Net Revenue

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

Overview

Net Revenue

- Energy market net revenues are significantly affected by energy prices and fuel prices. Energy prices and eastern gas prices were significantly higher in the first three months of 2022 than in the first three months of 2021.
- In the first three months of 2022, compared to the first three months of 2021, average energy market net revenues increased by 145 percent for a new combustion turbine (CT), 94 percent for a new combined cycle (CC), 54 percent for a new coal plant (CP), 75 percent for a new nuclear plant, 90 percent for a new diesel (DS), 87 percent for a new onshore wind installation, 86 percent for a new offshore wind installation and 112 percent for a new solar installation.
- The price of eastern natural gas increased by more than the price of coal in January and February 2022. As a result, the marginal costs of a new CC were greater than the marginal cost of a new CP in January 2022, and the marginal costs of a new CT were greater than the marginal cost of a new CP in January and February 2022.
- In the first three months of 2022 both spark spreads and dark spreads increased for COMED and PSEG and decreased for BGE and Western Hub, compared to the first three months of 2021. The volatility of both spark spreads and dark spreads increased for PSEG.
- All existing PJM nuclear plants are expected to more than cover their avoidable costs from energy and capacity market revenues in 2022.

Recommendations

- The MMU recommends that the net revenue calculation used by PJM to calculate the net Cost of New Entry (CONE) and net ACR be based on a forward looking estimate of expected energy and ancillary services net revenues using forward prices for energy and fuel. (Priority: Medium. 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 has an impact on energy markets. The reliability requirement results in maintaining a level of capacity in excess of the level that would result from the operation of an energy market alone. The result of that additional capacity is to reduce the level and volatility of energy market prices and to reduce the duration of high energy market prices. This, in turn, reduces net revenue to generation owners which reduces the incentive to invest. The exact level of both aggregate and locational excess capacity is a function of the calculation methods used by RTOs and ISOs.

Net Revenue

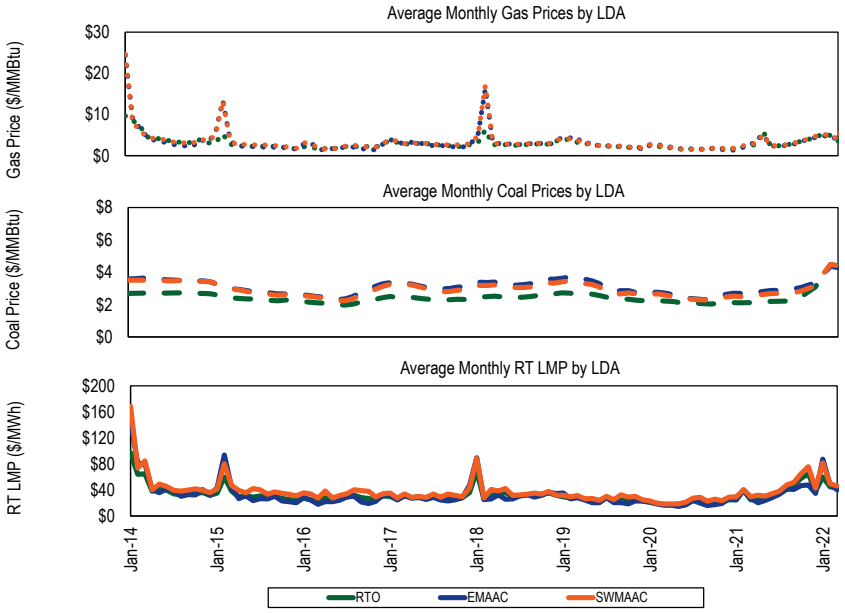
When compared to annualized fixed costs and avoidable costs, net revenue is an indicator of generation investment profitability, and thus is a measure of overall market performance as well as a measure of the incentive to invest in new generation and to maintain existing generation in PJM markets. Net 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, 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 revenues, net revenue from all sources would be expected to equal the annualized fixed and avoidable costs of generation for the marginal unit. Net revenue is a measure of whether generators are receiving competitive returns on invested capital and of whether market prices are high enough to encourage entry of new capacity and to encourage maintaining existing capacity. In actual wholesale power markets, where equilibrium seldom occurs, net revenue is expected to fluctuate above and below the equilibrium level based on actual conditions in all relevant markets.

Net revenues are significantly affected by energy prices, fuel prices and capacity prices. PJM real-time energy market prices increased significantly in the first three months of 2022. The load-weighted average real-time LMP was 75.5 percent higher in the first three months of 2022 than in the first three months of 2021, $54.13 per MWh versus $30.84 per MWh. Eastern gas prices and coal prices increased in the first three months of 2022 compared to the first three months of 2021. Gas price volatility increased and gas price differences among regions increased. The price of eastern natural gas was 102.3 percent higher and the price of western natural gas was 29.4 percent lower; the price of Northern Appalachian coal was 126.8 percent higher; the price of Central Appalachian coal was 84.5 percent higher; and the price of Powder River Basin coal was 77.6 percent higher (Figure 7-1).

Figure 7-1 Energy market net revenue factor trends: 2014 through March 2022



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

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 the first three months of 2022 both spark spreads and dark spreads increased for COMED and PSEG and decreased for BGE and Western Hub, compared to the first three months of 2021. The volatility of both spark spreads and dark spreads increased for PSEG.

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)

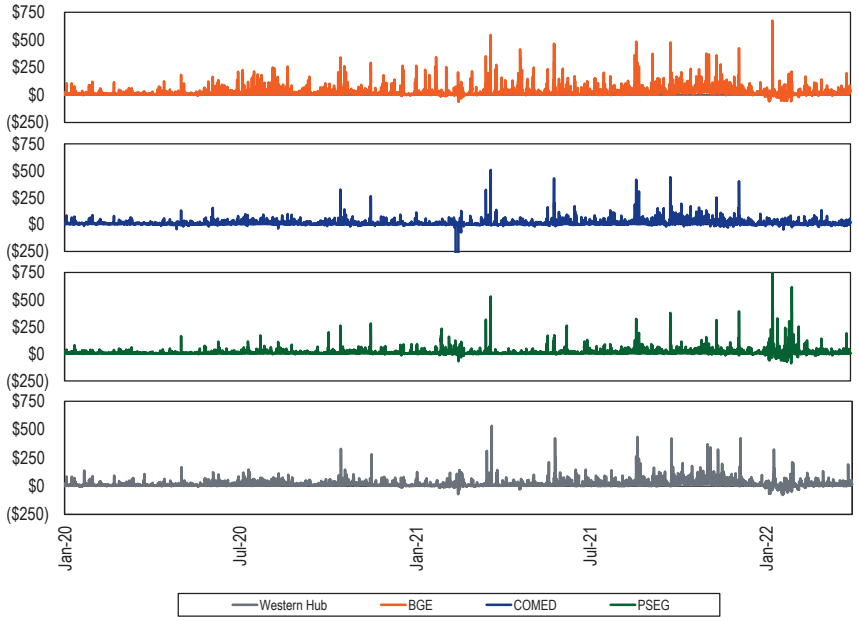
	BGE		COMED		PSEG		Western Hub	
Jan-Mar	Spark	Dark	Spark	Dark	Spark	Dark	Spark	Dark
2021	$15.92	$18.95	($18.67)	$10.45	$9.18	$8.83	$10.48	$13.34
2022	$11.97	$15.19	$11.19	$12.42	$13.30	$18.88	$6.70	$11.42

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

	BGE		COMED		PSEG		Western Hub	
Jan-Mar	Spark	Dark	Spark	Dark	Spark	Dark	Spark	Dark
2021	$38.0	$40.4	$144.4	$34.1	$27.3	$31.8	$28.2	$32.3
2022	$34.9	$38.0	$14.6	$15.0	$60.4	$67.5	$30.4	$26.7

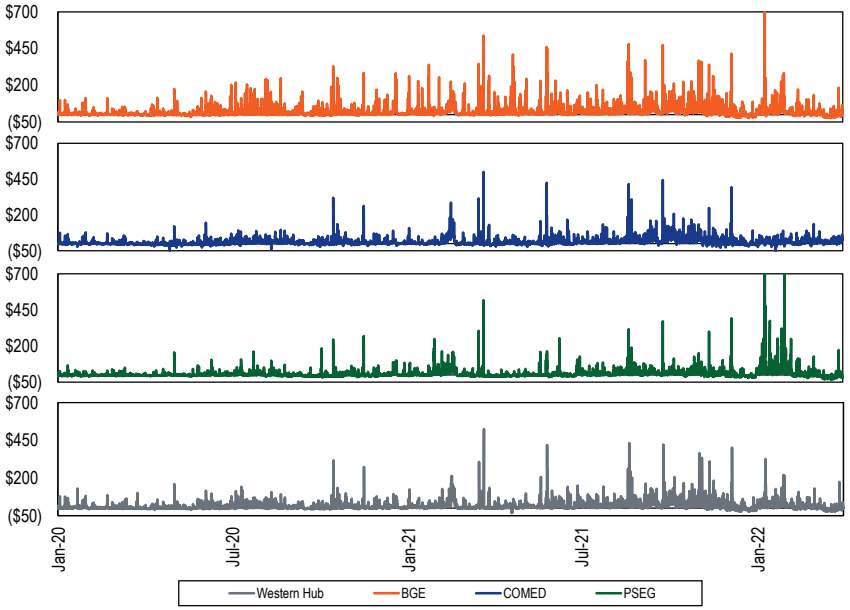
Figure 7-2 shows the hourly spark spread for peak hours for BGE, COMED, PSEG, and Western Hub.

Figure 7-2 Hourly spark spread (gas) for peak hours ($/MWh): 2020 through March 2022[2]



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.

Figure 7-3 Hourly dark spread (coal) for peak hours ($/MWh): 2020 through March 2022[3]



Theoretical Energy Market Net Revenue

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

Analysis of energy market net revenues for a new entrant 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 GE Frame 7HA.02 CT and a single steam turbine generator with an installed capacity of 1,137.2 MW, equipped with evaporative cooling, duct burners, a heat recovery steam generator (HRSG) for each CT, with steam reheat, and SCR for NO_x reduction.
- The CP is a subcritical steam unit with an installed capacity of 600.0 MW, equipped with selective catalytic reduction system (SCR) for NO_x control, a flue gas desulphurization (FGD) system with chemical injection for SO_x and mercury control, and a bag-house for particulate control.
- The DS plant is a single oil fired CAT 2 MW unit with an installed capacity of 2.0 MW using New York Harbor ultra low sulfur diesel.
- The nuclear plant includes two units and related facilities using the Westinghouse AP1000 technology with an installed capacity of 2,200 MW.
- The onshore wind installation includes 104 Siemens 2.9 MW wind turbines located in COMED with an installed capacity of 301.6 MW.
- The offshore wind installation includes of 43 Siemens 7.0 MW wind turbines with an installed capacity of 301.0 MW.
- The solar installation is a 236 acre ground mounted fixed tilt solar farm located in DOM with an installed AC capacity of 100 MW.

Net revenue calculations for the CT, CC and CP include the hourly effect of actual local ambient air temperature on plant heat rates and generator output for each of the three plant configurations.[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]

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.

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, including New Jersey.

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

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

Zonal net revenues reflect average zonal LMP and fuel costs based on locational fuel indices and zone specific delivery charges.[9] The delivered fuel cost for natural gas reflects the zonal, daily delivered price of natural gas from a specific pipeline and is from published commodity daily cash prices, with a basis adjustment for transportation costs.[10] The delivered cost of coal reflects the zone specific, delivered price of coal and was developed from the published prompt month prices, adjusted for rail transportation costs.[11] Net revenues are calculated for all zones except OVEC.[12]

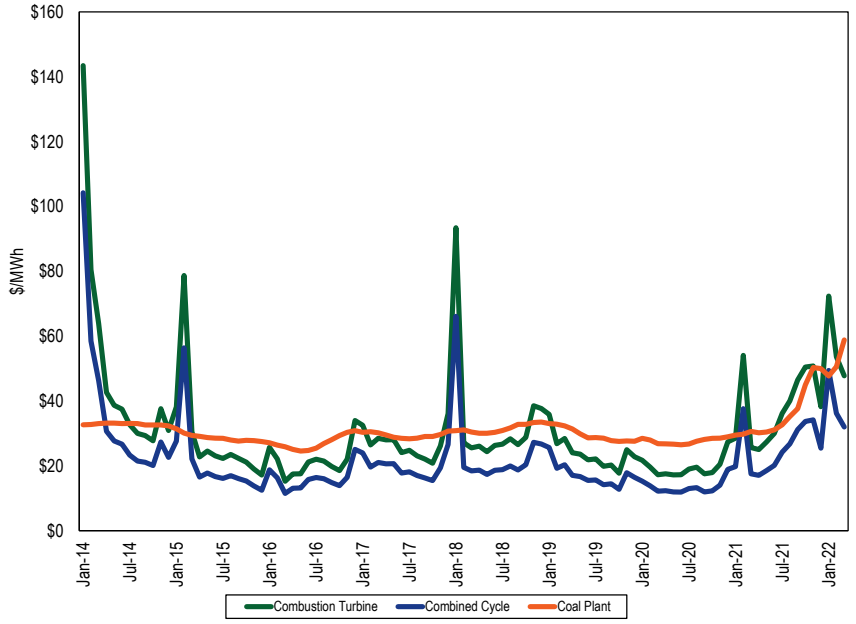
Short run marginal cost includes fuel costs, emissions costs, and the short run marginal component of VOM costs.[13] [14] Average short run marginal costs are shown, including all components, in Table 7-3 and the short run marginal component of VOM is also shown separately.

Table 7-3 Average short run marginal costs: January through March, 2022

Unit Type	Short Run Marginal Costs ($/MWh)	Heat Rate (Btu/kWh)	VOM ($/MWh)
CT	$57.90	9,241	$0.36
CC	$39.21	6,296	$1.41
CP	$52.37	9,250	$4.21
DS	$386.71	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). The marginal costs of a new CC were greater than the marginal cost of a new CP in January 2022, and the marginal costs of a new CT were greater than the marginal cost of a new CP in January and February 2022.

Figure 7-4 Average short run marginal costs: 2014 through March 2022



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.

8 Outage figures obtained from the PJM eGADS database.
9 Startup fuel burns and emission rates provided by Pasteris Energy, Inc. Startup station power consumption costs were obtained from the station service rates published quarterly by PJM and netted against the MW produced during startup at the preceding applicable hourly LMP. All starts associated with combined cycle units are assumed to be hot starts.
10 Gas daily cash prices obtained from Platts.
11 Coal prompt month prices obtained from Platts.
12 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.
13 Fuel costs are calculated using the daily spot price and may not equal what individual participants actually paid.
14 VOM rates provided by Pasteris Energy, Inc.

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

Table 7-4 Average capacity factor: January through March, 2014 through 2022

	CT	CC	CP	DS	Nuclear	On Shore Wind	Solar
2014	44%	69%	74%	6%	91%	33%	11%
2015	61%	74%	66%	4%	92%	32%	13%
2016	74%	79%	42%	1%	92%	33%	14%
2017	51%	73%	41%	0%	94%	34%	13%
2018	58%	80%	40%	4%	94%	37%	13%
2019	47%	79%	27%	0%	93%	33%	13%
2020	53%	80%	6%	0%	93%	31%	12%
2021	38%	38%	33%	1%	93%	31%	12%
2022	44%	37%	35%	1%	93%	34%	14%

New Entrant Combustion Turbine

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

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

New entrant CT plant energy market net revenues were higher in all zones in the first three months of 2022 as a result of significantly higher and more variable energy prices, despite higher gas costs (Table 7-5).

Table 7-5 Energy net revenue for a new entrant gas fired CT under economic dispatch: January through March, 2014 through 2022 (Dollars per installed MW-year)[15]

	Jan-Mar									Change in 2022
Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	from 2021
ACEC	$37,754	$12,776	$9,793	$5,094	$6,806	$7,471	$971	$2,519	$12,592	400%
AEP	$54,108	$28,204	$17,445	$8,061	$29,985	$9,977	$8,681	$7,386	$23,002	211%
APS	$67,470	$45,378	$13,746	$6,445	$36,990	$5,997	$2,111	$7,015	$13,984	99%
ATSI	$35,579	$23,015	$15,204	$8,790	$37,051	$10,895	$8,913	$9,488	$21,968	132%
BGE	$43,148	$12,147	$19,132	$8,307	$12,933	$5,766	$2,798	$8,385	$14,987	79%
COMED	$22,324	$11,462	$8,184	$3,957	$10,373	$4,047	$4,209	$3,279	$10,194	211%
DAY	$32,065	$20,233	$15,044	$7,517	$31,940	$11,113	$10,418	$13,494	$25,179	87%
DOM	$39,668	$16,211	$18,598	$7,708	$15,105	$7,316	$5,139	$6,897	$16,143	134%
DPL	$38,694	$12,217	$6,240	$3,796	$6,485	$3,500	$502	$11,557	$16,762	45%
DUKE	$29,200	$17,892	$14,061	$6,192	$38,188	$9,490	$8,904	$12,405	$23,300	88%
DUQ	$14,592	$9,130	$14,864	$4,724	$8,098	$3,872	$4,217	$4,285	$5,362	25%
EKPC	$49,038	$21,659	$15,107	$6,595	$20,778	$8,411	$7,595	$7,901	$23,133	193%
JCPLC	$41,229	$14,179	$7,559	$6,342	$7,018	$6,376	$990	$2,333	$11,685	401%
MEC	$41,388	$20,993	$13,828	$7,711	$11,234	$5,616	$5,731	$5,579	$20,241	263%
PE	$81,671	$58,960	$24,023	$9,259	$38,540	$10,088	$8,218	$11,934	$35,982	202%
PECO	$41,809	$20,891	$12,766	$6,174	$9,570	$5,030	$4,413	$3,208	$15,085	370%
PEPCO	$46,885	$13,007	$10,982	$6,099	$11,383	$4,754	$1,679	$5,131	$12,304	140%
PPL	$148,553	$84,974	$20,750	$10,291	$45,447	$7,185	$4,138	$8,804	$31,379	256%
PSEG	$52,790	$28,103	$15,489	$8,117	$10,758	$6,631	$1,107	$5,878	$15,330	161%
REC	$31,162	$16,289	$7,900	$5,640	$5,466	$5,443	$1,063	$11,775	$17,542	49%
PJM	$58,381	$24,386	$14,036	$6,841	$19,707	$6,949	$4,590	$7,463	$18,308	145%

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

New Entrant Combined Cycle

Energy market net revenue was calculated for a new CC plant economically dispatched by PJM. It was assumed that the CC plant had a minimum run time of four hours. The unit was first committed day ahead in profitable blocks of at least four hours, including start costs.[16] If the unit was not already committed day ahead, it was run in real time in standalone profitable blocks of at least four hours, or any profitable hours bordering the profitable day-ahead or real-time block.

New entrant CC plant energy market net revenues were higher in all zones as a result of significantly higher energy prices, despite higher gas costs (Table 7-6).

Table 7-6 Energy net revenue for a new entrant CC under economic dispatch: January through March, 2014 through 2022 (Dollars per installed MW-year)[17]

	Jan-Mar									Change in 2022
Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	from 2021
ACEC	$51,917	$21,960	$14,306	$11,375	$14,242	$15,408	$6,819	$1,326	$2,692	103%
AEP	$63,214	$35,476	$22,439	$14,388	$37,756	$18,967	$14,283	$8,023	$18,997	137%
APS	$79,776	$54,676	$25,811	$14,554	$46,949	$16,367	$11,146	$6,241	$13,961	124%
ATSI	$40,769	$31,458	$20,863	$14,986	$43,292	$19,794	$14,512	$9,577	$18,477	93%
BGE	$57,866	$21,830	$30,782	$16,487	$23,231	$15,669	$12,098	$6,866	$10,061	47%
COMED	$24,402	$18,254	$13,878	$8,627	$14,200	$9,662	$9,432	$4,269	$9,895	132%
DAY	$35,604	$28,773	$20,747	$14,010	$39,039	$20,098	$15,942	$11,579	$20,009	73%
DOM	$50,643	$25,250	$24,676	$14,431	$20,823	$16,407	$11,574	$7,932	$15,178	91%
DPL	$50,053	$18,656	$12,529	$5,832	$9,759	$4,873	$1,035	$5,375	$5,518	3%
DUKE	$31,977	$26,108	$19,795	$12,381	$44,259	$18,282	$14,548	$10,800	$19,061	76%
DUQ	$18,875	$12,222	$19,372	$10,714	$16,465	$10,886	$10,477	$5,776	$7,142	24%
EKPC	$57,036	$29,698	$20,355	$12,851	$29,400	$16,973	$13,540	$8,657	$18,583	115%
JCPLC	$57,370	$23,293	$12,163	$12,537	$14,412	$14,416	$6,985	$1,218	$4,270	251%
MEC	$52,805	$30,724	$17,860	$13,766	$19,939	$13,968	$11,572	$6,982	$13,527	94%
PE	$91,359	$59,225	$26,285	$15,380	$44,819	$19,147	$13,657	$10,828	$24,684	128%
PECO	$55,336	$32,397	$16,873	$12,277	$19,415	$12,909	$10,228	$5,483	$9,107	66%
PEPCO	$61,605	$23,012	$23,146	$13,829	$19,546	$14,156	$9,378	$3,861	$8,817	128%
PPL	$145,442	$78,794	$23,078	$15,942	$49,592	$14,995	$9,980	$8,869	$22,311	152%
PSEG	$72,991	$40,604	$19,821	$14,442	$21,129	$15,592	$7,789	$2,915	$5,068	74%
REC	$47,382	$23,878	$12,337	$11,761	$11,689	$13,869	$7,363	$4,791	$7,212	51%
PJM	$100,026	$31,814	$19,856	$13,029	$26,998	$15,122	$10,618	$6,568	$12,729	94%

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

New Entrant Coal Plant

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

New entrant CP plant energy market net revenues were higher in 14 of 20 zones and lower in six zones, as a result of different relative increases in energy prices and the cost of coal by zone (Table 7-7).

Table 7-7 Energy net revenue for a new entrant CP: January through March, 2014 through 2022 (Dollars per installed MW-year)[18]

	Jan-Mar									Change in 2022
Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	from 2021
ACEC	$107,792	$40,142	$3,745	$1,178	$27,616	$3,213	$0	$3,211	$5,443	69%
AEP	$70,724	$23,049	$7,207	$7,989	$25,147	$5,842	$351	$12,337	$10,603	(14%)
APS	$82,000	$30,858	$1,920	$4,367	$26,577	$2,782	$0	$5,977	$5,841	(2%)
ATSI	$78,044	$24,868	$5,250	$9,070	$26,103	$5,642	$53	$9,672	$10,512	9%
BGE	$128,660	$45,329	$11,045	$4,976	$32,587	$3,458	$73	$9,554	$13,544	42%
COMED	$64,187	$19,365	$3,321	$6,818	$9,309	$5,332	$66	$10,349	$18,171	76%
DAY	$71,016	$23,132	$4,989	$7,351	$22,582	$5,662	$325	$14,065	$10,258	(27%)
DOM	$109,653	$50,560	$13,348	$5,025	$35,570	$5,116	$384	$11,383	$26,765	135%
DPL	$131,152	$53,979	$6,464	$3,809	$33,156	$4,046	$6	$11,384	$15,459	36%
DUKE	$65,351	$20,314	$4,263	$5,715	$27,293	$4,441	$101	$12,785	$9,266	(28%)
DUQ	$61,547	$16,396	$4,752	$7,852	$25,393	$4,699	$27	$8,965	$8,577	(4%)
EKPC	$65,318	$19,449	$3,685	$5,339	$16,816	$3,322	$55	$11,588	$10,031	(13%)
JCPLC	$112,807	$41,387	$2,170	$1,327	$27,748	$2,940	$0	$3,215	$6,573	104%
MEC	$124,027	$49,857	$4,409	$4,229	$32,741	$4,316	$525	$8,670	$26,672	208%
PE	$92,537	$38,559	$4,808	$3,194	$24,633	$3,599	$35	$9,517	$22,066	132%
PECO	$105,865	$39,385	$1,975	$1,169	$27,486	$2,761	$0	$4,481	$11,875	165%
PEPCO	$106,471	$32,196	$2,494	$1,062	$25,469	$1,733	$0	$5,175	$7,337	42%
PPL	$105,142	$38,500	$2,031	$1,309	$26,658	$1,634	$0	$4,743	$11,712	147%
PSEG	$141,330	$60,005	$5,254	$3,272	$30,535	$4,276	$0	$4,396	$13,957	218%
REC	$138,906	$61,121	$4,860	$3,287	$28,539	$4,966	$0	$8,166	$16,878	107%
PJM	$98,126	$36,423	$4,900	$4,417	$26,598	$3,989	$100	$8,482	$13,077	54%

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

New Entrant Nuclear Plant

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

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

Table 7-8 Energy net revenue for a new entrant nuclear plant: January through March, 2014 through 2022 (Dollars per installed MW-year)[20]

	Jan-Mar									Change in 2022
Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	from 2021
ACEC	$211,846	$115,640	$48,725	$58,221	$94,760	$60,423	$37,593	$55,190	$103,773	88%
AEP	$138,944	$79,965	$52,917	$58,719	$81,608	$58,767	$40,931	$61,127	$99,644	63%
APS	$160,110	$97,683	$55,589	$60,569	$92,244	$60,182	$40,555	$60,590	$105,237	74%
ATSI	$147,452	$81,034	$52,730	$60,761	$85,634	$60,612	$41,365	$60,525	$98,729	63%
BGE	$221,336	$117,188	$72,903	$67,346	$105,209	$64,215	$43,501	$68,896	$120,259	75%
COMED	$121,565	$67,311	$47,298	$54,992	$57,591	$52,559	$38,015	$57,449	$81,266	41%
DAY	$138,517	$77,939	$52,634	$59,527	$80,788	$60,909	$42,956	$65,079	$102,175	57%
DOM	$190,797	$112,959	$62,378	$63,021	$102,639	$62,157	$40,958	$63,882	$118,812	86%
DPL	$224,316	$126,346	$61,073	$63,399	$100,951	$60,325	$38,079	$69,344	$115,539	67%
DUKE	$131,887	$74,773	$51,588	$57,464	$86,563	$58,821	$41,383	$63,281	$99,946	58%
DUQ	$127,759	$70,888	$52,008	$59,245	$84,336	$58,959	$41,119	$58,969	$95,205	61%
EKPC	$131,844	$73,721	$50,862	$56,994	$72,894	$57,057	$40,988	$61,600	$100,846	64%
JCPLC	$218,343	$116,586	$46,100	$59,689	$94,793	$59,323	$37,785	$54,901	$107,517	96%
MEC	$207,794	$111,544	$46,218	$59,539	$95,281	$59,162	$38,361	$57,647	$116,449	102%
PE	$170,103	$98,672	$50,863	$58,911	$87,072	$59,494	$39,506	$59,862	$110,807	85%
PECO	$209,402	$114,373	$45,162	$57,657	$94,548	$57,937	$36,838	$54,446	$103,707	90%
PEPCO	$217,980	$114,824	$65,798	$65,002	$102,966	$63,377	$42,283	$65,197	$118,429	82%
PPL	$208,338	$113,104	$46,485	$59,062	$91,735	$55,819	$36,183	$55,245	$106,738	93%
PSEG	$234,034	$124,111	$48,419	$60,394	$97,373	$61,330	$37,947	$60,042	$113,820	90%
REC	$231,133	$125,393	$47,495	$60,714	$94,786	$61,717	$38,526	$66,729	$121,412	82%
PJM	$182,175	$100,703	$52,862	$60,061	$90,189	$59,657	$39,744	$61,000	$107,015	75%

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

20 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.

New Entrant Diesel

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

New entrant DS plant energy market net revenues were higher in 12 of 20 zones and lower in eight zones in the first three months of 2022 as a result of different relative increases in energy prices and the cost of fuel by zone (Table 7-9).

Table 7-9 Energy market net revenue for a new entrant DS: January through March, 2014 through 2022 (Dollars per installed MW-year)

	Jan-Mar									Change in 2022
Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	from 2021
ACEC	$32,171	$11,172	$1,895	$131	$9,687	$1,171	$19	$760	$6,079	699%
AEP	$14,072	$2,816	$316	$18	$3,182	$228	$121	$1,129	$583	(48%)
APS	$17,632	$6,050	$391	$64	$5,853	$225	$79	$718	$920	28%
ATSI	$13,724	$2,448	$256	$70	$2,327	$203	$127	$688	$581	(16%)
BGE	$48,591	$9,773	$2,207	$843	$11,091	$588	$226	$2,349	$4,603	96%
COMED	$11,036	$1,626	$152	$0	$603	$164	$96	$1,304	$446	(66%)
DAY	$13,842	$2,296	$269	$17	$1,401	$246	$143	$1,362	$588	(57%)
DOM	$42,074	$9,235	$1,282	$390	$13,183	$385	$145	$1,180	$4,380	271%
DPL	$35,919	$12,810	$1,670	$732	$11,197	$1,176	$19	$10,663	$7,264	(32%)
DUKE	$13,051	$1,892	$399	$11	$2,689	$207	$121	$1,597	$545	(66%)
DUQ	$12,607	$2,016	$255	$72	$2,615	$181	$152	$715	$568	(21%)
EKPC	$14,101	$2,087	$493	$10	$1,485	$205	$122	$1,861	$562	(70%)
JCPLC	$32,414	$11,631	$456	$209	$10,693	$1,131	$17	$707	$5,833	725%
MEC	$31,497	$10,905	$425	$167	$10,574	$357	$109	$903	$6,751	648%
PE	$15,656	$5,284	$266	$95	$4,610	$94	$145	$696	$786	13%
PECO	$31,741	$11,085	$421	$173	$9,516	$1,071	$21	$734	$6,018	720%
PEPCO	$50,549	$8,848	$1,182	$394	$11,047	$466	$168	$1,124	$4,782	326%
PPL	$32,438	$11,661	$397	$199	$8,376	$82	$23	$755	$3,451	357%
PSEG	$31,987	$11,287	$520	$205	$9,756	$1,481	$19	$1,131	$6,335	460%
REC	$29,526	$12,515	$507	$200	$8,823	$1,325	$21	$5,124	$6,507	27%
PJM	$29,787	$7,372	$688	$200	$6,935	$549	$94	$1,775	$3,379	90%

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.[21]

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

Table 7-10 Energy market net revenue for an onshore wind installation (Dollars per installed MW-year): January through March, 2014 through 2022

	Jan-Mar									Change in 2022
Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	from 2021
AEP	$45,406	$26,566	$21,777	$22,697	$38,566	$23,727	$13,525	$18,024	$35,754	98%
APS	$53,819	$33,489	$19,391	$24,579	$39,477	$19,314	$13,487	$17,251	$33,236	93%
COMED	$39,397	$23,379	$16,746	$21,821	$24,103	$20,127	$11,754	$18,216	$28,315	55%
PE	$66,094	$43,528	$21,076	$25,331	$41,510	$20,090	$12,783	$17,270	$34,758	101%

New Entrant Offshore Wind Installation

Energy market net revenues for an offshore wind installation were calculated hourly assuming the unit generated at a 45 percent capacity factor.

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

Table 7-11 Energy market net revenue for an offshore wind installation (Dollars per installed MW-year): January through March, 2014 through 2022

	Jan-Mar									Change in 2022
Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	from 2021
ACEC	$96,357	$54,104	$23,705	$27,675	$45,810	$29,481	$18,414	$25,497	$53,111	108%
DOM	$99,725	$51,146	$28,579	$30,001	$50,997	$29,115	$19,397	$30,847	$58,071	88%
DPL	$102,937	$58,882	$27,522	$30,270	$48,750	$29,041	$18,625	$37,677	$60,871	62%

21 Net revenues are calculated for zones in which there are sufficient operating units to determine capacity factor for a new entrant unit.

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.[22]

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

Table 7-12 Energy market net revenue for a solar installation (Dollars per installed MW-year): January through March, 2014 through 2022

	Jan-Mar									Change in 2022
Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	from 2021
ACEC	$21,536	$13,316	$5,993	$6,914	$10,062	$7,282	$4,438	$5,187	$11,826	128%
DOM	-	-	$11,030	$12,432	$16,098	$10,274	$6,915	$9,150	$19,869	117%
DPL	-	-	$8,621	$9,593	$12,531	$8,845	$5,452	$7,086	$13,396	89%
JCPLC	$20,041	$10,930	$4,953	$6,140	$8,959	$6,448	$3,984	$4,666	$10,983	135%
PSEG	$19,380	$14,236	$6,048	$6,760	$10,192	$7,759	$4,895	$6,894	$13,254	92%

Historical New Entrant CC Revenue Adequacy

Total unit net revenues include energy and capacity revenues. Analysis of the total unit revenues of theoretical new entrant CCs for three representative locations shows that CC units that entered the PJM markets in 2007 have covered 87 percent of their total costs in the BGE Zone and PSEG Zone, and 47 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 99 percent of their total costs on a cumulative basis in the BGE Zone and PSEG Zone and 58 percent of total costs in the COMED Zone. Energy market revenues alone were not sufficient to cover total costs in any scenario, which demonstrates the critical role of the capacity market revenue in covering total costs.

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

Figure 7-5 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 7-5 Historical new entrant CC revenue adequacy: 2007 through March 2022 and 2012 through March 2022[23]

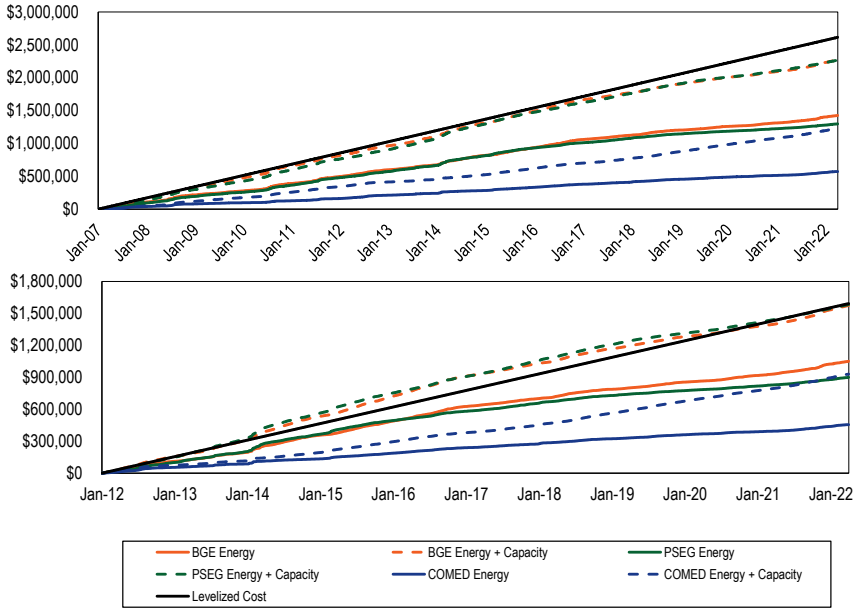


Table 7-13 shows the percent of levelized total costs recovered.

22 Net revenues are calculated for zones in which there are sufficient operating units to determine capacity factor for a new entrant unit.

23 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.

Table 7-13 Percent of levelized total costs recovered

	2007 CC	2012 CC
BGE	87%	99%
COMED	47%	58%
PSEG	87%	99%

Assumptions used for this analysis are shown in Table 7-14.

Table 7-14 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%

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.[24] [25] 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 2020.[26] 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 12.8 percent decrease from 2012 through 2020 for all plants including single and multiple unit plants).[27] NEI average incremental capital expenditures have decreased since their peak in 2012 (a 49.1 percent decrease from 2012 through 2020 for all plants including single and multiple unit plants).[28] 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.[29] 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.[30] 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. Energy prices in the first three months of 2022 are higher than historical energy prices for all years since 2008. Nuclear plant energy revenues based on forward period prices are higher than in previous years. The results for nuclear plants are also sensitive to changes in costs and whether actual unit costs are less than or greater than the benchmark NEI data.

24 Operating costs from: Nuclear Energy Institute (November, 2021). "Nuclear Costs in Context," <https://www.nei.org/CorporateSite/media/filefolder/resources/reports-and-briefs/Nuclear-Costs-in-Context-2021.pdf>. Individual plants may vary from the average due to factors such as geographic location, local labor costs, the timing of refueling outages and other unit specific factors. This is the most current NEI data available.

25 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.

26 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 costs than BWR reactors.

27 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 $1.73/MWh, or 7.0 percent, from 2019 to 2020. Operating costs for multiple unit plants decreased by $0.57/MWh, or 3.4 percent, from 2019 to 2020.

28 Capital expenditures have decreased 44.1 percent since 2012 for single unit plants and 49.5 percent for multiple unit plants.

29 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 $1.09 per MWh for a nuclear power plant operating at a capacity factor of 0.918 percent.

30 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.*

Table 7-15 includes the publicly available data on energy market prices, Table 7-16 and Table 7-17 show capacity market prices and Table 7-18 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.[31] The analysis excludes the Cook nuclear units, the Catawba 1 nuclear unit, and the North Anna and Surry nuclear units. The Cook nuclear units are designated FRR and receive cost of service revenues and are not subject to PJM market revenues.[32] Catawba 1 is not in PJM but is pseudo tied to PJM. North Anna 1 and 2 and Surry 1 and 2 are part of the Dominion FRR for the 2022/2023 Delivery Year.

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.

Table 7-15 Nuclear unit day-ahead LMP: 2008 through 2021

	ICAP	Average DA LMP ($/MWh)													
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
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
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
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
Calvert Cliffs	1,708	$78.63	$41.05	$51.27	$46.53	$35.19	$40.27	$57.88	$40.30	$32.64	$31.57	$38.79	$28.00	$21.88	$41.24
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
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
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
LaSalle	2,271	$47.96	$27.71	$31.53	$31.93	$27.56	$30.94	$37.88	$26.28	$23.95	$24.71	$27.19	$22.75	$18.14	$33.54
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
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
Oyster Creek	608	$75.49	$40.43	$49.29	$46.74	$33.69	$38.62	$52.85	$33.10	$23.79	$27.52	$34.03	$23.68	$18.07	$32.36
Peach Bottom	2,347	$73.09	$39.32	$47.70	$44.73	$32.81	$37.37	$51.52	$31.98	$23.07	$26.76	$32.63	$21.58	$16.93	$30.77
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
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
Salem	2,328	$73.41	$39.51	$48.02	$45.50	$33.06	$37.40	$51.96	$32.37	$23.18	$26.76	$32.90	$22.43	$17.32	$30.12
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
Susquehanna	2,520	$69.96	$38.24	$45.95	$44.78	$32.10	$36.76	$50.93	$32.47	$23.66	$27.14	$32.42	$21.08	$16.03	$30.36
Three Mile Island	803	$72.46	$39.11	$46.72	$44.15	$32.43	$36.83	$50.47	$30.94	$22.96	$27.12	$31.76	$23.47	$19.07	$39.58

31 Installed capacity is from NEI, "Map of U.S. Nuclear Plants," <https://www.nei.org/resources/map-of-us-nuclear-plants>.
32 See "Resources Designated in 2021/2022 FRR Capacity Plans as of May 1, 2018," <https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-resources-designated-in-frr-plans.ashx?la=en>.

Table 7-16 BRA capacity market clearing prices ($/MW-Day): 2007/2008 through 2022/2023[33] [34]

	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
Beaver Valley	1,808	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$165	$100	$77	$140	$50
Braidwood	2,337	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$215	$203	$188	$196	$69
Byron	2,300	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$215	$203	$188	$196	$69
Calvert Cliffs	1,708	$189	$210	$237	$174	$110	$133	$226	$137	$167	$119	$120	$165	$100	$86	$140	$96
Davis Besse	894	-	-	-	-	$109	$20	$28	$126	$357	$114	$120	$165	$100	$77	$171	$50
Dresden	1,797	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$215	$203	$188	$196	$69
Hope Creek	1,172	$198	$149	$191	$174	$110	$140	$245	$137	$167	$119	$120	$225	$120	$188	$166	$98
LaSalle	2,271	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$215	$203	$188	$196	$69
Limerick	2,242	$198	$149	$191	$174	$110	$140	$245	$137	$167	$119	$120	$225	$120	$188	$166	$98
North Anna	1,892	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$165	$100	$77	$140	-
Oyster Creek	608	$198	$149	$191	$174	$110	$140	$245	$137	$167	$119	$120	$225	$120	$188	-	-
Peach Bottom	2,347	$198	$149	$191	$174	$110	$140	$245	$137	$167	$119	$120	$225	$120	$188	$166	$98
Perry	1,240	-	-	-	-	$109	$20	$28	$126	$357	$114	$120	$165	$100	$77	$171	$50
Quad Cities	1,819	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$215	$203	$188	$196	$69
Salem	2,328	$198	$149	$191	$174	$110	$140	$245	$137	$167	$119	$120	$225	$120	$188	$166	$98
Surry	1,676	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$165	$100	$77	$140	-
Susquehanna	2,520	$41	$112	$191	$174	$110	$133	$226	$137	$167	$119	$120	$165	$100	$86	$140	$96
Three Mile Island	803	$41	$112	$191	$174	$110	$133	$226	$137	$167	$119	$120	$165	$100	$86	$140	-

Table 7-17 Nuclear unit capacity market revenue ($/MWh): 2008 through 2022[35] [36]

	ICAP	Capacity Revenue ($/MWh)														
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
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	$3.84	$5.12	$3.92
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	$8.63	$8.66	$5.46
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	$8.63	$8.66	$5.46
Calvert Cliffs	1,708	$8.73	$9.59	$8.64	$5.87	$5.38	$8.21	$7.53	$6.74	$6.04	$5.26	$6.42	$5.62	$4.09	$5.29	$5.13
Davis Besse	894	NA	NA	NA	NA	$2.49	$1.08	$3.70	$11.40	$9.33	$5.17	$6.42	$5.61	$3.84	$5.94	$4.51
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	$8.63	$8.66	$5.46
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	$7.09	$7.87	$5.67
LaSalle	2,271	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$7.71	$9.20	$8.63	$8.66	$5.46
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	$7.09	$7.87	$5.67
North Anna	1,892	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$6.42	$5.61	$3.84	$5.12	NA
Oyster Creek	608	$7.33	$7.37	$7.82	$5.87	$5.54	$8.81	$7.87	$6.74	$6.04	$5.26	NA	NA	NA	NA	NA
Peach Bottom	2,347	$7.33	$7.37	$7.82	$5.87	$5.54	$8.81	$7.87	$6.74	$6.04	$5.26	$7.98	$7.24	$7.09	$7.87	$5.67
Perry	1,240	NA	NA	NA	NA	$2.49	$1.08	$3.70	$11.40	$9.33	$5.17	$6.42	$5.61	$3.84	$5.94	$4.51
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	$8.63	$8.66	$5.46
Salem	2,328	$7.33	$7.37	$7.82	$5.87	$5.54	$8.81	$7.87	$6.74	$6.04	$5.26	$7.98	$7.24	$7.09	$7.87	$5.67
Surry	1,676	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$6.42	$5.61	$3.84	$5.12	NA
Susquehanna	2,520	$3.57	$6.72	$7.82	$5.87	$5.38	$8.21	$7.53	$6.74	$6.04	$5.26	$6.42	$5.61	$4.08	$5.29	$5.13
Three Mile Island	803	$3.57	$6.72	$7.82	$5.87	$5.38	$8.21	$7.53	$6.74	$6.04	$5.26	$6.42	$5.61	$4.08	$5.29	NA

33 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.

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

35 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 *2021 State of the Market Report for PJM*, Volume 2, Section 5: Capacity Market.

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

Table 7-18 Nuclear unit costs: 2008 through 2020[37] [38]

	ICAP	NEI Costs ($/MWh)												
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
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
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
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
Calvert Cliffs	1,708	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03
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
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
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
LaSalle	2,271	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03
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
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
Oyster Creek	608	$35.31	$39.36	$41.23	$45.45	$47.41	$44.16	$44.32	$44.51	$41.39	$42.66	NA	NA	NA
Peach Bottom	2,347	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03
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
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
Salem	2,328	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03
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
Susquehanna	2,520	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03
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	NA	NA

In 2020, no nuclear plants covered their fuel costs, operating costs, and incremental capital expenditures as a result of lower energy prices. In 2021, all nuclear plants covered their fuel costs, operating costs, and incremental capital expenditures as a result of higher energy prices.

Table 7-19 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 2021, all nuclear plants more than covered their fuel costs, operating costs, and capital expenditures as a result of higher energy prices. The surplus or shortfall assumes that the unit cleared its full unforced capacity at the BRA locational clearing price.[39] Unforced capacity is determined using the annual class average EFORd rate.

The market revenues are based in part on the sale of capacity. Some nuclear plants did not clear the capacity market as a result of decisions by plant owners about how to offer the plants. When nuclear plants do not clear in the capacity market, it is a result of the offer behavior of the plants and does not reflect the economic viability of the plants unless the plants offer accurate net avoidable costs and fail to clear. This analysis is intended to define whether the plants are receiving a retirement signal from the PJM markets. If the plants are viable including both energy and capacity market revenues based on actual clearing prices, then the PJM markets indicate that the plant is economically viable. If plant owners decide to offer so as to not clear in the capacity market, that does not change the market signals to the plants. Such decisions may reflect a variety of considerations. Quad Cities and a portion of Byron's capacity did not clear

37 Operating costs from: Nuclear Energy Institute (October, 2020). "Nuclear Costs in Context," <https://www.nei.org/resources/reports-briefs/nuclear-costs-in-context>.

38 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>.

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

in the 2019/2020 Auction.[40] Quad Cities did not clear in the 2020/2021 Auction.[41] Dresden and most of Byron did not clear in the 2021/2022 Auction.[42] Beaver Valley, Davis Besse, and Perry did not clear in the 2021/2022 Auction.[43] Byron, Dresden, and Quad Cities did not clear in the 2022/2023 Auction.[44]

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, and an average of 0.0 percent and a maximum of 0.3 percent in 2021.[45]

In 2021, all nuclear plants covered their fuel costs, operating costs, and incremental capital expenditures as a result of higher energy prices.

Table 7-19 Nuclear unit surplus (shortfall) based on public data: 2008 through 2021

	ICAP	Surplus (Shortfall) ($/MWh)													
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
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	($2.6)	$15.4
Braidwood	2,337	$24.9	$2.5	$6.4	$3.4	($6.1)	($2.6)	$7.2	($1.2)	($3.1)	($1.5)	$6.0	$3.9	$0.1	$15.6
Byron	2,300	$24.5	($1.3)	$3.4	($0.6)	($9.4)	($3.6)	$4.9	($6.1)	($9.5)	($2.7)	$5.8	$3.2	($0.5)	$14.6
Calvert Cliffs	1,708	$60.6	$20.9	$28.6	$17.9	$4.5	$14.6	$31.6	$14.1	$7.3	$6.1	$16.3	$5.4	($0.9)	$19.7
Davis Besse	894	NA	NA	NA	NA	($13.2)	($7.0)	$6.6	($1.2)	($4.0)	($8.4)	($0.9)	($6.2)	($15.0)	$3.9
Dresden	1,797	$25.6	$3.0	$7.6	$4.4	($5.2)	($1.0)	$9.1	$0.3	($1.5)	($0.0)	$7.2	$4.6	$0.7	$16.3
Hope Creek	1,172	$54.0	$17.0	$24.5	$16.9	$2.6	$12.4	$26.0	$6.3	($2.0)	$1.6	$12.3	$1.7	($2.2)	$11.4
LaSalle	2,271	$24.8	$2.5	$6.4	$3.3	($6.1)	($1.9)	$7.7	($0.9)	($3.5)	($1.8)	$6.0	$3.8	($0.1)	$15.4
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	$1.7	($2.5)	$12.0
North Anna	1,892	$52.0	$14.6	$25.5	$16.8	$0.2	$5.7	$23.2	$10.9	$3.0	$4.7	$16.0	$4.8	($2.0)	$18.2
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
Peach Bottom	2,347	$53.7	$16.9	$24.2	$16.1	$2.3	$12.3	$25.5	$5.8	($2.2)	$1.4	$11.8	$0.7	($2.7)	$11.9
Perry	1,240	NA	NA	NA	NA	($13.2)	($6.4)	$5.5	($0.3)	($4.0)	($7.3)	$1.9	($5.8)	($15.1)	$4.3
Quad Cities	1,819	$24.1	($0.4)	$2.4	($1.8)	($13.2)	($6.9)	$0.6	($7.7)	($9.5)	($3.4)	$4.4	$2.1	($2.3)	$13.2
Salem	2,328	$54.0	$17.1	$24.5	$16.9	$2.6	$12.4	$26.0	$6.2	($2.3)	$1.3	$11.9	$1.4	($2.5)	$11.1
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	$4.1	($2.6)	$17.6
Susquehanna	2,520	$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)	$8.9
Three Mile Island	803	$40.7	$6.5	$13.3	$4.6	($9.6)	$0.9	$13.7	($6.8)	($12.4)	($10.3)	($3.8)	NA	NA	NA

40 Exelon. "Exelon Announces Outcome of 2019-2020 PJM Capacity Auction," (May 25, 2016) <http://www.exeloncorp.com/newsroom/pjm-auction-results-2016>.
41 Exelon, "Exelon Announces Outcome of 2020-2021 PJM Capacity Auction," (May 24, 2017) <http://www.exeloncorp.com/newsroom/pjm-auction-results-release-2017>.
42 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>.
43 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>.
44 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/>.
45 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.

In order to evaluate the expected viability of nuclear plants, analysis was performed based on forward energy market prices for 2022, 2023 and 2024 and known capacity market prices for 2022. The purpose of the forward analysis is to evaluate whether current forward prices are consistent with nuclear plants covering their annual avoidable costs over the next three years. While the forward capacity market prices are known, actual energy prices will vary from forward values. Nuclear plants may sell their output at a range of forward prices and for a range of future years.

Table 7-20 shows PJM energy prices (LMP), annual fuel, and operating and capital expenditures used for the analysis of the period 2022 through 2024. Capacity revenues are not presented for calendar year 2023 because the 2023/2024 BRA has not been run. The LMPs are based on forward prices with a basis adjustment for the specific plant locations.[46] Forward prices are as of April 1, 2022. The 2022 energy prices in Table 7-20 include actual day-ahead market prices through March 31, 2022, and forward prices for April through December 2022. The capacity prices are known based on PJM capacity auction results.

Table 7-20 Forward prices in PJM energy markets, capacity revenue, and annual costs

	ICAP	Average Forward LMP ($/MWh)			Ancillary Revenue ($/MWh)	Capacity Revenue ($/MWh)		2019 NEI Costs ($/MWh)		
	(MW)	2022	2023	2024	Reactive	2022	2023	Fuel	Operating	Capital
Beaver Valley	1,808	$56.86	$53.41	$44.56	$0.25	$5.12	$3.92	$5.76	$16.43	$4.84
Braidwood	2,337	$51.54	$50.43	$41.98	$0.25	$8.66	$5.46	$5.76	$16.43	$4.84
Byron	2,300	$49.54	$48.43	$40.29	$0.21	$8.66	$5.46	$5.76	$16.43	$4.84
Calvert Cliffs	1,708	$64.16	$58.96	$49.16	$0.20	$5.29	$5.13	$5.76	$16.43	$4.84
Davis Besse	894	$57.34	$53.06	$44.28	$0.25	$5.94	$4.51	$5.76	$26.33	$7.55
Dresden	1,797	$52.36	$51.31	$42.70	$0.33	$8.66	$5.46	$5.76	$16.43	$4.84
Hope Creek	1,172	$50.88	$47.56	$39.53	$0.43	$7.87	$5.67	$5.76	$16.43	$4.84
LaSalle	2,271	$51.28	$50.17	$41.76	$0.18	$8.66	$5.46	$5.76	$16.43	$4.84
Limerick	2,242	$51.94	$47.88	$39.82	$0.14	$7.87	$5.67	$5.76	$16.43	$4.84
North Anna	1,892	$62.57	$57.91	$48.27	$0.17	$5.12	NA	$5.76	$16.43	$4.84
Peach Bottom	2,347	$51.70	$47.65	$39.61	$0.29	$7.87	$5.67	$5.76	$16.43	$4.84
Perry	1,240	$57.97	$54.42	$45.39	$0.25	$5.94	$4.51	$5.76	$26.33	$7.55
Quad Cities	1,819	$48.08	$46.41	$38.61	$0.18	$8.66	$5.46	$5.76	$16.43	$4.84
Salem	2,328	$50.85	$47.47	$39.47	$0.13	$7.87	$5.67	$5.76	$16.43	$4.84
Surry	1,676	$61.60	$57.32	$47.78	$0.17	$5.12	NA	$5.76	$16.43	$4.84
Susquehanna	2,520	$49.75	$45.80	$38.17	$0.29	$5.29	$5.13	$5.76	$16.43	$4.84

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 about inclusion of maintenance expense in energy offers, major maintenance costs can no longer be included in gross ACR values.[47] 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

46 Forward prices on April 1, 2022. 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 2021 data.
47 See 167 FERC ¶ 61,030 at P 41.

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 7-21, the capacity price required to cover avoidable costs in $ per MWh is calculated by taking the total NEI costs in $ per MWh and subtracting the total expected energy and ancillary services revenues in $ per MWh. Total expected energy revenue is the unit's ICAP multiplied by the average forward LMP multiplied by the class average equivalent availability factor. Total expected ancillary services revenue is reactive capability revenue.[48] The capacity price required to cover avoidable costs in $ per MW-day is calculated by multiplying the required price in $ per MWh by 24. Plants may have actual operating costs higher or lower than the NEI average.

In Table 7-21, for 2022, using actual day-ahead market prices through March 31, 2022, and forward prices, as of April 1, 2022, for April through December 2022, 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.[49] Net revenues based on forward energy prices are greater than or equal to avoidable costs in 2022, 2023, and 2024 without any contribution from capacity market revenues. The result is that all net ACR values in Table 7-21 are zero.

Table 7-21 Net ACR

	ICAP	Net ACR ($/MWh)			Net ACR ($/MW-Day)			Net ACR Excluding Capital ($/MW-Day)		
	(MW)	2022	2023	2024	2022	2023	2024	2022	2023	2024
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	1,708	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Davis Besse	894	$0.00	$0.00	$0.00	$0.00	$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	2,271	$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	2,347	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Perry	1,240	$0.00	$0.00	$0.00	$0.00	$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	2,328	$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	2,520	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

48 Reactive Supply & Voltage Control Revenue Requirements available from PJM <https://www.pjm.com/markets-and-operations/billing-settlements-and-credit.aspx>.
49 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 7-22 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 2020 NEI fuel, operating, and capital costs. Plants may have operating costs higher or lower than the NEI average. Table 7-22 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 plants are expected to cover their annual avoidable costs in 2022.

Hope Creek, Quad Cities, and Salem all currently receive subsidies. Braidwood, Byron, Dresden, and LaSalle will receive a subsidy if necessary to meet a target net revenue value, in dollar per MWh, from the energy and capacity markets. Based on forward prices as of April 1, 2022, and NEI average costs, none of these units need a subsidy, and therefore zero subsidy values are included for these plants in Table 7-22.

Table 7-22 Nuclear unit forward annual surplus (shortfall)[50] [51] [52] [53] [54]

	ICAP (MW)	Surplus (Shortfall) ($/MWh) 2022	Subsidy ($/MWh) 2022	Surplus (Shortfall) Excluding Subsidy ($ in millions) 2022	Surplus (Shortfall) Including Subsidy ($ in millions) 2022
Beaver Valley	1,808	$35.19		$513.9	$513.9
Braidwood	2,337	$33.42	$0.00	$630.7	$630.7
Byron	2,300	$31.38	$0.00	$583.0	$583.0
Calvert Cliffs	1,708	$42.63		$587.9	$587.9
Davis Besse	894	$23.89		$172.8	$172.8
Dresden	1,797	$34.31	$0.00	$497.9	$497.9
Hope Creek	1,172	$32.15	$10.00	$304.4	$398.6
LaSalle	2,271	$33.09	$0.00	$606.9	$606.9
Limerick	2,242	$32.92		$596.0	$596.0
North Anna	1,892	$40.83		$623.8	$623.8
Peach Bottom	2,347	$32.82		$622.2	$622.2
Perry	1,240	$24.52		$246.1	$246.1
Quad Cities	1,819	$29.89	$16.50	$439.2	$680.5
Salem	2,328	$31.81	$10.00	$598.1	$785.4
Surry	1,676	$39.86		$539.5	$539.5
Susquehanna	2,520	$28.30		$576.4	$576.4

50 Report to the General Assembly in Compliance with Section 1-75(d-5) of the Illinois Power Agency Act 20 ILCS 3855/1-75(d-5)(F)(2). Illinois Commerce Commission. 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.

51 *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).

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

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

54 The Illinois Energy Transition Act, SB 2408.