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 (NP), solar, and wind generating units.

Overview

Net Revenue

- Energy net revenues are significantly affected by energy prices and fuel prices. Energy prices were significantly lower in the first six months of 2019 than in the first six months of 2018 as a result of lower gas prices. Coal prices were slightly higher.
- In the first six months of 2019, average energy market net revenues decreased by 65 percent for a new CT, 44 percent for a new CC, 87 percent for a new CP, 34 percent for a new nuclear plant, 87 percent for a new DS, 30 percent for a new on shore wind installation, 30 percent for a new off shore wind installation and 23 percent for a new solar installation compared to the first six months of 2018.
- The relative prices of fuel varied during the first six months of 2019. As a result, the marginal cost of the new CC was consistently below that of the new CP in 2018, and the marginal cost of the new CT was above that of the new CP in January.
- Nuclear unit revenue is a combination of energy market revenue and capacity market revenue. Negative prices do not have a significant impact on nuclear unit revenue. Since 2014, negative prices have affected nuclear plants' annual revenues by an average of 0.1 percent.[1]

Historical New Entrant CT and CC Revenue Adequacy

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. The analysis also shows that theoretical new entrant CTs 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. Theoretical new entrant CCs that entered the PJM markets in 2012 have covered their total costs on a cumulative basis in the BGE Zone but have not covered total costs in the PSEG or ComEd Zones. Energy market revenues alone were not sufficient to cover total costs in any scenario, which demonstrates the critical role of the capacity market revenue in covering total costs.

1 Analysis is based on actual unit generation and received energy market and capacity market revenues. Negative prices in the DA and RT market were set to zero for the comparison.

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.

Unlike cost of service regulation, markets do not guarantee that units will cover their costs. 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. CCs that entered the PJM markets in 2012 have covered their total costs on a cumulative basis in the BGE zone but have not covered total costs in the PSEG or ComEd Zones. Energy market revenues alone were not sufficient to cover total costs in any scenario, which demonstrates the critical role of the capacity market revenue in covering total costs.

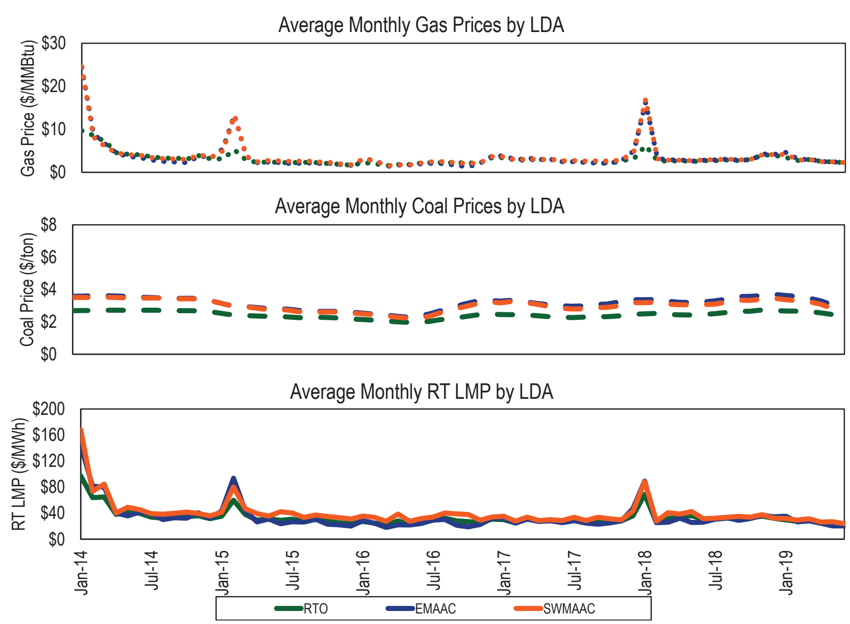
Net Revenue

When compared to annualized fixed costs and avoidable costs, net revenue is an indicator of generation investment profitability, and thus is a measure of overall market performance as well as a measure of the incentive to invest in new generation to serve PJM markets. Net revenue equals total revenue received by generators from PJM energy, capacity and ancillary service markets and from the provision of black start and reactive services less the short run marginal costs of energy production. In other words, net revenue is the amount that remains, after the short run marginal costs of energy production have been subtracted from gross revenue. Net revenues cover fixed costs, which include a return on investment, depreciation and income taxes, and avoidable costs, which include long term and intermediate term operation and maintenance expenses. Net revenue is the contribution to total fixed and avoidable costs received by generators from all PJM markets.

In a perfectly competitive, energy only market in long run equilibrium, net revenue from the energy market would be expected to equal the total of all annualized fixed and avoidable costs for the marginal unit, including a competitive return on investment. The PJM market design includes other markets intended to contribute to the payment of fixed and avoidable costs. In PJM, the energy, capacity and ancillary service markets are all significant sources of revenue to cover the fixed and avoidable costs of generators, as are payments for the provision of black start and reactive services. Thus, in a perfectly competitive market in long run equilibrium, with energy, capacity and ancillary service revenues, net revenue from all sources would be expected to equal the annualized fixed and avoidable costs of generation for the marginal unit. Net revenue is a measure of whether generators are receiving competitive returns on invested capital and of whether market prices are high enough to encourage entry of new capacity. In actual wholesale power markets, where equilibrium seldom occurs, net revenue is expected to fluctuate above and below the equilibrium level based on actual conditions in all relevant markets.

Net revenues are significantly affected by energy prices, fuel prices and capacity prices. The load-weighted, average real-time LMP was 35.2 percent lower in the first six months of 2019 than in the first six months of 2018, $27.49 per MWh versus $42.44 per MWh. Eastern and western natural gas prices decreased in the first six months of 2019. The price of Northern Appalachian coal was 1.1 percent higher; the price of Central Appalachian coal was 4.9 percent higher; the price of Powder River Basin coal was 0.1 percent lower; the price of eastern natural gas was 43.4 percent lower; and the price of western natural gas was 4.6 percent lower (Figure 7-1).

Figure 7-1 Energy market net revenue factor trends: 2014 through June 2019



Spark Spreads, Dark Spreads, and Quark Spreads

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

$$Spread\left(\frac{\$}{MWh}\right) = LMP\left(\frac{\$}{MWh}\right) - Fuel\ Price\left(\frac{\$}{MMBtu}\right) * Heat\ Rate\left(\frac{MMBtu}{MWh}\right)$$

Spread volatility is a result of fluctuations in LMP and the price of fuel. Spreads can be positive or negative. Spreads are lower in the first six months of 2019 as a result of lower energy prices.

Table 7-1 shows average peak hour spreads by year and Table 7-2 shows the associated standard deviation.

Table 7-1 Peak hour spreads ($/MWh): 2014 through June 2019

	BGE			ComEd			PSEG			Western Hub		
	Spark	Dark	Quark	Spark	Dark	Quark	Spark	Dark	Quark	Spark	Dark	Quark
2014	$30.27	$51.11	$66.58	$11.14	$42.50	$43.23	$19.85	$43.01	$60.19	$23.23	$39.58	$55.05
2015	$25.86	$34.71	$44.42	$14.48	$27.68	$26.98	$13.53	$23.38	$34.31	$23.59	$25.29	$35.00
2016	$28.29	$28.11	$38.32	$14.22	$25.72	$26.58	$13.44	$10.80	$24.06	$21.47	$18.53	$28.75
2017	$16.77	$18.41	$33.20	$11.81	$25.40	$28.19	$12.80	$10.89	$29.97	$16.30	$15.71	$30.50
2018	$15.64	$25.17	$41.16	$12.42	$26.62	$29.27	$7.61	$12.35	$34.23	$15.83	$21.05	$37.04
2019 (Jan-Jun)	$13.07	$13.24	$27.18	$9.07	$20.89	$22.47	$8.00	$3.31	$24.25	$10.42	$10.63	$24.58

Table 7-2 Peak hour spread standard deviation ($/MWh): 2014 through June 2019

	BGE			ComEd			PSEG			Western Hub		
	Spark	Dark	Quark	Spark	Dark	Quark	Spark	Dark	Quark	Spark	Dark	Quark
2014	$88.1	$118.9	$118.9	$68.1	$68.3	$68.3	$78.3	$94.0	$94.3	$83.0	$86.7	$86.7
2015	$42.4	$44.9	$45.0	$20.8	$22.5	$22.5	$32.7	$40.9	$41.1	$31.3	$33.1	$33.4
2016	$32.8	$32.6	$32.6	$16.4	$16.6	$16.8	$17.0	$18.6	$18.4	$19.1	$18.5	$18.5
2017	$23.5	$25.0	$25.0	$19.8	$19.9	$19.9	$19.9	$22.9	$23.0	$23.2	$22.5	$22.6
2018	$50.5	$36.9	$36.9	$17.0	$18.0	$17.9	$51.9	$33.3	$33.2	$42.3	$30.5	$30.4
2019 (Jan-Jun)	$24.3	$24.9	$24.9	$18.9	$19.0	$19.0	$21.5	$25.6	$26.0	$20.2	$20.0	$20.1

Figure 7-2 shows the hourly spark spread, Figure 7-3 shows the hourly dark spread, and Figure 7-4 shows the hourly quark spread for peak hours for BGE, ComEd, PSEG, and Western Hub.

Figure 7-2 Hourly spark spread (gas) for peak hours ($/MWh): 2018 through June 2019[2]

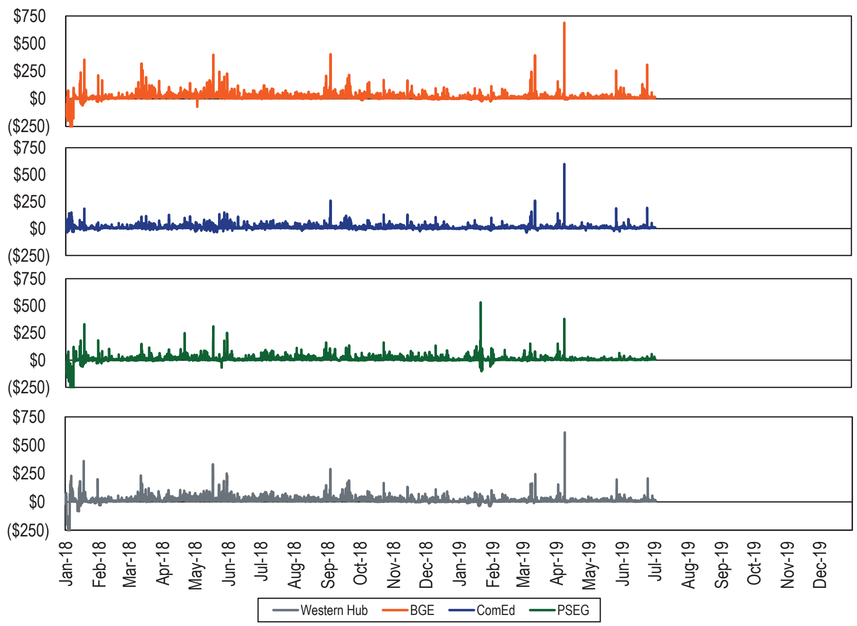
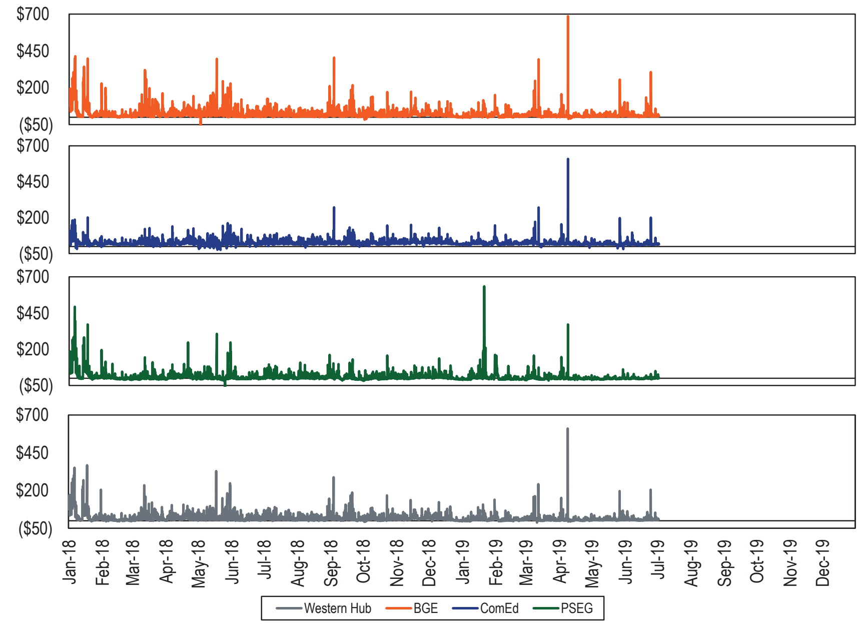


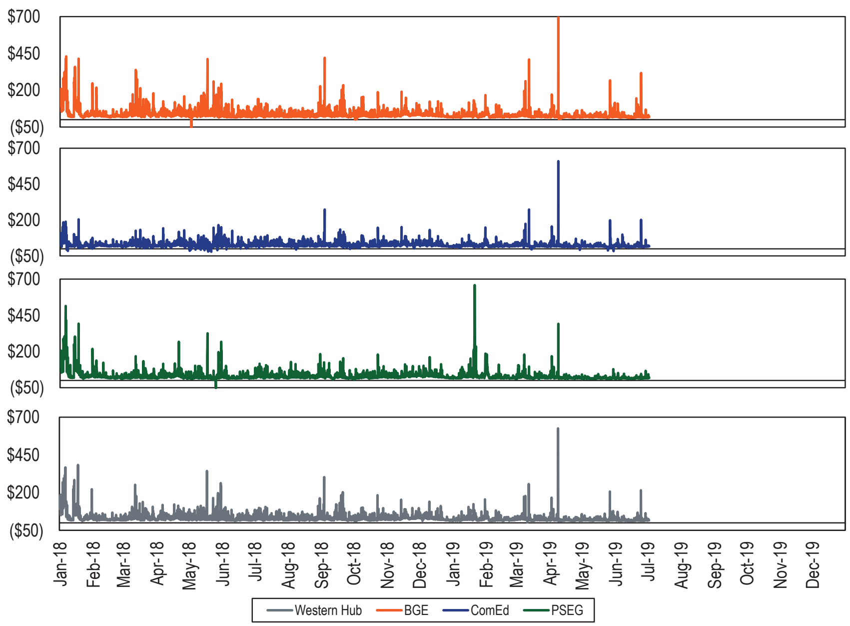
Figure 7-3 Hourly dark spread (coal) for peak hours ($/MWh): 2018 through June 2019[3]



2 Spark spreads use a combined cycle heat rate of 7,000 Btu/kWh, zonal hourly LMPs and daily gas prices; Chicago City Gate for ComEd, Zone 6 non-NY for BGE, Zone 6 NY for PSEG, and Texas Eastern M3 for Western Hub.

3 Dark spreads use a heat rate of 10,000 Btu/kWh, zonal hourly LMPs and daily coal prices; Powder River Basin coal for ComEd, Northern Appalachian coal for BGE and Western Hub, and Central Appalachian coal for PSEG.

Figure 7-4 Hourly quark spread (uranium) for selected zones ($/MWh): 2018 through June 2019[4]



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.

The analysis in this quarterly report includes only energy revenues unless explicitly stated. The analysis in the annual state of the market report includes revenues from all PJM markets.

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

- The CT plant has an installed capacity of 360.1 MW and consists of one GE Frame 7HA.02 CT, equipped with evaporative coolers and selective catalytic reduction (SCR) for NO_x reduction.
- The CC plant has an installed capacity of 1,137.2 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.
- 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 using New York Harbor ultra low sulfur diesel.
- The nuclear plant has an installed capacity of 2,200 MW and consists of two units and related facilities using the Westinghouse AP1000 technology.
- The on shore wind installation consists of 37 Siemens 2.7 MW wind turbines totaling 99.9 MW installed capacity.
- The off shore wind installation consists of 43 Siemens 7.0 MW wind turbines totaling 301.0 MW installed capacity.
- The solar installation consists of a 35.5 acre ground mounted solar farm totaling 10 MW of AC installed 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.[5] [6] Plant heat rates account for the efficiency changes and corresponding cost changes resulting from ambient air temperatures.

4 Quark spreads use a heat rate of 10,000 Btu/kWh, zonal hourly LMPs, and daily uranium prices.

5 Hourly ambient conditions supplied by DTN.

6 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.

CO_2, NO_x and SO_2 emission allowance costs are included in the hourly plant dispatch cost, the short run marginal cost. CO_2, NO_x and SO_2 emission allowance costs were obtained from daily spot cash prices.[7]

A forced outage rate for each class of plant was calculated from PJM data and incorporated into all revenue calculations.[8] In addition, each CT, CC, CP, and DS plant was assumed to take a continuous 14 day planned annual outage in the fall season.

Zonal net revenues reflect zonal fuel costs based on locational fuel indices and zone specific delivery charges.[9] 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.[10] The delivered cost of coal reflects the zone specific, delivered price of coal and was developed from the published prompt-month prices, adjusted for rail transportation costs.[11]

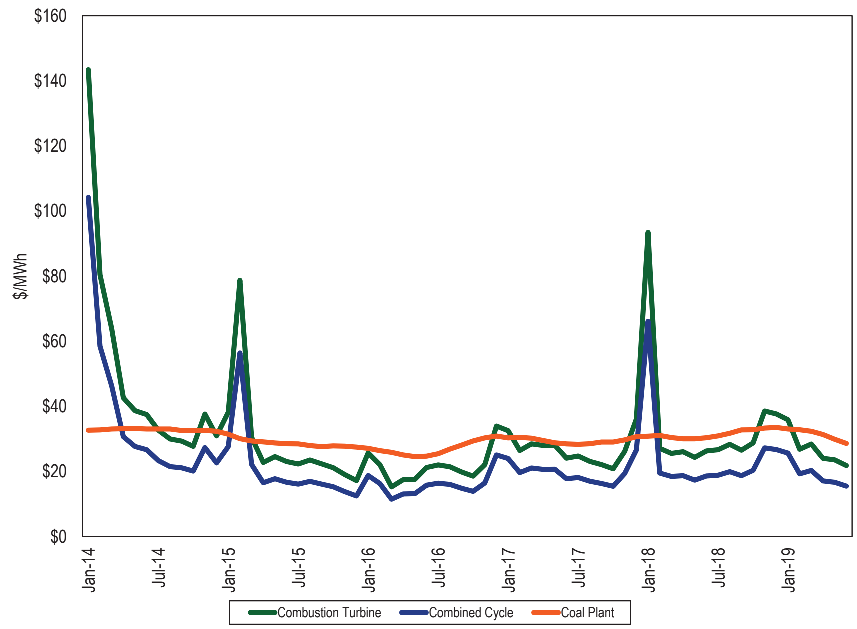
Short run marginal cost includes fuel costs, emissions costs, and the short run marginal component of VOM costs.[12] [13] Average short run marginal costs are shown, including all components, in Table 7-3 and the short run marginal component of VOM is also shown separately.

Table 7-3 Average short run marginal costs: 2019

Unit Type	Short Run Marginal Costs ($/MWh)	Heat Rate (Btu/kWh)	VOM ($/MWh)
CT	$26.76	9,241	$0.38
CC	$19.07	6,296	$1.39
CP	$31.34	9,250	$4.16
DS	$149.85	9,660	$0.25
Nuclear	$8.50	NA	$3.00
Wind	$0.00	NA	$0.00
Wind (off shore)	$0.00	NA	$0.00
Solar	$0.00	NA	$0.00

A comparison of the monthly average short run marginal cost of the theoretical CT, CC and CP plants since 2014, shows that, on average, the short run marginal costs of the CC plant have been less than those of the CP plant but 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 7-5).

Figure 7-5 Average short run marginal costs: 2014 through June 2019



7 CO_2, NO_x and SO_2 emission daily prompt prices obtained from Evolution Markets, Inc.
8 Outage figures obtained from the PJM eGADS database.
9 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.
10 Gas daily cash prices obtained from Platts.
11 Coal prompt prices obtained from Platts.
12 Fuel costs are calculated using the daily spot price and may not equal what participants actually paid.
13 VOM rates provided by Pasteris Energy, Inc.

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.

Gas prices, coal prices, and energy prices are reflected in new entrant run hours. Table 7-4 shows the average run hours by a new entrant unit.

Table 7-4 Average run hours: January through June, 2014 through 2019

	CT	CC	CP	DS	Nuclear
2014 (Jan-Jun)	2,180	3,945	3,887	148	4,368
2015 (Jan-Jun)	3,109	4,129	3,301	110	4,368
2016 (Jan-Jun)	3,578	4,281	2,498	25	4,392
2017 (Jan-Jun)	2,369	4,250	2,368	12	4,368
2018 (Jan-Jun)	2,837	4,166	2,537	105	4,368
2019 (Jan-Jun)	2,868	4,167	2,630	103	4,368

New Entrant Combustion Turbine

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

The new entrant CT is larger and more efficient than most CTs currently operating in PJM. The economically dispatched new entrant CT ran for more than twice as many hours as large CTs currently operating in PJM. The new entrant CT energy market net revenue results must therefore be interpreted carefully when comparing to existing CTs which are generally smaller and less efficient than the newest CT technology used by the new entrant CT.

New entrant CT plant energy market net revenues were lower across all zones in the first six months of 2019 than in the first six months of 2018 as a result of lower energy prices (Table 7-5).

Table 7-5 Energy net revenue for a new entrant gas fired CT under economic dispatch: January through June, 2014 through 2019 (Dollars per installed MW-year)[14 15]

Zone	2014 (Jan-Jun)	2015 (Jan-Jun)	2016 (Jan-Jun)	2017 (Jan-Jun)	2018 (Jan-Jun)	2019 (Jan-Jun)	Change in 2019 from 2018
AECO	$49,295	$26,071	$24,868	$12,593	$16,157	$11,983	(26%)
AEP	$59,609	$42,762	$34,549	$16,026	$51,364	$18,914	(63%)
APS	$74,182	$66,331	$27,435	$14,429	$55,217	$9,490	(83%)
ATSI	$41,997	$37,018	$31,099	$16,911	$61,218	$19,830	(68%)
BGE	$58,886	$38,448	$45,199	$17,637	$34,645	$12,556	(64%)
ComEd	$26,693	$17,202	$18,025	$10,604	$19,267	$9,038	(53%)
DAY	$37,561	$33,178	$30,991	$15,442	$56,960	$21,301	(63%)
DEOK	$34,262	$30,796	$28,939	$13,137	$64,866	$18,540	(71%)
DLCO	$24,138	$36,127	$32,926	$13,877	$31,620	$9,822	(69%)
Dominion	$48,078	$35,931	$39,586	$17,177	$37,992	$15,882	(58%)
DPL	$44,946	$19,199	$9,020	$6,285	$13,016	$6,048	(54%)
EKPC	$53,138	$32,610	$30,690	$13,510	$37,240	$15,669	(58%)
JCPL	$52,013	$26,947	$21,965	$15,214	$17,246	$10,893	(37%)
Met-Ed	$51,080	$46,697	$30,870	$20,742	$23,490	$11,356	(52%)
PECO	$52,263	$44,824	$28,574	$16,390	$22,107	$9,888	(55%)
PENELEC	$94,883	$88,250	$45,374	$20,417	$59,086	$17,181	(71%)
Pepco	$53,936	$28,205	$26,740	$12,101	$28,723	$8,549	(70%)
PPL	$161,377	$112,546	$36,533	$20,504	$64,877	$12,130	(81%)
PSEG	$66,370	$54,086	$33,236	$19,804	$25,294	$11,489	(55%)
RECO	$44,065	$29,578	$24,114	$15,166	$17,570	$10,866	(38%)
PJM	$58,381	$42,340	$30,037	$15,398	$36,898	$13,071	(65%)

14 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.
15 Energy net revenues presented for 2018 have been updated since the 2017 State of the Market Report for a one CT configuration and updated gas pipelines.

New Entrant Combined Cycle

Energy market net revenue was calculated for a new CC plant economically dispatched by PJM. It was assumed that the CC 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.[16] If the unit was not already committed day ahead, it was 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 CC plant energy market net revenues were lower in all zones in the first six months of 2019 than in the first six months of 2018 (Table 7-6).

Table 7-6 Energy net revenue for a new entrant CC under economic dispatch: January through June, 2014 through 2019 (Dollars per installed MW-year)[17]

Zone	2014 (Jan-Jun)	2015 (Jan-Jun)	2016 (Jan-Jun)	2017 (Jan-Jun)	2018 (Jan-Jun)	2019 (Jan-Jun)	Change in 2019 from 2018
AECO	$87,784	$47,143	$36,352	$27,788	$34,453	$30,556	(11%)
AEP	$90,890	$65,964	$48,022	$31,684	$74,182	$40,350	(46%)
APS	$117,381	$98,880	$53,855	$33,891	$84,506	$33,235	(61%)
ATSI	$64,588	$60,890	$45,570	$32,211	$82,982	$41,212	(50%)
BGE	$103,496	$68,721	$71,724	$37,846	$63,108	$37,783	(40%)
ComEd	$38,421	$32,432	$31,094	$21,150	$31,745	$23,523	(26%)
DAY	$57,714	$56,990	$45,557	$31,323	$79,738	$43,238	(46%)
DEOK	$51,249	$53,324	$43,235	$27,982	$86,856	$39,766	(54%)
DLCO	$44,807	$49,847	$45,493	$28,880	$53,618	$27,695	(48%)
Dominion	$80,367	$60,248	$54,373	$33,474	$57,914	$37,048	(36%)
DPL	$76,583	$35,423	$21,314	$11,972	$22,729	$8,916	(61%)
EKPC	$80,584	$55,218	$44,127	$28,425	$59,844	$36,087	(40%)
JCPL	$92,944	$48,160	$33,344	$30,487	$35,790	$29,777	(17%)
Met-Ed	$86,174	$67,572	$41,639	$35,514	$43,342	$30,752	(29%)
PECO	$90,454	$67,747	$39,320	$31,458	$44,157	$27,966	(37%)
PENELEC	$136,447	$103,904	$55,224	$35,820	$80,294	$38,423	(52%)
Pepco	$92,210	$58,044	$52,586	$30,267	$54,100	$31,058	(43%)
PPL	$198,142	$123,171	$46,325	$35,255	$81,806	$30,103	(63%)
PSEG	$115,064	$79,268	$44,488	$35,263	$48,193	$31,491	(35%)
RECO	$83,979	$49,520	$35,219	$30,398	$35,276	$30,366	(14%)
PJM	$100,026	$64,123	$44,443	$30,554	$57,732	$32,467	(44%)

16 All starts associated with combined cycle units are assumed to be warm starts.
17 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 for a new CP plant economically dispatched by PJM. It was assumed that the CP 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. If the unit was not already committed day-ahead, it was 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 CP plant energy market net revenues were lower in all zones as a result of lower energy prices (Table 7-7).

Table 7-7 Energy net revenue for a new entrant CP: January through June, 2014 through 2019 (Dollars per installed MW-year)[18]

Zone	2014 (Jan-Jun)	2015 (Jan-Jun)	2016 (Jan-Jun)	2017 (Jan-Jun)	2018 (Jan-Jun)	2019 (Jan-Jun)	Change in 2019 from 2018
AECO	$127,671	$49,512	$5,563	$1,814	$34,217	$3,841	(89%)
AEP	$106,327	$40,388	$17,675	$19,562	$49,742	$8,702	(83%)
APS	$111,873	$41,949	$5,274	$9,129	$41,230	$3,785	(91%)
ATSI	$118,146	$43,499	$14,454	$20,231	$49,961	$7,544	(85%)
BGE	$171,503	$73,596	$24,941	$8,478	$51,400	$5,557	(89%)
ComEd	$100,248	$29,357	$9,146	$16,608	$18,636	$8,506	(54%)
DAY	$108,663	$40,526	$13,494	$18,091	$48,274	$8,085	(83%)
DEOK	$99,661	$36,725	$11,611	$14,670	$55,279	$6,162	(89%)
DLCO	$93,481	$32,566	$12,509	$17,974	$49,590	$6,148	(88%)
Dominion	$152,402	$78,357	$28,316	$12,028	$59,415	$8,770	(85%)
DPL	$168,361	$70,399	$9,118	$6,154	$45,112	$5,908	(87%)
EKPC	$97,739	$31,520	$10,117	$13,561	$33,422	$4,502	(87%)
JCPL	$133,495	$49,827	$3,719	$2,303	$35,180	$3,567	(90%)
Met-Ed	$160,156	$66,639	$7,951	$9,407	$44,905	$6,195	(86%)
PECO	$124,808	$47,682	$3,374	$1,847	$34,169	$3,410	(90%)
PENELEC	$130,436	$55,207	$11,689	$7,006	$38,667	$5,211	(87%)
Pepco	$128,923	$41,993	$6,556	$1,742	$34,105	$2,512	(93%)
PPL	$123,789	$46,517	$3,412	$2,127	$33,525	$2,090	(94%)
PSEG	$181,265	$76,831	$7,082	$5,988	$40,502	$5,200	(87%)
RECO	$176,398	$77,524	$6,718	$5,906	$38,529	$6,068	(84%)
PJM	$155,324	$51,531	$10,636	$9,731	$41,793	$5,588	(87%)

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

New Entrant Nuclear Plant

Energy market net revenue was calculated assuming that the nuclear plant was dispatched day ahead by PJM for all available plant hours. The unit runs for all hours but output reflects the class average capacity factor.[19]

New entrant nuclear plant energy market net revenues were lower in all zones as a result of lower energy prices (Table 7-8).

Table 7-8 Energy net revenue for a new entrant nuclear plant: January through June, 2014 through 2019 (Dollars per installed MW-year)[20]

Zone	2014 (Jan-Jun)	2015 (Jan-Jun)	2016 (Jan-Jun)	2017 (Jan-Jun)	2018 (Jan-Jun)	2019 (Jan-Jun)	Change in 2019 from 2018
AECO	$265,091	$142,527	$59,775	$77,994	$116,221	$75,438	(35%)
AEP	$190,891	$112,394	$70,532	$82,292	$116,628	$80,771	(31%)
APS	$213,794	$132,923	$74,094	$84,025	$127,195	$81,714	(36%)
ATSI	$202,329	$115,700	$70,888	$85,307	$123,701	$82,850	(33%)
BGE	$288,161	$171,572	$104,753	$94,159	$148,506	$91,327	(39%)
ComEd	$165,670	$86,653	$60,710	$75,825	$76,097	$69,588	(9%)
DAY	$192,110	$111,674	$70,986	$84,326	$120,415	$85,001	(29%)
DEOK	$182,574	$107,801	$68,747	$80,603	$127,634	$81,259	(36%)
DLCO	$176,246	$104,093	$68,723	$82,921	$123,035	$80,379	(35%)
Dominion	$249,960	$154,475	$84,656	$89,727	$143,295	$86,623	(40%)
DPL	$283,809	$158,970	$73,045	$84,257	$127,849	$77,212	(40%)
EKPC	$180,525	$102,334	$67,191	$79,376	$103,988	$78,440	(25%)
JCPL	$270,761	$142,928	$56,534	$81,006	$117,423	$74,588	(36%)
Met-Ed	$257,376	$138,116	$56,634	$82,492	$115,515	$75,680	(34%)
PECO	$260,534	$139,277	$54,417	$77,959	$116,210	$72,692	(37%)
PENELEC	$226,372	$129,215	$66,142	$81,248	$117,247	$78,892	(33%)
Pepco	$281,053	$161,231	$92,072	$91,112	$144,004	$88,445	(39%)
PPL	$258,425	$138,562	$56,625	$79,569	$111,850	$70,397	(37%)
PSEG	$290,672	$151,524	$59,471	$82,200	$121,207	$76,830	(37%)
RECO	$285,370	$152,446	$59,010	$82,459	$120,059	$78,666	(34%)
PJM	$236,086	$132,721	$68,750	$82,943	$120,904	$79,340	(34%)

New Entrant Diesel

Energy market net revenue was calculated for a DS plant economically dispatched by PJM in real time.

New entrant DS plant energy market net revenues were lower in all zones except ComEd as a result of lower energy prices (Table 7-9).

Table 7-9 Energy market net revenue for a new entrant DS: January through June, 2014 through 2019 (Dollars per installed MW-year)

Zone	2014 (Jan-Jun)	2015 (Jan-Jun)	2016 (Jan-Jun)	2017 (Jan-Jun)	2018 (Jan-Jun)	2019 (Jan-Jun)	Change in 2019 from 2018
AECO	$33,053	$11,524	$2,098	$290	$10,305	$1,413	(86%)
AEP	$14,711	$3,035	$496	$93	$4,045	$835	(79%)
APS	$18,342	$6,396	$585	$185	$6,580	$814	(88%)
ATSI	$14,371	$2,775	$462	$300	$6,848	$777	(89%)
BGE	$50,389	$12,857	$4,596	$993	$12,654	$1,407	(89%)
ComEd	$11,536	$1,712	$244	$0	$630	$715	13%
DAY	$14,518	$2,878	$458	$80	$3,590	$892	(75%)
DEOK	$13,670	$2,293	$566	$123	$6,064	$822	(86%)
DLCO	$13,221	$2,247	$427	$288	$7,695	$743	(90%)
Dominion	$43,359	$9,906	$1,780	$666	$14,668	$1,220	(92%)
DPL	$37,127	$13,507	$1,694	$971	$12,015	$1,841	(85%)
EKPC	$14,728	$2,218	$670	$34	$1,760	$821	(53%)
JCPL	$33,304	$12,118	$558	$435	$11,467	$1,414	(88%)
Met-Ed	$32,359	$11,953	$534	$378	$11,311	$776	(93%)
PECO	$32,611	$11,438	$557	$530	$10,137	$1,360	(87%)
PENELEC	$16,281	$5,514	$410	$333	$5,542	$507	(91%)
Pepco	$52,117	$9,894	$2,246	$519	$12,368	$1,249	(90%)
PPL	$33,320	$12,104	$474	$457	$9,062	$388	(96%)
PSEG	$32,872	$11,598	$634	$429	$10,626	$1,778	(83%)
RECO	$30,367	$12,842	$668	$381	$9,797	$1,697	(83%)
PJM	$29,787	$7,940	$1,008	$374	$8,358	$1,073	(87%)

19 The annual class average capacity factor was applied to total energy market net revenues.
20 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.

New Entrant On Shore Wind Installation

Energy market net revenues for a wind installation were calculated hourly assuming the unit generated at the average capacity factor of operating wind units in the zone if 75 percent of existing wind units in the zone were generating at greater than or equal to 25 percent capacity factor in that hour. The unit is credited with wind RECs for its generation and is assumed to have taken a 1603 payment instead of either the Investment Tax Credit (ITC) or Production Tax Credit (PTC).[21]

On shore wind energy market net revenues were lower in the first six months of 2019 as a result of lower prices and less wind.

Table 7-10 Energy market net revenue for an on shore wind installation (Dollars per installed MW-year): January through June, 2014 through 2019

	2014 (Jan-Jun)	2015 (Jan-Jun)	2016 (Jan-Jun)	2017 (Jan-Jun)	2018 (Jan-Jun)	2019 (Jan-Jun)	Change in 2019 from 2018
AEP	$79,038	$47,237	$37,105	$40,662	$58,573	$39,589	(32%)
APS	$68,397	$46,892	$31,633	$43,983	$60,002	$34,382	(43%)
ComEd	$63,594	$37,372	$30,380	$40,615	$36,832	$35,988	(2%)
PENELEC	$90,237	$60,266	$32,862	$43,985	$60,645	$33,890	(44%)

New Entrant Off Shore Wind Installation

Energy market net revenues for an off shore wind installation were calculated by assuming the unit received the average annual zonal RT LMP and operated at a 45 percent capacity factor. The unit is credited with wind RECs for its generation and is assumed to have taken a 1603 payment instead of either the Investment Tax Credit (ITC) or Production Tax Credit (PTC).

Off shore wind energy market net revenues were lower in the first six months of 2019 than 2018 as a result of lower energy prices.

21 The 1603 payment is a direct payment of 30 percent of the project cost.

Table 7-11 Energy market net revenue for an off shore wind installation (Dollars per installed MW-year): January through March, 2014 through 2019

	2014 (Jan-Jun)	2015 (Jan-Jun)	2016 (Jan-Jun)	2017 (Jan-Jun)	2018 (Jan-Jun)	2019 (Jan-Jun)	Change in 2019 from 2018
AECO	$134,418	$81,270	$46,240	$53,639	$72,276	$50,462	(30%)

New Entrant Solar Installation

Energy market net revenues for a solar installation were calculated hourly assuming the unit was generating at the average hourly capacity factor of operating solar units in the zone if 75 percent of existing solar units in the zone were generating at greater than or equal to 25 percent capacity factor in that hour. The unit is credited with SRECs for its generation and is assumed to have taken a 1603 payment instead of either the Investment Tax Credit (ITC) or Production Tax Credit (PTC).[22]

Solar energy market net revenues were lower in the first six months of 2019 as a result of lower energy prices.

Table 7-12 Energy market ne ue for a solar installation (Dollars per installed MW-year): January through June, 2014 through 2019

	2014 (Jan-Jun)	2015 (Jan-Jun)	2016 (Jan-Jun)	2017 (Jan-Jun)	2018 (Jan-Jun)	2019 (Jan-Jun)	Change in 2019 from 2018
AECO	$31,086	$22,706	$14,716	$16,026	$18,428	$13,932	(24%)
Dominion	-	-	$32,249	$33,865	$36,260	$24,267	(33%)
DPL	-	-	$15,461	$21,260	$23,663	$17,496	(26%)
JCPL	$29,720	$16,706	$11,853	$12,894	$14,064	$10,795	(23%)
PSEG	$27,631	$19,910	$13,759	$13,977	$15,412	$13,894	(10%)

Historical New Entrant CT and CC Revenue Adequacy

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. The analysis also shows that theoretical

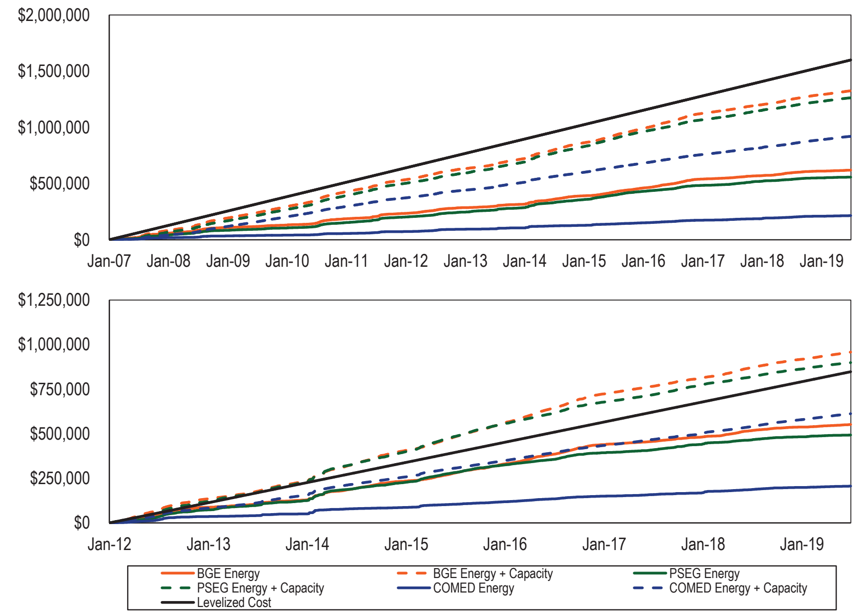
22 The 1603 payment is a direct payment of 30 percent of the project cost.

new entrant CTs 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. Theoretical new entrant CCs that entered the PJM markets in 2012 have covered their total costs on a cumulative basis in the BGE Zone but have not covered total costs in the PSEG or ComEd zones. Energy market revenues alone were not sufficient to cover total costs in any scenario, which demonstrates the critical role of the capacity market revenue in covering total costs.

Under cost of service regulation, units are guaranteed that they will cover their total costs, assuming that the costs were determined to be reasonable. To the extent that units built in the PJM markets did not cover their total costs, investors were worse off and customers were better off than under cost of service regulation.

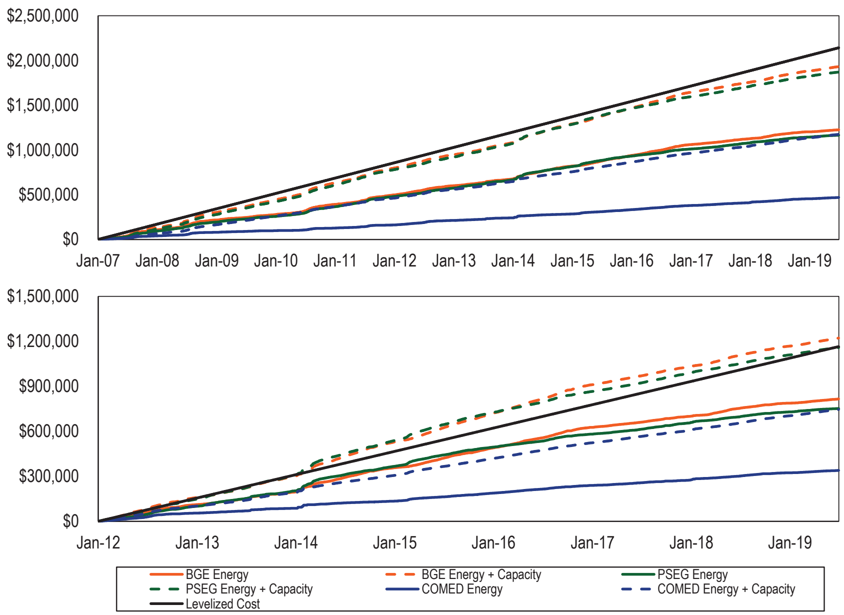
Figure 7-6 and Figure 7-7 compare cumulative energy market net revenues and energy market net revenues plus capacity market revenues to cumulative levelized costs for a new entrant CT and CC that began operation on January 1, 2007, and new entrant CT and CC that began operation on January 1, 2012. In each figure, the solid black line shows the total net revenue required to cover total costs. The solid colored lines show net energy revenue by zone. The dashed colored lines show the sum of net energy and capacity revenue by zone.

Figure 7-6 Historical new entrant CT revenue adequacy: January 2007 through June 2019 and January 2012 through June 2019[23]



23 The gas pipeline pricing points used in this analysis is Zone 6 non-NY for BGE, Chicago City Gate for ComEd, and Texas Eastern M3 for PSEG.

Figure 7-7 Historical new entrant CC revenue adequacy: January 2007 through June 2019 and January 2012 through June 2019[24]



Assumptions used for this analysis are shown in Table 7-13.

Table 7-13 Assumptions for analysis of new entry in 2007 and 2012

	2007 CT	2012 CT	2007 CC	2012 CC
Project Cost CT	$311,737,000	$319,167,000	$658,598,000	$665,995,000
Fixed O&M ($/MW-Year)	$14,475	$14,628	$20,016	$20,126
End of Life Value	$0	$0	$0	$0
Loan Term	20 years	20 years	20 years	20 years
Percent Equity (%)	50%	50%	50%	50%
Percent Debt (%)	50%	50%	50%	50%
Loan Interest Rate (%)	7%	7%	7%	7%
Federal Income Tax Rate (%)	35%	35%	35%	35%
State Income Tax Rate (%)	9%	9%	9%	9%
General Escalation (%)	2.5%	2.5%	2.5%	2.5%
Technology	GE Frame 7FA.04	GE Frame 7FA.05	GE Frame 7FA.04	GE Frame 7FA.05
ICAP (MW)	336	410	601	655
Depreciation MACRS 150% declining balance	15 years	15 years	20 years	20 years

24 The gas pipeline pricing points used in this analysis is Zone 6 non-NY for BGE, Chicago City Gate for ComEd, and Texas Eastern M3 for PSEG.

Nuclear Net Revenue Analysis

The analysis of nuclear plants includes annual avoidable costs and incremental capital expenditures from the Nuclear Energy Institute (NEI) based on NEI's calculations of average costs for all U.S. nuclear plants.[25] [26] The analysis includes the most recent operating cost data and incremental capital expenditure data published by NEI, for 2017. This is likely to result in conservatively high costs for the forward looking analysis. NEI average operating costs have decreased since their peak in 2012 (19.0 percent decrease from 2012 through 2017 for all plants including single and multiple unit plants). NEI average incremental capital expenditures have decreased since their peak in 2012 (40.8 percent decrease from 2012 through 2017 for all plants including single and multiple unit plants). NEI's incremental capital expenditures peaked in 2012 as a result of regulatory requirements following the 2011 accident at the Fukushima nuclear plant in Japan.

The results for nuclear plants are sensitive to small changes in PJM energy and capacity prices, both actual and forward prices.[27] When gas prices are high and LMPs are high as a result, net revenues to nuclear plants increase. In 2014, the polar vortex resulted in a significant increase in net revenues to nuclear plants. When gas prices are low and LMPs are low as a result, net revenues to nuclear plants decrease. In 2016, PJM energy prices were at the lowest level since the introduction of competitive markets on April 1, 1999, and remained low in 2017. As a result, in 2016 and 2017, a significant proportion of nuclear plants did not cover annual avoidable costs.[28] In 2018, high gas prices and high LMPs resulted in a significant increase in net revenues for nuclear plants in PJM. Energy prices in 2018 were significantly higher than in 2017. Forward prices for 2019 are lower than 2018 prices. The result is that nuclear plant net revenues based

25 Operating costs from: Nuclear Energy Institute (October, 2018). "Nuclear Costs in Context," <https://www.nei.org/CorporateSite/media/filefolder/resources/reports-and-briefs/nuclear-costs-context-201810.pdf>. Individual plants may vary from the average due to factors such as geographic location, local labor costs, the timing of refueling outages and other unit specific factors. This is the most current NEI data available.

26 The NEI costs for Hope Creek were treated as that of a two unit configuration because the unit is located in the same area as Salem 1 & 2. The net surplus of Hope Creek is sensitive to the accuracy of this assumption.

27 A change in the capacity market price of $24 per MW-day translates into a change in capacity revenue of $1.00 per MWh for a nuclear power plant operating in every hour. A change in the capacity market price of $24 per MW-day translates into a change in capacity revenue of $1.06 per MWh for a nuclear power plant operating at a capacity factor of 0.942 percent.

28 The IMM submitted testimony in New Jersey on the same issues of nuclear economics. *Establishing Nuclear Diversity Certificate Program.* Bill No. S-877 New Jersey Senate Environment and Energy Committee. (2018). *Revised Statement of Joseph Bowring.*

on the three year forward period prices are lower than 2018 net revenues. The results for nuclear plants are also sensitive to changes in costs and whether unit costs are less than or greater than the benchmark NEI data.

Table 7-14 includes the publicly available data on energy market prices, Table 7-15 and Table 7-16 shows capacity market prices and Table 7-17 shows nuclear cost data for the 18 nuclear plants in PJM and Oyster Creek, which retired September 17, 2018.[29]

For nuclear plants, all calculations are based on publicly available data in order to avoid revealing confidential information. Nuclear unit revenue is based on day-ahead LMP at the relevant node. Nuclear unit capacity revenue assumes that the unit cleared its full unforced capacity at the BRA locational clearing price. Unforced capacity is determined using the annual class average EFORd rate.

Table 7-14 Nuclear unit day-ahead LMP: 2008 through 2018

	ICAP	Average DA LMP ($/MWh)										
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Beaver Valley	1,808	$49.46	$31.51	$35.59	$37.43	$30.34	$34.24	$41.86	$30.35	$27.07	$29.11	$36.35
Braidwood	2,337	$48.10	$27.76	$31.48	$32.02	$27.51	$30.26	$37.34	$25.97	$24.30	$24.99	$27.11
Byron	2,300	$47.61	$23.98	$28.49	$28.09	$24.25	$29.22	$35.05	$21.00	$17.94	$23.79	$26.96
Calvert Cliffs	1,708	$78.63	$41.05	$51.27	$46.53	$35.19	$40.27	$57.88	$40.30	$32.64	$31.57	$38.79
Cook	2,069	$52.26	$32.20	$36.52	$37.41	$30.09	$34.14	$40.49	$29.94	$26.93	$28.03	$31.44
Davis Besse	894	-	-	-	$39.68	$31.68	$36.10	$47.21	$31.94	$27.80	$28.85	$34.44
Dresden	1,797	$48.76	$28.27	$32.73	$33.07	$28.42	$31.82	$39.22	$27.45	$25.89	$26.35	$28.25
Hope Creek	1,172	$73.34	$39.43	$48.03	$45.52	$33.07	$37.43	$51.99	$32.41	$23.20	$26.78	$32.93
LaSalle	2,271	$47.96	$27.71	$31.53	$31.93	$27.56	$30.94	$37.88	$26.28	$23.95	$24.71	$27.19
Limerick	2,242	$73.49	$39.49	$48.23	$45.27	$33.09	$37.28	$51.71	$32.65	$23.37	$26.99	$33.08
North Anna	1,892	$75.14	$39.89	$50.59	$45.47	$33.87	$38.55	$53.37	$38.05	$30.50	$31.27	$38.44
Oyster Creek	608	$75.49	$40.43	$49.29	$46.74	$33.69	$38.62	$52.85	$33.10	$23.79	$27.52	$34.03
Peach Bottom	2,347	$73.09	$39.32	$47.70	$44.73	$32.81	$37.37	$51.52	$31.98	$23.07	$26.76	$32.63
Perry	1,240	-	-	$36.99	$38.76	$31.68	$36.69	$46.14	$32.77	$27.84	$29.91	$37.24
Quad Cities	1,819	$47.28	$24.81	$27.53	$26.79	$20.43	$25.94	$30.71	$19.47	$18.04	$23.09	$25.54
Salem	2,328	$73.41	$39.51	$48.02	$45.50	$33.06	$37.40	$51.96	$32.37	$23.18	$26.76	$32.90
Surry	1,676	$71.96	$39.02	$49.30	$45.01	$33.62	$37.98	$51.75	$37.91	$30.08	$31.08	$38.50
Susquehanna	2,520	$69.96	$38.24	$45.95	$44.78	$32.10	$36.76	$50.93	$32.47	$23.66	$27.14	$32.42
Three Mile Island	803	$72.46	$39.11	$46.72	$44.15	$32.43	$36.83	$50.47	$30.94	$22.96	$27.12	$31.76

29 Installed capacity is from NEI, "Map of U.S. Nuclear Plants," <https://www.nei.org/resources/map-of-us-nuclear-plants>.

Table 7-15 BRA capacity market clearing prices ($/MW-Day): 2008 through 2021[30]

	ICAP	BRA Capacity Price ($/MW-Day)														
	(MW)	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22
Beaver Valley	1,808	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$165	$100	$77	$140
Braidwood	2,337	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$215	$203	$188	$196
Byron	2,300	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$215	$203	$188	$196
Calvert Cliffs	1,708	$189	$210	$237	$174	$110	$133	$226	$137	$167	$119	$120	$165	$100	$86	$140
Cook	2,069	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$165	$100	$77	$140
Davis Besse	894	-	-	-	-	$109	$20	$28	$126	$357	$114	$120	$165	$100	$77	$171
Dresden	1,797	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$215	$203	$188	$196
Hope Creek	1,172	$198	$149	$191	$174	$110	$140	$245	$137	$167	$119	$120	$225	$120	$188	$166
LaSalle	2,271	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$215	$203	$188	$196
Limerick	2,242	$198	$149	$191	$174	$110	$140	$245	$137	$167	$119	$120	$225	$120	$188	$166
North Anna	1,892	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$165	$100	$77	$140
Oyster Creek	608	$198	$149	$191	$174	$110	$140	$245	$137	$167	$119	$120	$225	$120	$188	-
Peach Bottom	2,347	$198	$149	$191	$174	$110	$140	$245	$137	$167	$119	$120	$225	$120	$188	$166
Perry	1,240	-	-	-	-	$109	$20	$28	$126	$357	$114	$120	$165	$100	$77	$171
Quad Cities	1,819	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$215	$203	$188	$196
Salem	2,328	$198	$149	$191	$174	$110	$140	$245	$137	$167	$119	$120	$225	$120	$188	$166
Surry	1,676	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$165	$100	$77	$140
Susquehanna	2,520	$41	$112	$191	$174	$110	$133	$226	$137	$167	$119	$120	$165	$100	$86	$140
Three Mile Island	803	$41	$112	$191	$174	$110	$133	$226	$137	$167	$119	$120	$165	$100	$86	$140

Table 7-16 Nuclear unit capacity market revenue ($/MWh): 2008 through 2021[31 32]

	ICAP	Capacity Revenue ($/MWh)													
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Beaver Valley	1,808	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$6.42	$5.56	$3.79	$4.99
Braidwood	2,337	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$7.71	$9.12	$8.52	$8.44
Byron	2,300	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$7.71	$9.12	$8.52	$8.44
Calvert Cliffs	1,708	$8.73	$9.59	$8.64	$5.87	$5.38	$8.21	$7.53	$6.74	$6.04	$5.26	$6.42	$5.57	$4.03	$5.16
Cook	2,069	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$6.42	$5.56	$3.79	$4.99
Davis Besse	894	NA	NA	NA	NA	$2.49	$1.08	$3.70	$11.40	$9.33	$5.17	$6.42	$5.56	$3.79	$5.80
Dresden	1,797	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$7.71	$9.12	$8.52	$8.44
Hope Creek	1,172	$7.33	$7.37	$7.82	$5.87	$5.54	$8.81	$7.87	$6.74	$6.04	$5.26	$7.98	$7.17	$7.00	$7.67
LaSalle	2,271	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$7.71	$9.12	$8.52	$8.44
Limerick	2,242	$7.33	$7.37	$7.82	$5.87	$5.54	$8.81	$7.87	$6.74	$6.04	$5.26	$7.98	$7.17	$7.00	$7.67
North Anna	1,892	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$6.42	$5.56	$3.79	$4.99
Oyster Creek	608	$7.33	$7.37	$7.82	$5.87	$5.54	$8.81	$7.87	$6.74	$6.04	$5.26	NA	NA	NA	NA
Peach Bottom	2,347	$7.33	$7.37	$7.82	$5.87	$5.54	$8.81	$7.87	$6.74	$6.04	$5.26	$7.98	$7.17	$7.00	$7.67
Perry	1,240	NA	NA	NA	NA	$2.49	$1.08	$3.70	$11.40	$9.33	$5.17	$6.42	$5.56	$3.79	$5.80
Quad Cities	1,819	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$7.71	$9.12	$8.52	$8.44
Salem	2,328	$7.33	$7.37	$7.82	$5.87	$5.54	$8.81	$7.87	$6.74	$6.04	$5.26	$7.98	$7.17	$7.00	$7.67
Surry	1,676	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$6.42	$5.56	$3.79	$4.99
Susquehanna	2,520	$3.57	$6.72	$7.82	$5.87	$5.38	$8.21	$7.53	$6.74	$6.04	$5.26	$6.42	$5.56	$4.03	$5.16
Three Mile Island	803	$3.57	$6.72	$7.82	$5.87	$5.38	$8.21	$7.53	$6.74	$6.04	$5.26	$6.42	$5.56	$4.03	$5.16

30 Oyster Creek retired September 17, 2018. Exelon. "Oyster Creek Generating Station Retires from Service," (September 17, 2018) <http://www.exeloncorp.com/newsroom/oyster-creek-retires>.

31 Capacity revenue calculated by adjusting the BRA Capacity Price for calendar year, by the class average EFORd, and by the 2018 class average capacity factor of 0.942 percent. Class average capacity factor is from *2018 State of the Market Report for PJM*, Volume 2, Section 5: Capacity Market.

32 Oyster Creek retired September 17, 2018. Exelon. "Oyster Creek Generating Station Retires from Service," (September 17, 2018) <http://www.exeloncorp.com/newsroom/oyster-creek-retires>.

Table 7-17 Nuclear unit costs: 2008 through 2018[33]

	ICAP	NEI Costs ($/MWh)										
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Beaver Valley	1,808	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$30.89
Braidwood	2,337	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$30.89
Byron	2,300	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$30.89
Calvert Cliffs	1,708	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$30.89
Cook	2,069	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$30.89
Davis Besse	894	$35.31	$39.36	$41.23	$45.45	$47.41	$44.16	$44.32	$44.51	$41.39	$42.66	$42.66
Dresden	1,797	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$30.89
Hope Creek	1,172	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$30.89
LaSalle	2,271	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$30.89
Limerick	2,242	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$30.89
North Anna	1,892	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$30.89
Oyster Creek	608	$35.31	$39.36	$41.23	$45.45	$47.41	$44.16	$44.32	$44.51	$41.39	$42.66	$42.66
Peach Bottom	2,347	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$30.89
Perry	1,240	$35.31	$39.36	$41.23	$45.45	$47.41	$44.16	$44.32	$44.51	$41.39	$42.66	$42.66
Quad Cities	1,819	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$30.89
Salem	2,328	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$30.89
Surry	1,676	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$30.89
Susquehanna	2,520	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$30.89
Three Mile Island	803	$35.31	$39.36	$41.23	$45.45	$47.41	$44.16	$44.32	$44.51	$41.39	$42.66	$42.66

Table 7-18 shows the surplus or shortfall in $/MWh for the 18 nuclear plants in PJM and Oyster Creek calculated using this cost data and historic LMPs.[34] In 2016, 15 nuclear plants, with a total capacity of 27,947 MW, in addition to Oyster Creek, did not recover all their fuel costs, operating costs, and capital expenditures. In 2017, eight nuclear plants with a total capacity of 13,461 MW, in addition to Oyster Creek, did not recover all their fuel costs, operating costs, and capital expenditures. In 2018, two nuclear plants, with a total capacity of 1,697 MW, in addition to Oyster Creek, did not recover all their fuel costs, operating costs, and capital expenditures. The surplus or shortfall assumes that the unit cleared its full unforced capacity at the BRA locational clearing price.[35] Unforced capacity is determined using the annual class average EFORd rate.

Some nuclear plants did not clear the capacity market primarily as a result of decisions by plant owners about how to offer the plants. Three Mile Island did not clear the 2018/2019 Auction[36] and Three Mile Island, Quad Cities, and a portion of Byron's capacity did not clear the 2019/2020 Auction.[37] Three Mile Island and Quad Cities did not clear the 2020/2021 Auction.[38] Three Mile Island, Dresden, and most of Byron did not clear the 2021/2022 Auction.[39] Beaver Valley, Davis Besse, and Perry did not clear the 2021/2022 Auction.[40]

Nuclear unit revenue is a combination of energy market revenue and capacity market revenue. Negative prices do not have a significant impact on nuclear unit revenue. Since 2014, negative prices have affected nuclear plants' annual revenues by an average of 0.1 percent. Negative LMPs reduced nuclear plant net revenues by an average of 0.0 percent and a maximum of 0.6 percent in 2014, an average of 0.2 percent and a maximum of 1.2 percent in 2015, an average of 0.1 percent and a maximum of 0.7 percent in 2016, an average of 0.0 percent and a maximum of 0.6 percent in 2017, and an average of 0.0 percent and a maximum of 0.0 percent in 2018 and the first six months of 2019.[41]

33 Oyster Creek retired on September 17, 2018. Exelon. "Oyster Creek Generating Station Retires from Service," (September 17, 2018) <http://www.exeloncorp.com/newsroom/oyster-creek-retires>.
34 Analysis excludes Catawba 1 which is pseudo tied to PJM.
35 Installed capacity is from NEI. "Maps of U.S. Nuclear Plants," <https://www.nei.org/resources/map-of-us-nuclear-plants>.
36 Exelon. "Exelon Announces Outcome of 2019-2020 PJM Capacity Auction," (May 25, 2016) <http://www.exeloncorp.com/newsroom/pjm-auction-results-2016>.
37 Exelon. "Exelon Announces Outcome of 2019-2020 PJM Capacity Auction," (May 25, 2016) <http://www.exeloncorp.com/newsroom/pjm-auction-results-2016>.
38 Exelon, "Exelon Announces Outcome of 2020-2021 PJM Capacity Auction," (May 24, 2017) <http://www.exeloncorp.com/newsroom/pjm-auction-results-release-2017>.
39 Exelon, "Exelon Announces Outcome of 2021-2022 PJM Capacity Auction," (May 24, 2018) <http://www.exeloncorp.com/newsroom/exelon-announces-outcome-of-2021-2022-pjm-capacity-auction>.
40 PRNewswire. "FirstEnergy Solutions Comments on Results of PJM Capacity Auction," (May 24, 2018) <https://www.prnewswire.com/news-releases/firstenergy-solutions-comments-on-results-of-pjm-capacity-auction-300654549.html>
41 Analysis is based on actual unit generation and received energy market and capacity market revenues. Negative prices in the DA and RT market were set to zero for comparison. Results round to 0.0 percent.

Table 7-18 Nuclear unit surplus (shortfall) based on public data: 2008 through 2018[42]

	ICAP (MW)	Surplus (Shortfall) ($/MWh)										
		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Beaver Valley	1,808	$26.3	$6.3	$10.5	$8.8	($3.3)	$1.4	$11.7	$3.2	($0.6)	$2.4	$11.9
Braidwood	2,337	$24.9	$2.5	$6.4	$3.4	($6.1)	($2.6)	$7.2	($1.2)	($3.4)	($1.7)	$3.9
Byron	2,300	$24.5	($1.3)	$3.4	($0.6)	($9.4)	($3.6)	$4.9	($6.1)	($9.7)	($2.9)	$3.8
Calvert Cliffs	1,708	$60.6	$20.9	$28.6	$17.9	$4.5	$14.6	$31.6	$14.1	$7.1	$5.9	$14.3
Cook	2,069	$29.1	$6.9	$11.4	$8.8	($3.6)	$1.3	$10.4	$2.8	($0.7)	$1.3	$7.0
Davis Besse	894	NA	NA	NA	NA	($13.2)	($7.0)	$6.6	($1.2)	($4.3)	($8.6)	($1.8)
Dresden	1,797	$25.6	$3.0	$7.6	$4.4	($5.2)	($1.0)	$9.1	$0.3	($1.8)	($0.4)	$5.1
Hope Creek	1,172	$54.0	$17.0	$24.5	$16.9	$2.6	$12.4	$26.0	$6.3	($2.4)	$1.2	$10.0
LaSalle	2,271	$24.8	$2.5	$6.4	$3.3	($6.1)	($1.9)	$7.7	($0.9)	($3.7)	($2.0)	$4.0
Limerick	2,242	$54.1	$17.1	$24.7	$16.6	$2.6	$12.2	$25.7	$6.5	($2.2)	$1.4	$10.2
North Anna	1,892	$52.0	$14.6	$25.5	$16.8	$0.2	$5.7	$23.2	$10.9	$2.8	$4.6	$14.0
Oyster Creek	608	$47.5	$8.4	$15.9	$7.2	($8.2)	$3.3	$16.4	($4.7)	($11.6)	($9.9)	NA
Peach Bottom	2,347	$53.7	$16.9	$24.2	$16.1	$2.3	$12.3	$25.5	$5.8	($2.5)	$1.1	$9.7
Perry	1,240	NA	NA	NA	NA	($13.2)	($6.4)	$5.5	($0.3)	($4.2)	($7.6)	$1.0
Quad Cities	1,819	$24.1	($0.4)	$2.4	($1.8)	($13.2)	($6.9)	$0.6	($7.7)	($9.6)	($3.6)	$2.4
Salem	2,328	$54.0	$17.1	$24.5	$16.9	$2.6	$12.4	$26.0	$6.2	($2.4)	$1.1	$10.0
Surry	1,676	$48.8	$13.8	$24.2	$16.4	($0.0)	$5.1	$21.6	$10.8	$2.4	$4.4	$14.0
Susquehanna	2,520	$46.8	$15.2	$22.4	$16.1	$1.4	$11.1	$24.6	$6.3	($1.9)	$1.5	$7.9
Three Mile Island	803	$40.7	$6.5	$13.3	$4.6	($9.6)	$0.9	$13.7	($6.8)	($12.4)	($10.3)	($4.5)

In order to evaluate the expected viability of nuclear plants, analysis was performed based on forward energy market prices for 2019, 2020 and 2021 and known capacity market prices for 2019, 2020 and 2021. The purpose of the forward analysis is to evaluate whether current forward prices are consistent with nuclear plants covering their annual avoidable costs over the next three years. While the forward capacity market prices are known, actual energy prices will vary from forward values.

Table 7-19 shows PJM energy prices (LMP), capacity prices (BRA), and annual fuel, operating and capital expenditures for the 2019 through 2021 period. The LMPs are based on forward prices with a basis adjustment for the specific plant locations.[43] Forward prices are as of July 1, 2019. The capacity prices are known based on PJM capacity auction results. The 2019 energy prices include actual day-ahead market prices through June 30, 2019, and forward prices for July through December 2019. The 2019 energy prices decreased by an average of $3.23 per MWh or 11.4 percent as a result of a decline in actual energy prices and forward prices. The 2020 forward prices for Western Hub decreased $5.16 per MWh or 16.0 percent and 2021 forward prices decreased $4.49 per MWh or 14.5 percent since April 1, 2019.

42 This table has changed slightly from previous versions because of the capacity factor adjustment made when converting capacity revenues in $/MW-Day to $/MWh.
43 Forward prices on July 1, 2019. Forward prices are reported for PJM trading hubs which are adjusted to reflect the historical differences between prices at the trading hub and prices at the relevant plant locations. The basis adjustment is based on 2018 data.

Table 7-19 Forward prices in PJM energy and capacity markets and annual costs[44] [45]

	ICAP	Average Forward LMP ($/MWh)			Capacity Revenue ($/MWh)			2017 NEI Costs ($/MWh)		
	(MW)	2019	2020	2021	2019	2020	2021	Fuel	Operating	Capital
Beaver Valley	1,808	$26.72	$27.89	$27.28	$5.56	$3.79	$4.99	$6.44	$18.46	$5.99
Braidwood	2,337	$23.01	$22.20	$21.72	$9.12	$8.52	$8.44	$6.44	$18.46	$5.99
Byron	2,300	$22.95	$22.19	$21.71	$9.12	$8.52	$8.44	$6.44	$18.46	$5.99
Calvert Cliffs	1,708	$27.45	$28.29	$27.71	$5.57	$4.03	$5.16	$6.44	$18.46	$5.99
Cook	2,069	$25.13	$25.07	$24.54	$5.56	$3.79	$4.99	$6.44	$18.46	$5.99
Davis Besse	894	$26.71	$27.10	$26.54	$5.56	$3.79	$5.80	$6.42	$27.32	$8.92
Dresden	1,797	$23.83	$23.04	$22.54	$9.12	$8.52	$8.44	$6.44	$18.46	$5.99
Hope Creek	1,172	$24.35	$24.47	$23.95	$7.17	$7.00	$7.67	$6.44	$18.46	$5.99
LaSalle	2,271	$23.01	$22.20	$21.72	$9.12	$8.52	$8.44	$6.44	$18.46	$5.99
Limerick	2,242	$24.46	$24.52	$24.00	$7.17	$7.00	$7.67	$6.44	$18.46	$5.99
North Anna	1,892	$27.16	$27.95	$27.38	$5.56	$3.79	$4.99	$6.44	$18.46	$5.99
Peach Bottom	2,347	$23.88	$24.36	$23.84	$7.17	$7.00	$7.67	$6.44	$18.46	$5.99
Perry	1,240	$27.48	$28.44	$27.82	$5.56	$3.79	$5.80	$6.42	$27.32	$8.92
Quad Cities	1,819	$22.05	$21.06	$20.60	$9.12	$8.52	$8.44	$6.44	$18.46	$5.99
Salem	2,328	$24.34	$24.45	$23.93	$7.17	$7.00	$7.67	$6.44	$18.46	$5.99
Surry	1,676	$26.85	$27.81	$27.24	$5.56	$3.79	$4.99	$6.44	$18.46	$5.99
Susquehanna	2,520	$22.75	$23.93	$23.42	$5.56	$4.03	$5.16	$6.44	$18.46	$5.99
Three Mile Island	803	$24.14	$23.53	$23.01	$5.56	$4.03	$5.16	$6.42	$27.32	$8.92

Table 7-20 shows the surplus or shortfall that would be received net of avoidable costs and incremental capital expenditures by year, based on forward prices, on a per MWh basis. The fuel and operating costs are the 2017 NEI fuel, operating, and capital costs. Plants may have operating costs higher or lower than the NEI average. Table 7-21 shows the total dollar surplus or shortfall and adjusts energy revenues and operating costs using the annual class average capacity factor.

The results of the forward analysis are quite different from prior results due to the significant decline in PJM energy market forward prices. Prior forward analysis showed that three nuclear plants would not cover their annual avoidable costs. The prior results were consistent and showed that the three plants would not cover their costs for each of the three forward years and that the other plants would cover their costs for each of the three forward years. The current analysis, based on forward prices for energy and known forward prices for capacity, shows different results by year for some plants. Five nuclear plants would not cover their annual avoidable costs in each year over the next three years (2019 through 2021). Of these five plants, the same three plants that prior analysis showed not covering costs, Davis Besse, Perry, and Three Mile Island, show much higher shortfalls, with an average annual shortfall of $11.57 per MWh, than the two additional plants. The three plants are single unit sites which have higher operating costs per MWh than multiple unit plants. In May 2017, TMI requested deactivation in 2019. In March 2018, Davis Besse and Perry requested deactivation in 2021 but reversed the decision based on new subsidies in Ohio. The two additional plants are Cook and Susquehanna, with an average annual shortfall of $1.90 per MWh. Susquehanna has reduced its operating costs and is not operating at a loss when the unit specific information is accounted for.[46] Cook nuclear units are designated FRR and receive cost of service revenues and are not subject to PJM market revenues.[47] In addition to the five plants that would not cover their avoidable costs over all three forward years, four plants would

44 Oyster Creek retired on September 17, 2018. Exelon. "Oyster Creek Generating Station Retires from Service," (September 17, 2018) <http://www.exeloncorp.com/newsroom/oyster-creek-retires>.
45 This table has changed slightly from previous versions because of the capacity factor adjustment made when converting capacity revenues in $/MW-Day to $/MWh.
46 Talen Energy Investor Day, February 12, 2019.
47 See PJM. "Resources Designated in 2021/2022 FRR Capacity Plans as of May 1, 2018," <https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-resources-designated-in-frr-plans.ashx?la=en>.

not cover avoidable costs in two of the three years with an average annual shortfall of $0.73 per MWh during shortfall years, given current forward prices: Braidwood; Byron; LaSalle; and Quad Cities.

Table 7-20 Nuclear unit forward annual surplus (shortfall) ($/MWh)[48 49]

	Surplus (Shortfall) ($/MWh)		
	2019	2020	2021
Beaver Valley	$1.40	$0.78	$1.38
Braidwood	$1.24	($0.17)	($0.73)
Byron	$1.18	($0.18)	($0.74)
Calvert Cliffs	$2.13	$1.43	$1.99
Cook	($0.20)	($2.03)	($1.36)
Davis Besse	($10.39)	($11.78)	($10.32)
Dresden	$2.06	$0.67	$0.09
Hope Creek	$0.63	$0.59	$0.74
LaSalle	$1.24	($0.17)	($0.73)
Limerick	$0.75	$0.63	$0.78
North Anna	$1.83	$0.85	$1.48
Peach Bottom	$0.16	$0.47	$0.62
Perry	($9.62)	($10.44)	($9.04)
Quad Cities	$0.28	($1.31)	($1.84)
Salem	$0.62	$0.57	$0.72
Surry	$1.52	$0.70	$1.34
Susquehanna	($2.58)	($2.93)	($2.31)
Three Mile Island	($12.95)	($15.10)	($14.49)

Table 7-21 Nuclear unit forward annual surplus (shortfall) ($ in millions)[50 51]

	Surplus (Shortfall) ($ in millions)		
	2019	2020	2021
Beaver Valley	$20.8	$11.7	$20.6
Braidwood	$24.0	($3.2)	($14.1)
Byron	$22.3	($3.5)	($14.0)
Calvert Cliffs	$30.0	$20.3	$28.0
Cook	($3.4)	($34.8)	($23.2)
Davis Besse	($76.6)	($87.1)	($76.2)
Dresden	$30.5	$9.9	$1.3
Hope Creek	$6.1	$5.7	$7.1
LaSalle	$23.2	($3.2)	($13.7)
Limerick	$13.8	$11.7	$14.5
North Anna	$28.6	$13.3	$23.1
Peach Bottom	$3.2	$9.1	$12.1
Perry	($98.5)	($107.1)	($92.5)
Quad Cities	$4.2	($19.7)	($27.7)
Salem	$12.0	$10.9	$13.8
Surry	$21.0	$9.7	$18.5
Susquehanna	($53.7)	($61.1)	($48.0)
Three Mile Island	($85.8)	($100.3)	($96.0)

48 Oyster Creek retired on September 17, 2018. Exelon. "Oyster Creek Generating Station Retires from Service," (September 17, 2018) <http://www.exeloncorp.com/newsroom/oyster-creek-retires>.
49 Three Mile Island is scheduled to retire on September 30, 2019 <https://www.pjm.com/planning/services-requests/gen-deactivations.aspx>.

50 Oyster Creek retired on September 17, 2018. Exelon. "Oyster Creek Generating Station Retires from Service," (September 17, 2018) <http://www.exeloncorp.com/newsroom/oyster-creek-retires>.
51 Three Mile Island is scheduled to retire on September 30, 2019 <https://www.pjm.com/planning/services-requests/gen-deactivations.aspx>.