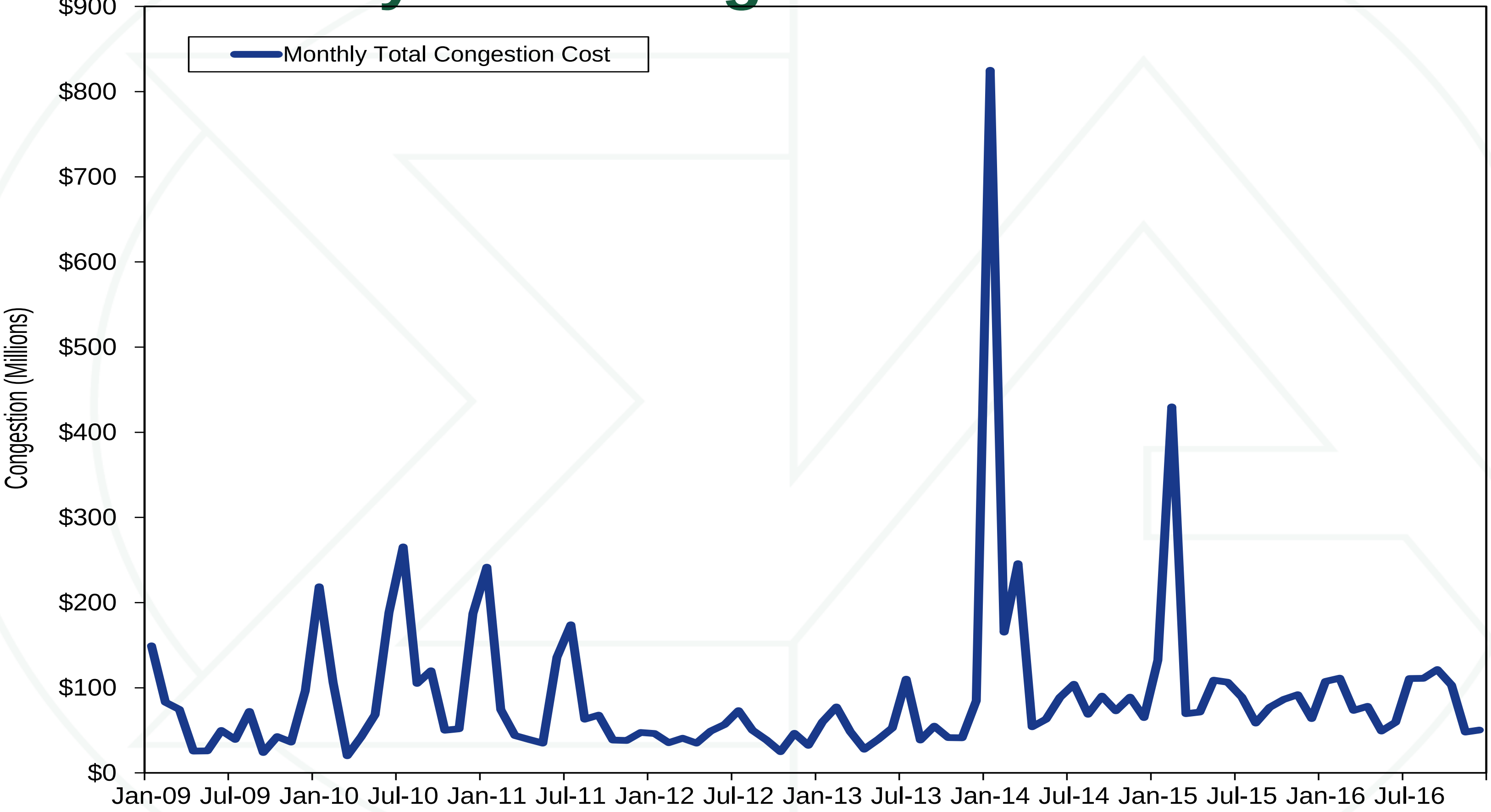
PJM up to congestion transactions by type of parent organization

	2015				2016			
Category	Total Up to Congestion Bid MW	Percent	Total Up to Congestion Cleared MW	Percent	Total Up to Congestion Bid MW	Percent	Total Up to Congestion Cleared MW	Percent
Financial	643,199,888	88.0%	134,523,544	79.8%	1,199,246,273	96.1%	283,295,621	93.8%
Physical	87,572,419	12.0%	34,149,529	20.2%	48,737,575	3.9%	18,744,457	6.2%
Total	730,772,307	100.0%	168,673,073	100.0%	1,247,983,848	100.0%	302,040,077	100.0%

Total PJM 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%)	$28,836	3.5%
2012	$529	(47.0%)	$29,181	1.8%
2013	$677	28.0%	$33,862	2.0%
2014	$1,932	185.5%	$50,040	3.9%
2015	$1,385	(28.3%)	$33,710	4.1%
2016	$1,024	(26.1%)	$39,050	2.6%

PJM monthly total congestion



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

Recommendations: Capacity Market

- Implement a MOPR for existing units
- 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 Net CONE should reflect actual flexibility of reference technology.

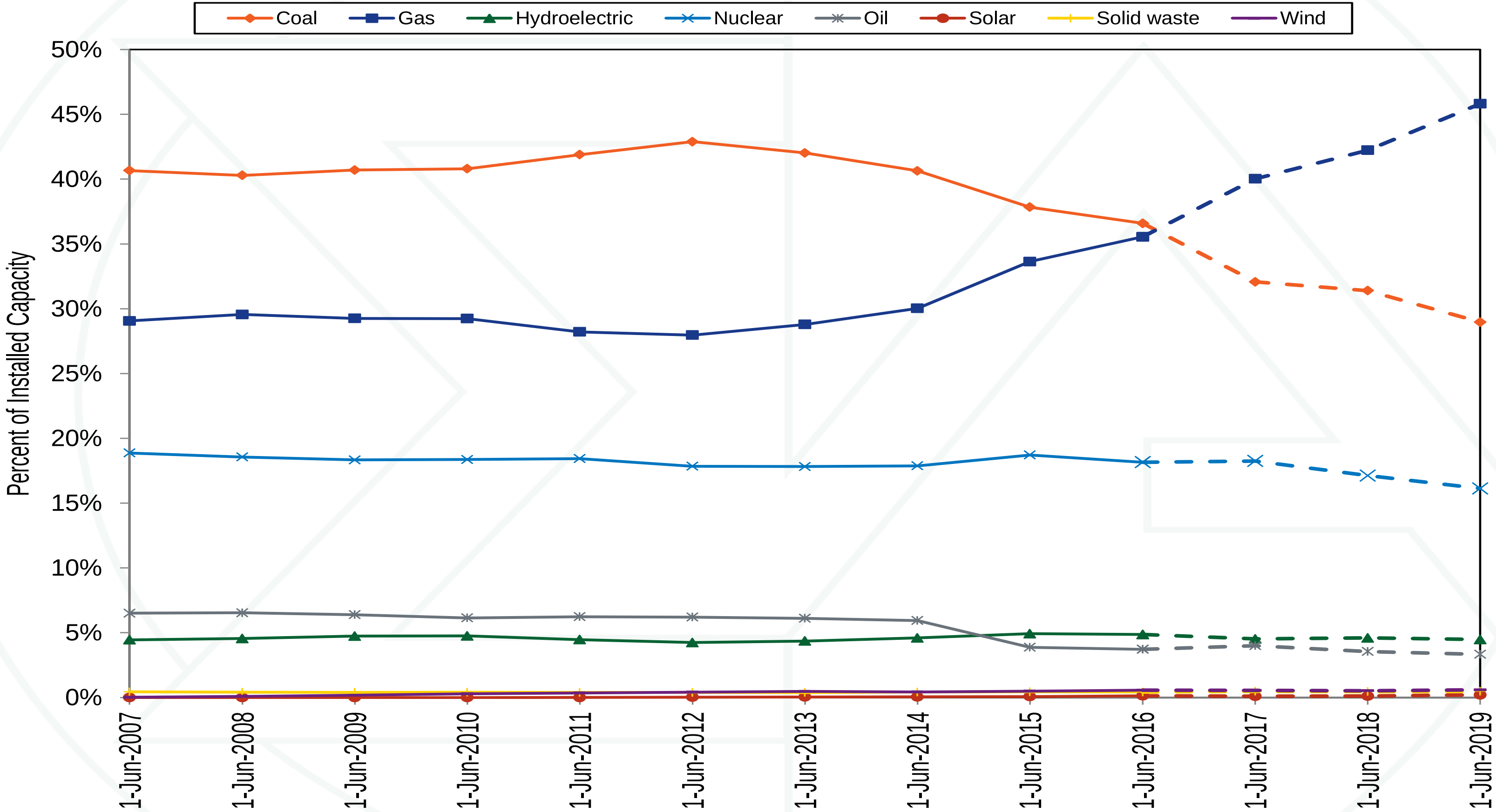
Recommendations: Capacity Market

- **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.**

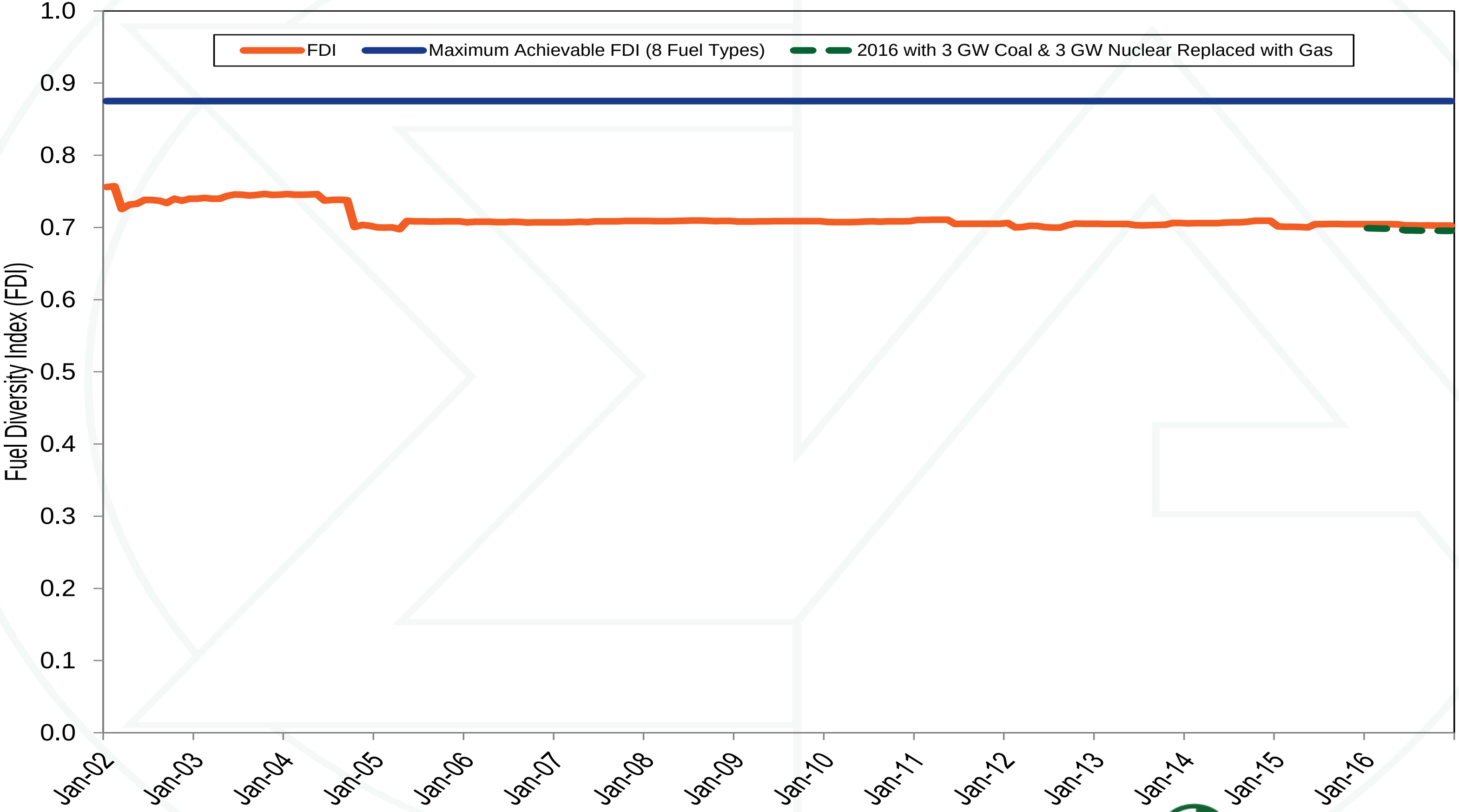
PJM installed capacity by fuel source

	1-Jan-16		31-May-16		1-Jun-16		31-Dec-16	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	66,674.8	37.5%	66,429.7	36.9%	66,619.9	36.6%	66,622.2	36.5%
Gas	60,487.4	34.0%	62,805.9	34.9%	64,721.7	35.5%	65,110.3	35.7%
Hydroelectric	8,787.5	4.9%	8,854.8	4.9%	8,850.4	4.9%	8,850.4	4.9%
Nuclear	33,071.5	18.6%	33,175.5	18.4%	33,050.6	18.2%	33,043.4	18.1%
Oil	6,851.8	3.9%	6,787.2	3.8%	6,779.8	3.7%	6,772.0	3.7%
Solar	128.0	0.1%	128.0	0.1%	252.4	0.1%	262.3	0.1%
Solid waste	769.4	0.4%	767.5	0.4%	767.5	0.4%	769.4	0.4%
Wind	912.4	0.5%	918.4	0.5%	1,019.1	0.6%	1,019.1	0.6%
Total	177,682.8	100.0%	179,867.0	100.0%	182,061.4	100.0%	182,449.1	100.0%

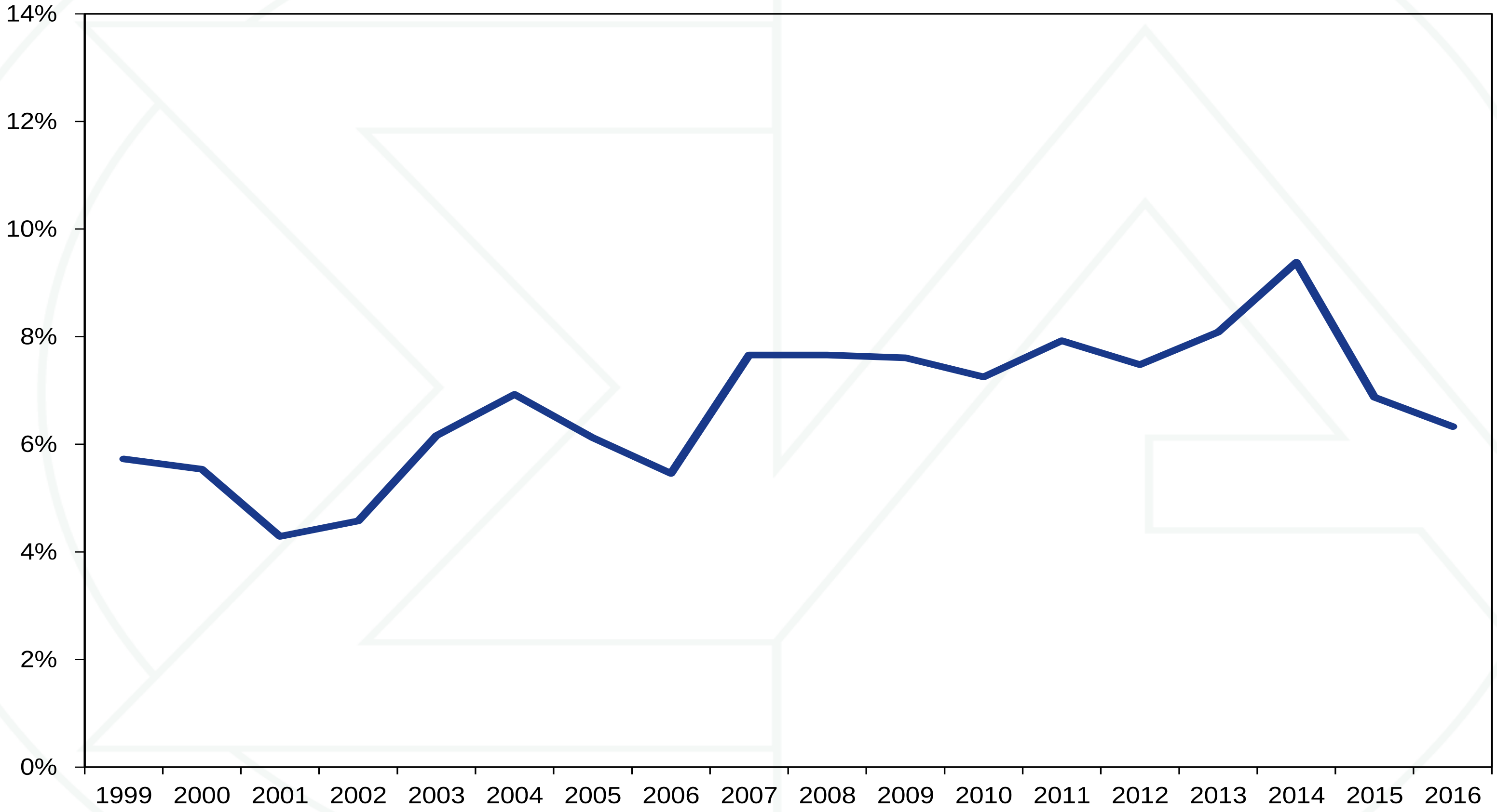
Share of PJM installed capacity by fuel source



Fuel Diversity Index for capacity

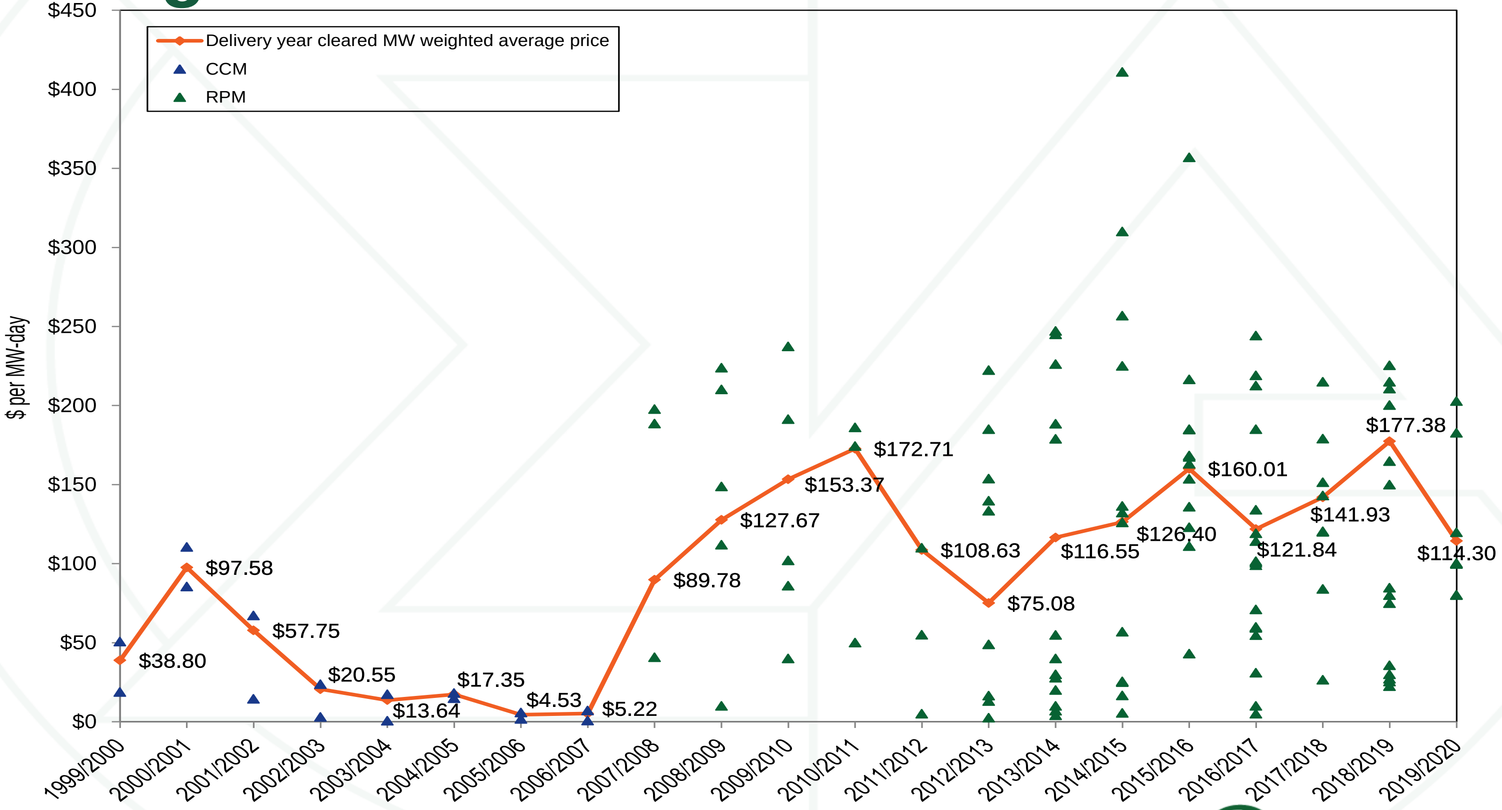


PJM EFORd

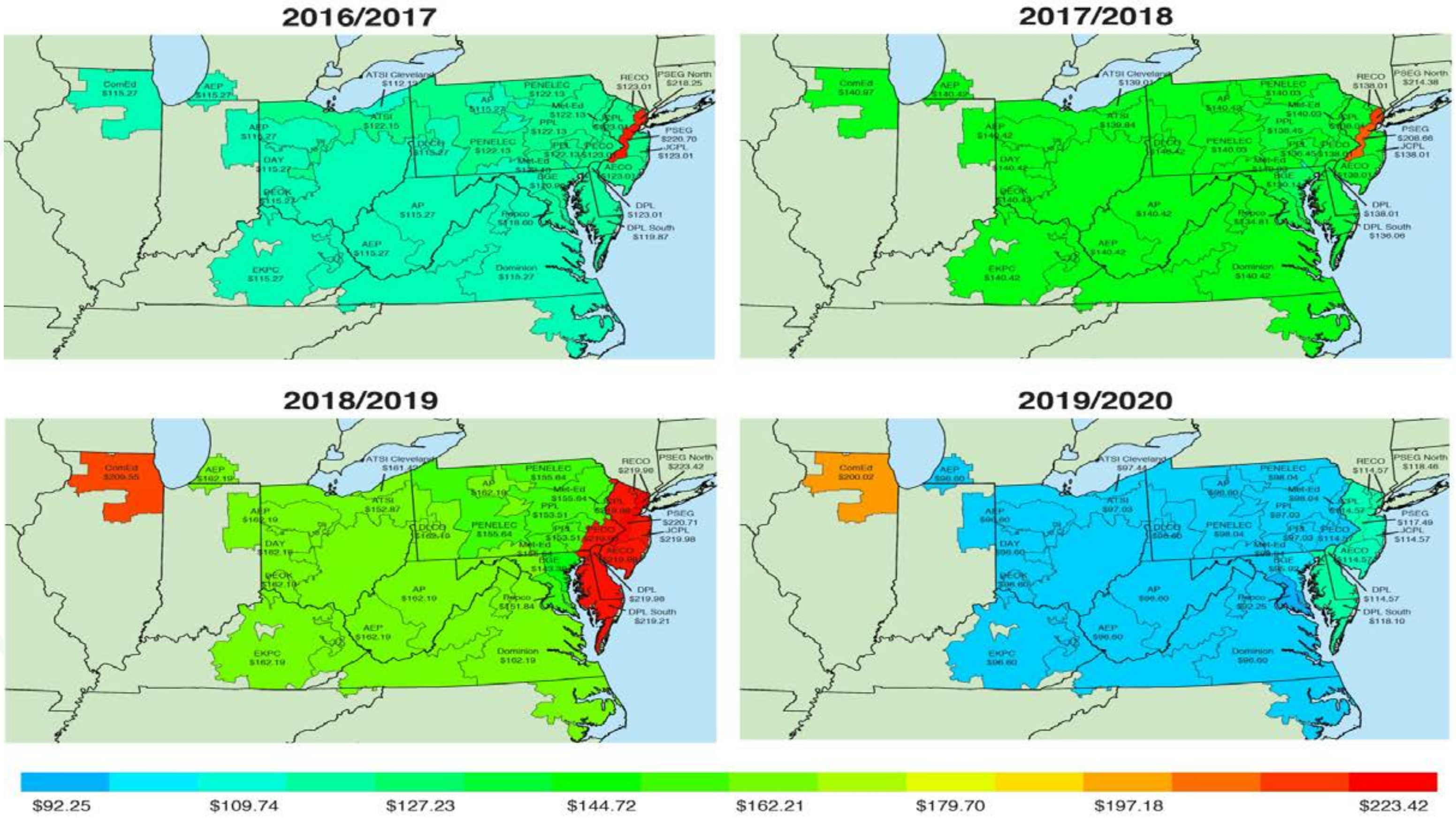


14%
12%
10%
8%
6%
4%
2%
0%
1999 2000 2001 2002 2003 2004 2005 2006 2007 2008 2009 2010 2011 2012 2013 2014 2015 2016

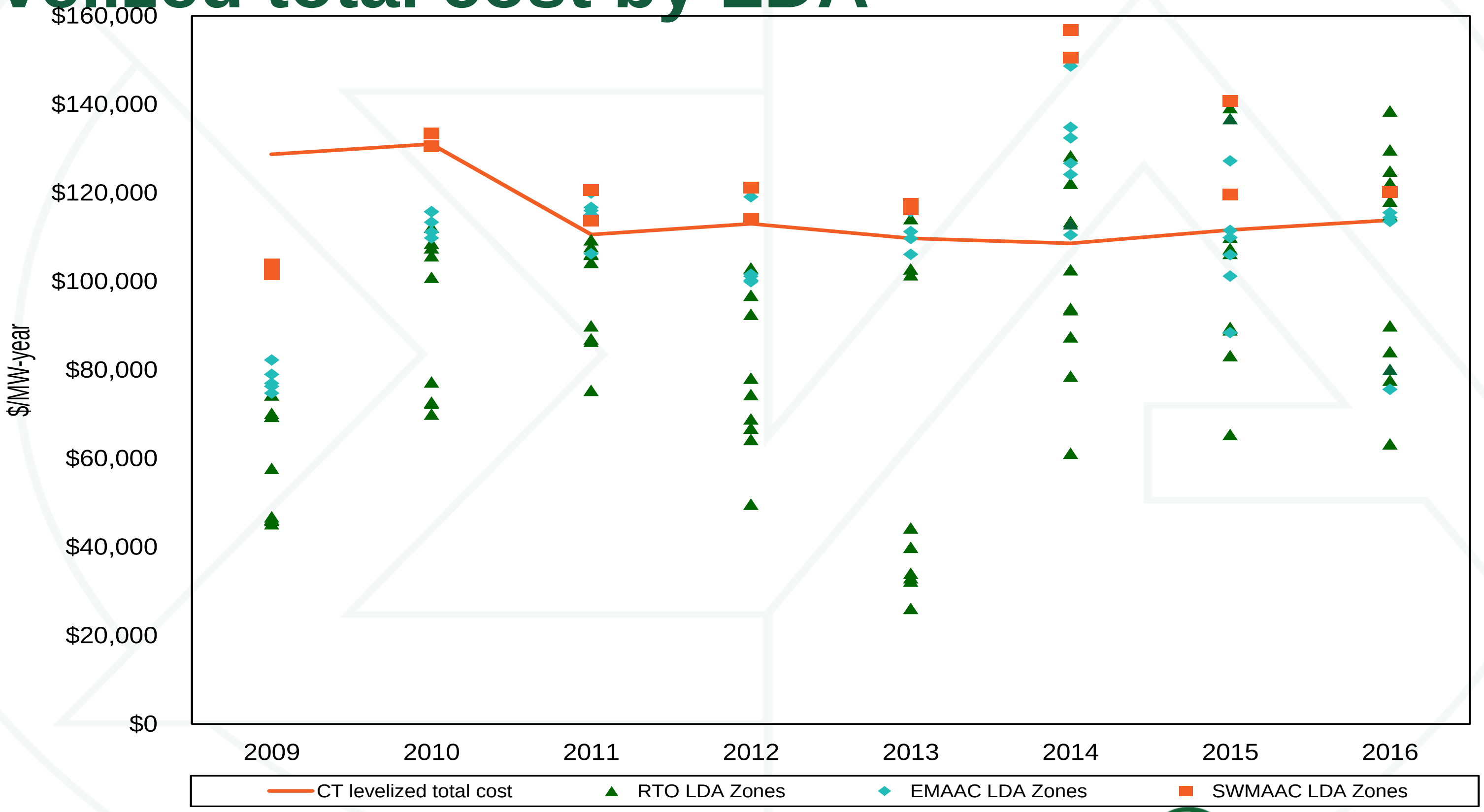
History of PJM capacity prices: 1999/2000 through 2019/2020



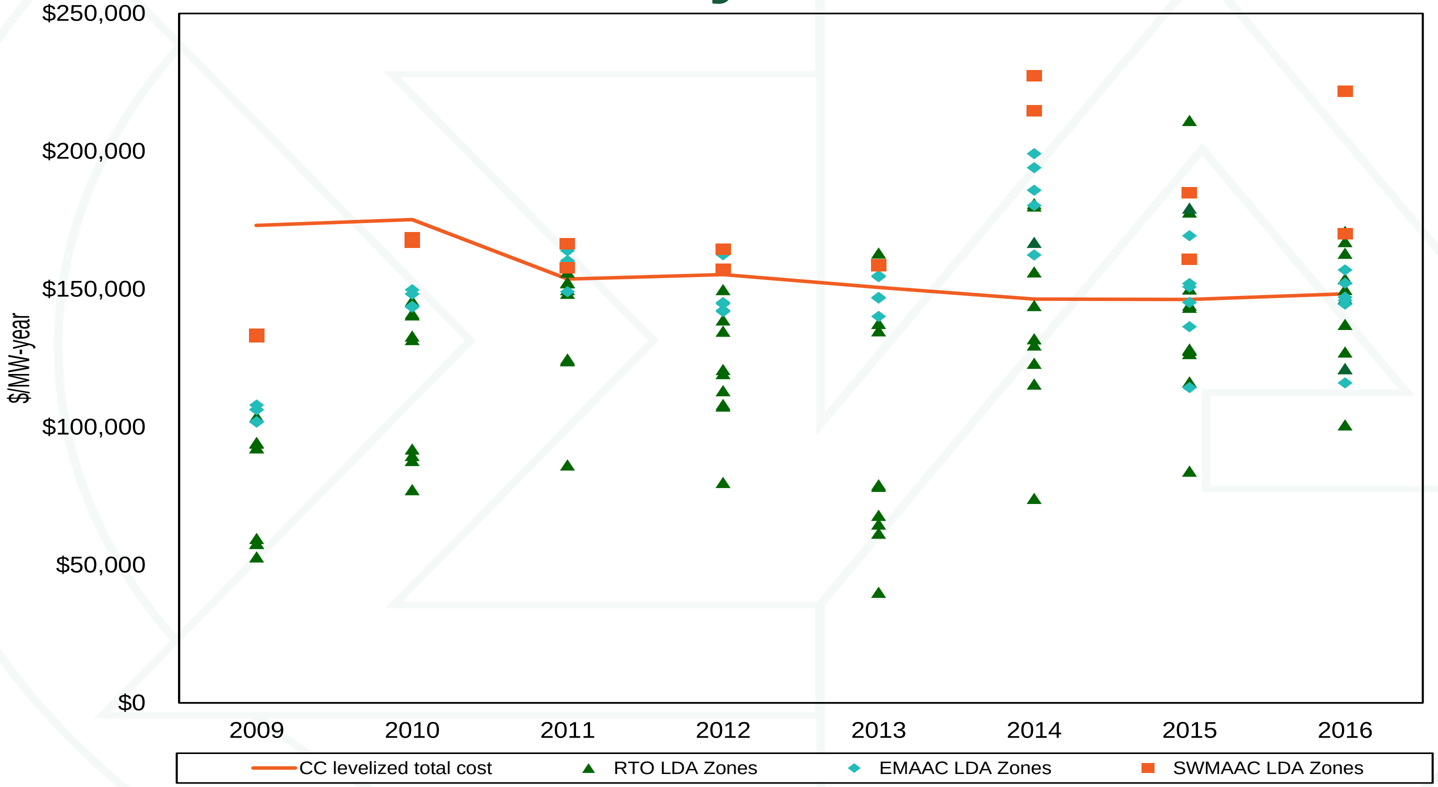
RPM capacity prices



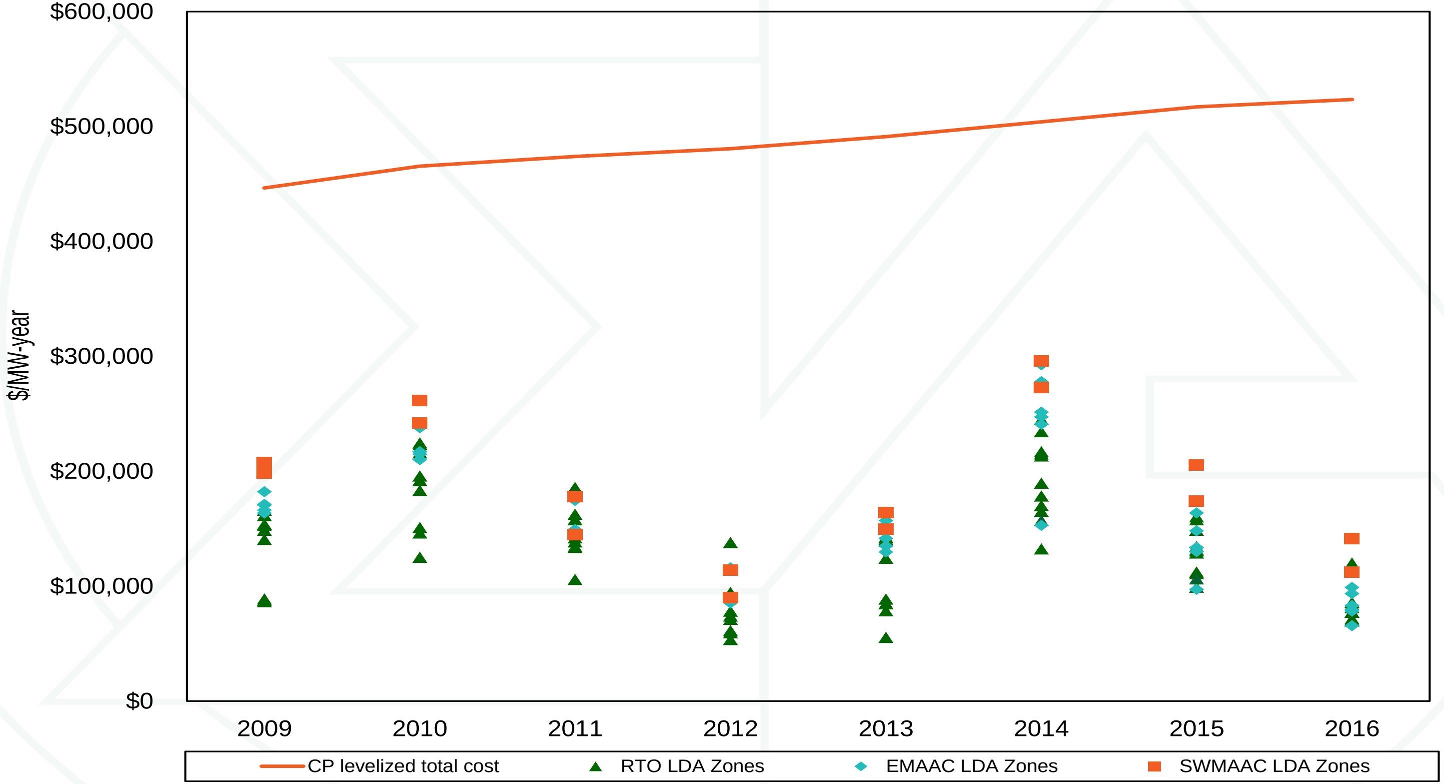
New entrant CT net revenue and 20-year levelized total cost by LDA



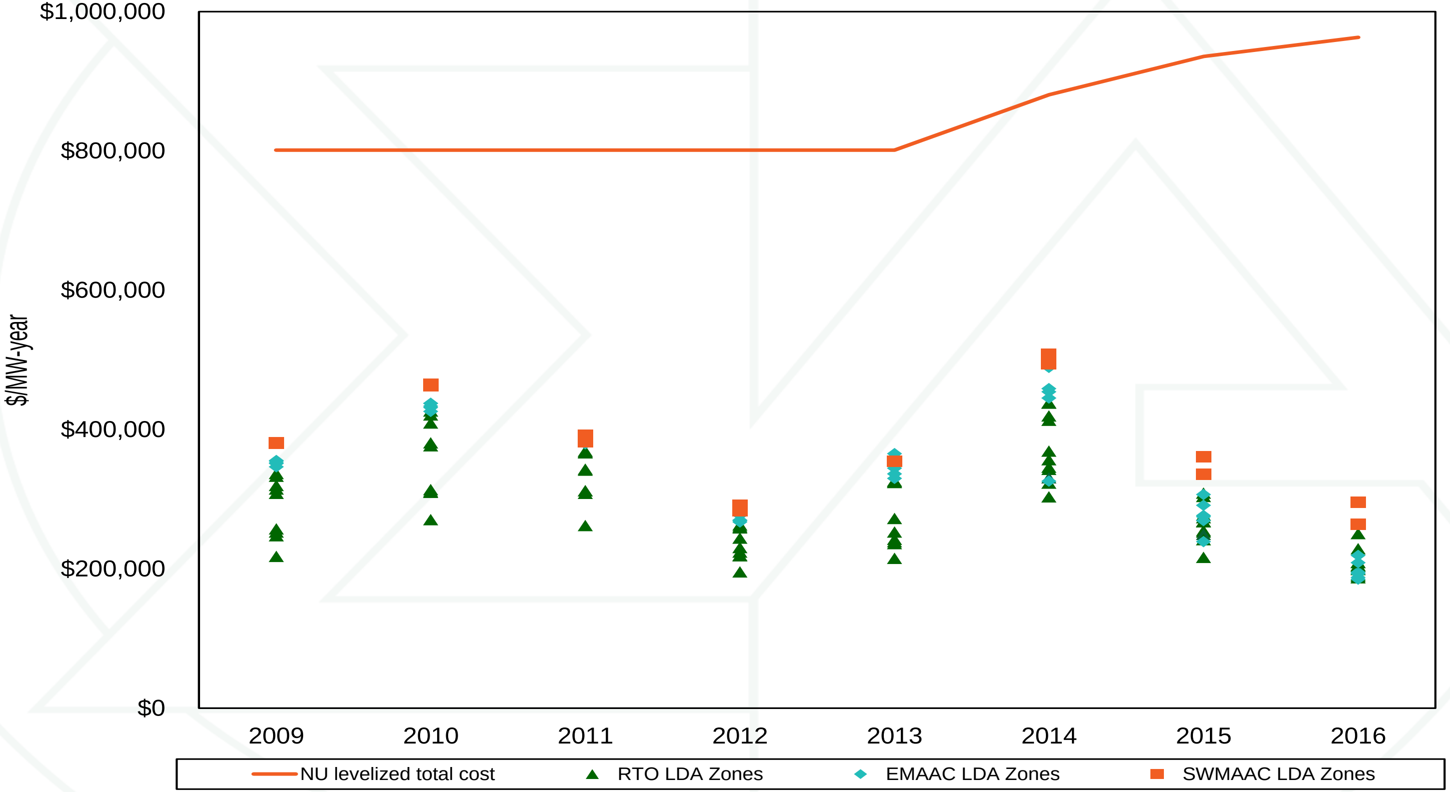
New entrant CC net revenue and 20-year levelized total cost by LDA



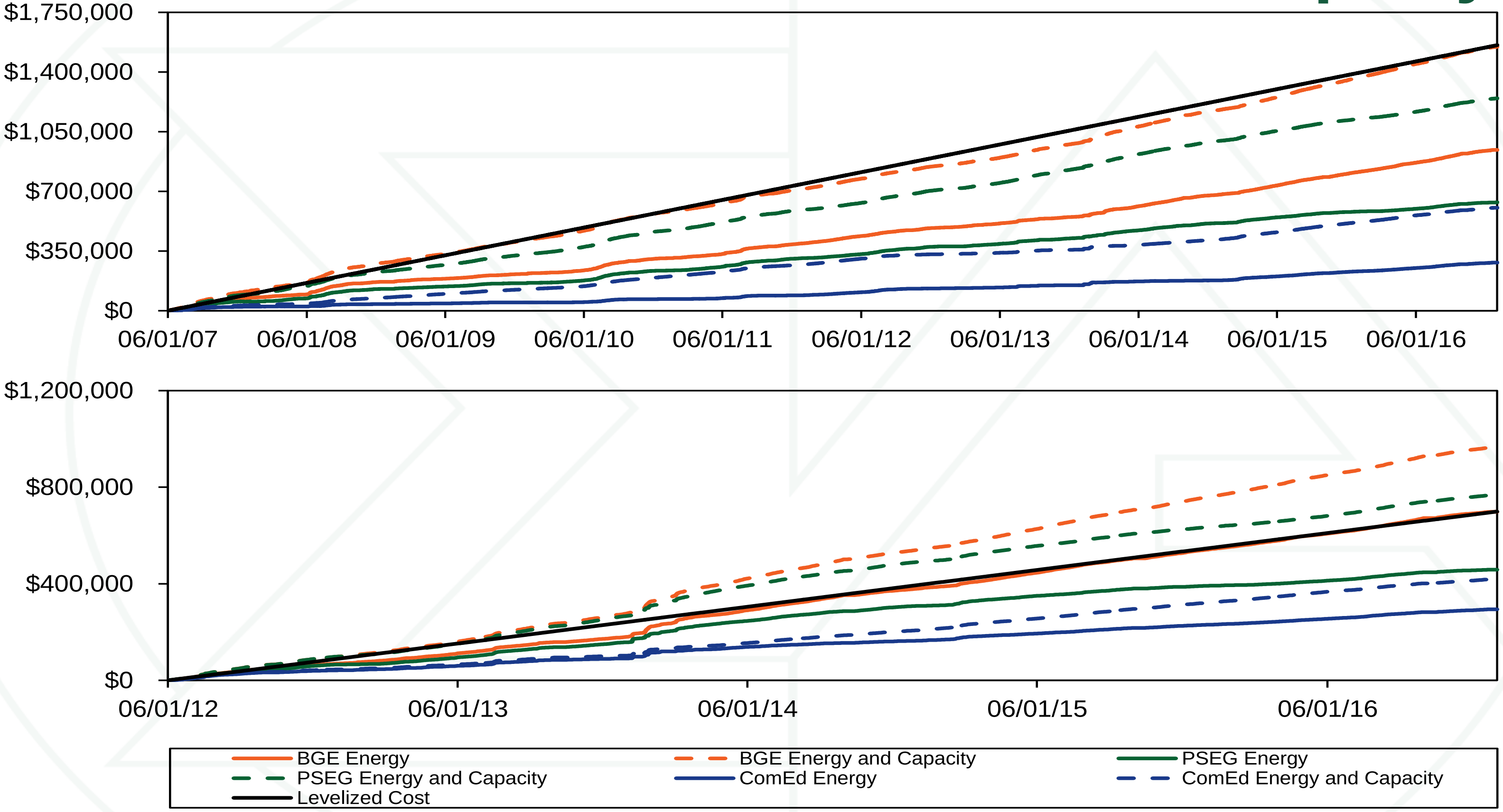
New entrant CP net revenue and 20-year levelized total cost by LDA



New entrant nuclear unit net revenue and 20-year levelized total cost by LDA



Historical new entrant CC revenue adequacy



Monitoring Analytics

Proportion of units recovering avoidable costs: 2011 through 2016

	Units with full recovery from energy and ancillary net revenue						Units with full recovery from all markets					
Technology	2011	2012	2013	2014	2015	2016	2011	2012	2013	2014	2015	2016
CC - Combined Cycle	55%	46%	50%	72%	59%	63%	85%	79%	79%	95%	88%	93%
CT - Aero Derivative	15%	6%	6%	53%	15%	8%	100%	96%	76%	98%	100%	99%
CT - Industrial Frame	26%	23%	17%	38%	13%	8%	99%	98%	83%	100%	100%	100%
Coal Fired	31%	17%	27%	80%	16%	15%	82%	36%	54%	85%	64%	41%
Diesel	48%	42%	37%	69%	56%	33%	100%	100%	77%	100%	100%	100%
Hydro	74%	61%	95%	97%	81%	79%	81%	77%	97%	98%	100%	100%
Oil or Gas Steam	8%	6%	11%	15%	3%	0%	92%	78%	86%	85%	91%	91%
Pumped Storage	NA	100%	95%	100%	100%	100%	NA	100%	100%	100%	100%	100%

Profile of units at risk of retirement

Technology	No. Units	ICAP (MW)	Avg. 2016 Run Hrs	Avg. Unit Age (Yrs)	Avg. Heat Rate
CC - Combined Cycle	4	915	1,002	28	9,523
CT - Aero Derivative	11	192	26	43	15,076
CT - Industrial Frame	44	1,217	123	39	14,542
Coal Fired	25	11,282	4,179	49	10,363
Diesel	4	30	330	25	10,999
Oil or Gas Steam	8	864	2,918	44	11,778
Total	96	14,500	3,197	34	11,391

Summary of PJM unit retirements by fuel (MW): 2011 through 2020

	Coal	Diesel	Heavy Oil	Hydro	Kerosene	Landfill Gas	Light Oil	Natural Gas	Nuclear	Wind	Wood Waste	Total
Retirements 2011	543.0	0.0	0.0	0.0	0.0	0.0	63.7	522.5	0.0	0.0	0.0	1,129.2
Retirements 2012	5,907.9	0.0	0.0	0.0	0.0	0.0	788.0	250.0	0.0	0.0	16.0	6,961.9
Retirements 2013	2,589.9	2.9	166.0	0.0	0.0	3.8	85.0	0.0	0.0	0.0	8.0	2,855.6
Retirements 2014	2,427.0	50.0	0.0	0.0	184.0	15.3	0.0	294.0	0.0	0.0	0.0	2,970.3
Retirements 2015	7,661.8	10.3	0.0	0.0	644.2	2.0	212.0	1,239.0	0.0	10.4	0.0	9,779.7
Retirements 2016	243.0	59.0	74.0	0.5	0.0	5.0	14.0	0.0	0.0	0.0	0.0	395.5
Planned Retirements Post-2016	3,501.0	0.0	182.0	0.0	0.0	6.0	0.0	661.8	614.5	0.0	0.0	4,965.3
Total	22,873.6	122.2	422.0	0.5	828.2	32.1	1,162.7	2,967.3	614.5	10.4	24.0	29,057.5

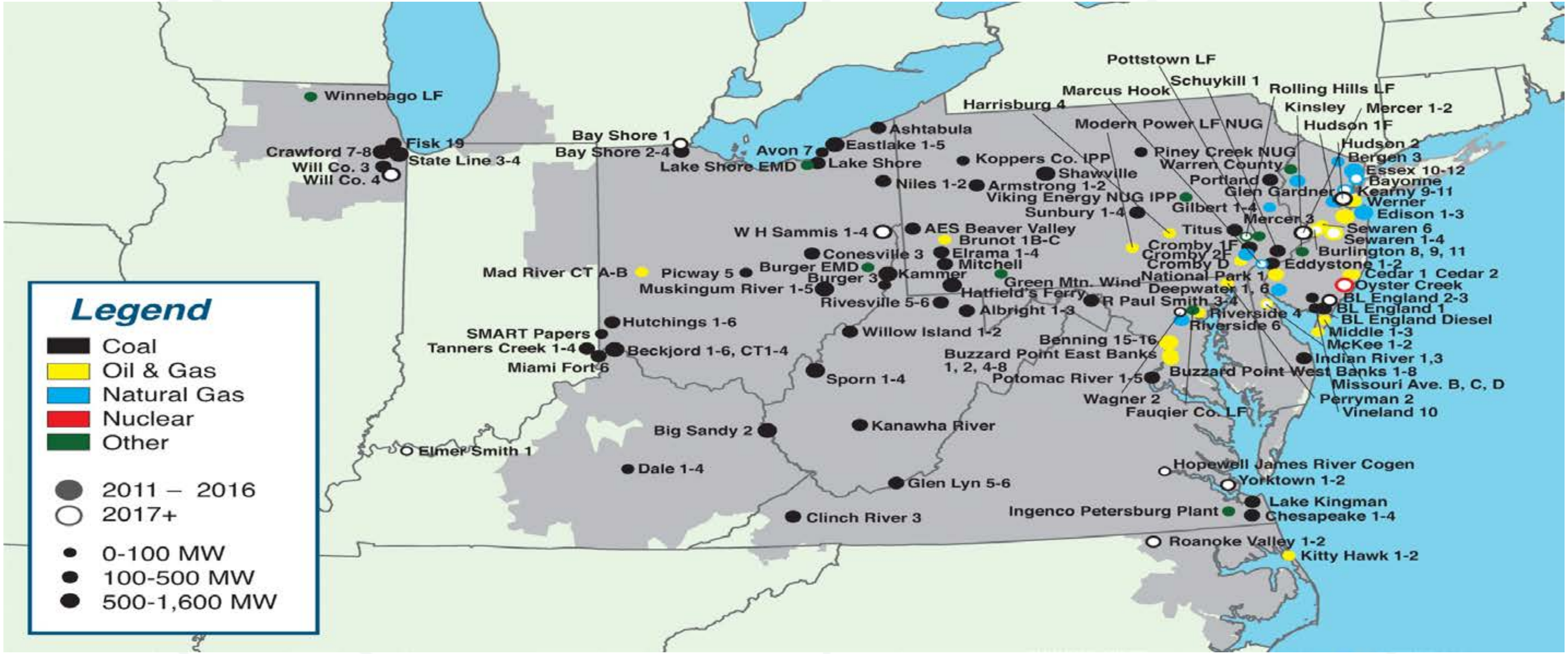
Unit deactivations in 2016

Company	Unit Name	ICAP (MW)	Primary Fuel	Zone Name	Average Age (Years)	Retirement Date
Exelon Corporation	Fauquier County Landfill	2.0	Diesel	Dominion	12	31-Jan-16
Exelon Corporation	Perryman 2	51.0	Diesel	BGE	44	01-Feb-16
NRG Energy Inc.	Avon Lake 7	94.0	Coal	ATSI	67	16-Apr-16
Eastern Kentucky Power Cooperative, Inc.	Dale 3	74.0	Coal	EKPC	59	16-Apr-16
Eastern Kentucky Power Cooperative, Inc.	Dale 4	75.0	Coal	EKPC	56	16-Apr-16
Rockland Capital Energy Investments, LLC	BL England Diesel Units 1-4	8.0	Diesel	AECO	55	31-May-16
Exelon Corporation	Riverside 4	74.0	Heavy Oil	BGE	65	01-Jun-16
South Jersey Industries, Inc.	Warren County Landfill Generator	3.0	LFG	JCPL	10	02-Jun-16
Great Bear Hydropower, Inc.	Columbia Dam Hydro	0.5	Hydro	JCPL	0	03-Oct-16
Talen Energy Corporation	Harrisburg 4 CT	14.0	Light Oil	PPL	49	17-Nov-16
Total		395.5				

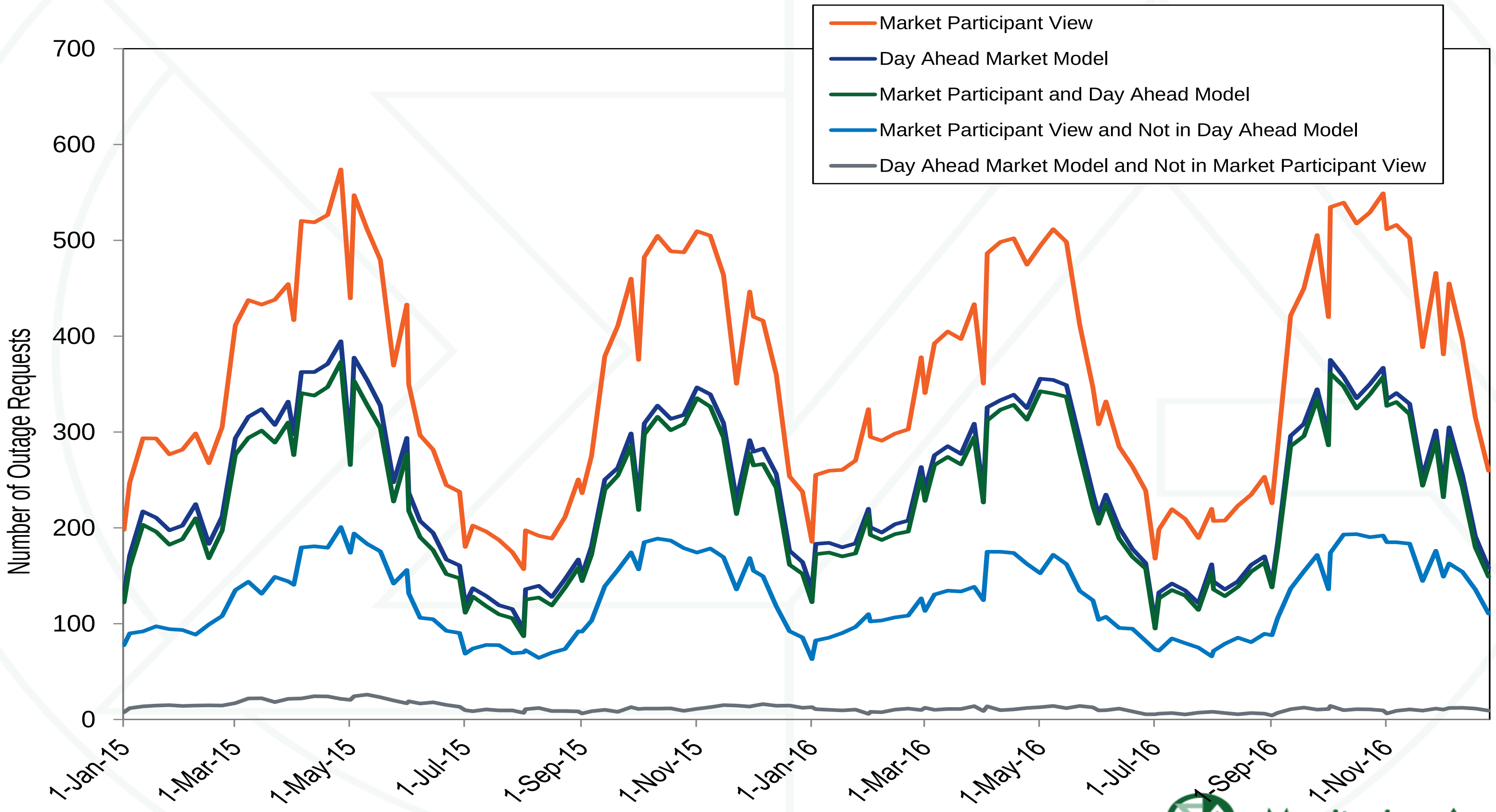
Planned retirement of PJM units: as of December 31, 2016

Unit	Zone	ICAP (MW)	Fuel	Unit Type	Projected Deactivation Date
Rolling Hills Landfill Generator	Met-Ed	6.0	LFG	Diesel	07-Dec-16
Roanoke Valley 1-2	Dominion	209.0	Coal	Steam	01-Mar-17
Yorktown 1-2	Dominion	323.0	Coal	Steam	15-Apr-17
BL England 2-3	AECO	303.0	Coal	Steam	30-Apr-17
McKee 1-2	DPL	34.0	Heavy Oil	Combustion Turbine	31-May-17
Hopewell James River Cogen	Dominion	89.0	Coal	Steam	31-May-17
Hudson 2	PSEG	620.0	Coal	Steam	01-Jun-17
Mercer 1-2	PSEG	632.0	Coal	Steam	01-Jun-17
Sewaren 1-4	PSEG	453.0	Kerosene	Combustion Turbine	01-Jun-18
Bayonne Cogen Plant (CC)	PSEG	158.0	Natural gas	Steam	01-Nov-18
MH50 Marcus Hook Co-gen	PECO	50.8	Natural gas	Steam	13-May-19
Elmer Smith U1	External	52.0	Coal	Steam	01-Jun-19
Oyster Creek	JCPL	614.5	Nuclear	Nuclear	31-Dec-19
Will County 4	ComEd	510.0	Coal	Steam	31-May-20
W H Sammis 1-4	ATSI	640.0	Coal	Steam	31-May-20
Wagner 2	BGE	135.0	Coal	Steam	01-Jun-20
Bay Shore 1	ATSI	136.0	Coal	Steam	01-Oct-20
Total		4,965.3			

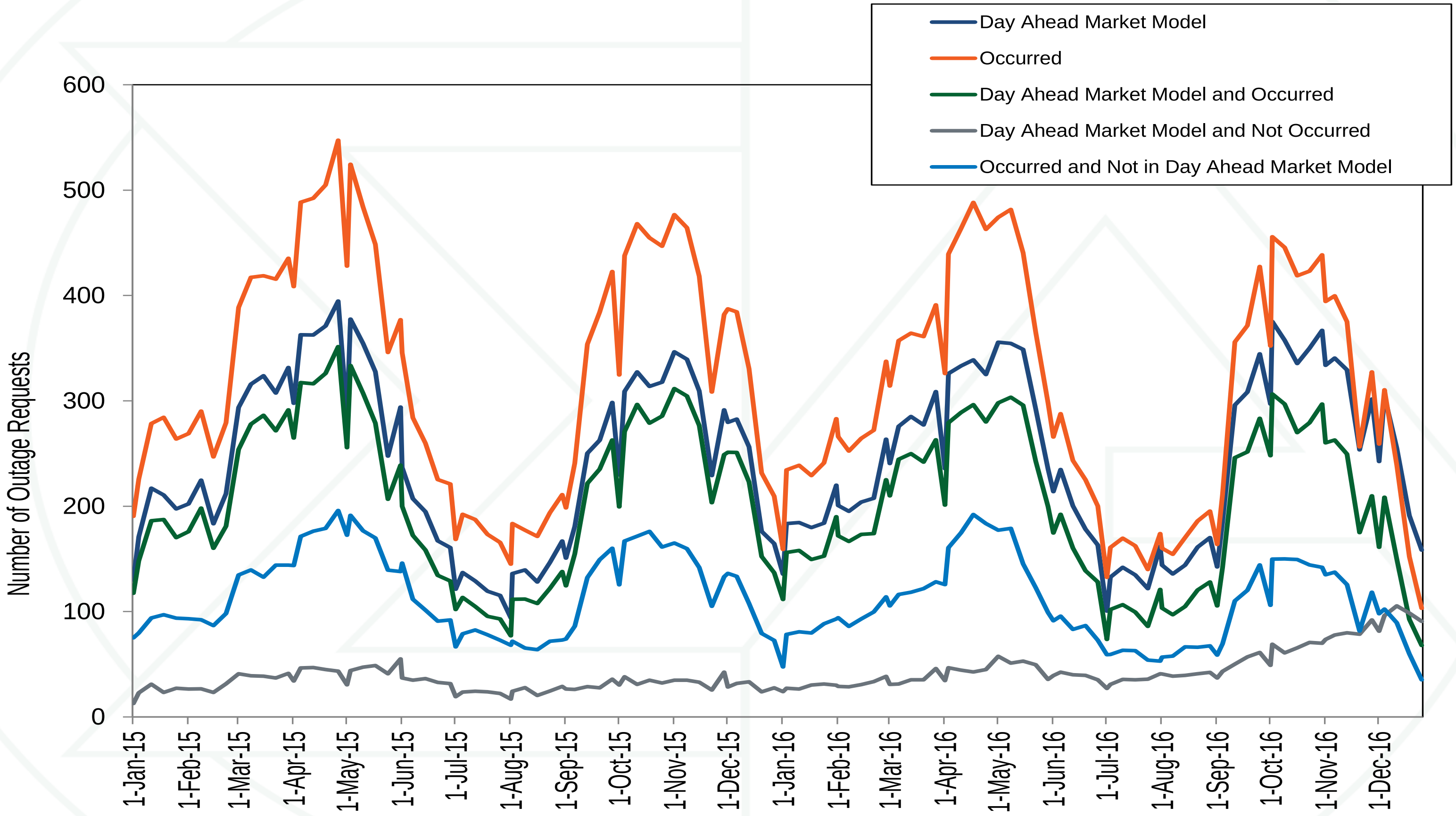
PJM unit retirements: 2011 through 2020



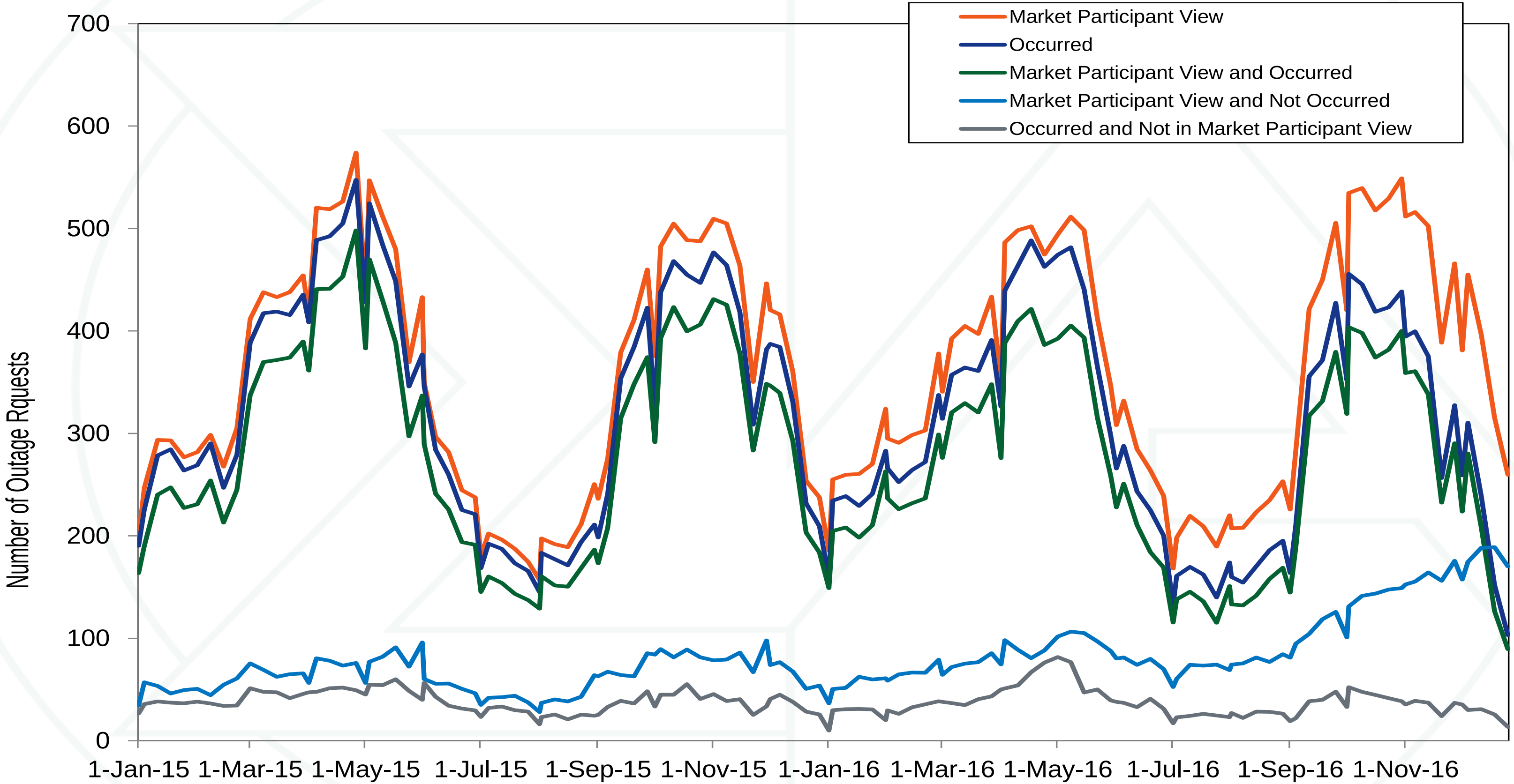
Approved or active TX outage requests



Day-ahead market model TX outages



Approved or active TX outage requests



Recommendations: Energy Market Uplift

- **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.**

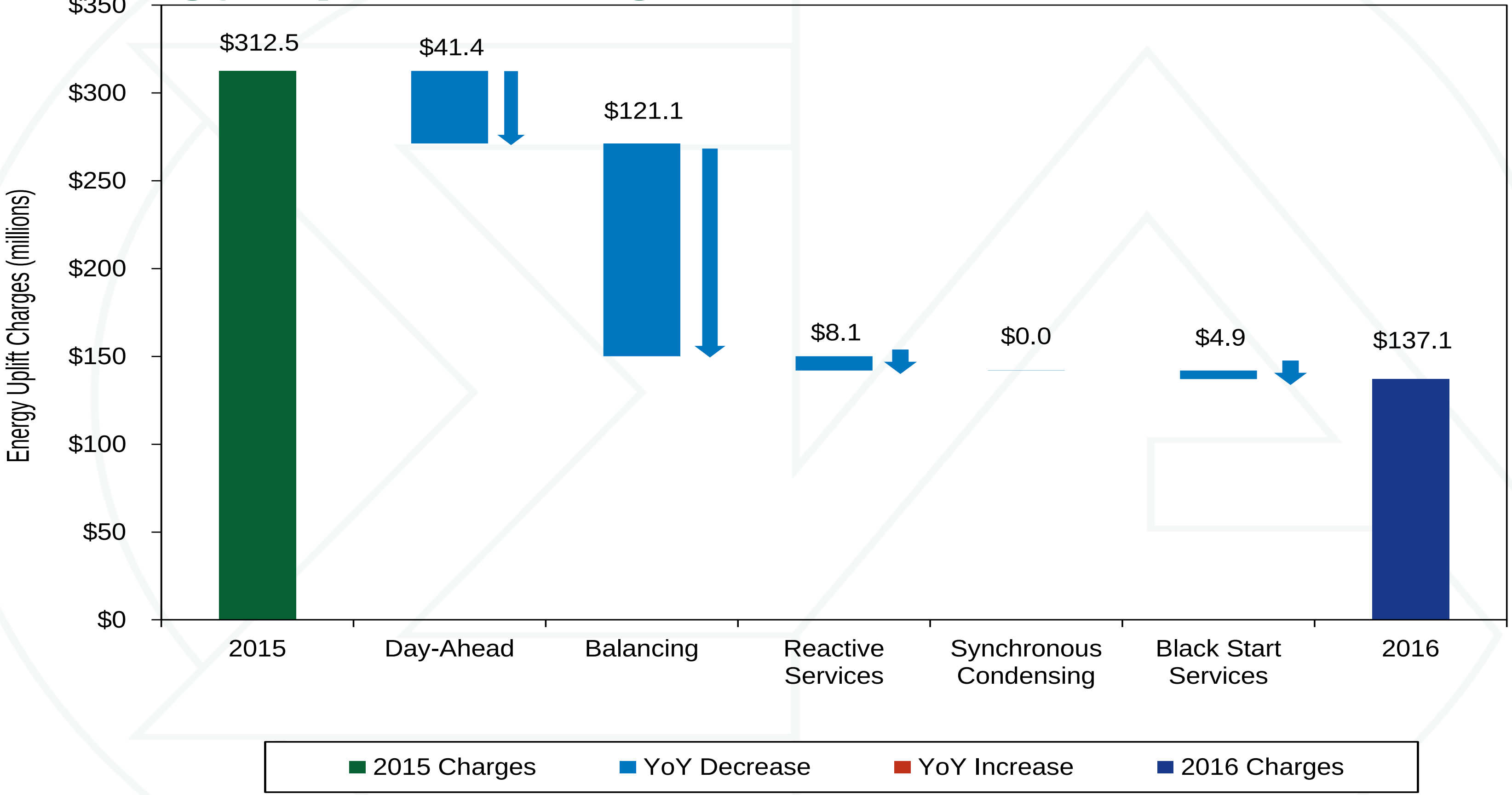
Recommendations: Energy Market Uplift

- **Disclose units receiving uplift**
- **Eliminate day-ahead uplift.**
- **Include regulation net revenue offset in uplift calculation.**
- **UTCs should pay uplift.**
- **Eliminate use of IBTs in calculating deviations.**

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	$67.1	30.9%	8.5%
2002	$273.7	($10.3)	(3.6%)	5.8%
2003	$376.5	$102.8	37.5%	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	($151.5)	(31.9%)	1.2%
2010	$623.2	$300.4	93.1%	1.8%
2011	$603.4	($19.8)	(3.2%)	1.7%
2012	$649.8	$46.5	7.7%	2.2%
2013	$843.0	$193.1	29.7%	2.5%
2014	$960.7	$117.7	14.0%	1.9%
2015	$312.5	($648.2)	(67.5%)	0.7%
2016	$137.1	($175.4)	(56.1%)	0.4%

Energy uplift changes: 2015 to 2016



Energy uplift credits by unit type: 2015 and 2016

Unit Type	2015 Credits (Millions)	2016 Credits (Millions)	Change	Percent Change	2015 Share	2016 Share
Combined Cycle	$72.4	$14.7	($57.8)	(79.8%)	23.2%	10.7%
Combustion Turbine	$112.3	$58.8	($53.5)	(47.7%)	36.0%	42.9%
Diesel	$1.8	$0.6	($1.2)	(65.8%)	0.6%	0.5%
Hydro	$1.1	$0.1	($1.1)	(95.5%)	0.4%	0.0%
Nuclear	$0.4	$1.2	$0.8	180.8%	0.1%	0.9%
Steam - Coal	$87.6	$56.4	($31.2)	(35.6%)	28.1%	41.2%
Steam - Other	$31.3	$3.5	($27.8)	(88.8%)	10.0%	2.6%
Wind	$4.7	$1.7	($3.0)	(63.3%)	1.5%	1.3%
Total	$311.8	$136.9	($174.9)	(56.1%)	100.0%	100.0%

Top 10 units and organizations energy uplift credits: 2016

		Top 10 Units		Top 10 Organizations	
Category	Type	Credits (Millions)	Credits Share	Credits (Millions)	Credits Share
Day-Ahead	Generators	$42.0	73.2%	$55.7	97.2%
Balancing	Canceled Resources	$0.1	100.0%	$0.1	100.0%
	Generators	$9.8	17.0%	$40.6	70.4%
	Local Constraints Control	$0.4	91.2%	$0.4	100.0%
	Lost Opportunity Cost	$4.9	26.5%	$13.0	69.8%
Reactive Services		$2.3	92.0%	$2.5	99.9%
Synchronous Condensing		$0.0	100.0%	$0.0	100.0%
Black Start Services		$0.1	47.3%	$0.3	92.9%
Total		$49.3	36.0%	$105.1	76.8%

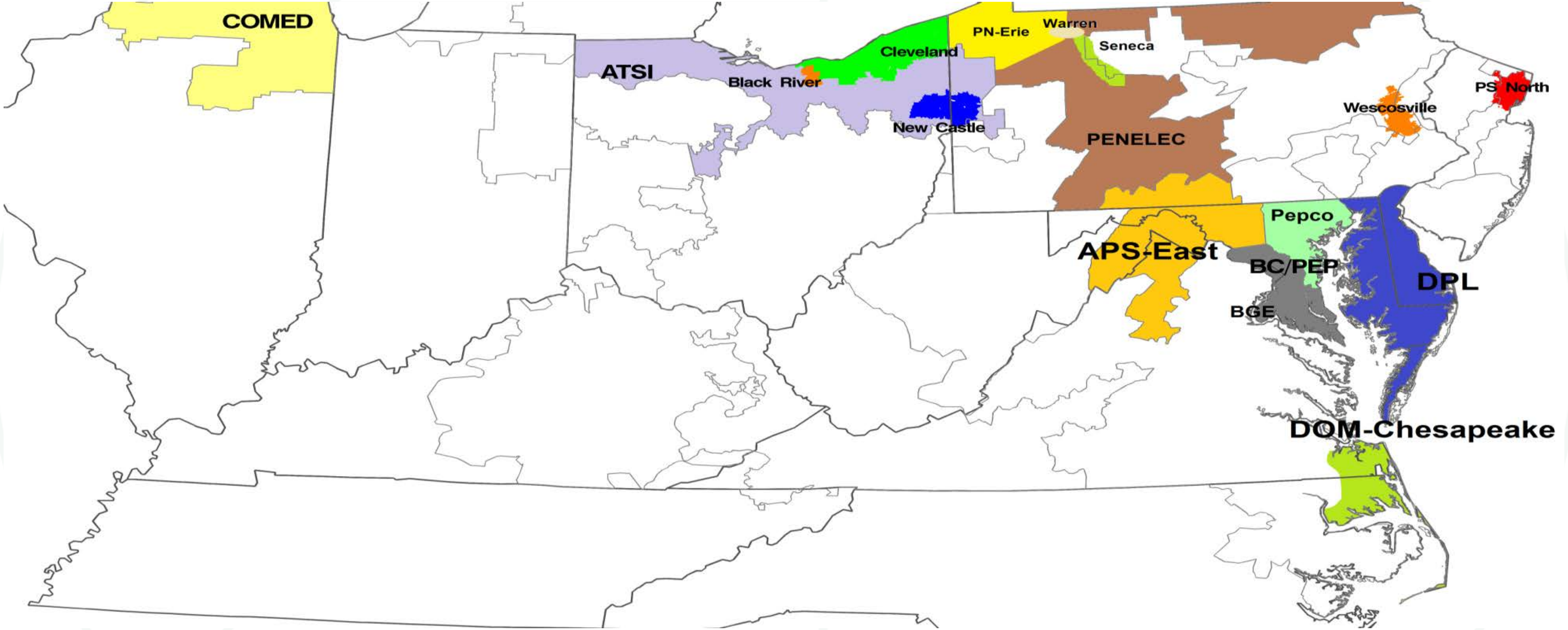
Operating reserve rates statistics ($/MWh): 2016

		Rates Charged ($/MWh)			
Region	Transaction	Maximum	Average	Minimum	Standard Deviation
East	INC	4.883	0.347	0.001	0.428
	DEC	4.904	0.418	0.021	0.420
	DA Load	0.730	0.071	0.000	0.067
	RT Load	0.297	0.031	0.000	0.043
	Deviation	4.883	0.347	0.001	0.428
West	INC	2.276	0.302	0.000	0.329
	DEC	2.340	0.372	0.021	0.322
	DA Load	0.730	0.071	0.000	0.067
	RT Load	0.241	0.023	0.000	0.032
	Deviation	2.276	0.302	0.000	0.329

Current and proposed average energy uplift rate by transaction: 2015 and 2016

	Transaction	2015 Current Rates ($/MWh)	2015 Proposed Rates - 100% UTC ($/MWh)	2015 Proposed Rates - 0% UTC ($/MWh)	2016 Current Rates ($/MWh)	2016 Proposed Rates - 100% UTC ($/MWh)	2016 Proposed Rates - 0% UTC ($/MWh)
East	INC	1.058	0.147	0.376	0.347	0.027	0.093
	DEC	1.174	0.147	0.376	0.418	0.027	0.093
	DA Load	0.115	0.013	0.015	0.071	0.004	0.006
	RT Load	0.050	0.118	0.118	0.031	0.058	0.058
	Deviation	1.058	0.497	0.723	0.347	0.387	0.451
West	INC	1.023	0.145	0.376	0.302	0.022	0.078
	DEC	1.138	0.145	0.376	0.372	0.022	0.078
	DA Load	0.115	0.013	0.015	0.071	0.004	0.006
	RT Load	0.042	0.118	0.118	0.023	0.058	0.058
	Deviation	1.023	0.429	0.659	0.302	0.312	0.366
UTC	East to East	NA	0.295	0.751	NA	0.055	0.186
	West to West	NA	0.290	0.752	NA	0.044	0.156
	East to/from West	NA	0.292	0.752	NA	0.049	0.171

PJM Closed loop interfaces

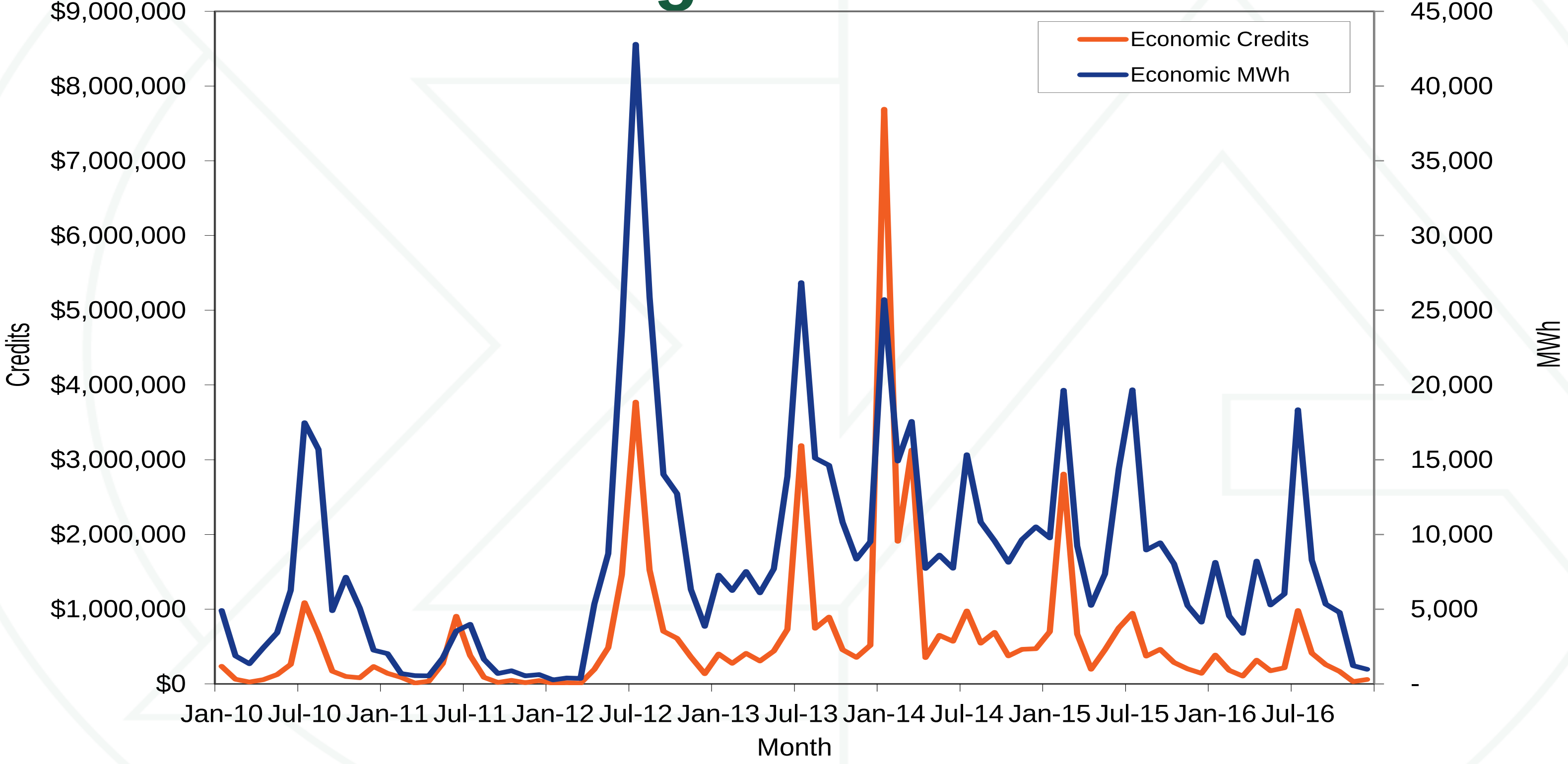


Monitoring Analytics

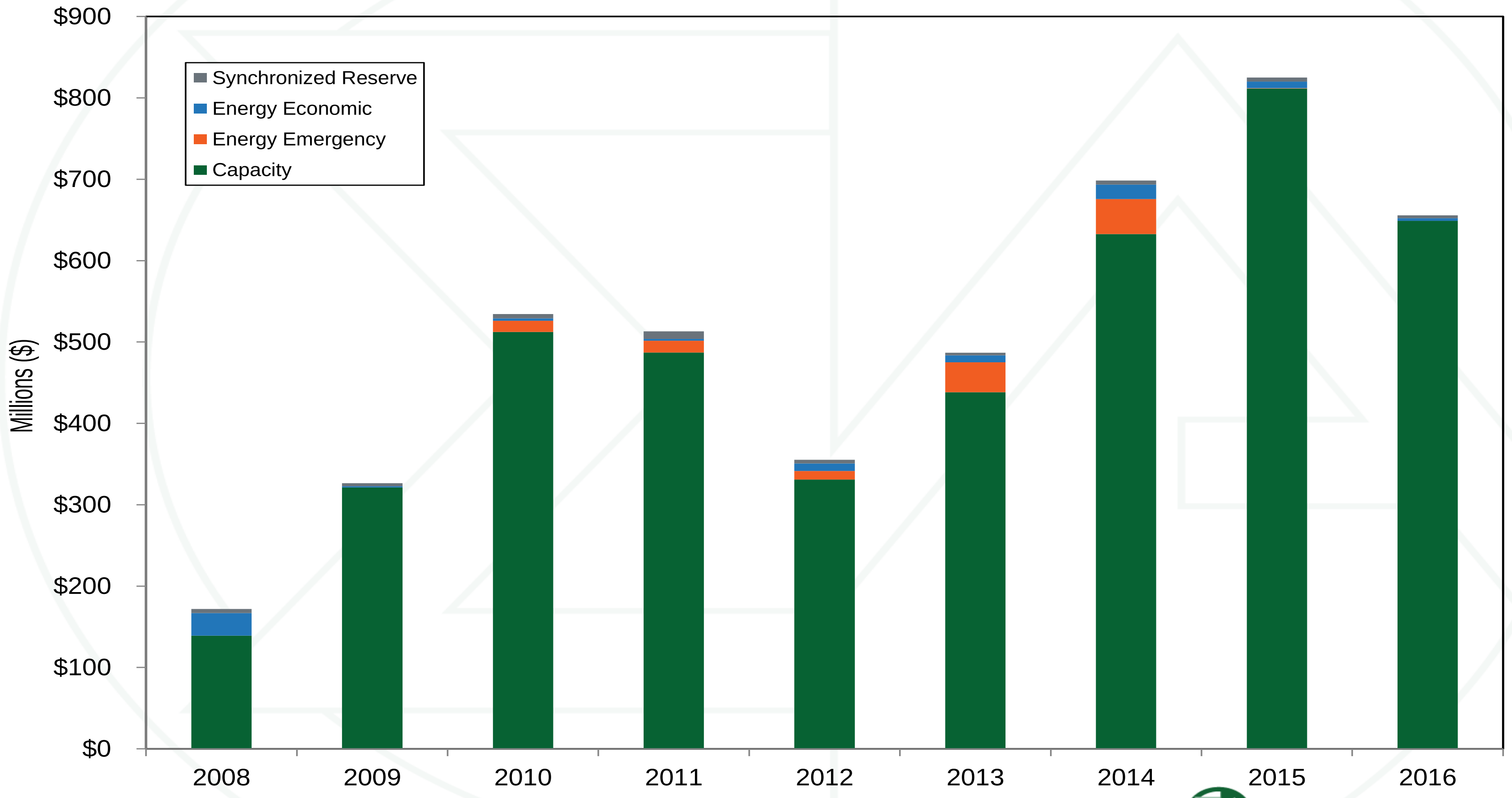
Recommendations: Demand Response

- Demand response should be removed from PJM capacity market.
  - Redesign to facilitate customers’ response to prices
- Eliminate guaranteed DR strike price; pay LMP
- Demand response should be fully nodal
  - Compliance across zones should be eliminated
- M&V: cap baselines at PLC uniformly
- Eliminate net benefits test
  - Pay (LMP – retail generation rate)
- Eliminate bankrupt customers from program

Economic program credits and MWh by month: 2010 through 2016



Demand response revenue by market



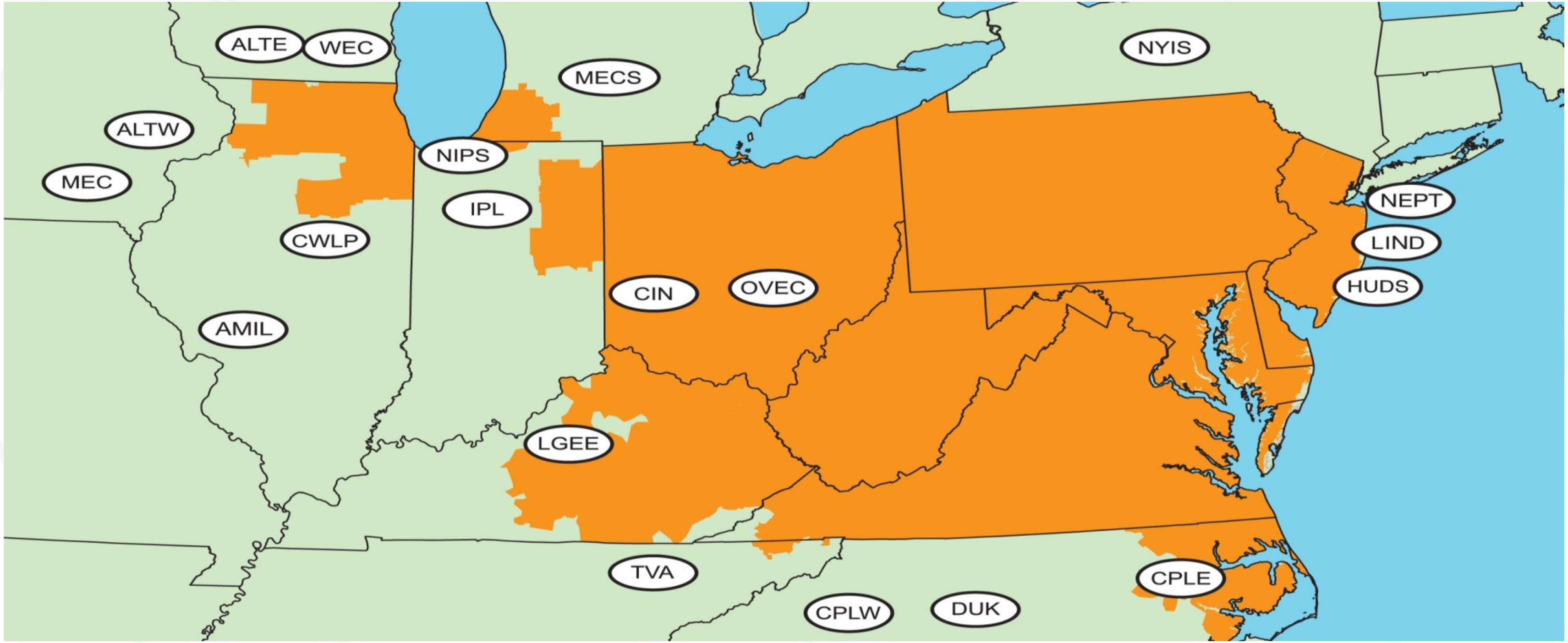
Recommendations: Transactions

- **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.**

Recommendations: Transactions

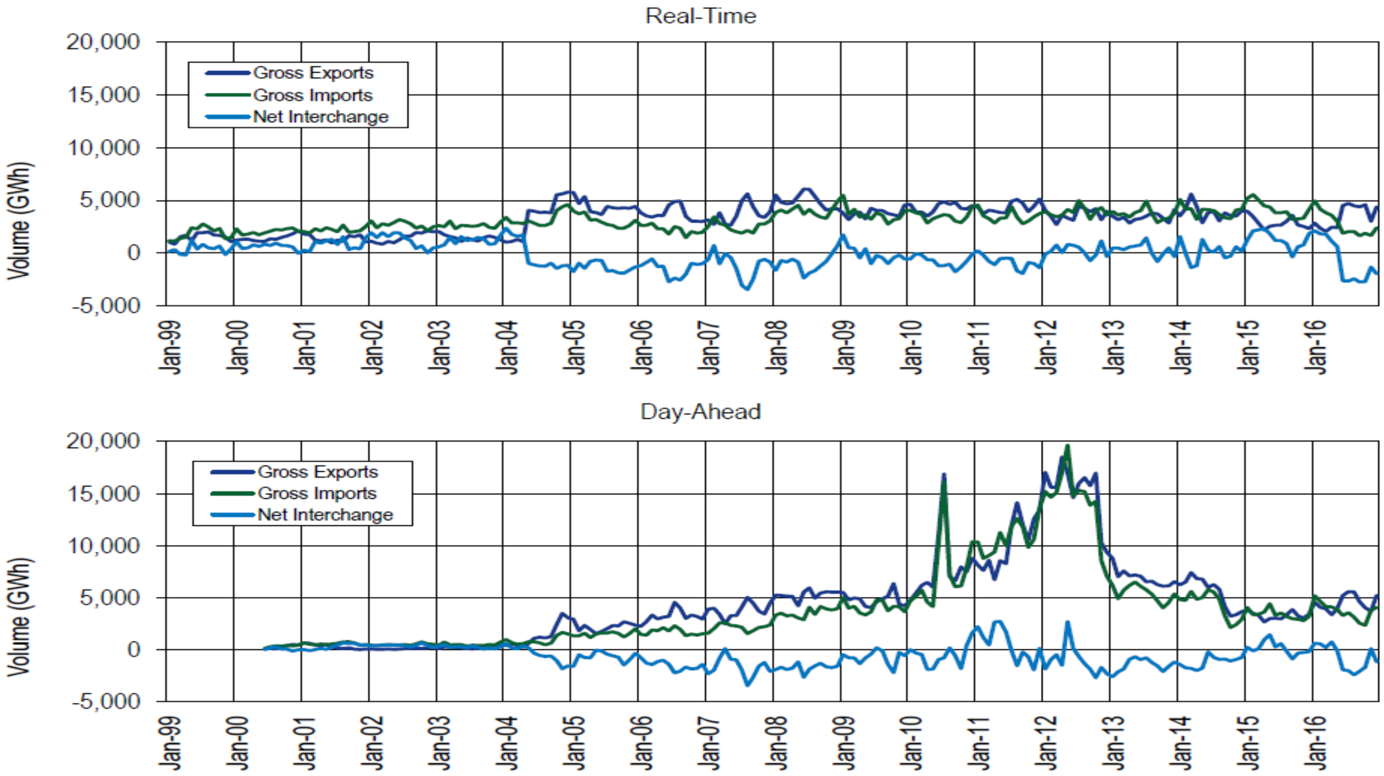
- Permit unlimited spot imports.
- Interchange pricing should reflect LMP logic.
  - No need for scheduling physical transactions.
- Make actual flow data available for eastern interconnection to MMUs and RTOs/ISOs.

PJM’s footprint and its external day-ahead and real-time scheduling interfaces



Monitoring Analytics

PJM real-time and day-ahead scheduled import and export transaction volume



The Regulation Market results were competitive

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

Monitoring Analytics

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 Day-Ahead Scheduling Reserve 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.**
- **Eliminate payment of Tier 2 price to Tier 1 when non-synchronized reserve price > 0.**

Recommendations: Ancillary Services

- **Eliminate DASR Market.**
- **The cost of reactive capability should be incorporated in the capacity market.**
- **Implement rules governing tier 1 biasing.**

Average price and cost of PJM regulation

Year	Weighted Regulation Market Price	Weighted Regulation Market Cost	Regulation Price as Percent Cost
2009	$22.99	$30.68	74.9%
2010	$18.00	$32.86	54.8%
2011	$16.48	$29.72	55.5%
2012	$19.02	$25.32	75.1%
2013	$30.85	$35.79	86.2%
2014	$44.48	$53.82	82.6%
2015	$31.92	$38.36	83.2%
2016	$15.72	$18.13	86.7%

Components of regulation cost, 2016

Month	Scheduled Regulation (MW)	Cost of Regulation Capability ($/MW)	Cost of Regulation Performance ($/MW)	Opportunity Cost ($/MW)	Total Cost ($/MW)
Jan	412,310.8	$14.49	$1.97	$1.95	$18.41
Feb	383,646.6	$16.00	$2.61	$1.40	$20.01
Mar	396,604.0	$12.01	$2.25	$1.14	$15.40
Apr	384,591.8	$17.38	$2.70	$1.67	$21.76
May	391,135.2	$13.56	$3.49	$1.40	$18.45
Jun	379,014.9	$13.33	$1.38	$1.10	$15.81
Jul	386,146.2	$16.53	$2.27	$1.80	$20.60
Aug	385,843.5	$16.74	$1.66	$1.56	$19.97
Sep	376,321.1	$16.68	$2.32	$1.68	$20.67
Oct	389,139.0	$14.11	$2.73	$1.19	$18.03
Nov	374,665.6	$11.28	$3.11	$1.03	$15.42
Dec	390,836.1	$10.12	$1.72	$1.24	$13.08
Annual	4,650,254.7	$14.35	$2.35	$1.43	$18.13

Price of tier 1 synchronized reserve due to a non synchronized reserve price above zero

Year	Month	Total Hours When NSRMCP>$0	Weighted Average SRMCP for Hours When NSRMCP>$0	Total Tier 1 MW Credited for Hours When NSRMCP>$0	Total Tier 1 Credits Paid When NSRMCP>$0	Average Tier 1 MW Paid
2015	Jan	145	$13.56	270,081	$3,662,674	1,862.6
2015	Feb	195	$24.56	373,536	$9,174,195	1,915.6
2015	Mar	179	$16.33	304,162	$4,967,882	1,699.2
2015	Apr	64	$25.19	101,487	$2,556,226	1,585.7
2015	May	75	$20.94	111,490	$2,335,087	1,486.5
2015	Jun	95	$17.64	185,149	$3,265,956	1,948.9
2015	Jul	46	$35.12	64,516	$2,265,614	1,402.5
2015	Aug	39	$22.73	51,398	$1,168,234	1,317.9
2015	Sep	49	$29.64	51,822	$1,535,903	1,057.6
2015	Oct	114	$16.98	127,919	$2,172,644	1,122.1
2015	Nov	29	$14.65	29,156	$427,056	1,005.4
2015	Dec	51	$16.07	53,898	$865,969	1,056.8
2015	Total	1,081	$19.95	1,724,614	$34,397,441	1,595.4
2016	Jan	41	$14.18	56,841	$806,038	1,386.4
2016	Feb	16	$9.42	24,752	$233,208	1,547.0
2016	Mar	73	$6.57	105,142	$690,294	1,440.3
2016	Apr	40	$28.83	38,662	$1,114,670	966.5
2016	May	22	$9.01	27,027	$243,515	1,228.5
2016	Jun	9	$15.24	11,630	$177,275	1,292.3
2016	Jul	10	$21.38	13,975	$298,736	1,397.5
2016	Aug	14	$32.45	19,649	$637,554	1,403.5
2016	Sep	9	$26.22	11,247	$294,857	1,249.7
2016	Oct	50	$12.12	33,761	$409,208	675.2
2016	Nov	12	$3.04	13,867	$42,216	1,155.6
2016	Dec	1	$0.58	888	$515	888.2
2016	Total	297	$13.84	357,442	$4,948,084	1,203.5

The FTR Auction Markets results were competitive

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

Recommendations: FTR/ARR

- ARR/FTR design should be modified to ensure that all congestion revenues are returned to load.
- All FTR auction revenues should be returned to load.
- Eliminate use of 1998 generation to load contract paths for allocating ARRs.
- Eliminate portfolio netting.
- Apply FTR forfeiture rule to UTCs.

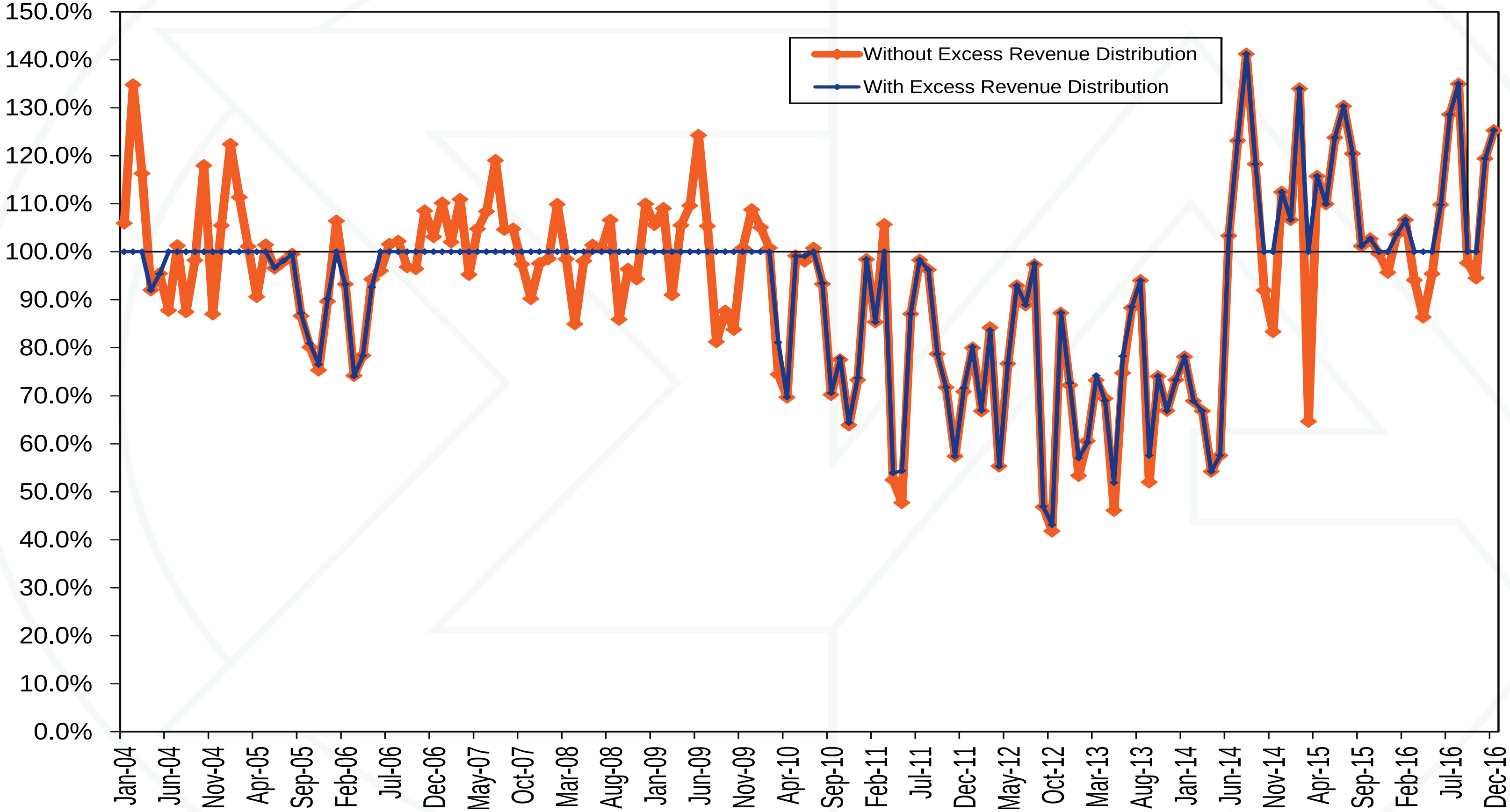
ARR and FTR total congestion offset ($M) for ARR holders

Planning Period	ARR Credits	FTR Credits	Total Congestion	Total ARR/FTR Offset	Percent Offset	Unreturned Revenue
2011/2012	$512.2	$249.8	$770.6	$762.0	98.9%	$8.5
2012/2013	$349.5	$181.9	$575.8	$531.4	92.3%	$44.4
2013/2014	$337.7	$456.4	$1,777.1	$794.0	44.7%	$983.1
2014/2015	$482.4	$404.4	$1,390.9	$886.8	63.8%	$504.1
2015/2016	$635.3	$223.4	$992.6	$858.8	86.5%	$133.8
2016/2017	$375.2	$122.2	$604.1	$497.5	82.3%	$106.7
Total	$2,692.4	$1,638.1	$6,111.0	$4,330.5	70.9%	$1,780.6

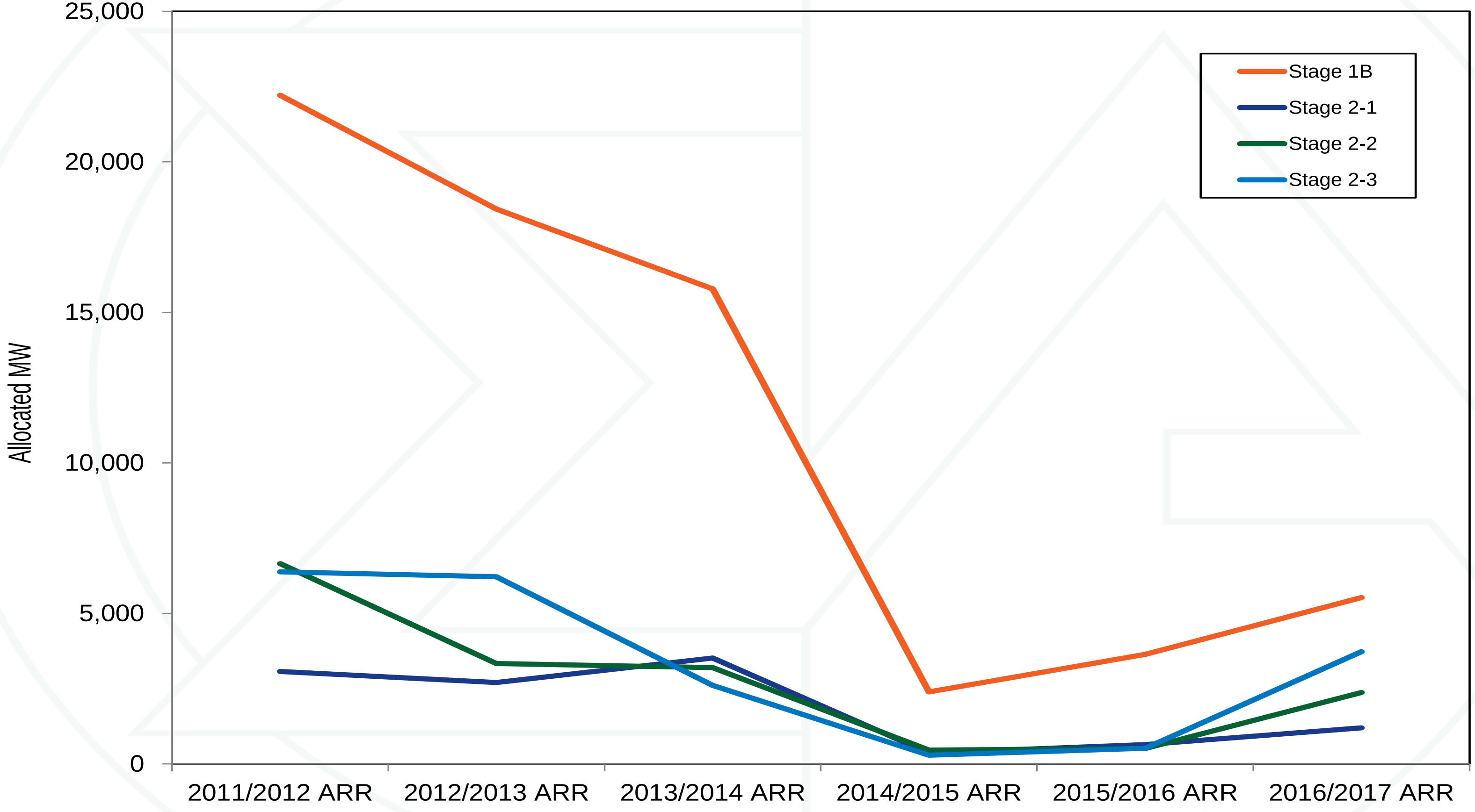
ARR and FTR total congestion offset ($M) for ARR holders under PJM's proposed FTR funding

	Old					Proposed				
Planning Period	ARR Credits	FTR Credits	Total Congestion	Total ARR/FTR Offset	Percent Offset	New Offset	Old Revenue Received	New Revenue Received	ARR Holder Change	FTR Over Payment
2011/2012	$512.2	$249.8	$770.6	$762.0	98.9%	83.3%	$762.0	$598.6	($163.4)	$113.9
2012/2013	$349.5	$181.9	$575.8	$531.4	92.3%	68.0%	$531.4	$275.9	($255.5)	$62.1
2013/2014	$337.7	$456.4	$1,777.1	$794.0	44.7%	43.2%	$794.0	$574.1	($219.9)	$0.0
2014/2015	$482.4	$404.4	$1,390.9	$886.8	63.8%	57.2%	$886.8	$686.6	($200.2)	$400.6
2015/2016	$635.3	$223.4	$992.6	$858.8	86.5%	78.2%	$858.8	$744.8	($113.9)	$188.9
2016/2017	$375.2	$122.2	$604.1	$497.5	82.3%	77.4%	$497.5	$453.7	($43.8)	$130.7
Total	$2,692.4	$1,638.1	$6,111.0	$4,330.5	70.9%	63.1%	$4,330.5	$3,333.8	($996.7)	$896.1

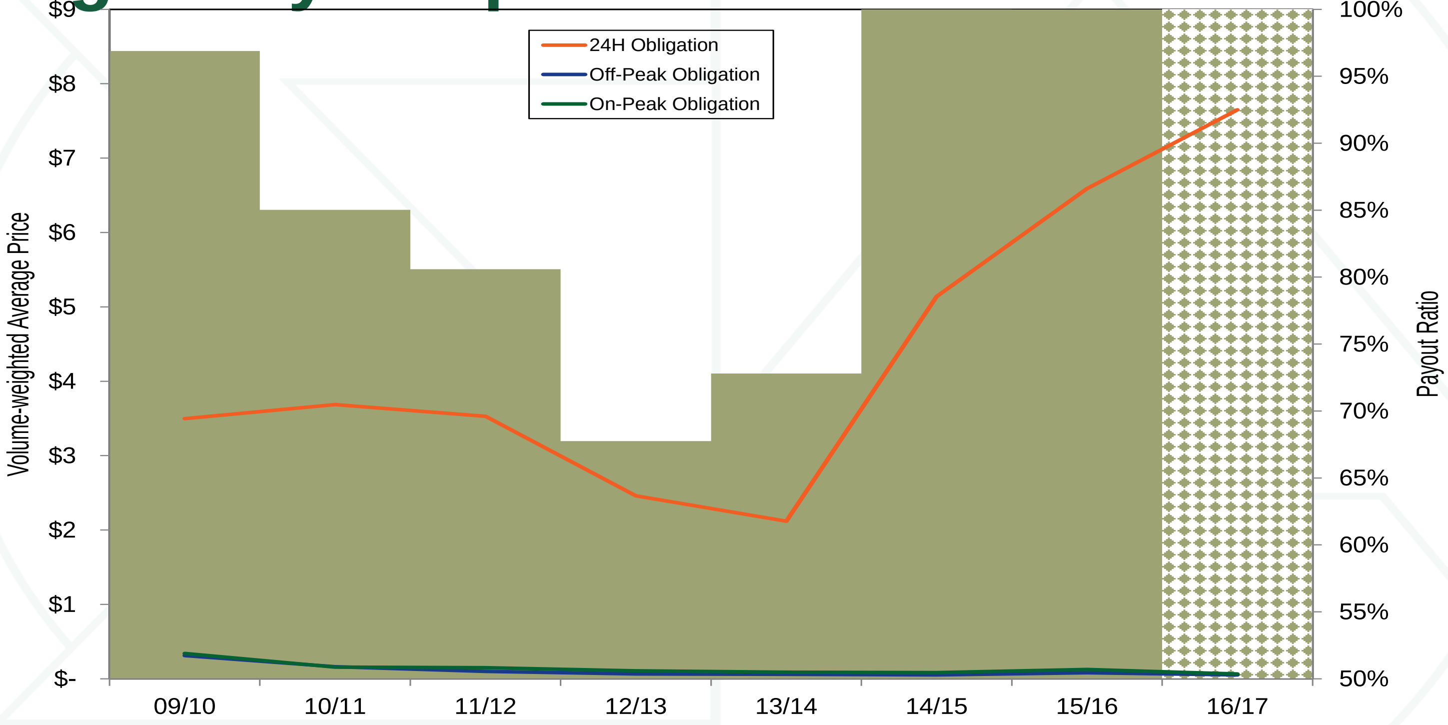
FTR payout ratio



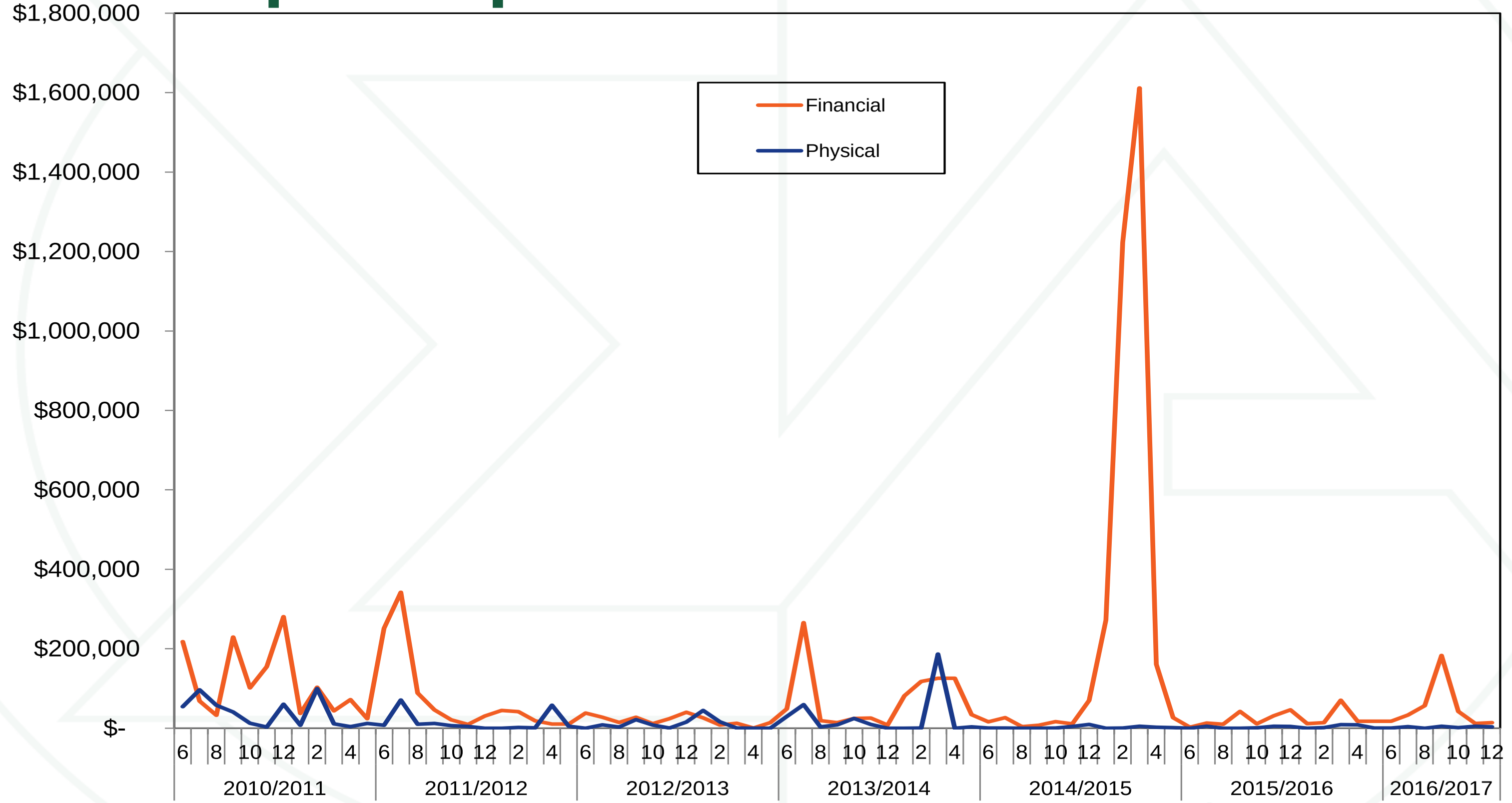
Stage 1B and Stage 2 ARR Allocations



Annual FTR Auction volume-weighted average buy bid price

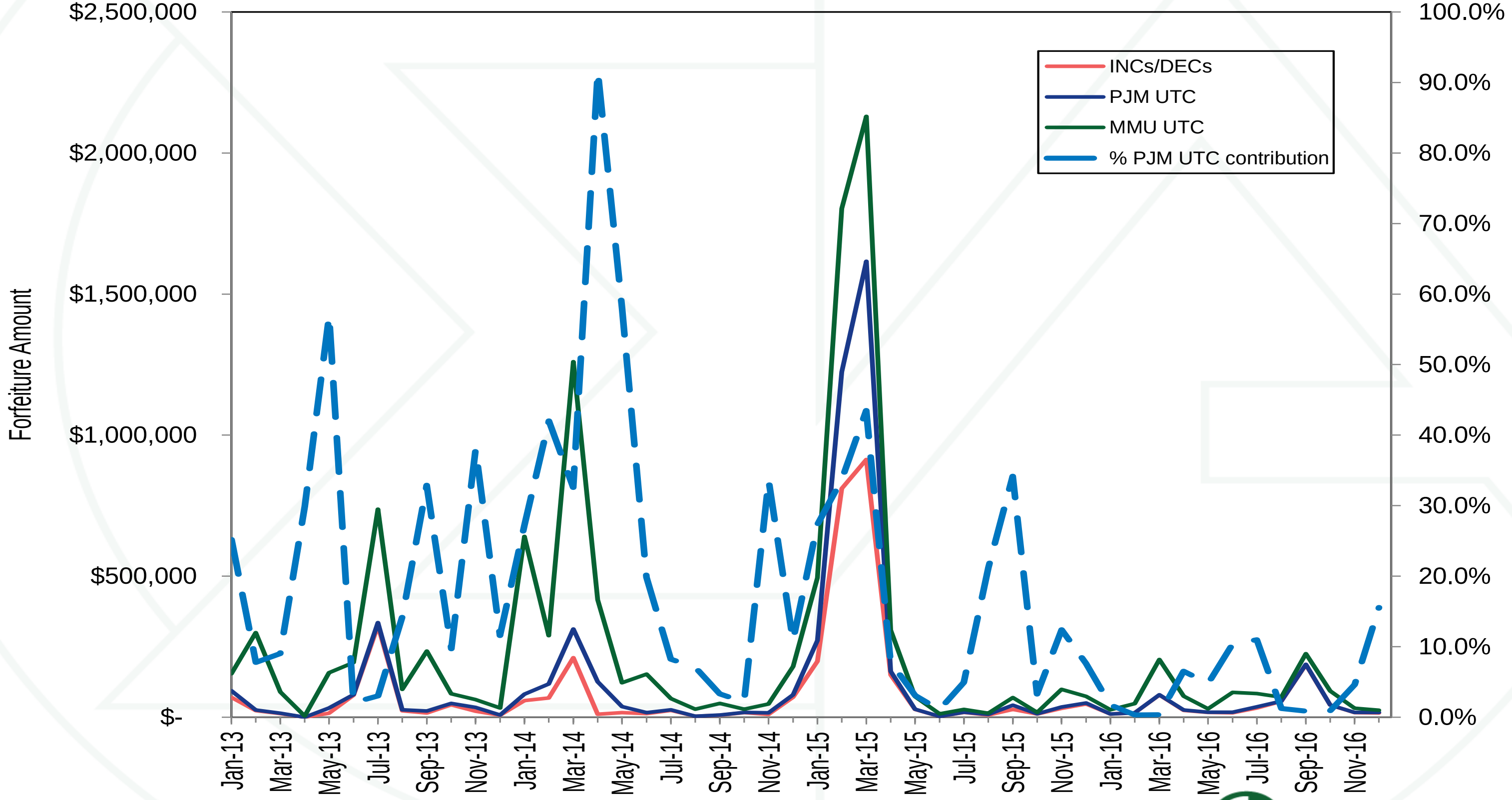


Monthly FTR forfeitures for physical and financial participants



Monitoring Analytics

FTR forfeitures for INCs/DECs and INCs/DECs/UTCs for PJM and MMU methods



Daily FTR net position ownership by FTR direction: 2016

	FTR Direction		
Organization Type	Prevailing Flow	Counter Flow	All
Physical	44.2%	24.0%	35.8%
Financial	55.8%	76.0%	64.2%
Total	100.0%	100.0%	100.0%

FTR profits by organization type

Calendar Year	Physical	Financial	Total
2011	$340,260,261	$125,697,493	$465,957,753
2012	($7,634,041)	$78,762,923	$71,128,882
2013	$170,180,569	$177,494,506	$347,675,076
2014	$873,909,275	$543,642,102	$1,417,551,377
2015	$453,547,398	$182,282,134	$635,829,532
2016	$244,139,718	$47,537,492	$291,677,210

Status of MMU reported recommendations: 1999 through 2016

Status	Priority High	Priority Medium	Priority Low	Total	Percent of Total
Adopted	19	12	18	49	21.7%
Partially Adopted (Continued Recommendation)	5	9	6	20	8.8%
Partially Adopted (Recommendation Closed)	2	4	4	10	4.4%
Partially Adopted (Total)	7	13	10	30	13.3%
Not Adopted	27	59	35	121	53.5%
Not Adopted (Pending before FERC)	3	1	0	4	1.8%
Not Adopted (Stakeholder Process)	4	6	2	12	5.3%
Not Adopted (Total)	34	66	37	137	60.6%
Replaced by Newer Recommendation	1	5	2	8	3.5%
Withdrawn	0	0	2	2	0.9%
Total	61	96	69	226	100.0%

Market Monitoring Unit

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

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