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 and fuel prices were higher in 2018 than in 2017. Energy prices increased more than gas prices in most locations except for Texas Eastern M-3 gas and CTs and CCs ran with higher margins as a result. Coal prices increased by less than gas prices and CPs ran for more hours and at higher margins in 2018 than in 2017.
- In 2018, average energy market net revenues increased by 39 percent for a new CT, 48 percent for a new CC, 138 percent for a new CP, 32 percent for a new nuclear plant, 255 percent for a new DS, 24 percent for a new on shore wind installation, 26 percent for a new off shore wind installation and 10 percent for a new solar installation compared to 2017.
- The relative prices of fuel varied during 2018. While the marginal cost of the new CC was consistently below that of the new CP in 2018, the marginal cost of the new CT was above that of the new CP in January and December.
- Capacity revenue accounted for 47 percent of total net revenues for a new CT, 36 percent for a new CC, 48 percent for a new CP, 87 percent for a new DS, and 21 percent for a new nuclear plant.
- In 2018, a new CT would have received sufficient net revenue to cover levelized total costs in 11 zones and would have covered at least 87 percent of levelized costs in all zones as a result of higher energy prices and higher locational capacity market prices.
- In 2018, a new CC would have received sufficient net revenue to cover levelized total costs in all zones.
- In 2018, a new CP would not have received sufficient net revenue to cover levelized total costs in any zone.
- In 2018, a new nuclear plant would not have received sufficient net revenue to cover levelized total costs in any zone.
- In 2018, net revenues covered more than 64 percent of the annual levelized total costs of a new entrant on shore wind installation in AEP, APS, ComEd and PENELEC. Renewable energy credits accounted for at least 30 percent of the total net revenue of an on shore wind installation.
- In 2018, net revenues covered 49 percent of the annual levelized total costs of a new entrant off shore wind installation in AECO. Renewable energy credits accounted for 31 percent of the total net revenue of an off shore wind installation.
- In 2018, net revenues covered more than 100 percent of the annual levelized total costs of a new entrant solar installation in AECO, Dominion, JCPL and PSEG. Renewable energy credits accounted for at least 64 percent of the total net revenue of a solar installation.
- In 2018, most units did not achieve full recovery of avoidable costs through net revenue from energy markets alone, illustrating the critical role of the PJM Capacity Market in providing incentives for continued operation and investment. In 2018, capacity revenues were sufficient to cover the shortfall between energy revenues and avoidable costs for the majority of units and technology types in PJM, with the exception of some coal units and some nuclear units.
- Using a forward analysis, a total of 14,954 MW of coal and nuclear capacity are at risk of retirement, in addition to the units that are currently planning to retire. The 14,954 MW considered to be at risk of retirement consists of 12,017 MW of coal and 2,937 MW of nuclear capacity.

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 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 any scenario, which demonstrates the critical role of the capacity market revenue in covering total costs.

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. CC units that entered the PJM markets in 2007 have 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.

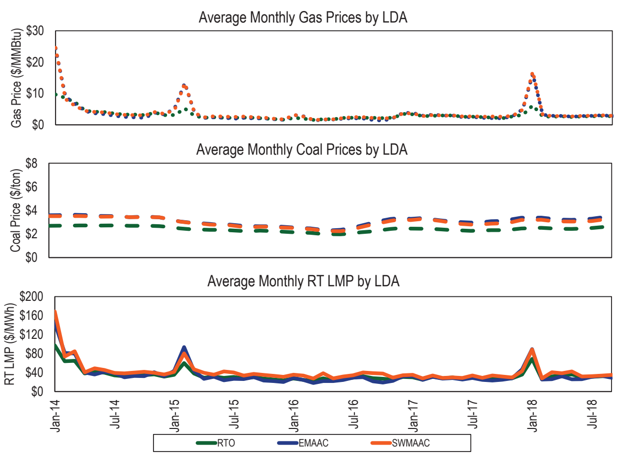
Net Revenue

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 23.4 percent higher in 2018 than in 2017, $38.24 per MWh versus $30.99 per MWh. Eastern natural gas prices and coal prices increased in 2018. The price of Northern Appalachian coal was 10.0 percent higher; the price of Central Appalachian coal was 12.0 percent higher; the price of Powder River Basin coal was 2.8 percent higher; the price of eastern natural gas was 43.8 percent higher; and the price of western natural gas was 10.1 percent higher (Figure 7-1).

Figure 7-1 Energy market net revenue factor trends: 2014 through 2018



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. While both energy prices and gas prices increased in January 2018, hourly energy prices did not increase as much as gas prices, which lead to negative spark spreads during some high LMP hours. As a result, the volatility of the spark spreads is significantly higher than in previous years.

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 2018

	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

Table 7-2 Peak hour spread standard deviation ($/MWh): 2014 through 2018

	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

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): 2017 through 2018[1]

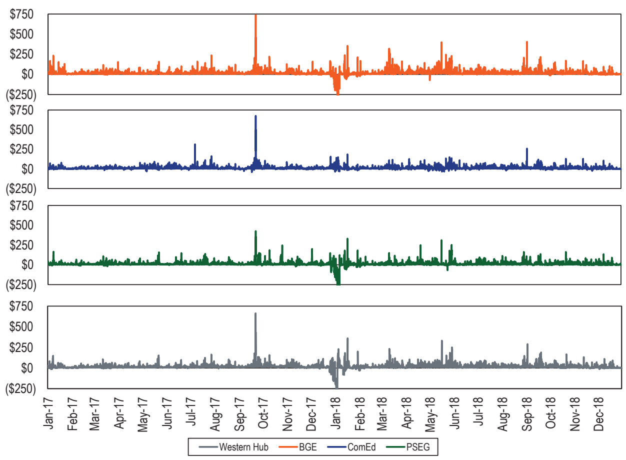


Figure 7-3 Hourly dark spread (coal) for peak hours ($/MWh): 2017 through 2018[2]

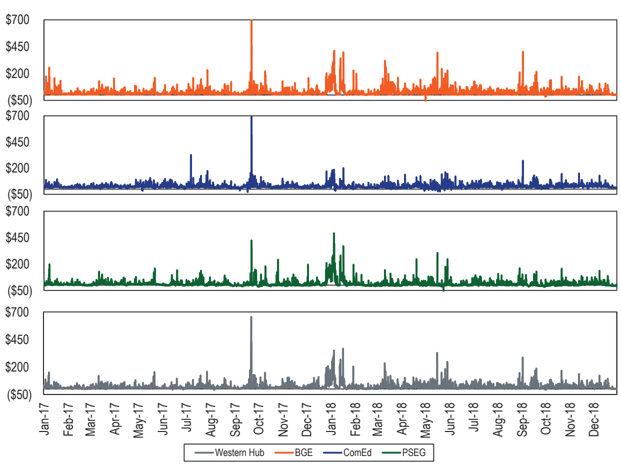
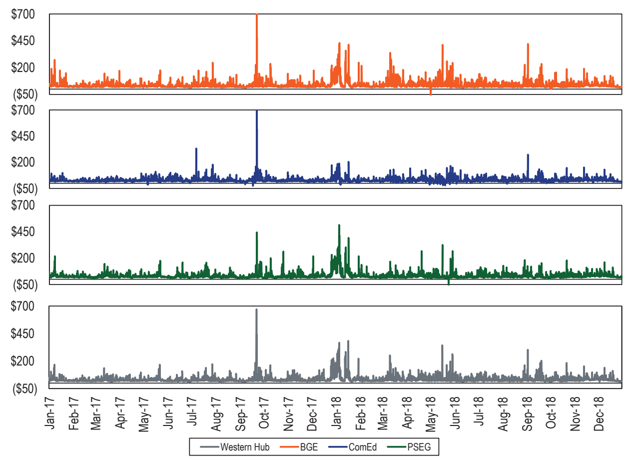


Figure 7-4 Hourly quark spread (uranium) for selected zones ($/MWh): 2017 through 2018[3]



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 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

1 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.

2 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.

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

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.[4 5] Plant heat rates account for the efficiency changes and corresponding cost changes resulting from ambient air temperatures.

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.[6]

A forced outage rate for each class of plant was calculated from PJM data and incorporated into all revenue calculations.[7] In addition, each CT, CC, CP, and DS plant was assumed to take a continuous 14 day planned annual outage in the fall season.

CT revenues for the provision of reactive services are based on the average reactive revenue per MW-year received by all CTs with 20 or fewer operating years. CC revenues for the provision of reactive services are based on the average reactive revenue per MW-year received by all CC generators with 20 or fewer operating years. CP revenues for the provision of reactive services are based on the average reactive revenue per MW-year received by all CP generators with 60 or fewer operating years. Table 7-3 includes reactive capability revenue of $3,350/MW-Yr for all unit types plus reactive service revenue.[8]

Table 7-3 New entrant reactive revenue (Dollars per MW-year)

	Reactive		
	CT	CC	CP
2014	$3,721	$4,046	$3,574
2015	$3,673	$4,911	$3,386
2016	$3,436	$4,573	$3,470
2017	$3,885	$3,591	$3,438
2018	$4,150	$3,350	$4,929

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 7-4 and the short run marginal component of VOM is also shown separately.

4 Hourly ambient conditions supplied by DTN.
5 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.
6 CO_2, NO_x and SO_2 emission daily prompt prices obtained from Evolution Markets, Inc.
7 Outage figures obtained from the PJM eGADS database.

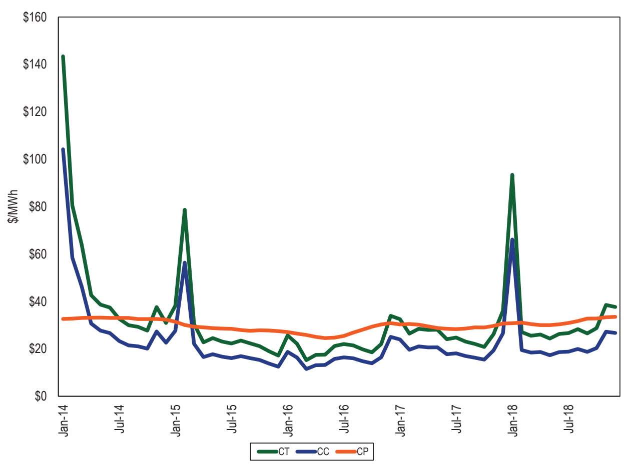
8 $3,350/MW-Yr is the average of reactive capability payments of selected units obtained from FERC filings.
9 Startup fuel burns and emission rates provided by Pasteris Energy, Inc. Startup station power consumption costs were obtained from the station service rates published quarterly by PJM and netted 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.

Table 7-4 Average short run marginal costs: 2018

Unit Type	Short Run Marginal Costs ($/MWh)	Heat Rate (Btu/kWh)	VOM ($/MWh)
CT	$34.10	9,241	$0.38
CC	$24.21	6,296	$1.09
CP	$31.48	9,250	$4.03
DS	$161.16	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 2018



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 7-5 shows the average run hours by a new entrant unit.

Table 7-5 Average run hours: 2014 through 2018

	CT	CC	CP	DS	Nuclear
2014	4,722	7,908	6,693	153	8,760
2015	6,266	8,133	5,605	141	8,760
2016	6,337	8,264	5,025	44	8,784
2017	4,974	8,230	4,520	38	8,760
2018	4,925	8,190	4,971	116	8,760

Capacity Market Net Revenue

Generators receive revenue from the sale of capacity in addition to revenue from the energy and ancillary service markets. In the PJM market design, the sale of capacity provides an important source of revenues to cover generator going forward costs and fixed costs. Capacity revenue for 2018 includes five months of the 2017/2018 capacity market clearing price and seven months of the 2018/2019 RPM capacity market clearing price.[14]

Table 7-6 Capacity revenue by PJM zones (Dollars per MW-year): 2014 through 2018[15]

Zone	2014	2015	2016	2017	2018
AECO	$66,206	$56,448	$50,948	$43,669	$65,655
AEP	$31,149	$48,128	$33,377	$34,645	$53,235
APS	$31,149	$48,128	$33,377	$34,645	$53,216
ATSI	$31,149	$95,422	$78,709	$42,929	$53,124
BGE	$63,360	$56,448	$50,948	$43,669	$52,953
ComEd	$31,149	$48,128	$33,377	$34,645	$63,994
DAY	$31,149	$48,128	$33,377	$34,645	$52,760
DEOK	$31,149	$48,128	$33,377	$34,645	$52,338
DLCO	$31,149	$48,128	$33,377	$34,645	$53,045
Dominion	$31,149	$48,128	$33,377	$34,645	$53,219
DPL	$66,206	$56,448	$50,948	$43,669	$65,106
EKPC	$31,149	$48,128	$33,377	$34,645	$52,400
JCPL	$66,206	$56,448	$50,948	$43,669	$64,763
Met-Ed	$63,360	$56,448	$50,948	$43,669	$53,353
PECO	$66,206	$56,448	$50,948	$43,669	$65,707
PENELEC	$63,360	$56,448	$50,945	$43,667	$53,154
Pepco	$66,529	$56,448	$50,948	$43,669	$53,323
PPL	$63,360	$56,448	$50,948	$43,669	$52,218
PSEG	$72,567	$60,936	$67,224	$73,401	$79,190
RECO	$72,567	$60,936	$67,224	$73,401	$79,190
PJM	$46,247	$54,646	$48,568	$44,809	$58,432

14 The RPM revenue values for PJM are load-weighted average clearing prices across the relevant base residual auctions.

15 See the *2018 State of the Market Report for PJM*, Appendix A: "PJM Geography," for details on the expansion of the PJM footprint.

Net Revenue Adequacy

When total net revenues exceed the annual, nominal levelized total costs for the technology, that technology is covering all its costs including a return on and of capital and all the expenses of operating the facility.

The extent to which net revenues cover the levelized total costs of investment is significantly dependent on technology type and location, which affect both energy and capacity revenue. Table 7-7 includes new entrant levelized total costs for selected technologies. The levelized total costs of all the technologies increased in 2018 over 2017 with the exception of the CC, diesel and nuclear plant.

Net revenues include net revenues from the PJM energy market, from the PJM Capacity Market and from any applicable ancillary services plus RECs for wind installations and SRECs for solar installations.

Levelized Total Costs

Table 7-7 New entrant 20-year levelized total costs (By plant type (Dollars per installed MW-year))[16 17 18]

	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
Solar Installation (with 1603 grant)	$236,289	$234,151	$218,937	$200,931	$232,230

Levelized Cost of Energy

The levelized cost of energy is a measure of the total cost per MWh of energy from a technology, including all fixed and variable costs. If a unit's revenues cover its levelized cost of energy, it is covering all its costs and earning the target rate of return. Table 7-8 shows the levelized cost of energy for a new entrant unit by technology type operating at the capacity factor for the new entrant unit type. CCs had a low levelized cost of energy in 2018 because they had a high capacity factor, which increases the MWh over which costs are spread. DS units had a high levelized cost of energy in 2018 because DS units ran for extremely few hours, which decreases the capacity factor, which decreases the MWh over which costs are spread. The levelized cost of on shore wind is comparable to or less than that of all other resources except CCs. The levelized cost of solar is high as a result of a low capacity factor.

Table 7-8 Levelized cost of energy: 2018

	CT	CC	CP	DS	Nuclear	Wind (On Shore)	Wind (Off Shore)	Solar
Levelized cost ($/MW-Yr)	$118,116	$113,641	$562,747	$154,683	$1,178,607	$214,780	$460,730	$232,230
Short run marginal costs ($/MWh)	$34.10	$24.21	$31.48	$161.16	$8.50	$0.00	$0.00	$0.00
Capacity factor (%)	54%	88%	49%	2%	94%	28%	45%	13%
Levelized cost of energy ($/MWh)	$59	$39	$161	$882	$151	$88	$117	$198

16 Levelized total costs provided by Pasteris Energy, Inc.

17 Under Section 1603 of the American Recovery and Reinvestment Tax Act of 2009 the United States Department of the Treasury makes payments to owners who place in service specified energy property and apply for such payments. The purpose of the payment is to reimburse eligible applicants for a portion of the capital cost of such property. Solar and wind energy properties are eligible for a 30 percent payment of the total eligible capital cost of the project. This 30 percent payment reduced the calculated fixed nominal levelized revenue requirements of the solar and wind technologies.

18 Combustion turbine levelized total costs presented for 2018 have been updated since the 2017 State of the Market Report for a one CT configuration.

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 higher across all zones except Met-Ed, PECO, and PSEG in 2018 than in 2017 (Table 7-9). The increase in energy prices more than offset the increase in gas prices except in these zones. Gas pipelines have been updated to reflect the most commonly used pipeline within the zone.

Table 7-9 Energy net revenue for a new entrant gas fired CT under economic dispatch: 2014 through 2018 (Dollars per installed MW-year)[19 20]

Zone	2014	2015	2016	2017	2018	Change in 2018 from 2017
AECO	$85,559	$53,906	$56,536	$32,852	$39,081	19%
AEP	$75,204	$70,174	$59,142	$39,723	$76,771	93%
APS	$100,254	$98,446	$65,715	$52,164	$76,110	46%
ATSI	$57,789	$60,807	$56,841	$42,410	$90,859	114%
BGE	$103,414	$84,034	$100,287	$45,242	$57,853	28%
ComEd	$38,012	$34,632	$37,422	$25,323	$36,620	45%
DAY	$52,492	$58,641	$55,345	$41,048	$85,337	108%
DEOK	$47,627	$56,302	$52,460	$39,499	$93,272	136%
DLCO	$54,731	$82,980	$76,646	$50,270	$62,740	25%
Dominion	$70,238	$71,643	$68,491	$41,336	$62,186	50%
DPL	$69,612	$39,809	$31,144	$24,901	$34,599	39%
EKPC	$66,059	$57,460	$51,507	$33,067	$58,944	78%
JCPL	$86,167	$51,989	$51,683	$36,336	$36,470	0%
Met-Ed	$88,304	$90,038	$75,322	$59,639	$49,038	(18%)
PECO	$90,605	$88,281	$70,435	$50,485	$42,762	(15%)
PENELEC	$135,004	$140,985	$93,894	$67,089	$87,635	31%
Pepco	$76,271	$55,534	$52,356	$30,641	$47,502	55%
PPL	$203,674	$156,556	$76,508	$62,547	$85,407	37%
PSEG	$108,183	$101,094	$76,120	$58,726	$48,683	(17%)
RECO	$82,044	$59,293	$57,561	$38,818	$39,194	1%
PJM	$58,381	$75,630	$63,271	$43,606	$60,553	39%

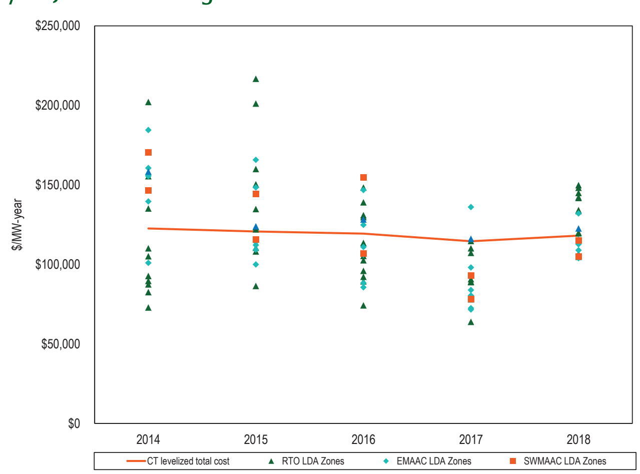
In 2018, a new CT would have received sufficient net revenue to cover levelized total costs in eleven zones and would have covered more than 87 percent of levelized costs in all zones as a result of higher energy prices and higher locational capacity market prices (Table 7-10). At 88 percent, the new CT would cover all avoidable costs and earn a positive but lower rate of return.

Table 7-10 Percent of 20-year levelized total costs recovered by CT energy and capacity net revenue: 2014 through 2018

Zone	2014	2015	2016	2017	2018
AECO	127%	94%	93%	70%	92%
AEP	90%	101%	80%	68%	114%
APS	110%	125%	86%	79%	113%
ATSI	76%	133%	116%	78%	125%
BGE	139%	119%	130%	81%	97%
ComEd	59%	72%	62%	56%	89%
DAY	71%	92%	77%	69%	120%
DEOK	67%	90%	75%	68%	127%
DLCO	73%	112%	95%	78%	102%
Dominion	86%	102%	88%	70%	101%
DPL	114%	83%	72%	63%	88%
EKPC	82%	91%	74%	62%	98%
JCPL	127%	93%	89%	73%	89%
Met-Ed	127%	124%	109%	94%	90%
PECO	131%	123%	105%	86%	95%
PENELEC	165%	167%	124%	100%	123%
Pepco	120%	96%	89%	68%	89%
PPL	221%	180%	110%	96%	120%
PSEG	150%	137%	123%	119%	112%
RECO	129%	103%	107%	101%	104%
PJM	88%	111%	97%	81%	104%

Figure 7-6 shows zonal net revenue and the annual levelized total cost for the new entrant CT by LDA.

Figure 7-6 New entrant CT net revenue and 20-year levelized total cost by LDA (Dollars per installed MW-year): 2014 through 2018



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

20 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.[21] 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 higher in all zones in 2018 than in 2017 (Table 7-11). The increase in energy prices offset the increase in gas prices. Gas pipelines have been updated to reflect the most commonly used pipeline within the zone.

Table 7-11 Energy net revenue for a new entrant CC under economic dispatch: 2014 through 2018 (Dollars per installed MW-year)[22]

Zone	2014	2015	2016	2017	2018	Change in 2018 from 2017
AECO	$145,019	$86,041	$77,436	$56,881	$75,553	33%
AEP	$122,938	$110,129	$87,008	$67,312	$121,414	80%
APS	$173,881	$159,605	$111,871	$86,244	$130,397	51%
ATSI	$95,226	$100,101	$84,691	$68,957	$134,358	95%
BGE	$178,861	$144,276	$147,033	$81,053	$110,097	36%
ComEd	$56,376	$62,091	$60,623	$43,655	$63,154	45%
DAY	$87,647	$98,713	$84,056	$69,165	$130,403	89%
DEOK	$76,708	$93,987	$79,855	$65,472	$135,931	108%
DLCO	$95,715	$110,504	$98,949	$73,380	$102,504	40%
Dominion	$121,923	$113,425	$98,902	$68,916	$103,559	50%
DPL	$125,605	$59,502	$50,853	$32,376	$55,107	70%
EKPC	$106,766	$96,164	$77,905	$59,573	$101,444	70%
JCPL	$148,884	$84,893	$72,755	$60,433	$72,751	20%
Met-Ed	$143,346	$119,387	$93,883	$81,360	$87,971	8%
PECO	$148,203	$119,922	$88,690	$73,232	$83,034	13%
PENELEC	$199,981	$167,584	$113,286	$88,862	$131,738	48%
Pepco	$133,442	$110,841	$97,806	$61,656	$94,278	53%
PPL	$261,970	$176,376	$95,223	$83,342	$121,142	45%
PSEG	$178,093	$135,601	$95,446	$81,765	$91,104	11%
RECO	$144,256	$92,028	$77,966	$62,871	$75,043	19%
PJM	$100,026	$112,059	$89,712	$68,325	$101,049	48%

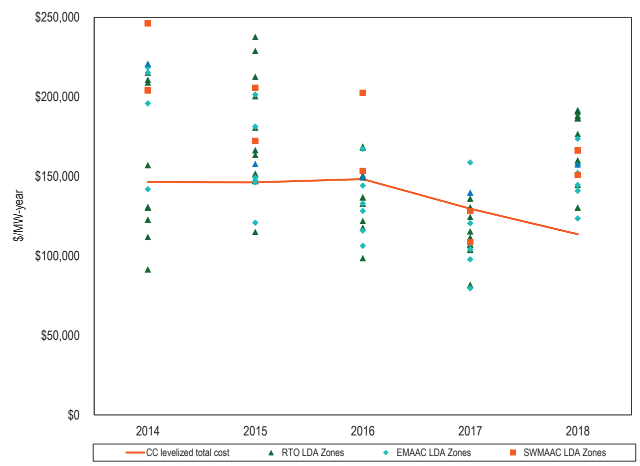
In 2018, a new CC would have received sufficient net revenue to cover levelized total costs in all zones (Table 7-12).

Table 7-12 Percent of 20-year levelized total costs recovered by CC energy and capacity net revenue: 2014 through 2018

Zone	2014	2015	2016	2017	2018
AECO	147%	101%	90%	80%	127%
AEP	108%	112%	84%	81%	157%
APS	143%	145%	101%	96%	165%
ATSI	89%	137%	113%	89%	168%
BGE	168%	141%	137%	99%	146%
ComEd	63%	79%	66%	63%	115%
DAY	84%	104%	82%	83%	164%
DEOK	76%	100%	79%	80%	169%
DLCO	89%	112%	92%	86%	140%
Dominion	107%	114%	92%	83%	141%
DPL	134%	83%	72%	61%	109%
EKPC	97%	102%	78%	75%	138%
JCPL	150%	100%	86%	83%	124%
Met-Ed	144%	124%	101%	99%	127%
PECO	149%	124%	97%	93%	134%
PENELEC	183%	156%	114%	105%	166%
Pepco	139%	118%	103%	84%	133%
PPL	225%	162%	102%	101%	155%
PSEG	174%	138%	113%	122%	153%
RECO	151%	108%	101%	108%	139%
PJM	103%	117%	96%	90%	143%

Figure 7-7 shows zonal net revenue and the annual levelized total cost for the new entrant CC by LDA.

Figure 7-7 New entrant CC net revenue and 20-year levelized total cost by LDA (Dollars per installed MW-year): 2009 through 2018



21 All starts associated with combined cycle units are assumed to be warm starts.

22 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 higher in all zones as a result of more run hours, higher gas prices and associated higher energy prices (Table 7-13).

Table 7-13 Energy net revenue for a new entrant CP: 2014 through 2018 (Dollars per installed MW-year)[23]

Zone	2014	2015	2016	2017	2018	Change in 2018 from 2017
AECO	$135,618	$57,738	$13,467	$9,372	$40,456	332%
AEP	$131,376	$59,291	$45,026	$41,987	$77,378	84%
APS	$122,804	$50,615	$18,633	$21,504	$53,394	148%
ATSI	$144,617	$60,042	$40,157	$42,021	$80,156	91%
BGE	$194,930	$98,895	$55,337	$24,037	$63,302	163%
ComEd	$130,840	$46,034	$33,781	$31,360	$45,189	44%
DAY	$136,357	$58,151	$36,942	$40,631	$75,823	87%
DEOK	$123,148	$53,572	$33,432	$37,064	$81,646	120%
DLCO	$114,884	$46,956	$35,006	$38,052	$79,622	109%
Dominion	$181,512	$104,919	$52,227	$32,934	$78,999	140%
DPL	$194,835	$85,228	$26,882	$20,957	$64,206	206%
EKPC	$118,789	$44,408	$28,752	$29,718	$52,381	76%
JCPL	$140,056	$55,433	$10,206	$10,469	$39,241	275%
Met-Ed	$178,817	$75,694	$23,786	$25,032	$61,234	145%
PECO	$129,947	$53,073	$10,853	$9,537	$37,622	294%
PENELEC	$150,457	$69,447	$27,272	$19,963	$56,293	182%
Pepco	$134,680	$51,598	$15,734	$8,585	$37,456	336%
PPL	$129,001	$51,990	$9,195	$9,699	$37,347	285%
PSEG	$202,692	$84,772	$16,581	$15,876	$45,705	188%
RECO	$198,435	$84,885	$16,104	$15,229	$46,115	203%
PJM	$155,324	$64,637	$27,469	$24,201	$57,678	138%

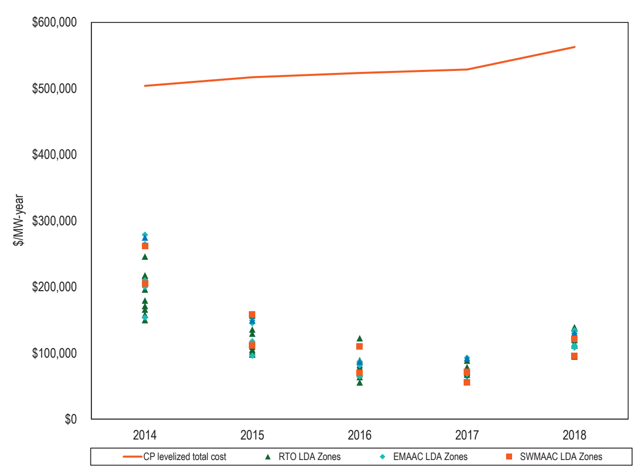
In 2018, a new CP would not have received sufficient net revenue to cover levelized total costs in any zone (Table 7-14). This has been the consistent result for a new CP for the entire five year period of the analysis.

Table 7-14 Percent of 20-year levelized total costs recovered by CP energy and capacity net revenue: 2014 through 2017

Zone	2014	2015	2016	2017	2018
AECO	41%	23%	13%	11%	20%
AEP	33%	21%	16%	15%	24%
APS	31%	20%	11%	11%	20%
ATSI	36%	31%	23%	17%	25%
BGE	52%	31%	21%	13%	22%
ComEd	33%	19%	13%	13%	20%
DAY	34%	21%	14%	15%	24%
DEOK	31%	20%	13%	14%	25%
DLCO	30%	19%	14%	14%	24%
Dominion	43%	30%	17%	13%	24%
DPL	52%	28%	16%	13%	24%
EKPC	30%	19%	13%	13%	19%
JCPL	42%	22%	12%	11%	19%
Met-Ed	49%	26%	15%	14%	21%
PECO	40%	22%	12%	11%	19%
PENELEC	43%	25%	16%	13%	20%
Pepco	41%	22%	13%	11%	17%
PPL	39%	22%	12%	11%	17%
PSEG	55%	29%	17%	18%	23%
RECO	54%	29%	17%	17%	23%
PJM	41%	24%	15%	14%	22%

Figure 7-8 shows zonal net revenue and the annual levelized total cost for the new entrant CP by LDA.

Figure 7-8 New entrant CP net revenue and 20-year levelized total cost by LDA (Dollars per installed MW-year): 2014 through 2018



23 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.[24]

New entrant nuclear plant energy market net revenues were higher in all zones as a result of higher gas prices and associated higher energy prices (Table 7-15).

Table 7-15 Energy net revenue for a new entrant nuclear plant: 2014 through 2018 (Dollars per installed MW-year)[25]

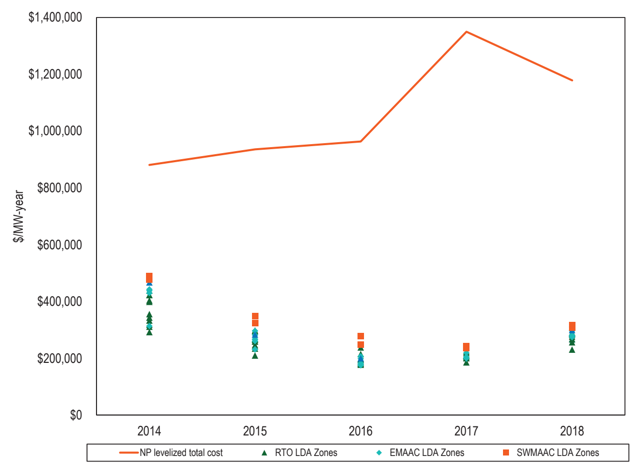
Zone	2014	2015	2016	2017	2018	Change in 2018 from 2017
AECO	$371,704	$210,951	$131,601	$156,342	$215,981	38%
AEP	$298,580	$196,283	$157,896	$171,019	$222,186	30%
APS	$323,903	$219,518	$162,740	$175,029	$233,849	34%
ATSI	$311,864	$199,801	$159,236	$176,249	$236,039	34%
BGE	$425,852	$291,608	$226,774	$198,271	$263,053	33%
ComEd	$260,958	$161,560	$144,334	$150,715	$166,306	10%
DAY	$301,626	$198,297	$159,007	$176,383	$232,332	32%
DEOK	$287,128	$193,109	$154,639	$172,138	$237,909	38%
DLCO	$279,720	$185,821	$153,346	$171,689	$235,049	37%
Dominion	$372,061	$249,796	$181,090	$189,531	$254,873	34%
DPL	$410,148	$239,877	$155,841	$175,178	$245,078	40%
EKPC	$282,325	$183,084	$149,713	$163,766	$205,510	25%
JCPL	$376,070	$209,466	$126,740	$160,983	$213,276	32%
Met-Ed	$358,792	$202,324	$129,738	$166,160	$213,557	29%
PECO	$363,090	$203,906	$124,425	$156,285	$208,282	33%
PENELEC	$335,356	$208,193	$146,528	$166,415	$222,108	33%
Pepco	$409,787	$267,502	$197,183	$192,440	$254,757	32%
PPL	$359,322	$202,890	$126,268	$157,925	$203,791	29%
PSEG	$399,029	$220,799	$131,275	$166,621	$217,635	31%
RECO	$394,147	$222,479	$132,357	$167,355	$219,857	31%
PJM	$346,073	$213,363	$152,537	$170,525	$225,071	32%

In 2018, a new nuclear plant would not have received sufficient net revenue to cover levelized total costs in any zone (Table 7-16). This has been the consistent result for a new nuclear plant for the entire five year period of the analysis.

Table 7-16 Percent of 20-year levelized total costs recovered by nuclear energy and capacity net revenue: 2014 through 2018

Zone	2014	2015	2016	2017	2018
AECO	50%	29%	19%	15%	24%
AEP	37%	26%	20%	15%	23%
APS	40%	29%	20%	16%	24%
ATSI	39%	32%	25%	16%	25%
BGE	56%	37%	29%	18%	27%
ComEd	33%	22%	18%	14%	20%
DAY	38%	26%	20%	16%	24%
DEOK	36%	26%	20%	15%	25%
DLCO	35%	25%	19%	15%	24%
Dominion	46%	32%	22%	17%	26%
DPL	54%	32%	21%	16%	26%
EKPC	36%	25%	19%	15%	22%
JCPL	50%	28%	18%	15%	24%
Met-Ed	48%	28%	19%	16%	23%
PECO	49%	28%	18%	15%	23%
PENELEC	45%	28%	21%	16%	23%
Pepco	54%	35%	26%	17%	26%
PPL	48%	28%	18%	15%	22%
PSEG	54%	30%	21%	18%	25%
RECO	53%	30%	21%	18%	25%
PJM	45%	29%	21%	16%	24%

Figure 7-9 New entrant NP net revenue and 20-year levelized total cost by LDA (Dollars per installed MW-year): 2014 through 2018



24 The annual class average capacity factor was applied to total energy market net revenues.
25 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 for a DS plant economically dispatched by PJM in real time.

New entrant DS plant energy market net revenues were higher in all zones except ComEd in 2018 (Table 7-17).

Table 7-17 Energy market net revenue for a new entrant DS: 2014 through 2018 (Dollars per installed MW-year)

Zone	2014	2015	2016	2017	2018	Change in 2018 from 2017
AECO	$33,704	$13,206	$2,347	$2,524	$10,603	320%
AEP	$14,731	$3,910	$950	$1,406	$4,240	201%
APS	$18,335	$7,390	$1,001	$1,327	$6,833	415%
ATSI	$14,366	$3,615	$2,054	$1,754	$7,378	321%
BGE	$51,010	$18,278	$8,113	$3,156	$13,132	316%
ComEd	$11,523	$2,284	$716	$1,325	$735	(45%)
DAY	$14,546	$3,699	$1,009	$1,656	$4,009	142%
DEOK	$13,708	$3,226	$1,376	$3,054	$6,809	123%
DLCO	$13,365	$3,113	$2,381	$1,499	$9,476	532%
Dominion	$43,399	$12,028	$2,488	$2,727	$15,543	470%
DPL	$39,134	$20,042	$3,638	$5,599	$14,648	162%
EKPC	$14,745	$2,915	$998	$961	$1,940	102%
JCPL	$33,656	$13,100	$883	$2,809	$11,464	308%
Met-Ed	$32,564	$13,084	$857	$3,755	$11,301	201%
PECO	$32,940	$12,493	$831	$2,810	$10,119	260%
PENELEC	$16,243	$6,428	$864	$1,674	$5,658	238%
Pepco	$52,350	$12,827	$3,424	$2,466	$12,714	416%
PPL	$33,521	$13,135	$756	$2,959	$9,039	205%
PSEG	$33,121	$12,688	$1,013	$3,243	$10,623	228%
RECO	$31,237	$13,751	$1,195	$2,991	$9,964	233%
PJM	$29,787	$9,561	$1,845	$2,485	$8,811	255%

In 2018, the new entrant DS would not have received sufficient net revenue to cover levelized total costs in any zone. This has been the consistent result for a new DS for the entire five year period of the analysis.

Table 7-18 Percent of 20-year levelized total costs recovered by DS energy and capacity net revenue: 2014 through 2018

Zone	2014	2015	2016	2017	2018
AECO	62%	41%	31%	29%	49%
AEP	28%	31%	20%	23%	37%
APS	31%	33%	20%	23%	39%
ATSI	28%	58%	47%	28%	39%
BGE	71%	44%	34%	29%	43%
ComEd	26%	30%	20%	23%	42%
DAY	28%	30%	20%	23%	37%
DEOK	28%	30%	20%	24%	38%
DLCO	28%	30%	21%	23%	40%
Dominion	46%	35%	21%	24%	44%
DPL	65%	45%	32%	31%	52%
EKPC	28%	30%	20%	22%	35%
JCPL	62%	41%	30%	29%	49%
Met-Ed	59%	41%	30%	30%	42%
PECO	61%	40%	30%	29%	49%
PENELEC	49%	37%	30%	29%	38%
Pepco	73%	41%	31%	29%	43%
PPL	60%	41%	30%	29%	40%
PSEG	65%	43%	39%	48%	58%
RECO	64%	44%	40%	48%	58%
PJM	47%	38%	29%	30%	43%

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).[26]

On shore wind energy market net revenues were higher in 2018 as a result of higher energy prices.

Table 7-19 Energy market net revenue for an on shore wind installation (Dollars per installed MW-year): 2014 through 2018

Zone	2014	2015	2016	2017	2018	Change in 2018 from 2017
AEP	$114,239	$80,178	$67,159	$70,717	$92,230	30%
APS	$102,906	$71,775	$62,440	$73,390	$95,929	31%
ComEd	$108,057	$81,422	$69,030	$74,787	$76,434	2%
PENELEC	$125,968	$82,392	$63,565	$72,304	$96,112	33%

Renewable energy credits ranged from 30 percent of the total net revenue of an on shore wind installation in APS to 38 percent of the total net revenue of an on shore wind installation in ComEd.

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

Table 7-20 RECs revenue for an on shore wind installation (Dollars per installed MW-year): 2014 through 2018

Zone	2014	2015	2016	2017	2018
AEP	$35,452	$40,709	$42,605	$44,740	$44,969
APS	$31,597	$31,921	$37,846	$44,409	$45,010
ComEd	$41,769	$48,128	$47,995	$52,940	$52,075
PENELEC	$35,598	$36,773	$41,347	$44,891	$45,880

In 2018, a new on shore wind installation would not have received sufficient net revenue to cover levelized total costs in any of the four zones analyzed. This has been the consistent result for a new wind installation for the entire five year period of the analysis. Renewable energy credits accounted for between 30 percent of the total net revenue of a wind installation in APS and 38 percent of the total net revenue of a wind installation in ComEd.

Table 7-21 Percent of 20-year levelized total costs recovered by on shore wind net revenue (Dollars per installed MW-year): 2014 through 2018

Zone	2014	2015	2016	2017	2018
AEP	78%	63%	49%	64%	67%
APS	70%	54%	45%	65%	69%
ComEd	78%	67%	52%	70%	64%
PENELEC	86%	62%	48%	65%	69%

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 higher in 2018 than 2017 as a result of higher energy prices.

Table 7-22 Energy market net revenue for an off shore wind installation (Dollars per installed MW-year): 2014 through 2018

Zone	2014	2015	2016	2017	2018	Change in 2018 from 2017
AECO	$201,681	$136,886	$102,884	$115,326	$145,738	26%

Renewable energy credits accounted for 31 percent of the total net revenue of an off shore wind installation.

Table 7-23 RECs revenue for an off shore wind installation (Dollars per installed MW-year): 2014 through 2018

Zone	2014	2015	2016	2017	2018
AECO	$55,002	$60,009	$64,741	$68,446	$69,916

In 2018, a new off shore wind installation would not have received sufficient net revenue to cover levelized total costs.

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%	30%	25%	28%	33%

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).[27]

Solar energy market net revenues were higher in 2018 as a result of higher energy prices.

Table 7-25 Energy market net revenue for a solar installation (Dollars per installed MW-year): 2014 through 2018

Zone	2014	2015	2016	2017	2018	Change in 2018 from 2017
AECO	$52,811	$40,145	$33,903	$32,591	$35,636	9%
Dominion	-	-	$68,474	$62,385	$67,774	9%
DPL	-	-	$39,785	$40,312	$49,960	24%
JCPL	$48,418	$32,538	$27,391	$27,698	$28,511	3%
PSEG	$68,093	$53,282	$38,566	$36,803	$38,380	4%

Renewable energy credits ranged from 64 percent of the total net revenue of a solar installation in DPL to 78 percent of the total net revenue of a solar installation in AECO.

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

Table 7-26 RECs revenue for a solar installation (Dollars per installed MW-year): 2014 through 2018

Zone	2014	2015	2016	2017	2018
AECO	$169,543	$221,495	$250,090	$250,546	$219,959
Dominion	-	-	$281,175	$221,189	$167,697
DPL	-	-	$175,753	$160,133	$135,394
JCPL	$160,696	$185,595	$204,688	$207,605	$181,659
PSEG	$212,050	$275,223	$286,233	$272,447	$232,241

In 2018, a new solar installation would have received sufficient net revenue to cover levelized total costs in AECO, Dominion, JCPL and PSEG.

Table 7-27 Percent of 20-year levelized total costs recovered by solar net revenue (Dollars per installed MW-year): 2014 through 2018

Zone	2014	2015	2016	2017	2018
AECO	105%	121%	139%	149%	121%
Dominion	-	-	165%	148%	110%
DPL	-	-	107%	108%	90%
JCPL	99%	102%	115%	125%	101%
PSEG	130%	150%	160%	168%	129%

Historical New Entrant CT and CC Revenue Adequacy

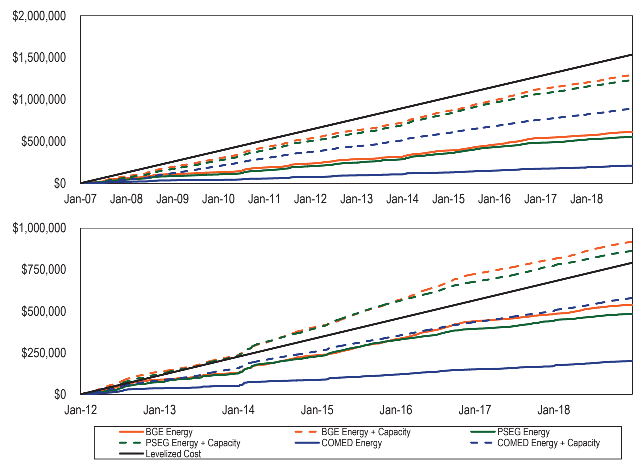
Total unit net revenues include energy and capacity revenues. Analysis of the total unit revenues of theoretical new entrant CTs and CCs for three representative locations shows that CT and CC units that entered the PJM markets in 2007 have not covered their total costs, including the return on and of capital, on a cumulative basis. The analysis also shows that theoretical new entrant CTs 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 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.

The summary figures compare net revenues for a new entrant CT and CC that began operation on January 1, 2007, at the start of the RPM Capacity Market, 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.

For the ComEd Zone, the PSEG Zone and the BGE Zone, Figure 7-10 compares cumulative energy market net revenues and energy market net revenues plus capacity market revenues to cumulative levelized costs for a new CT that began operation on January 1, 2007, and for a new CT that began operation on January 1, 2012. Cumulative energy and capacity market net revenues were less than cumulative total costs of the 2007 new entrant. Cumulative energy and capacity market net revenues were greater than the cumulative total costs of the 2012 new entrant CT unit in BGE and PSEG zones and less than total costs for the ComEd Zone.

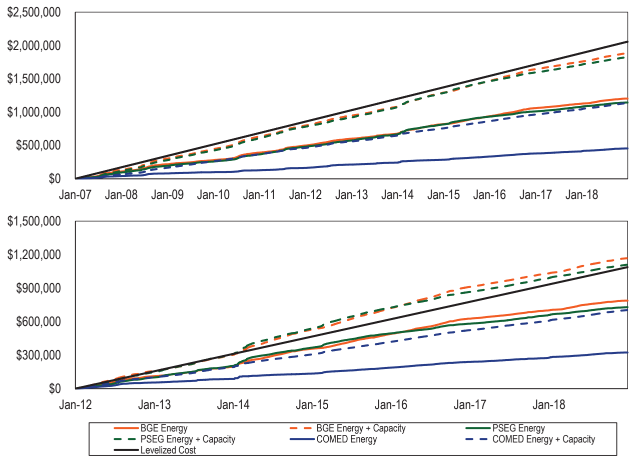
Figure 7-10 Historical new entrant CT revenue adequacy: January 2007 through December 2018 and January 2012 through December 2018[28]



28 The gas pipeline pricing point used in this analysis for ComEd remains Chicago City Gate. The gas pipelines used in this analysis have been updated to Zone 6 non-NY for BGE and Texas Eastern M3 for PSEG.

For the ComEd Zone, the PSEG Zone and the BGE Zone, Figure 7-11 compares cumulative energy market net revenues and energy market net revenues plus capacity market revenues to cumulative levelized costs for a new CC that began operation on January 1, 2007, and for a new CC that began operation on January 1, 2012. Cumulative energy and capacity market net revenues were greater than the cumulative total costs of the 2012 new entrant CC unit in BGE and PSEG zones and less than total costs for the 2007 and 2012 new entrant CC in ComEd Zone. 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.

Figure 7-11 Historical new entrant CC revenue adequacy: January 2007 through December 2018 and January 2012 through December 2018[29]



Assumptions used for this analysis are shown in Table 7-28.

Table 7-28 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

Factors in Net Revenue Adequacy

Although it can be expected that in the long run, in a competitive market, net revenue from all sources will cover the fixed and variable costs of investing in new generating resources, including a competitive return on investment, actual results are expected to vary from year to year. Wholesale energy markets, like other markets, are cyclical. When the markets are long, prices will be lower and when the markets are short, prices will be higher.

The net revenue for a new generation resource varied significantly with the input fuel type and the efficiency of the reference technology. In 2018, the average short run marginal cost of the CC was lower than the average short run

29 The gas pipeline pricing point used in this analysis for ComEd remains Chicago City Gate. The gas pipelines used in this analysis have been updated to Zone 6 non-NY for BGE and Texas Eastern M3 for PSEG.

marginal cost of the CP in every month except January and the operating cost of the CT was lower than the CP all months except January, November, and December. (Figure 7-5)

The net revenue results illustrate some fundamentals of the PJM wholesale power market. Higher energy prices, higher gas prices, and higher coal prices meant that all units ran for more hours with higher margins than in prior years. High demand hours result in less efficient units setting prices, which results in higher net revenues for more efficient units. Scarcity revenues in the energy market also contribute to covering fixed costs, when they occur, but scarcity revenues are not a predictable and systematic source of net revenue in the PJM design. In the PJM design, the balance of the net revenue required to cover the fixed costs of peaking units comes from the capacity market.

However, there may be a lag in capacity market prices which either offsets the reduction in energy market revenues or exacerbates the reduction in energy market revenues. Capacity market prices are a function of a three year historical average net revenue offset which is generally an inaccurate estimate of actual net revenues in the current operating year and an inaccurate estimate of expected net revenues for the forward capacity market. A forward looking estimate of expected energy and ancillary services net revenues is a preferred method for defining the offset in the capacity market. Capacity market prices and revenues have a substantial impact on the profitability of investing in CTs and CCs. In 2018, capacity market prices increased in all zones.

The returns earned by investors in generating units are a direct function of net revenues, the cost of capital, and the fixed costs associated with the generating unit. Positive returns may be earned at less than the annualized fixed costs, although the returns are less than the target. A sensitivity analysis was performed to determine the impact of changes in net revenue on the return on investment for a new generating unit. The internal rate of return (IRR) was calculated for a range of 20-year levelized net revenue streams, using 20-year levelized total costs from Table 7-7 . The results are shown in Table 7-29.[30]

Table 7-29 Internal rate of return sensitivity for CT, CC and CP generators

	CT		CC		CP	
	20-Year Levelized Net Revenue	20-Year After Tax IRR	20-Year Levelized Net Revenue	20-Year After Tax IRR	20-Year Levelized Net Revenue	20-Year After Tax IRR
Sensitivity 1	$124,974	13.5%	$119,116	13.5%	$598,944	13.3%
Base Case	$121,324	12.0%	$113,641	12.0%	$562,444	12.0%
Sensitivity 2	$117,674	10.4%	$108,166	10.4%	$525,944	10.6%
Sensitivity 3	$114,024	8.6%	$102,691	8.6%	$489,444	9.0%
Sensitivity 4	$110,374	6.5%	$97,216	6.6%	$452,944	7.2%
Sensitivity 5	$106,724	4.0%	$91,741	4.2%	$416,444	5.1%
Sensitivity 6	$103,074	0.8%	$86,266	1.1%	$379,944	2.3%

Additional sensitivity analyses were performed for the CT and the CC technologies for the debt to equity ratio; the term of the debt financing; and the costs of interconnection. Table 7-30 shows the levelized annual revenue requirements associated with a range of debt to equity ratios holding the 12 percent IRR constant. The base case assumes 50/50 debt to equity ratio. As the percent of equity financing decreases, the levelized annual revenue required to earn a 12 percent IRR falls.

Table 7-30 Debt to equity ratio sensitivity for CT and CC assuming 20 year debt term and 12 percent internal rate of return

	Equity as a percent of total financing	CT levelized annual revenue requirement	CC levelized annual revenue requirement
Sensitivity 1	60%	$126,862	$120,515
Sensitivity 2	55%	$124,082	$117,056
Base Case	50%	$121,324	$113,641
Sensitivity 3	45%	$118,586	$110,270
Sensitivity 4	40%	$115,870	$106,942
Sensitivity 5	35%	$113,174	$103,659
Sensitivity 6	30%	$110,500	$100,418

Table 7-31 shows the levelized annual revenue requirement associated with various terms for the debt financing, assuming a 50/50 debt to equity ratio and 12 percent rate of return. As the term of the debt financing decreases, more net revenue is required annually to maintain a 12 percent rate of return.

30 This analysis was performed for the MMU by Pasteris Energy, Inc. The annual costs were based on a 20-year project life, 50/50 debt to equity capital structure with a target IRR of 12 percent and a debt rate of 7 percent. For depreciation, the analysis assumed a 15-year modified accelerated cost-recovery schedule (MACRS) for the CT plant and 20-year MACRS for the CC and CP plants. An annual rate of cost inflation of 2.5 percent was used in all calculations.

Table 7-31 Debt term sensitivity for CT and CC assuming 50/50 debt to equity ratio and 12 percent internal rate of return

	Term of debt in years	CT levelized annual revenue requirement	CC levelized annual revenue requirement
Sensitivity 1	30	$112,990	$120,347
Sensitivity 2	25	$116,144	$116,914
Base Case	20	$121,324	$113,641
Sensitivity 3	15	$125,442	$110,531
Sensitivity 4	10	$130,904	$107,587

Table 7-32 shows the impact of a range of assumed interconnection costs on the levelized annual revenue requirement for the CT and the CC technologies. Interconnection costs vary significantly by location across PJM and even within PJM zones and can significantly impact the profitability of investing in peaking and midmerit generation technologies in a specific location. The impact on the annualized revenue requirements is more substantial for CTs than for CCs as interconnection costs are a larger proportion of overall project costs for CTs and as the new entrant CC has a higher energy output over which to spread the costs than the new entrant CT.

Table 7-32 Interconnection cost sensitivity for CT and CC

	CT			CC		
	Capital cost ($000)	Percent of total capital cost	Annualized revenue requirement ($/ICAP-Year)	Capital cost ($000)	Percent of total capital cost	Annualized revenue requirement ($/ICAP-Year)
Sensitivity 1	$0	0.0%	$119,079	$0	0.0%	$111,230
Sensitivity 2	$3,501	1.3%	$120,201	$11,056	1.2%	$112,436
Base Case	$7,001	2.6%	$121,324	$22,113	2.3%	$113,641
Sensitivity 3	$10,502	3.9%	$122,446	$33,169	3.5%	$114,847
Sensitivity 4	$14,003	5.2%	$123,568	$44,225	4.6%	$116,052
Sensitivity 5	$17,503	6.6%	$124,691	$55,281	5.8%	$117,257
Sensitivity 6	$21,004	7.9%	$125,793	$66,338	7.0%	$118,463

Actual Net Revenue

This analysis of net revenues is based on actual net revenues for actual units operating in PJM. Net revenues from energy and capacity markets are compared to avoidable costs to determine the extent to which the revenues from PJM markets provide sufficient incentive for continued operations in PJM markets. Avoidable costs are the costs which must be paid each year in order to keep a unit operating. Avoidable costs are less than total costs, which include the return on and of capital, and more than marginal costs, which are the purely short run incremental costs of producing energy. It is rational to operate a unit whenever the price is greater than its short run marginal costs. It is rational for an owner to continue to operate a unit rather than retire the unit if the unit is covering or is expected to cover its avoidable costs and therefore contributing to covering fixed costs. It is not rational for an owner to continue to operate a unit rather than retire the unit if the unit is not covering and is not expected to cover its avoidable costs. As a general matter, under those conditions, retirement of the unit is the logical option. Thus, this comparison of actual net revenues to avoidable costs is a measure of the extent to which units in PJM may be at risk of retirement.

The definition of avoidable costs, based on the RPM rules, includes both avoidable costs and the annualized fixed costs of investments required to maintain a unit as a capacity resource (APIR). When actual net revenues are compared to actual avoidable costs in this analysis, the actual avoidable costs are adjusted to exclude APIR. Existing APIR is a sunk cost and a rational decision about retirement would ignore such sunk costs. For example, APIR may reflect investments in environmental technology which were made in prior years to keep units in service. These costs are sunk costs.

The MMU calculated actual unit specific energy and ancillary service net revenues for a range of technology classes. These net revenues were compared to avoidable costs to determine the extent to which PJM energy and ancillary service markets alone provide sufficient incentive for continued operations in PJM markets. Energy and ancillary service revenues were then combined with the actual capacity revenues, and compared to actual avoidable costs to determine the extent to which the capacity market revenues covered any shortfall between energy and ancillary net revenues and avoidable costs. The comparison of the two results is an indicator of the significance of the role of the capacity market in maintaining the viability of existing generating units.

Actual energy net revenues include day-ahead and balancing market energy revenues, less short run marginal costs, plus any applicable day-ahead or balancing operating reserve credits. Ancillary service revenues include actual unit credits for regulation services, synchronized reserves, black start service, and reactive revenues.

The MMU calculated average avoidable costs in dollars per MW-year based on submitted avoidable cost rate (ACR) data for units associated with the most recent 2017/2018 RPM Auction.[31] For units that did not submit ACR data, the default ACR was used.

The PJM capacity market design provides supplemental signals to the market based on the locational and forward looking need for generation resources to maintain system reliability. For this analysis, unit specific capacity revenues associated with the 2017/2018 and 2018/2019 Delivery Years, reflecting commitments made in base residual auctions (BRA) and subsequent incremental auctions, net of any performance penalties, were added to unit specific energy and ancillary net revenues to determine total revenue from PJM markets in 2018. Any unit with a significant portion of installed capacity designated as FRR committed was excluded from the analysis.[32] For units exporting capacity, the applicable BRA clearing price was applied.

Net revenues were analyzed for most technologies for which avoidable costs are developed in the capacity market. The analysis is on a unit specific basis, using individual unit actual net revenues and individual unit avoidable costs. Net revenues are calculated using units' price-based offers for technologies other than nuclear. For nuclear units, public data on revenues and costs are used.

The unit specific energy and ancillary net revenues, avoidable costs and capacity revenues, on which the class averages shown in Table 7-33 are based, include a wide range of results. In order to illustrate this underlying variability while preserving confidentiality of unit specific information, the data are aggregated and summarized by quartile.

Table 7-33 shows energy and ancillary service net revenues by quartile for select technology classes.[33] Differences in energy net revenue within technology classes reflect differences in incremental costs which are a function of plant efficiencies, input fuels, variable operating and maintenance (VOM) expenses and emission rates, as well as differences in location which affect both the LMP and delivered costs for input fuels. Unlike the other technologies, nuclear data is from public sources in order to avoid revealing confidential information. Nuclear unit revenue is based on day-ahead LMP from the relevant node as shown in Table 7-36, adjusted by the class average equivalent availability factor. Nuclear unit capacity revenue assumes that the unit cleared its full installed capacity at the BRA locational clearing price as shown in Table 7-37.

Table 7-33 also includes new entrant energy market net revenue from Table 7-9, Table 7-11, Table 7-13, Table 7-15, and Table 7-17 for comparison purposes. The new entrant net revenues are higher than existing unit CC net revenues and coal plant net revenues, are not comparable to existing unit CT net revenues, are within the range of existing unit diesel net revenues, and are on the low end of existing nuclear plant net revenues.

31 If a unit submitted updated ACR data for an incremental auction, that data was used instead of the ACR data submitted for the base residual auction.

32 The MMU cannot assess the risk of FRR designated units because the incentives associated with continued operations for these units are not transparent and are not aligned with PJM market incentives. For the same reasons, units with significant FRR commitments are excluded from the analysis of units potentially facing significant capital expenditures associated with environmental controls.

33 The quartile numbers in the table are the dividing line between the quartiles. The first quartile result means that 25 percent of units have lower net revenues, the median result means that 50 percent of units have lower net revenues and the third quartile result means that 75 percent of units have lower net revenues.

Table 7-33 Net revenue by quartile for select technologies: 2018

		($/MW-Yr)									
	Total Installed Capacity	Energy and ancillary service net revenue				Capacity revenue			Energy, ancillary, and capacity revenue		
Technology	(ICAP)	New entrant	First quartile	Median	Third quartile	First quartile	Median	Third quartile	First quartile	Median	Third quartile
CC - Combined Cycle	32,620	$101,049	$183	$25,986	$70,404	$27,598	$54,879	$72,011	$59,910	$99,901	$126,493
CT - Aero Derivative	5,998	$60,553	$4,823	$8,510	$14,933	$52,122	$56,788	$77,458	$57,817	$72,370	$89,018
CT - Industrial Frame	21,639	-	($176)	$3,121	$9,026	$38,759	$55,734	$62,898	$37,206	$58,380	$71,248
Coal Fired	48,320	$57,678	$10,783	$23,689	$43,210	$44,330	$52,891	$64,965	$48,492	$80,955	$113,828
Diesel	242	$8,811	$0	$4,804	$15,934	$45,851	$55,199	$60,534	$53,307	$59,877	$75,316
Hydro	2,750	-	$108,381	$150,088	$172,256	$33,730	$51,103	$69,248	$168,280	$208,772	$223,148
Nuclear	33,233	$225,071	$231,022	$269,003	$297,212	$52,901	$63,510	$65,710	$294,531	$334,559	$350,113
Oil or Gas Steam	10,997	-	($2,734)	$0	$15,597	$45,752	$54,362	$63,049	$44,632	$61,111	$67,596
Pumped Storage	4,721	-	$34,960	$60,299	$60,299	$61,888	$62,605	$65,877	$98,425	$105,845	$123,079

Table 7-34 shows the percent of avoidable costs covered by net revenue from PJM energy and ancillary services markets by quartiles. In 2018, a substantial portion of units did not achieve full recovery of avoidable costs through energy markets alone. After including capacity revenues, net revenues from all markets cover avoidable costs for even the first quartile of most technology types, although this is not the case for every individual unit and it is not the case for coal units.

The analysis of nuclear plants includes publicly available data on energy market prices, capacity prices, and an estimate of annual avoidable costs and incremental capital expenditures from the Nuclear Energy Institute (NEI) based on NEI's average across all U.S. nuclear plants.[34] [35] The NEI annual avoidable costs used in the analysis are for 2017, the most recent data available.

Table 7-34 Avoidable cost recovery by quartile: 2018

	Total Installed	Recovery of avoidable costs from energy and ancillary net revenue			Recovery of avoidable costs from all markets		
Technology	Capacity (ICAP)	First quartile	Median	Third quartile	First quartile	Median	Third quartile
CC - Combined Cycle	32,620	1%	195%	527%	449%	748%	948%
CT - Aero Derivative	5,998	41%	72%	127%	490%	614%	755%
CT - Industrial Frame	21,639	(2%)	28%	83%	342%	536%	654%
Coal Fired	48,320	17%	38%	65%	79%	124%	175%
Diesel	242	0%	42%	139%	464%	521%	656%
Hydro	2,750	349%	484%	555%	542%	673%	719%
Nuclear	33,233	87%	102%	107%	108%	123%	133%
Oil or Gas Steam	10,997	(10%)	0%	15%	104%	182%	227%
Pumped Storage	4,721	385%	664%	664%	1,084%	1,166%	1,356%

Table 7-35 shows the proportion of units recovering avoidable costs from energy and ancillary services markets and from all markets. In 2018, capacity revenues were sufficient to cover the shortfall between energy revenues and avoidable costs for the majority of units and technology types in PJM, with the exception of coal and nuclear units.[36] [37] [38]

34 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>.

35 The NEI costs for Hope Creek and Salem were both treated as those associated with a two unit configuration because all three units are located in the same area.

36 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>.

37 The NEI costs for Hope Creek and Salem were both treated as those associated with a two unit configuration because all three units are located in the same area.

38 Analysis excludes Catawba 1 which joined PJM with the integration of DEOK.

Table 7-35 Proportion of units recovering avoidable costs: 2011 through 2018

	Units with full recovery from energy and ancillary net revenue								Units with full recovery from all markets							
Technology	2011	2012	2013	2014	2015	2016	2017	2018	2011	2012	2013	2014	2015	2016	2017	2018
CC - Combined Cycle	55%	46%	50%	72%	59%	63%	57%	66%	85%	79%	79%	95%	88%	93%	89%	98%
CT - Aero Derivative	15%	6%	6%	53%	15%	8%	10%	30%	100%	96%	76%	98%	100%	99%	100%	99%
CT - Industrial Frame	26%	23%	17%	38%	13%	8%	3%	21%	99%	98%	83%	100%	100%	100%	100%	96%
Coal Fired	31%	17%	27%	78%	16%	15%	12%	11%	82%	36%	54%	83%	64%	40%	36%	63%
Diesel	48%	42%	37%	69%	56%	33%	32%	39%	100%	100%	77%	100%	100%	100%	100%	97%
Hydro	74%	61%	95%	97%	81%	79%	95%	94%	81%	77%	97%	98%	100%	100%	97%	98%
Nuclear	-	-	53%	95%	16%	5%	16%	53%	-	-	63%	100%	58%	16%	53%	84%
Oil or Gas Steam	8%	6%	11%	15%	3%	0%	0%	10%	92%	78%	86%	85%	91%	88%	81%	76%
Pumped Storage	100%	100%	95%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

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.[39] [40] 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.[41] 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.[42] 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 and forward prices for 2019 are similar to 2018 prices. The result is that nuclear plant net revenues have continued to increase during 2018 and for the three year forward period. 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. The results for nuclear plants are also sensitive to forward prices and the extent to which the owners of the plants sell the output forward.

Table 7-36 includes the publicly available data on energy market prices, Table 7-37 shows capacity market prices and Table 7-38 shows nuclear cost data for the eighteen nuclear plants in PJM and Oyster Creek, which retired September 17, 2018.[43]

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.

39 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.

40 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.

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

42 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.*

43 Installed capacity is from NEI <https://www.nei.org/resources/map-of-us-nuclear-plants>.

Table 7-36 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

Table 7-37 Nuclear unit capacity market data: 2008 through 2021[44]

	ICAP	BRA Capacity Price ($/MWh)													
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Beaver Valley	1,808	$3.36	$4.24	$5.86	$5.54	$2.27	$0.95	$3.48	$5.41	$3.73	$3.93	$6.04	$5.25	$3.57	$4.69
Braidwood	2,337	$3.36	$4.24	$5.86	$5.54	$2.27	$0.95	$3.48	$5.41	$3.73	$3.93	$7.25	$8.59	$8.03	$7.95
Byron	2,300	$3.36	$4.24	$5.86	$5.54	$2.27	$0.95	$3.48	$5.41	$3.73	$3.93	$7.25	$8.59	$8.03	$7.95
Calvert Cliffs	1,708	$8.22	$9.03	$8.15	$5.54	$5.07	$7.72	$7.11	$6.35	$5.69	$4.96	$6.04	$5.26	$3.80	$4.86
Cook	2,069	$3.36	$4.24	$5.86	$5.54	$2.27	$0.95	$3.48	$5.41	$3.73	$3.93	$6.04	$5.25	$3.57	$4.69
Davis Besse	894	NA	NA	NA	NA	$2.35	$1.02	$3.48	$10.71	$8.81	$4.87	$6.04	$5.25	$3.57	$5.45
Dresden	1,797	$3.36	$4.24	$5.86	$5.54	$2.27	$0.95	$3.48	$5.41	$3.73	$3.93	$7.25	$8.59	$8.03	$7.95
Hope Creek	1,172	$6.91	$6.94	$7.37	$5.54	$5.22	$8.28	$7.43	$6.35	$5.69	$4.96	$7.50	$6.77	$6.59	$7.23
LaSalle	2,271	$3.36	$4.24	$5.86	$5.54	$2.27	$0.95	$3.48	$5.41	$3.73	$3.93	$7.25	$8.59	$8.03	$7.95
Limerick	2,242	$6.91	$6.94	$7.37	$5.54	$5.22	$8.28	$7.43	$6.35	$5.69	$4.96	$7.50	$6.77	$6.59	$7.23
North Anna	1,892	$3.36	$4.24	$5.86	$5.54	$2.27	$0.95	$3.48	$5.41	$3.73	$3.93	$6.04	$5.25	$3.57	$4.69
Oyster Creek	608	$6.91	$6.94	$7.37	$5.54	$5.22	$8.28	$7.43	$6.35	$5.69	$4.96	$7.50	NA	NA	NA
Peach Bottom	2,347	$6.91	$6.94	$7.37	$5.54	$5.22	$8.28	$7.43	$6.35	$5.69	$4.96	$7.50	$6.77	$6.59	$7.23
Perry	1,240	NA	NA	NA	NA	$2.35	$1.02	$3.48	$10.71	$8.81	$4.87	$6.04	$5.25	$3.57	$5.45
Quad Cities	1,819	$3.36	$4.24	$5.86	$5.54	$2.27	$0.95	$3.48	$5.41	$3.73	$3.93	$7.25	$8.59	$8.03	$7.95
Salem	2,328	$6.91	$6.94	$7.37	$5.54	$5.22	$8.28	$7.43	$6.35	$5.69	$4.96	$7.50	$6.77	$6.59	$7.23
Surry	1,676	$3.36	$4.24	$5.86	$5.54	$2.27	$0.95	$3.48	$5.41	$3.73	$3.93	$6.04	$5.25	$3.57	$4.69
Susquehanna	2,520	$3.36	$6.32	$7.37	$5.54	$5.07	$7.72	$7.11	$6.35	$5.69	$4.96	$6.04	$5.25	$3.80	$4.86
Three Mile Island	803	$3.36	$6.32	$7.37	$5.54	$5.07	$7.72	$7.11	$6.35	$5.69	$4.96	$6.04	$5.25	$3.80	$4.86

44 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 7-38 Nuclear unit costs: 2008 through 2018[45]

	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 7-39 shows the surplus or shortfall in $/MWh for the eighteen nuclear plants in PJM and Oyster Creek calculated using this data.[46] In Table 7-39, 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 2016 and 2017, and 15 nuclear plants with a total capacity of 27,947 MW did not recover all their fuel costs, operating costs, and capital expenditures in 2016. The surplus or shortfall assumes that the unit cleared its full unforced capacity at the BRA locational clearing price.[47] 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[48] and Three Mile Island, Quad Cities, and a portion of Byron's capacity did not clear the 2019/2020 Auction.[49] Three Mile Island and Quad Cities did not clear the 2020/2021 Auction.[50] Three Mile Island, Dresden, and most of Byron did not clear the 2021/2022 Auction.[51] Beaver Valley, Davis Besse, and Perry did not clear the 2021/2022 Auction.[52]

45 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>.

46 Analysis excludes Catawba 1 which is pseudo tied to PJM.

47 Installed capacity is from NEI <https://www.nei.org/resources/map-of-us-nuclear-plants>.

48 Exelon. "Exelon Announces Outcome of 2019-2020 PJM Capacity Auction," (May 25, 2016) <http://www.exeloncorp.com/newsroom/pjm-auction-results-2016>.

49 Exelon. "Exelon Announces Outcome of 2019-2020 PJM Capacity Auction," (May 25, 2016) <http://www.exeloncorp.com/newsroom/pjm-auction-results-2016>.

50 Exelon, "Exelon Announces Outcome of 2020-2021 PJM Capacity Auction," (May 24, 2017) <http://www.exeloncorp.com/newsroom/pjm-auction-results-release-2017>.

51 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>.

52 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>

Table 7-39 Nuclear unit surplus (shortfall) based on public data: 2008 through 2018

	ICAP	Surplus (Shortfall) ($/MWh)										
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Beaver Valley	1,808	$26.1	$6.0	$10.1	$8.5	($3.4)	$1.4	$11.5	$2.9	($0.8)	$2.1	$11.5
Braidwood	2,337	$24.7	$2.2	$6.0	$3.0	($6.3)	($2.6)	$7.0	($1.5)	($3.6)	($2.0)	$3.5
Byron	2,300	$24.2	($1.5)	$3.0	($0.9)	($9.5)	($3.7)	$4.7	($6.5)	($10.0)	($3.2)	$3.3
Calvert Cliffs	1,708	$60.1	$20.3	$28.1	$17.6	$4.2	$14.1	$31.1	$13.7	$6.7	$5.6	$13.9
Cook	2,069	$28.9	$6.7	$11.0	$8.4	($3.7)	$1.3	$10.1	$2.4	($1.0)	$1.1	$6.6
Davis Besse	894	NA	NA	NA	NA	($13.4)	($7.0)	$6.4	($1.9)	($4.8)	($8.9)	($2.2)
Dresden	1,797	$25.4	$2.8	$7.2	$4.1	($5.4)	($1.1)	$8.9	($0.0)	($2.0)	($0.6)	$4.6
Hope Creek	1,172	$53.5	$16.6	$24.1	$16.5	$2.2	$11.9	$25.6	$5.9	($2.7)	$0.9	$9.5
LaSalle	2,271	$24.6	$2.2	$6.0	$3.0	($6.2)	($1.9)	$7.5	($1.2)	($3.9)	($2.3)	$3.6
Limerick	2,242	$53.7	$16.7	$24.3	$16.3	$2.3	$11.7	$25.3	$6.1	($2.6)	$1.1	$9.7
North Anna	1,892	$51.8	$14.4	$25.1	$16.5	$0.1	$5.7	$23.0	$10.6	$2.6	$4.3	$13.6
Oyster Creek	608	$47.1	$8.0	$15.4	$6.8	($8.5)	$2.7	$16.0	($5.1)	($11.9)	($10.2)	($1.1)
Peach Bottom	2,347	$53.3	$16.5	$23.7	$15.8	$2.0	$11.8	$25.1	$5.4	($2.9)	$0.8	$9.2
Perry	1,240	NA	NA	NA	NA	($13.4)	($6.4)	$5.3	($1.0)	($4.7)	($7.9)	$0.6
Quad Cities	1,819	$23.9	($0.7)	$2.0	($2.2)	($13.4)	($7.0)	$0.3	($8.0)	($9.9)	($3.9)	$1.9
Salem	2,328	$53.6	$16.7	$24.0	$16.5	$2.2	$11.8	$25.5	$5.8	($2.8)	$0.8	$9.5
Surry	1,676	$48.6	$13.5	$23.8	$16.0	($0.2)	$5.1	$21.4	$10.4	$2.2	$4.1	$13.6
Susquehanna	2,520	$46.6	$14.8	$22.0	$15.8	$1.1	$10.6	$24.2	$5.9	($2.3)	$1.2	$7.6
Three Mile Island	803	$40.5	$6.1	$12.9	$4.2	($9.9)	$0.4	$13.3	($7.2)	($12.7)	($10.6)	($4.9)

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 7-40 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.[53] Forward prices are as of January 2, 2019. The capacity prices are known based on PJM capacity auction results.

Table 7-40 Forward prices in PJM energy and capacity markets and annual costs[54]

	ICAP	Average Forward LMP ($/MWh)				BRA Capacity Price ($/MWh)			2017 NEI Costs ($/MWh)		
	(MW)	2019	2020	2021	2022	2019	2020	2021	Fuel	Operating	Capital
Beaver Valley	1,808	$34.32	$33.37	$31.58	$30.38	$5.25	$3.57	$4.69	$6.44	$18.46	$5.99
Braidwood	2,337	$27.29	$26.53	$25.13	$24.12	$8.59	$8.03	$7.95	$6.44	$18.46	$5.99
Byron	2,300	$27.27	$26.51	$25.11	$24.10	$8.59	$8.03	$7.95	$6.44	$18.46	$5.99
Calvert Cliffs	1,708	$34.61	$33.88	$32.07	$30.81	$5.26	$3.80	$4.86	$6.44	$18.46	$5.99
Cook	2,069	$30.93	$29.94	$28.36	$27.22	$5.25	$3.57	$4.69	$6.44	$18.46	$5.99
Davis Besse	894	$33.44	$32.39	$30.69	$29.47	$5.25	$3.57	$5.45	$6.42	$27.32	$8.92
Dresden	1,797	$28.33	$27.52	$26.07	$25.03	$8.59	$8.03	$7.95	$6.44	$18.46	$5.99
Hope Creek	1,172	$29.69	$29.27	$27.69	$26.60	$6.77	$6.59	$7.23	$6.44	$18.46	$5.99
LaSalle	2,271	$27.29	$26.53	$25.13	$24.12	$8.59	$8.03	$7.95	$6.44	$18.46	$5.99
Limerick	2,242	$29.77	$29.33	$27.74	$26.66	$6.77	$6.59	$7.23	$6.44	$18.46	$5.99
North Anna	1,892	$34.19	$33.46	$31.67	$30.43	$5.25	$3.57	$4.69	$6.44	$18.46	$5.99
Peach Bottom	2,347	$29.56	$29.13	$27.56	$26.48	$6.77	$6.59	$7.23	$6.44	$18.46	$5.99
Perry	1,240	$34.88	$34.02	$32.21	$30.95	$5.25	$3.57	$5.45	$6.42	$27.32	$8.92
Quad Cities	1,819	$25.86	$25.18	$23.84	$22.88	$8.59	$8.03	$7.95	$6.44	$18.46	$5.99
Salem	2,328	$29.67	$29.24	$27.66	$26.58	$6.77	$6.59	$7.23	$6.44	$18.46	$5.99
Surry	1,676	$34.03	$33.29	$31.52	$30.28	$5.25	$3.57	$4.69	$6.44	$18.46	$5.99
Susquehanna	2,520	$29.06	$28.66	$27.09	$26.05	$5.25	$3.80	$4.86	$6.44	$18.46	$5.99
Three Mile Island	803	$28.51	$28.12	$26.60	$25.56	$5.25	$3.80	$4.86	$6.42	$27.32	$8.92

53 Forward prices on January 2, 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.

54 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 7-41 show the surplus or shortfall that would be received net of avoidable costs and incremental capital expenditures by year, based on forward prices, for the 2018 through 2021 period, on a per MWh basis. The fuel and operating costs are the 2017 NEI fuel, operating, and capital costs. Table 7-42 shows the total dollar surplus or shortfall and adjusts energy revenues and operating costs using the annual class average capacity factor. Based on forward prices for energy and known forward prices for capacity, all but three nuclear plants would cover their annual avoidable costs on average over the next three years (2019 through 2021). The three plants are Davis Besse, Perry, and Three Mile Island. In May 2017, TMI requested deactivation in 2019. In March 2018, Davis Besse and Perry requested deactivation in 2021. All three plants are single unit sites which have higher operating costs per MWh than multiple unit plants. The three plants together are 2,937 MW.

Table 7-41 Nuclear unit forward annual surplus (shortfall) in $/MWh[55]

	Surplus (Shortfall) ($/MWh)		
	2019	2020	2021
Beaver Valley	$8.68	$6.05	$5.39
Braidwood	$4.99	$3.67	$2.19
Byron	$4.97	$3.65	$2.18
Calvert Cliffs	$8.97	$6.79	$6.03
Cook	$5.29	$2.61	$2.16
Davis Besse	($3.97)	($6.70)	($6.52)
Dresden	$6.03	$4.66	$3.14
Hope Creek	$5.57	$4.97	$4.03
LaSalle	$4.99	$3.67	$2.19
Limerick	$5.65	$5.03	$4.08
North Anna	$8.55	$6.14	$5.48
Peach Bottom	$5.44	$4.83	$3.90
Perry	($2.53)	($5.07)	($5.00)
Quad Cities	$3.56	$2.32	$0.90
Salem	$5.55	$4.95	$4.00
Surry	$8.39	$5.97	$5.32
Susquehanna	$3.41	$1.56	$1.06
Three Mile Island	($8.91)	($10.74)	($11.20)

55 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 7-42 Nuclear unit forward annual surplus (shortfall) ($ in millions)[56]

	Surplus (Shortfall) ($ in millions)		
	2019	2020	2021
Beaver Valley	$134.3	$93.5	$84.7
Braidwood	$106.4	$80.3	$51.7
Byron	$104.3	$78.6	$50.6
Calvert Cliffs	$131.0	$99.0	$89.3
Cook	$95.8	$48.4	$41.9
Davis Besse	($26.9)	($47.8)	($45.6)
Dresden	$97.3	$76.4	$53.8
Hope Creek	$57.9	$52.0	$43.3
LaSalle	$103.5	$78.0	$50.2
Limerick	$112.2	$100.5	$83.8
North Anna	$138.6	$99.3	$90.0
Peach Bottom	$113.4	$101.5	$84.1
Perry	($22.6)	($49.6)	($47.8)
Quad Cities	$61.3	$42.2	$20.9
Salem	$114.6	$102.8	$85.5
Surry	$120.5	$85.6	$77.6
Susquehanna	$77.7	$37.4	$28.2
Three Mile Island	($56.9)	($69.6)	($72.3)

Units At Risk

The definition of units at risk of retirement is units that are not expected to recover their avoidable costs from the market.

Unit revenues are a combination of energy and ancillary service revenues and capacity market revenues. Units that fail to recover and are expected to continue to fail to recover avoidable costs from total market revenues, including capacity market revenues, are at risk of retirement particularly if the results are expected to continue.[57] Units that failed to clear the most recent capacity auction(s) are at increased risk of retirement if this result is outside the control of the plant owner and is expected to continue. The profile of coal and nuclear units that are not expected to cover their going forward costs over the next three years is shown in Table 7-43.[58] [59] These units are considered at risk of retirement.[60]

The analysis of coal units compares expected energy and capacity market revenues to ACR values and exclude APIR over the period 2019-2021. Bus level forward LMPs are based on forward prices with a basis adjustment for

56 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>.

57 FRR coal units, external coal units, and coal units that have either already started the deactivation process or requested deactivation review are excluded from the at risk analysis.

58 Avoidable costs for coal units are ACR values and exclude APIR.

59 For nuclear units, avoidable costs consist of fuel costs, operating costs, and capital expenditures.

60 Units expected to continue operations for reasons not directly related to market prices are not considered at risk of retirement.

the specific plant locations.[61] Forward prices are as of January 2, 2019.

The nuclear plants considered to be at risk of retirement are the plants in Table 7-42 showing a shortfall over the period 2019-2021.

Based on these criteria, a total of 14,954 MW of coal and nuclear capacity are at risk of retirement, in addition to the units that are currently planning to retire. The 14,954 MW considered to be at risk of retirement consist of 12,017 MW of coal and 2,937 MW of nuclear capacity.

Table 7-43 Profile of coal and nuclear units at risk of retirement

Technology	No. Units	ICAP (MW)	Avg. 2018 Run Hrs	Avg. Unit Age (Yrs)	Avg. Heat Rate (Btu/MWh)
Coal Fired	24	12,017	3,983	51	10,029
Nuclear	3	2,937	-	38	-
Total	27	14,954			

61 Forward prices on January 2, 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.