2011 State of the Market Report for PJM

Members Committee

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Monitoring Analytics

Figure 1-1 PJM's footprint and its 18 control zones

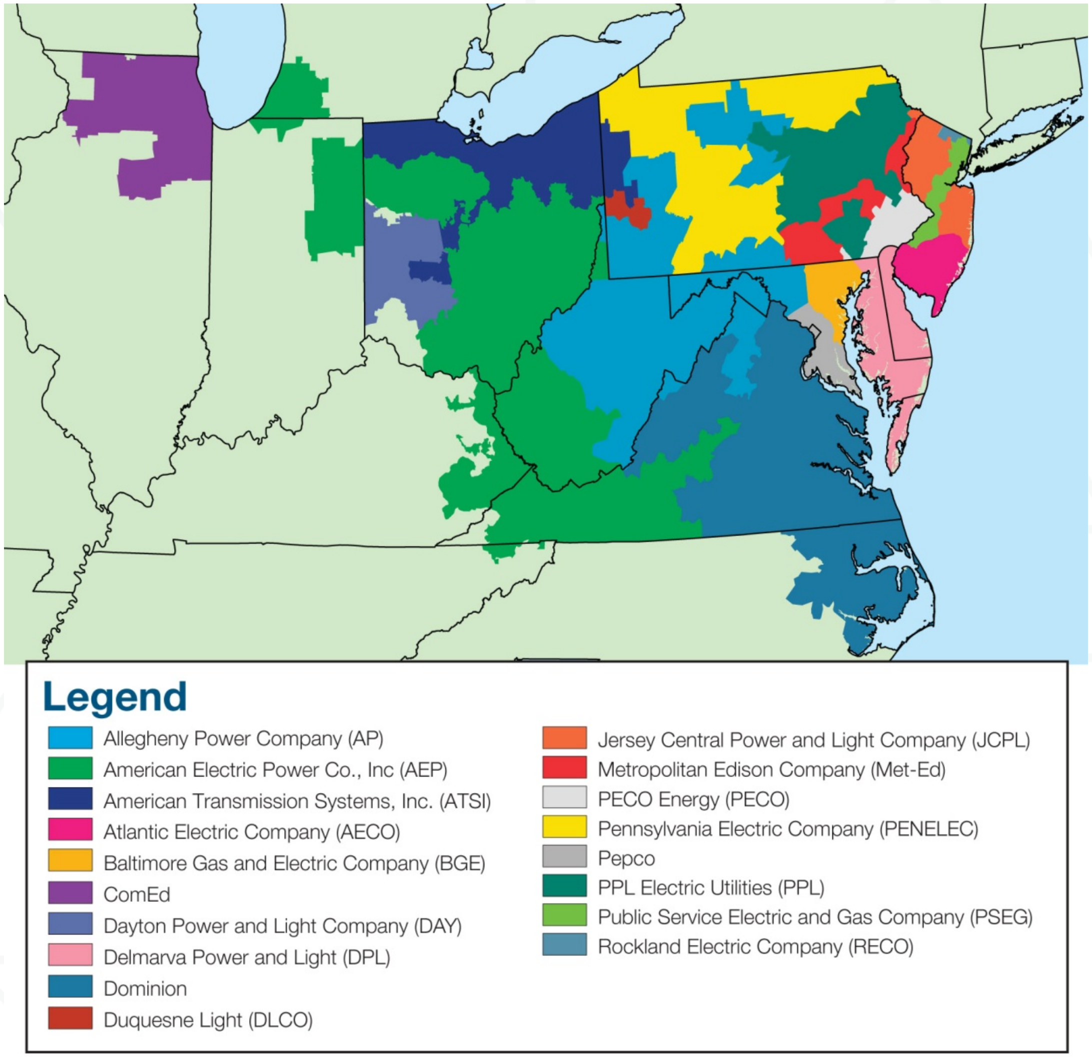

Table 1-1 The Energy Market results were competitive

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

Table 1-2 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: Local Market	Competitive	
Market Performance	Competitive	Mixed

Table 1-3 The Regulation Market results were not competitive

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

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Table 1-4 The Synchronized Reserve Markets results were competitive

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

Table 1-5 The Day-Ahead Scheduling Reserve Market results were competitive

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

Table 1-6 The FTR Auction Markets results were competitive

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

State of the Market Recommendations

- **Operating reserves.**
  - **Improve process of identifying reasons for paying credits.**
  - **Up to congestion transactions should pay operating reserve charges.**
- **Capacity market.**
  - **Improve rules to promote efficient outcomes.**
  - **Define obligations more clearly.**
  - **Improve performance incentives.**
  - **Clarify terms of RMR service.**

State of the Market Recommendations

- **Demand response**
  - **Eliminate limited DR products.**
  - **Implement subzonal dispatch/nodal dispatch.**
  - **Simplify Emergency Program.**
  - **Improve measurement and verification.**
- **Environment and renewables**
  - **Bring renewable energy credit markets into PJM markets**
- **Ancillary**
  - **Regulation**
  - **Synchronized reserve**
  - **Black start**

State of the Market Recommendations

- **Transactions.**
  - **Update interface price weights**
  - **Eliminate internal sources and sinks**
  - **Loop flow data**
  - **All pricing arrangements with other balancing authorities consistent with market principles**
- **Planning**
  - **Continue to address interconnection process**
- **Congestion and marginal losses**
  - **Address anomalous loss results via software review**
- **FTRs**
  - **Analysis of revenue adequacy**

Table 1-7 Total price per MWh by category and total revenues by category: 2010 and 2011

Category	2010 $/MWh	2011 $/MWh	Percent Change Totals	2010 Percent of Total	2011 Percent of Total
Energy	$48.35	$45.94	(5.0%)	72.5%	73.4%
Capacity	$12.15	$9.72	(20.0%)	18.2%	15.5%
Transmission Service Charges	$4.00	$4.42	10.5%	6.0%	7.1%
Operating Reserves (Uplift)	$0.79	$0.79	1.1%	1.2%	1.3%
Reactive	$0.44	$0.42	(6.6%)	0.7%	0.7%
PJM Administrative Fees	$0.36	$0.37	3.4%	0.5%	0.6%
Regulation	$0.35	$0.32	(6.6%)	0.5%	0.5%
Transmission Enhancement Cost Recovery	$0.21	$0.29	39.0%	0.3%	0.5%
Synchronized Reserves	$0.06	$0.09	47.4%	0.1%	0.1%
Transmssion Owner (Schedule 1A)	$0.09	$0.09	1.5%	0.1%	0.1%
Day Ahead Scheduling Reserve (DASR)	$0.01	$0.05	391.9%	0.0%	0.1%
Black Start	$0.02	$0.02	22.4%	0.0%	0.0%
NERC/RFC	$0.02	$0.02	(7.6%)	0.0%	0.0%
RTO Startup and Expansion	$0.01	$0.01	(1.9%)	0.0%	0.0%
Load Response	$0.00	$0.01	28.6%	0.0%	0.0%
Transmission Facility Charges	$0.00	$0.00	19.1%	0.0%	0.0%
Total	$66.72	$62.56	(6.2%)	100.0%	100.0%

Figure 2-1 Average PJM aggregate supply curves: Summer 2010 and 2011

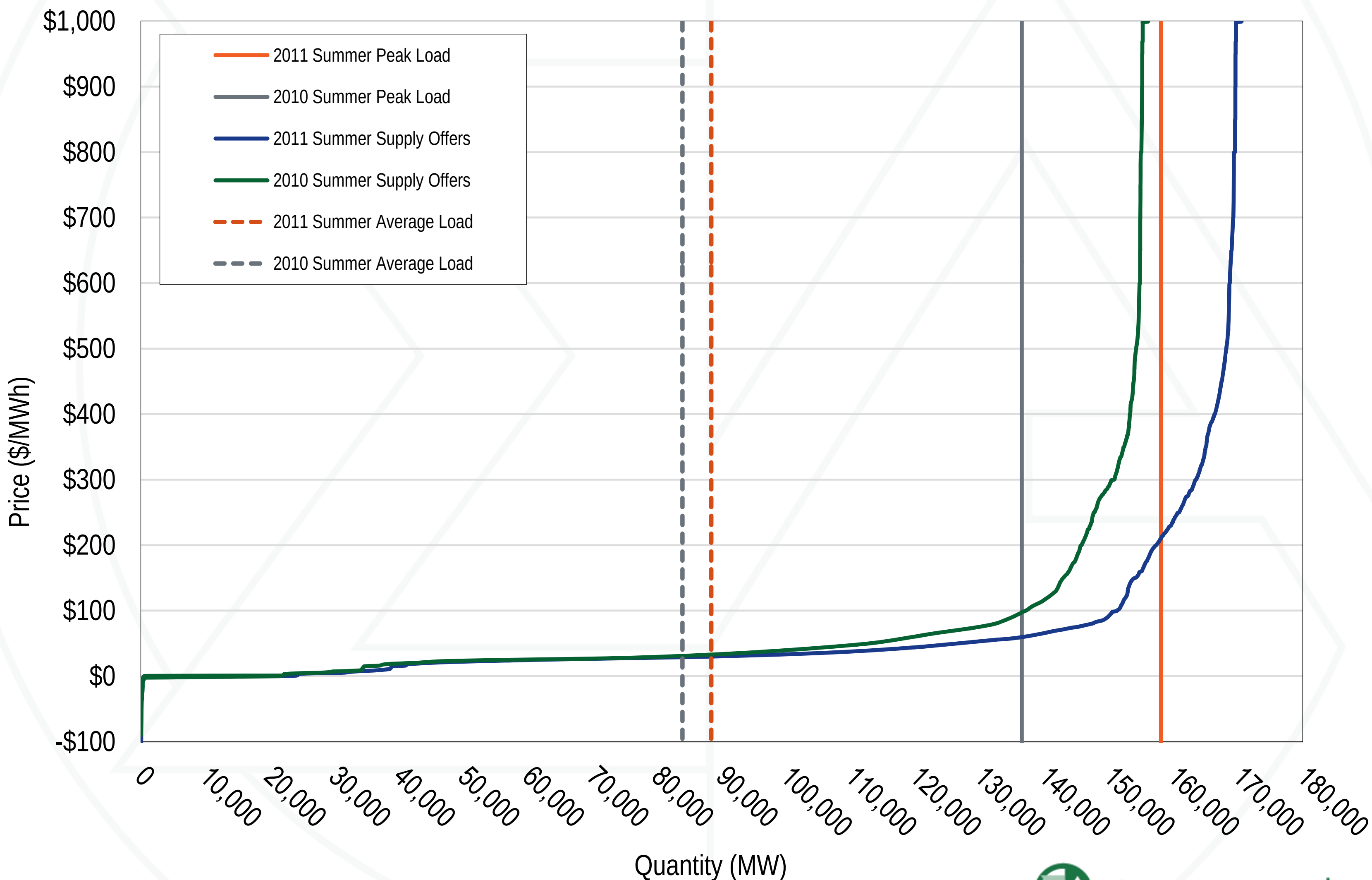

Table 2-2 PJM generation (By fuel source (GWh)): Calendar years 2010 and 2011

	2010 GWh	2010 Percent	2011 GWh	2011 Percent	Change in Output
Coal	363,035.1	48.7%	360,306.2	46.9%	(0.8%)
Standard Coal	350,539.2	47.0%	348,100.5	45.3%	(0.7%)
Waste Coal	12,495.9	1.7%	12,205.7	1.6%	(0.1%)
Nuclear	254,534.1	34.2%	262,968.3	34.2%	3.3%
Gas	93,455.9	12.5%	110,345.3	14.4%	18.1%
Natural Gas	91,729.4	12.3%	108,456.7	14.1%	18.2%
Landfill Gas	1,726.0	0.2%	1,887.9	0.2%	9.4%
Biomass Gas	0.5	0.0%	0.6	0.0%	39.4%
Hydroelectric	14,384.4	1.9%	15,277.9	2.0%	6.2%
Wind	9,688.2	1.3%	11,561.1	1.5%	19.3%
Waste	6,731.5	0.9%	5,559.6	0.7%	(17.4%)
Solid Waste	5,033.9	0.7%	4,442.9	0.6%	(11.7%)
Miscellaneous	1,697.7	0.2%	1,116.6	0.1%	(34.2%)
Oil	3,313.3	0.4%	2,136.0	0.3%	(35.5%)
Heavy Oil	2,748.3	0.4%	1,749.8	0.2%	(36.3%)
Light Oil	508.8	0.1%	356.6	0.0%	(29.9%)
Diesel	32.3	0.0%	16.9	0.0%	(47.9%)
Kerosene	23.8	0.0%	12.8	0.0%	(46.4%)
Jet Oil	0.1	0.0%	0.1	0.0%	1.0%
Solar	5.7	0.0%	55.7	0.0%	872.5%
Battery	0.3	0.0%	0.2	0.0%	(24.8%)
Total	745,148.6	100.0%	768,210.2	100.0%	3.1%

Figure 2-2 PJM footprint annual peak loads: 2002 to 2011

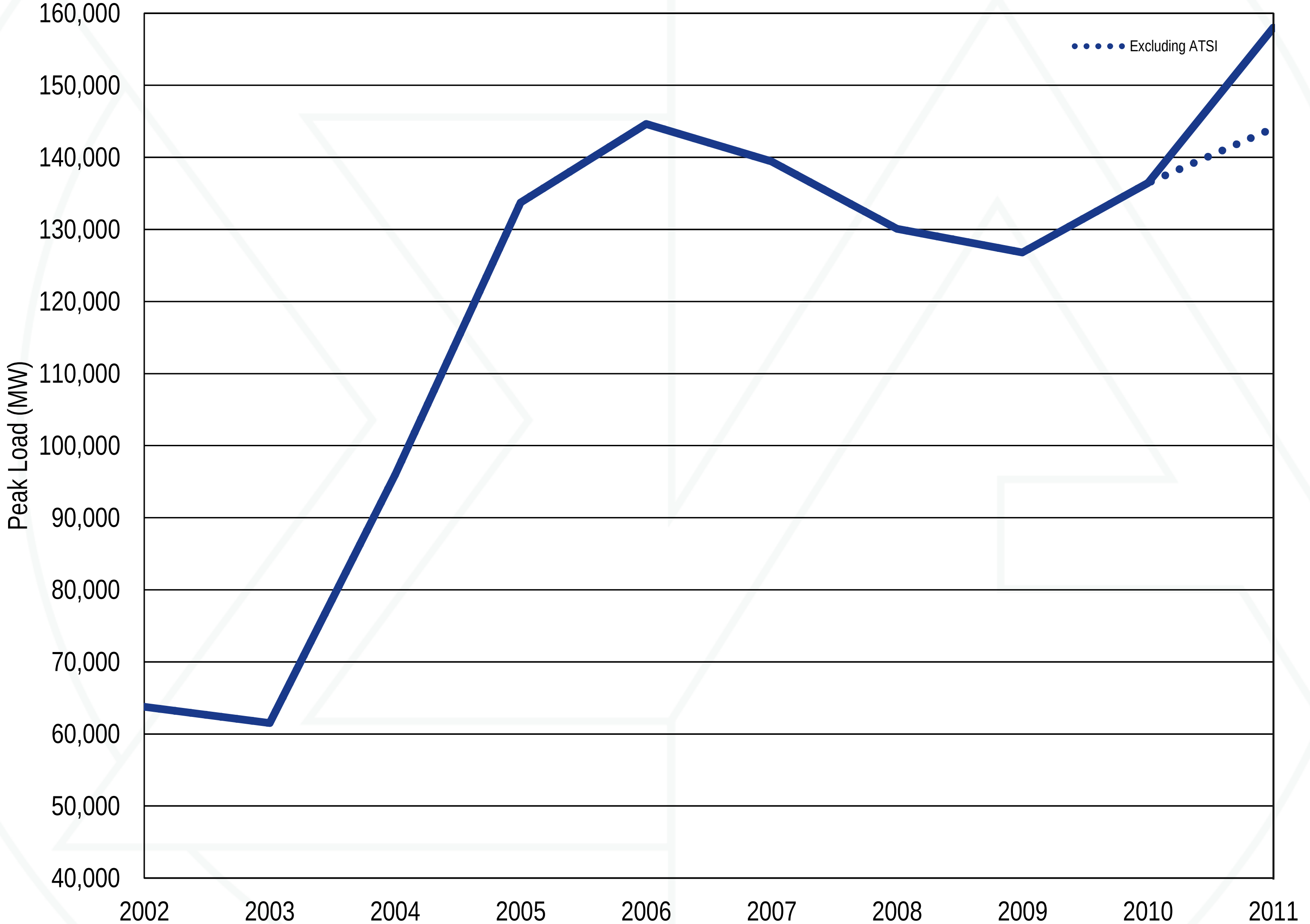

Table 2-4 Actual PJM footprint peak loads: 2002 to 2011

Year	Date	Hour Ending (EPT)	PJM Load (MW)	Annual Change (MW)	Annual Change (%)
2002	Wed, August 14	16	63,762	NA	NA
2003	Fri, August 22	16	61,499	(2,263)	(3.5%)
2004	Mon, December 20	19	96,016	34,517	56.1%
2005	Tue, July 26	16	133,761	37,746	39.3%
2006	Wed, August 02	17	144,644	10,883	8.1%
2007	Wed, August 08	16	139,428	(5,216)	(3.6%)
2008	Mon, June 09	17	130,100	(9,328)	(6.7%)
2009	Mon, August 10	17	126,798	(3,302)	(2.5%)
2010	Tue, July 06	17	136,460	9,662	7.6%
2011 (with ATSI)	Thu, July 21	17	158,016	21,556	15.8%
2011 (without ATSI)	Thu, July 21	17	144,063	7,603	5.6%

Table 2-28 PJM real-time average hourly load: Calendar years 1998 through 2011

	PJM Real-Time Load (MWh)		Year-to-Year Change	
Year	Average Load	Load Standard Deviation	Average Load	Load Standard Deviation
1998	28,578	5,511	NA	NA
1999	29,641	5,956	3.7%	8.1%
2000	30,113	5,529	1.6%	(7.2%)
2001	30,297	5,873	0.6%	6.2%
2002	35,731	8,013	17.9%	36.4%
2003	37,398	6,832	4.7%	(14.7%)
2004	49,963	13,004	33.6%	90.3%
2005	78,150	16,296	56.4%	25.3%
2006	79,471	14,534	1.7%	(10.8%)
2007	81,581	14,618	2.7%	0.6%
2008	79,515	13,758	(2.5%)	(5.9%)
2009	76,035	13,260	(4.4%)	(3.6%)
2010	79,611	15,504	4.7%	16.9%
2011	82,541	16,156	3.7%	4.2%

Figure 2-8 PJM real-time average hourly load: Calendar years 2010 and 2011

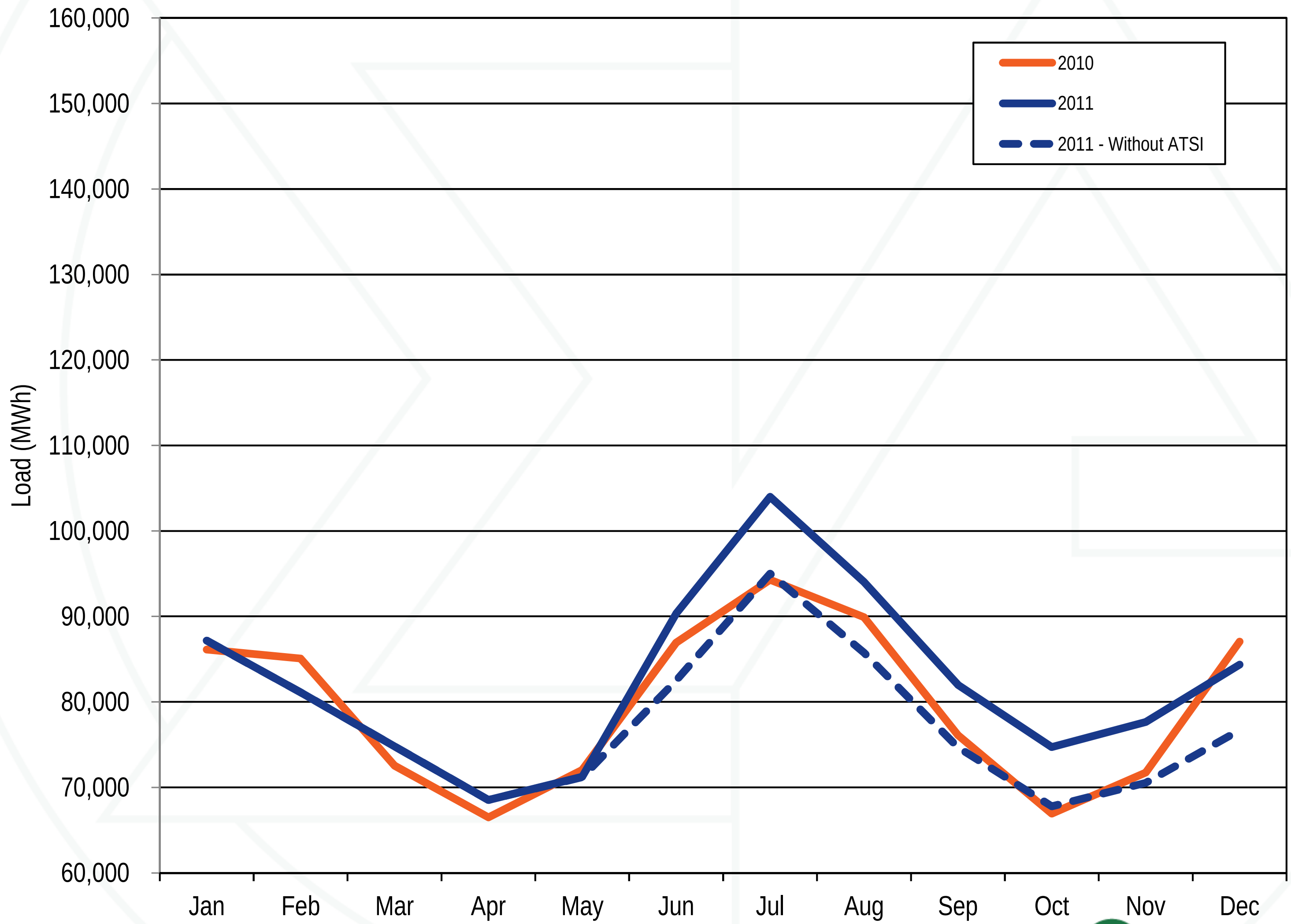

Table 2-37 PJM real-time, annual, load-weighted, average LMP (Dollars per MWh): Calendar years 1998 through 2011

	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%

Figure 2-16 PJM real-time, monthly, load-weighted, average LMP: Calendar years 2007 through 2011

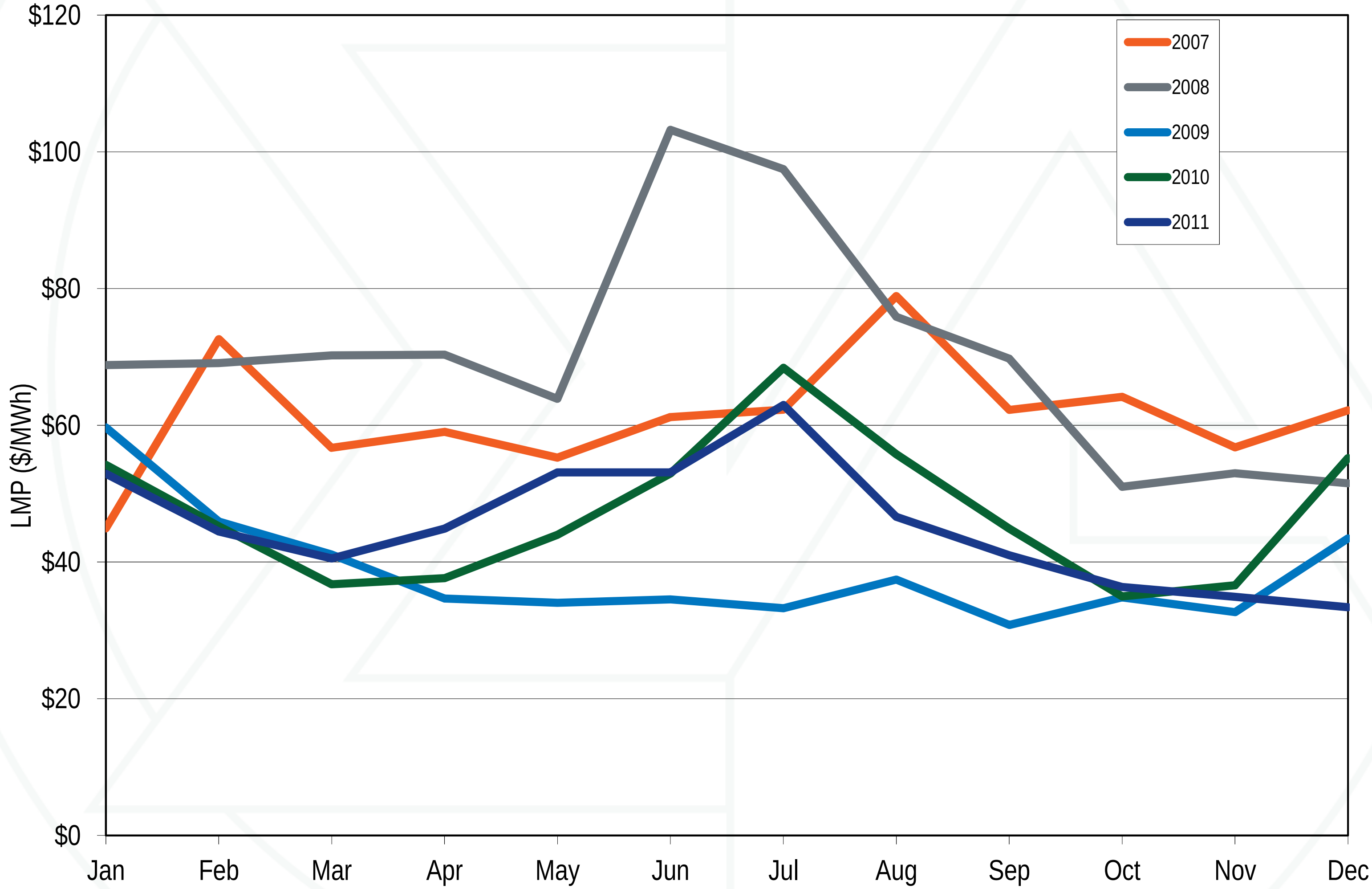

Figure 2-17 Spot average fuel price comparison: Calendar years 2010 through 2011

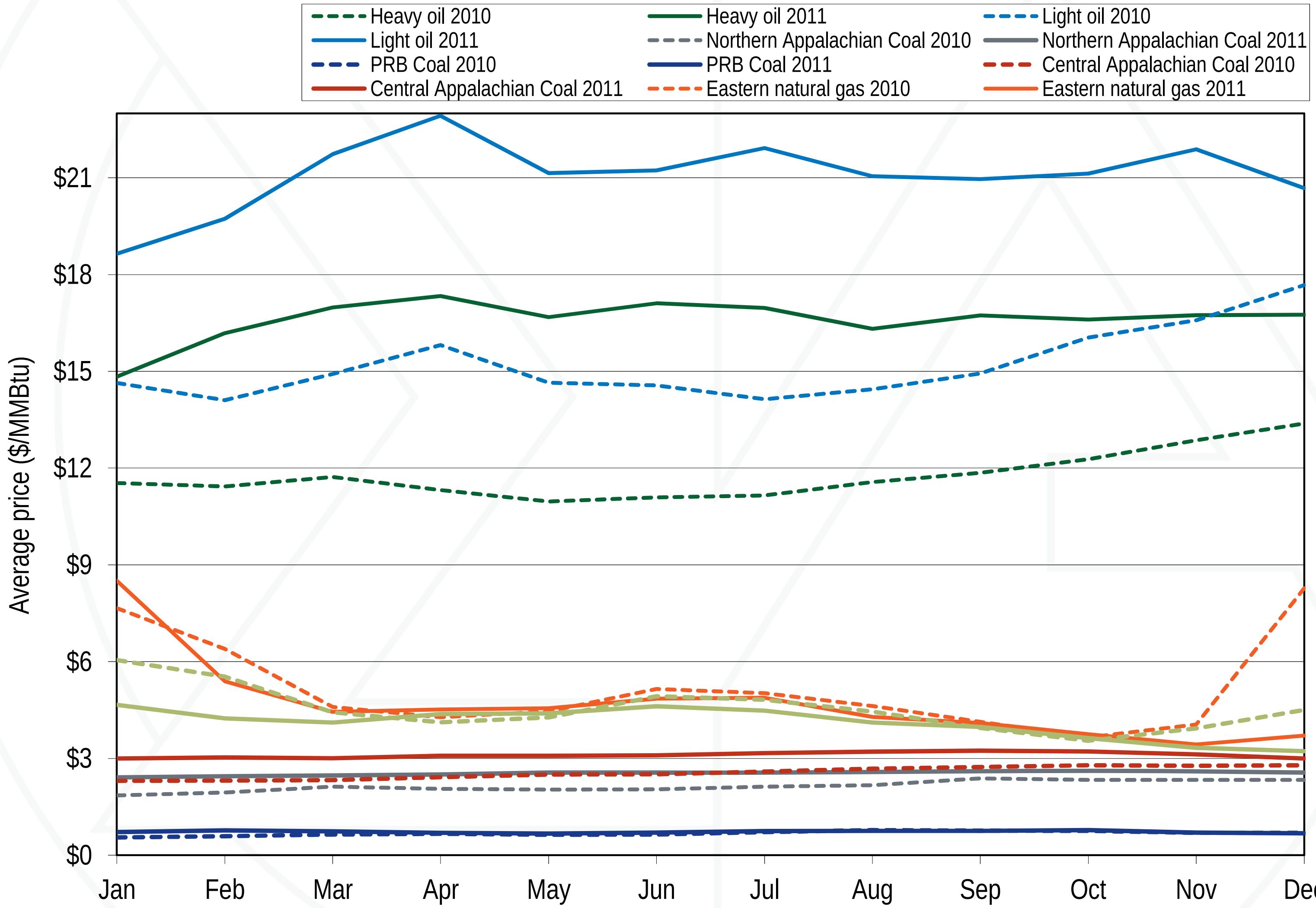

Table 2-38 PJM real-time annual, fuel-cost-adjusted, load-weighted average LMP (Dollars per MWh): Year-over-year method

	2011 Load-Weighted LMP	2011 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$45.94	$44.75	(2.6%)
	2010 Load-Weighted LMP	2011 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$48.35	$44.75	(7.4%)
	2010 Load-Weighted LMP	2011 Load-Weighted LMP	Change
Average	$48.35	$45.94	(5.0%)

Table 2-39 Components of PJM real-time, annual, load-weighted, average LMP: Calendar year 2011

Element	Contribution to LMP	Percent
Coal	$21.30	46.4%
Gas	$14.32	31.2%
10% Cost Adder	$3.95	8.6%
VOM	$2.52	5.5%
Markup	$1.28	2.8%
Oil	$1.21	2.6%
NA	$0.73	1.6%
NOX	$0.31	0.7%
CO2	$0.31	0.7%
FMU Adder	$0.12	0.3%
SO2	$0.04	0.1%
Unit LMP Differential	$0.02	0.1%
Municipal Waste	$0.00	0.0%
Uranium	$0.00	0.0%
M2M Adder	($0.00)	(0.0%)
Shadow Price Limit Adder	($0.00)	(0.0%)
Wind	($0.03)	(0.1%)
Dispatch Differential	($0.12)	(0.3%)
Total	$45.94	100.0%

Figure 4-1 History of capacity prices: Calendar year 1999 through 2014

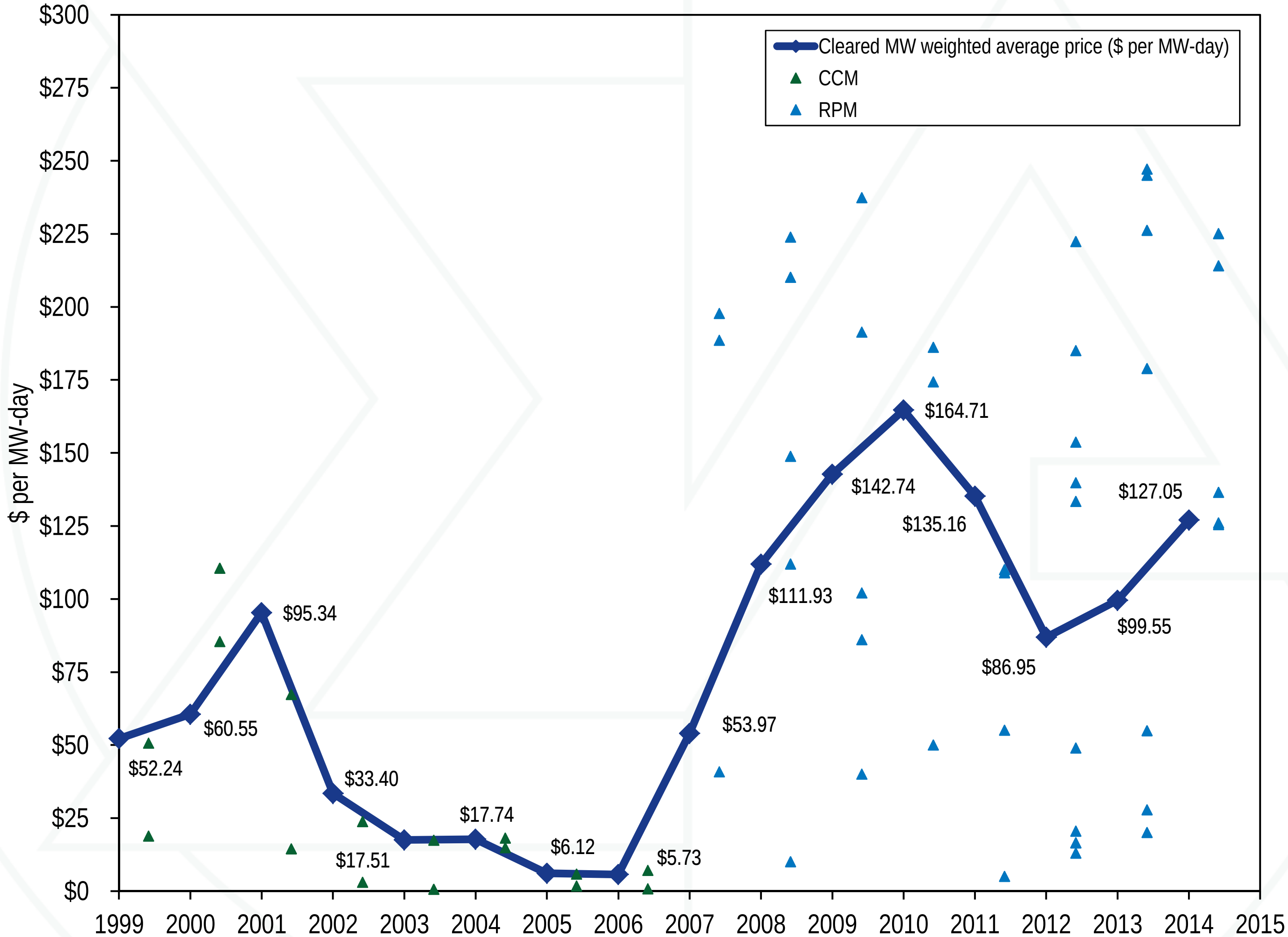

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Figure 6-2 New entrant CT net revenue and 20-year levelized fixed cost by LDA (Dollars per installed MW-year)

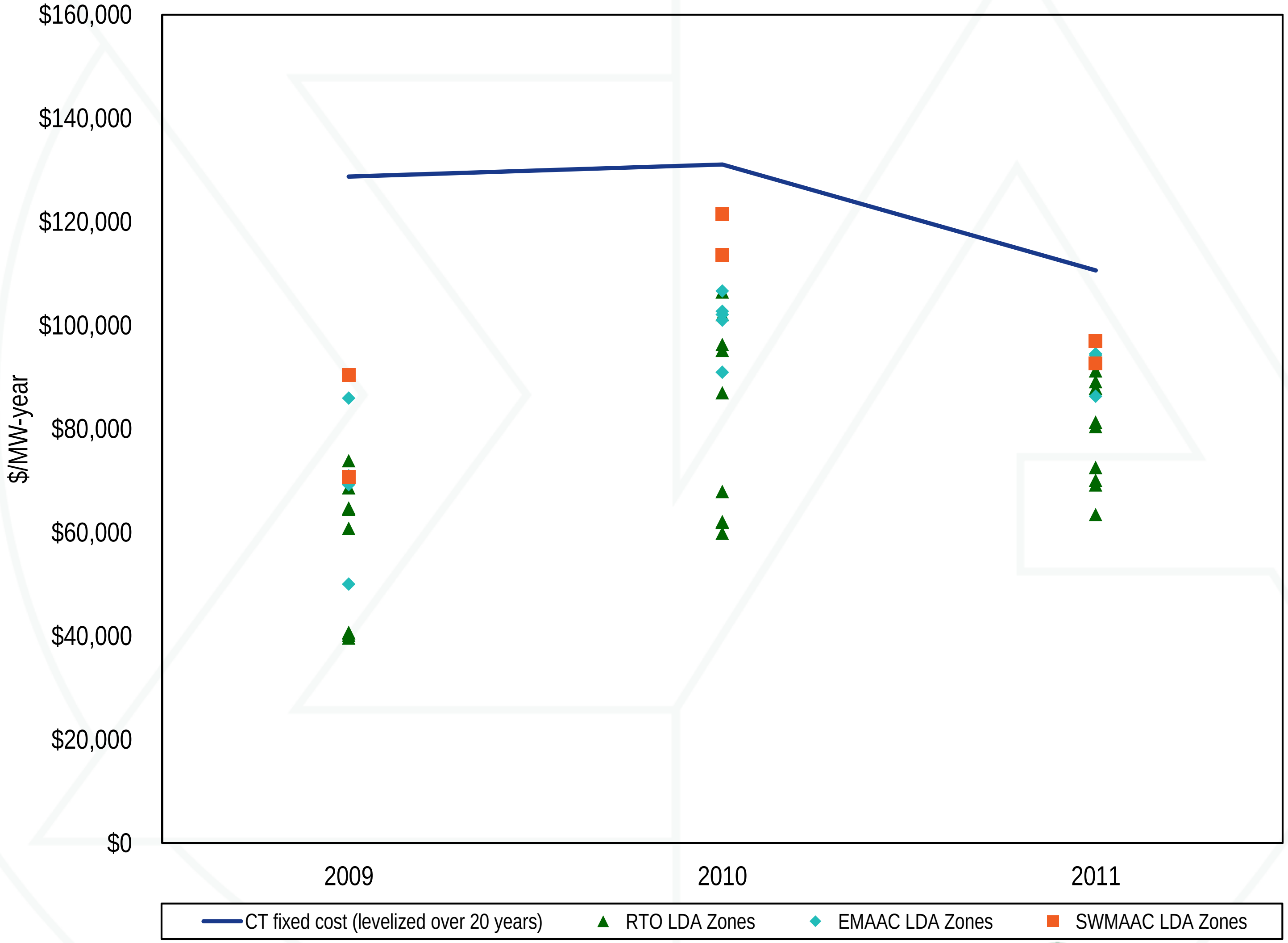

Figure 6-4 New entrant CC net revenue and 20-year levelized fixed cost by LDA (Dollars per installed MW-year)

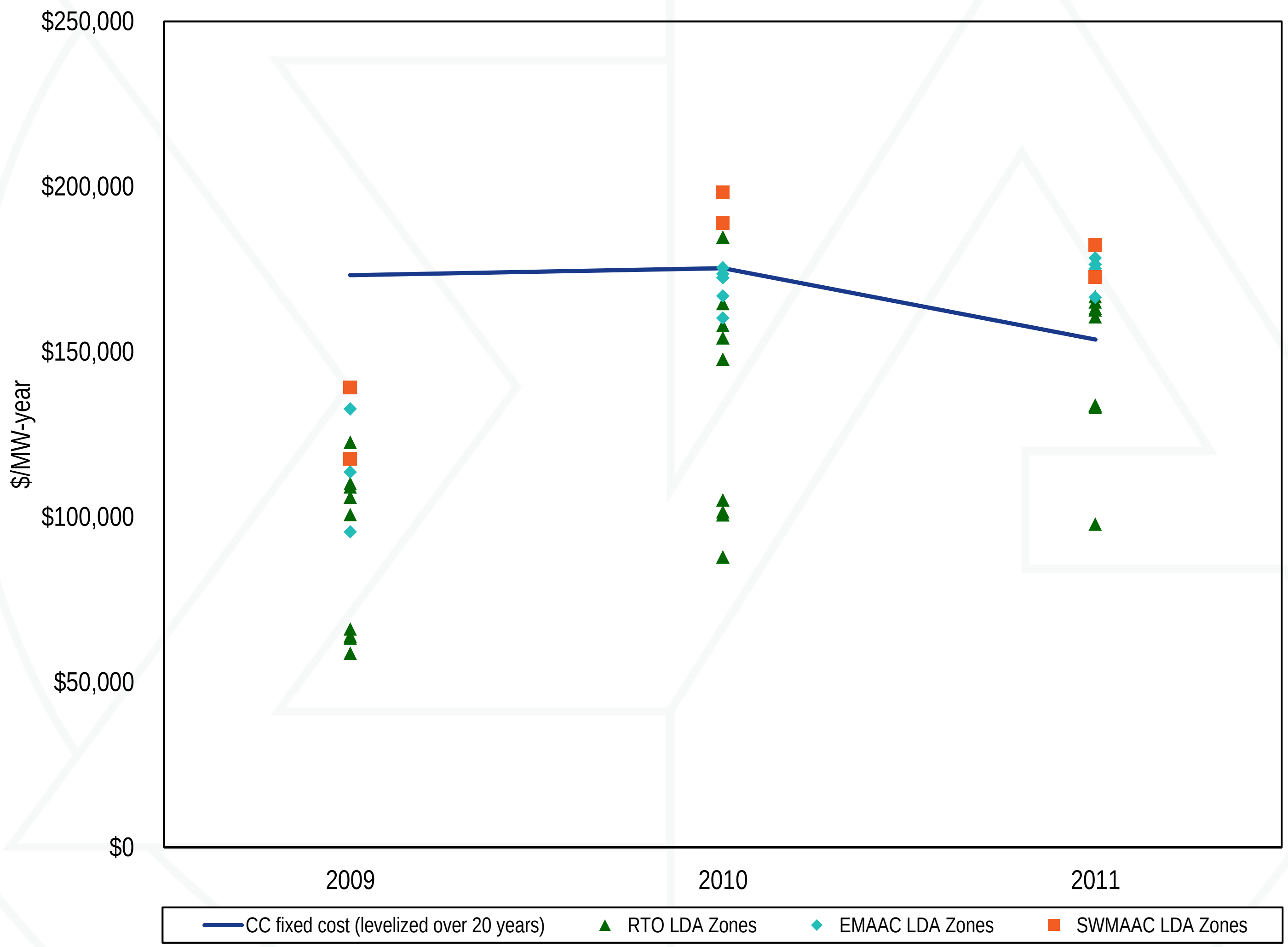

Figure 6-6 New entrant CP net revenue and 20-year levelized fixed cost by LDA (Dollars per installed MW-year)

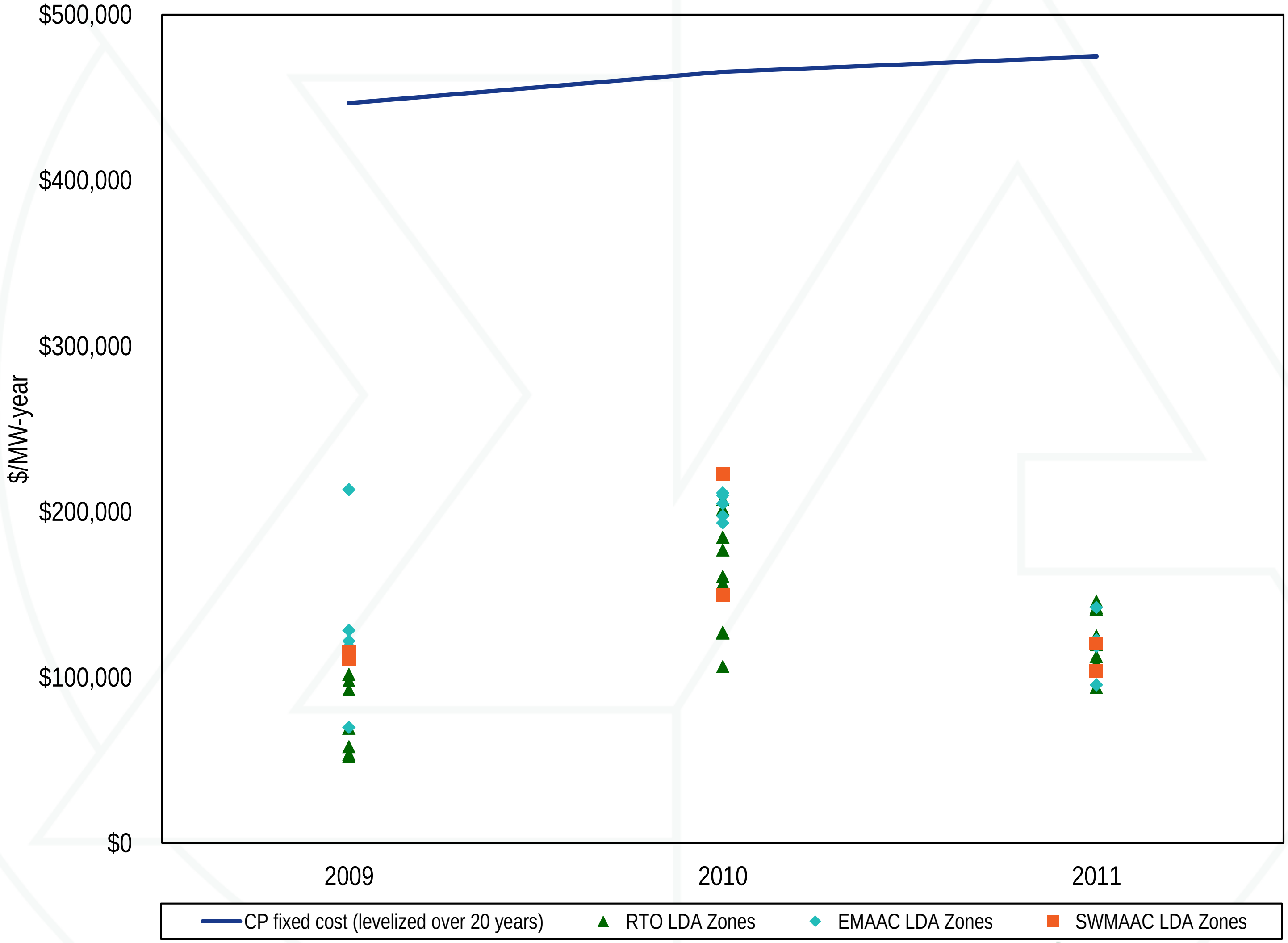

Table 11-2 Capacity additions of plants greater than 500 MW: Calendar year 2011

Plant Name	Zone	Unit Type	ICAP (MW)
Dresden Energy Facility	AEP	Combined Cycle	545
Longview Power	APS	Coal Steam	700
Fremont Energy Center	ATSI	Combined Cycle	685
Bear Garden Generating Station	Dominion	Combined Cycle	590
York Energy Center	PECO	Combined Cycle	565

Table 6-25 Proportion of units recovering avoidable costs from energy and ancillary markets as well as total markets for calendar years 2009 to 2011

	2009		2010		2011	
Technology	Units with full recovery from energy markets	Units with full recovery from all markets	Units with full recovery from energy markets	Units with full recovery from all markets	Units with full recovery from energy markets	Units with full recovery from all markets
CC - NUG Cogeneration Frame B or E Technology	57%	96%	83%	92%	64%	89%
CC - Two of Three on One Frame F Technology	63%	89%	84%	100%	87%	97%
CT - First & Second Generation Aero (P&W FT 4)	24%	99%	34%	100%	32%	99%
CT - First & Second Generation Frame B	30%	100%	34%	98%	29%	94%
CT - Second Generation Frame E	60%	100%	67%	100%	82%	100%
CT - Third Generation Aero	23%	99%	49%	99%	87%	99%
CT - Third Generation Frame F	41%	98%	69%	100%	79%	98%
Diesel	69%	97%	71%	97%	61%	91%
Hydro	100%	100%	100%	100%	96%	100%
Nuclear	100%	100%	100%	100%	100%	100%
Oil or Gas Steam	36%	90%	40%	87%	43%	86%
Pumped Storage	45%	100%	90%	100%	70%	100%
Sub-Critical Coal	66%	88%	73%	88%	63%	77%
Super Critical Coal	74%	91%	77%	80%	81%	88%

Table 6-26 Profile of coal units

	Coal plants with less than full recovery of avoidable costs	Coal plants with full recovery of avoidable costs
Total Installed Capacity (ICAP)	5,642	36,383
Avg. Installed Capacity (ICAP)	235	319
Avg. Age of Plant (Years)	46	38
Avg. Heat Rate (Btu/kWh)	11,135	10,701
Avg. Run Hours (Hours)	4,300	5,627
Avg. Avoidable Costs ($/MW-year)	512	146

Table 6-27 Installed capacity associated with levels of avoidable cost recovery: Calendar year 2011

Groups of coal plants by percent recovery of avoidable cost	Installed capacity (MW)	Percent of total
0% - 65%	3,793	9%
65% - 75%	111	0%
75% - 90%	465	1%
90% - 100%	1,273	3%
> 100%	36,383	87%
Total	42,025	100%

Table 6-29 Attributes of coal plants with and without MATS compliant environmental controls

	Coal plants lacking NOx, SO2, or particulate controls	Coal plants with NOx, SO2, and particulate controls
Number of units (excluding announced or expected deactivations)	80	58
ICAP within MAAC	6,618	5,247
ICAP in rest of RTO	10,487	19,674
Total installed capacity (ICAP)	17,104	24,921
ICAP associated with plants older than 40 years	14,248	9,216
ICAP associated with small coal plants (200 MW or less)	5,958	2,001
ICAP associated with medium coal plants (200 to 500 MW)	2,495	4,915
ICAP associated with large coal plants (500 MW or greater)	8,652	18,005
ICAP associated with 100 percent recovery of avoidable costs	14,927	21,456
ICAP associated with less than 100 percent recovery of avoidable costs	2,177	3,465

Table 6-30 At risk coal plants

	Coal plants covering less than	
	100% of avoidable costs or 100% of APIR (if any)	125% of avoidable costs or 125% of APIR (if any)
Number of units	26	30
ICAP within MAAC	1,630	1,765
ICAP in rest of RTO	4,135	5,172
Total installed capacity (ICAP)	5,764	6,936

Table 11-11 Summary of PJM unit Retirements (MW), Calendar year 2011 through 2019

	MW
Retirements 2011	1,322.3
Planned Retirements 2012	7,189.0
Planned Retirements Post-2012	10,374.7
Total	18,886.0

Figure 11-1 Unit retirements in PJM Calendar year 2011 through 2019

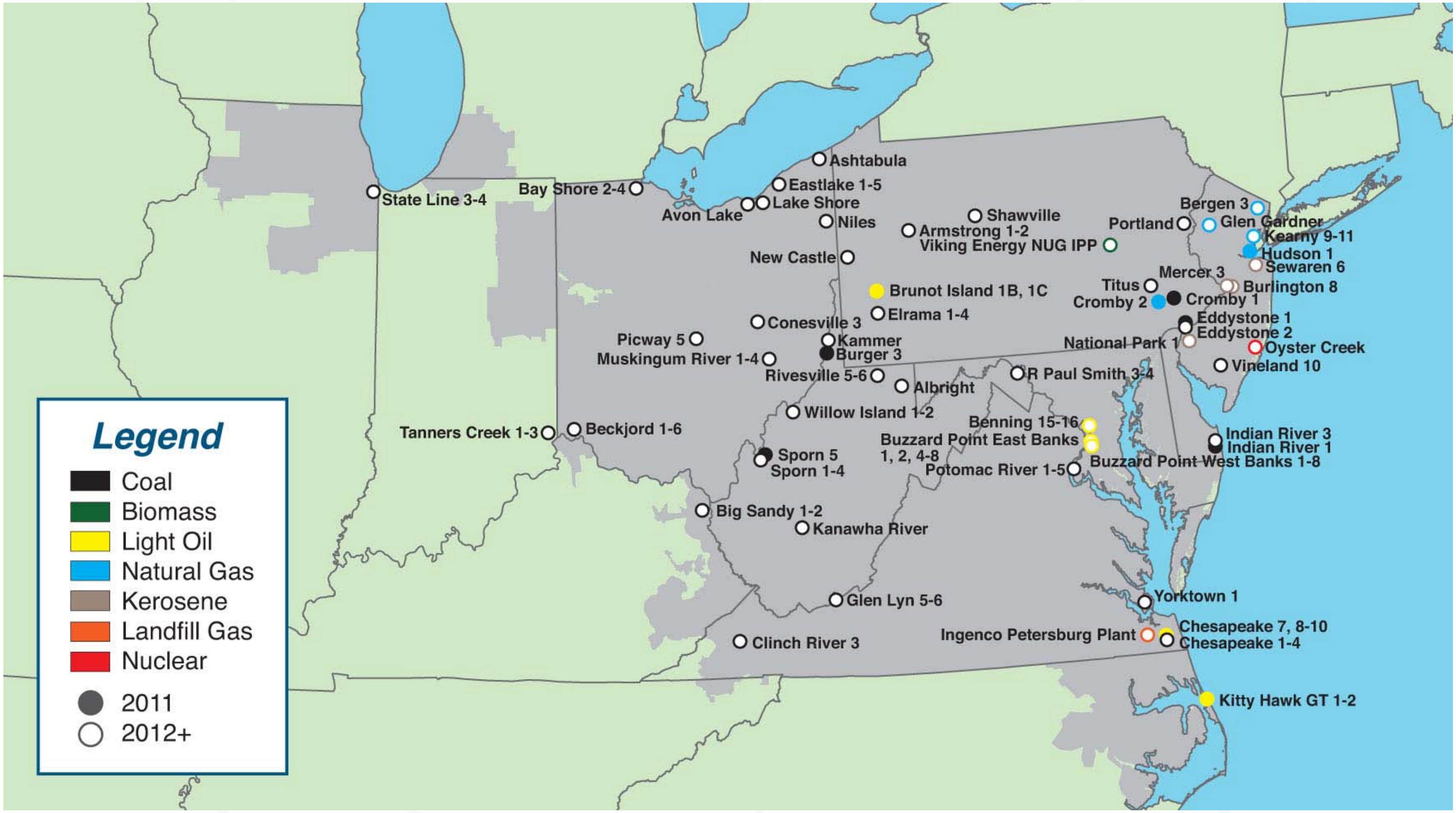

Table 3-6 Total day-ahead and balancing operating reserve charges: Calendar years 1999 to 2011

	Total Operating Reserve Charges	Annual Credit Change	Operating Reserve as a Percent of Total PJM Billing	Day-Ahead Rate ($/MWh)	Balancing RTO Deviation Rate ($/MWh)	Balancing RTO Reliability Rate ($/MWh)
1999	$133,897,428	NA	7.5%	NA	NA	NA
2000	$216,985,147	62.1%	9.6%	0.3412	0.5346*	NA
2001	$290,867,269	34.0%	8.7%	0.2746	1.0700*	NA
2002	$237,102,574	(18.5%)	5.0%	0.1635	0.7873*	NA
2003	$289,510,257	22.1%	4.2%	0.2261	1.1971*	NA
2004	$414,891,790	43.3%	4.8%	0.2300	1.2362*	NA
2005	$682,781,889	64.6%	3.0%	0.0762	2.7580*	NA
2006	$322,315,152	(52.8%)	1.5%	0.0781	1.3315*	NA
2007	$459,124,502	42.4%	1.5%	0.0570	2.3310*	NA
2008	$429,253,836	(6.5%)	1.3%	0.0844	2.1132*	NA
2009	$325,842,346	(24.1%)	1.2%	0.1201	0.6723	0.0092
2010	$572,286,706	75.6%	1.6%	0.1130	0.9120	0.0580
2011	$578,072,070	1.0%	1.6%	0.1068	0.9455	0.0681

Figure 3-2 Daily balancing operating reserve rates ($/MWh)

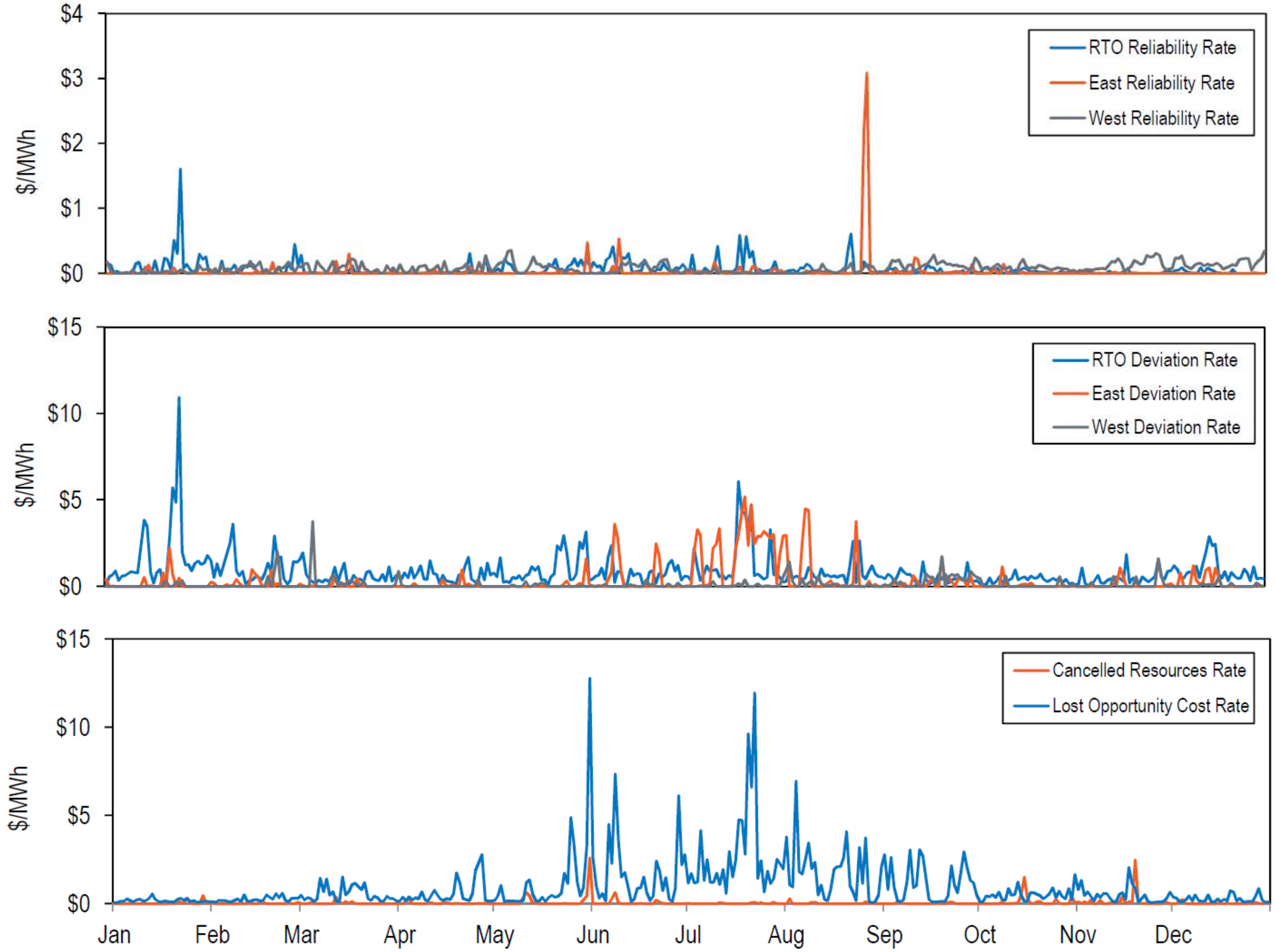

Table 3-11 Operating reserve rates statistics ($/MWh): Calendar year 2011

		Rates Charged ($/MWh)			
Region	Transaction	Maximum	Average	Minimum	Standard Deviation
East	INC	18.2083	2.2488	0.2377	2.5207
	DEC	18.2352	2.3581	0.3475	2.5039
	DA Load	0.4574	0.1094	0.0000	0.0727
	RT Load	3.2005	0.0910	0.0000	0.2454
	Deviation	18.2083	2.2488	0.2377	2.5207
West	INC	17.6208	2.0011	0.0867	2.0831
	DEC	17.6302	2.1104	0.3215	2.0690
	DA Load	0.4574	0.1094	0.0000	0.0727
	RT Load	1.6650	0.1458	0.0000	0.1401
	Deviation	17.6208	2.0011	0.0867	2.0831

Table 3-42 ALR and voltage support units' credits impact on the balancing operating reserve rates ($/MWh)

		Balancing Operating Reserve Rates ($/MWh)		Impact	
Category	Region	Without Units' Credits	Current	($/MWh)	Percentage
Reliability	RTO	0.0668	0.0681	0.0012	1.9%
	East	0.0274	0.0274	0.0000	0.0%
	West	0.0037	0.0775	0.0738	2,017.5%
Deviation	RTO	0.9207	0.9455	0.0248	2.7%
	East	0.4232	0.4232	0.0000	0.0%
	West	0.1032	0.1082	0.0050	4.9%

Table 3-44 Up-to Congestion Transactions Impact on the Operating Reserve Rates: Calendar year 2011

	Current Rates ($/MWh)	Rates Including Up-To Congestion Transactions ($/MWh)	Difference ($/MWh)	Percentage Difference
Day-Ahead	0.1068	0.0865	(0.0204)	(19.1%)
RTO Deviations	0.9455	0.2807	(0.6648)	(70.3%)
East Deviations	0.4232	0.1714	(0.2518)	(59.5%)
West Deviations	0.1082	0.0240	(0.0842)	(77.8%)
Lost Opportunity Cost	1.0678	0.3170	(0.7508)	(70.3%)
Canceled Resources	0.0560	0.0166	(0.0394)	(70.3%)

Key Legal/Regulatory Matters

- FTR Funding Study (EL12-18)
- Regulation (Order No. 755) compliance (ER11-1204)
- Generation Queue Reform (ER11-1177)
- Capacity Portability Tech Conference (ER11-4081)
- Balancing Operating Reserve Opp Cost Rebilling (ER12-469)

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