Gross Avoidable Costs for Existing Generation

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Executive Summary

Starting with the 2022/23 Delivery Year, PJM Interconnection, L.L.C. (PJM) is required under the Open Access Transmission Tariff (OATT or tariff) to update Default Gross Avoidable Cost Rates (ACRs) every four years.[1] This study informs PJM's filing by developing updated gross cost estimates for various existing generation types.

PJM uses Default Gross ACRs (minus unit-specific net energy and ancillary services (E&AS) revenues) to determine default offer thresholds for mitigating market power in its capacity market. For several years, the Default Gross ACRs were used only for mitigating so-called "buyer-side" market power; capacity resources that were subject to the Minimum Offer Price Rule (MOPR) were subject to default offer floors and could offer at lower prices only if accepted through a unit-specific review of actual costs.[2] However, in March 2021, the Federal Energy Regulatory Commission (FERC) ordered PJM to expand the application of Default ACRs to its mitigation of supplier market power, after finding that the existing offer caps were excessive.[3] Any resources subject to Market Seller Offer Caps (MSOCs) could now offer above the default ACRs only by demonstrating higher costs through unit-specific reviews. Thus, PJM's updated Default Gross ACRs will be used for mitigating supplier market power (via MSOC) as well as for MOPR purposes in PJM's Base Residual Auctions for 2026/27 and the following three delivery years.

To conduct this update of the Default ACRs, PJM retained The Brattle Group (Brattle) and Sargent & Lundy (S&L) to analyze the gross avoidable costs for several types of existing generation. We have done so based on bottom-up analysis of costs for representative plants, drawing on data and the combined experience of Brattle and S&L. We also solicited and incorporated stakeholder input through three rounds of presentations before the Market Implementation Committee (MIC) between October and December.

Our approach recognizes that existing generation resources vary considerably in their characteristics and costs, both across resource types and even within each type. This variability

1 PJM, PJM Open Access Transmission Tariff, Attachment DD, Section 5 Capacity Resource Commitment, Section 5.14(h-2)(3)(B).

2 See Minimum Offer Price Rule (MOPR)—Attachment DD § 5.14(h-2).

3 See Market Seller Offer Cap (MSOC)—Attachment DD § 6.4.

must be considered in developing coherent “types” and in developing default offer thresholds for each, trading off the risks of under-mitigation against the risks of over-mitigation and/or a burdensome amount of unit-specific reviews.

To inform PJM’s determination of a single Default Gross ACR for each resource type, we reviewed the range of characteristics of resources in the PJM market and identified the primary cost drivers among those characteristics for each resource type. We identified for each resource type the characteristics of a “representative plant” that is widely representative of most of the fleet and reflects the median MW in terms of cost structure. We also identified the characteristics for “representative low-cost” and “representative high-cost” plants to inform the range of costs PJM may see for each type of existing generation resource.

Given the assumed characteristics, we then estimated the avoidable gross costs of the representative plants to inform PJM’s filing of Default Gross ACRs. The cost estimates are based on S&L analysis of FERC Form 1 data and the Nuclear Energy Institute’s (NEI’s) “Nuclear Costs in Context” study and its own proprietary database, and Brattle analysis.

We also provide estimates for the Variable Operation and Maintenance (VOM) costs as a benchmark to inform PJM’s E&AS net revenue analysis when determining Net ACRs. The classification of costs categories as gross versus variable align with PJM’s current market rules concerning the 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 E&AS revenue component of Net ACRs). Accordingly, the costs of major maintenance and overhauls directly related to the production of electricity are included in variable costs as a “maintenance adder.”

Table ES-1 below shows the resulting gross costs for each existing generation resource type, expressed in 2022 dollars per-megawatt (MW) of nameplate capacity. Variable costs are presented separately, within the body of this report. Note that throughout this report, our results are presented as “gross costs” rather than “Gross ACRs” because the formal term reflects a tariff rate filed by PJM and approved by FERC, and our study only informs those rates.

TABLE ES-1: EXISTING GENERATION GROSS COSTS
(IN 2022 DOLLARS PER NAMEPLATE MW PER DAY)

Resource Type	Representative Plant $/MW-day
Multi-unit Nuclear	**$537**
Single-unit Nuclear	**$591**
Coal	**$94**
Natural Gas CC	**$113**
Simple Cycle CT	**$52**
ST O&G	**$64**
Onshore Wind	**$147**
Solar PV	**$70**

I. Introduction

A. Purpose of ACRs and this Analysis

In the presence of structural market power in capacity markets, PJM as market operator needs to be able to mitigate offers outside of reasonable bounds of competitive levels. Concerns surround both supplier market power and buyer market power. Supplier market power is deemed a threat where jointly-pivotal market sellers fail the Three Pivotal Supplier ("TPS") test, which all typically do.[4] Under such circumstances, resource offers would be subject to Market Seller Offer Caps (MSOC). Buyer market power—in the form of resources being offered at artificially lower prices—is deemed a concern under special circumstances and applicable resources would be subject to the Minimum Offer Price Rule (MOPR). MOPR applicability has recently been narrowed after much litigation.[5]

PJM will approach both instances by setting default offer thresholds for various resource types, such that higher-priced offers on MSOC-applicable resources could trigger a unit-specific review to consider setting a higher unit-specific MSOC; lower-priced offers on MOPR-applicable resources could trigger a unit-specific review to set a lower unit-specific MOPR. Default thresholds will be determined by a generic resource type-specific Gross Avoidable Cost Rate (ACR) minus resource-specific net revenues from energy and ancillary services markets (net E&AS offset).

Until recently, MSOCs were set uniformly across all existing resources, given by the Net Cost of New Entry (Net CONE) times an average "balancing ratio" of 85% based on an assumed number of Performance Assessment Intervals (PAIs). However, in March 2021, the Federal Energy Regulatory Commission (FERC) found the MSOCs to be unjust and unreasonable.[6] FERC found those rates to be too high, due to an unrealistically high estimate of the number of expected PAIs. FERC ordered PJM to use more specific Avoidable Cost Rates, as it uses for MOPR, and as it had used for MSOC purposes prior to the implementation of Capacity Performance in 2016.

4 PJM, Market Seller Offer Cap (MSOC) Reform, February 28, 2022.

5 Federal Energy Regulatory Commission, Notice of Filing Taking Effect by Operation of Law, Docket No. ER21-2582-000, September 29, 2021.

6 Federal Energy Regulatory Commission, Order Granting Complaints and Ordering Additional Briefing, Docket Nos. EL 19-47-000 and EL 19-63-000, March 18, 2021.

Thus, this updated ACR study will be used for both purposes, in fulfillment of PJM's requirement to periodically update its Default Avoidable Cost Rates (ACRs) every four years.[7] The last such study was conducted by us in 2020, but future studies will be conducted every four years.

For this study, PJM requested that we estimate Gross Costs for existing generation resource types. The types would be defined to span most of the PJM fleet, where each type includes similar resources with similar cost structures; types would not be defined for resource classes that exhibit highly idiosyncratic and varying avoidable costs. For each type, we were asked to develop bottom-up cost estimates of the gross fixed costs for a "representative" plant, For informational purposes we also provided a "representative low" and "representative high" for lower and higher-cost sub-groups within each type. Additionally, PJM requested that we determine the Variable Operation and Maintenance (VOM) costs for each resource type for informational purposes to aide PJM in determining E&AS revenues.

As PJM applies the study results to determine default offer thresholds, it will need to balance the need to mitigate the exercise of market power against the administrative burden and risks of over-mitigation. Over-mitigation is possible due to information asymmetries between PJM and capacity sellers, even in unit-specific reviews. That could result, for example, in a resource's MSOC being set below its true competitive costs—which could discourage participation in the market. Over-mitigation can be avoided in part by setting default MSOCs reasonably high so that many resources would not need a unit-specific review to justify higher offers; and by setting default MOPRs reasonably low for symmetrical reasons.

B. Analytical Approach

To calculate the gross default costs we first identified types that span most of the installed capacity in the PJM footprint and have sufficiently little variation of gross fixed costs within the type. We then analyzed the fleet and identified defining characteristics of the median plant by capacity; and then calculated the gross costs that would be avoided if such a plant retired. The calculations are consistent with PJM's tariff for the scope of costs allowable in Gross ACRs.

For the definition of types, we received an initial list from PJM that was based on the previously identified types from the 2020 Gross ACR study. These types were chosen to span a large

[7] PJM, PJM Open Access Transmission Tariff, Attachment DD, Section 5 Capacity Resource Commitment, Section 5.14(h-2)(3)(B).

portion of the overall PJM fleet and such that each type is coherent and has common cost characteristics within it. We then iterated upon the defined types with PJM and market stakeholders and included one additional type due to stakeholder feedback. A small remaining portion of the fleet that we did not characterize as "types" with a Default Gross ACR had more idiosyncratic cost characteristics among individual plants (e.g., due to older, non-standard technology) so did not lend themselves well to defining a standardized estimate of costs; absent a Gross ACR, these plants will have to rely on unit-specific reviews for nonzero capacity offers.

For each defined resource type, we identified the characteristics of a "representative plant" that is widely representative of the individual plants within that type. The "representative plant" standard that we agreed on with PJM staff and reviewed with stakeholders was a median for the population of PJM plants in each type, with the median being defined on a capacity (MW) basis. Since it would have been impractical to develop cost estimates for every plant in the fleet, we instead identified the median plant as one with median values of the main cost drivers: (1) the unit size; (2) the plant age and technology vintage; (3) the plant location in PJM; and (4) the configuration of the units, including pollution controls. We then estimated the costs for such a plant as described below.

While we agreed with PJM and stakeholders that the representative plant would be used to determine the Default Gross ACRs, we also sought to inform the range of costs PJM might see for each type. We thus defined a "representative high-cost" and a "representative low-cost" plant for each type, considering the range of characteristics and especially clusters thereof. This was unnecessary, however, for single-unit nuclear plants since the population consists of only two plants.

Given the assumed representative characteristics, we then estimated the costs of the representative plants to inform the gross costs, as well as the variable O&M costs to inform PJM's net E&AS analysis. Gross costs reflect the fixed costs of operating an existing generation resource for an additional year that could be avoided if the plant retires.[8] Our cost estimates for most types of thermal plants are based on S&L's regression analyses of FERC Form 1 filings for plants with characteristics similar to the representative plants for each resource type, benchmarked and adjusted using confidential cost estimates from S&L's project database. For nuclear plants, where FERC Form 1 submissions were deemed inconsistent, we relied on NEI's

[8] Given the very limited prevalence of "mothballing," meaning a unit that does not operate for the Delivery Year but is maintained in a state such that it may be brought back into service in a future year, we only consider the costs that are avoidable if a unit retires.

latest "Nuclear Costs in Context" study, with adjustments to reflect the representative plant. For wind and solar plants, for which FERC Form 1 data is sparse, we relied on S&L's extensive project database.

For most types, property taxes and insurance constitute a relatively small fraction of total cost, but they are less straightforward to quantify uniformly, and we have refined our approach since our 2020 study and over the course of this study based on stakeholder feedback. Our approach to estimating these costs varies by resource type given data availability, and is described under each type presented below.

One aspect of this study that required careful consideration was to distinguish which costs to include in the gross costs and which to consider as variable costs. Only the gross costs would determine resource types' Default Gross ACRs, while variable costs would presumably be accounted for in resources' Default Net ACRs for capacity offer mitigation purposes if generators include them in their cost-based energy offers. To avoid double counting any such costs, it is important to categorize these costs consistently with PJM's rules regarding energy market offers. We followed PJM guidance regarding its tariff and operating agreements.[9] Among other cost categories, PJM's tariff specifies that major maintenance costs can be included in variable costs in cost-based energy offers, under a maintenance adder that includes activities such as repair, replacement, and major inspection.[10] Therefore, consistent with tariff, our estimated gross costs include Fixed Capital Costs and Fixed Operation & Maintenance (FOM) costs but not major maintenance costs for systems directly related to electric production. In the case of nuclear plants, however, we provide an indicative estimate of the gross costs with major maintenance included for informational purposes in the hypothetical case if PJM were to determine that major maintenance should be included in the Gross ACR

[9] 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." 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 may include repair, replacement, and major inspection, and overhaul expenses including variable long term service agreement expenses." Schedule 2 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. 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. See PJM, PJM Open Access Transmission Tariff, Attachment DD, Section 6 Market Power Mitigation, Section 6.8(c).

[10] PJM, Operating Agreement of PJM Interconnection, L.L.C., Schedule 2, Section 4.

and adapts its tariff accordingly. For the remainder of plant types, given PJM's guidance, we identify the types of maintenance costs included in the gross costs and those included in the variable cost maintenance adder, and estimate the costs of each accordingly, as reported below.

II. Selection of Plant Types within PJM Fleet

Based on PJM input, the approach described above, and stakeholder feedback, we defined the following resource types for estimating gross costs:

- Multi-unit nuclear
- Single-unit nuclear
- Coal
- Natural gas-fired combined-cycle turbines (NG CC)
- Simple-cycle combustion turbines (Simple Cycle CT), previously limited to natural gas combustion turbines
- Oil and gas-fired steam turbines (ST O&G), new type based on stakeholder feedback
- Onshore wind
- Large-scale (>1 MW) solar photovoltaic plants (Solar PV)

These types are similar to those in the 2020 ACR study, but expanded based on stakeholder feedback. We added an oil and gas-fired steam turbine type and amplified the simple-cycle combustion turbine type to include oil peaker plants as well as gas plants compared to the 2020 ACR determination.[11] Table 1 shows a breakdown of the current capacity of the PJM fleet. The chosen resource types combined cover about 94% of the entire PJM fleet.

[11] Newell, et al., Gross Avoidable Cost Rates for Existing Generation and Net Cost of New Entry for New Energy Efficiency, March 17, 2020 ("2020 Gross ACR Study").

TABLE 1: PJM FLEET CAPACITY BY PLANT TYPE

Plant Type	Total MW (Summer ICAP)	% of Total PJM Capacity	Recommendation
NGCC	**55,828**	**28%**	**Included**
Coal	**41,554**	**21%**	**Included**
Nuclear	**32,556**	**16%**	**Included**
Simple Cycle CT	**28,496**	**14%**	**Included**
Wind	**9,911**	**5%**	**Included**
ST O&G	**9,240**	**5%**	**Included**
Solar	**7,790**	**4%**	**Included**
Pumped Storage	5,243	3%	Unit-specific review
Hydro	3,319	2%	Unit-specific review
Other	3,427	2%	Unit-specific review
PJM Total Installed Capacity	**197,364**	100%	

Notes and Sources: ABB, Energy Velocity Suite.

The remaining resource types, for which gross costs were not determined, represent a small percentage of PJM's capacity. These resource types either have very few plants in their population and/or highly idiosyncratic costs, making them better candidates for unit-specific reviews rather than a standardized ACR.

III. Gross Costs for Existing Generation

A. Multi-Unit Nuclear Plants

Most nuclear plants in PJM have multiple units installed at the same site. In total, there are currently 14 multi-unit nuclear plants operating in the PJM footprint. The capacity of multi-unit nuclear plants in PJM are mostly in the range of 1,750–2,500 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 Illinois and Pennsylvania.[12] Figure 1 below summarizes the age, size, and locations of these plants.

[12] The Hope Creek plant in New Jersey is classified as a multi-unit plant because it is co-located with the Salem nuclear plant. Figure 1 shows them as if they were a single 3-unit plant.

Based on our experience estimating costs for nuclear plants, the most significant cost drivers for nuclear plants are the plant size and number of units, reactor type such as the boiling water reactor (BWR) versus the pressurized water reactor (PWR), the location (which impacts property taxes and operating costs), the business model (merchant generation vs. regulated cost-of-service generation), and the operator's fleet size.

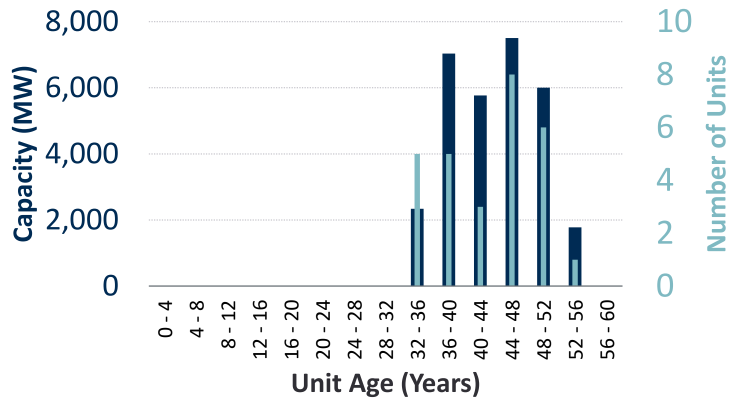
Representative Multi-Unit Nuclear Plant Characteristics

To choose a representative multi-unit nuclear plant we first determined the median plant size of the most frequent size bin of the nuclear fleet, which was between 2,200 MW to 2,400 MW as shown in Figure 1, Panel (B). We then filtered the multi-unit fleet data by this size bin (2,200 MW to 2,400 MW) and compared the median age of the filtered population to the median age of the unfiltered total multi-unit nuclear fleet and found that both were aligned, so we defined the representative age as the median of the fleet (44-years old). We then compared the reactor types, the locations, and the owners' business model and size in this filtered population to the overall fleet. Based on this approach, the representative multi-unit nuclear plant is a 44-year-old 2,400 MW (comprised of two 1,200 MW units) BWR merchant plant in Illinois with an owner that operates multiple plants.

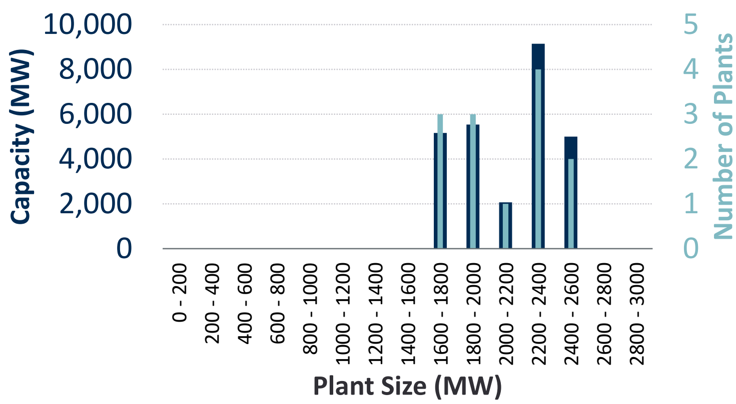
Given the limited number of nuclear plants and limited size variation, we did not alter the plant size for the representative low and high cost plants. For the representative low-cost plant, we chose a pressurized water reactor plant in Virginia, since PWRs have lower operating costs and Virginia has lower labor costs. For the representative high-cost plant, we assumed a plant similar to the representative plant but with the plant owner only operating a single plant, which would have higher costs due to reduced economies of scale.

FIGURE 1: MULTI-UNIT NUCLEAR FLEET CHARACTERIZATION

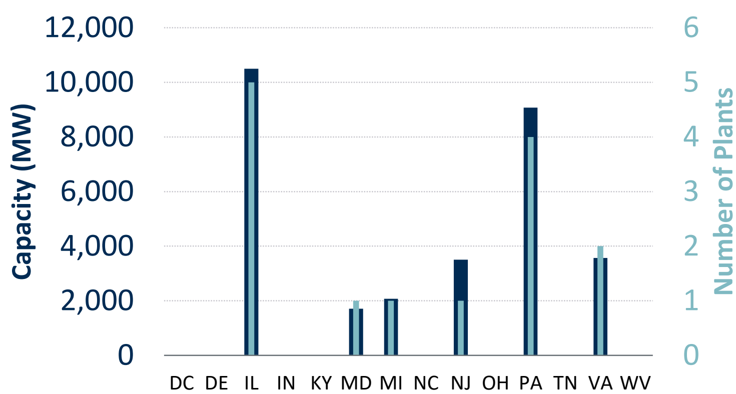
(A) UNIT AGE



(B) PLANT SIZE



(C) PLANT LOCATION



Notes and Sources: ABB, Energy Velocity Suite.

Cost Estimates for the Representative Multi-Unit Nuclear Plant

Our cost estimates for nuclear plants rely the 2022 NEI "Nuclear Plants in Context" study, with adjustments to best reflect the representative plant and PJM's characterization of "gross" versus variable costs, as described below.[13] Corresponding to the NEI report's , we present nuclear cost components as ongoing capital expenditures and operating costs, then add property taxes, which NEI did not estimate.

Ongoing Capital Expenditures: NEI's capital cost category includes capital spares, regulatory, infrastructure, information technology, enhancements, and sustaining costs (including insurance costs). To estimate the capital cost contribution to gross costs (and variable costs) for PJM multi-unit nuclear plants, we started with the 2021 average capital costs for all U.S. nuclear plants of $5.50/MWh, plus a year of inflation at 7.66%.[14] We then adjusted this value downward by 16.73% to account for the representative plant characteristics including its location, boiling water reactor, multiple units, and merchant status within a multiple-plant portfolio of the operator.[15] These adjustments yielded a total capital cost of $4.93/MWh in 2022 dollars. From this total, Capital Spares (1.2% of total capital costs) are excluded from the gross costs and counted as variable costs instead, consistent with PJM's tariff. Sustaining costs (37.2% of total capital costs) also are considered variable and excluded from the gross costs, since this category reflects investments in systems directly related to electric production that are necessary to maintain plant performance. In contrast to our prior approach in the 2020 Gross ACR Study, and in response to stakeholder feedback, we included the Enhancements component (36.3% of total capital costs) in the gross costs. These costs are part of continuing the life the plant, and they are incurred fairly consistently by the fleet over time; and they belong in gross costs as opposed to variable costs because they are not directly related to electricity production. The remaining 25.3% of 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 they too are included as a gross case. The resulting contribution of capital costs to multi-unit nuclear plants' gross costs is $3.04/MWh, and $1.89/MWh as part of variable costs (all in 2022 dollars).

13 Nuclear Energy Institute, Nuclear Costs in Context, October 2022 ("NEI Report").

14 U.S. Bureau of Labor Statistics, Consumer Price Index US City Average. Value obtained from 2022 January to October average CPI divided by 2021 average CPI or 291.735/270.970 = 1.0766.

15 NEI tabulated values included sensitivities for these characteristics, each of which were considered as a percentage change from the national average. The averages of these percentages were applied to the national average CapEx to yield the 16.73% net adjustment.

Non-Fuel Operating Costs: NEI's operating cost category includes engineering, loss prevention, materials and services, fuel management, operations, support services, training, and work management. We started with the 2021 average operating costs for all nuclear plants in the U.S. of $18.07/MWh, plus a year of GDP inflation at 7.66%.[16] We then adjusted this value upward by 1.74% to account for the representative plant characteristics including its location, boiling water reactor, multiple units, and merchant status within a multiple-plant portfolio of the operator. These adjustments yielded a total operating cost for our reference technology of $19.79/MWh in 2022 dollars. The components of operating costs primarily reflect labor costs that are not directly attributable to the production of electricity and so are included in the gross costs. We interpret the Materials & Services costs (1.5% of total operating costs) to account for consumables required to operate the nuclear plants and thus include those costs as variable operating costs but exclude them from the gross costs. The remaining 98.5% of the total operating costs are included in the gross costs. We applied these percentages to the total operating costs for a multi-unit BWR plant to calculate the variable and fixed operating costs. The resulting contribution of operating costs to multi-unit nuclear plants' gross costs is $19.50/MWh, and $0.30/MWh as part of variable costs (all in 2022 dollars).

Property Taxes: Property tax costs were determined using S&L's project database and expertise. S&L's discussions with operators of nuclear facilities determined broad ranges of taxes are assessed on nuclear facilities depending on the location. We selected a median annual value of $1.01/MWh from this dataset and applied the same value to all nuclear units.

These capital, operating, and property tax cost components are combined to estimate the total gross costs shown in Table 2. The result for the representative multi-unit nuclear plant in PJM is $537/MW-day (in 2022 dollars). The estimated variable costs for the representative multi-unit nuclear plant are $2.19/MWh. For the representative low-cost plant, estimated gross costs are $476/MW-day and variable costs are $2.22/MWh. For the representative high-cost plant, estimated gross costs are $552/MW-day and variable costs are $2.20/MWh.

[16] See footnote 14.

TABLE 2: MULTI-UNIT NUCLEAR GROSS AND NON-FUEL VARIABLE COSTS (2022 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 Costs	*$/MW-day*	$476	**$537**	$552
Capital Costs	*$/MW-day*	$72	**$69**	$69
Fixed Operating Costs	*$/MW-day*	$381	**$445**	$460
Property Taxes	*$/MW-day*	$23	**$23**	$23
Non-Fuel Variable Costs	*$/MWh*	$2.22	$2.19	$2.20
Operating Costs	*$/MWh*	$0.25	$0.30	$0.31
Major Maintenance	*$/MWh*	$1.96	$1.89	$1.90

Notes and Sources: gross costs are expressed in 2022 dollars per nameplate MW. The major maintenance costs per MWh depend on the capacity factor, which we assumed to be 95% corresponding to the average nuclear capacity factor in 2021.[17]

As described in Section I.A above, PJM's tariff specifies that major maintenance costs can be included in variable costs in cost-based energy offers, under a maintenance adder and includes activities such as repair, replacement, and major inspection. If PJM were to determine that major maintenance should instead be considered in gross costs and adapts its tariff accordingly, this would move the major maintenance adder ($1.89/MWh) out of variable costs and increase the gross costs of the representative multi-unit nuclear plant by $43/MW-day, to $580/MW-day. For the representative low-cost plant, this would move $1.96/MWh out of variable costs and increase the gross costs by $45/MW-day to result in $521/MW-day. For the representative high-cost plant, this would move $1.90/MWh out of variable costs and increase the gross costs by $43/MW-day to result in $596/MW-day.

B. Single-Unit Nuclear Plants

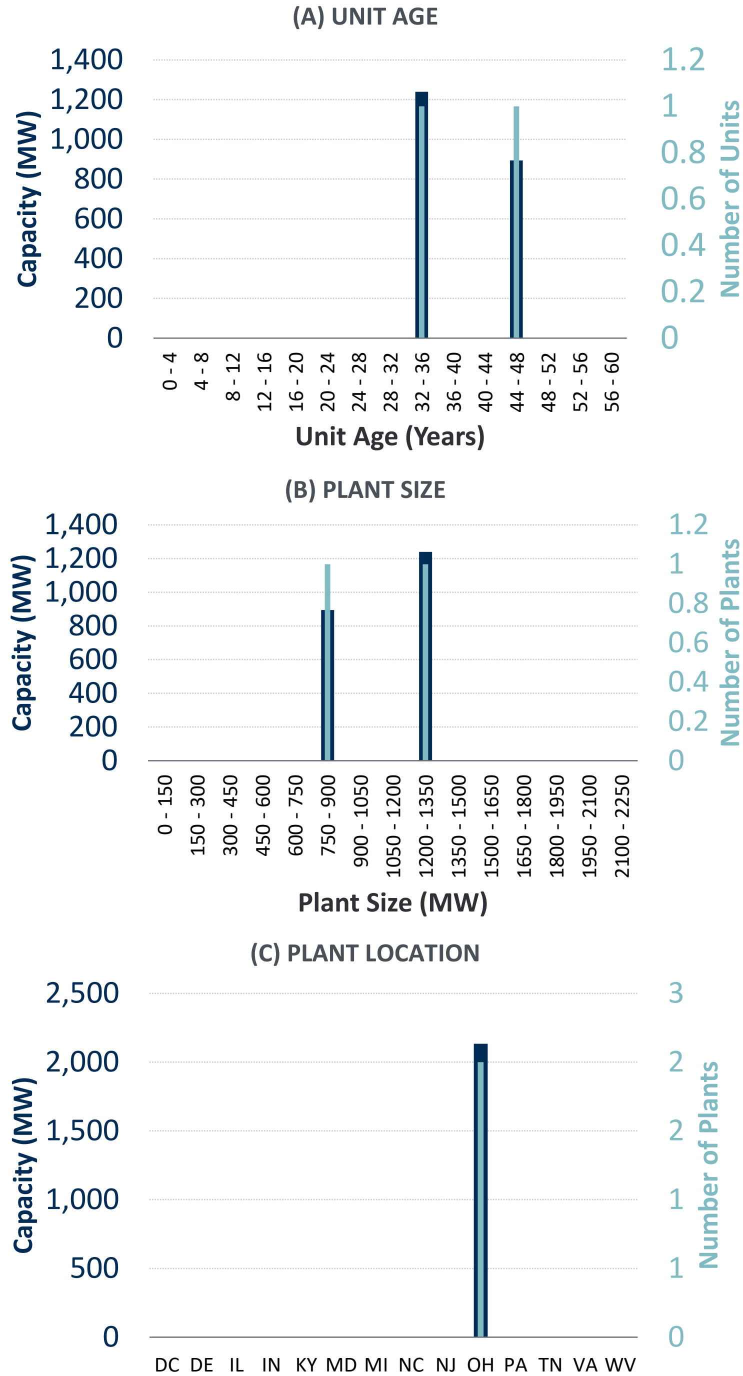
There are currently only two single-unit nuclear plants in the PJM market: the 894 MW Davis Besse plant and 1,240 MW Perry plant in Ohio.[18] Due to the small number of plants and the limited variation among them, we specified a single representative plant to be a 38-year-old 1,200 MW Boiling Water Reactor (BWR) unit in Ohio. With such a small population, we did not

17 Monitoring Analytics LLC, PJM's Independent Market Monitor, 2021 State of the Market Report for PJM Volume 2: Detailed Analysis, March 10, 2022.

18 See footnote 12, on the treatment of the Hope Creek plant in New Jersey.

designate a representative high or representative low-cost plant. Figure 2 below summarizes the age, size, and locations of these plants.

FIGURE 2: SINGLE-UNIT NUCLEAR FLEET CHARACTERIZATION



Notes and Sources: ABB, Energy Velocity Suite.

Cost Estimates for the Representative Single-Unit Nuclear Plant

Costs for the single-unit nuclear plant are estimated from NEI data in the same way as for multi-unit plants. The capital and operating costs are higher per MWh, but the property taxes are assumed to be the same per MWh.

Ongoing Capital Expenditures: following the same approach outlined above for multi-unit nuclear plants, we estimated annual avoidable capital costs of $3.38/MWh as part of gross costs and $2.11/MWh as variable costs based. We started with the 2021 average capital costs for all U.S. nuclear plants of $5.50/MWh, plus a year of GDP inflation at 7.66%.[19] We then adjusted this value downward by 7.27% to account for the representative plant characteristics, including its location, boiling water reactor, single-unit, and merchant status within a multiple-plant portfolio of the operator. As with multi-unit nuclear plants, the gross costs exclude Capital Spares and Sustaining costs but include Enhancements and the remaining capital costs, using the same percentages as for multi-unit nuclear plants.

Non-Fuel Operating Costs: We estimated avoidable fixed operating costs of $21.52/MWh and variable operating costs of $0.33/MWh for a single-unit BWR nuclear plant, just as described above for multi-unit nuclear plants. We started with the 2021 average operating costs for all U.S. nuclear plants of $18.07/MWh, plus a year of GDP inflation at 7.66%.[20] We then adjusted this value upward by 12.32% to account for the representative plant characteristics including its location, boiling water reactor, single-unit, and merchant status within a multiple-plant portfolio of the operator. These adjustments yielded a total operating cost for our reference technology of $21.85/MWh in 2022 dollars. As with multi-unit nuclear plants, the gross costs includes 98.5% of that, with only Materials & Services costs attributed to variable costs.

Table 3 below shows the resulting gross costs for a representative single-unit nuclear plant in PJM to be $591/MW-day (in 2022 dollars). The estimated variable costs for a single-unit nuclear plant are $2.44/MWh (in 2022 dollars).

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[19] See footnote 14.

[20] See footnote 14.

TABLE 3: SINGLE-UNIT NUCLEAR GROSS AND NON-FUEL VARIABLE COSTS (2022 DOLLARS)

	Units	Single-Unit Nuclear Plant
Capacity	*Nameplate MW*	1,200
Gross Costs	*$/MW-day*	**$591**
Capital Costs	*$/MW-day*	**$77**
Fixed Operating Costs	*$/MW-day*	**$491**
Property Taxes	*$/MW-day*	**$23**
Non-Fuel Variable Costs	*$/MWh*	$2.44
Operating Costs	*$/MWh*	$0.33
Major Maintenance	*$/MWh*	$2.11

Notes and Sources: gross costs are expressed in 2022 dollars per nameplate MW. The major maintenance costs per MWh depend on the capacity factor, which we assumed to be 95% corresponding to the average nuclear capacity factor in 2021.[21]

Similar to the multi-unit plant, if PJM determines major maintenance should be considered in gross costs instead of variable energy costs and adapts its tariff accordingly, this would move the major maintenance adder ($2.11/MWh) out of variable costs and increase the gross costs of the representative multi-unit nuclear plant by $48/MW-day, to $639/MW-day.

C. Coal Plants

The fleet of existing coal plants in PJM comprises a wide range of sizes, ages, and locations. There are over 120 existing coal units currently in the PJM market at approximately 60 different plant sites. Plant capacities range from less than 100 MW to nearly 3,000 MW with the average plant size of about 700 MW across all plants and 1,100 MW for plants that are at least 100 MW. Over half of the coal capacity is between 35–60 years old, with one plant dating back to 1942, and a few plants having come online in the last 10 years. West Virginia has the most installed capacity, followed by Pennsylvania and Ohio. The majority of coal plants have a dry lime or wet limestone flue-gas desulfurization (FGD) unit installed. Figure 3 below summarizes the age, size, locations, and pollution controls of these plants.

Coal plants of similar age tend to have similar plant size, configuration, and technology. The primary drivers of cost variability among plants are age (which typically dictates the capacity,

[21] Monitoring Analytics LLC, PJM's Independent Market Monitor, 2021 State of the Market Report for PJM Volume 2: Detailed Analysis, March 10, 2022.

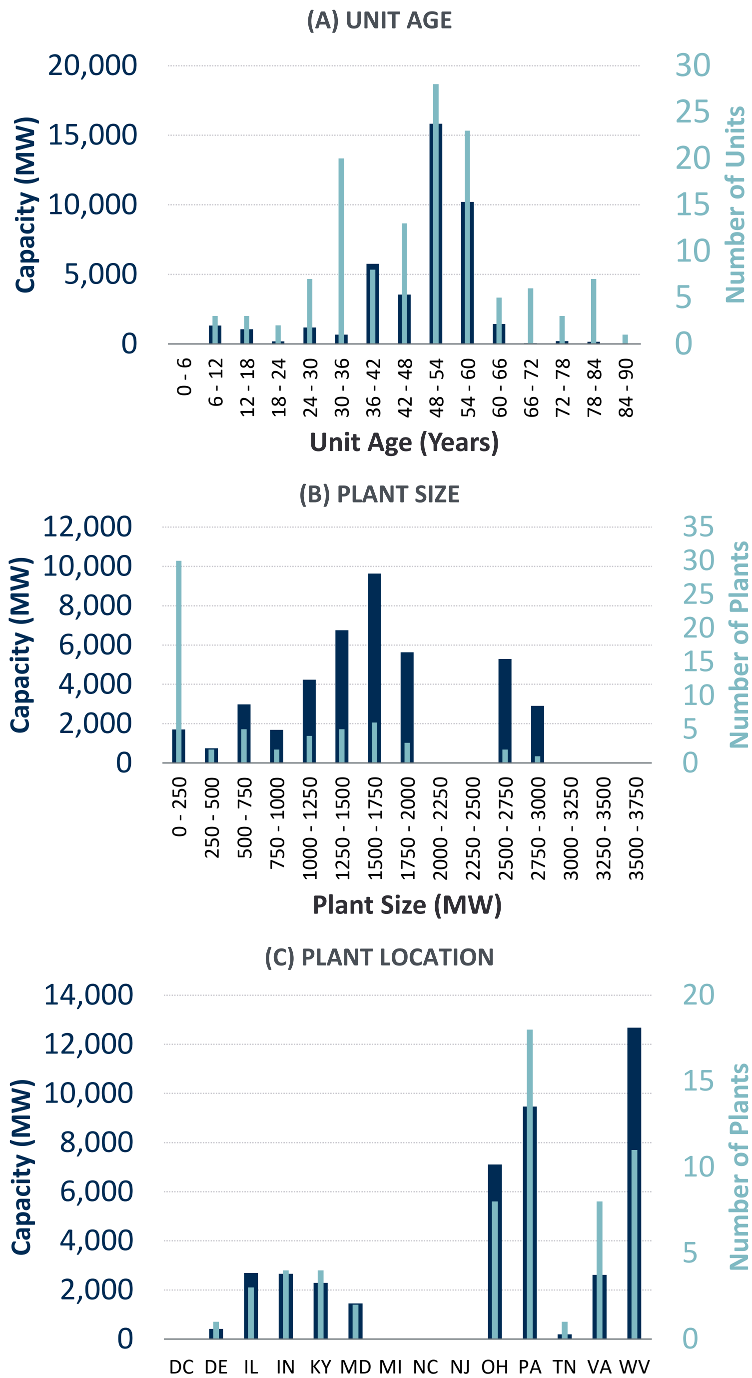
configuration, and technology), followed by the location and the types of post-combustion controls installed at the plant.

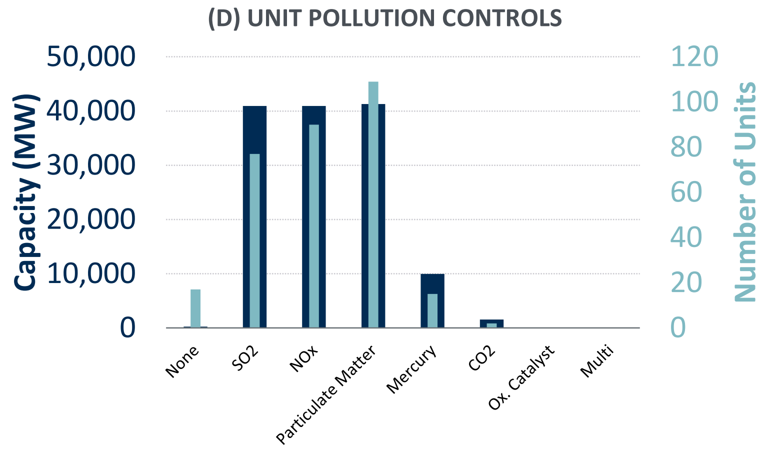
Representative Coal Plant Characteristics

Given that the age of a coal plant influences other cost drivers, we first determined the median plant age within the most frequent age bin of the coal fleet, which was between 48 to 54 years old as shown in Figure 3, Panel (A). We then filtered the coal fleet data by this age bin (48 to 54 years old) and compared the median age of the filtered population to the median age of the unfiltered total fleet. Both measurements were well aligned and were approximately 52 years old. Next, we determined the median capacity of the filtered population and reviewed the plant configurations of the filtered population. Then we reviewed the location of the filtered population and the installed pollution controls these plants had. Based on this approach, the representative coal plant is a 52-year-old 1,500 MW plant (with two 750-MW units) in Pennsylvania that burns Appalachian coal and has a wet limestone FGD unit.

For the representative low-cost plant and representative high-cost plant, we varied the age and capacity of the plant as the main cost differentiators. Because most coal plants in PJM have some type of sulfur dioxide control technology and the majority of them have wet FGD units, we did not change that assumption from the representative plant. To determine the representative high-cost plant, we filtered the fleet data for plants 30-years or younger and determined the median plant size and configuration of this filtered population, which was approximately a 100 MW plant consisting of one unit. We then reviewed the locations of these filtered plants. Based on this approach, the representative high-cost plant is a 30-year old 100-MW plant (one 100-MW unit) with FGD in West Virginia. For the representative low-cost plant, we only varied the capacity of the plant from the representative plant since larger plants would have lower per MW costs, and defined it as a 52-year-old 1,800 MW plant (with two 900-MW units) with FGD in Pennsylvania.

FIGURE 3: COAL FLEET CHARACTERIZATION





Notes and Sources: ABB, Energy Velocity Suite.

Cost Estimates for the Representative Coal Plant

We estimated the total annual costs for operating the representative coal plant using data recently released by the EIA and FERC.[22] 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 S&L's proprietary data for similar operating coal plants. Finally, where dollar values were referenced from a different year, we escalated the costs to 2022 using annual GDP inflation.[23]

Similar to the nuclear plants, we separated the costs that can be included in the gross costs from those included in the variable cost component of cost-based energy offers. Based on S&L's analysis of FERC Form 1 data and regression model for technically similar plants, a 52-year-old 1,500 MW coal plant would be expected to invest about $36 million in capital expenditures per year into the systems directly attributable to electricity production, which would be accounted

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; Federal Energy Regulatory Commission, FERC Form 1, Plant Cost Data, 2010 through 2019.

23 See footnote 14.

for in the variable cost "maintenance adder" based on PJM's current market rules.[24] Assuming a 50% capacity factor, the maintenance adder contributes about $5.47/MWh to variable costs.[25] Meanwhile, the gross costs estimate includes fixed operating costs that are not directly attributable to electricity production, such as labor, administrative costs, preventative maintenance to auxiliary equipment (buildings, HVAC, water treatment), insurance, and support services.

Property tax rates vary by municipality or even by property where sometimes there are negotiated payment in lieu of taxes (PILOT) agreements, and plant values are not assessed in a uniform manner. To estimate property taxes for the representative coal plant, we surveyed actual property taxes payed by plants that were close to the representative plant size and applied the median value. We also leveraged this analysis to estimate insurance costs. Like property taxes, insurance costs depend on the value of the plant, although the costs are generally not publicly available. S&L has in the past shown that insurance costs tend to be roughly three times as high as property taxes paid by large thermal plants in S&L's project database, and we applied this multiplier. Both turned out to be very small.

Table 4 below shows that the estimated gross costs for the representative coal plant are $94/MW-day (in 2022 dollars), and the variable costs are estimated at $10.92/MWh. For the representative low-cost coal plant, estimated gross costs are $88/MW-day variable costs are $10.47/MWh. For the representative high-cost coal plant, estimated gross costs are $142/MW-day, and variable costs are $9.61/MWh.

24 PJM, Operating Agreement of PJM Interconnection, L.L.C., Schedule 2, Section 4.

25 The capacity factors estimated are based on Figure 3-1 Capacity Factor vs. Age for All Coal Plants from the EIA's Generating Unit Annual Capital and Life Extension Costs Analysis Final Report on Modelling Aging-Related Capital and O&M Costs, prepared by Sargent & Lundy, May 2018.

TABLE 4: COAL PLANT GROSS AND NON-FUEL VARIABLE COSTS (2022 DOLLARS)

	Units	Coal Plant Representative Low-Cost Plant	Representative Plant	Representative High-Cost Plant
Capacity	*Nameplate MW*	1,800	1,500	100
Gross Costs	*$/MW-day*	$88	**$94**	$142
Labor	*$/MW-day*	$38	**$41**	$60
Fixed Expenses	*$/MW-day*	$48	**$51**	$79
Property Taxes	*$/MW-day*	$0.5	**$0.5**	$0.5
Insurance	*$/MW-day*	$1.5	**$1.5**	$1.5
Non-Fuel Variable Costs	*$/MWh*	$10.47	$10.92	$9.61
Operating Costs	*$/MWh*	$5.00	$5.45	$5.62
Maintenance Adder	*$/MWh*	$5.47	$5.47	$3.99

Notes and Sources: gross costs are expressed in 2022 dollars per nameplate MW. 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. The estimated maintenance adder costs per MWh are variable based on the capacity factor. The maintenance adders assume a 50% capacity factor for the low-cost and median representative plants, and 62% for the high-cost representative plant.[26]

D. Natural Gas-Fired Combined-Cycle Plants

Nearly all natural gas-fired combined-cycle (CC) plants have been built over the past 25 years, with more than 22,000 MW installed in the past 5 years, and most of the rest built in the early 2000s. Plants built in the early 2000s are in the 500 MW to 1,000 MW range while more recent projects typically exceed 1,000 MW. Many of the gas CCs have been built in regions with access to low-cost gas via pipelines or within gas supply basins, predominantly in Pennsylvania, followed by Virginia, Ohio, and New Jersey. Most are equipped with Selective Catalytic Reduction (SCR) to reduce emissions of nitrogen oxides (NO_x). Figure 4 below summarizes the age, size, locations, and pollution controls of these plants.

The main drivers of cost variability among CCs are the capacity, age, turbine type, plant configuration, and whether or not a plant has firm gas transportation service. Location is a secondary driver, through its effects on the costs of labor, property taxes, and firm fuel.

[26] The capacity factors estimated are based on Figure 3-1 Capacity Factor vs. Age for All Coal Plants from the EIA's Generating Unit Annual Capital and Life Extension Costs Analysis Final Report on Modelling Aging-Related Capital and O&M Costs, prepared by Sargent & Lundy, May 2018.

Determination of Representative Natural Gas-Fired Combined-Cycle Plant Characteristics

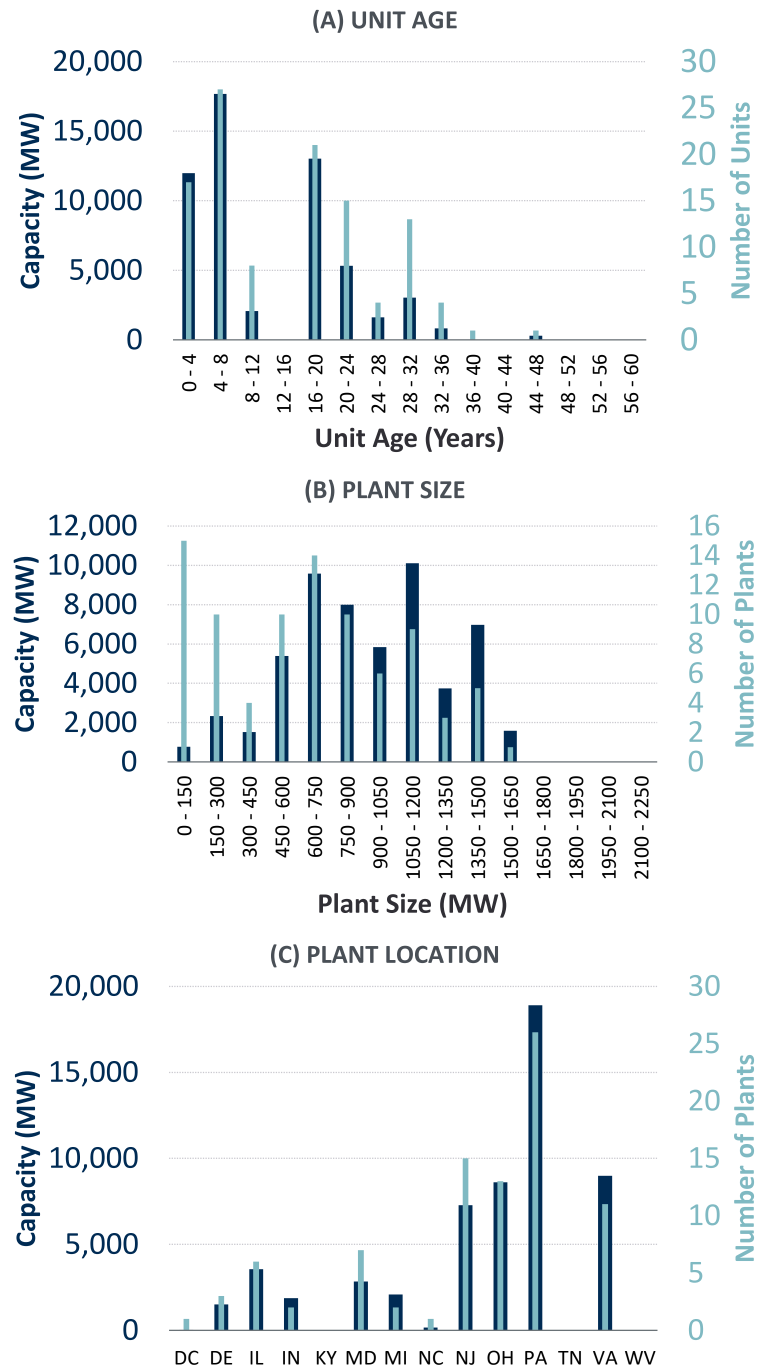
We relied on input from PJM indicating that the majority of existing CC plants have firm gas transportation contracts up to their economic maximum (EcoMax), and therefore the representative plant would be subject to this cost. Then we determined the median plant size of the CC fleet, which was 669 MW in the 600 MW to 750 MW bin as shown in Figure 4, Panel (B). We then filtered the CC fleet data for plants between 600 MW to 750 MW and compared the median age of the filtered population to the median age of the unfiltered total CC fleet and found that both were aligned, so we defined the representative age as the median of the fleet (11-years old). We then compared the plant configuration, location and the installed pollution controls in this filtered population to determine that most plants are in a 2×1 configuration, nearly all plants have SCR installed, and most are located in Pennsylvania. 11 years ago, F-class turbines were the predominant turbine technology, which had standardized sizes when employed in a 2×1 configuration. We adjusted the reference size to 750 MW to account for this standardization. Based on this approach, the representative gas CC plant is an 11-year-old 750 MW plant with two F-class gas turbines and one steam turbine (2×1) configuration in Pennsylvania that has SCR technology installed and has firm gas transportation service.

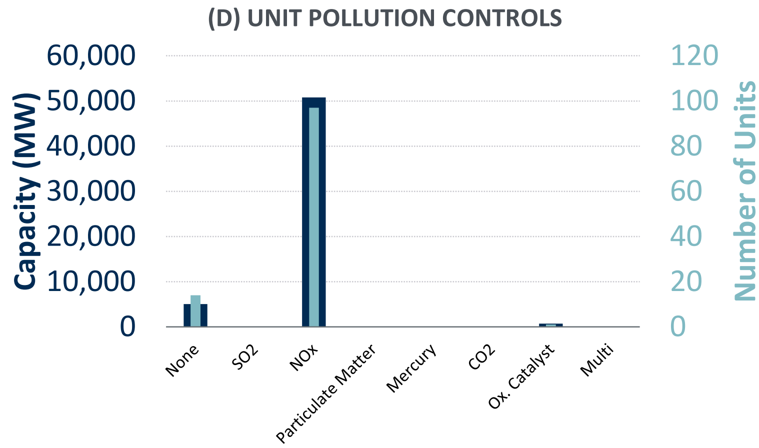
The representative high-cost and low-cost plants reflect the two modes of the bi-modal distribution of ages of CC plants in PJM. The older plants are smaller and have higher costs per MW-day, where newer plants are larger and have lower costs per MW-day with their economies of scale. Since nearly all CC plants in PJM have SCR installed for NO_x pollution control, we did not vary this assumption for the representative high or low-cost plants. Because the majority of the CC feet has firm gas up to EcoMax we also assume that the representative low-cost and representative high-cost plants have firm gas transport service as well.

For the representative high-cost plant, we first identified a plant size that was representative of the smaller plants in the fleet. We split the CC fleet into plants smaller than 750 MW and found the median of this sub-population, which were plants between 300 MW to 450 MW. We then filtered the CC sub-population for plants between 300 MW to 450 MW and chose a 400 MW median to represent the smaller/older CCs. New Jersey has the second most CCs in PJM so we chose this location for the representative older/smaller plant. The median CC plant age in New Jersey is approximately 30-years old. We assessed the plant configuration and turbine type of plants in this size range to be an F-class single unit. Based on this approach, the representative high-cost CC plant is a 30-year-old, 400 MW plant, with one F-class turbine in a 1×1 configuration in New Jersey.

For the representative low-cost plant, we identified plants in the 1,050–1,200 MW range, which represents a large proportion of the capacity and a high number of plants as shown in Figure 4, Panel (B). We filtered the CC fleet data by this size bin to obtain the representative low-cost age at a median of 5 years old. We used the CC fleet data filtered by this size to determine the plant configuration, turbine type, and location of the remaining plants. CC plants around this size and age tended to be larger with H-class turbines in a 2×1 configuration. Based on this approach, the representative low-cost CC plant is a 5-year-old 1,100 MW plant with two 550 MW H-class turbines in a 2×1 configuration in Pennsylvania.

FIGURE 4: NATURAL GAS-FIRED COMBINED CYCLE FLEET CHARACTERIZATION





Notes and Sources: ABB, Energy Velocity Suite.

Cost Estimates for the Representative Natural Gas-Fired Combined-Cycle Plants

To estimate the costs of the representative plants, we relied on the same methodology used to develop cost estimates for gas CCs in the PJM 2022 CONE Study.[27] Similar to how costs are specified in the 2022 CONE Study, we included the hours-based major maintenance costs specified in Long-Term Service Agreements (LTSAs) under variable O&M costs alongside operating costs associated with chemicals and consumables.

We used the cost information from the 2022 CONE Study to estimate components of the fixed O&M, variable O&M, and major maintenance for the representative low-cost plant (H-class 2×1). 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 400 MW F-class representative plants.

We adjusted the cost data from public sources to account for differences in turbine sizes, configurations, locations, and ages relative to the representative plants based on regression analyses of data from S&L's project database and validated the results against proprietary data for similar plants in operation.[28] 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 62% capacity factor, representative of CCs in PJM. Property taxes and insurance were estimated using the values

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27 Newell, et al., PJM CONE 2026/2027 Report, April 21, 2022 ("2022 CONE Study").

28 Adjustments come from S&L project database and public sources including FERC Form 1 and 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.

from the 2022 CONE study[29] with downward adjustments made for the older, less valuable plant.

Firm gas transportation costs were estimated at updated average tariff rate of $8.06/Dth per month incorporating reservation and usage charges for major pipelines servicing Pennsylvania under the FT-1 rate schedules.[30] We calculated the average heat rate for all natural gas-fired combined-cycle plants in the PJM fleet to be 7,212 Btu/kWh.[31] We then multiplied the nameplate plant capacity for the representative plants with the heat rate to estimate the average annual gas requirement. We then calculated the annual firm gas cost of $46/MW-day using the average tariff rate of $8.06/Dth per month applied to the annual gas requirement.

Table 5 below shows that the estimated gross costs for the representative plant are $113/MW-day and variable costs are $2.71/MWh (in 2022 dollars). The estimated gross costs for the representative low-cost plant are $94/MW-day and variable costs are $2.36/MWh. Estimated gross costs are higher for the smaller 400 MW representative high-cost plant at $160/MW-day due to the reduced economies of scale. The variable costs for the representative high-cost plant are $2.60/MWh.

Note that the $113/MW-Day gross costs of the representative existing CC plant are similar to the Fixed O&M costs for new CCs from the 2022 CONE Study as part of the Quadrennial Review.[32] Accounting for updates incorporated into the final submitted CONE values[33] and deflating those estimates to 2022 dollars, the Fixed Operation & Maintenance cost for the new CCs in the WMACC CONE Areas (most closely corresponding to the "PA" location of the representative existing CC) plant is $83/MW-day. This is $11/MW-day less than the $94/MW-day we are estimating for the gross costs of the comparably sized "Low-Cost" existing plant. The difference is primarily attributable to updated tariffed rates used to estimate the costs of firm fuel, partially offset by lower property taxes and insurance, and other adjustments.

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29 2022 CONE Study.

30 The tariff rate used in calculation of firm gas costs was the average of TETCO M3 rate and Transco Zone 6 rate. See Texas Eastern Transmission FERC Gas Tariff, M3-M3 effective August 1, 2022, and Transcontinential Gas Pipeline Company FERC Gas Tariff, Delivery Zone 6 and Receipt Zone 6 effective November 1, 2022.

31 Based on average full load heat rates with data from ABB, Energy Velocity Suite. Many combined-cycle plants employ duct firing to produce higher-pressure steam to increase plant capacity when operating in high ambient temperatures. However, the use of duct firing in CCs causes the efficiency to drop significantly and plants are not designed to be operated constantly with duct firing throughout a year; therefore, we calculate the annual gas requirement using the average full load heat rate without duct-firing.

32 PJM Interconnection, L.L.C., Docket No. ER22-2984-000 Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters, pdf page 364.

33 *Ibid*, Attachment D.

TABLE 5: COMBINED-CYCLE PLANTS' GROSS AND NON-FUEL VARIABLE COSTS (2022 DOLLARS)

		Natural Gas Combined Cycle Plant		
	Units	Representative Low-Cost Plant	Representative Plant	Representative High-Cost Plant
Capacity	*Nameplate MW*	1,100	750	400
Gross Costs	*$/MW-day*	$94	**$113**	$160
Labor	*$/MW-day*	$17	**$21**	$32
Fixed Expenses	*$/MW-day*	$52	**$72**	$120
Property Taxes	*$/MW-day*	$6	**$5**	$2
Insurance	*$/MW-day*	$19	**$15**	$6
Non-Fuel Variable Costs	*$/MWh*	$2.36	$2.71	$2.60
Operating Costs	*$/MWh*	$0.75	$0.52	$0.94
Maintenance Adder	*$/MWh*	$1.61	$2.19	$1.66

Notes and Sources: gross costs are expressed in 2022 dollars per nameplate MW. 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 firm gas transportation service. The estimated maintenance adder costs per MWh are variable based on the capacity factor. The maintenance adders assume a 62% capacity factor.

E. Simple-Cycle Combustion Turbines

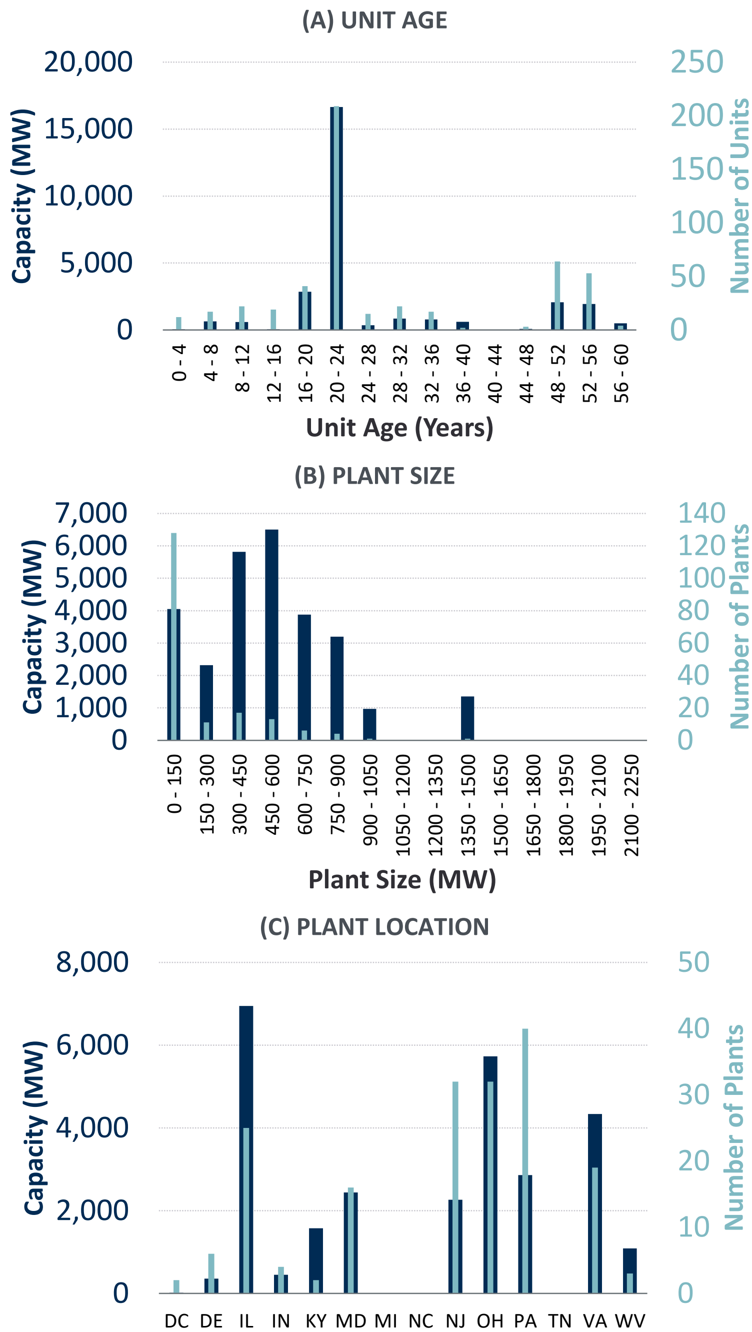
Simple-cycle combustion turbine (CT) plants include oil- and gas-fired CTs. Nearly all CTs were built around the early 2000s, but there is a wider range of sizes due to differences in the turbine technology and the number of turbines installed at each plant. There are many CT plants in the PJM fleet under 150 MW, but these plants cumulatively do not constitute a large amount of capacity compared to the larger plants in the 300–600 MW range. Most were built 20–24 years ago and the states with the most CTs include Ohio, Illinois, Pennsylvania, New Jersey, and Virginia. Unlike CCs, most CTs are not built with an SCR unit. Figure 5 below summarizes the age, size, locations, and pollution controls of these plants. The primary cost drivers for CTs are capacity, age, turbine type and configuration, and location.

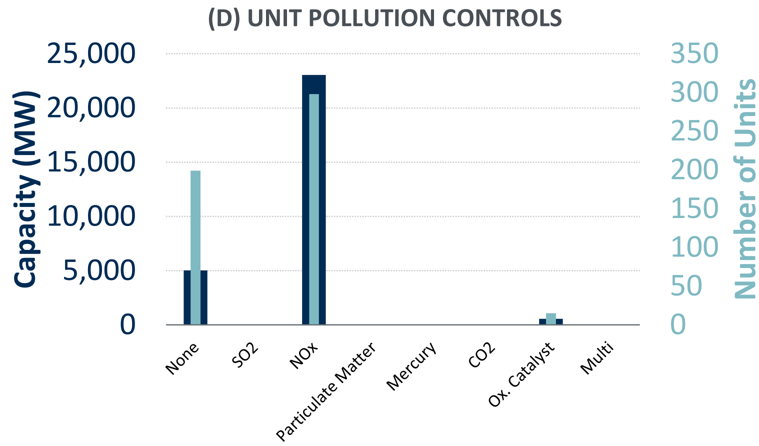
Determination of Representative Simple-Cycle Combustion Turbine Plant Characteristics

The median size of the fleet was 320 MW between the 300 MW to 450 MW size bin, as shown in Figure 5, Panel (B). We compared the median age of the CT fleet to the median age of the filtered population and found that both were approximately 20 years old. 20 years ago, F-class turbines were the predominant turbine technology. We then reviewed the location and configuration of the filtered population. Based on this approach, the representative CT plant is a 20-year-old 320 MW plant with two F-class turbines (2×160 MW) located in Illinois. Unlike CC plants, the majority of existing CT plants do not have firm gas transportation contracts up to EcoMax, according to PJM, so transportation costs were not included.

Because nearly all CT plants were built around the same time, we did not vary the age for the representative low-cost and representative high-cost plants and instead chose the low and high cost representative plant based on other factors. As shown in Figure 5 Panel (B), there are many plants that are less than 150 MW. To determine the representative low-cost plant, we filtered the 20-year-old CT fleet for plants smaller than 150 MW and determined the median capacity of this filtered population, which was 100 MW. Plants of this size were most frequently in Pennsylvania and typically use two LM600 aeroderivative turbines. Based on this approach, the representative high-cost CT is a 100 MW plant with two LM6000 aeroderivative turbines (2×50 MW) in Pennsylvania. To determine the representative low-cost plant, we filtered 20-year-old plants for sizes above 450 MW and found the median size of this filtered population, which was approximately 640 MW. These plants were most frequently in Illinois. Many plants of this size use several E-class turbines. Therefore, the representative low-cost CT is a 640 MW plant with eight E-class turbines (8×80 MW) in Illinois.

FIGURE 5: SIMPLE CYCLE COMBUSTION TURBINE FLEET CHARACTERIZATION





Notes and Sources: ABB, Energy Velocity Suite.

Cost Estimates for Representative Simple-Cycle Combustion Turbine Plants

To estimate costs, we reviewed cost estimates reported by the 2022 CONE Study, cost estimates from the EIA, and S&L's project database.[34] 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 estimates against proprietary data in S&L's project database 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.

The CT technologies included in the ACR study are significantly different from the selected single GE model 7HA.02 reference technology from the 2022 PJM CONE study, thus estimation of their property taxes and insurance was performed using the most representative references available in S&L's project database. Both property taxes and insurance were estimated based on a regression analysis of similar technologies with adjustments made for the size, type, and age of the CTs in this study. The high-cost plant is an aeroderivative, which is a fundamentally different technology, so costs were estimated from a different data set of similar plants.

The E-class and F-class turbines that operate 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. The LM6000 turbines however, would likely trigger major maintenance based on hours of operation therefore their maintenance adder is independent of the number of starts per year.

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34 2022 CONE Study; U.S. Energy Information Administration, Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2022, March 2022.

Table 6 below shows the resulting gross and variable costs for the simple cycle CT plants. The estimated gross costs of the representative CT are $52/MW-day and the variable costs are $4.29/MWh (in 2022 dollars). For the representative low-cost plant, the estimated gross costs are $43/MW-day and variable costs are $4.29/MWh. For the representative high-cost plant, estimated gross costs are $69/MW-day and variable costs are $5.39/MWh.

We also validated these costs against the Fixed O&M costs accepted in PJM's tariff as part of the 2022 CONE Study.[35] Accounting for subsequent updates in later affidavits, and deflating those estimates to 2022 dollars, the published Fixed Operation & Maintenance cost for the same area as the representative plant is $93/MW-day. This value included the cost of firm gas contracts, which amounted to approximately $49/MW-day in 2022 dollars. Excluding the firm gas cost, the 2022 CONE study Fixed Operation & Maintenance cost for new CTs becomes $44/MW-day, which is close to our representative plant gross costs of $52/MW-day. This difference is primarily attributable to the staffing assumptions made for the representative 2×160 MW existing plant compared to the 1×353 MW new plant in the CONE study.

TABLE 6: SIMPLE-CYCLE COMBUSTION TURBINE PLANTS GROSS AND NON-FUEL VARIABLE COSTS (2022 DOLLARS)

		Simple Cycle Combustion Turbine Plant		
	Units	**Representative Low-Cost Plant**	**Representative Plant**	**Representative High-Cost Plant**
Capacity	*Nameplate MW*	640	320	100
Gross Costs	*$/MW-day*	$43	**$52**	$69
Labor	*$/MW-day*	$6	**$10**	$23
Fixed Expenses	*$/MW-day*	$8	**$12**	$28
Property Taxes	*$/MW-day*	$16	**$16**	$3
Insurance	*$/MW-day*	$13	**$13**	$16
Non-Fuel Variable Costs	*$/MWh*	$4.29	$4.29	$5.39
Operating Costs	*$/MWh*	$0.42	$0.42	$0.97
Maintenance Adder	*$/MWh*	$3.88	$3.88	$4.43

Notes and Sources: gross costs are expressed in 2022 dollars per nameplate MW. Fixed Expenses in the gross costs includes preventive maintenance on auxiliary equipment (buildings, HVAC, water treatment, freeze protection, etc.), information technology, miscellaneous supplies, support services, and administrative and general. The maintenance adder assumes a 10% capacity factor with 12 hours per start. Actual major maintenance costs will vary with the number of starts, not strictly with MWh as expressed in this table, and will depend on actual duty cycles and maintenance agreement terms.

35 PJM Interconnection, L.L.C., Docket No. ER22-2984-000 Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters, pdf page 364.

F. Oil- and Gas-Fired Steam Turbines

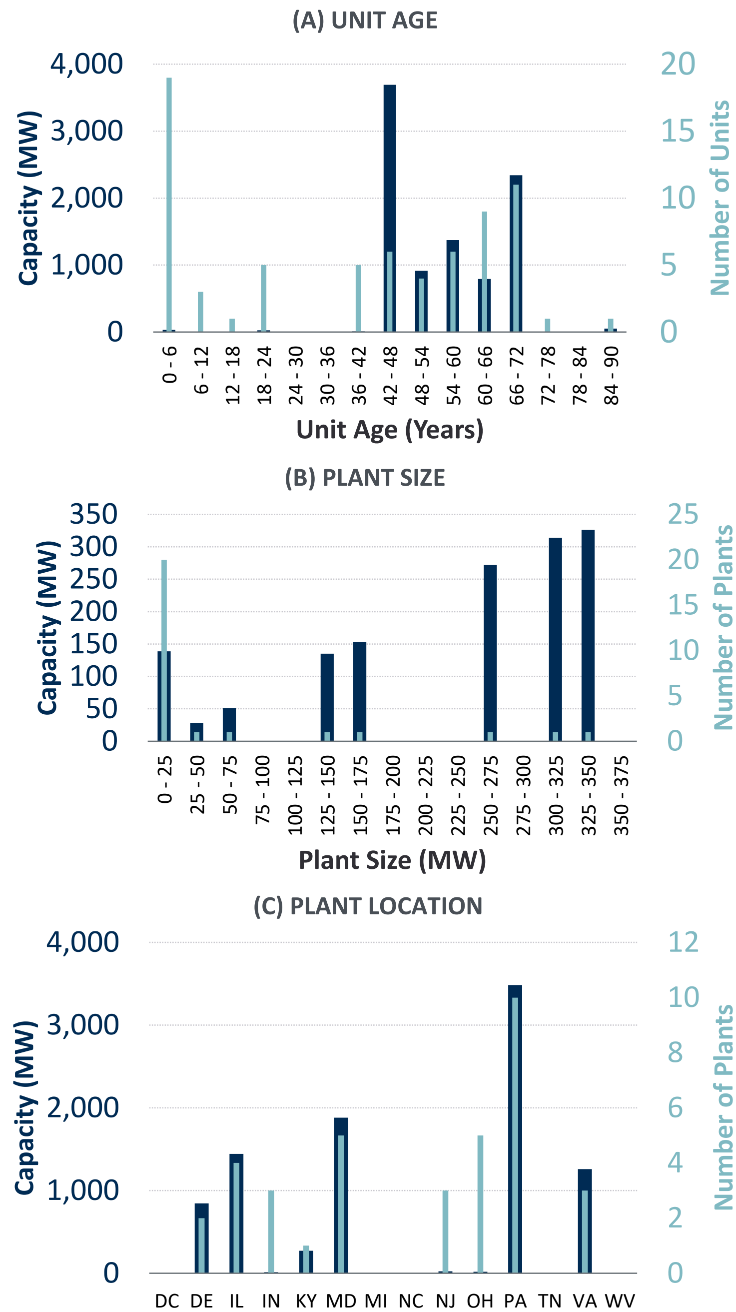
Steam turbine plants fueled by oil and gas (ST O&G) have a wide range of sizes. The majority of ST O&G plants are less than 25 MW but collectively do not contribute much capacity to the fleet. The average size is about 250 MW, which is skewed by a few very large plants on the order of 700 to 1,700 MW. Most of the larger plants and thus most of the capacity is located in Pennsylvania. Smaller plants are in Ohio, Maryland, and New Jersey. Ages of ST O&G plants range from 2–85 years old, with most capacity being 40–50 years old. Figure 6 below summarizes the age, size, locations, and pollution controls of these plants. The primary drivers of cost for ST O&G plants are age, capacity, location, and plant configuration.

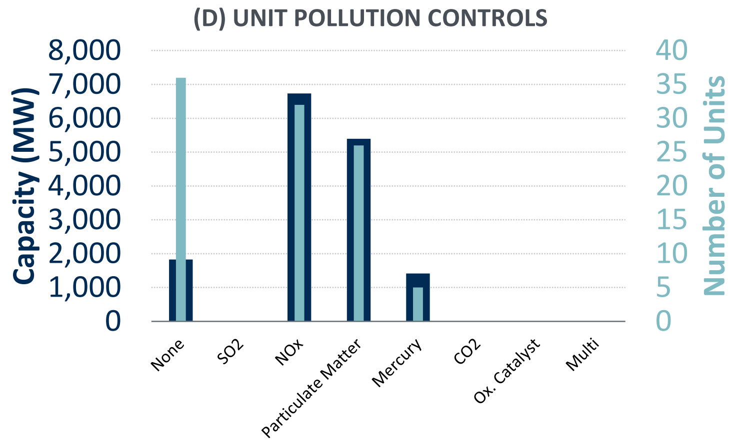
Determination of Representative Oil- and Gas-Fired Steam Turbine Plant Characteristics

The median MW in PJM's ST O&G fleet is in a 900 MW plant. We filtered the ST O&G fleet by this approximate size and compared the age of the filtered fleet with the age of the whole fleet. The age bucket contributing the most capacity to the ST O&G fleet are plants aged 42–48 years old, shown in Figure 6, Panel (A). We defined the representative age to be in this bucket (47-years old), which aligned with the ages of the filtered fleet. After further filtering for age, we ensured that the location of our representative plant reflected the location distribution of the whole fleet. The majority of existing ST O&G plants do not have firm gas transportation contracts up to EcoMax, according to PJM. Based on this approach, the representative ST O&G plant is a 47-year-old, 900 MW plant in Pennsylvania, without firm gas.

Since the majority of both ST O&G plants and capacity are in Pennsylvania, we did not vary the location for the representative low- and high-cost plants. To reflect the many small plants in the fleet, we filtered for plants under 900 MW. For plants in Pennsylvania under this size, we chose an approximate median of 350 MW to be the representative high-cost plant size. We then filtered the fleet for plants of approximately 350 MW and found that the median age of these smaller plants was 65 years old. Based on this approach, the representative high-cost ST O&G plant is a 65-year-old, 350 MW plant in Pennsylvania. To identify a representative low-cost plant, we began by selecting a larger plant to reflect economies of scale and filtered for plants above 900 MW. We determined a representative high-cost plant size of 1,300 MW. These larger plants have a median age of 47-years old. Based on this approach, the representative low-cost ST O&G plant is a 47-year old, 1,300 MW plant in Pennsylvania.

FIGURE 6: OIL AND GAS-FIRED STEAM TURBINE FLEET CHARACTERIZATION





Notes and Sources: ABB, Energy Velocity Suite. In Panel (B), the distribution is truncated at 375 MW to maintain legibility, but ST O&G plants range up to 1,700 MW with nine plants above 375 MW.

Cost Estimates for Representative Oil and Gas-Fired Steam Turbine Plant

To estimate the costs of the representative plants, we relied primarily on public cost information from the FERC Form 1, and S&L's project database.[36] We then developed the cost estimates for the representative plants accounting for differences in plant sizes, plant location, and ages based on regression analyses of data from S&L's project database and validated the results against proprietary data for similar plants in operation. For property taxes and insurance, we used the same survey approach as for coal described in Section III.C above, but in this case based on actual ST O&G plants in PJM. We again estimated insurance costs at three times as high as property taxes. Both turned out to be very small.

Table 7 below shows that the estimated total gross costs for the representative plant are \$64/MW-day (in 2022 dollars) and variable costs are \$5.81/MWh. For the representative low-cost ST O&G plant, estimated gross costs are \$53/MW-day and variable costs are \$5.51/MWh. For the smaller 350 MW representative high-cost plant, gross costs are significantly higher, at \$102/MW-day, due to the reduced economies of scale; variable costs are \$16.26/MWh.

[36] Federal Energy Regulatory Commission, FERC Form 1, Plant Cost Data, 2010 through 2019.

TABLE 7: STEAM OIL & GAS PLANT GROSS AND NON-FUEL VARIABLE COSTS (2022 DOLLARS)

		Oil and Gas-Fired Steam Turbine Plant		
	Units	**Representative Low-Cost Plant**	**Representative Plant**	**Representative High-Cost Plant**
Capacity	*Nameplate MW*	1,300	900	350
Gross Costs	*$/MW-day*	$53	**$64**	$102
Labor	*$/MW-day*	$21	**$26**	$43
Fixed Expenses	*$/MW-day*	$26	**$32**	$53
Property Taxes	*$/MW-day*	$1.6	**$1.6**	$1.6
Insurance	*$/MW-day*	$4.8	**$4.8**	$4.8
Non-Fuel Variable Costs	*$/MWh*	$5.51	$5.81	$16.26
Operating Costs	*$/MWh*	$1.19	$1.19	$1.19
Maintenance Adder	*$/MWh*	$4.32	$4.62	$15.07

Notes and Sources: gross costs are expressed in 2022 dollars per nameplate MW. Fixed Expenses include preventive maintenance on auxiliary equipment (buildings, HVAC, water treatment, freeze protection, etc.), information technology, miscellaneous supplies, support services, administrative and general expenses. The estimated maintenance adder costs per MWh are variable based on the capacity factor. The maintenance adders for the low-cost and representative plant assume a 20% capacity factor and the maintenance adder for the high-cost plant assumes a 10% capacity factor.

G. Onshore Wind Plants

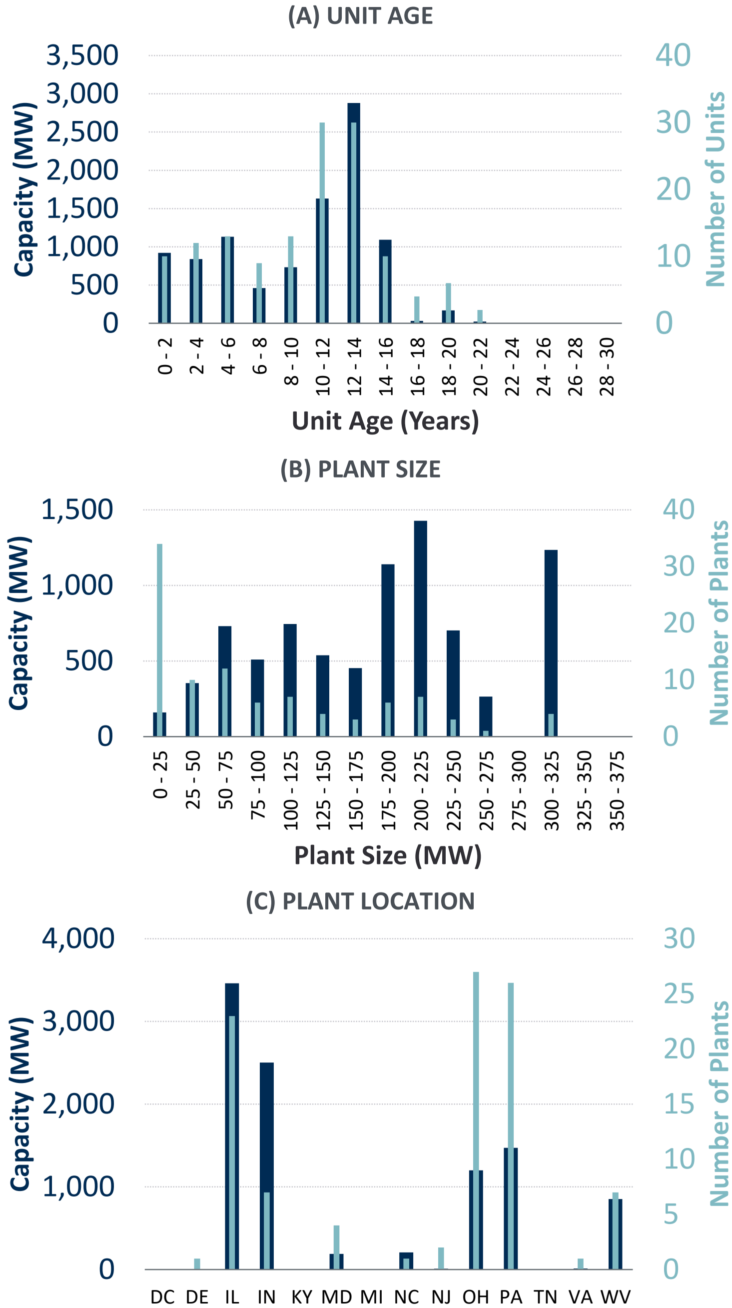
Over the past 15 years, nearly 10,000 MW of onshore wind plants have been built in PJM. The average size is 100 MW, which is skewed by the numerous small plants (less than 25 MW); however, 17 are at least 200 MW as shown in Figure 7 Panel (B) below. Plants larger than 100 MW make up of over 80% of the total capacity in PJM, and most are located in Illinois and Indiana, while smaller plants are located in Pennsylvania and Ohio. Ages of wind plants range from less than a year old to 20 years old. Figure 7 below summarizes the age, size, and locations of these plants. The primary cost drivers for wind plants tend to be the size and location, then the age and density of individual wind turbines at a plant site.

Determination of Representative Onshore Wind Plant Characteristics

To determine the representative onshore wind plant, we filtered the wind fleet for plants greater than 100 MW (since these plants contribute to more than 80% of the total capacity) and determined the median plant size of this filtered population, which was approximately 200 MW. We then found the median age of this filtered fleet, which was approximately 12 years old and reviewed the most frequent location, which was Illinois. Based on this approach, the representative onshore wind plant is a 12-year-old, 200 MW plant in Illinois.

To account for the size and age variation of the fleet, we varied these characteristics when determining the representative low-cost and representative high-cost plant. We filtered the wind fleet for plants less than 100 MW and determined a median size of 30 MW for the representative high-cost plant. We then found the median age of this filtered fleet, which was similar to the age for representative plants, so we maintained a 12-year-old plant. The most frequent location of these smaller plants was Pennsylvania. Based on this approach, the representative high-cost plant is a 12-year-old 30 MW plant in Pennsylvania. We increased the capacity for the representative low-cost plant to be a 300 MW plant, the median size for plants above 200 MW. By filtering for larger plants, we determined that the median age was slightly younger than the representative high-cost plant (10 years old) and the most frequent location was in Illinois. Based on this approach, the representative low-cost plant is a 10-year-old 300 MW plant in Illinois.

FIGURE 7: ONSHORE WIND PLANTS FLEET CHARACTERIZATION



Notes and Sources: ABB, Energy Velocity Suite. In panel (B), the distribution is truncated at 375 MW to maintain legibility, but wind plants range up to about 900 MW with two plants larger than 375 MW.

Cost Estimates for Representative Onshore Wind Plants

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.[37] We then developed the cost estimates for the representative plants accounting for differences in MW capacity, plant location, and ages relative to the representative plants based on regression analyses of data from S&L's project database and validated the results against proprietary data for similar plants in operation.

The representative wind plants were assumed to pay property taxes or have a negotiated payment in lieu of taxes (PILOT) agreement with the local jurisdiction. S&L found these costs to be accurately represented as a fixed fraction of the total fixed operating expenses based on S&L's project database for similar sized wind plants. Insurance includes liability insurance, property insurance, and equipment insurance, and the cost of insurance will depend on the location's specific risks. Values in the table below represent S&L's estimates based on systems in locations without any atypical regional risks, and have not been adjusted for any other regional cost sensitivities.

Table 8 below shows resulting gross costs for the representative plant of $147/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 costs, with no variable costs. The representative low-cost plant's estimated gross costs are $140/MW-day, and the representative high-cost plant's gross costs are $204/MW-day.

[37] National Renewable Energy Laboratory (NREL), 2022 Annual Technology Baseline, 2022; U.S. Energy Information Administration, Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2022, March 2022.

TABLE 8: ONSHORE WIND PLANT GROSS AND NON-FUEL VARIABLE COSTS (2022 DOLLARS)

		Onshore Wind Plant		
	Units	**Representative Low-Cost Plant**	**Representative Plant**	**Representative High-Cost Plant**
Capacity	*Nameplate MW*	300	200	30
Gross Costs	*$/MW-day*	$140	**$147**	$204
Labor	*$/MW-day*	$26	**$27**	$50
Fixed Expenses	*$/MW-day*	$95	**$99**	$126
Property Taxes	*$/MW-day*	$12	**$13**	$17
Insurance	*$/MW-day*	$8	**$8**	$11
Non-Fuel Variable Costs	*$/MWh*	$0.00	$0.00	$0.00
Operating Costs	*$/MWh*	$0.00	$0.00	$0.00
Maintenance Adder	*$/MWh*	$0.00	$0.00	$0.00

Notes and Sources: gross costs are expressed in 2022 dollars per nameplate MW. Fixed Expenses include scheduled and unscheduled wind turbine and balance-of-plant maintenance, parts and consumables, operations monitoring, land lease, general and administrative costs.

H. 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. All of the solar PV plants have been built in the past 15 years, with the most capacity added in Virginia, New Jersey, and North Carolina. Figure 8 below summarizes the age, size, and locations of these plants.

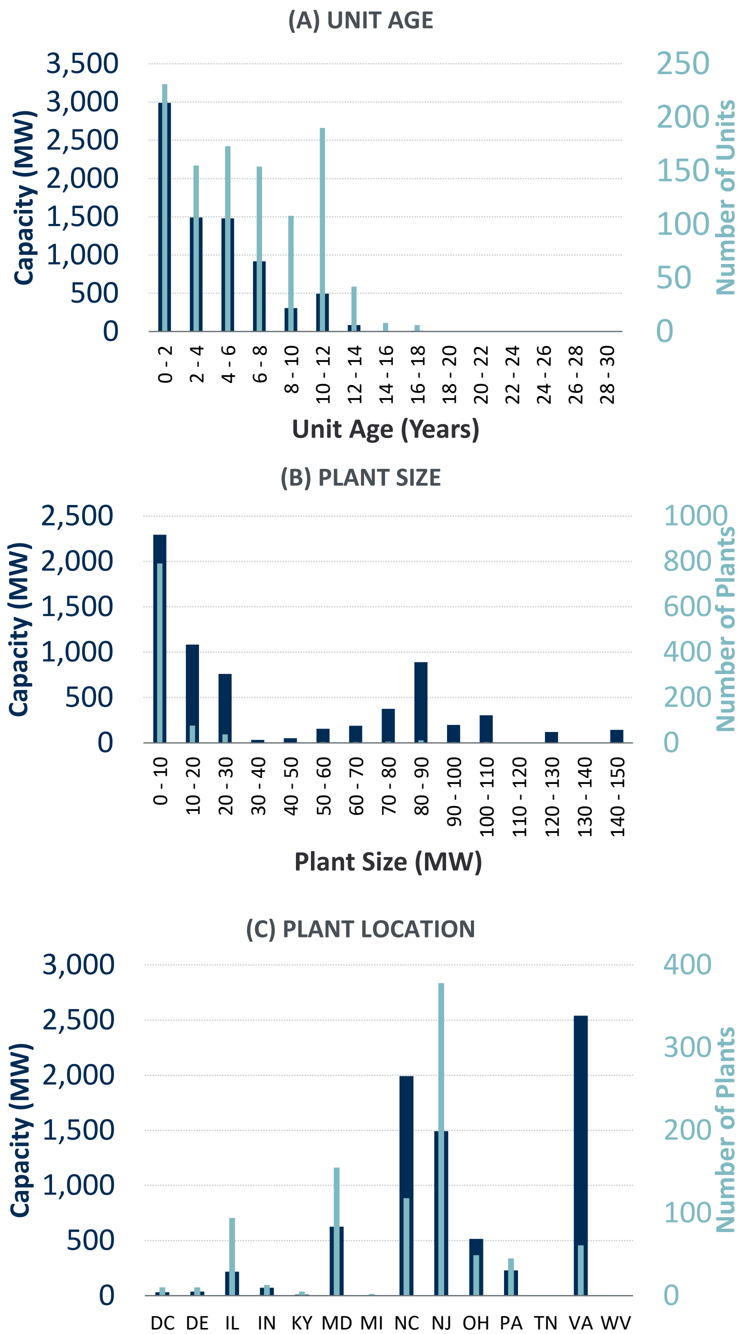
The age of a solar plant influences the plant capacity since more recent plants have tended to be built larger than in the past. Location also impacts the costs of solar PV plants due to differences in labor costs and property taxes.

Determination of Representative Large Scale Solar Photovoltaic Plant Characteristics

Because the age of a solar plant influences the plant size, to choose a representative solar plant we first determined the median age of the fleet, which was 5 years old. We filtered the solar fleet data by this age and compared the median plant size of this population to the median plant size of the fleet, which was approximately 10 MW. Then we reviewed the location of the fleet and the population with age and size filters. Based on this approach, the representative plant is a 10 MW single-axis tracking solar PV plant in New Jersey built 5 years ago.

For the representative high and low-cost plants, we varied size and age as the cost differentiators. The solar fleet is largely small plants 10 MW and under. For higher-cost plants under 10 MW, the median capacity is 2 MW. We filtered the solar fleet for plants of this size and determined these plants were slightly older than our representative plant (7 years old). We then analyzed the location of these smaller plants and found that they aligned with the most common location of the overall fleet, so we maintained the location as New Jersey. The representative low-cost plant would be much larger, but we avoided plants less than 5 years old because of the maintenance warranties that apply to younger plants and are not representative of the entire fleet. We filtered the entire fleet data by plants between 80–90 MW. The larger plants were most frequently located in North Carolina. Based on this approach, the representative low-cost plant is an 80 MW 5-year-old plant in North Carolina.

FIGURE 8: LARGE SCALE SOLAR FLEET CHARACTERIZATION



Notes and Sources: ABB, Energy Velocity Suite. In panel (B), the distribution is truncated at 150 MW to maintain legibility, but Solar PV plants range up to 500 MW with five plants larger than 150 MW.

Cost Estimates for Representative Large Scale Solar Photovoltaic Plants

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.[38] We then developed the cost estimates for the representative solar PV plants accounting for differences in the solar panel type, tracking type, plant size, location, and ages relative to the representative plants based on regression analyses of data from S&L's project database and validated the results against proprietary data for similar plants in operation.

The representative solar plants were assumed to pay property taxes or have a negotiated payment in lieu of taxes (PILOT) agreement with the local jurisdiction. S&L found these costs to be accurately represented as a fixed fraction of the overnight capital cost of the installation based on S&L's project database for similar sized solar plants. Insurance includes liability insurance, property insurance, and equipment insurance, and the cost of insurance will depend on the location's specific risks such as potential for damage from hail, or other natural disasters. Values in the table below represent S&L's estimates based on systems in locations without any atypical regional risks, and have not been adjusted for any other regional cost sensitivities.

Table 9 below shows that we estimated gross costs for the representative solar PV plant to be $70/MW-day (in 2022 dollars). Similar to onshore wind plants, 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. We estimated the representative low-cost gross costs to be $65/MW-day and the representative high-cost plant to be $74/MW-day.

[38] National Renewable Energy Laboratory (NREL), 2022 Annual Technology Baseline, 2022; U.S. Energy Information Administration, Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2022, March 2022.

TABLE 9: SOLAR PV PLANT GROSS AND NON-FUEL VARIABLE COSTS (2022 DOLLARS)

		Large Scale Solar Photovoltaic Plant		
	Units	Representative Low-Cost Plant	Representative Plant	Representative High-Cost Plant
Capacity	*Nameplate MW*	80	10	2
Gross Costs	*$/MW-day*	$65	**$70**	$74
Labor	*$/MW-day*	$20	**$22**	$25
Fixed Expenses	*$/MW-day*	$30	**$33**	$36
Property Taxes	*$/MW-day*	$5	**$4**	$4
Insurance	*$/MW-day*	$10	**$10**	$10
Non-Fuel Variable Costs	*$/MWh*	$0.00	$0.00	$0.00
Operating Costs	*$/MWh*	$0.00	$0.00	$0.00
Maintenance Adder	*$/MWh*	$0.00	$0.00	$0.00

Notes and Sources: gross costs are expressed in 2022 dollars per nameplate MW. Fixed Expenses include scheduled and unscheduled PV and BOP equipment maintenance, vegetation management, module cleaning, major maintenance reserve funds, land lease, general and administrative costs.