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, solar, and wind generating units.

Overview

Net Revenue

- Energy market net revenues are significantly affected by energy prices and fuel prices. Energy prices and fuel prices were lower in 2019 than in 2018. As a result, units ran with lower margins.
- In 2019, average energy market net revenues decreased by 44 percent for a new CT, 33 percent for a new CC, 78 percent for a new CP, 25 percent for a new nuclear plant, 52 percent for a new DS, 28 percent for a new onshore wind installation, 32 percent for a new offshore wind installation and 24 percent for a new solar installation compared to 2018.
- The relative prices of fuel varied during 2019. The marginal cost of the new CC was less than the marginal cost of the new CP in 2019, and the marginal cost of the new CT was less than the marginal cost of the new CP in all months except January.
- Capacity market revenue accounted for 60 percent of total net revenues for a new CT, 45 percent for a new CC, 79 percent for a new CP, 20 percent for a new nuclear plant, 87 percent for a new DS, 11 percent for a new onshore wind installation, 8 percent for a new offshore wind installation and 8 percent for a new solar installation.
- In 2019, a new CT would not have received sufficient net revenue to cover levelized total costs in any zones as a result of lower energy prices.
- In 2019, a new CC would have received sufficient net revenue to cover levelized total costs in ten out of 20 zones.
- In 2019, a new CP would not have received sufficient net revenue to cover levelized total costs in any zone.
- In 2019, a new nuclear plant would not have received sufficient net revenue to cover levelized total costs in any zone.
- In 2019, a new entrant onshore wind installation would not have received sufficient net revenue to cover levelized total costs in any of the four zones analyzed. Net revenues would have covered between 37 and 45 percent of levelized total costs of a new entrant onshore wind installation in AEP, APS, ComEd and PENELEC. Renewable energy credits accounted for at least 18 percent of the total net revenue of an onshore wind installation.
- In 2019, a new entrant offshore wind installation in AECO would not have received sufficient net revenue to cover levelized total costs. Net revenues would have covered 21 percent of levelized total costs. Renewable energy credits accounted for 18 percent of the total net revenue of an offshore wind installation.
- In 2019, a new entrant solar installation would have covered more than 100 percent of levelized total costs in three of the five zones analyzed. Renewable energy credits accounted for at least 55 percent of the total net revenue of a solar installation.
- In 2019, 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 2019, 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 9,543 MW of coal, CT, diesel, and nuclear capacity are at risk of retirement, in addition to the units that are currently planning to retire. The 9,543 MW at risk of retirement include 4,306 MW of coal, 3,103 MW of CT and diesel, and 2,134 MW of nuclear capacity.
- Negative prices do not have a significant impact on total nuclear unit market revenue. Since 2014, negative prices have affected nuclear plants' annual gross revenues by an average of 0.1 percent.[1]

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

Recommendations

The MMU recommends that the net revenue calculation used by PJM to calculate the net Cost of New Entry (CONE) and net ACR be based on a forward looking estimate of expected energy and ancillary services net revenues using forward prices for energy and fuel. (Priority: Medium. New recommendation. Status: Not adopted.)

Historical New Entrant CC Revenue Adequacy

Total unit net revenues include energy and capacity revenues. Analysis of the total unit revenues of theoretical new entrant CCs for three representative locations shows that CC units that entered the PJM markets in 2007 have not covered 100 percent of their total costs, including the return on and of capital, on a cumulative basis. The analysis also shows that theoretical new entrant CCs that entered the PJM markets in 2012 have covered their total costs on a cumulative basis in the BGE and PSEG zones, but have not covered 100 percent of total costs in the 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 not covered 100 percent of their total costs, including the return on and of capital, on a cumulative basis. CCs that entered the PJM markets in 2012 have covered their total costs on a cumulative basis in the BGE and PSEG zones, but have not covered 100 percent of total costs in the 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.

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 and to maintain existing 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 revenue is the contribution to fixed costs, which include a return on investment, depreciation and income taxes, and to avoidable costs, which include long term and intermediate term operation and maintenance expenses.[2] Net revenue is the contribution to total fixed and avoidable costs received by generators from all PJM markets.

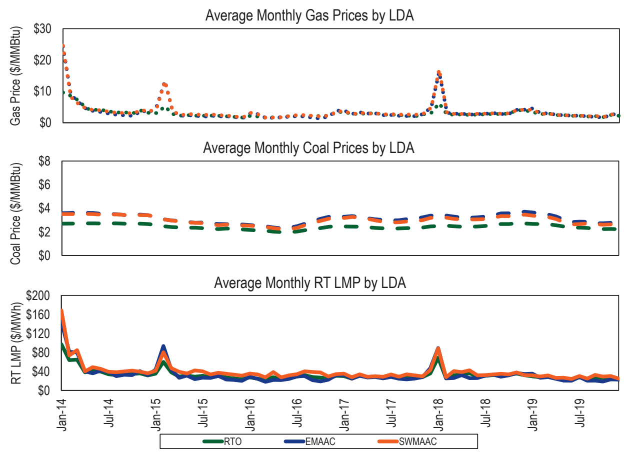
In a perfectly competitive, energy only market in long run equilibrium, net revenue from the energy market would be expected to equal the annualized fixed and avoidable costs for the marginal unit, including a

2 Avoidable costs are sometimes referred to as going forward costs.

competitive return on investment. The PJM market design includes other markets that 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 and to encourage maintaining existing 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 28.6 percent lower in 2019 than in 2018, \$27.32 per MWh versus \$38.24 per MWh. Eastern and western natural gas prices decreased in 2019. The price of Northern Appalachian coal was 10.4 percent lower; the price of Central Appalachian coal was 10.7 percent lower; the price of Powder River Basin coal was 0.9 percent higher; the price of eastern natural gas was 39.5 percent lower; and the price of western natural gas was 21.9 percent lower (Figure 7-1).

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



Spark Spreads, Dark Spreads, and Quark Spreads

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

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

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

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

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

	BGE			ComEd			PSEG			Western Hub		
	Spark	Dark	Quark	Spark	Dark	Quark	Spark	Dark	Quark	Spark	Dark	Quark
2014	$30.27	$51.11	$66.58	$11.14	$42.50	$43.23	$19.85	$43.01	$60.19	$23.23	$39.58	$55.05
2015	$25.86	$34.71	$44.42	$14.48	$27.68	$26.98	$13.53	$23.38	$34.31	$23.59	$25.29	$35.00
2016	$28.29	$28.11	$38.32	$14.22	$25.72	$26.58	$13.44	$10.80	$24.06	$21.47	$18.53	$28.75
2017	$16.77	$18.41	$33.20	$11.81	$25.40	$28.19	$12.80	$10.89	$29.97	$16.30	$15.71	$30.50
2018	$15.64	$25.17	$41.16	$12.42	$26.62	$29.27	$7.61	$12.35	$34.23	$15.83	$21.05	$37.04
2019	$16.48	$16.01	$28.30	$11.02	$21.01	$22.60	$9.18	$4.54	$22.20	$13.26	$12.72	$25.01

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

	BGE			ComEd			PSEG			Western Hub		
	Spark	Dark	Quark	Spark	Dark	Quark	Spark	Dark	Quark	Spark	Dark	Quark
2014	$88.1	$118.9	$118.9	$68.1	$68.3	$68.3	$78.3	$94.0	$94.3	$83.0	$86.7	$86.7
2015	$42.4	$44.9	$45.0	$20.8	$22.5	$22.5	$32.7	$40.9	$41.1	$31.3	$33.1	$33.4
2016	$32.8	$32.6	$32.6	$16.4	$16.6	$16.8	$17.0	$18.6	$18.4	$19.1	$18.5	$18.5
2017	$23.5	$25.0	$25.0	$19.8	$19.9	$19.9	$19.9	$22.9	$23.0	$23.2	$22.5	$22.6
2018	$50.5	$36.9	$36.9	$17.0	$18.0	$17.9	$51.9	$33.3	$33.2	$42.3	$30.5	$30.4
2019	$35.7	$35.8	$35.8	$24.8	$24.8	$24.8	$20.1	$22.6	$23.0	$28.7	$28.5	$28.5

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

Figure 7-2 Hourly spark spread (gas) for peak hours ($/MWh): 2018 through 2019[3]

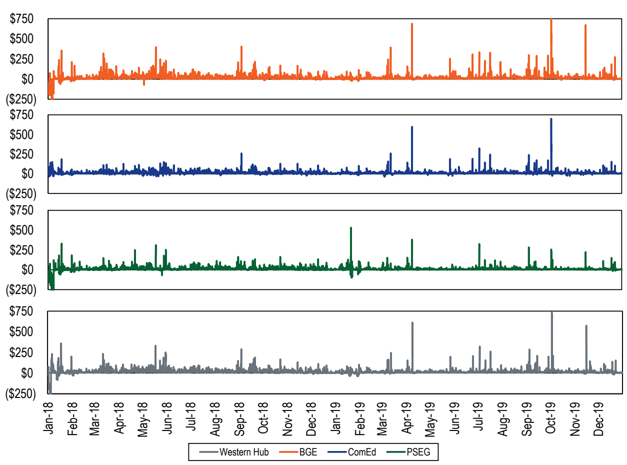
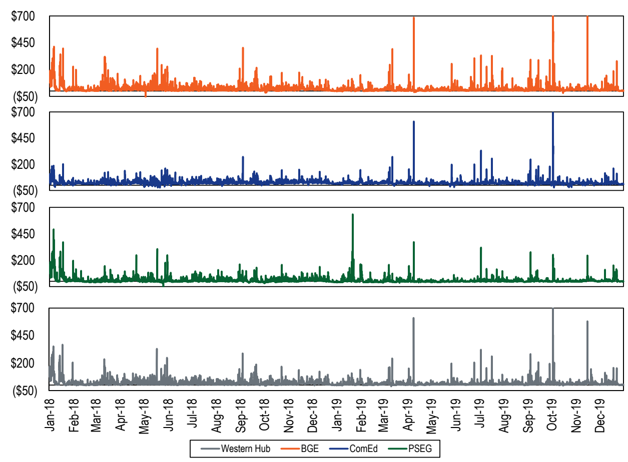


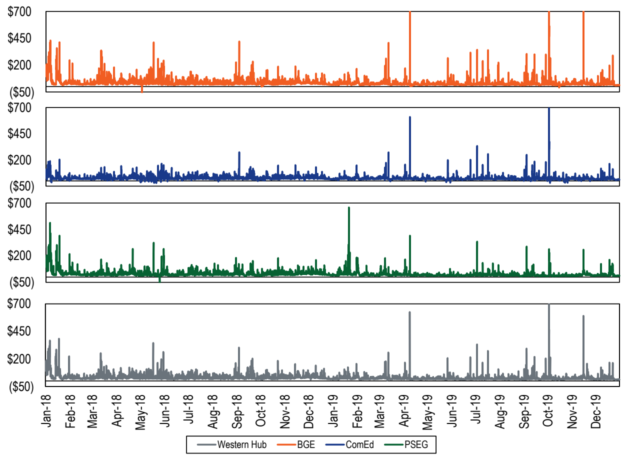
Figure 7-3 Hourly dark spread (coal) for peak hours ($/MWh): 2018 through 2019[4]



3 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.

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

Figure 7-4 Hourly quark spread (uranium) for selected zones ($/MWh): 2018 through 2019[5]



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.

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

- The CT plant is a single GE Frame 7HA.02 CT with an installed capacity of 360.1 MW, equipped with evaporative coolers, and selective catalytic reduction (SCR) for NO_x reduction.
- The CC plant includes two GE Frame 7HA.02 CTs and a single steam turbine generator with an installed capacity of 1,137.2 MW, equipped with evaporative cooling, duct burners, a heat recovery steam generator (HRSG) for each CT, with steam reheat, and SCR for NO_x reduction.
- The CP is a subcritical steam unit with an installed capacity of 600.0 MW, 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 is a single oil fired CAT 2 MW unit with an installed capacity of 2.0 MW using New York Harbor ultra low sulfur diesel.
- The nuclear plant includes two units and related facilities using the Westinghouse AP1000 technology with an installed capacity of 2,200 MW.
- The onshore wind installation includes 37 Siemens 2.7 MW wind turbines with an installed capacity of 99.9 MW.
- The offshore wind installation includes of 43 Siemens 7.0 MW wind turbines with an installed capacity of 301.0 MW.
- The solar installation is a 35.5 acre ground mounted fixed tilt solar farm with an installed AC capacity of 10 MW.

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.[6 7] 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.[8] CO_2, NO_x and SO_2 emission allowance costs were obtained from daily spot cash prices.[9]

The class average equivalent availability factor for each type of plant was calculated from PJM data and incorporated into all revenue calculations.[10] In addition, each CT, CC, CP, and DS plant was assumed to take a continuous 14 day annual planned outage in the fall season.

CT revenues for the provision of reactive services include both real-time reactive service revenues and reactive capability revenues. Reactive service revenues for CTs are based on the average reactive service revenue per MW-year received by all CTs with 20 or fewer operating years. Reactive service revenues for CCs are based on the average reactive service revenue per MW-year received by all CC generators with 20 or fewer operating

5 Quark spreads use a heat rate of 10,000 Btu/kWh, zonal hourly LMPs, and daily uranium (U_3O_8) prices.

6 Hourly ambient conditions supplied by DTN.

7 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.

8 CO_2 emission allowance costs only included for states participating in RGGI, including New Jersey.

9 CO_2, NO_x and SO_2 emission daily prompt prices obtained from Evolution Markets, Inc.

10 Outage figures obtained from the PJM eGADS database.

years. Reactive service revenues for CPs are based on the average reactive service revenue per MW-year received by all CP generators with 60 or fewer operating years. Table 7-3 includes reactive service revenues plus reactive capability revenue of $3,350/MW-year for all unit types plus reactive service revenue.[11]

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

	Reactive				
	CT	CC	CP	Diesel	Nuclear
2014	$3,721	$4,046	$3,574	$3,350	$3,350
2015	$3,673	$4,911	$3,386	$3,350	$3,350
2016	$3,436	$4,573	$3,470	$3,350	$3,350
2017	$3,885	$3,591	$3,438	$3,350	$3,350
2018	$4,150	$3,350	$4,929	$3,350	$3,350
2019	$3,519	$3,350	$3,629	$3,350	$3,350

Zonal net revenues reflect average zonal LMP and fuel costs based on locational fuel indices and zone specific delivery charges.[12] The delivered fuel cost for natural gas reflects the zonal, daily delivered price of natural gas from a specific pipeline and is from published commodity daily cash prices, with a basis adjustment for transportation costs.[13] 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.[14] Net revenues are calculated for all zones except OVEC.[15]

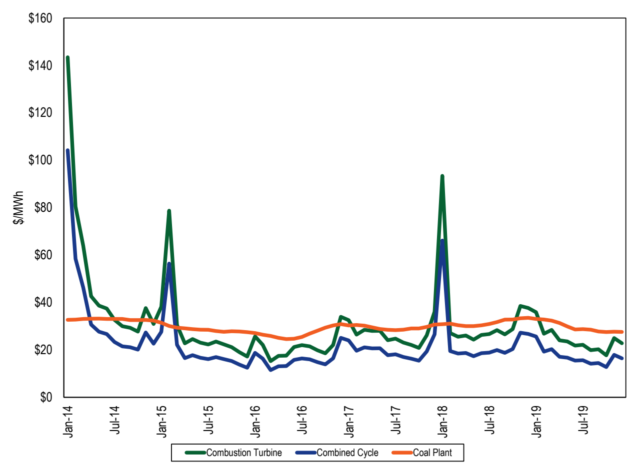
Short run marginal cost includes fuel costs, emissions costs, and the short run marginal component of VOM costs.[16] [17] Average short run marginal costs are shown, including all components, in Table 7-4 and the short run marginal component of VOM is also shown separately.

Table 7-4 Average short run marginal costs: 2019

Unit Type	Short Run Marginal Costs ($/MWh)	Heat Rate (Btu/kWh)	VOM ($/MWh)
CT	$24.03	9,241	$0.38
CC	$17.15	6,296	$1.39
CP	$29.65	9,250	$4.16
DS	$150.66	9,660	$0.25
Nuclear	$0.00	NA	$0.00
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 2019



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.

11 The value of $3,350/MW-year is the average of reactive capability payments of selected units obtained from FERC filings.
12 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.
13 Gas daily cash prices obtained from Platts.
14 Coal prompt month prices obtained from Platts.
15 The Ohio Valley Electric Corporation (OVEC) includes a generating plant in Ohio and a generating plant in Indiana, and high voltage transmission lines, but does not occupy a single geographic footprint like the other control zones.
16 Fuel costs are calculated using the daily spot price and may not equal what individual participants actually paid.
17 VOM rates provided by Pasteris Energy, Inc.

Table 7-5 Average run hours: 2014 through 2019

	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
2019	4,944	8,143	2,867	33	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 that contribute to covering generator avoidable costs and fixed costs. Capacity revenue for 2019 includes five months of the 2018/2019 capacity market clearing price and seven months of the 2019/2020 RPM capacity market clearing price.[18]

Table 7-6 Capacity revenue by PJM zones (Dollars per MW-year): 2014 through 2019[19]

Zone	2014	2015	2016	2017	2018	2019
AECO	$66,206	$56,448	$50,948	$43,669	$65,655	$58,103
AEP	$31,149	$48,128	$33,377	$34,645	$53,235	$45,873
APS	$31,149	$48,128	$33,377	$34,645	$53,216	$45,948
ATSI	$31,149	$95,422	$78,709	$42,929	$53,124	$45,781
BGE	$63,360	$56,448	$50,948	$43,669	$52,953	$45,651
ComEd	$31,149	$48,128	$33,377	$34,645	$63,994	$75,508
DAY	$31,149	$48,128	$33,377	$34,645	$52,760	$44,969
DEOK	$31,149	$48,128	$33,377	$34,645	$52,338	$44,515
DLCO	$31,149	$48,128	$33,377	$34,645	$53,045	$45,567
Dominion	$31,149	$48,128	$33,377	$34,645	$53,219	$45,665
DPL	$66,206	$56,448	$50,948	$43,669	$65,106	$57,607
EKPC	$31,149	$48,128	$33,377	$34,645	$52,400	$44,611
JCPL	$66,206	$56,448	$50,948	$43,669	$64,763	$56,462
Met-Ed	$63,360	$56,448	$50,948	$43,669	$53,353	$46,138
PECO	$66,206	$56,448	$50,948	$43,669	$65,707	$58,548
PENELEC	$63,360	$56,448	$50,945	$43,667	$53,154	$45,760
Pepco	$66,529	$56,448	$50,948	$43,669	$53,323	$46,207
PPL	$63,360	$56,448	$50,948	$43,669	$52,218	$45,398
PSEG	$72,567	$60,936	$67,224	$73,401	$79,190	$59,582
RECO	$72,567	$60,936	$67,224	$73,401	$79,190	$59,582
PJM	$46,247	$54,646	$48,568	$44,809	$58,432	$52,008

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 technologies except onshore wind increased in 2019 over 2018. The increase in levelized total costs of the solar installation includes the effect of tariffs on the cost of solar cells.

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.

18 The RPM revenue values for PJM are load-weighted, average clearing prices across the relevant base residual auctions. Differences in capacity market revenues reflect differences in clearing prices across LDAs.

19 See the *2019 State of the Market Report for PJM*, Appendix A: "PJM Geography," for details on the expansion of the PJM footprint.

Levelized Total Costs

Table 7-7 New entrant 20-year levelized total costs (By plant type (Dollars per installed MW-year))[20 21]

	20-Year Levelized Total Cost					
	2014	2015	2016	2017	2018	2019
Combustion Turbine	$122,604	$120,675	$119,346	$114,557	$118,116	$121,612
Combined Cycle	$146,443	$146,300	$148,327	$129,731	$113,641	$116,781
Coal Plant	$504,050	$517,017	$523,540	$528,701	$562,747	$581,567
Diesel Plant	$161,746	$170,500	$173,182	$158,817	$154,683	$169,859
Nuclear Plant	$880,770	$935,659	$963,107	$1,349,850	$1,178,607	$1,383,428
On Shore Wind Installation (with 1603 grant)	$198,033	$202,874	$231,310	$188,747	$214,780	$214,618
Off Shore Wind Installation (with 1603 grant)	-	-	-	-	$683,771	$710,472
Solar Installation (with 1603 grant)	$236,289	$234,151	$218,937	$200,931	$232,230	$243,936

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. The levelized cost of all units is sensitive to the capacity factor used. The LCOE of a solar installation is shown using a capacity factor of 17 percent. The LCOE of a solar installation is $133/MWh if a capacity factor of 21 percent is used because the costs are distributed over a greater number of MWh.

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 2019 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 because DS units had a very low capacity factor, which decreases the MWh over which costs are spread. The levelized costs of onshore wind, offshore wind and solar are higher than for a CT or CC and lower than for a CP or DS.

The levelized cost of all units is sensitive to the capacity factor used. The LCOE of a solar installation is shown using a capacity factor of 17 percent. The LCOE of a solar installation is $133/MWh if a capacity factor of 21 percent is used because the costs are distributed over a greater number of MWh.

Table 7-8 Levelized cost of energy: 2019

	CT	CC	CP	DS	Nuclear	Wind (On Shore)	Wind (Off Shore)	Solar
Levelized cost ($/MW-year)	$121,612	$116,781	$581,567	$169,859	$1,383,428	$214,618	$710,472	$243,936
Short run marginal costs ($/MWh)	$24.03	$17.15	$29.65	$150.66	$0.00	$0.00	$0.00	$0.00
Capacity factor (%)	52%	77%	24%	1%	94%	26%	45%	17%
Levelized cost of energy ($/MWh)	$51	$34	$307	$3,039	$168	$93	$180	$163

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.

20 Levelized total costs provided by Pasteris Energy, Inc.

21 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.

New entrant CT plant energy market net revenues were lower across all zones in 2019 as a result of lower energy prices (Table 7-9).

Table 7-9 Energy net revenue for a new entrant gas fired CT under economic dispatch: 2014 through 2019 (Dollars per installed MW-year)[22]

Zone	2014	2015	2016	2017	2018	2019	Change in 2019 from 2018
AECO	$84,836	$50,794	$52,699	$28,997	$34,625	$24,051	(31%)
AEP	$74,978	$69,424	$55,360	$36,440	$72,928	$44,651	(39%)
APS	$101,376	$97,467	$61,544	$48,564	$71,758	$24,930	(65%)
ATSI	$55,573	$59,263	$53,052	$38,949	$86,415	$45,733	(47%)
BGE	$99,953	$79,092	$92,965	$40,064	$52,362	$33,157	(37%)
ComEd	$34,672	$32,378	$34,109	$22,162	$32,571	$23,501	(28%)
DAY	$49,905	$57,180	$51,652	$37,682	$81,172	$51,092	(37%)
DEOK	$44,998	$54,542	$48,954	$36,051	$88,626	$46,495	(48%)
DLCO	$52,029	$81,445	$72,284	$46,308	$57,854	$30,516	(47%)
Dominion	$67,601	$68,742	$64,140	$37,075	$57,676	$35,826	(38%)
DPL	$65,984	$33,315	$26,615	$19,853	$28,229	$14,604	(48%)
EKPC	$65,277	$56,514	$48,036	$30,024	$55,351	$37,022	(33%)
JCPL	$85,599	$48,957	$48,143	$32,391	$32,118	$23,755	(26%)
Met-Ed	$87,153	$87,946	$71,178	$55,484	$44,929	$29,492	(34%)
PECO	$89,208	$86,138	$66,527	$46,494	$38,961	$22,037	(43%)
PENELEC	$139,617	$140,467	$89,309	$63,620	$83,911	$41,273	(51%)
Pepco	$70,396	$50,496	$46,753	$25,829	$42,134	$21,041	(50%)
PPL	$212,119	$155,947	$72,532	$59,248	$81,558	$28,443	(65%)
PSEG	$108,432	$99,278	$71,988	$54,477	$44,574	$24,808	(44%)
RECO	$80,365	$55,796	$53,746	$34,467	$35,019	$25,217	(28%)
PJM	$58,381	$73,259	$59,079	$39,709	$56,138	$31,382	(44%)

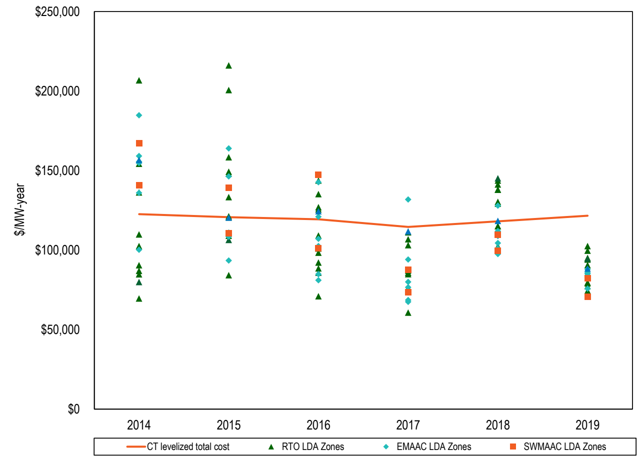
In 2019, a new CT would not have received sufficient net revenue to cover levelized total costs in any zone (Table 7-10).

Table 7-10 Percent of 20-year levelized total costs recovered by CT energy and capacity net revenue: 2014 through 2019

Zone	2014	2015	2016	2017	2018	2019
AECO	126%	92%	90%	67%	88%	70%
AEP	90%	100%	77%	65%	110%	77%
APS	111%	124%	82%	76%	109%	61%
ATSI	74%	131%	113%	75%	122%	78%
BGE	136%	115%	123%	76%	93%	68%
ComEd	57%	70%	59%	53%	85%	84%
DAY	69%	90%	74%	67%	117%	82%
DEOK	65%	88%	72%	65%	123%	78%
DLCO	71%	110%	91%	74%	97%	65%
Dominion	84%	100%	85%	66%	97%	70%
DPL	111%	77%	68%	59%	83%	62%
EKPC	82%	90%	71%	60%	95%	70%
JCPL	127%	90%	86%	70%	86%	69%
Met-Ed	126%	123%	105%	90%	87%	65%
PECO	130%	121%	101%	82%	92%	69%
PENELEC	169%	166%	120%	97%	120%	74%
Pepco	115%	92%	85%	64%	84%	58%
PPL	228%	179%	106%	93%	117%	64%
PSEG	151%	136%	120%	115%	108%	72%
RECO	128%	100%	104%	98%	100%	73%
PJM	88%	109%	93%	77%	101%	71%

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 2019



22 The energy net revenues presented for the PJM area in this section are calculated using the zonal average LMP.

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.[23] If the unit was not already committed day ahead, it was run in real time in standalone profitable blocks of at least four hours, or any profitable hours bordering the profitable day-ahead or real-time block.

New entrant CC plant energy market net revenues were lower in all zones in 2019 as a result of lower energy prices (Table 7-11).

Table 7-11 Energy net revenue for a new entrant CC under economic dispatch: 2014 through 2019 (Dollars per installed MW-year)[24]

Zone	2014	2015	2016	2017	2018	2019	Change in 2019 from 2018
AECO	$126,626	$74,716	$68,004	$50,259	$67,427	$51,977	(23%)
AEP	$109,036	$96,826	$76,488	$59,550	$109,104	$75,511	(31%)
APS	$154,231	$140,352	$98,353	$76,282	$117,114	$64,967	(45%)
ATSI	$82,670	$87,902	$74,459	$60,987	$120,740	$76,430	(37%)
BGE	$155,871	$125,088	$129,148	$71,490	$98,258	$75,145	(24%)
ComEd	$47,229	$54,134	$53,187	$38,278	$56,006	$45,701	(18%)
DAY	$76,213	$86,691	$73,887	$61,188	$117,206	$82,157	(30%)
DEOK	$66,685	$82,518	$70,201	$57,922	$122,183	$77,203	(37%)
DLCO	$82,827	$95,948	$86,877	$64,871	$91,162	$58,222	(36%)
Dominion	$106,993	$98,562	$86,903	$60,969	$92,066	$68,337	(26%)
DPL	$109,317	$50,497	$43,345	$27,674	$47,707	$21,780	(54%)
EKPC	$94,596	$84,530	$68,479	$52,705	$91,178	$67,735	(26%)
JCPL	$129,943	$73,929	$63,904	$53,388	$64,877	$52,372	(19%)
Met-Ed	$125,883	$104,606	$82,491	$71,970	$78,513	$58,243	(26%)
PECO	$130,722	$105,080	$77,959	$64,772	$74,100	$49,311	(33%)
PENELEC	$177,418	$147,403	$99,614	$78,602	$118,315	$70,955	(40%)
Pepco	$116,024	$96,499	$85,838	$54,535	$84,100	$58,997	(30%)
PPL	$232,421	$155,117	$83,707	$73,720	$108,706	$54,943	(49%)
PSEG	$157,086	$118,918	$83,897	$72,328	$81,207	$54,350	(33%)
RECO	$125,098	$79,151	$68,279	$55,405	$66,816	$54,423	(19%)
PJM	$100,026	$97,923	$78,751	$60,345	$90,339	$60,938	(33%)

In 2019, a new CC would have received sufficient net revenue to cover levelized total costs in 10 zones and more than 90 percent of levelized total costs in 18 out of 20 zones (Table 7-12).

Table 7-12 Percent of 20-year levelized total costs recovered by CC energy and capacity net revenue: 2014 through 2019

Zone	2014	2015	2016	2017	2018	2019
AECO	134%	93%	83%	75%	120%	97%
AEP	98%	102%	77%	75%	146%	107%
APS	129%	132%	92%	88%	153%	98%
ATSI	80%	129%	106%	83%	156%	108%
BGE	152%	127%	125%	92%	136%	106%
ComEd	56%	73%	61%	59%	109%	107%
DAY	76%	96%	75%	77%	153%	112%
DEOK	70%	93%	73%	74%	157%	107%
DLCO	81%	102%	84%	79%	130%	92%
Dominion	97%	104%	84%	76%	131%	100%
DPL	123%	76%	67%	58%	102%	71%
EKPC	89%	94%	72%	70%	129%	99%
JCPL	137%	92%	81%	78%	117%	96%
Met-Ed	132%	113%	93%	92%	119%	92%
PECO	137%	114%	90%	86%	126%	95%
PENELEC	167%	143%	105%	97%	154%	103%
Pepco	127%	108%	95%	78%	124%	93%
PPL	205%	148%	94%	93%	145%	89%
PSEG	160%	126%	105%	115%	144%	100%
RECO	138%	99%	94%	102%	131%	100%
PJM	103%	108%	89%	84%	134%	100%

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): 2014 through 2019

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

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

New Entrant Coal Plant

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

New entrant CP plant energy market net revenues were lower in all zones as a result of lower energy prices (Table 7-13).

Table 7-13 Energy net revenue for a new entrant CP: 2014 through 2019 (Dollars per installed MW-year)[25]

Zone	2014	2015	2016	2017	2018	2019	Change in 2019 from 2018
AECO	$115,697	$48,138	$10,643	$7,601	$31,260	$4,279	(86%)
AEP	$113,144	$51,079	$38,517	$35,658	$63,698	$19,004	(70%)
APS	$105,457	$42,147	$14,995	$17,879	$43,519	$5,688	(87%)
ATSI	$124,565	$51,785	$34,262	$35,618	$66,002	$14,847	(78%)
BGE	$167,855	$84,957	$46,952	$18,903	$51,185	$9,970	(81%)
ComEd	$112,699	$39,698	$28,732	$26,632	$37,054	$12,822	(65%)
DAY	$117,447	$50,088	$31,524	$34,467	$62,462	$18,807	(70%)
DEOK	$106,048	$46,117	$28,460	$31,389	$67,260	$16,583	(75%)
DLCO	$98,952	$40,461	$29,819	$32,250	$65,589	$13,181	(80%)
Dominion	$156,315	$90,406	$44,653	$27,496	$64,695	$17,805	(72%)
DPL	$167,509	$71,672	$21,952	$16,869	$50,348	$10,285	(80%)
EKPC	$102,305	$38,208	$24,436	$25,144	$43,091	$12,475	(71%)
JCPL	$119,656	$46,725	$7,933	$8,452	$30,416	$4,074	(87%)
Met-Ed	$153,809	$64,861	$19,709	$20,908	$49,202	$9,800	(80%)
PECO	$111,207	$44,763	$8,709	$7,691	$29,007	$4,053	(86%)
PENELEC	$129,578	$59,867	$23,206	$16,790	$46,051	$9,533	(79%)
Pepco	$114,167	$41,146	$10,499	$6,142	$29,304	$4,342	(85%)
PPL	$110,250	$43,645	$7,050	$7,770	$28,732	$3,234	(89%)
PSEG	$174,390	$72,812	$13,651	$12,882	$35,986	$6,201	(83%)
RECO	$170,401	$73,077	$13,238	$12,236	$35,919	$7,234	(80%)
PJM	$128,573	$55,083	$22,947	$20,139	$46,539	$10,211	(78%)

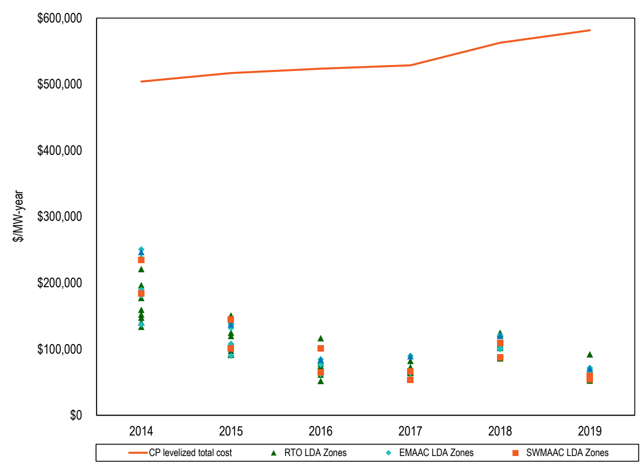
In 2019, a new CP would not have received sufficient net revenue to cover levelized total costs in any zone (Table 7-14). This has been the consistent result for a new CP since 2009.

Table 7-14 Percent of 20-year levelized total costs recovered by CP energy and capacity net revenue: 2014 through 2019

Zone	2014	2015	2016	2017	2018	2019
AECO	37%	21%	12%	10%	18%	11%
AEP	29%	20%	14%	14%	22%	12%
APS	28%	18%	10%	11%	18%	10%
ATSI	32%	29%	22%	16%	22%	11%
BGE	47%	28%	19%	12%	19%	10%
ComEd	29%	18%	13%	12%	19%	16%
DAY	30%	20%	13%	14%	21%	12%
DEOK	28%	19%	12%	13%	22%	11%
DLCO	27%	18%	13%	13%	22%	11%
Dominion	38%	27%	16%	12%	22%	12%
DPL	47%	25%	15%	12%	21%	12%
EKPC	27%	17%	12%	12%	18%	10%
JCPL	38%	21%	12%	11%	18%	11%
Met-Ed	44%	24%	14%	13%	19%	10%
PECO	36%	20%	12%	10%	18%	11%
PENELEC	39%	23%	15%	12%	19%	10%
Pepco	37%	20%	12%	10%	16%	9%
PPL	35%	20%	12%	10%	15%	9%
PSEG	50%	27%	16%	17%	21%	12%
RECO	49%	27%	16%	17%	21%	12%
PJM	35%	22%	14%	13%	20%	11%

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 2019



25 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 and output reflects the class average equivalent availability factor.[26]

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

Table 7-15 Energy net revenue for a new entrant nuclear plant: 2014 through 2019 (Dollars per installed MW-year)[27 28]

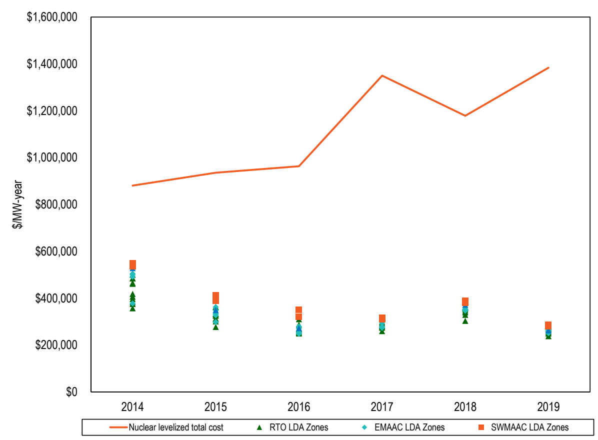
Zone	2014	2015	2016	2017	2018	2019	Change in 2019 from 2018
AECO	$430,088	$273,691	$200,584	$226,845	$285,185	$192,221	(33%)
AEP	$358,889	$259,420	$226,969	$241,589	$291,370	$217,407	(25%)
APS	$383,546	$282,041	$231,832	$245,633	$302,994	$216,401	(29%)
ATSI	$371,823	$262,859	$228,329	$246,859	$305,160	$219,369	(28%)
BGE	$482,796	$352,161	$296,138	$268,966	$332,101	$237,019	(29%)
ComEd	$322,257	$225,655	$213,368	$221,193	$235,676	$191,318	(19%)
DAY	$361,855	$261,380	$228,084	$246,977	$301,482	$226,472	(25%)
DEOK	$347,738	$256,348	$223,698	$242,729	$307,041	$220,799	(28%)
DLCO	$340,525	$249,258	$222,416	$242,278	$304,190	$216,018	(29%)
Dominion	$430,421	$311,499	$250,271	$260,185	$323,948	$225,667	(30%)
DPL	$467,506	$301,832	$224,906	$245,767	$314,185	$203,224	(35%)
EKPC	$343,061	$246,594	$218,753	$234,319	$274,749	$214,080	(22%)
JCPL	$434,325	$272,261	$195,704	$231,523	$282,490	$192,909	(32%)
Met-Ed	$417,516	$265,313	$198,714	$236,723	$282,769	$199,556	(29%)
PECO	$421,701	$266,837	$193,380	$226,787	$277,512	$188,645	(32%)
PENELEC	$394,697	$271,023	$215,556	$236,980	$291,292	$207,398	(29%)
Pepco	$467,154	$328,709	$266,428	$263,124	$323,833	$230,232	(29%)
PPL	$418,032	$265,864	$195,230	$228,451	$273,036	$188,993	(31%)
PSEG	$456,679	$283,287	$200,257	$237,187	$286,834	$194,920	(32%)
RECO	$451,926	$284,922	$201,343	$237,924	$289,049	$199,553	(31%)
PJM	$405,127	$276,048	$221,598	$241,102	$294,245	$209,110	(29%)

In 2019, 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 six 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 2019

Zone	2014	2015	2016	2017	2018	2019
AECO	57%	36%	26%	20%	30%	18%
AEP	45%	33%	27%	21%	30%	19%
APS	47%	36%	28%	21%	31%	19%
ATSI	46%	39%	32%	22%	31%	19%
BGE	62%	44%	36%	23%	33%	21%
ComEd	41%	30%	26%	19%	26%	20%
DAY	45%	33%	27%	21%	30%	20%
DEOK	43%	33%	27%	21%	31%	19%
DLCO	43%	32%	27%	21%	31%	19%
Dominion	53%	39%	30%	22%	32%	20%
DPL	61%	39%	29%	22%	32%	19%
EKPC	43%	32%	27%	20%	28%	19%
JCPL	57%	35%	26%	21%	30%	18%
Met-Ed	55%	35%	26%	21%	29%	18%
PECO	56%	35%	26%	20%	29%	18%
PENELEC	52%	35%	28%	21%	30%	19%
Pepco	61%	42%	33%	23%	32%	20%
PPL	55%	35%	26%	20%	28%	17%
PSEG	60%	37%	28%	23%	31%	19%
RECO	60%	37%	28%	23%	32%	19%
PJM	52%	36%	28%	21%	30%	19%

Figure 7-9 New entrant nuclear plant net revenue and 20-year levelized total cost by LDA (Dollars per installed MW-year): 2014 through 2019



26 The annual class average equivalent availability factor was used in the calculation of energy market net revenues.

27 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues because fuel costs for nuclear units are included in the NEI nuclear costs.

28 The net revenues have changed since the *2018 State of the Market Report for PJM*. The marginal cost of the nuclear plant has been reduced from $8.50/MWh to $0/MWh. Unit fuel costs have been moved to ACR.

New Entrant Diesel

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

New entrant DS plant energy market net revenues were lower in all zones except AEP, ComEd, DAY and EKPC as a result of lower energy prices (Table 7-17).

Table 7-17 Energy market net revenue for a new entrant DS: 2014 through 2019 (Dollars per installed MW-year)

Zone	2014	2015	2016	2017	2018	2019	Change in 2019 from 2018
AECO	$33,114	$13,159	$2,416	$2,554	$10,312	$2,029	(80%)
AEP	$14,469	$3,968	$987	$1,420	$4,154	$5,138	24%
APS	$18,020	$7,423	$1,051	$1,343	$6,675	$4,662	(30%)
ATSI	$14,114	$3,675	$2,090	$1,773	$7,209	$4,537	(37%)
BGE	$50,096	$18,305	$8,329	$3,202	$12,785	$6,899	(46%)
ComEd	$11,320	$2,327	$748	$1,333	$730	$3,476	377%
DAY	$14,288	$3,772	$1,044	$1,670	$3,946	$5,570	41%
DEOK	$13,467	$3,288	$1,415	$3,069	$6,675	$5,441	(18%)
DLCO	$13,132	$3,179	$2,416	$1,517	$9,248	$4,493	(51%)
Dominion	$42,609	$12,064	$2,596	$2,765	$15,094	$5,841	(61%)
DPL	$38,453	$19,925	$3,691	$5,637	$14,261	$6,375	(55%)
EKPC	$14,483	$2,970	$1,054	$972	$1,922	$4,868	153%
JCPL	$33,066	$13,042	$923	$2,848	$11,134	$2,085	(81%)
Met-Ed	$31,992	$13,020	$908	$3,794	$10,974	$2,670	(76%)
PECO	$32,360	$12,429	$875	$2,839	$9,838	$2,077	(79%)
PENELEC	$15,964	$6,436	$904	$1,699	$5,539	$2,906	(48%)
Pepco	$51,396	$12,842	$3,551	$2,497	$12,363	$6,314	(49%)
PPL	$32,931	$13,062	$796	$2,988	$8,799	$1,650	(81%)
PSEG	$32,550	$12,650	$1,064	$3,284	$10,325	$2,437	(76%)
RECO	$30,724	$13,740	$1,247	$3,031	$9,703	$2,627	(73%)
PJM	$29,787	$9,564	$1,905	$2,512	$8,584	$4,105	(52%)

In 2019, 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 six 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 2019

Zone	2014	2015	2016	2017	2018	2019
AECO	63%	43%	33%	31%	51%	37%
AEP	30%	33%	22%	25%	39%	32%
APS	32%	35%	22%	25%	41%	32%
ATSI	30%	60%	49%	30%	41%	32%
BGE	72%	46%	36%	32%	45%	33%
ComEd	28%	32%	22%	25%	44%	48%
DAY	30%	32%	22%	25%	39%	32%
DEOK	30%	32%	22%	26%	40%	31%
DLCO	29%	32%	23%	25%	42%	31%
Dominion	48%	37%	23%	26%	46%	32%
DPL	67%	47%	33%	33%	53%	40%
EKPC	30%	32%	22%	25%	37%	31%
JCPL	63%	43%	32%	31%	51%	36%
Met-Ed	61%	43%	32%	32%	44%	31%
PECO	63%	42%	32%	31%	51%	38%
PENELEC	51%	39%	32%	31%	40%	31%
Pepco	75%	43%	33%	31%	45%	33%
PPL	62%	43%	32%	31%	42%	30%
PSEG	67%	45%	41%	50%	60%	38%
RECO	66%	46%	41%	50%	60%	39%
PJM	49%	40%	31%	32%	45%	35%

New Entrant Onshore Wind Installation

Energy market net revenues for an onshore wind installation were calculated hourly assuming the unit generated at the average capacity factor of all operating wind units in the zone with an installed capacity greater than 3 MW. 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).[29]

Onshore wind energy market net revenues were lower as a result of lower energy prices.

Table 7-19 Energy market net revenue for an onshore wind installation (Dollars per installed MW-year): 2014 through 2019

	2014	2015	2016	2017	2018	2019	Change in 2019 from 2018
AEP	$106,499	$78,929	$67,826	$71,312	$93,621	$70,434	(25%)
APS	$108,148	$72,504	$62,352	$71,867	$95,329	$58,628	(38%)
ComEd	$95,745	$67,842	$58,915	$68,278	$65,111	$59,836	(8%)
PENELEC	$129,612	$85,543	$65,204	$73,843	$95,776	$55,603	(42%)

The new entrant onshore wind installation analysis is based on a 17.6 percent capacity factor for purposes of participating in the capacity market.[30]

Table 7-20 Capacity market net revenue for an onshore wind installation (Dollars per installed MW-year): 2014 through 2019

Zone	2014	2015	2016	2017	2018	2019
AEP	$5,482	$8,471	$5,874	$6,097	$9,369	$8,074
APS	$5,482	$8,471	$5,874	$6,097	$9,366	$8,087
ComEd	$5,482	$8,471	$5,874	$6,097	$11,263	$13,289
PENELEC	$11,151	$9,935	$8,966	$7,685	$9,355	$8,054

Wind units in the four zones were assumed to receive the higher of the MD or PA Tier I REC for the purposes of calculating RECs revenue.[31] Renewable energy credits were approximately 19 percent of the total net revenue of an onshore wind installation.

Table 7-21 RECs revenue for an onshore wind installation (Dollars per installed MW-year): 2014 through 2019

Zone	2014	2015	2016	2017	2018	2019
AEP	$37,956	$41,971	$30,518	$12,681	$15,679	$18,030
APS	$36,437	$33,539	$26,854	$12,202	$15,350	$14,957
ComEd	$40,539	$41,676	$28,828	$13,526	$15,102	$18,602
PENELEC	$41,808	$39,913	$30,101	$12,811	$15,746	$14,956

In 2019, a new onshore 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 six year period of the analysis.

Wind projects that are currently operating or under construction may have a different financing structure, require a lower rate of return, or have other factors that are not captured in the new entrant analysis presented in this section.

Table 7-22 Percent of 20-year levelized total costs recovered by onshore wind net revenue (Dollars per installed MW-year): 2014 through 2019

Zone	2014	2015	2016	2017	2018	2019
AEP	76%	64%	45%	48%	55%	45%
APS	76%	56%	41%	48%	56%	38%
ComEd	72%	58%	40%	47%	43%	43%
PENELEC	92%	67%	45%	50%	56%	37%

New Entrant Offshore Wind Installation

Energy market net revenues for an offshore wind installation were calculated hourly assuming the unit generated 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).

Offshore wind energy market net revenues were lower as a result of lower energy prices.

Table 7-23 Energy market net revenue for an offshore wind installation (Dollars per installed MW-year): 2014 through 2019

	2014	2015	2016	2017	2018	2019	Change in 2019 from 2018
AECO	$201,681	$129,548	$96,261	$109,649	$137,203	$93,518	(32%)

29 The 1603 payment is a direct payment of 30 percent of the project cost. The use of the 1603 option is based on observed behavior in the PJM markets.

30 PJM Planning. Class Average Capacity Factors Wind and Solar Resources. (Eff. June 1, 2017). <https://www.pjm.com/-/media/planning/res-adeq/class-average-wind-capacity-factors.ashx?la=en>

31 RECs prices obtained from Evolution Markets, Inc.

The new entrant offshore wind installation is based on a 45 percent capacity factor for purposes of participating in the capacity market.[32]

Table 7-24 Capacity market net revenue for an offshore wind installation (Dollars per installed MW-year): 2014 through 2019

Zone	2014	2015	2016	2017	2018	2019
AECO	$29,793	$25,402	$22,926	$19,651	$29,545	$26,146

The offshore wind unit was assumed to receive the higher of the MD or PA Tier I REC for the purposes of calculating RECs revenue.[33] Renewable energy credits accounted for 18 percent of the total net revenue of an off shore wind installation.

Table 7-25 RECs revenue for an offshore wind installation (Dollars per installed MW-year): 2014 through 2019

Zone	2014	2015	2016	2017	2018	2019
AECO	$62,616	$62,607	$45,956	$19,225	$23,931	$26,087

In 2019, a new offshore wind installation would not have received sufficient net revenue to cover levelized total costs.

Table 7-26 Percent of 20-year levelized total costs recovered by offshore wind net revenue (Dollars per installed MW-year): 2014 through 2019

Zone	2014	2015	2016	2017	2018	2019
AECO	43%	32%	24%	22%	28%	21%

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 with an installed capacity greater than 3 MW. 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).[34]

Solar energy market net revenues were lower as a result of lower energy prices.

Table 7-27 Energy market net revenue for a solar installation (Dollars per installed MW-year): 2014 through 2019

	2014	2015	2016	2017	2018	2019	Change in 2019 from 2018
AECO	$67,446	$48,285	$38,762	$38,022	$41,772	$32,636	(22%)
Dominion	-	-	$70,026	$68,150	$78,189	$59,472	(24%)
DPL	-	-	$45,546	$50,740	$61,773	$44,687	(28%)
JCPL	$61,850	$41,551	$33,986	$36,414	$39,433	$30,189	(23%)
PSEG	$61,548	$47,830	$39,380	$40,979	$43,469	$34,047	(22%)

The new entrant solar installation analysis is based on a 42.0 percent capacity factor for purposes of participating in the capacity market.[35]

Table 7-28 Capacity market net revenue for a solar installation (Dollars per installed MW-year): 2014 through 2019

Zone	2014	2015	2016	2017	2018	2019
AECO	$27,807	$23,708	$21,398	$18,341	$27,575	$24,403
Dominion	-	-	$14,018	$14,551	$22,352	$19,179
DPL	-	-	$21,398	$18,341	$27,345	$24,195
JCPL	$27,807	$23,708	$21,398	$18,341	$27,200	$23,714
PSEG	$30,478	$25,593	$28,234	$30,828	$33,260	$25,025

The solar installation was assumed to receive the highest of the DC, MD or NJ Solar REC, based on locational eligibility, for the purposes of calculating RECs revenue.[36] Renewable energy credits ranged from 55 percent of the total net revenue of a solar installation in DPL to 85 percent of the total net revenue of a solar installation in AECO.

Table 7-29 RECs revenue for a solar installation (Dollars per installed MW-year): 2014 through 2019

Zone	2014	2015	2016	2017	2018	2019
AECO	$240,050	$325,643	$373,683	$285,895	$273,161	$313,056
Dominion	-	-	$101,679	$20,760	$18,364	$99,084
DPL	-	-	$74,619	$17,514	$15,804	$85,624
JCPL	$222,593	$280,457	$332,265	$267,345	$258,291	$286,300
PSEG	$213,746	$303,612	$379,054	$294,273	$279,286	$319,285

In 2019, a new solar installation would have received sufficient net revenue to cover levelized total costs in AECO, JCPL and PSEG as a result of high RECs revenue and would not have received sufficient net revenue to cover levelized total costs in Dominion or DPL.

Solar projects that are currently operating or under construction may have a different financing structure, require a lower rate of return, or have other factors that

32 Lazard. Levelized Cost of Energy. Version 13.0. November 2019 <https://www.lazard.com/media/451086/lazards-levelized-cost-of-energy-version-130-vf.pdf>.

33 RECs prices obtained from Evolution Markets, Inc.

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

35 PJM Planning. Class Average Capacity Factors Wind and Solar Resources. (Eff. June 1, 2017). <https://www.pjm.com/-/media/planning/res-adeq/class-average-wind-capacity-factors.ashx?la=en>.

36 RECs prices obtained from Evolution Markets, Inc.

are not captured in the new entrant analysis presented in this section.

Table 7-30 Percent of 20-year levelized total costs recovered by solar net revenue (Dollars per installed MW-year): 2014 through 2019

Zone	2014	2015	2016	2017	2018	2019
AECO	142%	170%	198%	170%	147%	152%
Dominion	-	-	85%	51%	51%	73%
DPL	-	-	65%	43%	45%	63%
JCPL	132%	148%	177%	160%	140%	139%
PSEG	129%	161%	204%	182%	153%	155%

Historical New Entrant CC Revenue Adequacy

Total unit net revenues include energy and capacity revenues. Analysis of the total unit revenues of theoretical new entrant CCs for three representative locations shows that CC units that entered the PJM markets in 2007 have covered 89 percent of their total costs in the BGE and ComEd zones and 43 percent of total costs in the PSEG Zone, including the return on and of capital, on a cumulative basis. The analysis also shows that theoretical new entrant CCs that entered the PJM markets in 2012 have covered their total costs on a cumulative basis in the BGE and PSEG zones and 54 percent of total costs in the 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.

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 entrant CC that began operation on January 1, 2007, and a new entrant CC that began operation on January 1, 2012. The solid black line shows the total net revenue required to cover total costs. The solid colored lines show net energy revenue by zone. The dashed colored lines show the sum of net energy and capacity revenue by zone.

Figure 7-10 Historical new entrant CC revenue adequacy: January 2007 through 2019 and January 2012 through 2019[37]

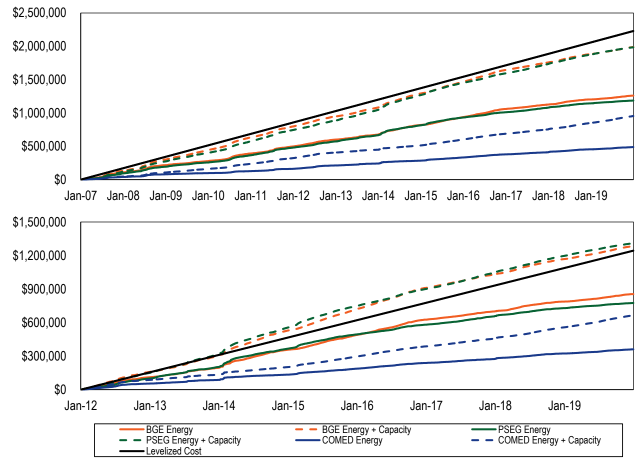


Table 7-31 shows the percent of levelized total costs recovered.

Table 7-31 Percent of levelized total costs recovered

	2007 CC	2012 CC
BGE	89%	103%
ComEd	43%	54%
PSEG	89%	105%

Assumptions used for this analysis are shown in Table 7-32.

Table 7-32 Assumptions for analysis of new entry in 2007 and 2012

	2007 CC	2012 CC
Project Cost	$658,598,000	$665,995,000
Fixed O&M ($/MW-Year)	$20,016	$20,126
End of Life Value	$0	$0
Loan Term	20 years	20 years
Percent Equity (%)	50%	50%
Percent Debt (%)	50%	50%
Loan Interest Rate (%)	7%	7%
Cost of Equity (%)	12.0%	12.0%
Federal Income Tax Rate (%)	35%	35%
State Income Tax Rate (%)	9%	9%
General Escalation (%)	2.5%	2.5%
Technology	GE Frame 7FA.04	GE Frame 7FA.05
ICAP (MW)	601	655
Depreciation MACRS 150% declining balance	20 years	20 years
IRR (%)	12.0%	12.0%

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

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 2019, the average short run marginal cost of the CC was lower than the average short run marginal cost of the CP in every month and the operating cost of the CT was lower than the CP in all months except January. (Figure 7-5)

The net revenue results illustrate some fundamentals of the PJM wholesale power market. Lower energy prices, lower gas prices, and lower coal prices meant that units ran with lower margins and sometimes for significantly fewer hours 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 new and existing units.

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 7-33.[38]

Table 7-33 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	$125,262	13.4%	$122,256	13.4%	$618,067	13.2%
Base Case	$121,612	12.0%	$116,781	12.0%	$581,567	12.0%
Sensitivity 2	$117,962	10.5%	$111,306	10.4%	$545,067	10.7%
Sensitivity 3	$114,312	8.8%	$105,831	8.7%	$508,567	9.2%
Sensitivity 4	$110,662	6.9%	$100,356	6.8%	$472,067	7.5%
Sensitivity 5	$107,012	4.7%	$94,881	4.5%	$435,567	5.4%
Sensitivity 6	$103,362	2.0%	$89,406	1.5%	$399,067	2.9%

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 7-34 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 7-34 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%	$127,423	$123,828
Sensitivity 2	55%	$124,507	$120,282
Base Case	50%	$121,612	$116,781
Sensitivity 3	45%	$118,739	$113,324
Sensitivity 4	40%	$115,889	$109,912
Sensitivity 5	35%	$113,061	$106,546
Sensitivity 6	30%	$110,254	$103,223

38 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 7-35 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 affect the profitability of investing in peaking and midmerit generation technologies at 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 7-35 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%	$119,306	$0	0.0%	$114,304
Sensitivity 2	$3,594	1.3%	$120,459	$11,351	1.2%	$115,543
Base Case	$7,188	2.6%	$121,612	$22,702	2.3%	$116,781
Sensitivity 3	$10,782	3.8%	$122,765	$34,053	3.5%	$118,019
Sensitivity 4	$14,376	5.1%	$123,918	$45,404	4.7%	$119,258
Sensitivity 5	$17,970	6.4%	$125,071	$56,755	5.8%	$120,496
Sensitivity 6	$21,595	7.7%	$126,224	$68,106	7.0%	$121,734

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 avoidable costs by unit type in dollars per MW-year.[39]

39 Avoidable costs provided by Pasteris Energy, Inc.

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 2018/2019 and 2019/2020 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 2019. Any unit with a significant portion of installed capacity designated as FRR committed was excluded from the analysis.[40] 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. As required by FERC, net revenues for units other than nuclear are calculated using units' price-based offers for technologies, unless the unit is cost-capped or the price-based offer is less than fuel plus environmental costs.[41] 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 7-36 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 7-36 shows energy and ancillary service net revenues by quartile for select technology classes.[42] 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 7-39, 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 7-40.

Table 7-36 also includes new entrant theoretical energy market net revenue from Table 7-9, Table 7-11, Table 7-13, Table 7-15, and Table 7-17 for comparison purposes. As an example, for the CC plants, the predominant form of new entry in PJM, existing resources in the top quartile of net revenue, earn net revenues that are comparable to the theoretical new entrant net revenues. This supports the conclusion that the theoretical new entrant results are a good representation of the performance of actual new entrants and existing plants with comparable technologies. The results for existing units vary based on location, technology and actual performance.

Table 7-36 Net revenue by quartile for select technologies: 2019[43]

		($/MW-Yr)										
	Total	Energy and ancillary service net revenue				Capacity revenue			Energy, ancillary, and capacity revenue			
Technology	Installed Capacity (ICAP)	New entrant	First quartile	Median	Third quartile	First quartile	Median	Third quartile	New entrant	First quartile	Median	Third quartile
CC - Combined Cycle	31,318	$64,288	$5,168	$28,845	$56,363	$24,311	$44,291	$58,136	$116,296	$54,986	$80,451	$122,177
CT - Aero Derivative	5,893	$34,901	$5,892	$10,682	$33,128	$44,138	$55,075	$62,980	$86,909	$38,435	$53,888	$77,273
CT - Industrial Frame	21,030	-	$571	$3,780	$14,386	$35,062	$44,972	$69,062	-	$42,517	$59,500	$83,538
Coal Fired	47,966	$13,840	($355)	$1,343	$14,169	$32,549	$43,321	$58,458	$65,848	$32,629	$50,451	$70,249
Diesel	289	$7,455	($3,030)	($795)	$1,982	$25,571	$45,481	$56,425	$59,463	$24,081	$40,705	$54,398
Hydro	2,329	-	$88,541	$94,283	$139,794	$33,502	$52,069	$74,398	-	$131,863	$146,949	$204,472
Nuclear	30,351	$212,460	$183,404	$188,200	$218,698	$42,574	$63,272	$69,635	$264,468	$248,141	$257,238	$264,615
Oil or Gas Steam	10,490	-	($2,089)	($864)	$376	$37,801	$46,199	$59,484	-	$34,604	$45,592	$60,999
Pumped Storage	4,721	-	$16,997	$38,960	$38,960	$52,365	$52,912	$80,463	-	$69,809	$91,789	$98,837

40 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.

41 154 FERC ¶ 61,151 at P 59.

42 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.

43 The nuclear results exclude Three Mile Island, which retired on September 20, 2019. Exelon. "Three Mile Island Generating Station Unit 1 Retires from Service After 45 Years," (September 20, 2019) <https://www.exeloncorp.com/newsroom/three-mile-island-generating-station-unit-1-retires>.

Table 7-37 shows the percent of avoidable costs covered by net revenue from PJM energy and ancillary services markets by quartiles. In 2019, 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.[44] [45] The NEI annual avoidable costs used in the analysis are for 2018, the most recent data available.

Table 7-37 Avoidable cost recovery by quartile: 2019[46]

		Recovery of avoidable costs from energy and ancillary net revenue			Recovery of avoidable costs from all markets		
Technology	Total Installed Capacity (ICAP)	First quartile	Median	Third quartile	First quartile	Median	Third quartile
CC - Combined Cycle	31,318	39%	216%	422%	407%	594%	900%
CT - Aero Derivative	5,893	50%	91%	281%	446%	615%	806%
CT - Industrial Frame	21,030	5%	34%	132%	341%	512%	695%
Coal Fired	47,966	(1%)	2%	22%	43%	75%	114%
Diesel	289	(26%)	(7%)	17%	214%	381%	515%
Hydro	2,329	285%	304%	450%	425%	473%	659%
Nuclear	30,351	74%	79%	89%	102%	106%	109%
Oil or Gas Steam	10,490	0%	0%	1%	106%	149%	209%
Pumped Storage	4,721	187%	429%	429%	769%	1,011%	1,089%

Table 7-38 shows the proportion of units recovering avoidable costs from energy and ancillary services markets and from all markets. In 2019, 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.[47] [48] [49]

Table 7-38 Proportion of units recovering avoidable costs: 2011 through 2019

	Units with full recovery fromenergy and ancillary net revenue									Units with full recovery from all markets								
Technology	2011	2012	2013	2014	2015	2016	2017	2018	2019	2011	2012	2013	2014	2015	2016	2017	2018	2019
CC - Combined Cycle	55%	46%	50%	72%	59%	63%	57%	66%	64%	85%	79%	79%	95%	88%	93%	89%	98%	90%
CT - Aero Derivative	15%	6%	6%	53%	15%	8%	10%	30%	46%	100%	96%	76%	98%	100%	99%	100%	99%	96%
CT - Industrial Frame	26%	23%	17%	38%	13%	8%	3%	21%	30%	99%	98%	83%	100%	100%	100%	100%	96%	92%
Coal Fired	31%	17%	27%	78%	16%	15%	12%	11%	2%	82%	36%	54%	83%	64%	40%	36%	63%	31%
Diesel	48%	42%	37%	69%	56%	33%	32%	39%	11%	100%	100%	77%	100%	100%	100%	100%	97%	91%
Hydro	74%	61%	95%	97%	81%	79%	95%	94%	90%	81%	77%	97%	98%	100%	100%	97%	98%	100%
Nuclear	-	-	50%	94%	17%	6%	17%	53%	0%	-	-	61%	100%	56%	17%	50%	88%	81%
Oil or Gas Steam	8%	6%	11%	15%	3%	0%	0%	10%	73%	92%	78%	86%	85%	91%	88%	81%	76%	66%
Pumped Storage	100%	100%	95%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

44 Operating costs from: Nuclear Energy Institute (September, 2019). "Nuclear Costs in Context," <https://www.nei.org/resources/reports-briefs/nuclear-costs-in-context>. Individual plant results may vary from the average due to factors including location, local labor costs, the timing of refueling outages, cost management practices, and other unit specific factors.

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

46 The nuclear results exclude Three Mile Island, which retired September 20, 2019. Exelon. "Three Mile Island Generating Station Unit 1 Retires from Service After 45 Years," (September 20, 2019) <https://www.exeloncorp.com/newsroom/three-mile-island-generating-station-unit-1-retires>.

47 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>.

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

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

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.[50] [51] The analysis includes the most recent operating cost data and incremental capital expenditure data published by NEI, for 2018. 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 (14.0 percent decrease from 2012 through 2018 for all plants including single and multiple unit plants). NEI average incremental capital expenditures have decreased since their peak in 2012 (46 percent decrease from 2012 through 2018 for all plants including single and multiple unit plants). NEI's incremental capital expenditures peaked in 2012 as a result of regulatory requirements following the 2011 accident at the Fukushima nuclear plant in Japan.

The results for nuclear plants are sensitive to small changes in PJM energy and capacity prices, both actual and forward prices.[52] 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 then 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.[53] In 2018, high gas prices and high LMPs resulted in a significant increase in net revenues for nuclear plants in PJM. Energy prices in 2018 were significantly higher than in 2017. Forward energy prices for 2020 are lower than 2018 prices and are higher or lower than 2019 prices, depending on location. The result is that nuclear plant net revenues based on the three year forward period prices are lower than 2018 net revenues. The results for nuclear plants are also sensitive to changes in costs and whether unit costs are less than or greater than the benchmark NEI data.

Table 7-39 includes the publicly available data on energy market prices, Table 7-40 and Table 7-41 show capacity market prices and Table 7-42 shows nuclear cost data for the 16 nuclear plants in PJM in addition to Oyster Creek, which retired September 17, 2018, and Three Mile Island, which retired September 20, 2019.[54] The analysis excludes Cook nuclear units and Catawba 1 nuclear unit. Cook nuclear units are designated FRR and receive cost of service revenues and are not subject to PJM market revenues.[55] Catawba 1 is not in PJM but is pseudo tied to PJM.

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.

50 Operating costs from: Nuclear Energy Institute (September, 2019). "Nuclear Costs in Context," <https://www.nei.org/resources/reports-briefs/nuclear-costs-in-context>. Individual plants may vary from the average due to factors such as geographic location, local labor costs, the timing of refueling outages and other unit specific factors. This is the most current NEI data available.

51 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.

52 A change in the capacity market price of $24 per MW-day translates into a change in capacity revenue of $1.00 per MWh for a nuclear power plant operating at a capacity factor of 100 percent. A change in the capacity market price of $24 per MW-day translates into a change in capacity revenue of $1.07 per MWh for a nuclear power plant operating at a capacity factor of 0.933 percent.

53 The MMU 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.*

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

55 See "Resources Designated in 2021/2022 FRR Capacity Plans as of May 1, 2018," <https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-resources-designated-in-frr-plans.ashx?la=en>.

Table 7-39 Nuclear unit day ahead LMP: 2008 through 2019

	ICAP	Average DA LMP ($/MWh)											
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
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	$26.22
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	$22.88
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	$22.19
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	$28.00
Davis Besse	894	-	-	-	$39.68	$31.68	$36.10	$47.21	$31.94	$27.80	$28.85	$34.44	$26.33
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	$23.41
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	$22.45
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	$22.75
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	$22.68
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	$27.39
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	$23.68
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	$21.58
Perry	1,240	-	-	$36.99	$38.76	$31.68	$36.69	$46.14	$32.77	$27.84	$29.91	$37.24	$26.76
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	$21.13
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	$22.43
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	$26.65
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	$21.08
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	$23.47

Table 7-40 BRA capacity market clearing prices ($/MW-Day): 2008 through 2021[56]

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

Capacity revenues are not presented for calendar year 2022 because the 2022/2023 BRA has not been run.

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>. Three Mile Island retired September 20, 2019. Exelon. "Three Mile Island Generating Station Unit 1 Retires from Service After 45 Years," (September 20, 2019) <https://www.exeloncorp.com/newsroom/three-mile-island-generating-station-unit-1-retires>.

Table 7-41 Nuclear unit capacity market revenue ($/MWh): 2008 through 2021[57] [58]

	ICAP	Capacity Revenue ($/MWh)													
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Beaver Valley	1,808	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$6.42	$5.61	$3.82	$5.03
Braidwood	2,337	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$7.71	$9.20	$8.60	$8.52
Byron	2,300	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$7.71	$9.20	$8.60	$8.52
Calvert Cliffs	1,708	$8.73	$9.59	$8.64	$5.87	$5.38	$8.21	$7.53	$6.74	$6.04	$5.26	$6.42	$5.62	$4.07	$5.21
Davis Besse	894	NA	NA	NA	NA	$2.49	$1.08	$3.70	$11.40	$9.33	$5.17	$6.42	$5.61	$3.82	$5.85
Dresden	1,797	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$7.71	$9.20	$8.60	$8.52
Hope Creek	1,172	$7.33	$7.37	$7.82	$5.87	$5.54	$8.81	$7.87	$6.74	$6.04	$5.26	$7.98	$7.24	$7.06	$7.74
LaSalle	2,271	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$7.71	$9.20	$8.60	$8.52
Limerick	2,242	$7.33	$7.37	$7.82	$5.87	$5.54	$8.81	$7.87	$6.74	$6.04	$5.26	$7.98	$7.24	$7.06	$7.74
North Anna	1,892	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$6.42	$5.61	$3.82	$5.03
Oyster Creek	608	$7.33	$7.37	$7.82	$5.87	$5.54	$8.81	$7.87	$6.74	$6.04	$5.26	NA	NA	NA	NA
Peach Bottom	2,347	$7.33	$7.37	$7.82	$5.87	$5.54	$8.81	$7.87	$6.74	$6.04	$5.26	$7.98	$7.24	$7.06	$7.74
Perry	1,240	NA	NA	NA	NA	$2.49	$1.08	$3.70	$11.40	$9.33	$5.17	$6.42	$5.61	$3.82	$5.85
Quad Cities	1,819	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$7.71	$9.20	$8.60	$8.52
Salem	2,328	$7.33	$7.37	$7.82	$5.87	$5.54	$8.81	$7.87	$6.74	$6.04	$5.26	$7.98	$7.24	$7.06	$7.74
Surry	1,676	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$6.42	$5.61	$3.82	$5.03
Susquehanna	2,520	$3.57	$6.72	$7.82	$5.87	$5.38	$8.21	$7.53	$6.74	$6.04	$5.26	$6.42	$5.61	$4.07	$5.21
Three Mile Island	803	$3.57	$6.72	$7.82	$5.87	$5.38	$8.21	$7.53	$6.74	$6.04	$5.26	$6.42	$5.61	$4.07	$5.21

Table 7-42 Nuclear unit costs: 2008 through 2019[59]

	ICAP	NEI Costs ($/MWh)											
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Beaver Valley	1,808	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$29.07
Braidwood	2,337	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$29.07
Byron	2,300	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$29.07
Calvert Cliffs	1,708	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$29.07
Davis Besse	894	$35.31	$39.36	$41.23	$45.45	$47.41	$44.16	$44.32	$44.51	$41.39	$42.66	$42.00	$42.00
Dresden	1,797	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$29.07
Hope Creek	1,172	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$29.07
LaSalle	2,271	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$29.07
Limerick	2,242	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$29.07
North Anna	1,892	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$29.07
Oyster Creek	608	$35.31	$39.36	$41.23	$45.45	$47.41	$44.16	$44.32	$44.51	$41.39	$42.66	$42.00	$42.00
Peach Bottom	2,347	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$29.07
Perry	1,240	$35.31	$39.36	$41.23	$45.45	$47.41	$44.16	$44.32	$44.51	$41.39	$42.66	$42.00	$42.00
Quad Cities	1,819	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$29.07
Salem	2,328	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$29.07
Surry	1,676	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$29.07
Susquehanna	2,520	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$29.07
Three Mile Island	803	$35.31	$39.36	$41.23	$45.45	$47.41	$44.16	$44.32	$44.51	$41.39	$42.66	$42.00	$42.00

Table 7-43 shows the surplus or shortfall in $/MWh for the 16 nuclear plants in PJM and Oyster Creek and Three Mile Island calculated using historic LMP and cost data. In 2016, 13 nuclear plants, with a total capacity of 25,075 MW, in addition to Oyster Creek and Three Mile Island, did not recover all their fuel costs, operating costs, and capital expenditures. In 2017, seven nuclear plants with a total capacity of 12,658 MW, in addition to Oyster Creek and Three Mile Island, did not recover all their fuel costs, operating costs, and capital expenditures. In 2018, one nuclear plant, with a total capacity of 894 MW, in addition to Oyster Creek and Three Mile Island, did not recover all its fuel costs, operating costs, and capital expenditures. In 2019, two nuclear plants, with a total capacity of 4,654 MW, in addition to Three Mile Island, did not recover all their fuel costs, operating costs, and capital expenditures. Although Susquehanna shows a shortfall in 2019, cost reductions mean that Susquehanna did cover their fuel costs, operating

57 Capacity revenue calculated by adjusting the BRA Capacity Price for calendar year, by the class average EFORd, and by the 2019 class average capacity factor of 0.933 percent. Class average capacity factor is from *2019 State of the Market Report for PJM*, Volume 2, Section 5: Capacity Market.

58 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>. Three Mile Island retired September 20, 2019. Exelon. "Three Mile Island Generating Station Unit 1 Retires from Service After 45 Years," (September 20, 2019) <https://www.exeloncorp.com/newsroom/three-mile-island-generating-station-unit-1-retires>.

59 Oyster Creek retired on September 17, 2018. Exelon. "Oyster Creek Generating Station Retires from Service," (September 17, 2018) <http://www.exeloncorp.com/newsroom/oyster-creek-retires>. Three Mile Island retired September 20, 2019. Exelon. "Three Mile Island Generating Station Unit 1 Retires from Service After 45 Years," (September 20, 2019) <https://www.exeloncorp.com/newsroom/three-mile-island-generating-station-unit-1-retires>.

costs, and capital expenditures.[60] The surplus or shortfall assumes that the unit cleared its full unforced capacity at the BRA locational clearing price.[61] Unforced capacity is determined using the annual class average EFORd rate.

The market revenues are based in part on the sale of capacity. Some nuclear plants did not clear the capacity market as a result of decisions by plant owners about how to offer the plants. When nuclear plants do not clear in the capacity market, it is a result of the offer behavior of the plants and does not reflect the economic viability of the plants unless the plants offer accurate net avoidable costs and fail to clear. This analysis is intended to define whether the plants are receiving a retirement signal from the PJM markets. If the plants are viable including both energy and capacity market revenues based on actual clearing prices then the PJM markets indicate that the plant is economically viable. If plant owners decide to offer so as to not clear in the capacity market, that does not change the market signals to the plants. Such decisions may reflect a variety of considerations. Three Mile Island did not clear the 2018/2019 Auction[62] and Three Mile Island, Quad Cities, and a portion of Byron's capacity did not clear the 2019/2020 Auction.[63] Three Mile Island and Quad Cities did not clear the 2020/2021 Auction.[64] Three Mile Island, Dresden, and most of Byron did not clear the 2021/2022 Auction.[65] Beaver Valley, Davis Besse, and Perry did not clear the 2021/2022 Auction.[66]

Nuclear unit revenue is a combination of energy market revenue, ancillary market revenue and capacity market revenue. Negative prices do not have a significant impact on nuclear unit revenue. Since 2014, negative prices have affected nuclear plants' annual total revenues by an average of 0.1 percent. Negative LMPs reduced nuclear plant total revenues by an average of 0.0 percent and a maximum of 0.6 percent in 2014, an average of 0.2 percent and a maximum of 1.2 percent in 2015, an average of 0.1 percent and a maximum of 0.7 percent in 2016, an average of 0.0 percent and a maximum of 0.6 percent in 2017, an average of 0.0 percent and a maximum of 0.0 percent in 2018 and an average of 0.0 percent and a maximum of 0.2 percent in 2019.[67]

Table 7-43 Nuclear unit surplus (shortfall) based on public data: 2008 through 2019[68]

	ICAP	Surplus (Shortfall) ($/MWh)											
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Beaver Valley	1,808	$26.3	$6.3	$10.5	$8.8	($3.3)	$1.4	$11.7	$3.2	($0.4)	$2.6	$13.9	$3.0
Braidwood	2,337	$24.9	$2.5	$6.4	$3.4	($6.1)	($2.6)	$7.2	($1.2)	($3.1)	($1.5)	$6.0	$3.3
Byron	2,300	$24.5	($1.3)	$3.4	($0.6)	($9.4)	($3.6)	$4.9	($6.1)	($9.5)	($2.7)	$5.8	$2.5
Calvert Cliffs	1,708	$60.6	$20.9	$28.6	$17.9	$4.5	$14.6	$31.6	$14.1	$7.2	$6.1	$16.3	$4.7
Davis Besse	894	NA	NA	NA	NA	($13.2)	($7.0)	$6.6	($1.2)	($4.0)	($8.4)	($0.9)	($9.8)
Dresden	1,797	$25.6	$3.0	$7.6	$4.4	($5.2)	($1.0)	$9.1	$0.3	($1.5)	($0.0)	$7.2	$3.9
Hope Creek	1,172	$54.0	$17.0	$24.5	$16.9	$2.6	$12.4	$26.0	$6.3	($2.0)	$1.6	$12.3	$1.0
LaSalle	2,271	$24.8	$2.5	$6.4	$3.3	($6.1)	($1.9)	$7.7	($0.9)	($3.5)	($1.8)	$6.0	$3.1
Limerick	2,242	$54.1	$17.1	$24.7	$16.6	$2.6	$12.2	$25.7	$6.5	($2.1)	$1.5	$12.1	$1.0
North Anna	1,892	$52.0	$14.6	$25.5	$16.8	$0.2	$5.7	$23.2	$10.9	$3.0	$4.7	$16.0	$4.1
Oyster Creek	608	$47.5	$8.4	$15.9	$7.2	($8.2)	$3.3	$16.4	($4.7)	($11.6)	($9.9)	NA	NA
Peach Bottom	2,347	$53.7	$16.9	$24.2	$16.1	$2.3	$12.3	$25.5	$5.8	($2.2)	$1.4	$11.8	$0.0
Perry	1,240	NA	NA	NA	NA	($13.2)	($6.4)	$5.5	($0.3)	($4.0)	($7.3)	$1.9	($9.4)
Quad Cities	1,819	$24.1	($0.4)	$2.4	($1.8)	($13.2)	($6.9)	$0.6	($7.7)	($9.5)	($3.5)	$4.4	$1.4
Salem	2,328	$54.0	$17.1	$24.5	$16.9	$2.6	$12.4	$26.0	$6.2	($2.3)	$1.3	$11.9	$0.7
Surry	1,676	$48.8	$13.8	$24.2	$16.4	($0.0)	$5.1	$21.6	$10.8	$2.6	$4.5	$16.0	$3.4
Susquehanna	2,520	$46.8	$15.2	$22.4	$16.1	$1.4	$11.1	$24.6	$6.3	($1.6)	$1.8	$10.0	($2.1)
Three Mile Island	803	$40.7	$6.5	$13.3	$4.6	($9.6)	$0.9	$13.7	($6.8)	($12.4)	($10.3)	($3.8)	NA

60 Talen Energy Investor Day, February 12, 2019.

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

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

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

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

65 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>.

66 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>.

67 Analysis is based on actual unit generation and received energy market and capacity market revenues. Negative prices in the DA and RT market were set to zero for comparison. Results round to 0.0 percent.

68 The values for 2016 through 2019 have changed slightly from previous values to account for reactive supply and voltage control revenues.

In order to evaluate the expected viability of nuclear plants, analysis was performed based on forward energy market prices for 2020, 2021 and 2022 and known capacity market prices for 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 7-44 shows PJM energy prices (LMP), annual fuel, operating and capital expenditures, and the required capacity revenue for total revenues to equal total costs for the 2020 through 2022 period. Capacity revenues are not presented for calendar year 2022 because the 2022/2023 BRA has not yet happened. The LMPs are based on forward prices with a basis adjustment for the specific plant locations.[69] Forward prices are as of January 2, 2020. The capacity prices are known based on PJM capacity auction results.

Table 7-44 Forward prices in PJM energy markets, capacity revenue, and annual costs[70]

	ICAP	Average Forward LMP ($/MWh)			Ancillary Revenue ($/MWh)	Capacity Revenue ($/MWh)		2018 NEI Costs ($/MWh)		
	(MW)	2020	2021	2022	Reactive	2020	2021	Fuel	Operating	Capital
Beaver Valley	1,808	$25.92	$27.20	$27.08	$0.24	$3.82	$5.03	$6.01	$17.44	$5.62
Braidwood	2,337	$23.25	$24.40	$24.29	$0.24	$8.60	$8.52	$6.01	$17.44	$5.62
Byron	2,300	$22.26	$23.38	$23.28	$0.21	$8.60	$8.52	$6.01	$17.44	$5.62
Calvert Cliffs	1,708	$27.09	$28.42	$28.30	$0.20	$4.07	$5.21	$6.01	$17.44	$5.62
Davis Besse	894	$25.84	$27.12	$27.01	$0.24	$3.82	$5.85	$5.84	$27.82	$8.34
Dresden	1,797	$23.72	$24.90	$24.80	$0.32	$8.60	$8.52	$6.01	$17.44	$5.62
Hope Creek	1,172	$23.08	$24.42	$24.36	$0.43	$7.06	$7.74	$6.01	$17.44	$5.62
LaSalle	2,271	$23.11	$24.26	$24.16	$0.18	$8.60	$8.52	$6.01	$17.44	$5.62
Limerick	2,242	$23.14	$24.49	$24.43	$0.14	$7.06	$7.74	$6.01	$17.44	$5.62
North Anna	1,892	$26.69	$28.00	$27.88	$0.17	$3.82	$5.03	$6.01	$17.44	$5.62
Peach Bottom	2,347	$22.38	$23.67	$23.61	$0.28	$7.06	$7.74	$6.01	$17.44	$5.62
Perry	1,240	$26.43	$27.77	$27.66	$0.24	$3.82	$5.85	$5.84	$27.82	$8.34
Quad Cities	1,819	$21.07	$22.19	$22.11	$0.18	$8.60	$8.52	$6.01	$17.44	$5.62
Salem	2,328	$23.10	$24.44	$24.39	$0.12	$7.06	$7.74	$6.01	$17.44	$5.62
Surry	1,676	$25.89	$27.19	$27.08	$0.17	$3.82	$5.03	$6.01	$17.44	$5.62
Susquehanna	2,520	$21.48	$22.51	$22.41	$0.28	$4.07	$5.21	$6.01	$17.44	$5.62

The MMU also calculates the capacity price that would be required to cover the net avoidable costs for each nuclear plant. Under the Commission's December 19, 2019, MOPR Order, a competitive offer in the capacity market for a subsidized nuclear plant is defined to be net avoidable costs.[71] As a result, subsidized nuclear plants could make offers in the capacity market as low as but no lower than net avoidable costs. The capacity price required to cover net avoidable costs, when compared to recent capacity market prices, is an indicator of whether nuclear plants subject to the MOPR rules would clear in a capacity auction.

Based on the recent FERC order about inclusion of maintenance expense in energy offers, major maintenance costs can no longer be included in gross ACR values.[72] The MMU calculates the capacity price that would be required to cover the net avoidable costs for each nuclear plant with major maintenance included in avoidable costs and with major maintenance excluded from avoidable costs. For the case including major maintenance, gross ACR is NEI total cost including fuel; operating cost; and capital expenditures. For the case excluding major maintenance, gross ACR is NEI total cost including fuel and operating cost, excluding capital expenditures as a proxy for fixed VOM given that NEI does not provide a breakout of major maintenance. NEI capital expenditures are likely to be a conservatively low estimate of major maintenance expense.

While the FERC order on major maintenance defines a competitive offer under the MOPR order, all generating plants including nuclear plants must cover their gross avoidable costs, including major maintenance, to remain economically viable. All of the MMU analysis of nuclear plant economics includes gross avoidable costs as reported by NEI unless explicitly stated otherwise.

The capacity price required to cover avoidable costs in $ per MWh is calculated by taking the total NEI costs

69 Forward prices on January 2, 2020. 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 2019 data.

70 Oyster Creek retired on September 17, 2018. Exelon. "Oyster Creek Generating Station Retires from Service," (September 17, 2018) <http://www.exeloncorp.com/newsroom/oyster-creek-retires>. Three Mile Island retired September 20, 2019. Exelon. "Three Mile Island Generating Station Unit 1 Retires from Service After 45 Years," (September 20, 2019) <https://www.exeloncorp.com/newsroom/three-mile-island-generating-station-unit-1-retires>.

71 *PJM Interconnection, L.L.C. et al.*, 169 FERC ¶ 61,239.

72 167 FERC ¶ 61,030.

in $ per MWh and subtracting the total expected energy and ancillary services revenues in $ per MWh. Total expected energy revenue is the average forward LMP. Total expected ancillary services revenue is reactive capability revenue.[73] The capacity price required to cover avoidable costs in $ per MW-day is calculated by multiplying the required price in $ per MWh by 24. Plants may have operating costs higher or lower than the NEI average.

For 2022, using forward prices as of January 2, 2020, the capacity price required to cover avoidable costs ranges from $13.79/MW-day for a multiple unit plant to $353.94/MW-day for a single unit plant for NEI data as reported including major maintenance, and from $0/MW-day for multiple unit plants to $153.78/MW-day for a single unit plant, excluding capital expenditures as a proxy for major maintenance.

plants in PJM. The current analysis, based on forward prices for energy and known forward prices for capacity, shows that two plants, Davis Besse and Perry, would not cover their annual avoidable costs. These plants are single unit sites which have higher operating costs per MWh than multiple unit plants and show an average annual shortfall of $10.13 per MWh. In March 2018, Davis Besse and Perry requested deactivation in 2021 but reversed the decision based on new subsidies in Ohio. Although the Susquehanna plant shows an average annual shortfall of $2.15 per MWh. Susquehanna has reduced its operating costs and is not operating at a loss when the unit specific information is accounted for.[74]

Table 7-45 Implied Net ACR

	ICAP	Net ACR ($/MWh)			Net ACR ($/MW-Day)			Net ACR Excluding Capital ($/MW-Day)		
	(MW)	2020	2021	2022	2020	2021	2022	2020	2021	2022
Beaver Valley	1,808	$2.90	$1.63	$1.75	$69.69	$39.10	$41.94	$0.00	$0.00	$0.00
Braidwood	2,337	$5.58	$4.43	$4.54	$133.91	$106.36	$108.98	$0.00	$0.00	$0.00
Byron	2,300	$6.60	$5.47	$5.58	$158.29	$131.40	$133.83	$23.41	$0.00	$0.00
Calvert Cliffs	1,708	$1.79	$0.45	$0.57	$42.85	$10.80	$13.79	$0.00	$0.00	$0.00
Davis Besse	894	$15.92	$14.64	$14.75	$382.12	$351.30	$353.94	$181.96	$151.14	$153.78
Dresden	1,797	$5.03	$3.85	$3.95	$120.73	$92.29	$94.88	$0.00	$0.00	$0.00
Hope Creek	1,172	$5.56	$4.22	$4.28	$133.47	$101.37	$102.72	$0.00	$0.00	$0.00
LaSalle	2,271	$5.77	$4.63	$4.73	$138.60	$111.06	$113.60	$3.72	$0.00	$0.00
Limerick	2,242	$5.79	$4.44	$4.50	$138.90	$106.65	$107.99	$4.02	$0.00	$0.00
North Anna	1,892	$2.21	$0.90	$1.03	$53.07	$21.66	$24.66	$0.00	$0.00	$0.00
Peach Bottom	2,347	$6.41	$5.12	$5.17	$153.72	$122.76	$124.16	$18.84	$0.00	$0.00
Perry	1,240	$15.32	$13.99	$14.10	$367.76	$335.74	$338.40	$167.60	$135.58	$138.24
Quad Cities	1,819	$7.82	$6.70	$6.79	$187.78	$160.83	$162.89	$52.90	$25.95	$28.01
Salem	2,328	$5.85	$4.50	$4.56	$140.32	$108.10	$109.40	$5.44	$0.00	$0.00
Surry	1,676	$3.01	$1.71	$1.82	$72.24	$41.13	$43.79	$0.00	$0.00	$0.00
Susquehanna	2,520	$7.31	$6.27	$6.38	$175.36	$150.58	$153.02	$40.48	$15.70	$18.14

Table 7-46 shows the surplus or shortfall that would be received net of avoidable costs and incremental capital expenditures by year, based on forward prices, on a per MWh basis. The fuel and operating costs are the 2018 NEI fuel, operating, and capital costs. Plants may have operating costs higher or lower than the NEI average. Table 7-46 shows the total dollar surplus or shortfall and adjusts energy revenues and operating costs using the annual class average capacity factor.

Changes in forward energy market prices can significantly affect expected profitability of nuclear

73 Reactive Supply & Voltage Control Revenue Requirements available from PJM <https://www.pjm.com/markets-and-operations/billing-settlements-and-credit.aspx>.

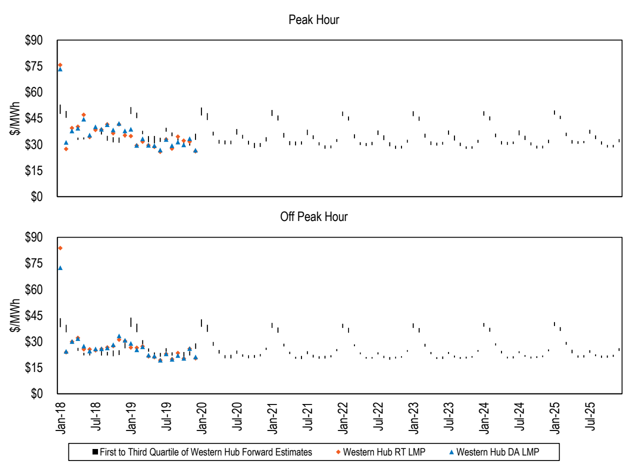
74 Talen Energy Investor Day, February 12, 2019.

Table 7-46 Nuclear unit forward annual surplus (shortfall)[75]

	ICAP	Surplus (Shortfall) ($/MWh)		Surplus (Shortfall) ($ in millions)	
	(MW)	2020	2021	2020	2021
Beaver Valley	1,808	$0.92	$3.41	$13.6	$50.3
Braidwood	2,337	$3.02	$4.09	$57.8	$78.1
Byron	2,300	$2.00	$3.05	$37.7	$57.2
Calvert Cliffs	1,708	$2.29	$4.76	$32.0	$66.4
Davis Besse	894	($12.10)	($8.79)	($88.7)	($64.2)
Dresden	1,797	$3.57	$4.67	$52.5	$68.7
Hope Creek	1,172	$1.50	$3.52	$14.4	$33.7
LaSalle	2,271	$2.82	$3.89	$52.5	$72.2
Limerick	2,242	$1.28	$3.30	$23.5	$60.4
North Anna	1,892	$1.61	$4.13	$24.9	$63.9
Peach Bottom	2,347	$0.66	$2.63	$12.7	$50.4
Perry	1,240	($11.50)	($8.14)	($116.9)	($82.5)
Quad Cities	1,819	$0.77	$1.82	$11.5	$27.0
Salem	2,328	$1.22	$3.24	$23.2	$61.6
Surry	1,676	$0.81	$3.32	$11.1	$45.5
Susquehanna	2,520	($3.24)	($1.07)	($67.0)	($21.9)

Western Hub forward prices reflect expectations of PJM prices. Figure 7-11 shows the first and third quartile of forward estimates for Western Hub compared to the realized real-time and day-ahead LMP, divided into peak hour and off peak hour. Both real-time and day-ahead realized prices can be well outside the range of.

Figure 7-11 Comparison of Western Hub forwards to realized prices: January 2018 through December 2025[76]



Units At Risk

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

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.[77] 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, CT and diesel, and nuclear units that are not expected to cover their avoidable costs over the next three years is shown in Table 7-47. These units are considered at risk of retirement.[78]

The analysis of coal units compares expected energy and capacity market revenues to ACR values over the period 2020-2021. Bus level forward LMPs are based on forward prices with a basis adjustment for the specific plant locations.[79] Forward prices are as of January 2, 2020.

The nuclear plants considered to be at risk of retirement are the Davis Besse and Perry plants, which show a shortfall over the period 2019-2021. Susquehanna is not considered to be at risk of retirement. Susquehanna has reduced its operating costs and is not operating at a loss when the unit specific information is accounted for.[80]

Based on these criteria, a total of 9,543 MW of coal, CT, diesel, and nuclear capacity are at risk of retirement, in addition to the units that are currently planning to retire. The 9,543 MW considered to be at risk of retirement includes 4,306 MW of coal, 3,103 MW of CT and diesel and 2,134 MW of nuclear capacity.[81]

75 Oyster Creek retired on September 17, 2018. Exelon. "Oyster Creek Generating Station Retires from Service," (September 17, 2018) <http://www.exeloncorp.com/newsroom/oyster-creek-retires>. Three Mile Island retired September 20, 2019. Exelon. "Three Mile Island Generating Station Unit 1 Retires from Service After 45 Years," (September 20, 2019) <https://www.exeloncorp.com/newsroom/three-mile-island-generating-station-unit-1-retires>.

76 Western Hub monthly peak and off peak prices are from Platts. Peak hours are from 7am to 11pm and exclude weekends and NERC holidays.

77 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.

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

79 Forward prices on January 2, 2020. 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 2019 data.

80 Talen Energy Investor Day, February 12, 2019.

81 Coal units at risk of retirement analysis is based on the default unit type ACR provided by Pasteris Energy, Inc. while the analysis in prior reports was based on PJM's higher posted ACR values.

Table 7-47 Profile of units at risk of retirement

Technology	No. Units	ACR ($/MW-day)	ICAP (MW)	Avg. 2019 Run Hrs	Avg. Unit Age (Yrs)	Avg. Heat Rate (Btu/MWh)
Coal Fired	8	$115.48	4,306	3,127	50	10,072
CT and Diesel	101	$107.96 CT / $55.96 DS	3,103	78	46	15,145
Nuclear	2	$940.46 single unit	2,134	-	37	-
Total	111	-	9,543	-	-	-

