Gross Avoidable Cost Rates for Existing Generation and Net Cost of New Entry for New Energy Efficiency

PREPARED FOR

PREPARED BY

Samuel A. Newell

J. Michael Hagerty

Sanem Sergici

Jesse Cohen

The Brattle Group

Sang H. Gang

John Wroble

Patrick S. Daou

Sargent & Lundy

March 17, 2020

Notice

- This report was prepared for PJM Interconnection, L.L.C., in accordance with The Brattle Group's engagement terms, and is intended to be read and used as a whole and not in parts.
- The report reflects the analyses and opinions of the authors and does not necessarily reflect those of The Brattle Group's clients or other consultants.
- There are no third party beneficiaries with respect to this report, and The Brattle Group does not accept any liability to any third party in respect of the contents of this report or any actions taken or decisions made as a consequence of the information set forth herein.

Table of Contents

Executive Summary

In December 2019, the Federal Energy Regulatory Commission (FERC) ordered the PJM Interconnection, L.L.C. (PJM) to expand the application of its Minimum Offer Price Review (MOPR) in its forward capacity market. To help implement this order, PJM retained The Brattle Group (Brattle) and Sargent & Lundy (S&L) to analyze the gross avoidable costs rates (ACRs) for several types of existing generation and the net cost of new entry (Net CONE) for new energy efficiency (EE) in the 2022/2023 Base Residual Auction. PJM will use the values to inform default offer floor prices for each resource type in its auctions.

Existing generation resources vary considerably in their characteristics and costs, even for a given type of resource. To inform PJM's determination of a single ACR for each resource type, we present a range of costs for the fleet of resources of each type operating in the PJM market. PJM can then determine the default offer floor price for each resource type at a value within the range that best fits its approach to complying with the order, trading off the risks of under-mitigation against the risks of over-mitigation and/or a burdensome amount of unit-specific reviews.

To do so, we reviewed the range of characteristics of resources installed in the PJM market and identified the primary cost drivers among those characteristics for each resource type. We then identified for each resource type the characteristics of a "representative plant" that is widely representative of most of the fleet as well as characteristics for "representative low-cost" and "representative high-cost" plants to inform the range of costs for each type of existing generation resource.

Given the assumed characteristics, we then estimated the costs of the representative plants to inform the Gross ACRs and the variable O&M costs for use in PJM's net energy and ancillary services (E&AS) revenue analysis. These cost estimates reflect PJM's market rules concerning the scope of costs that are includable in the Gross ACRs versus those that can be included in cost-based energy offers (and thus accounted for in the net E&AS revenue component of Net ACRs). Following guidance provided by PJM, the costs of major maintenance and overhauls on systems directly related to the production of electricity are included in variable costs as a "maintenance adder."

Table 1 below shows the resulting cost estimates for each existing generation resource type on a per-megawatt (MW) of nameplate capacity basis for informing PJM's 2022/2023 Gross ACRs.

Table 1: Existing Generation Costs for 2022/2023 Gross Avoidable Cost Rates
(in nominal dollars per MW-day)

Resource Type	Representative Low-Cost Plant	Representative Plant	Representative High-Cost Plant
Single-Unit Nuclear	---	**$697**	---
Multi-Unit Nuclear	$405	**$445**	$457
Coal	$74	**$80**	$166
Gas CC	$55	**$56**	$79
Gas CT	$42	**$50**	$65
Onshore Wind	$76	**$83**	$128
Solar PV	$29	**$40**	$60
Diesel Generator	---	**$3**	---

Table 2 below shows our estimates of the variable costs for each resource type that are consistent with the Gross ACR estimates. The variable costs shown include non-fuel operating costs and maintenance adders for all resource types.

Table 2: Existing Generation Costs for 2022/2023 Variable Costs
(in nominal dollars per MWh)

Resource Type	Representative Low-Cost Plant	Representative Plant	Representative High-Cost Plant
Single-Unit Nuclear	---	$4.00	---
Multi-Unit Nuclear	$2.63	$2.67	$3.66
Coal	$9.17	$9.56	$9.20
Gas CC	$2.24	$2.57	$2.53
Gas CT	$7.54	$7.54	$4.98
Onshore Wind	$0.00	$0.00	$0.00
Solar PV	$0.00	$0.00	$0.00
Diesel Generator	---	$0.00	---

Note: The estimated variable costs are calculated based on an assumed capacity factor for each resource type. We provide details on the assumed capacity factors and how to adjust the variable costs for different capacity factors in the report below.

To calculate the Net CONE for new EE resources, we analyzed the total costs and benefits of EE programs. Net CONE represents the amount of capacity market revenues that a resource would need to justify the investment. It represents the gap between the total costs of the EE investments (including all utility program costs and participant's out-of-pocket costs) and other revenues or benefits of EE (reduced wholesale energy costs and transmission and distribution system costs) that would need to be filled by revenues from the capacity market.

We reviewed publicly-available reports on EE program cost effectiveness and identified sufficient costs and performance data to calculate Net CONE for EE programs of three representative PJM utilities with the largest EE portfolios in their respective states: Baltimore Gas and Electric, Pennsylvania Power and Light and Commonwealth Edison. For those utilities, we identified 30 programs whose capacity could qualify for PJM's capacity market. We then calculated the Net CONE for each EE program by analyzing its costs, characteristics, and benefits per MW of qualified capacity. Finally, we calculated the capacity-weighted average across all qualified programs to produce a single Net CONE value for EE.

Table 3 below shows the estimated Net CONE for new EE in the 2022/2023 BRA is $64/MW ICAP-day, or $58/MW UCAP-day (in nominal dollars).

Table 3: 2022/2023 Net Cost of New Entry for New Energy Efficiency
(in nominal dollars)

Gross CONE	***$/kW ICAP-yr***	**$235**
Energy Savings	*$/kW ICAP-yr*	$177
T&D Savings	*$/kW ICAP-yr*	$35
Net CONE	***$/kW ICAP-yr***	**$23**
Net CONE	***$/MW ICAP-day***	**$64**
Net CONE	***$/MW UCAP-day***	**$58**

I. Introduction

In December 2019, the Federal Energy Regulatory Commission (FERC) issued an order in Docket Nos. EL 16-49-000 and EL 18-178-000 related to PJM Interconnection's (PJM) forward capacity market that directed PJM to expand its application of the current Minimum Offer Price Rule (MOPR) to "address state-subsidized electric generation resources."[1] FERC directed PJM to submit a compliance filing consistent with the order within 90 days.[2]

To implement the order, PJM requested that consultants at The Brattle Group and Sargent & Lundy (S&L) analyze:

- Gross avoidable costs rates (ACRs) for existing generation, and
- Net cost of new entry (Net CONE) for new energy efficiency (EE).

PJM will then estimate the energy and ancillary services (E&AS) net revenues for the existing generation resources and calculate Net ACRs for each resource type and zone. PJM will set default offer price floors for existing generation resources in its forward capacity market at the Net ACRs for each resource type and for new EE at its Net CONE. Resources will be able to receive a Unit-Specific Exemption to offer below the default offer price floor if they can justify their offer during a review of their expected costs and revenues by the Independent Market Monitor (IMM).

II. Gross ACRs for Existing Generation

A. Scope of Analysis

PJM requested that we estimate Gross ACRs for the following existing generation resource types:

- Single-unit nuclear plants
- Multi-unit nuclear plants
- Coal plants

1 U.S. Federal Energy Regulatory Commission, "FERC Directs PJM to Expand Minimum Offer Price Rule", News Release, December 19, 2019. Available at: https://www.ferc.gov/media/news-releases/2019/2019-4/12-19-19-E-1.asp#.Xl04BahKiHs

2 169 F.E.R.C. ¶ 61,239 (December 19, 2019).

- Natural gas-fired combined-cycle plants (CC)
- Natural gas-fired combustion turbine plants (CT)
- Onshore wind plants
- Large-scale (>1 MW) solar photovoltaic plants
- Behind-the-meter diesel generator plants

Gross ACRs reflect the fixed costs of operating an existing generation resource for an additional year, while the variable costs of operating a resource are accounted for in net E&AS revenues, then combined to calculate Net ACRs. The combination should include all avoidable costs to operate the resource for another year. Costs that are incurred infrequently to extend the life of the resource or enhance its performance for more than a year are not to be included in the Gross ACR or variable costs.

To determine which costs to include in the Gross ACR and which to include in variable costs, PJM staff reviewed the specifications in their tariff and operating agreements, and provided guidelines to follow based on their interpretation. The PJM Open Access Transmission Tariff (OATT) Attachment DD section 6.8(c) specifies that "[v]ariable costs that are directly attributable to the production of energy shall be excluded from a Market Seller's generation resource Avoidable Cost Rate."[3] Section 6.8 also lists eleven components of Avoidable Cost Rates. The PJM Operating Agreement Schedule 2 further specifies the expenses allowed to be included in the maintenance adder as a variable cost as part of energy offers, rather than in the Gross ACR: "Allowable expenses include repair, replacement, and major inspection, and overhaul expenses including variable long term service agreement expenses."[4] Schedule 2 also states that "preventative maintenance and routine maintenance on auxiliary equipment like buildings, HVAC, compressed air, closed cooling water, heat tracing/freeze protection, and water treatment" cannot be included in cost-based energy offers, and thus are included in the Gross ACR.[5] We understand that PJM interprets this to mean that all maintenance costs for systems directly related to electric production can be included in the operating costs maintenance adder for cost-based energy offers, and thus are excluded from the Avoidable Cost Rates.[6]

Given that guidance, we identify the types of maintenance costs included in the Gross ACR and those included in the variable cost maintenance adder, and estimate the costs of each accordingly, as reported below. Our approach aligns with the categories identified in Section 6.8 of the OATT

---

3 PJM, PJM Open Access Transmission Tariff*,* Attachment DD Market Power Mitigation, Section 6.8(c), accessed March 9, 2020, https://pjm.com/directory/merged-tariffs/oatt.pdf, p. 3429.

4 PJM, PJM Operating Agreement, Operating Agreement Schedule 2, Section 1.1(e), accessed March 9, 2020, https://www.pjm.com/directory/merged-tariffs/oa.pdf, p. 468.

5 PJM, PJM Operating Agreement, Operating Agreement Schedule 2, Section 1.1(e), accessed March 9, 2020, https://www.pjm.com/directory/merged-tariffs/oa.pdf, p. 468.

6 Based on discussions with PJM, the systems "directly attributable to electric production" include steam turbine, gas turbine, generator, boiler, Heat Recovery Steam Generators (HSRG), main steam, feed water, condensate, condenser, cooling towers, transformers, controls, and fuel systems.

as inputs to the ACRs, but based on PJM's guidance we do not include the Capacity Performance Quantifiable Risk (CPQR) premium nor the investment described as a part of Avoidable Project Investment Recovery Rate (APIR) for the purposes of setting the default offer floor prices.

B. Analytical Approach

There is significant variability in the costs of existing generation resources of a given type in PJM due to several factors, including: (1) the technologies used and how those changed over time; (2) the configuration of the units, including pollution controls; (3) the unit size; (4) the unit age; (5) how the resource has been operated; and (6) the level of maintenance performed in previous years on the plants. Considering this variability, we developed an approach to inform PJM of the range of costs for each type of existing generation resources so they can determine where on the range of costs best fits their approach to setting the default offer floor prices in the capacity market.

To do so, we reviewed the range of characteristics of resources that are installed in the PJM market and identified the primary cost drivers among those characteristics for each resource type.

We then identified for each resource type the characteristics of a "representative plant" that is widely representative of the costs of most of the fleet. In addition, we developed characteristics for a "representative low-cost plant" and a "representative high-cost plant" to inform the likely range of costs for each type of existing resources in PJM. These representative plants do not reflect the very highest and lowest cost plants in the market, but instead represent a population of plants near the high and low ends of the range.

Given the assumed characteristics, we then estimated the costs of the representative plants to inform the Gross ACRs and the variable O&M costs for use in PJM's net E&AS analysis. Our cost estimates are primarily based on our analysis of publicly-reported costs for plants with characteristics similar to the representative plants for each resource type, which we validated against confidential cost estimates within S&L's project database.

Our analysis incorporates input from the IMM and stakeholders. We shared preliminary results with the Internal Market Monitor on February 26, and with PJM stakeholders during a Markets Implementation Committee meeting on February 28 and received feedback from stakeholders on our approach and results. We reviewed the feedback provided during these meetings and incorporated it into our analysis where applicable.

C. Existing Generation Cost Estimates

1. Single-Unit Nuclear Plants

There are currently only three single-unit nuclear plants in the PJM market, as shown in Figure 1 below: the 970 MW Davis Besse plant and 1,310 MW Perry plant in Ohio and the 1,290 MW Hope Creek plant in New Jersey. Due to the small number of plants and the limited variation among them, we specified a single representative plant: a 35-year-old 1,200 MW Boiling Water Reactor BWR) unit in Ohio.

As noted above, we relied on costs reported in the 2019 NEI "Nuclear Costs in Context" report to develop cost estimates for both the single-unit and multi-unit nuclear plants.[7] The NEI report is the most comprehensive source of cost data that is publicly available for both merchant and regulated nuclear power plants. In this report, NEI provides the average costs incurred in 2018 across all nuclear units in the U.S. on a per-MWh basis, as well as the average costs for several sub-categories of nuclear plants: single-unit versus multi-unit plants; one-plant operators versus multiple-plant operators; plants competing in wholesale markets versus those under regulated cost-of-service; and boiling water reactor versus pressurized water reactor (PWR) plants. The costs are decomposed into three cost components: fuel costs, operating costs, and capital costs. For operating costs and capital costs, NEI further identifies several sub-categories of costs and shows the total 2018 costs for each in a series of bar charts.

We reviewed the NEI data to identify which costs are most applicable to the representative plants in PJM, and which costs components should be included in the Gross ACR as opposed to the variable costs based on PJM's market rules.

- **Capital Costs**: We estimated annual avoidable capital costs of $1.91/MWh as part of Gross ACR and $3.45/MWh as variable costs based on the following decomposition of NEI's capital costs for single-unit plants.[8] We started with the average capital costs for single-unit plants of $8.34/MWh.[9] We determined that the Enhancements and Capital Spares components of the capital costs (36% of total 2018 capital costs based on a detailed cost breakdown provided by NEI) should not be included in either Gross ACRs or variable costs since they reflect costs that extend the life of the plant beyond a year and would not be expected to be incurred on an annual basis. We assumed that the Sustaining costs (41% of total 2018 capital costs) reflect investment in systems directly related to electric production that are necessary to maintain plant performance, and thus by PJM's market rules should be included in variable costs. The remaining 23% of the total 2018 capital costs include upgrades to the plant that are expected to occur on an annual basis and are not directly related to electricity production so are included in the Gross ACR.

---

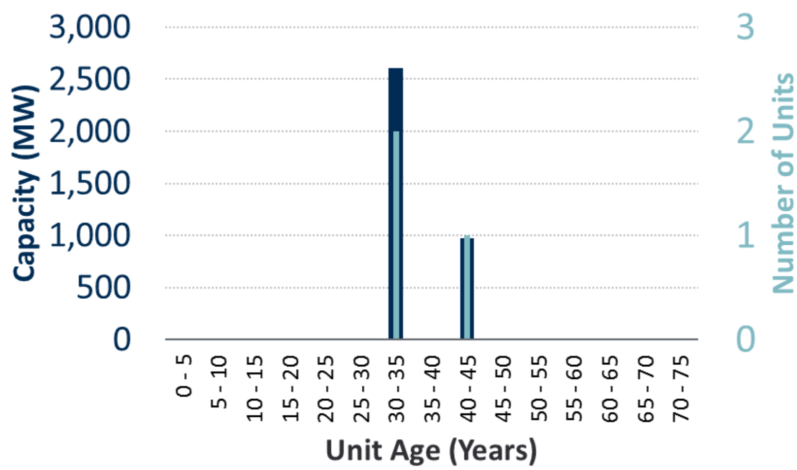
7 Nuclear Energy Institute, Nuclear Costs in Context, September 2019. ("NEI Report') Available at: https://www.nei.org/CorporateSite/media/filefolder/resources/reports-and-briefs/nuclear-costs-in-context-201909.pdf

8 NEI Report, p. 4.

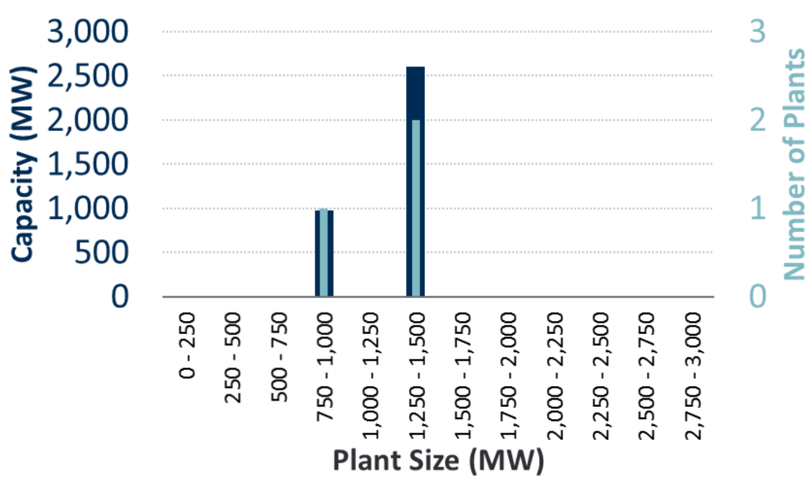
9 NEI Report, p. 2.

Figure 1: Single-Unit Nuclear Fleet Characterization

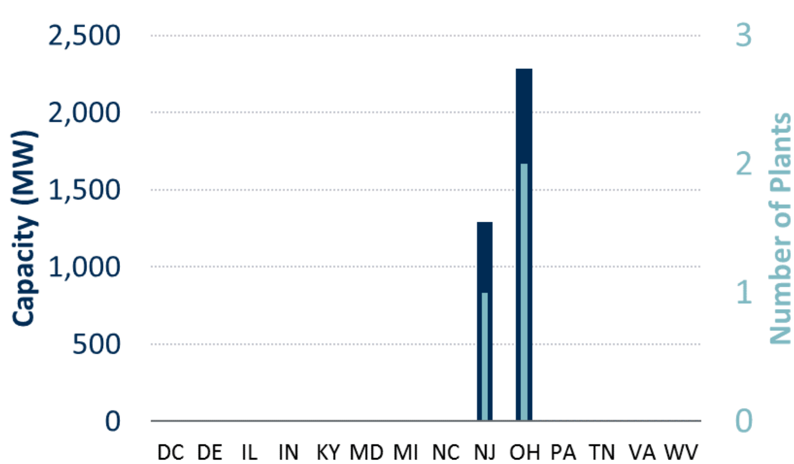
(a) Unit Age



(b) Plant Size



(c) Plant Location



Source: ABB, Energy Velocity Suite, accessed January 15, 2020.

- **Non-Fuel Operating Costs:** We estimated that the avoidable fixed operating costs is $28.80/MWh and the variable operating costs are $0.54/MWh for a single-unit BWR nuclear plant. We started with the operating costs for the average single-unit plant in the U.S. of $27.82/MWh.[10] We then increased the average costs by 5% ($1.52/MWh) to $29.34/MWh, based on the relative operating costs of BWR plants and PWR reported by NEI.[11] The components of operating costs primarily reflect labor costs that are not directly attractable to the production of electricity and so are included in the Gross ACR.[12] We interpret the Materials & Services costs (1.9% of total 2018 operating costs) to account for consumables required to operate the nuclear plants and thus include those costs as variable operating costs. The remaining 98% of the total 2018 operating costs are included in the Gross ACR. We applied these percentages to the total operating costs for a single-unit BWR plant ($29.34/MWh) to calculate the variable and fixed operating costs.

The data reported by NEI reflect the costs for operating nuclear plants in 2018. To estimate costs in 2022-2023 we reviewed the trends for each cost component. Operating costs (the largest cost component) are expected to remain relatively flat, while capital costs are declining slightly and may fall further on a nominal basis due to a reduction in regulatory capital expenditures.[13] The EIA projects that nuclear fuel costs are expected to increase by 0.2% above inflation through 2050.[14] Based on these trends, we concluded that the total costs of operating a nuclear plant are likely to remain constant in nominal terms from 2018 to 2022. For simplicity, we assume that each of the three components also stay constant in nominal terms even though there is evidence that fuel costs may slightly increase and capital costs may decrease.

Property taxes are not included in the NEI cost data. To estimate the property taxes paid by nuclear power plants to be included in the Gross ACR, we researched public records related to nuclear power plants in PJM and identified property taxes paid by six plants. Based on those records, we estimate that the average property taxes for nuclear plants in PJM are $0.77/MWh, or $17/MW-day.[15] These costs can be considered avoidable even if they continue when the plant retires since they would then no longer be paid by the plant owner, but by the plant's decommissioning fund.

---

10 NEI Report, p. 2.

11 The average operating costs for all BWR plants (both single-unit and multi-unit plants) is $21.10/MWh, which is higher than the average operating costs of a PWR of $18.97/MWh. Based on these values, we estimated that the costs of BWR plant are 5% higher cost than the average plant regardless of technology. NEI Report, p. 3.

12 NEI Report, p. 5.

13 NEI Report, pp. 4-5.

14 EIA, Annual Energy Outlook 2020, Table 3. Energy Prices by Sector and Source, January 29, 2020.

15 We identified publicly available information on property taxes for 8 nuclear plants in PJM. The property taxes had been paid between 2014 and 2020 and we assumed that they remain constant in nominal dollars. The reported property taxes or "taxes paid to the local government" ranged from $1/MW-day to $60/MW-day.

Finally, we assumed that nuclear plants in PJM will generate electricity with a capacity factor equal to the national average of 92.3% in 2018, which we use to convert the total costs reported on a per-MWh basis to per-MW-day for use as Gross ACR values.[16]

As shown in Table 4 below, we estimate that the Gross ACR for a single-unit nuclear plant in PJM is $697/MW-day (in 2022 dollars). We estimate that the variable costs are $4.00/MWh (in 2022 dollars), including $0.54/MWh for operating costs and $3.45/MWh for the maintenance adder.

Table 4: Estimated 2022 Costs for Existing Single-Unit Nuclear Plants in PJM
(in nominal dollars)

	Units	Single-Unit Nuclear Plant
Capacity	*Nameplate MW*	1,200
Gross ACR		
Fixed Operating Costs	*$/MWh*	$28.80
Fixed Capital Costs	*$/MWh*	$1.91
Property Taxes	*$/MWh*	$0.77
Total	*$/MWh*	$31.47
Gross ACR	***$/MW-day***	**$697**
Variable Costs		
Variable Operating Costs	*$/MWh*	$0.54
Maintenance Adder	*$/MWh*	$3.45
Total Variable Costs	***$/MWh***	**$4.00**

Note: We estimated the maintenance adder assuming a 92.3% capacity factor. If a different capacity factor will be assumed by PJM, the maintenance adder should be adjusted based on the ratio of 92.3% to the assumed capacity factor.

We recommend that PJM assume the fuel costs for single-unit nuclear plants are $5.05/MWh (in 2022 dollars) in its analysis of the net E&AS revenues, based on the average fuel costs for nuclear plants in wholesale markets reported by NEI.[17]

2. Multi-Unit Nuclear Plants

Most nuclear plants in the PJM market have multiple units installed at the same site. In total, there are currently 14 multi-unit nuclear plants operating in the PJM market. The age, size, and locations of these plants as shown in Figure 2 below. The capacity of multi-unit nuclear plants in PJM are

16 NEI, U.S. Nuclear Industry Capacity Factors, https://www.nei.org/resources/statistics/us-nuclear-industry-capacity-factors, March 2019.

17 NEI Report, p. 3.

mostly in the range of 2,000 – 2,750 MW, and in most cases these plants are 30 – 50 years old. There are six states in PJM with nuclear plants, with the most located in Pennsylvania and Illinois.

Based on our experience estimating costs for nuclear plants, the most significant cost drivers for nuclear plants are the technology (BWR versus PWR), locational labor costs and property taxes, and investments necessary to meet regulatory requirements for continuing to operate.

For the multi-unit nuclear plants, we set the characteristics of a representative plant to be a 40-year-old 2,400 MW (two 1,200 MW units) BWR plant in Pennsylvania with minimal regulatory costs. For the representative low-cost plant, we modified the technology to a PWR plant due to its lower cost of operations. For the representative high-cost plant, we assume a plant similar to the representative plant will incur additional ongoing regulatory costs to maintain operations.

We include the same scope of costs for the Gross ACR and variable costs as explained above for the single-unit nuclear plants, and the following cost for each category included in the NEI report:

- **Capital Costs**: We estimate annual avoidable capital costs of $1.28/MWh as part of Gross ACR and $2.33/MWh as variable costs for the representative plant. Similar to the approach for the single-unit plant, we started with the average capital costs for multi-unit nuclear plants of $5.62/MWh.[18] We apply the same assumptions for the composition of the capital costs as described above for single-unit plants, with 23% of the capital costs included in the Gross ACR, 41% included in variable costs, and 36% excluded from Gross ACR and variable costs since they reflect costs that extend the life of the plant beyond a year. For the representative high-cost plant, we increase the total capital costs to the average costs for regulated nuclear plants of $8.02/MWh to reflect higher ongoing regulatory costs.[19]
- **Operating Costs:** We estimate that the avoidable fixed operating costs for a multi-unit nuclear plant are $18.05/MWh and the variable operating costs are $0.34/MWh. This is based on the operating costs for the average multi-unit plant in the U.S. of $17.44/MWh, adjusted upward by $0.95/MWh to $18.39/MWh to account for the higher costs of a BWR plant.[20] We assume that 98% of the costs are included in the Gross ACR and 2% in variable costs. For the representative low-cost plant, we reduce the operating costs for the multi-unit nuclear plant by $1.86/MWh to reflect the lower costs of operating a PWR plant based on the lower operating costs of PWR plants reported by NEI for each type of reactor design.[21]

18 NEI Report, p. 2.

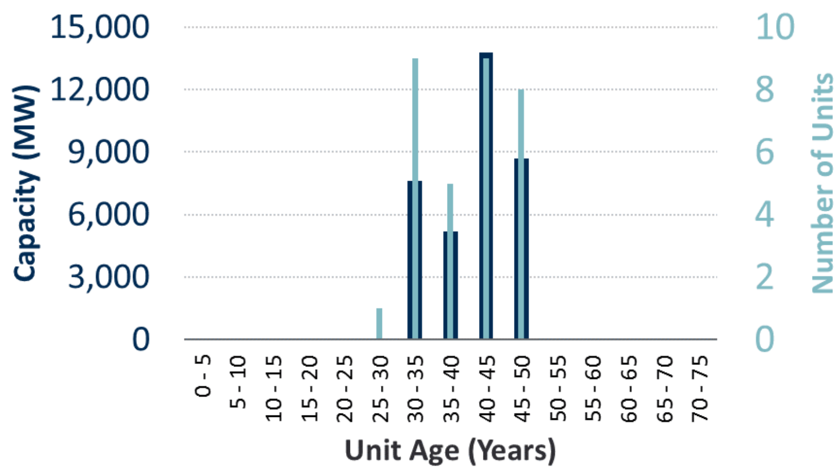
19 NEI Report, p. 3.

20 NEI Report, p. 2.

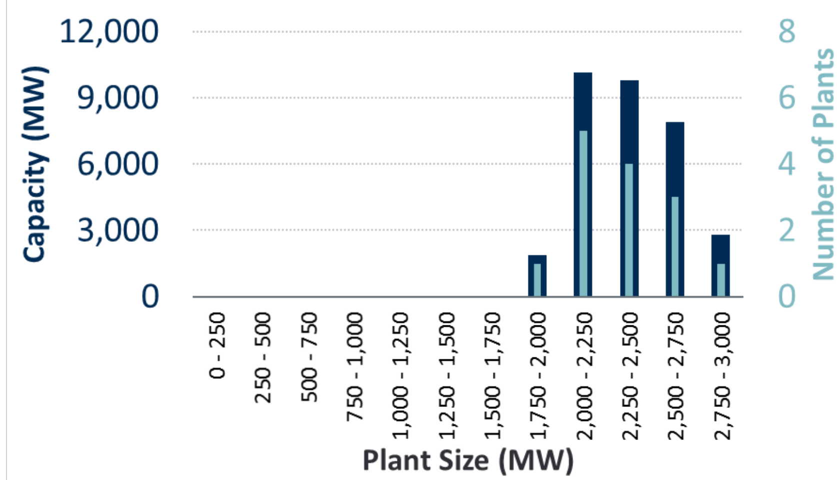
21 NEI Report, p. 3.

Figure 2: Multi-Unit Nuclear Fleet Characterization

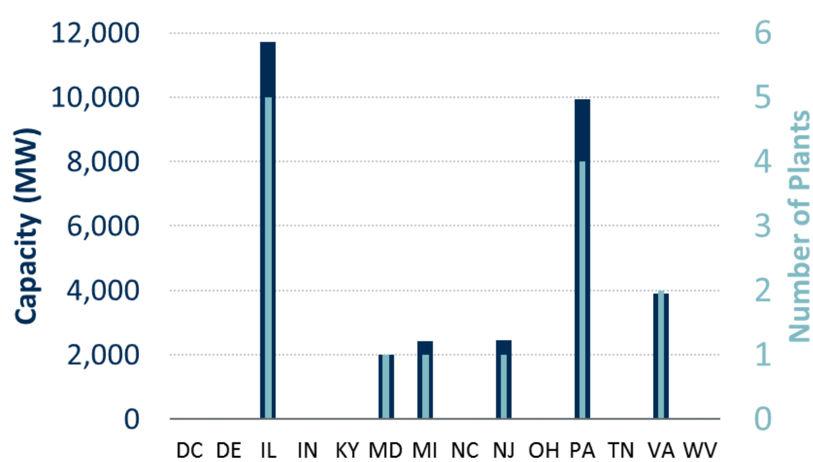
(a) Unit Age



(b) Plant Size



(c) Plant Location



Source: ABB, Energy Velocity Suite, accessed January 15, 2020.

As shown in Table 5 below, we estimate the Gross ACR for a representative multi-unit nuclear plant in PJM to be $445/MW-day, with a range of $405/MW-day to $457/MW-day (in 2022 dollars). The estimated variable costs for a multi-unit nuclear plant is $2.67/MWh with a range of $2.63/MWh to $3.66/MWh (in 2022 dollars).

Table 5: Estimated 2022 Costs for Existing Multi-Unit Nuclear Plants
(in nominal dollars)

		Multi-Unit Nuclear Plant		
	Units	**Representative Low-Cost Plant**	**Representative Plant**	**Representative High-Cost Plant**
Capacity	*Nameplate MW*	2,400	2,400	2,400
Gross ACR				
Fixed Operating Costs	*$/MWh*	$16.23	$18.05	$18.05
Fixed Capital Costs	*$/MWh*	$1.28	$1.28	$1.83
Property Taxes	*$/MWh*	$0.77	$0.77	$0.77
Total	*$/MWh*	$18.28	$20.10	$20.65
Gross ACR	***$/MW-day***	**$405**	**$445**	**$457**
Variable Costs				
Variable Operating Costs	*$/MWh*	$0.31	$0.34	$0.34
Maintenance Adder	*$/MWh*	$2.33	$2.33	$3.32
Total Variable Costs	***$/MWh***	**$2.63**	**$2.67**	**$3.66**

Note: We estimated the maintenance adder assuming a 92.3% capacity factor. If a different capacity factor will be assumed by PJM, the maintenance adder should be adjusted based on the ratio of 92.3% to the assumed capacity factor.

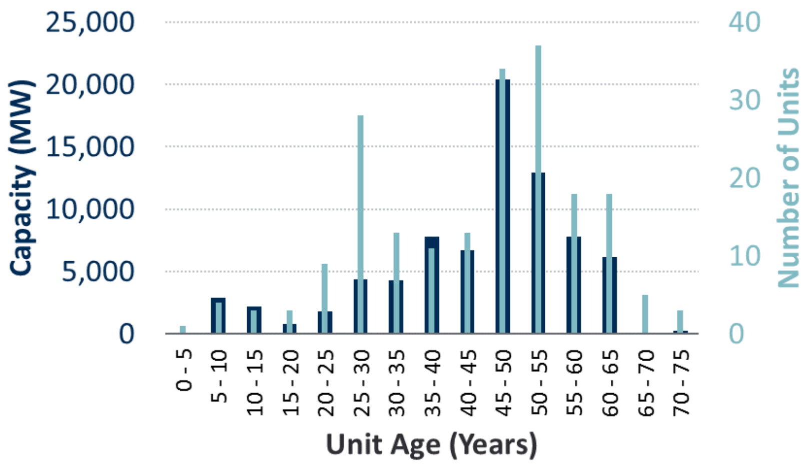
Similar to single-unit plants, we recommend that PJM assume the fuel costs for multi-unit nuclear plants are $5.05/MWh (in 2022 dollars) in its analysis of the net E&AS revenues.

3. Coal Plants

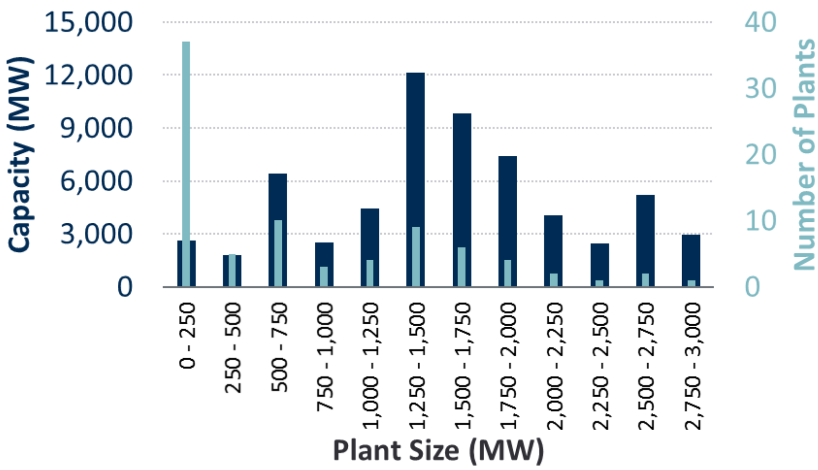
The fleet of existing coal plants in PJM comprises a much wider range of sizes, ages, and locations than the nuclear plants discussed above. We identified over 200 existing coal units currently in the PJM market at about 80 different plant sites. Figure 3 below shows the age, size, and locations of these plants. Plant capacities range from less than 100 MW to nearly 3,000 MW with the average plant size of 750 MW across all plants and 1,100 MW for plants that are at least 100 MW. Plant ages also vary. Several plants were built in the last 10 years, and the oldest was constructed in 1942. Over half of the coal capacity is 35-55 years old.

Figure 3: Coal Fleet Characterization

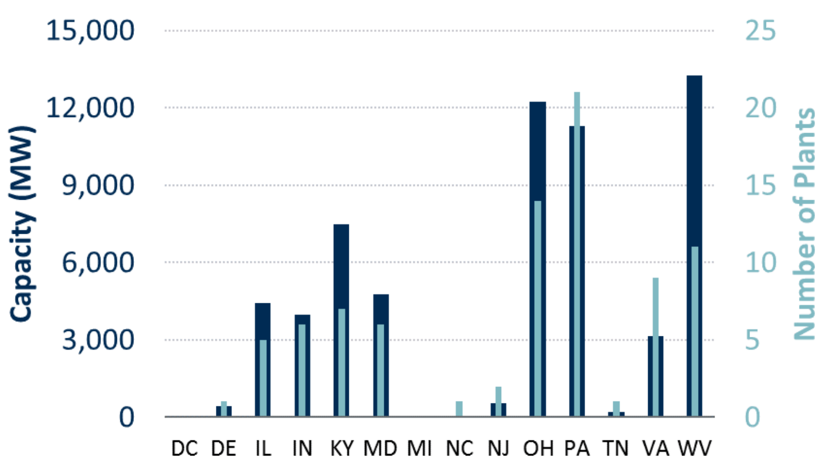
(a) Unit Age



(b) Plant Size



(c) Plant Location



Source: ABB, Energy Velocity Suite, accessed January 15, 2020.

Our experience shows us that the primary drivers of cost variability for coal plants is the total capacity of the plant, the location, and the types of post-combustion controls installed at the plant, especially a flue-gas desulfurization (FGD) unit. The majority of coal plants have a dry lime or wet limestone FGD unit installed.

For these reasons, we set the characteristics of the representative coal plant in PJM to be a 45-year-old 1,200 MW plant (two 600 MW units) in West Virginia that burns Appalachian coal and has a wet limestone flue-gas desulfurization (FGD) unit. For the representative low-cost plant and representative high-cost plant, we varied the capacity of the plant. We assume that the representative high-cost plant is a 300 MW plant (two 150 MW units) and the representative low-cost plant is an 1,800 MW plant (two 900 MW units). Because most coal plants in PJM have some type of sulfur dioxide control technology and the vast majority of them are wet FGD units, we chose not to vary that assumption. While there is a significant age range across the plants, we assume the high and low plants are also 45 years old because we do not expect plants in the range of 35 – 55 years old to have significantly different costs solely due to their age.

We estimated the total annual costs for operating the representative coal plants using data recently released by the EIA and FERC.[22,23] We reviewed the O&M costs, ongoing capital spending, and cost relationships across a broad range of plant configurations and developed our cost estimates by accounting for differences in unit sizes, number of units at the site, and ages in the reported costs relative to the representative plants. Our adjustments to the reported costs included estimation of staffing requirements, consumption of FGD reagent and other items, and disposal of ash and FGD sludge. The costs of staffing and other fixed expenses account for the economies of scale associated with larger unit sizes and multiple units at a site. We then validated the results against proprietary data for similar operating coal plants. Based on our review of publicly available projections of fixed operating costs (such as the NREL Annual Technology Baseline) and the recent cost trends we have observed in the industry, we escalated the costs from 2020 to 2022 by 2.0% per year.[24]

Similar to the nuclear plants, we identified the costs that are includable in the Gross ACR and those included in the variable cost component of cost-based energy offers. A 45-year-old 1,200 MW coal plant would be expected to invest about $30 million per year into the systems directly attributable to electricity production, which based on PJM's market rules would have to be accounted for in the variable cost "maintenance adder." Assuming a 60% capacity factor, the maintenance adder increases variable costs by about $5/MWh.[25] Meanwhile, the Gross ACR estimate includes fixed operating costs that are not directly attributable to electricity production,

---

22 EIA, Generating Unit Annual Capital and Life Extension Costs Analysis Final Report on Modeling Aging-Related Capital and O&M Costs, prepared by Sargent & Lundy, May 2018.

23 FERC, FERC Form No. 1, Plant Cost Data, 2014 through 2018.

24 This rate of cost escalation is consistent with our observations of recent trends in the industry.

25 Our estimate of a 60% capacity factor is based on our review of EPA data for coal plants similar to the representative plant. U. S. Environmental Protection Agency (EPA), National Electric Energy Data System (NEEDS), v6, 2019.

such as labor, administrative costs, preventative maintenance to auxiliary equipment (buildings, HVAC, water treatment), insurance, and support services.

We did not include property taxes for the representative coal plants because they are not likely to be significant for a 45-year-old coal plant. The property taxes actually paid would depend on the lesser of the remaining rate base or the fair market value, as negotiated with the local jurisdiction. In both cases, the property taxes are likely to be quite small based on the age of the plants and recent market conditions for coal plants in PJM.

Table 6 below shows that the estimated Gross ACR for the representative coal plant is $80/MW-day with a range of $74/MW-day to $166/MW-day (in 2022 dollars). The variable costs are similar across plant ranging from $9.17/MWh to $9.56/MWh (in 2022 dollars).

Table 6: Estimated 2022 Costs for Existing Coal Plants in PJM
(in nominal dollars)

		Coal Plant		
	Units	**Representative Low-Cost Plant**	**Representative Plant**	**Representative High-Cost Plant**
Capacity	*Nameplate MW*	1,800	1,200	300
Gross ACR				
Labor	*$ million*	$23.6	$20.4	$11.2
Fixed Expenses	*$ million*	$24.8	$14.7	$7.0
Total	*$ million*	$48.4	$35.1	$18.2
Gross ACR	***$/MW-day***	**$74**	**$80**	**$166**
Variable Costs				
Operating Costs	*$/MWh*	$4.37	$4.77	$4.40
Maintenance Adder	*$/MWh*	$4.80	$4.80	$4.80
Variable O&M	***$/MWh***	**$9.17**	**$9.56**	**$9.20**

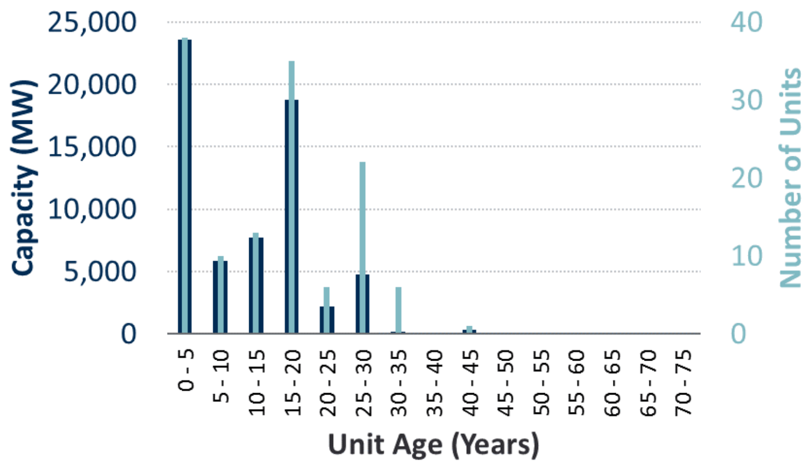
Note: Fixed Expenses include preventive maintenance on auxiliary equipment (buildings, HVAC, water treatment, freeze protection, etc.), information technology, miscellaneous supplies, support services, administrative and general, and insurance. We estimated the maintenance adder assuming a 60% capacity factor. If a different capacity factor will be assumed by PJM, the maintenance adder should be adjusted based on the ratio of 60% to the assumed capacity factor.

4. Natural Gas-Fired Combined-Cycle Plants

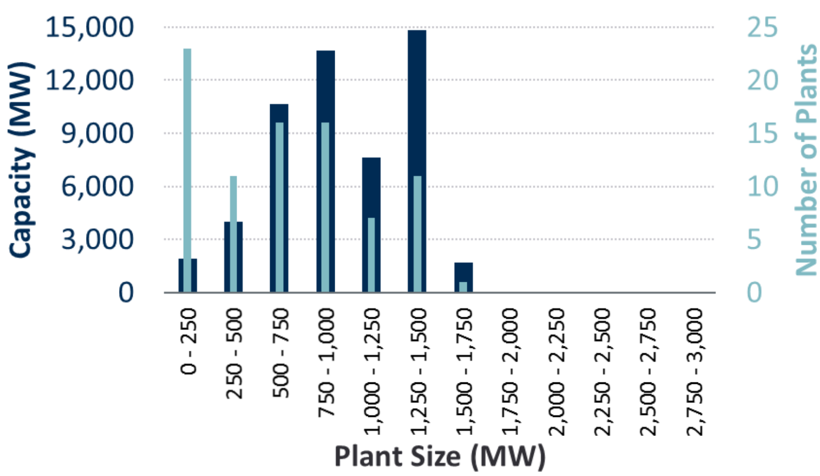
Most natural gas-fired combined-cycle (CC) plants and combustion turbine (CT) plants have been built more recently than coal plants with nearly all natural gas-fired resources built over the past 20 years and over 23,000 MW of CCs installed in the past 5 years alone. Figure 4 below shows the age, size, and locations of the existing gas CC plants. Most existing CCs that were built in the early 2000s are in the 500 MW to 1,000 MW range, while several recent projects exceed 1,000 MW. Most of the gas CCs have been built in regions with access to low-cost gas via pipeline or within production basins, including in Pennsylvania, Ohio, Virginia, and New Jersey. Most are equipped with Selective Catalytic Reduction (SCR) to reduce emissions of nitrogen oxides (NOx).

Figure 4: Natural Gas Combined-Cycle Fleet Characterization

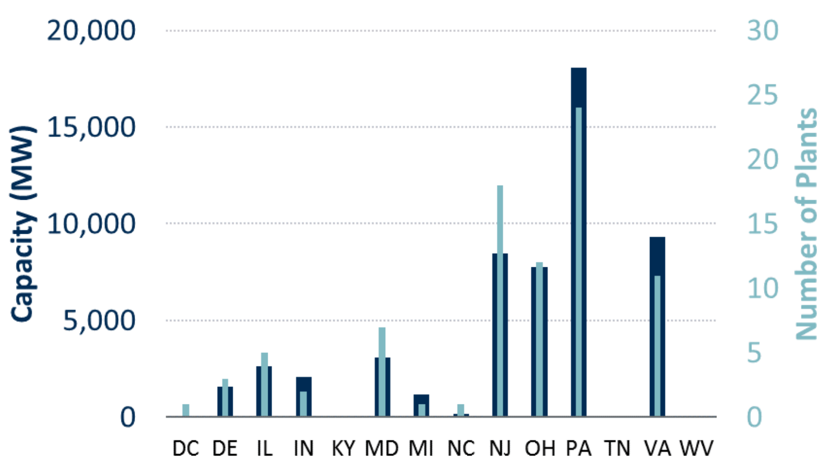
(a) Unit Age



(b) Plant Size



(c) Plant Location



Source: ABB, Energy Velocity Suite, accessed January 15, 2020.

The primary drivers of differences in costs for CCs tend to be the capacity of the units, the plant configuration, and the location, which affects labor costs and property taxes.

Based on the range of existing gas CCs, we specified the widely-representative plant to be a 15-year-old 750 MW plant with two F-class frame-type gas turbines and one steam turbine (2x1) in Pennsylvania. For the representative high-cost plant, we reduced the capacity to 360 MW to represent a 1x1 plant with a single F-class turbine, while we assumed the representative low-cost plant includes the larger H-class turbines in a 2x1 configuration for a total capacity of 1,100 MW (similar to the CC specifications developed for the PJM 2018 CONE Study).[26]

To estimate the costs of the representative plants, we relied primarily on cost estimates for gas CCs developed for the PJM 2018 CONE Study. Similar to how the costs are specified in the CONE Study, we included the hours-based major maintenance costs specified in Long-Term Service Agreements (LTSAs) under variable O&M costs as well as the operating costs associated with chemicals and consumables. The fixed costs for the gas CCs included labor, supplies, property taxes, and insurance costs.

We used the cost information from the CONE study to estimate components of the fixed O&M, variable O&M, and major maintenance for the representative low-cost plant (H-class 2 x 1). Other public sources and S&L's project database containing a broad range of CC configurations were used for estimating the cost components for the 750 MW and 360 MW F-class representative plants.[27,28] We adjusted the cost data in the public sources to account for differences in turbine sizes, configurations, locations, and ages relative to the representative plants and validated the results against proprietary data for similar plants in operation. These adjustments accounted for staffing requirements and the economies of scale associated with larger turbine sizes and multiple turbines at a site. The costs of major maintenance and consumables were derived using a 60% capacity factor, representative of CCs in PJM.[29] Property taxes were estimated using the rates in the CONE study for WMACC (Pennsylvania). We escalated the cost estimates from 2020 to 2022 by 2.0% per year based on our review of publicly available projections of fixed operating costs (such as the NREL Annual Technology Baseline) and the recent cost trends we have observed in the industry.

Table 7 below shows that the Gross ACR for the representative plant is $56/MW-day, which is slightly higher than the Gross ACR of the representative low-cost plant ($55/MW-day). Our cost estimates are significantly higher for the smaller 360 MW representative high-cost plant

---

26 Newell, et al., PJM Cost of New Entry Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date, April 2018. ("PJM 2018 CONE Study")

27 U.S. Energy Information Administration, Cost and Performance Estimates for New Utility-Scale Electric Power Generating Technologies, prepared by Sargent & Lundy, December 2019.

28 FERC, FERC Form 1, Plant Cost Data, 2014 through 2018.

29 Monitoring Analytics, 2019 State of the Market Report for PJM, Section 5 – Capacity Market, Table 5-28, March 12, 2020, p. 292. Available at: http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2019/2019-som-pjm-sec5.pdf

($79/MW-day) due to the reduced economies of scale. The variable O&M costs for these resources are similar in the range of $2.24/MWh to $2.57/MWh.

Table 7: Estimated 2022 Costs for Existing Natural Gas-Fired Combined-Cycle Plants in PJM
(in nominal dollars)

		Natural Gas Combined-Cycle Plant		
	Units	**Representative Low-Cost Plant**	**Representative Plant**	**Representative High-Cost Plant**
Capacity	*Nameplate MW*	1,100	750	360
Gross ACR				
Labor	*$ million*	$6.4	$4.5	$3.5
Fixed Expenses	*$ million*	$7.8	$5.5	$4.3
Property Taxes	*$ million*	$2.0	$1.3	$0.6
Insurance	*$ million*	$5.9	$4.0	$1.9
Total	*$ million*	$21.9	$15.3	$10.3
Gross ACR	***$/MW-day***	**$55**	**$56**	**$79**
Variable Costs				
Operating Costs	*$/MWh*	$0.71	$0.49	$0.91
Maintenance Adder	*$/MWh*	$1.53	$2.08	$1.61
Variable O&M	***$/MWh***	**$2.24**	**$2.57**	**$2.53**

Note: Fixed Expenses include preventive maintenance on auxiliary equipment (buildings, HVAC, water treatment, freeze protection, etc.), information technology, miscellaneous supplies, support services, and administrative and general. We estimated the maintenance adder assuming a 60% capacity factor. If a different capacity factor will be assumed by PJM, the maintenance adder should be adjusted based on the ratio of 60% to the assumed capacity factor.

5. Natural Gas-Fired Combustion Turbines

Natural gas-fired CT plants tend to have a wider range of sizes due to differences in the turbine technology and the number of turbines installed at each plant. As shown in Figure 5 below, the majority of CT plants are less than 100 MW with the most overall capacity in the 500 – 750 MW range, and most were built 15 to 20 years ago. The states with the most CTs include New Jersey, Illinois, Pennsylvania, and Ohio. Unlike gas CCs, most CTs are not built with an SCR unit.

The range of costs of the CTs are primarily driven by the capacity of the resources (based on the turbine type and number of turbines) and their location.

We specified the representative plant to be a 15 year old 320 MW CT plant with two F-class turbines (160 MW each) located in Illinois. We selected a larger 640 MW CT plant with eight E-class turbines (80 MW each) for the representative-low plant and a 100 MW CT with two LM6000 aeroderivative turbines (50 MW each) for the representative-high plant.

To estimate costs, we reviewed cost estimates reported by the PJM 2018 CONE Study, the EIA cost estimates, and S&L's project database.[30,31] We then developed the cost estimates for existing CTs similar to the representative plants by adjusting the publicly reported costs for differences in turbine sizes, configurations, locations, and ages. We validated the results of our cost estimate against proprietary data for similar plants in operation. The adjustments account for staffing requirements and the economies of scale associated with larger turbine sizes and multiple turbines at a site. Property taxes were estimated using the rates in the CONE study for RTO (Illinois). We escalated the cost estimates from 2020 to 2022 by 2.0% per year based on our review of publicly available projections of fixed operating costs (such as the NREL Annual Technology Baseline) and the recent cost trends we have observed in the industry.

The E-class and F-class turbines operating as peaking units would be expected to trigger major maintenance events based on the number of starts. For this reason, we estimated the variable cost maintenance adder assuming a 10% capacity factor and 12 hours of operation per start.[32] The LM6000 turbines would likely trigger major maintenance based on hours of operation such that their maintenance adder is independent of the number of starts per year.

---

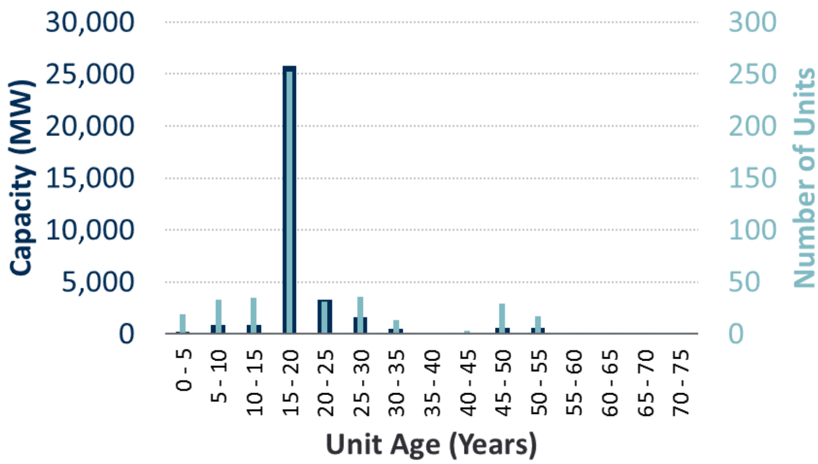
30 Newell, et al., PJM Cost of New Entry Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date, April 2018. Available at: https://brattlefiles.blob.core.windows.net/files/13896_20180420-pjm-2018-cost-of-new-entry-study.pdf

31 U.S. Energy Information Administration, Cost and Performance Estimates for New Utility-Scale Electric Power Generating Technologies, prepared by Sargent & Lundy, December 2019.

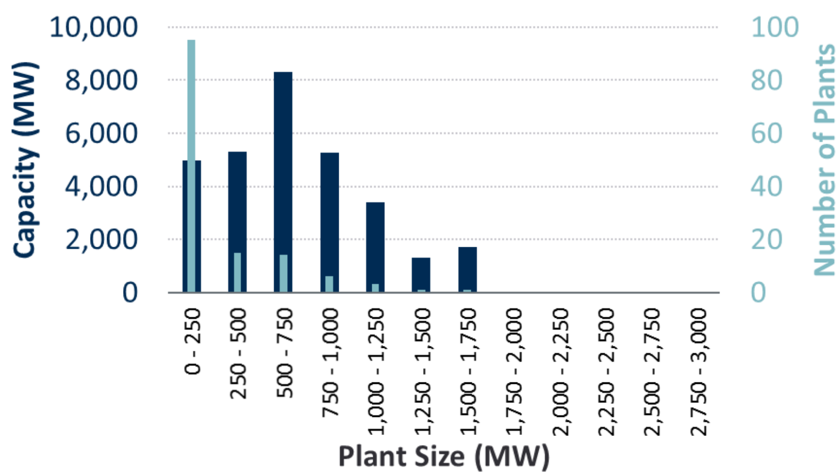
32 We assume 12 hours per start primarily based on the average operation hours per start estimated in the PJM 2018 VRR Curve Study (11 hours per start). Newell, et al., Fourth Review of PJM's Variable Resource Requirement Curve, April 19, 2018, p. 11. Available at: http://files.brattle.com/files/13894_20180420-pjm-2018-variable-resource-requirement-curve-study.pdf

Figure 5: Natural Gas Combustion Turbine Fleet Characterization

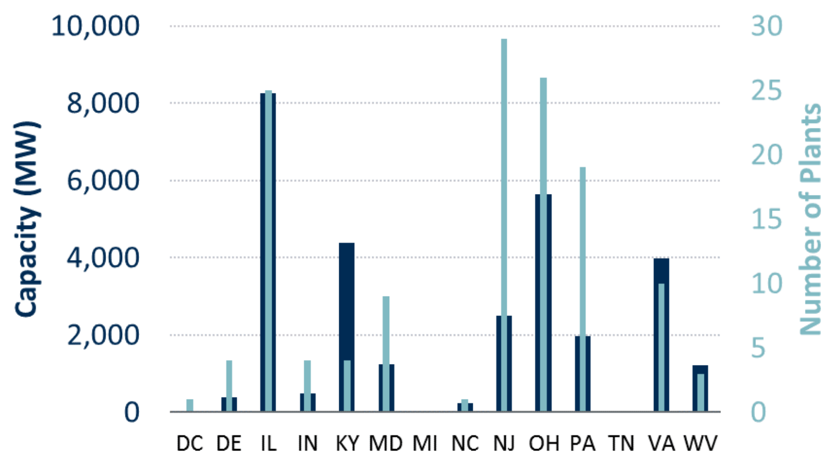
(a) Unit Age



(b) Plant Size



(c) Plant Location



Source: ABB, Energy Velocity Suite, accessed January 15, 2020.

Table 8 below shows the resulting Gross ACR and variable costs for the CT plants. The Gross ACR for the representative plant is $50/MW-day, with a range of $42/MW-day to $65/MW-day (in 2022 dollars). The variable costs for the CTs range from $4.98/MWh to $7.54/MWh (in 2022 dollars).

Table 8: Estimated 2022 Costs for Existing Natural Gas-Fired Combustion Turbine Plants in PJM
(in nominal dollars)

		Natural Gas Combustion Turbine Plant		
	Units	**Representative Low-Cost Plant**	**Representative Plant**	**Representative High-Cost Plant**
Capacity	*Nameplate MW*	640	320	100
Gross ACR				
Labor	*$ million*	$1.6	$1.3	$0.9
Fixed Expenses	*$ million*	$1.3	$1.1	$0.8
Property Taxes	*$ million*	$3.8	$1.9	$0.1
Insurance	*$ million*	$3.0	$1.5	$0.6
Total	*$ million*	$9.8	$5.8	$2.4
Gross ACR	***$/MW-day***	**$42**	**$50**	**$65**
Variable Costs				
Operating Costs	*$/MWh*	$0.39	$0.39	$0.89
Maintenance Adder	*$/MWh*	$7.16	$7.16	$4.09
Variable O&M	***$/MWh***	**$7.54**	**$7.54**	**$4.98**

Note: Fixed Expenses in the Gross ACR includes preventive maintenance on auxiliary equipment (buildings, HVAC, water treatment, freeze protection, etc.), information technology, miscellaneous supplies, support services, and administrative and general. We estimated the maintenance adder assuming a 10% capacity factor. If a different capacity factor will be assumed by PJM, the maintenance adder should be adjusted based on the ratio of 10% to the assumed capacity factor.

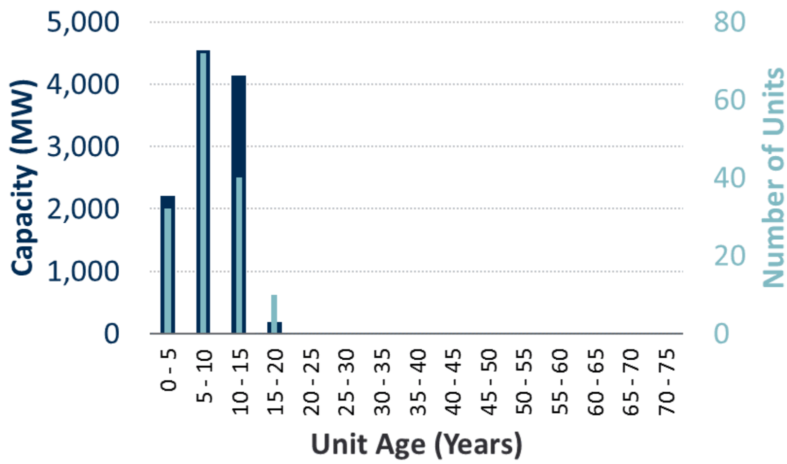
6. Onshore Wind Plants

Over the past 15 years, nearly 14,000 MW of onshore wind plants have been built in PJM. As shown in Figure 6 below, the majority of these plants are relatively small (less than 25 MW), but 15 have exceeded 200 MW. Most of the smaller plants are located in Pennsylvania and Ohio, while the larger ones are in Illinois and Indiana. The largest drivers of ongoing costs for wind plants tend to be their size and location.

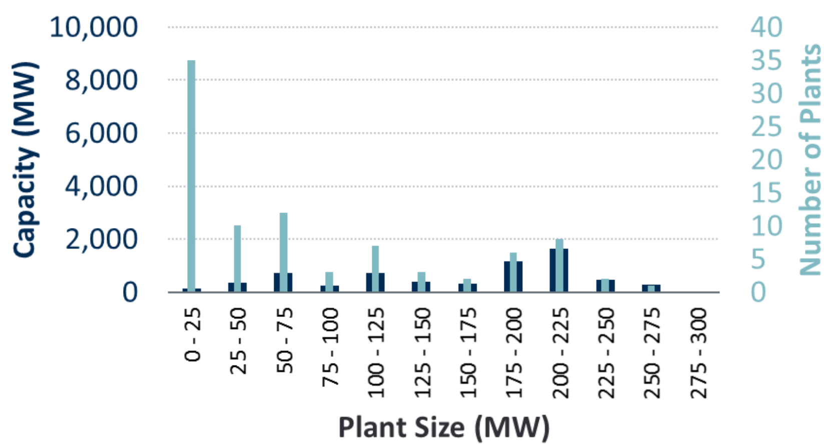
Based on the range of existing wind plants in PJM, we specified the representative plant to be a 60 MW wind farm (forty 1.5 MW turbines) in Pennsylvania that was built 10 years ago. For the higher end of the cost range, we reduced the capacity in half to 30 MW, and for the lower end of the range increased the capacity to 300 MW to represent some of the larger wind farms built in Illinois and Indiana.

Figure 6: Onshore Wind Fleet Characterization

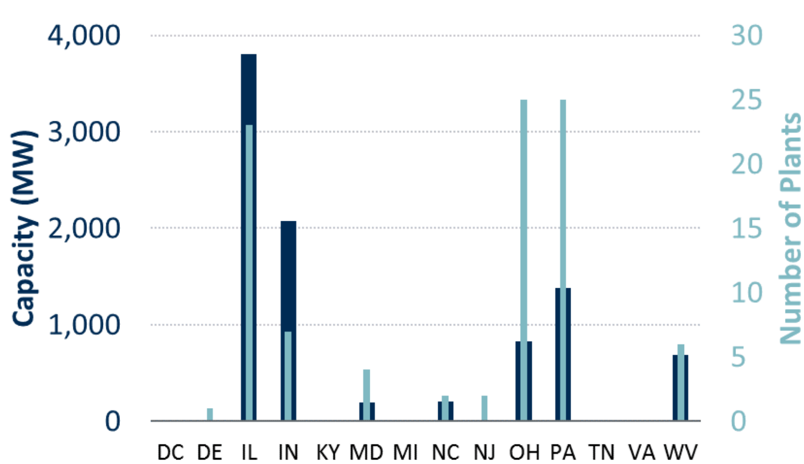
(a) Unit Age



(b) Plant Size



(c) Plant Location



Source: ABB, Energy Velocity Suite, accessed January 15, 2020.

We estimated fixed and variable O&M and capital costs for the representative wind plants by first reviewing recent public sources and S&L's project database.[33,34] We then developed the cost estimates for the representative plants accounting for differences in turbine sizes, number of turbines at the site, and ages relative to the representative plants, and validated the results against proprietary data for similar plants in operation. The representative plants were assumed to be exempt from property taxes or have a negotiated payment in lieu of taxes (PILOT) agreement with the local jurisdiction for a significantly reduced rate. We escalated the cost estimates from 2020 to 2022 by 2.0% per year based on our review of publicly available projections of fixed operating costs (such as the NREL Annual Technology Baseline) and the recent cost trends we have observed in the industry.

Table 9 below shows the resulting Gross ACR for the representative plant of $83/MW-day, with a range of $76/MW-day to $128/MW-day (in 2022 dollars). We assumed that all of the costs necessary to operate a wind plant (and a solar PV plant) are fixed and belong in the Gross ACR, with no variable costs. The costs do not vary with production, say in a windier year or a year with more curtailment and cannot be considered "directly attributable to the production of electricity" per PJM's standard for variable costs.

Table 9: Estimated 2022 Costs for Existing Onshore Wind Plants in PJM
(in nominal dollars)

		Onshore Wind Plant		
	Units	**Representative Low-Cost Plant**	**Representative Plant**	**Representative High-Cost Plant**
Capacity	*Nameplate MW*	300	60	30
Gross ACR				
Labor	*$ million*	$2.5	$0.5	$0.4
Fixed Expenses	*$ million*	$5.9	$1.3	$1.0
Total	***$ million***	**$8.4**	**$1.8**	**$1.4**
Gross ACR	***$/MW-day***	**$76**	**$83**	**$128**
Variable Costs				
Operating Costs	*$/MWh*	$0.00	$0.00	$0.00
Maintenance Adder	*$/MWh*	$0.00	$0.00	$0.00
Variable O&M	***$/MWh***	**$0.00**	**$0.00**	**$0.00**

---

33 U.S. Energy Information Administration, Cost and Performance Estimates for New Utility-Scale Electric Power Generating Technologies, prepared by Sargent & Lundy, December 2019.

34 National Renewable Energy Laboratory, 2019 Annual Technology Baseline, 2019.

7. Large-Scale Solar Photovoltaic Plants

Large-scale solar photovoltaic (PV) plants tend to be fairly small in PJM, with most plants under 10 MW and a few in the 50 – 100 MW range, as shown in Figure 7 below. All of the solar PV plants have been built in the past 15 years, with the most capacity added in New Jersey and North Carolina. Similar to wind plants, the capacity and location tend to have the most significant impacts on the costs of solar PV plants.

Based on our survey of the existing solar PV plants, we set the representative plant as a 10 MW single-axis tracking solar PV plant in New Jersey built 5 years ago. For the representative high-cost plant, we reduced the capacity to 2 MW and for the representative low-cost plant increased the capacity to 80 MW and located it in North Carolina.

We estimated fixed and variable O&M and capital costs for the representative solar PV plants by reviewing recent public sources and S&L's project database.[35,36] We then developed the cost estimates for the representative solar PV plants accounting for differences in the solar panel type, tracking type, plant size, and ages relative to the representative plants and validated the results against proprietary data for similar plants in operation. The representative plants were assumed to be exempt from property taxes or have a negotiated payment in lieu of taxes (PILOT) agreement with the local jurisdiction for a significantly reduced rate. We escalated the cost estimates from 2020 to 2022 by 2.0% per year based on our review of publicly available projections of fixed operating costs (such as the NREL Annual Technology Baseline) and the recent cost trends we have observed in the industry.

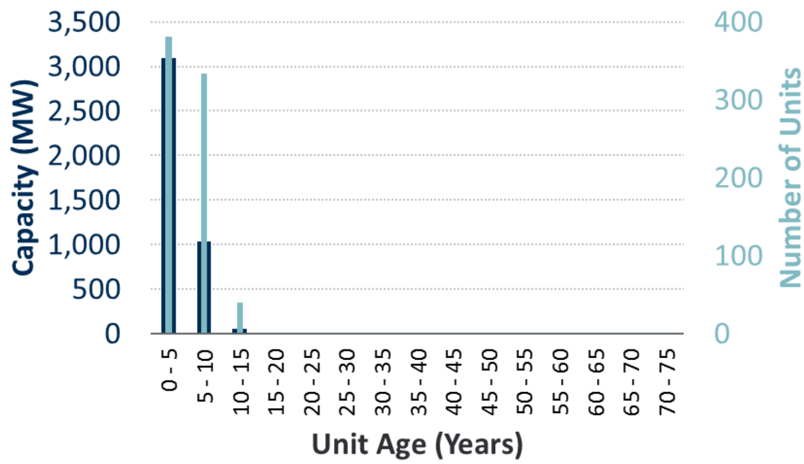
---

[35] National Renewable Energy Laboratory, 2019 Annual Technology Baseline, 2019.

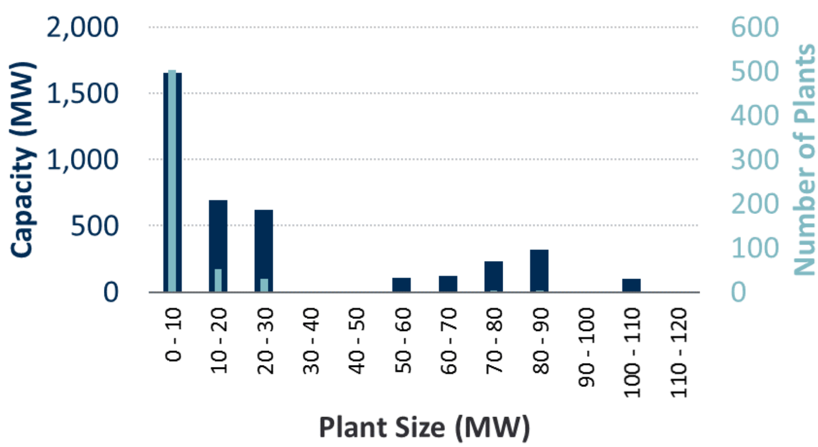
[36] Lawrence Berkeley National Laboratory, Utility-Scale Solar: Empirical Trends in Project Technology, Cost, Performance, and PPA Pricing in the United States – 2019 Edition, December 2019. Available at: https://emp.lbl.gov/sites/default/files/lbnl_utility_scale_solar_2019_edition_final.pdf

Figure 7: Large-Scale Solar Photovoltaic Fleet Characterization

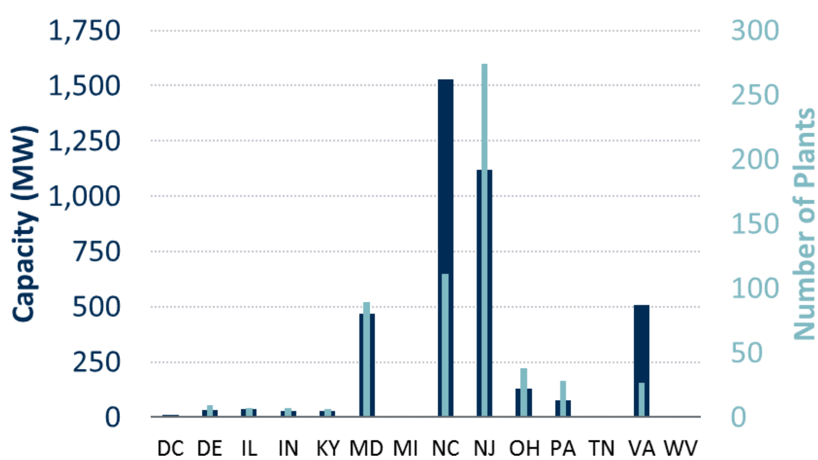
(a) Unit Age



(a) Plant Size



(a) Plant Location



Source: ABB, Energy Velocity Suite, accessed January 15, 2020.

Table 10 below shows that we estimated a Gross ACR for the representative solar PV plant of \$40/MW-day with a range of \$29/MW-day for the larger plant to \$60/MW-day for the smaller plant (in 2022 dollars). We assumed that all of the costs necessary to operate a solar PV plant are fixed costs that are not directly attributable to the production of electricity, and thus did not include any variable costs for the solar PV plants.

Table 10: Estimated 2022 Costs for Existing Large-Scale Solar Photovoltaic Plants in PJM
(in nominal dollars)

		Large-Scale Solar Photovoltaic Plant		
	Units	**Representative Low-Cost Plant**	**Representative Plant**	**Representative High-Cost Plant**
Capacity	*Nameplate MW*	80	10	2
Gross ACR				
Labor	*\$ million*	\$0.3	\$0.06	\$0.02
Fixed Expenses	*\$ million*	\$0.5	\$0.09	\$0.03
Total	*\$ million*	\$0.8	\$0.15	\$0.04
Gross ACR	***\$/MW-day***	**\$29**	**\$40**	**\$60**
Variable Costs				
Operating Costs	*\$/MWh*	\$0.0	\$0.0	\$0.0
Maintenance Adder	*\$/MWh*	\$0.0	\$0.0	\$0.0
Variable O&M	***\$/MWh***	**\$0.00**	**\$0.00**	**\$0.00**

8. Behind-the-Meter Diesel Generators

Based on a survey of the existing active demand response resources in the PJM market, we found that the average capacity of behind-the-meter diesel generators is about 600 kW and that they are primarily located at commercial facilities. These resources tend to hold emergency operating permits that allow them only to operate when called upon during emergency system conditions. For that reason, they are not expected to operate frequently and are likely controlled (for demand response purposes) by a demand response aggregator. Their primary annual cost is an annual maintenance contract to ensure the facility remains operational in case it is called upon. Property taxes for the commercial facility are assumed to be insignificantly affected by the installation of a behind-the-meter backup diesel generator, so we assume them to be zero.

Based on our discussions with vendors of diesel generators of this scale, we estimate that their annual maintenance contracts cost about \$1/kW, which translates to \$3/MW-day.

We would expect that the demand response aggregator that operates the diesel generator during emergency conditions to require a payment that is a portion of the capacity market revenues. Our past experience suggests payment rates of 20 – 30% of the capacity market prices earned. We have not included these costs due to a lack of transparency on how much they are likely to require and the uncertainty in future capacity market prices. Moreover, these costs are likely small relative to the reliability benefits of owning a backup generator that are not accounted for in Net ACRs. Protecting against local distribution outages is usually the primary driver for a commercial facility to install a backup generator behind the meter.

III. Net CONE for New Energy Efficiency

PJM requested that we estimate the net cost of new entry (Net CONE) for new EE resources offering into the capacity market. Estimating a representative Net CONE for EE is not as straightforward as doing so for new, standardized generation technologies, such as natural gas-fired CCs and CTs. EE resources represent energy-saving measures nearly as diverse as the uses of electricity in our society. To develop a single representative EE Net CONE, we had to define a portfolio of EE resources that is representative of that diversity and for which there is accurate, publicly available cost information, then take an average across that portfolio. This approach may result in a value that differs significantly from individual resources' actual net costs. However, as we demonstrate below, the prevailing net costs of EE measures are generally lower than typical capacity market prices (presumably reflecting "low-hanging fruit" opportunities to save energy cost-effectively) such that the vast majority of EE resources should clear the market no matter where the default offer is set.

A. Identifying a Representative EE Portfolio

In the 2021-2022 Base Residual Auction, over 2,800 MW (UCAP) of EE resources cleared across PJM.[37] Some of this capacity is offered by utilities and the rest by competitive energy service companies. Even that offered by competitive service companies, however, is partly based on helping customers take advantage of utility incentives. Because of the widespread relevance of utility programs for EE, as well as the availability of utility EE cost and benefit data (due to their state regulatory oversight), we use utility EE programs to develop our representative EE portfolio.

[37] The total EE resources that cleared the 2021/22 BRA increased by 1,100 MW from the previous auction. PJM, 2021/2022 RPM Base Residual Auction Results, https://pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-base-residual-auction-report.ashx?la=en, p. 11.

Table 11: EE Programs by Utility

Customer Class	Program Name	Included/ Excluded	Annual Energy Savings *MWh*	Peak Demand Savings *MW*
BGE				
Residential	Residential Lighting	Included	140,707	19.5
Residential	Appliance Rebates	Included	3,251	0.7
Residential	Home Performance with ENERGY STAR	Included	3,933	1.1
Residential	HVAC Rebates	Included	10,860	3.2
Residential	ENERGY STAR for New Homes	Included	6,377	2.5
C&I	Small Business Energy Solutions	Included	26,000	5.5
C&I	Prescriptive	Included	62,000	3.5
C&I	Custom	Included	21,000	5.5
C&I	Building Tune-up	Included	4,000	1.0
C&I	Instant Savings	Included	28,000	10.0
Residential	Appliance Recycling	Excluded	8,639	1.5
Residential	Quick Home Energy Check-up	Excluded	11,421	0.1
Residential	Smart Thermostats	Excluded	7,412	1.0
Residential	Smart Energy Manager	Excluded	46,102	10.4
Residential	Smart Energy Rewards	Excluded	1,573	115.2
C&I	Combined Heat and Power	Excluded	24,000	3.6
ComEd				
Residential	Appliance Rebates	Included	5,580	0.9
Residential	Elementary Energy Education	Included	1,734	0.2
Residential	Home Energy Assessments	Included	8,875	0.9
Residential	HVAC and Weatherization	Included	18,770	4.8
Residential	Multifamily - Tenant Area	Included	3,268	0.3
Residential	Res Fridge and Freezer	Included	26,185	2.6
Residential	Residential New Construction	Included	547	0.3
C&I	AirCare Plus	Included	2,786	0.3
C&I	Business Instant Lighting Discount	Included	282,451	51.1
C&I	Business New Construction	Included	43,303	8.6
C&I	Business Custom	Included	26,725	3.6
C&I	Data Centers	Included	19,153	1.8
C&I	Industrial Systems	Included	39,434	4.9
C&I	Retro- Commissioning	Included	25,215	0.5
C&I	Business Standard	Included	230,289	25.8
Residential	Meter Genius Pilot	Excluded	n/a	n/a
Residential	Res ES Lighting (Carryover)	Excluded	87,810	9.9
C&I	Business Instant Lighting Discount (Carryover)	Excluded	31,002	6.3
C&I	Energy Analyzer	Excluded	59,217	n/a
C&I	Strategic Energy Management Pilot	Excluded	7,160	n/a
PPL				
Residential	Efficient Lighting	Included	128,036	17.4
Residential	EE Kits & Education	Included	11,829	1.1
Residential	EE Home	Included	18,802	3.6
Residential	SEEE	Included	6,024	0.6
C&I	All Programs	Included	162,377	22.7
Residential	Appliance Recycling	Excluded	10,731	1.6
Residential	Home Energy Education	Excluded	30,311	5.3
Residential	LI WRAP	Excluded	14,412	1.6

Our first step was therefore to identify representative utilities with sufficiently detailed publicly available data on the cost and performance of EE programs to analyze their Net CONE. Based on the public reports we reviewed, we found sufficient program-level data for the following three PJM utilities that represent the largest utility programs in their respective states (hence serve as good representatives): Baltimore Gas and Electric (BGE) in Maryland, Commonwealth Edison (ComEd) in Illinois, and Pennsylvania Power and Light (PPL) in Pennsylvania.[38]

Our next step was to identify the relevant programs within each of these utilities. The three utilities provide information on their overall EE portfolio on a program-by-program basis (ranging from eight to 20 programs per utility), including a total of 44 programs with cumulative peak demand savings of 361 MW. We excluded 14 programs (157 MW) that PJM instructed us would not qualify for offering capacity or would participate in the capacity market as demand response, not EE.[39] Table 11 above shows the EE programs reported for each utility that we considered in our analysis and whether or not they are included in the calculation of Net CONE.

B. Net CONE Analysis Approach

Net CONE represents the net cost of providing new resources into the capacity market. It is the capacity market revenue that a resource would need to earn to justify the initial investment costs that are not covered by other benefits. The Net CONE calculation therefore includes the total economic costs of the EE programs minus all (non-capacity) cost savings:

- EE program costs spent by utilities, including the costs of providing incentives to participants and administering the programs;
- Incremental out-of-pocket costs to the participant of implementing the EE measure, compared to installing less efficient equipment or retaining old equipment;
- Cost savings from reduced purchases of energy, measured at the wholesale market price; and,
- Cost savings from reduced investment in the transmission and distribution (T&D) system associated with limiting load growth.

These costs and benefits (in the form of cost savings) are consistent with utilities' Total Resource Cost tests, but we exclude capacity cost savings since the capacity value needed for economic viability is what we are solving for when we calculate the Net CONE. This perspective differs from that of an individual participant in an EE program, who pays only a portion of the costs (with the remainder covered by utility program incentives) and receives benefits from reduced energy demand based on its retail rates. Calculating the benefits of reduced energy based on the retail

---

38 We reviewed publicly-available reports on EE programs in Delaware, Ohio, Illinois, Indiana, Maryland, New Jersey, Pennsylvania, Virginia, and Washington D.C. Reports on EE programs in Pennsylvania and Maryland included sufficient data to calculate Net CONE for all of the utilities in their state.

39 We also excluded programs with insufficient cost or performance data to calculate Net CONE, as indicated by "(Carryover)" or "n/a" in the table.

rates is not the right approach because retail rates include a portion of the fixed T&D costs allocated to the participant. The reduction in demand following the addition of the EE programs does not avoid these costs from being incurred, but instead shifts them to other customers. For this reason, using the retail rate would overstate the resource cost savings of the EE programs. Retail rates also include the costs of procuring capacity, which would double count the value of reduced peak demand if included in the Net CONE calculation. For these reasons, the costs and benefits included in the Total Resource Cost test provide the right basis for evaluating the economics of EE programs as a source of wholesale capacity.

Applying these concepts to the portfolio of EE programs included in our sample required analyzing each program's utility and participant costs, annual and lifetime energy savings, estimated energy losses, and peak demand savings. Consistent with PJM rules, the relevant capacity for capacity market purposes is the customer peak savings (Retail MW) during EE performance hours grossed up by the assumed energy losses during peak periods to calculate the "nominated EE value" (ICAP MW), and then grossed up again by the PJM pool requirement of 1.087 to calculate the "UCAP value of EE."[40]

We identified the costs of each program eligible for participation as an EE resource based on the utilities' documentation and then converted the costs into a gross cost of new entry (Gross CONE) per MW of capacity. Much like the Gross CONE calculation for new generation resources, this calculation is performed on a levelized basis. The levelization considers the estimated lifetime of the resource, and levelizes costs using PJM's assumed discount rate for merchant generation of 8.2%. This discount rate properly values the risks related to future wholesale market value of the investment in EE programs.

Similar to generation resources, calculating Net CONE requires subtracting from Gross CONE the value of the resource in the wholesale energy market. For EE programs, the value is based on the savings from reduced wholesale energy purchases. We estimated the wholesale energy savings for the EE programs in our analysis based on the total annual energy savings in each load zone and the three-year historical (2017-19) load-weighted average prices in each zone. This approach is consistent with how PJM estimates the net energy revenues for existing and new generation resources. By applying the annual energy savings to the load-weighted average prices, we are assuming that the energy savings from the EE programs are distributed throughout the year in proportion to the overall load.

We also deducted the value of reduced T&D investment using the values assumed by each utility in its EE cost-effectiveness analysis. While these costs vary from utility to utility and are uncertain, so too are the network upgrade costs that are included in the Net CONE calculations for generation resources. The key difference from generation is that EE provides T&D investment savings by reducing customer load growth, whereas as new generation generally incurs T&D investment costs to make it deliverable.

---

40 PJM, PJM Manual 18: PJM Capacity Market, Revision: 44, Section 4.4, pp. 78-82. Available at: https://www.pjm.com/~/media/documents/manuals/m18.ashx

Thus, we calculated the Net CONE for each EE program by subtracting the estimated wholesale energy savings and T&D savings from the Gross CONE. Finally, we calculated the capacity-weighted average of EE programs in our analysis to determine the Net CONE for the portfolio of EE resources.

C. Energy Efficiency Net CONE Results

Table 12 below summarizes the total peak demand savings in our analysis the energy and peak demand savings of the programs included in our analysis across the three utilities. We estimated the amount of wholesale energy savings and peak demand savings by grossing up the retail savings by the appropriate loss factor. The annual average energy savings of the EE programs in our analysis is 6,690 MWh per megawatt of peak demand savings.

Table 12: Energy and Peak Demand Savings of EE Programs by Utility

		Retail Savings				Losses		Wholesale Savings	
Utility	Programs	Peak Demand Savings	Annual Energy Savings	Lifetime Energy Savings	Average Lifetime	Average Losses	Peak Losses	Peak Demand Savings	Annual Energy Savings
	#	*Retail MW*	*GWh*	*GWh*	*years*	*%*	*%*	*MW ICAP*	*GWh*
BGE	10	53	306	4,774	16	6%	9%	57	324
ComEd	15	107	734	7,236	10	11%	26%	134	815
PPL	5	45	327	3,372	10	9%	9%	49	356
Total	**30**	**204**	**1,368**	**15,382**	**11**	**9%**	**18%**	**240**	**1,495**

We estimated that the average costs for the EE programs in our analysis are $1,812/kW ICAP (in 2022 dollars), as shown in Table 13 below.[41] We calculated that the Gross CONE for the portfolio

[41] BGE: We take the annual programs costs based from the "All Ratepayers Test (TRC)" for 2018-2020. See "Errata to Baltimore Gas and Electric Company's 2018-2020 EmPOWER Program Filing," *In the Matter of Baltimore Gas and Electric Company's Energy Efficiency, Conservation and Demand Response Programs Pursuant to the EMPOWER Maryland Energy Efficiency Act of 2008,* No. 9154, (Maryland Public Utilities Commission Sept. 22, 2017), ECF. No. 826.

ComEd: We take the annual program costs from the Program Year 8 "IL TRC Costs." We relied on the results for the Energy Efficiency Portfolio Standard (EEPS) portion of its EE programs and excluded the Illinois Power Agency (IPA) portion to be consistent with ComEd's cost-effectiveness tests. See Navigant, ComEd Review of PY8 Total Resource Cost Test Assumptions, Energy Efficiency/Demand Response Plan: Plan Year 8 (PY8) (6/1/2015-5/31/2016), January 28 2019, accessed March 13, 2020. Available at: http://ilsagfiles.org/SAG_files/Evaluation_Documents/TRC_Reports/ComEd/ComEd_PY8_TRC_Report_2019-01-28_Final.pdf.

PPL: We take the annual program costs based on the Program Year 9 costs for "TRC NPV Costs." Because PPL did not report lifetime energy savings at the program level, we used the aggregate cross-program lifetime energy savings and annual energy savings to derive an implied lifetime of 10 years, which we of EE programs is $235/kW ICAP-year based on the program costs, the program lifetime, and the 8.2% discount rate shown below.

Table 13: Total Costs and Gross CONE of EE Programs by Utility

Utility	Total Costs *$ million*	Total Costs *$/kW ICAP*	Discount Rate *%*	Average Lifetime *years*	Gross CONE *$/kW ICAP-yr*
BGE	$112.2	$1,963	8.2%	16	$212
ComEd	$198.7	$1,484	8.2%	10	$205
PPL	$124.6	$2,529	8.2%	10	$345
Total	**$435.6**	**$1,812**	**8.2%**	**11**	**$235**

Note: Total costs and Gross CONE are weighted averages by program installed capacity.
All monetary values are in 2022 dollars.

As shown in Table 14 below, the EE programs result in energy savings of $177/kW ICAP-year. The avoided energy prices range from $26/MWh in ComEd to $34/MWh in BGE based on historical average prices for 2017 to 2019 provided by PJM. For avoided T+D costs, we estimated that the average savings to ratepayers due to the EE programs is $35/kW ICAP-year. The T&D cost savings utilized by the utilities in their cost effectiveness tests range from $33/kW-year for ComEd to $54/kW-year for BGE.[42] While there is significant uncertainty about the savings from avoided T+D costs due to EE programs, a study completed for the New Jersey EE programs found that the assumed savings range from $0/kW-year to $200/kW-year across multiple utilities.[43] The weighted-average savings used in our analysis, $41/kW-year, is on the conservative end of this range, and is similar to the value used by ISO-NE in its most recent calculation of EE Net CONE ($38/kW-year).[44]

then applied to each individual program for discounting. See NMR Group, Inc., et al., SWE Annual Report Act 129 Program Year 9, February 28, 2019, accessed March 13, 2020, http://www.puc.pa.gov/Electric/pdf/Act129/Act129-SWE_AR_Y9_022819.pdf.

Program costs were escalated by 2% per year to 2022 assuming the costs remain constant in real terms.

42 PPL did not report the assumed T&D cost savings in its report. We have assumed the average of the ComEd and BGE numbers, $44/kW-yr.

43 Rutgers Center for Green Building, Energy Efficiency Cost-Benefit Analysis Avoided Cost Assumptions, Technical Memo, May 1, 2019.

44 Concentric Energy Advisors, ISO-NE CONE and ORTP Analysis: An evaluation of the entry cost parameters to be used in the Forward Capacity Auction to be held in February 2018 ("FCA-12") and forward, January 13, 2017, p. 82. Available at: https://www.iso-ne.com/static-assets/documents/2017/01/cone_and_ortp_updates.pdf

Table 14: Energy and T&D Savings of EE Programs by Utility

Utility	Energy Savings				T&D Savings			
	Average Energy Price	Wholesale Annual Energy Savings	Annual Energy Savings	Annual Energy Savings	Avoided T+D Costs	Retail Peak Demand Savings	Annual T+D Savings	Annual T+D Savings
	$/MWh	*GWh*	*$ million*	*$/kW ICAP-yr*	*$/kW-yr*	*Retail MW*	*$ million*	*$/kW ICAP-yr*
BGE	$34.12	324	$11.1	$193	$53.95	53	$2.8	$50
ComEd	$26.40	815	$21.5	$161	$33.32	107	$3.6	$27
PPL	$28.11	356	$10.0	$203	$43.64	45	$2.0	$40
Total	**$28.54**	**1,495**	**$42.6**	**$177**	**$40.91**	**204**	**$8.4**	**$35**

Note: Averages are weighted by program installed capacity. Avoided T+D Costs are reported by the utilities per MW of peak reduction at the customer meter.

We calculated that the EE Net CONE is $23/kW ICAP-year (or $64/MW ICAP-day) based on the Gross CONE of $235/kW ICAP-year and subtracting out the energy cost savings ($177/kW ICAP-year) and T&D cost savings ($35/kW ICAP-year). We calculated the EE Net CONE in terms of UCAP is $58/MW UCAP-day. The relationship between ICAP and UCAP reflects the 9% gross-up for the PJM pool requirement of 1.087.

Table 15: Net CONE of EE Programs by Utility

Utility	Gross CONE	Annual Energy Savings	Annual T+D Savings	Net CONE	Net CONE	Net CONE
	$/kW ICAP-yr	*$/kW ICAP-yr*	*$/kW ICAP-yr*	*$/kW ICAP-yr*	*$/MW ICAP-day*	*$/MW UCAP-day*
BGE	$212	$193	$50	-$31	-$86	-$79
ComEd	$205	$161	$27	$18	$48	$45
PPL	$345	$203	$40	$102	$278	$256
Total	**$235**	**$177**	**$35**	**$23**	**$64**	**$58**

Note: Net CONE equals Gross CONE minus the sum of Annual Energy Savings and Annual T+D Savings.

BOSTON
BRUSSELS
LONDON
MADRID

NEW YORK
ROME
SAN FRANCISCO
SYDNEY

TORONTO
WASHINGTON

THE Brattle GROUP