Appendix – Errata

Section 3, Energy Market

Change: On page 127 update Table 3-13 as shown below:

Table 3-13 Average hourly real-time generation and real-time generation plus imports: 2001 through 2018

	PJM Real-Time Supply (MWh)				Year-to-Year Change			
	Generation		Generation Plus		Generation		Generation Plus Imports	
	Generation	Standard Deviation	Supply	Standard Deviation	Generation	Standard Deviation	Supply	Standard Deviation
2001	29,553	4,937	32,552	5,285	NA	NA	NA	NA
2002	34,928	7,535	38,535	7,751	18.2%	52.6%	18.4%	46.7%
2003	36,628	6,165	40,205	6,162	4.9%	(18.2%)	4.3%	(20.5%)
2004	51,068	13,790	55,781	14,652	39.4%	123.7%	38.7%	137.8%
2005	81,127	15,452	86,353	15,981	58.9%	12.0%	54.8%	9.1%
2006	82,780	13,709	86,978	14,402	2.0%	(11.3%)	0.7%	(9.9%)
2007	85,860	14,018	90,351	14,763	3.7%	2.3%	3.9%	2.5%
2008	83,476	13,787	88,899	14,256	(2.8%)	(1.7%)	(1.6%)	(3.4%)
2009	78,026	13,647	83,058	14,140	(6.5%)	(1.0%)	(6.6%)	(0.8%)
2010	82,585	15,556	87,386	16,227	5.8%	14.0%	5.2%	14.8%
2011	85,775	15,932	90,511	16,759	3.9%	2.4%	3.6%	3.3%
2012	88,708	15,701	94,083	16,505	3.4%	(1.4%)	3.9%	(1.5%)
2013	89,769	15,012	94,833	15,878	1.2%	(4.4%)	0.8%	(3.8%)
2014	90,894	15,151	96,295	16,199	1.3%	0.9%	1.5%	2.0%
2015	88,628	16,118	94,330	17,313	(2.5%)	6.4%	(2.0%)	6.9%
2016	91,304	17,731	95,054	17,980	3.0%	10.0%	0.8%	3.9%
2017	90,945	15,194	92,721	15,493	(0.4%)	(14.3%)	(2.5%)	(13.8%)
2018	94,236	16,326	96,109	16,595	3.6%	7.5%	3.7%	7.1%

Change: On page 129 update Table 3-14 as shown below:

Table 3-14 Average hourly day-ahead supply and day-ahead supply plus imports: 2001 through 2018

	PJM Day-Ahead Supply (MWh)				Year-to-Year Change			
	Supply		Supply Plus Imports		Supply		Supply Plus Imports	
	Supply	Standard Deviation	Supply	Standard Deviation	Supply	Standard Deviation	Supply	Standard Deviation
2001	26,762	4,595	27,497	4,664	NA	NA	NA	NA
2002	31,434	10,007	31,982	10,015	17.5%	117.8%	16.3%	114.7%
2003	40,642	8,292	41,183	8,287	29.3%	(17.1%)	28.8%	(17.3%)
2004	62,755	17,141	63,654	17,362	54.4%	106.7%	54.6%	109.5%
2005	94,438	17,204	96,449	17,462	50.5%	0.4%	51.5%	0.6%
2006	100,056	16,543	102,164	16,559	5.9%	(3.8%)	5.9%	(5.2%)
2007	108,707	16,549	111,023	16,729	8.6%	0.0%	8.7%	1.0%
2008	105,485	15,994	107,885	16,136	(3.0%)	(3.4%)	(2.8%)	(3.5%)
2009	97,388	16,364	100,022	16,397	(7.7%)	2.3%	(7.3%)	1.6%
2010	107,307	21,655	110,026	21,837	10.2%	32.3%	10.0%	33.2%
2011	117,130	20,977	119,501	21,259	9.2%	(3.1%)	8.6%	(2.6%)
2012	134,479	17,905	136,903	18,080	14.8%	(14.6%)	14.6%	(15.0%)
2013	148,323	18,783	150,595	18,978	10.3%	4.9%	10.0%	5.0%
2014	146,672	33,145	148,906	33,346	(1.1%)	76.5%	(1.1%)	75.7%
2015	114,890	19,165	117,147	19,406	(21.7%)	(42.2%)	(21.3%)	(41.8%)
2016	131,618	22,329	133,246	22,368	14.6%	16.5%	13.7%	15.3%
2017	130,603	20,035	131,142	20,153	(0.8%)	(10.3%)	(1.6%)	(9.9%)
2018	114,556	20,239	114,967	20,224	(12.3%)	1.0%	(12.3%)	0.4%

Change: On page 136 update Table 3-20 as shown below:

Table 3-20 Average hourly day-ahead demand and day-ahead demand plus exports: 2001 through 2018

	PJM Day-Ahead Demand (MWh)				Year-to-Year Change			
	Demand		Demand Plus Exports		Demand		Demand Plus Exports	
	Demand	Standard Deviation	Demand	Standard Deviation	Demand	Standard Deviation	Demand	Standard Deviation
2001	33,370	6,562	33,757	6,431	NA	NA	NA	NA
2002	42,305	10,161	42,413	10,208	26.8%	54.8%	25.6%	58.7%
2003	44,674	7,841	44,807	7,811	5.6%	(22.8%)	5.6%	(23.5%)
2004	62,101	16,654	63,455	17,730	39.0%	112.4%	41.6%	127.0%
2005	93,534	17,643	96,447	17,952	50.6%	5.9%	52.0%	1.3%
2006	98,527	16,723	101,592	17,197	5.3%	(5.2%)	5.3%	(4.2%)
2007	105,503	16,686	108,932	17,030	7.1%	(0.2%)	7.2%	(1.0%)
2008	101,903	15,871	105,368	16,119	(3.4%)	(4.9%)	(3.3%)	(5.3%)
2009	94,941	15,869	98,094	15,999	(6.8%)	(0.0%)	(6.9%)	(0.7%)
2010	103,937	21,358	108,069	21,640	9.5%	34.6%	10.2%	35.3%
2011	113,866	20,708	117,681	20,929	9.6%	(3.0%)	8.9%	(3.3%)
2012	131,612	17,421	134,947	17,527	15.6%	(15.9%)	14.7%	(16.3%)
2013	144,858	18,489	148,132	18,570	10.1%	6.1%	9.8%	6.0%
2014	142,251	32,664	146,120	32,671	(1.8%)	76.7%	(1.4%)	75.9%
2015	111,644	18,716	114,827	18,872	(21.5%)	(42.7%)	(21.4%)	(42.2%)
2016	127,374	21,513	130,808	21,803	14.1%	14.9%	13.9%	15.5%
2017	125,794	19,402	128,757	19,625	(1.2%)	(9.8%)	(1.6%)	(10.0%)
2018	110,091	19,521	112,885	19,724	(12.5%)	0.6%	(12.3%)	0.5%

Section 5, Capacity Market

Change: On page 263, update Table 5-4 as follows:

	01-Jan-18			31-May-18			01-Jun-18			31-Dec-18		
Parent Company	ICAP (MW)	Percent of Total ICAP	Rank	ICAP (MW)	Percent of Total ICAP	Rank	ICAP (MW)	Percent of Total ICAP	Rank	ICAP (MW)	Percent of Total ICAP	Rank
Exelon Corporation	23,426.0	13.9%	1	23,423.1	13.8%	1	23,426.8	13.9%	1	22,819.1	13.3%	1
Dominion Resources, Inc.	21,098.5	12.5%	2	20,467.3	12.0%	2	20,610.8	12.2%	2	19,851.9	11.6%	2
FirstEnergy Corp.	15,840.6	9.4%	3	14,959.5	8.8%	4	14,943.3	8.9%	3	14,644.0	8.5%	3
NRG Energy, Inc.	15,756.5	9.3%	4	15,745.0	9.3%	3	13,937.3	8.3%	4	5,116.5	3.0%	10
Dynegy Inc.	12,307.4	7.3%	5									
Talen Energy Corporation	11,527.7	6.8%	6	11,121.2	6.5%	6	10,959.3	6.5%	6	10,959.3	6.4%	5
Vistra Energy Corp.				13,388.2	7.9%	5	12,115.0	7.2%	5	12,082.3	7.0%	4

Change: On page 267, update paragraph as follows:

In the 2021/2022 RPM Base Residual Auction, EMAAC had 4,352.6 MW of CTRs with a total value of ~~$487,459,785~~ $40,877,295, PSEG had 4,990.5 MW of CTRs with a total value of ~~$960,336,601~~ $70,238,159, ATSI had 6,402.8 MW of CTRs with a total value of ~~$1,284,412,293~~ $73,219,252, ComEd had 1,527.9 MW of CTRs with a total value of ~~$129,676,100~~ $30,978,820, and BGE had 5,125.6 MW of CTRs with a total value of ~~$1,584,218,328~~ $112,812,971.

Section 7, Net Revenue

Change: On page 335, update Table 7-7 as follows:

Table 7-7 New entrant 20-year levelized total costs (By plant type (Dollars per installed MW-year))

	20-Year Levelized Total Cost				
	2014	2015	2016	2017	2018
Combustion Turbine	$122,604	$120,675	$119,346	$114,557	$118,116
Combined Cycle	$146,443	$146,300	$148,327	$129,731	$113,641
Coal Plant	$504,050	$517,017	$523,540	$528,701	$562,747
Diesel Plant	$161,746	$170,500	$173,182	$158,817	$154,683
Nuclear Plant	$880,770	$935,659	$963,107	$1,349,850	$1,178,607
On Shore Wind Installation (with 1603 grant)	$198,033	$202,874	$231,310	$188,747	$214,780
Off Shore Wind Installation (with 1603 grant)	-	-	-	-	$683,771 ~~$460,730~~
Solar Installation (with 1603 grant)	$236,289	$234,151	$218,937	$200,931	$232,230

Change: On page 341, update Table 7-24 as follows:

Table 7-24 Percent of 20-year levelized total costs recovered by off shore wind net revenue (Dollars per installed MW-year): 2014 through 2018

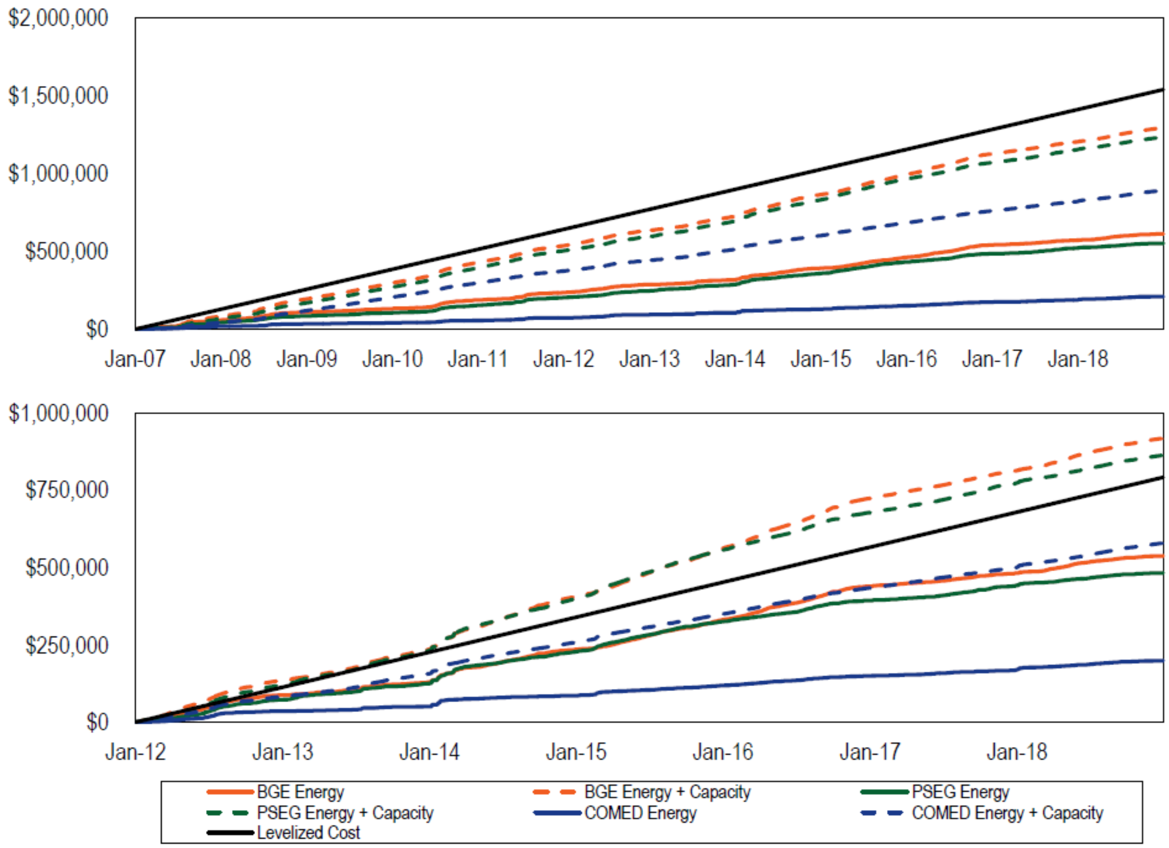
Zone	2014	2015	2016	2017	2018
AECO	40% ~~58%~~	30% ~~44%~~	25% ~~38%~~	28% ~~41%~~	33% ~~49%~~

Change: On page 342, update paragraph as follows:

Total unit net revenues include energy and capacity revenues. Analysis of the total unit revenues of theoretical new entrant CTs and CCs for three representative locations shows that CT and CC units that entered the PJM markets in 2007 have not covered their total costs, including the return on and of capital, on a cumulative basis ~~in the eastern PSEG and BGE zones but have not covered total costs in the western ComEd Zone~~. The analysis also shows that theoretical new entrant CTs and CCs that entered the PJM markets in 2012 have covered their total costs on a cumulative basis in the eastern PSEG and BGE zones but have not covered total costs in the western ComEd Zone. Energy market revenues alone were not sufficient to cover total costs in ~~BGE for a CC unit that entered the PJM markets in 2012 but not for~~ any ~~other~~ scenario, which demonstrates the critical role of the capacity market revenue in covering total costs.

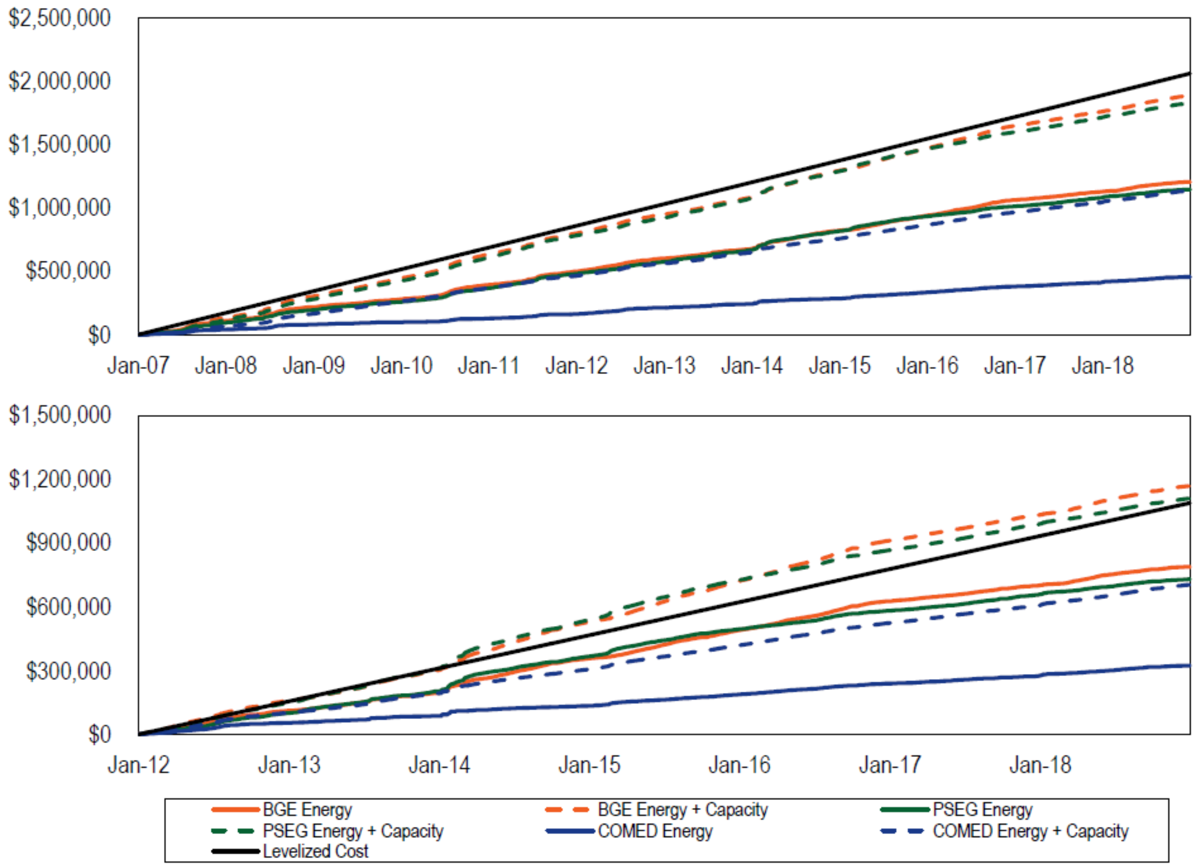
Change: On page 342, update Figure 7-10 as follows:

Figure 7-10 Historical new entrant CT revenue adequacy: January 2007 through December 2018 and January 2012 through December 2018



Change: On page 343, update Figure 7-11 as follows:

Figure 7-11 Historical new entrant CC revenue adequacy: January 2007 through December 2018 and January 2012 through December 2018



Change: On page 343, update sentence as follows:

Energy market revenues alone were not sufficient to cover total costs in ~~BGE for a CC unit that entered the PJM markets in 2012 but not for~~ any ~~other~~ scenario, which demonstrates the critical role of the capacity market revenue in covering total costs.

Section 13, Financial Transmission Rights and Auction Revenue Rights

Change: On page 616, update sentence as follows:

Had this surplus allocation been implemented in the 2017/2018 planning period the percent of congestion offset by ARRs and FTRs would have increased from 50.0 percent to ~~81.1~~74.3 percent.

Change: On page 622, update sentence as follows:

If this rule had been in effect for the 2017/2018 planning period, ARRs and FTRs would have offset ~~81.1~~74.3 percent of total congestion rather than 50.0 percent.

Change: On page 652, update sentence as follows:

ARRs and FTRs would have offset ~~76.8~~74.3 percent of total congestion rather than ~~50.7~~50.0 percent.

Change: On page 653, update sentence as follows:

The actual underpayment to load in the 2017/2018 planning period was ~~$124.9~~$125.8 million with a $370.7 million overpayment to FTR holders.

Change: On page 653, update Table 13-34 as follows:

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%	$563.0	79.8%
2012/2013	$349.5	$181.9	$524.8	($292.3)	$531.4	100.0%	$275.9	52.6%	$257.5	52.6%
2013/2014	$337.7	$456.4	$1,870.6	($678.7)	$794.0	42.4%	$574.1	30.7%	$623.1	30.7%
2014/2015	$482.4	$404.4	$1,357.6	$139.6	$886.8	65.3%	$686.6	50.6%	$715.0	52.7%
2015/2016	$635.3	$223.4	$951.1	$42.5	$858.8	90.3%	$744.8	78.3%	$745.2	78.4%
2016/2017	$640.0	$169.1	$780.8	$72.6	$809.1	100.0%	$727.7	93.2%	$763.8	97.8%
2017/2018	$427.3	$294.2	$1,192.6	$371.2	$721.5	60.5%	$595.7	50.0%	$886.5	74.3%
2018/2019*	$308.9	$91.3	$468.8	$32.5	$417.76	89.1%	$333.1	71.1%	$348.0	74.2%
Total	$3,693.4	$2,070.4	$7,896.0	($505.2)	$5,781.3	73.2%	$4,536.7	57.5%	$4,902.2	62.1%

* Seven months of 2018/2019 planning period