Net Revenue

The Market Monitoring Unit (MMU) analyzed measures of PJM energy market structure, participant conduct and market performance. As part of the review of market performance, the MMU analyzed the net revenues earned by combustion turbine (CT), combined cycle (CC), coal plant (CP), diesel (DS), nuclear (NU), solar, and wind generating units.

Overview

Net Revenue

- Net revenues are significantly affected by fuel prices, energy prices and capacity prices. Coal and natural gas prices and energy prices were lower in the first nine months of 2015 than in the first nine months of 2014. Net revenues from the energy market for all plant types were affected by the lower prices.
- In the first nine months of 2015, average energy market net revenues decreased by 13 percent for a new CT, 18 percent for a new CC, 53 percent for a new CP, 64 percent for a new DS, 39 percent for a new nuclear plant, 20 percent for a new wind installation, and 5 percent for a new solar installation. The comparison to the first nine months of 2014 reflects the very high net revenues in January 2014.

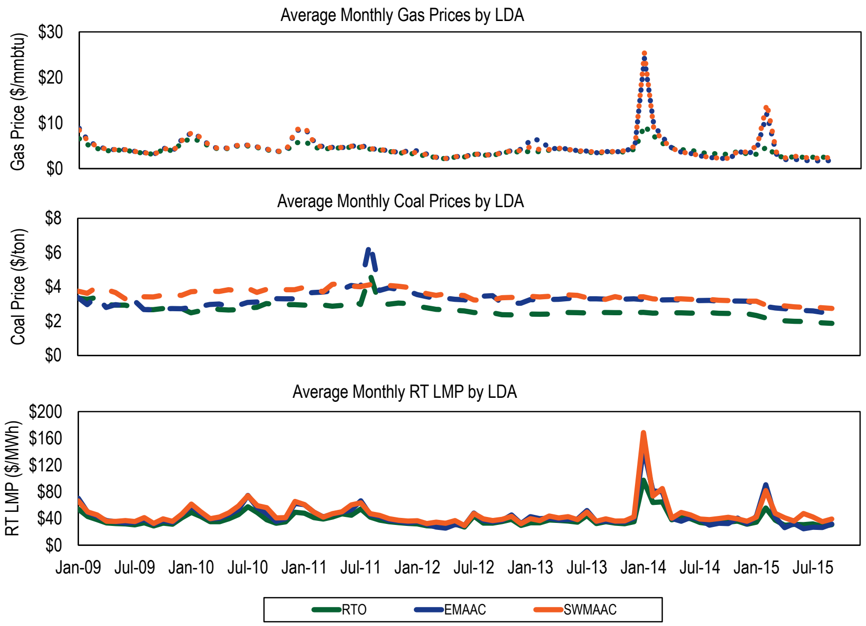
Conclusion

Wholesale electric power markets are affected by externally imposed reliability requirements. A regulatory authority external to the market makes a determination as to the acceptable level of reliability which is enforced through a requirement to maintain a target level of installed or unforced capacity. The requirement to maintain a target level of installed capacity can be enforced via a variety of mechanisms, including government construction of generation, full-requirement contracts with developers to construct and operate generation, state utility commission mandates to construct capacity, or capacity markets of various types. Regardless of the enforcement mechanism, the exogenous requirement to construct capacity in excess of what is constructed in response to energy market signals has an impact on energy markets. The reliability requirement results in maintaining a level of capacity in excess of the level that would result from the operation of an energy market alone. The result of that additional capacity is to reduce the level and volatility of energy market prices and to reduce the duration of high energy market prices. This, in turn, reduces net revenue to generation owners which reduces the incentive to invest. The exact level of both aggregate and locational excess capacity is a function of the calculation methods used by RTOs and ISOs.

Net Revenue

Net revenues are significantly affected by energy prices, fuel prices and capacity prices. The real-time load-weighted average LMP was 33.5 percent lower in the first nine months of 2015 than in the first nine months of 2014, $38.94 per MWh versus $58.60 per MWh. Coal and natural gas prices decreased in 2015. Comparing fuel prices in the first nine months of 2015 to the first nine months of 2014, the price of Northern Appalachian coal was 19.6 percent lower; the price of Central Appalachian coal was 22.9 percent lower; the price of Powder River Basin coal was 12.0 percent lower; the price of eastern natural gas was 42.3 percent lower; and the price of western natural gas was 50.0 percent lower (Figure 7-1).

Figure 7-1 Energy market net revenue factor trends: 2009 through 2015



Theoretical Energy Market Net Revenue

The net revenues presented in this section are theoretical as they are based on explicitly stated assumptions about how a new unit with specific characteristics would operate under economic dispatch. The economic dispatch uses technology specific operating constraints in the calculation of a new entrant's operations and potential net revenue in PJM markets. All technology specific, zonal net revenue calculations included in the new entrant net revenue analysis in this section are based on this economic dispatch scenario.

Analysis of energy market net revenues for a new entrant includes seven power plant configurations:

- The CT plant has an installed capacity of 641.2 MW and consists of two GE Frame 7HA.02 CTs, equipped with full inlet air mechanical refrigeration and selective catalytic reduction (SCR) for NO_x reduction.
- The CC plant has an installed capacity of 971.4 MW and consists of two GE Frame 7HA.02 CTs equipped with evaporative cooling, duct burners, a heat recovery steam generator (HRSG) for each CT with steam reheat and SCR for NO_x reduction with a single steam turbine generator.[1]
- The CP has an installed capacity of 600.0 MW and is a sub-critical steam unit, equipped with selective catalytic reduction system (SCR) for NO_x control, a flue gas desulphurization (FGD) system with chemical injection for SO_x and mercury control, and a bag-house for particulate control.
- The DS plant has an installed capacity of 2.0 MW and consists of one oil fired CAT 2 MW unit.
- The nuclear plant has an installed capacity of 2,200 MW and consists of two nuclear power units and related facilities using the Westinghouse AP1000 technology.
- The wind installation consists of twenty two Siemens 2.3 MW wind turbines totaling 50.6 MW installed capacity.
- The solar installation consists of a 60 acre ground mounted solar farm totaling 10 MW of AC capacity.

Net revenue calculations for the CT, CC and CP include the hourly effect of actual local ambient air temperature on plant heat rates and generator output for each of the three plant configurations.[2] [3] Plant heat rates account for the efficiency changes and corresponding cost changes resulting from ambient air temperatures.

NO_x and SO_2 emission allowance costs are included in the hourly plant dispatch cost. These costs are included in the definition of marginal cost. NO_x and SO_2 emission allowance costs were obtained from actual historical daily spot cash prices.[4]

A forced outage rate for each class of plant was calculated from PJM data and incorporated into all revenue calculations.[5] Each CT, CC, CP, and DS

1 The duct burner firing dispatch rate is developed using the same methodology as for the unfired dispatch rate, with adjustments to the duct burner fired heat rate and output.
2 Hourly ambient conditions supplied by Schneider Electric.
3 Heat rates provided by Pasteris Energy, Inc. No-load costs are included in the dispatch price since each unit type is dispatched at full load for every economic hour resulting in a single offer point.
4 NO_x and SO_2 emission daily prompt prices obtained from Evolution Markets, Inc.
5 Outage figures obtained from the PJM eGADS database.

plant was also given a continuous 14 day planned annual outage in the fall season. Ancillary service revenues for the provision of synchronized reserve service for all four plant types were set to zero. Ancillary service revenues for the provision of regulation service were calculated for the CP only. The regulation offer price was the sum of the calculated hourly cost to supply regulation service plus an adder of $12 per PJM market rules. This offer price was compared to the hourly clearing price in the PJM Regulation Market. If the reference CP could provide regulation more profitably than energy, the unit was assumed to provide regulation during that hour. No black start service capability is assumed for any of the unit types.

Zonal net revenues reflect zonal fuel costs based on locational fuel indices, actual unit consumption patterns, and zone specific delivery charges.[6] The delivered fuel cost for natural gas reflects the zonal, daily delivered price of natural gas and is from published commodity daily cash prices, with a basis adjustment for transportation costs.[7] The delivered cost of coal reflects the zone specific, delivered price of coal and was developed from the published prompt-month price, adjusted for rail transportation cost.[8]

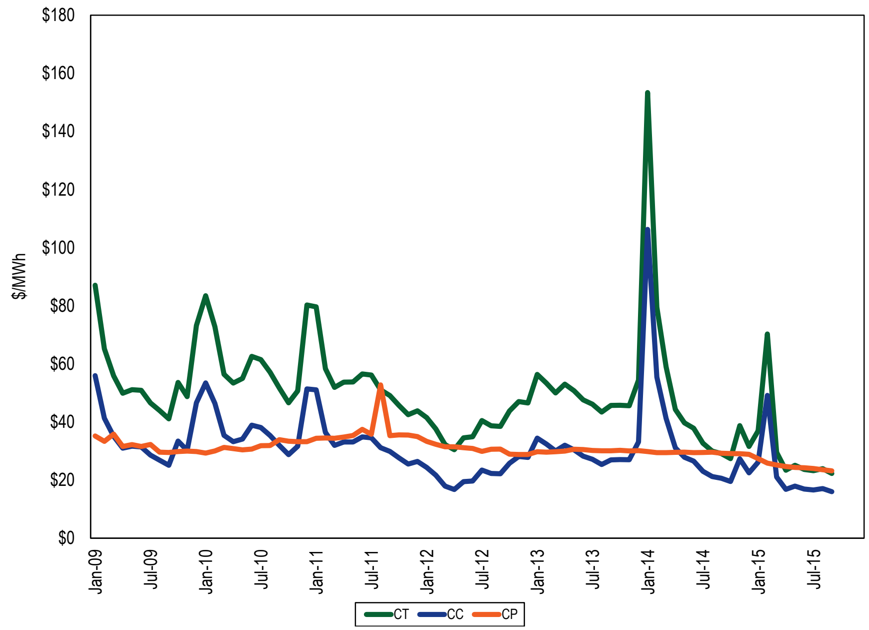
Operating costs are the short run marginal cost of operations and include fuel costs, emissions costs, and VOM costs.[9] [10] Average operating costs are shown in Table 7-1.

Table 7-1 Average operating costs: January through September, 2015

Unit Type	Operating Costs ($/MWh)	Heat Rate (Btu/kWh)	VOM ($/MWh)
CT	$31.51	9,476	$0.25
CC	$22.36	6,667	$1.00
CP	$25.74	9,250	$4.00
DS	$115.04	9,660	$0.25
Nuclear	$8.50	NA	$3.00
Wind	$0.00	NA	$0.00
Solar	$0.00	NA	$0.00

A comparison of the operating costs of the theoretical CT, CC and CP plants since January 2009 shows that the CC plant has been competitive with the CP plant but that the costs of the CC plant have been more volatile than the costs of the CP plant as a result of the higher volatility of gas prices compared to coal prices (Figure 7-2). A significant increase in gas prices on cold days resulted in a corresponding increase in the average operating cost of CTs and CCs in January 2014 and February 2015 (Figure 7-2).

Figure 7-2 Average operating costs: 2009 through 2015



The net revenue measure does not include the potentially significant contribution from the explicit or implicit sale of the option value of physical units or from bilateral agreements to sell output at a price other than the PJM day-ahead or real-time energy market prices, e.g., a forward price.

6 Startup fuel burns and emission rates provided by Pasteris Energy, Inc. Startup station power consumption costs were obtained from the station service rates published quarterly by PJM and netted against the MW produced during startup at the preceding applicable hourly LMP. All starts associated with combined cycle units are assumed to be hot starts.
7 Gas daily cash prices obtained from Platts.
8 Coal prompt prices obtained from Platts.
9 Fuel costs are calculated using the daily spot price and may not equal what participants actually paid.
10 VOM rates provided by Pasteris Energy, Inc.

New Entrant Combustion Turbine

Energy market net revenue was calculated for a CT plant dispatched by PJM. For this economic dispatch, it was assumed that the CT plant had a minimum run time of four hours. The unit was first committed day ahead in profitable blocks of at least four hours, including start costs. If the unit was not already committed day ahead, it was then run in real time in standalone profitable blocks of at least four hours, or any profitable hours bordering the profitable day ahead or real time block.

New entrant CT plant energy market net revenues were lower in most zones in the first nine months of 2015 (Table 7-2).

Table 7-2 Energy net revenue for a new entrant gas-fired CT under economic dispatch (Dollars per installed MW-year)[11]

Zone	2009 (Jan-Sep)	2010 (Jan-Sep)	2011 (Jan-Sep)	2012 (Jan-Sep)	2013 (Jan-Sep)	2014 (Jan-Sep)	2015 (Jan-Sep)	Change in 2015 from 2014
AECO	$11,373	$35,954	$43,565	$21,303	$17,972	$41,110	$40,510	(1%)
AEP	$3,275	$9,026	$19,149	$14,157	$11,646	$37,625	$28,375	(25%)
AP	$10,188	$24,704	$30,657	$18,615	$14,978	$50,982	$41,894	(18%)
ATSI	NA	NA	$13,388	$15,803	$13,855	$43,838	$30,833	(30%)
BGE	$13,644	$45,815	$45,074	$31,989	$24,917	$59,043	$47,466	(20%)
ComEd	$2,286	$8,696	$14,680	$12,326	$9,863	$17,815	$13,810	(22%)
DAY	$2,866	$9,477	$19,874	$15,784	$11,588	$38,328	$28,200	(26%)
DEOK	NA	NA	NA	$13,639	$11,005	$49,076	$59,980	22%
DLCO	$3,366	$14,995	$21,486	$16,821	$12,550	$33,939	$24,888	(27%)
Dominion	$14,315	$36,788	$36,231	$22,101	$19,400	$30,533	$26,051	(15%)
DPL	$12,718	$36,445	$41,528	$28,178	$21,180	$48,050	$29,245	(39%)
EKPC	NA	NA	NA	NA	$9,267	$51,012	$61,204	20%
JCPL	$10,527	$34,096	$41,387	$20,107	$22,451	$42,645	$40,378	(5%)
Met-Ed	$9,982	$34,786	$38,158	$21,141	$17,105	$38,188	$38,510	1%
PECO	$9,703	$33,483	$43,259	$21,996	$16,912	$39,250	$37,696	(4%)
PENELEC	$6,276	$17,766	$30,056	$19,505	$17,857	$75,568	$80,362	6%
Pepco	$16,205	$43,945	$41,106	$28,435	$23,260	$54,147	$38,126	(30%)
PPL	$9,104	$29,513	$40,481	$18,865	$16,872	$39,083	$37,989	(3%)
PSEG	$9,172	$33,308	$35,125	$19,683	$17,003	$34,477	$21,756	(37%)
RECO	$7,838	$30,977	$29,697	$18,039	$19,858	$33,877	$23,608	(30%)
PJM	$8,990	$28,222	$32,494	$19,920	$16,477	$42,929	$37,544	(13%)

11 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.

New Entrant Combined Cycle

Energy market net revenue was calculated for a CC plant dispatched by PJM. For this economic dispatch scenario, it was assumed that the CC plant had a minimum run time of eight hours. The unit was first committed day-ahead in profitable blocks of at least eight hours, including start costs.[12] If the unit was not already committed day ahead, it was then run in real time in standalone profitable blocks of at least eight hours, or any profitable hours bordering the profitable day-ahead or real-time block.

New entrant CC plant energy market net revenues were lower in all zones in the first nine months of 2015 (Table 7-3).

Table 7-3 Energy net revenue for a new entrant CC under economic dispatch (Dollars per installed MW-year)[13]

Zone	2009 (Jan-Sep)	2010 (Jan-Sep)	2011 (Jan-Sep)	2012 (Jan-Sep)	2013 (Jan-Sep)	2014 (Jan-Sep)	2015 (Jan-Sep)	Change in 2015 from 2014
AECO	$53,515	$88,338	$107,345	$79,262	$66,991	$86,678	$75,230	(13%)
AEP	$25,716	$35,573	$62,444	$72,292	$53,370	$73,300	$62,655	(15%)
AP	$51,473	$66,543	$90,972	$81,760	$62,573	$92,278	$79,346	(14%)
ATSI	NA	NA	$34,423	$75,787	$61,182	$83,204	$65,720	(21%)
BGE	$56,858	$101,942	$104,714	$100,014	$81,174	$117,214	$85,849	(27%)
ComEd	$18,383	$30,284	$40,529	$54,535	$36,458	$36,548	$35,371	(3%)
DAY	$23,596	$36,247	$61,392	$76,299	$55,564	$74,819	$62,820	(16%)
DEOK	NA	NA	NA	$67,497	$52,614	$93,594	$93,138	(0%)
DLCO	$22,923	$41,189	$61,420	$74,205	$50,180	$62,045	$56,044	(10%)
Dominion	$58,612	$93,795	$92,410	$84,249	$67,406	$68,933	$60,332	(12%)
DPL	$55,142	$88,420	$103,215	$90,497	$72,018	$102,423	$62,660	(39%)
EKPC	NA	NA	NA	NA	$29,517	$95,456	$93,339	(2%)
JCPL	$52,935	$85,690	$103,881	$78,139	$73,748	$89,651	$74,722	(17%)
Met-Ed	$47,338	$83,009	$92,173	$75,362	$64,216	$79,440	$70,372	(11%)
PECO	$49,620	$83,203	$102,742	$77,573	$62,394	$82,267	$71,171	(13%)
PENELEC	$42,010	$57,593	$87,881	$83,376	$77,731	$132,038	$115,201	(13%)
Pepco	$58,923	$100,141	$97,362	$94,094	$77,961	$109,236	$73,707	(33%)
PPL	$45,115	$73,814	$93,818	$71,777	$62,118	$80,848	$70,582	(13%)
PSEG	$50,355	$84,626	$94,511	$74,474	$66,000	$81,762	$48,937	(40%)
RECO	$44,897	$78,524	$77,170	$70,231	$71,256	$79,300	$49,956	(37%)
PJM	$44,553	$72,290	$83,800	$77,970	$62,224	$86,052	$70,358	(18%)

12 All starts associated with combined cycle units are assumed to be hot starts.
13 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.

New Entrant Coal Plant

Energy market net revenue was calculated assuming that the CP plant had a 24-hour minimum run time and was dispatched day ahead by PJM for all available plant hours. The calculations include operating reserve credits based on PJM rules, when applicable, since the assumed operation is under the direction of PJM. Regulation revenue is calculated for any hours in which the new entrant CP's regulation offer is below the regulation-clearing price.

New entrant CP plant energy market net revenues were lower in all zones in the first nine months of 2015 (Table 7-4).

Table 7-4 Energy net revenue for a new entrant CP (Dollars per installed MW-year)[14]

Zone	2009 (Jan-Sep)	2010 (Jan-Sep)	2011 (Jan-Sep)	2012 (Jan-Sep)	2013 (Jan-Sep)	2014 (Jan-Sep)	2015 (Jan-Sep)	Change in 2015 from 2014
AECO	$67,257	$123,525	$73,347	$14,772	$33,333	$160,383	$66,414	(59%)
AEP	$13,379	$48,458	$63,670	$24,202	$63,464	$139,583	$74,385	(47%)
AP	$36,322	$81,508	$88,159	$35,622	$71,702	$162,999	$94,881	(42%)
ATSI	NA	NA	$20,154	$30,575	$70,204	$152,280	$80,334	(47%)
BGE	$36,606	$65,752	$56,066	$16,709	$40,323	$191,226	$94,700	(50%)
ComEd	$30,169	$92,893	$81,958	$42,581	$48,494	$112,953	$48,679	(57%)
DAY	$19,206	$65,403	$55,551	$25,318	$73,127	$141,664	$70,400	(50%)
DEOK	NA	NA	NA	$21,047	$64,970	$131,031	$65,902	(50%)
DLCO	$14,410	$67,832	$44,901	$34,154	$17,243	$76,502	$30,077	(61%)
Dominion	$36,506	$119,130	$75,015	$11,634	$86,199	$202,678	$118,465	(42%)
DPL	$30,404	$121,440	$92,578	$19,940	$33,867	$193,558	$90,509	(53%)
EKPC	NA	NA	NA	NA	$20,243	$116,716	$55,882	(52%)
JCPL	$57,382	$121,034	$69,361	$15,697	$38,650	$166,193	$67,326	(59%)
Met-Ed	$45,652	$117,561	$60,001	$18,898	$31,734	$155,294	$64,372	(59%)
PECO	$60,767	$118,052	$73,109	$16,775	$30,480	$158,325	$65,534	(59%)
PENELEC	$59,243	$99,175	$85,430	$34,897	$81,468	$172,861	$97,596	(44%)
Pepco	$54,534	$133,117	$71,482	$18,183	$37,535	$180,022	$79,832	(56%)
PPL	$55,246	$96,923	$75,822	$11,838	$30,409	$155,768	$64,493	(59%)
PSEG	$135,308	$103,660	$47,426	$15,675	$51,343	$186,490	$75,263	(60%)
RECO	$54,556	$118,402	$57,467	$15,229	$56,616	$179,766	$75,220	(58%)
PJM	$47,467	$99,639	$66,194	$22,302	$49,070	$156,815	$74,013	(53%)

14 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.

New Entrant Diesel

Energy market net revenue was calculated assuming that the DS plant was economically dispatched on an hourly basis based on the real-time LMP.

New entrant DS plant energy market net revenues were lower in all zones in the first nine months of 2015 (Table 7-5).

Table 7-5 PJM energy market net revenue for a new entrant DS (Dollars per installed MW-year)

Zone	2009 (Jan-Sep)	2010 (Jan-Sep)	2011 (Jan-Sep)	2012 (Jan-Sep)	2013 (Jan-Sep)	2014 (Jan-Sep)	2015 (Jan-Sep)	Change in 2015 from 2014
AECO	$3,632	$9,668	$6,783	$1,420	$1,122	$37,235	$13,581	(64%)
AEP	$367	$485	$1,725	$807	$503	$15,989	$4,933	(69%)
AP	$2,019	$1,379	$2,019	$1,044	$771	$20,833	$9,290	(55%)
ATSI	NA	NA	$318	$1,057	$23,776	$15,705	$4,876	(69%)
BGE	$4,946	$11,657	$7,902	$2,498	$2,644	$55,889	$21,143	(62%)
ComEd	$96	$473	$817	$928	$399	$12,544	$2,954	(76%)
DAY	$354	$537	$1,906	$926	$535	$15,790	$4,922	(69%)
DEOK	NA	NA	NA	$682	$477	$14,918	$4,466	(70%)
DLCO	$677	$2,736	$2,180	$910	$1,198	$14,417	$4,582	(68%)
Dominion	$4,689	$8,837	$4,043	$1,642	$1,562	$47,537	$13,369	(72%)
DPL	$4,776	$8,382	$5,842	$2,254	$1,125	$43,571	$20,072	(54%)
EKPC	NA	NA	NA	NA	NA	$15,939	$3,913	(75%)
JCPL	$3,534	$6,856	$6,681	$1,589	$2,079	$37,336	$14,746	(61%)
Met-Ed	$3,190	$7,397	$5,093	$1,708	$1,292	$36,190	$14,615	(60%)
PECO	$3,161	$7,326	$5,446	$1,813	$1,024	$36,580	$13,603	(63%)
PENELEC	$782	$912	$2,671	$2,088	$1,141	$18,475	$7,828	(58%)
Pepco	$5,170	$10,551	$6,029	$1,978	$2,207	$57,314	$14,709	(74%)
PPL	$2,941	$6,569	$5,366	$1,640	$1,088	$37,104	$14,469	(61%)
PSEG	$3,030	$6,306	$5,519	$1,579	$1,302	$37,021	$14,299	(61%)
RECO	$2,588	$5,255	$4,310	$1,647	$2,469	$34,359	$15,806	(54%)
PJM	$2,703	$5,607	$4,147	$1,485	$2,459	$30,237	$10,909	(64%)

New Entrant Nuclear Plant

Energy market net revenue for a nuclear plant was calculated by assuming the unit was dispatched day ahead by PJM. The unit runs for all hours of the year.

New entrant nuclear plant energy market net revenues were lower in all zones in the first nine months of 2015 (Table 7-6).

Table 7-6 Energy net revenue for a new entrant nuclear plant (Dollars per installed MW-year)[15]

Zone	2009 (Jan-Sep)	2010 (Jan-Sep)	2011 (Jan-Sep)	2012 (Jan-Sep)	2013 (Jan-Sep)	2014 (Jan-Sep)	2015 (Jan-Sep)	Change in 2015 from 2014
AECO	$220,444	$283,596	$283,503	$163,202	$201,009	$338,646	$193,506	(43%)
AEP	$165,079	$199,798	$211,586	$146,910	$176,738	$257,847	$166,444	(35%)
AP	$195,683	$240,187	$241,006	$156,085	$185,986	$284,798	$189,999	(33%)
ATSI	NA	NA	$99,825	$150,207	$184,807	$271,947	$170,677	(37%)
BGE	$224,368	$302,330	$284,113	$183,600	$218,045	$381,897	$247,779	(35%)
ComEd	$132,962	$175,483	$177,828	$133,546	$159,147	$226,449	$135,395	(40%)
DAY	$160,936	$198,821	$210,644	$151,009	$179,154	$261,071	$167,080	(36%)
DEOK	NA	NA	NA	$141,979	$169,935	$248,818	$161,792	(35%)
DLCO	$155,568	$199,157	$207,369	$148,505	$172,976	$239,409	$156,760	(35%)
Dominion	$213,382	$286,412	$265,261	$166,221	$202,566	$330,659	$217,385	(34%)
DPL	$222,294	$285,118	$283,081	$173,940	$209,085	$364,267	$214,996	(41%)
EKPC	NA	NA	NA	NA	$74,659	$244,774	$153,903	(37%)
JCPL	$219,404	$280,306	$279,836	$161,878	$207,587	$342,907	$192,171	(44%)
Met-Ed	$212,079	$275,729	$265,977	$158,601	$197,535	$326,222	$185,055	(43%)
PECO	$215,347	$277,735	$278,425	$161,432	$196,192	$330,703	$187,210	(43%)
PENELEC	$189,728	$235,110	$240,027	$157,976	$195,363	$297,750	$183,926	(38%)
Pepco	$225,419	$299,684	$276,796	$177,902	$214,271	$368,649	$229,505	(38%)
PPL	$209,319	$265,668	$267,172	$154,991	$195,457	$327,259	$185,489	(43%)
PSEG	$223,101	$285,232	$285,000	$165,137	$222,893	$365,127	$203,176	(44%)
RECO	$216,226	$277,469	$264,609	$160,626	$228,625	$358,855	$204,483	(43%)
PJM	$200,079	$256,932	$245,670	$158,618	$189,601	$308,403	$187,337	(39%)

15 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.

New Entrant Wind Installation

Energy market net revenues for a wind installation located in the ComEd and PENELEC zones were calculated hourly assuming the unit was generating at the average capacity factor if 75 percent of existing wind units in the zone were generating power in that hour. Energy market net revenues for a wind installation include revenue from the Production Tax Credit (PTC) of $23 per MWh, from the Investment Tax Credit of $1 per MWh, and from Renewable Energy Certificates (RECs) of $1.24/MWh in ComEd and $14.81/MWh in PENELEC.[16]

Wind energy market net revenues were lower in the first nine months of 2015 (Table 7-7).

Table 7-7 Energy market net revenue for a wind installation (Dollars per installed MW-year)

Zone	2012 (Jan-Sep)	2013 (Jan-Sep)	2014 (Jan-Sep)	2015 (Jan-Sep)	Change in 2015 from 2014
ComEd	$51,905	$59,653	$134,328	$106,295	(21%)
PENELEC	$87,762	$117,931	$162,540	$130,524	(20%)

New Entrant Solar Installation

Energy market net revenues for a solar installation located in the PSEG Zone were calculated hourly assuming the unit was generating at the average capacity factor if 75 percent of existing solar units in the zone were generating power in that hour. Energy market net revenues for a solar installation in New Jersey include revenue from Solar Renewable Energy Certificates (SRECs) of $161.88/MWh.[17]

Solar energy market net revenues were lower in the first nine months of 2015 (Table 7-8).

Table 7-8 PSEG Energy Market net revenue for a solar installation (Dollars per installed MW-year)

Zone	2012 (Jan-Sep)	2013 (Jan-Sep)	2014 (Jan-Sep)	2015 (Jan-Sep)	Change in 2015 from 2014
PSEG	$314,402	$307,180	$327,944	$311,322	(5%)

Spark Spreads, Dark Spreads, and Quark Spreads

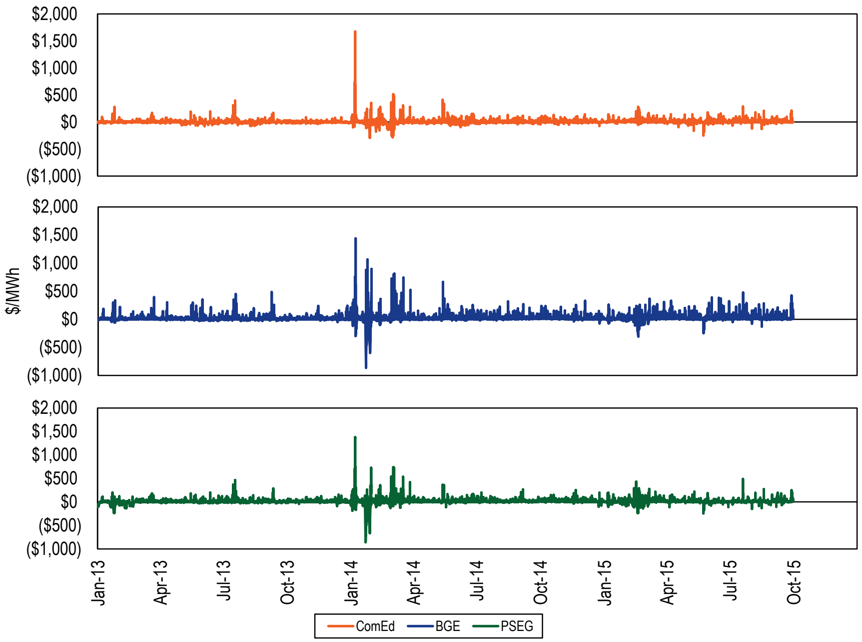
The spark, dark, or quark spread is defined as the difference in $/MWh between the LMP received for selling power and the cost of fuel used to generate power. The spark spread compares power prices to the price of gas, the dark spread compares power prices to the price of coal, and the quark spread compares power prices to the price of of uranium. The spread is a measure of the difference between revenues and fuel costs and is an indicator of net revenue and profitability.

Spread volatility is a result of fluctuations in LMP and the price of fuel. Spreads can be positive or negative.

16 REC prices provided by Evolution Markets.
17 SREC prices provided by Evolution Markets.

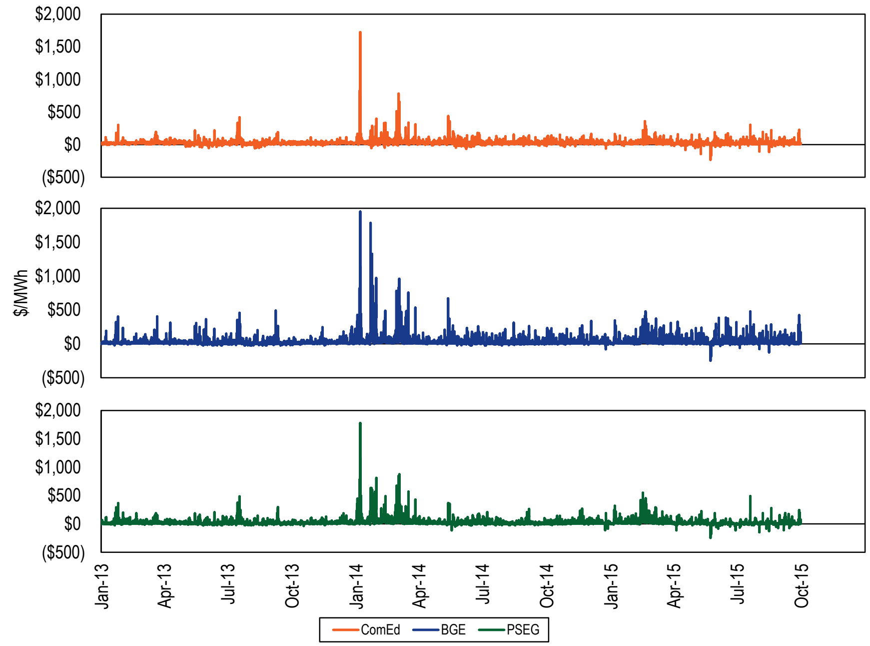
Figure 7-3 shows the spark spread since January 2013 for three PJM zones.[18] The average spark spread for the period January 2013 through September 2015 was $2.27 per MWh for ComEd, $14.03/MWh for BGE, and $5.24/MWh for PSEG.

Figure 7-3 Spark spread for selected zones: 2013 through 2015



The average dark spread for the period January 2013 through September 2015 was $27.48 per MWh for ComEd, $28.16/MWh for BGE, and $22.81/MWh for PSEG.

Figure 7-4 Dark spread for selected zones: 2013 through 2015[19]

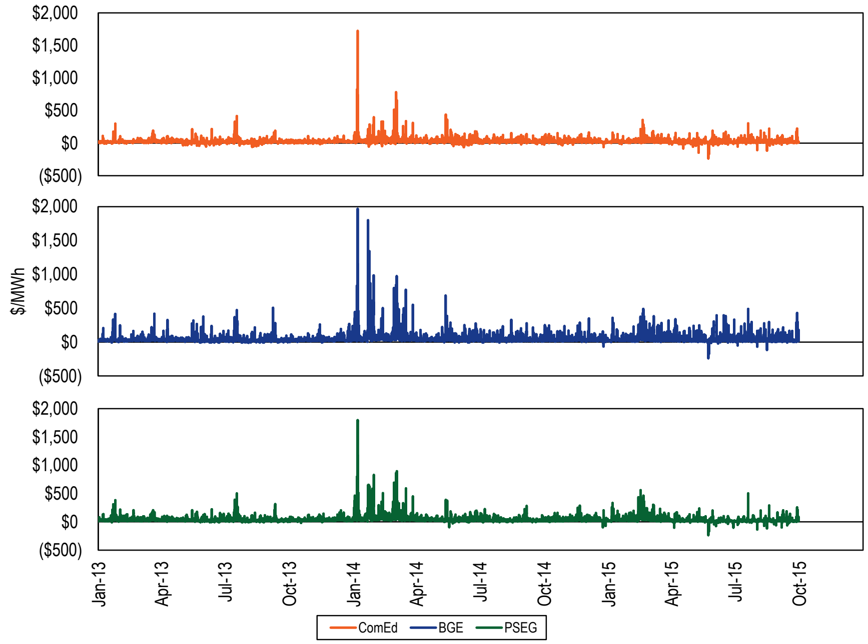


18 Spark spreads use a heat rate of 7,500 Btu/kWh, zonal LMPs and gas prices at Chicago City Gate for ComEd, Zone 6 Non-NY for BGE, and Zone 6 NY for PSEG.

19 Dark spreads use a heat rate of 10,000 Btu/kWh, zonal LMPs and Powder River Basin coal for ComEd, Northern Appalachian coal for BGE, and Central Appalachian coal for PSEG.

The average quark spread for the period January 2013 through September 2015 was $27.11 per MWh for ComEd, $41.77/MWh for BGE, and $38.31/MWh for PSEG.

Figure 7-5 Quark spread for selected zones: 2013 through 2015[20]



20 Quark spreads use a heat rate of 10,000 Btu/kWh and zonal LMPs.