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 analysis includes the theoretical new entrant net revenues for combustion turbine (CT), combined cycle (CC), coal plant (CP), diesel (DS), nuclear, solar, and wind generating units. The analysis also includes actual net revenues and net revenue adequacy for all technology types, net revenue adequacy for nuclear plants, and an assessment of the units at risk of retirement.

Overview

Net Revenue

- Energy market net revenues are significantly affected by energy prices and fuel prices. Energy prices and fuel prices were significantly lower in 2023 than in 2022. The net effects were that in 2023, average energy market theoretical net revenues decreased by 44 percent for a new combustion turbine (CT), 46 percent for a new combined cycle (CC), 67 percent for a new coal plant (CP), 57 percent for a new nuclear plant, 97 percent for a new diesel (DS), 61 percent for a new onshore wind installation, 62 percent for a new offshore wind installation and 65 percent for a new solar installation.
- The price of natural gas and coal decreased in 2023. The marginal costs of a new CC and CT were less than the marginal cost of a new CP in 2023.
- In 2023, spark spreads, dark spreads, and the volatility of both spark spreads and dark spreads decreased in BGE, COMED, PSEG, and Western Hub compared to 2022.
- In 2023, capacity market revenue accounted for 27 percent of theoretical total net revenues for a new CT, 20 percent for a new CC, 54 percent for a new CP, 8 percent for a new nuclear plant, 72 percent for a new DS, 2 percent for a new onshore wind installation, 4 percent for a new offshore wind installation and 3 percent for a new solar installation.
- In 2023, no new CT, CC, CP, nuclear, or DS units would have received sufficient total net revenue to cover levelized total costs in any zone.
- In 2023, a theoretical new entrant onshore wind installation would not have received sufficient net revenue to cover levelized total costs in any of the four zones analyzed. Total net revenues would have covered between 49 and 57 percent of levelized total costs of in AEP, APS, COMED and PE. Renewable energy credits (RECs) were an average of 50 percent of the total net revenue of an onshore wind installation.
- In 2023, a theoretical new entrant offshore wind installation would not have received sufficient net revenue to cover levelized total costs in any of the three zones analyzed. Total net revenues would have covered between 27 and 32 percent of levelized total costs. Renewable energy credits were an average of 56 percent of the total net revenue of an offshore wind installation.
- In 2023, a theoretical new entrant solar installation would have received sufficient net revenue to cover more than 100 percent of levelized total costs in ACEC, JCPLC and PSEG and between 78 and 98 percent of levelized total costs in DPL and DOM. Renewable energy credits were an average of 77 percent of the total net revenue of a solar installation.
- In 2023, most units did not achieve full recovery of avoidable costs through net revenue from energy and ancillary services markets alone, illustrating the critical role of the capacity market in providing incentives for continued operation and investment. In 2023, capacity market revenue was sufficient to cover the shortfall between net energy revenue and avoidable costs for the majority of units and technology types in PJM, with the exception of coal and CT units.
- All existing PJM nuclear plants are expected to cover their avoidable costs from energy and capacity market revenues in 2024, 2025, and 2026, without subsidies, with the exception of Davis Besse and Perry, both single unit nuclear plants, in 2024.
- New entrant solar and wind resources are competitive with existing coal resources, including the effect of current federal tax subsidies and RECs revenues available to the intermittent resources.
- Between 42,877 and 57,694 MW of capacity are at risk of retirement by 2030, consisting of 4,285

MW currently announced retirements, 19,635 MW expected to retire for regulatory reasons, and between 18,957 and 33,774 MW expected to be uneconomic. This capacity consists primarily of coal plants and CT units. Replacing the capacity of the retiring non-gas resources with gas-fired capacity would require between 1.9 and 4.8 BCF/day of new firm gas supply depending on the MW at risk and the extent to which new gas fired capacity is dual fuel.

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 calculation of expected energy and ancillary services net revenues using historical revenues that are scaled based on forward prices for energy and fuel. (Priority: Medium. First reported 2019. Status: Not adopted.)

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 alone 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. A basic purpose of the capacity market is allow all cleared capacity resources the opportunity to cover their net avoidable costs on an annual basis to ensure the economic sustainability of the reliable energy market.

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 in 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 and capability, and from subsidies like RECs, 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.[1] Net revenue is the contribution to total fixed and avoidable costs received by generators from all PJM markets.

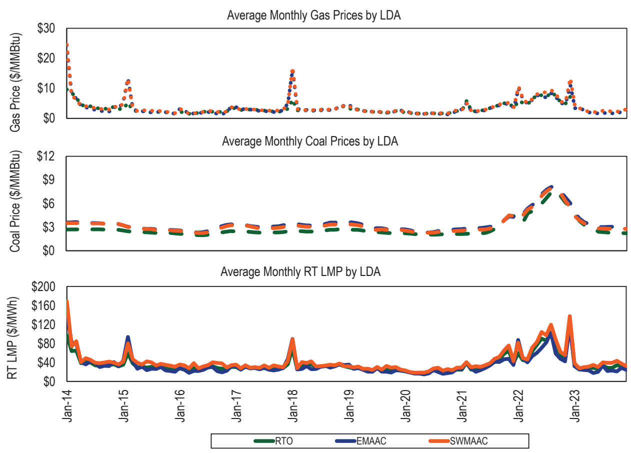
In a perfectly competitive, energy only market in long run equilibrium, net revenue from the energy market would be expected to equal the annualized fixed and avoidable costs for the marginal unit, including a competitive return on investment. The PJM market design includes other markets that contribute 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 markets, 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

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

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 real-time load-weighted average LMP in 2023 decreased 61.2 percent from 2022, from $80.14 per MWh to $31.08 per MWh. Gas prices and coal prices decreased in 2023 compared to 2022. The price of eastern natural gas was 70.8 percent lower, the price of western natural gas was 65.2 percent lower; the price of Northern Appalachian coal was 53.2 percent lower; the price of Central Appalachian coal was 46.0 percent lower; and the price of Powder River Basin coal was 18.3 percent lower (Figure 7-1).

Figure 7-1 Energy market net revenue factor trends: 2014 through 2023



Spark Spreads and Dark Spreads

The spark or dark 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 and the dark spread compares power prices to the cost of coal. 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.

In 2023, the spark spreads and dark spreads decreased compared to 2022. The volatility of both spark spreads and dark spreads also decreased.

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

Table 7-1 Peak hour spark and dark spreads ($/MWh)

	BGE		COMED		PSEG		Western Hub	
	Spark	Dark	Spark	Dark	Spark	Dark	Spark	Dark
2022	$52.04	$39.48	$30.83	$44.93	$26.35	$10.56	$38.06	$25.62
2023	$29.72	$12.18	$15.42	$8.21	$13.92	($7.25)	$23.60	$6.48
Percent change	(43%)	(69%)	(50%)	(82%)	(47%)	(169%)	(38%)	(75%)

Table 7-2 Peak hour spark and dark spread standard deviation ($/MWh)

	BGE		COMED		PSEG		Western Hub	
	Spark	Dark	Spark	Dark	Spark	Dark	Spark	Dark
2022	$141.4	$146.3	$97.6	$100.8	$94.3	$101.1	$116.1	$119.8
2023	$35.7	$36.1	$19.0	$19.3	$21.0	$19.7	$30.1	$27.9
Percent change	(75%)	(75%)	(81%)	(81%)	(78%)	(80%)	(74%)	(77%)

Figure 7-2 shows the hourly spark spread for peak hours for BGE, COMED, PSEG, and Western Hub.

Figure 7-2 Hourly spark spread (gas) for peak hours ($/MWh): 2021 through 2023[2]

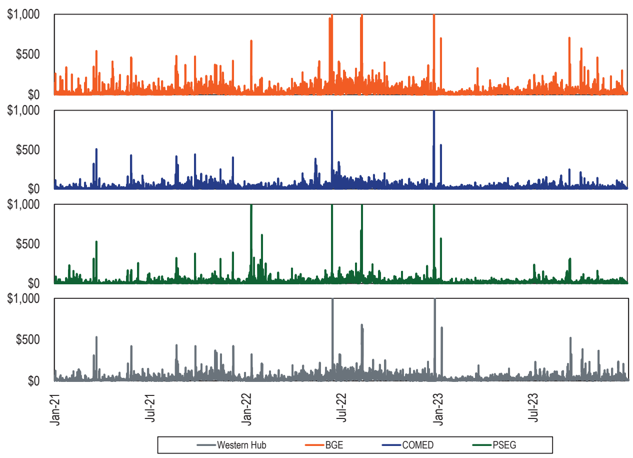
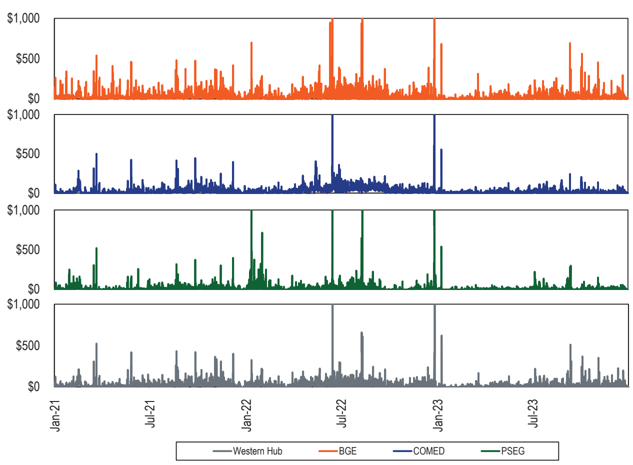


Figure 7-3 Hourly dark spread (coal) for peak hours ($/MWh): 2021 through 2023[3]



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

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

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 unit's operations and potential net revenue in PJM markets.

Analysis of energy market net revenues for a new unit includes eight 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 single shaft 1x1 GE Frame 7HA.02 CTs, each with a single combustion turbine, heat recovery steam generator, and steam turbine with a total installed capacity of 1,100 MW, equipped with SCR for NO_x reduction, dry cooling, duct burners, and dual fuel capability.
- 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 baghouse 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 104 Siemens 2.9 MW wind turbines with an installed capacity of 301.6 MW.
- The offshore wind installation includes of 40 Siemens 10.0 MW wind turbines with an installed capacity of 400.0 MW.
- The solar installation is a 472 acre ground mounted tracking solar farm with an installed AC capacity of 200 MW.
- The battery storage unit is a 2.5 MW, 10 hour battery capable of providing 2.5 MWh for 10 hours, or 25 MWh.

Net revenue calculations for the CT, CC and CP include the hourly effect of actual local ambient air temperature on plant heat rates and generator output for each of the three plant configurations.[4 5] Plant heat rates account for the efficiency changes and corresponding cost changes resulting from ambient air temperatures.

CO_2, NO_x and SO_2 emission allowance costs are included in the hourly plant dispatch cost, the short run marginal cost.[6] CO_2, NO_x and SO_2 emission allowance costs were obtained from daily spot cash prices.[7]

The class average equivalent availability factor for each type of plant was calculated from PJM data and incorporated into all revenue calculations.[8]

Revenues for the provision of reactive services include both real-time reactive service revenues and reactive capability revenues. Reactive service revenues for CT, CC, CP, and DS units are based on the average reactive service revenue per MW-year received by all generators of that unit type. Table 7-3 includes the class average reactive service revenues received plus reactive capability revenue by unit type.[9]

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

	Reactive						
	CT	CC	CP	Diesel	Nuclear	Solar	Wind
2021	$3,734	$2,648	$1,366	$6,366	$1,640	$6,167	$4,185
2022	$2,917	$2,504	$1,771	$7,042	$1,762	$8,040	$3,712
2023	$2,601	$2,399	$1,800	$6,992	$1,670	$8,040	$3,769

Zonal net revenues reflect average zonal LMP and fuel costs based on locational fuel indices and zone specific delivery charges.[10] 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.[11] The delivered cost of coal

4 Hourly ambient conditions supplied by DTN.
5 Heat rates provided by Pasteris Energy, Inc. No load costs are included in the dispatch price since each unit type is dispatched at full load for every economic hour resulting in a single offer point.
6 CO_2 emission allowance costs only included for states participating in RGGI.
7 CO_2, NO_x and SO_2 emission daily prompt prices obtained from Evolution Markets, Inc.
8 Outage figures obtained from the PJM eGADS database.
9 Reactive capability revenue by unit type is located in the *2022 Annual State of the Market Report for PJM*, Volume 2: Section 10, Ancillary Services Markets.
10 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 warm starts.
11 Gas daily cash prices obtained from Platts.

reflects the zone specific, delivered price of coal and was developed from the published prompt month prices, adjusted for rail transportation costs.[12] Net revenues are calculated for all zones except OVEC.[13]

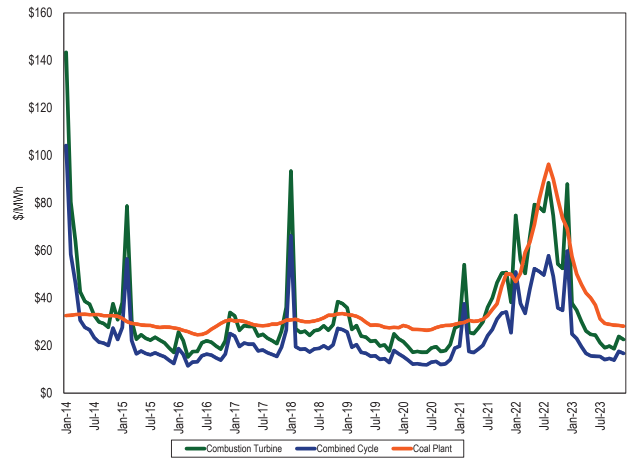
Short run marginal cost includes fuel costs, emissions costs, and the short run marginal component of VOM costs.[14 15] Average short run marginal costs are shown, including all components, in Table 7-4 and the short run marginal component of VOM is also shown separately.

Table 7-4 Average short run marginal costs: 2023

Unit Type	Short Run Marginal Costs ($/MWh)	Heat Rate (Btu/kWh)	VOM ($/MWh)
CT	$25.29	9,241	$0.54
CC	$17.32	6,369	$0.88
CP	$37.31	9,250	$5.64
DS	$287.07	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 7-4). In 2023, the marginal costs of a new CC and CT were less than the marginal cost of a new CP. The marginal costs are based on spot fuel costs. Individual generation plants may have contracts for coal that differ significantly from spot prices.

Figure 7-4 Average short run marginal costs: 2014 through 2023



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 unit capacity factors. Table 7-5 shows the average capacity factor for new units. The capacity factor for a new CP declined in 2023 compared to 2022, while the capacity factors for a new CT and a new CC increased.

Table 7-5 Average capacity factor: 2014 through 2023

	CT	CC	CP	DS	Nuclear	On Shore Wind	Solar
2014	48%	73%	58%	3%	92%	25%	15%
2015	64%	74%	52%	3%	92%	25%	17%
2016	65%	75%	46%	1%	92%	22%	16%
2017	53%	70%	40%	1%	94%	26%	17%
2018	52%	79%	42%	2%	94%	27%	16%
2019	52%	77%	24%	1%	93%	26%	15%
2020	48%	76%	13%	1%	93%	26%	16%
2021	42%	76%	37%	1%	93%	24%	17%
2022	40%	75%	30%	1%	93%	26%	16%
2023	60%	78%	25%	0%	94%	24%	16%

12 Coal prompt month prices obtained from Platts.
13 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.
14 Fuel costs are calculated using the daily spot price and may not equal what individual participants actually paid.
15 VOM rates provided by Pasteris Energy, Inc.

Capacity Market Net Revenue

Generators receive revenue from the capacity market in addition to revenue from the energy and ancillary service markets. In the PJM market design, the capacity market provides an important source of revenue that contributes to covering generator avoidable costs and fixed costs. Capacity market revenue for 2023 includes five months of the 2022/2023 RPM capacity market clearing price and seven months of the 2023/2024 RPM capacity market clearing price.[16]

Table 7-6 Capacity market revenue by zone (Dollars per MW-year): 2014 through 2023[17]

Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
ACEC	$66,206	$56,448	$50,948	$43,669	$65,655	$58,103	$57,650	$63,835	$45,967	$25,368
AEP	$31,149	$48,128	$33,377	$34,645	$53,235	$45,873	$31,371	$41,525	$31,842	$14,854
APS	$31,149	$48,128	$33,377	$34,645	$53,216	$45,948	$31,425	$41,647	$31,932	$14,854
ATSI	$31,149	$95,422	$78,709	$42,929	$53,124	$45,781	$31,351	$48,221	$36,571	$14,854
BGE	$63,360	$56,448	$50,948	$43,669	$52,953	$45,651	$33,380	$49,311	$49,777	$30,062
COMED	$31,149	$48,128	$33,377	$34,645	$63,994	$75,508	$70,901	$70,256	$44,273	$17,708
DAY	$31,149	$48,128	$33,377	$34,645	$52,760	$44,969	$30,957	$41,516	$31,840	$14,854
DOM	$31,149	$48,128	$33,377	$34,645	$53,219	$45,665	$31,221	$41,516	$31,840	$14,854
DPL	$66,206	$56,448	$50,948	$43,669	$65,106	$57,607	$57,573	$63,835	$45,967	$26,669
DUKE	$31,149	$48,128	$33,377	$34,645	$52,338	$44,515	$42,289	$49,590	$36,482	$18,129
DUQ	$31,149	$48,128	$33,377	$34,645	$53,045	$45,567	$31,239	$41,516	$31,840	$14,854
EKPC	$31,149	$48,128	$33,377	$34,645	$52,400	$44,611	$30,883	$41,516	$31,840	$14,854
JCPLC	$66,206	$56,448	$50,948	$43,669	$64,763	$56,462	$56,932	$63,832	$45,965	$25,367
MEC	$63,360	$56,448	$50,948	$43,669	$53,353	$46,138	$33,526	$42,952	$41,639	$25,055
PE	$63,360	$56,448	$50,945	$43,667	$53,154	$45,760	$33,376	$42,966	$41,639	$25,055
PECO	$66,206	$56,448	$50,948	$43,669	$65,707	$58,548	$57,940	$63,835	$45,967	$25,368
PEPCO	$66,529	$56,448	$50,948	$43,669	$53,323	$46,207	$33,590	$42,952	$41,639	$25,055
PPL	$63,360	$56,448	$50,948	$43,669	$52,218	$45,398	$33,569	$42,980	$41,659	$25,055
PSEG	$72,567	$60,936	$67,224	$73,401	$79,190	$59,582	$58,370	$69,285	$49,813	$25,368
REC	$72,567	$60,936	$67,224	$73,401	$79,190	$59,582	$58,370	$69,285	$49,813	$25,368
PJM	$46,247	$54,646	$48,568	$44,809	$58,432	$52,009	$42,222	$50,695	$39,442	$20,155

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.

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

Levelized Total Costs

Levelized total costs are the nominal 20 year levelized revenue requirements for the capital costs of each technology. Levelized total costs include return on and of capital and fixed O&M expenses. Variable operating expenses including fuel and variable operations and maintenance expenses are not included.

16 The RPM revenue values for PJM are load-weighted average clearing prices across the relevant base residual auctions. Differences in capacity market revenue reflect differences in clearing prices across LDAs.
17 See the *2022 Annual State of the Market Report for PJM*, Appendix A: "PJM Geography," for details on the expansion of the PJM footprint.

Table 7-7 New entrant 20-year levelized total costs (By plant type (Dollars per installed MW-year))[18 19 20 21]

	20-Year Levelized Total Cost									
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Combustion Turbine	$122,604	$120,675	$119,346	$114,557	$118,116	$121,612	$120,720	$134,297	$149,470	$163,333
Combined Cycle	$146,443	$146,300	$148,327	$129,731	$113,641	$116,781	$119,180	$132,378	$172,009	$183,473
Coal Plant	$504,050	$517,017	$523,540	$528,701	$562,747	$581,567	$599,912	$635,027	$678,134	$725,839
Diesel Plant	$161,746	$170,500	$173,182	$158,817	$154,683	$169,859	$177,843	$206,097	$231,006	$264,310
Nuclear Plant	$880,770	$935,659	$963,107	$1,349,850	$1,178,607	$1,383,428	$1,383,428	$1,706,638	$1,706,638	$1,768,834
On Shore Wind Installation (with 30% ITC)	$198,033	$202,874	$231,310	$188,747	$214,780	$214,618	$208,167	$245,031	$238,038	$256,990
Off Shore Wind Installation (with 30% ITC)	-	-	-	-	$683,771	$710,472	$707,739	$783,374	$678,226	$779,762
Solar Installation (with 30% ITC)	$236,289	$234,151	$218,937	$200,931	$232,230	$243,936	$189,391	$153,261	$206,778	$211,057
Battery Storage	-	-	-	-	-	-	-	$865,686	$691,548	$771,901

Levelized Cost of Energy

The levelized cost of energy (LCOE) is a measure of the total cost per MWh of energy from a technology, including all fixed and variable costs. The LCOE includes the levelized total costs plus short run marginal costs in $/MWh, based on an identified capacity factor. 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 LCOE is the standalone energy price needed for the unit type to be competitive. Revenues from the capacity market, ancillary services markets and subsidies reduce the LCOE required from the energy market.

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.

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 19 percent. The LCOE of a solar installation would be $48/MWh if a capacity factor of 50 percent were used because the costs are distributed over a greater number of MWh.[22]

Table 7-8 Levelized cost of energy: 2023

	CT	CC	CP	DS	Nuclear	Wind (On Shore)	Wind (Off Shore)	Solar
Levelized cost ($/MW-year)	$163,333	$183,473	$725,839	$264,310	$1,768,834	$256,990	$779,762	$211,057
Short run marginal costs ($/MWh)	$25.29	$17.32	$37.31	$287.07	$0.00	$0.00	$0.00	$0.00
Capacity factor (%)	60%	78%	25%	0%	95%	28%	45%	19%
Levelized cost of energy ($/MWh)	$56	$44	$371	$18,164	$213	$104	$198	$130

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 additional 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 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.

18 Levelized total costs provided 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 80 percent bonus depreciation and a 15-year modified accelerated cost-recovery schedule (MACRS) for the CT plant and 20-year MACRS for the CC plant. An annual rate of cost inflation of 2.5 percent was used in all calculations.

19 Bonus depreciation is 100 percent for capital investments placed in service after September 27, 2017 and before January 1, 2023. Bonus depreciation is 80 percent for capital investments placed in service after December 31, 2022, and before January 1, 2024, and the bonus depreciation level is reduced by 20 percent for each subsequent year through 2026. Capital investments placed in service after December 31, 2026, are not eligible for bonus depreciation. See 26 U.S. Code §168(k)(6)(A).

20 Under the Inflation Reduction Act solar and wind energy properties are eligible for an Investment Tax Credit of 30 percent of the total eligible capital cost of the project if they meet prevailing wage requirements. Solar and wind technologies may qualify for an additional 10 percent if they satisfy domestic content requirements. Solar and energy storage projects may qualify for an additional 10 percent tax credits for projects built within an energy community, as defined by the IRA. This analysis assumes eligibility only for the 30 percent ITC.

21 The battery is a 25 MWh battery capable of producing 2.5 MW for 10 hours. The 20-year levelized total cost for the battery is calculated using a 2.5 MW installed capacity.

22 Nuclear, solar, and onshore wind capacity factor from the *2023 Annual State of the Market Report for PJM*, Section 5: "Capacity Market." CT, CC, CP and DS capacity factors are based on the dispatch of the new entrant units.

New entrant CT plant energy market net revenues were lower in all zones in 2023 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 2023 (Dollars per installed MW-year)[23]

Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	Change in 2023 from 2022
ACEC	$84,836	$50,794	$52,699	$28,997	$34,625	$24,051	$9,052	$13,214	$65,244	$29,686	(55%)
AEP	$74,978	$69,424	$55,360	$36,440	$72,928	$44,651	$33,410	$57,279	$119,007	$65,003	(45%)
APS	$101,376	$97,467	$61,544	$48,564	$71,758	$24,930	$19,200	$38,134	$87,361	$79,288	(9%)
ATSI	$55,573	$59,263	$53,052	$38,949	$86,415	$45,733	$33,690	$56,512	$113,667	$60,876	(46%)
BGE	$99,953	$79,092	$92,965	$40,064	$52,362	$33,157	$31,522	$55,829	$148,692	$108,608	(27%)
COMED	$34,672	$32,378	$34,109	$22,162	$32,571	$23,501	$18,530	$32,811	$76,274	$43,956	(42%)
DAY	$49,905	$57,180	$51,652	$37,682	$81,172	$51,092	$40,100	$72,267	$132,357	$70,302	(47%)
DOM	$67,601	$68,742	$64,140	$37,075	$57,676	$35,826	$28,998	$62,761	$159,441	$72,730	(54%)
DPL	$65,984	$33,315	$26,615	$19,853	$28,229	$14,604	$14,297	$30,640	$94,804	$55,281	(42%)
DUKE	$44,998	$54,542	$48,954	$36,051	$88,626	$46,495	$36,049	$67,055	$125,035	$66,440	(47%)
DUQ	$52,029	$81,445	$72,284	$46,308	$57,854	$30,516	$31,432	$48,663	$120,066	$89,952	(25%)
EKPC	$65,277	$56,514	$48,036	$30,024	$55,351	$37,022	$29,760	$55,345	$108,260	$52,910	(51%)
JCPLC	$85,599	$48,957	$48,143	$32,391	$32,118	$23,755	$9,133	$12,844	$64,221	$31,489	(51%)
MEC	$87,153	$87,946	$71,178	$55,484	$44,929	$29,492	$36,074	$61,924	$148,217	$61,810	(58%)
PE	$139,617	$140,467	$89,309	$63,620	$83,911	$41,273	$44,218	$65,558	$131,818	$97,206	(26%)
PECO	$89,208	$86,138	$66,527	$46,494	$38,961	$22,037	$26,723	$27,052	$85,868	$34,706	(60%)
PEPCO	$70,396	$50,496	$46,753	$25,829	$42,134	$21,041	$14,094	$37,521	$90,124	$53,264	(41%)
PPL	$212,119	$155,947	$72,532	$59,248	$81,558	$28,443	$30,634	$53,261	$130,167	$62,110	(52%)
PSEG	$108,432	$99,278	$71,988	$54,477	$44,574	$24,808	$9,575	$16,699	$67,739	$31,611	(53%)
REC	$80,365	$55,796	$53,746	$34,467	$35,019	$25,217	$11,413	$26,286	$67,914	$38,582	(43%)
PJM	$58,381	$73,259	$59,079	$39,709	$56,138	$31,382	$25,395	$44,583	$106,814	$60,290	(44%)

In 2023, a new CT would not have received sufficient net revenue to cover levelized total costs in any zone (Table 7-10).

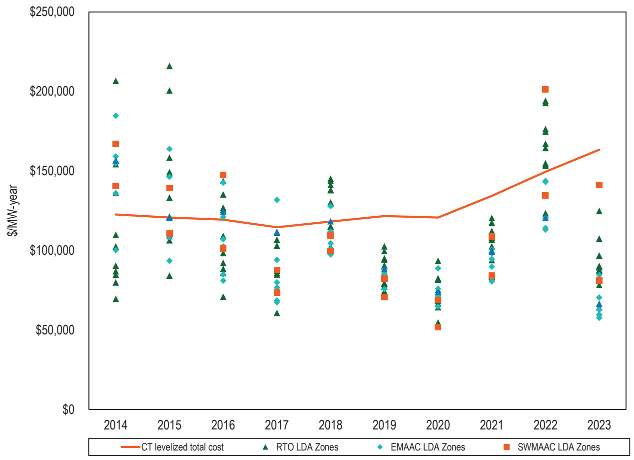
Table 7-10 Percent of 20-year levelized total costs recovered by CT energy and capacity net revenue: 2014 through 2023

Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
ACEC	126%	92%	90%	67%	88%	70%	59%	60%	76%	35%
AEP	90%	100%	77%	65%	110%	77%	57%	76%	103%	50%
APS	111%	124%	82%	76%	109%	61%	45%	62%	82%	59%
ATSI	74%	131%	113%	75%	122%	78%	57%	81%	102%	48%
BGE	136%	115%	123%	76%	93%	68%	57%	81%	135%	86%
COMED	57%	70%	59%	53%	85%	84%	77%	80%	83%	39%
DAY	69%	90%	74%	67%	117%	82%	62%	88%	112%	54%
DOM	84%	100%	85%	66%	97%	70%	53%	80%	130%	55%
DPL	111%	77%	68%	59%	83%	62%	63%	73%	96%	52%
DUKE	65%	88%	72%	65%	123%	78%	68%	90%	110%	53%
DUQ	71%	110%	91%	74%	97%	65%	55%	70%	104%	66%
EKPC	82%	90%	71%	60%	95%	70%	54%	75%	96%	43%
JCPLC	127%	90%	86%	70%	86%	69%	58%	60%	76%	36%
MEC	126%	123%	105%	90%	87%	65%	61%	81%	129%	55%
PE	169%	166%	120%	97%	120%	74%	68%	84%	118%	76%
PECO	130%	121%	101%	82%	92%	69%	73%	70%	90%	38%
PEPCO	115%	92%	85%	64%	84%	58%	43%	63%	90%	50%
PPL	228%	179%	106%	93%	117%	64%	57%	74%	117%	55%
PSEG	151%	136%	120%	115%	108%	72%	60%	67%	81%	36%
REC	128%	100%	104%	98%	100%	73%	61%	74%	81%	41%
PJM	88%	109%	93%	77%	101%	71%	59%	74%	100%	51%

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

Figure 7-5 shows zonal net revenue and the annual levelized total cost for the new entrant CT by LDA.

Figure 7-5 New entrant CT net revenue and 20-year levelized total cost by LDA (Dollars per installed MW-year): 2014 through 2023



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.[24] The unit was allowed to extend its run in real time if it was profitable to do so.

New entrant CC plant energy market net revenues were lower in all zones in 2023 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 2023 (Dollars per installed MW-year)[25]

Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	Change in 2023 from 2022
ACEC	$126,626	$74,716	$68,004	$50,259	$67,427	$51,397	$29,870	$42,582	$71,123	$46,443	(35%)
AEP	$109,077	$96,826	$76,488	$59,550	$109,104	$74,927	$55,042	$96,601	$208,879	$103,715	(50%)
APS	$154,260	$140,352	$98,353	$76,282	$117,114	$64,383	$54,111	$94,052	$168,877	$108,047	(36%)
ATSI	$82,670	$87,902	$74,459	$60,987	$120,740	$75,846	$55,328	$97,104	$201,560	$98,934	(51%)
BGE	$155,916	$125,088	$129,148	$71,490	$98,258	$74,567	$67,515	$115,493	$194,608	$140,781	(28%)
COMED	$47,229	$54,134	$53,187	$38,278	$56,006	$45,150	$34,101	$60,244	$139,223	$71,893	(48%)
DAY	$76,213	$86,691	$73,887	$61,188	$117,206	$81,573	$62,751	$114,111	$224,321	$110,397	(51%)
DOM	$107,034	$98,562	$86,903	$60,969	$92,066	$67,760	$50,597	$103,129	$240,238	$112,152	(53%)
DPL	$109,317	$50,497	$43,345	$27,674	$47,707	$21,528	$17,501	$46,552	$102,931	$70,755	(31%)
DUKE	$66,685	$82,518	$70,201	$57,922	$122,183	$76,621	$57,948	$107,384	$214,631	$105,819	(51%)
DUQ	$82,827	$95,948	$86,877	$64,871	$91,162	$57,652	$52,762	$87,864	$199,392	$123,233	(38%)
EKPC	$94,638	$84,530	$68,479	$52,705	$91,178	$67,152	$51,066	$94,868	$193,114	$90,816	(53%)
JCPLC	$129,988	$73,929	$63,904	$53,388	$64,877	$51,790	$30,243	$45,452	$72,004	$49,682	(31%)
MEC	$125,923	$104,606	$82,491	$71,970	$78,513	$57,663	$53,852	$100,142	$193,262	$94,324	(51%)
PE	$177,443	$147,403	$99,614	$78,602	$118,315	$70,370	$62,647	$106,350	$220,157	$128,847	(41%)
PECO	$130,760	$105,080	$77,959	$64,772	$74,100	$48,733	$44,819	$62,746	$112,684	$60,505	(46%)
PEPCO	$116,066	$96,499	$85,838	$54,535	$84,100	$58,426	$39,143	$83,010	$150,361	$84,324	(44%)
PPL	$232,400	$155,117	$83,707	$73,720	$108,706	$54,358	$48,885	$91,085	$215,043	$92,517	(57%)
PSEG	$157,117	$118,918	$83,897	$72,328	$81,207	$53,768	$32,989	$50,230	$74,914	$49,667	(34%)
REC	$125,098	$79,151	$68,279	$55,405	$66,816	$53,845	$33,766	$60,666	$110,722	$58,253	(47%)
PJM	$100,026	$97,923	$78,751	$60,345	$90,339	$60,375	$46,747	$82,983	$165,402	$90,055	(46%)

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

In 2023, a new CC would not have received sufficient net revenue to cover levelized total costs in any zone (Table 7-12).

Table 7-12 Percent of 20-year levelized total costs recovered by CC energy and capacity net revenue: 2014 through 2023

Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
ACEC	134%	93%	83%	75%	120%	97%	76%	82%	70%	40%
AEP	99%	102%	77%	75%	146%	106%	75%	106%	141%	66%
APS	129%	132%	92%	88%	153%	97%	75%	105%	118%	68%
ATSI	80%	129%	106%	83%	156%	107%	76%	112%	140%	63%
BGE	152%	127%	125%	92%	136%	106%	88%	126%	144%	94%
COMED	56%	73%	61%	59%	109%	106%	91%	101%	108%	50%
DAY	76%	96%	75%	77%	153%	111%	82%	120%	150%	70%
DOM	97%	104%	84%	76%	131%	100%	72%	111%	160%	71%
DPL	123%	76%	67%	58%	102%	71%	66%	85%	88%	54%
DUKE	70%	93%	73%	74%	157%	107%	87%	121%	147%	69%
DUQ	81%	102%	84%	79%	130%	91%	73%	100%	136%	77%
EKPC	89%	94%	72%	70%	129%	99%	72%	105%	132%	59%
JCPLC	137%	92%	81%	78%	117%	96%	76%	85%	70%	42%
MEC	132%	113%	93%	92%	119%	92%	76%	110%	138%	66%
PE	167%	143%	105%	97%	154%	102%	84%	115%	154%	85%
PECO	137%	114%	90%	86%	126%	95%	89%	98%	94%	48%
PEPCO	127%	108%	95%	78%	124%	92%	64%	97%	113%	61%
PPL	205%	148%	94%	93%	145%	88%	72%	103%	151%	65%
PSEG	160%	126%	105%	115%	144%	100%	80%	92%	74%	42%
REC	138%	99%	94%	102%	131%	100%	80%	100%	95%	47%
PJM	103%	108%	89%	84%	134%	99%	78%	103%	121%	61%

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

Figure 7-6 New entrant CC net revenue and 20-year levelized total cost by LDA (Dollars per installed MW-year): 2014 through 2023

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. The unit was allowed to extend its run in real time if it was profitable to do so.

New entrant CP plant energy market net revenues were lower in all zones in 2023 as a result of lower energy prices (Table 7-13).

Table 7-13 Energy net revenue for a new entrant CP: 2014 through 2023 (Dollars per installed MW-year)[26]

Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	Change in 2023 from 2022
ACEC	$115,697	$48,138	$10,643	$8,999	$31,658	$4,279	$1,176	$6,008	$25,421	$4,384	(83%)
AEP	$113,144	$52,219	$40,332	$38,197	$66,584	$19,004	$7,807	$53,319	$46,705	$18,227	(61%)
APS	$105,457	$42,154	$15,210	$19,486	$44,638	$5,688	$2,413	$19,025	$29,088	$25,212	(13%)
ATSI	$124,565	$52,704	$35,451	$38,199	$68,869	$14,847	$4,630	$47,849	$55,405	$19,203	(65%)
BGE	$167,855	$86,208	$50,522	$21,120	$52,340	$9,970	$6,209	$31,297	$68,083	$45,658	(33%)
COMED	$112,699	$40,858	$30,660	$27,836	$38,710	$12,822	$2,983	$53,710	$216,121	$59,959	(72%)
DAY	$117,561	$50,977	$32,927	$37,029	$65,266	$18,807	$9,763	$60,484	$45,789	$20,248	(56%)
DOM	$156,315	$91,939	$46,734	$30,562	$68,684	$17,805	$9,438	$58,809	$140,531	$40,344	(71%)
DPL	$167,509	$72,083	$21,952	$18,615	$52,130	$10,285	$6,805	$22,329	$54,269	$26,191	(52%)
DUKE	$106,048	$46,757	$29,597	$33,810	$69,969	$16,583	$8,587	$54,856	$42,685	$18,507	(57%)
DUQ	$98,952	$41,312	$30,713	$34,644	$68,317	$13,181	$5,229	$45,942	$49,483	$22,169	(55%)
EKPC	$102,305	$38,740	$25,523	$27,221	$45,357	$12,475	$6,577	$49,103	$40,731	$16,323	(60%)
JCPLC	$119,656	$46,725	$7,933	$9,818	$30,805	$4,074	$1,386	$6,107	$26,217	$4,258	(84%)
MEC	$153,809	$65,100	$19,709	$22,951	$50,243	$9,800	$6,897	$41,405	$90,124	$14,567	(84%)
PE	$129,578	$60,613	$23,206	$18,518	$47,150	$9,533	$5,186	$36,910	$61,695	$20,454	(67%)
PECO	$111,207	$44,763	$8,709	$9,112	$29,402	$4,053	$871	$14,715	$37,742	$4,485	(88%)
PEPCO	$114,167	$41,190	$10,634	$7,522	$29,682	$4,342	$1,347	$24,629	$37,332	$16,211	(57%)
PPL	$110,250	$43,645	$7,050	$9,171	$29,146	$3,234	$1,069	$24,886	$42,694	$4,651	(89%)
PSEG	$174,390	$72,864	$13,651	$14,719	$36,384	$6,201	$489	$6,048	$34,409	$4,931	(86%)
REC	$170,401	$73,116	$13,238	$13,921	$36,301	$7,234	$1,279	$11,829	$37,707	$4,568	(88%)
PJM	$128,578	$55,605	$23,720	$22,072	$48,082	$10,211	$4,507	$33,463	$59,112	$19,527	(67%)

In 2023, a new CP would not have received sufficient net revenue to cover levelized total costs in any zone (Table 7-14). This has been the consistent result for a new CP for the entire period of the analysis.

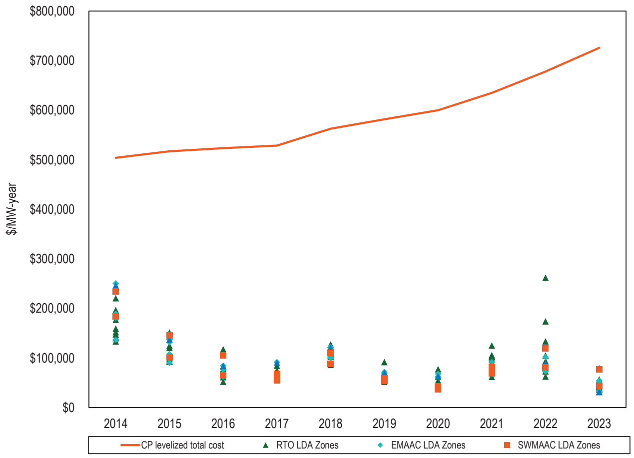
Table 7-14 Percent of 20-year levelized total costs recovered by CP energy and capacity net revenue: 2014 through 2023

Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
ACEC	37%	21%	12%	11%	18%	11%	10%	11%	11%	4%
AEP	29%	20%	15%	14%	22%	12%	7%	15%	12%	5%
APS	28%	18%	10%	11%	18%	10%	6%	10%	9%	6%
ATSI	32%	29%	22%	16%	23%	11%	7%	15%	14%	5%
BGE	47%	28%	20%	13%	20%	10%	7%	13%	18%	11%
COMED	29%	18%	13%	12%	19%	16%	13%	20%	39%	11%
DAY	30%	20%	13%	14%	22%	12%	7%	16%	12%	5%
DOM	38%	28%	16%	13%	23%	12%	7%	16%	26%	8%
DPL	47%	26%	15%	12%	22%	12%	11%	14%	15%	8%
DUKE	28%	19%	13%	14%	23%	11%	9%	17%	12%	5%
DUQ	27%	18%	13%	14%	22%	11%	7%	14%	12%	5%
EKPC	27%	17%	12%	12%	18%	10%	7%	14%	11%	5%
JCPLC	38%	21%	12%	11%	18%	11%	10%	11%	11%	4%
MEC	44%	24%	14%	13%	19%	10%	7%	13%	20%	6%
PE	39%	23%	15%	12%	19%	10%	7%	13%	15%	7%
PECO	36%	20%	12%	11%	18%	11%	10%	13%	13%	4%
PEPCO	37%	20%	12%	10%	16%	9%	6%	11%	12%	6%
PPL	35%	20%	12%	11%	15%	9%	6%	11%	13%	4%
PSEG	50%	27%	16%	17%	21%	12%	10%	12%	13%	4%
REC	49%	27%	16%	17%	21%	12%	11%	13%	13%	4%
PJM	35%	22%	14%	13%	20%	11%	8%	13%	15%	6%

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

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

Figure 7-7 New entrant CP net revenue and 20-year levelized total cost by LDA (Dollars per installed MW-year): 2014 through 2023



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.[27]

New entrant nuclear plant energy market net revenues were lower in all zones in 2023 as a result of lower energy prices (Table 7-15).

Table 7-15 Energy net revenue for a new entrant nuclear plant: 2014 through 2023 (Dollars per installed MW-year)[28]

Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	Change in 2023 from 2022
ACEC	$430,088	$273,691	$200,584	$226,845	$285,185	$192,221	$147,168	$260,754	$510,487	$196,597	(61%)
AEP	$358,889	$259,420	$226,969	$241,589	$291,370	$217,407	$170,937	$314,652	$568,246	$254,454	(55%)
APS	$383,546	$282,041	$231,832	$245,633	$302,994	$216,401	$170,914	$316,672	$577,110	$264,252	(54%)
ATSI	$371,823	$262,859	$228,329	$246,859	$305,160	$219,369	$170,965	$312,693	$562,963	$252,392	(55%)
BGE	$482,796	$352,161	$296,138	$268,966	$332,101	$237,019	$194,052	$354,544	$663,414	$312,889	(53%)
COMED	$322,257	$225,655	$213,368	$221,193	$235,676	$191,318	$154,963	$284,104	$489,572	$218,674	(55%)
DAY	$361,855	$261,380	$228,084	$246,977	$301,482	$226,472	$179,830	$332,994	$588,506	$265,232	(55%)
DOM	$430,421	$311,499	$250,271	$260,185	$323,948	$225,667	$176,991	$339,702	$677,389	$293,362	(57%)
DPL	$467,506	$301,832	$224,906	$245,767	$314,185	$203,224	$159,794	$300,139	$546,648	$220,644	(60%)
DUKE	$347,738	$256,348	$223,698	$242,729	$307,041	$220,799	$174,520	$324,772	$577,793	$260,372	(55%)
DUQ	$340,525	$249,258	$222,416	$242,278	$304,190	$216,018	$171,585	$308,427	$552,782	$254,468	(54%)
EKPC	$343,061	$246,594	$218,753	$234,319	$274,749	$214,080	$170,356	$316,730	$571,101	$254,242	(55%)
JCPLC	$434,325	$272,261	$195,704	$231,523	$282,490	$192,909	$147,714	$267,340	$520,340	$203,055	(61%)
MEC	$417,516	$265,313	$198,714	$236,723	$282,769	$199,556	$155,273	$307,271	$593,991	$224,840	(62%)
PE	$394,697	$271,023	$215,556	$236,980	$291,292	$207,398	$162,672	$303,466	$556,824	$250,153	(55%)
PECO	$421,701	$266,837	$193,380	$226,787	$277,512	$188,645	$145,298	$259,904	$500,962	$187,932	(62%)
PEPCO	$467,154	$328,709	$266,428	$263,124	$323,833	$230,232	$180,809	$341,826	$641,058	$296,184	(54%)
PPL	$418,032	$265,864	$195,230	$228,451	$273,036	$188,993	$146,492	$282,094	$548,480	$207,263	(62%)
PSEG	$456,679	$283,287	$200,257	$237,187	$286,834	$194,920	$149,103	$272,398	$526,856	$204,542	(61%)
REC	$451,926	$284,922	$201,343	$237,924	$289,049	$199,553	$153,187	$289,459	$545,519	$219,025	(60%)
PJM	$405,127	$276,048	$221,598	$241,102	$294,245	$209,110	$164,131	$304,497	$566,002	$242,029	(57%)

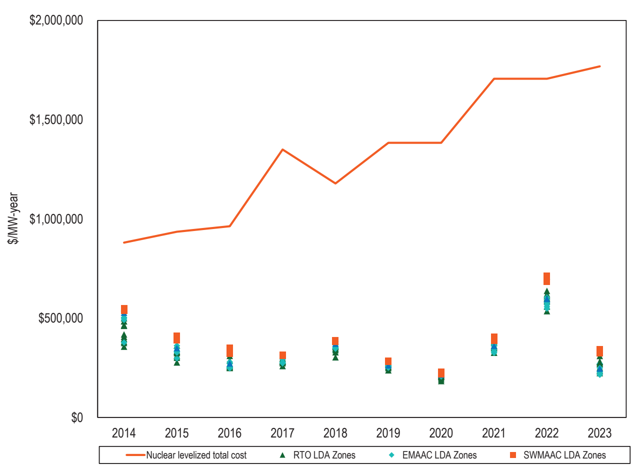
27 The annual class average equivalent availability factor was used in the calculation of energy market net revenues.
28 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues because fuel costs for nuclear units are included in the NEI nuclear costs.

In 2023, 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 period of the analysis.

Table 7-16 Percent of 20-year levelized total costs recovered by nuclear energy and capacity net revenue: 2014 through 2023

Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
ACEC	57%	36%	26%	20%	30%	18%	15%	19%	33%	13%
AEP	45%	33%	27%	21%	30%	19%	15%	21%	35%	15%
APS	47%	36%	28%	21%	31%	19%	15%	21%	36%	16%
ATSI	46%	39%	32%	22%	31%	19%	15%	21%	35%	15%
BGE	62%	44%	36%	23%	33%	21%	17%	24%	42%	19%
COMED	41%	30%	26%	19%	26%	20%	17%	21%	31%	13%
DAY	45%	33%	27%	21%	30%	20%	15%	22%	36%	16%
DOM	53%	39%	30%	22%	32%	20%	15%	22%	42%	18%
DPL	61%	39%	29%	22%	32%	19%	16%	21%	35%	14%
DUKE	43%	33%	27%	21%	31%	19%	16%	22%	36%	16%
DUQ	43%	32%	27%	21%	31%	19%	15%	21%	34%	15%
EKPC	43%	32%	27%	20%	28%	19%	15%	21%	35%	15%
JCPLC	57%	35%	26%	21%	30%	18%	15%	20%	33%	13%
MEC	55%	35%	26%	21%	29%	18%	14%	21%	37%	14%
PE	52%	35%	28%	21%	30%	19%	14%	20%	35%	16%
PECO	56%	35%	26%	20%	29%	18%	15%	19%	32%	12%
PEPCO	61%	42%	33%	23%	32%	20%	16%	23%	40%	18%
PPL	55%	35%	26%	20%	28%	17%	13%	19%	35%	13%
PSEG	60%	37%	28%	23%	31%	19%	15%	20%	34%	13%
REC	60%	37%	28%	23%	32%	19%	16%	21%	35%	14%
PJM	52%	36%	28%	21%	30%	19%	15%	21%	36%	15%

Figure 7-8 New entrant nuclear plant net revenue and 20-year levelized total cost by LDA (Dollars per installed MW-year): 2014 through 2023



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 in 2023 as a result of lower energy prices (Table 7-17).

Table 7-17 Energy market net revenue for a new entrant DS: 2014 through 2023 (Dollars per installed MW-year)

Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	Change in 2023 from 2022
ACEC	$33,114	$13,159	$2,416	$2,554	$10,312	$2,029	$835	$1,512	$31,382	$311	(99%)
AEP	$14,469	$3,968	$987	$1,420	$4,154	$5,138	$1,182	$3,654	$30,455	$549	(98%)
APS	$18,020	$7,423	$1,051	$1,343	$6,675	$4,662	$2,092	$3,676	$30,858	$751	(98%)
ATSI	$14,114	$3,675	$2,090	$1,773	$7,209	$4,537	$2,548	$3,301	$28,724	$584	(98%)
BGE	$50,096	$18,305	$8,329	$3,202	$12,785	$6,899	$4,980	$8,366	$42,586	$2,218	(95%)
COMED	$11,320	$2,327	$748	$1,333	$730	$3,476	$821	$3,172	$18,752	$217	(99%)
DAY	$14,288	$3,772	$1,044	$1,670	$3,946	$5,570	$1,146	$5,121	$30,781	$570	(98%)
DOM	$42,609	$12,064	$2,596	$2,765	$15,094	$5,841	$1,863	$9,114	$42,683	$3,399	(92%)
DPL	$38,453	$19,925	$3,691	$5,637	$14,261	$6,375	$8,788	$16,633	$37,252	$5,946	(84%)
DUKE	$13,467	$3,288	$1,415	$3,069	$6,675	$5,441	$1,013	$4,691	$30,350	$558	(98%)
DUQ	$13,132	$3,179	$2,416	$1,517	$9,248	$4,493	$3,973	$3,522	$28,758	$1,274	(96%)
EKPC	$14,483	$2,970	$1,054	$972	$1,922	$4,868	$1,003	$4,500	$33,159	$539	(98%)
JCPLC	$33,066	$13,042	$923	$2,848	$11,134	$2,085	$1,614	$1,430	$31,247	$314	(99%)
MEC	$31,992	$13,020	$908	$3,794	$10,974	$2,670	$3,020	$7,291	$37,264	$495	(99%)
PE	$15,964	$6,436	$904	$1,699	$5,539	$2,906	$1,355	$3,652	$25,993	$529	(98%)
PECO	$32,360	$12,429	$875	$2,839	$9,838	$2,077	$1,421	$1,693	$31,158	$292	(99%)
PEPCO	$51,396	$12,842	$3,551	$2,497	$12,363	$6,314	$1,884	$6,302	$40,652	$1,657	(96%)
PPL	$32,931	$13,062	$796	$2,988	$8,799	$1,650	$1,194	$3,052	$32,064	$355	(99%)
PSEG	$32,550	$12,650	$1,064	$3,284	$10,325	$2,437	$730	$1,956	$31,090	$308	(99%)
REC	$30,724	$13,740	$1,247	$3,031	$9,703	$2,627	$1,785	$6,473	$29,798	$331	(99%)
PJM	$29,787	$9,564	$1,905	$2,512	$8,584	$4,105	$2,162	$4,955	$32,250	$1,060	(97%)

In 2023, 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 period of the analysis.

Table 7-18 Percent of 20-year levelized total costs recovered by DS energy and capacity net revenue: 2014 through 2023

Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
ACEC	63%	43%	33%	31%	51%	37%	35%	35%	37%	12%
AEP	30%	33%	22%	25%	39%	32%	20%	25%	30%	8%
APS	32%	35%	22%	25%	41%	32%	21%	25%	30%	9%
ATSI	30%	60%	49%	30%	41%	32%	21%	28%	31%	8%
BGE	72%	46%	36%	32%	45%	33%	23%	31%	43%	15%
COMED	28%	32%	22%	25%	44%	48%	42%	39%	30%	9%
DAY	30%	32%	22%	25%	39%	32%	20%	26%	30%	8%
DOM	48%	37%	23%	26%	46%	32%	20%	28%	35%	10%
DPL	67%	47%	33%	33%	53%	40%	39%	42%	39%	15%
DUKE	30%	32%	22%	26%	40%	31%	26%	29%	32%	10%
DUQ	29%	32%	23%	25%	42%	31%	22%	25%	29%	9%
EKPC	30%	32%	22%	25%	37%	31%	20%	25%	31%	8%
JCPLC	63%	43%	32%	31%	51%	36%	35%	35%	36%	12%
MEC	61%	43%	32%	32%	44%	31%	22%	27%	37%	12%
PE	51%	39%	32%	31%	40%	31%	21%	26%	32%	12%
PECO	63%	42%	32%	31%	51%	38%	35%	35%	36%	12%
PEPCO	75%	43%	33%	31%	45%	33%	22%	27%	39%	13%
PPL	62%	43%	32%	31%	42%	30%	21%	25%	35%	12%
PSEG	67%	45%	41%	50%	60%	38%	35%	38%	38%	12%
REC	66%	46%	41%	50%	60%	39%	36%	40%	38%	12%
PJM	49%	40%	31%	32%	45%	35%	27%	30%	34%	11%

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.[29]

Onshore wind energy market net revenues were lower in 2023 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 2023

Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	Change in 2023 from 2022
AEP	$106,499	$78,929	$67,826	$71,312	$93,621	$70,434	$47,589	$78,259	$178,329	$65,591	(63%)
APS	$108,148	$72,504	$62,352	$71,867	$95,329	$58,628	$47,685	$74,369	$138,891	$65,061	(53%)
COMED	$95,745	$67,842	$58,915	$68,278	$65,111	$59,836	$39,899	$74,104	$153,856	$52,834	(66%)
PE	$129,612	$85,543	$65,204	$73,843	$95,776	$55,603	$42,652	$69,386	$135,622	$54,096	(60%)

The new entrant onshore wind installation analysis is based on a 35 percent ELCC derating factor for defining the MW offered in the capacity market.[30]

Table 7-20 Capacity market net revenue for an onshore wind installation (Dollars per installed MW-year): 2014 through 2023

Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
AEP	$5,482	$8,471	$5,874	$6,097	$9,369	$8,074	$5,521	$7,308	$4,776	$5,199
APS	$5,482	$8,471	$5,874	$6,097	$9,366	$8,087	$5,531	$7,330	$4,790	$5,199
COMED	$5,482	$8,471	$5,874	$6,097	$11,263	$13,289	$12,479	$12,365	$6,641	$6,198
PE	$11,151	$9,935	$8,966	$7,685	$9,355	$8,054	$5,874	$7,562	$6,246	$8,769

Wind units were assumed to receive class average reactive capability payments.

Table 7-21 Reactive capability revenue for an onshore wind installation (Dollars per installed MW-year): 2014 through 2023

Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
PJM	$4,185	$4,185	$4,185	$4,185	$4,185	$4,185	$4,185	$4,185	$3,712	$3,769

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 an average of 50 percent of the total net revenue of an onshore wind installation.

Table 7-22 RECs revenue for an onshore wind installation (Dollars per installed MW-year): 2014 through 2023

Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
AEP	$37,956	$41,971	$30,518	$12,681	$15,679	$18,030	$23,127	$34,136	$59,750	$72,092
APS	$36,437	$33,539	$26,854	$12,202	$15,350	$14,957	$22,491	$31,896	$50,576	$68,899
COMED	$40,539	$41,676	$28,828	$13,526	$15,102	$18,602	$23,227	$38,802	$66,679	$76,693
PE	$41,808	$39,913	$30,101	$12,811	$15,746	$14,956	$21,621	$32,326	$49,404	$59,274

In 2023, 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 49 and 57 percent of levelized total costs of a new entrant onshore wind installation in AEP, APS, COMED and PE.

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.

29 Net revenues are calculated for zones in which there are sufficient operating units to determine capacity factor for a new entrant unit.
30 PJM Planning. ELCC Class Ratings for 2025/2026 BRA. February 2, 2024. <https://www.pjm.com/-/media/planning/res-adeq/elcc/2025-26-bra-elcc-class-ratings.ashx>.
31 RECs prices obtained from Evolution Markets, Inc.

Table 7-23 Percent of 20-year levelized total costs recovered by onshore wind net revenue (Dollars per installed MW-year): 2014 through 2023

Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
AEP	78%	66%	47%	50%	57%	47%	39%	51%	104%	57%
APS	78%	59%	43%	50%	58%	40%	38%	48%	83%	56%
COMED	74%	60%	42%	49%	45%	45%	38%	53%	97%	54%
PE	94%	69%	47%	52%	58%	39%	36%	46%	82%	49%

New Entrant Offshore Wind Installation

Energy market net revenues for an offshore wind installation were calculated hourly assuming the unit generated at a 60 percent capacity factor.[32]

Offshore wind energy market net revenues were lower in 2023 as a result of lower energy prices.

Table 7-24 Energy market net revenue for an offshore wind installation (Dollars per installed MW-year): 2014 through 2023

Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	Change in 2023 from 2022
ACEC	$179,272	$115,153	$85,819	$97,466	$121,958	$83,127	$64,796	$112,040	$230,428	$81,647	(65%)
DOM	$190,967	$130,472	$106,354	$110,168	$136,889	$96,665	$76,784	$149,609	$313,145	$125,237	(60%)
DPL	$195,582	$128,928	$93,634	$107,415	$136,339	$88,160	$72,671	$132,600	$250,728	$94,706	(62%)

The new entrant offshore wind installation analysis is based on a 60 percent ELCC derating factor for defining the MW offered in the capacity market.[33]

Table 7-25 Capacity market net revenue for an offshore wind installation (Dollars per installed MW-year): 2014 through 2023

Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
ACEC	$26,482	$22,579	$20,379	$17,467	$26,262	$23,241	$23,060	$25,534	$18,387	$15,221
DOM	$12,460	$19,251	$13,351	$13,858	$21,287	$18,266	$12,489	$16,606	$12,736	$8,912
DPL	$26,482	$22,579	$20,379	$17,467	$26,043	$23,043	$23,029	$25,534	$18,387	$16,001

Offshore wind units were assumed to receive the same class average reactive capability payments as onshore wind.

Table 7-26 Reactive capability revenue for an offshore wind installation (Dollars per installed MW-year): 2014 through 2023

Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
PJM	$4,185	$4,185	$4,185	$4,185	$4,185	$4,185	$4,185	$4,185	$3,712	$3,769

The offshore wind unit in ACEC was assumed to receive NJ wind RECs. The offshore wind unit in DOM and DPL was assumed to receive the higher of the MD or PA Tier I REC for the purposes of calculating RECs revenue.[34] Renewable energy credits accounted for 56 percent of the total net revenue of an offshore wind installation.

Table 7-27 RECs revenue for an offshore wind installation (Dollars per installed MW-year): 2014 through 2023

Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
ACEC	$56,071	$56,792	$42,063	$17,934	$22,075	$23,331	$33,912	$54,454	$82,223	$112,495
DOM	$55,658	$55,651	$40,971	$17,089	$21,272	$23,188	$33,709	$54,447	$82,529	$110,744
DPL	$55,658	$55,651	$40,962	$17,089	$21,272	$23,188	$33,709	$54,447	$82,529	$110,744

32 PJM Planning. ELCC Class Ratings for 2025/2026 BRA. February 2, 2024. <https://www.pjm.com/-/media/planning/res-adeq/elcc/2025-26-bra-elcc-class-ratings.ashx>.
33 PJM Planning. ELCC Class Ratings for 2025/2026 BRA. February 2, 2024. <https://www.pjm.com/-/media/planning/res-adeq/elcc/2025-26-bra-elcc-class-ratings.ashx>.
34 RECs prices obtained from Evolution Markets, Inc.

In 2023, a new offshore wind installation would not have received sufficient net revenue to cover levelized total costs in any of the three zones analyzed.

Table 7-28 Percent of 20-year levelized total costs recovered by offshore wind net revenue (Dollars per installed MW-year): 2014 through 2023

Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
ACEC	39%	29%	22%	20%	26%	19%	18%	25%	49%	27%
DOM	39%	31%	24%	21%	27%	20%	18%	29%	61%	32%
DPL	41%	31%	23%	21%	27%	20%	19%	28%	52%	29%

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.[35]

Solar energy market net revenues were lower in 2023 as a result of lower energy prices.

Table 7-29 Energy market net revenue for a solar installation (Dollars per installed MW-year): 2014 through 2023

Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	Change in 2023 from 2022
ACEC	$67,446	$48,285	$38,762	$38,022	$41,772	$32,636	$23,716	$41,917	$95,800	$30,966	(68%)
DOM	-	-	$70,026	$68,150	$78,189	$59,472	$45,177	$90,539	$222,533	$78,683	(65%)
DPL	-	-	$45,546	$50,740	$61,773	$44,687	$33,323	$51,578	$110,931	$47,380	(57%)
JCPLC	$61,850	$41,551	$33,986	$36,414	$39,433	$30,189	$23,599	$41,144	$88,119	$29,171	(67%)
PSEG	$61,548	$47,830	$39,380	$40,979	$43,469	$34,047	$25,767	$45,977	$97,932	$31,385	(68%)

The new entrant solar installation analysis is based on a 14 percent ELCC derating factor for defining the MW offered in the capacity market.[36]

Table 7-30 Capacity market net revenue for a solar installation (Dollars per installed MW-year): 2014 through 2023

Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
ACEC	$27,807	$23,708	$21,398	$18,341	$27,575	$24,403	$24,213	$26,811	$17,468	$3,551
DOM	-	-	$14,018	$14,551	$22,352	$19,179	$13,113	$17,437	$12,099	$2,080
DPL	-	-	$21,398	$18,341	$27,345	$24,195	$24,181	$26,811	$17,468	$3,734
JCPLC	$27,807	$23,708	$21,398	$18,341	$27,200	$23,714	$23,911	$26,809	$17,467	$3,551
PSEG	$30,478	$25,593	$28,234	$30,828	$33,260	$25,025	$24,515	$29,100	$18,929	$3,551

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.[37]

Solar units were assumed to receive class average reactive capability payments.

Table 7-31 Reactive capability revenue for a solar installation (Dollars per installed MW-year): 2014 through 2023

Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
PJM	$6,167	$6,167	$6,167	$6,167	$6,167	$6,167	$6,167	$6,167	$8,040	$8,040

Renewable energy credits ranged from 56 percent of the total net revenue of a solar installation in DOM to 86 percent of the total net revenue of a solar installation in ACEC and PSEG.

35 Net revenues are calculated for zones in which there are sufficient operating units to determine capacity factor for a new entrant unit.
36 PJM Planning. ELCC Class Ratings for 2025/2026 BRA. February 2, 2024. <https://www.pjm.com/-/media/planning/res-adeq/elcc/2025-26-bra-elcc-class-ratings.ashx>.
37 RECs prices obtained from Evolution Markets, Inc.

Table 7-32 RECs revenue for a solar installation (Dollars per installed MW-year): 2014 through 2023

Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
ACEC	$240,050	$325,643	$373,683	$285,895	$273,161	$313,056	$292,165	$305,389	$329,699	$304,609
DOM	-	-	$101,679	$20,760	$18,364	$99,084	$150,493	$154,772	$128,570	$117,371
DPL	-	-	$74,619	$17,514	$15,804	$85,624	$121,982	$117,907	$92,284	$106,338
JCPLC	$222,593	$280,457	$332,265	$267,345	$258,291	$286,300	$281,980	$294,745	$301,281	$275,546
PSEG	$213,746	$303,612	$379,054	$294,273	$279,286	$319,285	$312,318	$317,419	$328,535	$292,912

In 2023, a new entrant solar installation would have received sufficient net revenue to cover more than 100 percent of levelized total costs in ACEC, JCPLC and PSEG and between 78 and 98 percent of levelized total costs in DPL and DOM.

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

Table 7-33 Percent of 20-year levelized total costs recovered by solar net revenue (Dollars per installed MW-year): 2014 through 2023

Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
ACEC	145%	172%	201%	173%	150%	154%	183%	248%	218%	164%
DOM	-	-	88%	55%	54%	75%	113%	175%	180%	98%
DPL	-	-	67%	46%	48%	66%	98%	132%	111%	78%
JCPLC	135%	150%	180%	163%	143%	142%	177%	241%	201%	150%
PSEG	132%	164%	207%	185%	156%	158%	195%	260%	219%	159%

Historical New Entrant CC Revenue Adequacy

Total unit net revenues include energy and capacity market 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 91 percent of their total costs in the BGE Zone and 85 percent of total costs in the PSEG Zone, and 49 percent of total costs in the COMED 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 over 100 percent of their total costs on a cumulative basis in the BGE Zone, 98 percent of their total costs in PSEG Zone, and 62 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. Covering 100 percent of total costs in this analysis includes earning the assumed rate of return. Units earned a positive rate of return even when covering less than 100 percent of the identified 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, ignoring the benefits of competition on increasing efficiency, reducing costs and improving technology and ignoring the possibility of over earning under cost of service regulation.

Figure 7-9 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 7-9 Historical new entrant CC revenue adequacy: 2007 through 2023 and 2012 through 2023[38]

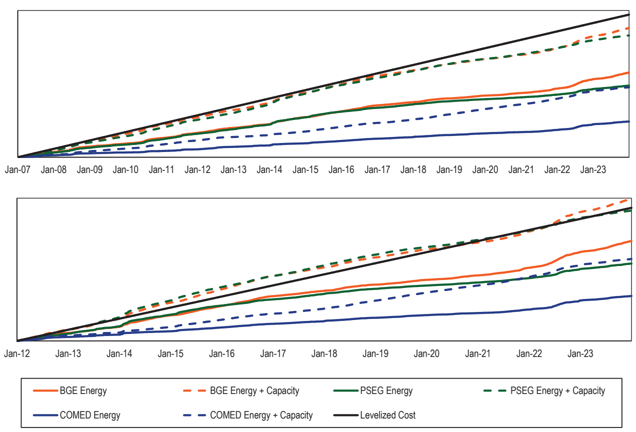


Table 7-34 shows the percent of levelized total costs recovered from the start date through 2023. Table 7-34 also shows the return (IRR) earned from the start date through 2023. For example, for a CC built in BGE in 2012, the resource would have earned a 14 percent IRR compared to the required 12 percent. In contrast, for a CC built in ComEd in 2012, the resource would have earned a 2 percent IRR compared to the required 12 percent.

Table 7-34 Percent of levelized total costs recovered

	2007 CC	2012 CC
Percent of levelized costs covered at 12% IRR		
BGE	91%	107%
COMED	49%	62%
PSEG	85%	98%
IRR at which levelized costs are covered		
BGE	9%	14%
COMED	0%	2%
PSEG	7%	11%

38 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.

The assumptions used for this analysis are shown in Table 7-35.

Table 7-35 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%

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 and may be volatile when affected by exogenous forces. 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.

The net revenue results illustrate some fundamentals of the PJM wholesale power market. Higher demand, higher energy prices, and higher spreads against fuel costs meant that units ran with higher margins and for more hours in 2021 than in 2020. 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, although a simple unit by unit forward modeling of optimal dispatch is not an accurate way to calculate forward net revenues because it assumes optimal dispatch and ignores interactive effects with other units on the system. A better approach would calculate forward looking expected energy and ancillary services net revenues using historical revenues that are scaled based on a comparison of forward prices for energy and fuel to the historical prices for energy and fuel. 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 and the 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 Levelized total costs are the nominal 20 year levelized revenue requirements for the capital costs of each technology. Levelized total costs include return on and of capital and fixed O&M expenses. Variable operating expenses including fuel and variable operations and maintenance expenses are not included. The results are shown in Table 7-36.[39]

Table 7-36 Internal rate of return sensitivity for CT and CC generators (Dollars per installed MW-year)

	20-Year After Tax IRR	20-Year Levelized Net Revenue ($/MW-Yr) CT	CC
Sensitivity 1	14.0%	$172,249	$196,977
Base Case	12.0%	$163,333	$183,473
Sensitivity 2	10.0%	$154,773	$170,613
Sensitivity 3	8.0%	$146,584	$158,409
Sensitivity 4	6.0%	$138,779	$146,869
Sensitivity 5	4.0%	$131,371	$135,999
Sensitivity 6	2.0%	$124,369	$125,802

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 7-37 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 7-37 Debt to equity ratio sensitivity for CT and CC assuming 20-year debt term and 12 percent internal rate of return (Dollars per installed MW-year)

	Equity as a percent of total financing	Levelized Annual Revenue Requirement ($/MW-Yr) CT	CC
Sensitivity 1	60%	$169,702	$193,275
Sensitivity 2	55%	$166,494	$188,331
Base Case	50%	$163,333	$183,473
Sensitivity 3	45%	$160,218	$178,702
Sensitivity 4	40%	$157,151	$174,019
Sensitivity 5	35%	$154,133	$169,423
Sensitivity 6	30%	$151,163	$164,916

Table 7-38 shows the impact of a range of capital costs on the levelized annual revenue requirement for the CT and the CC technologies. Capital costs can vary significantly by location across PJM and even within PJM zones.

39 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 80 percent bonus depreciation and a 15-year modified accelerated cost-recovery schedule (MACRS) for the CT plant and 20-year MACRS for the CC plant. An annual rate of cost inflation of 2.5 percent was used in all calculations.

Table 7-38 Capital cost sensitivity for CT and CC

	CT			CC		
	Capital cost ($000)	Percent of base case capital cost	Annualized revenue requirement ($/MW-Yr)	Capital cost ($000)	Percent of base case capital cost	Annualized revenue requirement ($/MW-Yr)
Sensitivity 1	$318,952	90.0%	$152,094	$1,237,666	90.0%	$168,309
Sensitivity 2	$336,672	95.0%	$157,710	$1,306,425	95.0%	$175,891
Base Case	$354,391	100.0%	$163,333	$1,375,185	100.0%	$183,473
Sensitivity 3	$372,111	105.0%	$168,952	$1,443,944	105.0%	$191,054
Sensitivity 4	$389,830	110.0%	$174,571	$1,512,703	110.0%	$198,636
Sensitivity 5	$407,550	115.0%	$180,191	$1,581,462	115.0%	$206,218
Sensitivity 6	$425,269	120.0%	$185,810	$1,650,222	120.0%	$213,800

Actual Net Revenue

This analysis of net revenues is based on actual net revenues for actual units operating in PJM. Net revenues from energy, ancillary, RECs 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 that 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 on an hour to hour basis whenever the price is greater than the unit's short run marginal costs. It is rational for an owner to continue to operate a unit on an annual basis 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 includes both avoidable costs and the annualized fixed costs of incremental 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 estimates avoidable costs for existing units for a range of technologies by estimating the total cost that must be paid each year in order to keep a unit operating. The avoidable costs in Table 7-39 include operations and maintenance, parts and labor, insurance, property taxes, major maintenance, and a portion of LTSA fixed fees and general and administrative expenses. The MMU ACR values are greater than the ACR values used by PJM because the MMU includes major maintenance costs and defines a larger share of plant expenses as avoidable. The MMU ACR values are also significantly greater than prior MMU ACR values based on a reevaluation of the definition of avoidable costs.

Table 7-39 Avoidable costs by technology[40]

Technology	ACR ($/MW-Day)
Coal	$311.91
Combined Cycle	$99.81
Combustion Turbine	$180.29
Diesel	$114.90
Solar	$59.35
Wind	$137.93

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 by technology class to determine the extent to which PJM energy and ancillary service markets alone provide sufficient incentive for continued operation in PJM markets. Actual capacity revenues were then added to energy and ancillary service 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

40 Avoidable costs provided by Pasteris Energy, Inc.

services, synchronized reserves, black start service, and reactive revenues.

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 2022/2023 and 2023/2024 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 2023. Any unit with a significant portion of installed capacity designated as FRR committed was excluded from the analysis.[41] 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, if available. 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.[42] 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 7-40 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 7-40 shows energy and ancillary service net revenues by quartile for select technology classes.[43] 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 cost 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 7-44, 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 7-45.

Table 7-40 also includes new entrant theoretical energy market net revenue from Table 7-9 through Table 7-30 for comparison purposes.[44] As an example, for the CC plants, the predominant form of new entry in PJM, some 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.

41 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.

42 154 FERC ¶ 61,151 at P 59 (2019).

43 The quartile numbers in the table are the dividing lines 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.

44 Wind new entrant energy and ancillary services net revenue includes RECs revenue to help ensure comparability between theoretical new entrant net revenues and actual net revenues for wind resources in this table. Actual net revenues for wind resources implicitly include RECs revenues because wind offers in the energy market generally include the RECs revenues as an offset to costs. Solar new entrant energy and ancillary services net revenue do not include RECs revenue because actual net revenues for solar resources do not include RECs revenues either implicitly or explicitly in this table.

Table 7-40 Net revenue by quartile for select technologies: 2023

		($/MW-Yr)										
	Total Installed	Energy and ancillary service net revenue				Capacity revenue			Energy, ancillary, and capacity revenue			
Technology	Capacity (ICAP)	New entrant	First quartile	Median	Third quartile	First quartile	Median	Third quartile	New entrant	First quartile	Median	Third quartile
Combined Cycle	47,073	$90,055	$26,773	$55,088	$95,208	$15,009	$24,364	$33,753	$112,609	$60,110	$85,821	$126,566
Combustion Turbine	25,839	$60,290	$1,268	$4,971	$10,697	$15,229	$18,802	$22,344	$83,046	$18,571	$23,289	$31,789
Coal Fired	30,111	$19,527	($35,059)	($7,937)	($158)	$9,975	$15,304	$20,271	$41,482	($28,125)	$3,995	$32,554
Diesel	681	$1,060	($403)	$0	$17,714	$25,762	$27,276	$32,516	$28,207	$26,196	$28,898	$49,574
Hydro	2,207		$69,351	$94,559	$133,830	$0	$15,559	$77,188		$97,079	$137,733	$207,340
Nuclear	26,111	$242,029	$196,235	$213,144	$250,128	$16,869	$17,580	$25,171	$263,853	$221,407	$230,723	$264,867
Oil or Gas Steam	3,610		($1,769)	$0	$16,331	$16,247	$26,526	$27,922		$16,882	$26,756	$41,510
Pumped Storage	2,308		$6,251	$19,266	$67,603	$14,468	$25,043	$40,466		$25,718	$34,311	$134,410
Solar	3,793	$51,557	$29,080	$33,706	$38,849	$0	$0	$6,448	$54,851	$30,000	$35,051	$47,304
Wind	10,717	$132,404	$56,429	$90,038	$165,095	$0	$2,436	$4,585	$138,746	$61,035	$90,038	$167,191

Table 7-41 shows the percent of avoidable costs covered by net revenue from PJM energy and ancillary services markets by quartiles. In 2023, 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 or CT 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.[45 46 47] The NEI annual avoidable costs used in the analysis are for 2022, the most recent data available.

Table 7-41 Avoidable cost recovery by quartile: 2023

	Total Installed	Recovery of avoidable costs from energy and ancillary net revenue			Recovery of avoidable costs from all markets		
Technology	Capacity (ICAP)	First quartile	Median	Third quartile	First quartile	Median	Third quartile
Combined Cycle	47,073	86%	202%	317%	180%	316%	435%
Combustion Turbine	25,839	2%	14%	31%	34%	71%	93%
Coal Fired	30,111	(31%)	(7%)	(0%)	(25%)	4%	29%
Diesel	681	(2%)	0%	42%	88%	120%	129%
Hydro	2,207	100%	100%	100%	100%	100%	100%
Nuclear	26,111	81%	86%	90%	92%	95%	97%
Oil or Gas Steam	3,610	(5%)	0%	78%	56%	73%	195%
Pumped Storage	2,308	100%	100%	100%	100%	100%	100%
Solar	3,793	134%	156%	179%	138%	162%	218%
Wind	10,717	112%	179%	328%	121%	179%	332%

Table 7-42 shows the proportion of units recovering avoidable costs from energy and ancillary services markets and from all markets from 2011 through 2023.[48] In 2023, capacity revenues were sufficient to cover the shortfall between energy revenues and avoidable costs for most CCs, DS, hydro, solar, and wind units in PJM.

45 Operating costs from: Nuclear Energy Institute (December 2023). "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.
46 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.
47 The nuclear analysis here excludes Cook, North Anna, and Surry. These units do not participate in the PJM capacity market.
48 Beginning in 2023, CTs are combined into a single category, corresponding to PJM's default Gross ACR CT category.

Table 7-42 Proportion of units recovering avoidable costs: 2011 through 2023

	Units with full recovery from energy and ancillary net revenue													Units with full recovery from all markets												
Technology	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Combined Cycle	55%	46%	50%	72%	59%	63%	57%	66%	64%	67%	50%	72%	73%	85%	79%	79%	95%	88%	93%	89%	98%	90%	93%	83%	80%	87%
CT - Aero Derivative	15%	6%	6%	53%	15%	8%	10%	30%	46%	42%	2%	7%	-	100%	96%	76%	98%	100%	99%	100%	99%	96%	96%	89%	33%	-
CT - Industrial Frame	26%	23%	17%	38%	13%	8%	3%	21%	30%	21%	2%	6%	-	99%	98%	83%	100%	100%	100%	100%	96%	92%	86%	84%	27%	-
Combustion Turbine	-	-	-	-	-	-	-	-	-	-	-	-	2%	-	-	-	-	-	-	-	-	-	-	-	-	21%
Coal Fired	31%	17%	27%	78%	16%	15%	12%	11%	2%	2%	22%	27%	2%	82%	36%	54%	83%	64%	40%	36%	63%	31%	5%	66%	33%	2%
Diesel	48%	42%	37%	69%	56%	33%	32%	39%	11%	37%	25%	35%	0%	100%	100%	77%	100%	100%	100%	100%	97%	91%	89%	83%	83%	72%
Hydro	74%	61%	95%	97%	81%	79%	95%	94%	90%	72%	95%	100%	100%	81%	77%	97%	98%	100%	100%	97%	98%	100%	74%	95%	100%	100%
Nuclear	-	-	50%	94%	17%	6%	17%	53%	0%	0%	88%	100%	14%	-	-	61%	100%	56%	17%	50%	88%	81%	0%	100%	100%	14%
Oil or Gas Steam	8%	6%	11%	15%	3%	0%	0%	10%	73%	6%	10%	10%	7%	92%	78%	86%	85%	91%	88%	81%	76%	66%	34%	67%	10%	40%
Pumped Storage	100%	100%	95%	100%	100%	100%	100%	100%	100%	100%	29%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Solar	-	95%	97%	99%	97%	95%	95%	98%	96%	95%	100%	97%	88%	-	95%	97%	99%	97%	95%	95%	98%	96%	95%	100%	97%	91%
Wind	88%	85%	96%	93%	92%	89%	93%	91%	88%	79%	94%	99%	81%	88%	85%	96%	93%	92%	89%	93%	91%	89%	79%	95%	99%	83%

Competitiveness of Wind and Solar

The role of intermittent resources will in part be a function of whether the resources are competitive in wholesale power markets. There are a number of ways to define the competitiveness metric. Given the current features of the PJM markets, new wind and solar units compete with new combined cycles and with existing coal plants. Table 7-43 shows the LMP needed to cover both levelized total costs and avoidable costs (ACR) and for each unit type for a range of capacity factors and ELCC derating factors.[49] The table includes the impact on costs of current tax subsidies and the impact on revenues of RECs subsidies. The results show that a new solar unit operating at a 20 percent capacity factor would need an LMP of $56 per MWh for all hours that the unit runs to cover levelized total costs, accounting for the significant RECS revenue. Existing coal units would need between $61 and $77 per /MWh to cover their short run marginal costs and avoidable costs. Each individual coal plant will have an ACR and fuel costs that may be higher or lower than the default values used in this analysis. The conclusion is that, including the effects of the 30 percent ITC from the Inflation Reduction Act and current RECS levels, new combined cycle, solar and wind resources are cost competitive with existing coal units in PJM.[50] Existing coal units only need to expect to cover avoidable costs in order to remain economic while new entry solar needs to expect to cover levelized total costs in order to enter.[51]

Table 7-43 Comparison of generation technologies

	Costs		Assumptions							Revenue		
Technology	ACR ($/MW-Day)	Short Run Marginal Costs ($/MWh)	Levelized Cost of a New Unit ($/MW-Yr)	Capacity Market Clearing Price ($/MW-Day)	Ancillary Services ($/MW-Yr)	Capacity Factor (%)	ELCC Rating	RECS Price ($/MWh)	Capacity + Ancillary + RECS ($/MW-Yr)	LMP Needed to Cover Levelized Costs ($/MWh)	LMP Needed to Cover ACR ($/MWh)
Coal	$311.91	$37.31	-	$29	$1,800	30%	85%	-	$10,772	-	$77
			-	-	-	40%	-	-	$10,772	-	$67
			-	-	-	50%	-	-	$10,772	-	$61
Combined Cycle	$99.81	$17.32	$183,473	$29	$2,399	45%	80%	-	$10,844	$61	$24
			-	-	-	60%	-	-	$10,844	$50	$22
			-	-	-	75%	-	-	$10,844	$44	$21
Solar	$59.35	$0.00	$211,057	$29	$8,040	15%	14%	$59	$87,044	$94	($50)
			-	-	-	20%	-	-	$112,886	$56	($52)
			-	-	-	25%	-	-	$138,728	$33	($53)
Wind	$137.93	$0.00	$256,990	$29	$3,769	35%	35%	$3	$17,189	$78	$11
			-	-	-	40%	-	-	$18,579	$68	$9
			-	-	-	45%	-	-	$19,968	$60	$8

49 The Capacity Market Clearing Price is the 2024/2025 BRA clearing price for Rest of RTO. <https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2024-2025/2024-2025-base-residual-auction-report.ashx>. The solar RECS price is the 2023 MD Solar REC price. The wind RECS price is the 2023 IL Wind REC price. RECs prices obtained from Evolution Markets, Inc.
50 See Inflation Reduction Act of 2022, Public Law 117-169 (August 16, 2022).
51 The calculations are a function of values for key variables including REC prices, capacity factors, ELCC derating factors, coal prices, and ACR values.

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.[52] [53] The analysis includes the most recent operating cost data and incremental capital expenditure data for single unit plants and multi unit plants published by NEI, for 2022.[54] 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 (a 10.8 percent decrease from 2012 through 2022 for all plants including single and multiple unit plants).[55] NEI average incremental capital expenditures have decreased since their peak in 2012 (a 34.5 percent decrease from 2012 through 2022 for all plants including single and multiple unit plants).[56] 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.[57] 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 based on current year prices.[58]

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. Although energy prices in 2019 were lower than in 2016, higher capacity market revenues more than offset the difference. In 2020, PJM energy prices were at the lowest level since the introduction of competitive markets, even lower than in 2016. Average energy prices in 2022 were higher than energy prices in any year since the inception of PJM markets in 1999. Based on forward prices as of December 29, 2023, expected nuclear plant energy revenues for 2024 and 2025 are higher than actual revenues in all years since 2014, with the exception of 2022. The actual net revenue results for individual nuclear plants are a function of the degree to which actual unit costs are less than or greater than the benchmark NEI data.

Table 7-44 shows energy market prices, Table 7-45 and Table 7-46 show capacity market prices and Table 7-47 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.[59] The analysis excludes the Catawba 1 nuclear unit. Partial data is provided for the Cook, North Anna, and Surry nuclear units. The AEP Cook nuclear units are designated FRR. North Anna 1 and 2 and Surry 1 and 2 are part of the Dominion FRR for the 2022/2023 Delivery Year. FRR units receive cost of service revenues and are not subject to PJM market revenues.[60] Duke's 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. Historical 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.

52 Operating costs from: Nuclear Energy Institute (December 2023). "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.

53 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.

54 NEI also provides average costs by plant run by operators with one plant or multiple plants, by market, and by type of nuclear reactor. Plants run by operators with multiple plants have lower average costs than plants run by operators with a single plant. Plants participating in wholesale markets have lower average costs than plants in regulated markets. PWR reactors have lower average generating costs than BWR reactors.

55 Operating costs in this paragraph are operating costs as specified by NEI and do not include fuel costs or capital expenditures. Operating costs for single unit plants increased by $1.31/MWh, or 5.3 percent, from 2021 to 2022 in nominal dollars, but decreased in real dollars (2022 dollars). Operating costs for multiple unit plants increased by $0.51/MWh, or 3.1 percent, from 2021 to 2022 in nominal dollars, but decreased in real dollars (2022 dollars).

56 Capital expenditures have decreased 28.9 percent since 2012 for single unit plants and 34.7 percent for multiple unit plants in nominal dollars.

57 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 $1.04 per MWh for a nuclear power plant operating at a capacity factor of 0.957 percent.

58 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.*

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

60 See "Resources Designated in 2022/2023 FRR Capacity Plans as of April 23, 2021," <https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2022-2023/2022-2023-resources-designated-in-frr-plans.ashx>.

Table 7-44 Nuclear unit day-ahead LMP: 2008 through 2023

	ICAP	Average DA LMP ($/MWh)															
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
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	$20.33	$37.07	$67.02	$29.63
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	$18.23	$33.74	$58.20	$25.78
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	$17.66	$32.81	$57.70	$25.36
Calvert Cliffs	1,726	$78.63	$41.05	$51.27	$46.53	$35.19	$40.27	$57.88	$40.30	$32.64	$31.57	$38.79	$28.00	$21.88	$41.24	$78.11	$35.45
Cook	2,177	$52.26	$32.20	$36.52	$37.41	$30.09	$34.14	$40.49	$29.94	$26.93	$28.03	$31.44	$25.07	$19.59	$34.81	$63.46	$28.88
Davis Besse	894	-	-	-	$39.68	$31.68	$36.10	$47.21	$31.94	$27.80	$28.85	$34.44	$26.33	$20.54	$37.34	$68.07	$29.63
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	$18.73	$34.32	$59.35	$25.11
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	$17.32	$30.16	$60.64	$22.97
LaSalle	2,265	$47.96	$27.71	$31.53	$31.93	$27.56	$30.94	$37.88	$26.28	$23.95	$24.71	$27.19	$22.75	$18.14	$33.54	$57.90	$25.55
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	$17.31	$31.05	$61.25	$23.16
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	$21.06	$39.99	$76.51	$33.75
Oyster Creek	608	$75.49	$40.43	$49.29	$46.74	$33.69	$38.62	$52.85	$33.10	$23.79	$27.52	NA	NA	NA	NA	NA	NA
Peach Bottom	2,550	$73.09	$39.32	$47.70	$44.73	$32.81	$37.37	$51.52	$31.98	$23.07	$26.76	$32.63	$21.58	$16.93	$30.77	$61.29	$23.01
Perry	1,240	-	-	$36.99	$38.76	$31.68	$36.69	$46.14	$32.77	$27.84	$29.91	$37.24	$26.76	$20.49	$37.76	$68.56	$30.39
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	$15.95	$31.39	$57.82	$25.01
Salem	2,285	$73.41	$39.51	$48.02	$45.50	$33.06	$37.40	$51.96	$32.37	$23.18	$26.76	$32.90	$22.43	$17.32	$30.12	$60.59	$22.95
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	$20.41	$39.30	$74.21	$32.74
Susquehanna	2,494	$69.96	$38.24	$45.95	$44.78	$32.10	$36.76	$50.93	$32.47	$23.66	$27.14	$32.42	$21.08	$16.03	$30.36	$59.60	$23.77
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	NA	NA	NA	NA	NA

Table 7-45 BRA capacity market clearing prices ($/MW-Day): 2007/2008 through 2024/2025[61 62]

	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	22/23	23/24	24/25
Beaver Valley	1,808	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$165	$100	$77	$140	$50	$34	$29
Braidwood	2,337	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$215	$203	$188	$196	$69	$34	$29
Byron	2,300	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$215	$203	$188	$196	$69	$34	$29
Calvert Cliffs	1,726	$189	$210	$237	$174	$110	$133	$226	$137	$167	$119	$120	$165	$100	$86	$140	$96	$49	$49
Cook	2,177	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Davis Besse	894	-	-	-	-	$109	$20	$28	$126	$357	$114	$120	$165	$100	$77	$171	$50	$34	$29
Dresden	1,797	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$215	$203	$188	$196	$69	$34	$29
Hope Creek	1,172	$198	$149	$191	$174	$110	$140	$245	$137	$167	$119	$120	$225	$120	$188	$166	$98	$49	$55
LaSalle	2,265	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$215	$203	$188	$196	$69	$34	$29
Limerick	2,242	$198	$149	$191	$174	$110	$140	$245	$137	$167	$119	$120	$225	$120	$188	$166	$98	$49	$55
North Anna	1,892	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$165	$100	$77	$140	NA	NA	NA
Oyster Creek	608	$198	$149	$191	$174	$110	$140	$245	$137	$167	$119	$120	$225	$120	$188	-	-	-	-
Peach Bottom	2,550	$198	$149	$191	$174	$110	$140	$245	$137	$167	$119	$120	$225	$120	$188	$166	$98	$49	$55
Perry	1,240	-	-	-	-	$109	$20	$28	$126	$357	$114	$120	$165	$100	$77	$171	$50	$34	$29
Quad Cities	1,819	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$215	$203	$188	$196	$69	$34	$29
Salem	2,285	$198	$149	$191	$174	$110	$140	$245	$137	$167	$119	$120	$225	$120	$188	$166	$98	$49	$55
Surry	1,676	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$165	$100	$77	$140	NA	NA	NA
Susquehanna	2,494	$41	$112	$191	$174	$110	$133	$226	$137	$167	$119	$120	$165	$100	$86	$140	$96	$49	$49
Three Mile Island	803	$41	$112	$191	$174	$110	$133	$226	$137	$167	$119	$120	$165	$100	$86	$140	-	-	-

61 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>. For the 2022/2023 Delivery Year, Surry is part of Dominion FRR.

62 Cook is designated FRR. North Anna and Surry are in Dominion FRR beginning with the 2022/2023 Delivery Year.

Table 7-46 Nuclear unit capacity market revenue ($/MWh): 2008 through 2024[63 64]

	ICAP	Capacity Revenue ($/MWh)																
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
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	$3.81	$4.93	$3.80	$1.76	$1.34
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	$8.58	$8.35	$5.28	$2.10	$1.34
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	$8.58	$8.35	$5.28	$2.10	$1.34
Calvert Cliffs	1,726	$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	$5.10	$4.97	$2.97	$2.14
Cook	2,177	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Davis Besse	894	NA	NA	NA	NA	$2.49	$1.08	$3.70	$11.40	$9.33	$5.17	$6.42	$5.61	$3.81	$5.73	$4.36	$1.76	$1.34
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	$8.58	$8.35	$5.28	$2.10	$1.34
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	$7.05	$7.59	$5.48	$3.00	$2.28
LaSalle	2,265	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$7.71	$9.20	$8.58	$8.35	$5.28	$2.10	$1.34
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	$7.05	$7.59	$5.48	$3.00	$2.28
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	$3.81	$4.93	NA	NA	NA
Oyster Creek	608	$7.33	$7.37	$7.82	$5.87	$5.54	$8.81	$7.87	$6.74	$6.04	$5.26	-	-	-	-	-	-	-
Peach Bottom	2,550	$7.33	$7.37	$7.82	$5.87	$5.54	$8.81	$7.87	$6.74	$6.04	$5.26	$7.98	$7.24	$7.05	$7.59	$5.48	$3.00	$2.28
Perry	1,240	NA	NA	NA	NA	$2.49	$1.08	$3.70	$11.40	$9.33	$5.17	$6.42	$5.61	$3.81	$5.73	$4.36	$1.76	$1.34
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	$8.58	$8.35	$5.28	$2.10	$1.34
Salem	2,285	$7.33	$7.37	$7.82	$5.87	$5.54	$8.81	$7.87	$6.74	$6.04	$5.26	$7.98	$7.24	$7.05	$7.59	$5.48	$3.00	$2.28
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	$3.81	$4.93	NA	NA	NA
Susquehanna	2,494	$3.57	$6.72	$7.82	$5.87	$5.38	$8.21	$7.53	$6.74	$6.04	$5.26	$6.42	$5.61	$4.06	$5.10	$4.97	$2.97	$2.14
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	-	-	-	-	-	-

Table 7-47 Nuclear unit costs: 2008 through 2022[65 66]

	ICAP	NEI Costs ($/MWh)														
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
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	$28.38	$27.03	$27.18	$28.63
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	$28.38	$27.03	$27.18	$28.63
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	$28.38	$27.03	$27.18	$28.63
Calvert Cliffs	1,726	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.18	$28.63
Cook	2,177	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.18	$28.63
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	$38.40	$39.64	$37.42	$41.08
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	$28.38	$27.03	$27.18	$28.63
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	$28.38	$27.03	$27.18	$28.63
LaSalle	2,265	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.18	$28.63
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	$28.38	$27.03	$27.18	$28.63
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	$28.38	$27.03	$27.18	$28.63
Oyster Creek	608	$35.31	$39.36	$41.23	$45.45	$47.41	$44.16	$44.32	$44.51	$41.39	$42.66	-	-	-	-	-
Peach Bottom	2,550	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.18	$28.63
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	$38.40	$39.64	$37.42	$41.08
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	$28.38	$27.03	$27.18	$28.63
Salem	2,285	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.18	$28.63
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	$28.38	$27.03	$27.18	$28.63
Susquehanna	2,494	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.18	$28.63
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	-	-	-	-

Table 7-48 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 2020, no nuclear plants covered their fuel costs, operating costs, and incremental capital expenditures as a result of lower energy prices. In 2021 and 2022, all nuclear plants more than covered their fuel costs, operating costs, and capital expenditures as a result of higher energy prices. In 2023, only two nuclear plants covered their fuel costs, operating costs, and incremental capital expenditures as a result of lower energy and capacity prices. The surplus or shortfall assumes that the unit receives the DA LMP, reactive capability revenue, cleared its full unforced capacity at the BRA locational clearing price, and has costs equal to the NEI average costs.[67] Unforced capacity is determined using the annual class average EFORd rate.

63 Capacity revenue calculated by adjusting the BRA Capacity Price for calendar year, by the class average EFORd, and by the annual class average capacity factor. Class average EFORd and capacity factor is from *2023 Annual State of the Market Report for PJM*, Volume 2, Section 5: Capacity Market.

64 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>.

65 Operating costs from: Nuclear Energy Institute (December, 2023). "Nuclear Costs in Context," <https://www.nei.org/CorporateSite/media/filefolder/resources/reports-and-briefs/2023-Costs-in-Context.pdf>.

66 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>.

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

The market revenues are based in part on the sale of capacity. Some nuclear plants did not clear the capacity market in some years as a result of decisions by plant owners about how to offer the plants in the capacity market auctions. When nuclear plants do not clear in the capacity market, it is a result of the offer behavior of the plants and does not accurately reflect the economic viability of the plants. 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. Quad Cities and a portion of Byron's capacity did not clear in the 2019/2020 Auction.[68] Quad Cities did not clear in the 2020/2021 Auction.[69] Dresden and most of Byron did not clear in the 2021/2022 Auction.[70] Beaver Valley, Davis Besse, and Perry did not clear in the 2021/2022 Auction.[71] Byron, Dresden, and Quad Cities did not clear in the 2022/2023 Auction.[72]

Nuclear unit revenue is a combination of energy market revenue, ancillary market revenue and capacity market revenue. Negative energy market prices do not have a significant impact on nuclear unit revenue. Since 2014, negative energy market 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, an average of 0.0 percent and a maximum of 0.2 percent in 2019, an average of 0.1 percent and a maximum of 1.7 percent in 2020, an average of 0.0 percent and a maximum of 0.3 percent in 2021, an average of 0.0 percent and a maximum of 0.0 percent in 2022, and an average of 0.0 percent and a maximum of 0.1 percent in 2023.[73]

In 2023, only two nuclear plants covered their fuel costs, operating costs, and incremental capital expenditures as a result of lower energy and capacity prices.

Table 7-48 Nuclear unit surplus (shortfall) based on public data in $/MWh: 2008 through 2023

	ICAP	Surplus (Shortfall) ($/MWh)															
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
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	$3.7	($2.7)	$15.0	$42.4	$3.0
Braidwood	2,337	$24.9	$2.5	$6.4	$3.4	($6.1)	($2.6)	$7.2	($1.2)	($3.2)	($1.6)	$5.9	$3.9	($0.0)	$15.1	$35.0	($0.6)
Byron	2,300	$24.5	($1.3)	$3.4	($0.6)	($9.4)	($3.6)	$4.9	($6.1)	($9.6)	($2.8)	$5.8	$3.2	($0.6)	$14.1	$34.5	($1.0)
Calvert Cliffs	1,726	$60.6	$20.9	$28.6	$17.9	$4.5	$14.6	$31.6	$14.1	$7.2	$6.1	$16.3	$5.4	($0.9)	$19.4	$54.6	$10.0
Cook	2,177	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Davis Besse	894	NA	NA	NA	NA	($13.2)	($7.0)	$6.6	($1.2)	($4.0)	($8.4)	($0.9)	($6.3)	($15.1)	$5.9	$31.6	($9.5)
Dresden	1,797	$25.6	$3.0	$7.6	$4.4	($5.2)	($1.0)	$9.1	$0.3	($1.6)	($0.1)	$7.1	$4.5	$0.5	$15.7	$36.2	($1.2)
Hope Creek	1,172	$54.0	$17.0	$24.5	$16.9	$2.6	$12.4	$26.0	$6.3	($1.9)	$1.6	$12.3	$1.8	($2.2)	$11.0	$38.0	($2.2)
LaSalle	2,265	$24.8	$2.5	$6.4	$3.3	($6.1)	($1.9)	$7.7	($0.9)	($3.6)	($1.9)	$6.0	$3.7	($0.2)	$14.8	$34.7	($0.9)
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	$1.6	($2.6)	$11.6	$38.2	($2.4)
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	$4.8	($2.0)	$17.9	NA	NA
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	NA	NA	NA	NA
Peach Bottom	2,550	$53.7	$16.9	$24.2	$16.1	$2.3	$12.3	$25.5	$5.8	($2.2)	$1.4	$11.8	$0.7	($2.7)	$11.5	$38.4	($2.3)
Perry	1,240	NA	NA	NA	NA	($13.2)	($6.4)	$5.5	($0.3)	($4.0)	($7.4)	$1.9	($5.8)	($15.1)	$6.3	$32.1	($8.7)
Quad Cities	1,819	$24.1	($0.4)	$2.4	($1.8)	($13.2)	($6.9)	$0.6	($7.7)	($9.5)	($3.5)	$4.3	$2.1	($2.4)	$12.7	$34.6	($1.4)
Salem	2,285	$54.0	$17.1	$24.5	$16.9	$2.6	$12.4	$26.0	$6.2	($2.1)	$1.5	$12.1	$1.6	($2.3)	$10.9	$37.8	($2.3)
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	$4.0	($2.6)	$17.2	NA	NA
Susquehanna	2,494	$46.8	$15.2	$22.4	$16.1	$1.4	$11.1	$24.6	$6.3	($1.6)	$1.8	$10.1	($1.4)	($6.6)	$8.6	$36.3	($1.6)
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	NA	NA	NA	NA

68 Exelon. "Exelon Announces Outcome of 2019-2020 PJM Capacity Auction," (May 25, 2016) <http://www.exeloncorp.com/newsroom/pjm-auction-results-2016>.
69 Exelon, "Exelon Announces Outcome of 2020-2021 PJM Capacity Auction," (May 24, 2017) <http://www.exeloncorp.com/newsroom/pjm-auction-results-release-2017>.
70 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>.
71 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>.
72 NuclearNewswire. "Byron, Dresden, Quad Cities Fail to Clear in PJM Capacity Auction," (June 8, 2021) <https://www.ans.org/news/article-2967/byron-dresden-quad-cities-fail-to-clear-in-pjm-capacity-auction/>.
73 Analysis is based on actual unit generation and received energy market and capacity market revenues. Negative prices in the DA and RT market were set to zero for comparison. Results round to 0.0 percent.

Table 7-48 shows the surplus or shortfall for the 16 nuclear plants in PJM. The $/MWh surplus or shortfall is multiplied by ICAP and the class average capacity factor.[74]

Table 7-49 Nuclear unit surplus (shortfall) based on public data ($M): 2008 through 2023

	ICAP	Surplus (Shortfall) ($ in millions)															
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Beaver Valley	1,808	$393.5	$93.3	$156.3	$131.1	($49.4)	$21.0	$174.8	$47.7	($8.9)	$35.7	$204.3	$51.0	($42.5)	$223.0	$632.2	$41.8
Braidwood	2,337	$482.3	$48.3	$122.8	$65.2	($118.7)	($49.6)	$138.9	($22.7)	($65.2)	($33.3)	$110.8	$70.7	($4.2)	$290.0	$674.9	($14.8)
Byron	2,300	$465.5	($24.2)	$64.1	($10.5)	($178.9)	($68.6)	$93.2	($116.7)	($185.2)	($55.5)	$106.4	$56.6	($14.8)	$267.5	$654.7	($22.7)
Calvert Cliffs	1,726	$865.9	$297.3	$406.9	$254.8	$64.5	$208.4	$449.6	$201.4	$100.7	$84.7	$229.8	$74.0	($15.3)	$275.3	$778.7	$141.6
Cook	2,177	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Davis Besse	894	NA	NA	NA	NA	($98.0)	($51.4)	$48.6	($8.6)	($31.5)	($63.7)	($8.4)	($47.2)	($111.5)	$42.1	$232.3	($72.6)
Dresden	1,797	$380.7	$44.6	$112.9	$65.7	($77.7)	($15.0)	$134.6	$4.4	($26.5)	($5.5)	$102.2	$62.2	$4.1	$231.7	$536.2	($21.4)
Hope Creek	1,172	$523.2	$164.8	$237.0	$163.2	$24.8	$119.9	$251.6	$60.5	($23.2)	$11.2	$114.5	$12.5	($25.4)	$103.0	$364.2	($26.1)
LaSalle	2,265	$464.9	$45.9	$119.9	$61.5	($114.1)	($35.3)	$144.7	($16.3)	($69.8)	($37.5)	$109.0	$66.1	($5.6)	$277.3	$648.5	($18.7)
Limerick	2,242	$1,003.7	$316.3	$457.2	$307.6	$47.8	$226.5	$476.3	$120.1	($41.1)	$25.3	$221.7	$28.2	($48.7)	$213.8	$707.9	($46.4)
North Anna	1,892	$813.9	$228.5	$397.7	$262.7	$3.5	$89.3	$362.6	$170.2	$44.3	$71.2	$246.5	$71.4	($33.3)	$279.3	NA	NA
Oyster Creek	608	$239.0	$42.4	$79.7	$35.9	($41.1)	$16.4	$82.3	($23.4)	($58.2)	($49.6)	NA	NA	NA	NA	NA	NA
Peach Bottom	2,550	$1,133.0	$356.3	$508.8	$338.5	$48.4	$259.6	$537.6	$122.6	($53.0)	$23.7	$242.9	$9.1	($63.3)	$237.2	$805.9	($56.0)
Perry	1,240	NA	NA	NA	NA	($135.8)	($65.3)	$56.6	($3.5)	($43.2)	($77.5)	$16.9	($61.1)	($155.2)	$62.6	$327.2	($92.8)
Quad Cities	1,819	$363.1	($6.7)	$36.3	($27.7)	($199.0)	($103.5)	$8.6	($115.3)	($145.0)	($54.5)	$62.7	$29.0	($37.1)	$190.1	$519.7	($23.2)
Salem	2,285	$1,021.3	$322.8	$461.9	$317.9	$48.2	$233.1	$490.0	$117.1	($45.5)	$21.3	$222.5	$24.0	($49.6)	$200.2	$708.9	($51.3)
Surry	1,676	$676.9	$190.3	$334.4	$226.4	($0.4)	$71.2	$298.9	$148.8	$33.5	$60.4	$219.1	$53.2	($38.4)	$237.8	NA	NA
Susquehanna	2,494	$965.9	$312.8	$461.6	$332.2	$29.4	$229.0	$506.6	$129.9	($39.7)	$31.2	$201.0	($34.4)	($141.3)	$172.0	$742.6	($39.6)
Three Mile Island	803	$270.5	$42.9	$88.2	$30.2	($63.7)	$5.9	$90.7	($45.2)	($82.3)	($68.1)	($25.3)	NA	NA	NA	NA	NA

In order to evaluate the expected viability of nuclear plants, analysis was performed based on forward energy market prices for 2024, 2025, and 2026 and known capacity market prices for 2024. 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 through the 2024/2025 Delivery Year, actual energy prices will vary from forward values. Nuclear plants may choose to sell their output at a range of forward prices and for a range of future years.

Table 7-50 shows PJM energy prices (LMP), annual fuel, and operating and capital expenditures used for the analysis of the period 2024 through 2026. Capacity revenues are not presented for calendar year 2025 because the 2025/2026 BRA has not yet been run. The LMPs are based on forward prices with a basis adjustment for the specific plant locations.[75] Forward prices are as of December 29, 2023. The capacity prices are known based on PJM capacity auction results.

Table 7-50 Forward prices in PJM energy markets, capacity revenue, and annual costs

		Average Forward LMP ($/MWh)			Ancillary Revenue ($/MWh)	Capacity Revenue ($/MWh)	2022 NEI Costs ($/MWh)		
	ICAP (MW)	2024	2025	2026	Reactive	2024	Fuel	Operating	Capital
Beaver Valley	1,808	$38.23	$43.26	$45.75	$0.21	$1.34	$5.36	$17.01	$6.26
Braidwood	2,337	$33.30	$37.89	$40.20	$0.17	$1.34	$5.36	$17.01	$6.26
Byron	2,300	$32.57	$37.14	$39.38	$0.15	$1.34	$5.36	$17.01	$6.26
Calvert Cliffs	1,726	$43.40	$48.84	$51.63	$0.19	$2.14	$5.36	$17.01	$6.26
Cook	2,177	$37.52	$42.23	$44.65	$0.13	NA	$5.36	$17.01	$6.26
Davis Besse	894	$37.49	$42.39	$44.85	$0.21	$1.34	$5.38	$26.09	$9.61
Dresden	1,797	$32.78	$37.44	$39.64	$0.23	$1.34	$5.36	$17.01	$6.26
Hope Creek	1,172	$30.62	$35.10	$37.23	$0.47	$2.28	$5.36	$17.01	$6.26
LaSalle	2,265	$33.16	$37.72	$40.01	$0.13	$1.34	$5.36	$17.01	$6.26
Limerick	2,242	$30.70	$35.18	$37.30	$0.10	$2.28	$5.36	$17.01	$6.26
North Anna	1,892	$42.15	$47.48	$50.24	$0.18	NA	$5.36	$17.01	$6.26
Peach Bottom	2,550	$30.54	$35.05	$37.17	$0.31	$2.28	$5.36	$17.01	$6.26
Perry	1,240	$39.12	$44.29	$46.85	$0.21	$1.34	$5.38	$26.09	$9.61
Quad Cities	1,819	$31.72	$36.28	$38.45	$0.13	$1.34	$5.36	$17.01	$6.26
Salem	2,285	$30.60	$35.08	$37.20	$0.35	$2.28	$5.36	$17.01	$6.26
Surry	1,676	$41.07	$46.29	$48.99	$0.16	NA	$5.36	$17.01	$6.26
Susquehanna	2,494	$30.90	$35.41	$37.51	$0.32	$2.14	$5.36	$17.01	$6.26

74 Nuclear capacity factor from the *2023 Annual State of the Market Report for PJM*, Volume 2: Section 5: "Capacity Market."

75 Forward prices on December 29, 2023. 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 2023 data.

The MMU also calculates the capacity price that would be required to cover the net avoidable costs for each nuclear plant.

Based on the FERC order allowing the inclusion of major maintenance in energy offers, major maintenance costs can no longer be included in gross ACR values offered in the capacity market.[76] 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 incremental 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 incremental capital expenditures are likely to be a conservatively low estimate of major maintenance expense.

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.

In Table 7-51, the capacity price required to cover avoidable costs in $/MWh is calculated by taking the total NEI costs in $/MWh and subtracting the total expected energy and ancillary services revenues in $/MWh. Total expected energy revenue is the unit's ICAP multiplied by the average forward LMP multiplied by the class average capacity factor. Total expected ancillary services revenue is unit specific reactive capability revenue.[77] The capacity price required to cover avoidable costs in $/MW-day is calculated by multiplying the required price in $/MWh by 24. Plants may have actual operating costs higher or lower than the NEI average.

In Table 7-51, for 2023, the capacity price required to cover avoidable costs is $0/MW-day for all units using NEI data as reported including capital expenditures, and is $0/MW-day for all plants, excluding capital expenditures as a proxy for major maintenance.[78] Net revenues based on forward energy prices alone are greater than or equal to avoidable costs in 2024, 2025, and 2026 without any contribution from capacity market revenues for all multiple unit plants. The result is that all net ACR values for multiple unit plants in Table 7-51 are zero. Davis Besse and Perry are both single unit plants and both have a positive net ACR for 2024.

Table 7-51 Net ACR

	ICAP	Net ACR ($/MWh)			Net ACR ($/MW-Day)			Net ACR Excluding Capital ($/MW-Day)		
	(MW)	2024	2025	2026	2024	2025	2026	2024	2025	2026
Beaver Valley	1,808	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Braidwood	2,337	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Byron	2,300	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Calvert Cliffs	1,726	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Cook	2,177	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Davis Besse	894	$3.39	$0.00	$0.00	$77.78	$0.00	$0.00	$0.00	$0.00	$0.00
Dresden	1,797	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Hope Creek	1,172	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
LaSalle	2,265	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Limerick	2,242	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
North Anna	1,892	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Peach Bottom	2,550	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Perry	1,240	$1.76	$0.00	$0.00	$40.33	$0.00	$0.00	$0.00	$0.00	$0.00
Quad Cities	1,819	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Salem	2,285	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Surry	1,676	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Susquehanna	2,494	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

76 See 167 FERC ¶ 61,030 at P 41 (2019).
77 Reactive Supply & Voltage Control Revenue Requirements available from PJM <https://www.pjm.com/markets-and-operations/billing-settlements-and-credit.aspx>.
78 PJM's tariff definition of avoidable costs excludes major maintenance. PJM includes major maintenance costs in the definition of short run marginal costs in energy offers.

Table 7-52 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 2022 NEI fuel, operating, and capital costs. Plants may have operating costs higher or lower than the NEI average. Table 7-52 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 plants in PJM. The current analysis, based on forward prices for energy and known forward prices for capacity, shows that all nuclear plants are expected to cover their annual avoidable costs in 2024, 2025 and 2026 with the exception of Davis Besse and Perry in 2024.

Hope Creek, Quad Cities, and Salem all currently receive state subsidies.[79] [80] The NJ Board of Public Utilities, having received no applications as of December 1, 2023, closed the third eligibility period of the ZEC program for the period beginning June 1, 2025.[81] Braidwood, Byron, Dresden, and LaSalle will receive a state subsidy if necessary to meet a target net revenue value, in dollars per MWh, from the energy and capacity markets.[82] The Inflation Reduction Act added a significant new federal subsidy for existing nuclear power plants.[83] All existing nuclear plants will receive the Zero Emission Nuclear Power Production Credit (Nuclear PTC) if revenues from energy, ancillary, capacity markets, and any state subsidies are less than $43.75/MWh, adjusted for inflation. The Nuclear PTC is increased by a factor of five if certain prevailing wage requirements are met. The 2024 nuclear unit surplus values are shown in Table 7-52 based on forward prices as of December 29, 2023, NEI average costs, and expected subsidy values.[84]

Table 7-52 Nuclear unit forward annual surplus (shortfall) for 2024[85] [86] [87]

	ICAP (MW)	Surplus (Shortfall) ($/MWh)	Subsidy ($/MWh)	Surplus (Shortfall) Excluding Subsidy ($ in millions)	Surplus (Shortfall) Including Subsidy ($ in millions)
Beaver Valley	1,808	$11.15	$3.15	$169.5	$217.4
Braidwood	2,337	$6.19	$7.15	$121.6	$262.1
Byron	2,300	$5.43	$7.75	$105.0	$254.9
Calvert Cliffs	1,726	$17.10	$0.00	$248.0	$248.0
Cook	2,177	NA	$4.90	NA	NA
Davis Besse	894	($2.04)	$3.75	($15.4)	$12.8
Dresden	1,797	$5.72	$7.50	$86.4	$199.7
Hope Creek	1,172	$4.73	$10.00	$46.6	$145.1
LaSalle	2,265	$6.00	$7.30	$114.3	$253.3
Limerick	2,242	$4.44	$8.55	$83.8	$244.9
North Anna	1,892	NA	$1.15	NA	NA
Peach Bottom	2,550	$4.49	$8.50	$96.3	$278.5
Perry	1,240	($0.41)	$2.45	($4.3)	$21.2
Quad Cities	1,819	$4.56	$16.50	$69.7	$322.0
Salem	2,285	$4.59	$10.00	$88.2	$280.3
Surry	1,676	NA	$2.00	NA	NA
Susquehanna	2,494	$4.73	$8.30	$99.2	$273.2

79 Illinois Commerce Commission, Report to the General Assembly in Compliance with Section 1-75(d-5) of the [CEJA, Public Act 102-0662,] 20 ILCS 3855/1-75(d-5)(F)(2) (August 2019). The report finds that while total ZECs payments are limited by rate impact caps and volume caps, the law's limitation does not unduly constrain the procurement of ZECs.

80 *Application of PSEG Nuclear, LLC for the Zero Emission Certificate Program – Hope Creek*, Order Determining the Eligibility of Hope Creek Nuclear Generator to Receive ZECs, BPU Docket No. ER20080559 (April 27, 2021). *Application of PSEG Nuclear, LLC for the Zero Emission Certificate Program – Salem 1*, Order Determining the Eligibility of Salem Unit 1 Nuclear Generator to Receive ZECs, BPU Docket No. ER20080557 (April 27, 201). *Application of PSEG Nuclear, LLC for the Zero Emission Certificate Program – Salem 2*, Order Determining the Eligibility of Salem Unit 2 Nuclear Generator to Receive ZECs. BPU Docket No. ER20080557 (April 27, 2021).

81 See *New Jersey BPU, In the Matter of the Third Eligibility Period for the Zero Emission Certificate Program Pursuant to N.J.S.A.* 48:3-87.3 TO 87.7, Order Closing the Third Eligibility Period of the Zero Emission Certificate Program, Docket No. EO23080548 (February 14, 2024).

82 CEJA, Public Act 102-0662, 20 ILCS 3855/1-75.

83 See Inflation Reduction Act of 2022, Public Law 117-169 (August 16, 2022).

84 Gross receipts used to calculate the unit subsidy include energy revenue, ancillary services revenue, capacity revenue, and state ZECs subsidies, and assumes the unit meets prevailing wage requirements and receives the Zero Emission Nuclear Power Production Credit 5 times multiplier. Effectively, nuclear power plants will receive the higher of the state or federal subsidy amount.

85 The state subsidy value for Braidwood, Byron, Dresden, and LaSalle is calculated by taking the applicable Baseline Cost less forward energy prices and known capacity prices.

86 The federal subsidy value for nuclear plants is defined in the Inflation Reduction Act of 2022, Public Law 117-169 (August 16, 2022).

87 North Anna and Surry are in Dominion FRR beginning with the 2022/2023 Delivery Year.

Units at Risk of Retirement

PJM is facing significant unit retirements through 2030 as a result of federal policies, state policies, and competitive market conditions. Federal environmental policies with a significant impact on retirements include the Cross-State Air Pollution Rule, regulations on the disposal of coal combustion residuals, and the Effluent Guidelines Program Plan.[88] [89] [90] State policies with a significant impact on retirements include the Illinois Climate and Equitable Jobs Act, the Virginia Clean Economy Act, New Jersey's rule on CO_2 emissions, and Maryland's Climate Solutions Now Act.[91] [92] [93] [94]

Unit revenues are a combination of energy and ancillary service revenues and capacity market revenues. Units that fail to recover avoidable costs and are expected to continue to fail to recover avoidable costs from total market revenues, including capacity market revenues, are at risk of retirement because they are uneconomic.[95] [96] The economic analysis scales 2021, 2022, and 2023 energy and ancillary net revenues by the ratio of forward annual PJM LMPs to historical annual PJM LMPs for 2024, 2025, and 2026.[97] These expected energy revenues are added to capacity market revenues based on cleared forward capacity prices and compared to avoidable costs (ACR) over the period 2024-2026. Forward LMPs are based on forward prices as of December 29, 2023. The capacity revenues for the 2024/2025 Delivery Year are carried forward for calendar years 2025 and 2026 because the 2025/2026 auction and the 2026/2027 auction have not been run.

A number of units have made formal deactivation requests and are planning to retire on identified dates.[98] Other units are expected to be affected by environmental regulations at the federal or state level and are expected to retire by 2030. The forward economic analysis shows additional units that are expected to be uneconomic and that are not included in the categories of requested deactivation or regulatory at risk.

A total of 57,694 MW of capacity are at risk of retirement, consisting of 4,285 MW currently planning to retire, 19,635 MW expected to retire for regulatory reasons, and 33,744 MW expected to be uneconomic. This capacity consists primarily of coal steam plants and CTs.[99] The profile of these units is shown in Table 7-53.[100] [101] [102]

88 *EPA Revised Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS (CSAPR)*, Docket No. EPA-HQ-OAR-2020-0272; FRL-10013-42- OAR, 85 Fed. Reg. 23054 (April 30, 2021); , <https://www.epa.gov/coalash/coal-ash-rule>.

89 See *Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals from Electric Utilities*, 80 Fed. Reg. 21302 (April 17, 2015) <https://www.epa.gov/coalash/coal-ash-rule>.

90 See *Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*, EPA Docket No. FRL 8794-04-OW, 86 Fed. Reg. 41801 (August 3, 2021); *Steam Electric Reconsideration Rule*, Docket No. EPA-HQ-OW-2009-0819; FRL-10014-41-OW, 85 Fed. Reg. 64650 (October 13, 2020); *Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*, EPA Docket No. EPA-HQ-OW-2009-0819; FRL-9930-48-OW, 80 Fed. Reg. 67838 (November 3, 2015) (collectively "Effluent Guidelines").

91 See Illinois Climate and Equitable Jobs Act (CEJA), Public Act 102-0662 (Sep. 15, 2015) <https://www2.illinois.gov/epa/topics/ceja>.

92 See Virginia House Bill No. 1526 (March 18, 2020) <https://lis.virginia.gov/cgi-bin/legp604.exe?201+sum+HB1526>.

93 See Control and Prohibition of Carbon Dioxide Emissions, N.J.A.C. 7:27F (December 2, 2022).

94 See Maryland Climate Solutions Now Act, SB 528 (Enacted April 8, 2022).

95 FRR units, units that have already requested deactivation, and units that are expected to retire for regulatory reasons by 2030 are excluded from the economic at risk analysis.

96 Units at risk of retirement for economic reasons analysis is based on the default unit type ACR provided by Pasteris Energy, Inc.

97 The method for calculating forward revenues used in defining units at risk because they are uneconomic has changed from the forward hourly dispatch method used in prior years.

98 PJM. Generator Deactivations. January 25, 2024. <https://www.pjm.com/planning/services-requests/gen-deactivations>.

99 Category Other consists of units with a primary fuel of diesel, landfill gas, light oil, propane, kerosene, heavy oil, municipal solid waste or waste coal.

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

101 No units are in multiple categories. MW expected to retire for regulatory reasons 2024 through 2030 are additional MW beyond the units that have requested deactivation. MW at risk for economic reasons are units that are expected to be uneconomic and have neither requested deactivation nor are expected to retire for regulatory reasons by 2030.

102 Includes FRR units that have requested deactivation. Includes FRR units that are expected to retire for regulatory reasons. Economic at risk analysis excludes FRR units.

Table 7-53 Profile of units expected to retire and at risk of retirement

	MW expected to retire							Total MW
	2024	2025	2026	2027	2028	2029	2030	2024-2030
MW requested deactivation								
Coal	180	1,578	410	0	0	0	0	2,168
Natural Gas	149	886	0	0	0	0	0	1,035
Other	503	579	0	0	0	0	0	1,082
Total MW requested deactivation	833	3,043	410	0	0	0	0	4,285
MW expected to retire for regulatory reasons								
Coal	0	1,493	116	1,760	3,605	0	3,550	10,524
Natural Gas	0	0	0	2,314	0	0	6,247	8,561
Other	103	0	0	0	189	0	259	550
Total MW expected to retire for regulatory reasons	103	1,493	116	4,074	3,794	0	10,056	19,635
Additional MW uneconomic 2024-2026								
Coal								17,725
Natural Gas								14,611
Other								1,438
Total MW uneconomic								33,774
Total								
Coal	180	3,071	526	1,760	3,605	0	3,550	30,417
Natural Gas	149	886	0	2,314	0	0	6,247	24,207
Other	606	579	0	0	189	0	259	3,071
Total MW At Risk of Retirement	935	4,536	526	4,074	3,794	0	10,056	57,694

In order to provide historical context, Table 7-54 shows PJM retirements for the period from 2011 through 2023.[103] The total retirements over that 12 year period is comparable to the retirements expected over the next eight years.

Table 7-54 Retirements and expected retirements

	MW Retired														MW at Risk
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2011-2023	2024-2030
Coal	543	5,908	2,590	2,239	7,065	243	2,038	3,167	4,111	2,132	1,020	5,385	4,380	40,820	30,417
Natural Gas	523	250	82	294	1,319	74	34	1,441	447	233	220	340	1,493	6,748	24,207
Other	131	804	187	437	879	83	41	935	899	891	70	439	855	6,651	3,071
Total MW	1,197	6,962	2,859	2,970	9,263	400	2,113	5,543	5,456	3,255	1,310	6,163	6,728	54,219	57,694

As a sensitivity, if ACR were reduced to 50 percent of what is shown in Table 7-39, the units at risk of retirement would decrease from 57,694 MW to 42,877 MW as a result of a reduction from 33,774 MW to 18,957 MW expected to be uneconomic.

Table 7-55 Profile of units expected to retire and at risk of retirement if total forward energy and capacity revenues are doubled

MW expected to retire 2024-2030	
MW requested deactivation	4,285
MW expected to retire for regulatory reasons	19,635
MW uneconomic 2024-2026 if total revenues are doubled	
Coal	10,627
Natural Gas	7,428
Other	902
Total MW uneconomic	18,957
Total MW At Risk of Retirement	42,877

103 Details on unit retirements are in the *2023 Annual State of the Market Report for PJM*, Volume 2: Section 12, Generation and Transmission Planning, Generation Retirements.

All of the units at risk may not retire. The probability of retirement is highest for the units that explicitly plan to retire (requested deactivation), very high for units expected to retire for regulatory reasons, and significantly lower for units identified as uneconomic. If all or most of the of the retirements related to explicit plans, and related to regulatory reasons do retire, that will, holding other things constant, tend to increase both energy and capacity prices. Higher prices would make uneconomic units more economic and reduce the MW identified as uneconomic. Given the current uncertainty in the capacity market, the capacity market prices in the 2025/2026 and 2026/2027 auctions could have an impact on the economic viability of these units. Risk created by the level of uncertainty about PJM's new capacity market design could also have an impact on the economic viability of these units. As a result, the actual level of MW that are expected to retire for economic reasons is uncertain. For example, a doubling of market revenues would reduce the units identified as uneconomic by 14,817 MW or 44 percent.

If all of the coal units identified as at risk (30,417 MW) are replaced by new gas-fired CCs, those new units would require a significant amount of firm gas pipeline capacity if the units are single fuel.[104] In aggregate, ignoring locational issues, the installed capacity of the coal units at risk of retirement could be replaced by 28 new two 1x1 combined cycle units. The new CC plants would require 4.8 BCF/day of firm pipeline capacity based on the maximum output level of the CCs to replace that coal capacity. (Table 7-56). If only the coal units identified as at risk based on explicit plans to retire and regulatory reasons (12,692 MW) and excluding all the uneconomic units are replaced, the installed capacity of those coal resources would require 2.0 BCF/day of firm pipeline capacity based on the maximum output level of the CCs to replace that coal capacity. The level of firm pipeline capacity required to replace the capacity and reliability value of the retiring coal units could also be reduced if the new CCs invested in dual fuel capability.

Table 7-56 shows the installed capacity of the units at risk by fuel type and the corresponding number of new CCs needed to replace the identified coal capacity.

Table 7-56 Gas pipeline capacity need to replace units at risk of retirement

	MW At Risk	
Gas pipeline capacity need to replace units at risk of retirement	**57,694**	**42,877**
ICAP		
Coal	30,417	23,319
Natural Gas	24,207	17,024
Other	3,071	2,534
Total	57,694	42,877
New CC unit ICAP (MW)	1,100	1,100
New CC unit heat rate (mmbtu/MWh)	6.543	6.543
Number of new CC units needed to replace coal at risk	28	22
Dth needed to replace all coal at risk (Dth/day)	4,836,586	3,800,174
Bcf needed to replace all coal at risk (Bcf/day)	4.8	3.8
Dth needed to replace half of coal at risk (Dth/day)	2,418,293	1,900,087
Bcf needed to replace half of coal at risk (Bcf/day)	2.4	1.9

104 This analysis assumes that retiring gas plants have pipeline capacity.